STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID GAS COST RECOVERY CHARGE : DOCKET NO. 4963

REPORT AND ORDER

I. Introduction

On September 3, 2019, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) submitted its Gas Cost Recovery (GCR) filing to the Public Utilities Commission (PUC or Commission).[1] The GCR is an annual filing that allows National Grid to annually adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity. The GCR allows the Company to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, and purchased gas working capital. The GCR proceeding also permits the Company to account for supplier refund credits, capacity credits from off-system sales, and revenues from capacity release transactions.[2] The new GCR rates are effective each year on November 1. The filing proposed a total annual bill decrease of approximately $147.58 for a typical residential heating customer using the equivalent of 845 therms per year.[3]

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[1] All filings in this docket are available at the Commission offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at http://www.ripuc.org/eventsactions/docket/4963page.html.
[2] The Narragansett Electric Company d/b/a/ National Grid R.I.P.U.C NG-GAS No 101, Section 2 Gas Charge, Sch. A, Sheet 1, Ninth Rev.(Sept. 1, 2018); https://www.nationalgridus.com/media/pdfs/billing-payments/rigas_tariff.pdf.
[3] The total monthly bill decrease of $147.58 is comprised of a decrease of $146.95 in the GCR-related factors; an increase of $3.80 on the Distribution Adjustment Charge related factors filed on August 1, 2019 and supplemented under separate cover in Docket No. 4955; and a decrease of $4.43 in the Gross Earnings Tax.

On October 4, 2019, the Division of Public Utilities and Carriers (Division) submitted testimony from its consultant, Jerome D. Mierzwa. On October 21, 2019, pursuant to the Company's effective gas tariff, RIPUC NG-GAS No. 101, Section 1, Schedule B, Sheet 1 (definition of British thermal unit (BTU) content factor), the Company filed its semi-annual BTU factor report[4] which proposed a BTU content factor of 1.030 for the period of November 1, 2019 through April 30, 2020.[5]

On October 22, 2019, the Commission conducted a hearing to examine the appropriateness of the Company's petition. At an Open Meeting on October 25, 2019, the approved the 2020 Gas Cost Recovery factors and the BTU factor as filed.

II. National Grid's September 3, 2019 Filing

Pursuant to the tariff, the GCR filing contains all costs of firm gas, including, but not limited to, commodity costs, demand charges, hedging and hedging related costs, local production and storage costs and other gas supply expense incurred to procure and transport supplies, transportation fees, inventory finance costs, requirements for purchased gas working capital, all applicable credits, taxes, and deferred gas costs.[6] The tariff requires that the Company calculate the gas charges separately for Sales Customers (a high load rate group and a low load rate group) and Firm Transportation (FT) Customers (marketers). The gas charges to Sales Customers consist of two components; fixed costs and variable

[4] National Grid's currently effective gas tariff, RIPUC NG-GAS No. 101, Section 1, Schedule B, Sheet 1 (definition of British thermal unit (BTU) content factor) requires National Grid to calculate the seasonal BTU content based upon the prior six-month experience for the equivalent season, which National Grid would then propose to take effect for the applicable May 1 and November 1. Such BTU content factors are used to convert volumetric meter readings into therms; Letter of Leticia Pimental (Oct. 21, 2019); http://www.ripuc.org/eventsactions/docket/4963-NGrid-BTUFactor%20(Period%2011-1-18%20to%204-30-19)(10-21-19).pdf.
[5] *Id*.
[6] The Narragansett Electric Company d/b/a/ National Grid R.I.P.U.C NG-GAS No 101, Section 2 Gas Charge, Sch. A, Sheet 1, Ninth Rev. (Sept. 1, 2018).

costs. The cost calculation includes an adjustment for an uncollectible percentage of 1.91% as approved in Docket No. 4770. These charges are subject to the Rhode Island Gross Earnings Tax, as set forth in Section 1, Schedule C of the gas tariff.

In support of its filing, National Grid submitted the prefiled testimonies of Elizabeth D. Arangio, the Director of Gas Supply Planning for the Service Company; Samara Jaffe, Lead Program Manager of Gas Contracting, Compliance, and Hedging;[7] Ann E. Leary, Manager of New England Gas Pricing for the Service Company, Michael J. Pini, Lead Program Manager, New England Pricing Department;[8] Theodore E. Poe, Jr., Principal Gas Regulatory Specialist for the Service Company; and John M. Protano, Manager of Origination and Price Volatility Management in the Energy Procurement organization of the Service Company.[9]

III. National Grid's Prefiled Testimony

A. Elizabeth D. Arangio and Samara A. Jaffe- Joint Testimony

1. Consumption projections

The Arangio/Jaffe testimony provided support for the estimated gas costs, assignment of pipeline capacity to marketers, other issues relating to the Company's proposed 2019-2020 factors, and modifications made to National Grid's portfolio for the 2019-2020 GCR period.[10] The witnesses explained that the proposed GCR factors are based on the New York Mercantile Exchange (NYMEX) strip as of the close of trading on

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[7] Ms. Arangio's testimony and Ms. Jaffe's testimony were submitted as joint testimony and shall be referred to as Arangio/Jaffe testimony.
[8] Ms. Leary and Mr. Pini's testimony were submitted as joint testimony and shall be referred to as Leary/Pini testimony.
[9] Joint Test. of Elizabeth D. Arangio, Samara A. Jaffe, Michael J. Pini, Ann E. Leary, Theodore E. Poe, Jr. (Sept. 3, 2019); http://www.ripuc.ri.gov/eventsactions/docket/4963-NGrid_GCR_Book_1.pdf; Test. of John Protano (Sept. 3, 2019); http://www.ripuc.ri.gov/eventsactions/docket/4963-NGrid_GCR_Book_2.pdf.
[10] Arangio/Jaffe Direct Test. at 5 (Sept. 3, 2019).

August 1, 2019. The GCR factors also reflect storage and inventory costs as of July 1, 2019, as well as the projected cost of purchasing gas through the remainder of the injection season as provided for in the Natural Gas Portfolio Management Plan (NGPMP).[11] They reported that overall, the August 2, 2019 NYMEX strip is an average of $0.453 or 15.3% lower compared to the August 2, 2018 NYMEX strip.[12]

The Arangio/Jaffe testimony asserted that the Company had planned for and contracted for the forecasted volume of 388,746 decatherms (Dth) to meet design day load requirements for November 2019 through October 2020, a decrease of 1,481 Dth or 0.4% from last year.[13] To meet design heating season load requirements for November 2019 through October 2020, the Company had planned for and contracted the forecasted volume of 29,822,626 Dth which was an increase of 0.5% over the 2018-2019 projected design heating season. The design year load (sales and transportation) requirement for November 2019 through October 2020 was a projected volume of 41,409,931 Dth, a decrease in design year load requirements over the 2018-2019 year, of 0.3%.[14]

The consumption projections also included the results of a cold snap analysis which was presented on the Company's Long-Range Resource and Requirements Plan (LRP) for the forecast period 2019-2020 to 2023-2024, as filed with the Division.

On January 29, 2019, Algonquin Gas Transmission LLC notified the Company that it may limit hourly takes to calculated hourly flow rates at each take station. This was a new requirement that historically had not been imposed. Although that particular restriction expired on April 1, 2019, the Company needed to adjust its planning for the

[11] *Id*. at 6.
[12] *Id*.
[13] *Id*. at 7.
[14] *Id*.

contingency that the same or similar restrictions may be imposed during the 2019 -2020 heating season. Therefore, the Company planned to meet peak hour requirements in addition to design day, design year and cold snap requirements. [15]

2. Cost Projections

The Arangio/Jaffe testimony described how the Company uses a SENDOUT model to calculate projected gas costs. The SENDOUT model performs a dispatch optimization of the entire Rhode Island portfolio of gas supply, pipeline transportation, underground storage, and peaking supplies to calculate projected gas costs. The pricing of pipeline services is based directly on the pipeline tariffs and rates in effect as of August 1, 2019. For purchases at locations other than the Henry Hub, the model uses the expected basis differential to the Henry Hub process, to determine the expected difference or basis.[16]

The witnesses outlined the two gas cost components for the GCR: (1) Supply Fixed Costs, which includes purchase, storage, or delivery of firm gas including pipeline and supplier fixed reservation costs, demand charges, and transportation fees; and (2) Supply Variable Costs, which includes all variable costs of firm gas, including but not limited to commodity costs, taxes on commodity, other gas supply expenses incurred to transport and store the gas, and inventory commodity costs.[17] The testimony described how the total gas costs within this proceeding were $11.1 million lower than projected in the Company's most recent Long-Range Plan filed on July 2, 2019. A $2.8 million dollar increase in fixed transportation costs were offset by a $3.0 million decrease in the Company's supplier fixed costs, due to an Asset Management Agreement. Total variable costs decreased by $3.1

[15] *Id*. at 8.
[16] *Id*. at 10-11.
[17] *Id.* at 11-12. Supporting detail for the gas costs was attached to the testimony as Attach. EDA/SAJ-1.

million from the Long-Range Plan to the GCR, primarily due to a decrease in gas commodity costs. Additionally, the Company did not include an estimate of its NGPMP credits in the Long-Range Plan. These credits are estimated in this GCR filing as $5.7 million, accounting for 49% of the gas cost decrease from the Long-Range Plan to this filing.[18]

3. Gas Supply Portfolio

The witnesses also explained that National Grid would continue to operate its portfolio similarly to its operation in the 2018-2019 GCR period. They described the Company's portfolio as 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. They noted that on most days the Company is able to purchase less expensive supplies on the Texas Eastern Transmission (Texas Eastern) Market Area 2 (M2) and Market Area 3 (M3) points delivered to the Company's city-gates on the Algonquin Gas Transmission (Algonquin) pipeline, as well as the Tennessee Gas Pipeline Company, LLC (Tennessee) Zone 4 (Zone 4) point using existing pipeline contracts previously used to purchase Gulf of Mexico supplies. These less expensive supplies can be accessed by the Company without incurring any additional fixed costs.[19] In 2018-2019, the Company increased its position at Dawn, Ontario to secure more reasonably priced supplies.

4. Transportation Capacity Portfolio

The Company's transportation capacity portfolio includes numerous contracts for gas delivery. The following subsections outline the changes to the portfolio for this year.

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[18] Arangio/Jaffe Direct Test. at 14.
[19] *Id.* at 15.

a. Millennium Expansion Project

The Company has contracted for 9,000 Dth per day as part of the Millennium Project for an initial term of fifteen years. This contract was available beginning January 2019 and went fully into service effective April 1, 2019.

b. Northeast Energy Center LLC

This project is in central Massachusetts and is expected to have an in-service date of April 1, 2020. 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. This project will connect to the Tennessee pipeline.[20]

c. Portland Natural Gas Transmission System (PNGTS) Capacity

For the 2019-2020 heating season, the Company will have access to 25,705 Dth per day on this path. Once fully phased-in, the addition of the PNGTS capacity will reduce the Company's exposure at Dracut and will allow the Company to access up to 29,000 Dth. per day from Dawn, Ontario, by way of agreements with Union TransCanada, and PNGTS to deliver firm supplies into Dracut.[21]

d. Incremental Dracut Capacity and Supply

The Company has contracted with Tennessee to add incremental capacity of 20,000 Dth. per day from Dracut to Cranston, Rhode Island, to meet design hour and design year requirements. This is existing, unsubscribed capacity on Tennessee's system and is available at maximum FT-A tariff rates and does not require any construction in order to be available.[22]

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[20] *Id*. at 16.
[21] *Id*. at 17.
[22] *Id*. at 18.

e. **Incremental Winter Supplies**

The Company issued a request for proposals for gas supplies delivered to the Company's citygates on either Tennessee or Algonquin by bidders demonstrating that they have either firm capacity to the Company's citygates or providing an explanation of the priority of service that would be utilized to serve the deliveries. As a result, the Company is now negotiating a contract for citygate supplies for the 2019/2020 through 2022/2023 season.

f. **Incremental Portable LNG Storage and Vaporization Contracts**

The Company has exercised an option for equipment rental and support services with Prometheus Energy Group, Inc. to support operations in Cumberland. The option is through the winter 2019/2020 season. Additionally, the Company is pursuing a multi-year agreement for portable injection services on Aquidneck Island.[23]

g. **Incremental Winter Liquid Volumes (Liquified Natural Gas - LNG)**

The Company planned to purchase a supplemental winter only LNG purchase agreement to support to portable LNG operations in Cumberland and Old Mill Lane in Portsmouth. Cost are not known at the time of filing, so the Company used an estimate based on historical usage.[24]

5. **Marketer Capacity Assignments**

The Company is required to provide pipeline capacity for Gas Marketers. The Arangio/Jaffe testimony represented that the Company had made available 35,258 Dth per day of capacity to marketers on seven different pipeline paths. The detailed testimony

[23] *Id*. at 20.
[24] *Id*. at 21.

explained the calculation of the surcharge/credit for each assigned pipeline path and the calculations of the delivered costs for each path released to marketers.[25]

B. Joint Testimony of Michael J. Pini & Ann E. Leary

The Leary/Pini testimony proposed GCR factors to become effective for November 1, 2019 for firm sales service and transportation service.[26] Firm sales service customers include the Residential Non-Heating and Heating rate classes, as well as Commercial and Industrial firm sales service in the Small, Medium, Large, and Extra-Large rate classes. Transportation service includes that provided to Gas Marketers and the associated Gas Marketer Fixed charges and factors.[27]

They explained that the proposed GCR factors are load specific (High Load and Low Load) and are necessary for the Company to be able to recover the projected gas costs allocated to its firm sales customers for the November 1, 2019 through October 31, 2020 period. For the twelve-month period ending October 31, 2020, projected gas costs for the Company's firm sales customers were approximately $137.5 million. They identified other costs and credits that, when added to the costs for the firm sales customers, would total $142.8 million in net costs necessary for the Company to collect.[28]

1. Fixed Costs

The Leary/Pini testimony explained that the Fixed Cost component includes all Fixed Costs related to the purchase, storage, and delivery of firm gas for both Low Load and High Load factor customers. They calculated total Fixed Costs of $61.1 million to be allocated to and collected from ratepayers based on their proportion of design-winter use

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[25] *Id*. at 25; Attach. EDA/SAJ-1 at 13.
[26] Leary/Pini Joint Test. at 4 (Sept.3, 2019).
[27] *Id*.
[28] *Id.* at 5-6.

requirements. They explained that the GCR factors were determined by dividing the allocated fixed gas cost by the projected throughput for each group, the Low Load group and the High Load group. They proposed a GCR Fixed Low Load factor of $2.2338 per Dth and a GCR Fixed High Load factor of $1.6788 per Dth.[29]

The Company did not allocate any demand costs to the Company's Distribution Adjustment Charge (DAC) filing in Docket 4955. However, the Company proposed to allocate LNG commodity costs associated with maintaining system pressure from the GCR to the DAC. They explained that the Company calculated a 2018-2019 reconciliation credit to Marketers of $4,444, as shown in Attachment MJP/AEL-7, Page 1, 17 Line (22). The calculation was performed in accordance with a Settlement Agreement in Docket No. 4199.

The Pini/Leary testimony described the calculation of the design sales forecast. They indicated that 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 2019 through March 2020. 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.[30]

2. Variable Costs

The Company's 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. The total estimated variable cost for the

[29] *Id.* at 8.
[30] *Id*. at 11, Attach. MJP/AEL-1, p 14-16.

period November 2019 through October 2020 is $81.7 million. The variable costs are divided by the projected throughput to obtain a variable cost factor of $2.9671 per Dth.[31] The total variable costs exclude $163,175 for the costs of 32,505 dekatherms of LNG per year from the Exeter LNG facility used to maintain system pressure. These costs are is proposed to be allocated to the DAC.[32] The Company also included an estimate of third-party portable LNG equipment and services at the former Cumberland LNG tank location and at Old Mill Lane on Aquidneck Island.[33]

3. Deferred Balance

On Attachment MJP/AEL-1, page 7, the witnesses presented the total estimated deferred balance for October 31, 2019 as an over-recovery of $1.5 million. This deferred balance was incorporated into the proposed GCR factors in this filing for the period November 1, 2019 through October 31, 2020.

4. FT-2 Rates

The Leary/Pini testimony presented a proposed FT-2 marketer demand rate of $12.4637 per Maximum Daily Quantity (MDQ) in Dth/month and the Storage and Peaking charge of $0.1076 per therm for FT-1 firm transportation customers returning to Transitional Sales Service (TSS). They also submitted capacity assignment percentages for the Low Load and High Load factors to be used in the determination of pipeline, underground storage, and peaking capacity for Marketers.[34] The FT-2 rate design separates storage costs into 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

[31] *Id*. at 11, Attach. MJP/AEL-1, Page 3, Line 12.
[32] *Id.* at 12, Attach. MJP/AEL-1, Page 3, Line 2.
[33] *Id*. at 12.
[34] *Id*. at 13, Attach. MJP/AEL-6.

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.[35]

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 dekatherm rate to be charged to Marketers. The proposed FT-2 Marketer Demand rate is $12.4637 per dekatherm and will be applied to the Marketers' storage and peaking MDQ.[36]

5. Bill Impact

The Leary/Pini testimony presented a combined bill impact to customers for the GCR factors and the DAC factors: for an average residential heating customer using 846 therms per year, the annual bill would be $1,202.81 which is a decrease of $147.58 or 10.9% from last year.[37]

C. Testimony of Theodore E. Poe, Jr.

Mr. Poe's testimony supported the underlying retail and wholesale forecasts of natural gas customer requirements used to estimate the Company's gas costs. He explained that every April 1, the Company utilizes a five-step process to determine its ten-year forecast of customer requirements. He explained that modeling of both customer count and use per customer is used to determine the Company's retail forecast, which is then

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[35] *Id*. at 13.
[36] *Id*. at 14; Attach. MJP/AEL-5.
[37] *Id*. at 15; This overall decrease is comprised of a decrease of $146.95 from the proposed GCR factors; an increase of $3.80 from the proposed DAC factors, for which the Company submitted a supplemental filing on Sept. 3, 2019 in Docket No. 4955; and a decrease of $4.43 in Gross Earnings Tax.

modeled at the rate class level and further sub-categorized. He stated that the volume forecast consists of the meter count and use-per-customer at the rate class level. The retail forecast also considers the impact of the Company's energy efficiency programs.[38] After determining the retail forecast, Mr. Poe explained that it is adjusted for billing lag and unaccounted-for-gas to determine the wholesale forecast. Both the retail and wholesale forecasts are used by the Company for supply, engineering, and financial planning.

Mr. Poe explained that sixty-eight percent of the Company's wholesale deliveries occur from November through March. The company's gas resource portfolio and gas supply purchases are designed to address its customers' needs during the winter peak period and throughout the year. He testified that the Company's forecast of sales and throughput requirements under normal weather conditions and under design winter conditions serves three purposes: (1) they provide key inputs for the calculation of GCR costs; (2) they form the basis for the Company's allocation of fixed costs between High Load Factor and Low Load Factor service classifications; and (3) they 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 its service, particularly during periods of extreme weather, as reflected in measures of design winter, cold snap, and design day requirements.[39]

Mr. Poe reported a 3.3% increase in forecast for Total Sales and an increase of 8.2% for C&I Transportation.[40] Wholesale sales volume growth is forecasted at 28,179,000

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[38] Theodore E. Poe, Jr. Direct Test. at 4-5 (Sept. 3, 2019); http://www.ripuc.ri.gov/eventsactions/docket/4963-NGrid_GCR_Book_1.pdf.
[39] *Id*. at 6-7.
[40] *Id*. at 8.

MMBtu for the period November 2019 through October 2020, a decrease of 4.3% from last year.[41]

Mr. Poe reported that 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 designs its standards using a three step process: (1) the Company performs statistical analyses of the coldest days and of the annual degree days recorded over a historical period; (2) 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; (3) the Company identifies design standards that would maintain reliability at the lowest cost.[42]

D. Testimony of John M. Protano

Mr. Protano discussed the results of the Gas Procurement Incentive Plan (GPIP)[43] for the period April 1, 2018 through March 31, 2019 and the results of the NGPMP for April 1, 2018 through March 31, 2019.[44]

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[41] *Id*. at 9.
[42] *Id*. at 12.
[43] The Gas Procurement Incentive Plan encourages the Company to purchase supply in a way that will stabilize supply and reduce the risk of extreme price escalation. It requires National Grid to lock in future gas prices over a twenty-four month horizon and to make these purchases in a structured series of monthly increments. The difference between the average unit cost of the mandatory hedges and the average unit cost of discretionary purchases is multiplied by the discretionary volumes to calculate total savings or cost.
[44] Protano Direct Test. (Sept. 3, 2019).

1. GPIP

The GPIP is designed to encourage the Company to purchase supply in a way designed to stabilize prices and reduce the risk of dramatically escalating commodity costs. To determine the incentive or penalty under the GPIP for each month, the total savings are multiplied by a percentage, depending upon the timing of the execution date of the purchase gas transaction and the specific unit costs savings. For instance, for transactions with unit cost savings of less than $0.50 which are executed more than four months prior to gas flow, the incentive payment to the Company is ten percent of the total costs savings. For transactions with unit cost savings greater than $0.50 which are executed more than eight months prior to gas flow, the incentive payment to the Company is twenty percent of the total costs savings. For transactions executed between one and four months, the incentive payment to the Company is five percent, regardless of total costs savings. The Company calculated a total incentive of $20,726, which Mr. Protano proposed be granted in full.[45]

2. NGPMP

Mr. Protano described the NGPMP, which shifted management of the Company's gas portfolio from an external company to internally within National Grid. He noted that the program produced a total of $6,440,519.59 in savings from April 2018 through March 2019, $5,696,467.63 of which customers would receive. Mr. Protano noted that the Company does not include any revenue from its Asset Management Agreement (AMA) in the incentive and was not proposing any changes to the NGPMP incentive at the current time. AMA fees are recorded as a credit on the pipeline demand charges and customers

[45] *Id*. at 5-6.

receive 100% of this benefit. The Company requested approval of a NGPMP incentive of $744,051.96 for the April 2018 through March 2019 period.[46]

IV. Division of Public Utilities and Carriers

On October 4, 2019, the Division submitted prefiled testimony from its consultant, Jerome D. Mierzwa.[47] Mr. Mierzwa made four recommendations to the Commission: (1) direct National Grid to work with the Division to develop appropriate cost allocation procedures to incremental design peak hour costs and to present those procedures in the next year's GCR filing; (2) direct National Grid to work with the Division to evaluate the Company's current cost allocation procedures for the interstate pipeline firm transportation capacity assigned to the Company's firm transportation customers and reflect modifications to the current approach which addresses the allocation of fixed gas supply reservation charges and to present those modifications in next year's GCR filing; (3) direct National Grid to work with the Division to develop data exchange protocols for the Gas Procurement Incentive Program (GPIP) and the Natural Gas Portfolio Management Plan (NGPMP) which provide additional transparency and for more efficient auditing; (4) defer a decision concerning the recovery of any costs associated with the incremental supplies purchased by National Grid related to operational problems at the Providence LNG facility experienced on January 21, 2019, until such time as the Division issues its investigative report. Mr. Mierzwa did not have any concerns with the Company's calculation of the GPIP or the NGPMP.

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[46] *Id*. at 8.
[47] Mierwa Direct Test. (Oct. 4, 2019); http://www.ripuc.ri.gov/eventsactions/docket/4963-DIV-Mierzwa%2010-4-19.pdf.

V. National Grid's Rebuttal

On October 15, 2019, National Grid filed its rebuttal testimony in which it agreed with Mr. Mierzwa's recommendations.[48]

VI. Hearing

At the hearing on October 22, 2019, National Grid's Motions for Protective Treatment were granted and, after ensuring no objection, all exhibits were marked as full exhibits. National Grid's counsel, Mr. Boyajian, presented Ms. Arangio, Ms. Leary, Mr. Poe, Mr. Protano, Mr. Pini, Ms. Jaffe and Ms. MaryBeth Carroll, as a panel.[49] All the witnesses adopted their prefiled testimony and sponsored data request responses.

Ms. Arangio testified that after the Company filed this proceeding, additional events occurred that caused the Company to plan for additional gas purchases, to ensure reliability on Aquidneck Island and to address a post-filing pressure reduction by Enbridge for the Algonquin Pipeline, due to planned maintenance on the pipeline.[50] She indicated that as a result of the pressure reductions, the volume placeholder for LNG in the filing was much higher and the costs more expensive. She stated that although the Company had pricing for the LNG, bids for transportation were due on the hearing day and were therefore not known. The total fixed costs for the LNG were $3.9 million which is roughly $2.9 million higher than presented in the filing.[51] Mr. Pini testified that the proposed GCR factors do not include recovery of the additional costs associated with these purchases. Rather, the Company proposes to recover these costs through next year's GCR.[52]

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[48] Jt. Rebuttal Test. (Oct. 15, 2019); http://www.ripuc.ri.gov/eventsactions/docket/4963-NGrid-Rebuttal%2010-15-19.PDF
[49] Ms. Carroll did not submit prefiled testimony but did sponsor answers to data requests.
[50] Hr'g. Tr. at 20-21.
[51] *Id*. at 21.
[52] *Id*. at 31.

On cross-examination by PUC staff, Ms. Jaffe explained that the Enbridge maintenance will cause pressure reductions which will translate into lower volumes of gas being delivered. On colder days and peak day, the Company would need to be prepared to meet customer requirements, knowing that due to the pressure reductions, the Company would not get the full volumes. Therefore, the Company needed a contingency plan to meet these requirements. Ms. Jaffe did indicate that the Company was also investigating its rights under its pipeline contracts to see whether it would have any recourse to recover the additional costs being incurred by the Company.[53] Division witness Mierzwa testified that to date, he is comfortable with the Company's efforts to investigate its recovery options under its Enbridge contracts.[54]

Ms. Jaffe also discussed an incident that occurred on January 21, 2019 where the Company was unable to vaporize enough LNG to meet demand. Therefore, the Company had to make up the shortfall. Additionally, on the same day, a low-pressure incident occurred on the Algonquin pipeline, so the Company incurred incremental costs to deploy portable LNG equipment on Aquidneck Island.[55] Also, in March 2019, the Company incurred costs for deploying LNG equipment to Aquidneck Island for a day that was colder than forecasted, in order to ensure reliability.[56]

Division witness Mierzwa and Commissioner Anthony discussed the changes that were made to the Long-Range Plan process and its contents. Mr. Mierzwa noted that there is much more data included in the recently filed Long Range Plan than was filed in prior plans. He stated that the LRP did assist in reviewing the GCR. He stated that while the

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[53] *Id*. at 45-46.
[54] *Id*. at 69.
[55] *Id*. at 57-58.
[56] *Id*. at 59.

LRP was an improvement, there's always room for even more improvement. Division counsel, Mr. Wold, indicated that the Division was very pleased with the cooperation and relationship it has developed with the Company with respect to the GCR and the LRP. He stated that the Company had provided a much modified and transparent LRP that conforms with the requirements worked out in the parties' joint memorandum concerning the LRP.[57]

VII. Commission's Findings

On October 25, 2019, the Commission conducted an Open Meeting to decide all pending factors and issues. The Commission approved a High Load GCR Charge of $1.6788 per therm for Residential Non-Heating, Large High Load, and Extra-Large High Load classes. It approved a Low Load GCR Charge of $2.2338 per therm for Residential Heating, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, and Extra-Large Low Load classes. Additionally, the PUC approved an FT-2 Marketer Demand charge of $12.4637 per dekatherm per month, a storage and peaking charge for FT-1 Transportation customers of $1.0762 per Dekatherm, and a weighted average system capacity charge of $0.8143 per dekatherm of capacity for usage on and after November 1, 2019.

The Commission found the Company's requests for the $20,726, incentive on its GPIP incentive and the NGPMP incentive of $744,051.96 were properly calculated in accordance with those programmatic requirements, as well as fair and reasonable, and approved the same. Finally, the PUC approved the BTU Conversion Factor of 1.030 per ccf. The Commission was satisfied that the rates proposed by National Grid and supported

[57] *Id*. at 83.

by the Division were properly calculated and would ensure that customers pay a just and reasonable rate.

Accordingly, it is hereby,

(23923) ORDERED:

1. National Grid shall work with the Division to develop appropriate cost allocation procedures to incremental design peak hour costs and to present those procedures in the next year's GCR filing.
2. National Grid shall work with the Division to evaluate the Company's current cost allocation procedures for the interstate pipeline firm transportation capacity assigned to the Company's firm transportation customers and reflect modifications to the current approach which addresses the allocation of fixed gas supply reservation charges and to present those modifications in next year's GCR filing.
3. National Grid shall work with the Division to develop data exchange protocols for the Gas Procurement Incentive Program (GPIP) and the Natural Gas Portfolio Management Plan (NGPMP) which provides additional transparency and for more efficient auditing.
4. A decision concerning the recovery of any costs associated with the incremental supplies purchased by National Grid related to operational problems at the Providence LNG facility experienced on January 21, 2019 is hereby deferred, until such time as the Division issues its investigative report
5. The Company's Motions for Protective Treatment are hereby granted for: Attachments EDA/SAJ-1, EDA/SAJ-8, Attachments MJP/AEL-1, MJP/AEL-

2, MJP/AEL-5, Responses to Div. 1-5, Div. 1-17, Div. 1-27, and Attachments 1-1-1, 1-1-3, 1-8,1-9, 1-21-1, 1-35-2, 1-36-2, 1-36-7, 1-36-8, 1-37, 1-38, 1-39, Responses to Div. 2-2 and Attachments 2-3-1 and 2-3-2.

6. The Gas Cost Recovery factors of:
    a. $1.6788 per therm for Residential Non-Heating customers, Large High Load, and Extra Large High Load Factor customers and
    b. $2.2338 per therm for Residential Heating customers, Small Commercial and Industrial, Medium Commercial and Industrial, Large Low Load, and Extra Large Low Load Factor customers are approved for usage on and after November 1, 2019.
7. A Weighted Average System Capacity Charge of $0.8143 per dekatherm is approved for usage on and after November 1, 2019.
8. The Gas Marketer Transportation factors of:
    a. $12.4637 per dekatherm for the FT-2 Firm Transportation Marketer Gas Charge and
    b. $1.0762 per dekatherm for a Storage and Peaking Charge are approved for usage on and after November 1, 2019.
9. The incentive of $744,051.96. for the Natural Gas Portfolio Management Plan, for the period April 1, 2018 through March 31, 2019, is approved.
10. The incentive of $20,726 for the Gas Procurement Incentive Plan, for the period for the period April 2018 through March 2019 is approved.
11. The BTU factor of 1.030 per ccf is approved.

EFFECTIVE NOVEMBER 1, 2019 IN WARWICK, RHODE ISLAND PURSUANT TO A DECISION MADE AT OPEN MEETING ON OCTOBER 25, 2019. WRITTEN ORDER ISSUED OCTOBER 8, 2020.

PUBLIC UTILITIES COMMISSION

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*Margaret E. Curran, Chairperson

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Marion S. Gold, Commissioner

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Abigail Anthony, Commissioner

*Chairperson Curran concurs with the decision but is unavailable for signature

NOTICE OF RIGHT OF APPEAL: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the PUC may, within seven days from the date of the order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or order.