The Narragansett Electric Company
d/b/a National Grid

2020 GAS COST RECOVERY

Testimony and Attachments of:

Gas Supply Panel: Elizabeth D. Arangio, MaryBeth M. Carroll & Samara Jaffe

Ryan M. Scheib & Michael J. Pini

Theodore E. Poe, Jr.

REDACTED

September 1, 2020

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 5066

Submitted by:
nationalgrid

Filing Letter & Motion

nationalgrid

Raquel J. Webster
Senior Counsel

September 1, 2020

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 5066 – 2020 Gas Cost Recovery Filing

Dear Ms. Massaro:

I have enclosed 10 copies of National Grid's[1] annual Gas Cost Recovery (GCR) filing, which the Company is submitting pursuant to the Gas Cost Recovery Clause in National Grid's gas tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A. The GCR filing reflects the customer class-specific factors necessary for National Grid to collect sufficient revenues to recover projected gas costs for the period November 1, 2020 through October 31, 2021.

This filing consists of the pre-filed testimony and attachments of Elizabeth D. Arangio, MaryBeth M. Carroll, Samara A. Jaffe, Ryan M. Scheib, Michael J. Pini, Theodore E. Poe, Jr., and John M. Protano. Ms. Arangio, Ms. Carroll, and Ms. Jaffe provide joint testimony relating to the estimated gas costs, assignments of pipeline capacity to marketers, and other items relating to the Company's proposed 2020-21 GCR factors. In addition, their testimony discusses modifications the Company has made to its portfolio for the 2020-21 GCR period. In their joint testimony, Mr. Scheib and Mr. Pini describe the development of the GCR factors proposed for effect November 1, 2020 and provide a bill impact analysis relative to those proposed factors. Mr. Poe's testimony provides support for the underlying wholesale and retail forecasts that National Grid uses to estimate gas costs in this filing. Mr. Protano's testimony discusses the results of the Gas Procurement Incentive Plan and the Natural Gas Portfolio Management Plan for the period April 1, 2019 through March 31, 2020. His testimony also introduces an exhibit, which illustrates the impact of current financial hedges for the upcoming period of November 2020 through October 2021 in the Gas Procurement Incentive Plan.

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As described in the joint testimony of Messrs Scheib and Pini, based on the GCR factors proposed for effect November 1, 2020 through October 31, 2021, an average residential heating customer using 845 therms per year will experience a total bill increase of approximately $101.47, or a 7.9 percent increase from the existing rates. This increase is comprised of an increase of $47.83 in the GCR-related factors; an increase of $50.60 in the Distribution

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

Adjustment Charge-related factors, filed on August 1, 2020 and supplemented today under separate cover in Docket No. 5040; and an increase of $3.04 in Gross Earnings Tax.

This filing also contains a Request for Protective Treatment of Confidential Information in accordance with Rule 810-RICR-00-00-1.3(H) 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 certain confidential gas-cost pricing information and commercial contract terms which are provided in Attachments GSP-1 to the prefiled joint direct testimony of the Gas Supply Panel and Attachments RMS/MJP-1, RMS/MJP-2, and RMS/MJP-5 to the prefiled joint direct testimony of Messrs. Scheib and Pini.

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.

Thank you for your attention to this matter. If you have any questions, please contact me at 781-907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 5066 Service List
Leo Wold, Esq.
John Bell, Division
Al Mancini, Division (w/Confidential Excel files via E-gress Switch)
Jerome D. Mierzwa, Division Consultant (w/Confidential Excel files via E-gress Switch)

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2020	)	Docket No. 5066

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

National Grid[1] respectfully requests that the Rhode Island Public Utilities Commission (PUC) grant protection from public disclosure certain confidential, competitively sensitive, and proprietary information submitted in this proceeding, as permitted by 810-RICR-00-00-1.3(H) (Rule 1.3(H)) of the PUC's Rules of Practice and Procedure and R.I. Gen. Laws § 38-2-2(4)(B). The Company also respectfully requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to Rule 1.3(H)(2).

I. BACKGROUND

On September 1, 2020, the Company submitted its 2020 Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. The GCR filing includes confidential gas cost pricing information and contract terms, which are provided in (1) Attachment GSP-1 to the pre-filed joint direct testimony of the Elizabeth D. Arangio, MaryBeth M. Carroll and Samara A. Jaffe, referred to as the Gas Supply Panel; and (2) Attachments RMS/MJP-1, RMS/MJP-2, and RMS/MJP-5 to the pre-filed joint direct testimony of Ryan M. Scheib and Michael J. Pini. In

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

accordance with Rule 1.3(H)(3), National Grid has provided a redacted public version of the GCR filing and an unredacted, confidential version.

Therefore, the Company requests that, pursuant to Rule 1.3(H), the PUC afford confidential treatment to the gas cost pricing information and contract terms contained in the following: (1) Attachment GSP-1 to the prefiled joint direct testimony of the Gas Supply Panel; and (2) Attachments RMS/MJP-1, RMS/MJP-2, and RMS/MJP-5 to the prefiled joint direct testimony of Messrs. Scheib and Pini.

II. LEGAL STANDARD

Rule 1.3(H) 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 the 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*, 774 A.2d 40 (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 and confidential contract terms – which are provided in Attachment GSP-1 to the Gas Supply Panel testimony, and Attachments RMS/MJP-1, RMS/MJP-2, and RMS/MJP-5 to the prefiled joint direct testimony of Messrs. Scheib and Pini – are confidential and privileged information of the type that National Grid 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.

[SIGNATURE ON NEXT PAGE]

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID

By its attorney,

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Dated: September 1, 2020

Certificate of Service

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

_________________________________ September 1, 2020

Docket No. 5066 – National Grid – 2020 Annual Gas Cost Recovery Filing (GCR) - Service List as of 9/1/2020

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Testimony of
Gas Supply Panel

JOINT DIRECT TESTIMONY

OF

GAS SUPPLY PANEL

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I. Introduction

Q. Please identify the members of the Gas Supply Panel.

A. The Gas Supply Panel ("Panel") consists of Elizabeth D. Arangio, MaryBeth M. Carroll, and Samara A. Jaffe.

Elizabeth D. Arangio

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

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

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

A. I am the Director of Gas Supply Planning for National Grid USA Service Company, Inc. In this position, I am responsible for overseeing the resource portfolio of The Narragansett Electric Company d/b/a National Grid (the Company). In addition, I am responsible for gas supply planning for the resource portfolios of National Grid's New York and Massachusetts subsidiaries. I also manage National Grid's gas Customer Choice programs. In this testimony, references to the "Company" relate solely to The Narragansett Electric Company.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the University of Massachusetts in 1991 with a Bachelor of Arts in Business Administration. In 1995, I graduated from Bentley College with a Masters of Business Administration.

From 1991 to 1994, I worked as a Gas Accounting Analyst in the Marketing Operations Department at Algonquin Gas Transmission Company. In 1994, I joined Boston Gas Company as a Gas Supply Analyst. In 1997, I was promoted to Group Leader Transportation Services. In this role, I was responsible for managing all activities associated with the Customer Choice program. In 1998, I was promoted to Director of Gas Acquisition and Transportation Services. In this role, I was responsible for the administration of the gas-resource portfolio and Customer Choice program in Massachusetts and, as of 2000, the resource portfolio of EnergyNorth Natural Gas, Inc., in New Hampshire. In February 2004, I assumed the additional responsibility of gas supply planning for the former KeySpan Corporation's New York and Long Island resource portfolios. Following the acquisition of KeySpan Corporation by National Grid plc, I assumed the added responsibility for the gas resource portfolios in upstate New York and Rhode Island. In August 2018, I assumed the added responsibility for all of National Grid's gas Customer Choice programs.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Northeast Gas Association and the New England-Canada Business Council.

Q. Have you previously testified before the PUC or any other regulatory commissions?

A. Yes. I have testified before the PUC on numerous occasions, most recently in support of the Company's 2019 Gas Cost Recovery (GCR) filing in Docket No. 4963. I have also testified before the Massachusetts Department of Public Utilities, the New Hampshire Public Utilities Commission, and the State of New York Department of Public Service.

<u>MaryBeth M. Carroll</u>

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

A. My name is MaryBeth M. Carroll. My business address is National Grid, 100 East Old Country Road, Hicksville, New York 11801.

Q. Please describe your business position and responsibilities.

A. I am a Manager of Gas Supply Planning with responsibility for The Narragansett Electric Company gas supply resource portfolio. I am also responsible for planning for the gas resource portfolio of National Grid's upstate NY subsidiary.

Q. Please summarize your educational background and professional experience.

A. I graduated from Kalamazoo College in 2005 with a Bachelor of Arts in Biology. In 2013, I graduated from Dowling College with a Master of Business Administration. From 2005 to 2008, I worked as a Gas Supply Planner at KeySpan with responsibilities for the downstate New York subsidiaries. Following National Grid's acquisition of KeySpan, I assumed additional responsibilities for Niagara Mohawk's and the Massachusetts subsidiaries' gas supply portfolios. In 2013, I was promoted to Manager of Gas Supply Planning for the Niagara Mohawk portfolio. In 2019, I assumed additional responsibilities for National Grid's Rhode Island subsidiary.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I testified before the PUC in support of the Company's 2019 GCR filing in Docket No. 4963. I have also provided testimony to the New York Public Service Commission on behalf of the Niagara Mohawk Power Corporation.

<u>Samara A. Jaffe</u>

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

A. My name is Samara A. Jaffe. My business address is National Grid, 100 East Old Country Road, Hicksville, NY 11801.

Q. Please state your business position and responsibilities.

A. I am the Lead Program Manager of Gas Contracting, Compliance and Hedging for National Grid USA Service Company, Inc. In this position, I am responsible for the acquisition of long-term gas supply and pipeline capacity; gas contract management; intervention in proceedings before the Federal Energy Regulatory Commission ("FERC"); and compliance with FERC regulations in connection with National Grid's gas trading activities for National Grid's gas distribution companies in Massachusetts, Rhode Island, and New York. In this proceeding, I am providing testimony on behalf of The Narragansett Electric Company.

Q. Please summarize your educational background and your professional experience.

A. I graduated from the State University of New York at Buffalo in 2006 with a Bachelor of Arts degree in Chemistry. In 2012, I graduated from Touro Law Center with a Juris Doctor. In 2016, I graduated from Dowling Institute with a Master of Business Administration. I joined KeySpan in 2007 as a Natural Gas Scheduler with responsibility for scheduling natural gas on interstate pipelines utilized by the Company to meet the requirements of its wholesale firm gas customers. After graduating from Touro Law Center in 2012, I accepted my current position with the Company.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I most recently testified before the PUC in support of the Company's 2019 GCR filing in Docket No. 4963. I have also testified numerous times before the Massachusetts Department of Public Utilities on behalf of Boston Gas.

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

A. Our testimony provides support for the estimated gas costs, assignments of pipeline capacity to marketers, and other items relating to the Company's proposed 2020-21 GCR factors. In addition, our testimony discusses modifications that the Company has made to its portfolio for the 2020-21 GCR period.

Q. Are you sponsoring attachments to your testimony?

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

Attachment GSP-1	Projected Gas Costs and Assignment of Pipeline Capacity – **CONFIDENTIAL Information**
Attachment GSP-2	NYMEX Strip Comparison & Forward Curves
Attachment GSP-3	Rule Curves
Attachment GSP-4	Customer Choice Storage Pricing
Attachment GSP-5	RFPs for PXP Phases I, II, III
Attachment GSP-6	RFP for AMA Dawn Waddington to Zone 6 Lincoln
Attachment GSP-7	RFPs for AMA Dracut to Citygate & Dracut Supply
Attachment GSP-8	RFP for AMA Columbia Gas Transmission ("TCo") - FSS, ST & FTS Assets

II. Projected Gas Costs

Q. What commodity prices were used to develop the proposed GCR factors?

A. The proposed GCR factors are based on the New York Mercantile Exchange (NYMEX) forward curve as of the close of trading on August 6, 2020. The NYMEX forward curve, which represents the current value of natural gas at the Henry Hub for delivery in the future, is the baseline price assumption for the GCR. The Company then adjusts this baseline with regional basis forward curves as of August 6, 2020 to estimate prices at the locations at which it expects to purchase gas supplies. The GCR factors also reflect underground storage and liquefied natural gas ("LNG") inventory costs as of August 1, 2020 and the projected cost of purchasing gas through the remainder of the underground and LNG injection season. Attachment GSP-1 page 1 of 19 provides a summary of gas costs by major cost categories; pages 2 of 19 through 13 of 19 shows the cost detail by supply source.

Q. How does the NYMEX forward curve referenced in the GCR year compare to last year's forward curve?

A. Attachment GSP-2 is a graph that compares NYMEX pricing from August 1, 2019 utilized in last year's GCR filing to NYMEX pricing from August 6, 2020 used in this current filing. On average, the August 6, 2020 NYMEX strip is $0.445, or 17.8 percent, higher compared to the August 1, 2019 NYMEX strip during the peak season of

November through March. During the off-peak season of April through October, the August 6, 2020 NYMEX strip is on average $0.274, or 11.4 percent, higher compared to the August 1, 2019 NYMEX strip. Overall, the August 6, 2020 NYMEX strip is an average of $0.345, or 14.1 percent, higher compared to the August 1, 2019 NYMEX strip.

Q. What normal heating season and normal year load is the Company planning for in 2020-21 as compared to last year's volumes?

A. A comparison of the normal heating season and normal year load forecasts for 2019-20 and 2020-21 is provided in the table below.

2019/2020 and 2020/2021 Normal Forecast Comparison

Normal Heating Season (November - March)	2019/20 Forecast	2020/21 Forecast	Delta	Delta %
Total Normal Heating Season (Sales + Transportation)	26,061,542	25,505,086	(556,456)	-2.1%
Normal Heating Season - Sales	20,654,948	20,908,961	254,013	1.2%
Normal Heating Season - Transportation	5,406,594	4,596,125	(810,468)	-15.0%

Normal Year	2019/20 Forecast	2020/21 Forecast	Delta	Delta %
Total Normal Year (Sales + Transportation)	36,869,436	36,152,015	(717,422)	-1.9%
Normal Year - Sales	28,178,961	28,669,989	491,028	1.7%
Normal Year - Transportation	8,690,475	7,482,026	(1,208,449)	-13.9%

The forecast filed in Docket No. 4963 against this year's forecast.
Volumes include only customers utilizing Company assets.
Volume are in dekatherms (Dth)

Q. What design day, design heating season, and design year load is the Company planning for in 2020-21 as compared to last year's volumes?

A. While the GCR factors are based on customer requirements assuming normal weather, a comparison of the design day, design heating season, and design year load forecasts for 2019-20 and 2020-21 is provided in the table below.

2019/2020 and 2020/2021 Design Forecast Comparison

Design Day	2019/20 Forecast	2020/21 Forecast	Delta	Delta %
Total Design Day (Sales + Transportation)	388,746	383,384	(5,362)	-1.4%
Design Day - Sales	323,811	326,920	3,109	1.0%
Design Day - Transportation	64,935	56,464	(8,471)	-13.0%

Design Heating Season (November - March)	2019/20 Forecast	2020/21 Forecast	Delta	Delta %
Total Design Heating Season (Sales + Transportation)	29,822,626	29,490,075	(332,551)	-1.1%
Design Heating Season - Sales	23,842,974	24,373,987	531,013	2.2%
Design Heating Season - Transportation	5,979,652	5,116,088	(863,564)	-14.4%

Design Year	2019/20 Forecast	2020/21 Forecast	Delta	Delta %
Total Design Year (Sales + Transportation)	41,409,931	40,914,912	(495,019)	-1.2%
Design Year - Sales	31,975,988	32,767,167	791,179	2.5%
Design Year - Transportation	9,433,943	8,147,745	(1,286,198)	-13.6%

The forecast filed in Docket No. 4963 against this year's forecast.
Volumes include only customers utilizing Company assets.
Volume are in dekatherms (Dth)

Q. Did the Company perform a cold snap analysis for the 2020-21 winter season?

A. Yes. As part of its annual portfolio planning process, the Company reviewed a cold snap scenario, in addition to design day and design year scenarios for the upcoming winter season. The cold snap analysis is set forth in the Company's Long-Range Resource and Requirements Plan for the Forecast Period 2020/21 to 2024/25 dated June 30, 2020 (Docket No. 5043) (the LRP).

Q. In addition to planning for design day, design year and cold snap requirements, is the Company continuing to plan to meet peak hour requirements?

A. Yes. The Company is continuing to plan for peak hour requirements in addition to design day, design year, and cold snap requirements. As the Company explained in RIPUC Docket No. 4963, on January 29, 2019, Algonquin Gas Transmission, LLC (AGT), one of the interstate pipeline companies that serves the Company, notified the Company (and all AGT customers served by AGT's G Lateral pipeline) that, during peak periods, it may issue orders under its tariff requiring local distribution companies, including the Company, to limit their hourly takes to calculated hourly flow limits at each take station. Under the Company's contracts with AGT, those calculated hourly flow limits are either 1/24th or 6% of the daily MDQ under each contract. The total calculated hourly flow limits for each take station are then equal to the combined calculated hourly flow limit for all contracts providing deliveries to each take station. The Company continues to plan as though AGT may issue a similar notice in the future, or even issue the types of orders described in the January 29, 2019 notice without first issuing another warning. Accordingly, the Company is making planning decisions so that it is able to comply with any such future orders. Because the Company's peak hour is greater than the daily 1/24th and 6% combination, the Company will now need to ensure that it has sufficient supply resources to meet the peak hour requirements of its customers.

Q. How does the Company determine peak hour requirements?

A. Once the design day sendout requirement for all firm customers[1] is established, the Company converts this sendout to a peak hour based on a 5% peak-hour factor (i.e. the peak hour requirement represents 1/20th of the peak day requirement). The Company then applies the peak-hour requirement to its Synergi network analysis modeling software by means of growth factors generated from the zonal (i.e., zip code) forecast. The resulting peak-hour Synergi models are used to perform various analyses necessary for distribution system operations (e.g., regulator pressure settings, LNG requirements) and capital planning.

[1] This design day requirement reflects total firm load, including FT- 1 capacity exempt design day load as well as the FT-1 capacity eligible storage and peaking design day load.

Q. How is the Company planning to allocate the costs of supplies or other assets necessary to meet the peak hour requirements of its customers?

A. Since the peak hour shortfall that exists without incremental resources cannot be attributed to any single party or customer, the Company believes that all firm customers should share the costs of the reliability resources secured to cure this shortfall. The Division's witness's testimony in Docket No. 4963 supported an allocation of the fixed costs of these assets across sales, FT-2 and FT-1 customers, and this recommendation was approved by the PUC. The Company's Distribution Adjustment Charge (DAC) is applicable to all firm customers, and inclusion of these costs in the DAC provides an equitable distribution to and collection from customers.

Because the DAC now captures fixed costs associated with the peak hour requirements, the Company has reflected a corresponding reduction in the fixed costs of the gas supply portfolio presented in the GCR. To determine whether an asset is used to meet design season, design day or design hour requirements, the Company will consider factors beyond cost, including the operational flexibility of the asset. When an asset cannot be allocated to marketers without compromising flexibility and reliability, the Company will retain control of the asset to meet the hourly peak requirement. For the 2020/21 year, these hourly peaking resources include; portable LNG equipment at Portsmouth and Cumberland sites, the LNG required at these sites, and city gate delivered supplies secured from Constellation and delivered via AGT. These costs are detailed on page 12 of GSP-1.

Q. Has the Company made other changes to its forecasting and planning processes that impact costs to customers? Please explain why any changes were made.

A. Yes. To address an issue raised by the Division's witness in Docket No. 4963 concerning cost assignment to marketers for various capacity paths, the Company is also proposing changes to the Customer Choice program effective November 1, 2020. While these proposed changes are detailed in a separate filing, the Company has prepared its LRP and GCR forecasts with its proposal in effect. The proposed capacity path assignments are presented in Pages 18 and 19 of Exhibit GSP-1 as well as a comparison of the average fixed costs for all transportation paths in the Company's portfolio and the resulting average fixed costs to marketers and sales customers under the proposal.

To develop its proposal, the Company consulted with the Division and the marketers, and the Company believes its proposal provides appropriate cost allocation and reliability benefits to all customers.

Since the Company's proposal eliminates the need for the surcharge/credit that is assessed to marketers to ensure they are paying the company average fixed and variable cost, which has been historically included in the GCR, the Company does not plan to include a reconciliation of this surcharge/credit in this or future GCR forecasts. However, there is a need to reconcile marketer costs for 2019/20. The Company is proposing a one-time bill adjustment to marketers to account for this final reconciliation.

Q. How are projected gas costs calculated?

A. Consistent with prior filings, projected gas costs are calculated using the SENDOUT® model to perform a dispatch optimization of the portfolio of gas supply, pipeline transportation, underground storage, and peaking supplies. SENDOUT® allows the Company to determine the optimal dispatch of its existing resources subject to contractual and operating constraints to minimize the cost of supply over the year. The pricing of various pipeline services is based directly on the pipeline tariffs and the rates in effect as of August 1, 2020. The pricing of gas supplies is based on the 8/6/20 NYMEX forward curve and regional basis curves, also from 8/6/20 as further described above.

Q. How did the Company categorize the projected gas cost components?

A. For the purpose of this filing, gas costs are disaggregated into two components: (1) Fixed Costs, and (2) Variable Costs. Fixed Costs include all fixed costs related to the purchase, storage, or delivery of firm gas, including pipeline and supplier fixed reservation costs and demand charges. The Company will incur Supply Fixed Cost Components in consideration of a right, but not the obligation, to call on transportation and/or supply needed to meet customers' supply requirements.

Variable Costs include all variable costs of firm gas, including, but not limited to, commodity costs, taxes on commodity and other gas supply expenses incurred to transport supplies, transportation fees, storage commodity costs, taxes on storage commodity and other gas storage expense incurred to transport supplies, and inventory commodity costs.

A summary of gas costs included in the GCR and disaggregated into these cost components by month for the period November 2020 through October 2021 is shown in Attachment GSP-1 page 1 of 21.

Q. Please describe Attachment GSP-1, Pages 2 through 19.

A. Attachment GSP-1 includes the following information:

- Pages 2 through 12: show the supporting detail for gas costs included in this filing for the period November 2020 through October 2021;
  - Pages 2 through 4: shows a summary of volumes and costs by supply path;
  - Pages 5 through 6: show the detail pertaining to Commodity costs listed by supply source;

  - Pages 7 through 10: show the variable and fixed costs detail for transportation and storage;
  - Page 11: includes the detail supporting the supplier fixed costs;
  - Page 12: shows the fixed costs attributable to hourly peaking needs;
- Page 13: includes a summary of the projected underground storage and LNG inventories;
- Pages 14 through 17: show the optimized, forecasted sendout by supply source under normal weather conditions from the SENDOUT® model and the detailed makeup of supply by pipeline source, storage contract, and peaking facility/contract;
  - Pages 14 through 15: shows the forecasted volumes at the receipt or purchase point;
  - Pages 16 through 17: shows the forecasted volumes at the point of delivery after all pipeline fuel is accounted for; and
- Pages 18 through 19: show the volumes and cost allocation of the Company's transportation paths to marketers and sales customers.

The pricing included in this filing reflects actual pricing and indicative pricing and terms based on the Company's current contracts with suppliers. To comply with confidentiality terms in the Company's agreements with suppliers, charges for the supply contracts have been redacted in the public version of the filing.

Q. How do the gas costs presented in the Company's Gas Cost Recovery filing compare with those submitted to the Division in the Company's Long Range Plan filed in Docket No. 5043?

A. Total gas costs are $2.4 million higher in this GCR filing compared with the costs forecasted in the Company's LRP. The differences are summarized in the following table:

Cost Item	Difference in $Millions (GCR value – LRP value)
a. Fixed Costs	$6.5
b. Fixed Cost Credits	$6.5
c. Net Fixed Costs (a-b)	$0.0
d. Variable Costs	$2.4
e. NGPMP Credit	$0.0
f. Total Gas Costs (c+d-e)	$2.4

Q. Please summarize major drivers for the differences in costs between the 2020 LRP (Docket No. 5043) and this 2020 GCR.

A. Total gas costs increased by $2.4 million between the LRP and GCR filing. The main drivers for the increase are an increase in the proposed Everett supply deal fixed costs, TCo's proposed transportation and storage rate increases, and an increase in the NYMEX and basis forward curves.

Fixed costs increased by $6.5 million, driven primarily by an increase in the proposed Everett supply deal fixed costs and TCo's proposed rate increases, further discussed below. This was offset by fixed cost credits of $6.5 million that were not included in the LRP. The Company now estimates the AMA credit and Hourly Fixed Cost credit to be $1.3 million and $5.2 million, respectively.

Total variable costs increased by $2.4 million from the LRP to the GCR, due primarily to an increase in gas commodity costs. This is largely the result of an increase in forward prices; the average November 2020 through March 2021 NYMEX forward curve increased by $0.17 per dekatherm or 6% and by $0.16 per dekatherm or 6% over the full 2020/21 gas year.

Q. Please describe the impact of any pending rate proceedings impacting the Company's transportation and/or storage providers.

A. On July 31, 2020, Columbia Gas Transmission, LLC (TCo) filed a rate increase request with the FERC. This is TCo's first rate increase request since 1995 and, since then, TCO has made substantial capital investments in modernizing its pipeline system. TCo's proposed rates, if approved, represent a 78% increase for transportation service rates and an increase of 134% for storage service rates. The Company intervened in TCo's rate increase docket and objected to the proposed rate increase. If a settlement cannot be reached by TCo, its customers, and the FERC, the proposed rates will take effect February 1, 2021. The Company has included TCo's proposed rates in the GCR effective February 1, 2021.

In addition to the proposed rate increase on TCo, as a customer of NGLNG, the Company has been notified by NGLNG that it anticipates filing a section 4 rate case with the FERC in Q4 2020. At this time, the Company is unaware of the impact NGLNG's proposal will have on fixed costs. The Company has assumed current NGLNG rates remain in effect for the 2020/21 GCR period.

III. Gas Supply Portfolio

Q. Have there been any significant changes to the way the Company purchases gas?

A. The Company's portfolio continues to be well positioned to take advantage of opportunities presented by the development of the Marcellus basin utilizing its economically-priced market area transportation on existing long and short-haul capacity. On most days, the Company is able to purchase less expensive supplies at the TETCO Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company's citygates on the Algonquin pipeline, as well as the Tennessee pipeline, Zone 4 point, using existing pipeline contracts previously used to purchase Gulf of Mexico supplies. The Company can take advantage of these less expensive supplies without incurring any additional fixed costs while still maintaining optionality to reach back to the Gulf basin should economics or reliability dictate it is prudent to do so. Additionally, since the Company expects that its participation in the Portland Natural Gas Transmission System (PNGTS) expansion will be fully phased in as of November 1, 2020, the Company has increased its position back to Dawn, Ontario to feed a significant portion of its TGP capacity and mitigate its historical exposure at Dracut.

Q. Have there been any changes and/or additions to the Company's capacity portfolio since last year that should be noted?

A. Yes. Each of the changes to the Company's transportation capacity portfolio is further described below. Where fixed and variable costs and credits of the below assets are reasonably known, the Company has included them in this GCR filing; where fixed and variable costs are not known, the Company has included estimates based on historical information or indicative pricing from the market.

<u>TCo Contracts</u>

The Company has held long term firm transportation agreements with TCo that provided access to both competitively priced Marcellus Shale supplies at the TCo pool, as well as access to TETCO M3 supplies at Eagle and Pennsburg for redelivery into the interconnect between TCo and AGT; in aggregate, the Company's TCo contracts having primary receipts at Eagle and Pennsburg, allowed the Company to transport up to 7,455 Dth/day of TCo supplies into AGT at Hanover for redelivery by the Company to its city-gates on AGT. Effective November 1, 2020, the Company has terminated these two upstream agreements. To finalize this decision, the Company negotiated with AGT to amend the primary receipt point on its downstream agreement away from the TCo interconnect to the more liquid interconnection with Millennium Pipeline Company LLC at Ramapo. Termination of these contracts results in fixed cost savings of $373,697 per year.

<u>NGLNG</u>

The Company previously entered into a precedent agreement for a term of 20 years for liquefaction services at NGLNG's currently-existing storage facilities located in Providence, Rhode Island. On October 17, 2018, FERC issued the Order granting a certificate of public convenience and necessity to National Grid LNG LLC in FERC Docket No. CP16-121-000 for the Fields Point Liquefaction Project. NGLNG filed its acceptance of the certificate of public convenience and necessity on October 29, 2018 and the Implementation Plan was filed on November 1, 2018. Based on the current timeline to construct and test the facilities, NGLNG expect to begin service of the liquefaction during the 2022 refill season. Once in service, the Company will be able to utilize its existing Algonquin capacity to transport volumes to the NGLNG plant in Providence for liquefaction during the off-peak period.

Northeast Energy Center, LLC (Northeast Energy)

The Company has entered into a Precedent Agreement for up to 1,780 Dth per day and 380,920 Dth per refill season for a term of fifteen years, commencing upon completion of the necessary facilities. The Northeast Energy project is located in central Massachusetts and was originally expected in-service date of April 1, 2020. However, however as a result of a revised scope to the permitting process and the impact of COVID-19, the project continues to await receipt of the necessary authorization to commence construction. Based on the current timeline in which Northeast Energy anticipates receipt of its necessary permits, the facility is now expected to be in service during the 2022 refill. The Northeast Energy Project will connect to the Tennessee pipeline and allow for the Company to utilize its existing Tennessee capacity to transport volumes from liquid supply basins to the proposed liquefaction facility located in Zone 6. The LNG will be trucked from the facility to the Company's LNG facilities in Rhode Island.

As a result of the delays in the NGLNG and Northeast Energy liquefaction projects, the Company has estimated the costs of LNG refill during the 2021 off-peak season based on the costs of its current arrangements.

<u>PNGTS Capacity</u>

Once fully phased in, the addition of the PNGTS capacity will reduce the Company's exposure at Dracut and allow the Company to access up to 29,000 Dth/day from Dawn, Ontario by way of agreements with Union, TransCanada, and PNGTS to deliver firm supplies into Dracut as part of the PXP Project. The PNGTS Agreement will feed into the Company's existing Dracut capacity (29,000 Dth/day). For the 2019/20 heating season, the Company had access to 25,705 Dth/day on this path and is expected to phase in the remaining 3,295 Dth effective November 1, 2020, pending completion of the necessary facilities on TransCanada and PNGTS.

In order to supply this path, the Company issued several RFPs soliciting proposals for AMAs to manage both its Canadian and/or domestic transportation capacity. Through the RFP process, the Company was willing to consider AMAs that only required assignment of the Company's capacity on Union and TransCanada to East Hereford, as well as AMAs that included a release of the Company's capacity on the downstream Portland and Tennessee assets for deliveries into the Company's Tennessee citygate. Additionally, the Company sought separate AMA transactions for the capacity that is already available under the first and second phases of the PXP Project and the additional capacity that is anticipated to be in service beginning November 1, 2020. Copies of each of the RFPs are found in Attachment EDA/SAJ-5. Based on the results of the RFPs, the Company will maintain the Portland and Tennessee capacity and move forward with AMAs for supplies delivered into East Hereford that will be transported by the Company to its citygates using the Company's Portland and Tennessee contracts. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned Canadian capacity for its own account. In exchange, the Company will receive an asset management fee, which is then fully credited to the customers. The Company is presently negotiating transaction confirmation(s) to memorialize these arrangements. As part of the agreement(s), the Company will reserve the right to withhold the necessary amount of capacity needed to satisfy its assignments to Marketers.

<u>Dracut Capacity and Supply</u>

For the 2019/20 heating season, the Company added an incremental contract with Tennessee for capacity in order to meet design hour and design year requirements. The contract with Tennessee provides for the Company to transport ad 20,000 Dth/day from Dracut, MA to Cranston, RI. In previous GCR periods, the Company has often filled its Dracut capacity through a supply deal which required the Company to pay a supplier a fixed demand fee in order to reserve the right to call upon the supplier to deliver such gas when requested by the Company. For the 2019/20 heating season, the Company filled this path through an AMA. For the 2020/21 heating season, the Company issued two RFPs that solicited offers for both an AMA to provide supply and manage its capacity from Dracut, MA to the Company's TGP city gate for a term of one year beginning November 1, 2020, as well as an RFP for a supply deal at Dracut which, if awarded, would allow the company to retain control of the TGP contract. The RFPs contemplated a total MDQ of 15,000 Dth per day to be managed by the Company, or its asset manager, after releases to Marketers were accounted for. Based on the results of the RFPs, the Company will release the Tennessee capacity under an AMA and will have a call option at its city-gate. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then fully credited to the customers. The Company is presently negotiating a transaction confirmation to memorialize this arrangement. Please see Attachment EDA/SAJ-6 for a copy of the RFP.

Incremental Winter Supplies

Beginning with the 2019/2020 heating season, the Company entered into an arrangement with Constellation LNG LLC(Constellation) whereby the Company has the right, but not the obligation, to call on Constellation to deliver up to 14,100 Dth/day to the Company's citygates on Algonquin. These supplies are backed by firm capacity and are needed to meet forecasted design hour and design season requirements and remain available to the Company through the 2022/23 heating season.

For the 2020/21 heating season, the Company is currently evaluating opportunities to meet additional customer requirements of 5,000 Dth/day which include purchasing supply at Everett, MA to fill its Tennessee transportation that is not currently satisfied through a long term supply agreement. The Company has included an estimate for the costs associated with this potential supply deal in its GCR forecast.

Incremental Portable LNG Storage and Vaporization Contracts

To support operations at Cumberland for the winter 2018/2019 season, the Company previously entered into an equipment rental and support services agreement with Prometheus Energy Group, Inc.[2] (Stabilis Energy). The Stabilis Energy agreement at Cumberland was intended as a temporary alternative until a permanent solution could be available to meet the supply needs previously served by the Cumberland LNG tank. At this time, a solution has not yet been identified that could be available prior to

[2] Prometheus Energy Group, Inc. was acquired by Stablis Energy, LLC.

November 2021. The Company engaged in discussions with Stabilis regarding an extension of the original agreement and was able to negotiate an extension of the equipment and rental services agreement at Cumberland through the 2021/22 heating season.

In addition to the portable operations at Cumberland, beginning with the 2019/20 heating season the Company has a multi-year contract for LNG storage and vaporization services at Old Mill Lane in Portsmouth with Stabilis Energy. The agreement allows the Company to access equipment and personnel sufficient to vaporize 650 Dth per hour at the injection site and, with minimal notice to Stabilis, to deploy the contingency services. The rental and support services agreement with Stabilis Energy at Old Mill Lane is available to the Company through the 2022/23 heating season.

Incremental Winter Liquid Volumes (LNG)

In order to support the portable LNG storage operations at Cumberland and Old Mill Lane, the Company will need to pursue a supplemental winter-only LNG purchase agreement. The Company may also need to purchase additional winter only liquid should it be determined that the Exeter and NGLNG/Providence LNG facilities will be utilized more actively for balancing purposes during the 2020/21 winter season.

As the costs of these supplies are not yet known, the Company has used an estimate based on historical winter LNG refill deals in its GCR forecast.

Q. How will the Company supply the Dawn capacity path in Ontario, Canada to Tennessee Zone 6 via Iroquois for the 2020-21 year?

A. The Company issued an RFP for an Asset Management Arrangement for a term of one year effective November 1, 2020. The RFP requested a MDQ of 1,000 Dth/day with a monthly option for the Company to elect a baseload quantity and any remaining volumes available as a daily call option during the months of November 2020 through April 2021. These supplies will be delivered directly to the Company's TGP city gate in Lincoln, RI by the asset manager. Subject to satisfying the gas supply requirements associated with the AMA, the named asset manager has the right to utilize the assigned capacity for its own account. In exchange, the Company will receive an asset management fee, which is then credited to its customers. The Company is presently negotiating a transaction confirmation to memorialize the trade. Please see Attachment EDA/SAJ-9 for a copy of the RFP.

Q. Will the Company be entering into an AMA using its Columbia Gas Pipeline transportation and storage capacity for the 2020-21 year?

A. The Company issued an RFP for an AMA for a term of one year effective November 1, 2020. The RFP requested a MDQ of 12,545 Dth/day for volumes available as a daily call option during the months of November 2020 through April 2021 via the release of both a portion of the Company's capacity from Broad Run to the interconnect with Algonquin at the Hanover, NJ interconnect as well as the conveyance of the Company's storage capacity on TCo. Based on the offers received in response to the RFP, the Company will not be awarding the RFP as proposed and is considering alternative structures to maximize value for the customer. Please see Attachment EDA/SAJ-10 for a copy of the RFP.

IV. <u>Marketer Capacity Paths</u>

Q. Are there proposed changes to the Customer Choice Program?

A. Yes. As discussed above, the Company has filed proposed changes to the program. The specific changes proposed are: (1) to make all significant capacity paths on Algonquin and Tennessee available to Marketers, whereby all Marketers would receive a pro-rata share of each capacity path; (2) to eliminate the current pipeline capacity path preference methodology in which marketers rank the paths identified by the Company as available to marketers in order of preference and the Company allocates accordingly; and (3) to eliminate the cost adjustment that currently exists to reconcile the paths released to Marketers with the full supply portfolio.

Q. Why is the Company proposing these changes to the Customer Choice program?

A. As previously discussed, the Company is proposing these changes in response to a recommendation by the Division's witness in Docket No. 4963 that the Company evaluate its current cost assignment process as part of the program. The Company is also proposing these changes to better align marketer deliveries with load across the system and to ensure that marketers and sales customers have equal access to assets in the supply portfolio.

Q. What assets will be available for assignment to Marketers?

A. The chart below shows the paths and corresponding quantities available for release to Marketers. In total, the Company has made capacity available on nine different pipeline paths.

Paths	Peak Day City Gate MDQ (Dth/day)	Contract
TGP Long Haul	29,335	TGP 1597
TGP ConneXion	11,600	TGP 64026
Dawn via PNGTS	29,000	PNGTS 225805
		TCPL 60659
		Union M12274
		TGP 62930
AIM	18,000	MPL 210615
		AGT 510801
TETCO CDS Long Haul	45,934	TETCO 800303
		AGT 93011E
		AGT 510985
TCO Appalachia	40,000	TCO 31524
		AGT 90106
		AGT 510985
AGT M3	18,099	AGT 93011E
		AGT 510985
		AGT 90107
Dracut	20,000	TGP 62930
TETCO SCT Long Haul	2,099	TETCO 800156
		AGT 93001ESC

The Company has excluded its smallest paths with volumes less than 2,000 Dth per day from the capacity assignment process. Allocating these very small contracts would be a burden for both the Company and the Marketers with little potential benefit. Rather, Marketers will have access to these assets through a bundled sale option as part of the current storage and peaking tiers of the program.

Q. How are the costs developed for each path released to Marketers?

A. Marketers will be released a pro-rata share of the capacity available on all the transportation paths listed in the table above. Because Marketers will be released capacity at the same cost paid by the Company, no cost calculations are necessary.

Q. How do the fixed costs to Marketers under the Company's proposal compare to the fixed costs to sales customers and the transportation portfolio in total?

A. The per unit fixed costs are nearly the same. Please see page 19 of GSP-1 for the comparison of per unit fixed costs to be paid by Marketers and sales customers, as well as the per unit fixed cost of the transportation portfolio in total.

Q. Does this conclude your testimony?

A. Yes.

Attachments of
Gas Supply Panel

Attachments of the Gas Supply Panel

Attachment GSP-1	Projected Gas Costs and Assignment of Pipeline Capacity – **CONFIDENTIAL Information**
Attachment GSP-2	NYMEX Strip Comparison & Forward Curves
AttachmentGSP-3	Rule Curves
Attachment GSP-4	Customer Choice Storage Pricing
Attachment GSP-5	RFPs for PXP Phases I, II & III
Attachment GSP-6	RFP for AMA Dawn Waddington to Zone 6 Lincoln
Attachment GSP-7	RFPs for AMA Dracut to Citygate & Dracut Supply
Attachment GSP-8	RFP for AMA Columbia Gas Transmission (“TCo”) - FSS, ST & FTS Assets

Attachment GSP-1

Attachment GSP-1

Summary of Projected Gas Costs

REDACTED VERSION

National Grid Rhode Island Gas Cost Recovery Cost of Gas ($000)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Normal Weather Scenario - Sales Only													
FIXED COSTS													
Total Transportation Fixed Costs	$ 4,601 3	$ 4,915.3	$ 4,912.6	$ 5,093.1	$ 5,093.1	$ 4,779.0	$ 4,779.0	$ 4,779.0	$ 4,779.0	$ 4,779.0	$ 4,779.0	$ 4,779.0	$ 58,068.0
Total Storage Delivery Fixed Costs	$ 431.0	$ 431.0	$ 431.0	$ 445 5	$ 445.5	$ 414.7	$ 414.7	$ 414.7	$ 414.7	$ 414.7	$ 414.7	$ 414.7	$ 5,087.1
Total Storage Fixed Costs	$ 435 8	$ 435.8	$ 435.8	$ 449 3	$ 449.3	$ 449 3	$ 449.3	$ 449 3	$ 449.3	$ 449.3	$ 449.3	$ 449.3	$ 5,351.3
Total Liquefaction Fixed Costs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Supplier Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 18,482.4
LESS:													
AMA Credits	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 108.1	$ 1,296.9
Hourly Peaking Fixed Costs	$ -	$ 1,311.2	$ 1,311.2	$ 1,311 2	$ 1,311.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,244.9
TOTAL FIXED COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 80,447.1
VARIABLE COSTS													
Commodity													
Commodity for Purchases to City Gate	$ 6,081.6	$ 9,383.1	$ 11,653.0	$ 10,094 2	$ 8,526.0	$ 5,186 8	$ 2,662.5	$ 1,677.1	$ 1,353.5	$ 1,388.4	$ 1,614.0	$ 3,377.1	$ 62,997.2
Commodity for Purchases to Injections	$ -	$ -	$ -	$ -	$ 649.8	$ 469 2	$ 1,681.6	$ 1,526 2	$ 983.6	$ 1,657.0	$ 1,657.2	$ 1,560.1	$ 10,184.7
Total Commodity Costs	$ 6,081.6	$ 9,383.1	$ 11,653.0	$ 10,094 2	$ 9,175.7	$ 5,656.0	$ 4,344.1	$ 3,203 3	$ 2,337.1	$ 3,045.4	$ 3,271.2	$ 4,937.2	$ 73,181.9
Withdrawal													
Underground Storage Withdrawal Value	$ 94.6	$ 1,727.3	$ 2,259.9	$ 2,014 2	$ 1,598.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,694.0
LNG Storage Withdrawal Value	$ 83 8	$ 84.3	$ 761.8	$ 522 3	$ 83.6	$ 79 9	$ 81.7	$ 78.4	$ 80.8	$ 80 9	$ 78.2	$ 80.7	$ 2,096.4
Total Storage Withdrawal Value	$ 178.4	$ 1,811.6	$ 3,021.7	$ 2,536 5	$ 1,681.6	$ 79 9	$ 81.7	$ 78.4	$ 80.8	$ 80 9	$ 78.2	$ 80.7	$ 9,790.4
Transportation													
Variable Costs for Purchases to City Gate	$ 287.0	$ 328.1	$ 369.5	$ 330 3	$ 302.4	$ 206.4	$ 73.2	$ 48.7	$ 63.8	$ 73.7	$ 42.0	$ 145.3	$ 2,270.4
Variable Costs for Storage Withdrawal	$ 7.1	$ 114.1	$ 149.3	$ 131 9	$ 103.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 506.3
Variable Costs for Storage Injection	$ -	$ -	$ -	$ -	$ 140.5	$ 71.6	$ 107.7	$ 97 9	$ 43.2	$ 59 5	$ 93.3	$ 71.9	$ 685.7
Total Transportation Variable Costs	$ 293.1	$ 414.9	$ 477.0	$ 425 8	$ 524.6	$ 274 3	$ 160.5	$ 130.4	$ 92.3	$ 111 9	$ 115.0	$ 197.1	$ 3,216.8
Total Storage Variable Costs	$ 0 9	$ 27.4	$ 41.9	$ 36 3	$ 22.1	$ 3.7	$ 20.4	$ 16 2	$ 14.8	$ 21 3	$ 20.3	$ 20.2	$ 245.6
LESS:													
LNG Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,948.4
Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 264.1	$ 1,507.4	$ 1,348 3	$ 1,003.3	$ 1,693.1	$ 1,553.4	$ 1,552.4	$ 8,922.0
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Storage and Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 10,870.4
TOTAL VARIABLE COSTS	$ 6,554.1	$ 11,637.0	$ 15,193.5	$ 13,092 9	$ 10,613.8	$ 5,473.1	$ 2,817.4	$ 1,804 2	$ 1,498.1	$ 1,543.0	$ 1,734.2	$ 3,603.1	$ 75,564.3
TOTAL FIXED AND VARIABLE COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 156,011.4
NGPMP Credit	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 437.6	$ 5,251.1
TOTAL GAS COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 150,760.4

Narragansett Electric Company
Volume & Cost Summary
Sendout Volumes (MDth)

Normal Weather Scenario - Sales Only

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Algonquin													
TETCO CDS Long Haul	1,098	1,136	1,136	1,026	1,037	969	440	262	563	1,001	434	1,000	10,102
TETCO SCT Long Haul	12	8	25	19	10	-	-	-	-	-	-	-	74
AIM	221	218	218	197	218	215	222	215	222	-	-	222	2,167
AGT M3	115	17	-	3	71	524	763	417	-	-	660	542	3,112
TCO Appalachia	372	931	986	883	998	25	49	49	-	50	32	18	4,392
Storage	46	448	661	581	389	-	-	-	-	-	-	-	2,126
Total Algonquin	1,863	2,759	3,026	2,707	2,723	1,732	1,474	943	785	1,051	1,126	1,782	21,972
Tennessee													
TGP Long Haul	592	460	569	554	297	233	3	83	-	-	73	212	3,075
TGP ConneXion	273	293	292	264	234	283	292	282	234	291	282	292	3,313
Storage	-	403	458	413	405	-	-	-	-	-	-	-	1,678
Total Tennessee	865	1,155	1,319	1,231	936	516	295	365	234	291	355	504	8,066
Other													
Dawn via PNGTS	18	194	447	376	182	-	-	-	-	-	-	-	1,218
Dracut	-	-	-	-	-	-	37	0	-	-	-	-	37
Dawn / Niagara / Waddington	5	38	49	41	31	0	-	-	-	-	-	-	165
Dominion / Transco Leidy	35	39	51	44	35	18	2	2	2	2	2	2	236
Everett	-	80	209	94	-	-	-	-	-	-	-	-	384
LNG Vapor	19	19	176	120	19	19	19	19	19	19	19	19	488
LNG Truck	-	-	-	-	192	71	74	71	5	5	50	19	488
City Gate	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	77	371	932	676	460	108	133	92	26	26	71	41	3,015
Total Purchases	2,806	4,285	5,277	4,614	4,120	2,356	1,902	1,401	1,045	1,369	1,553	2,327	33,053
LESS:													
Liquefaction	-	-	-	-	-	-	-	-	-	-	-	-	-
LNG Truck	-	-	-	-	192	71	74	71	5	5	50	19	488
AGT Storage Refill	-	-	-	-	-	64	489	311	267	514	466	453	2,563
TGP Storage Refill	-	-	-	-	-	43	157	264	158	211	248	251	1,332
Total	-	-	-	-	192	178	720	646	430	729	764	724	4,383
Total Sendout	2,806	4,285	5,277	4,614	3,927	2,178	1,182	755	615	640	788	1,603	28,670
Datacheck	2,806	4,285	5,277	4,614	3,927	2,178	1,182	755	615	640	788	1,603	28,670
Delta	-	-	-	-	-	-	-	-	-	-	-	-	-

Narragansett Electric Company
Volume & Cost Summary
Cost of Gas ($000)

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
DEMAND													
TETCO CDS Long Haul Transportation	$ 1,002	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	$ 1,001	*$ 12,017*
TETCO SCT Long Haul Transportation	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	$ 18	*$ 216*
AIM Transportation	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	$ 757	*$ 9,082*
AGT M3 Transportation	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	*$ 1,521*
TCO Appalachia Transportation	$ 515	$ 515	$ 515	$ 696	$ 696	$ 696	$ 696	$ 696	$ 696	$ 696	$ 696	$ 696	*$ 7,807*
TGP Long Haul Transportation	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	$ 459	*$ 5,508*
TGP ConneXion Transportation	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	$ 215	*$ 2,578*
Dawn via PNGTS Transportation	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	$ 997	*$ 11,962*
Dracut Transportation	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	$ 85	*$ 1,020*
Dawn / Niagara / Waddington Transportation	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	*$ 354*
Dominion / Transco Leidy Transportation	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	*$ 199*
Manchester Lateral / Yankee Interconnect	$ 257	$ 257	$ 254	$ 254	$ 254	$ 254	$ 254	$ 254	$ 254	$ 254	$ 254	$ 254	*$ 3,054*
Everett Transportation	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	*$ 1,275*
Storage Delivery	$ 449	$ 449	$ 449	$ 464	$ 464	$ 433	$ 433	$ 433	$ 433	$ 433	$ 433	$ 433	*$ 5,305*
Storage Capacity	$ 272	$ 272	$ 272	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	$ 286	*$ 3,386*
NGLNG	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	$ 164	*$ 1,965*
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*$ 5,967*
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*$ 1,256*
Supplier Reservation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*$ 12,515*
Total Demand	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 86,989
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 86,989
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
COMMODITY													
TETCO CDS Long Haul	$ 2,472	$ 3,166	$ 3,326	$ 2,980	$ 2,897	$ 2,415	$ 1,010	$ 601	$ 1,320	$ 2,329	$ 925	$ 2,194	$ 25,635
TETCO SCT Long Haul	$ 31	$ 26	$ 82	$ 61	$ 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 232
AIM	$ 500	$ 609	$ 634	$ 569	$ 605	$ 527	$ 520	$ 500	$ 527	$ -	$ -	$ 488	$ 5,479
AGT M3	$ 302	$ 67	$ -	$ 13	$ 238	$ 1,307	$ 1,792	$ 983	$ -	$ -	$ 1,415	$ 1,202	$ 7,319
TCO Appalachia	$ 904	$ 2,637	$ 2,915	$ 2,580	$ 2,772	$ 63	$ 119	$ 116	$ -	$ 120	$ 73	$ 40	$ 12,339
TGP Long Haul	$ 1,397	$ 1,310	$ 1,730	$ 1,666	$ 866	$ 598	$ 8	$ 201	$ -	$ -	$ 166	$ 490	$ 7,036
TGP ConneXion	$ 619	$ 806	$ 861	$ 770	$ 660	$ 704	$ 698	$ 669	$ 568	$ 701	$ 626	$ 656	$ 8,338
Dawn via PNGTS	$ 49	$ 593	$ 1,422	$ 1,198	$ 571	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,833
Dracut	$ -	$ -	$ -	$ -	$ -	$ -	$ 91	$ 0	$ -	$ -	$ -	$ -	$ 91
Dawn / Niagara / Waddington	$ 12	$ 107	$ 147	$ 122	$ 91	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ 480
Dominion / Transco Leidy	$ 81	$ 111	$ 151	$ 131	$ 97	$ 44	$ 5	$ 5	$ 5	$ 5	$ 4	$ 5	$ 643
Everett	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,366
Storage Withdrawals	$ 102	$ 1,841	$ 2,409	$ 2,146	$ 1,702	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,200
LNG Vapor	$ 84	$ 84	$ 762	$ 522	$ 84	$ 80	$ 82	$ 78	$ 81	$ 81	$ 78	$ 81	$ 2,096
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,948
City Gate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL COMMODITY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 86,435
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 86,435
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
TOTAL DC+CC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 173,424
LESS:													
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,948
AGT Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 156	$ 1,129	$ 717	$ 618	$ 1,184	$ 998	$ 980	$ 5,782
TGP Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 108	$ 378	$ 631	$ 385	$ 509	$ 556	$ 572	$ 3,140
Total Liquefaction & Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 10,870
TOTAL GAS COST	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 162,553
Commodity to Sendout	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 75,564
Days/month	30	31	31	28	31	30	31	30	31	31	30	31	365
Unit Commodity Cost ($/MMBtu)	$2.336	$2.716	$2 879	$2.838	$2.703	$2 513	$2.383	$2.391	$2.435	$2.413	$2.201	$2 247	$2.636
NYMEX (8/6/20)	$2.654	$2.985	$3.096	$3.053	$2.936	$2.661	$2.625	$2.654	$2.690	$2.697	$2.684	$2.704	

National Grid Rhode Island
Gas Commodity Costs
Normal Year

Commodity Cost ($000)	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 17.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17.0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 803.7
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 649.8
Dawn via IGTS	$ -	$ 15.2	$ 50.5	$ 34.7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100.4
Dawn via PNGTS	$ 48.8	$ 586.8	$ 1,406.2	$ 1,185.1	$ 564.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,791.2
Dominion SP	$ 29.4	$ 43.2	$ 45.1	$ 40.4	$ 42.9	$ 37.2	$ -	$ -	$ -	$ -	$ -	$ -	$ 238.2
Dracut Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 90.0
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,354.1
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Millennium	$ 460.1	$ 586.2	$ 611.8	$ 548.4	$ 581.8	$ 504.6	$ 497.1	$ 477.5	$ 504.0	$ -	$ -	$ 465.0	$ 5,236.4
Niagara	$ 6.9	$ 88.9	$ 92.7	$ 83.7	$ 70.3	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ -	$ 343.3
TCO Appalachia	$ 874.6	$ 2,561.7	$ 2,835.5	$ 2,509.0	$ 2,691.5	$ 61.1	$ 116.9	$ 114.2	$ -	$ 118.6	$ 71.8	$ 39.3	$ 11,994.3
Tetco M3	$ 294.4	$ 65.9	$ -	$ 13.1	$ 233.8	$ 1,274.2	$ 1,745.1	$ 957.1	$ -	$ -	$ 1,374.1	$ 1,169.0	$ 7,126.6
Transco Leidy	$ 43.2	$ 58.3	$ 91.8	$ 78.3	$ 46.0	$ 4.7	$ 4.6	$ 4.5	$ 4.8	$ 4.7	$ 4.2	$ 4.4	$ 349.6
Waddington	$ 5.2	$ 0.0	$ -	$ 0.0	$ 18.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23.8
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 48.6
Tetco M2 CDS	$ 2,323.1	$ 3,011.2	$ 3,171.5	$ 2,840.1	$ 2,755.6	$ 2,286.3	$ 974.8	$ 578.4	$ 1,257.2	$ 2,219.0	$ 889.9	$ 2,081.6	$ 24,388.7
Tetco M2 SCT	$ 25.1	$ 22.3	$ 69.5	$ 51.3	$ 26.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 195.1
TGP Z4 Cnx	$ 616.5	$ 804.3	$ 859.3	$ 768.5	$ 657.9	$ 700.5	$ 692.7	$ 664.6	$ 563.8	$ 695.9	$ 622.4	$ 652.0	$ 8,298.3
TGP Z4 LH	$ 1,337.3	$ 1,263.3	$ 1,672.8	$ 1,609.8	$ 836.3	$ 574.9	$ 7.7	$ 196.1	$ -	$ -	$ 161.4	$ 473.2	$ 8,132.7
Proposed Summer Refill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	**$ 6,081.6**	**$ 9,383.1**	**$ 11,653.0**	**$ 10,094.2**	**$ 9,175.7**	**$ 5,656.0**	**$ 4,344.1**	**$ 3,203.3**	**$ 2,337.1**	**$ 3,045.4**	**$ 3,271.2**	**$ 4,937.2**	**$ 73,181.9**

Unit Cost ($/Dth)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Weighted Average
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 2.54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.54
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dawn via IGTS	$ -	$ 2.96	$ 3.08	$ 3.08	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.06
Dawn via PNGTS	$ 2.60	$ 2.96	$ 3.08	$ 3.08	$ 3.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.05
Dominion SP	$ 2.06	$ 2.54	$ 2.66	$ 2.64	$ 2.53	$ 2.26	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.46
Dracut Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Millennium	$ 2.06	$ 2.55	$ 2.66	$ 2.64	$ 2.53	$ 2.26	$ 2.16	$ 2.14	$ 2.19	$ -	$ -	$ 2.02	$ 2.32
Niagara	$ 2.31	$ 2.66	$ 2.78	$ 2.78	$ 2.74	$ 2.55	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.73
TCO Appalachia	$ 2.29	$ 2.68	$ 2.80	$ 2.77	$ 2.63	$ 2.39	$ 2.32	$ 2.29	$ -	$ 2.30	$ 2.20	$ 2.18	$ 2.66
Tetco M3	$ 2.54	$ 3.78	$ -	$ 5.15	$ 3.28	$ 2.41	$ 2.27	$ 2.27	$ -	$ -	$ 2.06	$ 2.14	$ 2.27
Transco Leidy	$ 2.01	$ 2.49	$ 2.59	$ 2.59	$ 2.46	$ 2.14	$ 2.05	$ 2.05	$ 2.13	$ 2.09	$ 1.90	$ 1.95	$ 2.41
Waddington	$ 2.57	$ 3.58	$ -	$ 4.99	$ 3.06	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.94
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tetco M2 CDS	$ 2.05	$ 2.56	$ 2.69	$ 2.67	$ 2.56	$ 2.29	$ 2.16	$ 2.16	$ 2.17	$ 2.15	$ 1.99	$ 2.02	$ 2.34
Tetco M2 SCT	$ 2.05	$ 2.55	$ 2.69	$ 2.67	$ 2.56	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2.55
TGP Z4 Cnx	$ 2.23	$ 2.72	$ 2.90	$ 2.87	$ 2.78	$ 2.44	$ 2.33	$ 2.31	$ 2.36	$ 2.35	$ 2.17	$ 2.20	$ 2.47
TGP Z4 LH	$ 2.23	$ 2.72	$ 2.90	$ 2.87	$ 2.78	$ 2.44	$ 2.33	$ 2.31	$ -	$ -	$ 2.17	$ 2.20	$ 2.61
Proposed Summer Refill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Weighted Average	**$ 2.17**	**$ 2.67**	**$ 2.85**	**$ 2.81**	**$ 2.70**	**$ 2.37**	**$ 2.27**	**$ 2.28**	**$ 2.22**	**$ 2.20**	**$ 2.10**	**$ 2.09**	**$ 2.48**

National Grid Rhode Island
Gas Commodity Costs
Normal Year

Commodity to Injections ($000)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Grand Total
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dawn via IGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn via PNGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion SP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dracut Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Long-Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Swing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millennium	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ -	$ 116.9	$ 114.2	$ -	$ 118.6	$ 71.8	$ 39.3	$ 460.8
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Tetco M2 CDS	$ -	$ -	$ -	$ -	$ -	$ 150.3	$ 974.8	$ 578.4	$ 595.1	$ 1,026.6	$ 889.9	$ 904.9	$ 5,120.1
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 Cnx	$ -	$ -	$ -	$ -	$ -	$ 107.2	$ 374.5	$ 426.6	$ 381.2	$ 504.7	$ 390.6	$ 326.0	$ 2,510.9
TGP Z4 LH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 196.1	$ -	$ -	$ 157.4	$ 237.3	$ 590.8
Proposed Summer Refill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 649.8**	**$ 469.2**	**$ 1,681.6**	**$ 1,526.2**	**$ 983.6**	**$ 1,657.0**	**$ 1,657.2**	**$ 1,560.1**	**$ 10,184.7**

National Grid Rhode Island
Transportation Variable Costs
Normal Year
($000)

Transportation Costs	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Dracut	$ 0.3	$ 4.9	$ 11.5	$ 9.6	$ 4.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30.7
Everett	$ -	$ 2.6	$ 6.7	$ 3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12.2
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 446.3
Manchester Lateral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ 0.2	$ 2.5	$ 2.5	$ 2.3	$ 2.0	$ 0.0	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.6
Storage Delivery	$ 49.0	$ 79.7	$ 89.0	$ 78.5	$ 85.3	$ 29.6	$ 16.3	$ 6.7	$ 7.6	$ 7.8	$ 6.7	$ 24.7	$ 480.9
Yankee Interconnect	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM	$ 23.0	$ 22.7	$ 22.7	$ 20.5	$ 22.7	$ 22.4	$ 23.1	$ 22.4	$ 23.1	$ -	$ -	$ 23.1	$ 225.8
Transco	$ 6.9	$ 7.6	$ 11.8	$ 10.0	$ 5.9	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 43.4
TCO (Pool)	$ 15.9	$ 37.4	$ 38.4	$ 34.6	$ 38.6	$ 13.8	$ 13.6	$ 13.2	$ -	$ -	$ 13.2	$ 13.6	$ 232.3
TETCO SCT Long Haul	$ 5.1	$ 3.6	$ 10.9	$ 8.1	$ 4.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32.1
AGT M3	$ 64.1	$ 112.1	$ 125.2	$ 113.3	$ 103.4	$ 51.9	$ 17.6	$ 6.4	$ 11.0	$ 27.1	$ 21.4	$ 30.5	$ 683.8
TETCO CDS Long Haul	$ 83.9	$ 89.7	$ 91.8	$ 82.6	$ 82.2	$ 71.7	$ 20.1	$ 11.5	$ 33.1	$ 59.3	$ 19.2	$ 61.9	$ 707.0
Dominion	$ 0.9	$ 1.0	$ 1.1	$ 0.9	$ 1.0	$ 1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.0
Dawn via Waddington	$ 0.2	$ 0.4	$ 1.3	$ 0.9	$ 0.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.3
Dawn via PNGTS	$ 0.3	$ 1.8	$ 4.1	$ 3.5	$ 1.9	$ -	$ 1.2	$ 0.0	$ -	$ -	$ -	$ -	$ 12.8
TGP Long Haul	$ 41.3	$ 46.6	$ 57.6	$ 56.1	$ 30.1	$ 16.9	$ 0.3	$ 3.8	$ -	$ -	$ 3.4	$ 14.5	$ 270.6
TGP ConneXion	$ 2.0	$ 2.2	$ 2.2	$ 2.0	$ 1.7	$ 1.9	$ 1.5	$ 1.3	$ 1.1	$ 1.3	$ 1.4	$ 1.6	$ 20.1
Portable LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 3,216.8**

National Grid Rhode Island
Storage Variable Costs
Normal Year
($000)

Storage Costs	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Columbia FSS	$ 0.0	$ 0.5	$ 1.0	$ 0.9	$ 0.6	$ -	$ 0.7	$ 0.7	$ -	$ 0.8	$ 0.5	$ 0.3	$ 6.0
Dominion GSS	$ -	$ 4.3	$ 4.7	$ 3.8	$ 2.6	$ 1.9	$ 4.8	$ 4.5	$ 4.4	$ 4.2	$ 3.8	$ 3.8	$ 42.8
Dominion GSSTE	$ 0.9	$ 3.5	$ 3.5	$ 3.2	$ 3.5	$ -	$ 4.6	$ -	$ -	$ 5.5	$ 5.0	$ 4.9	$ 34.5
Providence LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee FSMA	$ -	$ 1.1	$ 1.4	$ 1.5	$ 2.1	$ -	$ 0.4	$ 1.4	$ 0.5	$ 1.0	$ 1.4	$ 1.5	$ 12.4
Tetco FSS1	$ -	$ 0.3	$ 0.9	$ 1.0	$ 0.4	$ 0.1	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 5.3
Tetco SS1	$ -	$ 17.6	$ 30.4	$ 26.0	$ 13.0	$ 1.7	$ 9.4	$ 9.1	$ 9.4	$ 9.4	$ 9.1	$ 9.4	$ 144.7
Exeter LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	**$ 0.9**	**$ 27.4**	**$ 41.9**	**$ 36.3**	**$ 22.1**	**$ 3.7**	**$ 20.4**	**$ 16.2**	**$ 14.8**	**$ 21.3**	**$ 20.3**	**$ 20.2**	**$ 245.6**

Withdrawal Value	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Columbia FSS	$ 5.0	$ 69.9	$ 127.0	$ 112.8	$ 73.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 388.2
Dominion GSS	$ -	$ 564.3	$ 611.2	$ 487.8	$ 336.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,999.7
Dominion GSSTE	$ 89.6	$ 350.3	$ 350.3	$ 316.4	$ 350.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,456 9
Exeter LNG	$ 25.2	$ 26.0	$ 273.4	$ 98.4	$ 25.8	$ 24.8	$ 25.3	$ 24.3	$ 25.1	$ 25.2	$ 24.5	$ 25.3	$ 623.4
Providence LNG	$ 58.6	$ 58.3	$ 488.4	$ 423.9	$ 57.7	$ 55.1	$ 56.4	$ 54.1	$ 55.7	$ 55.7	$ 53.7	$ 55.4	$ 1,473.0
Tennessee FSMA	$ -	$ 252.2	$ 307.5	$ 348.7	$ 469.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,378 3
Tetco FSS1	$ -	$ 12.5	$ 39.2	$ 41.7	$ 15.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108.7
Tetco SS1	$ -	$ 478.1	$ 824.7	$ 706.9	$ 352.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,362 2
Grand Total	**$ 178.4**	**$ 1,811.6**	**$ 3,021.7**	**$ 2,536.5**	**$ 1,681.6**	**$ 79.9**	**$ 81.7**	**$ 78.4**	**$ 80.8**	**$ 80.9**	**$ 78.2**	**$ 80.7**	**$ 9,790.4**

Injection Value	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Columbia FSS	$ -	$ -	$ -	$ -	$ -	$ -	$ 118.6	$ 115.9	$ -	$ 120.2	$ 72.8	$ 39.9	$ 467.4
Dominion GSS	$ -	$ -	$ -	$ -	$ -	$ 171.7	$ 416.9	$ 393.7	$ 389.9	$ 365.5	$ 310.9	$ 308.6	$ 2,357.3
Dominion GSSTE	$ -	$ -	$ -	$ -	$ -	$ -	$ 386.1	$ -	$ -	$ 459.1	$ 388.5	$ 384.3	$ 1,617.9
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 604.1
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,344.3
Tennessee FSMA	$ -	$ -	$ -	$ -	$ -	$ -	$ 115.1	$ 382.9	$ 138.4	$ 277.7	$ 358.7	$ 376.6	$ 1,649.4
Tetco FSS1	$ -	$ -	$ -	$ -	$ -	$ 4.1	$ 20.6	$ 19.9	$ 20.7	$ 20.5	$ 18.4	$ 19.3	$ 123.6
Tetco SS1	$ -	$ -	$ -	$ -	$ -	$ 88.3	$ 450.2	$ 435.9	$ 454.2	$ 450.0	$ 404.1	$ 423.6	$ 2,706.3
Grand Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ 790.3**	**$ 540.9**	**$ 1,789.3**	**$ 1,624.1**	**$ 1,026.8**	**$ 1,716.5**	**$ 1,750.5**	**$ 1,632.0**	**$ 10,870.4**

National Grid Rhode Island
Transportation Fixed Costs
Normal Year
($000)

Transportation Costs													
	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Dracut	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 85.0	$ 1,020.3
Everett	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 106.3	$ 1,275.4
LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Manchester Lateral	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 209.8	$ 2,517.1
Niagara	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 6.8	$ 82.1
Storage Delivery	$ 449.2	$ 449.2	$ 449.2	$ 463.7	$ 463.7	$ 432.9	$ 432.9	$ 432.9	$ 432.9	$ 432.9	$ 432.9	$ 432.9	$ 5,305.3
Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AIM	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 756.9	$ 9,082.4
Transco	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 9.4	$ 113.1
TCO (Pool)	$ 515.3	$ 515.3	$ 515.3	$ 695.7	$ 695.7	$ 695.7	$ 695.7	$ 695.7	$ 695.7	$ 695.7	$ 695.7	$ 695.7	$ 7,807.3
TETCO SCT Long Haul	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 18.0	$ 215.8
AGT M3	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 126.8	$ 1,521.5
TETCO CDS Long Haul	$ 1,001.6	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 1,001.4	$ 12,017.1
Dominion	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 7.1	$ 85.6
Dawn via Waddington	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 22.6	$ 271.8
Dawn via PNGTS	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 996.8	$ 11,962.0
TGP Long Haul	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 459.0	$ 5,507.6
TGP ConneXion	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 214.8	$ 2,577.6
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 63,155.1**

National Grid Rhode Island
Storage Fixed Costs
Normal Year
($000)

Storage Costs	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Columbia FSS	$ 9.7	$ 9.7	$ 9.7	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 23.2	$ 237.9
Dominion GSS	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 36.4	$ 436.7
Dominion GSSTE	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 46.8	$ 561.2
Exeter LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Providence LNG	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 163.7	$ 1,964.9
Tennessee FSMA	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 43.3	$ 519.1
Tetco FSS1	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 3.5	$ 42.0
Tetco SS1	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 132.5	$ 1,589.6
Grand Total	**$ 435.8**	**$ 435.8**	**$ 435.8**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 449.3**	**$ 5,351.3**

National Grid Rhode Island
Supply Fixed Costs
Normal Year
($000)

Supply Costs	11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021	Grand Total
Everett Supply Deal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ramapo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn East Hereford	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion South Point	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millenium East	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dracut Supply Deal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Supply Deal2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Summer Liquid Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Summer Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
AGT Citygate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Winter Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proposed Summer Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 18,482.4**

National Grid Rhode Island
Hourly Peaking Fixed Costs
Normal Year
($000)

Hourly Peaking Fixed Costs	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
Transportation Fixed Costs													
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Supplier Fixed Costs													
AGT Citygate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Winter Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Hourly Peaking Fixed Costs	$ -	$ 1,311.2	$ 1,311.2	$ 1,311.2	$ 1,311.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,244 9

National Grid Rhode Island
Storage Inventory
Normal Year
($000; MDth)

Storage Inventory		11/1/2020	12/1/2020	1/1/2021	2/1/2021	3/1/2021	4/1/2021	5/1/2021	6/1/2021	7/1/2021	8/1/2021	9/1/2021	10/1/2021
LNG	Beg Inv Value	$ 3,280.6	$ 3,196.8	$ 3,112.5	$ 2,350.7	$ 1,828.4	$ 2,535.1	$ 2,731.9	$ 2,932.1	$ 3,129 5	$ 3,072.3	$ 3,014.8	$ 3,133.7
LNG	Beg Inv Volume	753.0	733.7	714.3	538.4	418.7	591.7	644.3	698.5	751.1	736.3	721.5	753.0
LNG	End Inv Value	$ 3,196.8	$ 3,112.5	$ 2,350.7	$ 1,828.4	$ 2,535.1	$ 2,731.9	$ 2,932.1	$ 3,129.5	$ 3,072 3	$ 3,014.8	$ 3,133.7	$ 3,132.6
LNG	End Inv Volume	733.7	714.3	538.4	418.7	591.7	644.3	698.5	751.1	736 3	721.5	753.0	753.0
AGT Storage	Beg Inv Value	$ 6,279.2	$ 6,184.6	$ 5,131.6	$ 3,548 2	$ 2,152.8	$ 1,223.3	$ 1,378.9	$ 2,507.9	$ 3,224.9	$ 3,843.2	$ 5,027.2	$ 6,025.0
AGT Storage	Beg Inv Volume	3,173.7	3,126.5	2,593.0	1,789.0	1,080.5	610.2	674.1	1,163.3	1,473.9	1,741.1	2,254.7	2,720.9
AGT Storage	End Inv Value	$ 6,184.6	$ 5,131.6	$ 3,548.2	$ 2,152 8	$ 1,223.3	$ 1,378.9	$ 2,507.9	$ 3,224.9	$ 3,843.2	$ 5,027.2	$ 6,025.0	$ 7,005.0
AGT Storage	End Inv Volume	3,126 5	2,593.0	1,789.0	1,080.5	610 2	674.1	1,163.3	1,473.9	1,741.1	2,254.7	2,720.9	3,173.7
TGP Storage	Beg Inv Value	$ 2,642 9	$ 2,642.9	$ 1,968.7	$ 1,292.2	$ 673 3	$ 4.8	$ 113.3	$ 491.7	$ 1,123.1	$ 1,508.0	$ 2,017.1	$ 2,572.7
TGP Storage	Beg Inv Volume	1,334 2	1,334.2	995.7	652.9	343 8	2.4	45.3	202.3	466.1	624.0	834.9	1,082.8
TGP Storage	End Inv Value	$ 2,642.9	$ 1,968.7	$ 1,292.2	$ 673.3	$ 4 8	$ 113.3	$ 491.7	$ 1,123.1	$ 1,508.0	$ 2,017.1	$ 2,572.7	$ 3,145.0
TGP Storage	End Inv Volume	1,334.2	995.7	652.9	343.8	2.4	45.3	202.3	466.1	624.0	834.9	1,082.8	1,334.2

The Narragansett Electric Company Gas Cost Recovery Receipt Point Volumes (MDth)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	7	-	-	-	-	-	-	-	-	-	-	-	7
Dawn via IGTS	-	5	16	11	-	-	-	-	-	-	-	-	33
Dawn via PNGTS	19	198	457	385	186	-	-	-	-	-	-	-	1,245
Dominion SP	14	17	17	15	17	16	-	-	-	-	-	-	97
Dracut Supply	-	-	-	-	-	-	37	0	-	-	-	-	37
Everett Long-Term	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
Millennium	223	230	230	208	230	223	230	223	230	-	-	230	2,259
Niagara	3	33	33	30	26	0	-	-	-	-	-	-	126
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	382	956	1,012	906	1,025	26	-	-	-	-	-	-	4,307
Tetco M2 SCT	12	9	26	19	10	-	-	-	-	-	-	-	77
Tetco M2 CDS	1,131	1,179	1,179	1,064	1,076	932	-	-	304	554	-	582	8,001
Tetco M3	116	17	-	3	71	528	770	421	-	-	666	547	3,140
TGP Z4 Cnx	276	296	296	268	237	243	136	103	77	82	107	148	2,269
TGP Z4 LH	599	465	576	560	301	236	3	-	-	-	2	107	2,850
Transco Leidy	22	23	36	30	19	2	2	2	2	2	2	2	145
Waddington	2	0	-	0	6	-	-	-	-	-	-	-	8
TOTAL PURCHASES TO CITY GATE	2,805	3,510	4,088	3,595	3,204	2,207	1,180	749	614	637	777	1,617	24,984
STORAGE WITHDRAWALS													
Columbia FSS	3	36	65	57	37	-	-	-	-	-	-	-	198
Dominion GSS	-	282	307	246	169	-	-	-	-	-	-	-	1,004
Dominion GSSTE	45	175	175	158	175	-	-	-	-	-	-	-	727
Exeter LNG	6	6	65	23	6	6	6	6	6	6	6	6	149
Providence LNG	13	13	111	96	13	13	13	13	13	13	13	13	339
Tennessee FSMA	-	130	160	175	243	-	-	-	-	-	-	-	709
Tetco SS1	-	243	420	360	179	-	-	-	-	-	-	-	1,203
Tetco FSS1	-	6	20	21	8	-	-	-	-	-	-	-	55
TOTAL WITHDRAWALS TO CITY GATE	67	891	1,323	1,137	831	19	19	19	19	19	19	19	4,383
GRAND TOTAL TO CITY GATE	2,872	4,401	5,410	4,732	4,035	2,226	1,199	768	634	657	795	1,637	29,367

The Narragansett Electric Company
Gas Cost Recovery
Receipt Point Volumes (MDth)

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	-	-	-	-	-	-	-	-
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	488
Millennium	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara	-	-	-	-	-	-	-	-	-	-	-	-	-
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	-	-	-	-	-	-	50	50	-	51	33	18	202
Tetco M2 SCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 CDS	-	-	-	-	-	66	452	268	274	477	447	448	2,431
Tetco M3	-	-	-	-	-	-	-	-	-	-	-	-	-
TGP Z4 Cnx	-	-	-	-	-	44	160	184	161	215	180	148	1,093
TGP Z4 LH	-	-	-	-	-	-	-	85	-	-	73	108	265
Transco Leidy	-	-	-	-	-	-	-	-	-	-	-	-	-
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO INJECTIONS	-	-	-	-	192	181	737	658	439	748	782	741	4,480
STORAGE WITHDRAWALS													
Columbia FSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSSTE	-	-	-	-	-	-	-	-	-	-	-	-	-
Exeter LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Providence LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee FSMA	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco SS1	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco FSS1	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WITHDRAWALS TO STORAGE INJECTION	-	-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL TO CITY GATE	-	-	-	-	192	181	737	658	439	748	782	741	4,480

The Narragansett Electric Company
Gas Cost Recovery
Delivery Point Volumes (MDth)

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	7	-	-	-	-	-	-	-	-	-	-	-	7
Dawn via IGTS	-	5	16	11	-	-	-	-	-	-	-	-	32
Dawn via PNGTS	18	194	447	376	182	-	-	-	-	-	-	-	1,218
Dominion SP	14	16	16	15	16	16	-	-	-	-	-	-	93
Dracut Supply	-	-	-	-	-	-	37	0	-	-	-	-	37
Everett Long-Term	-	80	209	94	-	-	-	-	-	-	-	-	384
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
Millennium	215	218	218	197	218	215	222	215	222	-	-	222	2,160
Niagara	3	33	33	30	25	0	-	-	-	-	-	-	125
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	372	931	986	883	998	25	-	-	-	-	-	-	4,194
Tetco M2 SCT	12	8	25	19	10	-	-	-	-	-	-	-	74
Tetco M2 CDS	1,098	1,136	1,136	1,026	1,037	905	-	-	296	537	-	565	7,737
Tetco M3	115	17	-	3	71	524	763	417	-	-	660	542	3,112
TGP Z4 Cnx	273	293	292	264	234	240	135	102	76	81	106	147	2,241
TGP Z4 LH	592	460	569	554	297	233	3	-	-	-	2	106	2,815
Transco Leidy	21	23	35	30	18	2	2	2	2	2	2	2	143
Waddington	2	0	-	0	6	-	-	-	-	-	-	-	8
TOTAL PURCHASES TO CITY GATE	2,740	3,414	3,983	3,501	3,114	2,159	1,163	736	596	620	769	1,584	24,379
STORAGE WITHDRAWALS													
Columbia FSS	2	35	63	56	37	-	-	-	-	-	-	-	193
Dominion GSS	-	274	299	239	165	-	-	-	-	-	-	-	977
Dominion GSSTE	44	170	170	154	170	-	-	-	-	-	-	-	709
Exeter LNG	6	6	65	23	6	6	6	6	6	6	6	6	149
Providence LNG	13	13	111	96	13	13	13	13	13	13	13	13	339
Tennessee FSMA	-	129	158	173	240	-	-	-	-	-	-	-	701
Tetco SS1	-	237	409	351	175	-	-	-	-	-	-	-	1,171
Tetco FSS1	-	6	19	20	7	-	-	-	-	-	-	-	53
TOTAL WITHDRAWALS TO CITY GATE	65	870	1,295	1,113	813	19	19	19	19	19	19	19	4,291
GRAND TOTAL TO CITY GATE	2,806	4,285	5,277	4,614	3,927	2,178	1,182	755	615	640	788	1,603	28,670

REDACTED VERSION

The Narragansett Electric Company Gas Cost Recovery Delivery Point Volumes (MDth)	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	-	-	-	-	-	-	-	-
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Swing	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Millennium	-	-	-	-	-	-	-	-	-	-	-	-	-
Niagara	-	-	-	-	-	-	-	-	-	-	-	-	-
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	-	-	-	-	-	-	49	49	-	50	32	18	198
Tetco M2 SCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 CDS	-	-	-	-	-	64	440	262	267	463	434	435	2,366
Tetco M3	-	-	-	-	-	-	-	-	-	-	-	-	-
TGP Z4 Cnx	-	-	-	-	-	43	157	181	158	211	177	145	1,072
TGP Z4 LH	-	-	-	-	-	-	-	83	-	-	71	106	260
Transco Leidy	-	-	-	-	-	-	-	-	-	-	-	-	-
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO INJECTIONS	-	-	-	-	192	178	720	646	430	729	764	724	4,383
STORAGE WITHDRAWALS													
Columbia FSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion GSSTE	-	-	-	-	-	-	-	-	-	-	-	-	-
Exeter LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Providence LNG	-	-	-	-	-	-	-	-	-	-	-	-	-
Tennessee FSMA	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco SS1	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco FSS1	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL WITHDRAWALS TO STORAGE INJECTION	-	-	-	-	-	-	-	-	-	-	-	-	-
GRAND TOTAL TO CITY GATE	-	-	-	-	192	178	720	646	430	729	764	724	4,383

National Grid Rhode Island
Customer Choice Capacity Allocation Proposal
2020/21

Paths	Peak Day City Gate MDQ (Dth/day)	City Gate Contracts	Upstream	Percent of Portfolio	Percent of Release
TGP Long Haul	29,335	TGP 1597		7.1%	13.7%
TGP ConneXion	11,600	TGP 64025, TGP 64026		2.8%	5.4%
Dawn via PNGTS	29,000	TGP 62930, TGP 330580	Union M12274, TCPL 60659, TCPL 58577, PNGTS 210203	7.0%	13.5%
AIM	18,000	AGT 510801	MPL 214129	4.4%	8.4%
TETCO CDS Long Haul	45,934	AGT 93011E	TETCO 800303	11.1%	21.5%
TCO Appalachia	40,000	AGT 90107, AGT 90106, AGT 9001	TCO 31524, TCO 31523	9.7%	18.7%
AGT M3	18,099	AGT 93011E, AGT 90106, AGT 93401S, AGT 90107, AGT 9001		4.4%	8.5%
Dracut	20,000	TGP 62930		4.8%	9.3%
TETCO SCT Long Haul	2,099	AGT 93001ESC	TETCO 800156	0.5%	1.0%
Niagara	**1,067**	TGP 39173		0.3%	
Dawn via Waddington	**1,000**	TGP 95345	Union M12164, TCPL 42386, IGTS 50001	0.2%	
Transco	**1,240**	AGT 90106, AGT 96004SC	Transco 9081767	0.3%	
Dominion	**537**	AGT 96004SC		0.1%	
	217,911			52.7%	
Storage	37,357	TGP 10807, AGT 9W009E, AGT 9B105, AGT 933005, AGT 90106, AGT 9B105, AGT 9S100S		9.0%	
	37,357			9.0%	
Peaking	158,100	TGP 330581; TGP 330580; NGLNG; Exeter; DOMAC		38.2%	
	158,100			38.2%	
TOTAL	413,368			100.0%	

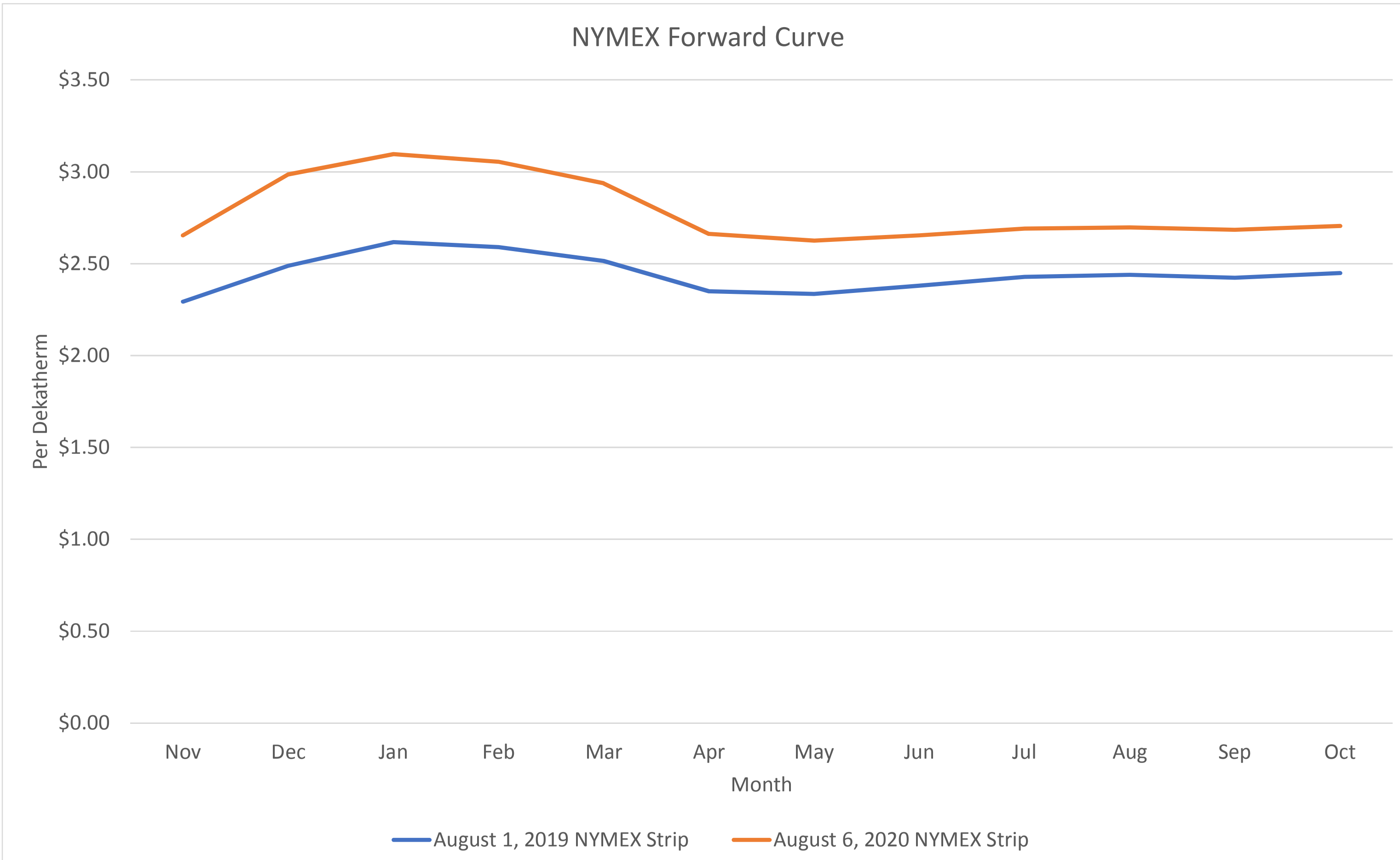
National Grid Rhode Island
Customer Choice Transportation Fixed Costs
2020/21

Sales & Customer Choice		
Annual Transportation Demand ($000)	$	67,983
Managed Capacity (Dth/day)		3,844
Annual Managed Capacity Demand ($000)	$	553
Design Day Transportation (Dth)		217,911
Daily Demand Per Design Day Dth	$	0.855
Sales Only		
Annual Transportation Demand ($000)	$	55,536
Managed Capacity (Dth/day)		3,473
Annual Managed Capacity Demand ($000)	$	499
Design Day Transportation (Dth)		178,042
Daily Demand Per Design Day Dth	$	0.854
Customer Choice		
Annual Transportation Demand ($000)	$	12,447
Managed Capacity (Dth/day)		371
Annual Managed Capacity Demand ($000)	$	53
Design Day Transportation (Dth)		39,498
Daily Demand Per Design Day Dth	$	0.859

Attachment GSP-2

NYMEX Strip Comparison & Forward Curves

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 1, 2019 NYMEX Strip	$2.293	$2.488	$2.617	$2.589	$2.514	$2.349	$2.335	$2.380	$2.427	$2.438	$2.422	$2.449
August 6, 2020 NYMEX Strip	$2.654	$2.985	$3.096	$3.053	$2.936	$2.661	$2.625	$2.654	$2.690	$2.697	$2.684	$2.704



SUPPLY AREA BASIS SUMMARY

November 2020 - October 2021

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
08/06/2020 NYMEX	$2.654	$2.985	$3.096	$3.053	$2.936	$2.661	$2.625	$2.654	$2.690	$2.697	$2.684	$2.704

SUPPLY AREA	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
TENN Z4	($0.422)	($0.270)	($0.192)	($0.181)	($0.156)	($0.221)	($0.290)	($0.339)	($0.326)	($0.351)	($0.516)	($0.506)
NIAGARA	($0.346)	($0.321)	($0.316)	($0.276)	($0.196)	($0.109)	($0.221)	($0.259)	($0.264)	($0.264)	($0.261)	($0.311)
IROQUOIS RECEIPTS	($0.085)	$0.594	$2.090	$1.934	$0.125	($0.190)	($0.249)	($0.141)	($0.148)	($0.173)	($0.290)	($0.176)
TETCO M3	($0.110)	$0.790	$2.172	$2.093	$0.342	($0.250)	($0.360)	($0.382)	($0.308)	($0.310)	($0.620)	($0.568)
DRACUT	$0.971	$2.646	$3.705	$3.659	$1.591	$0.594	$0.049	($0.001)	$0.106	$0.107	($0.179)	$0.024
TCO	($0.362)	($0.305)	($0.295)	($0.285)	($0.310)	($0.267)	($0.305)	($0.360)	($0.362)	($0.393)	($0.480)	($0.520)
DAWN	($0.055)	($0.023)	($0.018)	$0.027	$0.092	($0.067)	($0.180)	($0.218)	($0.222)	($0.223)	($0.220)	($0.270)
TETCO M2	($0.600)	($0.430)	($0.405)	($0.385)	($0.375)	($0.370)	($0.470)	($0.498)	($0.515)	($0.543)	($0.692)	($0.682)
TRANSCO LEIDY	($0.645)	($0.493)	($0.510)	($0.460)	($0.475)	($0.520)	($0.577)	($0.602)	($0.565)	($0.605)	($0.782)	($0.752)
ALGONQUIN	$0.828	$2.500	$3.548	$3.517	$1.432	$0.335	($0.213)	($0.242)	($0.145)	($0.143)	($0.408)	($0.238)
TENN Z6	$0.690	$2.485	$3.515	$3.500	$1.498	$0.327	($0.217)	($0.248)	($0.150)	($0.147)	($0.412)	($0.245)
DOMINION SP	($0.590)	($0.440)	($0.440)	($0.417)	($0.410)	($0.397)	($0.467)	($0.512)	($0.502)	($0.527)	($0.688)	($0.685)
DOMINION NP	($0.740)	($0.590)	($0.590)	($0.567)	($0.560)	($0.487)	($0.557)	($0.602)	($0.592)	($0.617)	($0.778)	($0.775)
IROQUOIS Z1	($0.085)	$0.594	$2.090	$1.934	$0.125	($0.190)	($0.249)	($0.141)	($0.148)	($0.173)	($0.290)	($0.176)
LEIDY HUB	($0.403)	($0.300)	($0.320)	($0.244)	($0.303)	($0.347)	($0.497)	($0.528)	($0.442)	($0.524)	($0.728)	($0.685)
MILLENNIUM EAST POOL	($0.605)	($0.425)	($0.458)	($0.525)	($0.545)	($0.457)	($0.520)	($0.590)	($0.545)	($0.533)	($0.692)	($0.688)
TENN Z6 NORTH	$0.828	$2.497	$3.548	$3.515	$1.432	$0.333	($0.213)	($0.242)	($0.145)	($0.143)	($0.408)	($0.238)

Attachment GSP-3

Rule Curves

Operational Parameters
Non-Daily Metered FT-2 Storage and Peaking Resources

The following Operational Parameters are pursuant to RIPUC NG-GAS No. 101, Section 6, Schedule C:

Effective Period: November 1, 2020 through October 31, 2021

Underground Storage:

Maximum Inventory Level at any time is 100% of MSQ-U
Injections are not allowed.
Minimum Inventory Levels:

November 1	95%
November 15	95%
December 1	94%
December 15	85%
January 1	75%
January 15	65%
February 1	52%
February 15	41%
March 1	31%
March 15	22%
April 1	13%

Peaking Inventory:

Inventory Level allocated on November 1, 2020 = MSQ-P
Injections are not allowed.
Minimum Inventory Levels:

November 1	100%
December 1	87%
January 1	79%
February 1	49%
March 1	31%
April 1	0%

MSQ-U	Maximum Storage Quantity - Underground
MDQ-U	Maximum Daily Quantity - Underground
MSQ-P	Maximum Storage Quantity - Peaking
MDQ-P	Maximum Daily Quantity - Peaking

Attachment GSP-4

Attachment GSP-4

Customer Choice Storage Pricing

Customer Choice Storage Pricing 2020-2021

SLF - Weighted Average Loss Factor on Storage Withdrawals

Storage	Withdrawals	Fuel %	Fuel Vol.	Fuel Avg.
TENN 501	505,461	0.00%	0	
GSS 300170	473,272	0.00%	0	
GSS 300168	149,429	0.00%	0	
GSS 300171	183,150	0.00%	0	
GSS-TE 600045	726,693	0.00%	0	
TETCO 400515	54,941	0.54%	297	
TETCO 400221	1,152,392	1.81%	20,858	
TETCO 400185	50,430	1.81%	913	
GSS 300169	198,049	0.00%	0	
COL FSS 9630	197,838	0.00%	0	
TENN 62918	203,700	0.00%	0	
	3,895,355		22,068	**0.5665%**

WWCC - Weighted Average Commodity Cost of Storage Withdrawals

Storage	Withdrawals	Unit Cost	Cost	Average
TENN 501	505,461	$0.0087	$4,398	
GSS 300170	473,272	$0.0153	$7,241	
GSS 300168	149,429	$0.0153	$2,286	
GSS 300171	183,150	$0.0153	$2,802	
GSS-TE 600045	726,693	$0.0201	$14,607	
TETCO 400515	54,644	$0.0477	$2,607	
TETCO 400221	1,131,534	$0.0740	$83,733	
TETCO 400185	49,517	$0.0740	$3,664	
GSS 300169	198,049	$0.0153	$3,030	
COL FSS 9630	197,838	$0.0153	$3,027	
TENN 62918	203,700	$0.0087	$1,772	
	3,873,287		$129,167	**$0.0333**

PLF - Weighted Average Loss Factor on Pipeline Contracts Used to Deliver Storage Withdrawals

Storage	Transported		Fuel %		Fuel Vol.	Fuel Avg.
TENN 501	505,461			1.22%	6,167	
GSS 300170	473,272		1.95%	1.22%	14,890	
GSS 300168	149,429			1.22%	1,823	
GSS 300171	183,150		1.29%	0.95%	4,080	
GSS-TE 600045	726,693		1.55%	0.95%	18,060	
TETCO 400515	54,644		2.35%	0.95%	1,789	
TETCO 400221	1,131,534			0.95%	10,750	
TETCO 400185	49,517			0.95%	470	
GSS 300169	198,049	1.95%	0.00%	0.95%	5,707	
COL FSS 9630	197,838		1.686%	0.95%	5,183	
TENN 62918	203,700			1.22%	2,485	
	3,873,287				71,404	**1.8435%**

PCC - Weighted Average Commodity Cost on Pipeline Contracts Used to Deliver Storage Withdrawals

Storage	Withdrawals		Unit Cost		Cost	Average
TENN 501	499,294			$0.1013	$50,579	
GSS 300170	458,382		$0.0175	$0.1013	$54,456	
GSS 300168	147,606			$0.1013	$14,952	
GSS 300171	179,070		$0.0478	$0.0637	$19,966	
GSS-TE 600045	708,633		$0.0782	$0.0637	$100,555	
TETCO 400515	52,855		$0.0660	$0.0637	$6,857	
TETCO 400221	1,120,784			$0.0637	$71,394	
TETCO 400185	49,047			$0.0637	$3,124	
GSS 300169	192,342	$0.0175	$0.0478	$0.0595	$24,004	
COL FSS 9630	192,655		$0.0180	$0.0637	$15,740	
TENN 62918	201,215			$0.1013	$20,383	
	3,801,883				$382,011	**$0.1005**

Attachment GSP-5

Attachment GSP-5

RFPs for PXP Phases I, II, & III

Request for Proposals ("RFP") for Asset Management Arrangements August 4, 2020

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for Asset Management Arrangements ("AMA") to manage all or a portion of its path originating at Dawn, Ontario for delivery at its city-gate on Tennessee Gas Pipeline ("TGP") in Zone 6 via Portland Natural Gas Transmission System ("PNGTS") as more fully set forth below. The successful bidder ("Seller") shall have the right to optimize the assigned assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

I. Provisions

Package No. 1 - AMA – Canadian Only (PXP Phases I&II)

Term: November 1, 2020 through October 31, 2021.

Assets: Beginning November 1, 2020, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union Gas Limited ("Union")	M12	15,757	16,625	Dawn	Parkway
TransCanada Gas Pipelines Limited ("TCPL")	FT	15,757	16,625	Parkway	East Hereford

Assignment of Assets/ Compliance with Buyer's State Retail Choice Program: Effective November 1, 2020, National Grid may begin allocating a portion of the Assets contemplated in this Package No. 1 to participants of its State Approved Retail Access Program ("Program") each month. Volumes assigned under the Program are made available to National Grid five business days before the 1st of each month and may change on a monthly basis. Based on historical activity National Grid expects approximately 25% of the subject assets to be reserved each month for the Program. **Bidders must therefore submit their asset management fee for this Package No. 1 on a volumetric basis** and must take all necessary actions to allow National Grid to administer the Program; the volume Buyer shall assign to Seller for each Month of the Term shall be communicated at least five Days prior to the start of the Month of production**. For avoidance of doubt, Seller shall not be responsible for supplying Buyer's Program participants with gas supply.**

The Assets shall be assigned by Buyer for the entire Term at no cost to Asset Manager; notwithstanding the foregoing, Asset Manager shall initially pay the demand charges and Buyer shall reimburse Asset Manager for 100% of the demand charges related to the Assets and for all imputed variable charges related to the volumes delivered by Asset Manager on behalf of Buyer; reimbursement for such charges shall be paid to Asset Manager in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Asset Manager shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. Buyer and Asset Manager each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Asset Manager and to comply with Buyer's Program. All assignments shall be subject to recall in the event that the Asset Manager fails to meet its gas supply obligation to Buyer.

Delivery Point: The Delivery Point shall be the point of interconnection between TCPL and PNGTS known as East Hereford, on the U.S. side.

Gas Supply Requirements: On any day during the period of **November 1, 2020 through April 30, 2021** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at East Hereford. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TCPL, as well as the volume assigned pursuant to the Program. Subject to satisfaction of these Gas Supply Requirements and the following criteria, Asset Manager shall have the right to optimize the assigned capacity for its own account:

(a) Base-Load Election: At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at East Hereford up to the MDQ made available to Seller during this delivery period.

(b) Daily Call: Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ at East Hereford.

Price:

The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to East Hereford.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to East Hereford.

Daily Call Nominations:

Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e*., nominated ratably on the Business Day prior to the Holiday).

Subject to the Gas Supply Requirements, the Program and Buyer's right to elect either Daily Call or Base-Load Gas purchases, Seller shall have the right to optimize the assigned capacity for its own account. Seller shall communicate to Buyer any upstream changes to supply contracts nominated pursuant to this section no later than 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow. Acceptance of changes to upstream supply arrangements communicated by Seller of Buyer after 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow shall be at Buyer's discretion. Consistent with the terms of the Transaction Confirmation and the deliverability of the Assets, Buyer may nominate, and Seller must supply those supplies unaccounted for after the 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow deadline from the Assets assigned to Seller by Buyer.

Asset Management Fee:

Subject to satisfying the Gas Supply Requirements associated with the AMA and compliance with Buyer's right to assign volumes under the Program, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA for the full MDQ assignable, as well as on a volumetric basis.**

Import/Export Reporting: Any import/export reporting requirement applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

Package No. 2 – AMA – Canadian Only (PXP Phase III)

Term: November 1, 2020 through October 31, 2021.

Assets: National Grid is currently party to a precedent agreement with PNGTS for the transportation of Gas from Dawn, Ontario to Dracut, MA Union, TCPL and PNGTS to serve its firm on TGP. On June 19, 2018, PNGTS filed an application with the Federal Energy Regulatory Commission ("FERC") to satisfy the requirements of Phase II of the Portland Xpress Project to achieve an in-service date of November 1, 2020 [CP18-506]; authorization of the necessary facilities by the FERC is a condition precedent of a transaction confirmation resulting from this RFP and necessary for the agreement between National Grid and PNGTS to become effective.

Once the agreement is effective, PNGTS will assign the corresponding upstream TCPL capacity to National Grid and, at that time, National Grid shall also have the right to take assignment of the corresponding volume of upstream Union capacity to feed TCPL. Following such assignments, National Grid will have transportation service agreements: with Union from Dawn to Parkway; with TCPL from Parkway to East Hereford; and with PNGTS from East Hereford to Dracut.

Beginning November 1, 2020, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	3,300	3,482	Dawn	Parkway
TCPL	FT	3,300	3,482	Parkway	East Hereford

Assignment of Assets:

The Assets shall be assigned by Buyer for the entire Term at no cost to Asset Manager; notwithstanding the foregoing, Asset Manager shall initially pay the demand charges and Buyer shall reimburse Asset Manager for 100% of the demand charges related to the Assets and for all imputed variable charges related to the volumes delivered by Asset

Manager on behalf of Buyer; reimbursement for such charges shall be paid to Asset Manager in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Asset Manager shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. Buyer and Asset Manager each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Asset Manager. All assignments shall be subject to recall in the event that the Asset Manager fails to meet its gas supply obligation to Buyer.

Delivery Point: The Delivery Point shall be the point of interconnection between TransCanada and PNGTS known as East Hereford, on the U.S. side.

Gas Supply Requirements: On any day during the period of **November 1, 2020 through April 30, 2021** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at East Hereford. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union and TCPL. Subject to satisfaction of these Gas Supply Requirements and the following, Asset Manager shall have the right to optimize the assigned capacity for its own account:

(a) Base-Load Election: At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ made available to Seller during this delivery period.

(b) Daily Call: Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ at East Hereford.

Price: The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to East Hereford.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to East Hereford.

<u>Daily Call Nominations</u>: Buyer shall make all nominations for delivery at East Hereford of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e*., nominated ratably on the Business Day prior to the Holiday).

Subject to the Gas Supply Requirements and Buyer's right to elect to purchase Gas pursuant to either a Daily Call or Base-Load Election, Seller shall have the right to optimize the assigned capacity for its own account. Seller shall communicate to Buyer any upstream changes to supply contracts nominated pursuant to this section no later than 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow. Acceptance of changes to upstream supply arrangements communicated by Seller of Buyer after 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow shall be at Buyer's discretion. Consistent with the terms of the Transaction Confirmation and the deliverability of the Assets, Buyer may nominate, and Seller must supply those supplies unaccounted for after the 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow deadline from the Assets assigned to Seller by Buyer.

<u>Asset Management Fee:</u> Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA.**

<u>Asset Management Fee:</u> Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA and <u>how the Asset Management Fee will be impacted if the condition precedent related to the in-service of Phase II of the Portland Xpress Project does not occur on November 1, 2019</u>.**

<u>Import/Export Reporting</u>: Any import/export reporting requirement applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy

Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

Package No. 3 - AMA – U.S. and Canadian (PXP Phases I&II)

Term: November 1, 2020 through October 31, 2021.

Assets: Beginning November 1, 2020, National Grid is seeking an AMA using the following Assets:

Pipeline	Rate Schedule	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Union	M12	10,000	10,550	Dawn	Parkway
TCPL	FT	10,000	10,550	Parkway	East Hereford
PNGTS	FT	10,000	n/a	Pittsburg	Dracut
TGP	FT-A	10,000	n/a	Dracut	Zone 6

Assignment and Release of Assets: The Assets shall be assigned/released by Buyer for the entire Term at no cost to Asset Manager; notwithstanding the foregoing, Asset Manager shall initially pay the demand charges and Buyer shall reimburse Asset Manager for 100% of the demand charges related to Union and TCPL and for all imputed variable charges related to the volumes delivered by Asset Manager on behalf of Buyer; reimbursement for such charges shall be paid to Asset Manager in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Asset Manager shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. Buyer and Asset Manager each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Asset Manager. All assignments shall be subject to recall in the event that the Asset Manager fails to meet its gas supply obligation to Buyer.

Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. *National Grid currently has a negotiated rate with PNGTS which is included herewith. National Grid shall not be responsible for loss of discount resulting from such inaction.*

The parties intend that any transaction entered into pursuant to this RFP shall be structured as an Asset Management Agreement pursuant to FERC Order 712 and any other applicable rules or regulations. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point: Unless otherwise specified by Buyer, the Delivery Point for Gas purchased hereunder shall be the point of interconnection between Buyer's facilities and TGP in TGP's Zone 6.

Gas Supply Requirements: On any day during the period of **November 1, 2020 through April 30, 2021** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Delivery Point on the U.S. assets of PNGTS and TGP. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union, TCPL, PNGTS and TGP. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

(a) Base-Load Election: At least three business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point on TGP up to the MDQ made available to Seller during this delivery period.

(b) Daily Call: Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ at TGP Zone 6.

(c) Additional Call: In addition to the Base-Load Election and the Daily Call, on any Day during the delivery period of November 1, 2020 through and including April 30, 2021, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity at the primary delivery point released by Buyer to Seller for each of the PNGTS and TGP Asset(s). Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to these Gas Supply Requirements shall not be cumulative, and the Additional Call may only be exercised after Buyer has exhausted its rights pursuant to the Base-Load Election and Daily Call (i.e., Buyer's right to request gas at any Delivery Point pursuant to this Additional Call provision shall be reduced by quantities already requested).

Price: The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily –*

Daily Price Survey ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to Buyer's City-Gate in TGP Zone 6.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to Buyer's City-Gate in TGP Zone 6.

The commodity price for Gas called on through the Additional Call shall be equal to TGP Zone 6 South + $0.05.

<u>Nominations</u>:

For calls at the Delivery Point at Buyer's City-Gate in TGP Zone 6, Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nominations shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Subject to the Gas Supply Requirements, Seller shall have the right to optimize the assigned capacity for its own account. Seller shall communicate to Buyer any upstream changes to supply contracts nominated pursuant to this section no later than 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow. Acceptance of changes to upstream supply arrangements communicated by Seller of Buyer after 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow shall be at Buyer's discretion. Consistent with the terms of the Transaction Confirmation and the deliverability of the Assets, Buyer may nominate, and Seller must supply those supplies unaccounted for after the 1:00 PM prevailing Eastern Standard Time on the Day prior to the Day of Gas flow deadline from the Assets assigned to Seller by Buyer.

Upon execution of a binding Transaction Confirmation, or adequate assurance that the Buyer and Seller intend the Transaction be binding by the first date of the Term, Buyer shall arrange for Seller's use and access of the National Grid Electronic Bulletin Board ("EBB"). Seller shall utilize EBB to schedule the supply to the Delivery Point on TGP, Buyer's city gate, for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the AMA for the full MDQ assignable, as well as on a volumetric basis.**

Import/Export Reporting: Any import/export reporting requirement applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

II. Instructions to Bidders

National Grid will consider Proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Included in this RFP is the form of Transaction Confirmation that National Grid proposes for execution. As part of their Proposal(s), Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation including, but not limited to, language related to FERC, the CFTC and any other applicable regulatory body.

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals must include: **(a) Seller's proposed Reservation Charge for the Package, (b) any specialized language Seller requires in the Transaction Confirmation, and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

III. Schedule (all times are Eastern Standard Time)

August 14, 2020 Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 21, 2020.**

IV. Miscellaneous

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgridus.com/media/procurement/supplier_code_of_conduct.pdf.

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

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Attachment GSP-6

RFP for AMA Dawn Waddington to Zone 6 Lincoln

Request for Proposals ("RFP") for Asset Management Arrangement August 4, 2020

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for an Asset Management Arrangement ("AMA") as more fully set forth below. The successful bidder ("Seller" or "Asset Manager") shall have the right to optimize the assigned assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements set forth below.

Package No. 4 – AMA (Dawn-Waddington-Zone 6)

I. Provisions:

Term: November 1, 2020 through October 31, 2021.

Delivery Period: November 1, 2020 through and including March 31, 2021.

Release/Assignment of Assets: The Assets to be assigned and released are set forth below. The Assets shall be assigned/released by Buyer for the entire Term at no cost to Seller. Buyer shall remain responsible for payment of all demand charges related to the Assets (except any potential loss of discount related to activities of Seller). Notwithstanding the forgoing, Seller shall initially pay the Union and TransCanada demand charges and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets; reimbursement for such charges shall be paid to Seller in U.S. dollars and based on Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the assignment of the Assets from Buyer to Seller. All assignments shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Assigned Assets: During the Term, Buyer shall assign firm transportation capacity on the following pipelines:

Union Gas Limited ("Union Gas")
TransCanada Pipelines Limited ("TransCanada")
Iroquois Gas Transmission System, L.P. ("Iroquois")
Tennessee Gas Pipeline Company, L.L.C. ("Tennessee")

Please see table below for contract details.

Pipeline	Contract	Quantity Dt/day	Quantity Gj/day	Receipt Point	Delivery Point
Union	M12164	1,025	1,081	Dawn	Parkway
TransCanada	42386	1,012	1,068	Parkway	Waddington
Iroquois	50001	1,012	NA	Waddington	Wright
Tennessee	95345	1,000	NA	Wright	Lincoln, RI

Delivery Point: The Delivery Point shall be the primary Delivery Point(s) of the FERC regulated Assets.

Gas Supply Requirements: On any day during the period of **November 1, 2020 through March 31, 2021** of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the *Tennessee Delivery Point.* The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union, TransCanada, Iroquois and Tennessee. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

(a) At least five business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this delivery period.

(b) Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

Additional Call – In addition to the Gas Supply Requirements above, on any Day during the period of November 1, 2020 through March 31, 2021 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity of each of the Iroquois and Tennessee Assets at the primary Delivery Point(s) under each such released Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm Base-Load and daily call supplies (*i.e.*, Buyer's right to request gas at the Iroquois or Tennessee Delivery Point pursuant to these Gas Supply Requirements provisions and under this Additional Call provision shall be reduced by quantities requested at any upstream Delivery Point).

Nominations:

Buyer shall make all nominations for delivery of Gas hereunder prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on Business Day prior to the Holiday).

Upon execution of a binding Transaction Confirmation, or adequate assurance that the Buyer and Seller intend the Transaction be binding by the first date of the Term, Buyer shall arrange for Seller's use and access of the National Grid Electronic Bulletin Board ("EBB"). Seller shall utilize EBB to schedule the supply to the Delivery Point on Tennessee, Buyer's city gate, for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

Price:

The commodity price for Gas called on through the exercise of a daily call shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Tennessee Delivery Point.

The commodity price for Gas called on through the Base-Load option shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Tennessee Delivery Point.

The commodity price for Gas called on through Additional Call shall be the greater of the Daily Call Price or the *Platts Gas Daily Daily Price Survey* price for Tennessee Zone 6 South Pool plus $0.10 per dt.

Asset Management Fee:

Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal, Bidders should specify the total proposed Asset Management Fee to be paid to Buyer for the Term.**

Form of Agreement:

Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB

Contract or ISDA Gas Annex. Included with this RFP is the form of Transaction Confirmation that National Grid proposes for execution. **As part of their Proposal, Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation.**

Import/Export Reporting: Any import/export reporting requirements applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

Submission of Proposals: Proposals must be submitted by the date specified in the Schedule below. Proposals must include: **(a) Seller's proposed Asset Management Payment or Price for the AMA Package, (b) any proposed exceptions to the Transaction Confirmation and (c) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

II. Instructions to Bidders:

Proposals must be submitted by the date specified in the Schedule below via email to the following email address:

GasRFP@nationalgrid.com.

Any questions in connection with this RFP should be sent via email to the email address provided above.

III. Schedule (all times are Eastern Standard Time):

August 14, 2020 — Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 21, 2020.**

V. Form of Agreement:

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Contract or ISDA Gas Annex. Please be advised that if the Winning

Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the CSA.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered by National Grid, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. Potential Sellers shall be subject to satisfactory credit review by National Grid.

VI. Compliance with National Grid's Supplier Code of Conduct:

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgridus.com/media/procurement/supplier_code_of_conduct.pdf.

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

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Director of FERC Compliance and Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning
Telephone: 781-907-1639

MaryBeth Carroll
Manager of Gas Supply Planning
Telephone: 516-545-3116

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

nationalgrid

Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid

TRANSACTION CONFIRMATION

Date: ____________

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposals for Asset Management Arrangements dated August 4, 2020. This Transaction Confirmation is subject to the Base Contract between Seller and Buyer, dated ________.
This Transaction Confirmation will not become binding until executed by both parties.

SELLER:	BUYER:
Attn: Phone: Fax: Transporters: Transporters Contract Number: Trader:	The Narragansett Electric Company d/b/a National Grid 100 East Old County Road Hicksville, New York 11801 Attn: Contract Administration Phone: (516) 545-6068 Fax: (516) 545-5466 Transporters: Union Gas Limited ("Union"), TransCanada Pipelines Limited ("TransCanada"), Iroquois Gas Transmission System, L.P. ("Iroquois") Tennessee Gas Pipeline Company, L.L.C. ("Tennessee"). Transporters Contract Number: Trader: Samara Jaffe

Contract Price: **See Special Conditions Section C below.**

Term: Begin: November 1, 2020 **End: October 31, 2021**

Performance Obligation and Contract Quantity: See Special Conditions below.

Delivery Point(s): Subject to Buyer's right to exercise the Additional Call, the primary Delivery Point shall be the point of interconnection between Tennessee and Buyer's distribution system that is the primary Delivery Point under the Tennessee Asset.

Special Conditions:

A. Definitions

"Assets" means the Agreements summarized as follows:

Pipeline	Contract	Quantity Dt/day	Quantity Gj/day	Receipt Point	Delivery Point
Union	M12164	1,025	1,081	Dawn	Parkway
TransCanada	42386	1,012	1,068	Parkway	Waddington
Iroquois	50001	1,012	NA	Waddington	Wright
Tennessee	95345	1,000	NA	Wright	Lincoln, RI

"CFTC" shall mean the Commodities Futures Trading Commission.

"Credit Support Provider" means__________________________.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"EBB" means Buyer's Electronic Bulletin Board utilized for confirmation of Gas. "FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A" by S&P and "A2" by Moody's in a form reasonable acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Services, Inc., or its successor.

"S&P" means S&P Global Ratings, or its successor.

B. Gas Service and Capacity Assignment

1. **Release and Assignment of Assets:** During the Term, Buyer will release/assign, on a pre-arranged, non-biddable basis, at no cost to Seller, the Assets. Buyer shall be responsible for the payment of all demand charges related to the Assets. Notwithstanding the foregoing, Seller shall initially pay the demand charges to TransCanada and Union and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets for the volumes delivered by Seller to Buyer under this Transaction Confirmation. Reimbursement of such charges shall be paid in U.S. dollars and based on the Bank of Canada's monthly average exchange rate for the month of business as published on the last business day of the month of production. Seller shall be responsible for all variable costs in connection with the Assets during the Term unrelated to deliveries for Buyer. Buyer and Seller each agree to take such actions and execute all documents as may be required to effectuate the assignment of the Assets from Buyer to Seller. All assignments shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

2. **Gas Supply Requirements:**

A. On any day during the period of November 1, 2020 through March 31, 2021 of the Term, Buyer shall have the right, but not the obligation, to call on Seller to deliver up to the MDQ at the Tennessee Delivery Point. The MDQ shall be adjusted upward or downward based upon the deliverability and applicable fuel retention on each of Union, TransCanada, Iroquois and Tennessee. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account. Subject to the following:

i. At least five business days prior to the 1st day of the following month of delivery, Buyer shall have the right, but not the obligation, to request Base-Load delivery of such Gas Supply at the Delivery Point up to the MDQ during this delivery period.

ii. Further, subject to Buyer having exercised its Base-Load rights, Buyer shall have a right to call on a quantity up to the remaining MDQ.

iii. Additional Call – In addition to the Gas Supply Requirements set forth in Special Condition B(2)(A) of this Transaction Confirmation, on any Day during the period of November 1, 2020 through March 31, 2021 of the Term, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the contract quantity of each of the Iroquois and Tennessee Assets at the primary Delivery Point(s) under each such released Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to all Gas Supply Requirements provisions above shall not be cumulative and may only be exercised after Buyer has exhausted its rights pursuant to firm base-load and daily call supplies (i.e., Buyer's right to request gas at the Iroquois or Tennessee Delivery Point(s) pursuant to these Gas Supply Requirements provisions and under this Additional Call provision shall be reduced by quantities requested at any upstream Delivery Point).

B. Termination Right: If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Nominations

Buyer shall make all nominations for all delivery of Gas hereunder prior to 10:00 a.m. prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (i.e., nominated ratably on Business Day prior to the Holiday).

Buyer shall arrange for Seller's use and access of the EBB. Seller shall utilize the EBB to schedule all Gas purchased pursuant to this AMA to the Delivery Point(s) for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

D. Price The commodity price for Gas purchased pursuant to Special Condition 2 shall be as follows:

1. The commodity price for Gas called on through the exercise of a daily call pursuant to Special Condition B(2)(A)(ii) shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

2. The commodity price for Gas called on through the Base-Load option pursuant to Special Condition B(2)(A)(i) shall be equal to *Platts Inside FERC* for Dawn, Ontario, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

3. The commodity price for Gas called on through the Additional Call option pursuant to Special Condition B(2)(B) shall be equal to the greater of the Daily Call Price or the *Platts Gas Daily Daily Price Survey* price for Tennessee Zone 6 South Pool plus $0.10 per dt.

E. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the assigned capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $___________, payable in equal monthly installments of $______.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB by S&P and/or Baa2 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement' for Seller means the Exposure (as defined below), minus the sum of (i) the amount of cash previously transferred by Seller to Buyer, (ii) the amount of cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of Buyer, and (iii) the undrawn value of each such Letter of Credit; provided, however, that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller has a Credit Rating of at least BBB from S&P and/or Baa2 from Moody's, and (ii) no Event of Default with respect to Seller has occurred and is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB by S&P and/or Baa2 by Moody's, (b) cash, or (c) a Letter of Credit. The "collateral Requirement" for Buyer means zero (0).

"Exposure" shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

G. Import/Export Reporting

Any import/export reporting requirements applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the National Energy Board, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service, or any other regulatory body having jurisdiction over the volumes, are the responsibility of Asset Manager.

H. Changes in Law

If the FERC, CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Transaction Confirmation or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller:	Buyer: The Narragansett Electric Company d/b/a National Grid

By: ______________________________________ Name: Title: Date:	By:____________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Attachment GSP-7

Attachment GSP-7

RFPs for AMA Dracut to Citygate & Dracut Supply

nationalgrid

Request for Proposals ("RFP") for The Narragansett Electric Company d/b/a National Grid Asset Management Arrangement ("AMA") and Gas Supply August 4, 2020

The Narragansett Electric Company d/b/a National Grid ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an AMA (Package No. 5) *and/or* Gas Supply (Package No. 6) in order to fill its requirements at Dracut as more fully set forth below. The successful bidder(s) ("Seller") shall have the right to optimize the assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements. **Bidders may bid on all or a portion of the MDQ for each Package.**

Package No. 5 – AMA (Dracut to City Gate)

I. Provisions

Term: November 1, 2020 through October 31, 2021.

Assets: During the Term, Buyer shall release FT-A capacity with Tennessee Gas Pipeline Company L.L.C. ("TGP"), having primary receipts at Dracut, MA (pin number 412538) and primary deliveries in Zone 6 at the point(s) of interconnection between TGP and Buyer's facilities in Cranston, RI, (pin number 420750) The maximum delivered quantity of the Assets is **7,500 dt/day** ("MDQ").

The Assets shall be released by Buyer for the entire Term at no cost to Seller. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

Delivery Point: The point of interconnection between TGP and Buyer's facilities at Cranston, RI.

Gas Supply Requirements: On any day during the period of **December 1, 2020 through April 30, 2021**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point. Subject to satisfaction of these Gas Supply Requirements, Asset Manager shall have the right to optimize the assigned capacity for its own account.

Price: For the first 75,000 dth which Buyer exercises the call option pursuant to Gas Supply Requirements, the Price shall be equal to the price for Tennessee, Zone 6, Delivered North - as published in *Platts Gas Daily Daily Price Survey* for the day of flow, plus the variables to transport Gas to the Delivery Point. After Buyer has exercised the first 75,000 dth of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to Tennessee, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* $0.10, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

Daily Call Nominations: Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday). **As part of their proposals, Bidder(s) should specify if they are able to offer non-ratable service.**

Upon execution of a binding Transaction Confirmation, or adequate assurance that the Buyer and Seller intend the transaction be binding by the first date of the Term, Buyer shall arrange for Seller's use and access of the National Grid Electronic Bulletin Board ("EBB"). Seller shall utilize EBB to schedule the supply to the Delivery Point on Tennessee, Buyer's city gate, for confirmation by National Grid's Gas Control. Use of the EBB for other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal, Bidders must specify the Asset Management Fee to be paid to Buyer.**

Package No. 6– Gas Supply (Dracut)

Term: December 1, 2020 through April 30, 2021.

Delivery Point: The Delivery Point shall be the interconnection between TGP and Maritimes & Northeast Pipeline, LLC, DART Pin No. 412538, located in Dracut, Massachusetts.

Gas Supply Requirements:	On any day during the Term, Buyer shall have the right, but not the obligation, to call on a maximum daily quantity up to 7,500 dth/day ("MDQ") and a maximum seasonal quantity ("MSQ") of 75,000 dth at the Delivery Point. Bidders may bid on all or a portion of the MDQ.
Nominations:	Buyer shall make all nominations for delivery of Gas hereunder prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on Business Day prior to the Holiday). **As part of their proposals, Bidder(s) should specify if they are able to offer non-ratable service.**
Price:	The commodity price for Gas called on any day will be equal to *Platts Gas Daily Daily Price Survey* – Tennessee, Zone 6, Delivered North for the day of flow.
Reservation Charge:	To be proposed by Bidder.
Daily Call Nominations:	For Daily Calls at the Delivery Point, Buyer shall make all nominations for delivery of Daily Call purchases prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested.

II. Instructions to Bidders

Any questions in connection with this RFP should be sent via email to the following email address:

GasRFP@nationalgrid.com.

All proposals in connection with this RFP should also be sent via email to the email address listed above. Proposals must be submitted by the date specified in the Schedule below. Proposals should include: **(a) Seller's proposed Asset Management Fee and/or Reservation Fee (b) any proposed exceptions to the Transaction Confirmation attached hereto for Package No. 5 (c) whether Bidder requires takes be ratable and (d) whether Seller shall require receipt of any additional internal approvals prior to accepting an award pursuant to this RFP.**

III. Schedule (all times are Eastern Time)

August 14, 2020	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 21, 2020.**

IV. Form of Agreement

National Grid will consider proposals only from Bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any other written or oral expression of communication. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP. The winning bid(s), if any, will be selected based on the proposal(s) that yield(s) the least cost, consistent with concerns for reliability of service and other business factors applied by National Grid in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by National Grid.

V. Compliance with National Grid's Supplier Code of Conduct

At National Grid we are always seeking ways to meet the evolving needs and desires of our customers. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values and can be accessed at https://www.nationalgridus.com/media/procurement/supplier_code_of_conduct.pdf.

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 3 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

National Grid has worked to establish the Natural Gas Supply Collaborative (NGSC). The NGSC is a voluntary collaborative of natural gas purchasers that are promoting safe and responsible practices for the development of natural gas supply. As a participant in the NGSC, National Grid is committed to encourage our natural gas suppliers and producers to support more robust voluntary reporting and increased transparency on 14 environmental and social performance indicators. The NGSC developed these indicators through a comprehensive stakeholder engagement undertaking including representation from both the environmental and natural gas production community.

As suppliers of natural gas to National Grid, it is our expectation that you will consider reporting on these 14 indicators. Over time, and in consultation with National Grid, we expect reporting on these 14 indicators will be fully embraced and easily identifiable on company web sites and may become a requirement for future business.

Supporting information on the NGSC can be found at the following Web site: http://www.mjbradley.com/NGSC

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Director of FERC Compliance and Contracting
Telephone: 516-545-3108

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MaryBeth Carroll
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Janet Prag
Senior Contract Specialist
Telephone: 516-545-5463

nationalgrid

Asset Management Arrangement (Package No. 5)
Transaction Confirmation
The Narragansett Electric Company d/b/a National Grid

TRANSACTION CONFIRMATION

		Date: ____________ Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangements dated August 4, 2020. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated ________. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:	BUYER:
_______ Attn:____ Phone:__ Fax:____ Base Contract No. _______ Transporters: ____ Transporters Contract Number: ___ Trader: _	The Narragansett Electric Company d/b/a National Grid 100 East Old County Road Hicksville, New York 11801 Attn: Contract Administration Phone: (516) 545-6068 Fax: (516) 545-5466 Base Contract No. Transporters: Tennessee Gas Pipeline Company, L.L.C. ("Tennessee") Trader: Samara Jaffe

Contract Price: See Special Conditions Section C Below

Term: Begin: November 1, 2020 End: October 31, 2021

Performance Obligation and Contract Quantity: See Special Conditions Below

Delivery Point(s): The point of interconnection between Tennessee and Buyer's facilities at Cranston, RI.

Special Conditions:

A. Definitions

"Assets" means Buyer's FT-A Contracts with Tennessee having primary receipts at Dracut, MA (pin number 412538) and primary deliveries in Zone 6 the point(s) of interconnection between Tennessee and Buyer's facilities in Cranston, RI (pin number 420750). The maximum delivered quantity of the Assets is **7,500 dt/day** ("MDQ").

"Credit Support Provider" means__________________________.

"CFTC" means the Commodity Futures Trading Commission.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"EBB" means Buyer's Electronic Bulletin Board utilized for confirmation of Gas.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Service, Inc. or its successor.

"S&P" means S&P Global Ratings, or its successor.

B. Gas Service and Capacity Release

a. **Release of Assets:** During the Term, Buyer shall release the Assets on a pre-arranged, non-biddable basis, at no cost to Seller. Buyer shall be responsible for the payment of all demand charges related to the Assets. Seller shall be responsible for all variable costs in connection with the Assets during the Term unrelated to deliveries for Buyer. Buyer and Seller each agree to take such actions and execute such documents as may be required to effectuate the release of the Assets from Buyer to Seller. All releases shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

b. **Daily Call:** On any day during the period of **December 1, 2020 through April 30, 2021**, Buyer shall have the right, but not the obligation, to call on a quantity of Gas up to the MDQ at the Delivery Point(s).

c. **Termination Option:** If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Price: For the 75,000 dth which Buyer exercises the call option pursuant to Gas Supply Requirements, the Price shall be equal to the price for Tennessee, Zone 6, Delivered North - as published in *Platts Gas Daily Daily Price Survey* for the day of flow, plus the variables to transport Gas to the Delivery Point. After Buyer has exercised 75,000 dth of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to Tennessee, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* $0.10, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

D. Nominations

Buyer shall make all nominations for delivery of all Gas Supply Requirements prior to 10:00 AM, prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Friday nomination shall be for Saturday through Monday (ratably). Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Buyer shall arrange for Seller's use and access of the EBB. Seller shall utilize the EBB to schedule all Gas purchased pursuant to this AMA to the Delivery Point(s) for confirmation by National Grid's Gas Control. Use of the EBB or other means of requests for confirmation of meter bounce transactions at the Delivery Point or other points of interconnection with Buyer's facilities shall be strictly prohibited.

E. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the released capacity for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $_______, payable in equal monthly installments of $_________. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to National Grid, (ii) the amount of Cash held by National Grid as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of National Grid ("Letter of Credit"), and (iii) the undrawn value of each Letter of Credit ; provided, however, that the Collateral Requirement of Seller will be deemed to be zero (0) if on the relevant Valuation Date, (i) no Event of Default with respect to Seller or its Credit Support Provider has occurred and is continuing, and (ii) the guaranty provided by Seller is in full force and effect. The "Collateral Requirement" for National Grid means zero (0).

Exposure. shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

G. Asset Management Arrangement

The Parties agree that the transactions hereunder constitute an Asset Management Arrangement, as defined by FERC in Order No. 712 (as modified and clarified) and in accordance with FERC's rules and regulations, and that Seller is acting as Asset Manager as defined in 18 CFR 284.8(h)(3).

H. Changes in Law

If the FERC, CFTC or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

Seller: By: ____________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company d/b/a National Grid By:___________________________________ Name: John V. Vaughn Title: Authorized Signatory Date:

Attachment GSP-8

Attachment GSP-8

RFP for AMA Columbia Gas Transmission (“TCo”) - FSS, ST & FTS Assets

nationalgrid

Request for Proposals ("RFP") for Asset Management Arrangement August 4, 2020

The Narragansett Electric Company d/b/a National Grid ("National Grid" or "Buyer") is seeking proposals ("Proposals") for an Asset Management Arrangement ("AMAs") using its Columbia Gas Transmission ("TCo") capacity and storage as more fully set forth below. The successful bidders ("Seller(s)") shall have the right to optimize the released/assigned assets ("Assets") subject to satisfying Buyer's gas supply requirements.

Package No. 7 – AMA (TCO)

Term: November 1, 2020 through October 31, 2021.

Released Assets: Buyer shall release the following assets, at no cost, to Seller:

(a) TCo FSS Contract No. 9630 with a maximum storage quantity ("MSQ") of 203,957 dt, a maximum daily injection quantity ("MDIQ") of 2,545 dt/day and a maximum daily withdrawal quantity ("MDWQ") of 2,545 dt/day. Such maximum rights and obligations are subject to the provisions of the TCo FSS Rate Schedule of the pipeline's FERC Gas Tariff including, but not limited to the Maximum Monthly Injection Quantities as more fully set forth below:

MDWQ		Month Limit	Min	Max
> 30%	2,545	November	none	81,583
20-30%	2,036	December	none	81,583
10-20%	1,654	January	none	81,583
< 10%	1,272	February	20,396	61,187
Apr - Sep	1,272	March	20,396	40,791

MMIQ		MDIQ	Max Inventory	
April	30,594	1,224		
May	40,791	1,632	Feb 1	132,572
June	40,791	1,632	Apr 1	50,989
July	40,791	1,632	Jun 30	122,374
August	36,712	1,468	Aug 31	173,363
September	26,514	1,061		
October	18,356	734		
November	10,198	340		
December	20,396	680		
January	20,396	816		
February	20,396	816		
March	20,396	816		

(b) TCo SST Contract No. 9631 having a maximum daily transportation quantity ("Storage MDQ") of 2,545 dt/day during the months of October through March with withdrawal rights from TCo FSS Contract No. 9630 for primary deliver to the point of interconnect between TCo and Algonquin Gas Transmission, LLC at Hanover

("TCo-Hanover"). During the months of April through September the Storage MDQ shall reduce to 1,272 dt/day; and

(c) TCo FTS Contract No. 31523 having a maximum daily quantity ("Transport MDQ") of 10,000 dt/day with primary receipts located at Broad Run and primary deliver to TCo-Hanover.

Transfer of Inventory: As of November 1, 2020, Buyer shall transfer and sell to Seller the inventory attributable to TCo FSS Contract No. 9630 ("Starting Balance"); the Starting Balance is expected to be ~97% of the MSQ. Seller shall be obligated to pay Buyer for such Gas by the payment date for sales occurring during October 2020 in accordance with the NAESB Agreement (or other agreement) between the parties. The price for such Gas shall be Buyer's weighted average cost of gas ("WACOG") for such storage field.

Supply Requirements: *Daily Call:*

On any Day during the period covered by November 1, 2020 through and including April 15, 2021, Buyer may call on Seller to deliver up to the sum of the Storage MDQ and the Transport MDQ available, which shall be 12,545 dt/day for the Months of November through and including March of the Term and reduces to 11,272 dt/day for the Month of April pursuant to the applicable TCo Rate Schedules ("Daily Call Quantity") at TCo-Hanover.

Additional Call:

In addition to the Daily Call specified above, on any Day during the period covered by November 2020 through and including April 2021, Buyer shall have the right to call on a quantity of Gas up to the contract quantity of each of the Released Assets (TCo FSS, SST and FTS) at the delivery point(s) under each such Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to the Supply Requirements' Daily Call provision above shall not be cumulative (i.e., Buyer's right to request gas at any delivery point pursuant to the Supply Requirements provision and under this Additional Call provision shall be reduced by quantities requested at any upstream delivery point or service agreement).

Delivery Point: Unless otherwise requested pursuant to the Additional Call, the Delivery Point shall be TCo-Hanover.

Price: *Daily Call:*

At Buyer's option, the price to be paid up to 2,545 dt/day during the months of November through March and 1,272 dt/day for the first half of April to Seller for Gas delivered on any Day shall be either: (a) the storage WACOG; or (b) the price posted in *Platts Gas Daily Daily Price Survey* Midpoint for "TCo Pool" for such Day (the "Gas Daily Price"). For all volumes purchased by Buyer in excess of 2,545 dt/day and up to the applicable Daily Call Quantity, the price shall be the Gas Daily Price, plus the imputed variable costs (including fuel) to transport such Gas to the Delivery Point.

In either case, Buyer shall also pay the imputed variable costs (including fuel) to transport such Gas to the Delivery Point. Buyer's right to call on Gas priced pursuant to the storage WACOG shall be limited to the storage quantity transferred pursuant to a Transaction Confirmation executed as a result of this RFP. In no event shall Buyer's right to call on Gas priced pursuant to the storage WACOG exceed Buyer's withdrawal rights pursuant to the applicable TCo agreements.

<u>*Additional Call:*</u>

The price for any Additional Call purchases shall be the greater of (1) the Gas Daily Price plus $0.05 per dt or (2) the *Gas Daily "Daily" Index* price for Algonquin City Gates.

Winter Ending Balance: Starting Balance in the FSS field as of November 1, 2020 less any supplies called on at the storage WACOG before fuel losses as of April 16, 2021.

Storage Refill: Seller shall ensure that the storage capacity shall be returned to Buyer at a volume equal to the Staring Balances of the end of the Term. The "Refill Quantity" shall be equal to the Starting Balance minus the Winter Ending Balance.

Refill Price: The "Refill Price" shall be equal to the average of NGI's Bidweek Survey First of Month Indices for "TCo Pool", plus imputed variables to inject using FTS Contract No. 31523 for each of the six months from Maythrough October 2021.

Paper Balance: During the Term, the parties shall maintain a "Paper Balance" and shall confirm the Paper Balance on a monthly basis. The Paper Balance on any Day shall be equal to the Starting Balance minus the sum of all prior purchases nominated by Buyer at the WACOG before fuel losses plus any injections by Seller on Buyer's behalf at the ratable refill quantity from May through October 2021 net of injection fuel. Quantities nominated by Buyer at the Gas Daily Price shall not be considered for purposes of calculating the Paper Balance.

Storage Return Price: As of November 1, 2021, the Storage Return Price shall be established and will be equal to ((the Winter Ending Balance x the WACOG) + (the Refill Quantity x the Refill Price)) divided by the Starting Balance. This price will be used for the return of storage to Buyer.

Storage Return: As of the start of Gas Day November 1, 2021, 100% of the FSS storage capacity shall revert to Buyer and Seller shall sell to Buyer the Paper Balance (via an in-field transfer) at the Storage Return Price. Payment for such Gas shall be due on the payment date for Gas delivered during the month of October 2021.

Nominations: Buyer shall make all nominations orally or in writing prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Upon such notification, Buyer shall notify Seller of the required quantity of Gas and the price option (ie, storage WACOG or Gas Daily Price). Friday nominations shall be for Saturday through Monday (ratably) however, such nominations need not be ratable when selecting the Storage Price. Holidays are as determined by ICE and shall be treated the same as weekends (*i.e.*, nominated ratably on Business Day prior to the Holiday.

Asset Management Fee: Subject to satisfying the Gas Supply Requirements associated with the AMA, Seller shall have the right to utilize and optimize the Assets for its own account. In exchange for such right, Seller shall pay Buyer an Asset Management Fee. **As part of their Proposal(s), Bidders should specify the total proposed Asset Management Fee to be paid to Buyer.**

Form of Agreement: Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Base Contract for Sale and Purchase of Natural Gas or ISDA with a Gas Annex. Included is the form of Transaction Confirmation that National Grid proposes for execution. **As part of their Proposal(s), Bidders *must* clearly identify any required Special Conditions or exceptions to the Transaction Confirmation including, but not limited to, language related to FERC, the CFTC and any other applicable regulatory body.**

Submission of Proposals: Proposals must be submitted by the date specified in the Schedule below. Proposals should include: **(a) Seller's proposed Asset Management Payment, (b) any proposed exceptions to the Transaction Confirmation and (c) whether Seller shall require receipt of any**

additional internal approvals prior to accepting an award pursuant to this RFP.

Proposals should be sent via email to the following email address:

GasRFP@nationalgrid.com.

Any questions in connection with this RFP should be sent via email to the email address provided above.

Schedule (all times are Eastern Standard Time):

August 14, 2020	Proposals must be received by National Grid by 12:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on August 21, 2020.**

Miscellaneous:

National Grid will consider proposals only from bidders who have an executed NAESB Base Contract for Sale and Purchase of Natural Gas or an executed ISDA with a Gas Annex with Buyer. Any transaction entered into as a result of this RFP shall be documented as a transaction under an active NAESB Agreement or ISDA Gas Annex. Please be advised that if the winning Bidder utilizes an ISDA with a Gas Annex, this transaction will be specifically excluded from margining calculation under the Credit Support Annex.

Bidders submitting bids in response to this RFP understand and agree that unless and until a definitive Transaction Confirmation has been executed and delivered, no contract or agreement providing for a transaction between such parties shall be deemed to exist between the parties, and neither party will be under any legal obligation of any kind whatsoever with respect to such transaction by virtue of this or any written or oral expression thereof, including, but not limited to, a letter of intent or any other preliminary agreement or any other written agreement or offer. National Grid reserves the right to withdraw or modify this RFP at any time and National Grid shall have the right, in its sole and absolute discretion, to reject any or all Proposals submitted in response to this RFP.

Compliance with National Grid's Supplier Code of Conduct:

At National Grid we are always seeking to improve our reputation as a sustainable and responsible company. We believe that a responsible approach to doing business is fundamental to what we do. In all of our activities we operate within Global Standards of Ethical Conduct. These standards include a commitment to the protection and enhancement of the environment, always seeking ways to minimize the environmental impact of our past, present and future activities and safeguarding our global environment for future generations. Our goal is to comply with regulations, reduce any impact that we may have and proactively seek out opportunities to improve the environment. In furtherance of this goal, National Grid has developed a "Supplier Code of Conduct" which describes our company's values. **(Please refer to the following Link to National Grid's "Supplier Code of Conduct" - https://www.nationalgrid.com/NR/rdonlyres/027656B7-ABDB-40C0-9886-B527962B60A6/46631/SupplierCodeofConductFinalUK2011.pdf.)**

We value the business relationships we have with you and we believe that you are an important and central part of our success. This means that we expect you to carry out your business in line with these values. More specifically, we refer you to Section 4 - "Protecting the Environment". This section explains National Grid's expectations with respect to its suppliers. In connection with the purchase of natural gas, we will reject proposals from parties that fail to adhere to these requirements or who knowingly produce or purchase gas that was produced in violation of applicable laws and regulations.

John Allocca
Director of FERC Compliance and Contracting
Telephone: 516-545-3108

Liz Arangio
Director of Gas Supply Planning
Telephone: 781-907-1639

Samara Jaffe
Program Manager of FERC Compliance & Contracting
Telephone: 516-545-5408

MaryBeth Carroll
Manager of Gas Supply Planning, RI
Telephone: 516-545-3116

Janet Prag
Senior Contract Specialist of FERC Compliance & Contracting
Telephone: 516-545-5463

nationalgrid

Asset Management Arrangement ("AMA") - Transaction Confirmation Package No. 7

		Date: Transaction Confirmation #: _______________

This Transaction Confirmation was awarded pursuant to National Grid's Request for Proposal for Asset Management Arrangements dated August 4, 2020. This transaction is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated ______. ***The terms of this Transaction Confirmation will not become binding until executed by both parties.***

Seller:	Buyer:
Attn: ____ Phone: ____ Fax: ____ Base Contract No. ________________________________ Base Contract No.________________________________ Transporter: _____________________________________ Transporter Contract Number: _______________________	The Narragansett Electric Company d/b/a National Grid 100 East Old Country Road Hicksville, New York 11801 Attn: Contract Administration Phone: (516) 545-6068 Base Contract No. Transporter: Columbia Gas Transmission (TCo) Transporter Contract Numbers: 9630, 9631, 31523 Trader: Samara Jaffe

Contract Price: See Special Condition C below.

Term: Begin Date: November 1, 2020 End Date: October 31, 2021

Performance Obligation and Contract Quantity: See Special Conditions Below**.**

Delivery Point(s): Unless otherwise specified pursuant to this Transaction Confirmation, the Delivery Point shall be the point of interconnection between TCo and Algonquin Gas Transmission, LLC at Hanover ("TCo- Hanover)

Special Conditions:

A. Definitions

"CFTC" shall mean the U.S. Commodity Futures Trading Commission.

"Credit Support Provider" shall mean _____________.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A " by S&P and "A2" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Services, Inc. or its successor.

"Paper Balance" means the Starting Balance minus the sum of all prior purchases nominated by Buyer at the WACOG before fuel losses plus any injections by Seller on Buyer's behalf at the ratable refill quantity from May through October 2021 net of injection fuel.

"Refill Price" shall be equal to the average of NGI's Bidweek Survey First of Month Indices for "TCo Pool", plus imputed variables to inject using FTS Contract No. 31523 for each of the six months from Maythrough October 2021.

"Refill Quantity" shall be equal to the Starting Balance minus the Winter Ending Balance.

"S&P" means Standard & Poor's Ratings Group (a division of McGraw-Hill, Inc.) or its successor.

"Starting Balance" means the TCo FSS inventory released to Seller on November 1, 2020.

"Winter Ending Balance" means the Starting Balance in the FSS field as of November 1, 2020 less any supplies called on at the storage WACOG before fuel losses as of April 16, 2021.

B. Gas Service and Capacity Release

1. **Release of Assets:** Buyer will release the following Assets on a pre-arranged, non-biddable basis, at no cost to Seller:

(a) TCo FSS Contract No. 9630 with a maximum storage quantity ("MSQ") of 203,957 dt, a maximum daily injection quantity ("MDIQ") of 2,545 dt/day and a maximum daily withdrawal quantity ("MDWQ") of 2,545 dt/day. Such maximum rights and obligations are subject to the provisions of the TCo FSS Rate Schedule of the pipeline's FERC Gas Tariff including, but not limited to the Maximum Monthly Injection Quantities as more fully set forth below:

MDWQ		Month Limit	Min	Max
> 30%	2,545	November	none	81,583
20-30%	2,036	December	none	81,583
10-20%	1,654	January	none	81,583
< 10%	1,272	February	20,396	61,187
Apr - Sep	1,272	March	20,396	40,791

MMIQ		MDIQ	Max Inventory	
April	30,594	1,224		
May	40,791	1,632	Feb 1	132,572
June	40,791	1,632	Apr 1	50,989
July	40,791	1,632	Jun 30	122,374
August	36,712	1,468	Aug 31	173,363
September	26,514	1,061		
October	18,356	734		
November	10,198	340		
December	20,396	680		
January	20,396	816		
February	20,396	816		
March	20,396	816		

(b) TCo SST Contract No. 9631 having a maximum daily transportation quantity ("Storage MDQ") of 2,545 dt/day during the months of October through March with withdrawal rights from TCo FSS Contract No. 9630 for primary deliver to the point of interconnect between TCo and Algonquin Gas Transmission, LLC at Hanover ("TCo-Hanover"). During the months of April through September the Storage MDQ shall reduce to 1,272 dt/day; and

(c) TCo FTS Contract No. 31523 having a maximum daily quantity ("Transport MDQ") of 10,000 dt/day with primary receipts located at Broad Run and primary deliver to TCo-Hanover.

Buyer shall be responsible for the payment of all demand charges related to the Assets. Seller shall be responsible for all variable costs related to the Assets not related to deliveries for Buyer. Seller shall be responsible for all incremental charges related to non-adherence or non-compliance with TCo's FERC Gas Tariff including, but not limited to, overrun penalties and/or failure to adhere to applicable rachet provisionss

2. **Transfer of Inventory**: As of November 1, 2020, Buyer shall transfer and sell to Seller the inventory attributable to TCo FSS Contract No. 9630 ("Starting Balance"); the Starting Balance is expected to be ~97% of the MSQ. Seller shall be obligated to pay Buyer for such Gas by the payment date for sales occurring during October 2020 in accordance with the NAESB Agreement (or other agreement) between the parties. The price for such Gas shall be Buyer's weighted average cost of gas ("WACOG") for such storage field.

3. **Supply Requirements**:

a. Daily Call: On any Day during the period covered by November 1, 2020 through and including April 15, 2021, Buyer may call on Seller to deliver up to the sum of the Storage MDQ and the Transport MDQ available, which shall be 12,545 dt/day for the Months of November through and including March of the Term and reduces to 11,272 dt/day for the Month of April pursuant to the applicable TCo Rate Schedules ("Daily Call Quantity") at TCo-Hanover.

b. Additional Call: In addition to the Daily Call specified above, on any Day during the period covered by November 2020 through and including April 2021, Buyer shall have the right to call on a quantity of Gas up to the contract quantity of each of the Released Assets (TCo FSS, SST and FTS) at the delivery point(s) under each such Asset. Seller's delivery obligations under this Additional Call provision and its delivery obligation pursuant to the Supply

Requirements' Daily Call provision above shall not be cumulative (i.e., Buyer's right to request gas at any delivery point pursuant to the Supply Requirements provision and under this Additional Call provision shall be reduced by quantities requested at any upstream delivery point or service agreement).

4. Storage Refill: Seller shall ensure that the storage capacity shall be returned to Buyer at a volume equal to the Staring Balances of the end of the Term. The "Refill Quantity" shall be equal to the Starting Balance minus the Winter Ending Balance.

5. Paper Balance: During the Term, the parties shall maintain a "Paper Balance" and shall confirm the Paper Balance on a monthly basis. The Paper Balance on any Day shall be equal to the Starting Balance minus the sum of all prior purchases nominated by Buyer at the WACOG before fuel losses plus any injections by Seller on Buyer's behalf at the ratable refill quantity from May through October 2021 net of injection fuel. Quantities nominated by Buyer at the Gas Daily Price shall not be considered for purposes of calculating the Paper Balance.

6. Storage Return: As of the start of Gas Day November 1, 2021, 100% of the FSS storage capacity shall revert to Buyer and Seller shall sell to Buyer the Paper Balance (via an in-field transfer) at the Storage Return Price. Payment for such Gas shall be due on the payment date for Gas delivered during the month of October 2021.

7. Termination Option: If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder (a "Delivery Failure"), unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall the Assets.

C. Price

1. Supply Requirements Price:

a. Daily Call: At Buyer's option, the price to be paid up to 2,545 dt/day during the months of November through March and 1,272 dt/day for the first half of April to Seller for Gas delivered on any Day shall be either: (a) the storage WACOG; or (b) the price posted in *Platts Gas Daily Daily Price Survey* Midpoint for "TCo Pool" for such Day (the "Gas Daily Price"). For all volumes purchased by Buyer in excess of 2,545 dt/day and up to the applicable Daily Call Quantity, the price shall be the Gas Daily Price, plus the imputed variable costs (including fuel) to transport such Gas to the Delivery Point.

In either case, Buyer shall also pay the imputed variable costs (including fuel) to transport such Gas to the Delivery Point. Buyer's right to call on Gas priced pursuant to the storage WACOG shall be limited to the storage quantity transferred pursuant to a Transaction Confirmation executed as a result of this RFP. In no event shall Buyer's right to call on Gas priced pursuant to the storage WACOG exceed Buyer's withdrawal rights pursuant to the applicable TCo agreements.

b. Additional Call: The price for any Additional Call purchases shall be the greater of (1) the Gas Daily Price plus $0.05 per dt or (2) the *Gas Daily "Daily" Index* price for Algonquin City Gates.

2. **Storage Return Price:** As of November 1, 2021, the Storage Return Price shall be established and will be equal to ((the Winter Ending Balance x the WACOG) + (the Refill Quantity x the Refill Price)) divided by the Starting Balance. This price will be used for the return of storage to Buyer.

D. Nominations

Buyer shall make all nominations orally or in writing prior to 10:00 AM prevailing Eastern Standard Time on the Business Day prior to the Gas Day on which delivery of Gas is requested. Upon such notification, Buyer shall notify Seller of the required quantity of Gas and the price option (ie, storage WACOG or Gas Daily Price). Friday nominations shall be for Saturday through Monday (ratably) however, such nominations need not be ratable when selecting the Storage Price. Holidays are as determined by ICE and shall be treated the same as weekends (i.e., nominated ratably on Business Day prior to the Holiday.

E. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the Assets for its own account. In exchange for such right, during the Term, Seller shall make a payment to Buyer of $______________________ per Month. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month.

F. Credit Provisions

Independent Amount. In the event Seller (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated as a function of price volatilities as well as the notional volume; provided, however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at the Gas Daily Index.

Collateral Requirement. The "Collateral Requirement" for Seller means the Exposure (as defined below), minus the sum of (i) the amount of Cash previously transferred by Seller to National Grid, (ii) the amount of Cash held by National Grid as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of National Grid ("Letter of Credit"), and (iii) the undrawn value of each Letter of Credit ; provided, however, that the Collateral Requirement of Seller will be deemed to be zero (0) if on the relevant Valuation Date, (i) no Event of Default with respect to Seller or its Credit Support Provider has occurred and is continuing, and (ii) the guaranty provided by Seller is in full force and effect. The "Collateral Requirement" for National Grid means zero (0).

Exposure. shall be calculated as the sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the term for each transaction under this Transaction Confirmation; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer**.**

G. Asset Management Arrangement

It is the intention of the parties to structure this transaction as an AMA as defined by the FERC in Order 712 (as modified and clarified) and in accordance with FERC's rules and regulations. Seller is acting as an Asset Manager as defined in 18 CFR 284.8(h)(3). If it is determined that this transaction does not constitute an AMA, the parties agree to modify the transaction as required while maintaining, to the extent possible, the economics of the transaction.

H. Changes in Law

If the FERC , the CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Transaction Confirmation or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other or either party may terminate this Transaction Confirmation upon Notice to the other party.

Seller: By: ____ Title: ____ Date: ____	**Buyer: The Narragansett Electric Company d/b/a National Grid** By: _____________________________________ John Vaughn Authorized Signatory Date: _____________________________________

Testimony of
Ryan M. Scheib &
Michael J. Pini

DIRECT TESTIMONY

OF

RYAN M. SCHEIB

AND

MICHAEL J. PINI

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I. <u>Introduction</u>

<u>Ryan M. Scheib</u>

Q. Please state your name and business address.

A. My name is Ryan M. Scheib and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am an Analyst in the New England Gas Pricing group employed by National Grid USA Service Company, Inc ("Service Company"). In this position, I am responsible for preparing and submitting various regulatory filings with the Rhode Island Public Utilities Commission ("PUC") on behalf of The Narragansett Electric Company d/b/a National Grid (the "Company").

Q. Please provide your educational background.

A. I received a Bachelor of Science in Finance from University of Delaware in 2016.

Q. Please provide your professional background.

A. In 2016, I joined National Grid as an Associate Analyst in the New England Gas Pricing group. In 2018, I was promoted to Analyst.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commissions?

A. Yes. I have testified before the PUC regarding the Company's Distribution Adjustment Charge filing in Docket No. 4955 and the Company's FY 2021 Gas Infrastructure, Safety, and Reliability Plan filing in Docket No. 4996.

<u>Michael J. Pini</u>

Q. Please state your name and business address.

A. My name is Michael J. Pini and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am a Lead Program Manager in the New England Pricing department for National Grid USA Service Company, Inc. (Service Company). My responsibilities include the design, implementation, and administration of rates and tariffs for the gas division of The Narragansett Electric Company d/b/a National Grid (the Company) and its Massachusetts affiliates, Boston Gas Company (Boston Gas) and Colonial Gas Company (Colonial Gas), each d/b/a National Grid.

Q. Please provide your educational background.

A. I earned a Bachelor of Science in Economics and Finance from Bentley University in 2010.

Q. Please provide your professional background.

A. In 2009, I joined National Grid as an intern in the Support Services function within the Gas Operations department. In 2010, I became an Associate Analyst in the Regulatory Compliance department. In 2011, I joined the New England Electric Pricing group and was promoted to Analyst in 2012. In 2013, my responsibilities changed to supporting Boston Gas and Colonial Gas and, in 2014, I was promoted to Senior Analyst in the same capacity. In 2017, I was promoted to Lead Program Manager, supporting the New England electric and gas operating companies.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commissions?

A. I have testified before the PUC in support of the Company's 2019-2020 GCR Filing in Docket No. 4963, the Company's FY 2020 Infrastructure, Safety and Reliability Plan filing in Docket No. 4916 and the Company's Excess Accumulated Deferred Income Tax True-Up filing in Docket No. 4770. Additionally, I have testified before the Massachusetts Department of Public Utilities on several occasions related to the Gas System Enhancement Plans for Boston Gas and Colonial Gas, namely, to present the calculation of proposed Gas System Enhancement Plan Factors and associated bill impacts.

Q. What is the purpose of your joint testimony?

A. The purpose of our testimony is to propose the Gas Cost Recovery (GCR) factors for effect on November 1, 2020 for the following services: (1) firm sales service to customers in the Residential Non-Heating and Heating rate classes and Commercial and Industrial (C&I) firm sales customers in the Small, Medium, Large, and Extra Large rate classes; and (2) transportation services provided to Gas Marketers and the associated Gas Marketer Fixed Charges and factors.

Q. How is your testimony organized?

A. Our testimony includes the following three general sections: I. Introduction; II. GCR Factor Development; and III. Bill Impacts.

Q. Are you including any attachments with your testimony?

A. Yes. We are sponsoring the following attachments with our testimony:

Attachment RMS/MJP-1	Gas Cost Recovery Factors
Attachment RMS/MJP-2	Annual GCR Reconciliation Filing
Attachment RMS/MJP-3	Projected Gas Cost Balances
Attachment RMS/MJP-4	Bill Impact Analysis

Attachment RMS/MJP-5	FT-2 Demand Rate
Attachment RMS/MJP-6	FT-2 Capacity Allocator Percentages
Attachment RMS/MJP-7	Marketer Reconciliation

II. GCR Factor Development

Q. Please provide an overview of the development of the proposed GCR factors.

A. The proposed GCR factors reflect the load specific (High Load and Low Load) factors necessary for the Company to recover the projected gas costs allocated to firm sales customers for the period November 1, 2020 through October 31, 2021. As shown in the joint pre-filed direct testimony of Company witnesses for the Gas Supply Panel ("GSP") on Attachment GSP-1, firm sales customers' gross gas costs for the 12 months ending October 31, 2021 are projected to be approximately $150.8 million. In addition to these projected costs, the GCR factors also include recovery of working capital costs, inventory financing costs, prior period reconciliations, impacts of hedging activities, liquefied natural gas (LNG) operation and maintenance (O&M) costs, and credits for FT-2 Market Storage Demand and costs allocated to the DAC factors. The table below summarizes the costs and credits included in the proposed 2020-21 GCR factors:

GCR Component	Amount (millions)	Reference
Firm Gas Costs	$150.8	GSP-1
Hedging Impact	($2.2)	JMP-5
Working Capital Costs	$1.2	RMS/MJP-1, Page 2, Line (9) and Page 3, Line (6)

GCR Component	Amount (millions)	Reference
Inventory Financing Costs	$0.7	RMS/MJP-1, Page 3, Lines (9) and (10)
Prior Period Deferred Balance (Includes the Marketer Fixed Costs Reconciliation)	$7.9	RMS/MJP-1, Page 2, Lines (10) and (11) and Page 3, Line (7)
LNG O&M Costs	$1.1	RMS/MJP-1, Page 2, Line (8) and Page 3, Line (8)
FT-2 Marketer Storage Demand Costs	($3.3)	RMS/MJP-1, Page 2, Line (4)
Total	$156.2	RMS/MJP-1, Page 2, Line (13) and RMS/MJP-1, Page 3, Line (12)

The proposed GCR factors are intended to recover approximately $156.2 million in net costs over the period November 1, 2020 through October 31, 2021.

Q. Please explain how the proposed GCR factors were developed.

A. The proposed GCR factors were developed based on the fixed and variable cost components as defined in the GCR clause of the Company’s tariff, RIPUC NG-GAS No. 101, Section 2, Gas Charge, Schedule A. Attachment RMS/MJP-1 provides a summary of the GCR fixed and variable gas cost components used to develop the rates for which the Company seeks approval in this filing.

Q. How was the fixed cost component of the proposed GCR factors developed?

A. The fixed cost component includes all fixed costs related to the purchase, storage, and delivery of firm gas for High Load Factor and Low Load Factor customers. As shown in Attachment RMS/MJP-1, Page 2, the fixed cost component is developed by taking the total fixed costs, which are already reduced by capacity release credits, less any credits such as customers' share of credits earned through the operation of the Natural Gas Portfolio Management Plan (NGPMP), demand costs allocated to the DAC mechanism, if any, and storage demand costs billed to FT-2 Marketers. The FT-2 storage demand costs are calculated by multiplying the FT-2 Demand Charge rate by the forecast of storage and peaking maximum daily quantity (MDQ) to be billed to FT-2 Marketers. Adjustments are also made for supply-related LNG costs, working capital costs, and prior period deferred fixed gas costs under/over-recovery balances, including an adjustment for the Marketer fixed cost reconciliation as stipulated in the Settlement Agreement between the Company and the Division of Public Utilities and Carriers (Division) in Docket No. 4199. This results in total fixed gas costs of $77.1 million to be recovered over the period November 2020 through October 2021.

Finally, because the Company's gas supply resources are planned so that there is sufficient capacity to meet the needs of firm customers (excluding firm customers with capacity exempt status) under design winter conditions, the total fixed gas cost to be recovered from customers is allocated between High Load Factor and Low Load Factor customers. The allocation is based on the proportion of design winter use of these two groups of customers. The High Load and Low Load Factors for each group are developed using the allocated fixed gas cost to each group and dividing each amount by each group's projected throughput for the upcoming year. Accordingly, the proposed

GCR fixed Low Load Factor is $2.8492 per dekatherm, while the proposed GCR fixed High Load Factor is $2.1719 per dekatherm, excluding the adjustment for uncollectible expense.

Q. In the calculation of the fixed cost, you mentioned that the total fixed cost excludes "demand costs allocated to the DAC mechanism, if any." Is the Company proposing any change to the demand costs allocated to the DAC?

A. Yes. As indicated in the direct testimony of Gas Supply Panel, the Company has proposed to recover the costs of peaking assets needed for design hour reliability from all customers directly via the Distribution Adjustment Clause (DAC). Therefore, the Company is proposing to allocate $5.2 million associated with hourly peaking demand costs to the DAC for the DAC factors proposed for effect November 1, 2020. These costs would include third-party portable LNG equipment and services at the former Cumberland LNG tank location and Old Mill Lane on Aquidneck Island, citygate deliveries on the Algonquin pipeline, and LNG trucking. These costs are reflected on Schedule GSP-1, Page 12 in this filing.

Q. How did the Company develop the 2020-21 throughput forecast used to calculate the High Load and Low Load GCR Factors?

A. The pre-filed direct testimony of Company witness Theodore E. Poe, Jr. supports the 2020-21 throughput forecast used to develop the proposed GCR factors.

Q. How did the Company calculate the Marketer fixed cost reconciliation balance?

A. In accordance with the Settlement Agreement approved in Docket No. 4199, the Company has included an annual reconciliation of Marketer fixed costs. The Company calculated the Marketer reconciliation by updating the 2019-20 pipeline surcharge/credit for each path that the Company filed last year based the update on actual, instead of projected, pipeline capacity costs. The Company then calculated the difference between the pipeline surcharge/credit approved in Docket No. 4963 for each path with the updated actual pipeline surcharge/credit. The Company then multiplied the difference by the Marketer's actual monthly capacity for the months of November 2019 through July 2020 and forecasted monthly capacity for the months of August 2020 through October 2020. This results in a surcharge to the Marketers of $689,80, as shown in Attachment RMS/MJP-7, Page 1, Line (22).

The Company also finalized the 2018-19 Marketer reconciliation that it filed last year in Docket No. 4963 to replace the Marketers' forecasted monthly capacity for the months of August 2019 through October 2019 with their actual monthly capacity as well as updating the actual pipeline surcharge/credit for the same period . This update results in a Marketer credit of $499,174 associated with the latter portion of the 2018-2019 period. In addition, the Company reconciled the actual revenue of $2,569 charged to Marketers during the period November 2019 through October 2020 with the actual 2018-19 Marketer credit of $499,174 and the prior period 2018-19 Marketer reconciliation surcharge balance of $345. This results in a net Marketer reconciliation credit of $501,398 for the 2018-19 period, as shown in Attachment RMS/MJP-7, Page 2, Line (48). The sum of the reconciliation amounts shown in Attachment RMS/MJP-7 for 2019-2020 (Page 1, Line (22)) and 2018-19 (Page 2, Line (48)) is the total Marketer reconciliation amount of ($188,452), as shown on Page 2, Line (50) and reflected in Attachment RMS/MJP-1, Page 2, Line (12).

Attachment RMS/MJP-7 shows the calculation of the Marketer reconciliation adjustment for the 2018/19 and 2019/20 periods. In addition to surcharging firm sales customers' fixed costs for this amount, the Company included the reconciliation in its calculation of the 2019/20 pipeline surcharge/credits, as detailed in the joint testimony of Ms. Arangio and Ms. Jaffe as shown in Attachment EDA/SAJ-1. The Company has provided additional detail for monthly capacity release information for each pipeline path in an Excel file contained in the USB flash drive provided to the Division with this filing.

Q. Please describe the calculation of the design sales forecast.

A. As done last year in Docket No. 4963, the Company calculated the monthly design sales forecast by applying a monthly heat factor to the monthly design degree days. The monthly heat factor was computed by dividing the heating component of the normal sales (normal sales less monthly base use) by normal degree days for each month during the period November 2020 through March 2021. To compute the monthly design sales, the

Company summed the monthly base use and the product of the monthly heat factor multiplied by the monthly design degree days. In Attachment RMS/MJP-1, Pages 14 through 16, the Company has provided detailed calculations showing the derivation of the monthly design sales.

Q. How did the Company develop the variable cost component of the proposed GCR factors?

A. The variable cost component includes all variable costs of gas such as commodity costs, supply-related LNG O&M, working capital, inventory finance costs, pipeline refunds, and deferred cost balances, and excludes variable costs allocated to the DAC mechanism, if any. As shown in Attachment RMS/MJP-1, Page 3, Line (12), the total estimated variable cost for the period November 2020 through October 2021 is $79.1 million. The variable costs are divided by the projected throughput to obtain a variable cost factor of $2.9076 per dekatherm.

Q. In the calculation of the variable cost, you mentioned that the total variable cost excludes "variable costs allocated to the DAC mechanism, if any." Is the Company proposing any change to the variable costs allocated to the DAC?

A. No. The Company has conducted an engineering study and has determined that it is not necessary to allocate any variable costs to the DAC mechanism for effect November 1, 2020.

Q. What is the Company's estimate of the deferred gas cost balance at the end of the current GCR period?

A. Based on actual data through July 2020 and forecasted data for the months of August through October 2020, the total estimated deferred balance at October 31, 2020 is an under-recovery of approximately $8.1 million, as shown in Attachment RMS/MJP-1, Page 7. This deferred balance is incorporated into the development of the proposed GCR factors proposed for the period November 1, 2020 to October 31, 2021. In addition, the Company shows the projected monthly deferred gas cost balances for November 2020 through October 2021 in Attachment RMS/MJP-3.

Q. Attachment RMS/MJP-2 provides the fiscal year 2020 Annual GCR Reconciliation balances. Does the monthly information shown in Attachment RMS/MJP-2 correspond with the monthly deferred balance reports filed in Docket Nos. 4872 and 4963?

A. Yes. The March 31, 2020 reconciliation balance of $827,573 shown in Attachment RMS/MJP-2 reflects the balance that was submitted on June 30, 2020 in the Company's annual GCR reconciliation report and is the same balance reflected in the July 2020 monthly deferred balance report filed in Docket No. 4963 on August 20, 2020.

Q. Is the Company proposing any other rates in this filing?

A. Yes. Consistent with the modifications in Docket No. 4270, the Company is submitting for approval its FT-2 Marketer Demand rate of $14.0154 per MDQ in dekatherms per month, as shown in Attachment RMS/MJP-5, as well as the storage and peaking charge of $0.1054 per therm for FT-1 firm transportation customers returning to Transitional Sale Service (TSS). The Company is also requesting approval of the capacity assignment percentages for the High Load and Low Load Factors to be used in the determination of pipeline, underground storage, and peaking capacity for Marketers. These percentages are set forth in Attachment RMS/MJP-6. The Company has also provided the detail calculations of the capacity assignment percentages in an Excel file contained in the USB flash drive provided to the Division with this filing.

Q. How was the proposed FT-2 Marketer Demand rate calculated?

A. The FT-2 rate design approved in Docket No. 4270 separates storage costs into the following two components: (1) the FT-2 Demand rate designed to recover the fixed costs associated with storage and peaking, which the Company is submitting for approval in this filing; and (2) the FT-2 Variable rate that is designed to recover variable underground storage costs, as well as the associated commodity costs and loss factors associated with pipeline contracts to bring the gas from storage to the citygate. In addition, Marketers may purchase peaking inventory at the Company’s cost of LNG inventory.

The FT-2 Demand rate is derived by first totaling the fixed storage costs, associated inventory finance, working capital charges, and supply-related LNG O&M costs, less any demand credits assigned to the DAC factors and any refunds, if applicable. That total is then divided by the total storage and peaking MDQ for the year to derive a monthly per dekatherm rate to be charged to Marketers. As shown in Attachment RMS/MJP-5, the proposed FT-2 Marketer Demand rate is $14.0352 per dekatherm and will be applied to the Marketers' storage and peaking MDQ.

III. Bill Impacts

Q. Is the Company presenting the impacts of its proposed rates for November 1, 2020 on customer bills in this filing?

A. Yes. The Company is presenting the bill impacts associated with its proposed GCR factors in this filing as well as its proposed DAC factors submitted in Docket No. 5040. The bill impacts are presented in Attachment RMS/MJP-4 and reflect current annual bills in Column (c) assuming that the rates in effect during September 2020 are effective for 12 months.

Q. What is the combined bill impact of the proposed GCR and DAC factors on customer bills as compared to bills over the past year?

A. An average Residential Heating customer using 845 therms per year will experience a total annual bill of $1,387.89 based on the proposed GCR and DAC factors, which is an increase of $101.47, or 7.9 percent, from last year's bills. This overall increase is comprised of an increase of $47.83 as a result of the proposed GCR factors; an increase of $50.60 as a result of the proposed DAC factors as revised in a supplemental filing on September 1, 2020 in Docket No. 5040; and an increase of $3.04 in Gross Earnings Tax.

Q. Does this conclude your testimony?

A. Yes

Attachments RMS/MJP

Attachments of Ryan M. Scheib and Michael J. Pini

Attachment RMS/MJP -1	Gas Cost Recovery Factors
Attachment RMS/MJP -2	Annual GCR Reconciliation Filing
Attachment RMS/MJP -3	Projected Gas Cost Balances
Attachment RMS/MJP -4	Bill Impact Analysis
Attachment RMS/MJP -5	FT-2 Demand Rate
Attachment RMS/MJP -6	FT-2 Capacity Allocator Percentages
Attachment RMS/MJP -7	Marketer Reconciliation

Attachment RMS/MJP-1

Attachment RMS/MJP-1
Gas Cost Recovery Factors

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2020

	Description (a)	Source: Reference (b)	Source: Line # (c)	High Load[1] (d)	Low Load[2] (e)	FT-2 Mkter[3] (f)
(1)	Fixed Cost Factor - $/dktherm	RMS/MJP-1, pg 2	Line (17)	$2.1719	$2.8492	
(2)	Variable Cost Factor -$/dktherm	RMS/MJP-1, pg 3	Line (14)	$2.9076	$2.9076	
(3)	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$5.0795	$5.7568	
(4)	Uncollectible %	Docket 4770		1.91%	1.91%	
(5)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) ÷ [1 - (4)]		$5.1784	$5.8688	
(6)	GCR Charge on a per therm basis	(5) ÷ 10		**$0.5178**	**$0.5868**	
(7)	Current rate effective 11/01/19 - $/therm	Docket 4963		$0.4736	$0.5302	
(8)	Increase / (Decrease) - $/therm	(6) - (7)		$0.0442	$0.0566	
(9)	Percent Decrease	(8) ÷ (7)		9.3%	10.7%	

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load
[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load
[3] See RMS/MJP-5 for calculation of FT-2 rate

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Fixed Cost Calculation ($ per Dth)

	Description	Source: Reference	Source: Line #	Amount	High Load Factor Total	Low Load Factor Total
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Costs (net of Cap Rel to marketers)	RMS/MJP-1, pg 5	Line (44)	$85,691,969		
	Less:					
(2)	NGPMP Customer Benefit	GSP-1		($5,251,052)		
(3)	Interruptible Costs			$0		
(4)	FT-2 Storage Demand Costs	RMS/MJP-5, pg 2	Line (25)	($3,253,068)		
(5)	System Pressure to DAC	GSP-1, pg 12		($5,244,853)		
(6)	Refunds			$0		
(7)	Total Credits	Sum[(2):(6)]		($13,748,972)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Dkt 4770	Compliance Attachment 2 Schedule 32 Pg 5	$829,823	$829,823	$69,152
(9)	Working Capital Requirement	RMS/MJP-1, pg 9	Line (16)	$608,558		
(10)	Deferred Fixed Cost Over-recovered	RMS/MJP-1, pg 7	Line (17)	$3,893,018		
(11)	Reconciliation Amount from Fixed costs- Marketers	RMS/MJP-7, pg 2	Line (50)	($188,452)		
(12)	Total Additions	Sum[(8):(11)]		$5,142,947		
(13)	Total Fixed Costs	(1) + (7) + (12)		$77,085,943		
(14)	Design Winter Sales Percentage	RMS/MJP-1, pg 13	Lines (10) & (11)		1.82%	98.18%
(15)	Allocated Supply Fixed Costs	(13) x (14)			$1,402,964	$75,682,979
(16)	Sales (Dth) Nov 2019 - Oct 2020	RMS/MJP-1, pg 12	Line (9)	27,208,322	645,959	26,562,363
(17)	Fixed Factor	(15) ÷ (16)			**$2.1719**	**$2.8492**

(16) Col (e): RMS/MJP-1 page 12, Sum[Lines (1), (6), (8)]
Col (f): RMS/MJP-1 page 12, Sum[Lines (2)-(5), (7)]

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Variable Cost Calculation ($ per Dth)

	Description (a)	Source: Reference (b)	Source: Line # (c)	Amount (d)
(1)	Variable Costs, excluding Refunds	RMS/MJP-1, pg 6	Line (79) - Line (76)	$73,352,280
	Less:			
(2)	System Pressure to DAC			$0
(3)	Non-Firm Sales			$0
(4)	Refunds	RMS/MJP-1, pg 6	Line (76)	$0
(5)	Total Credits	Sum [(2):(4)]		$0
	Plus:			
(6)	Working Capital	RMS/MJP-1, pg 9	Line (32)	$554,887
(7)	Deferred Variable Cost Under-recovered	RMS/MJP-1, pg 7	Line (35)	$4,210,357
(8)	Supply Related LNG O&M	Docket 4770	Compliance Attachment 2 Schedule 32 Pg 5 Ln 15 - Ln 12	$302,244
(9)	Inventory Financing - LNG	RMS/MJP-1, pg 11	Line (22)	$239,415
(10)	Inventory Financing - Storage	RMS/MJP-1, pg 11	Line (12)	$452,816
(11)	Total Additions	Sum [(6):(10)]		$5,759,720
(12)	Total Variable Supply Costs	(1) + (5) + (11)		$79,112,000
(13)	Sales (Dth) Nov 2019 - Oct 2020	RMS/MJP-1, pg 12	Line (9)	27,208,322
(14)	Variable Cost Factor	(12) ÷ (13)		**$2.9076**

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-20 (c)	Dec-20 (d)	Jan-21 (e)	Feb-21 (f)	Mar-21 (g)	Apr-21 (h)	May-21 (i)	Jun-21 (j)	Jul-21 (k)	Aug-21 (l)	Sep-21 (m)	Oct-21 (n)	Nov-Oct (o)
Supply Fixed Costs - Pipeline Delivery														
(1) Dawn to E Here	GSP-1	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$996,831	$11,961,968
(2) Dawn to WADDY	GSP-1	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$22,646	$271,755
(3) Dominion SP	GSP-1	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$7,134	$85,614
(4) Dracut	GSP-1	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$85,024	$1,020,288
(5) Everett	GSP-1	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$106,280	$1,275,360
(6) Manchester Lateral	GSP-1	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$209,758	$2,517,098
(7) Millennium/AIM	GSP-1	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$756,864	$9,082,364
(8) Niagara	GSP-1	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$6,842	$82,103
(9) TCO (Pool)	GSP-1	$515,268	$515,268	$515,268	$695,725	$695,725	$695,725	$695,725	$695,725	$695,725	$695,725	$695,725	$695,725	$7,807,332
(10) AGT M3	GSP-1	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$126,790	$1,521,482
(11) TETCO SCT Long Haul	GSP-1	$17,982	$17,979	$17,979	$17,979	$17,979	$17,979	$17,979	$17,979	$17,979	$17,979	$17,979	$17,979	$215,751
(12) TETCO CDS Long Haul	GSP-1	$1,001,576	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$1,001,410	$12,017,091
(13) Transco Leidy	GSP-1	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$9,429	$113,147
(14) Yankee Interconnect	GSP-1	$46,961	$46,961	$44,292	$44,292	$44,292	$44,292	$44,292	$44,292	$44,292	$44,292	$44,292	$44,292	$536,843
(15) TGP Long Haul	GSP-1	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$458,965	$5,507,585
(16) TGP ConneXion	GSP-1	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$214,803	$2,577,641
(17) AMA Credits	GSP-1	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($108,075)	($1,296,899)
(18) Less Credits from Mkter Releases	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19) Total Supply Fixed Costs - Pipeline	Sum[(1) (18)]	$4,475,079	$4,474,911	$4,472,242	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$55,296,522
Supply Fixed - Supplier														
(20) Distrigas FCS	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21) Total	(20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22) Total Supply Fixed (Pipeline & Supplier)	(20) + (21)	$4,475,079	$4,474,911	$4,472,242	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$4,652,699	$55,296,522
Storaged Fixed Costs - Facilities														
(23) Columbia FSS	GSP-1	$9,694	$9,694	$9,694	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$237,871
(24) Dominion GSS	GSP-1	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$36,391	$436,695
(25) Dominion GSSTE	GSP-1	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$46,764	$561,168
(26) Providence LNG	GSP-1	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$1,964,880
(27) Tennessee FSMA	GSP-1	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$43,258	$519,091
(28) Tetco FSS1	GSP-1	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$3,499	$41,987
(29) Tetco SS1	GSP-1	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$132,468	$1,589,620
(30) Total Fixed Storage Costs	Sum[(23):(29)]	$435,814	$435,814	$435,814	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$5,351,312

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-20 (c)	Dec-20 (d)	Jan-21 (e)	Feb-21 (f)	Mar-21 (g)	Apr-21 (h)	May-21 (i)	Jun-21 (j)	Jul-21 (k)	Aug-21 (l)	Sep-21 (m)	Oct-21 (n)	Nov-Oct (o)
Storage Fixed Costs - Delivery														
(31) Storage Delivery	GSP-1	$449,175	$449,175	$449,175	$463,689	$463,689	$432,910	$432,910	$432,910	$432,910	$432,910	$432,910	$432,910	$5,305,275
(32) LNG	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(33) Proposed CNG/LNG	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(34) Everett Supply Deal	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(35) Dracut Supply Deal	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(36) Everett Supply Deal2	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(37) Summer Liquid Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(38) Summer Trucking	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(39) AGT Citygate	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(40) Winter Trucking	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(41) Proposed Summer Liquid	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(42) Storage Delivery Fixed Cost	Sum[(31):(41)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(43) Total Storage Fixed	(30) + (42)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(44) Total Fixed Costs	(22)+(30)+(42)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$85,691,969

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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-20 (c)	Dec-20 (d)	Jan-21 (e)	Feb-21 (f)	Mar-21 (g)	Apr-21 (h)	May-21 (i)	Jun-21 (j)	Jul-21 (k)	Aug-21 (l)	Sep-21 (m)	Oct-21 (n)	Nov-Oct (o)
Variable Commodity Costs														
(45) AGT Citygate	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(46) AIM at Ramapo	GSP-1	$17,030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,030
(47) Const Summer Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(48) Const Winter Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(49) Dawn via IGTS	GSP-1	$0	$15,180	$50,479	$34,727	$0	$0	$0	$0	$0	$0	$0	$0	$100,386
(50) Dawn via PNGTS	GSP-1	$48,791	$586,765	$1,406,183	$1,185,084	$564,378	$0	$0	$0	$0	$0	$0	$0	$3,791,201
(51) Dominion SP	GSP-1	$29,391	$43,209	$45,094	$40,423	$42,887	$37,198	$0	$0	$0	$0	$0	$0	$238,202
(52) Dracut Supply	GSP-1	$0	$0	$0	$0	$0	$0	$89,874	$121	$0	$0	$0	$0	$89,994
(53) Everett Long-Term	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(54) Everett Swing	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(55) Millennium	GSP-1	$460,067	$586,192	$611,759	$548,395	$581,816	$504,647	$497,054	$477,453	$503,964	$0	$0	$465,038	$5,236,385
(56) Niagara	GSP-1	$6,876	$88,864	$92,733	$83,668	$70,346	$854	$0	$0	$0	$0	$0	$0	$343,341
(57) TCO Appalachia	GSP-1	$874,645	$2,561,724	$2,835,486	$2,509,038	$2,691,529	$61,055	$116,926	$114,240	$0	$118,563	$71,760	$39,322	$11,994,289
(58) Tetco M3	GSP-1	$294,398	$65,865	$0	$13,092	$233,821	$1,274,174	$1,745,082	$957,098	$0	$0	$1,374,113	$1,168,975	$7,126,618
(59) Transco Leidy	GSP-1	$43,215	$58,285	$91,810	$78,337	$46,008	$4,692	$4,638	$4,497	$4,812	$4,737	$4,168	$4,420	$349,620
(60) Waddington	GSP-1	$5,182	$28	$0	$39	$18,522	$0	$0	$0	$0	$0	$0	$0	$23,770
(61) Nextera Summer Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(62) Tetco M2 CDS	GSP-1	$2,323,083	$3,011,192	$3,171,474	$2,840,074	$2,755,622	$2,286,275	$974,841	$578,419	$1,257,209	$2,219,010	$889,926	$2,081,616	$24,388,740
(63) Tetco M2 SCT	GSP-1	$25,123	$22,322	$69,507	$51,280	$26,849	$0	$0	$0	$0	$0	$0	$0	$195,081
(64) TGP Z4 Cnx	GSP-1	$616,490	$804,330	$859,267	$768,503	$657,899	$700,464	$692,665	$664,580	$563,762	$695,928	$622,380	$652,025	$8,298,294
(65) TGP Z4 LH	GSP-1	$1,337,286	$1,263,254	$1,672,795	$1,609,751	$836,283	$574,932	$7,718	$196,118	$0	$0	$161,424	$473,186	$8,132,747
(66) Total Variable Commodity Costs	Sum[(45):(65)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable Storage Costs														
(67) Underground Storage	GSP-1	$94,604	$1,727,309	$2,259,883	$2,014,184	$1,598,037	$0	$0	$0	$0	$0	$0	$0	$7,694,016
(68) LNG Withdrawals and Trucking	GSP-1	$83,794	$84,323	$761,809	$522,287	$83,556	$79,885	$81,713	$78,394	$80,777	$80,931	$78,198	$80,706	$2,096,372
(69) Total Variable Storage Costs	(67) + (68)	$178,398	$1,811,632	$3,021,692	$2,536,471	$1,681,592	$79,885	$81,713	$78,394	$80,777	$80,931	$78,198	$80,706	$9,790,388
Variable Transportation Costs														
(70) Variable Costs for Purchases to City Gate	GSP-1	$286,991	$328,149	$369,519	$330,262	$302,371	$206,387	$73,195	$48,694	$63,840	$73,688	$41,970	$145,330	$2,270,396
(71) Variable Cost for Storage Withdrawal	GSP-1	$7,093	$114,109	$149,339	$131,915	$103,832	$0	$0	$0	$0	$0	$0	$0	$506,287
(72) Variable Cost for Storage Injection	GSP-1	$0	$0	$0	$0	$140,488	$71,640	$107,730	$97,909	$43,230	$59,460	$93,325	$71,934	$685,717
(73) Total Variable Transportation Costs	Sum[(70):(72)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Injections														
(74) Cost of Injections	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(75) Variable Cost for Storage Injection	GSP-1	$0	$0	$0	$0	($140,488)	($71,640)	($107,730)	($97,909)	($43,230)	($59,460)	($93,325)	($71,934)	($685,717)
(76) Refunds	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(77) Total Injections	Sum[(74):(76)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hedging Impact														
(78) Hedging Impact	JMP-5	$85,087	($128,447)	($189,459)	($131,358)	($165,546)	($250,215)	($242,621)	($187,170)	($195,399)	($198,614)	($283,384)	($324,888)	($2,212,013)
(79) Total Variable Costs	(66)+(69)+(73)+(77) +(78)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$73,352,280
(80) Total Supply Costs	(44) + (79)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$159,044,249
Storage Costs for FT-2 Calculation														
(81) Storage Fixed Costs - Facilities	(30)	$435,814	$435,814	$435,814	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$449,319	$5,351,312
(82) Storage Fixed Costs - Deliveries	(42)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(83) Total Storage Costs	(81) + (82)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
GCR Deferred Balances

	Description	Nov-19 actual	Dec-19 actual	Jan-20 actual	Feb-20 actual	Mar-20 actual	Apr-20 actual	May-20 actual	Jun-20 actual	Jul-20 actual	Aug-20 forecast	Sep-20 forecast	Oct-20 forecast	Nov-Oct
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	I Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	($7,052,348)	($6,102,864)	($5,550,440)	($8,028,986)	($8,639,528)	($8,461,383)	($9,710,995)	($12,426,527)	($9,488,015)	($6,100,630)	($2,633,677)	$802,832	($7,052,348)
(4)	Supply Fixed Costs (net of cap rel)	$6,327,903	$8,645,307	$8,638,059	$8,536,820	$8,602,536	$5,567,480	$2,777,190	$5,553,300	$5,391,037	$5,561,006	$5,561,006	$5,561,006	$76,722,651
(5)	Reservation Charge _ Crary Street	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6)	Supply Related LNG O&M	$69,152	$590,121	$539,696	$303,380	($118,633)	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$1,867,779
(7)	NGPMP Credits	($475,000)	($475,000)	($1,004,242)	($475,000)	($221,260)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($5,975,502)
(8)	Working Capital	$47,869	$65,399	$65,344	$64,578	$65,076	$42,116	$21,009	$42,009	$40,782	$42,067	$42,067	$42,067	$580,383
(9)	Total Supply Fixed Costs	$5,969,924	$8,825,827	$8,238,857	$8,429,778	$8,327,717	$5,203,748	$2,392,351	$5,189,461	$5,025,971	$5,197,226	$5,197,226	$5,197,226	$73,195,311
(10)	Supply Fixed - Revenue	$5,000,953	$8,259,810	$10,701,564	$9,022,756	$8,136,639	$6,444,030	$5,096,139	$2,239,697	$1,630,316	$1,725,639	$1,759,777	$2,109,531	$62,126,849
(11)	Monthly Under/(Over) Recovery	$968,971	$566,017	($2,462,707)	($592,978)	$191,078	($1,240,282)	($2,703,788)	$2,949,764	$3,395,655	$3,471,587	$3,437,449	$3,087,695	$11,068,461
(12)	Prelim Ending Under/(Over) Recovery	($6,083,378)	($5,536,847)	($8,013,147)	($8,621,965)	($8,448,450)	($9,701,664)	($12,414,782)	($9,476,763)	($6,092,360)	($2,629,043)	$803,772	$3,890,527	$4,016,113
(13)	Month's Average Balance	($6,567,863)	($5,819,856)	($6,781,793)	($8,325,475)	($8,543,989)	($9,081,523)	($11,062,888)	($10,951,645)	($7,790,187)	($4,364,837)	($914,953)	$2,346,679	
(14)	Interest Rate (BOA Prime minus 200 bps)	2 75%	2 75%	2 75%	2 75%	1 78%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	
(15)	Interest Applied	($14,845)	($13,593)	($15,840)	($17,563)	($12,933)	($9,330)	($11,745)	($11,252)	($8,270)	($4,634)	($940)	$2,491	($118,454)
(16)	Marketer Reconcilation	($4,641)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($4,641)
(17)	Fixed Ending Under/(Over) Recovery	($6,102,864)	($5,550,440)	($8,028,986)	($8,639,528)	($8,461,383)	($9,710,995)	($12,426,527)	($9,488,015)	($6,100,630)	($2,633,677)	$802,832	$3,893,018	$3,893,018
(18)	II Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$5,109,999	$8,659,769	$11,209,584	$10,622,654	$11,089,511	$9,288,955	$7,486,618	$4,141,027	$3,753,168	$3,975,835	$3,708,802	$3,532,859	$5,109,999
(20)														
(21)	Variable Supply Costs	$9,270,622	$13,029,252	$13,220,051	$11,838,236	$8,413,386	$6,292,144	$2,983,048	$2,126,101	$1,913,246	$1,591,771	$1,712,077	$3,009,939	$75,399,873
(22)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23)	Supply Related LNG O&M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(24)	Inventory Financing - LNG	$25,458	$24,655	$24,006	$24,744	$24,319	$23,875	$23,482	$23,089	$23,331	$13,876	$16,908	$16,893	$264,636
(25)	Inventory Financing - UG	$80,040	$73,770	$67,115	$59,355	$53,426	$52,404	$56,661	$58,782	$62,219	$41,089	$51,005	$60,943	$716,811
(26)	Working Capital	$70,129	$98,562	$100,006	$89,553	$63,645	$47,598	$22,566	$16,083	$14,473	$12,041	$12,951	$22,769	$570,377
(27)	Total Supply Variable Costs	$9,471,436	$13,251,426	$13,436,365	$12,037,076	$8,579,963	$6,441,208	$3,110,944	$2,249,242	$2,038,456	$1,683,965	$1,818,128	$3,135,732	$77,253,941
(28)	Supply Variable - Revenue	$5,957,913	$10,724,788	$14,048,760	$11,593,097	$10,395,930	$8,252,159	$6,462,704	$2,641,154	$1,819,890	$1,955,074	$1,997,790	$2,462,342	$78,311,601
(29)	Monthly Under/(Over) Recovery	$3,513,523	$2,526,638	($612,396)	$443,979	($1,815,967)	($1,810,951)	($3,351,760)	($391,912)	$218,566	($271,109)	($179,662)	$673,390	($1,057,660)
(30)	Prelim Ending Under/(Over) Recovery	$8,623,522	$11,186,407	$10,597,188	$11,066,633	$9,273,544	$7,478,005	$4,134,858	$3,749,115	$3,971,734	$3,704,725	$3,529,141	$4,206,249	$4,052,339
(31)	Month's Average Balance	$6,866,760	$9,923,088	$10,903,386	$10,844,643	$10,181,527	$8,383,480	$5,810,738	$3,945,071	$3,862,451	$3,840,280	$3,618,972	$3,869,554	
(32)	Interest Rate (BOA Prime minus 200 bps)	2 75%	2 75%	2 75%	2 75%	1 78%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	
(33)	Interest Applied	$15,521	$23,177	$25,466	$22,878	$15,412	$8,613	$6,169	$4,053	$4,101	$4,077	$3,718	$4,108	$137,292
(34)	Gas Procurement Incentive/(penalty)	$20,726	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,726
(35)	Variable Ending Under/(Over) Recovery	$8,659,769	$11,209,584	$10,622,654	$11,089,511	$9,288,955	$7,486,618	$4,141,027	$3,753,168	$3,975,835	$3,708,802	$3,532,859	$4,210,357	$4,210,357
(36)	GCR Deferred Summary													
(37)	Beginning Under/(Over) Recovery	($1,942,350)	$2,556,905	$5,659,143	$2,593,668	$2,449,983	$827,573	($2,224,377)	($8,285,500)	($5,734,847)	($2,124,796)	$1,075,125	$4,335,691	($1,942,350)
(38)	Gas Costs	$15,688,223	$22,289,867	$22,422,992	$20,703,623	$16,922,475	$11,953,963	$5,854,577	$7,773,739	$7,398,622	$7,247,116	$7,367,423	$8,665,284	$154,287,906
(39)	Inventory Finance	$105,498	$98,425	$91,121	$84,100	$77,746	$76,279	$80,143	$81,871	$85,550	$54,965	$67,913	$77,836	$981,447
(40)	Working Capital	$117,998	$163,961	$165,350	$154,131	$128,720	$89,714	$43,574	$58,092	$55,255	$54,109	$55,019	$64,837	$1,150,760
(41)	NGPMP Credits	($475,000)	($475,000)	($1,004,242)	($475,000)	($221,260)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($475,000)	($5,975,502)
(42)	Total Costs	$15,436,719	$22,077,253	$21,675,222	$20,466,854	$16,907,681	$11,644,957	$5,503,295	$7,438,703	$7,064,427	$6,881,190	$7,015,354	$8,332,957	$150,444,611
(43)	Revenue	$10,958,866	$18,984,598	$24,750,324	$20,615,853	$18,532,569	$14,696,189	$11,558,842	$4,880,850	$3,450,206	$3,680,713	$3,757,567	$4,571,873	$140,438,450
(44)	Monthly Under/(Over) Recovery	$4,477,853	$3,092,655	($3,075,102)	($148,999)	($1,624,889)	($3,051,233)	($6,055,548)	$2,557,852	$3,614,221	$3,200,478	$3,257,787	$3,761,085	$10,006,161
(45)	Prelim Ending Under/(Over) Recovery	$2,535,504	$5,649,560	$2,584,041	$2,444,668	$825,094	($2,223,660)	($8,279,924)	($5,727,648)	($2,120,626)	$1,075,682	$4,332,913	$8,096,776	$8,063,811
(46)	Month's Average Balance	$296,577	$4,103,232	$4,121,592	$2,519,168	$1,637,538	($698,043)	($5,252,151)	($7,006,574)	($3,927,736)	($524,557)	$2,704,019	$6,216,233	
(47)	Interest Rate (BOA Prime minus 200 bps)	2 75%	2 75%	2 75%	2 75%	1 78%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	
(48)	Interest Applied	$676	$9,584	$9,626	$5,314	$2,479	($717)	($5,576)	($7,199)	($4,170)	($557)	$2,778	$6,599	$18,838
(49)	Gas Purchase Plan Incentives/(Penalties)	$20,726	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,726
(50)		$0	$0	$0		$0	$0	$0	$0	$0	$0	$0	$0	
(51)	Ending Under/(Over) Recovery W/ Interest	$2,556,905	$5,659,143	$2,593,668	$2,449,983	$827,573	($2,224,377)	($8,285,500)	($5,734,847)	($2,124,796)	$1,075,125	$4,335,691	$8,103,375	$8,103,375

Source: Docket No 4963 filed on August 20, 2020

REDACTED

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
GCR - Gas Cost Revenue

	Description (a)	Nov-20 fcst (b)	Dec-20 fcst (c)	Jan-21 fcst (d)	Feb-21 fcst (e)	Mar-21 fcst (f)	Apr-21 fcst (g)	May-21 fcst (h)	Jun-21 fcst (i)	Jul-21 fcst (j)	Aug-21 fcst (k)	Sep-21 fcst (l)	Oct-21 fcst (m)	Total Nov-Oct (n)
(1)	I Fixed Cost Revenue													
(2)	(a) Low Load dth	1,840,236	3,367,595	4,600,060	5,170,258	3,814,281	3,111,846	1,191,380	827,843	628,259	595,478	613,567	801,559	26,562,363
(3)	Fixed Cost Factor	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	$2 8492	
(4)	Low Load Revenue	$5,243,199	$9,594,952	$13,106,492	$14,731,098	$10,867,651	$8,866,273	$3,394,480	$2,358,689	$1,790,037	$1,696,637	$1,748,176	$2,283,802	$75,681,486
(5)	(b) High Load dth	47,180	70,967	83,791	89,030	70,167	62,930	38,685	40,356	32,266	34,547	37,622	38,418	645,959
(6)	Fixed Cost Factor	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	$2 1719	
(7)	High Load Revenue	$102,471	$154,132	$181,986	$193,364	$152,396	$136,678	$84,019	$87,650	$70,079	$75,032	$81,712	$83,440	$1,402,959
(8)	sub-total Dth	1,887,416	3,438,561	4,683,852	5,259,288	3,884,449	3,174,777	1,230,065	868,199	660,525	630,025	651,190	839,977	27,208,322
(9)	FT-2 Storage Revenue from marketers	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$271,089	$3,253,068
(10)	Total Fixed Revenue	$5,616,759	$10,020,173	$13,559,567	$15,195,551	$11,291,136	$9,274,040	$3,749,588	$2,717,428	$2,131,205	$2,042,758	$2,100,977	$2,638,331	$80,337,513
(11)	II Variable Cost Revenue													
(12)	(a) Firm Sales dth	1,887,416	3,438,561	4,683,852	5,259,288	3,884,449	3,174,777	1,230,065	868,199	660,525	630,025	651,190	839,977	27,208,322
(13)	Variable Cost Factor	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	$2 9076	
(14)	Variable Revenue	$5,487,850	$9,997,961	$13,618,767	$15,291,904	$11,294,423	$9,230,981	$3,576,537	$2,524,375	$1,920,544	$1,831,860	$1,893,399	$2,442,317	$79,110,918
(15)	Total Variable Revenue	$5,487,850	$9,997,961	$13,618,767	$15,291,904	$11,294,423	$9,230,981	$3,576,537	$2,524,375	$1,920,544	$1,831,860	$1,893,399	$2,442,317	$79,110,918
(16)	Total Gas Cost Revenue	$11,104,609	$20,018,134	$27,178,334	$30,487,455	$22,585,559	$18,505,021	$7,326,125	$5,241,803	$4,051,749	$3,874,618	$3,994,376	$5,080,648	$159,448,431

(2) RMS/MJP-1, pg 12, Sum [Lines (2)-(5), (7)]
(3) RMS/MJP-1, pg 1, Line 1, col (e)
(4) Line (2) x Line (3)
(5) RMS/MJP-1, pg 12, Sum [Lines (1), (6), (8)]
(6) RMS/MJP-1, pg 1, Line 1, col (d)
(7) Line (5) x Line (6)
(8) Line (2) + Line (5)
(9) [RMS/MJP-5, pg 2, Line (25)] ÷ 12
(10) Sum[Lines (4), (7), (9)]
(12) Line (8)
(13) RMS/MJP-1, pg 1, Line (2)
(14) Line (12) x Line (13)
(15) Line (14)
(16) Line (10) + Line (15)

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Working Capital Estimate

Description (a)	Nov-20 (b)	Dec-20 (c)	Jan-21 (d)	Feb-21 (e)	Mar-21 (f)	Apr-21 (g)	May-21 (h)	Jun-21 (i)	Jul-21 (j)	Aug-21 (k)	Sep-21 (l)	Oct-21 (m)	Total (n)
(1) Fixed Costs	$5,841,318	$9,829,495	$9,826,825	$10,035,301	$10,035,301	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$85,691,969
(2) Capacity Release Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(3) Less System Pressure to DAC	$0	($1,311,213)	($1,311,213)	($1,311,213)	($1,311,213)	$0	$0	$0	$0	$0	$0	$0	($5,244,853)
(4) Less: Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6) Allowable Working Capital Costs	$5,841,318	$8,518,281	$8,515,612	$8,724,088	$8,724,088	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$80,447,116
(7) Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(8) Working Capital Requirement	$526,839	$768,279	$768,038	$786,841	$786,841	$516,976	$516,976	$516,976	$516,976	$516,976	$516,976	$516,976	
(9) Weighted Average Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(10) Return on Working Capital Requirement	$37,564	$54,778	$54,761	$56,102	$56,102	$36,860	$36,860	$36,860	$36,860	$36,860	$36,860	$36,860	
(11) Cost of Debt (Long Term Debt + Short Term Debt)	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(12) Interest Expense	$12,644	$18,439	$18,433	$18,884	$18,884	$12,407	$12,407	$12,407	$12,407	$12,407	$12,407	$12,407	
(13) Taxable Income	$24,919	$36,340	$36,328	$37,218	$37,218	$24,453	$24,453	$24,453	$24,453	$24,453	$24,453	$24,453	
(14) 1 - Combined Tax Rate	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(15) Return and Tax Requirement	$31,544	$45,999	$45,985	$47,111	$47,111	$30,953	$30,953	$30,953	$30,953	$30,953	$30,953	$30,953	
(16) Fixed Working Capital Requirement	$44,188	$64,438	$64,418	$65,995	$65,995	$43,361	$43,361	$43,361	$43,361	$43,361	$43,361	$43,361	$608,558
(17) Variable Costs	$6,639,143	$11,508,564	$15,004,056	$12,961,499	$10,448,208	$5,222,883	$2,574,775	$1,617,046	$1,302,679	$1,344,373	$1,450,804	$3,278,250	$73,352,280
(18) Less: Non-firm Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19) Less: Supply Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20) Less: Bal Related Syst Pressure Commodity to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22) Allowable Working Capital Costs	$6,639,143	$11,508,564	$15,004,056	$12,961,499	$10,448,208	$5,222,883	$2,574,775	$1,617,046	$1,302,679	$1,344,373	$1,450,804	$3,278,250	$73,352,280
(23) Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(24) Working Capital Requirement	$598,796	$1,037,978	$1,353,243	$1,169,021	$942,343	$471,061	$232,224	$145,844	$117,491	$121,251	$130,851	$295,671	
(25) Weighted Average Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(26) Return on Working Capital Requirement	$42,694	$74,008	$96,486	$83,351	$67,189	$33,587	$16,558	$10,399	$8,377	$8,645	$9,330	$21,081	
(27) Cost of Debt (Long Term Debt + Short Term Debt)	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(28) Interest Expense	$14,371	$24,911	$32,478	$28,056	$22,616	$11,305	$5,573	$3,500	$2,820	$2,910	$3,140	$7,096	
(29) Taxable Income	$28,323	$49,096	$64,008	$55,295	$44,573	$22,281	$10,984	$6,898	$5,557	$5,735	$6,189	$13,985	
(30) 1 - Combined Tax Rate	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(31) Return and Tax Requirement	$35,852	$62,147	$81,023	$69,993	$56,421	$28,204	$13,904	$8,732	$7,035	$7,260	$7,834	$17,703	
(32) Variable Working Capital Requirement	$50,223	$87,059	$113,501	$98,050	$79,037	$39,510	$19,477	$12,232	$9,854	$10,170	$10,975	$24,799	$554,887

(1) RMS/MJP-1, Pg 2, Line (1)
(3) GSP-1, Pg 12
(6) Sum[Lines (1)-(5)]
(7) Dkt 4770
(8) [Line (6) x Line (7)] ÷ 365
(9) Dkt 4955
(10 Line (8) x Line (9)
(11) Dkt 4955
(12) Line (8) x Line (11)
(13) Line (10) - Line (12)
(14) Tax Law effective Jan 1, 2018
(15) Line (13) ÷ Line (14)
(16) Line (12) + Line (17)
(17) RMS/MJP-1, Pg 6, Line (74)
(20) RMS/MJP-1, Pg 3, Line (2) ÷ 12
(22) Sum[Lines (17):(21)]
(23) Dkt 4770
(24) [Line (22) x Line (23)] ÷ 365
(25) Dkt 4955
(26) Line (24) x Line (25)
(27) Dkt 4955
(28) Line (24) x Line (27)
(29) Line (26) - Line (28)
(30) Tax Law effective Jan 1, 2018
(31) Line (29) ÷ Line (30)
(32) Line (28) + Line (31)

REDACTED

Storage Fixed Cost Working Capital Calculation for FT-2 Demand Rate (see RMS/MJP-5, pg 2)

Description (a)	Nov-20 (b)	Dec-20 (c)	Jan-21 (d)	Feb-21 (e)	Mar-21 (f)	Apr-21 (g)	May-21 (h)	Jun-21 (i)	Jul-21 (j)	Aug-21 (k)	Sep-21 (l)	Oct-21 (m)	Total (n)
(33) Storage Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(34) Less: System Pressure to DAC													
(35) Less: Credits													
(36) Plus: Supply Related LNG O&M Costs													
(37) Allowable Working Capital Costs													
(38) Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(39) Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(40) Weighted Average Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(41) Return on Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(42) Cost of Debt (Long Term Debt + Short Term Debt)	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(43) Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(44) Taxable Income	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(45) 1 - Combined Tax Rate	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(46) Return and Tax Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(47) Storage Fixed Working Capital Requirement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$190,257

(33) RMS/MJP-1, pg 6, Line (78)
(34) Line (3)
(37) Sum[Lines (33) - (36)]
(38) Dkt 4770
(39) [Line (37) x Line (38)] ÷ 365
(40) Dkt 4955
(41) Line (39) x Line (40)
(42) Dkt 4955
(43) Line (39) x Line (42)
(44) Line (41) - Line (43)
(45) Tax Law effective Jan 1, 2018
(46) Line (44) ÷ Line (45)
(47) Line (43) + Line (46)

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Inventory Finance Estimate

Description (a)	Source (b)	Nov-20 (c)	Dec-20 (d)	Jan-21 (e)	Feb-21 (f)	Mar-21 (g)	Apr-21 (h)	May-21 (i)	Jun-21 (j)	Jul-21 (k)	Aug-21 (l)	Sep-21 (m)	Oct-21 (n)	Total (o)
(1) **Storage Inventory Balance**	GSP-1	$8,827,525	$7,092,549	$4,829,125	$2,825,192	$1,228,112	$1,492,221	$2,999,637	$4,347,947	$5,351,214	$7,044,297	$8,597,739	$10,150,092	
(2) Hedging		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(3) Subtotal	(1) + (2)	$8,827,525	$7,092,549	$4,829,125	$2,825,192	$1,228,112	$1,492,221	$2,999,637	$4,347,947	$5,351,214	$7,044,297	$8,597,739	$10,150,092	
(4) Weighted Average Cost of Capital	Dkt 4955	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(5) Return on Working Capital Requirement	(3) x (4)	$629,403	$505,699	$344,317	$201,436	$87,564	$106,395	$213,874	$310,009	$381,542	$502,258	$613,019	$723,702	$4,619,217
(6) Cost of Debt (LTD + STD)*	Dkt 4955	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(7) Interest Charges Financed	(3) x (6)	$211,861	$170,221	$115,899	$67,805	$29,475	$35,813	$71,991	$104,351	$128,429	$169,063	$206,346	$243,602	$1,554,856
(8) Taxable Income	(5) - (7)	$417,542	$335,478	$228,418	$133,632	$58,090	$70,582	$141,883	$205,658	$253,112	$333,195	$406,673	$480,099	
(9) 1 - Combined Tax Rate		0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(10) Return and Tax Requirement	(8) ÷ (9)	$528,534	$424,655	$289,136	$169,154	$73,531	$89,344	$179,599	$260,326	$320,395	$421,766	$514,776	$607,721	$3,878,938
(11) Working Capital Requirement	(7) + (10)	$740,395	$594,876	$405,035	$236,958	$103,006	$125,158	$251,590	$364,677	$448,825	$590,829	$721,122	$851,323	$5,433,794
(12) Storage-Related Inventory Costs	(11) ÷ 12	$61,700	$49,573	$33,753	$19,747	$8,584	$10,430	$20,966	$30,390	$37,402	$49,236	$60,093	$70,944	$452,816
(13) **LNG Inventory Balance**	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(14) Weighted Average Cost of Capital	Dkt 4955	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	
(15) Return on Working Capital Requirement	(13) x (14)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,442,297
(16) Cost of Debt (LTD + STD)*	Dkt 4955	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	
(17) Interest Charges Financed	(13) x (16)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$822,091
(18) Taxable Income	(15) - (17)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
(19) 1 - Combined Tax Rate		0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	0 7900	
(20) Return and Tax Requirement	(18) ÷ (19)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,050,893
(21) Working Capital Requirement	(17) + (20)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,872,984
(22) LNG-Related Inventory Costs	(21) ÷ 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$239,415
(23) Total Inventory Financing Costs	(12) + (22)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$692,232

*LTD: Long Term Debt
*STD: Short Term Debt

REDACTED

REDACTED

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Forecasted Throughput (Dth)

	Rate Class	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	SALES													
(1)	Residential Non-Heating	22,647	37,576	49,643	55,213	41,396	33,754	14,313	16,613	13,587	12,979	13,211	16,397	327,328
(2)	Residential Heating	1,425,252	2,561,188	3,457,951	3,868,527	2,854,494	2,285,288	835,249	586,155	460,711	440,051	454,182	613,380	19,842,428
(3)	Small C&I	135,705	299,060	449,122	511,867	365,377	303,165	112,463	65,607	45,108	41,941	43,562	44,282	2,417,258
(4)	Medium C&I	234,216	414,187	561,520	640,565	475,154	417,765	199,957	154,905	111,312	104,083	106,527	127,820	3,548,011
(5)	Large LLF	38,830	81,885	117,530	133,490	105,688	93,661	38,763	18,824	10,355	8,869	8,737	13,504	670,135
(6)	Large HLF	17,111	22,615	27,851	28,316	24,866	24,920	18,887	16,837	12,948	13,104	15,532	14,568	237,554
(7)	Extra Large LLF	6,233	11,276	13,938	15,810	13,569	11,967	4,949	2,352	773	534	559	2,573	84,532
(8)	Extra Large HLF	7,422	10,775	6,298	5,501	3,905	4,257	5,485	6,906	5,731	8,464	8,880	7,454	81,078
(9)	**Total Sales**	1,887,416	3,438,561	4,683,852	5,259,288	3,884,449	3,174,777	1,230,065	868,199	660,525	630,025	651,190	839,977	27,208,322
	TRANSPORTATION													
(10)	FT- Small	9,120	20,201	28,619	32,911	20,674	17,753	7,285	4,842	3,134	2,653	1,497	4,893	153,583
(11)	FT- Medium	196,001	313,294	399,649	443,397	335,834	283,393	142,911	107,219	80,798	75,473	76,980	104,444	2,559,393
(12)	FT- Large LLF	193,006	306,989	383,975	413,276	318,773	245,458	106,342	58,556	37,131	35,819	37,113	77,787	2,214,226
(13)	FT- Large HLF	72,490	96,408	110,317	115,400	95,865	83,710	69,666	65,005	58,363	59,837	64,050	64,524	955,636
(14)	FT- Extra Large LLF	141,680	174,265	202,078	201,175	178,043	113,963	53,092	28,895	23,422	20,969	26,864	69,904	1,234,349
(15)	FT- Extra Large HLF	424,785	481,420	528,032	526,088	506,299	456,528	405,563	407,508	393,483	401,279	387,120	404,615	5,322,721
(16)	**Total FT Transportation**	1,037,081	1,392,578	1,652,672	1,732,248	1,455,488	1,200,806	784,860	672,024	596,331	596,029	593,625	726,167	12,439,908
	Total THROUGHPUT													
(17)	Residential Non-Heating	22,647	37,576	49,643	55,213	41,396	33,754	14,313	16,613	13,587	12,979	13,211	16,397	327,328
(18)	Residential Heating	1,425,252	2,561,188	3,457,951	3,868,527	2,854,494	2,285,288	835,249	586,155	460,711	440,051	454,182	613,380	19,842,428
(19)	Small C&I	144,825	319,261	477,741	544,777	386,051	320,918	119,748	70,449	48,243	44,594	45,059	49,175	2,570,841
(20)	Medium C&I	430,217	727,481	961,169	1,083,961	810,988	701,158	342,868	262,123	192,110	179,556	183,508	232,264	6,107,404
(21)	Large LLF	231,836	388,874	501,505	546,767	424,461	339,119	145,105	77,380	47,486	44,688	45,850	91,291	2,884,361
(22)	Large HLF	89,601	119,023	138,168	143,717	120,731	108,630	88,553	81,843	71,311	72,940	79,582	79,091	1,193,189
(23)	Extra Large LLF	147,912	185,541	216,016	216,984	191,612	125,930	58,041	31,247	24,195	21,503	27,423	72,477	1,318,881
(24)	Extra Large HLF	432,208	492,195	534,330	531,589	510,204	460,785	411,048	414,414	399,214	409,743	396,000	412,069	5,403,799
(25)	**Total Throughput**	2,924,497	4,831,139	6,336,523	6,991,535	5,339,937	4,375,583	2,014,924	1,540,223	1,256,856	1,226,054	1,244,814	1,566,144	39,648,231

Source: Attachement TEP-1

REDACTED

The Narragansett Electric Company
d/b/a National Grid
Docket No. 5066
Attachment RMS/MJP-1
Confidential
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National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Design Winter Period and Design Day Throughput (Dth)

	Rate Class (a)	Reference	Line #	Nov-20 (b)	Dec-20 (c)	Jan-21 (d)	Feb-21 (e)	Mar-21 (f)	Total (g)	% (h)
	SALES (dth)									
(1)	Residential Non-Heating	MJP/AEL-1, pg 16	Line (70)	23,931	41,489	55,558	62,154	42,084	225,216	1.06%
(2)	Residential Heating	MJP/AEL-1, pg 16	Line (71)	1,555,775	2,901,805	3,947,793	4,428,332	2,913,481	15,747,186	74.05%
(3)	Small C&I	MJP/AEL-1, pg 16	Line (72)	148,064	340,337	515,238	588,433	373,282	1,965,354	9.24%
(4)	Medium C&I	MJP/AEL-1, pg 16	Line (74)	251,370	463,664	635,459	728,256	484,174	2,562,924	12.05%
(5)	Large LLF	MJP/AEL-1, pg 16	Line (76)	42,773	93,612	135,173	153,771	108,056	533,385	2.51%
(6)	Large HLF	MJP/AEL-1, pg 16	Line (78)	17,582	24,007	30,109	30,790	25,133	127,622	0.60%
(7)	Extra Large LLF	MJP/AEL-1, pg 16	Line (80)	6,979	12,999	16,110	18,286	13,887	68,260	0.32%
(8)	Extra Large HLF	MJP/AEL-1, pg 16	Line (82)	7,422	11,261	6,298	5,501	3,905	34,387	0.16%
(9)	Total Sales	Sum[(1):(8)]		2,053,896	3,889,175	5,341,738	6,015,523	3,964,002	21,264,334	100.00%
(10)	Low Load Factor	Sum[(2)-(5),(7)]		2,004,960	3,812,419	5,249,773	5,917,078	3,892,880	20,877,109	98.18%
(11)	High Load Factor	Sum[(1),(6),(8)]		48,936	76,757	91,964	98,445	71,123	387,225	1.82%

2020/2021 Design Day Send Out

(12)	Pipeline	212,822	Dktherm
(13)	Underground Storage	42,721	Dktherm
(14)	LNG	[redacted]	Dktherm
(15)	Total Projected 2020/2021 Design Day	[redacted]	Dktherm

(1) Column (h): [Line (1), Col (g)]÷[Line (9), Col (g)]
(2) Column (h): [Line (2), Col (g)]÷[Line (9), Col (g)]
(3) Column (h): [Line (3), Col (g)]÷[Line (9), Col (g)]
(4) Column (h): [Line (4), Col (g)]÷[Line (9), Col (g)]
(5) Column (h): [Line (5), Col (g)]÷[Line (9), Col (g)]
(6) Column (h): [Line (6), Col (g)]÷[Line (9), Col (g)]
(7) Column (h): [Line (7), Col (g)]÷[Line (9), Col (g)]
(8) Column (h): [Line (8), Col (g)]÷[Line (9), Col (g)]
(10) Column (h): [Line (10), Col (g)]÷[Line (9), Col (g)]
(11) Column (h): [Line (11), Col (g)]÷[Line (9), Col (g)]

REDACTED

Derivation of Monthly Design Sales

Normal Volumes (Dth)

	(a)	Nov-20 (b)	Dec-20 (c)	Jan-21 (d)	Feb-21 (e)	Mar-21 (f)	Apr-21 (g)	May-21 (h)	Jun-21 (i)	Jul-21 (j)	Aug-21 (k)	Sep-21 (l)	Oct-21 (m)	Nov-Oct (n)
(1)	Residential Non-Heating	22,647	37,576	49,643	55,213	41,396	33,754	14,313	16,613	13,587	12,979	13,211	16,397	327,328
(2)	Residential Heating	1,425,252	2,561,188	3,457,951	3,868,527	2,854,494	2,285,288	835,249	586,155	460,711	440,051	454,182	613,380	19,842,428
(3)	Small C&I	135,705	299,060	449,122	511,867	365,377	303,165	112,463	65,607	45,108	41,941	43,562	44,282	2,417,258
(4)	Small Transport	9,120	20,201	28,619	32,911	20,674	17,753	7,285	4,842	3,134	2,653	1,497	4,893	153,583
(5)	Medium C&I	234,216	414,187	561,520	640,565	475,154	417,765	199,957	154,905	111,312	104,083	106,527	127,820	3,548,011
(6)	Med Transport	196,001	313,294	399,649	443,397	335,834	283,393	142,911	107,219	80,798	75,473	76,980	104,444	2,559,393
(7)	Large Low Load	38,830	81,885	117,530	133,490	105,688	93,661	38,763	18,824	10,355	8,869	8,737	13,504	670,135
(8)	Large Low Load- Transport	193,006	306,989	383,975	413,276	318,773	245,458	106,342	58,556	37,131	35,819	37,113	77,787	2,214,226
(9)	Large High Load	17,111	22,615	27,851	28,316	24,866	24,920	18,887	16,837	12,948	13,104	15,532	14,568	237,554
(10)	Large High Load- Transport	72,490	96,408	110,317	115,400	95,865	83,710	69,666	65,005	58,363	59,837	64,050	64,524	955,636
(11)	XL Low Load	6,233	11,276	13,938	15,810	13,569	11,967	4,949	2,352	773	534	559	2,573	84,532
(12)	XL Low Load-Transport	141,680	174,265	202,078	201,175	178,043	113,963	53,092	28,895	23,422	20,969	26,864	69,904	1,234,349
(13)	XL High Load	7,422	10,775	6,298	5,501	3,905	4,257	5,485	6,906	5,731	8,464	8,880	7,454	81,078
(14)	XL High Load-Transport	424,785	481,420	528,032	526,088	506,299	456,528	405,563	407,508	393,483	401,279	387,120	404,615	5,322,721
(15)	**Total**	2,924,497	4,831,139	6,336,523	6,991,535	5,339,937	4,375,583	2,014,924	1,540,223	1,256,856	1,226,054	1,244,814	1,566,144	39,648,231
(16)	HLF	544,455	648,794	722,141	730,519	672,331	603,169	513,914	512,869	484,112	495,662	488,793	507,557	6,924,316
(17)	LLF	2,380,042	4,182,345	5,614,382	6,261,017	4,667,606	3,772,414	1,501,011	1,027,354	772,745	730,392	756,022	1,058,586	32,723,914

Baseload

		Nov-20 30	Dec-20 31	Jan-21 31	Feb-21 29	Mar-21 31	Apr-21 30	May-21 31	Jun-21 30	Jul-21 31	Aug-21 31	Sep-21 30	Oct-21 31	Nov-Oct
(18)	Residential Non-Heating	12,971	13,403	13,403	12,538	13,403	12,971	13,403	12,971	13,403	12,979	12,971	13,403	157,817
(19)	Residential Heating	441,830	456,557	456,557	427,102	456,557	441,830	456,557	441,830	456,557	440,051	441,830	456,557	5,373,816
(20)	Small C&I	42,591	44,010	44,010	41,171	44,010	42,591	44,010	42,591	44,010	41,941	42,591	44,010	517,537
(21)	Small Transport	2,375	2,454	2,454	2,296	2,454	2,375	2,454	2,375	2,454	2,454	1,497	2,454	28,099
(22)	Medium C&I	104,975	108,474	108,474	101,475	108,474	104,975	108,474	104,975	108,474	104,083	104,975	108,474	1,276,298
(23)	Med Transport	76,060	78,596	78,596	73,525	78,596	76,060	78,596	76,060	78,596	75,473	76,060	78,596	924,813
(24)	Large Low Load	9,118	9,422	9,422	8,814	9,422	9,118	9,422	9,118	9,422	8,869	8,737	9,422	110,304
(25)	Large Low Load- Transport	35,890	37,086	37,086	34,694	37,086	35,890	37,086	35,890	37,086	35,819	35,890	37,086	436,592
(26)	Large High Load	13,560	14,012	14,012	13,108	14,012	13,560	14,012	13,560	12,948	13,104	13,560	14,012	163,458
(27)	Large High Load- Transport	59,429	61,410	61,410	57,448	61,410	59,429	61,410	59,429	58,363	59,837	59,429	61,410	720,414
(28)	XL Low Load	609	629	629	588	629	609	629	609	629	534	559	629	7,281
(29)	XL Low Load-Transport	23,235	24,010	24,010	22,461	24,010	23,235	24,010	23,235	23,422	20,969	23,235	24,010	279,841
(30)	XL High Load	7,422	7,775	6,298	5,501	3,905	4,257	5,485	6,906	5,731	7,775	7,524	7,454	76,034
(31)	XL High Load-Transport	385,396	398,243	398,243	372,550	398,243	385,396	398,243	385,396	393,483	398,243	385,396	398,243	4,697,077
(32)	Total	1,215,460	1,256,081	1,254,603	1,173,271	1,252,211	1,212,295	1,253,791	1,214,944	1,244,578	1,222,131	1,214,254	1,255,760	14,769,380
(33)	HLF	478,778	494,843	493,365	461,145	490,973	475,613	492,553	478,262	483,928	491,937	478,880	494,522	5,814,801
(34)	LLF	736,682	761,238	761,238	712,126	761,238	736,682	761,238	736,682	760,650	730,194	735,374	761,238	8,954,580

REDACTED

Derivation of Monthly Design Sales

Heat Volumes

	(a)	Nov-20 (b)	Dec-20 (c)	Jan-21 (d)	Feb-21 (e)	Mar-21 (f)	Apr-21 (g)	May-21 (h)	Jun-21 (i)	Jul-21 (j)	Aug-21 (k)	Sep-21 (l)	Oct-21 (m)	Nov-Oct (n)
(35)	Residential Non-Heating	9,676	24,173	36,240	42,674	27,993	20,783	910	3,642	184	0	240	2,994	169,511
(36)	Residential Heating	983,422	2,104,630	3,001,394	3,441,425	2,397,937	1,843,458	378,692	144,325	4,154	0	12,352	156,823	14,468,612
(37)	Small C&I	93,115	255,049	405,111	470,696	321,366	260,574	68,453	23,016	1,098	0	971	272	1,899,722
(38)	Small Transport	6,745	17,747	26,165	30,615	18,220	15,378	4,831	2,466	680	198	0	2,438	125,483
(39)	Medium C&I	129,242	305,713	453,046	539,089	366,681	312,791	91,483	49,930	2,838	0	1,553	19,346	2,271,713
(40)	Med Transport	119,940	234,698	321,054	369,872	257,238	207,333	64,316	31,158	2,203	0	920	25,848	1,634,580
(41)	Large Low Load	29,712	72,463	108,108	124,676	96,266	84,543	29,341	9,706	933	0	0	4,082	559,831
(42)	Large Low Load- Transport	157,116	269,903	346,889	378,583	281,687	209,568	69,256	22,666	44	0	1,223	40,701	1,777,634
(43)	Large High Load	3,551	8,603	13,839	15,208	10,854	11,360	4,875	3,278	0	0	1,972	556	74,095
(44)	Large High Load- Transport	13,061	34,998	48,907	57,952	34,455	24,281	8,256	5,576	0	0	4,621	3,114	235,221
(45)	XL Low Load	5,624	10,647	13,309	15,221	12,940	11,359	4,320	1,743	144	0	0	1,944	77,251
(46)	XL Low Load-Transport	118,444	150,256	178,069	178,714	154,033	90,728	29,082	5,660	0	0	3,629	45,894	954,509
(47)	XL High Load	0	3,000	0	0	0	0	0	0	0	689	1,355	0	5,044
(48)	XL High Load-Transport	39,389	83,177	129,789	153,538	108,056	71,132	7,320	22,112	0	3,036	1,724	6,372	625,644
(49)	Total	1,709,037	3,575,058	5,081,920	5,818,264	4,087,725	3,163,288	761,134	325,279	12,278	3,923	30,560	310,384	24,878,850
(50)	HLF	65,677	153,951	228,776	269,373	181,358	127,556	21,361	34,607	184	3,725	9,912	13,036	1,109,516
(51)	LLF	1,643,360	3,421,107	4,853,144	5,548,891	3,906,368	3,035,732	739,773	290,672	12,094	198	20,648	297,348	23,769,334
(52)	**Normal Billing DD**	**437**	**760**	**1011**	**1125**	**935**	**673**	**262**	**131**	**19**	**0**	**13**	**156**	**5522**

Heat Factors

	(a)	Nov-20 (b)	Dec-20 (c)	Jan-21 (d)	Feb-21 (e)	Mar-21 (f)	Apr-21 (g)	May-21 (h)	Jun-21 (i)	Jul-21 (j)	Aug-21 (k)	Sep-21 (l)	Oct-21 (m)	Nov-Oct
(53)	Residential Non-Heating	22	32	36	38	30	31	3	28	10	0	18	19	31
(54)	Residential Heating	2,250	2,769	2,969	3,059	2,565	2,739	1,445	1,102	219	0	950	1,005	2,620
(55)	Small C&I	213	336	401	418	344	387	261	176	58	0	75	2	344
(56)	Small Transport	15	23	26	27	19	23	18	19	36	0	0	16	23
(57)	Medium C&I	296	402	448	479	392	465	349	381	149	0	119	124	411
(58)	Med Transport	274	309	318	329	275	308	245	238	116	0	71	166	296
(59)	Large Low Load	68	95	107	111	103	126	112	74	49	0	0	26	101
(60)	Large Low Load- Transport	360	355	343	337	301	311	264	173	2	0	94	261	322
(61)	Large High Load	8	11	14	14	12	17	19	25	0	0	152	4	13
(62)	Large High Load- Transport	30	46	48	52	37	36	32	43	0	0	355	20	43
(63)	XL Low Load	13	14	13	14	14	17	16	13	8	0	0	12	14
(64)	XL Low Load-Transport	271	198	176	159	165	135	111	43	0	0	279	294	173
(65)	XL High Load	0	4	0	0	0	0	0	0	0	0	104	0	1
(66)	XL High Load-Transport	90	109	128	136	116	106	28	169	0	0	133	41	113
(67)	Total	3,911	4,704	5,027	5,172	4,372	4,700	2,905	2,483	646	0	2,351	1,990	4,505
(68)	**NormalBilling DD**	**437**	**760**	**1011**	**1125**	**935**	**673**	**262**	**131**	**19**	**0**	**13**	**156**	**5522**
(69)	**DesignBilling DD**	**495**	**883**	**1176**	**1308**	**958**	**771**	**292**	**154**	**27**	**0**	**9**	**177**	**6250**

REDACTED

Derivation of Monthly Design Sales

Design Sales

	(a)	Nov-18 (b)	Dec-18 (c)	Jan-19 (d)	Feb-19 (e)	Mar-19 (f)	Apr-19 (g)	May-19 (h)	Jun-19 (i)	Jul-19 (j)	Aug-19 (k)	Sep-19 (l)	Oct-19 (m)	Nov-Oct
(70)	Residential Non-Heating	23,931	41,489	55,558	62,154	42,084	36,780	14,417	17,252	13,403	12,979	13,137	16,800	349,984
(71)	Residential Heating	1,555,775	2,901,805	3,947,793	4,428,332	2,913,481	2,553,726	878,611	611,495	456,557	440,051	450,381	634,491	21,772,498
(72)	Small C&I	148,064	340,337	515,238	588,433	373,282	341,109	120,301	69,648	44,010	41,941	43,263	44,319	2,669,945
(73)	Small Transport	10,015	23,073	32,889	37,891	21,122	19,993	7,838	5,275	2,454	2,454	1,497	5,221	169,724
(74)	Medium C&I	251,370	463,664	635,459	728,256	484,174	463,313	210,432	163,671	108,474	104,083	106,050	130,424	3,849,370
(75)	Med Transport	211,919	351,278	452,047	503,563	342,162	313,584	150,276	112,689	78,596	75,473	76,697	107,923	2,776,207
(76)	Large Low Load	42,773	93,612	135,173	153,771	108,056	105,972	42,123	20,528	9,422	8,869	8,737	14,053	743,089
(77)	Large Low Load- Transport	213,859	350,671	440,589	474,859	325,702	275,975	114,272	62,535	37,086	35,819	36,737	83,266	2,451,371
(78)	Large High Load	17,582	24,007	30,109	30,790	25,133	26,574	19,445	17,413	12,948	13,104	14,925	14,642	246,673
(79)	Large High Load- Transport	74,223	102,072	118,299	124,827	96,713	87,246	70,612	65,984	58,363	59,837	62,628	64,943	985,747
(80)	XL Low Load	6,979	12,999	16,110	18,286	13,887	13,621	5,444	2,658	629	534	559	2,835	94,540
(81)	XL Low Load-Transport	157,400	198,583	231,140	230,246	181,832	127,174	56,422	29,889	23,422	20,969	25,747	76,082	1,358,906
(82)	XL High Load	7,422	11,261	6,298	5,501	3,905	4,257	5,485	6,906	5,731	7,775	8,463	7,454	80,458
(83)	XL High Load-Transport	430,013	494,881	549,215	551,064	508,957	466,886	406,401	411,390	393,483	398,243	386,590	405,473	5,402,597
(84)	Total	3,151,326	5,409,734	7,165,917	7,937,973	5,440,490	4,836,210	2,102,077	1,597,333	1,244,578	1,222,131	1,235,411	1,607,926	42,951,107
(85)	HLF	553,172	673,710	759,478	774,337	676,792	621,743	516,360	518,945	483,928	491,937	485,743	509,312	7,065,458
(86)	LLF	2,598,154	4,736,024	6,406,439	7,163,636	4,763,698	4,214,467	1,585,717	1,078,388	760,650	730,194	749,668	1,098,614	35,885,649

Source: Attachement TEP-1

Attachment RMS/MJP -2
Annual GCR Reconciliation Filing

REDACTED

Deferred Gas Cost Balances

	Description	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-Mar
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	
(1)	# of Days in Month	30	31	30	31	31	30	31	30	31	31	28	31	365
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
(2)	I Fixed Cost Deferred													
(3)	Beginning Under/(Over) Recovery	($10,178,562)	($15,354,534)	($16,918,562)	($15,686,922)	($13,431,804)	($11,123,421)	($9,054,997)	($7,052,348)	($6,102,864)	($5,550,440)	($8,028,986)	($8,639,528)	($10,178,562)
(4)	Supply Fixed Costs (net of cap rel)	$4,743,933	$4,553,884	$4,848,986	$4,764,467	$4,722,839	$4,804,663	$5,009,434	$6,327,903	$8,645,307	$8,638,059	$8,536,820	$8,602,536	$74,198,830
(5)	System Pressure to DAC (Res Chge - Crary St)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6)	Supply Related LNG O&M	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$590,121	$539,696	$303,380	($118,633)	$1,867,779
(7)	NGPMP Credits	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($600,550)	($333,333)	($475,000)	($475,000)	($1,004,242)	($475,000)	($221,260)	($5,251,052)
(8)	Working Capital	$35,972	$34,531	$36,769	$36,128	$35,812	$36,432	$37,985	$47,869	$65,399	$65,344	$64,578	$65,076	$561,895
(9)	Total Supply Fixed Costs	$4,515,723	$4,324,233	$4,621,573	$4,536,414	$4,494,470	$4,309,698	$4,783,238	$5,969,924	$8,825,827	$8,238,857	$8,429,778	$8,327,717	$71,377,452
(10)	Supply Fixed - Revenue	$9,655,022	$5,840,364	$3,343,103	$2,238,081	$2,152,244	$2,214,359	$2,760,095	$5,000,953	$8,259,810	$10,701,564	$9,022,756	$8,136,639	$69,324,990
(11)	Monthly Under/(Over) Recovery	($5,139,299)	($1,516,131)	$1,278,470	$2,298,333	$2,342,226	$2,095,339	$2,023,143	$968,971	$566,017	($2,462,707)	($592,978)	$191,078	$2,052,461
(12)	Prelim Ending Under/(Over) Recovery	($15,317,861)	($16,870,665)	($15,640,091)	($13,388,589)	($11,089,578)	($9,028,082)	($7,031,854)	($6,083,378)	($5,536,847)	($8,013,147)	($8,621,965)	($8,448,450)	($8,126,101)
(13)	Month's Average Balance	($12,748,211)	($16,112,600)	($16,279,326)	($14,537,756)	($12,260,691)	($10,075,752)	($8,043,426)	($6,567,863)	($5,819,855)	($6,781,793)	($8,325,475)	($8,543,989)	
(14)	Interest Rate (BOA Prime minus 200 bps)	3.50%	3.50%	3.50%	3.50%	3.25%	3.25%	3.00%	2.75%	2.75%	2.75%	2.75%	1.78%	
(15)	Interest Applied	($36,673)	($47,896)	($46,831)	($43,215)	($33,843)	($26,915)	($20,494)	($14,845)	($13,593)	($15,840)	($17,563)	($12,933)	($330,641)
(16)	Marketer Reconcilation	$0	$0	$0	$0	$0	$0	$0	($4,641)	$0	$0	$0	$0	($4,641)
(17)	Fixed Ending Under/(Over) Recovery	($15,354,534)	($16,918,562)	($15,686,922)	($13,431,804)	($11,123,421)	($9,054,997)	($7,052,348)	($6,102,864)	($5,550,440)	($8,028,986)	($8,639,528)	($8,461,383)	($8,461,383)
(18)	II Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$15,610,587	$9,875,091	$6,657,384	$5,364,603	$5,145,112	$4,992,076	$4,922,278	$5,109,999	$8,659,769	$11,209,584	$10,622,654	$11,089,511	$15,610,587
(20)	Variable Supply Costs	$5,203,973	$3,500,697	$2,291,416	$1,964,297	$1,933,479	$2,080,032	$3,008,264	$9,270,622	$13,029,252	$13,220,051	$11,838,236	$8,413,386	$75,753,703
(21)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	Supply Related LNG O & M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(23)	Inventory Financing - LNG	$25,905	$26,524	$26,234	$25,872	$26,074	$25,921	$25,788	$25,458	$24,655	$24,006	$24,744	$24,319	$305,500
(24)	Inventory Financing - UG	$41,121	$46,491	$51,042	$58,392	$66,079	$74,543	$79,961	$80,040	$73,770	$67,115	$59,355	$53,426	$751,336
(25)	Working Capital	$39,460	$26,545	$17,375	$14,895	$14,661	$15,772	$22,811	$70,129	$98,562	$100,006	$89,553	$63,645	$573,414
(26)	Total Supply Variable Costs	$5,335,646	$3,625,444	$2,411,253	$2,088,642	$2,065,480	$2,221,454	$3,162,011	$9,471,436	$13,251,426	$13,436,365	$12,037,076	$8,579,963	$77,686,197
(27)	Supply Variable - Revenue	$11,107,747	$6,867,686	$3,721,301	$2,323,731	$2,232,487	$2,304,477	$2,987,055	$5,957,913	$10,724,788	$14,048,760	$11,593,097	$10,395,930	$84,264,973
(28)	Monthly Under/(Over) Recovery	($5,772,102)	($3,242,242)	($1,310,048)	($235,089)	($167,007)	($83,023)	$174,956	$3,513,523	$2,526,638	($612,396)	$443,979	($1,815,967)	($6,578,776)
(29)	Prelim Ending Under/(Over) Recovery	$9,838,486	$6,632,848	$5,347,336	$5,129,515	$4,978,105	$4,909,054	$5,097,234	$8,623,522	$11,186,407	$10,597,188	$11,066,633	$9,273,544	$9,031,811
(30)	Month's Average Balance	$12,724,537	$8,253,969	$6,002,360	$5,247,059	$5,061,608	$4,950,565	$5,009,756	$6,866,760	$9,923,088	$10,903,386	$10,844,643	$10,181,527	
(31)	Interest Rate (BOA Prime minus 200 bps)	3.50%	3.50%	3.50%	3.50%	3.25%	3.25%	3.00%	2.75%	2.75%	2.75%	2.75%	1.78%	
(32)	Interest Applied	$36,605	$24,536	$17,267	$15,597	$13,971	$13,224	$12,765	$15,521	$23,177	$25,466	$22,878	$15,412	$236,418
(33)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$20,726	$0	$0	$0	$0	$20,726
(34)	Variable Ending Under/(Over) Recovery	$9,875,091	$6,657,384	$5,364,603	$5,145,112	$4,992,076	$4,922,278	$5,109,999	$8,659,769	$11,209,584	$10,622,654	$11,089,511	$9,288,955	$9,288,955
(35)	**GCR Deferred Summary**													
(36)	Beginning Under/(Over) Recovery	$5,432,025	($5,479,443)	($10,261,177)	($10,322,319)	($8,286,692)	($6,131,345)	($4,132,719)	($1,942,350)	$2,556,905	$5,659,143	$2,593,668	$2,449,983	$5,432,025
(37)	Gas Costs	$10,042,244	$8,148,919	$7,234,741	$6,823,103	$6,750,657	$6,979,034	$8,112,037	$15,688,223	$22,289,867	$22,422,992	$20,703,623	$16,922,475	$152,117,915
(38)	Inventory Finance	$67,026	$73,016	$77,276	$84,264	$92,153	$100,463	$105,749	$105,498	$98,425	$91,121	$84,100	$77,746	$1,056,836
(39)	Working Capital	$75,432	$61,076	$54,144	$51,022	$50,473	$52,205	$60,796	$117,998	$163,961	$165,350	$154,131	$128,720	$1,135,309
(40)	NGPMP Credits	($333,333)	($333,333)	($333,333)	($333,333)	($333,333)	($600,550)	($333,333)	($475,000)	($475,000)	($1,004,242)	($475,000)	($221,260)	($5,251,052)
(41)	Total Costs	$9,851,369	$7,949,677	$7,032,827	$6,625,056	$6,559,950	$6,531,152	$7,945,249	$15,436,719	$22,077,253	$21,675,222	$20,466,854	$16,907,681	$149,059,008
(42)	Revenue	$20,762,769	$12,708,051	$7,064,404	$4,561,811	$4,384,731	$4,518,836	$5,747,149	$10,958,866	$18,984,598	$24,750,324	$20,615,853	$18,532,569	$153,589,963
(43)	Monthly Under/(Over) Recovery	($10,911,400)	($4,758,374)	($31,577)	$2,063,244	$2,175,218	$2,012,316	$2,198,099	$4,477,853	$3,092,655	($3,075,102)	($148,999)	($1,624,889)	($4,530,956)
(44)	Prelim Ending Under/(Over) Recovery	($5,479,375)	($10,237,817)	($10,292,755)	($8,259,075)	($6,111,474)	($4,119,029)	($1,934,620)	$2,535,504	$5,649,560	$2,584,041	$2,444,668	$825,094	
(45)	Month's Average Balance	($23,675)	($7,858,630)	($10,276,966)	($9,290,697)	($7,199,083)	($5,125,187)	($3,033,670)	$296,577	$4,103,232	$4,121,592	$2,519,168	$1,637,538	
(46)	Interest Rate (BOA Prime minus 200 bps)	3.50%	3.50%	3.50%	3.50%	3.25%	3.25%	3.00%	2.75%	2.75%	2.75%	2.75%	1.78%	
(47)	Interest Applied	($68)	($23,361)	($29,564)	($27,618)	($19,871)	($13,691)	($7,730)	$676	$9,584	$9,626	$5,314	$2,479	($94,223)
(48)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$20,726	$0	$0	$0	$0	$20,726
(49)	**Ending Under/(Over) Recovery W/ Interest**	($5,479,443)	($10,261,177)	($10,322,319)	($8,286,692)	($6,131,345)	($4,132,719)	($1,942,350)	$2,556,905	$5,659,143	$2,593,668	$2,449,983	$\boxed{\$827,573}$	$827,573

(3) Dkt 4963, Sch MJP/AEL-2, pg 1, line (17), col (m)
(4) Sch 2, line (37)
(5) Dkt 4872; Dkt 4963
(6) Docket 4770
(8) Sch 4, line (15)
(9) Sum[Lines (4) : (8)]
(10) Sch 3, line (13)
(11) Line (9) - Line (10)
(12) Line (3) + Line (11)
(13) [Line (3) + Line (12)] ÷ 2
(15) ([Line (13) x Line (14)] ÷ 365) x Line (1)
(16) Dkt 4963
(17) Line (12) + Line (15) + Line (16)
(19) Dkt 4963, Sch MJP/AEL-2, pg 1, line (34), col (m)
(20) Sch 2, line (87)
(21) Dkt 4872; Dkt 4955
(22) Docket 4770
(23) Sch 5, line (22)
(24) Sch 5, line (12)
(25) Sch 4, line (30)
(26) Sum[Lines (20) : (25)]
(27) Sch 3, line (30)
(28) Line (26) - Line (27)
(29) Line (19) + Line (28)
(30) [Line (19) + Line (29)] ÷ 2
(32) ([Line (30) x Line (31)] ÷ 365) x Line (1)
(34) Line (29) + Line (32) + Line (33)
(36) Line (3) + Line (19)
(37) Sum[Lines (4):(6), (16), (20) (22)]
(38) Line (23) + Line (24)
(39) Line (8) + Line (25)
(40) Line (7)
(41) Sum[Lines (37) : (40)]
(42) Line (10) + Line (27)
(43) Line (41) - Line (42)
(44) Line (36) + Line (43)
(45) [[Line (36) + Line (44)] ÷ 2
(47) Line (15) + Line (32)
(48) Line (33)
(49) Line (44) + Line (47) + Line (48)

REDACTED

Supply Estimates Actuals for Filing

Description	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(1) **SUPPLY FIXED COSTS - Pipeline Delivery**													
(2) Dawn to E Here	$331,203	$339,113	$332,515	$344,458	$333,926	$329,551	$338,630	$1,184,940	$1,151,362	$1,151,688	$1,107,013	$1,116,504	$8,060,903
(3) Dawn to WADDY	$12,790	$12,672	$12,672	$11,751	$12,484	$12,488	$12,488	$11,895	$11,895	$11,895	$11,895	$11,895	$146,819
(4) Dominion SP	$6,452	$6,452	$8,112	$8,111	$8,200	$8,200	$8,200	$8,196	$8,211	$8,211	$8,185	$8,185	$94,715
(5) Dracut	$0	$0	$0	$0	$0	$0	$0	$85,024	$85,024	$85,024	$85,024	$85,024	$425,120
(6) Everett	$114,220	$114,220	$114,220	$114,220	$114,220	$114,220	$114,220	$104,580	$104,580	$104,580	$104,580	$104,580	$1,322,439
(7) Manchester Lateral	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$262,800	$3,153,600
(8) Millennium/AIM	$921,820	$927,475	$921,820	$927,475	$927,475	$921,820	$927,475	$934,257	$932,840	$933,474	$922,668	$934,297	$11,132,895
(9) Niagara	$7,474	$7,474	$7,474	$7,475	$7,474	$7,474	$7,474	$6,842	$6,842	$6,842	$6,842	$6,842	$86,530
(10) TCO App	$270,165	$269,530	$269,568	$273,797	$270,880	$270,880	$270,880	$249,811	$241,112	$251,491	$264,131	$264,131	
(11) TCO App/M3/Storage	$371,463	$372,429	$418,694	$417,021	$418,695	$418,695	$418,695	$418,695	$418,695	$418,694	$339,517	$418,695	$4,849,986
(12) TCO M3	$50,352	$50,233	$50,241	$50,716	$50,485	$50,485	$50,485	$50,485	$50,798	$50,798	$53,154	$53,154	$611,388
(13) Tetco M2	$727,359	$727,359	$1,019,232	$1,019,233	$1,029,491	$1,029,503	$1,029,491	$1,029,491	$1,031,216	$1,031,099	$1,019,921	$1,024,974	$11,718,368
(14) TetcoM2/M3	$368,340	$368,340	$368,340	$368,340	$368,340	$368,341	$368,340	$368,248	$368,341	$368,340	$368,341	$368,340	$4,419,993
(15) Transco Leidy	$10,446	$9,401	$9,198	$9,401	$9,401	$9,198	$9,401	$9,198	$9,401	$9,401	$8,995	$9,401	$112,841
(16) Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(17) Zone 4	$616,305	$616,305	$616,305	$616,305	$616,305	$617,543	$616,305	$449,572	$449,572	$449,572	$449,572	$449,572	$6,563,231
(18) Zone 4 CXN	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,938	$263,953	$263,953	$263,953	$263,953	$263,953	$3,167,334
(19) AMA Credits	$8,832	$8,745	$8,863	$9,103	$8,727	$8,755	$8,782	($5,101)	($5,101)	($5,101)	($5,101)	($5,101)	$36,302
(20) Less Credits from Mkter Releases	($734,489)	($940,887)	($1,118,272)	($1,223,169)	($1,243,931)	($1,170,944)	($988,313)	($846,014)	($871,069)	($871,201)	($840,155)	($880,355)	($11,728,800)
(21) **Supply Fixed - Supplier**													
(22) Distrigas FCS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23) **Total**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(24) **STORAGE FIXED COSTS - Facilities**													
(25) Columbia FSS	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$9,694	$116,328
(26) Dominion GSS	$36,363	$36,363	$36,363	$36,363	$36,363	$36,363	$36,363	$36,391	$36,391	$36,391	$36,391	$36,391	$436,495
(27) Dominion GSSTE	$46,728	$46,728	$46,728	$43,128	$46,728	$46,728	$46,728	$46,764	$46,764	$46,764	$46,764	$46,764	$557,317
(28) Providence LNG	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$163,740	$1,964,880
(29) Tennessee FSMA	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$47,277	$43,258	$43,258	$43,258	$43,258	$43,258	$547,228
(30) Tetco FSS1	$890	$879	$4,231	$4,231	$3,209	$3,720	$3,720	$3,716	$3,701	$3,705	$3,715	$3,711	$39,427
(31) Tetco SS1	$85,018	$84,845	$156,729	$156,724	$131,840	$149,116	$149,124	$149,050	$148,806	$148,930	$148,447	$148,437	$1,657,066
(32) **STORAGE FIXED COSTS - Delivery**													
(33) Storage Delivery	$300,915	$304,921	$374,668	$378,499	$381,243	$381,243	$389,660	$413,122	$409,860	$413,699	$413,157	$413,330	$4,574,317
(34) Constellation LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(35) Transgas	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(36) Prometheus Energy	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(37) **TOTAL FIXED COSTS**	$4,743,933	$4,553,884	$4,848,986	$4,764,467	$4,722,839	$4,804,663	$5,009,434	$6,327,903	$8,645,307	$8,638,059	$8,536,820	$8,602,536	$71,032,455

(37) Sum[Lines (2) : (36)]

REDACTED

Supply Estimates Actuals for Filing

Description	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(38) **VARIABLE COMMODITY COSTS**													
(39) AGT Citygate													
(40) AIM at Ramapo													
(41) Dawn via IGTS													
(42) Dawn via PNGTS													
(43) Dominion SP													
(44) Everett Swing													
(45) Millennium													
(46) Niagara													
(47) TCO Appalachia													
(48) TCO M3													
(49) Tetco M2													
(50) Tetco M3													
(51) TGP Z4													
(52) Transco Leidy													
(53) Waddington													
(54) Confidential Pipeline and Peaking Supplies													
(55) Total Pipeline Commodity Charges	$4,490,089	$2,862,848	$1,718,278	$1,524,244	$1,450,834	$1,418,057	$2,063,472	$7,602,305	$9,684,821	$8,257,301	$6,463,119	$4,228,396	$51,763,764
(56) Less: Incremental Costs of Supplemental Gas Supply	$0	$0	$0	$0	$0	$0	($193,902)	$0	$0	$0	$0	$0	
(56) **INJECTIONS & HEDGING IMPACT**													
(57) Hedging	($66,582)	$161,695	$81,476	$205,959	$296,242	$413,786	$785,012	$762,650	$1,615,709	$3,290,717	$3,948,300	$2,934,635	$14,429,598
(58) Refunds	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(59) Less: Costs of Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(60) **TOTAL VARIABLE SUPPLY COSTS**	$4,423,507	$3,024,543	$1,799,754	$1,730,202	$1,747,076	$1,831,843	$2,654,581	$8,364,955	$11,300,530	$11,548,019	$10,411,418	$7,163,031	$65,999,460
(61) **VARIABLE STORAGE COSTS**													
(62) Underground Storage	$413,072	$281,470	$240,870	$44,792	$38,194	$51,568	$138,918	$529,754	$1,166,629	$952,613	$1,004,123	$971,107	$5,833,110
(63) LNG Withdrawals and Trucking	$89,568	$94,154	$80,144	$80,686	$78,831	$68,998	$74,757	$183,268	$197,076	$212,296	$81,901	$87,661	$1,329,339
(64) **TOTAL VARIABLE STORAGE COSTS**	$502,640	$375,624	$321,014	$125,478	$117,025	$120,567	$213,675	$713,022	$1,363,705	$1,164,909	$1,086,024	$1,058,768	$7,162,449
(65) **TOTAL VARIABLE COSTS**	$4,926,147	$3,400,167	$2,120,768	$1,855,680	$1,864,101	$1,952,410	$2,868,256	$9,077,977	$12,664,236	$12,712,927	$11,497,442	$8,221,799	$73,161,909
(66) **TOTAL SUPPLY COSTS**	$9,670,079	$7,954,051	$6,969,754	$6,620,147	$6,586,940	$6,757,073	$7,877,690	$15,405,880	$21,309,542	$21,350,986	$20,034,262	$16,824,334	$147,360,739

(55) Sum[Lines (39) : (54)]
(60) Sum[Lines (55) : (59)]
(64) Sum[Lines (62) : (63)]
(65) Line (60) + Line (64)
(66) Line (37) + Line (65)

REDACTED

Supply Estimates Actuals for Filing

Description	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(67) **Storage Costs for FT-2 Calculation**													
(68) **Storage Fixed Costs - Facilities**	$389,710	$389,526	$464,761	$461,157	$438,850	$456,638	$456,646	$452,613	$452,354	$452,482	$452,009	$451,995	$5,318,741
(69) **Storage Fixed Costs - Deliveries**	$697,790	$701,796	$771,543	$775,374	$778,118	$778,118	$786,535	$1,241,457	$4,146,489	$4,078,935	$3,842,077	$3,900,322	$22,498,554
(70) **Sub-Total Storage Costs**	$1,087,499	$1,091,322	$1,236,305	$1,236,531	$1,216,968	$1,234,756	$1,243,181	$1,694,070	$4,598,844	$4,531,417	$4,294,086	$4,352,318	$27,817,296
(71) **Tennessee Dracut for Peaking.**	$114,220	$114,220	$114,220	$114,220	$114,220	$114,220	$114,220	$189,604	$189,604	$189,604	$189,604	$189,604	$1,747,559
(72) **Inventory Financing**	$67,026	$73,016	$77,276	$84,264	$92,153	$100,463	$105,749	$105,498	$98,425	$91,121	$84,100	$77,746	$1,056,836
(73) **Supply related LNG O&M Costs**	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$829,823
(74) **Working Capital Requirement**	$5,964	$5,963	$6,534	$6,506	$6,337	$6,472	$6,472	$12,815	$34,789	$34,279	$32,483	$32,924	$191,538
(75) **Total FT-2 Storage Fixed Costs**	$1,343,862	$1,353,673	$1,503,486	$1,510,673	$1,498,830	$1,525,063	$1,538,775	$2,071,138	$4,990,813	$4,915,573	$4,669,424	$4,721,743	$31,643,052
(76) **System Storage MDQ (Dth)**	243,574	243,814	246,251	246,851	246,014	247,476	247,126	249,446	222,897	232,150	230,168	231,169	2,886,936
(77) **FT-2 Storage Cost per MDQ (Dth)**	$5 5173	$5 5521	$6 1055	$6 1198	$6 0925	$6 1625	$6 2267	$8 3029	$22 3907	$21 1741	$20 2870	$20 4255	$10 9608
(78) Pipeline Variable	$4,926,147	$3,400,167	$2,120,768	$1,855,680	$1,864,101	$1,952,410	$2,868,256	$9,077,977	$12,664,236	$12,712,927	$11,497,442	$8,221,799	$73,161,909
(79) Less Non-firm Gas Costs	($103,733)	($62,470)	($20,233)	$19,106	($13,057)	($15,046)	($26,230)	($48,873)	($192,204)	($220,972)	($75,497)	($57,074)	($816,283)
(80) Less Company Use	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(81) Less Manchester St Balancing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(82) Plus Cashout	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(83) Less Mkter W/drawals/Injections	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(84) Mkter Over-takes/Undertakes	$263,270	$77,801	$107,175	($14,850)	($27,130)	$30,915	$67,134	$133,299	$357,881	$501,685	$214,579	$37,982	$1,749,740
(85) Plus Pipeline Srchg/Credit	$102,145	$98,476	$109,263	$106,917	$109,565	$115,127	$109,838	$119,939	$205,037	$219,050	$219,483	$205,754	$1,720,594
(86) Less Mkter FT-2 Daily weather true-up	$16,144	($13,278)	($25,557)	($2,557)	$0	($3,373)	($10,734)	($11,719)	($5,697)	$7,361	($17,771)	$4,925	($62,257)
(87) **TOTAL FIRM COMMODITY COSTS**	$5,203,973	$3,500,697	$2,291,416	$1,964,297	$1,933,479	$2,080,032	$3,008,264	$9,270,622	$13,029,252	$13,220,051	$11,838,236	$8,413,386	$75,753,703

(70) Line (68) + Line (69)
(75) Sum[Lines (70) : (74)]
(77) Line (75) ÷ Line (76)
(78) Line (65)
(87) Sum[Lines (78) : (86)]

REDACTED

GCR Revenue

	Description	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(1)	**I. Fixed Cost Revenue**													
(2)	(a) Low Load dth	2,813,404	1,720,635	917,416	527,899	537,103	557,070	730,871	1,668,288	3,506,818	4,561,130	3,820,624	3,439,475	24,800,730
(3)	Fixed Cost Factor	$3 0737	$3 0737	$3 0719	$3 2772	$3 0753	$3 0725	$3 0786	$2 6865	$2 2422	$2 2352	$2 2399	$2 2307	
(4)	Low Load Revenue	$8,647,655	$5,288,761	$2,818,183	$1,730,051	$1,651,776	$1,711,595	$2,250,058	$4,481,800	$7,863,100	$10,194,822	$8,557,677	$7,672,336	$62,867,814
(5)	(b) High Load dth	74,397	62,942	51,176	42,456	39,484	40,018	43,249	51,400	71,330	96,079	71,506	68,533	712,569
(6)	Fixed Cost Factor	$2 1496	$2 1496	$2 1494	$2 1502	$2 1503	$2 1495	$2 1495	$1 9769	$1 6783	$1 6831	$1 6779	$1 6789	
(7)	High Load Revenue	$159,923	$135,298	$109,998	$91,290	$84,901	$86,017	$92,966	$101,611	$119,710	$161,708	$119,981	$115,060	$1,378,463
(8)	Sub-total throughput Dth	2,887,801	1,783,577	968,591	570,355	576,588	597,088	774,120	1,719,687	3,578,148	4,657,209	3,892,129	3,508,007	25,513,299
(9)	FT-2 Storage Revenue from marketers	$844,065	$413,085	$412,181	$413,224	$411,784	$414,232	$413,647	$417,542	$277,000	$345,034	$345,099	$349,244	$5,056,137
(10)	Manchester Steet Volumes (dth)	1,079	1,028	875	1,122	1,207	803	1,093	0	0	0	0	0	
(11)	Fixed cost factor (dth)	3 1326	3 1326	3 1326	3 1326	3 1326	3 1326	3 1326	2 2773	2 2773	2 2773	2 2773	2 2773	
(12)	Manchester Street Revenue	$3,379	$3,221	$2,741	$3,515	$3,782	$2,514	$3,424	$0	$0	$0	$0	$0	$22,575
(13)	**TOTAL Fixed Revenue**	$9,655,022	$5,840,364	$3,343,103	$2,238,081	$2,152,244	$2,214,359	$2,760,095	$5,000,953	$8,259,810	$10,701,564	$9,022,756	$8,136,639	$69,324,990
(14)	**II. Variable Cost Revenue**													
(15)	(a) Firm Sales dth	2,887,801	1,783,577	968,591	570,355	576,588	597,088	774,120	1,719,687	3,578,148	4,657,209	3,892,129	3,508,007	25,513,299
(16)	Variable Supply Cost Factor	$3 8357	$3 8357	$3 8335	$4 0708	$3 8376	$3 8342	$3 8414	$3 4454	$2 9776	$2 9690	$2 9750	$2 9630	
(17)	Variable Supply Revenue	$11,076,839	$6,841,288	$3,713,081	$2,321,810	$2,212,733	$2,289,372	$2,973,726	$5,925,044	$10,654,292	$13,827,326	$11,578,998	$10,394,325	$83,808,835
(18)	(b) TSS Sales dth	14,314	9,263	805	734	832	1,027	771	4,202	6,482	22,250	18,844	18,086	97,610
(19)	TSS Surcharge Factor	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 2530	$0 0000	$0 0000	$0 0000	
(20)	TSS Surcharge Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$1,640	$0	$0	$0	$1,640
(21)	(c) Default Sales dth	8,174	2,697	424	(368)	1,617	1,417	1,306	4,509	8,780	27,294	(2,440)	5,561	58,971
(22)	Variable Supply Cost Factor	$3 17	$6 91	$6 91	$6 90	$6 91	$6 91	$6 91	$6 91	$4 63	$8 11	($2 13)	$0 02	
(23)	Variable Supply Revenue	$25,900	$18,627	$2,928	($2,540)	$11,169	$9,785	$9,023	$31,139	$40,644	$221,435	$5,207	$105	$373,422
(24)	(d) Peaking Gas Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(25)	(e) Deferred Responsibility	$792	$3,752	$1,873	$75	$3,866	$2,182	$33	$1,729	$28,212	$0	$8,892	$1,500	$52,904
(26)	(e) FT-1 Storage and Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(27)	Manchester Steet Volumes (dth)	1,079	1,028	875	1,122	1,207	803	1,093	0	0	0	0	0	
(28)	Variable Supply Cost Factor (dth)	$3 9093	$3 9093	$3 9093	$3 9093	$3 9093	$3 9093	$3 9093	$3 0249	$3 0249	$3 0249	$3 0249	$3 0249	
(29)	Manchester Street Revenue	$4,217	$4,020	$3,420	$4,386	$4,719	$3,138	$4,272	$0	$0	$0	$0	$0	$28,172
(30)	**TOTAL Variable Revenue**	$11,107,747	$6,867,686	$3,721,301	$2,323,731	$2,232,487	$2,304,477	$2,987,055	$5,957,913	$10,724,788	$14,048,760	$11,593,097	$10,395,930	$84,264,973
(31)	**Total Gas Cost Revenue (w/o FT-2)**	$20,762,769	$12,708,051	$7,064,404	$4,561,811	$4,384,731	$4,518,836	$5,747,149	$10,958,866	$18,984,598	$24,750,324	$20,615,853	$18,532,569	$153,589,963

Lines (12) and (29): Pursuant to the Division of Public Utilities and Carriers' approval in Docket 4963, the Company is no longer crediting imputed revenue to offset the gas costs associated with heater gas used at Manchester St Station

(2) Sch 6, Sum[lines (24) : (28), (30)]
(3) Line (4) ÷ Line (2)
(5) Sch 6, Sum[lines (22), (23), (29), (31)]
(6) Line (7) ÷ Line (5)
(8) Line (2) + Line (5)
(10) Monthly Meter Use
(11) Inherent in approved GCR
(12) Line (10) x Line (11)
(13) Line (4) + Line (7) + Line (9) + Line (12)
(15) Line (8)
(16) Line (17) ÷ Line (15)
(18) Sch 6, line (20)
(19) Company's website
(20) Line (18) x Line (19)
(21) Sch 6, line (61)
(22) Line (23) ÷ Line (21)
(25) Company Data
(27) Monthly Meter Use
(28) Inherent in approved GCR
(29) Line (27) x Line (28)
(30) Sum[Lines (17), (20), (23):(26), (29)]
(31) Line (13) + Line (30)

REDACTED

National Grid
Rhode Island - Gas

Schedule 4
Page 1 of 1

WORKING CAPITAL

	Description	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(1)	**Supply Fixed Costs**	$4,743,933	$4,553,884	$4,848,986	$4,764,467	$4,722,839	$4,804,663	$5,009,434	$6,327,903	$8,645,307	$8,638,059	$8,536,820	$8,602,536	$74,198,830
(2)	Less: System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(3)	Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5)	Allowable Working Capital Costs	$4,743,933	$4,553,884	$4,848,986	$4,764,467	$4,722,839	$4,804,663	$5,009,434	$6,327,903	$8,645,307	$8,638,059	$8,536,820	$8,602,536	$74,198,830
(6)	Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(7)	Working Capital Requirement	$427,864	$410,723	$437,339	$429,716	$425,961	$433,341	$451,810	$570,725	$779,736	$779,082	$769,951	$775,878	
(8)	Cost of Capital	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 13%	7 13%	7 13%	7 13%	7 13%	
(9)	Return on Working Capital Requirement	$30,592	$29,367	$31,270	$30,725	$30,456	$30,984	$32,304	$40,693	$55,595	$55,549	$54,898	$55,320	
(10)	Weighted Cost of Debt	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 40%	2 40%	2 40%	2 40%	2 40%	
(11)	Interest Expense	$10,354	$9,939	$10,584	$10,399	$10,308	$10,487	$10,934	$13,697	$18,714	$18,698	$18,479	$18,621	
(12)	Taxable Income	$20,238	$19,427	$20,686	$20,326	$20,148	$20,497	$21,371	$26,995	$36,881	$36,851	$36,419	$36,699	
(13)	1 - Combined Tax Rate	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(14)	Return and Tax Requirement	$25,618	$24,591	$26,185	$25,729	$25,504	$25,946	$27,051	$34,171	$46,685	$46,646	$46,100	$46,454	
(15)	**Supply Fixed Working Capital Requirement**	$35,972	$34,531	$36,769	$36,128	$35,812	$36,432	$37,985	$47,869	$65,399	$65,344	$64,578	$65,076	$561,895
(16)	**Supply Variable Costs**	$5,203,973	$3,500,697	$2,291,416	$1,964,297	$1,933,479	$2,080,032	$3,008,264	$9,270,622	$13,029,252	$13,220,051	$11,838,236	$8,413,386	$75,753,703
(17)	Less: Bal Related Syst Pressure Commodity to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18)	Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19)	Total Adjustments	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20)	Allowable Working Capital Costs	$5,203,973	$3,500,697	$2,291,416	$1,964,297	$1,933,479	$2,080,032	$3,008,264	$9,270,622	$13,029,252	$13,220,051	$11,838,236	$8,413,386	$75,753,703
(21)	Number of Days Lag	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	32 92	
(22)	Working Capital Requirement	$469,356	$315,734	$206,667	$177,163	$174,384	$187,602	$271,321	$836,134	$1,175,131	$1,192,340	$1,067,712	$758,818	
(23)	Cost of Capital	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 13%	7 13%	7 13%	7 13%	7 13%	
(24)	Return on Working Capital Requirement	$33,559	$22,575	$14,777	$12,667	$12,468	$13,414	$19,399	$59,616	$83,787	$85,014	$76,128	$54,104	
(25)	Weighted Cost of Debt	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 40%	2 40%	2 40%	2 40%	2 40%	
(26)	Interest Expense	$11,358	$7,641	$5,001	$4,287	$4,220	$4,540	$6,566	$20,067	$28,203	$28,616	$25,625	$18,212	
(27)	Taxable Income	$22,201	$14,934	$9,775	$8,380	$8,248	$8,874	$12,833	$39,549	$55,584	$56,398	$50,503	$35,892	
(28)	1 - Combined Tax Rate[2]	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(29)	Return and Tax Requirement	$28,102	$18,904	$12,374	$10,607	$10,441	$11,232	$16,245	$50,062	$70,359	$71,389	$63,928	$45,433	
(30)	**Supply Variable Working Capital Requirement**	$39,460	$26,545	$17,375	$14,895	$14,661	$15,772	$22,811	$70,129	$98,562	$100,006	$89,553	$63,645	$573,414

(1) Sch 1, line (4)
(2) Sch 1, line (5)
(3) Docket 4770
(4) Line (2) + Line (3)
(5) Line (1) + Line (4)
(6) Docket 4770
(7) [Line (5) x Line (6)] ÷ 365
(8) Docket 4955
(9) Line (7) x Line (8)
(10) Docket 4955
(11) Line (7) x Line (10)
(12) Line (9) - Line (11)
(13) Docket 4770
(14) Line (12) ÷ Line (13)
(15) Line (11) + Line (14)
(16) Sch 1, line (20)
(17) Sch 1, line (21)
(18) Docket 4770
(19) Line (17) + Line (18)
(20) Line (16) + Line (19)
(21) Docket 4770
(22) [Line (20) x Line (21)] ÷ 365
(23) Docket 4955
(24) Line (22) x Line (23)
(25) Docket 4955
(26) Line (22) x Line (25)
(27) Line (24) - Line (26)
(28) Docket 4770
(29) Line (27) ÷ Line (28)
(30) Line (26) + Line (29)

REDACTED

INVENTORY FINANCE

	Description	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(1)	**Storage Inventory Balance**	$5,876,579	$6,579,416	$7,184,108	$8,072,699	$8,940,942	$9,818,145	$10,289,591	$10,339,360	$9,700,660	$9,096,787	$8,289,909	$7,643,829	
(2)	Monthly Storage Deferral/Amortization	($7,294)	$56,425	$101,196	$261,726	$490,675	$821,522	$1,123,441	$1,112,206	$853,815	$505,549	$202,220	$1	
(3)	**Subtotal**	$5,869,285	$6,635,842	$7,285,305	$8,334,424	$9,431,618	$10,639,668	$11,413,031	$11,451,566	$10,554,475	$9,602,336	$8,492,129	$7,643,830	
(4)	Cost of Capital	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 13%	7 13%	7 13%	7 13%	7 13%	
(5)	Return on Working Capital Requirement	$419,654	$474,463	$520,899	$595,911	$674,361	$760,736	$816,032	$816,497	$752,534	$684,647	$605,489	$545,005	$7,666,227
(6)	Weighted Cost of Debt	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 40%	2 40%	2 40%	2 40%	2 40%	
(7)	Interest Charges Financed	$142,037	$160,587	$176,304	$201,693	$228,245	$257,480	$276,195	$274,838	$253,307	$230,456	$203,811	$183,452	$2,588,406
(8)	Taxable Income	$277,617	$313,875	$344,595	$394,218	$446,116	$503,256	$539,836	$541,659	$499,227	$454,190	$401,678	$361,553	
(9)	1 - Combined Tax Rate[1]	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(10)	Return and Tax Requirement	$351,414	$397,311	$436,196	$499,010	$564,703	$637,033	$683,337	$685,644	$631,933	$574,925	$508,453	$457,662	$6,427,621
(11)	Working Capital Requirement	$493,451	$557,898	$612,500	$700,704	$792,948	$894,513	$959,533	$960,482	$885,240	$805,381	$712,264	$641,114	$9,016,028
(12)	Monthly Average	$41,121	$46,491	$51,042	$58,392	$66,079	$74,543	$79,961	$80,040	$73,770	$67,115	$59,355	$53,426	$751,336
(13)	**LNG Inventory Balance**	$3,697,445	$3,785,860	$3,744,415	$3,692,730	$3,721,633	$3,699,696	$3,680,807	$3,642,329	$3,527,431	$3,434,662	$3,540,226	$3,479,444	
(14)	Cost of Capital	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 15%	7 13%	7 13%	7 13%	7 13%	7 13%	
(15)	Return on Working Capital Requirement	$264,367	$270,689	$267,726	$264,030	$266,097	$264,528	$263,178	$259,698	$251,506	$244,891	$252,418	$248,084	$3,117,213
(16)	Weighted Cost of Debt	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 42%	2 40%	2 40%	2 40%	2 40%	2 40%	
(17)	Interest Charges Financed	$89,478	$91,618	$90,615	$89,364	$90,064	$89,533	$89,076	$87,416	$84,658	$82,432	$84,965	$83,507	$1,052,725
(18)	Taxable Income	$174,889	$179,071	$177,111	$174,666	$176,033	$174,996	$174,102	$172,282	$166,847	$162,460	$167,453	$164,578	
(19)	1 - Combined Tax Rate[1]	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	0 79	
(20)	Return and Tax Requirement	$221,379	$226,672	$224,191	$221,096	$222,827	$221,513	$220,382	$218,079	$211,199	$205,645	$211,965	$208,326	$2,613,276
(21)	Working Capital Requirement	$310,857	$318,290	$314,806	$310,460	$312,890	$311,046	$309,458	$305,495	$295,858	$288,077	$296,931	$291,833	$3,666,001
(22)	Monthly Average	$25,905	$26,524	$26,234	$25,872	$26,074	$25,921	$25,788	$25,458	$24,655	$24,006	$24,744	$24,319	$305,500
(23)	TOTAL GCR Inventory Financing Costs	$67,026	$73,016	$77,276	$84,264	$92,153	$100,463	$105,749	$105,498	$98,425	$91,121	$84,100	$77,746	$1,056,836

[1]For the period Apr 2018 through Dec 2018, Dkt 4323; and for the period Jan 2019 through Mar 2019, Dkt 4770

(3) Line (1) + Line (2)
(4) Docket 4955
(5) Line (3) x Line (4)
(6) Docket 4955
(7) Line (3) x Line (6)
(8) Line (5) - Line (7)
(9) Docket 4770
(10) Line (8) ÷ Line (9)
(11) Line (7) + Line (10)
(12) Line (11) ÷ 12
(14) Docket 4955
(15) Line (13) x Line (14)
(16) Docket 4955
(17) Line (13) x Line (16)
(18) Line (15) - Line (17)
(19) Docket 4770
(20) Line (18) ÷ Line (19)
(21) Line (17) + Line (20)
(22) Line (21) ÷ 12
(23) Line (12) + Line (22)

REDACTED

National Grid
Rhode Island - Gas

Actual Dth Usage for Filing

	THROUGHPUT (Dth) Rate Class	Apr-19 Actual (a)	May-19 Actual (b)	Jun-19 Actual (c)	Jul-19 Actual (d)	Aug-19 Actual (e)	Sep-19 Actual (f)	Oct-19 Actual (g)	Nov-19 Actual (h)	Dec-19 Actual (i)	Jan-20 Actual (j)	Feb-20 Actual (k)	Mar-20 Actual (l)	Apr-Mar (m)
(1)	**SALES**													
(2)	Residential Non-Heating	38,587	29,538	22,499	16,446	13,922	14,254	15,925	22,483	36,558	48,091	38,026	37,484	333,811
(3)	Residential Non-Heating Low Income	1,858	1,407	976	681	469	508	604	1,033	1,829	2,257	2,094	2,182	15,898
(4)	Residential Heating	1,925,301	1,183,145	628,685	375,358	355,224	368,582	504,116	1,171,987	2,453,453	3,220,071	2,651,134	2,415,017	17,252,072
(5)	Residential Heating Low Income	184,696	116,482	65,878	41,262	39,839	41,864	52,216	102,552	211,978	259,473	214,561	222,999	1,553,798
(6)	Small C&I	239,545	133,765	65,323	39,949	42,004	39,496	52,988	132,899	324,135	424,272	391,679	298,414	2,184,469
(7)	Medium C&I	364,912	236,012	138,807	92,219	90,658	97,602	109,321	215,214	431,392	521,280	459,434	405,100	3,161,949
(8)	Large LLF	77,149	38,697	15,714	(22,213)	8,268	8,217	10,023	37,707	72,990	105,970	78,205	72,828	503,553
(9)	Large HLF	28,275	24,804	20,577	16,706	15,659	17,026	17,500	18,555	22,601	28,766	23,415	22,386	256,270
(10)	Extra Large LLF	8,809	4,369	2,205	590	279	284	1,436	4,006	6,814	8,456	7,463	8,239	52,948
(11)	Extra Large HLF	4,356	6,094	7,124	8,624	9,435	8,230	9,220	9,050	9,917	16,323	7,276	5,272	100,920
(12)	Total Sales	2,873,487	1,774,313	967,786	569,621	575,755	596,061	773,349	1,715,485	3,571,667	4,634,958	3,873,286	3,489,921	25,415,689
(13)	**TSS**													
(14)	Small	1,296	511	180	139	123	0	20	183	797	2,489	2,202	1,961	9,901
(15)	Medium	10,781	6,711	523	414	600	934	662	1,075	3,761	10,854	10,469	11,126	57,911
(16)	Large LLF	917	943	102	180	109	93	89	2,666	1,497	8,266	5,478	3,789	24,128
(17)	Large HLF	1,321	1,099	0	0	0	0	0	278	426	642	695	1,209	5,670
(18)	Extra Large LLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Extra Large HLF	0	0	0	0	0	0	0	0	0	0	0	0	0
(20)	Total TSS	14,314	9,263	805	734	832	1,027	771	4,202	6,482	22,250	18,844	18,086	97,610
(21)	**Sales & TSS THROUGHPUT**													
(22)	Residential Non-Heating	38,587	29,538	22,499	16,446	13,922	14,254	15,925	22,483	36,558	48,091	38,026	37,484	333,811
(23)	Residential Non-Heating Low Income	1,858	1,407	976	681	469	508	604	1,033	1,829	2,257	2,094	2,182	15,898
(24)	Residential Heating	1,925,301	1,183,145	628,685	375,358	355,224	368,582	504,116	1,171,987	2,453,453	3,220,071	2,651,134	2,415,017	17,252,072
(25)	Residential Heating Low Income	184,696	116,482	65,878	41,262	39,839	41,864	52,216	102,552	211,978	259,473	214,561	222,999	1,553,798
(26)	Small C&I	240,840	134,276	65,503	40,088	42,126	39,496	53,008	133,082	324,932	426,761	393,882	300,376	2,194,370
(27)	Medium C&I	375,693	242,723	139,330	92,634	91,258	98,535	109,983	216,289	435,153	532,134	469,902	416,227	3,219,861
(28)	Large LLF	78,066	39,640	15,815	(22,033)	8,377	8,310	10,112	40,373	74,487	114,235	83,682	76,618	527,682
(29)	Large HLF	29,596	25,903	20,577	16,706	15,659	17,026	17,500	18,834	23,027	29,408	24,110	23,595	261,940
(30)	Extra Large LLF	8,809	4,369	2,205	590	279	284	1,436	4,006	6,814	8,456	7,463	8,239	52,948
(31)	Extra Large HLF	4,356	6,094	7,124	8,624	9,435	8,230	9,220	9,050	9,917	16,323	7,276	5,272	100,920
(32)	Total Sales & TSS Throughput	2,887,801	1,783,577	968,591	570,355	576,588	597,088	774,120	1,719,687	3,578,148	4,657,209	3,892,129	3,508,007	25,513,299
(33)	**FT-1 TRANSPORTATION**													
(34)	FT-1 Small	0	0	0	0	0	0	0	0	0	0	0	0	0
(35)	FT-1 Medium	71,255	19,604	20,573	9,039	17,908	23,548	24,749	53,139	99,181	95,693	81,537	68,651	584,876
(36)	FT-1 Large LLF	107,684	13,866	9,590	(5,738)	11,205	16,881	19,629	68,022	155,934	159,940	126,285	106,814	790,111
(37)	FT-1 Large HLF	43,657	26,457	29,815	34,614	42,664	21,686	31,531	35,389	52,761	54,759	52,024	41,698	467,053
(38)	FT-1 Extra Large LLF	170,300	18,203	37,663	(17,533)	16,377	20,516	26,066	111,045	203,164	195,580	168,091	146,577	1,096,050
(39)	FT-1 Extra Large HLF	534,117	404,390	414,590	405,585	409,233	414,417	389,253	497,179	511,433	574,478	549,787	456,170	5,560,633
(40)	Default	8,174	2,697	424	(368)	1,617	1,417	1,306	4,509	8,780	27,294	(2,440)	5,561	58,971
(41)	Total FT-1 Transportation	935,187	485,217	512,654	425,598	499,004	498,464	492,534	769,282	1,031,253	1,107,744	975,284	825,471	8,557,693
(42)	**FT-2 TRANSPORTATION**													
(43)	FT-2 Small	18,072	10,965	5,779	3,518	3,292	3,551	4,692	10,620	24,989	32,330	27,897	25,796	171,499
(44)	FT-2 Medium	204,180	142,688	83,752	53,571	50,285	54,556	69,733	136,235	258,296	315,596	271,771	253,296	1,893,960
(45)	FT-2 Large LLF	144,138	93,697	40,495	18,319	18,682	16,859	31,607	101,167	205,211	247,984	220,822	201,996	1,340,978
(46)	FT-2 Large HLF	53,588	47,684	37,070	33,455	29,032	36,534	38,243	45,680	63,038	83,507	67,890	65,872	601,593
(47)	FT-2 Extra Large LLF	2,781	1,692	383	111	67	167	309	1,610	10,059	12,201	10,319	9,785	49,484
(48)	FT-2 Extra Large HLF	39,551	47,053	34,343	44,504	36,322	36,902	42,122	40,682	55,588	42,762	36,927	42,387	499,142
(49)	Total FT-2 Transportation	462,311	343,779	201,822	153,479	137,680	148,568	186,706	335,993	617,179	734,380	635,627	599,132	4,556,655
(50)	**Total THROUGHPUT**													
(51)	Residential Non-Heating	38,587	29,538	22,499	16,446	13,922	14,254	15,925	22,483	36,558	48,091	38,026	37,484	333,811
(52)	Residential Non-Heating Low Income	1,858	1,407	976	681	469	508	604	1,033	1,829	2,257	2,094	2,182	15,898
(53)	Residential Heating	1,925,301	1,183,145	628,685	375,358	355,224	368,582	504,116	1,171,987	2,453,453	3,220,071	2,651,134	2,415,017	17,252,072
(54)	Residential Heating Low Income	184,696	116,482	65,878	41,262	39,839	41,864	52,216	102,552	211,978	259,473	214,561	222,999	1,553,798
(55)	Small C&I	258,912	145,241	71,282	43,606	45,418	43,046	57,700	143,702	349,921	459,091	421,778	326,172	2,365,869
(56)	Medium C&I	651,128	405,015	243,655	155,243	159,451	176,639	204,465	405,663	792,629	943,423	823,210	738,174	5,698,696
(57)	Large LLF	329,888	147,203	65,900	(9,452)	38,265	42,049	61,347	209,562	435,633	522,159	430,790	385,427	2,658,771
(58)	Large HLF	126,840	100,044	87,462	84,775	87,355	75,245	87,274	99,903	138,826	167,674	144,024	131,166	1,330,586
(59)	Extra Large LLF	181,890	24,264	40,251	(16,832)	16,722	20,966	27,812	116,661	220,037	216,237	185,873	164,601	1,198,482
(60)	Extra Large HLF	578,024	457,537	456,056	458,713	454,990	459,549	440,595	546,911	576,937	633,563	593,990	503,828	6,160,694
(61)	Default	8,174	2,697	424	(368)	1,617	1,417	1,306	4,509	8,780	27,294	(2,440)	5,561	58,971
(62)	Total Throughput	4,285,298	2,612,572	1,683,067	1,149,432	1,213,272	1,244,120	1,453,360	2,824,963	5,226,581	6,499,333	5,503,040	4,932,610	38,627,647

Attachment RMS/MJP -3
Projected Gas Cost Balances

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Projected Gas Cost Deferred Balances

	Description	Nov-20 forecast	Dec-20 forecast	Jan-21 forecast	Feb-21 forecast	Mar-21 forecast	Apr-21 forecast	May-21 forecast	Jun-21 forecast	Jul-21 forecast	Aug-21 forecast	Sep-21 forecast	Oct-21 forecast	Nov - Oct
(1)	# of Days in Month	30	31	31	28	31	30	31	30	31	31	30	31	365
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
(2)	**I. Fixed Cost Deferred**													
(3)	Beginning Under/(Over) Recovery	$3,893,018	$3,608,826	$1,805,810	($3,543,085)	($10,323,634)	($13,205,606)	($17,088,314)	($15,448,278)	($12,773,310)	($9,509,450)	($6,153,632)	($2,852,347)	$3,893,018
(4)	Fixed Costs (net of capacity release)	$5,841,318	$9,829,495	$9,826,825	$10,035,301	$10,035,301	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$5,731,961	$85,691,969
(5)	Supply Related System Pressure to DAC	$0	($1,311,213)	($1,311,213)	($1,311,213)	($1,311,213)	$0	$0	$0	$0	$0	$0	$0	($5,244,853)
(6)	NGPMP Credits	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($5,251,052)
(7)	Working Capital	$44,188	$64,438	$64,418	$65,995	$65,995	$43,361	$43,361	$43,361	$43,361	$43,361	$43,361	$43,361	$608,558
(8)	Supply Related LNG O & M	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$829,823
(9)	Total Supply Fixed Costs	$5,517,070	$8,214,284	$8,211,594	$8,421,647	$8,421,647	$5,406,886	$5,406,886	$5,406,886	$5,406,886	$5,406,886	$5,406,886	$5,406,886	$76,634,445
(10)	Fixed - Revenue	($5,616,759)	($10,020,173)	($13,559,567)	($15,195,551)	($11,291,136)	($9,274,040)	($3,749,588)	($2,717,428)	($2,131,205)	($2,042,758)	($2,100,977)	($2,638,331)	($80,337,513)
(11)	Prelim Ending Under/(Over) Recovery	$3,793,329	$1,802,937	($3,542,163)	($10,316,988)	($13,193,122)	($17,072,760)	($15,431,016)	($12,758,820)	($9,497,629)	($6,145,323)	($2,847,723)	($83,793)	
(12)	Month's Average Balance	$3,843,174	$2,705,881	($868,177)	($6,930,037)	($11,758,378)	($15,139,183)	($16,259,665)	($14,103,549)	($11,135,469)	($7,827,387)	($4,500,678)	($1,468,070)	
(13)	Interest Rate (BOA Prime minus 200 bps)	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	
(14)	Interest Applied	$3,948	$2,873	($922)	($6,645)	($12,483)	($15,554)	($17,262)	($14,490)	($11,822)	($8,310)	($4,624)	($1,559)	($86,849)
(15)	Marketer Reconciliation	($188,452)												($188,452)
(16)	Fixed Ending Under/(Over) Recovery	$3,608,826	$1,805,810	($3,543,085)	($10,323,634)	($13,205,606)	($17,088,314)	($15,448,278)	($12,773,310)	($9,509,450)	($6,153,632)	($2,852,347)	($85,351)	($85,351)
(17)	**II. Variable Cost Deferred**													
(18)	Beginning Under/(Over) Recovery	$4,210,357	$5,526,103	$7,227,046	$8,809,711	$6,642,540	$5,933,592	$2,023,867	$1,109,958	$293,098	($230,752)	($612,959)	($938,129)	$4,210,357
(19)	Variable Costs	$6,639,143	$11,508,564	$15,004,056	$12,961,499	$10,448,208	$5,222,883	$2,574,775	$1,617,046	$1,302,679	$1,344,373	$1,450,804	$3,278,250	$73,352,280
(20)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21)	Supply Related LNG O & M	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$25,187	$302,244
(22)	Inventory Financing - LNG	$22,345	$21,755	$16,427	$12,846	$17,786	$19,161	$20,560	$21,939	$21,538	$21,135	$21,966	$21,957	$239,415
(23)	Inventory Financing - UG	$61,700	$49,573	$33,753	$19,747	$8,584	$10,430	$20,966	$30,390	$37,402	$49,236	$60,093	$70,944	$452,816
(24)	Working Capital	$50,223	$87,059	$113,501	$98,050	$79,037	$39,510	$19,477	$12,232	$9,854	$10,170	$10,975	$24,799	$554,887
(25)	Total Variable Costs	$6,798,597	$11,692,138	$15,192,924	$13,117,328	$10,578,802	$5,317,171	$2,660,965	$1,706,795	$1,396,661	$1,450,101	$1,569,025	$3,421,137	$74,901,643
(26)	Variable - Revenue	($5,487,850)	($9,997,961)	($13,618,767)	($15,291,904)	($11,294,423)	($9,230,981)	($3,576,537)	($2,524,375)	($1,920,544)	($1,831,860)	($1,893,399)	($2,442,317)	($79,110,918)
(27)	Prelim Ending Under/(Over) Recovery	$5,521,104	$7,220,280	$8,801,203	$6,635,135	$5,926,920	$2,019,782	$1,108,296	$292,378	($230,785)	($612,511)	($937,333)	$40,690	
(28)	Month's Average Balance	$4,865,731	$6,373,192	$8,014,125	$7,722,423	$6,284,730	$3,976,687	$1,566,082	$701,168	$31,157	($421,631)	($775,146)	($448,719)	
(29)	Interest Rate (BOA Prime minus 200 bps)	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	
(30)	Interest Applied	$4,999	$6,766	$8,508	$7,405	$6,672	$4,086	$1,663	$720	$33	($448)	($796)	($476)	$39,132
(31)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(32)	Variable Ending Under/(Over) Recovery	$5,526,103	$7,227,046	$8,809,711	$6,642,540	$5,933,592	$2,023,867	$1,109,958	$293,098	($230,752)	($612,959)	($938,129)	$40,214	$40,214
(33)	**GCR Deferred Summary**													
(34)	Beginning Under/(Over) Recovery	$8,103,375	$9,134,929	$9,032,856	$5,266,626	($3,681,093)	($7,272,014)	($15,064,446)	($14,338,319)	($12,480,211)	($9,740,202)	($6,766,591)	($3,790,477)	$8,103,375
(35)	Gas Costs	$12,386,348	$20,121,184	$23,614,007	$21,779,926	$19,266,635	$11,049,183	$8,401,075	$7,443,346	$7,128,979	$7,170,673	$7,277,104	$9,104,550	$154,743,011
(36)	Inventory Finance	$84,044	$71,328	$50,180	$32,592	$26,369	$29,591	$41,526	$52,329	$58,940	$70,371	$82,059	$92,901	$692,232
(37)	Working Capital	$94,411	$151,497	$177,919	$164,045	$145,033	$82,870	$62,838	$55,593	$53,215	$53,530	$54,335	$68,159	$1,163,445
(38)	NGPMP Credits	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($437,588)	($5,251,052)
(39)	Total Costs	$12,127,216	$19,906,422	$23,404,518	$21,538,975	$19,000,450	$10,724,057	$8,067,851	$7,113,680	$6,803,547	$6,856,987	$6,975,911	$8,828,022	$151,347,636
(40)	Revenue	($11,104,609)	($20,018,134)	($27,178,334)	($30,487,455)	($22,585,559)	($18,505,021)	($7,326,125)	($5,241,803)	($4,051,749)	($3,874,618)	($3,994,376)	($5,080,648)	($159,448,431)
(41)	Prelim Ending Under/(Over) Recovery	$9,125,982	$9,023,217	$5,259,040	($3,681,853)	($7,266,203)	($15,052,978)	($14,322,720)	($12,466,442)	($9,728,413)	($6,757,834)	($3,785,056)	($43,102)	$2,580
(42)	Month's Average Balance	$8,614,678	$9,079,073	$7,145,948	$792,387	($5,473,648)	($11,162,496)	($14,693,583)	($13,402,381)	($11,104,312)	($8,249,018)	($5,275,824)	($1,916,789)	
(43)	Interest Rate (BOA Prime minus 200 bps)	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	1 25%	
(44)	Interest Applied	$8,948	$9,639	$7,586	$760	($5,811)	($11,468)	($15,599)	($13,770)	($11,789)	($8,758)	($5,420)	($2,035)	($47,717)
(45)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(46)	Ending Under/(Over) Recovery W/ Interest	$9,134,929	$9,032,856	$5,266,626	($3,681,093)	($7,272,014)	($15,064,446)	($14,338,319)	($12,480,211)	($9,740,202)	($6,766,591)	($3,790,477)	$\boxed{(\$45,137)}$	($45,137)

(3) RMS/MJP-7, Line (17)(m)
(4) RMS/MJP-1, pg 2, Line (1)
(6) GSP-1
(7) RMS/MJP-1, pg 9, Line (17)
(8) RMS/MJP-1, pg 2, Line (8) ÷ 12
(9) Sum[(4)-(8)]
(10) RMS/MJP-1, pg 8, Line (10)
(11) Sum[Lines (3), (9), (10)]
(12) [Lines (3) + Line (11)] ÷ 2
(14) [Line (12) x Line (13)] ÷ 365 x Line (1)
(15) RMS/MJP-7, Pg 2, Line (50)
(16) Sum[Lines (11), (14), (15)]
(18) Nov-19 RMS/MJP-1, pg 7, Line (35)(m)
(19) RMS/MJP-1, pg 6, Line (74)
(21) RMS/MJP-1, pg 3, Line (8) ÷ 12
(22) RMS/MJP-1, pg 11, Line (22)
(23) RMS/MJP-1, pg 11, Line (12)
(24) RMS/MJP-1, pg 9, Line (32)
(25) Sum[Lines (19)-(24)]
(26) RMS/MJP-1, pg 8, Line (15)
(27) Sum[Lines (18), (25), (26)]
(28) [Line (18) + Line (27)] ÷ 2
(30) [Line (28) x Line (29)] ÷ 365 x Line (1)
(32) Sum[Lines (27), (30), (31)]
(34) Line (3) + Line (18)
(35) Sum[Lines (4),(8),(15),(19)-(21)]
(36) Line (22) + Line (23)
(37) Line (7) + Line (24)
(38) Line (6)
(39) Sum[Lines (35)-(38)]
(40) Line (10) + Line (26)
(41) Sum[Lines (34), (39), (40)]
(42) [Lines (34) + Line (41)] ÷ 2
(44) Line (14) + Line (30)
(45) Line (31)
(46) Sum[Lines (41), (44), (45)]

Attachment RMS/MJP-4

Attachment RMS/MJP -4
Bill Impact Analysis
Includes the proposed GCR And DAC Factors

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Heating:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(5)	548	$964.42	$898.59	$65.84	7.3%	$31.02	$32.84	$0.00	$0.00	$0.00	$1.98
(6)	608	$1,050.00	$976.93	$73.07	7.5%	$34.47	$36.41	$0.00	$0.00	$0.00	$2.19
(7)	667	$1,134.13	$1,054.01	$80.12	7.6%	$37.78	$39.94	$0.00	$0.00	$0.00	$2.40
(8)	726	$1,218.30	$1,131.08	$87.22	7.7%	$41.11	$43.49	$0.00	$0.00	$0.00	$2.62
(9)	785	$1,302.34	$1,208.04	$94.30	7.8%	$44.43	$47.04	$0.00	$0.00	$0.00	$2.83
(10)	845	$1,387.89	$1,286.41	$101.47	7.9%	$47.83	$50.60	$0.00	$0.00	$0.00	$3.04
(11)	905	$1,473.45	$1,364.76	$108.69	8.0%	$51.22	$54.21	$0.00	$0.00	$0.00	$3.26
(12)	964	$1,557.54	$1,441.76	$115.78	8.0%	$54.57	$57.74	$0.00	$0.00	$0.00	$3.47
(13)	1,023	$1,641.67	$1,518.80	$122.87	8.1%	$57.93	$61.25	$0.00	$0.00	$0.00	$3.69
(14)	1,082	$1,725.79	$1,595.86	$129.93	8.1%	$61.24	$64.79	$0.00	$0.00	$0.00	$3.90
(15)	1,142	$1,811.36	$1,674.23	$137.13	8.2%	$64.63	$68.39	$0.00	$0.00	$0.00	$4.11

Residential Heating Low Income:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	Total Bill Discount	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(20)	548	$716.32	$668.02	$48.30	7.2%	$31.02	($15.62)	$31.45	$0.00	$0.00	$0.00	$1.45
(21)	608	$779.75	$726.12	$53.64	7.4%	$34.47	($17.34)	$34.90	$0.00	$0.00	$0.00	$1.61
(22)	667	$842.09	$783.29	$58.80	7.5%	$37.78	($19.01)	$38.27	$0.00	$0.00	$0.00	$1.76
(23)	726	$904.45	$840.45	$64.01	7.6%	$41.11	($20.70)	$41.67	$0.00	$0.00	$0.00	$1.92
(24)	785	$966.73	$897.54	$69.19	7.7%	$44.43	($22.37)	$45.06	$0.00	$0.00	$0.00	$2.08
(25)	845	$1,030.15	$955.66	$74.49	7.8%	$47.83	($24.09)	$48.51	$0.00	$0.00	$0.00	$2.23
(26)	905	$1,093.53	$1,013.77	$79.76	7.9%	$51.22	($25.79)	$51.94	$0.00	$0.00	$0.00	$2.39
(27)	964	$1,155.85	$1,070.88	$84.97	7.9%	$54.57	($27.48)	$55.33	$0.00	$0.00	$0.00	$2.55
(28)	1,023	$1,218.20	$1,128.00	$90.19	8.0%	$57.93	($29.16)	$58.72	$0.00	$0.00	$0.00	$2.71
(29)	1,082	$1,280.54	$1,185.17	$95.37	8.0%	$61.24	($30.84)	$62.10	$0.00	$0.00	$0.00	$2.86
(30)	1,142	$1,343.97	$1,243.31	$100.66	8.1%	$64.63	($32.55)	$65.56	$0.00	$0.00	$0.00	$3.02

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Non-Heating:

						Difference due to:					
(31)							DAC				
(32)	Annual	Proposed	Current								
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET
(34)											
(35)	144	$396.68	$387.08	$9.60	2.5%	$6.37	$2.94	$0.00	$0.00	$0.00	$0.29
(36)	158	$417.43	$406.91	$10.53	2.6%	$6.99	$3.22	$0.00	$0.00	$0.00	$0.32
(37)	172	$438.18	$426.77	$11.41	2.7%	$7.57	$3.50	$0.00	$0.00	$0.00	$0.34
(38)	189	$463.41	$450.85	$12.57	2.8%	$8.34	$3.85	$0.00	$0.00	$0.00	$0.38
(39)	202	$482.73	$469.28	$13.45	2.9%	$8.93	$4.12	$0.00	$0.00	$0.00	$0.40
(40)	220	$509.38	$494.73	$14.65	3.0%	$9.73	$4.48	$0.00	$0.00	$0.00	$0.44
(41)	238	$536.08	$520.26	$15.82	3.0%	$10.51	$4.84	$0.00	$0.00	$0.00	$0.47
(42)	251	$555.40	$538.71	$16.69	3.1%	$11.08	$5.11	$0.00	$0.00	$0.00	$0.50
(43)	268	$580.61	$562.72	$17.90	3.2%	$11.86	$5.50	$0.00	$0.00	$0.00	$0.54
(44)	282	$601.37	$582.58	$18.79	3.2%	$12.46	$5.77	$0.00	$0.00	$0.00	$0.56
(45)	297	$623.61	$603.84	$19.77	3.3%	$13.11	$6.07	$0.00	$0.00	$0.00	$0.59

Residential Non-Heating Low Income:

							Difference due to:					
(46)												
(47)	Annual	Proposed	Current				Total Bill	DAC				
(48)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(49)												
(50)	144	$295.70	$288.76	$6.94	2.4%	$6.37	($2.24)	$2.60	$0.00	$0.00	$0.00	$0.21
(51)	158	$311.10	$303.49	$7.61	2.5%	$6.99	($2.46)	$2.85	$0.00	$0.00	$0.00	$0.23
(52)	172	$326.45	$318.22	$8.23	2.6%	$7.57	($2.66)	$3.08	$0.00	$0.00	$0.00	$0.25
(53)	189	$345.16	$336.09	$9.07	2.7%	$8.34	($2.93)	$3.39	$0.00	$0.00	$0.00	$0.27
(54)	202	$359.47	$349.77	$9.70	2.8%	$8.93	($3.14)	$3.62	$0.00	$0.00	$0.00	$0.29
(55)	220	$379.25	$368.68	$10.58	2.9%	$9.73	($3.42)	$3.95	$0.00	$0.00	$0.00	$0.32
(56)	238	$399.04	$387.61	$11.43	2.9%	$10.51	($3.70)	$4.27	$0.00	$0.00	$0.00	$0.34
(57)	251	$413.35	$401.31	$12.04	3.0%	$11.08	($3.89)	$4.49	$0.00	$0.00	$0.00	$0.36
(58)	268	$432.05	$419.15	$12.90	3.1%	$11.86	($4.17)	$4.83	$0.00	$0.00	$0.00	$0.39
(59)	282	$447.43	$433.90	$13.53	3.1%	$12.46	($4.37)	$5.04	$0.00	$0.00	$0.00	$0.41
(60)	297	$463.93	$449.67	$14.26	3.2%	$13.11	($4.61)	$5.33	$0.00	$0.00	$0.00	$0.43

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I Small:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(61)											
(62)											
(63)											
(64)											
(65)	830	$1,416.21	$1,315.68	$100.53	7.6%	$46.98	$50.53	$0.00	$0.00	$0.00	$3.02
(66)	919	$1,533.74	$1,422.43	$111.31	7.8%	$52.04	$55.93	$0.00	$0.00	$0.00	$3.34
(67)	1,010	$1,654.06	$1,531.73	$122.33	8.0%	$57.16	$61.50	$0.00	$0.00	$0.00	$3.67
(68)	1,099	$1,771.68	$1,638.54	$133.13	8.1%	$62.20	$66.94	$0.00	$0.00	$0.00	$3.99
(69)	1,187	$1,888.04	$1,744.24	$143.80	8.2%	$67.20	$72.29	$0.00	$0.00	$0.00	$4.31
(70)	1,277	$2,007.03	$1,852.32	$154.71	8.4%	$72.29	$77.78	$0.00	$0.00	$0.00	$4.64
(71)	1,367	$2,125.90	$1,960.32	$165.58	8.4%	$77.34	$83.27	$0.00	$0.00	$0.00	$4.97
(72)	1,456	$2,243.51	$2,067.15	$176.36	8.5%	$82.38	$88.69	$0.00	$0.00	$0.00	$5.29
(73)	1,544	$2,359.89	$2,172.86	$187.03	8.6%	$87.36	$94.06	$0.00	$0.00	$0.00	$5.61
(74)	1,635	$2,480.18	$2,282.14	$198.04	8.7%	$92.52	$99.58	$0.00	$0.00	$0.00	$5.94
(75)	1,725	$2,599.08	$2,390.12	$208.96	8.7%	$97.65	$105.04	$0.00	$0.00	$0.00	$6.27

C & I Medium:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	Difference due to: GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(76)											
(77)											
(78)											
(79)											
(80)	6,907	$8,971.04	$8,076.72	$894.32	11.1%	$390.93	$476.56	$0.00	$0.00	$0.00	$26.83
(81)	7,650	$9,822.08	$8,831.51	$990.57	11.2%	$432.98	$527.87	$0.00	$0.00	$0.00	$29.72
(82)	8,391	$10,670.29	$9,583.81	$1,086.48	11.3%	$474.94	$578.95	$0.00	$0.00	$0.00	$32.59
(83)	9,136	$11,523.37	$10,340.45	$1,182.92	11.4%	$517.07	$630.36	$0.00	$0.00	$0.00	$35.49
(84)	9,880	$12,375.46	$11,096.17	$1,279.29	11.5%	$559.21	$681.70	$0.00	$0.00	$0.00	$38.38
(85)	10,623	$13,226.48	$11,850.97	$1,375.51	11.6%	$601.26	$732.98	$0.00	$0.00	$0.00	$41.27
(86)	11,366	$14,077.47	$12,605.73	$1,471.74	11.7%	$643.33	$784.26	$0.00	$0.00	$0.00	$44.15
(87)	12,111	$14,930.59	$13,362.36	$1,568.23	11.7%	$685.50	$835.68	$0.00	$0.00	$0.00	$47.05
(88)	12,855	$15,782.62	$14,118.11	$1,664.52	11.8%	$727.59	$886.99	$0.00	$0.00	$0.00	$49.94
(89)	13,596	$16,630.87	$14,870.39	$1,760.47	11.8%	$769.52	$938.14	$0.00	$0.00	$0.00	$52.81
(90)	14,340	$17,482.90	$15,626.10	$1,856.80	11.9%	$811.64	$989.46	$0.00	$0.00	$0.00	$55.70

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(91)						Difference due to:					
(92)											
(93)											
(94)											
(95)	37,587	$45,454.67	$42,408.95	$3,045.72	7.2%	$2,127.44	$826.91	$0.00	$0.00	$0.00	$91.37
(96)	41,634	$50,080.96	$46,707.29	$3,373.67	7.2%	$2,356.50	$915.96	$0.00	$0.00	$0.00	$101.21
(97)	45,683	$54,709.89	$51,008.17	$3,701.72	7.3%	$2,585.64	$1,005.03	$0.00	$0.00	$0.00	$111.05
(98)	49,731	$59,337.93	$55,308.17	$4,029.75	7.3%	$2,814.77	$1,094.09	$0.00	$0.00	$0.00	$120.89
(99)	53,777	$63,963.21	$59,605.61	$4,357.60	7.3%	$3,043.79	$1,183.08	$0.00	$0.00	$0.00	$130.73
(100)	57,825	$68,591.19	$63,905.56	$4,685.63	7.3%	$3,272.91	$1,272.15	$0.00	$0.00	$0.00	$140.57
(101)	61,873	$73,219.13	$68,205.51	$5,013.62	7.4%	$3,502.02	$1,361.19	$0.00	$0.00	$0.00	$150.41
(102)	65,920	$77,845.40	$72,503.86	$5,341.54	7.4%	$3,731.05	$1,450.24	$0.00	$0.00	$0.00	$160.25
(103)	69,967	$82,472.41	$76,802.91	$5,669.51	7.4%	$3,960.15	$1,539.27	$0.00	$0.00	$0.00	$170.09
(104)	74,016	$87,101.38	$81,103.83	$5,997.55	7.4%	$4,189.30	$1,628.32	$0.00	$0.00	$0.00	$179.93
(105)	78,063	$91,727.69	$85,402.20	$6,325.48	7.4%	$4,418.36	$1,717.36	$0.00	$0.00	$0.00	$189.76

C & I HLF Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC: Base DAC	DAC: ISR	EE	LIHEAP	GET
(106)						Difference due to:					
(107)											
(108)											
(109)											
(110)	41,956	$42,006.25	$38,943.92	$3,062.33	7.9%	$1,854.45	$1,116.01	$0.00	$0.00	$0.00	$91.87
(111)	46,471	$46,259.51	$42,867.61	$3,391.90	7.9%	$2,054.02	$1,236.12	$0.00	$0.00	$0.00	$101.76
(112)	50,991	$50,517.05	$46,795.21	$3,721.85	8.0%	$2,253.83	$1,356.36	$0.00	$0.00	$0.00	$111.66
(113)	55,507	$54,771.12	$50,719.71	$4,051.41	8.0%	$2,453.41	$1,476.46	$0.00	$0.00	$0.00	$121.54
(114)	60,028	$59,029.53	$54,648.08	$4,381.45	8.0%	$2,653.27	$1,596.74	$0.00	$0.00	$0.00	$131.44
(115)	64,545	$63,284.45	$58,573.33	$4,711.12	8.0%	$2,852.91	$1,716.88	$0.00	$0.00	$0.00	$141.33
(116)	69,062	$67,539.38	$62,498.56	$5,040.81	8.1%	$3,052.54	$1,837.05	$0.00	$0.00	$0.00	$151.22
(117)	73,583	$71,797.73	$66,426.93	$5,370.79	8.1%	$3,252.34	$1,957.33	$0.00	$0.00	$0.00	$161.12
(118)	78,099	$76,051.83	$70,351.42	$5,700.41	8.1%	$3,451.96	$2,077.44	$0.00	$0.00	$0.00	$171.01
(119)	82,619	$80,309.34	$74,278.99	$6,030.35	8.1%	$3,651.77	$2,197.67	$0.00	$0.00	$0.00	$180.91
(120)	87,137	$84,566.06	$78,205.96	$6,360.10	8.1%	$3,851.45	$2,317.85	$0.00	$0.00	$0.00	$190.80

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Extra-Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(121)						Difference due to:					
(122)											
(123)											
(124)											
(125)	233,835	$213,066.78	$194,239.43	$18,827.35	9.7%	$13,235.07	$5,027.46	$0.00	$0.00	$0.00	$564.82
(126)	259,019	$235,346.49	$214,491.49	$20,855.00	9.7%	$14,660.45	$5,568.90	$0.00	$0.00	$0.00	$625.65
(127)	284,197	$257,621.64	$234,739.37	$22,882.27	9.7%	$16,085.56	$6,110.24	$0.00	$0.00	$0.00	$686.47
(128)	309,381	$279,901.38	$254,991.37	$24,910.01	9.8%	$17,511.00	$6,651.71	$0.00	$0.00	$0.00	$747.30
(129)	334,562	$302,178.79	$275,241.39	$26,937.40	9.8%	$18,936.21	$7,193.07	$0.00	$0.00	$0.00	$808.12
(130)	359,745	$324,457.81	$295,492.76	$28,965.05	9.8%	$20,361.58	$7,734.52	$0.00	$0.00	$0.00	$868.95
(131)	384,928	$346,736.77	$315,744.10	$30,992.67	9.8%	$21,786.93	$8,275.96	$0.00	$0.00	$0.00	$929.78
(132)	410,110	$369,014.94	$335,994.74	$33,020.20	9.8%	$23,212.23	$8,817.36	$0.00	$0.00	$0.00	$990.61
(133)	435,293	$391,293.93	$356,246.12	$35,047.81	9.8%	$24,637.60	$9,358.78	$0.00	$0.00	$0.00	$1,051.43
(134)	460,471	$413,569.02	$376,493.96	$37,075.05	9.8%	$26,062.66	$9,900.14	$0.00	$0.00	$0.00	$1,112.25
(135)	485,655	$435,848.78	$396,746.04	$39,102.73	9.9%	$27,488.07	$10,441.58	$0.00	$0.00	$0.00	$1,173.08

C & I HLF Extra-Large:

Line	Annual Consumption (Therms)	Proposed Rates	Current Rates	Difference	% Chg	GCR	DAC Base DAC	DAC ISR	EE	LIHEAP	GET
(136)						Difference due to:					
(137)											
(138)											
(139)											
(140)	486,528	$384,223.44	$348,862.38	$35,361.06	10.1%	$21,504.55	$12,795.68	$0.00	$0.00	$0.00	$1,060.83
(141)	538,924	$424,934.98	$385,765.76	$39,169.22	10.2%	$23,820.43	$14,173.71	$0.00	$0.00	$0.00	$1,175.08
(142)	591,320	$465,645.73	$422,668.35	$42,977.38	10.2%	$26,136.33	$15,551.73	$0.00	$0.00	$0.00	$1,289.32
(143)	643,718	$506,358.61	$459,572.90	$46,785.71	10.2%	$28,452.37	$16,929.77	$0.00	$0.00	$0.00	$1,403.57
(144)	696,109	$547,065.81	$496,472.33	$50,593.47	10.2%	$30,768.01	$18,307.66	$0.00	$0.00	$0.00	$1,517.80
(145)	748,506	$587,778.00	$533,376.31	$54,401.69	10.2%	$33,083.94	$19,685.70	$0.00	$0.00	$0.00	$1,632.05
(146)	800,903	$628,490.20	$570,280.22	$58,209.98	10.2%	$35,399.92	$21,063.76	$0.00	$0.00	$0.00	$1,746.30
(147)	853,294	$669,197.43	$607,179.63	$62,017.80	10.2%	$37,715.62	$22,441.65	$0.00	$0.00	$0.00	$1,860.53
(148)	905,692	$709,910.31	$644,084.24	$65,826.06	10.2%	$40,031.60	$23,819.68	$0.00	$0.00	$0.00	$1,974.78
(149)	958,088	$750,620.98	$680,986.76	$69,634.22	10.2%	$42,347.48	$25,197.71	$0.00	$0.00	$0.00	$2,089.03
(150)	1,010,485	$791,333.20	$717,890.68	$73,442.52	10.2%	$44,663.47	$26,575.77	$0.00	$0.00	$0.00	$2,203.28

Attachment RMS/MJP-5

Attachment RMS/MJP -5
FT-2 Demand Rate

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Summary of Marketer Transportation Factors

	Item (a)	Reference (b)	Proposed (c)	Billing Units (d)
(1)	FT-2 Demand Usage (Dt) Nov 2019 - Oct 2020	Pg 2, Line (21)	$14.0154	Dth/Mth
(2)	Storage and Peaking charge for FT-1 firm transportation Customers eligible for TSS	Pg 3, Line (5)	$1.0542	Per Dth

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Calculation of FT- 2 Demand Rate (per Dth)

	Description	Source Reference	Source Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Storage Fixed Costs	RMS/MJP-1 pg 5	Line (43)	[redacted]	
	Less:				
(2)	System Pressure to DAC			($5,244,853)	
(3)	Credits			$0	
(4)	Refunds			$0	
(5)	Total Credits	Sum [(2)-(4)]		($5,244,853)	
	Plus:				
(6)	Supply Related LNG O&M Costs	RMS/MJP-1 Pg 2	Line (8)	$829,823	
(7)	Working Capital Requirement	RMS/MJP-1 pg 10	Line (47)	$190,257	
(8)	FT Demand Everett	RMS/MJP-1 pg 4	Line (5)	$1,275,360	
(9)	Total Additions	Sum [(6)-(8)]		$2,295,440	
(10)	Total Storage Fixed Costs	(1) + (5) + (9)		[redacted]	
	Inventory Financing				
(11)	Underground	RMS/MJP-1 pg 11	Line (12)	$452,816	
(12)	LNG	RMS/MJP-1 pg 11	Line (22)	$239,415	
(13)	Total Storage Fixed Costs	(10) + (11) + (12)		[redacted]	
(14)	LNG Storage MDQ (Dth)	RMS/MJP-1 pg 13	Line (14)	[redacted]	
(15)	AGT	GSP-1			
(16)	TENN	GSP-1			
(17)	Total Storage MDQ	Sum [(14)-(16)]			
(18)	Storage MDQ X 12 Months	(17) x 12		[redacted]	MDCQ Dth
(19)	FT- 2 Demand Rate	(13) ÷ (18)		$13.7478	per MDCQ Dth
(20)	Uncollectible %	Docket 4770		1.91%	
(21)	Total FT-2 Demand Rate adjusted for Uncollectibles	(19) ÷ [(1 - (20)]		$14.0154	per MDCQ Dth
(22)	MDQ-U	Mkter MDQ Forecast		4,582	
(23)	MDQ-P	Mkter MDQ Forecast		15,137	
(24)	Marketer MDQs	(22) + (23)		19,719	Dth/Mth
(25)	FT-2 Storage Costs	(19) x (24) x 12 Months		**$3,253,068**	

National Grid - RI Gas
Gas Cost Recovery (GCR) Filing
Calculation of FT-1 Storage and Peaking Charge Applied to Firm Transportation Customers Eligible for TSS

		Source			
	Description	Reference	Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Total Storage Fixed Costs	Pg 2	Line (13)	[redacted]	
(2)	Usage (Dth) Nov 2020 - Oct 2021	RMS/MJP-1, pg 2	Line (16)	[redacted]	
(3)	Volumetric Rate	(1) ÷ (2)		$1.0341	
(4)	Uncollectible %	Docket 4770		1.91%	
(5)	Volumetric Rate Including Uncollectible	(3) ÷ [1 - (4)]		$1.0542	per dth
(6)	Storage & Peaking charge applied to FT-1 customers eligible for TSS	(5) ÷ 10		$0.1054	per therm

Attachment RMS/MJP-6

Attachment RMS/MJP -6
FT-2 Capacity Allocator Percentages

RI Gas Company
Capacity Assignment Table

			% of Peak Day Requirement				% of Total Capacity		
			Pipeline	Storage	Peaking	Total	Pipeline	Storage	Peaking
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	HLF	Res - Non-Heating	68.0%	7.0%	25.0%	100.0%	0.9%	0.7%	0.7%
2	HLF	Res - Non-Heating LI	68.0%	7.0%	25.0%	100.0%			
3	LLF	Res - Heating	53.0%	11.0%	36.0%	100.0%	61.0%	63.6%	63.6%
4	LLF	Res - Heating LI	53.0%	11.0%	36.0%	100.0%			
5	LLF	Small	53.0%	11.0%	36.0%	100.0%	7.5%	8.0%	8.0%
6	LLF	Med	53.0%	11.0%	36.0%	100.0%	9.2%	9.1%	9.1%
7	LLF	Large Low Load	53.0%	11.0%	36.0%	100.0%	2.0%	2.2%	2.2%
8	HLF	Large High Load	68.0%	7.0%	25.0%	100.0%	0.5%	0.3%	0.3%
9	LLF	XL Low Load	53.0%	11.0%	36.0%	100.0%	0.1%	0.2%	0.2%
10	HLF	XL High Load	68.0%	7.0%	25.0%	100.0%	0.3%	0.2%	0.2%
11	HLF	High Load Factor	68.0%	7.0%	25.0%	100.0%	6.9%	3.7%	3.7%
12	LLF	Low Load Factor	53.0%	11.0%	36.0%	100.0%	93.1%	96.3%	96.3%
13		Total	54.0%	11.0%	35.0%	100.0%	100.0%	100.0%	100.0%

Attachment RMS/MJP -7
Marketer Reconciliation

2018-19 & 2019-20 Annual Marketer Reconciliation

	Description	# of days	Tetco ELA/Algonquin	Tetco WLA/Algonquin	Tennessee Zone 1 to NEGC	Tetco STX/Algonquin	Algonquin @ Lambertville, NJ	Columbia (Maumee/Downington)	Tennessee 6 to 6 Dracut	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j) = Sum[(c) : (i)]
	2019-2020 Marketer Reconciliation									
	Month of activity									
(1)	Nov-19	30	195,000	255,000	285,000	121,320	79,980	90,000	24,420	1,050,720
(2)	Dec-19	31	201,500	263,500	303,769	125,364	83,948	93,000	30,318	1,101,399
(3)	Jan-20	31	201,500	263,500	303,800	125,364	84,072	93,000	30,721	1,101,957
(4)	Feb-20	28	188,500	246,500	287,071	117,276	78,532	87,000	28,623	1,033,502
(5)	Mar-20	31	201,469	263,469	306,838	125,333	83,855	93,000	30,101	1,104,065
(6)	Apr-20	30	195,000	255,000	296,970	121,320	80,970	90,000	31,260	1,070,520
(7)	May-20	31	201,500	263,500	306,900	125,364	83,018	93,000	30,132	1,103,414
(8)	Jun-20	30	195,000	255,000	297,000	121,320	79,770	90,000	27,150	1,065,240
(9)	Jul-20	31	195,000	255,000	297,000	121,320	79,770	90,000	27,150	1,065,240
(10)	Aug-20	31	195,000	255,000	297,000	121,320	79,770	90,000	27,150	1,065,240
(11)	Sep-20	30	195,000	255,000	297,000	121,320	79,770	90,000	27,150	1,065,240
(12)	Oct-20	31	195,000	255,000	297,000	121,320	79,770	90,000	27,150	1,065,240
(13)	Total		2,359,469	3,085,469	3,575,348	1,467,941	973,225	1,089,000	341,325	12,891,777
	Approved									
(14)	System Average		$0 8143	$0 8143	$0 8143	$0 8143	$0 8143	$0 8143	$0 8143	
(15)	Path		$0 9623	$1 1466	$1 0006	$1 4064	$0 5848	$0 3349	$1 9442	
(16)	Credit/Surcharge		($0 1480)	($0 3323)	($0 1863)	($0 5921)	$0 2295	$0 4794	($1 1299)	
	Revised									
(17)	System Average		$0 8315	$0 8315	$0 8315	$0 8315	$0 8315	$0 8315	$0 8315	
(18)	Path		$0 9275	$1 1013	$0 9420	$1 3387	$0 6125	$0 3717	$1 9314	
(19)	Credit/Surcharge		($0 0960)	($0 2698)	($0 1105)	($0 5072)	$0 2190	$0 4598	($1 0999)	
(20)	Variance_Approved Surcharge/Credit vs Revised Surch		$0 0520	$0 0625	$0 0758	$0 0849	($0 0105)	($0 0196)	$0 0300	
(21)	Annual MDCQ		2,359,469	3,085,469	3,575,348	1,467,941	973,225	1,089,000	341,325	12,891,777
(22)	Updated 2018-19 Marketer Reconciliation Adjustment		$122,692	$192,842	$271,011	$124,628	($10,219)	($21,344)	$10,240	$689,850

(13): Sum[Lines (1) : (12)]
(14) & (15): Dkt 4963 EDA/SAJ-1 filed on September 3, 2019
(16): Line (14) - Line (15)
(19): Line (17) - Line (18)
(20): Line (19) - Line (16)
(21): Line (13)
(22): Line (20) x Line (21)

2018-19 & 2019-20 Annual Marketer Reconciliation

	Description (a)	# of days (b)	Tetco ELA/Algonquin (c)	Tetco WLA/Algonquin (d)	Tennessee Zone 1 to NEGC (e)	Tetco STX/Algonquin (f)	Algonquin @ Lambertville, NJ (g)	Columbia (Maumee/Downington) (h)	Tennessee 6 to 6 Dracut (i)	Total (j) = Sum[(c) : (i)]
	2018-2019 Marketer Reconciliation									
	Month of activity									
(23)	Nov-18	30	194,970	255,000	285,000	121,320	74,340	87,300	6,330	1,024,260
(24)	Dec-18	31	201,500	263,500	294,500	125,333	79,329	93,000	12,059	1,069,221
(25)	Jan-19	31	201,500	263,500	294,500	125,364	78,864	93,000	9,393	1,066,121
(26)	Feb-19	29	182,000	238,000	266,000	113,232	71,400	84,000	9,100	963,732
(27)	Mar-19	31	201,469	263,500	294,500	125,364	78,895	93,000	8,928	1,065,656
(28)	Apr-19	30	195,000	255,000	285,000	121,320	76,230	90,000	8,370	1,030,920
(29)	May-19	31	201,500	263,500	294,500	125,364	80,135	93,000	13,888	1,071,887
(30)	Jun-19	30	194,970	254,970	284,970	121,320	77,640	90,000	14,250	1,038,120
(31)	Jul-19	31	201,500	263,500	294,500	125,364	79,856	93,000	14,043	1,071,763
(32)	Aug-19	31	201,500	263,500	294,500	125,364	80,817	93,000	17,918	1,076,599
(33)	Sep-19	30	195,000	254,970	285,000	121,320	77,850	90,000	16,230	1,040,370
(34)	Oct-19	31	201,500	263,500	294,500	125,364	81,623	93,000	21,266	1,080,753
(35)	Total		2,372,409	3,102,440	3,467,470	1,476,029	936,979	1,092,300	151,775	12,599,402
	Approved									
(36)	System Average		$0 7693	$0 7693	$0 7693	$0 7693	$0 7693	$0 7693	$0 7693	
(37)	Path		$0 7847	$0 8774	$1 0298	$1 1580	$0 5192	$0 2702	$2 2692	
(38)	Credit/Surcharge		($0 0154)	($0 1081)	($0 2605)	($0 3887)	$0 2501	$0 4991	($1 4999)	
	Revised									
(39)	System Average		$0 7821	$0 7821	$0 7821	$0 7821	$0 7821	$0 7821	$0 7821	
(40)	Path		$0 8633	$0 9806	$1 0163	$1 2853	$0 5192	$0 2823	$2 2659	
(41)	Credit/Surcharge		($0 0812)	($0 1985)	($0 2342)	($0 5032)	$0 2629	$0 4998	($1 4838)	
(42)	Variance_Approved Surcharge/Credit vs Revised Surch		($0 0658)	($0 0904)	$0 0263	($0 1145)	$0 0128	$0 0007	$0 0161	
(43)	Annual MDCQ		2,372,409	3,102,440	3,467,470	1,476,029	936,979	1,092,300	151,775	12,599,402
(44)	Updated 2018-19 Marketer Reconciliation Adjustment		($156,105)	($280,461)	$91,194	($169,005)	$11,993	$765	$2,444	($499,174)
(45)	Under/(Over)-collections 2018-19 Marketer Reconciliation[1]									$345
(46)	Total 2018-19 amount subject to Marketer Reconciliation									($498,829)
(47)	Already Collected from Marketers[2]									$2,569
(48)	Under/(Over)-collections for 2019-20 Marketer Reconciliation									($501,398)
(49)	Total 2018-19 & 2019-20 Marketer Reconciliation Surcharged to Marketers									$188,452
(50)	Total 2018-19 & 2019-20 Marketer Reconciliation_Credit to Firm Sales Customers									**($188,452)**

(36) & (37): Dkt 4872 EDA-4
(38): Line (36) - Line (37)
(41): Line (39) - Line (40)
(42): Line (41) - Line (38)
(43): Line (35)
(44): Line (42) x Line (43)
(46): Line (44) + Line (45)
(48): Line (46) - Line (47)
(49): Line (22) + Line (48)
(50): - Line (49)

[1] Docket No 4963 Attachment MJP/AEL-7, Line 48, updated to reflect actual collections for Jul 2019-Oct 2019

[2] Nov 2019 - July 2020 as reflected in GCR Monthly Deferred Report filed on August 20, 2020 Schedule 2, Line 78 Aug 2020 - Oct 2020 are projected collections

Testimony of
Theodore J. Poe, Jr.

DIRECT TESTIMONY

OF

THEODORE E. POE, JR.

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I. Introduction

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

A. I am the Principal Analyst for Gas Load Forecasting for National Grid USA Service Company, Inc. In this position, I am responsible for preparing forecasts of the resource requirements for the New England local gas distribution companies that operate as The Narragansett Electric Company (the Company), Boston Gas Company, and Colonial Gas Company, each d/b/a National Grid. In addition to the New England portfolios, I am responsible for preparing forecasts of the resource requirements for The Brooklyn Union Gas Company d/b/a National Grid NY (formerly KeySpan Energy Delivery New York), KeySpan Gas East Corporation d/b/a National Grid (formerly d/b/a KeySpan Energy Delivery Long Island), and Niagara Mohawk Power Corporation, all of which are located in New York. For purposes of this testimony, references to the Company relate solely to The Narragansett Electric Company.

Q. Please summarize your educational background and professional experience.

A. I graduated from the Massachusetts Institute of Technology in 1978 with a Bachelor of Science degree in Geology. From 1981 to 1989, I worked as a Research Associate with

Jensen Associates, Inc. of Boston, where I was responsible for developing a variety of computer-forecasting models to analyze natural gas supply and demand for interstate pipeline and local gas distribution companies. I joined Boston Gas Company in 1989, where I was responsible for modeling and forecasting customers' natural gas resource requirements and managing the resource planning process. In 1998-99, I assumed the same responsibilities for Essex Gas Company and Colonial Gas Company. In 2000, I assumed responsibility for modeling and forecasting the natural gas resource requirements of The Brooklyn Union Gas Company and KeySpan Gas East Corporation. In 2008, I assumed responsibility for modeling and forecasting the natural gas resource requirements for the Company and Niagara Mohawk Power Corporation.

Q. Are you a member of any professional organizations?

A. Yes. I am a member of the Northeast Gas Association, the New England-Canada Business Council, and the American Meteorological Society.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC) or any other regulatory commissions?

A. Yes. I testified before the PUC in previous Gas Cost Recovery filings in Docket Nos. 4719, 4647, 4872, and 4963. I also submitted pre-filed written testimony in support of the Company's 2017 rate case filing in Docket No. 4770. In addition, I have testified in a number of proceedings before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

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

A. My testimony supports the underlying retail and wholesale forecasts of natural gas customer requirements that are used to estimate gas costs in the Company's Gas Cost Recovery submission.

Q. Are you sponsoring any attachments?

A. Yes. I am sponsoring the following attachments with my testimony:

Attachment TEP-1	National Grid RI Retail Volume Forecast 2020 vs. 2019 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2020 vs. 2019 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2020 vs. 2019 Forecast
Attachment TEP-4	National Grid RI Retail Volume Forecast by Rate Class 2020 vs. 2019 Forecast
Attachment TEP-5	National Grid RI Retail Meter Count Forecast by Rate Class 2020 vs. 2019 Forecast

Q. What was the source of the projected sendout requirements and costs used in this filing?

A. As in prior cost of gas filings, the Company used its internal billing and cost data and external economic data to forecast its sendout requirements.

II. Summary of Retail and Wholesale Natural Gas Forecasts

Q. How did the Company develop its retail and wholesale forecasts?

A. Annually, beginning in April, the Company uses the following five-step process to prepare its 10-year forecast of customer requirements:

1) Forecast retail demand requirements;
2) Develop reference-year wholesale sendout requirements using regression analysis;
3) Normalize forecast of customer requirements;
4) Determine design weather planning standards; and
5) Determine wholesale customer requirements under design weather conditions.

For the Company's forecast, "retail" refers to gas delivered and metered at customers' burner tips, and "wholesale" refers to gas received and metered flowing into the Company's distribution system. The Company's retail forecast is prepared through econometric and statistical modeling of both customer count (meter count) and use-per-customer. This process is documented in greater detail in the Company's Gas Long-

Range Resource and Requirements Plan for the Forecast Period 2020/21 through 2024/25 dated June 30, 2020 that was filed with the Rhode Island Division of Public Utilities and Carriers (Long Range Plan) in Docket 5043. Billing data is modeled at the rate class level and further sub-categorized as sales or transportation (either capacity-eligible or capacity-exempt). The Company's volume forecast is the product of meter count and use-per-customer at the rate class level. The retail forecast takes into account the impact of the COVID-19 Pandemic on the Rhode Island economy and the impact of the Company's energy efficiency programs.

The Company's wholesale forecast is based on its retail forecast. The retail forecast is adjusted to correct for the billing lag inherent therein, and it is further adjusted to account for unaccounted-for gas. Unaccounted-for gas is the measure of the difference between gas supplies that are received and metered flowing into the Company's distribution system and gas delivered and metered at customers' burner tips. These two forecasts (retail and wholesale) serve as the annual basis of the Company's supply, engineering, and financial planning.

III. <u>The 2020 Gas Forecast</u>

Q. What is the role of the 2020 gas forecast in the Gas Cost Recovery proceeding?

A. With 73 percent of the Company's wholesale deliveries occurring between the months of November through March, as set forth in the pre-filed joint direct testimony of the

Company's Gas Supply Panel the Company's gas resource portfolio and gas supply purchase planning are designed to address its customers' needs during the winter peak period and throughout the year. Each year, the Company develops its gas forecast by accounting for the most recent heating season's actual customer usage patterns. This provides the Company with a growing set of historical data with which to build its econometric forecast using its most recent economic outlook.

The Company's forecast of sales and throughput requirements under normal weather conditions and under design winter conditions serves three purposes. First, the forecasts provide key inputs for the computation of National Grid's projected Gas Cost Recovery costs. Second, the Company's forecasts of design winter requirements form the basis for the Company's allocation of fixed costs between High Load Factor and Low Load Factor service classifications. Third, forecasts of total annual sales and throughput requirements provide the denominators used in the Company's computation of applicable charges on a dollars per therm basis. The Company's forecasts of future gas service requirements also serve as important indicators of the need for additional capacity to ensure the reliability of the Company's service, particularly during periods of extreme weather, as reflected in measures of design winter, cold snap, and design day requirements. The Company's long-range forecasts of service requirements also play an important role in assessing the economics of alternative gas supply resources.

Q. How do the forecasted sales requirements for 2020/21 compare to the prior retail forecast for 2019/20?

A. A comparison of the Company's 2019 gas forecast of firm retail volumes for the period November 2019 through October 2020 and its current firm retail volume forecast for November 2020 through October 2021 is shown in Table 1 below.

Table 1

	2019/20 Forecasted Volume (MMBtu)	2020/21 Forecasted Volume (MMBtu)
Residential Sales	20,300,786	20,169,756
C&I Sales	7,256,274	7,038,567
Total Sales	27,557,060	27,208,323
C&I Transportation	14,095,997	12,439,909
Total	41,653,037	39,648,231

Source: Attachment TEP-1

In summary, the 2020/21 forecast shows a 4.8 percent decrease in Total Sales and Commercial and Industrial (C&I) Transportation customer volumes over the 2019/20 forecast, with Total Sales decreasing by 1.3 percent and C&I Transportation decreasing by 11.7 percent.

Attachment TEP-1 contains tables showing planning year[1] (PY) volumes from PY 2011 through PY 2028 for the Company's current (2020) volume forecast and last year's (2019) forecast. The data is presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts are provided in Attachment TEP-1 for visual comparison. The primary change in the forecast from 2019 to 2020 is the short-term decrease in Residential, C&I Sales, and C&I Firm Transportation volumes and the subsequent rebound due to the COVID-19 pandemic. The five-year per annum growth rate in volumes (excluding Other) from PY 2020 to PY 2025 is 2.0 percent, which is greater than the 0.9 percent per annum growth rate forecasted last year.

Attachment TEP-2 contains tables from PY 2011 through PY 2028 showing the Company's current (2020) meter count forecast and last year's (2019) forecast. The data is presented for Residential Non-Heating, Residential Heating, C&I Sales, C&I FT-1 Transportation, and C&I FT-2 Transportation customers, and all other volumes. Charts are provided in Attachment TEP-2 for visual comparison. The primary changes in the meter count forecast from 2019 to 2020 are increases in the forecasted growth rates of all customer groups as the Rhode Island economy rebounds from the impact of COVID-19. The five-year per annum growth rate in meter count (excluding Other) from PY 2020 to

[1] The forecast planning year is November 1 through October 31.

PY 2025 is 1.2 percent, which is greater than the 1.0 percent per annum growth rate forecasted last year.

On a wholesale basis (see Attachment GSP-1, Page 14 of 17), the Company forecasts sales volumes to be 28,670,000 MMBtu[2] for the period November 2020 through October 2021. Comparatively, in the Company's previous wholesale forecast for November 2019 through October 2020, as filed in Docket No. 4963, the sales volume was projected to be 28,179,000 MMBtu. Wholesale sales volume is projected to increase 1.7 percent.

Attachment TEP-3 contains tables for calendar year economic data from 1990 through 2028 for the Company's current (2020) forecast and last year's (2019) forecast. The data is presented for the following key indicators: Natural Gas Residential Price, Residential No. 2 Oil Price, the Gas-to-Oil Price Ratio, Rhode Island Gross Domestic Product, Households, and Non-Farm Employment. Charts are provided in Attachment TEP-3 for visual comparison. The overall 2020 economic forecast, as compared to the 2019 economic forecast, shows lower natural gas and oil prices with the economic dip and recovery driven by the COVID-19 pandemic.

[2] One million British thermal units (MMBtu).

Q. Have there been any changes to the forecasted sales requirements for 2020/21 as compared to the Company's Long Range Plan filed in Docket No. 5043?

A. No. There are no changes to the forecasted sales requirements for 2020/21 as compared to the Company's Long Range Plan filed in Docket No. 5043.

Q. How has the Company accounted for the effects of weather variations in the historic data inputs to its 2020 gas forecast?

A. In preparing the 2020 gas forecast, the Company used its monthly customer billing data (volume and number of customers) for the period September 2010 through February 2020 to forecast the number of customers and use-per-customer for each of the rate groups the Company analyzes. The Company obtained the historical monthly use-per-customer values by dividing volume of total billed therms for each month by the number of customers for the month. Weather, particularly heating degree days, plays the dominant role in modeling the use-per-customer behavior of the Company's customers under the wide range of weather observed in the historical period. The Company's forecast then applies its normalized heating degree days as the basis of its forecast of use-per-customer under normal weather conditions.

Q. How did the Company's 2019/20 forecast compare to the actual billings weather normalized for the same period?

A. According to the Company's most recent analysis where it normalized its actual billing data for November 2019 through February 2020 and forecasted March through October 2020, actual normalized Firm Sales customers plus C&I Transportation customers totaled 39,842,972 MMBtu. In the Company's 2019 Gas Cost Recovery filing (Docket 4963), the Company's normalized forecast volume for November 2019 through October 2020 was 41,653,037 MMBtu, as set forth in Table 1, above. Actual normalized sales were 4.3 percent lower than forecast, driven principally by the impact of the COVID-19 Pandemic.

Q. How has the Company addressed the effects of colder than normal weather on the development of its design winter and design day requirements?

A. The Company develops appropriate design day and design year planning standards to design a least-cost, reliable supply portfolio for its forecast period. The purpose of a design day standard is to establish the amount of system-wide throughput (interstate pipeline and underground storage capacity plus local supplemental capacity) that is required to maintain the integrity of the distribution system. The Company maintains a design year standard for planning purposes to identify the amount of seasonal supplies of natural gas that will be required to provide continuous service under all reasonable weather conditions. The Company establishes its design standards using a three-step process. First, the Company performs statistical analyses of the coldest days and of the annual degree days recorded over a historical period. Second, the Company conducts cost-benefit analyses to evaluate the cost of maintaining the resources necessary to meet design-level demand versus the cost to customers of experiencing service curtailments. Third, the Company identifies design standards that would maintain reliability at the lowest cost.

Q. Does this conclude your testimony?

A. Yes.

Attachments TEP

Attachments of Theodore E. Poe, Jr.

Attachment TEP-1	National Grid RI Retail Volume Forecast 2020 vs. 2019 Forecast
Attachment TEP-2	National Grid RI Retail Meter Count Forecast 2020 vs. 2019 Forecast
Attachment TEP-3	National Grid RI Economic Forecast 2020 vs. 2019 Forecast
Attachment TEP-4	National Grid RI Retail Volume Forecast by Rate Class 2020 vs. 2019 Forecast
Attachment TEP-5	National Grid RI Retail Meter Count Forecast by Rate Class 2020 vs. 2019 Forecast

Attachment TEP-1

Attachment TEP-1

National Grid RI Retail Volume Forecast
2020 vs. 2019 Forecast

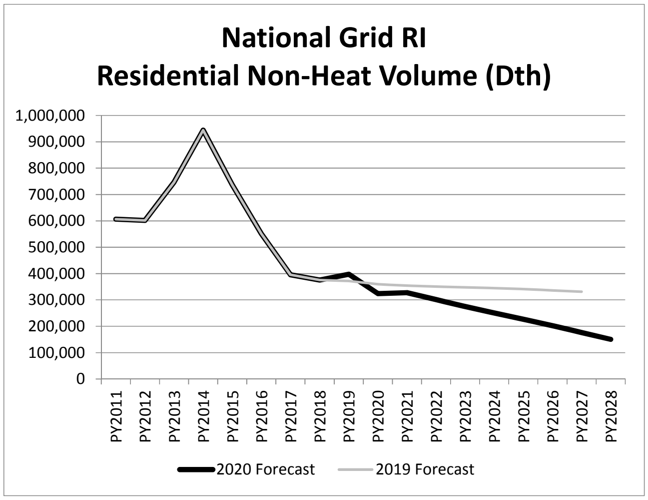
2020 National Grid RI Volume Forecast (Dth) Chart III-B-1
Planning Year (Nov-Oct) Page 1 of 2

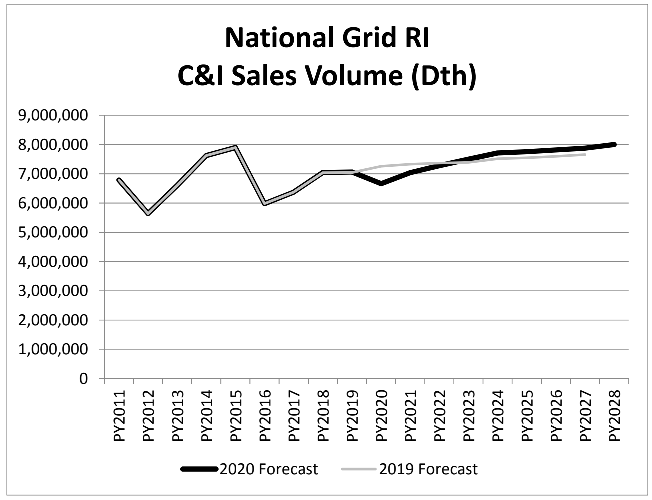
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,789,174	7,680,544	2,569,158	*35,383,514*	2,205,459	*37,588,973*
PY2012	601,399	14,783,757	5,641,589	7,610,425	2,334,007	*30,971,177*	2,176,034	*33,147,211*
PY2013	746,890	17,315,788	6,599,751	8,278,483	3,062,257	*36,003,170*	1,985,726	*37,988,895*
PY2014	944,174	19,573,872	7,621,400	8,563,673	3,585,382	*40,288,502*	1,734,538	*42,023,040*
PY2015	736,952	20,389,772	7,898,157	9,416,525	3,745,573	*42,186,979*	1,736,206	*43,923,185*
PY2016	551,336	16,675,372	5,979,056	8,656,943	3,646,308	*35,509,014*	1,769,137	*37,278,152*
PY2017	395,749	18,594,264	6,371,615	8,698,747	4,060,420	*38,120,794*	1,727,212	*39,848,006*
PY2018	375,500	19,943,386	7,042,087	9,022,578	4,340,031	*40,723,581*	1,782,779	*42,506,360*
PY2019	397,642	20,381,686	7,058,464	8,770,816	4,647,746	*41,256,354*	1,815,523	*43,071,878*
PY2020	323,837	19,039,603	6,660,947	8,251,676	4,460,282	*38,736,344*	1,709,348	*40,445,691*
PY2021	327,328	19,842,428	7,038,567	8,051,014	4,388,895	*39,648,231*	1,622,522	*41,270,753*
PY2022	301,598	20,377,128	7,278,674	8,426,323	4,547,044	*40,930,767*	1,696,767	*42,627,535*
PY2023	274,203	20,948,766	7,497,649	8,866,659	4,693,204	*42,280,482*	1,752,841	*44,033,323*
PY2024	251,856	21,339,906	7,712,797	8,908,249	4,756,063	*42,968,871*	1,744,164	*44,713,035*
PY2025	226,569	21,313,493	7,757,075	8,749,950	4,740,637	*42,787,724*	1,711,463	*44,499,187*
PY2026	201,699	21,431,465	7,817,513	8,647,306	4,753,783	*42,851,766*	1,689,747	*44,541,514*
PY2027	176,056	21,553,988	7,875,964	8,550,507	4,767,125	*42,923,640*	1,669,232	*44,592,871*
PY2028	150,402	21,841,445	8,001,657	8,517,749	4,819,695	*43,330,948*	1,661,462	*44,992,409*
PY25/PY20	-6.9%	2.3%	3.1%	1.2%	1.2%	2.0%	0.0%	1.9%

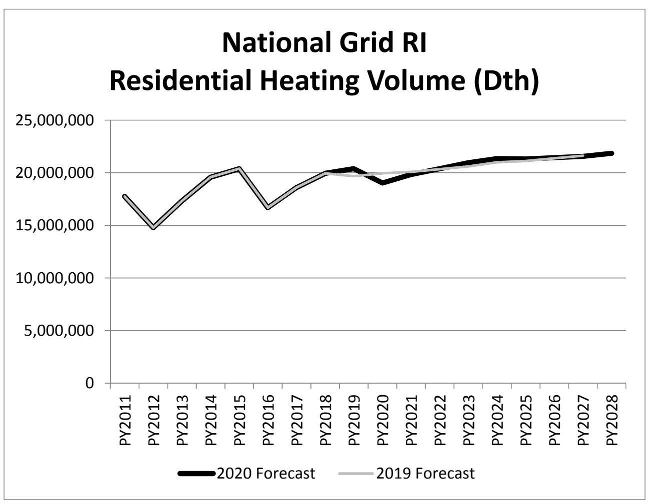
2019 National Grid RI Volume Forecast (Dth)
Planning Year (Nov-Oct)

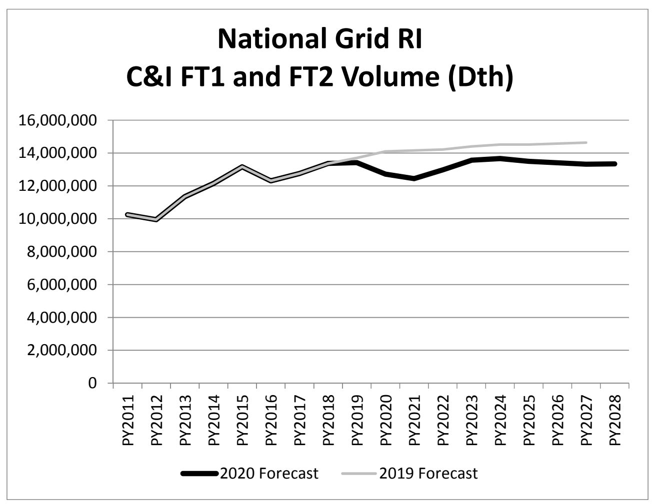
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,785,948	7,680,544	2,569,158	35,380,289	2,205,459	37,585,748
PY2012	601,399	14,783,757	5,641,385	7,610,425	2,334,007	30,970,973	2,175,385	33,146,358
PY2013	746,890	17,315,788	6,597,004	8,278,483	3,062,257	36,000,422	1,985,726	37,986,148
PY2014	944,174	19,573,872	7,624,248	8,563,673	3,585,382	40,291,350	1,734,538	42,025,888
PY2015	736,952	20,389,772	7,897,957	9,416,525	3,745,573	42,186,778	1,736,206	43,922,984
PY2016	551,336	16,675,346	5,978,805	8,656,943	3,646,308	35,508,738	1,769,137	37,277,875
PY2017	395,746	18,594,052	6,371,076	8,698,747	4,058,521	38,118,143	1,727,212	39,845,355
PY2018	375,420	19,942,385	7,039,693	9,022,578	4,335,718	40,715,795	1,782,779	42,498,574
PY2019	371,670	19,674,485	7,043,065	9,100,758	4,596,876	40,786,854	1,855,857	42,642,712
PY2020	359,772	19,941,015	7,256,274	9,391,677	4,704,300	41,653,037	1,889,959	43,542,996
PY2021	354,474	20,078,627	7,328,416	9,450,501	4,704,220	41,916,238	1,891,966	43,808,204
PY2022	350,941	20,337,068	7,367,641	9,495,708	4,719,281	42,270,639	1,898,378	44,169,017
PY2023	347,655	20,593,684	7,389,007	9,663,594	4,729,763	42,723,702	1,905,470	44,629,172
PY2024	345,785	20,992,308	7,516,469	9,758,175	4,755,377	43,368,114	1,914,636	45,282,750
PY2025	340,294	21,113,260	7,548,063	9,763,110	4,754,715	43,519,441	1,918,349	45,437,790
PY2026	335,883	21,368,315	7,599,371	9,791,351	4,780,638	43,875,558	1,926,862	45,802,420
PY2027	331,273	21,621,960	7,654,444	9,822,601	4,809,220	44,239,498	1,935,888	46,175,385
PY2028	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY25/PY20	-1.1%	1.1%	0.8%	0.8%	0.2%	0.9%	0.3%	0.9%

Chart III-B-1
Page 2 of 2









Attachment TEP-2

Attachment TEP-2

National Grid RI Retail Meter Count Forecast
2020 vs. 2019 Forecast

2020 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

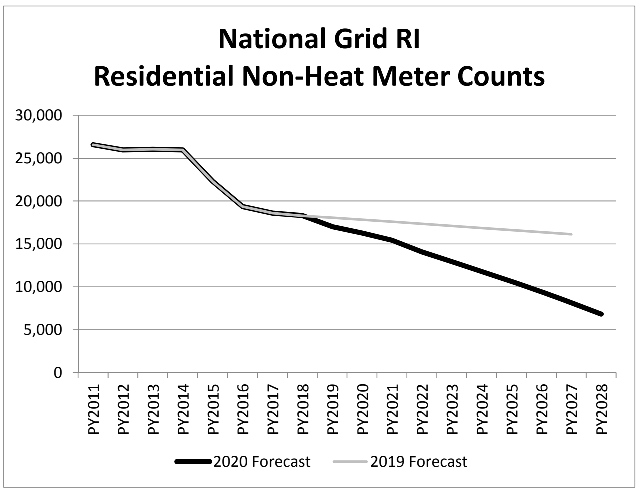
Chart III-B-2
Page 1 of 2

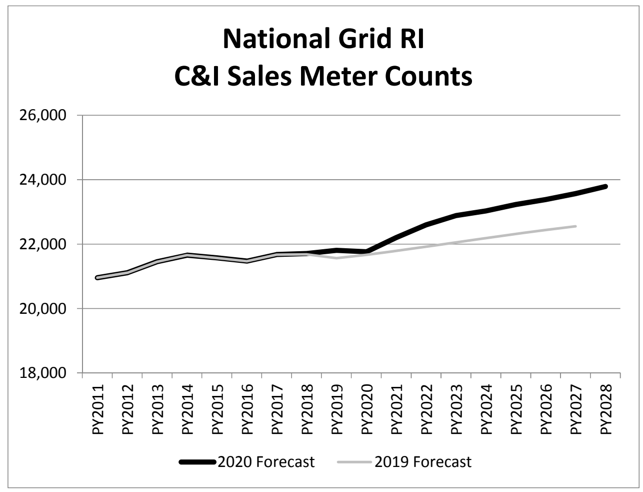
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,954	747	1,244	*245,929*	50	*245,979*
PY2012	25,955	200,463	21,108	734	1,412	*249,672*	49	*249,721*
PY2013	26,042	204,521	21,453	721	1,613	*254,350*	43	*254,393*
PY2014	25,958	206,568	21,655	699	1,621	*256,501*	39	*256,540*
PY2015	22,313	212,900	21,570	684	1,840	*259,307*	35	*259,342*
PY2016	19,351	218,313	21,470	674	2,131	*261,939*	34	*261,973*
PY2017	18,590	222,122	21,675	636	2,297	*265,320*	35	*265,355*
PY2018	18,304	225,228	21,705	624	2,375	*268,236*	35	*268,271*
PY2019	17,012	228,896	21,807	609	2,666	*270,990*	35	*271,025*
PY2020	16,272	227,624	21,761	588	2,669	*268,914*	34	*268,948*
PY2021	15,436	231,871	22,205	603	2,723	*272,838*	35	*272,873*
PY2022	14,078	239,512	22,595	616	2,775	*279,576*	35	*279,611*
PY2023	12,912	244,122	22,884	629	2,813	*283,360*	35	*283,395*
PY2024	11,787	245,713	23,027	636	2,831	*283,994*	35	*284,029*
PY2025	10,613	247,442	23,226	641	2,853	*284,775*	35	*284,810*
PY2026	9,396	249,132	23,382	643	2,873	*285,426*	35	*285,461*
PY2027	8,125	250,853	23,568	649	2,896	*286,091*	36	*286,127*
PY2028	6,820	252,737	23,789	655	2,922	*286,923*	36	*286,959*
PY25/PY20	-8.2%	1.7%	1.3%	1.7%	1.3%	1.2%	0.6%	1.2%

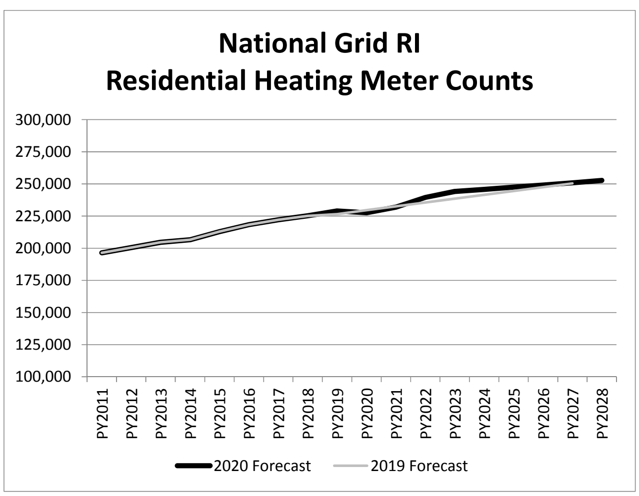
2019 National Grid RI Meter Count Forecast
End of Planning Year (Nov-Oct)

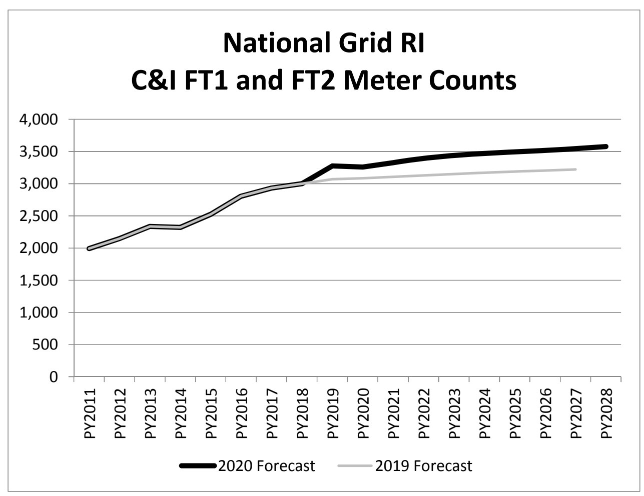
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,954	747	1,244	245,929	50	245,979
PY2012	25,955	200,463	21,108	734	1,412	249,672	49	249,721
PY2013	26,042	204,520	21,453	721	1,613	254,349	43	254,392
PY2014	25,958	206,567	21,654	699	1,621	256,499	39	256,538
PY2015	22,313	212,899	21,568	684	1,840	259,304	35	259,339
PY2016	19,351	218,312	21,468	674	2,131	261,936	34	261,970
PY2017	18,589	222,114	21,669	636	2,297	265,305	35	265,340
PY2018	18,280	225,136	21,679	624	2,375	268,094	35	268,129
PY2019	18,059	226,499	21,559	601	2,467	269,185	35	269,220
PY2020	17,816	229,543	21,666	606	2,479	272,110	35	272,145
PY2021	17,574	232,610	21,784	613	2,493	275,074	35	275,109
PY2022	17,332	235,549	21,921	619	2,510	277,931	35	277,966
PY2023	17,090	238,549	22,053	624	2,525	280,841	35	280,876
PY2024	16,847	241,525	22,185	630	2,540	283,727	35	283,762
PY2025	16,605	244,499	22,314	633	2,555	286,606	35	286,641
PY2026	16,363	247,462	22,434	635	2,568	289,462	36	289,498
PY2027	16,120	250,404	22,550	639	2,583	292,296	36	292,332
PY2028	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY25/PY20	-1.4%	1.3%	0.6%	0.9%	0.6%	1.0%	0.0%	1.0%

Chart III-B-2
Page 2 of 2









Attachment TEP-3

Attachment TEP-3

National Grid RI Economic Forecast
2020 vs. 2019 Forecast

2020 National Grid RI Economic Data — Chart III-B-3
(Prices in 2019 $/Dth) — Page 1 of 3

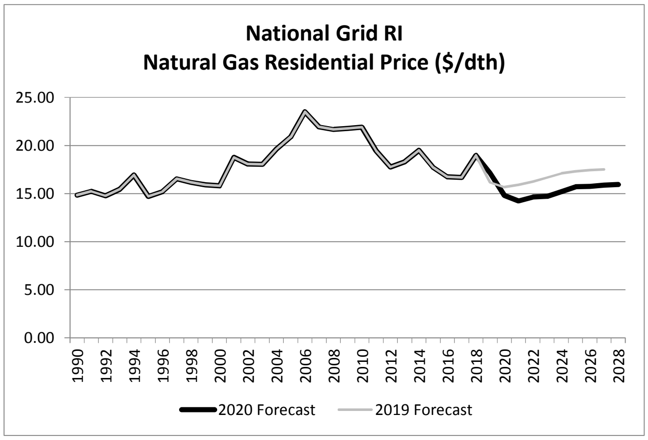
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR* *Residential Gas-to-Oil Price Ratio*	GDP GDP (2009 Millions of $)	HH Households (thousands)	EMPL Non-Farm Employment (thousands)
1990	*14.81*	*15.15*	*0.98*	36839.585	377.373	454.190
1991	*15.24*	*13.26*	*1.15*	*35539.133*	380.882	424.258
1992	*14.75*	*12.22*	*1.21*	*36224.632*	383.671	424.072
1993	*15.45*	*11.50*	*1.34*	*36889.078*	387.338	429.968
1994	*16.92*	*10.89*	*1.55*	*36979.512*	391.370	434.163
1995	*14.71*	*10.67*	*1.38*	*37653.857*	395.089	439.036
1996	*15.19*	*11.63*	*1.31*	*38064.341*	400.857	440.670
1997	*16.52*	*11.37*	*1.45*	*40153.328*	405.470	449.901
1998	*16.17*	*9.83*	*1.64*	*41786.083*	410.969	457.987
1999	*15.90*	*9.60*	*1.66*	*43171.471*	411.177	465.502
2000	*15.79*	*13.48*	*1.17*	*45244.521*	410.049	476.758
2001	*18.75*	*12.92*	*1.45*	*45915.757*	407.463	478.395
2002	*18.07*	*11.61*	*1.56*	*47607.003*	410.076	479.285
2003	*18.02*	*13.24*	*1.36*	*49369.717*	410.587	484.105
2004	*19.62*	*15.07*	*1.30*	*51581.537*	412.092	488.396
2005	*20.90*	*19.88*	*1.05*	*52314.301*	411.401	491.003
2006	*23.50*	*22.31*	*1.05*	*53517.296*	411.374	492.856
2007	*21.93*	*23.61*	*0.93*	*52092.223*	411.527	491.890
2008	*21.64*	*30.26*	*0.72*	*50448.408*	414.262	480.982
2009	*21.76*	*20.81*	*1.05*	*50211.828*	414.154	459.350
2010	*21.87*	*24.89*	*0.88*	*51465.706*	414.552	457.965
2011	*19.46*	*31.28*	*0.62*	*51269.958*	417.269	460.528
2012	*17.75*	*32.97*	*0.54*	*51641.120*	421.180	465.451
2013	*18.29*	*32.01*	*0.57*	*52084.527*	424.916	471.478
2014	*19.50*	*30.12*	*0.65*	*52133.133*	427.766	478.584
2015	*17.74*	*20.96*	*0.85*	*53094.754*	427.825	485.055
2016	*16.73*	*17.50*	*0.96*	*53091.108*	427.465	489.745
2017	*16.65*	*19.09*	*0.87*	*52989.040*	425.787	493.379
2018	*18.97*	*22.29*	*0.85*	*53622.309*	425.721	496.221
2019	*17.14*	*20.69*	*0.83*	*54463.679*	428.982	501.399
2020	*14.79*	*16.50*	*0.90*	*53470.277*	431.492	495.047
2021	*14.23*	*16.83*	*0.85*	*54932.845*	431.689	496.341
2022	*14.64*	*17.39*	*0.84*	*57587.703*	433.502	505.719
2023	*14.71*	*17.78*	*0.83*	*59639.574*	435.804	513.017
2024	*15.18*	*18.36*	*0.83*	*61109.377*	438.017	515.315
2025	*15.68*	*18.75*	*0.84*	*62449.158*	440.037	516.838
2026	*15.74*	*19.06*	*0.83*	*63819.540*	441.906	518.501
2027	*15.86*	*19.12*	*0.83*	*65280.292*	443.492	520.200
2028	*15.92*	*19.39*	*0.82*	*66808.987*	444.888	522.132
PY25/PY20	1.2%	2.6%	-1.4%	3.2%	0.4%	0.9%

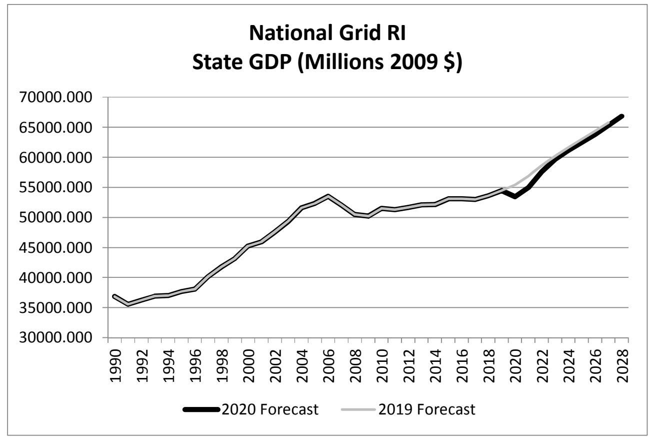
2019 National Grid RI Economic Data
(Prices in 2018 $/Dth)

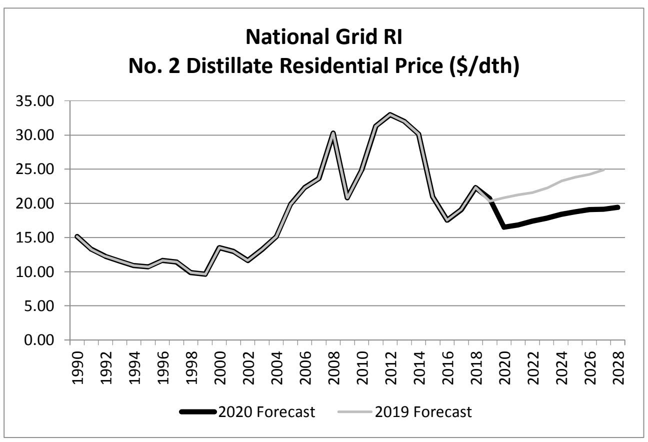
Chart III-B-3
Page 2 of 3

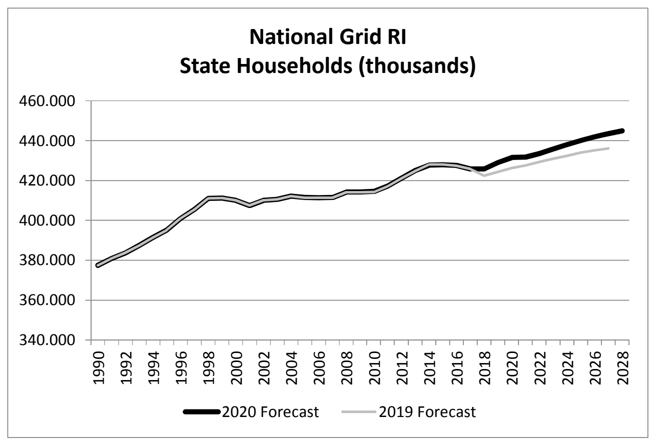
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	GORR Residential Gas-to-Oil Price Ratio	GDP GDP (2009 Millions of $)	HH Households (thousands)	EMPL Non-Farm Employment (thousands)
1990	*14.81*	*15.15*	*0.98*	*36839.59*	377.38	*454.19*
1991	*15.24*	*13.26*	*1.15*	*35539.13*	380.90	*424.26*
1992	*14.75*	*12.22*	*1.21*	*36224.63*	383.70	*424.07*
1993	*15.45*	*11.50*	*1.34*	*36889.08*	387.38	*429.97*
1994	*16.92*	*10.89*	*1.55*	*36979.51*	391.40	*434.16*
1995	*14.71*	*10.67*	*1.38*	*37653.86*	395.11	*439.04*
1996	*15.19*	*11.63*	*1.31*	*38064.34*	400.85	*440.67*
1997	*16.52*	*11.37*	*1.45*	*40153.33*	405.50	*449.90*
1998	*16.17*	*9.83*	*1.64*	*41786.08*	410.96	*457.99*
1999	*15.90*	*9.60*	*1.66*	*43171.47*	411.19	*465.50*
2000	*15.79*	*13.48*	*1.17*	*45244.52*	410.05	*476.76*
2001	*18.75*	*12.92*	*1.45*	*45915.76*	407.45	*478.39*
2002	*18.07*	*11.61*	*1.56*	*47607.00*	410.06	*479.28*
2003	*18.02*	*13.24*	*1.36*	*49369.72*	410.57	*484.10*
2004	*19.62*	*15.07*	*1.30*	*51581.54*	412.05	*488.40*
2005	*20.90*	*19.88*	*1.05*	*52314.30*	411.33	*491.00*
2006	*23.50*	*22.31*	*1.05*	*53517.30*	411.26	*492.86*
2007	*21.93*	*23.61*	*0.93*	*52092.22*	411.35	*491.89*
2008	*21.64*	*30.26*	*0.72*	*50448.41*	414.02	*480.98*
2009	*21.76*	*20.81*	*1.05*	*50211.83*	413.98	*459.35*
2010	*21.87*	*24.89*	*0.88*	*51465.71*	414.27	*457.96*
2011	*19.46*	*31.28*	*0.62*	*51269.96*	417.09	*460.53*
2012	*17.75*	*32.97*	*0.54*	*51641.12*	421.16	*465.45*
2013	*18.29*	*32.01*	*0.57*	*52084.53*	424.75	*471.48*
2014	*19.50*	*30.12*	*0.65*	*52133.13*	427.95	*478.58*
2015	*17.74*	*20.96*	*0.85*	*53094.75*	428.07	*485.05*
2016	*16.73*	*17.50*	*0.96*	*53091.11*	427.38	*489.74*
2017	*16.65*	*19.09*	*0.87*	*52989.04*	425.78	*493.38*
2018	*18.97*	*22.29*	*0.85*	*53622.31*	422.40	*496.22*
2019	16.17	20.28	0.80	54456.38	424.34	507.42
2020	15.66	20.82	0.75	55401.13	426.19	509.79
2021	15.90	21.24	0.75	56891.47	427.52	509.24
2022	16.23	21.56	0.75	58647.13	429.32	512.49
2023	16.65	22.20	0.75	60157.76	430.93	515.23
2024	17.11	23.23	0.74	61647.14	432.41	517.54
2025	17.29	23.81	0.73	63012.85	433.87	519.69
2026	17.42	24.21	0.72	64358.10	435.12	521.78
2027	17.50	24.86	0.70	65762.27	436.11	523.85
2028	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY25/PY20	2.0%	2.7%	-0.7%	2.6%	0.4%	0.4%

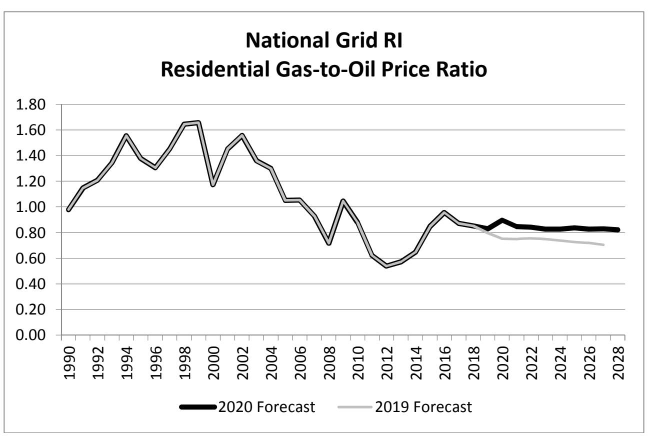
Chart III-B-3
Page 3 of 3

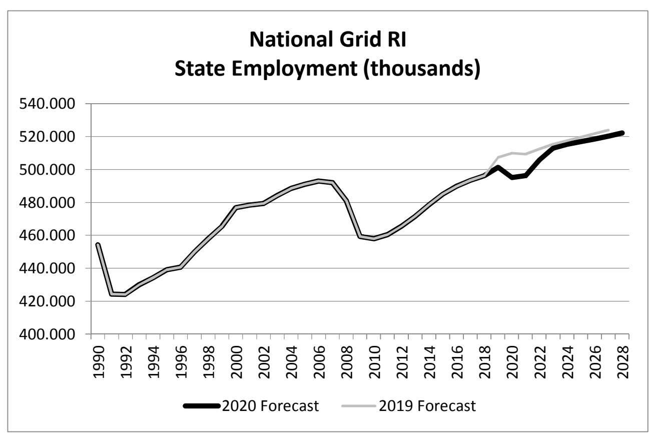












Attachment TEP-4

Chart III-B-4
Page 1 of 3

National Grid
2020 and 2019 Volume Forecasts by Rate Class
(Therms; Planning Year)

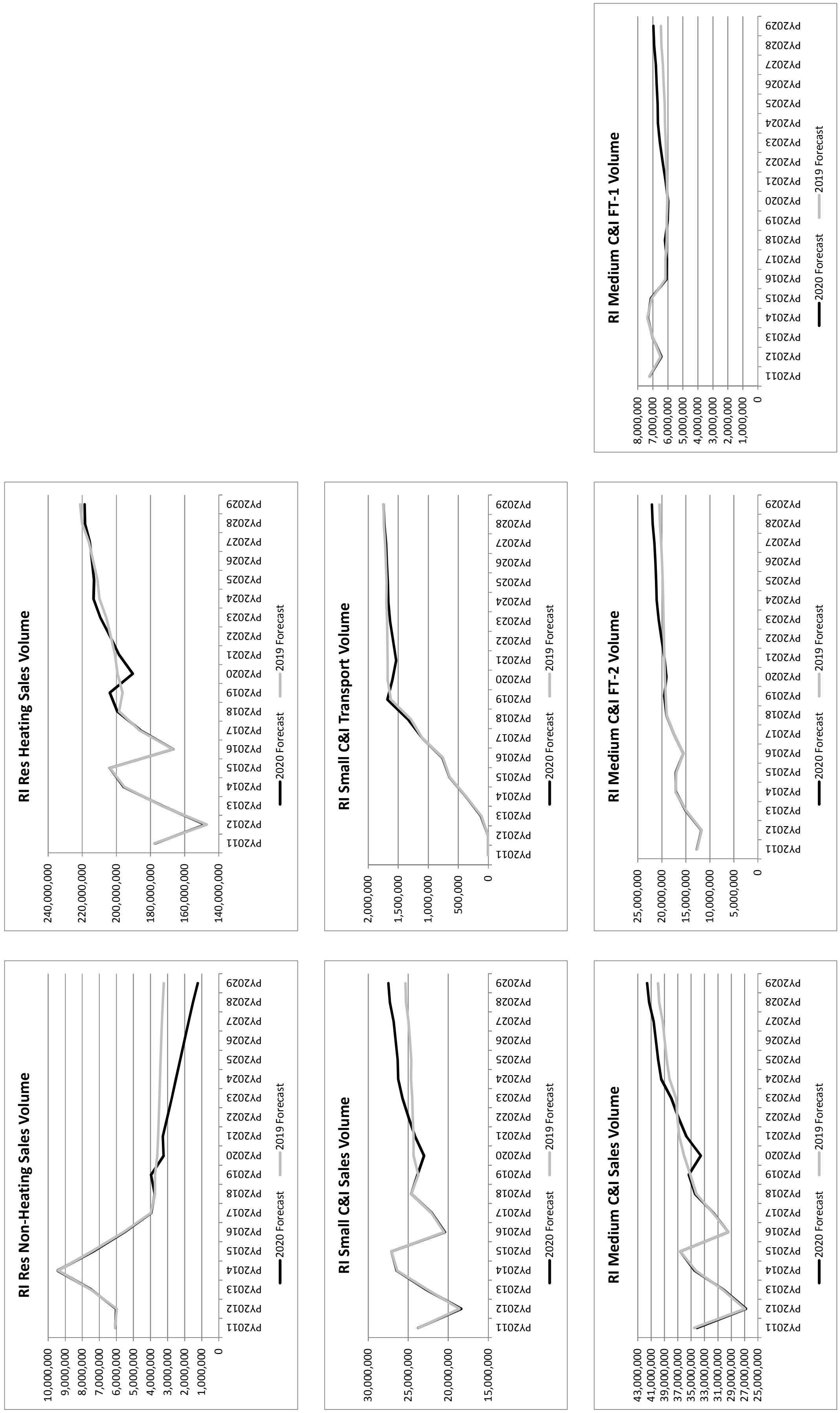
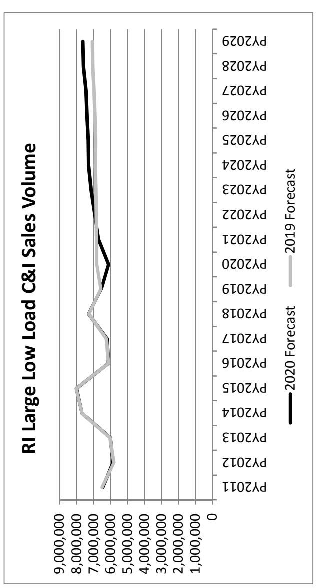
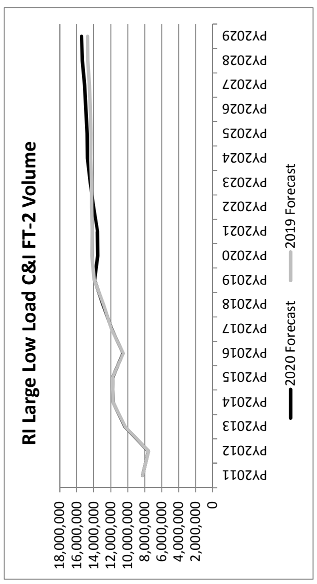
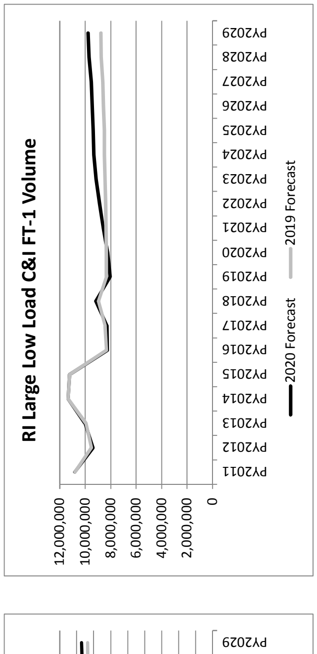


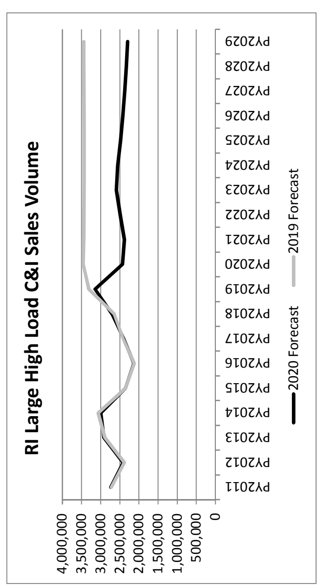
Chart III-B-4
Page 2 of 3

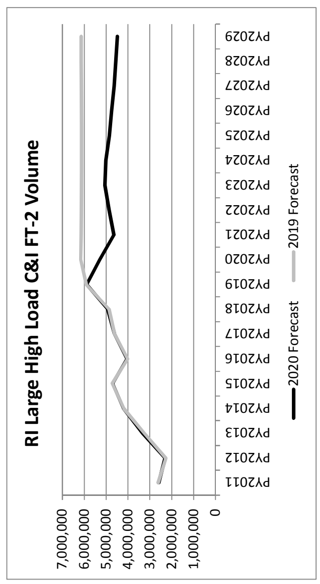
National Grid
2020 and 2019 Volume Forecasts by Rate Class
(Therms; Planning Year)

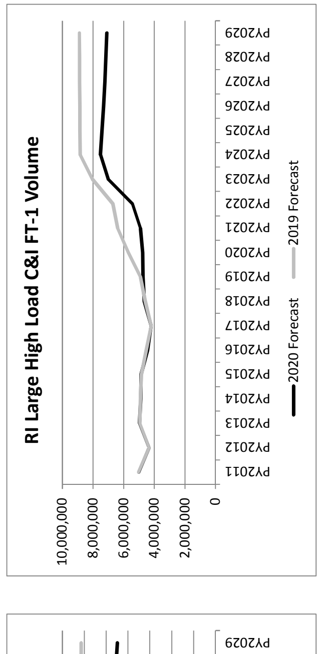


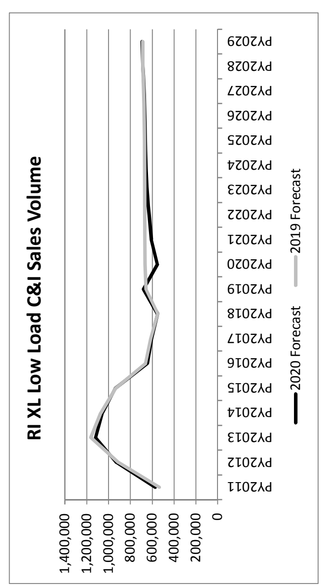


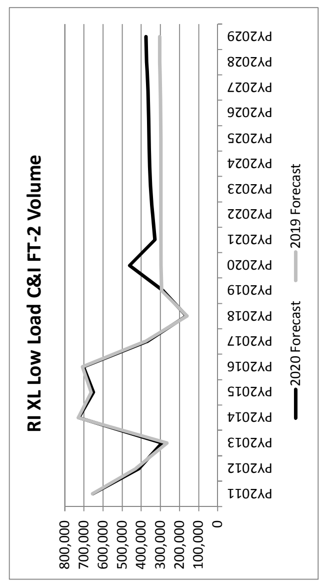


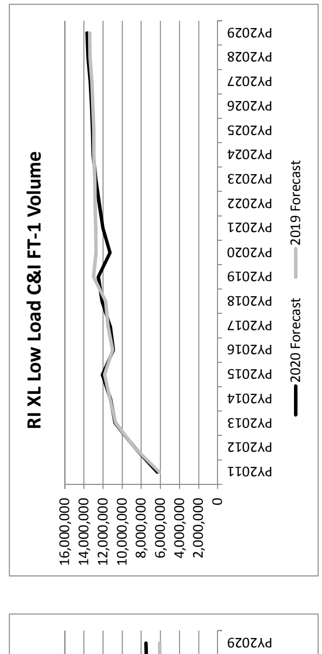




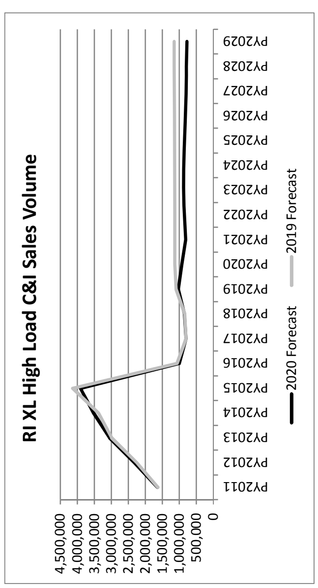


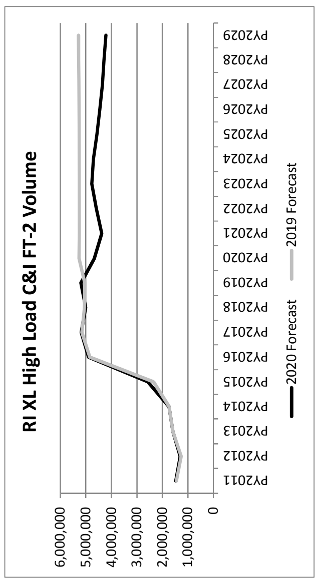


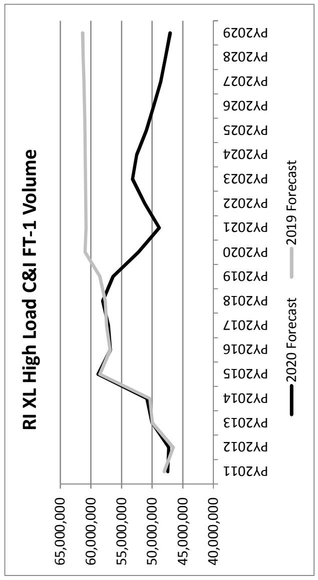


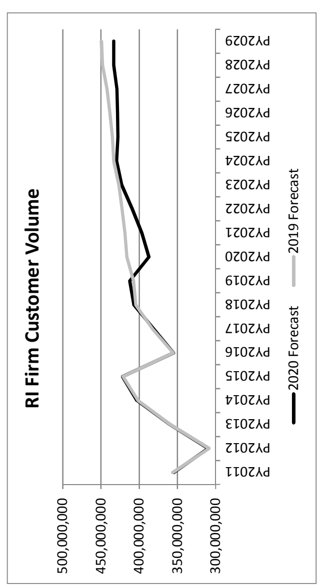


National Grid
2020 and 2019 Volume Forecasts by Rate Class
(Therms; Planning Year)





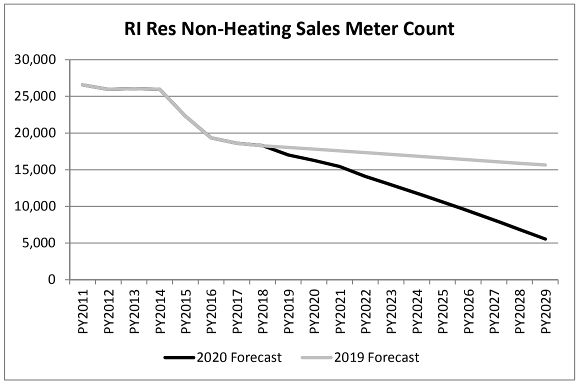


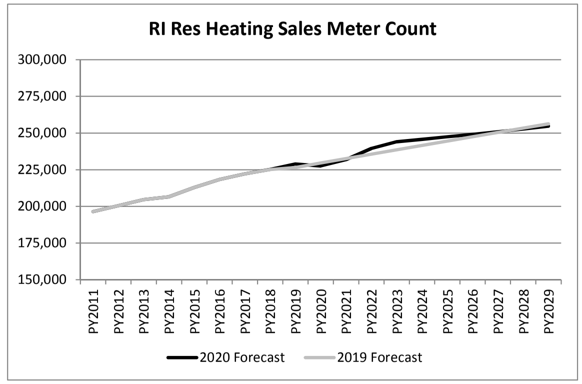


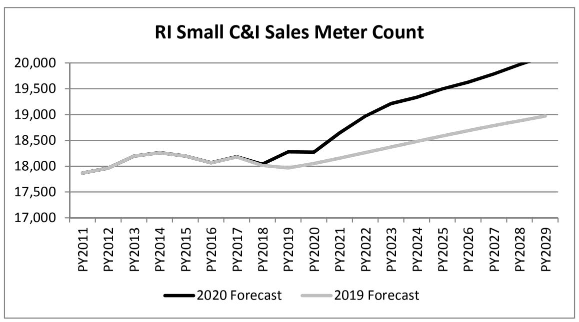
<u>Attachment TEP-5</u>

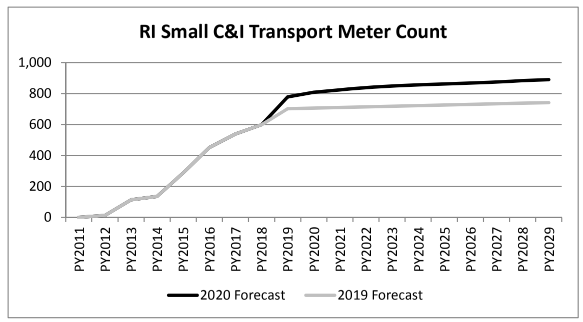
National Grid RI Retail Meter Count Forecast by Rate Class
2020 vs. 2019 Forecast

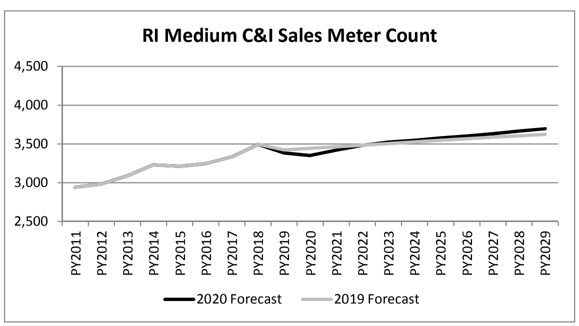
National Grid
2020 and 2019 Meter Count Forecasts by Rate Class
(end of Planning Year)

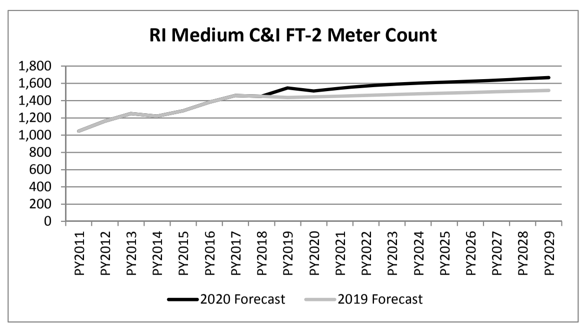


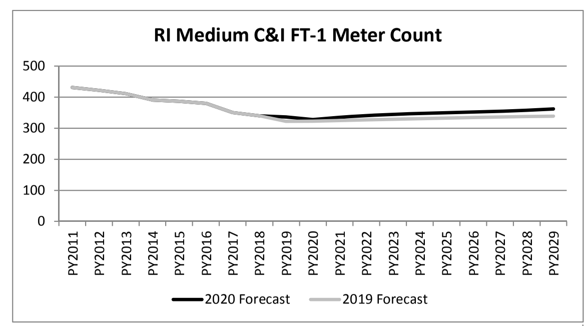




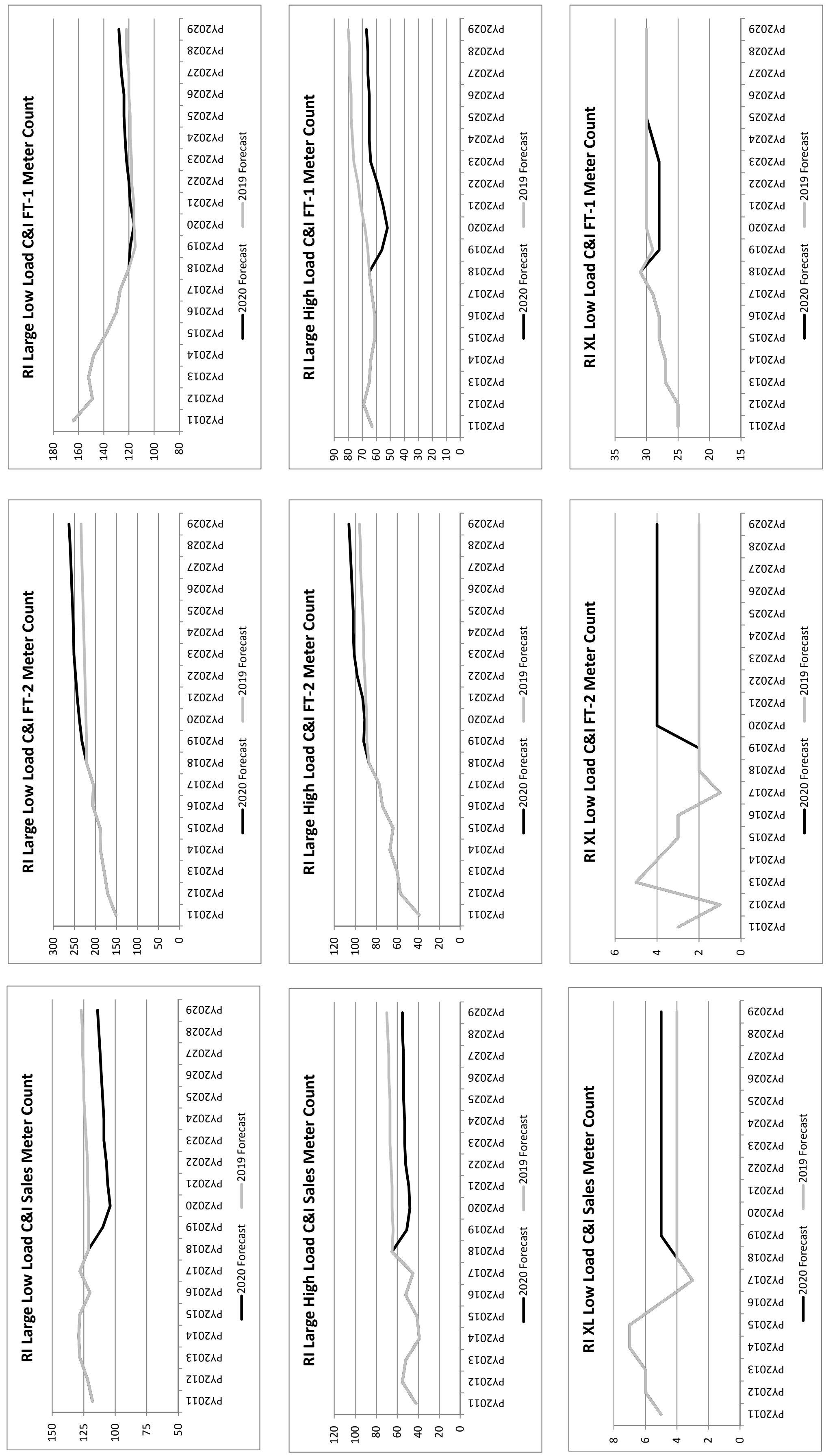








National Grid
2020 and 2019 Meter Count Forecasts by Rate Class
(end of Planning Year)



National Grid
2020 and 2019 Meter Count Forecasts by Rate Class
(end of Planning Year)