nationalgrid

Raquel J. Webster
Senior Counsel

September 17, 2020

BY ELECTRONIC MAIL

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

RE: Docket 5040 - 2020 Distribution Adjustment Charge (DAC)
<u>Responses to Division Data Requests – Set 2</u>

Dear Ms. Massaro:

I have enclosed an electronic version of National Grid's[1] responses to the Division of Public Utilities and Carriers' Second Set of Data Requests in the above-referenced docket.[2]

The Company's responses to data requests Division 2-7 and 2-11 are pending.

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

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 5040 Service List
Leo Wold, Esq.
John Bell, Division
Al Mancini, Division

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

[2] Per practice during the COVID-19 emergency period, the Company is providing PDF versions of the enclosures. The Company will provide the Commission Clerk with hard copies and, if needed, additional hard copies of the enclosures at a later date.

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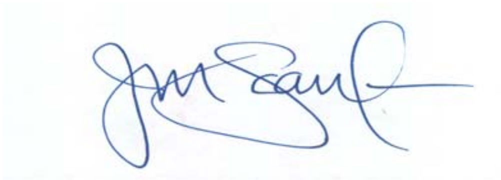
Certificate of Service

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



Joanne M. Scanlon

September 17, 2020
Date

Docket No. 5040 – National Grid –2020 Annual Distribution Adjustment Charge Filing (DAC) - Service List as of 9/9/2020

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File an original & nine (9) copies w/: Luly E. Massaro, Commission Clerk Margaret Hogan, Commission Counsel Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Patricia.lucarelli@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107
	Alan.nault@puc.ri.gov;	

Division 2-1

Request:

Please indicate whether any AGT funds have been committed, but not paid, for FY 2020 or FY 2021. If yes,

a. Please identify the amount for each of the fiscal years and the customers to whom payments will be made.
b. Describe the nature of the projects for which funding has been committed.
c. Indicate when the Company expects payments to be made.

Response:

a. No AGT funds have been paid or committed in the previous two years. Currently, there are no additional AGT projects under consideration.
b. Please see the response to subpart a.
c. Please see the response to subpart a.

Division 2-2

Request:

Please provide a narrative or explanation which indicates whether the Company believes the AGT fund is effectively achieving the goal of developing energy-efficient natural gas technologies that increase utilization of natural gas during periods of low demand. Include supporting documentation for the Company's conclusions. In your response:

a. Indicate whether the effectiveness of the AGT fund, as a tool for developing natural gas technology to expand the use of natural gas, has been studied by the Company. If yes, please provide copies of the studies.

b. Please provide any studies, analyses or policy papers produced within the last 2 calendar years that demonstrate the need for the AGT fund.

c. Please indicate whether the Company has explored other approaches that would effectively promote the use of natural gas technology as a tool for expanding (or increasing) the use of natural gas during periods of low demand. If yes, please disclose and explain what has been explored.

Response:

a. Overall, the Company believes that the AGT Program is an effective tool in promoting the development of energy efficient natural gas technologies that increase utilization of natural gas during periods of low demand. However, based on feedback from project developers and customers, the Company discovered that the current methodology of calculating the potential customer's AGT incentive is complex and a major barrier to participation in the AGT Program.

   In a letter to the Division dated July 26, 2018, a copy of which is attached as Attachment DIV 2-2(a), the Company proposed to replace the current three calculation methods with a single, simplified pre-approved prescriptive value and anticipated collaborating with the Division on these proposed changes. The current AGT Program and methodology for determining the appropriate rebate levels was established in Docket No. 2025. AGT Program rebate levels are determined as the lesser of a projected amount of (i) 75% the lifetime net present value or marginal revenue to the Company; (ii) 75% of total job cost; or (iii) an amount resulting in a payback period of 1.5 years, subject to current budgetary allowances. Unfortunately, other critical issues arose that required the time and attention of the Company and the Division to resolve; therefore, the Division and the Company were not able to pursue further collaboration regarding the revisions to the calculation of the AGT Program rebate.

Under the current AGT Program framework, the potential customer rebate to be gained by AGT funding is negated because the marginal revenue in part (i) above is linked to the Contribution in Aid of Construction ("CIAC") calculation. Due to the sizes of these systems, nearly all projects require natural gas upgrades, which, in turn, require CIACs. As a result, the incremental margin to the Company realized from the project is offset by the CIAC. Since marginal revenue is negated by the CIAC, the AGT Program rebate is also negated based on part (i) of the three-part rebate calculation discussed above. This phenomenon has disincentivized customers from participating in the AGT Program.

b. The Company has not produced any studies or policy papers on the need for AGT Program in the last two years. However, the Company did evaluate adding a large 1 MW Combined Heat and Power ("CHP") customer in South County and had hoped to assist the customer with funding with an AGT Program rebate. However, these funds have not been pursued due to the Gas Connections funding requirement discussed in the response to part (a) above. The customer has had difficulty gathering sufficient funding since the project inception and has not successfully reached a positive scenario to pursue the project. This project is one example of the need for the AGT Program; however, the barriers discussed above sometimes prevent the program from accomplishing its goals. The Company believes that certain revisions to the calculation of the AGT Program rebate may enable a customer to progress its project to installation.

c. The Company has not investigated other approaches to effectively promote increased natural gas use during periods of low demand other than the simplifying changes to the eligibility criteria discussed above in part (a) with respect to the AGT Program. However, the Company has been in discussions with the Division to broaden the scope of the AGT Program to include funding for studies regarding the decarbonization of natural gas with the goal of reducing greenhouse gas emissions. If agreed to by the Division and approved by the PUC, the AGT factor included in the Company's Distribution Adjustment Clause ("DAC") could include the recovery of actual costs prudently incurred by the Company for studies on the decarbonization of natural gas with the goal of reduced greenhouse gas emissions. Please see Attachment DIV 2-2(b) for proposed illustrative tariff language regarding these suggested changes to the AGT Program.

Prepared by or under the supervision of:
David Moreira, Ryan Scheib, Michael Pini, and Lee Gresham

nationalgrid

Robert J. Humm
Senior Counsel

July 26, 2018

VIA ELECTRONIC MAIL

Al Mancini
Rhode Island Division of Public Utilities and Carrier
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 4708 – 2017 Distribution Adjustment Charge
<u>Update on Advanced Gas Technology Program</u>

Dear Mr. Mancini:

I write to provide the Division of Public Utilities and Carriers (Division) an update regarding National Grid's[1] efforts to improve the Advanced Gas Technology (AGT) program before the Company's 2018 Distribution Adjustment Charge (DAC) filing. Over the last year, the Company has reviewed its AGT program to see how it could simplify the application process for a customer to receive an incentive under the AGT program. By speaking with project developers and participating customers, the Company learned that one of the major barriers was the complex calculations needed to determine the value of an incentive. Project developers have informed the Company that they need an estimated value of the incentive up-front so that they can develop pro-forma project proposals to provide to their customers earlier in the project development stage. This is not presently possible because two of the current tests require the development of the natural gas distribution margin for each job, along with the calculations of any associated contribution in aid of construction (CIAC) for any gas services associated with the project.

Based on this feedback, the Company proposes the following. The Company would replace the current three calculation methods with a single, simplified pre-approved prescriptive value. This value would then be multiplied by the incremental annual therms added to the Company's distribution system. Attached is a table the Company has developed to help customers calculate their incentive earlier in their process when considering the AGT program. The amount per therm would vary with the equipment's load factor and size, so the AGT program could attract technologies with low peak usages.

Another practice the Company has experienced success with this year is the use of energy efficiency technical assessment studies to identify potential AGT measures. Using the data from these studies has saved, and should continue to save, customers time and money because customers no longer need to complete their own study, while also expediting the application process.

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

The Company looks forward to continuing to collaborate with the Division regarding improvements to the AGT program. Please let me know if the Division would like to further discuss the above-referenced improvements to the AGT program.

Thank you for your attention to this matter. If you have any questions, please do not hesitate to contact me at 401-784-7415.

Very truly yours,

Robert J. Humm

Enclosure

cc: John Bell, Division
Leo Wold, Esq.
Bruce Oliver
David Moreira, National Grid

Percent Consumed in May-Oct Months

Rate	31%	35%	40%	45%	50%	55%	60%	65%	70%+
SMALL LOW LOAD FACTOR	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00	$ 2.13	$ 2.25
SMALL HIGH LOAD FACTOR	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00	$ 2.13	$ 2.25
MEDIUM LOW LOAD FACTOR	$ 1.00	$ 1.13	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00
MEDIUM HIGH LOAD FACTOR	$ 1.00	$ 1.13	$ 1.25	$ 1.38	$ 1.50	$ 1.63	$ 1.75	$ 1.88	$ 2.00
LARGE LOW LOAD FACTOR	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00	$ 1.13	$ 1.25
LARGE HIGH LOAD FACTOR	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00	$ 1.13	$ 1.25
XTRA LARGE LOW LOAD FACTOR	$ 0.25	$ 0.25	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00
XTRA LARGE HIGH LOAD FACTOR	$ 0.25	$ 0.25	$ 0.25	$ 0.38	$ 0.50	$ 0.63	$ 0.75	$ 0.88	$ 1.00

Incremental Therms estimated during May-Oct months times $/therms

TECHNOLOGY	**APPLICATION**
Air Compressor	Product cooling or movement
Compressed Natural Gas	Personal or fleet cars and trucks
Engine-Driven Pump	Municipal water pumping
Convection Oven & Burner	Curing, drying and forming
Absorption/Engine Driven Chiller	Office air conditioning or process cooling
Desiccant Dehumidifier	Office or process dehumidification
Engine-Driven Generator	Cogeneration
Catalytic Infra-Red Heater	Curing, drying and forming
Incinerator	Solid waste or air pollutant destruction
Boiler & Burner	Process heating (i.e., steam, hot water, etc.)

DISTRIBUTION ADJUSTMENT CLAUSE

TCF Tax Credit Factor. See Item 3.10 for calculation.

The Distribution Adjustment Charge, excluding the RDA, shall be increased by the uncollectible expense percentage approved in the most recent general rate case.

3.0 DISTRIBUTION ADJUSTMENT CALCULATIONS

3.1 System Pressure Factor:

The System Pressure factor shall be computed in a manner that identifies and includes all fixed and variable gas supply costs required on an annual basis to maintain pressure within the Company's distribution system and shall identify and consider all gas supply costs that are required to maintain pressure for all portions of the Company's distribution system:

$$SP = \frac{GCSP \times SP\%}{Dt_T}$$

Where:

SP System Pressure Amount.

GCSP Forecasted Gas Costs associated with supply used to maintain system pressures, including both demand and commodity costs.

SP% Percent of supply used to maintain system pressures, as established in the most recent general rate case or DAC proceeding.

Dt_T Forecasted annual firm throughput.

3.2 AGT Factor:

The Advanced Gas Technology factor shall be determined ~~-~~annually, or as otherwise approved by the PUC, based on the following:

(1) pursuant to the Company's AGT program, an estimate of AGT grants to be disbursed during the upcoming year, ~~adjusted by any AGT grants from the prior year in excess of available funding or available funding in excess of AGT grants from the prior year,~~ the total of which is the eligible AGT Costs to be approved for recovery by the PUC;~~.~~ and

DISTRIBUTION ADJUSTMENT CLAUSE

(2) actual costs prudently incurred by the Company to conduct or in support of studies on the decarbonization of natural gas with the goal of reduced greenhouse gas emissions, the scope, estimated cost, and purpose of which has been reviewed and supported in writing by the Division, and formally approved by the PUC after a description of the study (including the scope, estimated cost, and purpose) has been filed by the Company with the PUC.

The Company will recover the total of the costs of AGT grants and prudently incurred costs of the decarbonization studies in excess of available funding from the prior year, if any, through the AGT Factor. The formula will be as follows:

$$AGT = \frac{AGT}{Dt_T}$$

Where:

AGT	AGT Factor
AGT	AGT Costs
Dt_T	Forecasted annual firm throughput in dekatherms

3.3 **Infrastructure, Safety and Reliability Plan:**

3.3.1 Gas Infrastructure, Safety, and Reliability Plan Filing:

In compliance with R.I.G.L. Section 39-1-27.7.1, no later than January 1 of each year, the Company shall submit to the PUC a Gas Infrastructure, Safety, and Reliability Plan (Gas ISR Plan) for the upcoming fiscal year (April to March) for review and approval within 90 days. The Gas ISR Plan shall include the upcoming fiscal year's forecasted capital investment on its gas distribution system infrastructure and may include any other costs relating to maintaining safety and reliability that have been mutually agreed upon by the Division and the Company.

3.3.2 Infrastructure, Safety and Reliability Factor:

Effective each April 1, the Company shall recover through a change in Distribution Adjustment Charge rates the Cumulative Revenue Requirement on the Adjusted Cumulative Non-growth Capital spending as approved by the PUC in the Company's

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Division 2-3

Request:

According to the footnote on page 15 of the Distribution Adjustment Charge testimony of witnesses Ryan M. Scheib and Michael J. Pini, dated August 3, 2020, the "Company determined that the CY 2018 Net Write-offs provided in Docket No. 4955 were incorrect and should have been $7,350,264 and not $4,984,020. However, this revision would not change the amount of CY 18 Recoverable Arrearage Forgiveness Amount included in the DAC effective November 1, 2019". Please explain and show how the net charge off amount can be incorrect, but not affect the recoverable arrearage.

Response:

To recover arrearage forgiveness credits associated with successful participants in the Arrearage Management Program ("AMP"), the Company must demonstrate that actual net write-offs exceed the adjusted allowable bad debt amount determined in the Company's most recent base distribution rate case.[1] In Docket No. 4955, the Company calculated the CY 2018 allowable bad debt amount as $11,979,260 and the actual bad debt amount as $4,984,020. Therefore, the Company was not allowed to recover arrearage forgiveness credits for successful participants.

The Company later discovered the CY 2018 actual bad debt amount should have been $7,350,264. However, since the corrected CY 2018 bad debt amount of $7,350,264 is less than the allowable bad debt amount of $11,979,260, the Company is still not entitled to recover any arrearage forgiveness credits associated with successful participants in the AMP. Therefore, the CY 2018 Recoverable Arrearage Forgiveness Due to AMP Successful Participants found in Schedule RMS/AEL-6S, page 2, line (10) of the Company's 2018 Distribution Adjustment Charge Filing, Docket 4955) remains zero.

[1] The bad debt amount for non-base distribution revenues is updated annually by multiplying calendar year billing by the bad debt percentage approved in the Company's most recent base distribution rate case.

Division 2-4

Request:

According to the Distribution Adjustment Charge testimony of witnesses Ryan M. Scheib and Michael J. Pini, dated August 3, 2020, at page 16, line 14, the Company has sought relief from penalties incurred during the first quarter due to issues related to the Gas Business Enablement rollout and a second quarter penalty as a result of an exogenous and/or force majeure event in Docket No. 3476. Those penalties were not reflected in Schedule RMS/MJP-9. Please provide a recalculation of Schedule RMS/MJP-9 to include the penalties for which the Company has sought relief from the Commission.

Response:

Please see Attachment DIV 2-4, which is a recalculation of Schedule RMS/MJP-9 that includes the penalties for which the Company has sought relief from the Commission.

National Grid - RI Gas
Service Quality Performance Factor
Effective November 1, 2020

(1)	SQP Penalty Amount - Leak Call Response (Normal Business Hours)	($91,008)	
(2)	SQP Penalty Amount - Meter Testing	($75,000)	
(3)	SQP Penalty Amount - Leak Call Response (Normal Business Hours)	($92,383)	
(4)	SQP Penalty Amount - Leak Call Response (After Business Hours)	($273,337)	
(5)	Total SQP Penalty Amount	($531,728)	
(6)	Firm Throughput	39,648,231	dths
(7)	SQP Factor per dth	($0.0130)	per dth
(8)	SQP Factor per therm	($0.0013)	per therm

(1) Docket 3476, FY2020 First Quarter Report on Service Quality Plan, filed on November 4, 2019
(2) Docket 3476, FY2020 Second Quarter Report on Service Quality Plan, filed on March 11, 2020
(3) Docket 3476, FY2020 Second Quarter Report on Service Quality Plan, filed on March 11, 2020
(4) Docket 3476, FY2020 Second Quarter Report on Service Quality Plan, filed on March 11, 2021
(5) Sum Lines (1) - (4)
(6) Company Forecast
(7) Line (5) ÷ Line (6)
(8) Line (7) ÷ 10, truncated to 4 decimal places

Division 2-5

Request:

According to the Distribution Adjustment Charge testimony of witnesses Ryan M. Scheib and Michael J. Pini, dated August 3, 2020, at page 21, beginning at line 15, please explain, specifically, the nature of the payroll taxes and the 401K match and what specifically qualifies them as incremental.

Response:

The Company applies labor burdens[1] to all worked time, base labor, and overtime, from Narragansett Electric Direct employees. The Company separately calculated the incremental payroll tax and 401K match on the overtime labor component since there is an incremental portion of these two payroll burdens. If an employee works overtime in support of storm recovery activities, the Company incurs more payroll tax and 401K match expense on the overtime labor, unlike the other payroll burdens. Therefore, the amount of payroll tax and 401K match expense calculated to be incremental was removed from the Storm Net Revenue Adjustment as mentioned in the Distribution Adjustment Charge testimony of witness Ryan M. Scheib and Michael J. Pini, dated August 3, 2020, at page 21. Payroll tax and the 401K match were specifically identified in the Company's storm fund settlement in Docket No. 4686 as categories of labor overhead costs that are eligible for recovery as incremental storm restoration costs.

The payroll tax and 401K match burdens applied to base payroll are factored into the Storm Net Revenue adjustment since these burdens are not incremental and are recovered in the Company's base distribution rates. Since the Company's gas customers pay for the base components of employees' payroll burdens through base distribution rates, they should receive a credit for the base payroll burdens when those employees are performing storm recovery work for other companies. However, since the Company's gas customers do not pay for the incremental portion of employees' payroll tax and 401K match burdens related to overtime storm recovery work, they should not receive a credit for the incremental portion of the payroll costs.

[1] A labor burden is a payroll overhead applied to labor.

Prepared by or under the supervision of: Jeffrey Oliveira

Division 2-6

Request:

According to the Distribution Adjustment Charge testimony of witness Melissa A. Little, dated August 3, 2020, at page 8, lines 1 through 6, please explain the rationale for removing Off-system Gas Sales. Please provide citations to support the adjustment.

Response:

Off-system Gas Sales is one of three accounts, along with Excess Sharing and Contract Sharing, that comprise the Natural Gas Performance Management Plan ("NGPMP") benefits sharing incentive established in Docket No. 4038, Order No. 19627, which the Company has included as Attachment Division 2-6 for reference. On page 3 of the Order, the Rhode Island Public Utilities Commission ("PUC") explains that effective April 1, 2009, the NGPMP will be reviewed with each Gas Cost Recovery ("GCR") filing and the benefits sharing provisions under the plan will then be applied to reduce amounts in the Company's GCR filing. This practice is further confirmed in the Company's gas tariff, RIPUC NG-GAS No, 101, Section 2, Schedule A, Sheets 3 and 4, which includes NGPMP credits in the Supply Fixed Cost Component of the Gas Charge Calculation.

Because the NGPMP benefits are shared through the separate GCR mechanism, the Company removes the Off-system Gas Sales, Excess Sharing, and Contract Sharing accounts from the calculation of the Earnings Sharing Mechanism in the DAC.

Prepared by or under the supervision of: Melissa A. Little

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

NATIONAL GRID NATURAL GAS	:	
PORTFOLIO MANAGEMENT PLAN	:	**DOCKET NO. 4038**

REPORT AND ORDER

On February 24, 2009, National Grid ("NGrid" or "the Company") filed its Natural Gas Portfolio Management Plan ("NGPMP") with the Commission through which NGrid proposed changes to its current gas portfolio management plan. The changes include the Company discontinuing contracting with an asset manager as a full outsource supplier. NGrid plans to perform the functions previously performed by its asset manager. Additionally, the NGPMP proposes to guarantee Rhode Island customers an annual gas cost optimization benefit of $1 million per year commencing each April 1 and provide these customers with 80% of all net proceeds in excess of the first $1 million.

NGrid's filing moved the Commission to grant it protective treatment pursuant to Commission Rule 1.2(g) and R.I. Gen. Laws §38-2-2(4)(i)(B). Specifically, NGrid seeks protection of references to portfolio management fees agreed to by Merrill Lynch and ConocoPhillips under the terms of Rhode Island portfolio-management contracts. Additionally, the filing contains information of the results of its asset management RFP in Massachusetts and Rhode Island. In support of its motion, NGrid asserts that the information is competitively sensitive and proprietary and that NGrid has agreed to keep the same confidential. Furthermore, the Company alleges that disclosure of the information would be commercially harmful to Merrill Lynch and ConocoPhillips and their negotiating positions and give their competitors an unfair advantage and dissuade potential portfolio managers from providing services in Rhode Island.

NGrid filed direct testimony of Stephen A. McCauley, Elizabeth Danehy Arangio and Gary L. Beland. Mr. McCauley is the Director of Origination in Energy Portfolio Management for NGrid. He explained that under the NGPMP, NGrid will in-source the functions previously performed by the asset manager. He described the NGPMP as being designed to encourage NGrid to minimize gas costs to its customers by combining a least cost dispatch with an asset optimization program. Mr. McCauley stated that currently, the asset manager, Merrill Lynch, purchases gas for Rhode Island customers based on projections provided to it by NGrid. The goal of Merrill Lynch, as the asset manager, is to provide reliable low-cost supplies for these customers.[1]

Mr. McCauley explained how the assets, particularly transportation contracts, underground storage contracts, peaking supplies and the Distrigas Firm Combination Service ("FCS") contract can be used to optimize the purchase and dispatch of gas supplies. He noted that the mix of these assets provides for greater flexibility and opportunities to optimize in a manner to create value for Rhode Island customers. Mr. McCauley identified the ways that the NGPMP is more beneficial to customers than the current third party asset manager plan. Specifically, NGrid managing its own portfolio will reduce the risk of performance failure by a third party such as financial distress or bankruptcy. Additionally, NGrid will have staff with expertise, market intelligence and contractual relationships to best meet future needs of its customers.[2]

[1] NGrid Exhibit 1, Natural Gas Portfolio Management Plan, Direct Testimony of Stephen A. McCauley filed February 24, 2009 at 1-4.
[2] *Id.* at 4-6.

Mr. McCauley described the financial benefits that would be realized by Rhode Island customers under the NGPMP which include a guarantee credit of $1 million and 80% of any proceeds realized above the $1 million guarantee. NGrid would receive 20% of the incremental benefit derived through optimization of the assets. This differs from the current plan which caps the financial benefit received by customers at the fixed guarantee. This guarantee is currently determined through a bidding process. The NGPMP does not propose to modify the current least cost purchase dispatch formula. Additionally, under the current plan, only the asset manager knows how much value is realized after providing the fixed guarantee to customers. NGrid's proposal requires the Company to file quarterly reports of the portfolio's realized value and an annual report of benefits sharing.[3]

The NGPMP will become effective April 1, 2009 and be reviewed with each Gas Cost Recovery ("GCR") filing. Additionally, NGrid will file a report showing the results of the plan for a twelve month period April 1 through March 31 by June 1. Mr. McCauley again described the revenue sharing provisions noting that each month, Rhode Island customers will receive 1/12 of the $1 million guarantee and the additional 80% benefit discussed above will be applied to reduce amounts in the Company's GCR filing.[4]

Elizabeth Danehy Arangio, Director of Gas Supply Planning, described the role of the Gas Supply Planning Group in the procurement of the natural gas supply for Rhode Island customers. Ms. Arangio identified the goal of the gas supply planning process as ensuring that there are adequate gas supplies to reliably meet the needs of customers over the planning period. NGrid determines its load supply by: 1) establishing planning

[3] *Id.* at 7-10.
[4] *Id.* at 10-11.

criteria, 2) preparing a demand forecast under normal weather conditions for firm-service customers including those transportation customers and 3) converting the normal weather load requirement to a design weather load requirement.[5]

Ms. Arangio noted that every month, the Gas Supply Planning group determines the base load volume amounts for delivery to the Tennessee and Algonquin citygates. On a daily basis, that group nominates a separate incremental volume for delivery if needed. The incremental volume can come from transportation capacity, storage, citygate purchases and/or additional company assets. The Gas Supply Planning group is also responsible for ensuring compliance with contractual terms and managing the pipeline balancing activity. Finally, Ms. Arangio stated that NGrid is fully capable, by building a capable staff and with prior experience in New Hampshire, New York and Massachusetts, of managing its natural gas portfolios.[6]

Gary L. Beland, Manager in the Pricing and Regulatory Department, provided testimony to explain the relationship between the Gas Purchase Incentive Plan ("GPIP") and the proposed NGPMP. He noted that under the GPIP, NGrid tries to stabilize prices by locking in gas prices over a twenty-four (24) month period in an attempt to protect customers from the impacts of large price swings. Mr. Beland indicated that NGrid's proposed NGPMP will have no effect on the GPIP and that the two plans are independent of each other. He described the GPIP as a hedging plan using financial instruments to stabilize gas costs that is separate from the Company's physical purchase of supply. On

[5] NGrid Exhibit 1, Natural Gas Portfolio Management Plan, Direct Testimony of Elizabeth Danehy Arangio filed February 24, 2009 at 1-3.
[6] *Id.* at 4-7.

the other hand, Mr. Beland described the NGPMP as an asset management plan designed to optimize the total gas supply portfolio in order to minimize costs to the customer.[7]

Finally, Mr. Beland noted that NGrid will not seek to recover any incremental staffing costs in this filing. However, there will be certain costs associated with the Company conducting the supply and asset management process including minimal trading fees that NGrid considers part of expects to recover as a gas cost.[8]

On March 20, 2009, the Division of Public Utilities and Carriers ("Division") filed the testimony of Bruce R. Oliver to address NGrid's proposal. Mr. Oliver noted that with two exceptions, he supported the Commission adopting the proposal. Mr. Oliver's two exceptions are: 1) that the language in paragraph II.C. be deleted because the general representation that NGrid will operate the plan in a way that parallels the current practices is unnecessary and 2) that the reporting requirements be expanded.[9]

Mr. Oliver noted that NGrid's proposal appears to offer the potential for increased ratepayer benefits without considerable risk. He opined that over time, the Commission and Division should exercise oversight into the appropriateness of the level of the guaranteed minimum credit provided to ratepayers, the transparency of the asset value determinations and the reasonableness and appropriateness of costs charged to asset management transactions. Mr. Oliver noted that should NGrid assume its asset management, the market-based assessment of value that occurs with the competitive

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[7] NGrid Exhibit 1, Natural Gas Portfolio Management Plan, Direct Testimony of Gary L. Beland filed February 24, 2009 at 1-5.
[8] *Id.* at 5-7.
[9] Division Exhibit 1, Direct Testimony of Bruce R. Oliver filed March 20, 2009 at 2-3.

bidding process would be lost, and therefore periodic review of the guaranteed minimum annual credit is warranted.[10]

Mr. Oliver stated that the $1 million guaranteed minimum annual benefit is reasonable in light of the uncertainty regarding the expected value of natural gas assets. He noted that this guarantee coupled with 80% of the incremental revenue to benefit firm gas sales service customers is reasonable and prudent. Regarding the necessity for transparency of transactions and costs incurred to conduct transactions, Mr. Oliver noted that the loss of market based determination of value will leave the Commission with few, if any, external benchmarks against which to measure the Company's actions. Transparency will enable the Commission and the Division to gain confidence that NGrid's transactions and costs are both reasonable and appropriate. Even with the transparency, Mr. Oliver pointed out that it will be incumbent upon NGrid to assist the Commission and the Division in understanding the levels of costs and benefits because of the lack of historical or comparable data to measure the performance of the in-house activities.[11]

Mr. Oliver opined that the in-sourcing of the asset management activities provides the potential for greater customer benefits. He also noted that in light of the current financial times, while a well drafted contract may provide protection from the third party's financial problems, the amount of protection contracted for may reduce the levels of benefits offered by the asset manager. Mr. Oliver pointed out that NGrid has the size and experience to offer the in-sourcing as an alternative to contracting with a third party asset manager. Additionally, he noted that under no circumstances will customers

[10] *Id.* at 5-7.
[11] *Id.* at 7-10.

receive less in credit than what they are currently receiving and those customers could in fact receive more should the net asset management revenue exceed $1 million in a year. Mr. Oliver recommended that the Commission review the program in two years and then again in four years to allow for further refinement or termination if necessary.[12]

On March 25, 2009, the Commission conducted a hearing to further investigate NGrid's proposal to discontinue the use of a third party asset manager and the benefits of assuming the duties of the asset manager in house. Richard A. Rapp, Jr., Senior Vice President of Energy Portfolio, testified on behalf of NGrid. He explained the proposal and stated that NGrid had no objection to and would comply with the suggestions made by Mr. Oliver, namely that paragraph II.C be deleted, that the reporting requirements be expanded and that the program be reviewed by the Division and the Commission in two years and then again in four years.[13]

Mr. Oliver reiterated his prefiled testimony and noted that asset management is becoming a common practice in the gas industry. NGrid has the size and experience to in-source its asset management efficiently and with some economies of scale. He noted four areas of oversight that he recommended the Commission focus on: transparency to ensure confidence in the reasonableness of the market transactions undertaken, tracking and ensuring economies of scale are achieved and ratepayers receive some benefit, the relationship between the minimum guarantee and asset values to ensure the Company is rewarded for the value it adds in the process, and ensuring the program is structured so that ratepayers are never exposed to a negative credit to their cost of gas. He pointed out

[12] *Id.* at 10-13.
[13] Transcript of Hearing ("T."), March 25, 2009, at 34-35.

that the minimums proposed in the Company's program ensure that ratepayers will never be exposed to a negative credit.[14]

The Commission finds that NGrid's proposal to assume the duties of the third party asset manager in house is in the best interest of ratepayers. The proposal will guarantee ratepayers more than the $1million they receive from the current arrangement. The transparency of the proposal and the 80% of proceeds realized by the Company to be given to ratepayers will certainly provide them with a better situation than currently exists with third party situation and no transparency. The Commission commends the Company and the Division for being proactive in trying to lower costs for all ratepayers.

Accordingly, it is

(19627) ORDERED:

1. The Motion for Protective Treatment to protect as confidential references to portfolio management fees agreed to by Merrill Lynch and ConocoPhillips under the terms of Rhode Island portfolio-management contracts and information of the results of its asset management RFP in Massachusetts and Rhode Island is approved.
2. National Grid's in-sourcing and performing the functions previously performed by its third party asset manager in house is approved.
3. National Grid shall comply with the reporting requirements and all other findings and directives contained in this Report and Order.

[14] T. at 38, 40, 44-47.

EFFECTIVE IN WARWICK, RHODE ISLAND PURSUANT TO OPEN MEETING DECISION ON MARCH 31, 2009. WRITTEN ORDER ISSUED APRIL 24, 2009.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert B. Holbrook, Commissioner*

Mary E. Bray, Commissioner

*Commissioner Holbrook did not participate in the decision.

Division 2-8

Request:

Please explain the nature of Inventory Financing as presented on page 8, lines 17 through 21 of the Distribution Adjustment Charge testimony of witness Melissa A. Little, dated August 3, 2020.

Response:

Inventory Financing is defined in the Company's gas tariff, RIPUC NG-GAS No, 101, Section 1, Schedule B, Sheet 5 as "finance charges associated with the storage of natural gas as calculated using a working capital calculation." These inventory finance charges are added to the variable costs of firm gas and included in the Gas Charge Factor pursuant to the Gas Cost Recovery Clause described in Section 2, Schedule A of the tariff. The Company does not include stored gas inventory in its rate base; therefore, it also removes the associated inventory financing from revenue in the earnings sharing calculation.

Prepared by or under the supervision of: Melissa A. Little

Division 2-9

Request:

Please provide a brief explanation of the nature of the Aquidneck Island Event and provide a copy or cite of the Commission directive for accounting for cost related to the event.

Response:

The Narragansett Electric Company d/b/a National Grid (the "Company") understands this data request to refer to the use of the term "Aquidneck Island Event" at page 9 of the Pre-Filed Direct Testimony of Melissa A. Little, and page 14 of Schedule MAL-1.

The Company used this term in Ms. Little's pre-filed direct testimony and schedules to refer to the gas service interruption to some customers in Middletown and Newport, Rhode Island that began on January 21, 2019, and the Company's response to that gas service interruption.

On January 21, 2019, the Company experienced low inlet pressure into its Portsmouth take station, which is the location where the Company receives natural gas to distribute to customers on Aquidneck Island, including customers in Middletown and Newport. The Company mobilized its personnel to respond to the low inlet pressures at the Portsmouth take station in an effort to maintain sufficient pressures on its Aquidneck Island distribution systems to maintain service to customers. Despite the Company's efforts, including the shutdown of a segment of the distribution system serving a portion of Middletown, the low inlet pressures resulted in low pressures on the low-pressure distribution system in a portion of Newport, resulting in service interruptions to a number of customers in that area. Because of those service interruptions and the low pressures that existed on the system, the Company determined that it had to shut down the entirety on the low-pressure distribution system in Newport.

The process for shutting down the low-pressure distribution system in Middletown and Newport required the Company to: (1) manually shut off each gas service at each customer location, (2) re-pressurize the system, and (3) manually re-lighting gas service at each customer location. The Company mobilized hundreds of Company personnel and called on mutual aid assistance from other utilities to complete this work as quickly and efficiently as possible. The Company completed the re-lighting process for nearly all impacted customers by January 29, 2019 at 12:00 p.m.

The Commission has not issued a directive for accounting for cost related to the event.

Prepared by or under the supervision of: Melissa A. Little

F. Incentive-Based Earnings Sharing Mechanism

The Settling Parties agree that a properly structured incentive-based rate plan can align the interests of the Company and its customers by establishing appropriate incentives to maximize merger-related savings for the benefit of the Company and its customers. To that end, the Settling Parties agree that the Company will implement an earnings-sharing mechanism ("ESM") to provide for the sharing of net merger-related savings, or other savings, that may be achieved in excess of those identified and incorporated into the consolidated revenue requirement. The ESM will remain in place for the period July 1, 2002 through June 30, 2010. Any amounts due to customers as a result of the application of the ESM will be credited to customers through the DAC.

1. Earnings Sharing Calculation

The Company will file the earnings-sharing calculation by September 1 of each year, based on financial results for the 12-month period ending each June 30. For the purpose of such earnings reports, the determination of earnings subject to the ESM will be based on an benchmark return on equity of 11.25 percent, excluding the Company's portion of non-firm margins addressed in section H, below. Results will be adjusted to reflect established Commission ratemaking principles, including the impact of the Weather Normalization Clause, discussed in section J, below. However, there will be no adjustment to actual results to recognize or annualize known and measurable changes.

The return on common equity will be calculated by dividing the net income available for common equity by the common equity applicable to rate base; where the net income available for common equity is equal to operating income adjusted to reflect Commission ratemaking principles less applicable interest and preferred dividends (if any), subject to the

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limitations in paragraph 2, below. The applicable interest shall be calculated by multiplying average rate base by the percentage debt in the capital structure times the applicable cost rate, and the applicable preferred dividends shall be calculated by multiplying average rate base by the percentage of preferred stock in the capital structure times the applicable cost rate.

The common equity applicable to rate base shall be calculated by multiplying the actual common equity ratio, subject to the limitations in paragraph 2 below, by rate base. The rate base used in these calculations will be the average rate base for the relevant period, based on a five-quarter average and established Commission ratemaking principles. The working capital allowance will be calculated pursuant to the method approved by the Commission in Docket No. 2286. Construction work in progress will be included in rate base, and the allowance for funds used during construction will be included in operating income. No prepaid taxes will be included in rate base. The deferred debits in rate base as of July 1, 2002 will be $3,060,000, representing the remaining balance of deferred Year 2000 costs, exclusive of the legacy customer information system costs, as of that date. These deferred Year 2000 costs, exclusive of the legacy customer information system costs, will continue to be amortized at a rate of $240,000 per year.

2. <u>Capital Structure</u>

Because the Company's actual equity as shown for financial accounting purposes cannot be distinguished from that of Southern Union Company ("Southern Union") as a result of the merger, the Company will use an imputed capital structure for the purpose of calculating the earned return on equity subject to the ESM. The imputed capital structure will be as follows during the Rate-Freeze Period:

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The Narragansett Electric Company d/b/a National Grid
Rate Base Summary
Five Quarter Average Ending June 30, 2017 through Rate Year Ending August 31, 2021

	Description	Five Quarter Average Ending June 30, 2017	Adjustments	Rate Year 1 Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021
		(a)	(b)	(c)	(d)	(e)
1	Gas Plant In Service	$1,092,141,316	$214,715,738	$1,306,857,054	$1,328,015,869	$1,349,443,902
2	Normalizing Adjustment: Smallworld GIS[1]	$3,996,550	$0	$3,996,550	$3,996,550	$3,996,550
3	Gas Plant In Service	$1,096,137,866	$214,715,738	$1,310,853,604	$1,332,012,419	$1,353,440,451
4						
5	Construction Work In Progress	$49,783,414	($5,570,043)	$44,213,371	$45,444,229	$46,739,869
6						
7	Less: Accumulated Depreciation	$389,907,868	$37,266,066	$427,173,934	$428,191,816	$429,895,395
8	Normalizing Adjustment: Smallworld GIS[1]	$2,987,945	$0	$2,987,945	$3,414,129	$3,840,314
9	Test Year Adjusted Accumulated Depreciation	$392,895,813	$37,266,066	$430,161,879	$431,605,945	$433,735,709
10						
11	Less: Contribution in Aid of Construction	$38	($984)	($946)	($2,250)	($3,622)
12						
13	Net Plant	$753,025,429	$171,880,612	$924,906,042	$945,852,952	$966,448,234
14						
15	Additions:					
16	Materials and Supplies	$3,941,353	($1,261,179)	$2,680,174	$2,159,157	$1,610,719
17	Prepaid Expenses, Excluding Taxes	$393,734	($189,233)	$204,501	$276,014	$351,290
18	Deferred Debits	$411,653	($411,653)	$0	$0	$0
19	Cash Working Capital	$8,974,216	($2,301,262)	$6,672,954	$6,672,954	$6,672,954
20	Unamortized Interest Lock expense $550M	$1,068,051	($350,778)	$717,273	$555,375	$393,477
21	Unamortized Issuance Costs $300M	$406,500	($37,950)	$368,550	$351,035	$333,519
22	Unamortized Issuance Costs $250M	$81,303	($54,906)	$26,397	$4,434	$0
23	Unamortized Issuance Costs $200M	$274,996	($23,064)	$251,932	$241,287	$230,642
24	Unamortized Issuance Costs $350M	$0	$454,825	$454,825	$406,525	$358,225
25	Unamortized Issuance Costs Mortgage Bonds	$103,899	($49,670)	$54,229	$31,304	$8,379
26	Total Additions	$15,655,704	($4,224,871)	$11,430,834	$10,698,085	$9,959,206
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28	Deductions:					
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31	Customer Deposits	$2,342,658	($875,181)	$1,467,477	$1,208,830	$936,570
32	Total Deductions	$136,186,909	$39,585,171	$175,772,080	$183,266,434	$187,720,560
33						
34	Rate Base	$632,494,225	$128,070,571	$760,564,795	$773,284,603	$788,686,880
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36	Total Rate Base			$760,564,795	$773,284,603	$788,686,880

[1]Gas Information System

Column Notes
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(b) (c) minus (a)

Line Notes
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8(d) 8(c) plus Schedule 5-GAS Page 1 of 1 Column Notes (e)
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