The Narragansett Electric Company
d/b/a Rhode Island Energy

2022 GAS COST RECOVERY

Testimony and Attachments of:
Gas Supply Panel,
Paul J. Hibbard,
Peter R. Blazunas, and
Gas Load Forecasting

REDACTED

September 1, 2022

Submitted to:
Rhode Island Public Utilities Commission
RIPUC Docket No. 22-20-NG

Submitted by:

Rhode Island Energy™
a PPL company

Filing Letter
& Motion

Robinson+Cole

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September 1, 2022

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888 508

RE: Docket 22-20-NG – 2022 Gas Cost Recovery Filing

Dear Ms. Massaro:

Attached you will find an electronic version of Rhode Island Energy's[1] annual Gas Cost Recovery ("GCR") filing, which the Company is submitting pursuant to the Gas Cost Recovery Clause in Rhode Island Energy's gas tariff, RIPUC NG-GAS No. 101, Section 2, Schedule A. The GCR filing reflects the customer class-specific factors necessary for Rhode Island Energy to collect sufficient revenues to recover projected gas costs for the period November 1, 2022 through October 31, 2023.

This filing includes the pre-filed testimony and attachments of the following witnesses: Elizabeth D. Arangio, Samara A. Jaffe and James M. Stephens (Gas Supply Panel); Paul J. Hibbard; Peter R. Blazunas; Theodore E. Poe, Jr., and Shira Horowitz; and John M. Protano and Stephen D. Longo (Energy Portfolio Management Panel). The Gas Supply Panel testimony provides support for the estimated gas costs and items relating to the Company's proposed 2022-23 GCR factors. In addition, the Gas Supply Panel testimony describes modifications that the Company has made to its portfolio for the 2022-23 GCR period.

Mr. Hibbard's testimony offers an analysis of current natural gas and liquefied natural gas market conditions that have affected supply costs for the GCR year commencing November 1, 2022.

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[1] The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company").

In his testimony, Mr. Blazunas calculates the GCR factors proposed for effect on November 1, 2022 for the following services: (1) firm sales service to customers in the Residential Non-Heating and Heating rate classes and firm sales customers in the Small, Medium, Large, and Extra-Large Commercial and Industrial ("C&I") rate classes; and (2) transportation services provided to Gas Marketers and the associated Gas Marketer Fixed Charges and factors.

In their testimony, Mr. Poe and Ms. Horowitz provide support for 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.

Finally, in their testimony, Messrs. Protano and Longo describe the results of the Gas Procurement Incentive Plan ("GPIP") and the Natural Gas Portfolio Management Plan ("NGPMP") for the period April 1, 2021 through March 31, 2022. They also provides an exhibit that illustrates the impact of current financial hedges for the upcoming period of November 2022 through October 2023 in the GPIP.

As described in Mr. Blazunas's testimony, based on the GCR factors proposed for effect November 1, 2022 through October 31, 2023, an average residential heating customer using 845 therms per year will see a total annual bill of $1,741.91 based on the proposed GCR and DAC factors, which is an increase of $227.23, or 15.0 percent, from bills based on current rates. This overall increase is comprised of an increase of $73.70 as a result of the proposed GCR factors; an increase of $146.71 as a result of the proposed DAC factors as revised in a supplemental filing on September 1, 2021 in Docket No. 22-13-NG; and an increase of $6.82 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). Rhode Island Energy seeks protection from public disclosure certain confidential gas-cost pricing information and commercial contract terms which are provided in Attachment GSP-1 to the pre-filed joint direct testimony of the Gas Supply Panel and Attachments PRB-1, PRB-2 and PRB-5 to the pre-filed direct testimony of Mr. Blazunas. Attachment EPM-4, the Company's annual NGPMP Report, also contains confidential information. It is the subject of a previously filed motion for protective treatment dated June 2, 2022.

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Accordingly, Rhode Island Energy has provided the PUC with two complete unredacted copies 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 401-709-3359.

Very truly yours,

Steven J. Boyajian

Enclosures

cc: Docket No. 22-20-NG Service List
Leo Wold, Esq.
John Bell, Division
Al Mancini, Division (w/confidential Excel Files)
Jerome D. Mierzwa, Division Consultant (w/confidential Excel Files)

STATE OF RHODE ISLAND

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Annual Gas Cost Recovery Filing 2022	)	Docket No. 22-20-NG

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

Rhode Island Energy[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, 2022, the Company submitted its 2022 Annual Gas Cost Recovery (GCR) filing in the above-captioned docket. The GCR filing includes confidential gas cost pricing information, contract terms and counter-party identities which are provided in (1) Attachment GSP-1 to the pre-filed joint direct testimony of the Elizabeth D. Arangio and Samara A. Jaffe, referred to as the Gas Supply Panel; (2) Attachments PRB-1, PRB -2, and PRB -5 to the pre-filed direct testimony of Peter R. Blazunas; and (3) Attachment EPM-4 to the pre-filed direct

[1] The Narragansett Electric Company d/b/a Rhode Island Energy (Rhode Island Energy or the Company).

testimony of John M. Protano and Stephen D. Longo, referred to as the Energy Portfolio Management Panel.[2] In accordance with Rule 1.3(H)(3), Rhode Island Energy 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, contract terms and counter-party identities contained in the following: (1) Attachment GSP-1 to the prefiled joint direct testimony of the Gas Supply Panel; and (2) Attachments PRB-1, PRB-2, and PRB-5 to the prefiled joint direct testimony of Mr. Blazunas.

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.

[2] Attachment EPM-4 consists of the Company's Natural Gas Portfolio Management Plan report for the period from April 1, 2020, to March 31, 2021. This report was filed with the PUC on June 2, 2022, subject to a separate motion for protective treatment.

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, confidential contract terms and counter-party identities– which are provided in Attachment GSP-1 to the Gas Supply Panel testimony, and Attachments PRB-1, PRB-2, and PRB-5 to the pre-filed direct testimony of Mr. Blazunas – are confidential and privileged information of the type that Rhode Island Energy would not ordinarily make public. As such, the information should be protected from public disclosure. Public disclosure of such information could impair Rhode Island Energy's ability to obtain advantageous pricing or other terms in the future, thereby causing substantial competitive harm. Accordingly, Rhode Island Energy 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, Rhode Island Energy respectfully requests that the PUC grant its Motion for Protective Treatment of Confidential Information.

[SIGNATURES ON NEXT PAGE]

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY d/b/a RHODE ISLAND ENERGY

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Dated: September 1, 2022

Certificate of Service

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

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

____
Joanne M. Scanlon

September 1, 2022
Date

Docket No. 22-20-NG – The Narragansett Electric Co. d/b/a Rhode Island Energy – 2022 Annual Gas Cost Recovery Filing (GCR)
Service List as of 8/16/22

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Testimony of
Gas Supply Panel

JOINT DIRECT TESTIMONY

OF

GAS SUPPLY PANEL

Table of Contents

I. Introduction

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

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

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. ("National Grid Service Company"). In this position, I am responsible for gas supply planning for the resource portfolios for National Grid USA ("National Grid"). I am also responsible for National Grid's gas Customer Choice programs. I offer this testimony on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") pursuant to the Transition Services Agreement by and among National Grid Service Company, National Grid (solely with respect to Section 4.6) and the Company ("TSA").

Q. Please describe your involvement with the Company.

A. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL Corporation, acquired 100% of the outstanding shares of common stock of the Company from National Grid (the "Acquisition"). Following the Acquisition, I have continued to fulfill my former job responsibilities for the Company pursuant to the TSA. I will continue to oversee these functions on behalf of Rhode Island Energy for the duration of the TSA.

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 Master 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 2021 Gas Cost Recovery ("GCR") filing in Docket No. 5180. 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.

Samara A. Jaffe

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 Director of Gas Contracting, Compliance and Hedging for National Grid Service Company. 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 and New York and oversight of the Company's Hedging program.

Q. Please describe your involvement with the Company.

A. Prior to the Acquisition, I managed the Company's acquisition of long-term gas supply and pipeline capacity, gas contract management and interventions and compliance with FERC regulations, as well as oversight of the Company's hedging program. For the duration of the TSA, I will continue to advise the Company on matters related to acquisition of long-term gas supply and pipeline capacity, gas contract management, provide input in federal regulatory proceedings to develop Company positions for its interstate pipeline service portfolio, as well as oversee the hedging program on behalf of Rhode Island Energy. In this proceeding, I am offering testimony on behalf of the Company pursuant to the TSA.

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 the role of Program Manager for my group and was promoted to Director in April of 2021.

Q. Have you previously testified in regulatory proceedings?

A. Yes. I most recently testified before the PUC in support of the Company's 2021 GCR filing in Docket No. 5180. I have also testified numerous times before the Massachusetts Department of Public Utilities on behalf of Boston Gas.

<u>James M. Stephens</u>

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

A. My name is James M. Stephens. My business address is Rhode Island Energy, 280 Melrose Street, Providence, Rhode Island 02907.

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

A. I am employed by PPL Services Corporation, and I serve as the Director of Gas Procurement for Rhode Island Energy. In this position, I am responsible for leading the planning, contracting, and procurement of natural gas commodity, pipeline and storage capacity, and peaking resources to meet the short- and long-term requirements of the RIE gas customers. I am also responsible for Rhode Island Energy's Customer Choice program. My testimony in this docket relates to the question of whether the Act on Climate has impacted the Company's gas procurement plans in the coming year.

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

A. I hold a Bachelor of Science degree in Management and a Master of Business Administration with a concentration in Operations Management from Bentley College. I have over 30 years of experience in the energy industry and have held management positions at consulting firms and natural gas local distribution companies. In my role as a consultant, I have assisted numerous clients with various natural gas related engagements, including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure; the evaluation of capacity opportunities associated with open seasons on various pipelines; the evaluation of new markets/opportunities; integrated resource plans; and natural gas supply portfolio evaluation and optimization. I was also responsible for Gas Supply Procurement and Portfolio Optimization for Colonial Gas Company, which is now a subsidiary of National Grid.

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, Northeast Energy and Commerce Association, and the Guild of Gas Managers.

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

A. Yes. While I have not testified before the Rhode Island PUC, I have submitted testimony in several other regulatory jurisdictions, including the Federal Energy Regulatory Commission, the states of Alaska, Maine, Massachusetts, and New Hampshire, and the Canadian provinces of Alberta, New Brunswick, Nova Scotia, Ontario, and Québec.

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

A. Our testimony provides support for the estimated gas costs, and items relating to the Company's proposed 2022-23 GCR factors. In addition, our testimony discusses modifications that the Company has made to its portfolio for the 2022-23 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 – **CONFIDENTIAL Information**
Attachment GSP-2	NYMEX Strip Comparison & Forward Curves
Attachment GSP-3	Rule Curves
Attachment GSP-4	RFP for AMA Dawn Waddington to Zone 6
Attachment GSP-5	RFPs for AMA Portland Express ("PXP")
Attachment GSP-6	RFP for AMA Columbia Gas Transmission ("TCo")
Attachment GSP-7	RFP for AMA Millennium Pipeline to Ramapo
Attachment GSP-8	RFP for AMA Dracut to Citygate
Attachment GSP-9	RFP for Everett and Beverly Supply

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 5, 2022. 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 5, 2022, 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, 2022, and the projected cost of purchasing gas through the remainder of the underground and LNG injection season. Attachment GSP-1 page 1 of 17 provides a summary of gas costs by major cost categories; pages 2 of 17 through 13 of 17 show 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 compares NYMEX pricing from August 3, 2021 utilized in last year's GCR filing to NYMEX pricing from August 5, 2022 used in this current filing. On average, the August 5, 2022 NYMEX strip is $3.686, or 89.3 percent, higher compared to the August 3, 2021 NYMEX strip during the peak season of November through March. During the off-peak season of April through October, the August 5, 2022 NYMEX strip is on average $1.576, or 47.8 percent, higher compared to the August 3, 2021 NYMEX strip. Overall, the August 5, 2022 NYMEX strip is an average of $2.455, or 67.4 percent, higher compared to the August 3, 2021 NYMEX strip.

Q. What normal heating season and normal year load is the Company planning for in 2022-23 as compared to last year's volumes?

A. A comparison of the normal heating season and normal year load forecasts for 2021-22 and 2022-23 is provided in the table below.

2021/2022 and 2022/2023 Normal Forecast Comparison

Normal Heating Season (November - March)	2021/22 Forecast	2022/23 Forecast	Delta	Delta %
Total Normal Heating Season (Sales + Transportation)	26,011,254	26,727,067	715,813	2.8%
Normal Heating Season - Sales	21,409,531	20,897,020	(512,511)	-2.4%
Normal Heating Season - Transportation	4,601,723	5,830,047	1,228,324	26.7%

Normal Year	2021/22 Forecast	2022/23 Forecast	Delta	Delta %
Total Normal Year (Sales + Transportation)	36,469,985	37,588,446	1,118,462	3.1%
Normal Year - Sales	29,229,975	28,495,515	(734,460)	-2.5%
Normal Year - Transportation	7,240,009	9,092,931	1,852,922	25.6%

The forecast filed in Docket No. 5180 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 2022-23 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 2021-22 and 2022-23 is provided in the table below.

2021/2022 and 2022/2023 Design Forecast Comparison

Design Day	2021/22 Forecast	2022/23 Forecast	Delta	Delta %
Total Design Day (Sales + Transportation)	393,077	393,652	576	0.1%
Design Day - Sales	334,030	320,655	(13,375)	-4.0%
Design Day - Transportation	59,046	72,997	13,951	23.6%

Design Heating Season (November - March)	2021/22 Forecast	2022/23 Forecast	Delta	Delta %
Total Design Heating Season (Sales + Transportation)	30,148,659	30,823,148	674,489	2.2%
Design Heating Season - Sales	24,949,968	24,253,952	(696,015)	-2.8%
Design Heating Season - Transportation	5,198,691	6,569,195	1,370,504	26.4%

Design Year	2021/22 Forecast	2022/23 Forecast	Delta	Delta %
Total Design Year (Sales + Transportation)	41,406,253	42,518,678	1,112,425	2.7%
Design Year - Sales	33,417,434	32,497,604	(919,830)	-2.8%
Design Year - Transportation	7,988,819	10,021,075	2,032,256	25.4%

The forecast filed in Docket No. 5180 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 2022-23 winter season?

A. Yes. As part of its annual portfolio planning process, the Company reviewed a cold snap scenario and 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 2022/23 to 2026/27 dated June 30, 2022 (Docket No. 22-06-NG) (the "LRP").

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

A. Yes. The Company continues to plan for forecast peak hour requirements in addition to design day, design year and cold snap requirements.

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.

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

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

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, 2022. The pricing of gas supplies is based on the August 5, 2022 NYMEX forward curve and regional basis curves, also from August 5, 2022 as 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 2022 through October 2023 is shown in Attachment GSP-1 page 1 of 17.

Q. Please describe Attachment GSP-1, Pages 2 through 17.

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 2022 through October 2023;
    - Pages 2 through 4: show 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: show the forecasted volumes at the receipt or purchase point;
    - Pages 16 through 17: show the forecasted volumes at the point of delivery after all pipeline fuel is accounted for; and
    - 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. Please describe the Company's process for calculating fixed costs associated with peak hour requirements.

A. The Company has identified the various contracts needed to support peak hour demand that is in excess of peak day demand.[2] While all contracts are required to meet total peak hour demand, the fixed costs associated with the following assets have been specifically allocated to the peak hour: (1) portable LNG; (2) the Company's transportation contract on Tennessee for 25,000 Dth having receipts within the pipeline's Zone 6 market area; (3) citygate delivered arrangement on Algonquin; (4) LNG trucking; and (5) the Company's transportation contract on Algonquin with a receipt point of Beverly, MA for the Winter 22/23 season. The fixed costs of these assets will be incorporated into the System Pressure Factor calculations and will be charged to all customers through the Distribution Adjust Clause ("DAC"). The Company is filing its Supplemental DAC in Docket No. 22-13-NG concurrently with this filing, which includes the System Pressure Factor, as discussed further in the Direct Testimony of Company witness, Peter Blazunas.

Q. Please describe the Company's process for calculating variable costs associated with peak hour requirements.

[2] See R.I.P.U.C. Order No. 24275, Docket No. 5180 dated December 16, 2022, at ¶ 23. The Company has allocated the full volume of the Tennessee transportation capacity and associated supply to meet peak hour requirements.

A. As a result of discussions with the Division in 2020, the Company intends to include the 2022/23 incremental variable costs associated with the peak hour resources in the DAC reconciliation if these costs are significant. As was the case for 2021/22, the Company will track the volumes and variable costs of these resources when they are dispatched to meet the hourly requirements of the Company's customers and will work with the Division after the winter to determine whether they are significant enough to include in the DAC reconciliation. The Company is not proposing to include any variable costs associated with 2021/22 supplies in the 2021/22 DAC reconciliation as no supplies were dispatched to specifically meet peak hour requirements during the 2021/22 winter season.

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. 22-06-NG?

A. Total gas costs are $16 million lower 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	$35.1
b. Fixed Cost Credits	$31.1
c. Net Fixed Costs (a-b)	$4.00
d. Variable Costs	$(20.1)
e. NGPMP Credit	$0.00
f. Total Gas Costs (c+d-e)	$(16.1)

Q. Please summarize major drivers for the differences in costs between the 2022 LRP (Docket No. 22-06-NG) and this 2022 GCR.

A. Total gas costs decreased by $16.1 million between the 2022 LRP and this 2022 GCR filing.

1. **FIXED COSTS**: Fixed costs increased by $35.1 million. This increase is driven primarily by an increase in supplier demand charges which are discussed further below. This increase of $35.1 million is offset by an increased fixed cost credit of $31.1 million, resulting in a net fixed cost increase of $4 million.

2. **VARIABLE COSTS**: Total variable costs decreased by $20.1 million from the 2022 LRP to the 2022 GCR due primarily to a decrease in gas commodity costs. This is largely the result of a decrease in forward prices; the average November 2022 through March 2023 NYMEX forward curve decreased by $1.18 per dekatherm or 14% and by $1.02 per dekatherm or 13% over the full 2022/23 gas year.

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

A. In September 2021, each of Texas Eastern Transmission, LP ("TETCO") and Eastern Gas Transmission and Storage ("EGTS") filed for rate increases with the FERC. Filed for rate increases on each pipeline took effect as of February 1, 2022 and April 1, 2022 respectively, subject to refund based on the outcome of each proceeding and any settlement that may be reached with its customers. Since that time, each of TETCO and EGTS have been actively engaged in settlement discussions with intervening parties. As of the date the Company prepared this GCR,[3] settlement in principle between participants respect to various matters in each pending rate case has been reached in each case however the terms of such settlement have not been filed with the FERC for review and approval. The Company, therefore, utilized currently effective rates on each of TETCO and EGTS, which shall be subject to refund based on the final outcome of each case. In addition to filed rate cases with EGTS and TETCO, in July 2022, Iroquois Gas Transmission System, L.P. ("Iroquois") submitted to the FERC a pre-filed settlement to reduce Iroquois' rates under its tariff in three phases, to be effective September 1, 2022. The Company has reflected Iroquois' revised base rates in this GCR.

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,

[3] Rates used in preparation of the GCR were obtained from each of TETCO and EGTS's tariff sheets effective as of August 19, 2022.

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.

The Company also maintains a significant position back to Dawn, Ontario to serve as the upstream feed for a portion of its Tennessee capacity.

Q. What is the status of the NGLNG and Northeast Energy Center liquefaction projects?

A. For purposes of the GCR and as more fully set forth below, the Company currently anticipates both projects to be available for the 2023 refill. As each liquefaction project progresses through construction and commissioning activities in order to commence service, the Company will evaluate whether incremental LNG purchases for the 2023 refill will be required. The Company is providing the following updates on the status of liquefaction projects with both NGLNG and Northeast Energy Center based on recent updates provided by the project developers.

<u>NGLNG</u>

The Company previously entered into a precedent agreement for a term of 20 years for liquefaction services at NGLNG's 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. Based on the current timeline to construct and test the facilities, NGLNG recently requested of the FERC an extension of its certificate to allow for additional time to ensure that the facility's product is of acceptable quality to bring into the Company distribution system. NGLNG however continues to anticipate that the project could begin service during October of 2022, and the Company would be required to begin payment for such services once available. Due to the potential mid-month in service date, for the purposes of the GCR, the Company has not assumed it will be responsible for fixed costs until November 1, 2022. 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. Based on the current construction timeline, the facility is now expected to be in service during the 2023 refill season. For purposes of this filing, the Company has assumed it will be responsible for fixed costs beginning April, 2023. The Northeast Energy Project will interconnect with the Tennessee Gas 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.

Q. How will the Company supply the Dawn capacity path in Ontario, Canada to Tennessee Zone 6 via Iroquois for the 2022-23 year?

A. The Company issued an RFP for an Asset Management Arrangement ("AMA") for a term of one-year effective November 1, 2022. The RFP requested an 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 2022 through April 2023. 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 GSP-4 for a copy of the RFP.

Q. How will the Company supply the PNGTS PXP Project capacity path for the 2022-23 year?

A. The PNGTS PXP capacity allows the Company to access up to 29,000 Dth/day from Dawn, Ontario by way of agreements with Enbridge Canada, TransCanada, and PNGTS to deliver firm supplies into Dracut as part of the PXP Project. In order to supply this path, the Company issued RFPs soliciting proposals for AMAs to manage its Canadian transportation capacity. Through the RFP process, the Company was willing to consider AMAs that required assignment of the Company's capacity on Enbridge and TransCanada to East Hereford and was willing to consider offers for both ratable and non-ratable service to manage fluctuations across holidays and weekends. Copies of each of the RFPs are found in Attachment GSP-5. 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 this arrangement. 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.

Q. Will the Company be entering into an AMA using its Columbia Gas Pipeline transportation for the 2022-23 year?

A. The Company issued an RFP for an AMA for a term of one-year effective November 1, 2022. The RFP requested a MDQ of 10,000 Dth/day for volumes available as a daily call option during the months of November 2022 through April 15, 2023 via the release of a portion of the Company's capacity from Broad Run to the interconnect with Algonquin at the Hanover, NJ interconnect. These supplies will be delivered directly to the interconnection between Columbia and Algonquin at Hanover 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 GSP-6 for a copy of the RFP.

Q. Will the Company be entering into an AMA using its Millennium Pipeline transportation for the 2022-23 year?

A. The Company issued an RFP for an AMA for a term of one-year effective November 1, 2022. The RFP requested a MDQ of 5,000 Dth/day for volumes available as a daily call option during the months of November 2022 through April 2023 and also for any 60 days for the period of May 2023 through October 2023 via the release of a portion of the Company's capacity from Corning-Empire PL to the interconnect with Algonquin at the Ramapo interconnect. Please see Attachment GSP-7 for a copy of the RFP.

Q. Will the Company be entering into an AMA using its existing Tennessee Dracut capacity for the 2022-23 year?

A. For the 2022/23 heating season, the Company issued an RFP soliciting offers for an AMA to provide supply and manage its existing capacity from Dracut, MA (not served by upstream capacity) to the Company's TGP city gate for a term of one year beginning November 1, 2022. The RFP contemplated a total MDQ of 15,000 Dth per day to be managed by the asset manager, after releases to Marketers were accounted for. As proposed in the RFP, the Company will release the Tennessee capacity under an AMA and will have a rateable 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 GSP-8 for a copy of the RFP.

Q. How will the Company supply the existing 25,000 Dth capacity path from Everett for the 2022-23 year?

A. For the 2022/23 heating season, the Company issued an RFP for a supply arrangement for a term of four months beginning December 2022 through March 2023 to serve its Tennessee transportation that is not currently satisfied through a long-term agreement in an illiquid market area. The RFP requested a maximum daily quantity ("MDQ") of 25,000 Dth/day with a maximum seasonal quantity ("MSQ") of 890,000 Dth. The Company is presently negotiating a transaction confirmation to memorialize the awarded transaction and the corresponding changes to its transportation contract necessary to transport these supplies during the peak season. Please see Attachment GSP-9 for a copy of the RFP.

Q. Does the Company have any new capacity it the portfolio for the 2022-23 year?

A. Yes. The Company is in the process of securing access to 5,000 Dths/day of capacity from Beverly to the Company's citygate at Dey Street beginning November 2022. For the 2022/23 heating season, the Company issued an RFP for a supply arrangement for a term of four months beginning December 2022 through March 2023 to serve this capacity. The RFP requested a maximum daily quantity ("MDQ") of 5,000 Dth/day with a maximum seasonal quantity ("MSQ") of 100,000 Dth. The Company is presently negotiating a transaction confirmation to memorialize the awarded trade. Please see Attachment GSP-9 for a copy of the RFP.

Q. Is the Algonquin citygate supply arrangement still in place for the 2022-23 year?

A. Yes. 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 remain available to the Company through the 2023/24 heating season.

Q. Has the Company contracted for winter liquid volumes for the 2022-23 year?

A. Yes. As in years past, the Company contracts for winter-only LNG to support LNG operations throughout the winter period at the portable LNG storage sites at Cumberland and Old Mill Lane, as well as the Exeter and NGLNG/Providence LNG facilities. The Company is in the process of negotiating a transaction confirmation to memorialize the purchase of 194,350 Dth of winter only liquid.

Q. Are Portable LNG Storage and Vaporization Contracts still in place for the 2022-23 year?

A. Yes. To support operations at Cumberland beginning with the 2018/2019 winter season, the Company previously entered into an equipment rental and support services agreement with Prometheus Energy Group, Inc. which was later acquired by Stabilis Energy, LLC ("Stabilis"). The rental and support services agreement with Stabilis at Cumberland will be available to the Company for the 2022/23 heating season. The Company is currently in discussions with Stabilis regarding the impact of inflation, labor and resource shortages on the existing agreement to ensure continuity of services for the

2022-23 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. 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 at Old Mill Lane will be available to the Company for the 2022/23 heating season. The Company is currently in discussions with Stabilis Energy regarding the impact of inflation, labor, and resource shortages on the existing agreement to ensure continuity of services for the 2022-23 season.

Q. Does this filing have any potential impacts on the Act on Climate's requirements for reduction in carbon emissions?

A. No. The Company's customer demand forecast, and the procurement of supply to meet that demand, assumes that the requirements of the Act on Climate will not have an effect on customer requirements for natural gas supply in the coming GCR year. Therefore, the Company has designed its supply plan, and calculated the resulting factors to recover the costs of gas supply, consistent with prior years. The Company has presented those costs to be incurred in the procurement of gas supplies necessary to meet forecasted customer demand consistent with least cost dispatch.

Q. Does this conclude your testimony?

A. Yes.

Attachments of the Gas Supply Panel

Attachment GSP-1

Redacted

Attachment GSP-1

Summary of Projected Gas Costs

REDACTED

The Narragansett Electric Company
Gas Cost Recovery
Cost of Gas ($000)

Normal Weather Scenario - Sales

	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
FIXED COSTS													
Total Transportation Fixed Costs	$ 5,275.1	$ 5,679.0	$ 5,679 0	$ 5,679.0	$ 5,679.0	$ 5,275.1	$ 5,275.1	$ 5,275.1	$ 5,275.1	$ 5,275.1	$ 5,275.1	$ 5,275.1	$ 64,916.8
Total Storage Delivery Fixed Costs	$ 497.2	$ 497.2	$ 497 2	$ 497.2	$ 497.2	$ 445.5	$ 445 5	$ 445.5	$ 445.5	$ 445 5	$ 445.5	$ 445.5	$ 5,604.4
Total Storage Fixed Costs	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 703.6	$ 8,442.8
Total Liquefaction Fixed Costs	$ 510.1	$ 510.1	$ 510.1	$ 510.1	$ 510.1	$ 712.9	$ 712 9	$ 712.9	$ 712.9	$ 712 9	$ 712.9	$ 712.9	$ 7,540.8
Total Supplier Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] 73,119.6
LESS:													
AMA Credits	$ 128.5	$ 128.5	$ 128 5	$ 128.5	$ 128.5	$ 128.5	$ 128 5	$ 128.5	$ 128.5	$ 128 5	$ 128.5	$ 128.5	$ 1,541.9
Hourly Peaking Fixed Costs	$ 149.4	$ 16,865.5	$ 16,865 5	$ 16,865.5	$ 16,865.5	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 68,657.4
TOTAL FIXED COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 89,425.1
VARIABLE COSTS													
Commodity													
Commodity for Purchases to City Gate	$ 16,041.9	$ 23,129.3	$ 26,651 8	$ 25,457.5	$ 21,895.1	$ 9,806.3	$ 4,272 5	$ 2,691.7	$ 2,203.0	$ 2,270 3	$ 2,473.2	$ 5,545.9	$ 142,438.3
Commodity for Purchases to Injections	$ -	$ -	$ -	$ -	$ -	$ 1,075.5	$ 2,271 8	$ 3,462.1	$ 3,204.2	$ 3,200 9	$ 2,943.3	$ 2,827.8	$ 18,985.7
Total Commodity Costs	$ 16,041.9	$ 23,129.3	$ 26,651 8	$ 25,457.5	$ 21,895.1	$ 10,881.8	$ 6,544 3	$ 6,153.8	$ 5,407.2	$ 5,471 2	$ 5,416.5	$ 8,373.7	$ 161,424.0
Withdrawal													
Underground Storage Withdrawal Value	$ 2,971.5	$ 4,586.5	$ 4,592 9	$ 3,655.7	$ 2,045.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,852.4
LNG Storage Withdrawal Value	$ 112.6	$ 798.2	$ 2,737.1	$ 653.0	$ 116.3	$ 119.5	$ 123 8	$ 116.5	$ 119.4	$ 118.7	$ 113.0	$ 114.8	$ 5,242.9
Total Storage Withdrawal Value	$ 3,084.1	$ 5,384.6	$ 7,330.1	$ 4,308.6	$ 2,162.2	$ 119.5	$ 123 8	$ 116.5	$ 119.4	$ 118.7	$ 113.0	$ 114.8	$ 23,095.3
Transportation													
Variable Costs for Purchases to City Gate	$ 246.0	$ 298.5	$ 350.4	$ 329.8	$ 332.8	$ 96.7	$ 123.1	$ 79.4	$ 59.0	$ 64.4	$ 85.2	$ 149.3	$ 2,214.4
Variable Costs for Storage Withdrawal	$ 76.8	$ 112.3	$ 108 3	$ 89.6	$ 42.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 429.6
Variable Costs for Storage Injection	$ -	$ -	$ -	$ -	$ -	$ 227.3	$ 264.1	$ 281.3	$ 277.0	$ 281 3	$ 276.2	$ 185.4	$ 1,792.4
Total Transportation Variable Costs	$ 290.3	$ 365.6	$ 416 8	$ 378.9	$ 365.7	$ 320.1	$ 370.6	$ 336.1	$ 315.4	$ 321 8	$ 338.3	$ 311.8	$ 4,131.3
Total Storage Variable Costs	$ 32.5	$ 45.2	$ 41 9	$ 40.6	$ 9.7	$ 3.9	$ 16 5	$ 24.5	$ 20.6	$ 23 9	$ 23.0	$ 22.9	$ 305.2
LESS:													
LNG Trucking	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 456.4	$ 1,715 2	$ 2,960.3	$ 2,667.0	$ 2,672 5	$ 2,506.8	$ 2,541.8	$ 15,520.1
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ 846.3	$ 820.7	$ 783.1	$ 814.2	$ 809.7	$ 712.7	$ 471.4	$ 5,258.0
Total Storage and Liquefaction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 20,778.2
TOTAL VARIABLE COSTS	$ 19,448.8	$ 28,924.6	$ 34,440 5	$ 30,185.5	$ 24,432.7	$ 10,022.5	$ 4,519.4	$ 2,887.6	$ 2,381.4	$ 2,453.4	$ 2,671.3	$ 5,810.0	$ 168,177.7
TOTAL FIXED AND VARIABLE COSTS	$ 26,192.8	$ 37,591.5	$ 43,107 3	$ 38,852.4	$ 33,099.5	$ 16,881.6	$ 11,378 5	$ 9,746.7	$ 9,240.5	$ 9,312 5	$ 9,530.4	$ 12,669.1	$ 257,602.8
NGPMP Credit	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 970.6	$ 11,646.7
TOTAL GAS COSTS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 245,956.1

REDACTED

Narragansett Electric Company
Volume & Cost Summary

Normal Weather Scenario - Sales

Sendout Volumes (MDth)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
Algonquin													
TETCO CDS Long Haul	1,093	1,023	1,092	958	1,027	58	924	945	688	845	929	1,094	10,677
TETCO SCT Long Haul	-	-	-	-	22	-	-	-	-	-	-	-	22
AIM	222	221	221	200	242	237	224	217	224	224	216	227	2,676
AGT M3	47	-	-	-	293	1,580	122	1	-	-	12	471	2,527
TCO Appalachia	435	994	994	898	994	85	50	3	50	50	32	25	4,610
Storage	420	576	555	507	170	-	-	-	-	-	-	-	2,228
Total Algonquin	2,217	2,815	2,862	2,563	2,748	1,961	1,321	1,167	962	1,120	1,189	1,818	22,741
Tennessee													
TGP Long Haul	115	378	656	713	449	169	30	130	98	-	120	251	3,109
TGP ConneXion	179	288	292	264	292	236	274	274	283	283	274	283	3,222
Storage	235	426	463	290	272	-	-	-	-	-	-	-	1,686
Total Tennessee	529	1,092	1,411	1,267	1,013	405	304	404	380	283	394	534	8,017
Other													
Dawn via PNGTS	16	-	3	237	74	-	-	-	-	-	-	-	330
Dracut	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn / Niagara / Waddington	2	5	32	14	4	32	10	-	-	-	-	-	99
Dominion / Transco Leidy	48	54	54	49	54	18	18	2	18	2	3	19	341
Everett	-	164	388	337	-	-	-	-	-	-	-	-	889
LNG Vapor	19	126	469	113	19	19	19	19	19	19	19	19	880
LNG Truck	-	-	-	-	-	-	-	-	-	-	-	-	-
Beverly	-	28	44	28	-	-	-	-	-	-	-	-	99
City Gate	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Other	85	377	990	777	152	69	47	21	38	22	22	38	2,637
Total Purchases	2,831	4,283	5,264	4,606	3,913	2,435	1,672	1,591	1,380	1,424	1,605	2,390	33,395
LESS:													
Liquefaction	-	-	-	-	-	131	136	132	136	136	132	84	887
LNG Truck	-	-	-	-	-	-	-	-	-	-	-	-	-
AGT Storage Refill	-	-	-	-	-	58	315	476	395	515	467	454	2,678
TGP Storage Refill	-	-	-	-	-	42	109	264	261	159	248	251	1,334
Total	-	-	-	-	-	230	560	871	792	810	847	789	4,899
Total Sendout	2,831	4,283	5,264	4,606	3,913	2,205	1,112	720	589	614	758	1,602	28,496
Datacheck	2,831	4,283	5,264	4,606	3,913	2,205	1,112	720	589	614	758	1,602	28,496
Delta	-	-	-	-	-	-	-	-	-	-	-	-	-

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

	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
DEMAND													
TETCO CDS Long Haul Transportation	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 1,448	$ 17,378
TETCO SCT Long Haul Transportation	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 311
AIM Transportation	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 765	$ 9,175
AGT M3 Transportation	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 127	$ 1,521
TCO Appalachia Transportation	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 611	$ 7,332
TGP Long Haul Transportation	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 444	$ 5,331
TGP ConneXion Transportation	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 217	$ 2,608
Dawn via PNGTS Transportation	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 1,098	$ 13,175
Dracut Transportation	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 82	$ 983
Dawn / Niagara / Waddington Transportation	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 373
Dominion / Transco Leidy Transportation	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 224
Manchester Lateral / Yankee Interconnect	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 258	$ 3,096
Everett Transportation	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 1,229
Storage Delivery	$ 497	$ 497	$ 497	$ 497	$ 497	$ 445	$ 445	$ 445	$ 445	$ 445	$ 445	$ 445	$ 5,604
Storage Capacity	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 413	$ 4,957
NGLNG	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 291	$ 3,486
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 12,218
Liquefaction	$ 510	$ 510	$ 510	$ 510	$ 510	$ 713	$ 713	$ 713	$ 713	$ 713	$ 713	$ 713	$ 7,541
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,615
Beverly	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 47	$ 564
Supplier Reservation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 60,902
Total Demand	$ 7,022	$ 25,661	$ 25,661	$ 25,661	$ 25,661	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 159,624
Datacheck	$ 7,022	$ 25,661	$ 25,661	$ 25,661	$ 25,661	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 7,137	$ 159,624
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
COMMODITY													
TETCO CDS Long Haul	$ 8,183	$ 8,109	$ 8,913	$ 7,446	$ 6,540	$ 258	$ 3,725	$ 3,778	$ 2,782	$ 3,355	$ 3,228	$ 3,880	$ 60,198
TETCO SCT Long Haul	$ -	$ -	$ -	$ -	$ 155	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 155
AIM	$ 1,657	$ 1,706	$ 1,733	$ 1,496	$ 1,526	$ 1,125	$ 935	$ 888	$ 916	$ 927	$ 801	$ 806	$ 14,515
AGT M3	$ 371	$ -	$ -	$ -	$ 2,080	$ 7,156	$ 491	$ 5	$ -	$ -	$ 44	$ 1,707	$ 11,854
TCO Appalachia	$ 3,300	$ 7,837	$ 7,988	$ 6,853	$ 6,289	$ 389	$ 203	$ 14	$ 203	$ 202	$ 122	$ 93	$ 33,492
TGP Long Haul	$ 890	$ 3,022	$ 5,306	$ 5,510	$ 2,880	$ 807	$ 134	$ 555	$ 422	$ -	$ 451	$ 967	$ 20,054
TGP ConneXion	$ 1,375	$ 2,281	$ 2,336	$ 2,016	$ 1,849	$ 1,215	$ 1,304	$ 1,264	$ 1,319	$ 1,322	$ 1,120	$ 1,182	$ 18,583
Dawn via PNGTS	$ 131	$ -	$ 24	$ 1,968	$ 540	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,663
Dracut	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn / Niagara / Waddington	$ 17	$ 43	$ 258	$ 112	$ 28	$ 150	$ 42	$ -	$ -	$ -	$ -	$ -	$ 651
Dominion / Transco Leidy	$ 364	$ 423	$ 431	$ 373	$ 342	$ 106	$ 97	$ 10	$ 102	$ 10	$ 13	$ 73	$ 2,345
Everett	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Storage Withdrawals	$ 3,048	$ 4,699	$ 4,701	$ 3,745	$ 2,089	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 18,282
LNG Vapor	$ 113	$ 798	$ 2,737	$ 653	$ 116	$ 120	$ 124	$ 117	$ 119	$ 119	$ 113	$ 115	$ 5,243
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ [redacted]
Beverly	$ -	$ 1	$ 1	$ 1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3
City Gate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL COMMODITY	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 188,956
Datacheck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 188,956
Delta	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

REDACTED

	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
TOTAL DC+CC	$ 26,471	$ 54,585	$ 60,101	$ 55,846	$ 50,093	$ 18,462	$ 14,192	$ 13,768	$ 13,000	$ 13,073	$ 13,028	$ 15,960	$ 348,580
LESS:													
Liquefaction	$ -	$ -	$ -	$ -	$ -	$ 846	$ 821	$ 783	$ 814	$ 810	$ 713	$ 471	$ 5,258
LNG Truck	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
AGT Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 258	$ 1,236	$ 1,839	$ 1,547	$ 1,989	$ 1,581	$ 1,580	$ 10,029
TGP Storage Refill	$ -	$ -	$ -	$ -	$ -	$ 198	$ 479	$ 1,122	$ 1,120	$ 683	$ 926	$ 962	$ 5 491
Total Liquefaction & Storage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 20,778
TOTAL GAS COST	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]7	$ 327,802
Commodity to Sendout	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 168,178
Days/month	30	31	31	28	31	30	31	30	31	31	30	31	365
Unit Commodity Cost ($/MMBtu)	$6.870	$6.753	$6.543	$6.553	$6.244	$4.546	$4.064	$4.011	$4.046	$3.997	$3.524	$3.627	$5.902
NYMEX (08/05/2022)	$8.120	$8.230	$8.294	$7.860	$6.565	$4.954	$4.786	$4.829	$4.873	$4.886	$4.872	$4.922	

The Narragansett Electric Company
Gas Commodity Costs
Normal Year

Commodity Cost ($000)	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 53.42	$ -	$ -	$ -	$ 148.91	$ 93.77	$ -	$ -	$ -	$ -	$ -	$ 16.26	$ 312.4
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Dawn via IGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn via PNGTS	$ 130.63	$ -	$ 23.90	$ 1,959.65	$ 537.01	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,651.2
Dominion SP	$ 109.39	$ 124.76	$ 126.72	$ 109.41	$ 100.56	$ 69.79	$ 63.76	$ -	$ 63.42	$ -	$ 3.56	$ 55.92	$ 827.3
Dracut Supply	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Millennium	$ 1,596.93	$ 1,699.76	$ 1,726.51	$ 1,490.68	$ 1,370.14	$ 950.93	$ 868.68	$ 836.19	$ 864.06	$ 856.68	$ 727.04	$ 761.88	$ 13,749.5
Niagara	$ 16.74	$ 43.00	$ 255.50	$ 111.23	$ 27.77	$ 144.63	$ 41.24	$ -	$ -	$ -	$ -	$ -	$ 640.1
TCO Appalachia	$ 3,277.39	$ 7,784.99	$ 7,935.72	$ 6,805.61	$ 6,236.60	$ 384.14	$ 201.81	$ 13.45	$ 201.40	$ 200.68	$ 120.65	$ 92.51	$ 33,255.0
Tetco M3	$ 369.19	$ -	$ -	$ -	$ 2,067.15	$ 7,046.81	$ 486.03	$ 5.14	$ -	$ -	$ 43.96	$ 1,687.43	$ 11,705.7
Transco Leidy	$ 243.30	$ 284.96	$ 291.50	$ 251.44	$ 227.89	$ 11.16	$ 8.42	$ 8.07	$ 8.37	$ 8.36	$ 7.05	$ 7.47	$ 1,358.0
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M2 CDS	$ 7,994.40	$ 7,931.17	$ 8,721.81	$ 7,279.69	$ 6,362.21	$ 253.51	$ 3,525.77	$ 3,563.49	$ 2,621.55	$ 3,170.28	$ 3,034.06	$ 3,708.07	$ 58,166.0
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ 137.83	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 137.8
TGP Z4 Cnx	$ 1,372.56	$ 2,277.53	$ 2,331.58	$ 2,012.74	$ 1,845.13	$ 1,137.82	$ 1,217.65	$ 1,181.03	$ 1,232.86	$ 1,235.23	$ 1,036.92	$ 1,096.70	$ 17,977.7
TGP Z4 LH	$ 877.90	$ 2,983.11	$ 5,238.51	$ 5,437.04	$ 2,833.89	$ 789.26	$ 130.98	$ 546.40	$ 415.51	$ -	$ 443.30	$ 947.44	$ 20,643.3
Proposed Summer Refill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[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]	$ -
Beverly	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Grand Total	**$ 16,041.87**	**$ 23,129.28**	**$ 26,651.76**	**$ 25,457.50**	**$ 21,895.09**	**$ 10,881.82**	**$ 6,544.33**	**$ 6,153.77**	**$ 5,407.18**	**$ 5,471.24**	**$ 5,416.52**	**$ 8,373.68**	**$ 161,424.0**

Unit Cost ($/Dth)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Weighted Average
AGT Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM at Ramapo	$ 7.84	$ -	$ -	$ -	$ 6.96	$ 4.41	$ -	$ -	$ -	$ -	$ -	$ 3.55	$ 5.8
[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	$ 8.05	$ -	$ 8.17	$ 8.06	$ 7.07	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7.8
Dominion SP	$ 7.15	$ 7.37	$ 7.49	$ 7.16	$ 5.94	$ 4.26	$ 3.77	$ -	$ 3.75	$ -	$ 3.26	$ 3.30	$ 5.5
Dracut Supply	[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]	$ -
Everett Swing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Millennium	$ 7.15	$ 7.37	$ 7.48	$ 7.15	$ 5.94	$ 4.26	$ 3.77	$ 3.75	$ 3.75	$ 3.71	$ 3.26	$ 3.30	$ 5.1
Niagara	$ 7.76	$ 7.84	$ 7.89	$ 7.86	$ 6.97	$ 4.47	$ 4.25	$ -	$ -	$ -	$ -	$ -	$ 6.4
TCO Appalachia	$ 7.33	$ 7.59	$ 7.74	$ 7.35	$ 6.08	$ 4.38	$ 3.92	$ 3.93	$ 3.91	$ 3.89	$ 3.70	$ 3.59	$ 7.00
Tetco M3	$ 7.83	$ -	$ -	$ -	$ 6.96	$ 4.41	$ 3.92	$ 3.87	$ -	$ -	$ 3.49	$ 3.55	$ 4.58
Transco Leidy	$ 7.11	$ 7.37	$ 7.53	$ 7.20	$ 5.89	$ 4.22	$ 3.70	$ 3.67	$ 3.68	$ 3.68	$ 3.21	$ 3.29	$ 6.74
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Tetco M2 CDS	$ 7.11	$ 7.50	$ 7.73	$ 7.36	$ 6.02	$ 4.26	$ 3.73	$ 3.68	$ 3.73	$ 3.66	$ 3.17	$ 3.29	$ 5.30
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ 6.02	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6.02
TGP Z4 Cnx	$ 7.55	$ 7.78	$ 7.86	$ 7.51	$ 6.22	$ 4.60	$ 4.25	$ 4.11	$ 4.16	$ 4.16	$ 3.61	$ 3.70	$ 5.39
TGP Z4 LH	$ 7.55	$ 7.78	$ 7.86	$ 7.51	$ 6.22	$ 4.60	$ 4.25	$ 4.11	$ 4.16	$ -	$ 3.61	$ 3.70	$ 6.53
Proposed Summer Refill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[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]	$ -
Beverly	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Weighted Average	**$ 7.24**	**$ 7.13**	**$ 6.89**	**$ 6.72**	**$ 6.18**	**$ 4.42**	**$ 3.86**	**$ 3.80**	**$ 3.86**	**$ 3.78**	**$ 3.31**	**$ 3.44**	**$ 5.50**

The Narragansett Electric Company
Gas Commodity Costs
Normal Year

Commodity to Injections ($000)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	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]	$ -
Dawn via IGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn via PNGTS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion SP	$ -	$ -	$ -	$ -	$ -	$ 52.9	$ 48.1	$ -	$ 57.7	$ -	$ -	$ 15.6	$ 174.3
Dracut Supply	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Long-Term	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Everett Swing	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millennium	$ -	$ -	$ -	$ -	$ -	$ 179.9	$ 128.5	$ 98.2	$ 97.1	$ 137.1	$ 126.2	$ 40.1	$ 807.1
Niagara	$ -	$ -	$ -	$ -	$ -	$ 11.2	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.2
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ -	$ 201.8	$ 13.4	$ 201.4	$ 200.7	$ 120.6	$ 64.8	$ 802.8
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ 107.7	$ -	$ -	$ -	$ -	$ -	$ -	$ 107.7
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ 6.2	$ 4.8	$ 4.7	$ 4.7	$ 3.6	$ 4.0	$ 1.5	$ 29.5
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Tetco M2 CDS	$ -	$ -	$ -	$ -	$ -	$ 253.5	$ 1,140.9	$ 1,979.7	$ 1,466.0	$ 1,913.2	$ 1,552.0	$ 1,518.1	$ 9,823.4
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 Cnx	$ -	$ -	$ -	$ -	$ -	$ 464.1	$ 704.5	$ 819.7	$ 961.8	$ 946.4	$ 702.7	$ 590.8	$ 5,190.0
TGP Z4 LH	$ -	$ -	$ -	$ -	$ -	$ -	$ 43.2	$ 546.4	$ 415.5	$ -	$ 437.7	$ 596.8	$ 2,039.6
Proposed Summer Refill	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[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]	$ -
Beverly	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ -
Grand Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,075.5**	**$ 2,271.8**	**$ 3,462.1**	**$ 3,204.2**	**$ 3,200.9**	**$ 2,943.3**	**$ 2,827.8**	**$ 18,985.7**

REDACTED

The Narragansett Electric Company
Transportation Variable Costs
Normal Year
($000)

Transportation Costs	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Grand Total
Dracut	$ 0.51	$ -	$ -	$ 7.66	$ 2.30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.5
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,463.9
Manchester Lateral	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ 0.17	$ 0.42	$ 2.49	$ 1.09	$ 0.31	$ 2.49	$ 0.75	$ -	$ -	$ -	$ -	$ -	$ 7.7
Storage Delivery	$ 45 25	$ 72.18	$ 72.33	$ 65.47	$ 65.32	$ 22.93	$ 14.67	$ 5.68	$ 6.54	$ 8.04	$ 7.28	$ 22.70	$ 408.4
Yankee Interconnect	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AIM	$ 6 25	$ 6.25	$ 6.25	$ 5.64	$ 6.77	$ 6.62	$ 6.31	$ 6.10	$ 6.31	$ 6.31	$ 6.08	$ 6.40	$ 75.3
Transco	$ 10 91	$ 12.36	$ 12.36	$ 11.16	$ 12.36	$ 0.28	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 0.13	$ 60.2
TCO (Pool)	$ 13 27	$ 24.54	$ 24.54	$ 22.17	$ 24.54	$ 10.04	$ 2.31	$ 0.05	$ -	$ -	$ 0.36	$ 5.53	$ 127.4
TETCO SCT Long Haul	$ -	$ -	$ -	$ -	$ 16.66	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16.7
AGT M3	$ 54 88	$ 63.07	$ 65.44	$ 56.81	$ 52.54	$ 37.56	$ 16.28	$ 12.10	$ 7.11	$ 6.86	$ 12.30	$ 24.76	$ 409.7
TETCO CDS Long Haul	$ 144 64	$ 137.78	$ 147.72	$ 129.61	$ 138.74	$ 6.25	$ 100.10	$ 84.54	$ 61.85	$ 71.67	$ 84.97	$ 106.85	$ 1,214.7
Dominion	$ 0.16	$ 0.18	$ 0.35	$ 0.16	$ 0.18	$ 0.17	$ 0.18	$ -	$ 0.18	$ -	$ 0.01	$ 0.18	$ 1.8
Dawn via Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn via PNGTS	$ 0.07	$ -	$ 0.11	$ 1.08	$ 0.43	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1.7
TGP Long Haul	$ 11.77	$ 38.78	$ 67.39	$ 62.73	$ 41.60	$ 13.95	$ 0.85	$ 5.97	$ 4.49	$ -	$ 5.60	$ 10.16	$ 263.3
TGP ConneXion	$ 2.42	$ 3.89	$ 3.94	$ 3.56	$ 3.95	$ 2.99	$ 3.10	$ 2.85	$ 2.77	$ 2.80	$ 2.89	$ 3.27	$ 38.4
Portable LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Beverly	$ -	$ 0.83	$ 1.31	$ 0.83	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3.0
[redacted]	$ -	$ 5.29	$ 12.55	$ 10.87	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28.7
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	**$ 4,131.3**

REDACTED

The Narragansett Electric Company
Storage Variable Costs
Normal Year
($000)

Storage Costs	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
Columbia FSS	$ 0.2	$ 1.2	$ 1.1	$ 0.6	$ 0.0	$ -	$ 0.8	$ 0.1	$ 0.8	$ 0.8	$ 0.5	$ 0.3	$ 6.2
Dominion GSS	$ 4.9	$ 7.6	$ 4.2	$ 5.9	$ 4.1	$ 2.7	$ 6.4	$ 6.0	$ 5.9	$ 5.6	$ 5.1	$ 5.0	$ 63.4
Dominion GSSTE	$ 4.4	$ 4.6	$ 4.6	$ 4.1	$ 4.6	$ -	$ -	$ 7.6	$ 2.8	$ 7.3	$ 6 6	$ 6.5	$ 53.0
Providence LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tennessee FSMA	$ 0.5	$ 1.3	$ 2.7	$ 0.6	$ 1.1	$ -	$ -	$ 1.4	$ 1.4	$ 0.6	$ 1.4	$ 1.5	$ 12.5
Tetco FSS1	$ 0.5	$ 0.7	$ 0.7	$ 0.7	$ -	$ 0.1	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 0.4	$ 5.1
Tetco SS1	$ 22.0	$ 29.8	$ 28.7	$ 28.7	$ -	$ 1.1	$ 8.9	$ 9.0	$ 9.2	$ 9.3	$ 9.0	$ 9.3	$ 165.0
Exeter LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grand Total	**$ 32.5**	**$ 45.2**	**$ 41.9**	**$ 40.6**	**$ 9.7**	**$ 3.9**	**$ 16.5**	**$ 24.5**	**$ 20.6**	**$ 23.9**	**$ 23.0**	**$ 22.9**	**$ 305.2**

Withdrawal Value	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
Columbia FSS	$ 50.0	$ 387.8	$ 346.7	$ 187.0	$ 0.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 972.4
Dominion GSS	$ 916.1	$ 1,418.4	$ 770.6	$ 1,091.4	$ 761.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,957.9
Dominion GSSTE	$ 724.9	$ 749.1	$ 749.1	$ 676.6	$ 749.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,648.8
Exeter LNG	$ 38.6	$ 678.2	$ 314.5	$ 36.1	$ 39.9	$ 39.4	$ 40.2	$ 37.6	$ 38.9	$ 39.0	$ 36 9	$ 37.2	$ 1,376.8
Providence LNG	$ 73.9	$ 119.9	$ 2,422.6	$ 616.9	$ 76.4	$ 80.1	$ 83.6	$ 78.9	$ 80.5	$ 79.7	$ 76.1	$ 77.6	$ 3,866.2
Tennessee FSMA	$ 238.2	$ 621.5	$ 1,370.2	$ 344.3	$ 534.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,108.8
Tetco FSS1	$ 51.0	$ 66.3	$ 63.8	$ 63.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 244.9
Tetco SS1	$ 991.2	$ 1,343.3	$ 1,292.5	$ 1,292.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,919.6
Grand Total	**$ 3,084.1**	**$ 5,384.6**	**$ 7,330.1**	**$ 4,308.6**	**$ 2,162.2**	**$ 119.5**	**$ 123.8**	**$ 116.5**	**$ 119.4**	**$ 118.7**	**$ 113.0**	**$ 114.8**	**$ 23,095.3**

Injection Value	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
Columbia FSS	$ -	$ -	$ -	$ -	$ -	$ -	$ 203.2	$ 13.5	$ 202.8	$ 202.0	$ 121.5	$ 65.3	$ 808.3
Dominion GSS	$ -	$ -	$ -	$ -	$ -	$ 346.7	$ 742.4	$ 685.7	$ 677.0	$ 635.6	$ 507.5	$ 510.3	$ 4,105.2
Dominion GSSTE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 815.2	$ 305.4	$ 774.2	$ 615.4	$ 621.4	$ 3,131.7
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,307.2
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 3,950.8
Tennessee FSMA	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 680.4	$ 685.0	$ 272.6	$ 598.0	$ 633.3	$ 2,869.2
Tetco FSS1	$ -	$ -	$ -	$ -	$ -	$ 5.1	$ 35.0	$ 33.4	$ 34.9	$ 34.4	$ 29.0	$ 31.1	$ 203.0
Tetco SS1	$ -	$ -	$ -	$ -	$ -	$ 104.6	$ 734.7	$ 732.0	$ 761.9	$ 753.7	$ 635.5	$ 680.4	$ 4,402.8
Grand Total	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,302.8**	**$ 2,535.9**	**$ 3,743.4**	**$ 3,481.1**	**$ 3,482.3**	**$ 3,219.5**	**$ 3,013.2**	**$ 20,778.2**

REDACTED

The Narragansett Electric Company
Transportation Fixed Costs
Normal Year
($000)

Transportation Costs	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
Dracut	$ 81 9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81.9	$ 81 9	$ 983.2
LNG	$ 510.1	$ 510.1	$ 510.1	$ 510.1	$ 510.1	$ 712.9	$ 712.9	$ 712.9	$ 712.9	$ 712.9	$ 712.9	$ 712.9	$ 7,540.8
Manchester Lateral	$ 211 0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 211.0	$ 2,532.2
Niagara	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 6.6	$ 78.9
Storage Delivery	$ 497 2	$ 497.2	$ 497.2	$ 497.2	$ 497.2	$ 445.5	$ 445.5	$ 445.5	$ 445.5	$ 445.5	$ 445.5	$ 445.5	$ 5,604.4
Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 563.5
AIM	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 764.6	$ 9,175.4
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	$ 113.2
TCO (Pool)	$ 611 0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 611.0	$ 7,332.2
TETCO SCT Long Haul	$ 25 9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25.9	$ 25 9	$ 310.7
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	$ 1,448 2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 1,448.2	$ 17,378.4
Dominion	$ 9 3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3	$ 9 3	$ 111.0
Dawn via Waddington	$ 24 5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24.5	$ 24 5	$ 294.3
Dawn via PNGTS	$ 1,097 9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 1,097.9	$ 13,174.6
TGP Long Haul	$ 444 3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 444.3	$ 5,331.1
TGP ConneXion	$ 217 3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 217.3	$ 2,607.9
Portable LNG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 1,615.4
Beverly	$ 47 0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47.0	$ 47 0	$ 564.3
[redacted]	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 102.4	$ 1,229.0
Grand Total	[redacted]												**$ 78,061.9**

REDACTED

The Narragansett Electric Company
Storage Fixed Costs
Normal Year
($000)

Storage Costs	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
Columbia FSS	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 16.1	$ 193.5
Dominion GSS	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 70.2	$ 842.0
Dominion GSSTE	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 90.4	$ 1,085.2
Exeter LNG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Providence LNG	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 290.5	$ 3,486.2
Tennessee FSMA	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 41.4	$ 496.4
Tetco FSS1	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 4.8	$ 57.3
Tetco SS1	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 190.2	$ 2,282.2
Grand Total	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 703.6**	**$ 8,442.8**

REDACTED

The Narragansett Electric Company
Supply Fixed Costs
Normal Year
($000)

Supply Costs	11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	10/1/2023	Grand Total
Ramapo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn East Hereford	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dawn Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dominion South Point	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Millenium East	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Niagara	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO Appalachia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TCO M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transco Leidy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Waddington	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Dracut Supply Deal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Citygate	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Summer Liquid Refill	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 36.0
Tetco M2 CDS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tetco M2 SCT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 CnX	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP Z4 LH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
AGT Citygate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 2,792.3
Proposed Summer Liquid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Winter Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 12,181.9
Beverly Supply Deal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 6,000.0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] 52,109.5
Grand Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted] **73,119.6**

The Narragansett Electric Company
Hourly Peaking Fixed Costs
Normal Year
($000)

Hourly Peaking Fixed Costs	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
Transportation Fixed Costs	[redacted]												
Portable LNG													
Beverly													
[redacted]													
Supplier Fixed Costs	[redacted]												
AGT Citygate													
Winter Liquid													
Beverly Supply Deal													
[redacted]													
Total Hourly Peaking Fixed Costs	$ 149.4	$ 16,865 5	$ 16,865 5	$ 16,865.5	$ 16,865.5	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 149.4	$ 68,657.4

REDACTED

The Narragansett Electric Company
Storage Inventory
Normal Year
($000; MDth)

Storage Inventory													
		11/1/2022	12/1/2022	1/1/2023	2/1/2023	3/1/2023	4/1/2023	5/1/2023	6/1/2023	7/1/2023	8/1/2023	9/1/2023	$ 45,200.0
LNG	Beg Inv Value	$ 4,417.2	$ 4,304.6	$ 3,506.4	$ 769.3	$ 116 3	$ -	$ 726.8	$ 1,423.7	$ 2,090 2	$ 2,785.0	$ 3,476.0	$ 4,075.7
LNG	Beg Inv Volume	745.5	726.7	601.0	132.0	19.4	-	111.8	228.6	341.7	458.5	575.4	$ 688.5
LNG	End Inv Value	$ 4,304.6	$ 3,506.4	$ 769.3	$ 116.3	$ -	$ 726.8	$ 1,423.7	$ 2,090.2	$ 2,785 0	$ 3,476.0	$ 4,075.7	$ 4,432.3
LNG	End Inv Volume	726.7	601.0	132.0	19.4	-	111.8	228.6	341.7	458 5	575.4	688.5	$ 753.0
AGT Storage	Beg Inv Value	$ 13,797.0	$ 11,941.5	$ 8,956.0	$ 5,879.6	$ 3,207.1	$ 2,174.9	$ 2,433.3	$ 3,669.3	$ 5,507 8	$ 7,054.4	$ 9,043.7	$ 10,624.3
AGT Storage	Beg Inv Volume	3,176.2	2,739.4	2,056.3	1,356.1	741 5	507.4	565.1	879.7	1,355.4	1,750.0	2,264.7	$ 2,731.9
AGT Storage	End Inv Value	$ 11,941.5	$ 8,956.0	$ 5,879.6	$ 3,207.1	$ 2,174 9	$ 2,433.3	$ 3,669.3	$ 5,507.8	$ 7,054.4	$ 9,043.7	$ 10,624.3	$ 12,204.0
AGT Storage	End Inv Volume	2,739.4	2,056.3	1,356.1	741.5	507.4	565.1	879.7	1,355.4	1,750 0	2,264.7	2,731.9	$ 3,185.5
TGP Storage	Beg Inv Value	$ 6,230.3	$ 5,114.3	$ 3,513.3	$ 1,996.8	$ 1,013.7	$ -	$ 198.0	$ 677.3	$ 1,799 0	$ 2,919.4	$ 3,602.7	$ 4,528.9
TGP Storage	Beg Inv Volume	1,338.8	1,105.8	762.2	421.1	219 0	-	41.8	151.2	415 0	676.0	835.4	$ 1,083.1
TGP Storage	End Inv Value	$ 5,114.3	$ 3,513.3	$ 1,996.8	$ 1,013.7	$ -	$ 198.0	$ 677.3	$ 1,799.0	$ 2,919.4	$ 3,602.7	$ 4,528.9	$ 5,491.0
TGP Storage	End Inv Volume	1,105.8	762.2	421.1	219.0	-	41.8	151.2	415.0	676 0	835.4	1,083.1	1,334.2

REDACTED

The Narragansett Electric Company Gas Cost Recovery Receipt Point Volumes (MDth)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	7	-	-	-	21	21	-	-	-	-	-	5	54
Beverly	-	28	44	28	-	-	-	-	-	-	-	-	100
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	16	-	3	243	76	-	-	-	-	-	-	-	338
Dominion SP	15	17	17	15	17	4	4	-	2	-	1	12	104
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	890
Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
Millennium	223	231	231	208	231	181	197	197	205	194	184	219	2,500
Niagara	2	5	32	14	4	30	10	-	-	-	-	-	98
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	447	1,025	1,025	926	1,025	88	-	-	-	-	-	8	4,545
Tetco M2 SCT	-	-	-	-	23	-	-	-	-	-	-	-	23
Tetco M2 CDS	1,125	1,057	1,128	989	1,056	-	639	430	310	344	467	665	8,211
Tetco M3	47	-	-	-	297	1,575	124	1	-	-	13	475	2,532
TGP Z4 Cnx	182	293	296	268	297	147	121	88	65	69	93	137	2,055
TGP Z4 LH	116	383	666	724	456	172	21	-	-	-	2	95	2,634
Transco Leidy	34	39	39	35	39	1	1	1	1	1	1	2	193
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO CITY GATE	2,215	3,243	3,871	3,788	3,541	2,218	1,115	717	583	608	760	1,617	24,277
STORAGE WITHDRAWALS													
Columbia FSS	10	79	71	38	0	-	-	-	-	-	-	-	198
Dominion GSS	185	290	160	224	156	-	-	-	-	-	-	-	1,015
Dominion GSSTE	169	175	175	158	175	-	-	-	-	-	-	-	851
Exeter LNG	6	105	49	6	6	6	6	6	6	6	6	6	214
Providence LNG	13	21	420	107	13	13	13	13	13	13	13	13	666
Tennessee FSMA	56	146	312	73	122	-	-	-	-	-	-	-	709
Tetco SS1	238	322	310	310	-	-	-	-	-	-	-	-	1,180
Tetco FSS1	11	15	14	14	-	-	-	-	-	-	-	-	54
TOTAL WITHDRAWALS TO CITY GATE	689	1,152	1,510	929	472	19	19	19	19	19	19	19	4,887
GRAND TOTAL TO CITY GATE	2,904	4,395	5,381	4,717	4,014	2,237	1,135	736	602	628	779	1,636	29,164

REDACTED

The Narragansett Electric Company Gas Cost Recovery Receipt Point Volumes (MDth)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Beverly	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	12	13	-	15	-	-	5	45
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Millennium	-	-	-	-	-	42	34	26	26	37	39	12	216
Niagara	-	-	-	-	-	2	-	-	-	-	-	-	2
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	-	-	-	-	-	-	52	3	52	52	33	18	209
Tetco M2 SCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 CDS	-	-	-	-	-	59	306	538	393	523	489	461	2,770
Tetco M3	-	-	-	-	-	24	-	-	-	-	-	-	24
TGP Z4 Cnx	-	-	-	-	-	101	166	199	231	227	195	160	1,279
TGP Z4 LH	-	-	-	-	-	-	10	133	100	-	121	161	526
Transco Leidy	-	-	-	-	-	1	1	1	1	1	1	0	8
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO INJECTIONS	-	-	-	-	-	243	581	901	819	840	877	818	5,080
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	-	-	-	-	-	243	581	901	819	840	877	818	5,080

The Narragansett Electric Company Gas Cost Recovery Delivery Point Volumes (MDth)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
To City Gate													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	7	-	-	-	21	21	-	-	-	-	-	4	52
Beverly	-	28	44	28	-	-	-	-	-	-	-	-	99
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	16	-	3	237	74	-	-	-	-	-	-	-	330
Dominion SP	15	16	16	15	16	4	4	-	1	-	1	12	100
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
[redacted]	-	164	388	337	-	-	-	-	-	-	-	-	889
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Millennium	216	221	221	200	222	176	191	191	199	188	178	211	2,414
Niagara	2	5	32	14	4	30	10	-	-	-	-	-	97
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	435	994	994	898	994	85	-	-	-	-	-	7	4,406
Tetco M2 SCT	-	-	-	-	22	-	-	-	-	-	-	-	22
Tetco M2 CDS	1,093	1,023	1,092	958	1,027	-	625	421	304	337	454	646	7,980
Tetco M3	47	-	-	-	293	1,556	122	1	-	-	12	471	2,503
TGP Z4 Cnx	179	288	292	264	292	144	119	87	64	68	91	135	2,024
TGP Z4 LH	115	378	656	713	449	169	20	-	-	-	2	93	2,595
Transco Leidy	34	38	38	34	38	1	1	1	1	1	1	2	190
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO CITY GATE	2,157	3,156	3,776	3,696	3,452	2,186	1,093	701	569	594	739	1,582	23,702
STORAGE WITHDRAWALS													
Columbia FSS	10	76	68	37	0	-	-	-	-	-	-	-	192
Dominion GSS	180	282	156	217	152	-	-	-	-	-	-	-	988
Dominion GSSTE	165	170	170	153	170	-	-	-	-	-	-	-	828
Exeter LNG	6	105	49	6	6	6	6	6	6	6	6	6	214
Providence LNG	13	21	420	107	13	13	13	13	13	13	13	13	666
Tennessee FSMA	55	144	307	72	120	-	-	-	-	-	-	-	699
Tetco SS1	234	315	303	303	-	-	-	-	-	-	-	-	1,156
Tetco FSS1	11	14	14	14	-	-	-	-	-	-	-	-	52
TOTAL WITHDRAWALS TO CITY GATE	674	1,127	1,487	910	462	19	19	19	19	19	19	19	4,794
GRAND TOTAL TO CITY GATE	2,831	4,283	5,264	4,606	3,913	2,205	1,112	720	589	614	758	1,602	28,496

REDACTED

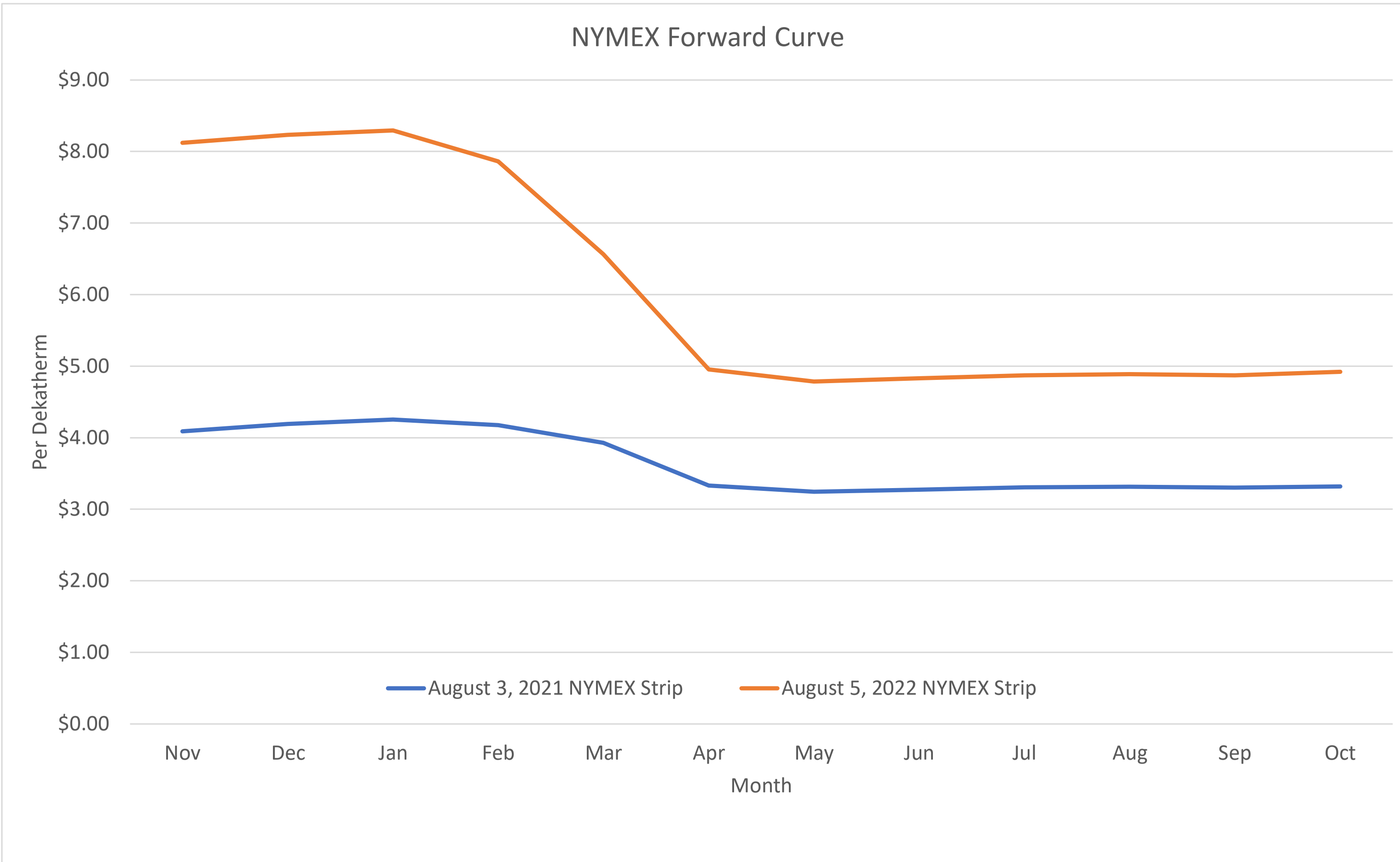
The Narragansett Electric Company Gas Cost Recovery Delivery Point Volumes (MDth)	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
To Storage Injection													
GAS PURCHASES													
AGT Citygate	-	-	-	-	-	-	-	-	-	-	-	-	-
AIM at Ramapo	-	-	-	-	-	-	-	-	-	-	-	-	-
Beverly	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via IGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dawn via PNGTS	-	-	-	-	-	-	-	-	-	-	-	-	-
Dominion SP	-	-	-	-	-	12	12	-	15	-	-	5	43
Dracut Supply	-	-	-	-	-	-	-	-	-	-	-	-	-
Everett Long-Term	-	-	-	-	-	-	-	-	-	-	-	-	-
[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-
Liquid	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Millennium	-	-	-	-	-	41	33	25	25	36	37	12	210
Niagara	-	-	-	-	-	2	-	-	-	-	-	-	2
Proposed Liquid	-	-	-	-	-	-	-	-	-	-	-	-	-
TCO Appalachia	-	-	-	-	-	-	50	3	50	50	32	18	204
Tetco M2 SCT	-	-	-	-	-	-	-	-	-	-	-	-	-
Tetco M2 CDS	-	-	-	-	-	58	299	524	384	509	475	448	2,696
Tetco M3	-	-	-	-	-	24	-	-	-	-	-	-	24
TGP Z4 Cnx	-	-	-	-	-	92	155	187	218	215	183	148	1,198
TGP Z4 LH	-	-	-	-	-	-	10	130	98	-	118	158	514
Transco Leidy	-	-	-	-	-	1	1	1	1	1	1	0	8
Waddington	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PURCHASES TO INJECTIONS	-	-	-	-	-	230	560	871	792	810	847	789	4,899
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	-	-	-	-	-	230	560	871	792	810	847	789	4,899

Attachment GSP-2

Attachment GSP-2

NYMEX Strip Comparison & Forward Curves

	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct
August 3, 2021 NYMEX Strip	$4.089	$4.190	$4.256	$4.175	$3.930	$3.331	$3.244	$3.273	$3.308	$3.315	$3.301	$3.320
August 5, 2022 NYMEX Strip	$8.120	$8.230	$8.294	$7.860	$6.565	$4.954	$4.786	$4.829	$4.873	$4.886	$4.872	$4.922



SUPPLY AREA BASIS SUMMARY

November 2022 - October 2023

	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23
August 5, 2022 NYMEX Strip	$8.120	$8.230	$8.294	$7.860	$6.565	$4.954	$4.786	$4.829	$4.873	$4.886	$4.872	$4.922

SUPPLY AREA	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23
TENN Z4	($0.575)	($0.448)	($0.430)	($0.348)	($0.345)	($0.358)	($0.538)	($0.715)	($0.717)	($0.722)	($1.260)	($1.225)
NIAGARA	($0.360)	($0.389)	($0.399)	$0.000	$0.401	($0.485)	($0.538)	($0.537)	($0.537)	($0.538)	($0.538)	($0.538)
IROQUOIS RECEIPTS	$0.182	$3.699	$9.261	$9.170	$1.571	($0.250)	($0.250)	($0.250)	($0.250)	($0.250)	($0.250)	($0.250)
TETCO M3	($0.285)	$3.185	$8.665	$8.855	$0.395	($0.548)	($0.862)	($0.960)	($0.670)	($0.745)	($1.380)	($1.372)
DRACUT	$5.406	$21.490	$28.102	$28.220	$10.303	$1.598	($0.125)	($0.465)	$0.150	$0.178	($0.922)	($0.905)
TCO	($0.785)	($0.638)	($0.555)	($0.512)	($0.483)	($0.572)	($0.870)	($0.903)	($0.965)	($0.992)	($1.172)	($1.328)
DAWN	($0.075)	($0.080)	($0.120)	$0.205	$0.505	($0.135)	($0.168)	($0.185)	($0.210)	($0.220)	($0.218)	($0.232)
TETCO M2	($1.015)	($0.730)	($0.562)	($0.502)	($0.540)	($0.690)	($1.052)	($1.147)	($1.147)	($1.230)	($1.698)	($1.630)
TRANSCO LEIDY	($1.012)	($0.865)	($0.760)	($0.665)	($0.675)	($0.738)	($1.082)	($1.163)	($1.190)	($1.208)	($1.658)	($1.628)
ALGONQUIN	$6.705	$22.792	$29.482	$29.602	$11.630	$1.355	($0.360)	($0.715)	($0.095)	($0.072)	($1.172)	($1.155)
TENN Z6	$6.702	$22.785	$29.452	$29.552	$11.620	$1.355	($0.360)	($0.715)	($0.095)	($0.072)	($1.175)	($1.155)
EASTERN SP	($0.966)	($0.861)	($0.809)	($0.705)	($0.625)	($0.694)	($1.020)	($1.083)	($1.127)	($1.172)	($1.615)	($1.619)
EASTERN NP	($1.116)	($1.010)	($0.958)	($0.854)	($0.775)	($0.784)	($1.110)	($1.173)	($1.217)	($1.264)	($1.705)	($1.709)
IROQUOIS Z1	$0.222	$3.739	$9.301	$9.210	$1.611	($0.210)	($0.210)	($0.210)	($0.210)	($0.210)	($0.210)	($0.210)
LEIDY HUB	($0.913)	($0.781)	($0.795)	($0.618)	($0.628)	($0.760)	($3.127)	($3.136)	($2.257)	($2.852)	($1.658)	($1.625)
MILLENNIUM EAST POOL	($0.965)	($0.850)	($0.782)	($0.700)	($0.607)	($0.770)	($1.108)	($1.167)	($1.220)	($1.192)	($1.665)	($1.640)
TENN Z6 NORTH	$6.702	$22.785	$29.452	$29.552	$11.620	$1.355	($0.360)	($0.715)	($0.095)	($0.072)	($1.175)	($1.155)

Attachment GSP-3

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, 2022 through October 31, 2023

Underground Storage:

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

November 1	96%
November 15	89%
December 1	81%
December 15	72%
January 1	60%
January 15	50%
February 1	38%
February 15	30%
March 1	22%
March 15	17%
April 1	11%

Peaking Inventory:

Inventory Level allocated on November 1, 2022 = MSQ-P
Injections are not allowed.
Minimum Inventory Levels:

November 1	100%
December 1	84%
January 1	81%
February 1	34%
March 1	16%
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

RFP for AMA Dawn Waddington to Zone 6 Lincoln

nationalgrid

Request for Proposals ("RFP") for Asset Management Arrangement May 18, 2022

The Narragansett Electric Company ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an Asset Management Arrangement ("AMA") of its capacity originating at Dawn, Ontario for delivery to its customers behind its Tennessee Gas Pipeline Company, L.L.C. ("Tennessee") Zone 6 city-gate in Rhode Island 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. 1 – AMA (Dawn- Tennessee Zone 6)

I. Provisions

Term: November 1, 2022 through October 31, 2023.

Delivery Period: November 1, 2022 through and including March 31, 2023.

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 Enbridge 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:

Enbridge Gas Inc. ("Enbridge")
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
Enbridge	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, 2022 through March 31, 2023 ("Delivery Period")** 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 Enbridge, 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 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 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, 2022 through March 31, 2023 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). For avoidance of doubt, this Additional Call provision shall only apply to residual capacity remaining on the transportation path as a result of fuel retention applicable to the Assigned Assets.

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 $0.05 per dt.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load, Daily Call or Additional Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Daily Call Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Tennessee Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

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 Canada Energy Regulator ("CER"), 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)

May 25, 2022	Proposals must be received by Narragansett by 5:00PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on June 1, 2022.**
September 1, 2022	Please note that in order to prepare any and all filings related to gas cost recovery in its respective jurisdictions, it is Narragansett's desire to finalize all contract arrangements no later than this date.

V. Form of Agreement

Narragansett 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 Narragansett, 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. Narragansett reserves the right to withdraw or modify this RFP at any time and Narragansett 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 Narragansett.

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.nationalgrid.com/document/83526/download

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

Liz Arangio
Director of Gas Supply Planning
Email: Elizabeth.Arangio@nationalgrid.com

Megan Borst
Manager of Gas Supply Planning
Email: Megan.Borst@nationalgrid.com

Samara Jaffe
Director of Gas Contracting, Compliance & Hedging
Email: Samara.Jaffe@nationalgrid.com

Janet Prag
Senior Contract Specialist of Gas Contracting, Compliance & Hedging
Email: Janet.Prag@nationalgrid.com

Kate Toriello
Senior Program Manager of Gas Contracting, Compliance & Hedging
Email: Kate.Toriello@nationalgrid.com

nationalgrid

Transaction Confirmation – Package 1
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date: ____________

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposals for Asset Management Arrangements dated May 18, 2022. This Transaction Confirmation is subject to the Base Contract between Seller and Buyer, dated ________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER:

Attn:
Phone:
Fax:
Transporters:
Transporters Contract Number:
Trader:

BUYER:
The Narragansett Electric Company
100 East Old County Road
Hicksville, New York 11801
Attn: Contract Administration
Email: confirmationseprm@nationalgrid.com
Transporters: Enbridge Gas Inc. ("Enbridge"), 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, 2022 **End: October 31, 2023**

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
Enbridge	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

"CER" shall mean the Canada Energy Regulator

"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 Enbridge 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, 2022 through March 31, 2023 (“Delivery Period”) 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 Enbridge, 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 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 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, 2022 through March 31, 2023 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. [Bidders ***must*** specify with their offer whether this language is accepted as part of their bid. Non-conforming proposals to this provision will only be considered where Seller agrees that for each undelivered dth that is not excused by Force Majeure, Seller shall pay to Buyer the higher of Buyer’s actual replacement cost or 150% of the Price per dth for the date of delivery.]

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 the Intercontinental Exchange (“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 $0.05 per dt.

4. Notwithstanding the foregoing, if in Buyer's sole discretion operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load, Daily Call or Additional Call Price stated in this Section D, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Tennessee Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure to deliver shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate this Transaction Confirmation.

5.

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 CER, 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 CER, 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: By: ___________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By:_________________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-5

Attachment GSP-5

RFPs for ANA Portland Express (“PXP”)

nationalgrid

**Request for Proposals ("RFP") for
Asset Management Arrangements
May 18, 2022**

The Narragansett Electric Company ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for Asset Management Arrangements ("AMA") to manage all of its capacity originating at Dawn, Ontario using its capacity on Enbridge Gas Inc. ("Enbridge") and TransCanada Pipeline Limited ("TCPL"). This capacity feeds our customers via transportation on Portland Natural Gas Transmission System ("PNGTS") and Tennessee Gas Pipeline ("TGP") which are not being proposed to be released as part of this AMA.

Bidders are advised that due to requirements of its State Approved Retail Access Program ("Program"), National Grid is required to allocate a portion of the Assets to its Program participants 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 and will be conveyed to Seller in the manner set forth below. Based on historical activity National Grid expects approximately 25% of the ***total*** subject assets to be reserved each month for the Program. ***Bidders must therefore submit their asset management fee for Package No. 2 only on a volumetric basis*** and must take all necessary actions to allow National Grid to administer the Program. **Bidders may bid on packages in increments of 10,000 dth and must indicate the maximum volume and AMA fee for which they are willing to accept an award pursuant to this RFP; in order to administer the Program,** Buyer's allocation of awards pursuant to Package No. 2 shall take into consideration its ability to administer the Program and its ability to maximize value for its firm gas customers.

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. 2 - AMA – PXP - Canadian Only (Ratable)

Term: November 1, 2022 through October 31, 2023.

Delivery Period: November 1, 2022 through April 30, 2023.

Assets: Beginning November 1, 2022, National Grid is seeking an AMA using the following Assets:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	29,056	30,656	Dawn	Parkway
TCPL	FT 64273	29,056	30,656	Parkway	East Hereford

Assignment of Assets/ Compliance with Buyer's State Retail Choice Program:

The Assets summarized above represent Buyer's *total* contract path contemplated under this Package No. 2 prior to allocation under the Program. Assets not assigned under Buyer's Program shall be assigned by Buyer for the entire term at no cost to Seller; notwithstanding the foregoing, Seller shall initially pay the demand charges and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets and for all imputed variable charges related to the volumes delivered by Seller on behalf of Buyer; 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. Seller shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. 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 and to comply with Buyer's Program. Further, all assignments shall be subject to recall in the event that the Seller 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, 2022 through April 30, 2023 ("Delivery Period")** 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.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

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 Canada Energy Regulator, 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 – PXP - Canadian Only (Non-Ratable)

Term: November 1, 2022 through October 31, 2023.

Delivery Period: November 1, 2022 through April 30, 2023.

Assets: Beginning November 1, 2022, National Grid is seeking an AMA using the following Assets:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	29,056	30,656	Dawn	Parkway
TCPL	FT 64273	29,056	30,656	Parkway	East Hereford

<u>Assignment of Assets/ Compliance with Buyer's State Retail Choice Program:</u>

The Assets summarized above represent Buyer's *total* contract path contemplated under this Package No. 3 Assets not assigned under Buyer's Program shall be assigned by Buyer for the entire term at no cost to Seller; notwithstanding the foregoing, Seller shall initially pay the demand charges and Buyer shall reimburse Seller for 100% of the demand charges related to the Assets and for all imputed variable charges related to the volumes delivered by Seller on behalf of Buyer; 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. Seller shall be responsible for all variable charges in connection with the Assets during the Term not related to Buyer's deliveries. 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 and to comply with Buyer's Program. Further, all assignments shall be subject to recall in the event that the Seller fails to meet its gas supply obligation to Buyer.

<u>Delivery Point:</u>

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

<u>Gas Supply Requirements:</u>

On any day during the period of **November 1, 2022 through April 30, 2023 ("Delivery Period")** 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. Nominations need not be ratable for holidays and weekends.

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.

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assigned Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

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. ***Nominations need not be ratable across Holidays and weekends*****.**

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 Canada Energy Regulator, 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

Narragansett 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 Narragansett 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 CER, 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)

May 25, 2022	Proposals must be received by Narragansett by **5:00 PM**. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on June 1, 2022.**
September 1, 2022	Please note that in order to prepare any and all filings related to gas cost recovery in its respective jurisdictions, it is Narragansett's desire to finalize all contract arrangements no later than this date.

IV. Form of Agreement

Narragansett 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. Narragansett reserves the right to withdraw or modify this RFP at any time and Narragansett 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 Narragansett in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by Narragansett.

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.nationalgrid.com/document/83526/download

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

Liz Arangio
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Email: Elizabeth.Arangio@nationalgrid.com

Megan Borst
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nationalgrid

Asset Management Arrangement – Package 2 & 3
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

Date:

Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposals for Asset Management Arrangements ("AMA") dated May 18, 2022. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall be defined as set forth in Base Contract. ***This Transaction Confirmation will not become binding until executed by both parties.***

SELLER/ASSET MANAGER:

BUYER:
The Narragansett Electric Company
100 East Old County Road
Hicksville, New York 11801
Attn: Contract Administration
Email: Confirmationseprm@nationalgrid.com
Transporters: Enbridge Gas Inc. ("Enbridge"), TransCanada Pipelines Limited ("TransCanada")
Transporters Contract Number:
Trader: Samara Jaffe

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

Term: Begin: November 1, 2022 **End: October 31, 2023**

Performance Obligation and Contract Quantity: See Special Conditions below.

Delivery Point(s): The Delivery Point shall be the point of interconnection between TransCanada and Portland Natural Gas Transmission System known as East Hereford, on the U.S. side.

Special Conditions:

A. Definitions

"Assets" means the Agreements summarized as follows:

Pipeline	Contract No.	Volume (dth)	Volume (Gj)	Receipt Point	Delivery Point
Enbridge	M12274	29,056	30,656	Dawn	Parkway
TransCanada	FT 64273	29,056	30,656	Parkway	East Hereford

"CER" shall mean the Canada Energy Regulator.

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

"Credit Support Provider" means _______________.

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

"Demand Charges" means the applicable demand charges due to Union and TransCanada under the assigned Assets.

"FERC" means the Federal Energy Regulatory Commission.

"Program" means Buyer's state approved retail access program.

B. Gas Service and Capacity Assignment

1. **Assignment of Assets:** During the Term, Buyer will assign the Assets to Seller on a Monthly basis after determining Program requirements. Seller shall initially pay the Demand Charges to TransCanada and Enbridge and Buyer shall reimburse Seller for such charges. Buyer shall reimburse Seller for Demand Charges in U.S. dollars using 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. 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 and to comply with Buyer's Program. All assignments shall be subject to recall in the event that the Seller fails to meet its Gas supply obligation to Buyer.

   At least five (5) Days prior to the 1st calendar Day of each Month, Buyer shall communicate to Seller, in writing via email, the volume of the Assets that Buyer must assign under the Program and the residual amount that shall be made available to Seller under the transaction for the applicable Month of the Term. Seller agrees to take all necessary actions to allow National Grid to administer the assignments necessary and comply with the Program.

2. **Gas Supply Requirements:**

   i. **November through April:** On any Day during the period of November 1, 2022 through April 30, 2023 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 of the Assets in Seller's control. Subject to satisfaction of these "Gas Supply Requirements" and compliance with National Grid's Program, Asset Manager shall have the right to optimize the assigned capacity for its own account subject to the following:

      a) Base-Load Quantities Option: At least three (3) 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 Requirements at the Delivery Point up to the MDQ during the period of November 1, 20221 through April 30, 2023.

      b) Daily-Call Quantities Option: Further, subject to Buyer having exercised its Base-Load Quantities Option pursuant to Special Condition B.2(i)(a), Buyer shall have a right to call on a quantity up to the remaining MDQ for the period of November 1, 2022 through April 30, 2023.

   Subject to these 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 supplies called on 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 firm Base-Load Quantities 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.

3. **Nominations:** Buyer shall make all nominations for delivery of Daily Call Quantities 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 the Intercontinental Exchange ("ICE") and shall be treated the same as weekends (*i.e.*, nominated ***ratably*** on Business Day prior to the Holiday).

4. **Termination Option/Recall Rights:** If at any time during the Term, Seller fails to deliver Gas required to be delivered hereunder or compliance with allowing Buyer to administer its Program, 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 under the terms of the Base Contract. [Bidders ***must*** specify with their offer whether this language is accepted as part of their bid. Non-conforming proposals to this provision will only be considered where Seller agrees that for each undelivered dth that is not excused by Force Majeure, Seller shall pay to Buyer the higher of Buyer's actual replacement cost or 150% of the Price per dth for the date of delivery.]

C. Price

A. Base-Load Quantities: The Contract Price for Gas purchased pursuant to B.2(i)(a) shall be equal to the price posted as the "Index" for Upper Midwest, "Dawn, Ontario," as published in *Platts Inside FERC* for the Month of delivery, plus imputed variable costs (including fuel) to transport Gas from Dawn to the Delivery Point.

B. Daily Call Quantities: The Price for Gas purchased pursuant to B.2(ii)(b) shall be equal to *Platts Gas Daily Daily Price Survey*, Midpoint for Day of flow, Dawn, Ontario, plus imputed variable costs (including fuel) to transport such quantity from Dawn to the Delivery Point.

C. Notwithstanding the foregoing, if in Buyer's sole discretion operational issues on the Assigned Assets may preclude Seller from delivering Gas to the East Hereford Delivery Point at the Base-Load or Daily Call Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the East Hereford Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assigned Assets and Buyer may immediately terminate this Transaction Confirmation.

D. 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 $______ per MMBtu of capacity made available by Buyer to Seller calculated on the TransCanada East Hereford Delivery Point for the Month of flow. 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 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 Baa3 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 Baa3 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 Gas delivered to Buyer hereunder, whether of the Canada Energy Regulator, 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.

G. Changes in Law

If the CER, 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, either party shall provide Notice of such event to the other party and 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: By: ____________________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By: ________________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-6

Attachment GSP-6

RFP for AMA Columbia Gas Transmission ("TCo")

Request for Proposals ("RFP") for
The Narragansett Electric Company ~~d/b/a National Grid~~
Asset Management Arrangement ("AMA")
May 18, 2022

The Narragansett Electric Company ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an AMA as more fully set forth below. This capacity on Colombia Gas Transmission, L.L.C. to be released under the proposed AMA feeds Buyer's capacity on Algonquin Transmission L.L.C. for customers in Rhode Island. The successful bidder(s) ("Seller") shall have the right to optimize the assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

Package No. 4_ - AMA (TCo – Broadrun to Hanover)

I. Provisions

Term: November 1, 2022 through October 31, 2023.

Delivery Period: November 1, 2022 through April 15, 2023.

Assets: During the Term, Buyer shall release FTS contract 31523 with Columbia Gas Transmission L.L.C. ("TCo"), having primary receipts at Broadrun and primary deliveries in at the interconnection between TCo and Algonquin Gas Transmission, LLC ("AGT") at TCo-Hanover and a maximum daily quantity of 10,000 dth/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 TCo and AGT into AGT known as TCo-Hanover.

Gas Supply Requirements: On any day during the period of **November 1, 2022 through April 15, 2023** ("Delivery Period"), 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 subject to the following.

(a) At least three business days prior to the 1st day of the following month of delivery for the months November through and including March, 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 the right to call on a quantity up to the remaining MDQ for the full delivery period of November through and including April 15, 2023.

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 TCo Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

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

Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.

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).

Subject to these 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 supplies called on 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 firm Base-Load Quantities 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, 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.**

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 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 Time)

May 25, 2022	Proposals must be received by Narragansett by 5:00 PM EST. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on June 1, 2022.**
September 1, 2022	Please note that in order to prepare any and all filings related to gas cost recovery in its respective jurisdictions, it is Narragansett's desire to finalize all contract arrangements to later than this date.

IV. Form of Agreement

Narragansett 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. Narragansett reserves the right to withdraw or modify this RFP at any time and Narragansett 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 Narragansett in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by Narragansett.

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.nationalgrid.com/document/83526/download

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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Kate Toriello
Senior Program Manager of Gas Contracting, Compliance & Hedging
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nationalgrid

Asset Management Arrangement – Package 4
Transaction Confirmation
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

		Date: ____________ Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposal for Asset Management Arrangements dated May 18, 2022. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated _________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***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 100 East Old County Road Hicksville, New York 11801 Attn: Contract Administration Email: Confirmationseprm@nationalgrid.com Base Contract No. Transporters: Columbia Gas Transmission L.L.C. ("TCo") Trader: Samara Jaffe

Contract Price: See Special Conditions Section C Below

Term: Begin: November 1, 2022 End: October 31, 2023

Performance Obligation and Contract Quantity: See Special Conditions Below

Delivery Point(s): The point of interconnection between TCo and Algonquin Gas Transmission LLC ("AGT") into AGT known as TCo-Hanover.

Special Conditions:

A. Definitions

"Assets" means Buyer's FTS contract 31523 with TCo, having primary receipts at Broadrun and primary deliveries in at the interconnection between TCo and AGT at TCo-Hanover and a maximum daily quantity of 10,000 dth/day ("MDQ").

"Credit Support Provider" means___________________________.

"CFTC" means the Commodity Futures Trading Commission.

"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 "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. **Gas Supply Requirements:** On any day during the period of **November 1, 2022 through April 15, 2023** ("Delivery Period"), 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 the following

(i) At least three business days prior to the 1st day of the following month of delivery for the months November through and including March, 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 for the full delivery period of November through and including April 15, 2023.

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. [Bidders ***must*** specify with their offer whether this language is accepted as part of their bid. Non-conforming proposals to this provision will only be considered where Seller agrees that for each undelivered dth that is not excused by Force Majeure, seller shall pay to Buyer the higher of Buyer's actual replacement cost or 150% of the Price per dth for the date of delivery.]

C. 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 TCo Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point.

The commodity price for Gas called on through the exercise of a Base-Load option shall be equal to *Platts Inside FERC* for TCo Pool.

Notwithstanding the foregoing, if in *Buyer's sole discretion* operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate this Transaction Confirmation.

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 the Intercontinental Exchange ("ICE") and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Subject to these 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 supplies called on 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 firm Base-Load Quantities 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.

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- by S&P and/or Baa3 by 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 Buyer, (ii) the amount of Cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Buyer for the benefit of Buyer, and (iii) the undrawn value of each 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- by S&P and/or Baa3 by 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 Baa3 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. 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 By:__________________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-7

Attachment GSP-7

RFP for AMA Millennium Pipeline to Ramapo

nationalgrid

Request for Proposals ("RFP") for
Asset Management Arrangement
May 18, 2022

The Narragansett Electric Company ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an Asset Management Arrangement ("AMA") as more fully set forth below. This AMA is for the management of Buyer's capacity on Millennium Pipeline Company, L.P. ("Millennium") which feeds Buyer's managed transportation on Algonquin Gas Transmission Company ("AGT") to serve customers in Rhode Island. The successful bidder ("Seller") shall have the right to optimize the released assets ("Assets") subject to satisfying Buyer's Gas Supply Requirements.

Package No. 5 – AMA – Millennium Eastern System Upgrade – Corning-to Ramapo AGT

I. Provisions:

Term: November 1, 2022 through October 31, 2023.

Delivery Period: November 1, 2022 through April 30, 2023.

Assets and the Release of Assets: During the Term, Buyer shall release at no cost to Seller, 5,000 dth/day (the "MDQ") of its Firm Transportation Contract No. 210165 with Millennium having a primary point of receipt of Corning-Empire PL and primary firm delivery entitlements to Ramapo-AGT.

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). A copy of Buyer's Contract No. 210165 and the negotiated rate agreement with Millennium are included with this RFP. National Grid will not advise Bidders or an Asset Manager on potential transactions that may result in a loss of discount.

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. The parties intend that any transaction entered into pursuant to this RFP shall be structured as an AMA 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 (s): The Delivery Point shall be the point of interconnect between Millennium and Algonquin Gas Transmission Pipeline ("AGT") at Ramapo-AGT, into Buyer's AGT capacity.

Gas Supply Requirements: **Peak Period Daily Call Supplies:** On any day during the period of **November 1, 2022 through April 30, 2023** ("Delivery Period") 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. 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 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 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.

(c) Off-Peak Season Daily Call: On any 60 days during the period May 1, 2022 through and including October 31, 2022, Buyer shall have the right, but not the obligation, to call on a quantity of up to the MDQ at the Delivery Point.

<u>Price:</u>	Peak Period Daily Call and Off-Peak Season Daily Call: The commodity price for Gas called on through the exercise of a daily call shall be based on *Platts Gas Daily* – Daily Price Survey ($MMBtu) Midpoint for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point. The commodity price for Gas called on through the Base-Load option shall be based on *Platts Inside FERC* for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point. Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.
<u>Daily Call Nominations</u>:	For Daily Calls at the Delivery Point(s), 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 these 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 supplies called on 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 firm Base-Load Quantities 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 each 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.**

Form of Agreement: Narragansett 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 Narragansett 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.

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 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)

May 25, 2022	Proposals must be received by Narragansett by **5:00 PM**. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on June 1, 2022.**
September 1, 2022	Please note that in order to prepare any and all filings related to gas cost recovery in its respective jurisdictions, it is Narragansett's desire to finalize all contract arrangements no later than this date.

IV. Form of Agreement

Narragansett 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. Narragansett reserves the right to withdraw or modify this RFP at any time and Narragansett 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 Narragansett in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by Narragansett.

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.nationalgrid.com/document/83526/download

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

Liz Arangio
Director of Gas Supply Planning
Email: Elizabeth.Arangio@nationalgrid.com

Megan Borst
Manager of Gas Supply Planning
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Samara Jaffe
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Senior Program Manager of Gas Contracting, Compliance & Hedging
Email: Kate.Toriello@nationalgrid.com

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Form of Transaction Confirmation – Package 5
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

		Date: ____________ Transaction Confirmation #: ____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposal for Asset Management Arrangements dated May 18, 2022. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer dated________("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***The terms of this Transaction Confirmation are binding upon execution hereof by both parties.***

Seller:	**Buyer:**
Attn: ________________________________ Phone: ______________________________ Fax: ________________________________	The Narragansett Electric Company 100 East Old Country Road Hicksville, New York 11801 Attn: Contract Administration Email: Confirmationseprm@nationalgrid.com Base Contract No. Transporter: Millennium Pipeline Company, L.LC. ("Millennium"} Transporter Contract Number: 210165 Trader: Samara Jaffe

Contract Price: See Special Conditions below.

Term: Begin: November 1, 2022 End: October 31, 2023

Performance Obligation and Contract Quantity: See Special Conditions Below.

Delivery Point(s): The Delivery Point(s) shall be the point of interconnect between Millennium and Algonquin Gas Transmission Pipeline ("AGT") at Ramapo-AGT, into Buyer's capacity on AGT.,

Special Conditions:

A. Definitions

"Assets" means the released portion of Buyer's Millennium Contract No. 210165, having primary points of receipt at Corning-Empire PL and primary firm delivery entitlements to Ramapo-AGT.

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

"Credit Support Provider" shall mean _____________.

"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 Services, Inc. or its successor.

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

B. Gas Service and Release of Assets

1. **Release of Assets:** During the Term, Buyer shall release at no cost to Seller, 5,000 dth/day (the "MDQ") of its Firm Transportation Contract No. 210165 with Millennium having a primary point of receipt of Corning-Empire PL and primary firm delivery entitlements to Ramapo AGT.

   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). Seller shall be responsible for all variable costs in connection with the Assets during the Term. 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.

2. **Gas Supply Requirements: Peak Period Daily Call Supplies:** On any day during the period of November 1, 2022 through April 30, 2023 ("Delivery Period") 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 Points. 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 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 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.

   (c) Off-Peak Season Daily Call: On any 60 days during the period May 1, 2022 through and including October 31 2022, Buyer shall have the right, but not the obligation, to call on a quantity of up to the MDQ at the Delivery Point.

3. **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. [Bidders ***must*** specify with their offer whether this language is accepted as part of their bid. Non-conforming proposals to this provision will only be considered where Seller agrees that for each undelivered dth that is not excused by Force Majeure, Seller shall pay to Buyer the higher of Buyer's actual replacement cost or 150% of the Price per dth for the date of delivery.]

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

(a) For Gas purchased pursuant to Special Condition 2, 2(b) or 2(c) (i.e., called on through the exercise of a daily call) the price shall be equal to *Platts Gas Daily – Daily Price Survey* ($MMBtu) Midpoint for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point(s).

(b) For Gas purchased through the Base-Load option pursuant to Special Condition 2(a), the price shall be equal to *Platts Inside FERC* for Millennium East Pool, plus the imputed variables to deliver the Gas Supply to the Delivery Point(s).

(c) Notwithstanding the foregoing, if in Buyer's sole discretion operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Base-Load or Daily Call Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate this Transaction Confirmation.

B. Nominations

For Daily Calls at the Delivery Point(s) purchase pursuant to Special Condition 2, 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 the Intercontinental Exchange ("ICE") and shall be treated the same as weekends (*i.e.*, nominated ratably on the Business Day prior to the Holiday).

Subject to these 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 supplies called on 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 firm Base-Load Quantities 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.

C. 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 $_______________, payable in equal monthly installments of $ _______. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month.

D. 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 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 Baa3 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- from S&P and/or Baa3 from Moody's, (b) cash, or (c) a Letter of Credit. 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.

E. Asset Management Arrangement ("AMA")

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.

F. 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: ______________________________ Name: Title: Date:	Buyer: The Narragansett Electric Company By: ______________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-8

Attachment GSP-8

RFP for AMA Dracut to Citygate

nationalgrid

Request for Proposals ("RFP") for The Narragansett Electric Company Asset Management Arrangement ("AMA") and Gas Supply May 18, 2022

The Narragansett Electric Company ("Narragansett" or "Buyer") is seeking proposals ("Proposals") for an AMA of its capacity on Tennessee Gas Pipeline Company ("TGP") to deliver supply into its Rhode Island customers in Zone 6 South 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 in increments of 7,500 dth/day and should indicate the maximum volume they would be willing to receive under an AMA.** The maximum delivered quantity of the Assets to be released by Buyer pursuant to an AMA resulting from this RFP is **15,000 dt/day** ("MDQ").

Package No. 6_ – AMA (Dracut to City Gate)

I. Provisions

Term: November 1, 2022 through October 31, 2023.

Delivery Period: December 1, 2022 through April 30, 2023

Assets: During the Term, Buyer shall release FT-A capacity Contract No. 349449 with 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 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, 2022 through April 30, 2023**, 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.

<u>Price:</u>	For the first 50 days 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 50 days of call, the Price for each additional exercise of the call option pursuant to Gas Supply Requirements shall be equal to TGP, Zone 6, Delivered North as published in *Platts Gas Daily Daily Price Survey* for the day of flow *plus* \$0.05, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered. Notwithstanding the foregoing, if in ***Buyer's sole discretion*** operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Price stated in a Transaction Confirmation resulting from this RFP, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate a Transaction Confirmation resulting from the RFP.
<u>Daily Call Nominations</u>:	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). 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.
<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, Bidders must specify the Asset Management Fee to be paid to Buyer.**

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)

May 25, 2022	Proposals must be received by Narragansett by **5:00 PM EST**. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on June 1, 2022.**
September 1, 2022	Please note that in order to prepare any and all filings related to gas cost recovery in its respective jurisdictions it is Narragansett's desire to finalize all contract arrangements no later than this date.

IV. Form of Agreement

Narragansett 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. Narragansett reserves the right to withdraw or modify this RFP at any time and Narragansett 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 Narragansett in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by Narragansett.

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.nationalgrid.com/document/83526/download

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 Gas Supply Planning
Email: Elizabeth.Arangio@nationalgrid.com

Megan Borst
Manager of Gas Supply Planning
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Samara Jaffe
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nationalgrid

Asset Management Arrangement – Package 6
Transaction Confirmation
The Narragansett Electric Company ("Narragansett")

TRANSACTION CONFIRMATION

		Date: _____________ Transaction Confirmation #: _____________

This Transaction Confirmation was awarded pursuant to Narragansett's Request for Proposal for Asset Management Arrangements dated May 18, 2022. This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas between Seller and Buyer, dated __________ ("Base Contract"). Terms not defined in this Transaction Confirmation shall have the meaning provided in the Base Contract. ***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 100 East Old County Road Hicksville, New York 11801 Attn: Contract Administration Email: Confirmationseprm@nationalgrid.com 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, 2022 End: October 31, 2023

Performance Obligation and Contract Quantity: See Special Conditions Below

Delivery Point(s): The primary points of interconnection between Tennessee and Buyer's facilities in Tennessee Zone 6 released by Buyer to Seller as part of the Assets

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. The maximum delivered quantity of the Assets is **15,000 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, 2022 through April 30, 2023**, 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. [Bidders must specify with their offer whether this language is accepted as part of their bid. Non-conforming proposals to this provision will only be considered where Seller agrees that for each undelivered dth that is not excused by Force Majeure, Seller shall pay to Buyer the higher of Buyer's actual replacement cost or 150% of the Price per dth for the date of delivery.]

C. Price: For the 50 days 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 50 days 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* $0.05, plus the variables to transport Gas to the Delivery Point, for each dth of Gas delivered.

Notwithstanding the foregoing, if in *Buyer's sole discretion* operational issues on the Assets may preclude Seller from delivering Gas to the Delivery Point at the Price stated in this Special Condition C, then Buyer may direct Seller at the Nominations deadline to deliver a certain percentage of the MDQ at a fair market price for the Delivery Point. If Buyer makes such request for alternative pricing and Seller fails to deliver Gas at the alternative pricing requested by Buyer or Buyer and Seller are unable to agree to a fair market price for such deliveries, Seller's failure shall not be excused as a result of a failure of the Assets and Buyer may immediately terminate this Transaction Confirmation.

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 the Intercontinental Exchange ("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 By:______________________________ Name: James G. Holodak, Jr. Title: Vice President Date:

Attachment GSP-9

Attachment GSP-9

RFP for Everett and Beverly Supply

Request for Proposals ("RFP") for Gas Supply July 8, 2022

The Narragansett Electric Company d/b/a Rhode Island Energy ("Narragansett") is seeking proposals ("Proposals") for Gas Supplies into its firm transportation capacity on Tennessee Gas Pipeline ("TGP") in Zone 6 (Package No. 7) and Algonquin Gas Transmission LLC ("AGT") (Package No. 8). The winning bidder(s) ("Seller(s)") shall deliver the required gas supply to Narragansett at the Delivery Point.

I. Gas Supply Requirements

Package No. 7 – Gas Supply - Everett

Term: December 1, 2022 through March 31, 2023.

Delivery Point: The Delivery Point shall be the interconnection between the facilities of Constellation LNG, LLC at Everett, MA and Narragansett's firm transportation agreement with TGP.

Bidders wishing to deliver to alternative delivery points must indicate so with their offer, inclusive of the specific point of interconnect between either TGP and AGT and Narragansett's distribution system; an awarded bidder will not be allowed to deliver to alternative delivery points without prior permission from Narragansett.

Quantity: Daily Call: The maximum daily quantity shall be up to 25,000 dt/day ("MDQ") and the maximum seasonal quantity ("MSQ") shall be 890,000 dt.

Bidders wishing to submit offers less than the MDQ may adjust the MSQ of both proportionately.

Package No. 8 – Gas Supply – Beverly, MA

Term: December 1, 2022 through March 31, 2023.

Delivery Point: The "Delivery Point" shall be the interconnection between Maritimes US and AGT Meter #00215, located in Salem, Massachusetts (Essex County).

Bidders wishing to deliver to alternative delivery points must indicate so with their offer, inclusive of the specific point of interconnect between either TGP and AGT and Narragansett's distribution system; an awarded bidder will not be allowed to deliver to alternative delivery points without prior permission from Narragansett.

Quantity: Daily Call: The maximum daily quantity shall be up to 5,000 dt/day ("MDQ") and the maximum seasonal quantity ("MSQ") shall be 100,000 dt.

II. Provisions Applicable to *both* Package No.s 7 and 8

Price:

Commodity:
The commodity price for Gas called on any day shall be presented to Buyer in two alternative proposals as follows:

1) The commodity price shall be equal to Platts Gas Daily – Daily Price Survey ($MMBtu) Midpoint for either Tennessee (Package No. 7) or AGT City-Gates (Package No. 8) for the day supplies are delivered.

2) NYMEX.

Reservation Charge: To be proposed by Bidder for ***both*** commodity price alternatives.

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.

As part of their bids, bidders must specify whether bids need be ***ratable*** across weekends and holidays

Damages:

On any day Buyer nominates Gas pursuant to an agreement resulting from this RFP and Seller fails to deliver the nominated quantity, Seller shall reimburse Buyer for each undelivered dth an amount equal to the greater of Buyer's Cover costs or 150% of the greater of Gas Daily Midpoint for AGT City-Gates or Tennessee Zone 6 North per dth for the applicable day.

Trade Restrictions:

Bidders warrant to be aware of all economic sanctions laws, anti-boycott laws, and trade restrictions imposed by the US, UK, UN and EU, as may be amended from time to time, and warrant to comply with them in all respects related to the performance of this RFP and any contract that may result from this RFP. This warranty refers particularly but not exclusively to sanctions laws pertaining to the Russian Federation, its citizens and any businesses they may own, control, or have a charter for, and in general to any other person, company or entity involved in the performance of this RFP and any contract that may result from this RFP. Bidder shall indemnify Narragansett and hold it fully harmless in the event of loss or damage suffered by bidders, their principals or their affiliates, as a result of any breach, whether intentional or not, of the abovementioned economic sanctions laws, anti-boycott laws and/or trade restrictions by bidders or any of the persons, companies and entities comprised in the Buyers' warranty under the terms of this clause. Nothing in this RFP or any contract that may result from this RFP is meant to require either party to take any action which is likely to place it, or its affiliates, in a position of non-compliance with, or in contravention of, the above-mentioned laws and restrictions. In particular, but without limitation, Narragansett shall at any time be entitled to reject or withdraw acceptance of any bidder or contract that may result from this RFP, where the bidder or contract would place Narragansett or its affiliates in a position of non-compliance with, or in contravention of, the said laws and restrictions

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 must include: **(a) Seller's proposed Price (including Reservation Charge), (b) any specialized language Seller requires in the Transaction Confirmation pertaining to the FERC or to the CFTC, 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)

July 22, 2022	Proposals must be received by Narragansett by 5:00 PM. **All proposals shall expressly provide that they will remain binding and in effect, without modification, until 5:00 PM on July 29, 2022.**
September 1, 2022	Please note that in order to prepare any and all filings related to gas cost recovery in its respective jurisdictions it is Narragansett's desire to finalize all contract arrangements no later than this date.

IV. Miscellaneous

Narragansett 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. Narragansett reserves the right to withdraw or modify this RFP at any time and Narragansett 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 Narragansett in its sole discretion. Potential Sellers shall be subject to satisfactory credit review by Narragansett.

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Testimony of
Paul J. Hibbard

PRE-FILED DIRECT TESTIMONY

OF

PAUL J. HIBBARD

Table of Contents

I. Introduction and Qualifications

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

A. My name is Paul J. Hibbard. My business address is 111 Huntington Avenue, Boston, MA 02199.

Q. On whose behalf are you testifying in this matter?

A. The Narragansett Electric Company, d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy").

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

A. I am employed by Analysis Group as a Principal.

Q. Please summarize your professional and educational background.

A. I provide consulting services to clients in the areas of energy and environmental markets, regulation, and policy. I have been with Analysis Group for approximately sixteen years, since 2003. First, from 2003 to April 2007, and most recently, from August 2010 to the present. In between, from April 2007 to June 2010, I served as Chairman of the Massachusetts Department of Public Utilities ("Department"). While Chairman, I also served as a member of the Massachusetts Energy Facilities Siting Board, the New England Governors' Conference Power Planning Committee, and the NARUC Electricity Committee and Procurement Work Group. I also served as State Manager for the New

England States Committee on Electricity and as Treasurer to the Executive Committee of the 41-state Eastern Interconnect States' Planning Council.

I previously worked in energy and environmental consulting with Lexecon, Inc. from 2000 to 2003. Prior to working with Lexecon, I worked in state energy and environmental agencies for almost ten years. From 1998 to 2000, I worked for the Massachusetts Department of Environmental Protection on the development and administration of air quality regulations, Clean Air Act State Implementation Plans, and emission control programs for the electric industry with a focus on criteria pollutants and carbon dioxide, as well as various policy issues related to controlling pollutants from electric power generators within the Commonwealth of Massachusetts. From 1991 to 1998, I worked in the Electric Power Division of the Department on cases related to the setting of utility rates, restructuring of the electric industry in Massachusetts and New England, quantification of environmental externalities, integrated resource planning, energy efficiency, utility compliance with state and federal emission control requirements, regional electricity market structure development, and coordination with other states on electricity and gas policy issues through the staff subcommittee of the New England Conference of Public Utility Commissioners.

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

A. Yes. While I have not testified before the Rhode Island PUC, I have submitted testimony before the Federal Energy Regulatory Commission ("FERC") and state public utility commissions and siting boards on a variety of subject areas. I have testified numerous times on behalf of the New England Independent System Operator ("ISO-NE") and the New York Independent System Operator ("NYISO") on a range of wholesale electricity market issues including the setting of capacity market demand curves, changes to wholesale market designs, and the cost impact of new wholesale market rules. I have also submitted testimony to FERC on jurisdictional ratemaking issues. I have testified in state public utility commission natural gas and electric utility proceedings related to company mergers, the prudence of natural gas system investments, rate design, environmental impacts, and natural gas and electric integrated resource planning. I have testified before siting boards related to the proposed siting of new power plant infrastructure in New England. Finally, I have testified before New England state legislators on environmental policy and before the U.S. Congress on natural gas-electric system coordination issues and on interstate transmission. Additional detail regarding my credentials and experience can be found in my *curriculum vitae*, which is attached as Attachment PJH-1 to this testimony.

II. Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. I have been asked by the Company to provide background on regional and international factors that affect the pricing of natural gas supply and transportation, as context for the gas supply costs that underlie the Company's Gas Cost Recovery ("GCR") filing. In particular, my testimony explains context for the purchase of natural gas in, and delivery of natural gas to, the New England region; the region's unique reliance on liquefied natural gas ("LNG") delivery and storage for supply during winter months; and how recent events have affected the pricing and supply of natural gas to customers in the New England region.

Q. Please summarize your findings.

A. The Company's GCR includes expected increases in rates associated with changes in the underlying costs to procure, store, and transport natural gas for use in Rhode Island. These increases are fully consistent with fundamental changes in underlying factors affecting natural gas supply and demand in the U.S. and, in particular, in New England. The natural gas market factors driving the increased GCR costs are being experienced by natural gas (as well as electric) local distribution companies, and are due to at least the following factors:

(1) New England has a strong winter peak due to (i) widespread use of natural gas for heating homes and businesses in the region, and (ii) a dependence on spot market

purchases of natural gas for operating power plants needed to maintain winter electric system reliability;

(2) New England has significant constraints on the delivery of natural gas for meeting the combined heating and electricity demand in the winter. The region has no indigenous sources of natural gas and sits effectively at the end of the pipeline system delivering gas from the south and west. Although there is a pipeline connection to Eastern Canada, the primary source of deliveries from Canada historically – Sable Island – shut down in 2018. Finally, the New England region, in recent years, has been unable to develop additional natural gas supply and transportation infrastructure to alleviate the persistent winter natural gas transportation constraints. As a result, the natural gas delivery infrastructure that does exist in the region is at or near capacity on most winter days and is operating at maximum capacity on many cold winter days each year.

(3) Finally, these conditions leave New England strongly dependent on international shipments of LNG to meet natural gas demand during cold winter periods. Yet since power plant owners have little incentive to pre-contract for LNG supplies, the availability of LNG for injection on cold winter days in sufficient quantities to meet combined heating and electricity demand is relatively expensive and highly uncertain, adding pricing volatility and uncertainty to the region's natural gas markets.

In a normal year, these conditions can lead to elevated and highly variable natural gas prices in New England during winter months, and correspondingly high pricing in natural gas futures markets, with relatively minor variations in the conditions of supply and demand. Yet, this is not a normal year. The impact of the Russian invasion of Ukraine has fundamentally changed international markets for natural gas, including LNG. The increased demand for global supplies of natural gas from Europe has increased the price of natural gas throughout the U.S. and in much of the world, resulting in increasing exports from the U.S. to Europe and increasing the cost of securing LNG supplies for the LNG import terminals serving New England.

Q. How is your testimony organized?

A. In **Section III**, I summarize the key factors affecting natural gas prices in New England, including the nature of the region's demand for natural gas, supply and delivery sources and challenges, and the pricing dynamics associated with a constrained system and reliance on imported LNG. In **Section IV**, I describe how the circumstances of supply and demand, and the impact of recent turmoil in the market for natural gas, have affected and are affecting the expected cost of natural gas delivered to New England and Rhode Island, in particular. In **Section V**, I describe how the Company's customers are not alone – that other natural gas local distribution company ("LDC") customers are and will see similar impacts, as will electric utility customers. Finally, in **Section VI**, I summarize my observations and conclusions.

III. <u>The Drivers of Natural Gas Pricing in New England</u>

Q. Please summarize the key drivers affecting the cost of natural gas supply in New England.

A. There are three key drivers of natural gas costs in Rhode Island and, more generally, New England. The first involves the nature and timing of natural gas demand. The second relates to the significant constraints on the interstate natural gas infrastructure used to supply and deliver natural gas to the region. The third involves New England's unique reliance on LNG to meet winter natural gas demand. While all three of these are related, I will discuss each separately.

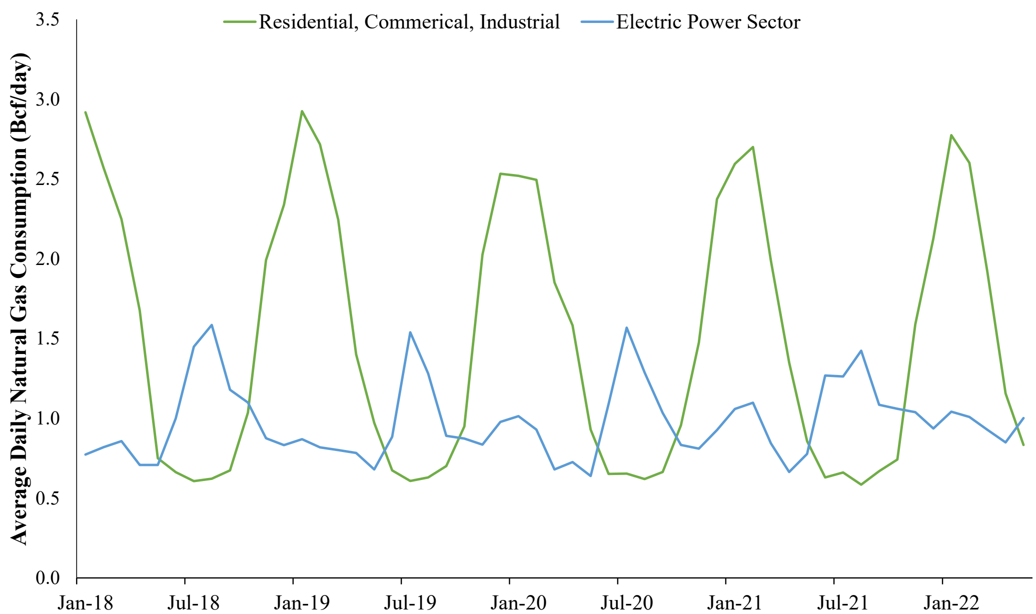
Q. Please describe the nature of natural gas demand in New England.

A. There are two main components of natural gas demand in Rhode Island and the rest of New England. One is LDC demand associated primarily with heating, cooking, and water heating in homes and businesses across the region. This demand is dominated by heating, and reaches its highest levels during winter months when heating is needed. The second is the demand for natural gas to generate electricity in power plants located across New England. This demand is year-round and strongest in the summer, but as described below, has a major influence on winter natural gas price levels and volatility.

As can be seen in **Figure 1**, the total demand for natural gas for (primarily) heating, cooking, and water heating in the residential, commercial, and industrial sectors dominates natural gas demand, reaching peak demand levels of approximately 3.0 Bcf/day on average during the coldest winter months. Electric sector demand for natural gas in turn peaks in the summer, when electricity demand is highest in the region, reaching 1.5 Bcf/day on average during the peak months of summer electricity demand. However, electric sector demand has an important second (albeit lower) peak in the winter, adding 1.0 Bcf/day on average on top of the natural gas demand served by LDCs during the cold winter months.

Figure 1: New England Natural Gas Demand by End-Use Sector[1]

January 2018 – May 2022



Notes:
[1] Average daily New England natural gas consumption is the sum of monthly consumption across Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont divided by the number of days in the month.
[2] Natural gas use in the transportation sector is minimal and is not included.

[1] "Natural Gas Consumption by End Use," EIA, available at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_svt_m.htm.

Q. Please describe how the procurement of natural gas in the electric sector differs from the supply of natural gas to LDCs.

A. Natural gas LDCs have an obligation to reliably meet the demand of their customers, and thus contract for supply, including pipeline transportation, conventional natural gas, and LNG, in advance and over the long-term to ensure firm supply and delivery of sufficient natural gas to meet expected and "design day" peak demand during winter months. This need for long-term, firm supply and delivery of natural gas, and the associated contracts, provide the financial basis for investment in the natural gas infrastructure needed to ensure aggregate LDC regional peak demand can be met on the coldest of winter days.

The gas procurement incentives and practices of gas-fired power plants needed to meet electricity demand are very different. Power plant owners are not subject to rate regulation, and generally do not have an obligation to reliably meet the electricity needs of retail customers.[2] Opportunities to earn revenues (and profits) in electricity markets are instead contingent on being able to supply electricity at the lowest possible cost, with offers that are lower than those of competing power plants. Power plants cannot earn revenues in the energy market if they do not offer competitive prices, and the lower the cost of running the plant, the greater the profit margin. Any increase in the cost to obtain power plant fuel over short-term commodity prices (from, for example, obtaining firm

[2] Power plants earn revenues in the capacity market for being available to generate electricity if called upon, but the ability to earn capacity market revenues is not contingent on any obligation to demonstrate forward procurement of the fuel needed to operate.

transportation service) by definition increases costs relative to competitors and reduces (or eliminates) opportunities for profit in electricity markets.

Thus, there is little to no incentive for power plant owners to contract for natural gas supply any sooner than the day before they offer to provide electricity, if doing so would increase fuel costs and make them less competitive in wholesale electricity markets. As noted by the New England Independent System Operator ("ISO-NE"):

> *Because generators have no guarantee for when or how long they'll be called to run—and there's no practical way for them to store excess pipeline gas or electricity on site—contracting for pipeline capacity only when needed helps natural-gas-fired generators keep their costs as low as possible to maintain competitiveness in the wholesale electricity markets.*
> *While that strategy works for most of the year, on cold days the pipelines are running at or near maximum capacity solely to meet heating demand. During several recent winters, this situation has severely limited the delivery of fuel to much of the region's power plants, which, in turn, threatened the reliable supply of electricity and drove up wholesale electricity prices and air emissions.*[3]

This practice of just-in-time natural gas procurement provides little incentive for the pipeline or LNG supply industry to commit to capital investments to develop infrastructure needed by the region's gas-fired power plants.

[3] "Natural Gas Infrastructure Constraints," ISO New England, available at https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints

Q. How does the status of New England's supply and transportation infrastructure, in combination with the electric sector's participation in natural gas markets, influence the levels and volatility of natural gas prices in winter months?

A. The pricing of natural gas in the Northeast in winter months is sensitive to the circumstances of supply and demand. Unfortunately, these conditions have grown worse over the last several years due to events related to the loss of a major supply source from the eastern end of the system and failure to increase interstate pipeline capacity from the west. As shown in **Figure 2**, several pipelines transport natural gas to New England from the south and west with additional flows arriving on the pipeline systems connected to Canada. There are also three LNG import terminals in the area: Everett in Massachusetts, the Northeast Gateway buoy offshore of Massachusetts, and the St. John facility in New Brunswick Canada, which is connected into New England by the Maritimes and Northeast ("MNE") pipeline.

Figure 2: New England Natural Gas Infrastructure[4]

Beginning in 1999 and for many years thereafter, the Sable Offshore Energy Project ("Sable") in Eastern Canada provided significant injections of natural gas of 12 million cubic meters/day (or approximately 0.4 Bcf/day) or more into the northeastern end of New England (that is, from the opposite direction of the major interstate pipeline supply from the south and west) via the MNE pipeline connecting New England to Eastern Canada. See **Figures 3** and **4**. However, Sable's production declined relatively quickly, and was shut down completely in December 2018.[5] See **Figure 4**. While there is LNG storage and regasification capacity in Eastern Canada (the St. John facility), it has provided less than 30 Bcf/year (0.08 Bcf/day on average) of natural gas into New

[4] "New England natural gas infrastructure map," EIA, as of August 26, 2022, available at https://www.eia.gov/dashboard/new-england-energy-api/archives/202208/20220826_new_england_dashboard.pdf.

[5] "Sable Offshore Energy Project," CNSOPB, available at https://www.cnsopb.ns.ca/offshore-activity/current-activity/sable-offshore.

England since 2013.[6] Sable was the largest supplier of gas for the MNE pipeline connecting New England to Eastern Canada, and its declining production and subsequent closure has switched the MNE pipeline from an importer of Canadian gas to (primarily) an exporter of U.S. gas.[7] See **Figure 3**. Moreover, other supplies from Canada have not increased sufficiently to replace the lost production from Sable. For example, although the Portland Natural Gas Transmission System ("PNGTS"), shown in green in **Figure 2**, has approximately doubled its capacity in recent years, this increase amounted to less than 0.2 Bcf/day, less than half of Sable's production at its peak.[8]

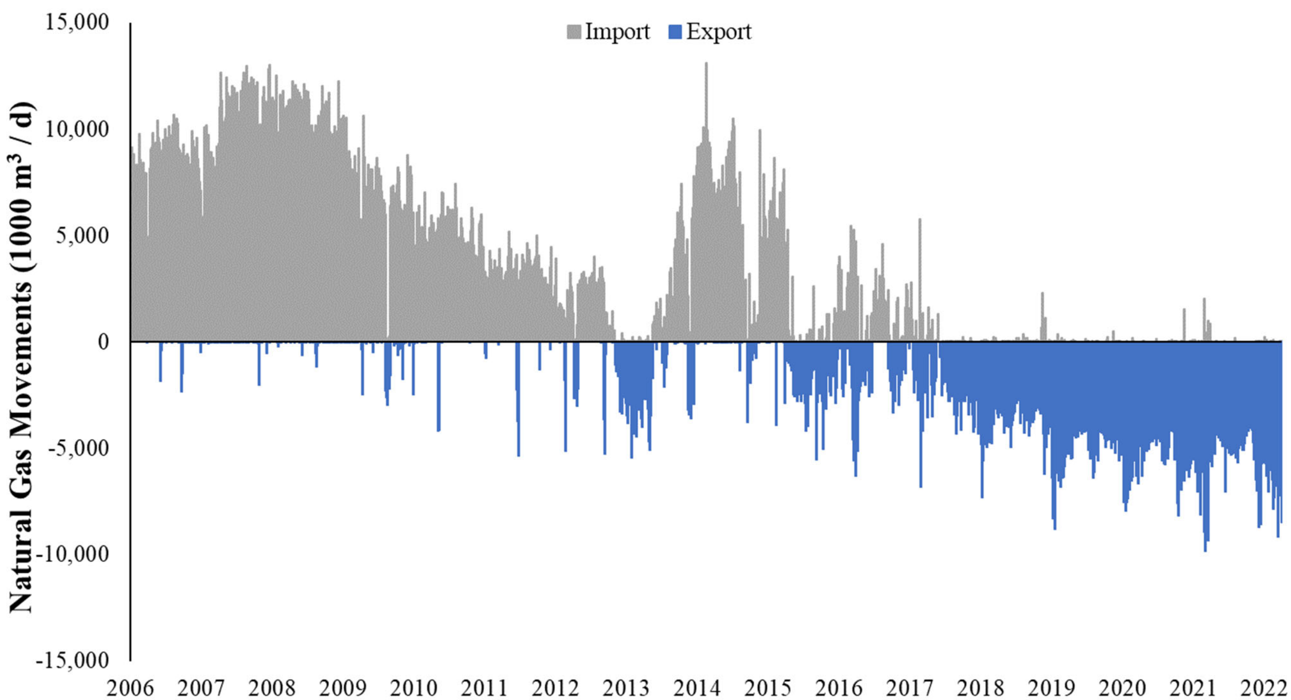
[6] "LNG Imports, Northeast Terminals, 2011-21," Northeast Gas Association, available at https://www.northeastgas.org/pdf/lng_annual0222.pdf; "Description of Pipelines/LNG Import Facilities Serving the Northeast Market," Northeast Gas Association, available at https://www.northeastgas.org/pdf/lng_importers0722.pdf.

[7] "Market Snapshot: The end of natural gas production in the Maritimes increases reliance on imports," Canadian Energy Regulator, February 27, 2019, available at https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2019/market-snapshot-end-natural-gas-production-in-maritimes-increases-reliance-imports.html.

[8] "Portland Natural Gas Transmission System," TC PipeLines, LP, available at https://www.tcpipelineslp.com/assets/pngts/.

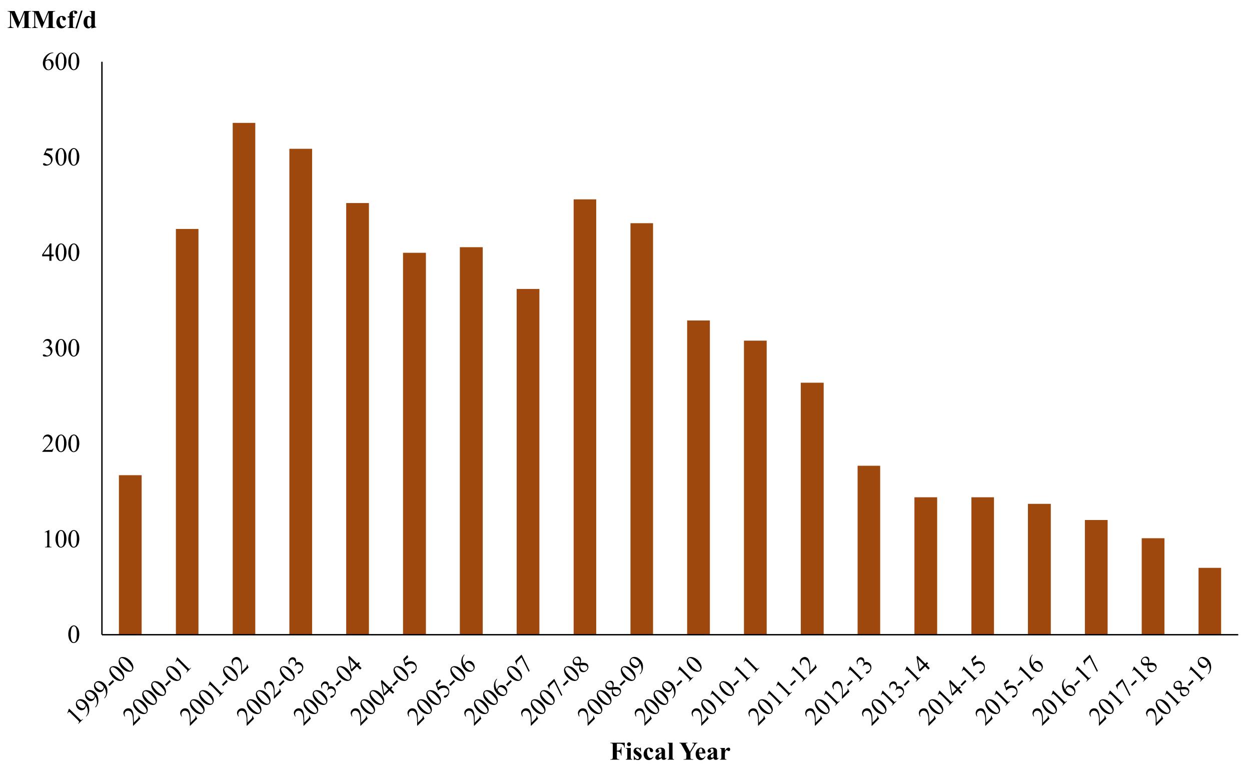
Figure 3: Natural Gas Imports to the U.S. from Canada and Exports from the U.S. to Canada on the MNE Pipeline[9]

2006 – 2022



[9] "Pipeline Throughput and Capacity Data, Maritimes," Canada Energy Regulator, available at https://open.canada.ca/data/en/dataset/dc343c43-a592-4a27-8ee7-c77df56afb34.

Figure 4: Sable Average Gas Production per Day by Fiscal Year[10]
1999/00 – 2018/19



In addition to the loss of Sable, New England has been unable to add natural gas transportation capacity into the region. Most noticeably, in 2016, Kinder Morgan suspended work and spending on a proposed new 430 mile pipeline project to deliver gas through New York and into New England.[11] Similarly, in 2017, Enbridge and its utility partners in New England suspended further work on the Access Northeast pipeline

[10] "SOEP Average Gas Rate by Fiscal Year," Canada-Nova Scotia Offshore Petroleum Board, available at https://www.cnsopb.ns.ca/sites/default/files/resource/sable_final.pdf.

[11] "Kinder Morgan Generates More Than $1.2 Billion of Distributable Cash Flow for First Quarter 2016," Kinder Morgan, April 20, 2016, available at https://ir.kindermorgan.com/news/news-details/2016/Kinder-Morgan-Generates-More-Than-12-Billion-of-Distributable-Cash-Flow-for-First-Quarter-2016/default.aspx.

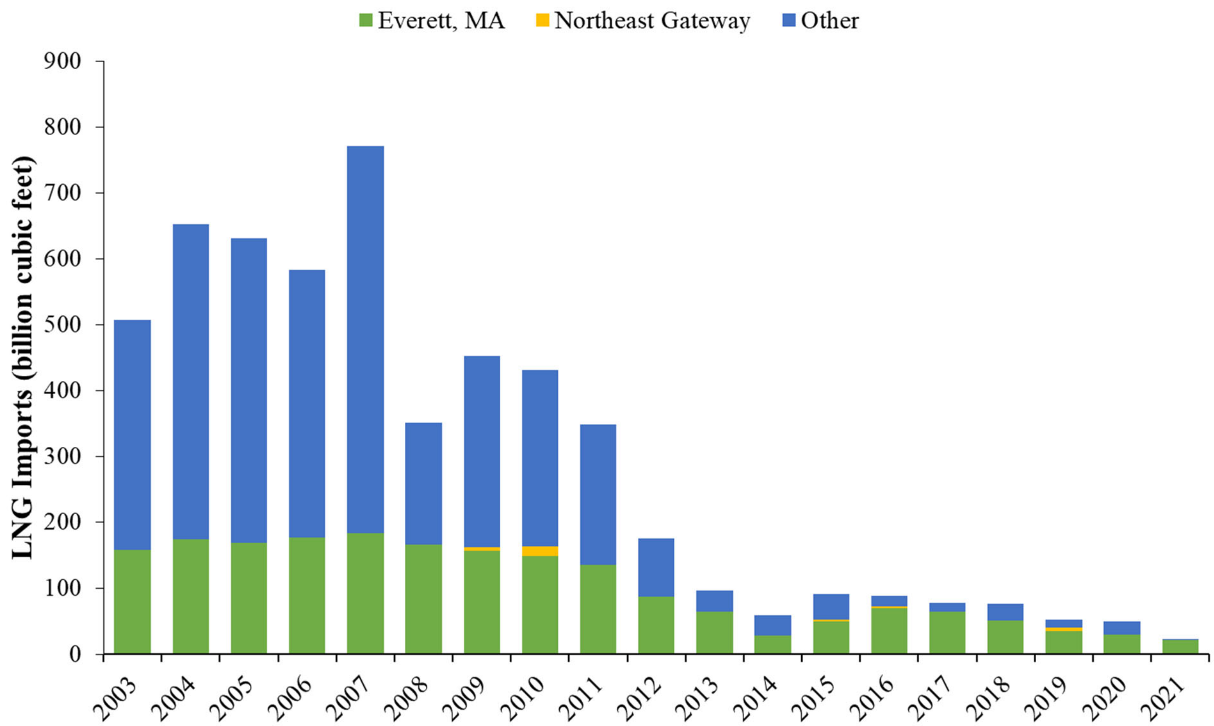
expansion project, another major pipeline project that would have increased natural gas transportation capacity into New England from the Pennsylvania shale gas region.[12] The combined impact of growing demand from the electric sector and its reliance on short-term spot markets for procuring supplies, the potential for significant increases in demand for natural gas for heating during extreme cold weather events, the loss of supply from Eastern Canada, and the lack of a meaningful increase in transportation capacity into New England all combine to put pressure on delivered natural gas price indices within New England, and make prices very sensitive to relatively small perturbations in supply and demand.

Q. Please describe the changing role that LNG plays in meeting U.S. energy needs and in meeting New England's winter supply needs.

A. The U.S., as a whole, has a long history of importing LNG, with peak imports in 2006-2008, but the emergence of shale gas as a plentiful, relatively low-cost domestic resource has led to plummeting LNG import volumes over the last ten to twelve years, with the Everett facility in Massachusetts becoming the primary import terminal. See **Figure 5**.

[12] "Spectra Energy Partners Reports Second Quarter 2017 Results," Spectra Energy Partners, August 2, 2017, available at https://www.spectraenergypartners.com/investors/press-releases?id=122495.

Figure 5: U.S. LNG Imports by Import Terminal[13]
2003 – 2021

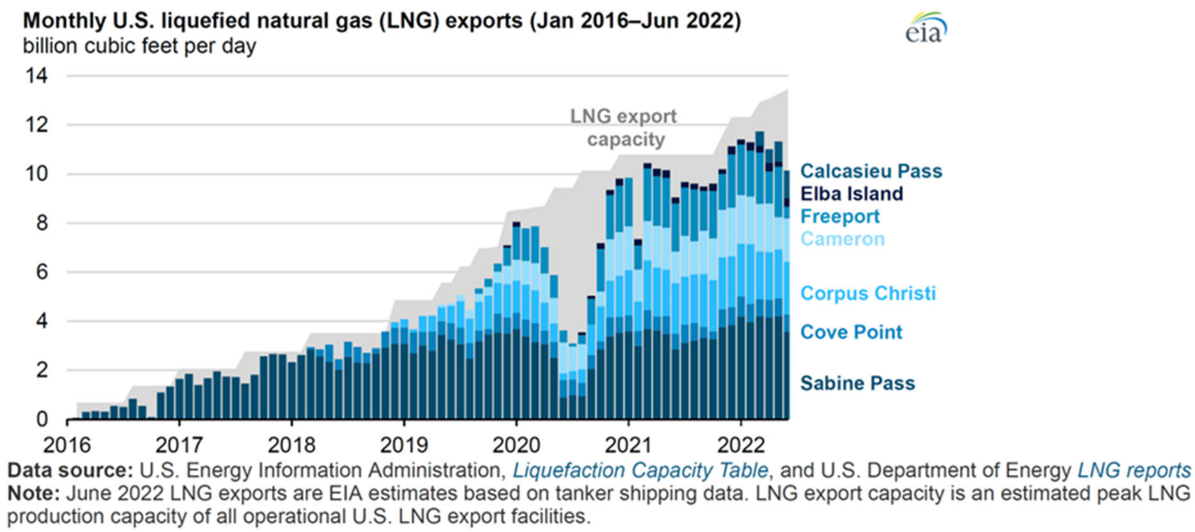


With the growth in shale gas production, the U.S. increased its LNG export capability, with export volumes keeping pace with the growth in export capability over time. See **Figure 6**. In the first half of 2022, U.S. LNG exports increased to 11.2 Bcf/day on average, a 12 percent increase compared to the second half of 2021, making the U.S. the world's largest LNG exporter.[14]

[13] "US Natural Gas Imports by Point of Entry, Liquified Natural Gas Volumes," EIA, available at https://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm.

[14] "The United States became the world's largest LNG exporter in the first half of 2022," EIA, July 25, 2022, available at https://www.eia.gov/todayinenergy/detail.php?id=53159.

Figure 6: Monthly U.S. LNG exports[15]



Despite the major changes in the U.S. LNG import/export picture, LNG imports have continued to play a critical role in meeting New England's winter natural gas demand. According to data from the U.S. Energy Information Administration ("EIA"), New England has been responsible for more than 60 percent of imports each year since 2016 and was the recipient of 100 percent of the LNG imports in 2021.[16] See **Figure 5**.

Q. Why are these factors important to consider in the context of natural gas pricing in New England?

A. These conditions – constrained transportation infrastructure, just-in-time procurement of a significant amount of natural gas by power plants needed for winter power system

[15] "The United States became the world's largest LNG exporter in the first half of 2022," EIA, July 25, 2022, available at https://www.eia.gov/todayinenergy/detail.php?id=53159.

[16] "US Natural Gas Imports by Port of Entry, Liquified Natural Gas Volumes," EIA, available at https://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm.

reliability, and the region's reliance in the winter on international shipments of LNG – put upward pressure on natural gas price indices and introduce pricing uncertainty and volatility to New England's markets in "normal" years. This upward pressure translates into higher natural gas supply costs and upward pressure on futures markets that set prices for longer-term procurements. Perhaps more importantly, *this is not a normal year*. The impact of the Russian invasion of Ukraine has fundamentally changed international markets for natural gas, including LNG. The increased demand for global supplies of natural gas from Europe has increased the price of natural gas throughout the U.S. and in much of the world, resulting in increasing exports from the U.S. to Europe and increasing the cost of securing LNG supplies for the LNG import terminals serving New England.

IV. <u>The Impact of Market Factors on Natural Gas Prices in New England</u>

Q. You have indicated that recent events – in particular the war in Ukraine – are creating an environment for high natural gas prices in New England. Could you please explain in general how these international events and market dynamics affect natural gas prices in this region?

A. As discussed above, natural gas prices in New England are typically higher in winter than in summer due to the demand for heating in winter. Yet as presented in more detail below, the price of natural gas in spot and forward/futures markets – in particular for this winter but also next winter – have increased well beyond prices experienced historically.

The EIA cites to a number of reasons why natural gas prices in 2022 are elevated relative to 2021, including the continued economic recovery, limited natural gas production increases, forecasts that winter 2022-23 will be colder than winter 2021-22, smaller than average inventories of natural gas in the U.S., and limited switching to coal-fired generation due to generator retirements, as well as limited stocks of coal and issues with coal delivery.[17]

Yet, an additional major influence on gas pricing for the New England region is related to the impact of international events on U.S. markets and prices for LNG shipments. Russia's invasion of Ukraine in February 2022 caused – and continues to cause – upheavals in markets for natural gas in Europe, given Europe's heavy dependence on Russia for natural gas supply, Europe's sanctions of Russia, and the ensuing disputes over natural gas supply.[18] Specifically, Russia's pipeline exports to Europe and the United Kingdom in the first seven months of 2022 dropped by almost half compared to the previous five-year average.[19] See **Figure 7**. In turn, prices for natural gas in Europe were trading at over $100/MMBtu in onshore markets as of August 26, 2022 while spot

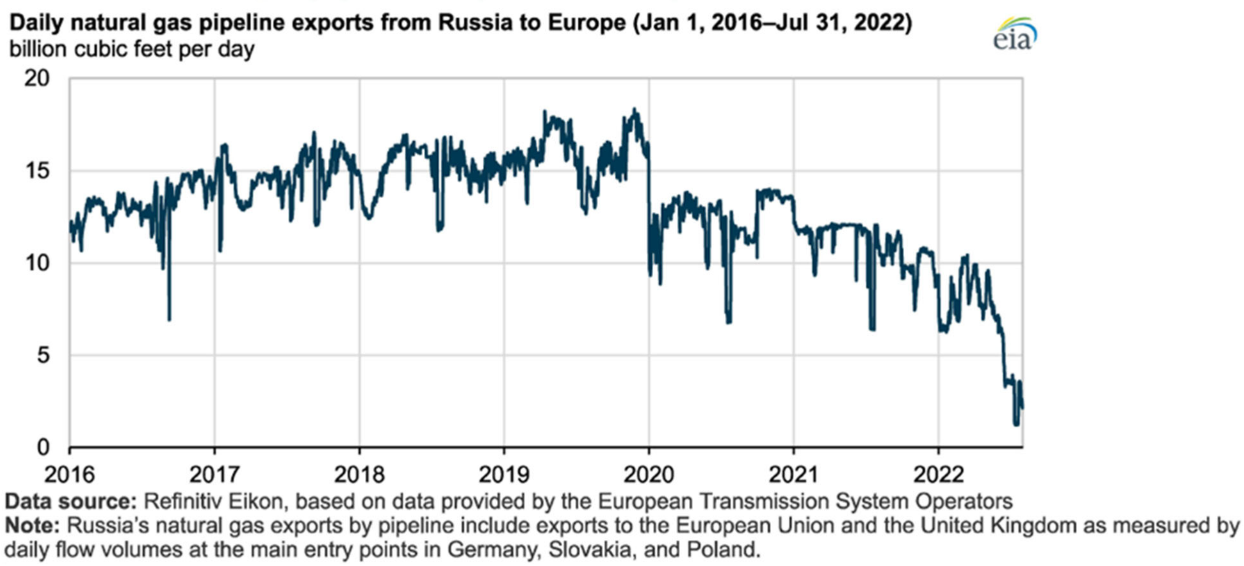
[17] See "Short-Term Energy Outlook: Natural Gas," EIA, July 12, 2022, available at https://www.eia.gov/outlooks/steo/archives/Jul22.pdf; Weber, Maya, "Spot gas prices to top $8/MMBtu in H2'22 despite production growth, EIA predicts," S&P Global Market Intelligence, June 7, 2022; Micek, Kassia, "US EIA sees summer power prices climbing on fuel costs, delivery constraints," S&P Global Market Intelligence, June 17, 2022.

[18] Wallace, Joe and Jenny Strasburg, "Ukraine Reduced Russian Gas Flowing to Europe Through Key Pipeline," The Wall Street Journal, May 11, 2022; Pancevski, Bojan and Jenny Strasburg, "Europe Fears Widespread Economic Fallout if Russian Gas Outage Drags On," The Wall Street Journal, July 18, 2022; "Short-Term Energy Outlook: Natural Gas," EIA, July 12, 2022, available at https://www.eia.gov/outlooks/steo/archives/Jul22.pdf.

[19] "Russia's natural gas pipeline exports to Europe decline to almost 40-year lows," EIA, August 9, 2022, available at https://www.eia.gov/todayinenergy/detail.php?id=53379.

LNG import prices in Europe set a record for the third day in a row at $74.49/MMtu "putting pressure on U.S. LNG export terminals to step up production."[20]

Figure 7: Daily Natural Gas Pipeline Exports from Russia to Europe[21]



Europe's efforts to replace Russian natural gas supplies with supplies from other sources increase the price of natural gas in the U.S. given the increasing expansion of U.S. LNG

[20] "US LNG export terminals stage production push as European gas prices top $100/MMBtu," S&P Global Commodity Insights, August 26, 2022, available at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/082622-us-lng-export-terminals-stage-production-push-as-european-gas-prices-top-100mmbtu.

[21] "Russia's natural gas pipeline exports to Europe decline to almost 40-year lows," EIA, August 9, 2022, available at https://www.eia.gov/todayinenergy/detail.php?id=53379.

export capability, discussed above (see **Figure 6**).[22] As demand for natural gas in Europe strengthens, so does the price Europeans are willing to pay for natural gas, which strengthens the incentive for U.S. producers to export natural gas to Europe.[23] With more domestic supply going to Europe, the price of natural gas delivered in the U.S. increases, including in New England. For example, in the first quarter of 2022, the U.S. supplied 47 percent of the European Union's LNG imports, representing a 235 percent increase in year-on-year LNG exports from the U.S. to the European Union.[24] Similarly, the EIA expects that total LNG exports from the U.S. in 2022 will be 22 percent higher than in 2021.[25]

Moreover, New England's expected and realized natural gas prices are tied in part to the region's critical dependence on LNG for reliable winter gas supply. Yet for this supply,

[22] *See, e.g.,* Weber, Maya, "'Uncomfortable questions' seen ahead for global gas supply dynamics," S&P Global Market Intelligence, July 15, 2022; "Short-Term Energy Outlook: Natural Gas," EIA, July 12, 2022, available at https://www.eia.gov/outlooks/steo/archives/Jul22.pdf ("LNG prices in Europe remain high amid supply uncertainties because of Russia's invasion of Ukraine and the need to replenish Europe's natural gas inventories, which has kept Europe's demand for LNG elevated… The Henry Hub spot price averaged $6.07 per million British thermal units (MMBtu) in 1H22, rising steadily from an average of $4.38/MMBtu in January to $8.14/MMBtu in May… The increase through May resulted from continued demand for LNG exports, increased demand in electric power generation as a result of limited natural gas-to-coal switching, and decreased production compared with the end of 2021.").

[23] "Short-Term Energy Outlook: Natural Gas," EIA, July 12, 2022, available at https://www.eia.gov/outlooks/steo/archives/Jul22.pdf ("Strong natural gas demand and high LNG prices in Europe and Asia drove the continued growth in U.S. LNG exports in the first half of this year.").

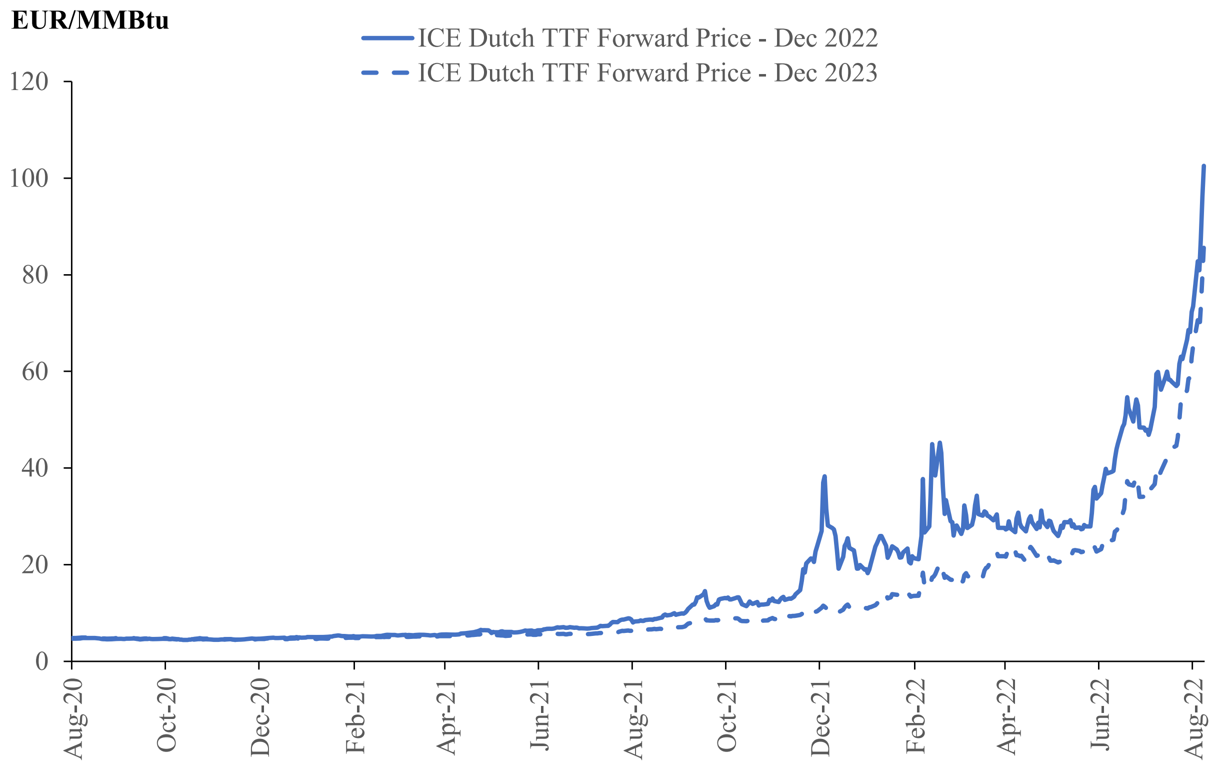
[24] "Quarterly Report on European Gas Markets," European Commission, Vol. 15, Issue 1, Q1 2022, available at https://ec.europa.eu/info/sites/default/files/energy_climate_change_environment/quarterly_report_on_european_gas_markets_q1_2022.pdf, p.16. *See also* Weber, Maya, "'Uncomfortable questions' seen ahead for global gas supply dynamics," S&P Global Market Intelligence, July 15, 2022 ("In the first half of 2022, [the International Energy Agency's] report showed European LNG imports rose by more than 50% compared to last year, while two-thirds of the increase in global LNG trade came from the U.S. alone.").

[25] Weber, Maya, "Spot gas prices to top $8/MMBtu in H2'22 despite production growth, EIA predicts," S&P Global Market Intelligence, June 7, 2022.

New England competes for LNG cargoes in a global market where buyers in Western Europe are moving aggressively to secure supplies given the uncertainty over gas supply from Russia, at the same time that demand from Asian utilities for LNG cargoes is also increasing.[26] This means that New England natural gas suppliers have been, and over the next year, will be, competing for LNG cargoes in a market of rapidly-increasing international prices. See **Figures 8** and **9** for the prices of Dutch TTF natural gas forward contracts in Europe and spot LNG prices in Asia, respectively.

[26] Benjamin Storrow, "How the Ukraine war could make New Englanders shiver," E&E News, May 10, 2022, available at https://www.eenews.net/articles/how-the-ukraine-war-could-make-new-englanders-shiver/.

Figure 8: Forward Prices for Natural Gas in Europe[27]
December 2022 and December 2023 Contracts



Note: The unit of measurement has been converted from the original EUR/MWh to EUR/MMBtu

[27] "Dutch TTF Gas Futures," Intercontinental Exchange, available at https://www.theice.com/products/27996665/Dutch-TTF-Gas-Futures/data?marketId=5419234.

Figure 9: Asian Spot LNG Prices[28]
January 2022 – August 2022

Q. Please describe how the factors you have been describing are affecting U.S. and New England spot prices for natural gas.

A. Spot prices for natural gas at the Henry Hub more than doubled over the past year. Specifically, spot prices at Henry Hub went from $3.86/MMBtu on August 19, 2021 to $9.42/MMBtu on August 19, 2022.[29] Spot prices at Henry Hub have not been above $8/MMBtu since 2008.[30] Similarly, the spot price at the Algonquin City Gate increased

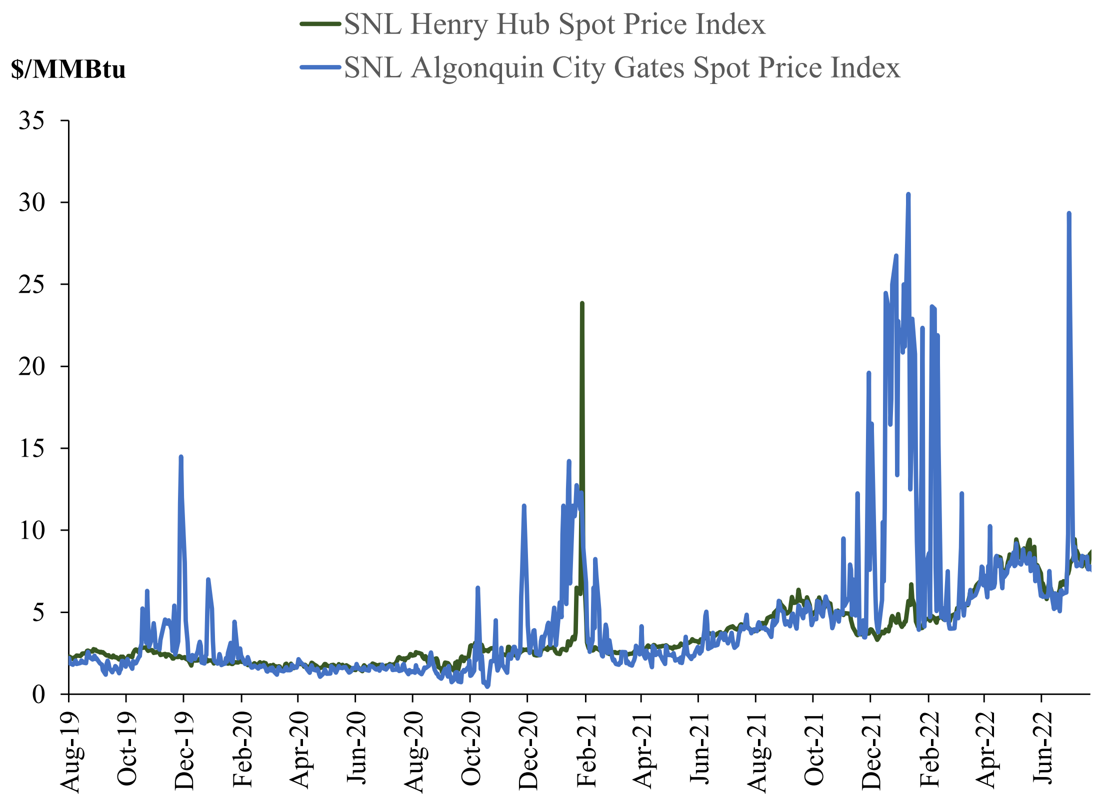
[28] "Asia's LNG winter procurement activity heats up despite strengthening prices," S&P Global Commodity Insights, August 18, 2022, available at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/081822-asias-lng-winter-procurement-activity-heats-up-despite-strengthening-prices.

[29] "SNL Henry Hub Spot Natural Gas Index," S&P Global Market Intelligence.

[30] "U.S. monthly average Henry Hub spot price nearly doubled in 12 months," EIA, July 14, 2022, available at https://www.eia.gov/todayinenergy/detail.php?id=53039.

by over two hundred percent over a one year period, increasing from $3.86/MMBtu on August 19, 2021, to $8.85/MMBtu on August 19, 2022.[31] See **Figure 10**.

Figure 10: U.S. and New England Natural Gas Spot Prices[32]
August 2019 – August 2022



[31] "SNL Algon Gates Spot Natural Gas Index" and "SNL Henry Hub Spot Natural Gas Index," S&P Global Market Intelligence.

[32] "SNL Algon Gates Spot Natural Gas Index" and "SNL Henry Hub Spot Natural Gas Index," S&P Global Market Intelligence.

Q. Are forward prices for the U.S. and New England showing similar trends?

A. Yes. On August 4, 2022, the Henry Hub front-month natural gas futures contract settled at \$8.12/MMBtu, rising from \$2.39/MMBtu on July 1, 2022.[33] On two days in June 2022 the front-month natural gas futures price topped \$9.00/MMBtu.[34] Forward prices and expectations are even more severe for New England. Winter gas prices in New England are hitting record highs in recent trading; Algonquin City Gate peak-winter gas prices for the upcoming season have more than doubled since the start of this year.[35] The January 2023 contract is now priced at a record high of over \$40/MMBtu, while the December 2022 contract recently settled at a new high of over \$34/MMBtu.[36] The pace of change in forward prices has been significant; as of October 4, 2021 the forward price for December 2022 was \$10.05/MMBtu; by August 11, 2022, the price had more than tripled to \$31.54/MMBtu.[37] See **Figure 11**. This trend is consistent both with the influence of this past year's events, with the expectation that New England prices will be driven in part by competition for LNG cargoes with Europe, and with the high price of natural gas

[33] "Short-Term Energy Outlook: Natural Gas Market Review," EIA, August 9, 2022, available at https://www.eia.gov/outlooks/steo/marketreview/natgas.php.

[34] "Short-Term Energy Outlook: Natural Gas Market Review," EIA, August 9, 2022, available at https://www.eia.gov/outlooks/steo/marketreview/natgas.php.

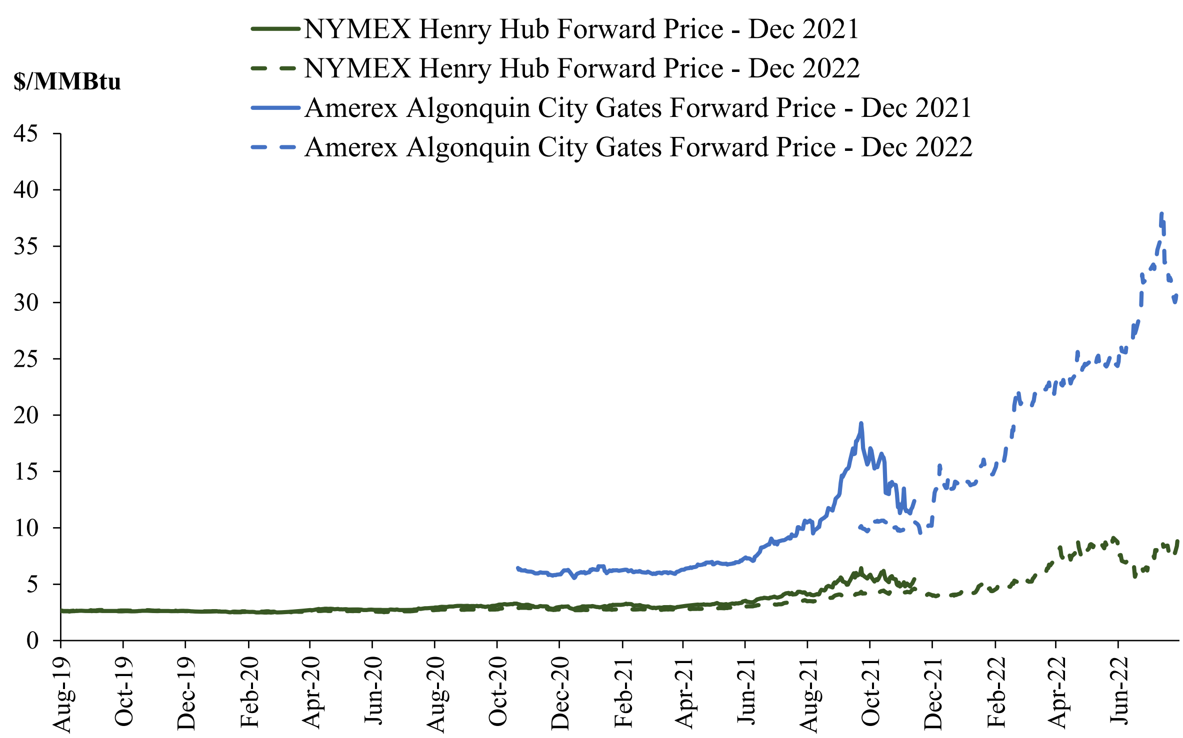
[35] "New England winter natural gas prices top \$40 as global LNG market tightens," S&P Global Commodity Insights, July 22, 2022, available at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/072222-new-england-winter-natural-gas-prices-top-40-as-global-lng-market-tightens.

[36] "New England winter natural gas prices top \$40 as global LNG market tightens," S&P Global Commodity Insights, July 22, 2022, available at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/072222-new-england-winter-natural-gas-prices-top-40-as-global-lng-market-tightens.

[37] "Amerex Algon Gates Natural Gas Full Value Monthly," S&P Global Market Intelligence.

contracts at the Dutch TTF hub in Europe, which are now trading at more than 100 Euro/MMBtu for December 2022. See **Figure 8**.

Figure 11: U.S. and New England Natural Gas Forward Prices[38]
December 2021 and December 2022 Contracts



[38] "NYMEX Henry Hub Natural Gas Futures" and "Amerex Algon Gates Natural Gas Full Value Monthly," S&P Global Market Intelligence.

Q. What do you conclude based on your review of changes in regional, national, and international markets for the supply of natural gas?

A. The cost to supply natural gas to retail customers in Rhode Island has always varied – at times significantly – with changes in the forces of supply, demand, and pipeline transportation utilization.

In addition to the better-known risks affecting natural gas prices – such as regional supply and transportation limitations and the ever-present risk of severe weather – this past year introduced into the equation extreme forces outside of the control of natural gas suppliers in Rhode Island and New England. Russia's invasion of Ukraine and intentional restriction of natural gas exports to Europe have thrown international markets for natural gas and LNG, and the U.S. balance of supply and demand, into disarray. As a result, over the past year, natural gas purchasers in the U.S., and in particular in New England, have faced extreme and sustained increases in the cost of natural gas. These factors and the impact they have had on natural gas markets in the U.S. and New England are fully consistent with and responsible for the increase in supply costs that underlie the Company's GCR filing.

V. <u>The Regional Impact of Market Factors on Prices of Natural Gas in Other States and on the Price of Electric Power</u>

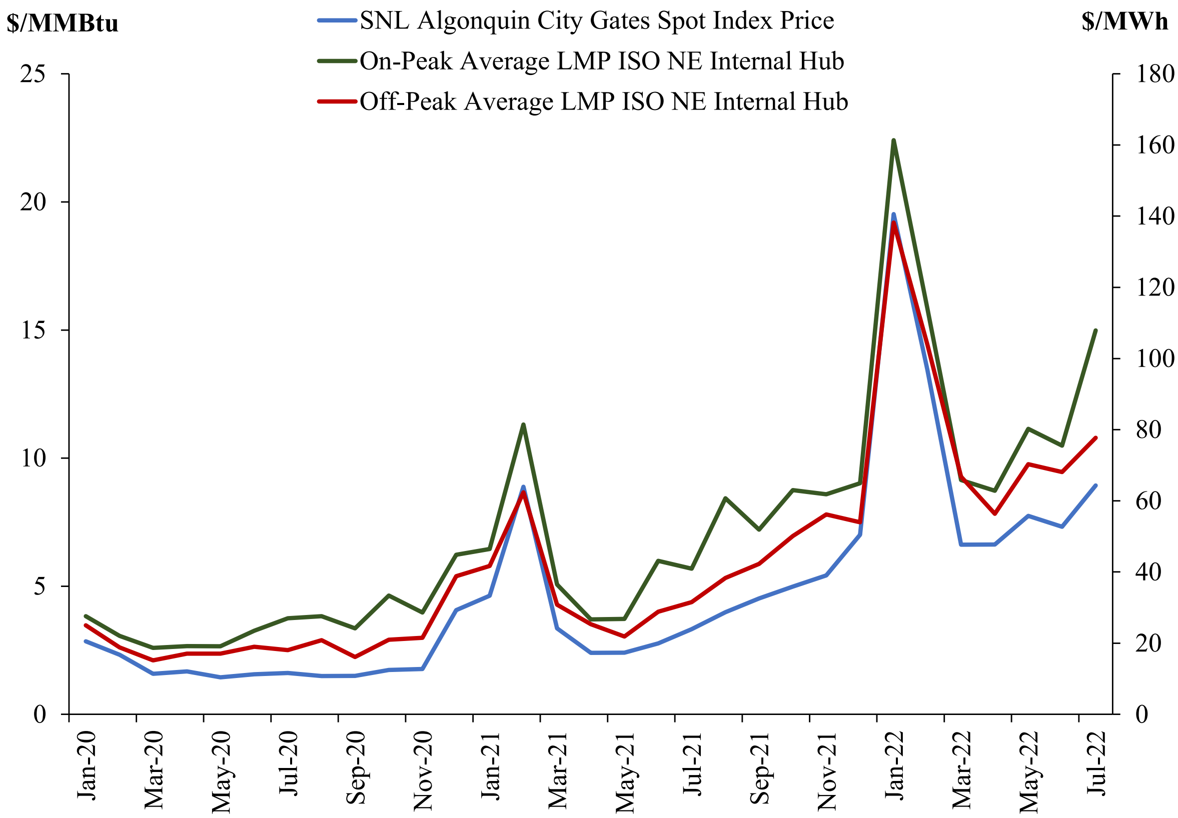
Q. Is the Company's need to adjust rates to incorporate the rising cost of natural gas unique?

A. No. To the contrary, not only are all natural gas LDCs going to need to adjust rates to address increasing natural gas supply costs, but this is also likely to be the case for electric utilities.

Q. Please describe how the price of electricity has been changing over the past year.

A. Since natural gas is the fuel on the margin most hours of the year in New England's wholesale electricity markets, and because power plant owners in New England largely secure natural gas through spot market transactions, wholesale electricity market prices have increased in lock step with increases in the cost to procure natural gas over the past year. See **Figure 12**.

Figure 12: Spot Prices for Natural Gas and Electricity in New England[39]
January 2020 – August 2022



Note: The prices shown are monthly averages.

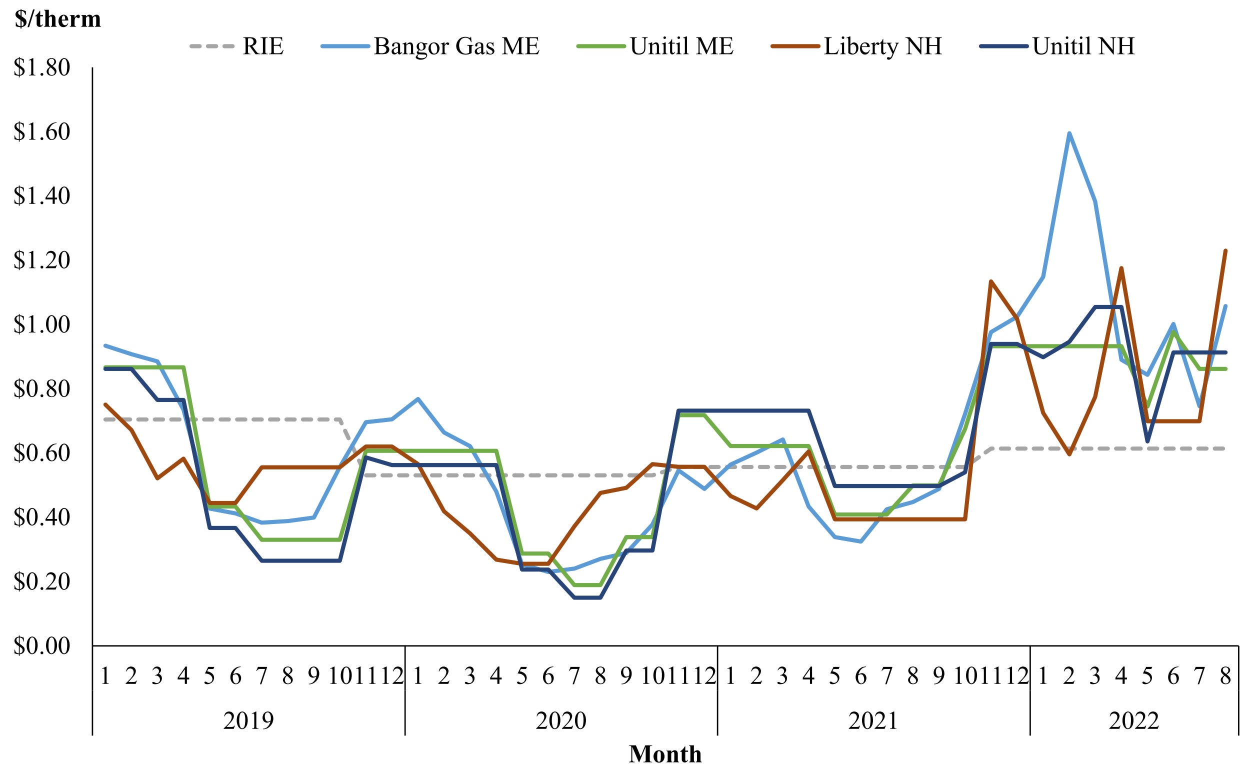
Q. Have you reviewed whether other natural gas LDCs are experiencing and/or have requested similar increases in rates to cover increases in gas supply costs?

A. Yes. It is important to recognize that it is difficult to construct a true apples-to-apples comparison of natural gas LDC supply costs. This is because the New England states

[39] "SNL Algon Gates Spot Natural Gas Index," S&P Global Market Intelligence; "Day-Ahead and Real-Time Monthly LMP Index Report," ISO New England.

have different requirements for recovery of fixed and variable costs; different states and utilities have different timelines for supply planning, procurement and contracting; companies change rates at different times and with different frequencies; and different costs are often collected over different time frames. Nevertheless, for purpose of illustration at a high level, I compared natural gas supply rates for several LDCs in New England. As can be seen in **Figure 13**, while there are meaningful differences month to month and season to season, utilities across New England are dealing with the same set of market impacts on their costs to acquire natural gas for service to their customers. In particular, it is clear that underlying market forces over the past year are leading to substantial increases in costs, and thus in rates, across the region.

Figure 13: Natural Gas Supply Rates for Select New England Utilities 2019-2022[40]



[40] RIPUC Docket No. 4872, Order No. 23693; RIPUC Docket No. 5040 and Docket No. 5066, Order No. 23963; RIPUC Docket No. 5165 and Docket No. 5180, Order No. 24275; "Understanding Natural Gas Rates," Summit Natural Gas Maine, available at https://www.summitnaturalgasmaine.com/rates-tariff ; "Natural Gas Costs," Bangor Natural Gas, available at https://www.bangorgas.com/about-us/natural-gas-costs/ ; "ME Historical Gas Supply Rates (Excel)," Until, available at https://unitil.com/suppliers/energy-supplier-resources#historical; Maine PUC Docket No. 2021-00249; Maine PUC Docket No. 2022-00044; "NH Historical Gas Supply Rates (Excel)," Until, available at https://unitil.com/suppliers/energy-supplier-resources#historical; "New Hampshire Monthly Cost of Gas Report, Winter Period, December 2021 Summary, Table 1" Northern Utilities, available at https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-131/LETTERS-MEMOS-TARIFFS/21-131_2021-12-21_NORTHERN_DEC-COG-RPT.PDF; NPUC Docket No. DG 21-131, Order No. 26,539; "New Hampshire Monthly Cost of Gas Report, Summer Period, April 2022 Summary, Table 1" Northern Utilities, available at https://www.puc.nh.gov/Regulatory/Docketbk/2021/21-131/LETTERS-MEMOS-TARIFFS/21-131_2022-04-22_NORTHERN_APRIL-COG-RPT.PDF; NPUC Docket No. DG 21-131, Order No. 26,627; "Gas Archive," Liberty Utilities NH, available at https://new-hampshire.libertyutilities.com/allenstown/residential/rates-and-tariffs/archive-natural-gas.html; NPUC Docket No. DG 20-141, Calculation of the Projected Over or Under Collection of the 2020 - 2021 Winter Cost of Gas Filing.

VI. Conclusions

Q. Please summarize your findings.

A. The Company's GCR includes expected increases in rates associated with changes in the underlying costs to procure, store, and transport natural gas for use in Rhode Island. These increases are fully consistent with fundamental changes in underlying factors affecting natural gas supply and demand in the U.S. and, in particular, in New England. The natural gas market factors driving the increased GCR costs are being experienced by natural gas (as well as electric) local distribution companies, and are due to at least the following factors:

(1) New England has a strong winter peak due to (i) widespread use of natural gas for heating homes and businesses in the region, and (ii) a dependence on spot market purchases of natural gas for operating power plants needed to maintain winter electric system reliability;

(2) New England has significant constraints on the delivery of natural gas for meeting the combined heating and electricity demand in the winter. The region has no indigenous source of natural gas, and sits effectively at the end of the pipeline system delivering gas from the south and west. Although there is a pipeline connection to Eastern Canada, the primary source of deliveries from Canada historically – Sable Island – shut down in 2018. Finally, the New England region, in recent years, has been unable to develop additional natural gas supply and transportation infrastructure to alleviate the persistent winter natural gas transportation constraints. As a result, the natural gas delivery

infrastructure that does exist in the region is at or near capacity on most winter days, and is operating at maximum capacity on many cold winter days each year;

(3) Finally, these conditions leave New England strongly dependent on international shipments of LNG to meet natural gas demand during cold winter periods. Yet since power plant owners have little incentive to pre-contract for LNG supplies, the availability of LNG for injection on cold winter days is sufficient quantities to meet combined heating and electricity demand is relatively expensive and highly uncertain, adding pricing volatility and uncertainty to the region's natural gas markets;

In a normal year, these conditions can lead to elevated and highly variable natural gas prices in New England during winter months, and correspondingly high pricing in natural gas futures markets, with relatively minor variations in the conditions of supply and demand. Yet, this is not a normal year. The impact of the Russian invasion of Ukraine has fundamentally changed international markets for natural gas, including LNG. The increased demand for global supplies of natural gas from Europe has increased the price of natural gas throughout the U.S. and in much of the world, resulting in increasing exports from the U.S. to Europe and increasing the cost of securing LNG supplies for the LNG import terminals serving New England.

Q. Does this complete your testimony?

A. Yes.

Attachment PJH-1

Attachment PJH-1

Curriculum Vitae of Paul J. Hibbard

Appendix A
PAUL J. HIBBARD
Principal

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Boston, MA 02199

Mr. Hibbard is an expert on economics, strategy, regulation, and policy in the electric and natural gas industries. He has a comprehensive background merging business development, technical analysis, resource planning and development modeling, economics, and public policy in the energy and environmental fields. Mr. Hibbard has provided technical and strategic advice to government, industry, business, public interest groups, and trade organizations on energy market structure, electric and natural gas infrastructure planning and siting, utility resource solicitation and procurement, emission allocation and environmental policy, renewable resource program design and administration, transmission pricing, climate change policy, utility ratemaking practices, and the transfer of US federal and state emission control programs to other countries.

Prior to joining Analysis Group, Mr. Hibbard was chairman of the Massachusetts Department of Public Utilities. During his tenure, he carried out a forward-looking ratemaking and policy agenda to advance energy efficiency and renewable resources, coordinate regional efforts in the development of energy resources and associated infrastructure, and promote the administration of fair and efficient transmission pricing models in regional and national contexts. He also has provided testimony on resource planning, competitive electricity markets, and transmission pricing in hearings before committees of the Massachusetts legislature and the US House of Representatives, the Federal Energy Regulatory Commission (FERC), and state and regional planning councils. Mr. Hibbard has also served as a member of many energy-related boards and committees.

EDUCATION

M.S.	Energy and resources, University of California, Berkeley *Thesis: Safety and Environmental Hazards of Nuclear Reactor Designs* *(Ph.D. coursework in nuclear engineering)*
B.S.	Physics, University of Massachusetts Amherst

PROFESSIONAL EXPERIENCE

2010–Present	**Analysis Group, Inc.** *Principal (2015–Present)* *Vice President (2010–2015)*
2007–2010	**Massachusetts Department of Public Utilities** *Chairman* *Member, Energy Facilities Siting Board* *Manager, New England States Committee on Electricity (NESCOE)* *Treasurer, Executive Committee, Eastern Interconnect States' Planning Council*

2007–2010	**Massachusetts Department of Public Utilities** (continued)
	Representative, New England Governors' Conference (NEGC)
	    Power Planning Committee
	Member, National Association of Regulatory Utility Commissioners (NARUC)
	    Electricity Committee, Procurement Work Group

2003–2007	**Analysis Group, Inc.** *Vice President (2005–2007)* *Manager (2003–2005)*
2000–2003	**Lexecon Inc.** *Senior Consultant (2002–2003)* *Consultant (2000–2002)*
1998–2000	**Massachusetts Department of Environmental Protection** *Environmental Analyst*
1991–1998	**Massachusetts Department of Public Utilities** *Senior Analyst, Electric Power Division*
1988–1991	**University of California, Berkeley** *Research Assistant, Safety/Environmental Factors in Nuclear Designs*

SELECTED PUBLIC-SECTOR EXPERIENCE (MASSACHUSETTS)

- ***Chairman, Department of Public Utilities***
  - Chaired the state's public utilities commission during a period of aggressive change in state policies affecting the electricity and natural gas industries, including initial implementation of several new state energy laws and initiatives restructuring the setting of utility rates, promoting the expansion of energy efficiency and demand response, facilitating the retail and wholesale market integration of renewable and low-carbon resources, and revising state policy on the siting of major generation and transmission infrastructure.
  - Oversaw the issuance of initial regulations and policy related to revenue decoupling, net metering, long-term contracting for renewables, and power system emergency planning and outage restoration.
  - Led Massachusetts's work with regulators across the Northeast to pursue large-scale renewable resource development through coordinated procurement strategies to develop coordinated positions related to national transmission development proposals and establish a regional presence on transmission-related provisions in federal legislation.
  - As chairman, served as the administrative and policy head of an agency of nearly 150 employees, and was responsible for agency management and growth, budgeting, legislative matters, press inquiries, and policy agenda-setting.
  - Oversaw the completion of all dockets jurisdictional to the department, including rate cases and associated tariff matters, forecast and supply planning for electric and natural gas industries, and state oversight of natural gas pipeline safety and public transit authorities.
  - Responsible for all interaction with the governor's office, legislature, and Executive Office of Energy and Environmental Affairs, as well as representing the state in regional deliberations related to electric and natural gas utility policy, electricity market design and oversight, and regional power system reliability issues.

- ***Member, Energy Facilities Siting Board***
  Sitting member of the state board responsible for reviewing all proposals for major generation and transmission infrastructure projects within the state, as well as state intervention in federal review of natural gas pipeline infrastructure. Review involved technical, environmental, and economic evaluation of jurisdictional power plants, transmission lines, and other energy infrastructure, as well as ruling on proposals for exemption from state and local zoning ordinances.
- ***Manager, NESCOE***
  State representative of the regional group chartered to develop New England regional policy positions on electricity market and transmission planning issues. Responsibilities included consideration of group development issues, input into regional determinations of the Installed Capacity Requirement, consideration of regional approaches to transmission planning and the consideration of non-transmission alternatives, and coordinated development of a regional RFP/RFI for the solicitation of renewable power under long-term contracts for the New England states.
- ***Treasurer, Executive Committee, Eastern Interconnection States' Planning Council***
  Elected treasurer of the steering committee for the state council formed under a US Department of Energy (DOE) grant to coordinate with power system operators on developing long-range plans for a transmission system spanning 41 states in the eastern US. Coordinated New England states' approach to policy issues stemming from council efforts.
- ***Representative, NEGC Power Planning Committee***
  Represented the governor's office in all discussions related to regional energy/environmental issues, including transmission cost allocation, regional energy policy coordination, and development of mechanisms for and approaches to procurement of renewable power through long-term contracts with sources in New England and eastern Canada. Engaged in collaborative discussions with counterparts representing the Eastern Canadian Premiers.

SELECTED CONSULTING EXPERIENCE

Government, Foundations, Commissions, and Cooperatives

- ***For the Natural Resources Defense Council (NRDC)*** – Coauthored a public report on the Clean Electricity Payment Program's (CEPP) positive impact on the US economy if adopted (2021).
- ***For Advanced Energy Economy (AEE)*** – Coauthored a public report on the potential economic impacts of applying stimulus funds to electrification of the US transportation sector using estimated spending levels from President Biden's American Jobs Plan (2021).
- ***For AEE*** – Coauthored a public report on the potential economic impacts of applying stimulus funds to develop advanced energy technologies, products, and services in the US using estimated spending levels from President Biden's American Jobs Plan (2021).
- ***For the Coalition for Green Capital*** – Coauthored a white paper examining the potential of the federally authorized Clean Energy and Sustainability Accelerator that could address economic and climate crises (2021).
- ***For AEE*** – Coauthored a series of public reports on the economic impacts in select states of potential stimulus spending on clean and advanced energy resources (2020).
- ***For a municipal association*** – Drafted a white paper related to the fuel mix and emission characteristics of the portfolio of generating assets and power contracts used by municipal electric light companies in Massachusetts (2020).
- ***For the Wellesley Municipal Light Plant (WMLP)*** – Coauthored two white papers on the greenhouse gas (GHG) impacts of the WMLP power portfolio, and considerations for the WMLP associated with achieving continued reductions in carbon emissions over the ensuing decades (2020).

- ***For the Georgetown Climate Center*** – Conducted a bill impact analysis related to Virginia's proposed implementation of a carbon cap-and-trade program (2018).
- ***For Energy New England*** **–** Provided strategic assistance on energy market and public policy issues in New England (2017).
- ***For the Environmental Defense Fund*** – Coauthored a white paper related to historical power system emission trends (2015).
- ***For the Massachusetts Attorney General*** **–** Coauthored a report evaluating electric and natural gas infrastructure in New England from the perspectives of reliability, cost, and GHG emissions (2015).
- ***For AEE*** – Coauthored a report on the status of the electric industry in the State of Ohio, and developed recommendations on state energy policy in consideration of the state's market and technological circumstances at the time.
- ***For the Energy Foundation and industry groups*** – Coauthored multiple white papers on the reliability, cost, and market efficiency impacts of the US Environmental Protection Agency's (EPA's) proposed regulations to control emissions of carbon dioxide from existing electric generating facilities. Presented results in numerous conference, stakeholder, and regulatory settings.
- ***For a foundation*** – Led a study of the economic impacts of a state clean energy policy (2013–2014).
- ***For the Massachusetts Department of Energy Resources*** **–** Provided testimony on the ratepayer and social benefits of reducing methane leaks from a local natural gas distribution company's system (2013).
- ***For AEE***– Facilitated a regional symposium for the New England Conference of Public Utility Commissioners and staff related to advanced energy technology development and commercialization, and the legal and regulatory structures needed to facilitate integration of emerging technologies (2013).
- ***For the Regional Greenhouse Gas Initiative (RGGI)*** – Conducted a bill impact analysis related to changes to retail customer electric bills in New England, New York, and RGGI Pennsylvania, New Jersey, and Maryland Interconnection (PJM) states associated with various changes considered by RGGI to program cap level and use of allowance revenues (2012).
- ***For AEE*** – Participated in a project advising AEE with respect to its national program to support public utility commission consideration of policies and regulations related to the development and integration of advanced energy technologies (2012–2013).
- ***For the Merck Family Fund*** – Developed an interactive tool to compare the impacts of energy, economic, environmental, legislative, and regulatory policies and programs across the US (2012).
- ***For AEE*** – Coauthored a report on the perspectives of CEOs at advanced energy companies doing business in California on California's energy policies. Conducted over 30 interviews with energy business leaders to get perspectives and recommendations for policy changes (2012).
- ***For the Barr Foundation*** – Coauthored a report on the benefits and costs associated with reducing natural gas leaks on natural gas distribution systems through implementation of targeted infrastructure replacement ratemaking mechanisms in Massachusetts, Rhode Island, and Ohio. Developed a cost-benefit model to quantify the impacts of such programs (2012–2013).
- ***For the American Clean Skies Foundation*** – Developed a dispatch price and emissions model to forecast power system outcomes in the PJM Interconnection, Midwest Independent System Operator, and Southwest Power Pool regions (2012).
- ***For a national environmental organization*** – Conducted a comprehensive national review of energy efficiency monitoring and verification programs in order to support development of a protocol that

could be used to allow energy efficiency to be used as a compliance tool in national carbon emission control regimes (2012–2013).

- ***For the Merck Family Fund –*** Co-led a project to carry out an analysis of the economic impacts of the Northeast states' use of revenues collected from the auctioning of carbon allowances associated with RGGI (2011).
- ***For AEE –*** Developed background on electric industry structure, regional planning and market structures and operations, and state energy policy organization and initiatives. Assisted with the development of a web-based information platform (2011).
- ***For the American Clean Skies Foundation –*** Authored a paper on the redesign of wholesale electricity market structures to efficiently integrate a higher level of variable resources (2012). Coauthored a white paper examining electric reliability and air emission issues associated with the potential retirement of the Potomac River Generating Station in Alexandria, Virginia (2011).
- ***For the Public Service Commission of Colorado –*** Coauthored a white paper on the design of incentives for the photovoltaic (PV) solar energy market (2011).
- ***For a national environmental organization*** – Conducted an economic analysis of key US cities that were or had been in nonattainment under the National Ambient Air Quality Standards, to explore relationships between air quality control requirements and the local economy (2011).
- ***For a national environmental organization*** – Completed a comprehensive report on the full scope of energy efficiency and demand response programs administered by New York electric utilities and the New York Independent System Operator (NYISO). Assessed the potential for additional innovative programs to improve energy efficiency and demand response in New York City (2010).
- ***For the North Carolina Attorney General –*** Managed a project in support of expert testimony on the economic and financial feasibility of requiring the installation of controls to reduce emissions of sulfur dioxide, nitrogen oxides, and mercury from coal-fired power plants owned by the Tennessee Valley Authority (TVA). The project was in the context of a public nuisance lawsuit brought by the North Carolina Attorney General against TVA (2006).
- ***For the National Commission on Energy Policy –*** Authored white papers on (1) the implications for US energy infrastructure of the damage to Gulf Coast energy facilities from Hurricanes Katrina and Rita (2006); (2) the practical and economic implications of various mechanisms for the allocation of carbon dioxide emission allowances to the electric sector under potential federal carbon control regimes (2005); and (3) national energy infrastructure needs for the electricity, natural gas, and petroleum industries, and for addressing the long-term impacts of energy production and use associated with spent nuclear fuel and carbon dioxide (2004).
- ***For the Massachusetts Health and Educational Facilities Authority (MHEFA) PowerOptions Program*** – Managed several projects providing regulatory, economic, and strategic advice to PowerOptions to assist in their selection and pricing of retail electricity products from competitive electricity suppliers. Over a three-year period, projects included analyses of forward prices and wholesale markets for capacity and reserves; analysis of contract price options, terms, and conditions; and analysis of congestion pricing implications for retail supply (2002–2004).
- ***For the Energy Foundation*** – Coauthored a report (with Dr. Susan Tierney) documenting best practices in energy facility siting regulations in the US, and analyzing in particular the impact of California's energy facility siting process on that state's electricity crisis (2002). Supported a foundation-based program to provide international assistance to China's efforts to privatize and restructure its electric industry, and to develop regulations to control air emissions from power plants in that country (2000–2003).
- ***For the Massachusetts Technology Collaborative (MTC) –*** Managed projects in support of the MTC's renewable and premium power programs, including the (1) creation of a standard financial

pro-forma for wind and landfill gas technologies in New England under various assumptions related to capital and operating costs, financing, discount rates, and the impact of state and federal policies to support renewable development; (2) development of an economic model to determine the financial impact on potential wind and combined heat and power facilities of proposed changes to utility standby service tariffs; and (3) research, strategic, and regulatory support of MTC's efforts to advance distributed generation in Massachusetts to promote renewable resources and improve power reliability for commercial and industrial customers (2000–2002).

ENERGY INDUSTRY STAKEHOLDERS

- ***For PECO Energy*** – Provided testimony on traditional ratemaking principles as applied to PECO's cost of providing gas delivery service (2021).
- ***For the Hingham Municipal Lighting Plant (HMLP)*** **–** Conducted an internal evaluation of the impact of decarbonization of residential and commercial energy use in the town, and its effect on HMLP's investments and operations (2020).
- ***For a natural gas interstate pipeline company*** **–** Coauthored a white paper and presention showing options to decarbonize the company's operations. The study included an analysis of its GHG footprint, identification of options and pathways to reduce net GHG emissions from operations to zero over time, and the development of recommendations for senior management (2020).
- ***For Oracle Corporation*** – Conducted an analysis of and report on the GHG emission reduction impacts of various types of energy efficiency programs and measures, with a focus on the comparison of structural and behavioral energy efficiency programs (2020).
- ***For NYISO*** – Conducted a study of the parameters used as the basis to set the NYISO's installed capacity demand curves for the four capability years beginning with the summer 2021 capability period (2020).
- ***For NYISO*** **–** Conducted an internal study of the potential reliability impacts on the electric grid due to changes in system mix and operations associated with a changing climate, and with state programs to address climate change (2020).
- ***For NYISO*** – Conducted a study of the potential risks to New York power system operations associated with an increased reliance on natural gas for power generation (2020).
- ***For Commonwealth Edison*** **–** Provided testimony on issues associated with a request for a certificate of public convenience and necessity by NextEra related to the proposed acquisition of the transmission assets of Rochelle Municipal Utilities (2020).
- ***For Repsol Energy North America*** – Provided strategic assistance related to the potential impacts of electric system market rules and public policy on the potential marketability of liquefied natural gas (LNG) in New England (2020).
- ***For Liberty Utilities*** – Provided testimony on the need for and economic and environmental impacts of the proposed Granite Bridge pipeline and LNG project in the State of New Hampshire (2020).
- ***For NYISO*** **–** Coauthored a white paper for NYISO on the potential impacts of a proposed carbon pricing mechanism in New York on power prices; energy policy; and economic, environmental, and public health impacts in New York (2020).
- ***For NTE Energy*** **–** Provided testimony before the Connecticut Siting Council on the need for and potential benefits associated with a proposed new natural gas-fired power plant in the State of Connecticut (2020).
- ***AltaGas*** **–** Provided testimony before the Maryland and District of Columbia public utility commissions on the potential environmental impacts of a proposed merger between AltaGas and Washington Gas (2017–2018).

- ***For Calpine Corporation*** – Coauthored a white paper on the design of a proposed carbon trading mechanism in Massachusetts (2017).
- ***For Vermont Gas*** **–** Provided testimony on the prudence of Vermont Gas' decisions and investments with respect to the Addison natural gas project (2017).
- ***For the Vermont Electric Power Company (VELCO)*** – Coauthored a white paper on VELCO's capital structure associated with its transmission assets and operations (2016).
- ***For the Merck Family Fund*** – Coauthored a white paper on economic principles associated with the trading of emission allowances associated with RGGI (2016).
- ***For a consortium of solar companies*** – Developed a white paper on the appropriate evaluation and treatment of behind-the-meter solar PV generation from the perspective of net metering policies in Massachusetts (2015).
- ***For a group of owners of electric generating facilities*** – Developed a comprehensive quantitative and qualitative critique of a utility proposal to invest in electricity storage capability in the State of Texas. Drafted a report for circulation to legislative, regulatory, and market interests stating the results of the critique and analysis (2015).
- ***For an energy resource developer*** – Conducted a financial and ratepayer analysis of the benefits of a project to develop a power plant and natural gas pipeline in the State of Maine. Submitted testimony to the Maine Public Utilities Commission describing the results (2014–2015).
- ***For an energy storage company*** – Developed an optimization analysis to evaluate the security, reliability, economic, and environmental benefits and costs of multiple battery storage installations across the Hawaiian Islands in different industry settings (renewable generator, island utility, military base, hotel/resort). Drafted a report presenting the results, considering the state's unique energy price and fuel security context (2014–2015).
- ***For NYISO*** – Developed a model to compare cost, resource, and emission outcomes of alternative designs for a capacity market in the State of New York. Coauthored a report presenting the results of the analysis and a comprehensive review of the benefits and drawbacks of moving from a spot to a forward capacity market (FCM) structure. Presented results to NYISO senior management and several meetings of New York electricity market participants and stakeholders (2014–2015).
- ***For multiple regional transmission organizations (RTOs)*** – Provided strategic support at the board-of-director and senior-management levels for considering the changing structures of retail regulation and wholesale market incentives within their regions (2014–2015).
- ***For Calpine Corporation*** **–** Provided testimony on the costs and benefits of different proposals for generation capacity in Florida (2014).
- ***For an RTO*** – Conducted an internal analysis of the financial risk associated with the RTO's position in administering the trading of power system transmission rights (2014).
- ***For a regional transmission operator*** – Conducted a top-to-bottom review of the content and design of the RTO's Rate Schedule 1 tariff for the collection of operational costs from market participants. Presented results of the analysis to the RTO's board of directors and senior management (2014).
- ***For a retail electricity supplier*** – Provided analytic and strategic support with respect to the supplier's participation in a state regulatory proceeding related to changing the nature of and rate structure for electric distribution service (2014).
- ***For Ambri Inc.*** **–** Led a study of the economic feasibility of using battery storage in conjunction with wind and solar for a micro-grid application (2013–2014).
- ***For Calpine Corporation*** **–** Provided testimony on the costs and benefits of different proposals for generation capacity in Minnesota (2013).

- ***For the New England Independent System Operator (ISO-NE) –*** Assisted on several projects related to addressing the codependence of electric and natural gas systems in New England through a mix of short- and long-term market rule changes and administrative actions. Assistance included review of market structures to improve unit performance, particularly under stressed natural gas system conditions; quantification of the costs of potential natural gas and electric system infrastructure, and contractual responses to market rules and administrative actions (e.g., dual-fuel capability, new pipeline investment, LNG purchasing, and firm natural gas transportation agreements); and assistance with a series of discussions between ISO-NE and regional electricity and natural gas market participants. Also quantified the potential benefits of improved performance associated with reduced system interruptions (2012–2013).
- ***For the ISO-NE*** – Developed an economic supply/demand model of the FCM to estimate the cost impact of integrating a new long-term performance incentive design element into the FCM auctions and pricing structure (2012–2013).
- ***For Calpine Corporation*** – Filed a report with the EPA on the impact of emergency generation demand response programs on the costs and emissions associated with power system dispatch in the PJM electricity market (2012).
- ***For the ISO-NE*** – Organized and helped lead a strategic planning initiative to address unit retirement, fuel mix, operational performance, and wind resource integration issues. Oversaw comprehensive generating unit performance analysis and electric-gas system risk review. Conducted a thorough internal risk assessment and key-challenge solution development. Facilitated meetings and developed organizational and concept documents to explore outcomes and assist in deliberations with states and regional industry stakeholders, and participated in external meetings to gain input and feedback (2010–2012).
- ***For an RTO*** – Conducted a top-to-bottom review of its external market monitoring function and a comprehensive best-practices survey of all internal and external market monitoring functions at US RTOs and independent system operators (ISOs) (2012).
- ***For a wind power development company*** – Conducted a regional review of wind power development projects and an assessment of potentially valuable projects for acquisition based on power system location and siting viability (2012).
- ***For an energy services company –*** Oversaw and conducted an analysis of business, legal, and regulatory conditions related to a legal dispute over the legitimacy of a contract for energy and water management services. Coauthored a report to be used in the development of legal strategy and legal proceedings (2012).
- ***For an international power company*** – Conducted a review of a regional utility's compliance with the FERC requirements for transmission open access, and developed strategies for the filing of complaints of anticompetitive conduct before the FERC (2011–2012).
- ***For an RTO*** – Comprehensively reviewed and suggested changes to the design of regional market structures; oversaw data review and analysis related to key market design features and asset performance (2011).
- ***For Direct Energy*** – Assisted with the development of strategies to increase retail choice in Pennsylvania, including the design of an opt-in descending-clock auction to increase migration from default service to competitive supply. Prepared comments and analysis on utility contract structures. Provided testimony before the Pennsylvania Public Utilities Commission (2011).
- ***For Algonquin Gas*** – Submitted affidavits and testified in bankruptcy court on the impact on power plant value of changes in market rules related to the FCM in New England. Also provided testimony on the impact on power system reliability of the availability of firm transportation contracts for natural gas supplied to power plants in New England (2010).

- ***For an RTO*** – Conducted a best-practices and performance metrics analysis to benchmark the ISO's performance against industry peers with respect to responsiveness to consumers, stakeholders, and policymakers. Drafted a report with comprehensive benchmarking and performance metric recommendations; participated in stakeholder discussions (2010).
- ***For a power generators trade association*** – Developed and facilitated an all-day group discussion concerning key economic, environmental, legal, and policy challenges to the economic viability of existing and new power generation capacity in regional wholesale electricity markets (2010).
- ***For a coalition of electric companies*** – Coauthored the report "Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," which reviewed the impact on power plant operations of proposed EPA rules to reduce emissions of sulfur dioxide, nitrogen oxides, mercury, and other hazardous air pollutants. Presented findings to numerous regional and national industry and regulatory groups (2010).
- ***For an industry coalition*** – Conducted a study and coauthored a white paper (with Dr. Susan Tierney) for the New England Energy Alliance on New England energy infrastructure needs and policy issues (e.g., facility siting policies, RGGI/climate change) influencing the future addition of energy infrastructure in the region (2006).
- ***For an interstate pipeline company and offshore LNG developer*** – Authored a report related to recent developments in the supply and demand for natural gas in New England, and surveyed the development, regulatory, and commercial status of proposed LNG projects across the US (2006); coauthored a report (with Susan Tierney) providing an overview of Northeastern natural gas markets and conditions, and an assessment of natural gas supply and demand conditions (2005).
- ***For independent system operators*** – Managed several projects and coauthored reports or analyses for the Northeast region's ISOs/RTOs related to ISO/RTO annual strategic plans; market monitoring and mitigation best practices; and the links between wholesale electricity markets and local distribution company retail prices (2002–2006).
- ***For electric utilities*** – Managed or participated in numerous engagements with wires-only as well as vertically integrated electric utilities within New England and across the country related to rate case strategy and regulatory support; strategic planning; power supply resource planning and procurement (including the role of independent monitor of utility procurements); price and environmental analyses related to the siting of new high-voltage transmission lines; and evaluation of the allocation of SO_2 and NO_x emission allowances under the EPA Clean Air Interstate Rule (CAIR) program (2001–2006).
- ***For a developer of a land-based LNG facility*** – Assisted in the preparation of confidential reports on US natural gas supply/demand conditions, market pricing indices, US LNG facilities' status, Northeast interstate and intrastate pipeline infrastructure conditions and prospects, and LNG supply contract prices, terms, and conditions (2006).
- ***For retail energy providers*** – Managed projects and authored or coauthored confidential reports on the experience with retail competition in the US, a benefit/cost analysis of wholesale electricity competition, and comparative analyses of retail electricity prices for utility and competitive retail suppliers in select states (2004–2006).
- ***For merchant generating companies/coalitions*** – Managed production cost dispatching analyses for strategic planning related to the construction of new generating capacity in New England; assisted in the development of regulatory proposals for new wholesale market organizations and policies in New England (2001–2002).
- ***For a major interstate pipeline owner/operator*** – Modeled the electrical load characteristics of pipeline operations and utility rate structures to quantify the extent to which the company was being overcharged for electricity services. Supported company intervention in public utility commission proceedings and with analytical support in settlement negotiations (2002).

- ***For a renewable power developer association*** – Provided testimony on the potential negative effects – and remedial policy options – related to the impact of locational marginal pricing on the development and operation of renewable generating resources in New England (2001).

OTHER PROFESSIONAL ACTIVITIES

AEE
Advisory Board (2011)

SELECTED REPORTS, TESTIMONY, PUBLICATIONS, AND PRESENTATIONS

Prepared Answering Testimony of Paul J. Hibbard before FERC, Docket No. ER20-2441-002 on behalf of McKenzie Electric Cooperative, Inc. (July 15, 2022)

Testimony of Paul J. Hibbard before the U.S. District Court, Southern District of Florida, Ft. Lauderdale Division on behalf of Simon Property Group et al., Case No. 0:20-cv-60981-AMC (June 6, 2022)

Methane Reduction Technology Electricity and Abatement Costs: The Cost to Power Zero-Emission Pneumatic Controllers and Pumps in Grid-Connected and Remote Locations, with Scott Ario and Elisa Gan (May 6, 2022)

Affidavit of Paul Hibbard and Charles Wu before FERC, Docket No. ER22-772-000 on behalf of NYISO (January 5, 2022)

Modifications to the BSM Construct in the NYISO Capacity Market: Analysis of Potential Capacity Market Competitiveness and Reliability Outcomes, with Charles Wu (December 2021)

Economic Impact of a Clean Electricity Payment Program, with Pavel Darling and Luke Daniels (September 2021)

"Why Hydrogen?," presentation during the EBC Energy Resources Webinar: Future of Green Hydrogen – Earthshot Effort to Meet the Needs of Climate Change (September 30, 2021)

"Decarbonization and The Power System," presentation during the Northeast Public Power Association RodE&O Conference and Expo, Engineering Track (September 22, 2021)

"Net Zero Carbon: What Is It and What Should It Be?," presentation during the LDC Gas Forum (September 14, 2021)

"Net Zero Carbon: What Is It and What Should It Be?," presentation during the NEPPA Annual Conference, General Session (August 23–24, 2021)

"Motivating Customers to Decarbonize with an Eye Toward Equity," presentation during the 2021 NARUC Summer Policy Summit (July 18, 2021)

Economic Impact of Stimulus Investment in Advanced Energy for America, with Pavel Darling (June 2021)

Economic Impact of Stimulus Investment in Transportation Electrification, with Pavel Darling (June 2021)

"A Step Through the Looking Glass – Outlook for Natural Gas in the Northeast," Webinar for the Northeast Gas Association (NGA) Regional Market Trends Forum, What are the Market Pathways and Their Various Implications (April 29, 2021)

Accelerating Job Growth and an Equitable Low-Carbon Energy Transition: The Role of the Clean Energy Accelerator, with Susan F. Tierney (January 2021)

"Carbon Pricing: This Is the Way," presentation on a plenary panel to the New England Restructuring Roundtable (December 11, 2020)

"Approaches to Meeting Decarbonization Mandates: Important Decisions with Cost, Equity, and Reliability Implications," presentation during the EUCI Decarbonization Summit on state decarbonization opportunities (December 9, 2020)

"Approaches to Meeting Decarbonization Mandates: Important Decisions with Cost, Equity, and Reliability Implications," presentation during the New England Energy Summit on state decarbonization opportunities (November 23, 2020)

Affidavit of Paul J. Hibbard before FERC, Docket No. ER21-502-000 on behalf of NYISO (November 30, 2020)

Economic Impact of Stimulus Investment in Advanced Energy (series of 10 state-specific reports), with Pavel G. Darling (September–October 2020)

Climate Change Impact and Resilience Study – Phase II: An Assessment of Climate Change Impacts on Power System Reliability in New York State, with Charles Wu, Hannah Krovetz, Tyler Farrell, and Jessica Landry (September 2020)

Presented virtually at the Annual NECA Conference on how New England can transition away from fossil fuels, as well as the costs, reliability, and societal implications of moving toward low-carbon alternatives (September 30, 2020)

Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2021/2022 through 2024/2025 Capability Years – Final Report, with Todd Schatzki, Charles Wu, Christopher Llop, Matthew Lind, Kiernan McInerney, and Stephanie Villarreal (September 9, 2020)

Utility energy efficiency program performance from a climate change perspective: A comparison of structural and behavioral programs, with Jonathan Baker, Mona Birjandi-Feriz, and Hannah Krovetz (August 2020)

"Energy Efficiency for Climate, Not Ratepayers," presentation on a plenary panel to the American Council for an Energy-Efficient Economy (ACEEE) Summer Study Session (August 19, 2020)

For the New England Power Generators Association (NEPGA), coauthored a report assessing the potential use of carbon pricing in New England; the analysis applied tested industry models to identify effective and efficient economy-wide pricing of carbon dioxide (CO_2) emissions consistent with New England states' GHG emission reduction targets (June 23, 2020)

Carbon Pricing for New England: Context, Key Factors, and Impacts, with Joseph Cavicchi (June 2020)

"Decarbonization and Wholesale Markets in New England – Looking Ahead: Achieving 80% GHG Reduction by 2050," presentation on a plenary panel to the Association of Energy Engineers Conference, "ISO-NE in 2050: Getting to an advanced energy future in New England," Boston, MA (March 18, 2020)

"Decarbonization and Natural Gas in the Northeast," panel moderator and presenter at the EUCI conference on Natural Gas Decarbonization, Denver, CO (January 22–23, 2020)

Fuel and Energy Security in New York State: An Assessment of Winter Operational Risks for a Power System in Transition, with Charles Wu (November 2019)

Clean Energy in New York State: The Role and Economic Impacts of a Carbon Price in NYISO's Wholesale Electricity Markets, with Susan F. Tierney (October 2019)

"Natural Gas in Power Generation: Role Going Forward," 7th Annual Maine Natural Gas Conference to discuss power generation in the New England region. Falmouth, ME (October 3, 2019)

Direct Testimony of Paul J. Hibbard before the New Hampshire Public Utilities Commission on the need for and economic and environmental impacts of proposed Liberty Utilities Granite Bridge pipeline and LNG project, Docket No. DG 17-152 (June 28, 2019)

Rebuttal Testimony on Reopening of Paul J. Hibbard before the Illinois Commerce Commission on Behalf of Commonwealth Edison, Docket No. 18-0843 (May 31, 2019)

Pre-filed Testimony of Paul J. Hibbard before the Connecticut Siting Council on behalf of NTE Connecticut LLC, Docket No. 470 (January 18, 2019)

Vehicle Fuel-Economy and Air Pollution Standards: A Literature Review of the Rebound Effect, with Susan F. Tierney, Benjamin Dalzell, Grace Howland, Jonathan Baker, Tom Beckford, Sarah Centanni, Asie Makarova, and Scott Ario (June 28, 2018)

"An Expanding Carbon Cap-and-trade Regime? A Decade of Experience with RGGI Charts a Path Forward," with Susan F. Tierney and Pavel G. Darling, *The Electricity Journal* (June 2018)

Testimony of Paul J. Hibbard before the District of Columbia on behalf of AltaGas, Case No. 1142 (May 25, 2018)

The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Atlantic States, review of RGGI's third three-year compliance period (2015–2017), with Susan F. Tierney, Pavel G. Darling, and Sarah Cullinan (April 2018)

Post-Settlement Testimony of Paul J. Hibbard before the Maryland Public Service Commission on behalf of AltaGas, Case No. 9449 (January 5, 2018)

Rebuttal Testimony of Paul J. Hibbard before the Public Service Commission of the District of Columbia on behalf of AltaGas, Formal Case No. 1142 (October 27, 2017)

Capacity Resource Performance in NYISO Markets: An Assessment of Wholesale Market Options, with Todd Schatski and Sarah Bolthrunis (November 2017)

RGGI and Emissions Allowance Trading: Options for Voluntary Cooperation Among RGGI and Non-RGGI States, with Ellery Berk (July 2017)

"Analytical Issues in Linking," presentation on Virginia and the Regional Greenhouse Gas Initiative, Virginia Commonwealth University, Richmond, VA (July 12, 2017)

Electricity Markets, Reliability and the Evolving U.S. Power System, with Susan Tierney and Katherine Franklin (June 2017)

"Storage and Microgrids – New Applications," panel presentation during the Electricity Advisory Committee's Energy Storage Session (June 8, 2017)

Supplemental Affidavit of Paul J. Hibbard before FERC, Docket No. ER17-386-000 on behalf of NYISO (December 18, 2016)

Affidavit of Paul J. Hibbard before FERC, Docket No. ER17-386-000 on behalf of NYISO (November 18, 2016)

Evaluation of Vermont Transco, LLC Capital Structure, with Craig Aubuchon and Mike Cliff (October 2016)

Rebuttal Testimony of Paul J. Hibbard before the State of Vermont Public Service Board on behalf of Vermont Gas Systems Inc., Docket Nos. 8698 and 8710 (September 26, 2016)

RGGI and CO_2 Emissions Trading Under the Clean Power Plan: Options for Trading Among Generating Units in RGGI and Other States, Susan Tierney and Ellery Berk (July 12, 2016)

Affidavit of Paul J. Hibbard before the FERC, Docket No. ER16-1751-000 on behalf of the NYISO (May 20, 2016)

Declaration of Paul J. Hibbard and Andrea M. Okie in the US Court of Appeals for the District of Columbia Circuit, Case No. 15-1363 (and consolidated cases) on behalf of multiple parties (December 8, 2015)

Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas, report for the Massachusetts Office of the Attorney General, with Craig Aubuchon (November 2015)

Testimony of Paul J. Hibbard before the Senate Committee on Global Warming and Climate Change, *Power System Reliability in New England: Meeting Electric Resource Needs in an Era of Growing Dependence on Natural Gas* (November 24, 2015)

The Economic Impacts of the Regional Greenhouse Gas Initiative on Nine Northeast and Mid-Altantic States, review of RGGI's Second Three-Year Compliance Period (2012–2014), with Andrea Okie, Susan Tierney, and Pavel Darling (July 14, 2015)

Electric System Reliability and EPA's Clean Power Plan: The Case of MISO, report for the Energy Foundation, with Susan Tierney and Craig Aubuchon (June 8, 2015)

Net Metering in the Commonwealth of Massachusetts: A Framework for Evaluation (May 2015)

NYISO Capacity Market: Evaluation of Options, report for the NYISO, with Todd Schatzki, Craig Aubuchon, and Charles Wu (May 2015)

Ohio's Electricity Future: Assessment of Context and Options, report for Advanced Energy Economy, with Andrea Okie (April 2015)

Electric System Reliability and EPA's Clean Power Plan: The Case of PJM, report for the Energy Foundation, with Susan Tierney and Craig Aubuchon (March 16, 2015)

Electric System Reliability and EPA's Clean Power Plan: Tools and Practices, report for the Energy Foundation, with Susan Tierney and Craig Aubuchon (February 2015)

Tools States Can Utilize for Managing Compliance Costs and the Distribution of Economic Benefits to Consumers Under EPA's Clean Power Plan, Electricity Forum, with Andrea Okie and Susan Tierney (February 2015)

The Economic Potential of Energy Efficiency, report for the Environmental Defense Fund, with Katherine Franklin and Andrea Okie (December 2014)

Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels, report for the Environmental Defense Fund and National Resources Defense Council, with Andrea Okie and Katherine Franklin (December 2014)

"EPA's Proposed Clean Power Plan and States' Planning for Implementation," presentation to the Power-Gen International Annual Conference (December 2014)

"Storage/Renewables Valuation: A Case Study Hitting Multiple Perspectives," presentation to the Caribbean Renewable Energy Forum 2014 (October 2014)

"Electric Industry Transformation: A New World, or a Step Through the Looking Glass?" presentation to the New England Independent System Operator Quarterly Meeting (September 2014)

"Consumers, Markets, and Infrastructure: New England at a Crossroads," presentation to the New England Consumer Liaison Group (September 2014)

"Columbia River Treaty Hydropower: Perspectives on Power Benefits," presentation to the LSI Conference on the Columbia River Treaty (September 2014)

Direct Testimony of Paul J. Hibbard on Behalf of Calpine Construction Finance Company, L.P., before the Florida Public Service Commission, Docket No. 140110-E1 (July 2014)

"States in Control: EPA's Clean Power Plan and State Implementation," presentation at the National Association of Regulatory Utility Commissioners Summer Meetings (July 2014)

"EPA's Clean Power Plan: States' Tools for Reducing Costs and Increasing Benefits to Consumers," with Andrea Okie and Susan Tierney, *The Electricity Journal* (July 2014)

Direct Testimony of Paul J. Hibbard on behalf of Calpine Construction Finance Company, L.P., before the Florida Public Service Commission, Docket No. 140110-E1 (July 14, 2014)

"Project Vigilance: Value of Ambri Batteries at Joint Base Cape Cod," presentation to the Raab Restructuring Roundtable, Boston MA (June 2014)

Further Explanation on Rate Calculations, with Todd Schatzki, memo to the New England Independent System Operator Markets Committee on setting the compensation rate for the ISO Winter Program (May 28, 2014)

"Markets, Infrastructure, and Policy: New England at a Crossroads," presentation to the US/Canada Cross-Border Power Summit (April 2014)

"Siting Infrastructure: Economic and Siting Hurdles," presentation to the US/Canada Cross-Border Power Summit (April 2014)

Economic Impact of the Green Communities Act in the Commonwealth of Massachusetts: Review of the Impacts of the First Six Years," with Susan Tierney and Pavel Darling (March 4, 2014)

Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments: Recommended Framework for Proposed Guidance on Quantifying Energy Savings and Emission Reductions in Section 111(d) State Plans Implementing the Carbon Pollution Standards for Existing Power Plants, report for the Environmental Defense Fund, with Andrea Okie (March 2014)

"Climate Policy and the Economy," presentation to the 2014 Joint Institute for Strategic Energy Analysis Annual Meeting, NREL, Golden CO (March 2014)

Testimony of Paul Hibbard and Todd Schatzki on behalf of the New England Independent System Operator before the Federal Energy Regulatory Commission, Docket Nos. ER14-1050-000 and ER14-1050-001 (February 12, 2014)

Project Vigilance: Functional Feasibility Study for the Installation of Ambri Energy Storage Batteries at Joint Base Cape Cod, report for demonstration project under the MassInnovate Program of the Massachusetts Clean Energy Center, with Steve Carpenter, Pavel Darling, Margaret Reilly, and Susan Tierney (February 2014)

Testimony of Paul J. Hibbard before the Maine Public Utilities Commission on behalf of Loring Holdings LLC; testimony described the results of a financial and ratepayer analysis of the benefits of a project to develop a power plant and natural gas pipeline in the State of Maine (2014–2015)

Rebuttal Testimony of Paul Hibbard on behalf of Calpine Corporation before the Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240 (October 18, 2013)

Direct Testimony of Paul Hibbard on behalf of Calpine Corporation before the Minnesota Public Utilities Commission, MPUC Docket No. E-002/CN-12-1240 (September 27, 2013)

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives, with Todd Schatzki (September 2013)

"Market Monitoring at US RTOs," presentation to the 12th Annual Gas and Power Institute, Houston, TX (August 2013)

Testimony of Paul J. Hibbard before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Department of Energy Resources, DPU 13-07 (May 31, 2013)

Testimony of Paul Hibbard before the House Committee on Energy and Commerce, Subcommittee on Energy and Power, *The Role of Regulators and Grid Operators in Meeting Natural Gas and Electric Coordination Challenges* (March 19, 2013)

Testimony of Paul J. Hibbard, on behalf of the Massachusetts Department of Energy Resources, on the ratepayer and social benefits of reducing methane leaks from a local natural gas distribution company's system (2013)

California's Advanced Energy Economy – Advanced Energy Business Leaders' Perspectives and Recommendations on California's Energy Policies, with Andrea Okie and Susan Tierney, Advanced Energy Economy Institute, (February 2013)

Information from the Literature on the Potential Value of Measures that Improve System Reliability, memo to the New England Independent System Operator (January 24, 2013)

Information on the Range of Costs Associated with Potential Market Responses to Address the Risks Associated with New England's Reliance on Natural Gas, New England Independent System Operator (January 24, 2013)

Summary of Quantifiable Benefits and Costs Related to Select Targeted Infrastructure Replacement Programs, with Craig Aubuchon, report for the Barr Foundation, (January 2013)

"Demand Response in Capacity Markets: Reliability, Dispatch and Emission Outcomes," *The Electricity Journal*, with Andrea Okie and Pavel Darling (November 2012)

"The Electric Generation Landscape – A Marathon of Challenges," presentation to SNL Generation Landscape, Chicago IL (October 2012)

"Economics, EPA, and Old Capacity – Bring Out Your Dead," presentation to LSI Energy in the Northeast, Boston MA (September 2012)

Paul Hibbard, *Reliability and Emission Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets*, report to the EPA on behalf of Calpine Corporation (August 2012)

"Uncertainty in Electricity Infrastructure Development – Key Drivers, International Context," presentation to NCEA Annual Conference, Brainerd, MN (June 2012)

"The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," with Todd Schatzki, *The Electricity Journal* (May 2012)

"Economic Impacts of RGGI," presentation to the New Hampshire Environmental Business Council (April 2012)

Testimony of Paul Hibbard before the California Legislature, *The Economic Impacts of RGGI's First Three Years*, California Select Committee on the Environment, the Economy, and Climate Change (March 27, 2012)

Testimony of Paul Hibbard before the New Hampshire Legislature, *RGGI and the Economy – Following the Dollars*," New Hampshire House Committee on Science, Technology, and Energy (February 14, 2012)

Testimony of Paul Hibbard before the Massachusetts Legislature, *RGGI and the Economy – Following the Dollars*," Massachusetts Senate Committee on Global Warming and Climate Change (February 13, 2012)

"Economic Impacts of RGGI: Following the Dollars," presentation tothe California Business Climate Network, with Susan Tierney (February 2012)

"Carbon Control and the Economy: Economic Impacts of RGGI's First Three Years," with Susan Tierney, *The Electricity Journal* (December 2011)

"Public Policy Transmission: Competition and Cooperation," presentation to the Energy Bar Association Renewables Subcommittee, Washington, DC (November 2011)

"Competitive Markets and Wind Power: Challenge and Opportunity," presentation to the Governors' Wind Energy Coalition, Washington, DC (November 2011)

The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States; Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period, with Susan Tierney, Andrea Okie, and Pavel Darling (November 15, 2011)

Testimony before the Pennsylvania Public Utilities Commission on retail opt-in auctions (November 10, 2011)

"Interdependence and Opportunity: The Growing Link Between Electricity and Natural Gas," presentation to the Colorado Oil & Gas Association Energy Epicenter Conference, Denver, CO (August 2011)

Potomac River Generating Station: Update on Reliability and Environmental Considerations, with Pavel Darling and Susan Tierney (July 19, 2011)

"Retirement is Coming: Preparing for New England's Capacity Transition," *Public Utilities Fortnightly* (June 2011)

Generation Fleet Turnover in New England: Modeling Energy Market Impacts, with Todd Schatzki, Pavel Darling, and Bentley Clinton (June 2011)

Solar Development Incentives: Status of Colorado's Solar PV Program, Practices in Other States, and Suggestions for Next Steps, with Susan Tierney and Andrea Okie (June 30, 2011)

"The Balancing Act: Challenges in Traversing the Modernization of New England's Infrastructure," presentation to the NECA Annual Conference, Mystic, CT (May 2011)

"Renewables v. Gas: The Future of New England Infrastructure," presentation to the EBC Energy Seminar, Waltham, MA (April 2011)

"Upcoming Power Sector Environmental Regulations: Framing the Issues About Potential Reliability/ Cost Impacts," presentation to the Raab Restructuring Roundtable, Boston, MA (October 2010)

"Carbon Regulation: Action and Convergence Spanning the Pond," presentation to the Energy Smart Conference, Boston, MA (October 2010)

"Renewables Development – A Tricky Time to be Placing Bets," presentation to the NECA Renewables Committee, Boston, MA (October 2010)

"Energy Infrastructure Challenges in the Current Policy Environment, A Wide Angle Point of View," presentation to NARUC, Providence, RI, September 2010.

Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability, with Susan F. Tierney, Michael J. Bradley, Christopher Van Atten, Amlan Saha, and Carrie Jenks (August 2010)

"Renewables Development – National Policies, New England Progress," presentation to the National Association of State Energy Officials Annual Meeting, Boston, MA (September 2010)

"Northeast US and Eastern Canada – Competitive Markets and Renewable Resource Development," presentation to the LSI Conference on US/Canada Energy Transactions, Vancouver, BC (August 2010)

"Renewables in the Northeast – Local Opportunities, National Context," presentation to the Council of State Governments, Portland, ME (August 2010)

"Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability," with Susan Tierney, Michael Bradley, Christopher Van Atten, Amlan Saha, and Carrie Jenks (August 2010)

"Federal Transmission Legislation," comments to Capitol Hill briefing of the Coalition for Fair Transmission Policy, Washington, DC (April 2010)

"Transmission Planning & Cost Allocation Alternatives under Order 890," comments to the Energy Bar Association's 64th Meeting, Washington, DC (April 2010)

"Deregulation and Sustainable Energy," class lecture, Massachusetts Institute of Technology (Jonathan Raab Energy Course), Cambridge, MA (March 2010)

"Transmission for Renewables," presentation to the Raab Restructuring Roundtable, Boston, MA (March 2010)

"US Electric Power Transmission: The Battle of the Jurisdictions," comments to CERAWeek 2010 (March 2010)

"New England Blueprint and the Federal Context," presentation to the New England Independent System Operator Consumer Liaison Group Meeting, Westborough, MA (February 2010)

"Interconnection-Wide Planning and Renewable Energy," comments to the National Wind Coordinating Collaborative, Transmission Update Briefing (December 2009)

"Infrastructure Planning," comments to the Northeast Energy and Commerce Association Power Markets Conference, Westborough, MA (November 2009)

"Transmission for Renewables - Risks and Opportunities for the Northeast," presentation to the Governor's Clean Energy Innovation Forum, New Brunswick, NJ (October 2009)

"Renewable Energy Development – The Role of Markets and Planning," presentation to the Northeast Power Planning Council General Meeting, Cambridge, MA (September 2009)

"Transmission Planning," comments to the Federal Energy Regulatory Commission Technical Conference on Transmission Planning Processes Under Order No. 890, Docket No. AD09-8-000, Philadelphia, PA (September 2009)

"New England Governors' Blueprint – Purpose and Context," presentation to the Raab Restructuring Roundtable, Boston, MA (September 2009)

"Wind, Transmission, and Federal Legislation," comments to the MIT Wind Group, Cambridge, MA (Fall 2009)

"National Transmission Policy," comments to The Energy Daily's Transmission Siting Policy Summit, Washington, DC (September 2009)

Testimony before the Massachusetts Joint Committee on Telecommunications, Utilities and Energy Hearing to Review Implementation of the Green Communities Act, Boston, MA (July 8, 2009)

"Federal Transmission Legislation," comments to the National Association of State Utility Consumer Advocates, Boston, MA (July 2009)

"Renewable Energy Development – The Role of Markets and Planning," presentation to the Governor's Wind Energy Coalition, Washington, DC (July 2009)

"Transmission and Renewables: ISO and Regulator Perspectives" comments to the Raab Restructuring Roundtable, Boston, MA (June 2009)

"Renewable Development in and for New England: Massachusetts' Perspective," presentation to Law Seminars International, Boston, MA (June 2009)

"Roadmap to New Renewable Resources in New England," comments on the New England Governors' Blueprint to the New England Conference of Public Utilities Commissioners Annual Symposium, Newport, RI (May 2009)

"Comments of Chairman Paul Hibbard," presentation to the EBC Energy Seminar: New Transmission – The Key to Renewable Resource Integration in New England, Boston, MA (April 2009)

"Coordinating Wind and Transmission Development – Who Pays?" comments to the 2009 Platts Wind Power Development Conference, Chicago, IL (March 2009)

"Integrating Energy and Environmental Regulations in Massachusetts," presentation to the Northeast Sustainable Energy Association Building Energy Conference, Boston, MA (March 2009)

"One Reason for the GCA: Energy Pricing in Massachusetts," presentation to the South Shore Coalition, Hingham, MA (January 2009)

"Non-Reliability Transmission: State Choice and Control," presentation to the New England Conference of Public Utility Commissioners Transmission Group, Chelmsford, MA (January 2009)

"Regulation and Renewable Energy Policy," panel moderator, Center for Resource Solutions National Renewable Energy Marketing Conference, Denver, CO (October 2008)

"Energy Pricing in Massachusetts (… and What We Should Do About It)," presentation to the Berkshire Gas Large Commercial and Industrial Customer Annual Meeting, Lenox, MA (October 2008)

"Conversation with Chairman Hibbard," presentation to the New England Energy Alliance, Boston, MA (September 2008)

"Creating the Path: Delivering Clean Energy through Transmission Improvements," presentation to the New England Independent System Operator Lights, Power, Action Conference, Boston, MA (September 2008)

"Distributed Resources, the Decoupling Model, and the Green Communities Act," presentation to the Raab Restructuring Roundtable, Boston, MA (September 2008)

"Resource Planning: The Contribution of Efficiency and Renewables in Massachusetts," presentation to the Law Seminars International Renewable Energy in New England Conference, Boston, MA (September 2008)

"Remarks to Economic Studies Working Group," ESWG Committee Meeting, Westborough, MA (July 2008)

"Power Trade: Market Context and Opportunities," presentation to the New England Governors' Council/Eastern Canadian Premiers' Energy Dialogue, Montreal, Canada (May 2008)

"New England Transmission Investment," presentation to the Municipal Electric Association of Massachusetts Annual Business Meeting, North Falmouth, MA (April 2008)

"Bringing Power from the North," presentation to the Raab Restructuring Roundtable, Boston, MA (February 2008)

"Natural Gas: Drivers of Supply, Demand, and Prices," comments to the Guild of Gas Managers (November 2007)

"Generation and Demand Outlook for New England," presentation to NECA Dinner Meeting, Cambridge, MA (September 2007)

"Comments on ISO's Draft Regional System Plan," presentation to the Independent System Operator Planning Advisory Committee, Boston, MA (September 2007)

"Regulatory Pressures, Policy Opinions," presentation to the Environmental Business Council, Boston, MA (July 2007)

"Is New England Ensuring the Adequacy and Cost Effectiveness of the Region's Transmission Grid?" panel moderator, New England Conference of Public Utility Commissioners Annual Symposium, Mystic, CT (June 2007)

"Energy Regulation in Massachusetts – Concerns and Options," presentation to the Raab Restructuring Roundtable, Boston, MA (June 2007)

"View From the Regulatory Bench," comments to the New England Energy Conference and Exposition, Groton, CT (May 2007)

"Energy for New England – The Demand, Supply and Price Context," presentation to Massachusetts Municipal Wholesale Electric Cooperative Annual Meeting, Boylston, MA (May 2007)

"Demand Resources in New England: New Opportunities and Future Directions," presentation to the New England Independent System Operator Annual Demand Resources Summit, Westborough, MA (May 2007)

"Power Supply for the New England Region," presentation to the Boston Bar Association, Boston, MA (March 2007)

"Fuel Supplies and the Need for Fuel Diversity: Forecast for Global Fuel Markets and the Likely Impact on Electric Generation in the Northeast," presentation to the Law Seminars International Seminar on Resource Adequacy and Reliability in the Northeast (October 16, 2006)

"Consumers and Politicians Claim They Want Cheap, Reliable and Clean Energy – Do They Have the Will to Make That Happen?" presentation to the National Association of Energy Service Companies New England Regional Meeting (September 28, 2006)

"The Need for New LNG Infrastructure in Massachusetts and New England: An Update," report prepared for Northeast Gateway Energy Bridge, LLC, and Algonquin Gas Transmission, LLC (August 2006)

"Natural Gas & LNG for New England: What's Needed & How To Get It," presentation to the Foundation for American Communications Meeting on *New England's Energy Needs – Who Pays and Who Suffers?* (May 17, 2006)

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"Siting Power Plants: Recent Experience in California and Best Practices in Other States," with Susan Tierney, prepared for The Hewlett Foundation and The Energy Foundation (February 2002)

"Setting and Administering Output-Based Emission Standards for the Power Sector: A Case Study of the Massachusetts Output-Based Emission Control Programs," prepared for the China Sustainable Energy Program, Paul Hibbard, N. Seidman, and B. Finamore (October 2001)

Joint Affidavit before the Federal Energy Regulatory Commission, New England Power Pool and ISO New England, Inc., Docket No. ER01-2329, on behalf of the New England Renewable Power Producers Association, with Janet Besser, (July 3, 2001)

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Testimony of
Peter R. Blazunas

DIRECT TESTIMONY

OF

PETER R. BLAZUNAS

Table of Contents

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Peter R. Blazunas and my business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. Please state your position.

A. I am a Project Manager for Concentric Energy Advisors, Inc. ("Concentric"), a management consulting firm. I am testifying on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company").

Q. Please describe your educational background.

A. I received a Bachelor of Arts degree in Economics from the University of Dayton in 2009 and a Master of Arts degree in Economics from the University of Akron in 2011.

Q. Please describe your professional background.

A. I began my career with FirstEnergy Corp. in 2012 as a State Regulatory Analyst in the Ohio Rates and Regulatory Affairs Department. In July 2017, I joined the Potomac Electric Power Company ("Pepco") Regulatory Strategy and Revenue Policy team of the Regulatory Affairs Department of Pepco Holdings Inc. (PHI) as a Senior Rate Analyst. In November 2018, I assumed the position of Manager of Rate Administration for Pepco. In that role, I was responsible for the development of electric rates, including tariff surcharges, for Pepco's Maryland and District of Columbia jurisdictions, and also participated in the development of Pepco's policies and practices with respect to rate design and assisted with regulatory compliance matters, including tariff administration and periodic filings. I left Pepco in January 2021 and assumed my current role at Concentric in October 2021.

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

A. Yes. I have submitted pre-filed testimony before the PUC in support of the Company's Renewable Energy (RE) Growth Program Factor filing in Docket No. 22-04-REG, the Company's Gas Revenue Decoupling Mechanism (RDM) Reconciliation filing in Docket No. 22-13-NG, the Company's Distribution Adjustment Charge (DAC) in Docket No. 22-13-NG, and the Company's Electric Infrastructure, Safety, and Reliability (ISR) Plan Annual Reconciliation filing in Docket No. 5098.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to calculate the Gas Cost Recovery ("GCR") factors proposed for effect on November 1, 2022 for the following services: (1) firm sales service to customers in the Residential Non-Heating and Heating rate classes and firm sales customers in the Small, Medium, Large, and Extra-Large Commercial and

Industrial ("C&I") 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. My 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. I am sponsoring the following attachments to my testimony:

Attachment PRB-1	Proposed Gas Cost Recovery Factors
Attachment PRB-2	Annual GCR Reconciliation Filing
Attachment PRB-3	Projected Gas Cost Deferral Balances
Attachment PRB-4	Bill Impact Analysis
Attachment PRB-5	FT-2 Demand Rate
Attachment PRB-6	FT-2 Capacity Allocator Percentages

II. <u>GCR Factor Development</u>

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, 2022 through October 31, 2023. As shown in the joint pre-filed direct testimony of the Company's witnesses for the Gas Supply Panel ("GSP") on Attachment GSP-1, firm sales customers' gross gas costs for the 12 months ending October 31, 2023 are projected to be approximately $246.0 million. In addition to these projected costs, the proposed 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 2022-23 GCR factors:

GCR Component	**Amount (millions)**	**Attachment**
Firm Gas Costs	$246.0	GSP-1
Hedging Impact	($77.7)	JMP-5
Working Capital Costs	$1.3	PRB-1, Page 2, Line (9) + PRB-1, Page 3, Line (6)
Inventory Financing Costs	$0.9	PRB-1, Page 3, Lines (9) + (10)
Prior Period Deferred Balance	$16.7	PRB-1, Page 2, Line (10) + PRB-1, Page 3, Line (7)
LNG O&M Costs	$1.1	PRB-1, Page 2, Line (8) + PRB-1, Page 3, Line (8)
FT-2 Marketer Storage Demand Costs	($3.5)	PRB-1, Page 2, Line (4)
Total	$184.7	PRB-1, Page 2, Line (12) + PRB-1, Page 3, Line (12)

The proposed GCR factors are intended to recover approximately $184.7 million in net costs over the period November 1, 2022 through October 31, 2023.

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, R.I.P.U.C. NG-GAS No. 101, Section 2, Gas Charge, Schedule A. Attachment PRB-1 provides a summary of the GCR fixed and variable gas cost components used to develop the rates for which the Company requests 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 PRB-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. This results in total fixed gas costs of $79.5 million to be recovered over the period November 2022 through October 2023.

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 $2.9688 per dekatherm, while the proposed GCR fixed High Load Factor is $2.2875 per dekatherm, both 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 demand costs to be allocated to the DAC?

A. Yes. As indicated in the direct testimony of the GSP, the Company has proposed to recover the costs of peaking assets needed for design hour reliability from all customers directly via the DAC. Therefore, the Company is proposing to allocate approximately $68.7 million associated with hourly peaking demand costs to the DAC mechanism to be recovered through the System Pressure Factor in the DAC proposed for effect November 1, 2022. These costs are reflected on Schedule GSP-1 in this filing.

Q. How did the Company develop the 2022-23 throughput forecast used to calculate the High Load and Low Load GCR Factors?

A. The pre-filed joint direct testimony of Company witnesses Theodore E. Poe, Jr. and Shira Horowitz supports the 2022-23 throughput forecast used to develop the proposed GCR factors.

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

A. As done last year in Docket No. 5180, 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 2022 through March 2023. 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 PRB-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 PRB-1, Page 3, Line (12), the total estimated variable cost for the period November 2022 through October 2023 is $105.2 million. The variable costs are divided by the projected throughput to obtain a variable cost factor of $3.9070 per dekatherm.

Q. With respect to 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, 2022.

Q. Has the Company included any incremental variable costs associated with peaking assets needed for design hour reliability to be allocated to the DAC?

A. No. In Docket No. 5040, the Division recommended the Company include incremental variable cost associated with peak hour resources in the DAC if those costs are significant, and to report those costs in the next year's DAC and GCR filing, if found to be significant.[1] The Company has found that the incremental variable costs associated

[1] R.I.P.U.C. Docket No. 5040/5066, Public Utilities Commission Order (01/05/2021), Page 5.

with peaking assets needed for design hour reliability were not significant; therefore, the Company is not including any incremental variable costs in this filing.

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 2022 and forecasted data for the months of August through October 2022, the total estimated deferred balance at October 31, 2022 is an under-recovery of approximately $16.7 million, consisting of a fixed cost deferral of $3.7 million, a variable cost deferral of $12.5 million, and a COVID deferral of $0.5 million, as shown in Attachment PRB-1, Page 7, column (n), Lines (17), (34), and (42). As discussed below, the Company is not proposing separate COVID Deferral Factors. Consequently, for purposes of establishing the total amount deferred for recovery beginning November 1, the COVID deferral balance as of October 31, 2022 was incorporated into the fixed and variable cost deferral balances as of October 31, 2022. This was accomplished by allocating the COVID deferral balance as of October 31, 2022, to the fixed and variable cost deferral balances as of October 31, 2022 in proportion to their relative deferral balances as of October 31, 2022. This calculation is shown on Line (58) to (66) of page 7 of Attachment PRB-1. The total amount deferred for recovery beginning November 1 of $16.7 million is incorporated into the development of the proposed GCR factors for the period November 1, 2022 to October 31, 2023. In addition, the Company shows the projected monthly deferred gas cost balances for November 2022 through October 2023 in Attachment PRB-3.

Q. Is the Company proposing a COVID Deferral Factor?

A. No. The Company proposes that the COVID Deferral Recovery Factor be removed as a component of the GCR effective November 1, 2022. The COVID Deferral Recovery Factor presently in effect for the period November 2021 to October 2022 was designed to recover the remaining fifty percent of the November 2020 to October 2021 GCR increase. As there was no deferral of the November 2021 to October 2022 GCR increase and, with the remaining COVID deferral balance as of October 31, 2022 allocated to the fixed and variable cost deferral balances as of October 31, 2022 as described above, the COVID Deferral Factor is no longer necessary starting November 1, 2022.

Q. Attachment PRB-2 provides the fiscal year 2022 Annual GCR Reconciliation balances. Does the monthly information shown in Attachment PRB-2 correspond with the monthly deferred balance reports filed in Docket Nos. 5066 and 5180?

A. Yes. The March 31, 2022 reconciliation balance of $11,659,178 shown in Attachment PRB-2 reflects the balance that was submitted on June 30, 2022 in the Company's annual GCR reconciliation report and is the same balance reflected in the July 2022 monthly deferred balance report filed in Docket No. 5180 on August 19, 2022.

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 $14.8192 per MDQ in dekatherms per month, as shown in Attachment PRB-5, as well as the storage and peaking charge of $0.11687 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 PRB-6. The Company has also provided the detailed 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 PRB-5, the proposed FT-2 Marketer Demand rate is $14.8192 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, 2022 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. 22-13-NG. The bill impacts are presented in Attachment PRB-4 and reflect current annual bills in Column (c) assuming that the rates in effect during September 2022 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 see a total annual bill of $1,741.91 based on the proposed GCR and DAC factors, which is an increase of $227.23, or 15.0 percent, from last year's bills. This overall increase is comprised of an increase of $73.70 as a result of the proposed GCR factors; an increase of $146.71 as a result of the proposed DAC factors as revised in a supplemental filing on September 1, 2022 in Docket No. 22-13-NG; and an increase of $6.82 in Gross Earnings Tax.

Q. What are the main drivers causing the increase presented in the bill impact analysis?

A. The annual residential heating bill increase is attributable to the following drivers:

	$ Inc (Dec)	%
Annual Bill at Current Rates	$1,514.68	
Demand Costs Allocated to DAC[2]	$133.93	8.8%
Net Increase in Other DAC Components	$12.78	0.8%
Net Increase in GCR	$73.70	4.9%
Increase in Gross Earnings Tax	$6.82	0.5%
	$1,741.91	

Overall, the increase in an average residential heating customer's bill of $227.23, or 15.0 percent, is driven in large part by an increase of $133.93, or 8.8%, due to an increase in demand costs allocated to the DAC and recovered via the System Pressure Factor of the DAC, as well as $93.30, or 6.2%, due to a net increase in other costs associated with the DAC and the GCR. The drivers of natural gas pricing (and GCR rates) in New England are discussed in the testimony of Company Witness Paul J. Hibbard. The changes in the

[2] Recovered via the System Pressure Factor of the DAC.

individual components of the DAC relative to last year's filing are provided on page 2 of Schedule PRB-1S of Company Witness Blazunas's Supplemental Testimony in Docket No. 22-13-NG, the Company's Supplemental DAC filing, made on September 1, 2022.

Q. Does this conclude your testimony?

A. Yes.

Attachments of Peter R. Blazunas

Attachment PRB-1

Gas Cost Recovery Factors

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Page 1 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Factors Effective November 1, 2022

	Description	Source: Reference	Source: Line #	High Load[1]	Low Load[2]	FT-2 Mkter[3]
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Cost Factor - $/dktherm	PRB-1, pg 2	Line (16)	$2.2875	$2.9688	
(2)	Variable Cost Factor -$/dktherm	PRB-1, pg 3	Line (14)	$3.9070	$3.9070	
(3)	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$6.1945	$6.8758	
(4)	Uncollectible %	Docket No. 4770		1.91%	1.91%	
(5)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) ÷ [1 - (4)]		$6.3151	$7.0096	
(6)	GCR Charge on a per therm basis	(5) ÷ 10		**$0.6315**	**$0.7009**	
(7)	Current rate effective 11/01/21 - $/therm	Docket No. 5180		$0.5413	$0.6137	
(8)	Increase / (Decrease) - $/therm	(6) - (7)		$0.0902	$0.0872	
(9)	Percent Increase	(8) ÷ (7)		16.7%	14.2%	

[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 PRB-5 for calculation of FT-2 rate
(6): Truncated to 4 decimals.

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Page 2 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
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 Capacity Release to marketers)	PRB-1, pg 5	Line (57)	$158,082,458		
	Less:					
(2)	NGPMP Customer Benefit	GSP-1		($11,646,741)		
(3)	Interruptible Costs			$0		
(4)	FT-2 Storage Demand Costs	PRB-5, pg 2	Line (25)	($3,541,023)		
(5)	System Pressure to DAC	GSP-1, pg 12		($68,657,362)		
(6)	Refunds			$0		
(7)	Total Credits	Sum[(2):(6)]		($83,845,125)		
	Plus:					
(8)	Supply Related LNG O&M Costs	Docket No. 4770	Compliance Attachment 2 Schedule 32 Pg 5	$829,823		
(9)	Working Capital Requirement	PRB-1, pg 9	Line (16)	$650,664		
(10)	Deferred Fixed Cost Under-recovered	PRB-1, pg 7	Line (17)	$3,794,338		
(11)	Total Additions	Sum[(8):(10)]		$5,274,825		
(12)	Total Fixed Costs	(1) + (7) + (11)		$79,512,158		
(13)	Design Winter Sales Percentage	PRB-1, pg 13	Lines (10) & (11)		1.87%	98.13%
(14)	Allocated Supply Fixed Costs	(12) x (13)			$1,486,877	$78,025,281
(15)	Sales (Dth) Nov 2022 - Oct 2023	PRB-1, pg 12	Line (9)	26,932,120	649,996	26,282,124
(16)	Fixed Factor	(14) ÷ (15)			**$2.2875**	**$2.9688**

(15) Col (e): PRB-1 page 12, Sum[Lines (1), (6), (8)]
Col (f): PRB-1 page 12, Sum[Lines (2)-(5), (7)]

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Page 3 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Variable Cost Calculation ($ per Dth)

	Description	Source: Reference	Source: Line #	Amount
	(a)	(b)	(c)	(d)
(1)	Variable Costs, excluding Refunds	PRB-1, pg 6	Line (93) - Line (90)	$90,436,217
	Less:			
(2)	System Pressure to DAC			$0
(3)	Non-Firm Sales			$0
(4)	Refunds	PRB-1, pg 6	Line (90)	$0
(5)	Total Credits	Sum [(2):(4)]		$0
	Plus:			
(6)	Working Capital	PRB-1, pg 9	Line (32)	$658,021
(7)	Deferred Variable Cost Under-recovered	PRB-1, pg 7	Line (34)	$12,877,724
(8)	Supply Related LNG O&M	Docket No. 4770	Compliance Attachment 2 Schedule 32 Pg 5 Ln 15 - Ln 12	$302,244
(9)	Inventory Financing - LNG	PRB-1, pg 11	Line (22)	$186,264
(10)	Inventory Financing - Storage	PRB-1, pg 11	Line (12)	$763,374
(11)	Total Additions	Sum [(6):(10)]		$14,787,627
(12)	Total Variable Supply Costs	(1) + (5) + (11)		$105,223,844
(13)	Sales (Dth) Nov 2022 - Oct 2023	PRB-1, pg 12	Line (9)	26,932,120
(14)	Variable Cost Factor	(12) ÷ (13)		**$3.9070**

Redacted

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Page 4 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

	Description (a)	Reference (b)	Nov-22 (c)	Dec-22 (d)	Jan-23 (e)	Feb-23 (f)	Mar-23 (g)	Apr-23 (h)	May-23 (i)	Jun-23 (j)	Jul-23 (k)	Aug-23 (l)	Sep-23 (m)	Oct-23 (n)	Nov-Oct (o)
	Supply Fixed Costs - Pipeline Delivery														
(1)	Dracut	GSP-1	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$81,936	$983,232
(2)	Manchester Lateral	GSP-1	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$211,015	$2,532,177
(3)	Niagara	GSP-1	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$6,576	$78,917
(4)	Yankee Interconnect	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$563,538
(5)	AIM	GSP-1	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$764,616	$9,175,397
(6)	Transco	GSP-1	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$9,430	$113,164
(7)	TCO (Pool)	GSP-1	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$611,017	$7,332,207
(8)	TETCO SCT Long Haul	GSP-1	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$25,889	$310,664
(9)	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
(10)	TETCO CDS Long Haul	GSP-1	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$1,448,198	$17,378,375
(11)	Dominion	GSP-1	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$9,251	$111,017
(12)	Dawn via Waddington	GSP-1	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$24,528	$294,336
(13)	Dawn via PNGTS	GSP-1	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$1,097,880	$13,174,555
(14)	TGP Long Haul	GSP-1	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$444,260	$5,331,116
(15)	TGP ConneXion	GSP-1	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$217,326	$2,607,914
(16)	Beverly	GSP-1	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$47,024	$564,288
(17)	[redacted]	GSP-1	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$102,420	$1,229,040
(18)	Less Credits from Mkter Releases*	GSP-1	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($128 490)	($1 541 882)
(19)	Total Supply Fixed Costs - Pipeline	Sum[(1) (18)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$61,759,536
	Storaged Fixed Costs - Facilities														
(20)	Columbia FSS	GSP-1	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$16,121	$193,457
(21)	Dominion GSS	GSP-1	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$70,164	$841,972
(22)	Dominion GSSTE	GSP-1	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$90,431	$1,085,174
(23)	Exeter LNG	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(24)	Providence LNG	GSP-1	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$290,520	$3,486,240
(25)	Tennessee FSMA	GSP-1	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$41,367	$496,403
(26)	Tetco FSS1	GSP-1	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$4,773	$57,280
(27)	Tetco SS1	GSP-1	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$190 186	$2 282 227
(28)	Total Fixed Storage Costs	Sum[(20) (27)]	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$8,442,753

* Capacity release credits included in forecasted supply costs

Redacted

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-22 (c)	Dec-22 (d)	Jan-23 (e)	Feb-23 (f)	Mar-23 (g)	Apr-23 (h)	May-23 (i)	Jun-23 (j)	Jul-23 (k)	Aug-23 (l)	Sep-23 (m)	Oct-23 (n)	Nov-Oct (o)
Storage Fixed Costs - Delivery														
(29) Storage Delivery	GSP-1	$497,213	$497,213	$497,213	$497,213	$497,213	$445,475	$445,475	$445,475	$445,475	$445,475	$445,475	$445,475	$5,604,391
(30) LNG	GSP-1	$510,120	$510,120	$510,120	$510,120	$510,120	$712,880	$712,880	$712,880	$712,880	$712,880	$712,880	$712,880	$7,540,759
(31) Portable LNG	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$1,615,380
(32) Ramapo	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(33) Dawn East Hereford	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(34) Dawn Waddington	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(35) Dominion South Point	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(36) Millenium East	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(37) Niagara	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(38) TCO Appalachia	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(39) TCO M3	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(40) Tetco M3	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(41) Transco Leidy	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(42) Waddington	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(43) Dracut Supply Deal	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(44) TGP Citygate	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(45) Summer Liquid Refill	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$35,985
(46) Tetco M2 CDS	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(47) Tetco M2 SCT	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(48) TGP Z4 CnX	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(49) TGP Z4 LH	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(50) AGT Citygate	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$2,792,296
(51) Proposed Summer Liquid	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(52) Winter Liquid	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$12,181,858
(53) Beverly Supply Deal	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6,000,000
(54) [redacted]	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$52,109,500
(55) Storage Delivery Fixed Cost	Sum[(29) (54)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$87,880,169
(56) Total Storage Fixed	(28) + (55)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$96,322,922
(57) Total Fixed Costs	(19)+(28)+(55)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$158,082,458

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Gas Cost Estimate

Description (a)	Reference (b)	Nov-22 (c)	Dec-22 (d)	Jan-23 (e)	Feb-23 (f)	Mar-23 (g)	Apr-23 (h)	May-23 (i)	Jun-23 (j)	Jul-23 (k)	Aug-23 (l)	Sep-23 (m)	Oct-23 (n)	Nov-Oct (o)
Variable Commodity Costs														
(58) AGT Citygate	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(59) AIM at Ramapo	GSP-1	$53,418	$0	$0	$0	$148,910	$93,769	$0	$0	$0	$0	$0	$16,263	$312,359
(60) [redacted]	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
(61) Dawn via IGTS	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(62) Dawn via PNGTS	GSP-1	$130,630	$0	$23,901	$1,959,649	$537,006	$0	$0	$0	$0	$0	$0	$0	$2,651,185
(63) Dominion SP	GSP-1	$109,394	$124,755	$126,719	$109,410	$100,563	$69,794	$63,757	$0	$63,419	$0	$3,557	$55,919	$827,287
(64) Dracut Supply	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
(65) Millennium	GSP-1	$1,596,934	$1,699,758	$1,726,515	$1,490,680	$1,370,140	$950,928	$868,678	$836,192	$864,065	$856,683	$727,036	$761,881	$13,749,489
(66) Niagara	GSP-1	$16,742	$43,004	$255,504	$111,226	$27,772	$144,629	$41,243	$0	$0	$0	$0	$0	$640,121
(67) TCO Appalachia	GSP-1	$3,277,394	$7,784,987	$7,935,724	$6,805,612	$6,236,603	$384,142	$201,813	$13,450	$201,401	$200,680	$120,646	$92,510	$33,254,962
(68) Tetco M3	GSP-1	$369,189	$0	$0	$0	$2,067,147	$7,046,809	$486,027	$5,140	$0	$0	$43,963	$1,687,434	$11,705,709
(69) Transco Leidy	GSP-1	$243,299	$284,963	$291,502	$251,445	$227,893	$11,162	$8,422	$8,066	$8,374	$8,363	$7,053	$7,470	$1,358,010
(70) Waddington	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(71) Tetco M2 CDS	GSP-1	$7,994,399	$7,931,167	$8,721,812	$7,279,692	$6,362,214	$253,512	$3,525,767	$3,563,494	$2,621,551	$3,170,283	$3,034,056	$3,708,072	$58,166,018
(72) Tetco M2 SCT	GSP-1	$0	$0	$0	$0	$137,826	$0	$0	$0	$0	$0	$0	$0	$137,826
(73) TGP Z4 Cnx	GSP-1	$1,372,565	$2,277,532	$2,331,580	$2,012,744	$1,845,130	$1,137,816	$1,217,649	$1,181,029	$1,232,855	$1,235,229	$1,036,917	$1,096,695	$17,977,740
(74) TGP Z4 LH	GSP-1	$877,904	$2,983,110	$5,238,509	$5,437,044	$2,833,889	$789,262	$130,976	$546,399	$415,512	$0	$443,296	$947,438	$20,643,338
(75) Proposed Summer Refill	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(76) [redacted]	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
(77) [redacted]	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
(78) Beverly	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(79) [redacted]	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
(80) Total Variable Commodity Costs	Sum[(58) (79)]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$161,424,044
Variable Storage Costs														
(81) Underground Storage	GSP-1	$2,971,547	$4,586,457	$4,592,901	$3,655,653	$2,045,864	$0	$0	$0	$0	$0	$0	$0	$17,852,423
(82) LNG Withdrawals and Trucking	GSP-1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$5,242,919
(83) Total Variable Storage Costs	(81) + (82)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$23,095,342
Variable Transportation Costs														
(84) Variable Costs for Purchases to City Gate	GSP-1	$245,961	$298,481	$350,392	$329,797	$332,759	$96,697	$123,053	$79,388	$58,986	$64,373	$85,177	$149,333	$2,214,397
(85) Variable Cost for Storage Withdrawal	GSP-1	$76,830	$112,256	$108,299	$89,613	$42,646	$0	$0	$0	$0	$0	$0	$0	$429,644
(86) Variable Cost for Storage Injection	GSP-1	$0	$0	$0	$0	$0	$227,265	$264,083	$281,260	$276,974	$281,316	$276,187	$185,351	$1,792,437
(87) Total Variable Transportation Costs	Sum[(84) (86)]	$322,791	$410,737	$458,691	$419,410	$375,405	$323,962	$387,136	$360,649	$335,961	$345,689	$361,365	$334,683	$4,436,477
Injections														
(88) Cost of Injections	GSP-1	$0	$0	$0	$0	$0	($1,075,499)	($2,271,837)	($3,462,112)	($3,204,175)	($3,200,943)	($2,943,349)	($2,827,805)	($18,985,720)
(89) Variable Cost for Storage Injection	GSP-1	$0	$0	$0	$0	$0	($227,265)	($264,083)	($281,260)	($276,974)	($281,316)	($276,187)	($185,351)	($1,792,437)
(90) Refunds	GSP-1	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(91) Total Injections	Sum[(88) (90)]	$0	$0	$0	$0	$0	($1,302,764)	($2,535,920)	($3,743,373)	($3,481,149)	($3,482,259)	($3,219,536)	($3,013,156)	($20,778,156)
Hedging Impact														
(92) Hedging Impact	JMP-5	($9,521,099)	($15,123,099)	($16,623,012)	($14,115,320)	($9,398,966)	($2,798,106)	($2,412,521)	($1,762,812)	($1,537,639)	($1,448,457)	($1,412,039)	($1,588,419)	($77,741,490)
(93) Total Variable Costs	(80)+(83)+(87)+(91)+(92)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$90,436,217
(94) Total Supply Costs	(57) + (93)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$248,518,676
Storage Costs for FT-2 Calculation														
(95) Storage Fixed Costs - Facilities	(28)	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$703,563	$8,442,753
(96) Storage Fixed Costs - Deliveries	(55)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$87,880,169
(97) Total Storage Costs	(95) + (96)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$96,322,922

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Page 7 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
GCR Deferred Balances

	Description	Nov-21 actual	Dec-21 actual	Jan-22 actual	Feb-22 actual	Mar-22 actual	Apr-22 actual	May-22 actual	Jun-22 actual	Jul-22 actual	Aug-22 forecast	Sep-22 forecast	Oct-22 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	$3,599,748	$5,597,557	$5,373,221	$831,550	($4,932,771)	($10,664,992)	($14,257,795)	($13,541,047)	($9,895,433)	($6,722,434)	($2,978,073)	$675,074	$3,599,748
(4)	Supply Fixed Costs (net of cap rel)	$6,294,660	$11,100,764	$10,874,060	$10,878,670	$11,856,836	$4,649,747	$5,982,264	$5,838,094	$5,670,233	$6,270,008	$6,269,607	$6,269,607	$91,954,550
(5)	Supply Related System Pressure to DAC	($20,156)	($2,300,929)	($2,102,104)	($2,083,120)	($2,034,875)	$68,844	$21,107	($20,156)	($20,156)	($20,484)	($20,484)	($20,484)	($8,552,998)
(6)	Supply Related LNG O & M	$69,152	$69,152	$69,152	$69,152	($160,615)	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$69,152	$600,056
(7)	NGPMP Credits	($669,932)	($669,932)	($2,259,353)	($669,932)	($4,654,267)	($669,932)	($669,932)	($30,969)	($669,932)	($669,932)	($669,932)	($669,932)	($12,973,973)
(8)	Working Capital	$46,220	$64,822	$64,617	$64,790	$72,351	$34,758	$44,222	$42,857	$41,620	$46,036	$46,033	$46,033	$614,358
(9)	Total Supply Fixed Costs	$5,719,943	$8,263,876	$6,646,372	$8,259,561	$5,079,431	$4,152,569	$5,446,813	$5,898,977	$5,090,917	$5,694,780	$5,694,376	$5,694,376	$71,641,993
(10)	Supply Fixed - Revenue	$3,726,857	$8,494,033	$11,191,334	$14,021,917	$10,802,576	$7,730,017	$4,707,235	$2,230,511	$1,897,853	$1,936,023	$2,037,921	$2,700,653	$71,476,932
(11)	Monthly Under/(Over) Recovery	$1,993,086	($230,157)	($4,544,962)	($5,762,356)	($5,723,146)	($3,577,448)	$739,578	$3,668,466	$3,193,064	$3,758,757	$3,656,455	$2,993,723	$165,061
(12)	Prelim. Ending Under/(Over) Recovery	$5,592,835	$5,367,400	$828,258	($4,930,806)	($10,655,917)	($14,242,441)	($13,518,217)	($9,872,580)	($6,702,368)	($2,963,676)	$678,382	$3,668,798	$3,764,809
(13)	Month's Average Balance	$4,596,292	$5,482,478	$3,100,739	($2,049,628)	($7,794,344)	($12,453,717)	($13,888,006)	($11,706,813)	($8,298,901)	($4,843,055)	($1,149,845)	$2,171,936	
(14)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.37%	1.50%	1.94%	2.38%	2.85%	3.50%	3.50%	3.50%	
(15)	Interest Applied	$4,722	$5,820	$3,292	($1,965)	($9,076)	($15,354)	($22,830)	($22,852)	($20,065)	($14,396)	($3,308)	$6,456	($89,555)
(16)	Marketer Reconcilation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17)	FIXED ENDING UNDER/(OVER) RECOVERY	$5,597,557	$5,373,221	$831,550	($4,932,771)	($10,664,992)	($14,257,795)	($13,541,047)	($9,895,433)	($6,722,434)	($2,978,073)	$675,074	$3,675,254	$3,675,254
(18)	II. Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$9,981,529	$12,885,890	$11,441,585	$22,637,551	$23,313,734	$20,383,618	$18,891,234	$16,510,646	$15,501,190	$15,949,368	$13,252,052	$11,096,001	$9,981,529
(20)	Variable Supply Costs	$6,682,445	$8,311,948	$24,074,997	$17,100,507	$9,616,502	$7,149,300	$2,772,424	$1,253,004	$2,282,378	($849,061)	($194,173)	$4,067,968	$82,268,240
(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	$25,041	$24,539	$24,656	$24,655	$27,509	$27,041	$26,253	$25,650	$27,564	$27,444	$28,755	$30,054	$319,161
(24)	Inventory Financing - UG	$51,353	$54,758	$52,608	$53,532	$57,508	$66,658	$57,979	$56,328	$53,468	$102,059	$111,575	$137,450	$855,276
(25)	Working Capital	$49,225	$61,228	$177,343	$125,967	$70,838	$52,664	$20,422	$9,230	$16,813	($6,254)	($1,430)	$29,966	$606,010
(26)	Total Supply Variable Costs	$6,833,251	$8,477,660	$24,354,791	$17,329,848	$9,797,544	$7,320,850	$2,902,265	$1,369,399	$2,405,410	($700,626)	($30,086)	$4,290,625	$84,350,932
(27)	Supply Variable - Revenue	$3,961,268	$9,934,871	$13,176,906	$16,675,686	$12,753,085	$8,837,430	$5,311,927	$2,410,068	$1,995,208	$2,040,028	$2,160,936	$2,948,045	$82,205,458
(28)	Monthly Under/(Over) Recovery	$2,871,983	($1,457,211)	$11,177,885	$654,162	($2,955,541)	($1,516,579)	($2,409,662)	($1,040,669)	$410,202	($2,740,654)	($2,191,022)	$1,342,580	$2,145,473
(29)	Prelim. Ending Under/(Over) Recovery	$12,853,512	$11,428,679	$22,619,470	$23,291,713	$20,358,192	$18,867,038	$16,481,572	$15,469,977	$15,911,393	$13,208,714	$11,061,030	$12,438,581	$12,127,003
(30)	Month's Average Balance	$11,417,521	$12,157,285	$17,030,528	$22,964,632	$21,835,963	$19,625,328	$17,686,403	$15,990,311	$15,706,292	$14,579,041	$12,156,541	$11,767,291	
(31)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.37%	1.50%	1.94%	2.38%	2.85%	3.50%	3.50%	3.50%	
(32)	Interest Applied	$11,730	$12,907	$18,080	$22,021	$25,425	$24,196	$29,074	$31,214	$37,975	$43,338	$34,971	$34,979	$325,910
(33)	Gas Procurement Incentive/(penalty)	$20,648	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,648
(34)	VARIABLE ENDING UNDER/(OVER) RECOVERY	$12,885,890	$11,441,585	$22,637,551	$23,313,734	$20,383,618	$18,891,234	$16,510,646	$15,501,190	$15,949,368	$13,252,052	$11,096,001	$12,473,560	$12,473,560
(35)	III. COVID Deferred													
(36)	Beginning Balance	$4,792,618	$4,808,823	$4,267,226	$3,546,676	$2,637,642	$1,940,552	$1,446,864	$1,152,555	$1,021,983	$913,771	$803,104	$685,285	$4,792,618
(37)	COVID Cost Deferral	($11,275)	$546,412	$724,696	$911,998	$699,753	$495,775	$296,444	$132,693	$110,549	$113,215	$119,957	$163,831	$4,304,047
(38)	Prelim. Ending Balance	$4,803,893	$4,262,411	$3,542,530	$2,634,678	$1,937,889	$1,444,778	$1,150,420	$1,019,863	$911,434	$800,556	$683,147	$521,454	
(39)	Month's Average Balance	$4,798,256	$4,535,617	$3,904,878	$3,090,677	$2,287,765	$1,692,665	$1,298,642	$1,086,209	$966,708	$857,163	$743,126	$603,369	
(40)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.37%	1.50%	1.94%	2.38%	2.85%	3.50%	3.50%	3.50%	
(41)	Interest Applied	$4,930	$4,815	$4,146	$2,964	$2,664	$2,087	$2,135	$2,120	$2,337	$2,548	$2,138	$1,794	$34,677
(42)	Ending Balance	$4,808,823	$4,267,226	$3,546,676	$2,637,642	$1,940,552	$1,446,864	$1,152,555	$1,021,983	$913,771	$803,104	$685,285	$523,247	$4,338,724
(43)	GCR Deferred Summary													
(44)	Beginning Under/(Over) Recovery	$18,373,896	$23,292,270	$21,082,032	$27,015,776	$21,018,604	$11,659,178	$6,080,304	$4,122,154	$6,627,741	$10,140,705	$11,077,083	$12,456,360	$18,373,896
(45)	Gas Costs	$13,051,288	$17,206,121	$32,941,292	$25,990,397	$19,303,035	$11,962,230	$8,870,133	$7,165,281	$8,026,794	$5,494,802	$6,149,290	$10,411,430	$166,572,092
(46)	Inventory Finance	$76,394	$79,297	$77,264	$78,187	$85,017	$93,699	$84,232	$81,978	$81,032	$129,503	$140,330	$167,504	$1,174,437
(47)	Working Capital	$95,444	$126,050	$241,960	$190,757	$143,189	$87,422	$64,645	$52,086	$58,433	$39,781	$44,602	$75,998	$1,220,369
(48)	NGPMP Credits	($669,932)	($669,932)	($2,259,353)	($669,932)	($4,654,267)	($669,932)	($669,932)	($30,969)	($669,932)	($669,932)	($669,932)	($669,932)	($12,973,973)
(49)	Total Costs	$12,553,194	$16,741,536	$31,001,163	$25,589,409	$14,876,975	$11,473,419	$8,349,078	$7,268,377	$7,496,327	$4,994,155	$5,664,290	$9,985,002	$155,992,925
(50)	Revenue	$7,676,850	$18,975,317	$25,092,936	$31,609,601	$24,255,414	$17,063,222	$10,315,606	$4,773,272	$4,003,610	$4,089,266	$4,318,814	$5,812,529	$157,986,438
(51)	Monthly Under/(Over) Recovery	$4,876,344	($2,233,781)	$5,908,227	($6,020,191)	($9,378,440)	($5,589,803)	($1,966,528)	$2,495,104	$3,492,718	$904,889	$1,345,476	$4,172,472	($1,993,513)
(52)	Prelim. Ending Under/(Over) Recovery	$23,250,240	$21,058,490	$26,990,259	$20,995,585	$11,640,164	$6,069,375	$4,113,776	$6,617,259	$10,120,458	$11,045,594	$12,422,559	$16,628,832	$16,380,383
(53)	Month's Average Balance	$20,812,068	$22,175,380	$24,036,145	$24,005,681	$16,329,384	$8,864,277	$5,097,040	$5,369,707	$8,374,099	$10,593,149	$11,749,821	$14,542,596	
(54)	Interest Rate (BOA Prime minus 200 bps)	1.25%	1.25%	1.25%	1.25%	1.37%	1.50%	1.94%	2.38%	2.85%	3.50%	3.50%	3.50%	
(55)	Interest Applied	$21,382	$23,542	$25,518	$23,019	$19,014	$10,929	$8,379	$10,482	$20,247	$31,489	$33,801	$43,229	$271,031
(56)	Gas Purchase Plan Incentives/(Penalties)	$20,648	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,648
(57)	ENDING UNDER/(OVER) RECOVERY W/ INTEREST	$23,292,270	$21,082,032	$27,015,776	$21,018,604	$11,659,178	$6,080,304	$4,122,154	$6,627,741	$10,140,705	$11,077,083	$12,456,360	$16,672,062	$16,672,062

(58)	FIXED ENDING UNDER/(OVER) RECOVERY - October 2022 ($)	$3,675,254	= Column (m), Line (17)
(59)	VARIABLE ENDING UNDER/(OVER) RECOVERY - October 2022 ($)	$12,473,560	= Column (m), Line (34)
(60)	% Fixed of Fixed + Variable Ending Under/(Over) Recovery - October 2022	23%	= (58) / ((58) + (59))
(61)	% Variable of Fixed + Variable Ending Under/(Over) Recovery - October 2022	77%	= (59) / ((58) + (59))
(62)	COVID Deferred Ending Under/(Over) Recovery - October 2022	$523,247	= Column (m), Line (42)
(63)	COVID Deferred Ending Under/(Over) Recovery - October 2022 - Allocated to Fixed	$119,084	= (60) x (62)
(64)	COVID Deferred Ending Under/(Over) Recovery - October 2022 - Allocated to Variable	$404,163	= (61) x (62)
(65)	FIXED ENDING UNDER/(OVER) RECOVERY - October 2022 ($) Including COVID Deferral Allocation	$3,794,338	= (58) + (63)
(66)	VARIABLE ENDING UNDER/(OVER) RECOVERY - October 2022 ($) Including COVID Deferral Allocation	$12,877,724	= (59) + (64)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
GCR - Gas Cost Revenue

	Description (a)	Nov-22 fcst (b)	Dec-22 fcst (c)	Jan-23 fcst (d)	Feb-23 fcst (e)	Mar-23 fcst (f)	Apr-23 fcst (g)	May-23 fcst (h)	Jun-23 fcst (i)	Jul-23 fcst (j)	Aug-23 fcst (k)	Sep-23 fcst (l)	Oct-23 fcst (m)	Total Nov-Oct (n)
(1)	I Fixed Cost Revenue													
(2)	(a) Low Load dth	1,843,033	3,357,860	4,544,203	5,150,730	3,818,312	3,055,050	1,188,030	788,045	608,568	571,185	585,472	771,634	26,282,124
(3)	Fixed Cost Factor	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	$2 9688	
(4)	Low Load Revenue	$5,471,521	$9,968,676	$13,490,642	$15,291,275	$11,335,646	$9,069,706	$3,526,975	$2,339,517	$1,806,692	$1,695,711	$1,738,126	$2,290,794	$78,025,281
(5)	(b) High Load dth	49,096	72,098	85,604	91,603	72,888	63,149	44,676	38,411	32,504	30,838	33,334	35,795	649,996
(6)	Fixed Cost Factor	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	$2 2875	
(7)	High Load Revenue	$112,308	$164,926	$195,821	$209,543	$166,733	$144,455	$102,197	$87,865	$74,354	$70,543	$76,252	$81,881	$1,486,878
(8)	sub-total Dth	1,892,129	3,429,958	4,629,807	5,242,333	3,891,200	3,118,199	1,232,706	826,456	641,072	602,023	618,806	807,428	26,932,120
(9)	FT-2 Storage Revenue from marketers	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$295,085	$3,541,023
(10)	Total Fixed Revenue	$5,878,914	$10,428,687	$13,981,548	$15,795,903	$11,797,464	$9,509,246	$3,924,257	$2,722,467	$2,176,131	$2,061,339	$2,109,463	$2,667,760	$83,053,182
(11)	II Variable Cost Revenue													
(12)	(a) Firm Sales dth	1,892,129	3,429,958	4,629,807	5,242,333	3,891,200	3,118,199	1,232,706	826,456	641,072	602,023	618,806	807,428	26,932,120
(13)	Variable Cost Factor	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	$3 9070	
(14)	Variable Revenue	$7,392,553	$13,400,854	$18,088,666	$20,481,806	$15,202,926	$12,182,810	$4,816,186	$3,228,965	$2,504,670	$2,352,106	$2,417,677	$3,154,623	$105,223,842
(15)	Total Variable Revenue	$7,392,553	$13,400,854	$18,088,666	$20,481,806	$15,202,926	$12,182,810	$4,816,186	$3,228,965	$2,504,670	$2,352,106	$2,417,677	$3,154,623	$105,223,842
(16)	Total Gas Cost Revenue	$13,271,467	$23,829,541	$32,070,214	$36,277,709	$27,000,390	$21,692,056	$8,740,443	$5,951,432	$4,680,801	$4,413,445	$4,527,140	$5,822,383	$188,277,024

(2) PRB-1, pg 12, Sum [Lines (2)-(5), (7)]
(3) PRB-1, pg 1, Line 1, col (e)
(4) Line (2) x Line (3)
(5) PRB-1, pg 12, Sum [Lines (1), (6), (8)]
(6) PRB-1, pg 1, Line 1, col (d)
(7) Line (5) x Line (6)
(8) Line (2) + Line (5)
(9) [PRB-5, pg 2, Line (25)] ÷ 12

(10) Sum[Lines (4), (7), (9)]
(12) Line (8)
(13) PRB-1, pg 1, Line (2)
(14) Line (12) x Line (13)
(15) Line (14)
(16) Line (10) + Line (15)

Redacted

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No 22-20-NG
Attachment PRB-1
Page 9 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Working Capital Estimate

	Description (a)	Nov-22 (b)	Dec-22 (c)	Jan-23 (d)	Feb-23 (e)	Mar-23 (f)	Apr-23 (g)	May-23 (h)	Jun-23 (i)	Jul-23 (j)	Aug-23 (k)	Sep-23 (l)	Oct-23 (m)	Total (n)
(1)	Fixed Costs	$6,893,509	$25,532,282	$25,532,282	$25,532,282	$25,532,282	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$158,082,458
(2)	Capacity Release Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(3)	Less System Pressure to DAC	($149,444)	($16,865,453)	($16,865,453)	($16,865,453)	($16,865,453)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($68,657,362)
(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	$6,744,065	$8,666,830	$8,666,830	$8,666,830	$8,666,830	$6,859,102	$6,859,102	$6,859,102	$6,859,102	$6,859,102	$6,859,102	$6,859,102	$89,425,096
(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	$608,259	$781,677	$781,677	$781,677	$781,677	$618,635	$618,635	$618,635	$618,635	$618,635	$618,635	$618,635	
(9)	Weighted Average Cost of Capital	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	
(10)	Return on Working Capital Requirement	$41,422	$53,232	$53,232	$53,232	$53,232	$42,129	$42,129	$42,129	$42,129	$42,129	$42,129	$42,129	
(11)	Cost of Debt (Long Term Debt + Short Term Debt)	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	
(12)	Interest Expense	$12,652	$16,259	$16,259	$16,259	$16,259	$12,868	$12,868	$12,868	$12,868	$12,868	$12,868	$12,868	
(13)	Taxable Income	$28,771	$36,973	$36,973	$36,973	$36,973	$29,261	$29,261	$29,261	$29,261	$29,261	$29,261	$29,261	
(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	$36,419	$46,802	$46,802	$46,802	$46,802	$37,040	$37,040	$37,040	$37,040	$37,040	$37,040	$37,040	
(16)	Fixed Working Capital Requirement	$49,070	$63,061	$63,061	$63,061	$63,061	$49,907	$49,907	$49,907	$49,907	$49,907	$49,907	$49,907	$650,664
(17)	Variable Costs	$9,927,672	$13,801,541	$17,817,494	$16,070,206	$15,033,711	$7,224,422	$2,106,856	$1,124,754	$843,768	$1,004,913	$1,259,299	$4,221,581	$90,436,217
(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	$9,927,672	$13,801,541	$17,817,494	$16,070,206	$15,033,711	$7,224,422	$2,106,856	$1,124,754	$843,768	$1,004,913	$1,259,299	$4,221,581	$90,436,217
(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	$895,394	$1,244,786	$1,606,992	$1,449,401	$1,355,917	$651,584	$190,021	$101,444	$76,101	$90,635	$113,578	$380,752	
(25)	Weighted Average Cost of Capital	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	
(26)	Return on Working Capital Requirement	$60,976	$84,770	$109,436	$98,704	$92,338	$44,373	$12,940	$6,908	$5,182	$6,172	$7,735	$25,929	
(27)	Cost of Debt (Long Term Debt + Short Term Debt)	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	
(28)	Interest Expense	$18,624	$25,892	$33,425	$30,148	$28,203	$13,553	$3,952	$2,110	$1,583	$1,885	$2,362	$7,920	
(29)	Taxable Income	$42,352	$58,878	$76,011	$68,557	$64,135	$30,820	$8,988	$4,798	$3,600	$4,287	$5,372	$18,010	
(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	$53,610	$74,530	$96,216	$86,781	$81,183	$39,013	$11,377	$6,074	$4,556	$5,427	$6,800	$22,797	
(32)	Variable Working Capital Requirement	$72,235	$100,421	$129,641	$116,928	$109,386	$52,565	$15,330	$8,184	$6,139	$7,312	$9,163	$30,717	$658,021

(1) PRB-1, Pg 2, Line (1)
(3) GSP-1
(6) Sum[Lines (1)-(5)]
(7) Docket No 4770
(8) [Line (6) x Line (7)] ÷ 365
(9) Docket No 22-13-NG
(10 Line (8) x Line (9)
(11) Docket No 22-13-NG
(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 (15)
(17) PRB-1, Pg 3, Line (1)
(20) PRB-1, Pg 3, Line (2) ÷ 12
(22) Sum[Lines (17):(21)]
(23) Docket No 4770
(24) [Line (22) x Line (23)] ÷ 365
(25) Docket No 22-13-NG
(26) Line (24) x Line (25)
(27) Docket No 22-13-NG
(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)

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Redacted
Page 10 of 16

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

Description (a)	Nov-22 (b)	Dec-22 (c)	Jan-23 (d)	Feb-23 (e)	Mar-23 (f)	Apr-23 (g)	May-23 (h)	Jun-23 (i)	Jul-23 (j)	Aug-23 (k)	Sep-23 (l)	Oct-23 (m)	Total (n)
(33) Storage Fixed Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$96,322,922
(34) Less: System Pressure to DAC	($149,444)	($16,865,453)	($16,865,453)	($16,865,453)	($16,865,453)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($68,657,362)
(35) Less: Credits	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(36) Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(37) Allowable Working Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$27,665,560
(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	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	
(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 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	
(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]	$201,297

(33) PRB-1, pg 5, Line (40)
(34) Line (3)
(37) Sum[Lines (33) - (36)]
(38) Docket No 4770
(39) [Line (37) x Line (38)] ÷ 365
(40) Docket No 22-13-NG
(41) Line (39) x Line (40)
(42) Docket No 22-13-NG
(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)

Redacted

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No 22-20-NG
Attachment PRB-1
Page 11 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Inventory Finance Estimate

Description	Source	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Total
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
(1) **Storage Inventory Balance**	GSP-1	$17,055,766	$12,469,309	$7,876,408	$4,220,754	$2,174,890	$2,631,330	$4,346,564	$7,306,841	$9,973,822	$12,646,368	$15,153,212	$17,695,001	
(2) Hedging		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(3) Subtotal	(1) + (2)	$17,055,766	$12,469,309	$7,876,408	$4,220,754	$2,174,890	$2,631,330	$4,346,564	$7,306,841	$9,973,822	$12,646,368	$15,153,212	$17,695,001	
(4) Weighted Average Cost of Capital	Docket No 22-13-NG	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	
(5) Return on Working Capital Requirement	(3) x (4)	$1,161,498	$849,160	$536,383	$287,433	$148,110	$179,194	$296,001	$497,596	$679,217	$861,218	$1,031,934	$1,205,030	$7,732,773
(6) Cost of Debt (LTD + STD)*	Docket No 22-13-NG	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	
(7) Interest Charges Financed	(3) x (6)	$354,760	$259,362	$163,829	$87,792	$45,238	$54,732	$90,409	$151,982	$207,455	$263,044	$315,187	$368,056	$2,361,846
(8) Taxable Income	(5) - (7)	$806,738	$589,798	$372,554	$199,642	$102,872	$124,462	$205,592	$345,614	$471,762	$598,173	$716,747	$836,974	
(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)	$1,021,187	$746,580	$471,587	$252,711	$130,218	$157,547	$260,244	$437,486	$597,167	$757,181	$907,275	$1,059,460	$6,798,642
(11) Working Capital Requirement	(7) + (10)	$1,375,947	$1,005,942	$635,417	$340,503	$175,456	$212,278	$350,652	$589,468	$804,622	$1,020,226	$1,222,461	$1,427,516	$9,160,488
(12) Storage-Related Inventory Costs	(11) ÷ 12	$114,662	$83,828	$52,951	$28,375	$14,621	$17,690	$29,221	$49,122	$67,052	$85,019	$101,872	$118,960	$763,374
(13) **LNG Inventory Balance**	GSP-1	$4,304,598	$3,506,428	$769,278	$116,317	$0	$726,816	$1,423,673	$2,090,248	$2,784,998	$3,476,007	$4,075,714	$4,432,290	
(14) Weighted Average Cost of Capital	Docket No 22-13-NG	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	6 81%	
(15) Return on Working Capital Requirement	(13) x (14)	$293,143	$238,788	$52,388	$7,921	$0	$49,496	$96,952	$142,346	$189,658	$236,716	$277,556	$301,839	$1,886,804
(16) Cost of Debt (LTD + STD)*	Docket No 22-13-NG	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	2 08%	
(17) Interest Charges Financed	(13) x (16)	$89,536	$72,934	$16,001	$2,419	$0	$15,118	$29,612	$43,477	$57,928	$72,301	$84,775	$92,192	$576,292
(18) Taxable Income	(15) - (17)	$203,608	$165,854	$36,387	$5,502	$0	$34,378	$67,340	$98,869	$131,730	$164,415	$192,781	$209,647	
(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)	$257,731	$209,942	$46,059	$6,964	$0	$43,517	$85,240	$125,150	$166,747	$208,120	$244,027	$265,376	$1,658,875
(21) Working Capital Requirement	(17) + (20)	$347,267	$282,876	$62,060	$9,384	$0	$58,635	$114,853	$168,627	$224,675	$280,421	$328,802	$357,568	$2,235,167
(22) LNG-Related Inventory Costs	(21) ÷ 12	$28,939	$23,573	$5,172	$782	$0	$4,886	$9,571	$14,052	$18,723	$23,368	$27,400	$29,797	$186,264
(23) Total Inventory Financing Costs	(12) + (22)	$143,601	$107,401	$58,123	$29,157	$14,621	$22,576	$38,792	$63,175	$85,775	$108,387	$129,272	$148,757	$949,638

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

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No 22-20-NG
Attachment PRB-1
Page 12 of 16

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Forecasted Throughput (Dth)

	Rate Class	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	SALES													
(1)	Residential Non-Heating	24,595	36,494	45,636	49,655	38,800	32,722	17,627	14,729	12,134	11,633	11,842	14,932	310,797
(2)	Residential Heating	1,449,312	2,596,057	3,498,553	3,915,982	2,891,087	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	20,025,849
(3)	Small C&I	131,203	282,550	412,804	497,959	360,161	263,710	114,865	57,952	50,105	39,487	38,085	49,715	2,298,596
(4)	Medium C&I	222,677	392,733	516,336	598,322	458,833	385,399	183,377	136,456	95,356	89,680	91,490	109,410	3,280,069
(5)	Large LLF	33,227	76,910	105,933	127,285	96,299	78,186	33,464	17,298	8,130	7,493	8,041	11,983	604,248
(6)	Large HLF	17,687	21,288	28,468	32,766	28,409	25,367	20,339	15,688	13,142	12,569	14,192	14,340	244,255
(7)	Extra Large LLF	6,615	9,610	10,577	11,182	11,931	10,400	4,532	2,404	1,288	1,206	1,158	2,457	73,361
(8)	Extra Large HLF	6,814	14,317	11,500	9,181	5,679	5,061	6,710	7,993	7,228	6,636	7,300	6,523	94,943
(9)	**Total Sales**	1,892,129	3,429,958	4,629,807	5,242,333	3,891,200	3,118,199	1,232,706	826,456	641,072	602,023	618,806	807,428	26,932,120
	TRANSPORTATION													
(10)	FT- Small	11,536	23,373	30,909	36,658	27,174	22,134	10,132	6,469	4,082	3,755	3,717	4,901	184,842
(11)	FT- Medium	199,205	302,095	378,565	413,442	325,078	281,684	141,517	102,313	73,956	70,871	72,808	96,863	2,458,396
(12)	FT- Large LLF	202,056	314,133	400,247	421,310	315,722	263,527	112,927	61,653	35,440	33,215	36,878	72,549	2,269,656
(13)	FT- Large HLF	76,155	94,673	122,240	131,148	120,401	105,475	85,982	74,469	73,198	67,817	72,258	73,605	1,097,421
(14)	FT- Extra Large LLF	139,416	170,966	208,928	191,732	151,429	121,600	48,167	25,644	22,172	22,945	27,121	65,836	1,195,958
(15)	FT- Extra Large HLF	487,308	530,839	565,303	569,455	533,886	501,257	453,238	415,066	412,284	423,828	426,513	438,880	5,757,858
(16)	**Total FT Transportation**	1,115,676	1,436,080	1,706,192	1,763,745	1,473,690	1,295,678	851,963	685,615	621,133	622,432	639,295	752,634	12,964,131
	Total THROUGHPUT													
(17)	Residential Non-Heating	24,595	36,494	45,636	49,655	38,800	32,722	17,627	14,729	12,134	11,633	11,842	14,932	310,797
(18)	Residential Heating	1,449,312	2,596,057	3,498,553	3,915,982	2,891,087	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	20,025,849
(19)	Small C&I	142,739	305,923	443,713	534,617	387,336	285,844	124,997	64,421	54,187	43,242	41,803	54,616	2,483,438
(20)	Medium C&I	421,882	694,828	894,901	1,011,764	783,911	667,083	324,894	238,769	169,312	160,551	164,298	206,272	5,738,465
(21)	Large LLF	235,282	391,043	506,180	548,595	412,020	341,713	146,391	78,951	43,570	40,707	44,919	84,532	2,873,904
(22)	Large HLF	93,842	115,961	150,708	163,914	148,810	130,842	106,321	90,157	86,340	80,386	86,450	87,945	1,341,676
(23)	Extra Large LLF	146,031	180,576	219,506	202,914	163,360	132,000	52,699	28,048	23,460	24,151	28,280	68,293	1,269,319
(24)	Extra Large HLF	494,122	545,156	576,803	578,636	539,565	506,318	459,948	423,059	419,512	430,465	433,813	445,403	5,852,801
(25)	**Total Throughput**	3,007,805	4,866,038	6,336,000	7,006,078	5,364,890	4,413,877	2,084,669	1,512,071	1,262,205	1,224,455	1,258,101	1,560,062	39,896,251

Source: Attachment GLF-1

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Design Winter Period and Design Day Throughput (Dth)

	Rate Class (a)	Reference	Line #	Nov-22 (b)	Dec-22 (c)	Jan-23 (d)	Feb-23 (e)	Mar-23 (f)	Total (g)	% (h)
	SALES (dth)									
(1)	Residential Non-Heating	PRB-1, pg 16	Line (70)	26,318	40,458	51,125	55,970	42,748	216,619	1.00%
(2)	Residential Heating	PRB-1, pg 16	Line (71)	1,583,947	2,943,476	3,996,189	4,486,954	3,250,761	16,261,327	75.27%
(3)	Small C&I	PRB-1, pg 16	Line (72)	143,091	321,316	473,154	572,639	406,878	1,917,078	8.87%
(4)	Medium C&I	PRB-1, pg 16	Line (74)	240,263	441,214	585,398	681,959	512,696	2,461,529	11.39%
(5)	Large LLF	PRB-1, pg 16	Line (76)	36,612	88,067	121,920	146,819	109,310	502,728	2.33%
(6)	Large HLF	PRB-1, pg 16	Line (78)	18,308	22,557	30,920	36,120	30,614	138,519	0.64%
(7)	Extra Large LLF	PRB-1, pg 16	Line (80)	7,335	10,966	12,103	12,821	13,508	56,732	0.26%
(8)	Extra Large HLF	PRB-1, pg 16	Line (82)	6,814	15,479	12,213	9,627	5,679	49,813	0.23%
(9)	Total Sales	Sum[(1):(8)]		2,062,688	3,883,534	5,283,023	6,002,909	4,372,192	21,604,345	100.00%
(10)	Low Load Factor	Sum[(2)-(5),(7)]		2,011,249	3,805,039	5,188,764	5,901,191	4,293,152	21,199,394	98.13%
(11)	High Load Factor	Sum[(1),(6),(8)]		51,440	78,495	94,259	101,717	79,040	404,951	1.87%

2022/2023 Design Day Send Out

(12)	Pipeline	216,649	Dktherm
(13)	Underground Storage	38,894	Dktherm
(14)	LNG	[redacted]	Dktherm
(15)	Total Projected 2022/2023 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)]

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The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-1
Redacted
Page 13 of 16

Redacted

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No 22-20-NG
Attachment PRB-1
Page 14 of 16

Derivation of Monthly Design Sales

Normal Volumes (Dth)

	(a)	Nov-22 (b)	Dec-22 (c)	Jan-23 (d)	Feb-23 (e)	Mar-23 (f)	Apr-23 (g)	May-23 (h)	Jun-23 (i)	Jul-23 (j)	Aug-23 (k)	Sep-23 (l)	Oct-23 (m)	Nov-Oct (n)
(1)	Residential Non-Heating	24,595	36,494	45,636	49,655	38,800	32,722	17,627	14,729	12,134	11,633	11,842	14,932	310,797
(2)	Residential Heating	1,449,312	2,596,057	3,498,553	3,915,982	2,891,087	2,317,355	851,793	573,936	453,690	433,319	446,697	598,069	20,025,849
(3)	Small C&I	131,203	282,550	412,804	497,959	360,161	263,710	114,865	57,952	50,105	39,487	38,085	49,715	2,298,596
(4)	Small Transport	11,536	23,373	30,909	36,658	27,174	22,134	10,132	6,469	4,082	3,755	3,717	4,901	184,842
(5)	Medium C&I	222,677	392,733	516,336	598,322	458,833	385,399	183,377	136,456	95,356	89,680	91,490	109,410	3,280,069
(6)	Med Transport	199,205	302,095	378,565	413,442	325,078	281,684	141,517	102,313	73,956	70,871	72,808	96,863	2,458,396
(7)	Large Low Load	33,227	76,910	105,933	127,285	96,299	78,186	33,464	17,298	8,130	7,493	8,041	11,983	604,248
(8)	Large Low Load- Transport	202,056	314,133	400,247	421,310	315,722	263,527	112,927	61,653	35,440	33,215	36,878	72,549	2,269,656
(9)	Large High Load	17,687	21,288	28,468	32,766	28,409	25,367	20,339	15,688	13,142	12,569	14,192	14,340	244,255
(10)	Large High Load- Transport	76,155	94,673	122,240	131,148	120,401	105,475	85,982	74,469	73,198	67,817	72,258	73,605	1,097,421
(11)	XL Low Load	6,615	9,610	10,577	11,182	11,931	10,400	4,532	2,404	1,288	1,206	1,158	2,457	73,361
(12)	XL Low Load-Transport	139,416	170,966	208,928	191,732	151,429	121,600	48,167	25,644	22,172	22,945	27,121	65,836	1,195,958
(13)	XL High Load	6,814	14,317	11,500	9,181	5,679	5,061	6,710	7,993	7,228	6,636	7,300	6,523	94,943
(14)	XL High Load-Transport	487,308	530,839	565,303	569,455	533,886	501,257	453,238	415,066	412,284	423,828	426,513	438,880	5,757,858
(15)	**Total**	3,007,805	4,866,038	6,336,000	7,006,078	5,364,890	4,413,877	2,084,669	1,512,071	1,262,205	1,224,455	1,258,101	1,560,062	39,896,251
(16)	HLF	612,559	697,611	773,147	792,206	727,175	669,882	583,896	527,945	517,987	522,484	532,105	548,280	7,505,275
(17)	LLF	2,395,246	4,168,427	5,562,853	6,213,872	4,637,715	3,743,995	1,500,774	984,125	744,218	701,971	725,996	1,011,782	32,390,976

Baseload

		Nov-22 30	Dec-22 31	Jan-23 31	Feb-23 28	Mar-23 31	Apr-23 30	May-23 31	Jun-23 30	Jul-23 31	Aug-23 31	Sep-23 30	Oct-23 31	Nov-Oct
(18)	Residential Non-Heating	11,612	11,999	11,999	10,838	11,999	11,612	11,999	11,612	11,999	11,633	11,612	11,999	140,909
(19)	Residential Heating	434,904	449,401	449,401	405,911	449,401	434,904	449,401	434,904	449,401	433,319	434,904	449,401	5,275,253
(20)	Small C&I	41,634	43,022	43,022	38,858	43,022	41,634	43,022	41,634	43,022	39,487	38,085	43,022	499,463
(21)	Small Transport	3,768	3,893	3,893	3,517	3,893	3,768	3,893	3,768	3,893	3,755	3,717	3,893	45,654
(22)	Medium C&I	90,172	93,177	93,177	84,160	93,177	90,172	93,177	90,172	93,177	89,680	90,172	93,177	1,093,592
(23)	Med Transport	70,968	73,333	73,333	66,236	73,333	70,968	73,333	70,968	73,333	70,871	70,968	73,333	860,977
(24)	Large Low Load	7,716	7,974	7,974	7,202	7,974	7,716	7,974	7,716	7,974	7,493	7,716	7,974	93,401
(25)	Large Low Load- Transport	34,413	35,560	35,560	32,119	35,560	34,413	35,560	34,413	35,440	33,215	34,413	35,560	416,224
(26)	Large High Load	13,012	13,445	13,445	12,144	13,445	13,012	13,445	13,012	13,142	12,569	13,012	13,445	157,129
(27)	Large High Load- Transport	69,546	71,864	71,864	64,909	71,864	69,546	71,864	69,546	71,864	67,817	69,546	71,864	842,093
(28)	XL Low Load	1,191	1,231	1,231	1,112	1,231	1,191	1,231	1,191	1,231	1,206	1,158	1,231	14,432
(29)	XL Low Load-Transport	23,556	24,341	24,341	21,986	24,341	23,556	24,341	23,556	22,172	22,945	23,556	24,341	283,033
(30)	XL High Load	6,814	7,131	7,131	6,441	5,679	5,061	6,710	6,901	7,131	6,636	6,901	6,523	79,062
(31)	XL High Load-Transport	411,726	425,450	425,450	384,277	425,450	411,726	425,450	411,726	412,284	423,828	411,726	425,450	4,994,542
(32)	Total	1,221,031	1,261,822	1,261,822	1,139,710	1,260,369	1,219,277	1,261,400	1,221,118	1,246,063	1,224,455	1,217,486	1,261,213	14,795,765
(33)	HLF	512,709	529,889	529,889	478,610	528,437	510,956	529,468	512,796	516,420	522,484	512,796	529,281	6,213,736
(34)	LLF	708,321	731,932	731,932	661,100	731,932	708,321	731,932	708,321	729,643	701,971	704,690	731,932	8,582,029

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No 22-20-NG
Attachment PRB-1
Page 15 of 16

Derivation of Monthly Design Sales

Heat Volumes

	(a)	Nov-22 (b)	Dec-22 (c)	Jan-23 (d)	Feb-23 (e)	Mar-23 (f)	Apr-23 (g)	May-23 (h)	Jun-23 (i)	Jul-23 (j)	Aug-23 (k)	Sep-23 (l)	Oct-23 (m)	Nov-Oct (n)
(35)	Residential Non-Heating	12,983	24,495	33,637	38,818	26,801	21,110	5,628	3,117	135	0	231	2,933	169,888
(36)	Residential Heating	1,014,408	2,146,656	3,049,152	3,510,071	2,441,686	1,882,451	402,392	139,031	4,289	0	11,793	148,668	14,750,597
(37)	Small C&I	89,569	239,528	369,782	459,101	317,139	222,076	71,843	16,318	7,083	0	0	6,693	1,799,134
(38)	Small Transport	7,768	19,480	27,016	33,141	23,281	18,366	6,239	2,701	189	0	0	1,008	139,188
(39)	Medium C&I	132,505	299,556	423,159	514,161	365,656	295,227	90,200	46,284	2,178	0	1,319	16,232	2,186,477
(40)	Med Transport	128,238	228,762	305,232	347,205	251,745	210,716	68,184	31,346	623	0	1,840	23,529	1,597,419
(41)	Large Low Load	25,510	68,937	97,959	120,083	88,325	70,469	25,490	9,581	156	0	325	4,010	510,846
(42)	Large Low Load- Transport	167,643	278,573	364,687	389,191	280,162	229,114	77,367	27,241	0	0	2,465	36,989	1,853,432
(43)	Large High Load	4,675	7,842	15,023	20,622	14,964	12,355	6,894	2,676	0	0	1,180	894	87,126
(44)	Large High Load- Transport	6,609	22,809	50,376	66,239	48,537	35,929	14,118	4,923	1,334	0	2,712	1,741	255,328
(45)	XL Low Load	5,424	8,379	9,347	10,071	10,701	9,209	3,302	1,214	57	0	0	1,226	58,929
(46)	XL Low Load-Transport	115,860	146,625	184,587	169,746	127,088	98,044	23,826	2,088	0	0	3,565	41,495	912,925
(47)	XL High Load	0	7,185	4,369	2,740	0	0	0	1,092	97	0	398	0	15,881
(48)	XL High Load-Transport	75,582	105,389	139,853	185,178	108,436	89,532	27,788	3,340	0	0	14,787	13,430	763,315
(49)	Total	1,786,774	3,604,216	5,074,178	5,866,368	4,104,522	3,194,600	823,269	290,953	16,141	0	40,615	298,849	25,100,486
(50)	HLF	99,849	167,721	243,258	313,596	198,739	158,926	54,428	15,149	1,566	0	19,308	18,999	1,291,539
(51)	LLF	1,686,925	3,436,495	4,830,920	5,552,772	3,905,783	3,035,674	768,842	275,804	14,575	0	21,307	279,850	23,808,947
(52)	**Normal Billing DD**	**437**	**760**	**1011**	**1125**	**835**	**673**	**262**	**131**	**19**	**0**	**13**	**156**	**5422**

Heat Factors

	(a)	Nov-22 (b)	Dec-22 (c)	Jan-23 (d)	Feb-23 (e)	Mar-23 (f)	Apr-23 (g)	May-23 (h)	Jun-23 (i)	Jul-23 (j)	Aug-23 (k)	Sep-23 (l)	Oct-23 (m)	Nov-Oct
(53)	Residential Non-Heating	30	32	33	35	32	31	21	24	7	0	18	19	31
(54)	Residential Heating	2,321	2,825	3,016	3,120	2,924	2,797	1,536	1,061	226	0	907	953	2,721
(55)	Small C&I	205	315	366	408	380	330	274	125	373	0	0	43	332
(56)	Small Transport	18	26	27	29	28	27	24	21	10	0	0	6	26
(57)	Medium C&I	303	394	419	457	438	439	344	353	115	0	101	104	403
(58)	Med Transport	293	301	302	309	301	313	260	239	33	0	142	151	295
(59)	Large Low Load	58	91	97	107	106	105	97	73	8	0	25	26	94
(60)	Large Low Load- Transport	384	367	361	346	336	340	295	208	0	0	190	237	342
(61)	Large High Load	11	10	15	18	18	18	26	20	0	0	91	6	16
(62)	Large High Load- Transport	15	30	50	59	58	53	54	38	70	0	209	11	47
(63)	XL Low Load	12	11	9	9	13	14	13	9	3	0	0	8	11
(64)	XL Low Load-Transport	265	193	183	151	152	146	91	16	0	0	274	266	168
(65)	XL High Load	0	9	4	2	0	0	0	8	5	0	31	0	3
(66)	XL High Load-Transport	173	139	138	165	130	133	106	25	0	0	1,137	86	141
(67)	Total	4,089	4,742	5,019	5,215	4,916	4,747	3,142	2,221	850	0	3,124	1,916	4,629
(68)	**NormalBilling DD**	**437**	**760**	**1,011**	**1,125**	**835**	**673**	**262**	**131**	**19**	**-**	**13**	**156**	**5422**
(69)	**DesignBilling DD**	**495**	**883**	**1,176**	**1,308**	**958**	**771**	**292**	**154**	**27**	**-**	**9**	**177**	**6250**

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No 22-20-NG
Attachment PRB-1
Page 16 of 16

Derivation of Monthly Design Sales

Design Sales

		Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-Oct
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
(70)	Residential Non-Heating	26,318	40,458	51,125	55,970	42,748	35,796	18,271	15,276	11,999	11,633	11,771	15,326	336,692
(71)	Residential Heating	1,583,947	2,943,476	3,996,189	4,486,954	3,250,761	2,591,472	897,868	598,346	449,401	433,319	443,068	618,082	22,292,883
(72)	Small C&I	143,091	321,316	473,154	572,639	406,878	296,048	123,091	60,817	43,022	39,487	38,085	50,616	2,568,244
(73)	Small Transport	12,567	26,526	35,319	42,049	30,604	24,808	10,847	6,943	3,893	3,755	3,717	5,037	206,065
(74)	Medium C&I	240,263	441,214	585,398	681,959	512,696	428,389	193,705	144,582	93,177	89,680	91,085	111,595	3,613,743
(75)	Med Transport	216,226	339,119	428,380	469,921	362,161	312,368	149,324	107,817	73,333	70,871	72,241	100,030	2,701,790
(76)	Large Low Load	36,612	88,067	121,920	146,819	109,310	88,447	36,382	18,980	7,974	7,493	7,941	12,523	682,468
(77)	Large Low Load- Transport	224,306	359,217	459,766	484,618	356,991	296,890	121,786	66,436	35,440	33,215	36,119	77,529	2,552,313
(78)	Large High Load	18,308	22,557	30,920	36,120	30,614	27,166	21,129	16,158	13,142	12,569	13,829	14,460	256,971
(79)	Large High Load- Transport	77,032	98,365	130,461	141,923	127,551	110,707	87,598	75,333	71,864	67,817	71,423	73,839	1,133,914
(80)	XL Low Load	7,335	10,966	12,103	12,821	13,508	11,741	4,910	2,618	1,231	1,206	1,158	2,622	82,217
(81)	XL Low Load-Transport	154,794	194,696	239,054	219,344	170,150	135,877	50,895	26,010	22,172	22,945	26,024	71,422	1,333,384
(82)	XL High Load	6,814	15,479	12,213	9,627	5,679	5,061	6,710	8,185	7,131	6,636	7,177	6,523	97,237
(83)	XL High Load-Transport	497,339	547,896	588,128	599,577	549,860	514,295	456,420	415,652	412,284	423,828	421,963	440,688	5,867,929
(84)	Total	3,244,951	5,449,352	7,164,130	7,960,341	5,969,509	4,879,064	2,178,937	1,563,154	1,246,063	1,224,455	1,245,604	1,600,292	43,725,851
(85)	HLF	625,811	724,755	812,848	843,218	756,451	693,024	590,128	530,605	516,420	522,484	526,164	550,837	7,692,744
(86)	LLF	2,619,140	4,724,597	6,351,282	7,117,123	5,213,058	4,186,040	1,588,809	1,032,549	729,643	701,971	719,441	1,049,455	36,033,107

Source: Attachement GLF-1

Attachment PRB-2
Redacted

Attachment PRB-2

Annual GCR Reconciliation Filing

REDACTED

Rhode Island Energy
Rhode Island - Gas

Deferred Gas Cost Balances

	Description	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	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	($11,636,525)	($13,864,154)	($13,168,237)	($10,294,563)	($6,558,105)	($3,408,687)	$76,011	$3,599,748	$5,597,557	$5,373,221	$831,550	($4,932,771)	($11,636,525)
(4)	Supply Fixed Costs (net of cap rel)	$5,642,607	$5,545,613	$5,818,330	$5,462,123	$5,428,320	$5,527,961	$5,724,356	$6,294,660	$11,100,764	$10,874,060	$10,878,670	$11,856,836	$90,154,298
(5)	Supply Related System Pressure to DAC	($5,414)	($20,574)	($20,574)	($20,574)	($20,574)	($20,574)	($20,574)	($20,156)	($2,300,929)	($2,102,104)	($2,083,120)	($2,034,875)	($8,670,045)
(6)	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	($160,615)	$600,056
(7)	NGPMP Credits	($437,588)	($437,588)	($437,588)	($105,189)	($437,588)	($457,423)	($437,588)	($669,932)	($669,932)	($2,259,353)	($669,932)	($4,654,267)	($11,673,965)
(8)	Working Capital	$42,644	$41,795	$43,858	$41,164	$40,908	$41,662	$43,147	$46,220	$64,822	$64,617	$64,790	$72,351	$607,978
(9)	Total Supply Fixed Costs	$5,311,400	$5,198,398	$5,473,178	$5,446,675	$5,080,218	$5,160,777	$5,378,493	$5,719,943	$8,263,876	$6,646,372	$8,259,561	$5,079,431	$71,018,322
(10)	Supply Fixed - Revenue	$7,525,937	$4,488,139	$2,587,457	$1,701,276	$1,925,512	$1,674,367	$1,856,706	$3,726,857	$8,494,033	$11,191,334	$14,021,917	$10,802,576	$69,996,112
(11)	Monthly Under/(Over) Recovery	($2,214,537)	$710,259	$2,885,721	$3,745,399	$3,154,705	$3,486,410	$3,521,787	$1,993,086	($230,157)	($4,544,962)	($5,762,356)	($5,723,146)	$1,022,210
(12)	Prelim Ending Under/(Over) Recovery	($13,851,061)	($13,153,895)	($10,282,516)	($6,549,164)	($3,403,400)	$77,722	$3,597,798	$5,592,835	$5,367,400	$828,258	($4,930,806)	($10,655,917)	($10,614,315)
(13)	Month's Average Balance	($12,743,793)	($13,509,025)	($11,725,377)	($8,421,863)	($4,980,752)	($1,665,483)	$1,836,905	$4,596,292	$5,482,478	$3,100,739	($2,049,628)	($7,794,344)	
(14)	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%	1.37%	
(15)	Interest Applied	($13,093)	($14,342)	($12,047)	($8,941)	($5,288)	($1,711)	$1,950	$4,722	$5,820	$3,292	($1,965)	($9,076)	($50,678)
(16)	Marketer Reconciliation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17)	Fixed Ending Under/(Over) Recovery	($13,864,154)	($13,168,237)	($10,294,563)	($6,558,105)	($3,408,687)	$76,011	$3,599,748	$5,597,557	$5,373,221	$831,550	($4,932,771)	($10,664,992)	($10,664,992)
(18)	II Variable Cost Deferred													
(19)	Beginning Under/(Over) Recovery	$14,095,362	$11,279,428	$9,200,801	$8,449,829	$8,544,732	$9,161,532	$9,560,171	$9,981,529	$12,885,890	$11,441,585	$22,637,551	$23,313,734	$14,095,362
(20)	Variable Supply Costs	$4,842,056	$2,380,847	$1,654,565	$1,559,313	$2,326,413	$1,822,899	$2,041,961	$6,682,445	$8,311,948	$24,074,997	$17,100,507	$9,616,502	$82,414,453
(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	$22,641	$22,543	$22,448	$22,114	$22,078	$22,185	$24,304	$25,041	$24,539	$24,656	$24,655	$27,509	$284,712
(24)	Inventory Financing - UG	$43,664	$45,398	$44,966	$47,761	$50,178	$56,731	$55,447	$51,353	$54,758	$52,608	$53,532	$57,508	$613,905
(25)	Working Capital	$36,629	$18,010	$12,516	$11,796	$17,599	$13,790	$15,447	$49,225	$61,228	$177,343	$125,967	$70,838	$610,387
(26)	Total Supply Variable Costs	$4,970,176	$2,491,986	$1,759,682	$1,666,170	$2,441,455	$1,940,792	$2,162,346	$6,833,251	$8,477,660	$24,354,791	$17,329,848	$9,797,544	$84,225,701
(27)	Supply Variable - Revenue	$7,799,139	$4,581,479	$2,519,717	$1,580,284	$1,834,049	$1,551,765	$1,751,355	$3,961,268	$9,934,871	$13,176,906	$16,675,686	$12,753,085	$78,119,604
(28)	Monthly Under/(Over) Recovery	($2,828,962)	($2,089,493)	($760,034)	$85,887	$607,406	$389,027	$410,991	$2,871,983	($1,457,211)	$11,177,885	$654,162	($2,955,541)	$6,106,097
(29)	Prelim Ending Under/(Over) Recovery	$11,266,400	$9,189,935	$8,440,766	$8,535,716	$9,152,138	$9,550,559	$9,971,162	$12,853,512	$11,428,679	$22,619,470	$23,291,713	$20,358,192	$20,201,460
(30)	Month's Average Balance	$12,680,881	$10,234,682	$8,820,784	$8,492,772	$8,848,435	$9,356,045	$9,765,666	$11,417,521	$12,157,285	$17,030,528	$22,964,632	$21,835,963	
(31)	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%	1.37%	
(32)	Interest Applied	$13,028	$10,866	$9,062	$9,016	$9,394	$9,612	$10,368	$11,730	$12,907	$18,080	$22,021	$25,425	$161,510
(33)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$20,648	$0	$0	$0	$0	$20,648
(34)	Variable Ending Under/(Over) Recovery	$11,279,428	$9,200,801	$8,449,829	$8,544,732	$9,161,532	$9,560,171	$9,981,529	$12,885,890	$11,441,585	$22,637,551	$23,313,734	$20,383,618	$20,383,618
(35)	III COVID Deferred													
(36)	Beginning Balance	$3,330,403	$3,852,884	$4,159,592	$4,331,097	$4,439,946	$4,564,971	$4,672,130	$4,792,618	$4,808,823	$4,267,226	$3,546,676	$2,637,642	$3,330,403
(37)	COVID Cost Deferral	$518,793	$302,457	$167,146	$104,195	$120,247	$102,417	$115,467	$11,275	($546,412)	($724,696)	($911,998)	($699,753)	($1,440,862)
(38)	Prelim Ending Balance	$3,849,196	$4,155,341	$4,326,738	$4,435,293	$4,560,193	$4,667,388	$4,787,597	$4,803,893	$4,262,411	$3,542,530	$2,634,678	$1,937,889	
(39)	Month's Average Balance	$3,589,800	$4,004,113	$4,243,165	$4,383,195	$4,500,070	$4,616,179	$4,729,863	$4,798,256	$4,535,617	$3,904,878	$3,090,677	$2,287,765	
(40)	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%	1.37%	
(41)	Interest Applied	$3,688	$4,251	$4,359	$4,653	$4,777	$4,743	$5,021	$4,930	$4,815	$4,146	$2,964	$2,664	$51,011
(42)	Ending Balance	$3,852,884	$4,159,592	$4,331,097	$4,439,946	$4,564,971	$4,672,130	$4,792,618	$4,808,823	$4,267,226	$3,546,676	$2,637,642	$1,940,552	$1,940,552
(43)	GCR Deferred Summary													
(44)	Beginning Under/(Over) Recovery	$5,789,241	$1,268,158	$192,156	$2,486,364	$6,426,573	$10,317,815	$14,308,312	$18,373,896	$23,292,270	$21,082,032	$27,015,777	$21,018,604	$5,789,241
(45)	Gas Costs	$10,573,587	$8,000,225	$7,546,659	$7,095,200	$7,828,497	$7,424,624	$7,840,082	$13,051,288	$17,206,121	$32,941,292	$25,990,397	$19,303,035	$164,801,007
(46)	Inventory Finance	$66,305	$67,942	$67,414	$69,875	$72,256	$78,916	$79,751	$76,394	$79,297	$77,264	$78,187	$85,017	$898,617
(47)	Working Capital	$79,272	$59,806	$56,375	$52,959	$58,507	$55,451	$58,594	$95,444	$126,050	$241,960	$190,757	$143,189	$1,218,364
(48)	NGPMP Credits	($437,588)	($437,588)	($437,588)	($105,189)	($437,588)	($457,423)	($437,588)	($669,932)	($669,932)	($2,259,353)	($669,932)	($4,654,267)	($11,673,965)
(49)	Total Costs	$10,281,577	$7,690,384	$7,232,860	$7,112,845	$7,521,673	$7,101,569	$7,540,839	$12,553,194	$16,741,536	$31,001,163	$25,589,409	$14,876,975	$155,244,024
(50)	Revenue	$14,806,283	$8,767,161	$4,940,028	$3,177,364	$3,639,314	$3,123,715	$3,492,594	$7,676,850	$18,975,317	$25,092,936	$31,609,601	$24,255,414	$149,556,578
(51)	Monthly Under/(Over) Recovery	($4,524,706)	($1,076,777)	$2,292,832	$3,935,481	$3,882,358	$3,977,854	$4,048,244	$4,876,344	($2,233,781)	$5,908,227	($6,020,191)	($9,378,440)	$5,687,445
(52)	Prelim Ending Under/(Over) Recovery	$1,264,535	$191,381	$2,484,988	$6,421,845	$10,308,931	$14,295,668	$18,356,557	$23,250,240	$21,058,490	$26,990,259	$20,995,585	$11,640,164	
(53)	Month's Average Balance	$3,526,888	$729,770	$1,338,572	$4,454,104	$8,367,752	$12,306,742	$16,332,435	$20,812,068	$22,175,380	$24,036,145	$24,005,681	$16,329,384	
(54)	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%	1.37%	
(55)	Interest Applied	$3,624	$775	$1,375	$4,729	$8,884	$12,644	$17,339	$21,382	$23,542	$25,518	$23,019	$19,014	$161,844
(56)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$20,648	$0	$0	$0	$0	$20,648
(57)	Ending Under/(Over) Recovery W/ Interest	$1,268,158	$192,156	$2,486,364	$6,426,573	$10,317,815	$14,308,312	$18,373,896	$23,292,270	$21,082,032	$27,015,777	$21,018,604	$11,659,178	$11,659,178

(3) Dkt 5066, Sch RMS/MJP-2, pg 1, line (17), col (m)
(4) Sch 2, line (44)
(5) Dkt 4955; Dkt 5040
(6) Docket 4770
(8) Sch 4, line (15)
(9) Sum[Lines (4) : (8)]
(10) Sch 3, line (10)
(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 5066
(17) Line (12) + Line (15) + Line (16)
(19) Dkt 5066, Sch RMS/MJP-2, pg 1, line (34), col (m)
(20) Sch 2, line (100)
(21) Dkt 4955; Dkt 5040
(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 (24)
(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)
(37) Sch 6, Line (38)
(38) Line (36) + Line (37)
(39) [[Line (36) + Line (38)] ÷ 2
(41) ([Line (39) x Line (40)] / 365) x Line (1)
(42) Line (38) + Line (41)
(44) Line (3) + Line (19) + Line (36)
(45) Sum[Lines (4) (6), (16), (20):(22)]
(46) Line (23) + Line (24)
(47) Line (8) + Line (25)
(48) Line (7)
(49) Sum[Lines (45) : (48)]
(50) Line (10) + Line (27) + Line (37)
(51) Line (49) - Line (50)
(52) Line (44) + Line (51)
(53) [[Line (44) + Line (52)] ÷ 2
(55) Line (15) + Line (32) + Line (41)
(56) Line (33)
(57) Line (52) + Line (55) + Line (56)

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Rhode Island Energy
Rhode Island - Gas

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Schedule 2
Page 1 of 3

Supply Estimates Actuals for Filing

	Description	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(1)	**SUPPLY FIXED COSTS - Pipeline Delivery**													
(2)	Dawn to E Here	$1,202,115	$1,234,803	$1,213,105	$1,206,854	$1,203,714	$1,201,594	$1,207,933	$1,376,090	$1,319,400	$1,293,622	$1,257,904	$1,296,737	$15,013,871
(3)	Dawn to WADDY	$23,741	$23,827	$24,252	$24,143	$23,438	$23,627	$23,635	$11,721	$11,462	$11,462	$11,462	$11,462	$224,232
(4)	Dominion SP	$7,021	$7,021	$3,978	$7,021	$7,021	$7,021	$7,021	$7,011	$7,010	$7,010	$7,010	$8,094	$82,236
(5)	Dracut	$83,636	$83,636	$83,636	$83,636	$83,636	$83,636	$83,636	$72,811	$72,811	$72,811	$72,811	$72,811	$949,507
(6)	Everett	$102,872	$102,872	$102,872	$102,872	$102,872	$102,872	$102,872	$100,781	$100,781	$100,781	$100,781	$100,781	$1,224,012
(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	$927,625	$933,474	$927,625	$933,474	$933,474	$928,032	$933,474	$927,625	$933,474	$933,474	$915,926	$933,474	$11,161,148
(9)	Niagara	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,718	$6,576	$6,576	$6,576	$6,576	$6,576	$79,905
(10)	TCO (Pool)	$749,673	$752,233	$752,233	$752,233	$752,216	$752,233	$752,233	$746,524	$641,727	$625,370	$625,845	$627,290	$8,529,811
(11)	AGT M3	$320,817	$320,817	$320,817	$320,817	$320,817	$324,147	$320,817	$320,817	$320,817	$320,817	$320,943	$320,817	$3,853,261
(12)	TETCO SCT Long Haul	$23,246	$23,352	$23,245	$23,246	$23,268	$23,268	$23,267	$23,268	$23,238	$23,238	$23,473	$40,380	$296,489
(13)	TETCO CDS Long Haul	$1,217,302	$1,217,302	$1,217,302	$1,217,302	$1,218,426	$1,231,744	$1,218,426	$1,218,426	$1,217,599	$1,217,758	$1,230,215	$2,168,358	$15,590,161
(14)	Transco Leidy	$8,836	$8,995	$32,803	$8,994	$8,995	$8,836	$8,995	$8,836	$8,995	$8,995	$8,519	$8,994	$130,793
(15)	Yankee Interconnect	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(16)	TGP Long Haul	$552,367	$552,366	$552,366	$552,366	$552,366	$552,365	$552,369	$540,269	$540,268	$540,270	$540,269	$540,269	$6,567,908
(17)	TGP ConneXion	$264,222	$264,222	$264,222	$264,222	$264,222	$264,222	$264,222	$231,150	$259,532	$264,309	$264,309	$264,309	$3,133,167
(18)	AMA Credits	($42,351)	($31,333)	($31,333)	($31,333)	($31,333)	($31,333)	($45,553)	($104,501)	($102,585)	($102,818)	($94,832)	($102,956)	($752,262)
(19)	Less Credits from Mkter Releases	($1,010,266)	($1,173,470)	($1,177,748)	($1,342,402)	($1,384,461)	($1,290,379)	($1,103,852)	($1,002,217)	($1,034,529)	($1,023,663)	($968,746)	($1,100,403)	($13,612,139)
(20)	**Supply Fixed - Supplier**													
(21)	Distrigas FCS	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	**Total**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(23)	**STORAGE FIXED COSTS - Facilities**													
(24)	Columbia FSS	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$23,199	$15,431	$15,431	$15,431	$15,431	$247,314
(25)	Dominion GSS	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,412	$36,342	$36,342	$36,342	$36,342	$36,342	$436,590
(26)	Dominion GSSTE	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,790	$46,702	$46,703	$46,702	$46,702	$46,702	$561,041
(27)	Providence LNG	$163,740	$163,740	$450,960	$290,520	$290,520	$290,520	$290,520	$256,460	$290,520	$290,520	$290,520	$290,520	$3,359,060
(28)	Tennessee FSMA	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$42,313	$41,367	$41,367	$41,367	$41,367	$41,367	$503,028
(29)	Tetco FSS1	$2,397	$2,402	$2,405	$2,404	$2,404	$2,404	$2,404	$2,402	$2,398	$2,399	$2,396	$4,540	$30,954
(30)	Tetco SS1	$113,915	$113,993	$114,038	$114,024	$114,127	$114,129	$114,129	$114,106	$114,027	$114,041	$115,091	$221,891	$1,477,510
(31)	**STORAGE FIXED COSTS - Delivery**													
(32)	Storage Delivery	$336,434	$340,789	$340,952	$340,871	$340,884	$340,884	$357,087	$386,130	$377,826	$377,827	$377,918	$420,861	$4,338,462
(33)	**Confidential Pipeline and Peaking Supplies**	$132,743	$142,048	$138,074	$128,337	$139,191	$135,616	$148,198	$595,675	$5,542,482	$5,343,658	$5,324,674	$5,276,428	$23,047,126
(34)	**TOTAL FIXED COSTS**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Supply Estimates Actuals for Filing

Description	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(35) **VARIABLE COMMODITY COSTS**													
(36) AGT Citygate													
(37) AIM at Ramapo													
(38) Dawn via IGTS													
(39) Dawn via PNGTS													
(40) Dominion SP													
(41) Dracut Supply													
(42) Everett Swing													
(43) Millennium													
(44) Niagara													
(45) TCO Appalachia													
(46) Tetco M3													
(47) Transco Leidy													
(48) Waddington													
(49) Tetco M2 CDS													
(50) Tetco M2 SCT													
(51) TGP Z4 Cnx													
(52) TGP Z4 LH													
(53) Confidential Pipeline and Peaking Supplies													
(54) Variable Transportation Costs													
(55) Total Pipeline Commodity Charges	$4,235,538	$2,622,805	$1,567,615	$2,287,226	$2,506,590	$2,755,103	$4,759,024	$12,853,757	$15,144,812	$25,161,817	$22,977,390	$13,096,042	$109,967,718
(56) **INJECTIONS & HEDGING IMPACT**													
(57) Hedging	($33,232)	($367,021)	($289,272)	($515,757)	($551,706)	($1,100,541)	($3,078,463)	($7,058,735)	($7,881,708)	($4,055,080)	($10,306,983)	($4,672,250)	($39,910,749)
(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**	$4,202,306	$2,255,784	$1,278,343	$1,771,469	$1,954,884	$1,654,562	$1,680,561	$5,795,022	$7,263,104	$21,106,737	$12,670,406	$8,423,792	$70,056,969
(61) **VARIABLE STORAGE COSTS**													
(62) Underground Storage	$392,753	$73,294	$199,443	$36,438	$51,021	$24,941	$102,258	$981,497	$1,161,756	$2,232,344	$1,800,919	$1,112,268	$8,168,932
(63) LNG Withdrawals and Trucking	$71,504	$67,145	$96,053	$73,094	$69,645	$59,169	$83,443	$97,829	$85,293	$350,483	$389,556	($24,735)	$1,418,478
(64) **TOTAL VARIABLE STORAGE COSTS**	$464,257	$140,440	$295,496	$109,532	$120,665	$84,110	$185,701	$1,079,326	$1,247,049	$2,582,827	$2,190,474	$1,087,533	$9,587,410
(65) **TOTAL VARIABLE COSTS**	$4,666,562	$2,396,223	$1,573,839	$1,881,001	$2,075,550	$1,738,672	$1,866,262	$6,874,348	$8,510,152	$23,689,564	$14,860,881	$9,511,325	$79,644,379
(66) **TOTAL SUPPLY COSTS**	$10,309,169	$7,941,836	$7,392,168	$7,343,124	$7,503,870	$7,266,633	$7,590,618	$13,169,007	$19,610,916	$34,563,624	$25,739,551	$21,368,161	$169,798,678

(55) Sum[Lines (36) : (54)]
(60) Sum[Lines (55) : (59)]
(64) Sum[Lines (62) : (63)]
(65) Line (60) + Line (64)
(66) Line (34) + Line (66)

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Rhode Island Energy
Rhode Island - Gas

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Supply Estimates Actuals for Filing

	Description	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(67)	**Storage Costs for FT-2 Calculation**													
(68)	**Storage Fixed Costs - Facilities**	$428,766	$428,849	$716,116	$555,662	$555,765	$555,766	$555,766	$520,578	$546,788	$546,801	$547,849	$656,792	$6,615,498
(69)	**Storage Fixed Costs - Deliveries**	$469,177	$482,837	$479,027	$469,208	$480,075	$476,500	$505,285	$981,805	$5,920,308	$5,721,485	$5,702,593	$5,697,289	$27,385,589
(70)	**Sub-Total Storage Costs**	$897,943	$911,687	$1,195,143	$1,024,869	$1,035,840	$1,032,267	$1,061,051	$1,502,383	$6,467,096	$6,268,286	$6,250,441	$6,354,082	$34,001,087
(71)	**Tennessee Dracut for Peaking.**	$186,508	$186,508	$186,508	$186,508	$186,508	$186,508	$186,508	$173,592	$173,592	$173,592	$173,592	$173,592	$2,173,519
(72)	**Inventory Financing**	$66,305	$67,942	$67,414	$69,875	$72,256	$78,916	$79,751	$76,394	$79,297	$77,264	$78,187	$85,017	$898,617
(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	($160,615)	$600,056
(74)	**Working Capital Requirement**	$6,752	$6,741	$8,885	$7,597	$7,680	$7,653	$7,871	$10,918	$30,689	$30,689	$30,698	$31,816	$187,990
(75)	**Total FT-2 Storage Fixed Costs**	$1,226,659	$1,242,029	$1,527,102	$1,358,002	$1,371,436	$1,374,496	$1,404,333	$1,832,439	$6,819,826	$6,618,984	$6,602,070	$6,483,892	$37,861,269
(76)	**System Storage MDQ (Dth)**	197,537	198,691	198,945	197,277	196,243	195,538	194,958	195,803	207,965	207,649	205,804	204,700	2,401,110
(77)	**FT-2 Storage Cost per MDQ (Dth)**	$6 2098	$6 2511	$7 6760	$6 8837	$6 9885	$7 0293	$7 2033	$9 3586	$32 7931	$31 8759	$32 0794	$31 6751	$15 7682
(78)	Pipeline Variable	$4,666,562	$2,396,223	$1,573,839	$1,881,001	$2,075,550	$1,738,672	$1,866,262	$6,874,348	$8,510,152	$23,689,564	$14,860,881	$9,511,325	$79,644,379
(79)	Less Non-firm Gas Costs	($157,164)	($61,167)	($11,089)	($16,725)	($10,319)	($29,218)	($34,190)	($110,960)	($474,266)	($336,165)	$9,866	($194,754)	($1,426,151)
(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	$317,617	$45,380	$102,934	($306,494)	$269,833	$113,445	$211,207	($65,337)	$249,948	$746,010	$2,231,156	$117,335	$4,033,034
(85)	Marketer Reconciliation Surcharge	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(86)	Plus Pipeline Srchg/Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(87)	Less Mkter FT-2 Daily weather true-up	$15,041	$410	($11,119)	$1,530	($8,650)	$0	($1,317)	($15,606)	$26,113	($24,413)	($1,396)	$182,596	$163,191
(88)	**TOTAL FIRM COMMODITY COSTS**	$4,842,056	$2,380,847	$1,654,565	$1,559,313	$2,326,413	$1,822,899	$2,041,961	$6,682,445	$8,311,948	$24,074,997	$17,100,507	$9,616,502	$82,414,453

(70) Line (68) + Line (69)
(75) Sum[Lines (71) : (74)]
(77) Line (75) ÷ Line (76)
(78) Line (65)
(88) Sum[Lines (78) : (87)]

Rhode Island Energy
Rhode Island - Gas

REDACTED

Schedule 3
Page 1 of 1

GCR Revenue

	Description	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(1)	**I. Fixed Cost Revenue**													
(2)	(a) Low Load dth	2,601,159	1,505,788	824,017	535,358	588,686	500,603	563,167	1,260,208	3,033,331	4,027,041	5,075,589	3,863,655	24,378,603
(3)	Fixed Cost Factor	$2 7488	$2 7512	$2 7417	$2 5988	$2 7415	$2 7427	$2 7422	$2 6972	$2 6732	$2 6798	$2 6795	$2 6816	
(4)	Low Load Revenue	$7,150,005	$4,142,785	$2,259,174	$1,391,263	$1,613,863	$1,372,984	$1,544,296	$3,399,042	$8,108,728	$10,791,550	$13,600,240	$10,360,762	$65,734,693
(5)	(b) High Load dth	65,309	50,001	41,702	33,925	35,306	30,804	36,209	44,574	71,441	78,122	90,794	100,453	678,641
(6)	Fixed Cost Factor	$2 0901	$2 0904	$2 0897	$2 0898	$2 0899	$2 0898	$2 1018	$2 0300	$2 0019	$2 0208	$2 0035	$2 0241	
(7)	High Load Revenue	$136,501	$104,524	$87,146	$70,898	$73,788	$64,376	$76,106	$90,486	$143,018	$157,865	$181,908	$203,331	$1,389,948
(8)	Sub-total throughput Dth	2,666,469	1,555,790	865,719	569,283	623,992	531,407	599,376	1,304,782	3,104,773	4,105,163	5,166,383	3,964,108	25,057,243
(9)	FT-2 Storage Revenue from marketers	$239,431	$240,829	$241,137	$239,116	$237,862	$237,007	$236,305	$237,329	$242,287	$241,918	$239,769	$238,483	$2,871,472
(10)	**TOTAL Fixed Revenue**	$7,525,937	$4,488,139	$2,587,457	$1,701,276	$1,925,512	$1,674,367	$1,856,706	$3,726,857	$8,494,033	$11,191,334	$14,021,917	$10,802,576	$69,996,112
(11)	**II. Variable Cost Revenue**													
(12)	(a) Firm Sales dth	2,666,469	1,555,790	865,719	569,283	623,992	531,407	599,376	1,304,782	3,104,773	4,105,163	5,166,383	3,964,108	25,057,243
(13)	Variable Supply Cost Factor	$2 9164	$2 9188	$2 9089	$2 7652	$2 9057	$2 9084	$2 9053	$3 0158	$3 1545	$3 1659	$3 1552	$3 1658	
(14)	Variable Supply Revenue	$7,776,525	$4,541,029	$2,518,294	$1,574,168	$1,813,123	$1,545,523	$1,741,348	$3,934,964	$9,794,113	$12,996,346	$16,300,954	$12,549,683	$77,086,071
(15)	(b) TSS Sales dth	17,991	13,185	1,223	1,327	3,479	796	1,971	3,677	7,556	14,358	28,103	22,085	115,748
(16)	TSS Surcharge Factor	$0 0000	$0 0130	$0 0880	$0 5410	$0 5680	$1 1190	$1 6050	$2 2170	$1 4510	$0 0850	$1 8640	$0 5100	
(17)	TSS Surcharge Revenue	$0	$171	$108	$718	$1,976	$891	$3,163	$8,151	$10,963	$1,220	$52,383	$11,263	$91,008
(18)	(c) Default Sales dth	6,058	3,408	106	(174)	1,235	981	1,255	2,679	9,958	8,689	9,162	6,638	49,993
(19)	Variable Supply Cost Factor	$3 54	$5 46	$5 46	$5 45	$5 46	$5 46	$5 46	$6 77	$12 62	$20 35	$34 99	$28 61	
(20)	Variable Supply Revenue	$21,419	$18,592	$580	($948)	$6,739	$5,351	$6,844	$18,153	$125,620	$176,843	$320,525	$189,930	$889,648
(21)	(d) Peaking Gas Revenue	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(22)	(e) Deferred Responsibility	$1,195	$21,687	$736	$6,345	$12,211	$0	$0	$0	$4,175	$2,496	$1,823	$2,208	$52,877
(23)	(e) FT-1 Storage and Peaking	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(24)	**TOTAL Variable Revenue**	$7,799,139	$4,581,479	$2,519,717	$1,580,284	$1,834,049	$1,551,765	$1,751,355	$3,961,268	$9,934,871	$13,176,906	$16,675,686	$12,753,085	$78,119,604
(25)	**III. Reduction to GCR**													
(26)	(a) Low Load dth	2,601,159	1,505,788	824,017	535,358	588,686	500,603	563,167	1,260,208	3,033,331	4,027,041	5,075,589	3,863,655	24,378,603
(27)	Low Load COVID Factor ($/dth)	($0 1956)	($0 1958)	($0 1951)	($0 1849)	($0 1951)	($0 1952)	($0 1951)	($0 0090)	$0 1765	$0 1769	$0 1769	$0 1771	
(28)	Low Load Revenue	($508,795)	($294,801)	($160,763)	($99,002)	($114,843)	($97,702)	($109,892)	($11,286)	$535,399	$712,539	$897,990	$684,096	$1,432,940
(29)	(b) High Load dth	65,309	50,001	41,702	33,925	35,306	30,804	36,209	44,574	71,441	78,122	90,794	100,453	678,641
(30)	High Load COVID Factor ($/dth)	($0 1531)	($0 1531)	($0 1531)	($0 1531)	($0 1531)	($0 1531)	($0 1539)	$0 0002	$0 1542	$0 1556	$0 1543	$0 1559	
(31)	High Load Revenue	($9,998)	($7,656)	($6,383)	($5,193)	($5,405)	($4,715)	($5,574)	$11	$11,013	$12,156	$14,008	$15,657	$7,922
(32)	Total Reduction to GCR	($518,793)	($302,457)	($167,146)	($104,195)	($120,247)	($102,417)	($115,467)	($11,275)	$546,412	$724,696	$911,998	$699,753	$1,440,862
(33)	**Total Gas Cost Revenue (w/o FT-2)**	$14,806,283	$8,767,161	$4,940,028	$3,177,364	$3,639,314	$3,123,715	$3,492,594	$7,676,850	$18,975,317	$25,092,936	$31,609,601	$24,255,414	$149,556,578

(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) Line (4) + Line (7) + Line (9)
(12) Line (8)
(13) Line (14) ÷ Line (12)
(15) Sch 6, line (20)
(16) Company's website
(17) Line (15) x Line (16)
(18) Sch 6, line (61)
(19) Line (20) ÷ Line (18)
(22) Company Data
(24) Sum[Lines (14), (17), (20):(23)]
(26) Sch 6, Sum[lines (24) : (28), (30)]
(27) Line (28) ÷ Line (26)
(29) Sch 6, Sum[lines (22), (23), (29), (31)]
(30) Line (31) ÷ Line (29)
(32) Line (28) + Line (31)
(33) Line (10) + Line (24) + Line (32)

REDACTED

Rhode Island Energy
Rhode Island - Gas

REDACTED

Schedule 4
Page 1 of 1

WORKING CAPITAL

	Description	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(1)	**Supply Fixed Costs**	$5,642,607	$5,545,613	$5,818,330	$5,462,123	$5,428,320	$5,527,961	$5,724,356	$6,294,660	$11,100,764	$10,874,060	$10,878,670	$11,856,836	$90,154,298
(2)	Less: System Pressure to DAC	($5,414)	($20,574)	($20,574)	($20,574)	($20,574)	($20,574)	($20,574)	($20,156)	($2,300,929)	($2,102,104)	($2,083,120)	($2,034,875)	($8,670,045)
(3)	Plus: Supply Related LNG O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(4)	Total Adjustments	($5,414)	($20,574)	($20,574)	($20,574)	($20,574)	($20,574)	($20,574)	($20,156)	($2,300,929)	($2,102,104)	($2,083,120)	($2,034,875)	($8,670,045)
(5)	Allowable Working Capital Costs	$5,637,192	$5,525,039	$5,797,755	$5,441,548	$5,407,746	$5,507,386	$5,703,781	$6,274,503	$8,799,834	$8,771,956	$8,795,551	$9,821,961	$81,484,254
(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	$508,428	$498,313	$522,910	$490,783	$487,734	$496,721	$514,434	$565,909	$793,673	$791,158	$793,286	$885,860	
(8)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	6 91%	6 91%	6 91%	6 91%	6 91%	
(9)	Return on Working Capital Requirement	$36,251	$35,530	$37,283	$34,993	$34,775	$35,416	$36,679	$39,104	$54,843	$54,669	$54,816	$61,213	
(10)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 18%	2 18%	2 18%	2 18%	2 18%	
(11)	Interest Expense	$12,202	$11,960	$12,550	$11,779	$11,706	$11,921	$12,346	$12,337	$17,302	$17,247	$17,294	$19,312	
(12)	Taxable Income	$24,049	$23,570	$24,734	$23,214	$23,070	$23,495	$24,333	$26,767	$37,541	$37,422	$37,522	$41,901	
(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	$30,441	$29,836	$31,308	$29,385	$29,202	$29,740	$30,801	$33,883	$47,520	$47,369	$47,497	$53,039	
(15)	**Supply Fixed Working Capital Requirement**	$42,644	$41,795	$43,858	$41,164	$40,908	$41,662	$43,147	$46,220	$64,822	$64,617	$64,790	$72,351	$607,978
(16)	**Supply Variable Costs**	$4,842,056	$2,380,847	$1,654,565	$1,559,313	$2,326,413	$1,822,899	$2,041,961	$6,682,445	$8,311,948	$24,074,997	$17,100,507	$9,616,502	$82,414,453
(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	$4,842,056	$2,380,847	$1,654,565	$1,559,313	$2,326,413	$1,822,899	$2,041,961	$6,682,445	$8,311,948	$24,074,997	$17,100,507	$9,616,502	$82,414,453
(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	$436,714	$214,733	$149,228	$140,637	$209,823	$164,410	$184,168	$602,702	$749,669	$2,171,367	$1,542,325	$867,329	
(23)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	6 91%	6 91%	6 91%	6 91%	6 91%	
(24)	Return on Working Capital Requirement	$31,138	$15,310	$10,640	$10,027	$14,960	$11,722	$13,131	$41,647	$51,802	$150,041	$106,575	$59,932	
(25)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 18%	2 18%	2 18%	2 18%	2 18%	
(26)	Interest Expense	$10,481	$5,154	$3,581	$3,375	$5,036	$3,946	$4,420	$13,139	$16,343	$47,336	$33,623	$18,908	
(27)	Taxable Income	$20,657	$10,157	$7,058	$6,652	$9,925	$7,777	$8,711	$28,508	$35,459	$102,706	$72,952	$41,025	
(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	$26,148	$12,857	$8,935	$8,420	$12,563	$9,844	$11,027	$36,086	$44,885	$130,007	$92,344	$51,930	
(30)	**Supply Variable Working Capital Requirement**	$36,629	$18,010	$12,516	$11,796	$17,599	$13,790	$15,447	$49,225	$61,228	$177,343	$125,967	$70,838	$610,387

(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 4770
(9) Line (7) x Line (8)
(10) Docket 4770
(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 4770
(24) Line (22) x Line (23)
(25) Docket 4770
(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

REDACTED

Rhode Island Energy
Rhode Island - Gas

Schedule 5
Page 1 of 1

REDACTED

INVENTORY FINANCE

	Description	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(1)	**Storage Inventory Balance**	$6,249,978	$6,727,440	$6,919,386	$7,687,536	$8,681,173	$10,726,463	$11,952,578	$11,389,695	$11,028,595	$9,483,418	$8,605,364	$8,449,452	
(2)	Monthly Storage Deferral/Amortization	($2,895)	($232,166)	($485,997)	($854,188)	($1,502,083)	($2,609,778)	($4,019,658)	($3,844,613)	($2,983,161)	($1,753,867)	($740,044)	$1	
(3)	**Subtotal**	$6,247,083	$6,495,274	$6,433,389	$6,833,348	$7,179,089	$8,116,685	$7,932,921	$7,545,082	$8,045,433	$7,729,551	$7,865,320	$8,449,454	
(4)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	6 91%	6 91%	6 91%	6 91%	6 91%	
(5)	Return on Working Capital Requirement	$445,417	$463,113	$458,701	$487,218	$511,869	$578,720	$565,617	$521,365	$555,939	$534,112	$543,494	$583,857	$6,249,422
(6)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 18%	2 18%	2 18%	2 18%	2 18%	
(7)	Interest Charges Financed	$149,930	$155,887	$154,401	$164,000	$172,298	$194,800	$190,390	$164,483	$175,390	$168,504	$171,464	$184,198	$2,045,746
(8)	Taxable Income	$295,487	$307,226	$304,299	$323,217	$339,571	$383,919	$375,227	$356,882	$380,549	$365,608	$372,030	$399,659	
(9)	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	
(10)	Return and Tax Requirement	$374,034	$388,894	$385,189	$409,136	$429,837	$485,974	$474,971	$451,750	$481,708	$462,795	$470,924	$505,898	$5,321,108
(11)	Working Capital Requirement	$523,964	$544,781	$539,590	$573,136	$602,135	$680,774	$665,361	$616,233	$657,098	$631,299	$642,388	$690,096	$7,366,855
(12)	Monthly Average	$43,664	$45,398	$44,966	$47,761	$50,178	$56,731	$55,447	$51,353	$54,758	$52,608	$53,532	$57,508	$613,905
(13)	**LNG Inventory Balance**	$3,239,295	$3,225,320	$3,211,678	$3,163,845	$3,158,813	$3,174,078	$3,477,218	$3,679,159	$3,605,444	$3,622,604	$3,622,437	$4,041,821	
(14)	Cost of Capital	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	7 13%	6 91%	6 91%	6 91%	6 91%	6 91%	
(15)	Return on Working Capital Requirement	$230,962	$229,965	$228,993	$225,582	$225,223	$226,312	$247,926	$254,230	$249,136	$250,322	$250,310	$279,290	$2,898,251
(16)	Weighted Cost of Debt	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 40%	2 18%	2 18%	2 18%	2 18%	2 18%	
(17)	Interest Charges Financed	$77,743	$77,408	$77,080	$75,932	$75,812	$76,178	$83,453	$80,206	$78,599	$78,973	$78,969	$88,112	$948,464
(18)	Taxable Income	$153,219	$152,558	$151,912	$149,650	$149,412	$150,134	$164,472	$174,024	$170,538	$171,349	$171,341	$191,178	
(19)	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	
(20)	Return and Tax Requirement	$193,948	$193,111	$192,294	$189,430	$189,129	$190,043	$208,193	$220,284	$215,870	$216,898	$216,888	$241,998	$2,468,085
(21)	Working Capital Requirement	$271,691	$270,519	$269,374	$265,362	$264,940	$266,221	$291,646	$300,489	$294,469	$295,870	$295,857	$330,109	$3,416,549
(22)	Monthly Average	$22,641	$22,543	$22,448	$22,114	$22,078	$22,185	$24,304	$25,041	$24,539	$24,656	$24,655	$27,509	$284,712
(23)	TOTAL GCR Inventory Financing Costs	$66,305	$67,942	$67,414	$69,875	$72,256	$78,916	$79,751	$76,394	$79,297	$77,264	$78,187	$85,017	$898,617

(3) Line (1) + Line (2)
(4) Docket 4770
(5) Line (3) x Line (4)
(6) Docket 4770
(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 4770
(15) Line (13) x Line (14)
(16) Docket 4770
(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

Rhode Island Energy
Rhode Island - Gas

Actual Dth Usage for Filing

	THROUGHPUT (Dth) Rate Class	Apr-21 Actual (a)	May-21 Actual (b)	Jun-21 Actual (c)	Jul-21 Actual (d)	Aug-21 Actual (e)	Sep-21 Actual (f)	Oct-21 Actual (g)	Nov-21 Actual (h)	Dec-21 Actual (i)	Jan-22 Actual (j)	Feb-22 Actual (k)	Mar-22 Actual (l)	Apr-Mar (m)
(1)	**SALES**													
(2)	Residential Non-Heating	34,029	23,197	17,925	12,436	11,714	10,845	13,047	17,050	27,945	34,833	42,634	34,760	280,413
(3)	Residential Non-Heating Low Income	2,131	1,380	1,007	869	920	807	976	1,445	2,347	2,871	3,610	2,822	21,184
(4)	Residential Heating	1,814,236	1,050,464	576,769	366,195	365,369	339,355	401,934	876,018	2,090,016	2,779,726	3,457,289	2,623,099	16,740,469
(5)	Residential Heating Low Income	168,437	97,119	56,418	42,515	42,792	38,309	47,020	101,407	218,612	280,070	362,471	276,386	1,731,554
(6)	Small C&I	224,067	113,818	56,289	33,403	61,290	19,839	39,358	93,411	258,466	382,779	502,073	378,396	2,163,188
(7)	Medium C&I	316,650	192,394	113,953	83,029	90,150	92,750	97,556	157,051	375,818	474,276	582,551	463,274	3,039,449
(8)	Large LLF	56,349	36,999	17,944	8,247	25,418	9,476	(24,173)	28,156	81,584	94,784	142,136	98,874	575,793
(9)	Large HLF	21,784	17,117	15,973	14,234	14,110	12,162	14,272	15,573	26,551	26,488	32,869	38,133	249,265
(10)	Extra Large LLF	3,764	2,971	1,422	643	189	79	405	1,319	2,843	2,819	4,662	4,487	25,601
(11)	Extra Large HLF	7,032	7,147	6,797	6,386	8,562	6,991	7,013	9,675	13,036	12,160	7,987	21,793	114,579
(12)	Total Sales	2,648,478	1,542,605	864,496	567,956	620,513	530,611	597,405	1,301,105	3,097,217	4,090,805	5,138,281	3,942,023	24,941,495
(13)	**TSS**													
(14)	Small	1,014	746	28	28	777	1	20	47	479	2,289	3,377	1,553	10,358
(15)	Medium	10,755	7,730	1,073	1,274	2,682	779	1,020	2,395	4,154	9,175	14,808	12,957	68,802
(16)	Large LLF	5,888	3,547	122	25	20	16	29	405	1,361	1,124	6,224	4,630	23,390
(17)	Large HLF	334	1,162	0	0	0	0	902	830	1,562	1,770	3,694	2,946	13,199
(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	17,991	13,185	1,223	1,327	3,479	796	1,971	3,677	7,556	14,358	28,103	22,085	115,748
(21)	**Sales & TSS THROUGHPUT**													
(22)	Residential Non-Heating	34,029	23,197	17,925	12,436	11,714	10,845	13,047	17,050	27,945	34,833	42,634	34,760	280,413
(23)	Residential Non-Heating Low Income	2,131	1,380	1,007	869	920	807	976	1,445	2,347	2,871	3,610	2,822	21,184
(24)	Residential Heating	1,814,236	1,050,464	576,769	366,195	365,369	339,355	401,934	876,018	2,090,016	2,779,726	3,457,289	2,623,099	16,740,469
(25)	Residential Heating Low Income	168,437	97,119	56,418	42,515	42,792	38,309	47,020	101,407	218,612	280,070	362,471	276,386	1,731,554
(26)	Small C&I	225,081	114,564	56,317	33,431	62,067	19,840	39,377	93,458	258,945	385,068	505,450	379,949	2,173,546
(27)	Medium C&I	327,405	200,124	115,026	84,302	92,832	93,529	98,576	159,446	379,971	483,450	597,358	476,231	3,108,250
(28)	Large LLF	62,237	40,547	18,066	8,271	25,437	9,492	(24,145)	28,560	82,945	95,908	148,360	103,504	599,183
(29)	Large HLF	22,118	18,278	15,973	14,234	14,110	12,162	15,174	16,404	28,113	28,258	36,563	41,078	262,464
(30)	Extra Large LLF	3,764	2,971	1,422	643	189	79	405	1,319	2,843	2,819	4,662	4,487	25,601
(31)	Extra Large HLF	7,032	7,147	6,797	6,386	8,562	6,991	7,013	9,675	13,036	12,160	7,987	21,793	114,579
(32)	Total Sales & TSS Throughput	2,666,469	1,555,790	865,719	569,283	623,992	531,407	599,376	1,304,782	3,104,773	4,105,163	5,166,383	3,964,108	25,057,243
(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	56,825	26,595	14,819	11,454	21,774	(13,496)	39,277	36,028	78,189	77,145	110,056	58,104	516,770
(36)	FT-1 Large LLF	83,147	35,511	(501)	579	14,006	17,138	18,594	57,441	152,925	132,303	208,845	91,761	811,749
(37)	FT-1 Large HLF	30,134	19,524	23,373	20,975	40,338	13,458	28,793	26,635	44,169	36,279	56,326	25,455	365,460
(38)	FT-1 Extra Large LLF	120,997	49,582	(6,597)	(1,317)	20,649	19,333	28,559	73,507	193,626	178,365	247,104	168,286	1,092,095
(39)	FT-1 Extra Large HLF	545,631	367,165	395,978	430,729	407,953	440,373	393,641	470,231	516,587	574,697	600,503	446,653	5,590,140
(40)	Default	6,058	3,408	106	(174)	1,235	981	1,255	2,679	9,958	8,689	9,162	6,638	49,993
(41)	Total FT-1 Transportation	842,793	501,785	427,178	462,245	505,954	477,788	510,118	666,521	995,454	1,007,478	1,231,995	796,897	8,426,207
(42)	**FT-2 TRANSPORTATION**													
(43)	FT-2 Small	18,987	11,207	5,686	3,398	4,442	3,269	4,466	9,067	21,364	27,096	35,733	26,411	171,125
(44)	FT-2 Medium	193,908	123,388	76,353	49,152	51,566	46,338	47,943	93,812	207,302	252,893	302,223	242,759	1,687,637
(45)	FT-2 Large LLF	154,638	92,937	28,202	24,466	16,325	15,962	24,869	69,890	188,731	242,227	259,945	239,790	1,357,979
(46)	FT-2 Large HLF	58,111	49,549	47,399	31,139	35,253	34,774	30,398	31,276	61,593	59,934	68,295	59,079	566,799
(47)	FT-2 Extra Large LLF	6,859	3,928	1,757	1,286	1,584	1,185	1,265	2,677	8,497	10,128	12,706	11,432	63,303
(48)	FT-2 Extra Large HLF	33,244	34,337	32,977	27,015	27,744	37,403	35,765	36,594	56,374	43,304	49,724	45,212	459,695
(49)	Total FT-2 Transportation	465,746	315,345	192,374	136,456	136,914	138,930	144,707	243,316	543,860	635,582	728,626	624,682	4,306,538
(50)	**Total THROUGHPUT**													
(51)	Residential Non-Heating	34,029	23,197	17,925	12,436	11,714	10,845	13,047	17,050	27,945	34,833	42,634	34,760	280,413
(52)	Residential Non-Heating Low Income	2,131	1,380	1,007	869	920	807	976	1,445	2,347	2,871	3,610	2,822	21,184
(53)	Residential Heating	1,814,236	1,050,464	576,769	366,195	365,369	339,355	401,934	876,018	2,090,016	2,779,726	3,457,289	2,623,099	16,740,469
(54)	Residential Heating Low Income	168,437	97,119	56,418	42,515	42,792	38,309	47,020	101,407	218,612	280,070	362,471	276,386	1,731,554
(55)	Small C&I	244,067	125,771	62,003	36,829	66,509	23,109	43,844	102,525	280,309	412,164	541,183	406,360	2,344,671
(56)	Medium C&I	578,137	350,108	206,197	144,908	166,172	126,371	185,796	289,286	665,462	813,488	1,009,638	777,094	5,312,657
(57)	Large LLF	300,022	168,994	45,768	33,316	55,768	42,592	19,318	155,891	424,600	470,438	617,149	435,055	2,768,911
(58)	Large HLF	110,363	87,351	86,745	66,348	89,701	60,394	74,365	74,314	133,875	124,472	161,184	125,613	1,194,723
(59)	Extra Large LLF	131,620	56,481	(3,418)	613	22,421	20,597	30,230	77,503	204,965	191,311	264,471	184,204	1,180,999
(60)	Extra Large HLF	585,907	408,648	435,752	464,130	444,260	484,768	436,419	516,500	585,997	630,162	658,213	513,658	6,164,414
(61)	Default	6,058	3,408	106	(174)	1,235	981	1,255	2,679	9,958	8,689	9,162	6,638	49,993
(62)	Total Throughput	3,975,008	2,372,919	1,485,271	1,167,985	1,266,860	1,148,125	1,254,201	2,214,619	4,644,087	5,748,222	7,127,004	5,385,688	37,789,989

REDACTED

Attachment PRB-3

Attachment PRB-3

Projected Gas Cost Balances

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Projected Gas Cost Deferred Balances

	Description	Nov-22 forecast	Dec-22 forecast	Jan-23 forecast	Feb-23 forecast	Mar-23 forecast	Apr-23 forecast	May-23 forecast	Jun-23 forecast	Jul-23 forecast	Aug-23 forecast	Sep-23 forecast	Oct-23 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 (October 31, 2022)	$3,794,338	$3,818,083	$1,225,361	($4,933,209)	($12,924,573)	($16,937,876)	($20,493,285)	($18,467,764)	($15,231,034)	($11,439,147)	($7,521,025)	($3,638,918)	$3,794,338
(4)	Fixed Costs (net of capacity release)	$6,893,509	$25,532,282	$25,532,282	$25,532,282	$25,532,282	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$7,008,546	$158,082,458
(5)	Supply Related System Pressure to DAC	($149,444)	($16,865,453)	($16,865,453)	($16,865,453)	($16,865,453)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($149,444)	($68,657,362)
(6)	NGPMP Credits	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($11,646,741)
(7)	Working Capital	$49,070	$63,061	$63,061	$63,061	$63,061	$49,907	$49,907	$49,907	$49,907	$49,907	$49,907	$49,907	$650,664
(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	$5,891,725	$7,828,481	$7,828,481	$7,828,481	$7,828,481	$6,007,599	$6,007,599	$6,007,599	$6,007,599	$6,007,599	$6,007,599	$6,007,599	$79,258,843
(10)	Fixed - Revenue	($5,878,914)	($10,428,687)	($13,981,548)	($15,795,903)	($11,797,464)	($9,509,246)	($3,924,257)	($2,722,467)	($2,176,131)	($2,061,339)	($2,109,463)	($2,667,760)	($83,053,182)
(11)	Prelim. Ending Under/(Over) Recovery	$3,807,149	$1,217,876	($4,927,707)	($12,900,632)	($16,893,557)	($20,439,523)	($18,409,943)	($15,182,632)	($11,399,566)	($7,492,887)	($3,622,889)	($299,079)	
(12)	Month's Average Balance	$3,800,744	$2,517,979	($1,851,173)	($8,916,921)	($14,909,065)	($18,688,699)	($19,451,614)	($16,825,198)	($13,315,300)	($9,466,017)	($5,571,957)	($1,968,999)	
(13)	Interest Rate (BOA Prime minus 200 bps)	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
(14)	Interest Applied	$10,934	$7,485	($5,503)	($23,941)	($44,319)	($53,762)	($57,822)	($48,401)	($39,581)	($28,139)	($16,029)	($5,853)	($304,931)
(15)	Fixed Ending Under/(Over) Recovery	$3,818,083	$1,225,361	($4,933,209)	($12,924,573)	($16,937,876)	($20,493,285)	($18,467,764)	($15,231,034)	($11,439,147)	($7,521,025)	($3,638,918)	($304,932)	($304,932)
(16)	**II. Variable Cost Deferred**													
(17)	Beginning Under/(Over) Recovery (October 31, 2022)	$12,877,724	$15,694,903	$16,376,196	$16,366,569	$12,164,493	$12,180,602	$7,350,596	$4,738,516	$2,741,594	$1,203,648	($873)	($997,063)	$12,877,724
(18)	Variable Costs	$9,927,672	$13,801,541	$17,817,494	$16,070,206	$15,033,711	$7,224,422	$2,106,856	$1,124,754	$843,768	$1,004,913	$1,259,299	$4,221,581	$90,436,217
(19)	Supply Related System Pressure to DAC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20)	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
(21)	Inventory Financing - LNG	$28,939	$23,573	$5,172	$782	$0	$4,886	$9,571	$14,052	$18,723	$23,368	$27,400	$29,797	$186,264
(22)	Inventory Financing - UG	$114,662	$83,828	$52,951	$28,375	$14,621	$17,690	$29,221	$49,122	$67,052	$85,019	$101,872	$118,960	$763,374
(23)	Working Capital	$72,235	$100,421	$129,641	$116,928	$109,386	$52,565	$15,330	$8,184	$6,139	$7,312	$9,163	$30,717	$658,021
(24)	Total Variable Costs	$10,168,694	$14,034,550	$18,030,446	$16,241,479	$15,182,905	$7,324,751	$2,186,164	$1,221,300	$960,869	$1,145,799	$1,422,921	$4,426,242	$92,346,120
(25)	Variable - Revenue	($7,392,553)	($13,400,854)	($18,088,666)	($20,481,806)	($15,202,926)	($12,182,810)	($4,816,186)	($3,228,965)	($2,504,670)	($2,352,106)	($2,417,677)	($3,154,623)	($105,223,842)
(26)	Prelim. Ending Under/(Over) Recovery	$15,653,865	$16,328,600	$16,317,976	$12,126,242	$12,144,472	$7,322,543	$4,720,574	$2,730,850	$1,197,793	($2,659)	($995,630)	$274,556	
(27)	Month's Average Balance	$14,265,794	$16,011,752	$16,347,086	$14,246,406	$12,154,482	$9,751,573	$6,035,585	$3,734,683	$1,969,693	$600,495	($498,252)	($361,254)	
(28)	Interest Rate (BOA Prime minus 200 bps)	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
(29)	Interest Applied	$41,039	$47,597	$48,593	$38,251	$36,130	$28,052	$17,941	$10,744	$5,855	$1,785	($1,433)	($1,074)	$273,480
(30)	Gas Procurement Incentive/(penalty)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(31)	Variable Ending Under/(Over) Recovery	$15,694,903	$16,376,196	$16,366,569	$12,164,493	$12,180,602	$7,350,596	$4,738,516	$2,741,594	$1,203,648	($873)	($997,063)	$273,482	$273,482
(32)	**III. GCR Deferred Summary**													
(33)	Beginning Under/(Over) Recovery (October 31, 2022)	$16,672,062	$19,512,986	$17,601,557	$11,433,360	($760,081)	($4,757,273)	($13,142,689)	($13,729,249)	($12,489,440)	($10,235,499)	($7,521,899)	($4,635,981)	$16,672,062
(34)	Gas Costs	$16,766,075	$22,562,710	$26,578,663	$24,831,375	$23,794,879	$14,177,863	$9,060,296	$8,078,195	$7,797,209	$7,958,354	$8,212,740	$11,175,022	$180,993,381
(35)	Inventory Finance	$143,601	$107,401	$58,123	$29,157	$14,621	$22,576	$38,792	$63,175	$85,775	$108,387	$129,272	$148,757	$949,638
(36)	Working Capital	$121,305	$163,482	$192,702	$179,989	$172,447	$102,473	$65,237	$58,091	$56,047	$57,219	$59,070	$80,624	$1,308,685
(37)	NGPMP Credits	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($970,562)	($11,646,741)
(38)	Total Costs	$16,060,420	$21,863,031	$25,858,926	$24,069,959	$23,011,386	$13,332,350	$8,193,764	$7,228,899	$6,968,468	$7,153,399	$7,430,520	$10,433,841	$171,604,963
(39)	Revenue	($13,271,467)	($23,829,541)	($32,070,214)	($36,277,709)	($27,000,390)	($21,692,056)	($8,740,443)	($5,951,432)	($4,680,801)	($4,413,445)	($4,527,140)	($5,822,383)	($188,277,024)
(40)	Prelim. Ending Under/(Over) Recovery	$19,461,014	$17,546,476	$11,390,269	($774,390)	($4,749,085)	($13,116,979)	($13,689,368)	($12,451,782)	($10,201,773)	($7,495,545)	($4,618,519)	($24,523)	$1
(41)	Month's Average Balance	$18,066,538	$18,529,731	$14,495,913	$5,329,485	($2,754,583)	($8,937,126)	($13,416,028)	($13,090,515)	($11,345,606)	($8,865,522)	($6,070,209)	($2,330,252)	
(42)	Interest Rate (BOA Prime minus 200 bps)	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	
(43)	Interest Applied	$51,972	$55,082	$43,091	$14,309	($8,188)	($25,710)	($39,881)	($37,658)	($33,726)	($26,354)	($17,462)	($6,927)	($31,451)
(44)	Gas Purchase Plan Incentives/(Penalties)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
(45)	Ending Under/(Over) Recovery W/ Interest	$19,512,986	$17,601,557	$11,433,360	($760,081)	($4,757,273)	($13,142,689)	($13,729,249)	($12,489,440)	($10,235,499)	($7,521,899)	($4,635,981)	$\boxed{(\$31,450)}$	($31,450)

(3) Nov-22: PRB-1, pg 7, Line (65)(m)
(4) PRB-1, pg 5, Line (57)
(6) GSP-1
(7) PRB-1, pg 9, Line (16)
(8) PRB-1, pg 2, Line (8) ÷ 12
(9) Sum[(4)-(8)]
(10) PRB-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) Line (11) + Line (14)
(17) Nov-22: PRB-1, pg 7, Line (66)(m)
(18) PRB-1, pg 6, Line (93)
(20) PRB-1, pg 3, Line (8) ÷ 12
(21) PRB-1, pg 11, Line (22)
(22) PRB-1, pg 11, Line (12)
(23) PRB-1, pg 9, Line (32)
(24) Sum[Lines (18)-(23)]
(25) PRB-1, pg 8, Line (15)
(26) Sum[Lines (17), (24), (25)]
(27) [Line (17) + Line (26)] ÷ 2
(29) [Line (27) x Line (28)] ÷ 365 x Line (1)
(31) Sum[Lines (26), (29), (30)]
(33) Nov-22: Line (3)(b) + Line (17)(b)
(34) Sum[Lines (4)-(5);(8);(18)-(20)]
(35) Line (21) + Line (22)
(36) Line (7) + Line (23)
(37) Line (6)
(38) Sum[Lines (34)-(37)]
(39) Line (10) + Line (25)
(40) Sum[Lines (33);(38)-(39)]
(41) [Lines (33) + Line (40)] ÷ 2
(43) Line (14) + Line (29)
(44) Line (30)
(45) Sum[Lines (40), (43), (44)]

The Narragansett Electric Company
d/b/a Rhode Island Energy
Docket No. 22-20-NG
Attachment PRB-3
Page 1 of 1

Attachment PRB-4

Attachment PRB-4

Bill Impact Analysis

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Heating:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(1)							Difference due to:					
(2)	Annual	Proposed	Current				DAC					
(3)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(4)												
(5)	548	$1,193.96	$1,046.62	$147.34	14.1%	$47.78	$95.14	$0.00	$0.00	$0.00	$4.42	
(6)	608	$1,304.68	$1,141.20	$163.48	14.3%	$53.03	$105.55	$0.00	$0.00	$0.00	$4.90	
(7)	667	$1,413.55	$1,234.21	$179.34	14.5%	$58.15	$115.81	$0.00	$0.00	$0.00	$5.38	
(8)	726	$1,522.39	$1,327.18	$195.21	14.7%	$63.29	$126.06	$0.00	$0.00	$0.00	$5.86	
(9)	785	$1,631.22	$1,420.13	$211.09	14.9%	$68.46	$136.30	$0.00	$0.00	$0.00	$6.33	
(10)	845	$1,741.91	$1,514.68	$227.23	15.0%	$73.70	$146.71	$0.00	$0.00	$0.00	$6.82	
(11)	905	$1,852.63	$1,609.29	$243.34	15.1%	$78.93	$157.11	$0.00	$0.00	$0.00	$7.30	
(12)	964	$1,961.43	$1,702.19	$259.24	15.2%	$84.07	$167.39	$0.00	$0.00	$0.00	$7.78	
(13)	1,023	$2,070.26	$1,795.20	$275.06	15.3%	$89.20	$177.61	$0.00	$0.00	$0.00	$8.25	
(14)	1,082	$2,179.14	$1,888.21	$290.93	15.4%	$94.35	$187.85	$0.00	$0.00	$0.00	$8.73	
(15)	1,142	$2,289.85	$1,982.81	$307.04	15.5%	$99.56	$198.27	$0.00	$0.00	$0.00	$9.21	

Residential Heating Low Income:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
					#NAME?							
(16)								Difference due to:				
(17)	Annual	Proposed	Current				Total Bill	DAC				
(18)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Discount	Base DAC	ISR	EE	LIHEAP	GET
(19)												
(20)	548	$885.24	$776.88	$108.36	13.9%	$47.78	($35.04)	$92.37	$0.00	$0.00	$0.00	$3.25
(21)	608	$967.18	$846.93	$120.25	14.2%	$53.03	($38.88)	$102.49	$0.00	$0.00	$0.00	$3.61
(22)	667	$1,047.72	$915.83	$131.89	14.4%	$58.15	($42.65)	$112.43	$0.00	$0.00	$0.00	$3.96
(23)	726	$1,128.25	$984.69	$143.56	14.6%	$63.29	($46.42)	$122.38	$0.00	$0.00	$0.00	$4.31
(24)	785	$1,208.75	$1,053.49	$155.27	14.7%	$68.46	($50.20)	$132.35	$0.00	$0.00	$0.00	$4.66
(25)	845	$1,290.67	$1,123.54	$167.13	14.9%	$73.70	($54.04)	$142.46	$0.00	$0.00	$0.00	$5.01
(26)	905	$1,372.61	$1,193.60	$179.01	15.0%	$78.93	($57.88)	$152.59	$0.00	$0.00	$0.00	$5.37
(27)	964	$1,453.08	$1,262.43	$190.65	15.1%	$84.07	($61.65)	$162.51	$0.00	$0.00	$0.00	$5.72
(28)	1,023	$1,533.62	$1,331.32	$202.31	15.2%	$89.20	($65.41)	$172.45	$0.00	$0.00	$0.00	$6.07
(29)	1,082	$1,614.18	$1,400.18	$214.00	15.3%	$94.35	($69.19)	$182.42	$0.00	$0.00	$0.00	$6.42
(30)	1,142	$1,696.10	$1,470.23	$225.87	15.4%	$99.56	($73.03)	$192.56	$0.00	$0.00	$0.00	$6.78

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

Residential Non-Heating:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(31)							Difference due to:					
(32)	Annual	Proposed	Current				DAC					
(33)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(34)												
(35)	144	$443.22	$394.63	$48.60	12.3%	$13.00	$34.14	$0.00	$0.00	$0.00	$1.46	
(36)	158	$468.52	$415.20	$53.32	12.8%	$14.26	$37.46	$0.00	$0.00	$0.00	$1.60	
(37)	172	$493.78	$435.80	$57.98	13.3%	$15.49	$40.75	$0.00	$0.00	$0.00	$1.74	
(38)	189	$524.53	$460.75	$63.77	13.8%	$17.05	$44.81	$0.00	$0.00	$0.00	$1.91	
(39)	202	$548.04	$479.89	$68.15	14.2%	$18.24	$47.87	$0.00	$0.00	$0.00	$2.04	
(40)	220	$580.56	$506.36	$74.20	14.7%	$19.83	$52.14	$0.00	$0.00	$0.00	$2.23	
(41)	238	$613.09	$532.81	$80.29	15.1%	$21.49	$56.39	$0.00	$0.00	$0.00	$2.41	
(42)	251	$636.60	$551.92	$84.68	15.3%	$22.68	$59.46	$0.00	$0.00	$0.00	$2.54	
(43)	268	$667.36	$576.91	$90.44	15.7%	$24.20	$63.53	$0.00	$0.00	$0.00	$2.71	
(44)	282	$692.60	$597.51	$95.08	15.9%	$25.42	$66.81	$0.00	$0.00	$0.00	$2.85	
(45)	297	$719.75	$619.58	$100.16	16.2%	$26.78	$70.38	$0.00	$0.00	$0.00	$3.00	

Residential Non-Heating Low Income:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(46)								Difference due to:				
(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	$329.70	$294.04	$35.66	12.1%	$13.00	($11.53)	$33.12	$0.00	$0.00	$0.00	$1.07
(51)	158	$348.43	$309.29	$39.13	12.7%	$14.26	($12.65)	$36.35	$0.00	$0.00	$0.00	$1.17
(52)	172	$367.13	$324.54	$42.60	13.1%	$15.49	($13.77)	$39.60	$0.00	$0.00	$0.00	$1.28
(53)	189	$389.86	$343.05	$46.81	13.6%	$17.05	($15.14)	$43.49	$0.00	$0.00	$0.00	$1.40
(54)	202	$407.27	$357.23	$50.04	14.0%	$18.24	($16.18)	$46.48	$0.00	$0.00	$0.00	$1.50
(55)	220	$431.31	$376.82	$54.49	14.5%	$19.83	($17.62)	$50.65	$0.00	$0.00	$0.00	$1.63
(56)	238	$455.37	$396.40	$58.96	14.9%	$21.49	($19.07)	$54.77	$0.00	$0.00	$0.00	$1.77
(57)	251	$472.75	$410.57	$62.19	15.1%	$22.68	($20.11)	$57.75	$0.00	$0.00	$0.00	$1.87
(58)	268	$495.50	$429.10	$66.40	15.5%	$24.20	($21.47)	$61.68	$0.00	$0.00	$0.00	$1.99
(59)	282	$514.18	$444.35	$69.84	15.7%	$25.42	($22.58)	$64.90	$0.00	$0.00	$0.00	$2.10
(60)	297	$534.25	$460.73	$73.52	16.0%	$26.78	($23.77)	$68.31	$0.00	$0.00	$0.00	$2.21

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I Small:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(61)							Difference due to:					
(62)	Annual	Proposed	Current				DAC					
(63)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(64)												
(65)	830	$1,759.01	$1,535.52	$223.49	14.6%	$72.36	$144.43	$0.00	$0.00	$0.00	$6.70	
(66)	919	$1,913.35	$1,665.87	$247.47	14.9%	$80.14	$159.91	$0.00	$0.00	$0.00	$7.42	
(67)	1,010	$2,071.24	$1,799.28	$271.96	15.1%	$88.08	$175.72	$0.00	$0.00	$0.00	$8.16	
(68)	1,099	$2,225.69	$1,929.74	$295.95	15.3%	$95.86	$191.21	$0.00	$0.00	$0.00	$8.88	
(69)	1,187	$2,378.42	$2,058.76	$319.66	15.5%	$103.51	$206.56	$0.00	$0.00	$0.00	$9.59	
(70)	1,277	$2,534.47	$2,190.61	$343.86	15.7%	$111.34	$222.20	$0.00	$0.00	$0.00	$10.32	
(71)	1,367	$2,690.60	$2,322.50	$368.10	15.8%	$119.20	$237.86	$0.00	$0.00	$0.00	$11.04	
(72)	1,456	$2,845.00	$2,452.94	$392.06	16.0%	$126.94	$253.36	$0.00	$0.00	$0.00	$11.76	
(73)	1,544	$2,997.74	$2,581.97	$415.77	16.1%	$134.65	$268.65	$0.00	$0.00	$0.00	$12.47	
(74)	1,635	$3,155.62	$2,715.34	$440.28	16.2%	$142.59	$284.48	$0.00	$0.00	$0.00	$13.21	
(75)	1,725	$3,311.70	$2,847.25	$464.45	16.3%	$150.41	$300.11	$0.00	$0.00	$0.00	$13.93	

C & I Medium:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(76)							Difference due to:					
(77)	Annual	Proposed	Current				DAC					
(78)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(79)												
(80)	6,907	$11,625.50	$9,799.07	$1,826.43	18.6%	$602.29	$1,169.35	$0.00	$0.00	$0.00	$54.79	
(81)	7,650	$12,762.03	$10,739.16	$2,022.88	18.8%	$667.07	$1,295.12	$0.00	$0.00	$0.00	$60.69	
(82)	8,391	$13,895.13	$11,676.25	$2,218.88	19.0%	$731.70	$1,420.61	$0.00	$0.00	$0.00	$66.57	
(83)	9,136	$15,034.55	$12,618.68	$2,415.88	19.1%	$796.66	$1,546.74	$0.00	$0.00	$0.00	$72.48	
(84)	9,880	$16,172.53	$13,559.92	$2,612.61	19.3%	$861.54	$1,672.69	$0.00	$0.00	$0.00	$78.38	
(85)	10,623	$17,309.13	$14,500.01	$2,809.11	19.4%	$926.34	$1,798.50	$0.00	$0.00	$0.00	$84.27	
(86)	11,366	$18,445.63	$15,440.06	$3,005.57	19.5%	$991.12	$1,924.28	$0.00	$0.00	$0.00	$90.17	
(87)	12,111	$19,585.07	$16,382.51	$3,202.56	19.5%	$1,056.07	$2,050.41	$0.00	$0.00	$0.00	$96.08	
(88)	12,855	$20,723.03	$17,323.76	$3,399.28	19.6%	$1,120.94	$2,176.36	$0.00	$0.00	$0.00	$101.98	
(89)	13,596	$21,856.10	$18,260.88	$3,595.22	19.7%	$1,185.57	$2,301.79	$0.00	$0.00	$0.00	$107.86	
(90)	14,340	$22,994.10	$19,202.14	$3,791.96	19.7%	$1,250.44	$2,427.76	$0.00	$0.00	$0.00	$113.76	

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Large:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(91)								Difference due to:				
(92)	Annual	Proposed	Current				DAC					
(93)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(94)												
(95)	37,587	$59,121.47	$49,453.48	$9,667.99	19.5%	$3,277.59	$6,100.36	$0.00	$0.00	$0.00	$290.04	
(96)	41,634	$65,219.27	$54,510.32	$10,708.95	19.6%	$3,630.50	$6,757.18	$0.00	$0.00	$0.00	$321.27	
(97)	45,683	$71,320.49	$59,570.13	$11,750.36	19.7%	$3,983.52	$7,414.33	$0.00	$0.00	$0.00	$352.51	
(98)	49,731	$77,420.40	$64,628.77	$12,791.63	19.8%	$4,336.55	$8,071.33	$0.00	$0.00	$0.00	$383.75	
(99)	53,777	$83,516.82	$69,684.50	$13,832.32	19.8%	$4,689.33	$8,728.02	$0.00	$0.00	$0.00	$414.97	
(100)	57,825	$89,616.69	$74,743.18	$14,873.52	19.9%	$5,042.32	$9,384.99	$0.00	$0.00	$0.00	$446.21	
(101)	61,873	$95,716.57	$79,801.81	$15,914.76	19.9%	$5,395.31	$10,042.01	$0.00	$0.00	$0.00	$477.44	
(102)	65,920	$101,814.37	$84,858.68	$16,955.69	20.0%	$5,748.22	$10,698.80	$0.00	$0.00	$0.00	$508.67	
(103)	69,967	$107,912.82	$89,916.22	$17,996.60	20.0%	$6,101.07	$11,355.63	$0.00	$0.00	$0.00	$539.90	
(104)	74,016	$114,014.07	$94,975.93	$19,038.14	20.0%	$6,454.21	$12,012.79	$0.00	$0.00	$0.00	$571.14	
(105)	78,063	$120,111.91	$100,032.82	$20,079.08	20.1%	$6,807.12	$12,669.59	$0.00	$0.00	$0.00	$602.37	

C & I HLF Large:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(106)								Difference due to:				
(107)	Annual	Proposed	Current				DAC					
(108)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(109)												
(110)	41,956	$57,534.19	$47,166.29	$10,367.90	22.0%	$3,784.45	$6,272.41	$0.00	$0.00	$0.00	$311.04	
(111)	46,471	$63,458.47	$51,974.89	$11,483.58	22.1%	$4,191.68	$6,947.39	$0.00	$0.00	$0.00	$344.51	
(112)	50,991	$69,388.81	$56,788.22	$12,600.59	22.2%	$4,599.41	$7,623.16	$0.00	$0.00	$0.00	$378.02	
(113)	55,507	$75,314.31	$61,597.77	$13,716.54	22.3%	$5,006.75	$8,298.29	$0.00	$0.00	$0.00	$411.50	
(114)	60,028	$81,245.89	$66,412.16	$14,833.73	22.3%	$5,414.53	$8,974.19	$0.00	$0.00	$0.00	$445.01	
(115)	64,545	$87,172.60	$71,222.67	$15,949.94	22.4%	$5,821.96	$9,649.48	$0.00	$0.00	$0.00	$478.50	
(116)	69,062	$93,099.35	$76,033.16	$17,066.19	22.4%	$6,229.42	$10,324.78	$0.00	$0.00	$0.00	$511.99	
(117)	73,583	$99,030.93	$80,847.59	$18,183.34	22.5%	$6,637.17	$11,000.67	$0.00	$0.00	$0.00	$545.50	
(118)	78,099	$104,956.41	$85,657.10	$19,299.31	22.5%	$7,044.52	$11,675.81	$0.00	$0.00	$0.00	$578.98	
(119)	82,619	$110,886.77	$90,470.48	$20,416.29	22.6%	$7,452.25	$12,351.55	$0.00	$0.00	$0.00	$612.49	
(120)	87,137	$116,815.61	$95,282.93	$21,532.68	22.6%	$7,859.74	$13,026.96	$0.00	$0.00	$0.00	$645.98	

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Bill Impact Analysis with Various Levels of Consumption

C & I LLF Extra-Large:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(121)								Difference due to:				
(122)	Annual	Proposed	Current				DAC					
(123)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(124)												
(125)	233,835	$296,041.91	$236,474.26	$59,567.65	25.2%	$20,390.41	$37,390.21	$0.00	$0.00	$0.00	$1,787.03	
(126)	259,019	$327,258.07	$261,274.98	$65,983.09	25.3%	$22,586.46	$41,417.14	$0.00	$0.00	$0.00	$1,979.49	
(127)	284,197	$358,467.46	$286,070.47	$72,396.99	25.3%	$24,781.98	$45,443.10	$0.00	$0.00	$0.00	$2,171.91	
(128)	309,381	$389,683.65	$310,871.23	$78,812.41	25.4%	$26,978.01	$49,470.03	$0.00	$0.00	$0.00	$2,364.37	
(129)	334,562	$420,896.45	$335,669.34	$85,227.11	25.4%	$29,173.81	$53,496.49	$0.00	$0.00	$0.00	$2,556.81	
(130)	359,745	$452,111.48	$360,469.22	$91,642.26	25.4%	$31,369.78	$57,523.21	$0.00	$0.00	$0.00	$2,749.27	
(131)	384,928	$483,326.55	$385,269.11	$98,057.44	25.5%	$33,565.74	$61,549.98	$0.00	$0.00	$0.00	$2,941.72	
(132)	410,110	$514,540.44	$410,068.10	$104,472.34	25.5%	$35,761.58	$65,576.59	$0.00	$0.00	$0.00	$3,134.17	
(133)	435,293	$545,755.55	$434,867.98	$110,887.57	25.5%	$37,957.57	$69,603.37	$0.00	$0.00	$0.00	$3,326.63	
(134)	460,471	$576,964.85	$459,663.44	$117,301.41	25.5%	$40,153.06	$73,629.31	$0.00	$0.00	$0.00	$3,519.04	
(135)	485,655	$608,181.05	$484,464.24	$123,716.81	25.5%	$42,349.11	$77,656.20	$0.00	$0.00	$0.00	$3,711.50	

C & I HLF Extra-Large:

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
(136)								Difference due to:				
(137)	Annual	Proposed	Current				DAC					
(138)	Consumption (Therms)	Rates	Rates	Difference	% Chg	GCR	Base DAC	ISR	EE	LIHEAP	GET	
(139)												
(140)	486,528	$547,185.14	$426,405.81	$120,779.33	28.3%	$43,884.83	$73,271.12	$0.00	$0.00	$0.00	$3,623.38	
(141)	538,924	$605,446.62	$471,660.17	$133,786.45	28.4%	$48,610.91	$81,161.95	$0.00	$0.00	$0.00	$4,013.59	
(142)	591,320	$663,707.31	$516,913.63	$146,793.68	28.4%	$53,337.09	$89,052.78	$0.00	$0.00	$0.00	$4,403.81	
(143)	643,718	$721,970.81	$562,169.50	$159,801.31	28.4%	$58,063.35	$96,943.92	$0.00	$0.00	$0.00	$4,794.04	
(144)	696,109	$780,226.31	$607,419.05	$172,807.26	28.4%	$62,789.02	$104,834.02	$0.00	$0.00	$0.00	$5,184.22	
(145)	748,506	$838,488.82	$652,674.13	$185,814.69	28.5%	$67,515.25	$112,725.00	$0.00	$0.00	$0.00	$5,574.44	
(146)	800,903	$896,751.31	$697,929.19	$198,822.12	28.5%	$72,241.45	$120,616.01	$0.00	$0.00	$0.00	$5,964.66	
(147)	853,294	$955,006.80	$743,178.72	$211,828.08	28.5%	$76,967.15	$128,506.09	$0.00	$0.00	$0.00	$6,354.84	
(148)	905,692	$1,013,270.33	$788,434.63	$224,835.70	28.5%	$81,693.42	$136,397.21	$0.00	$0.00	$0.00	$6,745.07	
(149)	958,088	$1,071,530.99	$833,688.08	$237,842.91	28.5%	$86,419.54	$144,288.08	$0.00	$0.00	$0.00	$7,135.29	
(150)	1,010,485	$1,129,793.45	$878,943.16	$250,850.29	28.5%	$91,145.75	$152,179.03	$0.00	$0.00	$0.00	$7,525.51	

Attachment PRB-5

FT-2 Demand Rate

The Narragansett Electric Company
d/b/a Rhode Island Energy
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 2021 - Oct 2022	Pg 2, Line (21)	$14.8192	Dth/Mth
(2)	Storage and Peaking charge for FT-1 firm transportation Customers eligible for TSS	Pg 3, Line (5)	$1.1687	Per Dth

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Calculation of FT- 2 Demand Rate (per Dth)

		Source			
	Description	Reference	Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Storage Fixed Costs	PRB-1 pg 5	Line (56)	$96,322,922	
	Less:				
(2)	System Pressure to DAC			($68,657,362)	
(3)	Credits			$0	
(4)	Refunds			$0	
(5)	Total Credits	Sum [(2)-(4)]		($68,657,362)	
	Plus:				
(6)	Supply Related LNG O&M Costs	PRB-1 Pg 2	Line (8)	$829,823	
(7)	Working Capital Requirement	PRB-1 pg 10	Line (47)	$201,297	
(8)	[redacted]	PRB-1 pg 4	Line (17)	$1,229,040	
(9)	Total Additions	Sum [(6)-(8)]		$2,260,160	
(10)	Total Storage Fixed Costs	(1) + (5) + (9)		$29,925,720	
	Inventory Financing				
(11)	Underground	PRB-1 pg 11	Line (12)	$763,374	
(12)	LNG	PRB-1 pg 11	Line (22)	$186,264	
(13)	Total Storage Fixed Costs	(10) + (11) + (12)		$30,875,358	
(14)	LNG Storage MDQ (Dth)	PRB-1 pg 13	Line (14)	[redacted]	
(15)	AGT Storage	GSP-1		[redacted]	
(16)	TGP Storage	GSP-1		[redacted]	
(17)	Total Storage MDQ	Sum [(14)-(16)]		[redacted]	
(18)	Storage MDQ X 12 Months	(17) x 12		[redacted]	MDCQ Dth
(19)	FT- 2 Demand Rate	(13) ÷ (18)		$14 5362	per MDCQ Dth
(20)	Uncollectible %	Docket No 4770		1 91%	
(21)	Total FT-2 Demand Rate adjusted for Uncollectibles	(19) ÷ [(1 - (20)]		$14 8192	per MDCQ Dth
(22)	MDQ-U	Mkter MDQ Forecast		4,682	
(23)	MDQ-P	Mkter MDQ Forecast		15,618	
(24)	Marketer MDQs	(22) + (23)		20,300	Dth/Mth
(25)	FT-2 Storage Costs	(19) x (24) x 12 Months		**$3,541,023**	

(21): Truncated to 4 decimals

REDACTED

The Narragansett Electric Company
d/b/a Rhode Island Energy
Gas Cost Recovery (GCR) Filing
Calculation of FT-1 Storage and Peaking Charge Applied to Firm Transportation Customers Eligible for TSS

	Description	Source: Reference	Source: Line #	Amount	
	(a)	(b)	(c)	(d)	
(1)	Total Storage Fixed Costs	Pg 2	Line (13)	\$30,875,358	
(2)	Usage (Dth) Nov 2022 - Oct 2023	PRB-1, pg 2	Line (15)	26,932,120	
(3)	Volumetric Rate	(1) ÷ (2)		\$1.1464	
(4)	Uncollectible %	Docket No. 4770		1.91%	
(5)	Volumetric Rate Including Uncollectible	(3) ÷ [1 - (4)]		\$1.1687	per dth
(6)	Storage & Peaking charge applied to FT-1 customers eligible for TSS	(5) ÷ 10		\$0.1168	per therm

(6): Truncated to 4 decimals.

Attachment PRB-6

Attachment PRB-6

FT-2 Capacity Allocator Percentages

The Narragansett Electric Company
d/b/a Rhode Island Energy
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	67.0%	7.0%	26.0%	100.0%	0.7%	0.6%	0.6%
2	HLF	Res - Non-Heating LI	67.0%	7.0%	26.0%	100.0%			
3	LLF	Res - Heating	53.0%	10.0%	37.0%	100.0%	58.9%	60.8%	60.8%
4	LLF	Res - Heating LI	53.0%	10.0%	37.0%	100.0%			
5	LLF	Small	53.0%	10.0%	37.0%	100.0%	7.4%	7.9%	7.9%
6	LLF	Med	53.0%	10.0%	37.0%	100.0%	9.2%	9.0%	9.0%
7	LLF	Large Low Load	53.0%	10.0%	37.0%	100.0%	1.7%	1.8%	1.8%
8	HLF	Large High Load	67.0%	7.0%	26.0%	100.0%	0.5%	0.3%	0.3%
9	LLF	XL Low Load	53.0%	10.0%	37.0%	100.0%	0.1%	0.1%	0.1%
10	HLF	XL High Load	67.0%	7.0%	26.0%	100.0%	0.2%	0.1%	0.1%
11	HLF	High Load Factor	67.0%	7.0%	26.0%	100.0%	6.8%	3.9%	3.9%
12	LLF	Low Load Factor	53.0%	10.0%	37.0%	100.0%	93.2%	96.1%	96.1%
13		Total	53.0%	11.0%	36.0%	100.0%	100.0%	100.0%	100.0%

Testimony of
Poe & Horowitz

JOINT DIRECT TESTIMONY

OF

THEODORE POE, JR.

AND

SHIRA HOROWITZ

September 1, 2022

Table of Contents

I. <u>Introduction</u>

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

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

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

A. I am Manager, Gas Load Forecasting for National Grid USA Service Company, Inc. ("National Grid Service Company"). In this position, I prepared the forecast of the resource requirements for The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") pursuant to the Transition Service Agreement between and among National Grid Service Company, National Grid USA ("National Grid") (solely with respect to Section 4.6) and the Company ("TSA").

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 National Grid in Rhode Island and New York.

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, 4963, and 5180. 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. Ms. Horowitz, please state your name and business address.

A. My name is Shira Horowitz, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am the Director, Load Forecasting & Analysis for the National Grid Service Company. I oversee the gas and electric load forecasts for National Grid. I offer this testimony on behalf of the Company pursuant to the TSA.

Q. Please summarize your professional and educational background.

A. I have been in my current position with the National Grid Service Company since May 2021 where I oversaw gas load forecasting for National Grid. In July 2022, I added the responsibility of overseeing National Grid's electric load forecasting. Before that, from June 2019 through April 2021 I was the Manager of Economics and Load Forecasting at National Grid. Prior to joining National Grid, I worked at Consolidated Edison in New York and PJM Interconnection in Pennsylvania.

I received a Bachelor of Engineering in Electrical Engineering from The Cooper Union in New York and a Doctor of Philosophy in Engineering and Public Policy from Carnegie Mellon University in Pennsylvania. I also completed a Fulbright Fellowship in Sustainable Power Generation in Stockholm, Sweden.

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

A. Yes. I have provided testimony at the evidentiary hearings in RIPUC Docket No. 5076 and RIPUC Docket No. 5127 and provided joint prefiled testimony regarding the Company's gas load forecast in RIPUC Docket No. 5180.

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

A. Our joint 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. We are sponsoring the following attachments with this testimony:

Attachment GLF-1	Rhode Island Energy RI Retail Volume Forecast 2022 vs. 2021 Forecast
Attachment GLF-2	Rhode Island Energy RI Retail Meter Count Forecast 2022 vs. 2021 Forecast
Attachment GLF-3	Rhode Island Energy RI Economic Forecast 2022 vs. 2021 Forecast
Attachment GLF-4	Rhode Island Energy RI Retail Volume Forecast by Rate Class 2022 vs. 2021 Forecast
Attachment GLF-5	Rhode Island Energy RI Retail Meter Count Forecast by Rate Class 2022 vs. 2021 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 2022/23 through

2026/27, dated June 30, 2022 ("Long Range Plan") that was submitted in Docket 22-06-NG. 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 current economic outlook 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 2022 Gas Forecast</u>

Q. What is the role of the 2022 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 the Company'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 2022/23 compare to the prior retail forecast for 2021/22?

A. A comparison of the Company's 2021 gas forecast of firm retail volumes for the period November 2021 through October 2022 and its current firm retail volume forecast for November 2022 through October 2023 is shown in Table 1 below.

Table 1

	2021/22 Forecasted Volume (MMBtu)	2022/23 Forecasted Volume (MMBtu)
Residential Sales	20,504,326	20,336,646
C&I Sales	7,034,186	6,572,205
Total Sales	27,538,512	26,908,851
C&I Transportation	12,546,041	12,779,289
Total	40,084,553	39,688,140

Source: Attachment GLF-1

In summary, the 2022/23 forecast shows a 1.0 percent decrease in Total Sales and Commercial and Industrial ("C&I") Transportation customer volumes over the 2021/22 forecast, with Total Sales decreasing by 2.3 percent and C&I Transportation increasing by 1.9 percent.

Attachment GLF-1 contains tables showing planning year[1] ("PY") volumes from PY 2011 through PY 2032 for the Company's current (2022) volume forecast and last year's (2021) 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 GLF-1 for visual comparison. The primary change in the forecast from 2021 to 2022 is the prolonged effects of the COVID-19 pandemic plus the economic outlook in the Residential, C&I Sales, and C&I Firm Transportation volumes. The five-year per annum growth rate in volumes (excluding Other) from PY 2022 to PY 2027 is 1.7 percent, which is lower than the 2.1 percent per annum growth rate forecasted last year for the same period.

Attachment GLF-2 contains tables from PY 2011 through PY 2032 showing the Company's current (2022) meter count forecast and last year's (2021) 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 GLF-2 for visual comparison. The primary change in the meter count forecast from 2021 to 2022 is a minor increase in the overall forecasted growth rate 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 2022 to PY

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

2027 is 1.0 percent, which is greater than the 0.9 percent per annum growth rate forecasted last year.

On a wholesale basis (see Attachment GSP-1, 'Delivery Point Volumes'), the Company forecasts sales volumes to be 28,496,000 MMBtu[2] for the period November 2022 through October 2023. Comparatively, in the Company's previous wholesale forecast for November 2021 through October 2022, as filed in Docket No. 5180, the sales volume was projected to be 29,230,000- MMBtu. Wholesale sales volume is projected to decrease 2.5 percent.

Attachment GLF-3 contains tables for calendar year economic data from 1990 through 2032 for the Company's current (2022) forecast and last year's (2021) 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 GLF-3 for visual comparison. The overall 2022 economic forecast, as compared to the 2021 economic forecast, shows higher natural gas and oil prices and higher GDP with the economic recovery from the COVID-19 pandemic.

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

Q. Have there been any changes to the forecasted sales requirements for 2022/23 as compared to the Company's Long Range Plan filed in Docket No. 22-06-NG on June 30, 2022?

A. No. There are no changes to the forecasted sales requirements for 2022/23 as compared to the Company's Long Range Plan filed on June 30, 2022 in Docket No. 22-06-NG.

Q. How has the Company accounted for the effects of weather variations in the historic data inputs to its 2022 gas forecast?

A. In preparing the 2022 gas forecast, the Company used its monthly customer billing data (volume and number of customers) for the period September 2010 through February 2022 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 a 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 2021/22 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 2021 through February 2022 and forecasted March through October 2022, actual normalized Firm Sales customers plus C&I Transportation customers totaled 40,701,100 MMBtu. In the Company's 2021 Gas Cost Recovery filing (Docket 5180), the Company's normalized forecast volume for November 2021 through October 2022 was 40,084,553 MMBtu, as set forth in Table 1, above. Actual normalized sales were 1.5 percent higher than forecast.

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 of Theodore Poe, Jr. and Shira Horowitz

Attachment GLF-1

Attachment GLF-1

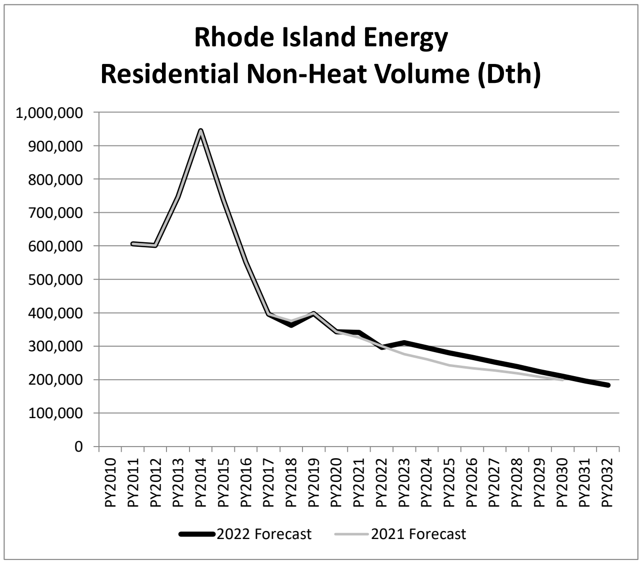
Rhode Island Energy Retail Volume Forecast 2022 vs 2021 Forecast

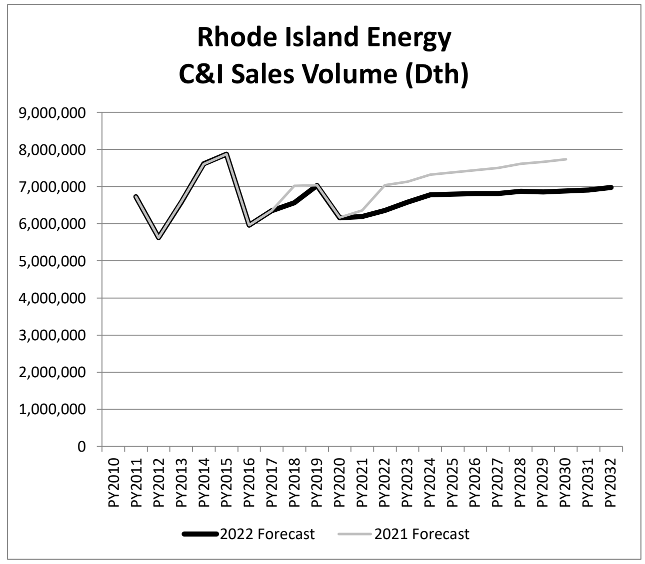
2022 Rhode Island Energy Volume Forecast (Dth) Chart III-B-1
Planning Year (Nov-Oct) Page 1 of 2

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,290	6,726,982	7,680,544	2,569,158	35,321,323	2,267,651	37,588,974
PY2012	601,399	14,783,757	5,621,831	7,610,425	2,333,884	30,951,297	2,195,914	33,147,211
PY2013	746,890	17,315,789	6,571,992	8,278,483	3,049,869	35,963,022	2,014,143	37,977,165
PY2014	944,175	19,573,872	7,610,946	8,563,673	3,548,382	40,241,047	1,795,342	42,036,389
PY2015	736,952	20,389,772	7,870,336	9,416,524	3,680,836	42,094,420	1,828,765	43,923,185
PY2016	551,336	16,675,372	5,959,482	8,656,944	3,569,930	35,413,063	1,865,144	37,278,207
PY2017	395,749	18,594,253	6,348,283	8,698,746	3,950,370	37,987,401	1,860,594	39,847,995
PY2018	362,687	18,694,105	6,556,966	8,875,527	4,024,743	38,514,028	1,942,194	40,456,222
PY2019	397,686	20,371,781	7,022,556	8,768,245	4,462,606	41,022,875	2,011,798	43,034,673
PY2020	343,088	19,176,946	6,157,256	8,212,992	4,303,418	38,193,700	2,068,653	40,262,352
PY2021	341,808	18,757,551	6,195,869	8,278,086	4,267,481	37,840,794	1,994,377	39,835,170
PY2022	296,073	18,672,736	6,355,910	8,222,207	4,179,500	37,726,427	1,942,020	39,668,447
PY2023	310,797	20,025,849	6,572,205	8,385,242	4,394,047	39,688,142	1,997,522	41,685,664
PY2024	295,980	20,444,274	6,776,015	8,506,662	4,464,857	40,487,788	2,016,215	42,504,003
PY2025	280,310	20,564,640	6,798,457	8,515,508	4,461,983	40,620,898	2,017,669	42,638,566
PY2026	266,198	20,807,911	6,808,711	8,528,716	4,467,870	40,879,406	2,020,862	42,900,268
PY2027	252,250	21,040,524	6,809,029	8,537,191	4,468,498	41,107,492	2,022,697	43,130,189
PY2028	239,356	21,417,131	6,864,548	8,567,158	4,498,441	41,586,633	2,030,814	43,617,448
PY2029	224,245	21,517,576	6,852,017	8,568,672	4,492,608	41,655,117	2,030,940	43,686,057
PY2030	210,247	21,758,893	6,878,647	8,586,651	4,507,929	41,942,367	2,035,754	43,978,121
PY2031	196,422	21,997,053	6,903,882	8,604,393	4,522,553	42,224,303	2,040,484	44,264,787
PY2032	183,591	22,376,858	6,969,029	8,640,009	4,558,932	42,728,419	2,050,259	44,778,678
PY27/PY22	-3.2%	2.4%	1.4%	0.8%	1.3%	1.7%	0.8%	1.7%

2021 Rhode Island Energy Volume Forecast (Dth)
Planning Year (Nov-Oct)

	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	606,350	17,738,289	6,726,982	7,680,544	2,569,158	35,321,323	2,267,651	37,588,973
PY2012	601,399	14,783,757	5,621,832	7,610,425	2,333,884	30,951,297	2,195,914	33,147,211
PY2013	746,890	17,315,788	6,583,721	8,278,483	3,049,869	35,974,752	2,014,144	37,988,895
PY2014	944,174	19,573,872	7,599,237	8,563,673	3,548,382	40,229,338	1,793,702	42,023,040
PY2015	736,952	20,389,772	7,870,336	9,416,525	3,680,836	42,094,420	1,828,764	43,923,185
PY2016	551,336	16,675,372	5,959,428	8,656,943	3,569,930	35,413,008	1,865,144	37,278,152
PY2017	395,749	18,594,274	6,348,282	8,698,747	3,950,370	37,987,422	1,860,594	39,848,016
PY2018	375,502	19,943,709	7,021,050	9,022,578	4,205,501	40,568,340	1,938,339	42,506,679
PY2019	397,877	20,381,718	7,033,149	8,768,235	4,469,173	41,050,152	2,012,027	43,062,179
PY2020	343,560	19,204,168	6,161,983	8,208,510	4,313,144	38,231,365	2,067,717	40,299,082
PY2021	325,747	18,874,655	6,358,826	7,907,310	4,334,777	37,801,316	2,045,839	39,847,155
PY2022	300,785	20,203,541	7,034,186	7,779,116	4,766,925	40,084,553	2,459,542	42,544,095
PY2023	276,392	20,488,801	7,126,983	8,050,746	4,832,976	40,775,897	2,499,722	43,275,619
PY2024	260,581	20,878,142	7,319,546	8,134,775	4,898,558	41,491,601	2,511,128	44,002,729
PY2025	242,867	21,008,058	7,382,548	8,080,974	4,908,508	41,622,955	2,495,241	44,118,195
PY2026	233,703	21,239,154	7,443,635	8,034,205	4,934,251	41,884,947	2,482,684	44,367,632
PY2027	226,965	21,467,738	7,503,053	7,989,121	4,959,688	42,146,566	2,470,607	44,617,173
PY2028	218,461	21,828,142	7,607,716	7,958,767	5,010,890	42,623,977	2,463,942	45,087,919
PY2029	208,599	21,934,358	7,656,121	7,914,767	5,031,032	42,744,877	2,451,954	45,196,830
PY2030	198,661	22,170,600	7,736,384	7,885,606	5,070,235	43,061,486	2,445,121	45,506,607
PY2031	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2032	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY27/PY22	-5.5%	1.2%	1.3%	0.5%	0.8%	1.0%	0.1%	1.0%


Rhode Island Energy
Residential Non-Heat Volume (Dth)
1,000,000
900,000
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026 PY2027 PY2028 PY2029 PY2030 PY2031 PY2032
2022 Forecast
2021 Forecast


Rhode Island Energy
C&I Sales Volume (Dth)
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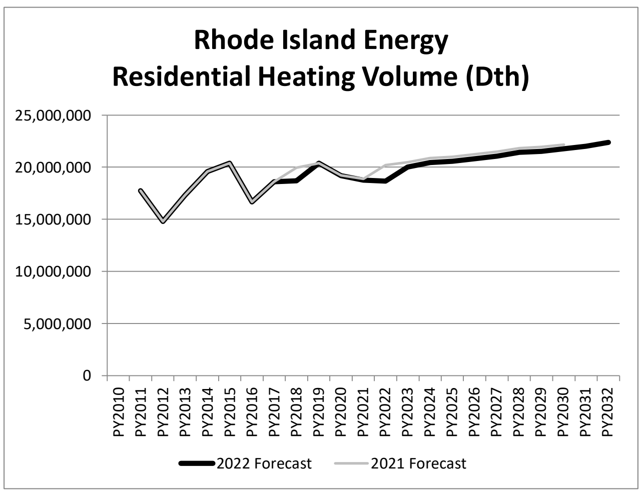
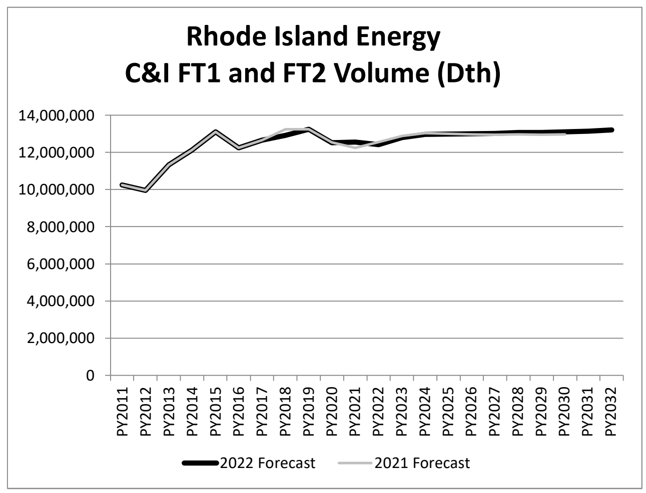
8,000,000
7,000,000
6,000,000
5,000,000
4,000,000
3,000,000
2,000,000
1,000,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026 PY2027 PY2028 PY2029 PY2030 PY2031 PY2032
2022 Forecast
2021 Forecast


Rhode Island Energy
Residential Heating Volume (Dth)
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
PY2010 PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026 PY2027 PY2028 PY2029 PY2030 PY2031 PY2032
2022 Forecast
2021 Forecast


Rhode Island Energy
C&I FT1 and FT2 Volume (Dth)
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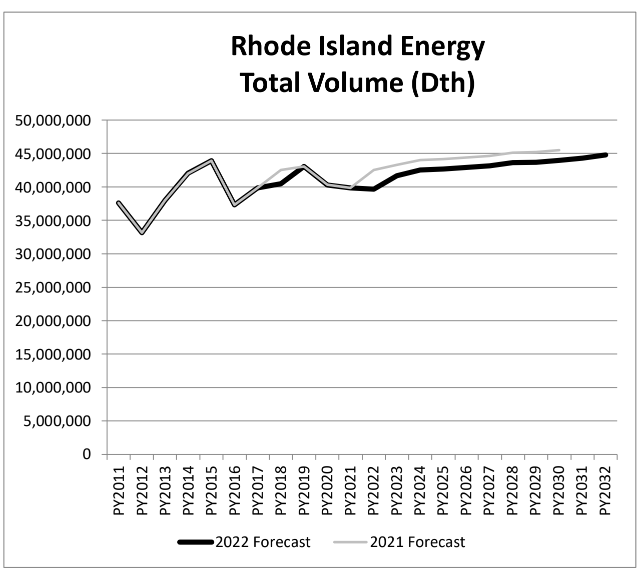
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026 PY2027 PY2028 PY2029 PY2030 PY2031 PY2032
2022 Forecast
2021 Forecast


Rhode Island Energy
Total Volume (Dth)
50,000,000
45,000,000
40,000,000
35,000,000
30,000,000
25,000,000
20,000,000
15,000,000
10,000,000
5,000,000
0
PY2011 PY2012 PY2013 PY2014 PY2015 PY2016 PY2017 PY2018 PY2019 PY2020 PY2021 PY2022 PY2023 PY2024 PY2025 PY2026 PY2027 PY2028 PY2029 PY2030 PY2031 PY2032
2022 Forecast
2021 Forecast

Attachment GLF-2

Attachment GLF-2

Rhode Island Energy Retail Meter Count Forecast 2022 vs 2021 Forecast

2022 Rhode Island Energy Meter Count Forecast
End of Planning Year (Nov-Oct)

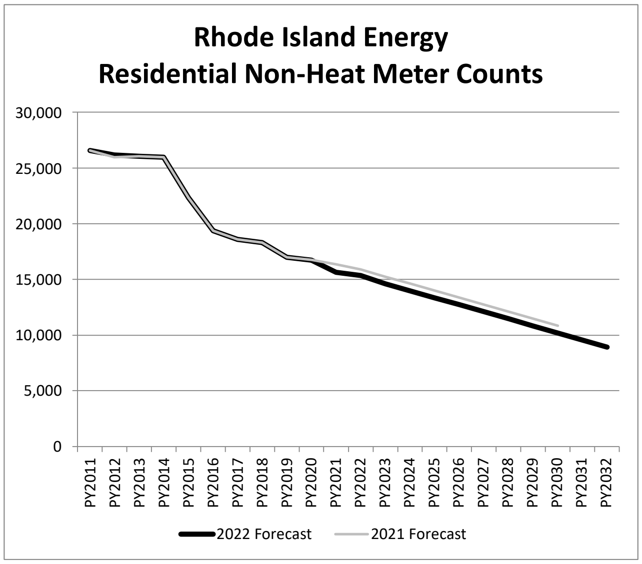
Chart III-B-2
Page 1 of 2

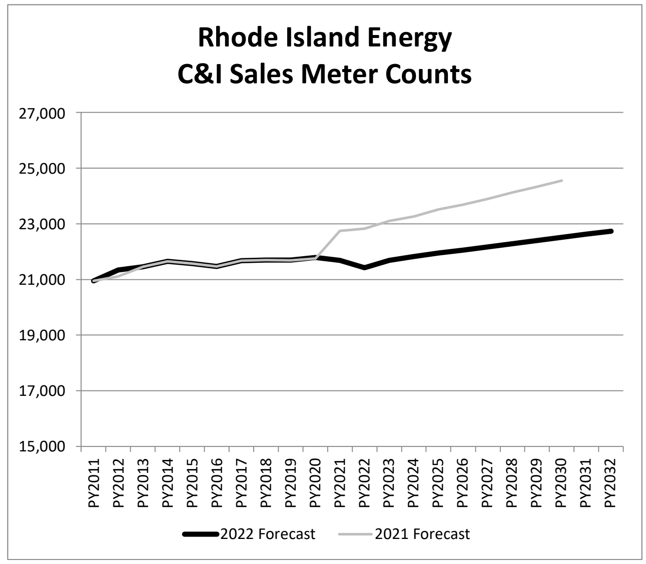
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,950	747	1,244	*245,925*	54	*245,979*
PY2012	26,165	202,192	21,338	744	1,413	*251,852*	69	*251,921*
PY2013	26,042	204,521	21,451	721	1,499	*254,234*	159	*254,393*
PY2014	25,958	206,568	21,651	699	1,486	*256,362*	178	*256,540*
PY2015	22,313	212,900	21,567	684	1,552	*259,016*	326	*259,342*
PY2016	19,351	218,314	21,467	674	1,680	*261,486*	488	*261,974*
PY2017	18,591	222,124	21,670	636	1,758	*264,779*	577	*265,356*
PY2018	18,298	225,211	21,694	624	1,776	*267,603*	637	*268,240*
PY2019	16,977	228,476	21,691	609	1,865	*269,618*	812	*270,430*
PY2020	16,729	230,436	21,786	595	1,828	*271,374*	870	*272,244*
PY2021	15,623	230,913	21,689	586	1,821	*270,632*	835	*271,467*
PY2022	15,340	231,149	21,417	564	1,730	*270,200*	768	*270,968*
PY2023	14,600	234,761	21,688	573	1,752	*273,374*	777	*274,151*
PY2024	13,966	237,936	21,826	576	1,762	*276,066*	782	*276,848*
PY2025	13,339	241,012	21,951	579	1,771	*278,652*	786	*279,438*
PY2026	12,725	243,953	22,055	580	1,779	*281,092*	790	*281,882*
PY2027	12,100	246,808	22,168	583	1,787	*283,446*	794	*284,240*
PY2028	11,468	249,641	22,285	584	1,797	*285,775*	798	*286,573*
PY2029	10,825	252,468	22,405	588	1,806	*288,092*	802	*288,894*
PY2030	10,185	255,280	22,518	591	1,814	*290,388*	806	*291,194*
PY2031	9,545	258,031	22,627	594	1,822	*292,619*	809	*293,428*
PY2032	8,904	260,744	22,733	597	1,832	*294,810*	813	*295,623*
PY27/PY22	-4.6%	1.3%	0.7%	0.7%	0.7%	1.0%	0.7%	1.0%

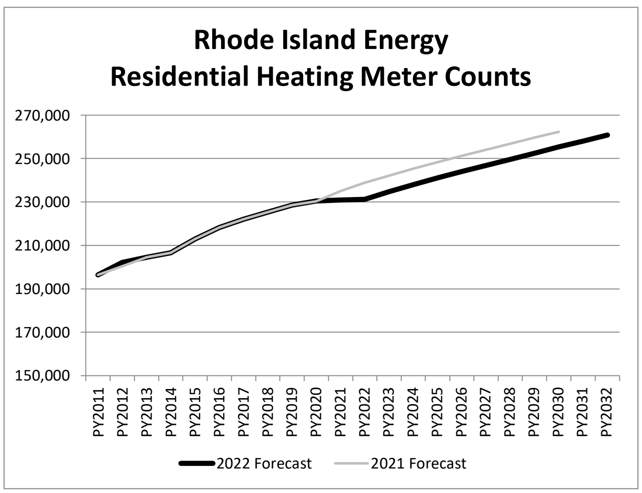
2021 Rhode Island Energy Meter Count Forecast
End of Planning Year (Nov-Oct)

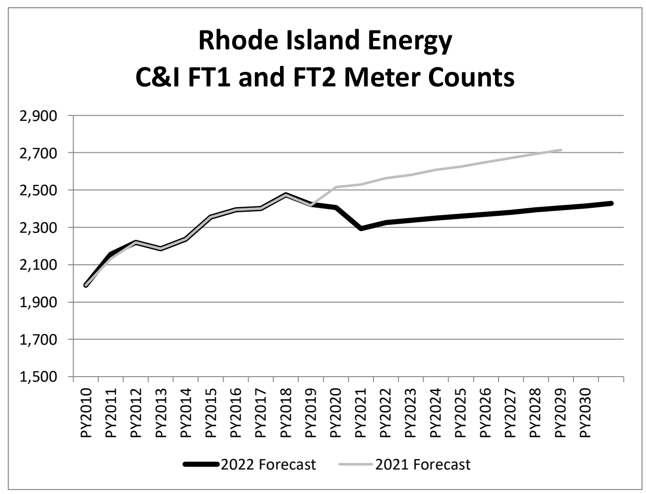
	RNH	RH	CI_Sales	FT1	FT2	Subtotal	Other	Total
PY2011	26,570	196,414	20,950	747	1,244	245,925	54	245,979
PY2012	25,955	200,463	21,105	734	1,399	249,656	65	249,721
PY2013	26,042	204,521	21,451	721	1,499	254,234	159	254,393
PY2014	25,958	206,568	21,651	699	1,486	256,362	178	256,540
PY2015	22,313	212,900	21,567	684	1,552	259,016	326	259,342
PY2016	19,351	218,314	21,467	674	1,680	261,486	488	261,974
PY2017	18,591	222,124	21,670	636	1,758	264,779	577	265,356
PY2018	18,299	225,211	21,693	624	1,776	267,603	637	268,240
PY2019	16,978	228,468	21,685	609	1,865	269,605	812	270,417
PY2020	16,750	230,384	21,757	595	1,823	271,309	870	272,179
PY2021	16,329	235,062	22,745	614	1,902	276,652	876	277,528
PY2022	15,883	238,872	22,826	619	1,911	280,111	880	280,991
PY2023	15,215	242,148	23,110	628	1,935	283,036	891	283,927
PY2024	14,617	245,378	23,268	634	1,947	285,844	896	286,740
PY2025	13,996	248,385	23,513	640	1,967	288,501	905	289,406
PY2026	13,372	251,226	23,689	645	1,981	290,913	912	291,825
PY2027	12,738	254,023	23,900	650	1,998	293,309	920	294,229
PY2028	12,105	256,778	24,132	655	2,017	295,687	928	296,615
PY2029	11,476	259,550	24,342	660	2,034	298,062	936	298,998
PY2030	10,852	262,321	24,556	664	2,050	300,443	944	301,387
PY2031	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY2032	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY27/PY22	-4.3%	1.2%	0.9%	1.0%	0.9%	0.9%	0.9%	0.9%

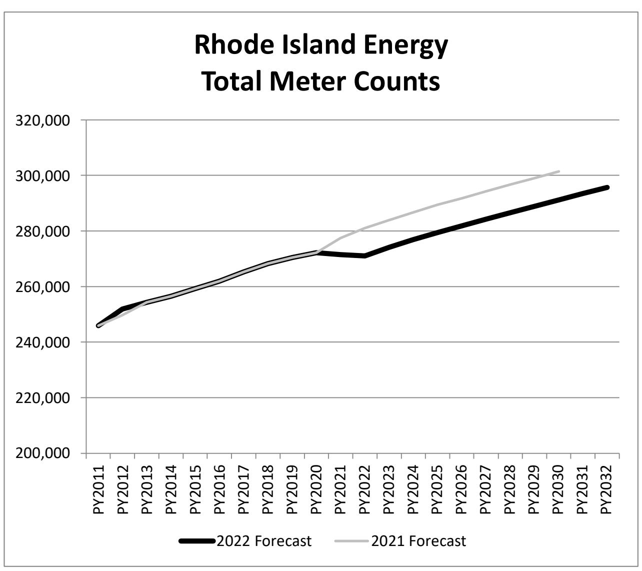
Chart III-B-2
Page 2 of 2











Attachment GLF-3

Attachment GLF-3

Rhode Island Energy Economic Forecast 2022 vs 2021 Forecast

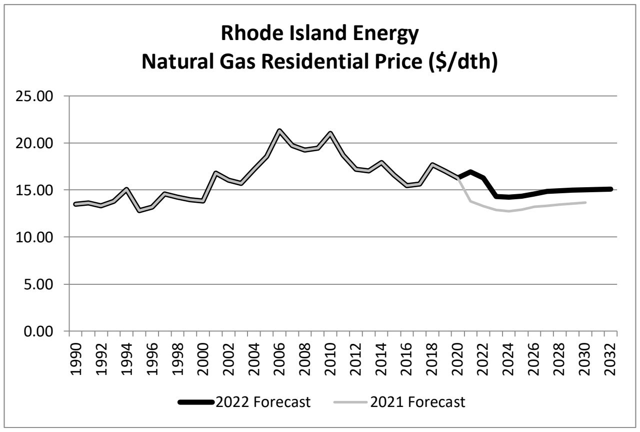
2022 Rhode Island Energy Economic Data
(Prices in 2022 $/Dth)

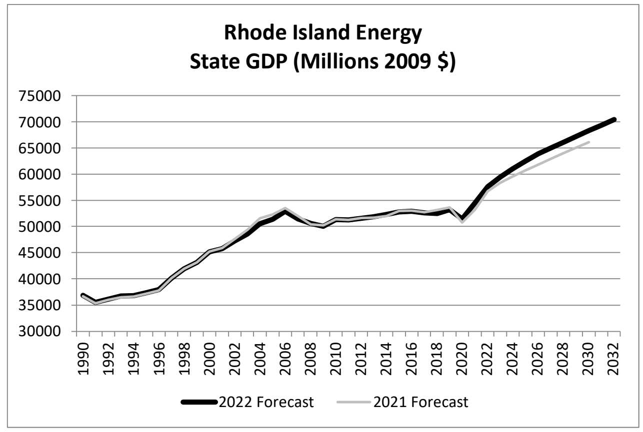
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR* *Residential Gas-to-Oil Price Ratio*	GDP GDP (2009 Millions of $)	HH Households (thousands)	EMPL Non-Farm Employment (thousands)
1990	*13.50*	16.41	*0.82*	36853	377	457
1991	*13.62*	14.97	*0.91*	35521	381	427
1992	*13.33*	13.13	*1.01*	36136	384	427
1993	*13.77*	12.58	*1.09*	36705	387	432
1994	*15.06*	11.91	*1.26*	36774	391	436
1995	*12.79*	11.58	*1.11*	37358	395	441
1996	*13.18*	12.63	*1.04*	37946	401	443
1997	*14.58*	12.58	*1.16*	40140	405	452
1998	*14.24*	10.89	*1.31*	41910	411	460
1999	*13.96*	10.17	*1.37*	43141	411	468
2000	*13.82*	14.50	*0.95*	45177	410	480
2001	*16.81*	14.16	*1.19*	45748	407	481
2002	*16.03*	12.55	*1.28*	47221	410	482
2003	*15.68*	14.97	*1.05*	48567	411	487
2004	*17.18*	15.86	*1.08*	50512	412	491
2005	*18.56*	20.23	*0.92*	51367	411	494
2006	*21.29*	23.78	*0.90*	52899	411	496
2007	*19.70*	24.80	*0.79*	51473	412	495
2008	*19.25*	31.05	*0.62*	50576	414	484
2009	*19.45*	21.90	*0.89*	50004	414	463
2010	21.00	26.76	*0.78*	51330	415	462
2011	18.69	33.15	*0.56*	51280	417	464
2012	17.20	35.29	*0.49*	51582	421	469
2013	17.05	34.67	*0.49*	51910	425	475
2014	17.89	33.40	*0.54*	52292	428	482
2015	16.56	23.33	*0.71*	52818	428	489
2016	15.48	18.52	*0.84*	52903	428	494
2017	15.63	21.35	*0.73*	52610	426	497
2018	17.69	23.64	*0.75*	52492	426	501
2019	16.99	22.67	*0.75*	53227	429	504
2020	16.29	17.90	*0.91*	51415	427	462
2021	16.94	22.02	*0.77*	54509	429	480
2022	16.29	31.54	*0.52*	57593	431	493
2023	14.29	29.77	*0.48*	59430	434	500
2024	14.22	31.65	*0.45*	61045	436	503
2025	14.34	32.41	*0.44*	62516	437	504
2026	14.58	33.23	*0.44*	63863	437	504
2027	14.86	34.23	*0.43*	64988	438	504
2028	14.92	34.61	*0.43*	66070	438	505
2029	14.98	34.88	*0.43*	67194	438	505
2030	15.03	34.90	*0.43*	68265	439	505
2031	15.08	35.33	*0.43*	69333	439	505
2032	15.09	35.49	*0.43*	70439	439	505
PY27/PY22	-1.8%	1.7%	-3.4%	2.4%	0.3%	0.4%

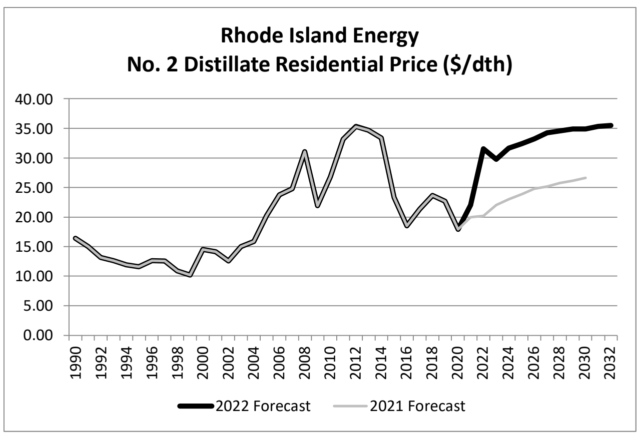
2021 Rhode Island Energy Economic Data
(Prices in 2021 $/Dth)

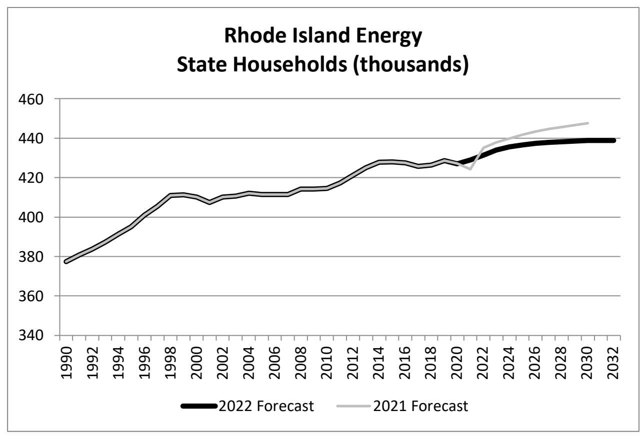
Chart III-B-3
Page 2 of 3

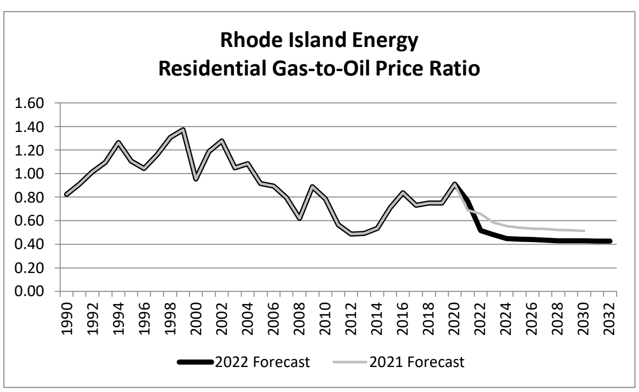
Year	NGPRCR Natural Gas Residential Price	OILPRCR No 2 Distillate Residential Price by All Sellers	*GORR*	GDP (2005 Millions of $)	Households (thousands)	Non-Farm Employment (thousands)
1990	13.50	16.41	0.82	36680	377	457
1991	13.62	14.97	0.91	35355	381	427
1992	13.33	13.13	1.01	35967	384	427
1993	13.77	12.58	1.09	36534	387	432
1994	15.06	11.91	1.26	36605	391	436
1995	12.79	11.58	1.11	37187	395	441
1996	13.18	12.63	1.04	37773	401	443
1997	14.58	12.58	1.16	40135	405	452
1998	14.24	10.89	1.31	41918	411	460
1999	13.96	10.17	1.37	43157	411	468
2000	13.82	14.50	0.95	45250	410	480
2001	16.81	14.16	1.19	45903	407	481
2002	16.03	12.55	1.28	47581	410	482
2003	15.68	14.97	1.05	49344	411	487
2004	17.18	15.86	1.08	51552	412	491
2005	18.56	20.23	0.92	52284	411	494
2006	21.29	23.78	0.90	53492	411	496
2007	19.70	24.80	0.79	51999	412	495
2008	19.25	31.05	0.62	50413	414	484
2009	19.45	21.90	0.89	50216	414	463
2010	21.00	26.76	0.78	51363	415	462
2011	18.69	33.15	0.56	51263	417	464
2012	17.20	35.29	0.49	51607	421	469
2013	17.05	34.67	0.49	51679	425	475
2014	17.89	33.40	0.54	52004	428	482
2015	16.56	23.33	0.71	52956	428	489
2016	15.48	18.52	0.84	53031	428	494
2017	15.63	21.35	0.73	52728	426	497
2018	17.69	23.64	0.75	53133	426	500
2019	16.99	22.67	0.75	53671	429	504
2020	16.29	17.90	0.91	50796	427	465
2021	13.79	19.99	0.69	53216	424	476
2022	13.28	20.19	0.66	56770	435	490
2023	12.86	22.03	0.58	58328	438	498
2024	12.73	23.01	0.55	59566	440	502
2025	12.91	23.87	0.54	60747	442	504
2026	13.21	24.77	0.53	61800	443	506
2027	13.32	25.17	0.53	62899	445	507
2028	13.45	25.76	0.52	63982	446	509
2029	13.56	26.11	0.52	65056	447	510
2030	13.65	26.63	0.51	66078	448	512
2031	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
2032	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
PY27/PY22	0.0%	4.5%	-4.3%	2.1%	0.4%	0.7%

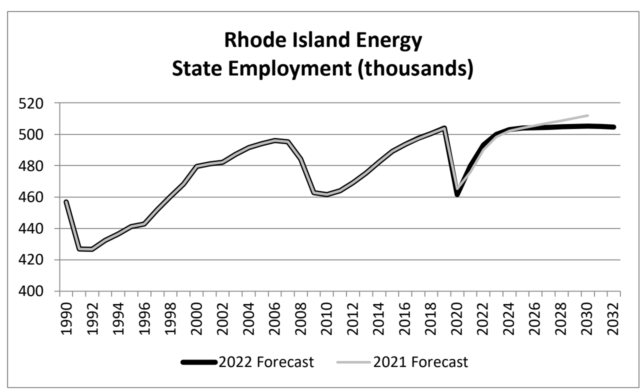

Rhode Island Energy
Natural Gas Residential Price ($/dth)
2022 Forecast
2021 Forecast


Rhode Island Energy
State GDP (Millions 2009 $)
2022 Forecast
2021 Forecast


Rhode Island Energy
No. 2 Distillate Residential Price ($/dth)
2022 Forecast
2021 Forecast


Rhode Island Energy
State Households (thousands)
2022 Forecast
2021 Forecast


Rhode Island Energy
Residential Gas-to-Oil Price Ratio
2022 Forecast
2021 Forecast


Rhode Island Energy
State Employment (thousands)
2022 Forecast
2021 Forecast

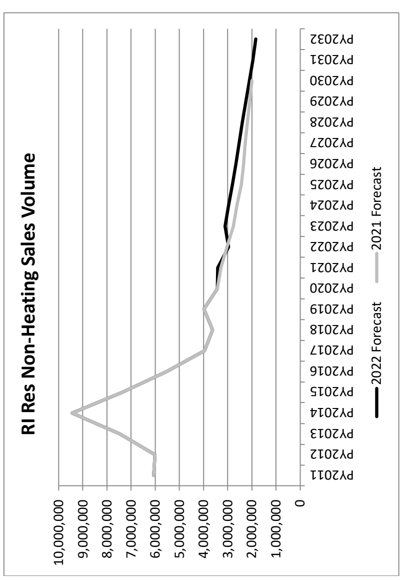
Attachment GLF-4

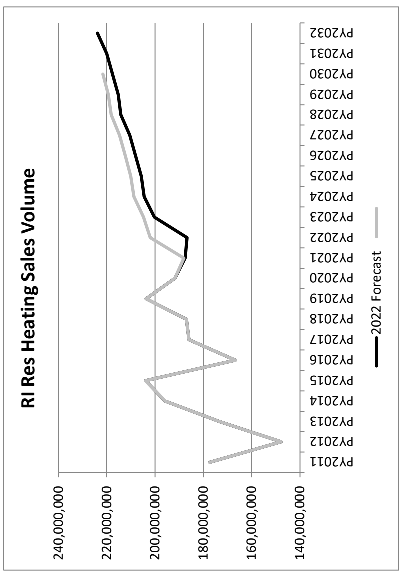
Attachment GLF-4

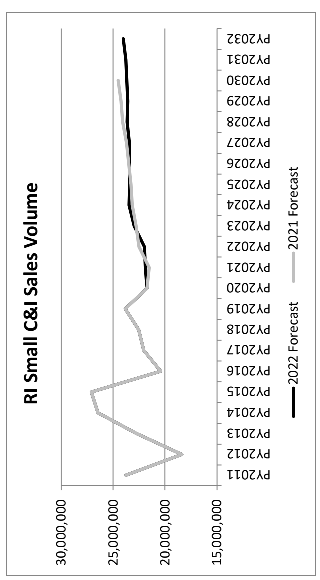
Rhode Island Energy Retail Volume Forecast by Rate Class 2022 vs 2021 Forecast

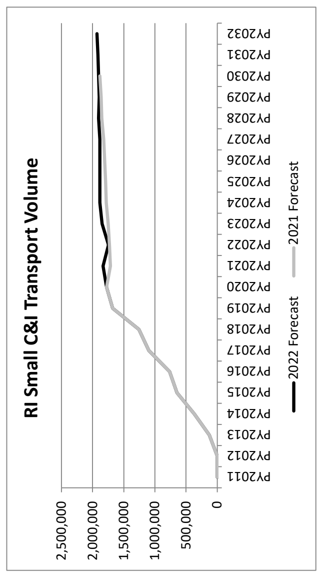
Chart III-B-4
Page 1 of 3

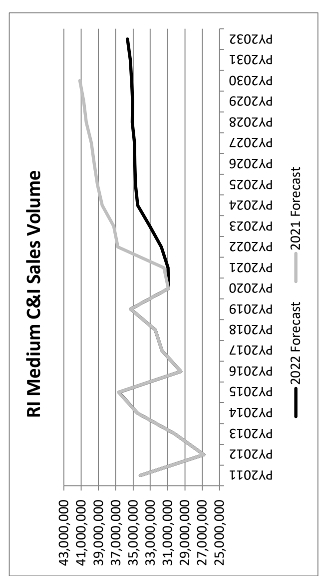
Rhode Island Energy
2022 and 2021 Volume Forecasts by Rate Class
(Therms; Planning Year)

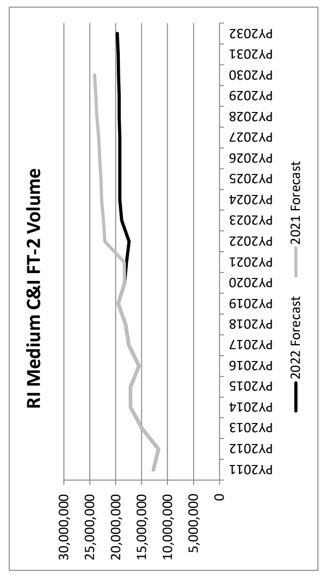


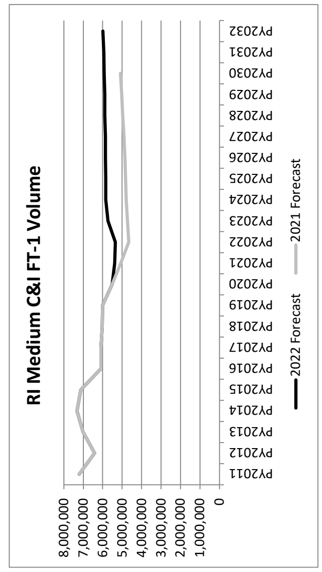




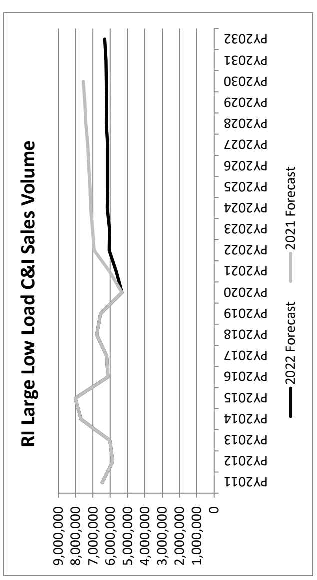


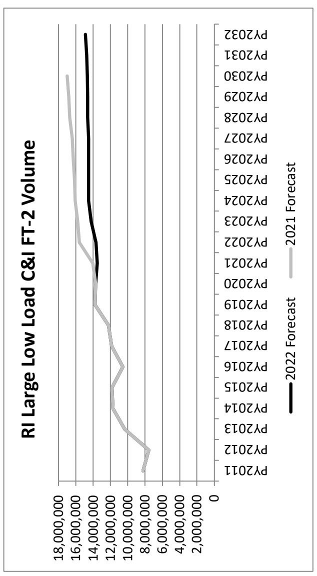


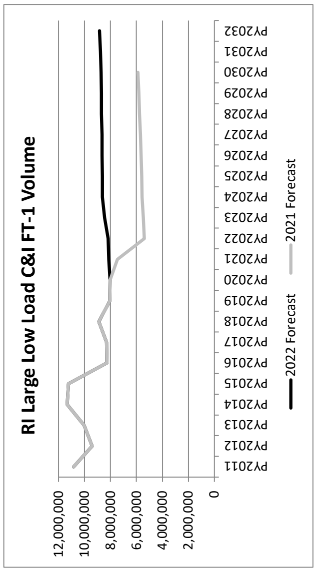


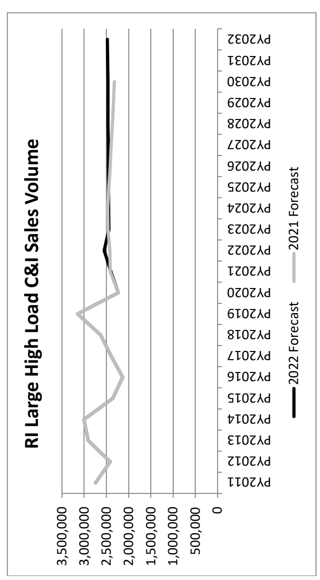


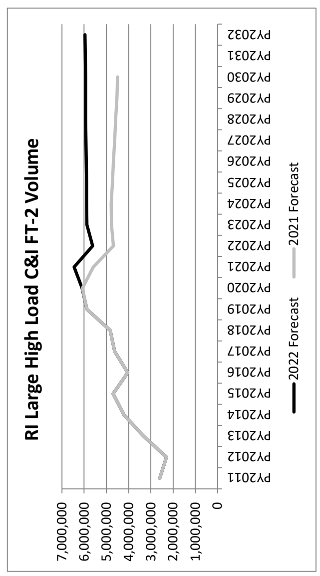
Rhode Island Energy
2022 and 2021 Volume Forecasts by Rate Class
(Therms; Planning Year)

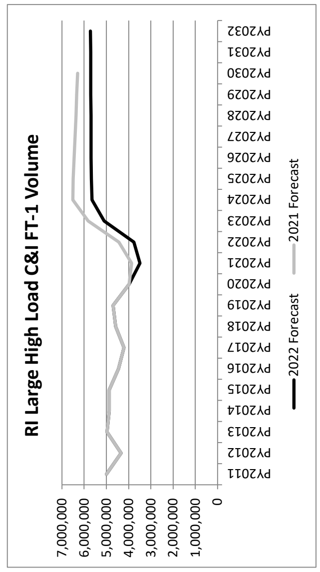


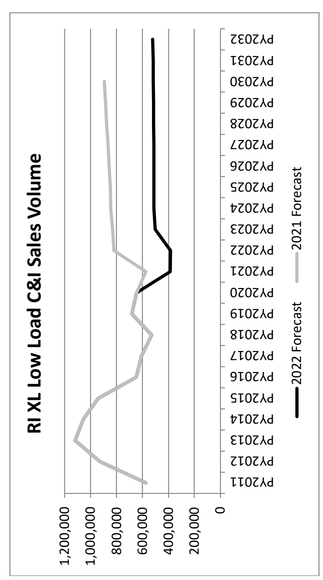


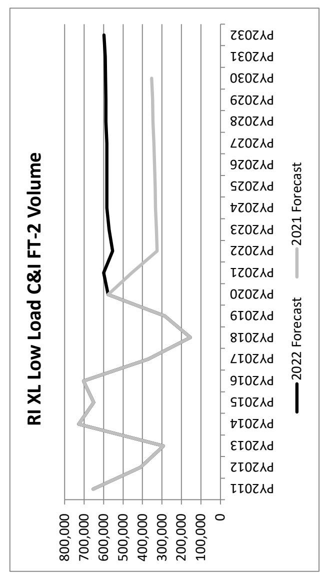


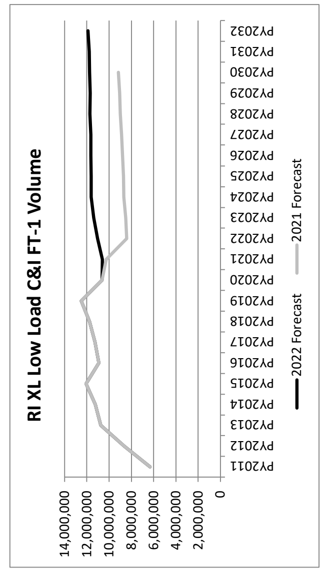




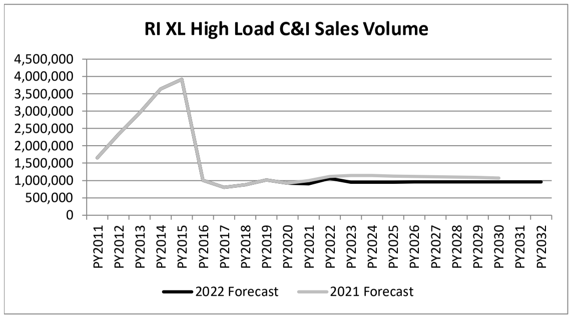


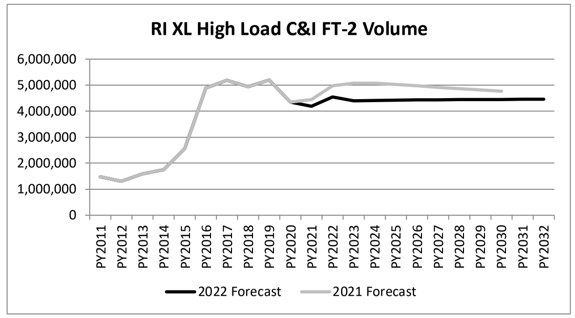


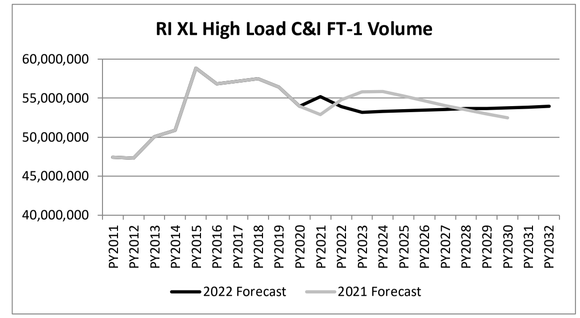


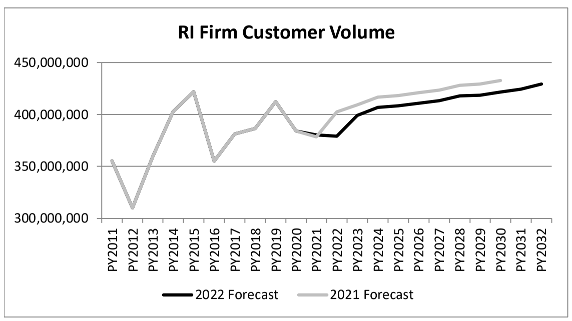


Rhode Island Energy
2022 and 2021 Volume Forecasts by Rate Class
(Therms; Planning Year)







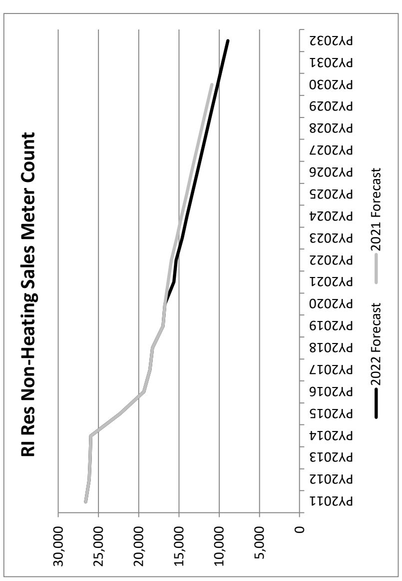


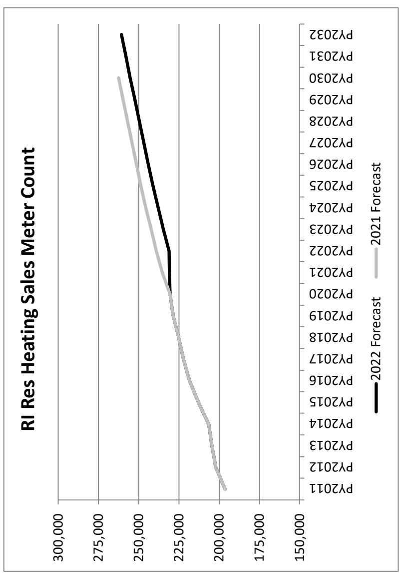
Attachment GLF-5

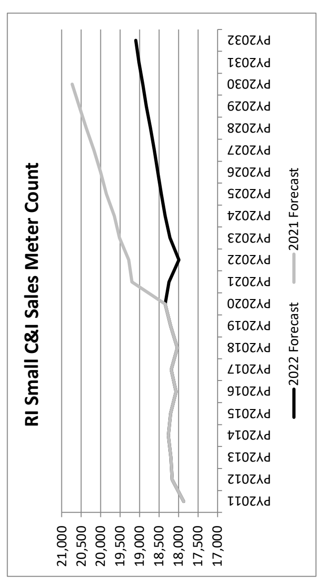
Attachment GLF-5

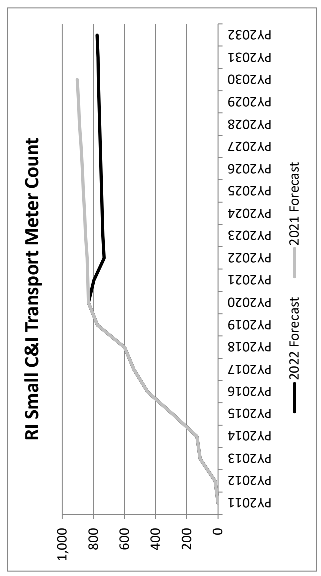
Rhode Island Energy Retail Meter Count Forecast by Rate Class 2022 vs 2021 Forecast

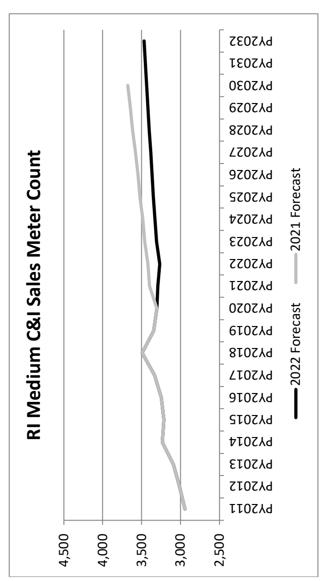
Rhode Island Energy
2022 and 2021 Meter Count Forecasts by Rate Class
(end of Planning Year)

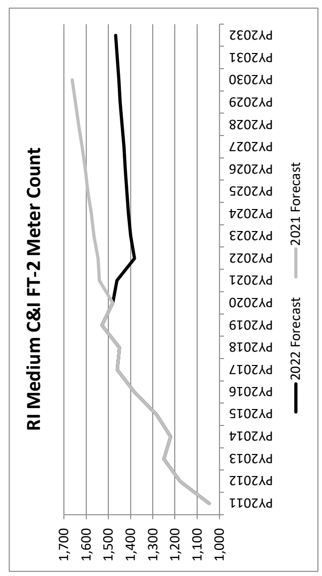


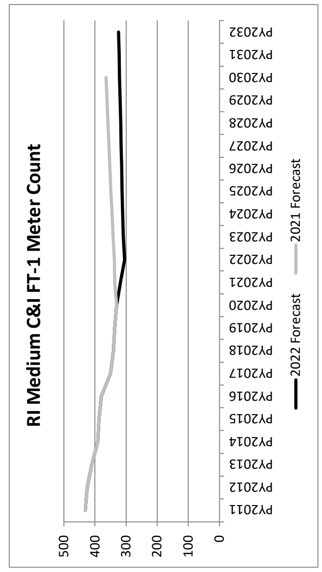




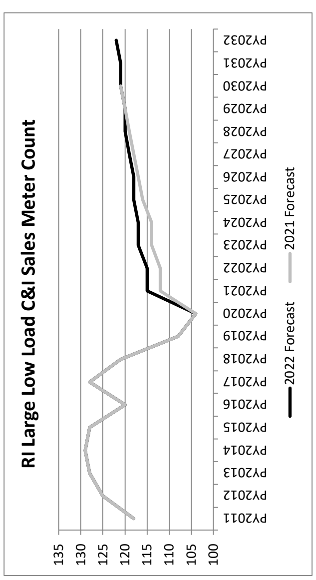


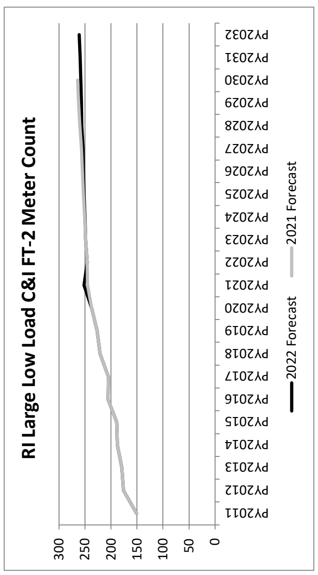


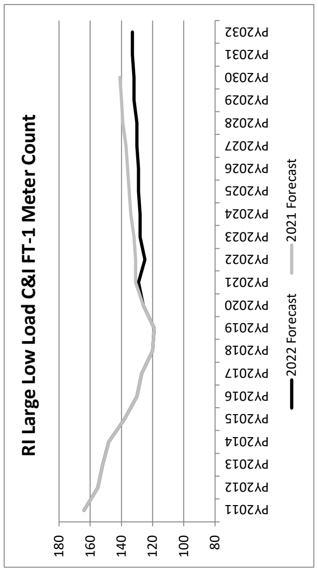


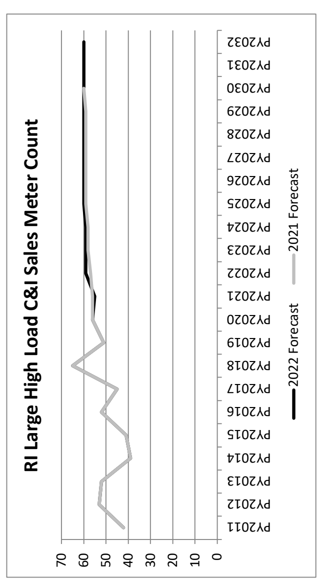


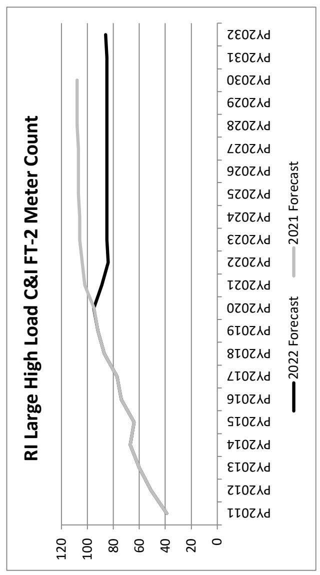
Rhode Island Energy
2022 and 2021 Meter Count Forecasts by Rate Class
(end of Planning Year)

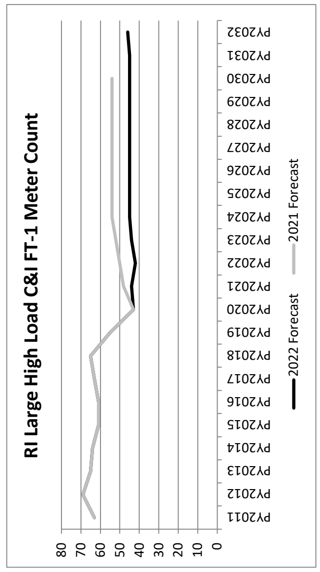


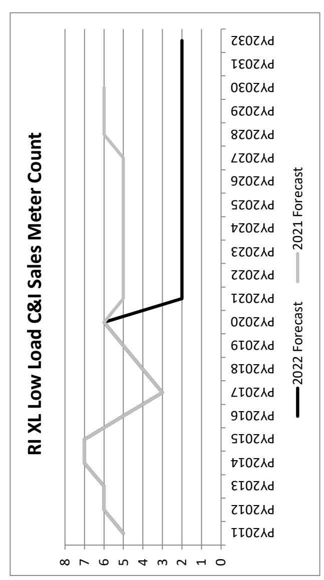


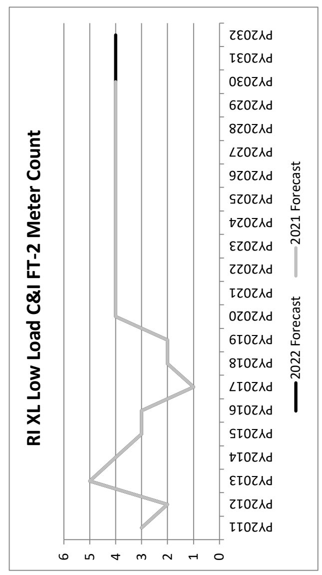


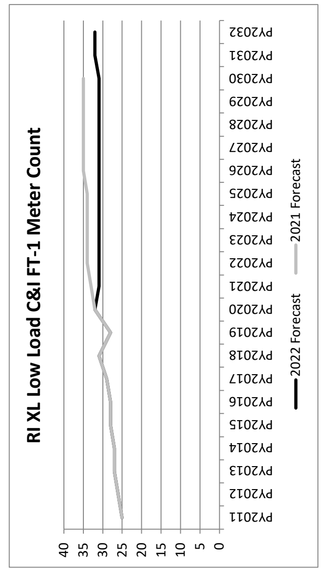












Rhode Island Energy
2022 and 2021 Meter Count Forecasts by Rate Class
(end of Planning Year)