STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE:	**THE NARRAGANSETT ELECTRIC**	**:**	
	COMPANY d/b/a NATIONAL GRID	**:**	**DOCKET NO. 5165**
	DISTRIBUTION ADJUSTMENT	**:**	**DOCKET NO. 5180**
	CHARGE and GAS COST RECOVERY	**:**	

ORDER

On August 2, 2021 and September 1, 2021, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) filed its Distribution Adjustment Charge (DAC) and Gas Cost Recovery (GCR) filings with the Rhode Island Public Utilities Commission (Commission or PUC) for effect November 1, 2021.[1] The DAC recovers certain specified costs that relate to delivering gas to all customers safely and reliably, the costs of which are not already recovered in base gas distribution rates or other applicable rate recovery mechanisms. The GCR recovers the costs of providing gas supply to firm gas sales customers of the Company who do not purchase their gas supply from third party marketers; but, instead, purchase firm supply from the Company who procures the gas supply and associated transportation on their behalf.[2]

On September 20, 2021, National Grid also filed its semi-annual BTU factor report.[3] Subsequent to the initial DAC and GCR filings, the Company made supplemental filings that included updated and new testimony, schedules, rate factors, and bill impact analyses. The resulting incremental increase sought for recovery under the DAC was approximately $19.7

[1] All filings in this docket are available at the PUC offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at http://www.ripuc.org/eventsactions/docket/5165page.html and http://www.ripuc.org/eventsactions/docket/5180page.html.

[2] All residential customers receive firm gas supply from the Company, along with a subset of non-residential customers who do not take firm or interruptible supply from an unregulated marketer. Residential customers do not have the choice to purchase gas from marketers.

[3] 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 covert volumetric meter readings into therms.

million all of which is recovery of the amount deferred from the 2020 in what was coined as the COVID deferral, while the incremental increase sought for recovery under the GCR was approximately $17.6 million, for a total cost increase of approximately $37.3 million.

In response to the initial filings, the Division of Public Utilities and Carriers (Division) filed testimony and several memoranda addressing the Company's proposed rate factors, incentive payment requests, and other issues. The memoranda recommended that the Commission approve the rate factors with certain changes it had recommended.

In both dockets, the Company filed revised testimony and schedules. The Division filed a memorandum in the DAC and prefiled testimony in the GCR on September 24, 2021. On October 26, 2021, the Commission conducted an Open Meeting where it deliberated on the Company's DAC and GCR proposals. It approved recovery of the costs associated with all but one of the Company's proposed DAC factors and ordered elimination of the one. It approved recovery of all the costs associated with the Company's requests regarding the GCR.

WITNESSES PRESENTING TESTIMONY

The following witnesses provided pre-filed testimony for the Company for the DAC:

1. Ryan M. Scheib provided testimony to describe the reconciliation of the various components of the DAC and to propose new factors to become effective November 1, 2021. He provided two sets of supplemental testimony to update and revise his original testimony and present a bill impact analysis of the proposed revisions.

2. Amy Smith and Nathan Kocon provided joint testimony to present the Company's FY 2021 Annual Reconciliation filing for the Gas ISR Plan, including the actual spending

for the period April 1, 2020 through March 31, 2021 and the Adjusted Capital Additions In-Service in FY 2021. They also provided detailed information regarding the major spending variances for this period.

3. Jeffrey D. Oliveria and James H. Allen provided joint testimony to describe the origin of the Company's Pension and Post-Retirement Benefits Other than Pensions (PBOP) expense reconciliation and provided the calculation of the Pension and PBOP costs to the allowance for recovery in base distribution rates.

4. Melissa A. Little provided testimony to describe the Company's gas earnings subject to National Grid's Earnings Sharing Mechanism for the 12-month period ending December 31, 2021.

Ms. Little did not testify at the hearing as no earnings to be shared were reported for the period. Also, while David Moreira did not file prefiled testimony; he responded to data requests and testified at the hearing regarding the Advanced Gas Technology program.

The following witnesses provided pre-filed testimony for the Company for the GCR:

1. Elizabeth D. Arangio, Megan J. Borst, and Samara A. Jaffe provided joint testimony as the Gas Supply Panel regarding estimated gas costs and items relating the Company's proposed GCR factors. Their testimony also discussed the modifications that the Company made to its portfolio for the 2021-2022 GCR period.

2. Ryan M. Scheib provided testimony to calculate the GCR factors proposed for effect November 1, 2021.

3. Theodore Poe, Jr. and Shira Horowitz provided joint testimony as the Gas Load Forecasting Panel to support the retail and wholesale forecasts of natural gas customer requirements that are used to estimate gas costs.

4. John M. Protano provided testimony to discuss the results of the Company's Gas Procurement Incentive Plan (GPIP) and Natural Gas Portfolio Management Plan (NGPMP) for the period April 1, 2020 through March 31, 2021 and to provide an exhibit illustrating the impact of the current financial hedges for November 2021 through October 2022 in the GPIP.

Mr. Poe did not attend the hearing; however, Ms. Horowitz was present to discuss the testimony she filed jointly with Mr. Poe. Mr. Protano was unable to attend the evidentiary hearing, and Mr. Stephen Longo appeared at the hearing to adopt the pre-filed testimony of Mr. Protano as his own. All other witnesses for the Company who provided pre-filed testimony appeared at the hearing.

The Division's expert witness for both the DAC and GCR, Mr. Mierzwa, did not appear at the hearing, but a memorandum he prepared jointly with Lafayette Morgan, Jr. regarding the DAC and his prefiled testimony regarding the GCR were entered into the record without objection, as full exhibits. At the evidentiary hearing, Mr. Alberico Mancini appeared on behalf of the Division to answer questions in both matters.

<u>THE DISTRIBUTION ADJUSTMENT CHARGE</u>

The DAC is filed annually to establish a rate that reconciles estimated gas costs to actual gas costs for the prior 12-month period from November 1 through October 31, as well as costs forecasted for the next twelve-month period beginning on November 1. The DAC provides for funding, or the reconciliation and refund, of amounts associated with several of the Company's specific gas programs, services, and initiatives, the costs of which are not already being recovered in base distribution rates. Each of the associated cost categories are tracked and reconciled separately. The net costs are allocated and charged across various rate classes through separate rate components referred to as "factors" that add up to the final DAC "factor" for each applicable rate class.[4] As part of the DAC filing, National Grid also files an Annual Environmental Report for Gas Service, a Revenue Decoupling Mechanism (RDM) Reconciliation Filing, and a Gas Infrastructure, Safety, and Reliability (ISR) Plan Annual Reconciliation Filing, each of which provides data supporting the request for the increases in the various applicable rate components. In addition to reconciling and addressing certain gas service costs, the reconciliation process under the DAC tariff also facilitates the timely rate recognition of certain incentive/penalty provisions associated with the Company's management of certain gas costs.

The components or factors underlying the final DAC factor are: 1) a System Pressure factor; 2) an Advanced Gas Technology (AGT) factor; 3) an Environmental Response Cost (ERC) factor; 4) a Pension Adjustment factor; 5) an Arrearage Management Adjustment factor; 6) an Earnings Sharing Mechanism (ESM) factor; 7) a Low Income Discount Recovery (LIDR) factor; 8) a Service Quality Plan factor; 9) a Revenue Decoupling Adjustment (RDA) factor; 10) a rate class specific Infrastructure, Safety, and Reliability (ISR) factor; 11) two Reconciliation factors

[4] The term "factor," when used in the context of the rates, refers to a rate component designed to recover a particular type of cost that is specified and calculated in a manner defined in the Company's tariffs that have been approved by the Commission in prior proceedings. As indicated, the final DAC factor is a rate that is made up of numerous other factors which, when added together, sum to the final DAC factor.

for last year's DAC factors;[5] and 12) a Storm Net Revenue factor. Most of the DAC factors are grossed up to include a 1.91% uncollectible percentage as approved in Docket No. 4770.[6]

National Grid's August 2, 2021 DAC filing, September 1, 2021 Supplemental filing, and a revision filed on September 10, 2021 provided testimony and support for an aggregate rate decrease of approximately $8,000, when all the components are taken into account. However, in Docket Nos. 5040 and 5066, the Commission ordered National Grid to "implement a COVID Deferral Factor that reduces each of the applicable approved DAC and GCR factors to achieve a deferral equal to fifty (50) percent of the combined incremental increases" until the Commission allowed recovery in future rates.[7] The Company proposed to recover the cost increases through a DAC factor of $0.0515 per therm for the Residential and Small and Medium Commercial and Industrial (C&I) customers, $0.0493 per therm for the Large and Extra-Large C&I customers, and $0.0331 per therm for Residential Low Income customers. After including the annual ISR component that varied from credits ranging from $0.0658 per therm to $0.0035 per therm depending on customer class, the final DAC rates proposed by the Company ranged from $0.1854 per therm for all Residential Heating customers to $0.0851 per therm for the Extra-Large Low Load C&I customers.[8] Firm throughput which is used to calculate many of the factors was identified as 40,273,298 Dth.[9]

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[5] The two reconciliations are the "Revenue Decoupling Adjustment Reconciliation" and the "ISR Reconciliation."
[6] The two factors relating to revenue decoupling are not grossed up by the uncollectible rate.
[7] Order No. 23967.
[8] Scheib Second Supp. DAC Test. Sch. RMS-1S (Sept. 10, 2021). The Company filed two revisions to the August 2, 2021 filing. The supplemental testimony included schedules where some of the factors were updated and which replaced original schedules. Updated schedules are referred to with a number and "S" indicating it is a supplement with the most current figures and calculations. All references to schedules in this order and footnotes herein refer to the most recent schedule filed even though original testimony may be cited.
[9] DAC Filing, Scheib Test. at 26 (Aug. 2, 2021).

The Company proposed a System Pressure factor of $0.0165 per therm for an estimated $6.7 million in hourly peaking fixed costs from the November 1, 2021 through October 31, 2022 period.[10] In a memorandum filed on September 24, 2021 by its consultants, Jerome D. Mierzwa and Lafayette Morgan, Jr. of Exeter Associates, Inc, the Division found the Company's removal of $6.7 million in hourly peaking costs from the GCR filing and including those costs in the System Pressure Factor to be reasonable. The Division noted that although the Commission ordered the Company to revisit whether the 20,000 Dth per day Everett gas supply contract should be included in the System Pressure Factor as hourly peaking costs when that contract expires, the contract does not expire until the end of the 2021-2022 winter season. The Division recommended that when the contract does expire, the Company conduct the analysis. The Division also noted that the Company had incurred no incremental variable costs in meeting the hourly peak demands during the winter season and recommended that it report if it incurs any during this winter season, and if so, remove those costs from the 2022 GCR reconciliation process and include them in the DAC reconciliation process.[11]

National Grid did not propose funding the AGT factor, which is a funding mechanism in the Company's gas distribution tariffs which provides a means for the Company to recover the costs of providing financial incentives to customers who increase gas usage or shift gas usage to off-peak periods. Last year the Commission ordered the $713,040 balance in the fund to be returned to ratepayers. Interest on the fund from April to October 2021 is $5,226 and the remaining

[10] Scheib Supp. DAC Test. at 4, Sch. RMS-1S, RMS-2S (Sept. 1, 2021).
[11] Mierzwa and Morgan Mem. at 4-5 (Sept. 24, 2021).

balance is $86,918, which National Grid proposed be credited to ratepayers through the Reconciliation factor.[12] The Division provided no objection to the Company's proposal.[13]

National Grid also proposed the following factors, of which the Division recommended approval after finding them to be appropriate: 1) $0.0016 per therm for Environmental Response Costs to recover the incremental cost of $653,054;[14] 2) $0.0112 per therm for Pensions and Postretirement Benefits Other than Pensions to recover the incremental cost of $4,584,169;[15] 3) $0.0005 per therm for the Arrearage Management Adjustment to recover the incremental cost of $202,940;[16] 4) ($0.0000) per therm for the FY 2021 RDM Reconciliation factor because the $28,000 over-recovery was too small to calculate a factor, so the Company will carry it forward into next year's RDM reconciliation;[17] 5) ($0.0001) for a Service Quality Factor to credit customer for the $75,000 penalty the Company incurred for performance in meter testing;[18] 6) $0.0000 per therm for the Earnings Sharing Mechanism factor because the Company's return on equity was below the earnings sharing threshold;[19] 7) $0.0015 per therm for the Reconciliation factor for all Residential and Small and Medium C&I rate classes and $0.0011 per therm for the Large and Extra-Large rate classes to recover $589,937;[20] 8) $0.0018 per therm for a FY 2021 RDM Reconciliation applicable to Residential and Small and Medium D&I rate classes to recover $533,563;[21] 9) $0.0180 per therm for the Low-Income Discount Recovery factor to recover the

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[12] Scheib DAC Test. at 6-7 (Aug. 3, 2021); Scheib DAC Test. RMS-3, RMS-10S (Sept. 10, 2021).
[13] Mierzwa and Morgan Mem. at 4-5.
[14] Scheib DAC Test. at 7-8, Sch. RMS-1S, RMS-4; Annual Environmental Report for Gas Service (Jul. 30, 2021); Mierzwa and Morgan Mem. at 5-6.
[15] Scheib DAC Test. at 9, Sch. RMS-1S; RMS-5; Mancini Mem. at 4 (Sept. 24, 2021).
[16] Scheib DAC Test. at 10-14, Sch. RMS-1S, RMS-6; Mierzwa and Morgan Mem. at 6.
[17] Scheib DAC Test. at 14-15, Sch. RMS-1S, RMS-7; RDM Reconciliation Filing (July 1, 2021); Mierzwa and Morgan Mem. at 6-7.
[18] Scheib DAC Test. at 16, Sch. RMS-1S, RMS-9; Mierzwa and Morgan Mem. at 7.
[19] Scheib DAC Test. at 17, Sch. RMS-1S, Sch. RMS-12; Mierzwa and Morgan Mem. at 7-8.
[20] Scheib Supp. DAC Test. at 6-7, Sch. RMS-1S, RMS-10S (Sept. 1, 2021); Mierzwa and Morgan Mem. at 7.
[21] Scheib DAC Test. at 23, RMS-1S, RMS-10S; Mierzwa and Morgan Mem. at 7.

total annual cost of the discount provided to the low-income rate class of $6,974,977;[22] and 10) ($0.0004) per therm for a Storm Net Revenue factor calculated to credit $173,714 to customers.[23]

To reconcile its ISR costs, which recover the incremental revenue requirement for the Company's capital investments for the applicable period, National Grid proposed factors ranging from ($0.0035) to ($0.0658) per therm.[24] The Commission previously approved a budget of $198.61 million for the Company's ISR Plan in Docket No. 4996. The ISR Reconciliation filing submitted by the Company on July 30, 2021 showed that it had actual spending of $165.27 million which was $33.34 million less than the approved budget.[25] The ISR Reconciliation filing calculated the actual revenue requirement at $14,851,995 reflecting a $7,909,534 decrease from the forecasted revenue requirement of $22,761,529 approved by the Commission in Docket No. 4996.[26] This resulted in an over-collection of the revenue requirement associated with the incremental forecasted costs in the ISR, equal to $7,909,534.[27] The updated actual revenue requirement of $14,851,955 was allocated among the applicable rate classes, resulting in the range of factors by rate class from ($0.0035) to ($0.0658) per therm.[28] The Company provided explanations for the variances in spending for the different programs. A large portion of the total variance was due to the COVID-19 Pandemic.[29] The Division filed a memorandum recommending approval of the Company's proposed factors. It found that the underspending was reasonable and recommended no adjustment to the updated $14,851,995 revenue requirement.[30]

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22 Scheib Second Supp. DAC Test. at 4, Sch. RMS-1S, RMS-13S (Sept. 10, 2021); Mierzwa and Morgan Mem. at 8. The Low-Income Discount Recovery factor provides a 25% discount to Rates 11 and 13 customers.
23 Scheib Second Supp DAC Test. at 5, Sch. RMS-1S, RMS-14S; Mierzwa and Morgan Mem. at 8. .
24 Scheib DAC Test. Sch. RMS-1S.
25 Smith/Kocon ISR Reconciliation Test. at 5 (Jul. 30, 2021).
26 Little ISR Reconciliation Test. at 4-17, Att. MAL-1, (Jul. 30, 2021).
27 *Id.* at 4.
28 Scheib DAC Test. Sch. RMS-1S.
29 Smith/Kocon ISR Reconciliation Test. at 5.
30 Mancini Mem. at 1-4.

In Docket No. 5040 and Docket No. 5066, the Commission ordered the Company to implement a COVID Deferral Factor and to reduce each of the applicable approved DAC and GCR factors, respectively, to achieve a deferral equal to fifty (50) percent of the combined incremental increases. The Commission did so in order to mitigate the financial burdens of heating costs on ratepayers during a time of economic crisis for many as a result of the global pandemic which caused many businesses to close and many individuals to have no reliable form of income. The deferred amount for the DAC was estimated to be $9,685,528, while the deferral for the GCR was estimated to be $3,323,607.[31] In order to recover the $9,685,528 amount of under-recovery resulting from the DAC deferral, the Company proposed factors ranging from $0.0109 to $0.0301 depending on rate class. The under-recovery is based on nine months of actual credit revenue (November 2020 through July 2021) and three months of forecasted credit revenue (August 2021 through October 2021) plus interest incurred.[32] The GCR deferral was embedded in the Company's reconciliation of gas costs.[33] The Division recommended that the Commission adopt the Company's proposal for the recovery of the DAC-related deferral and recommended approval of the GCR rates.[34]

THE GAS COST RECOVERY RATES

The GCR is an annual filing that allows National Grid to adjust its rates for firm sales and the weighted average cost of upstream pipeline transportation capacity. It allows the Company to recover the costs of gas supplies, pipeline and storage capacity, production capacity and storage, and purchased gas working capital. It also permits the Company to account for supplier refund

[31] Attachment RMS-2, page 1.
[32] Scheib DAC Test. at 19-20; Scheib Supp. DAC Test. at 6, RMS-1S.
[33] Attachment RMS-2, page 1.
[34] Mierzwa and Morgan Mem. at 8; GCR Hr'g Tr. at 39 (Oct. 13, 2021).

credits, capacity credits from off-system sales, and revenues from capacity release transactions. National Grid calculates the gas charges separately for sales customers (a high load group and a low load group) and Firm Transportation (FT) customers (marketers). The gas charges to sales customers consist of two components: fixed costs and variable costs. Like the DAC, the cost calculation includes an adjustment for an uncollectible percentage of 1.91% as approved in Docket No. 4770.

In a September 10, 2021 Revised GCR filing, National Grid proposed the following: 1) a high load factor of $0.5413 per therm; 2) a low load factor of $0.6137 per therm; 3) an FT-2 Demand Rate Usage of $11.8772 Dth/Mth; and 4) an FT-2 Storage and Peaking for FT-1 firm transportation customers eligible for TSS of $0.9323 per dekatherm.[35]

National Grid explained how it projected and calculated gas costs.[36] The Company explained that the GCR factors were based on the New York Mercantile Exchange ("NYMEX") forward curve as of the close of trading on August 3, 2021.[37] It noted that its total gas costs are $21.6 million higher than those forecasted in the Long Rang Plan. The higher costs are attributable to: 1) an increase in the supplier demand charges and 2) an increase in gas commodity costs.[38] The Company presented a fiscal year 2021 Annual GCR Reconciliation balance of $5,789,241.[39]

[35] Scheib GCR Revised Test., Revised Attach. RMS-1 at 1, Revised Attach. RMS-5 (Sept. 10, 2021). National Grid originally made a filing on September 1, 2021 but on September 10, 2021 revised it to reflect the impact of the August 31, 2021 Federal Regulatory Commission "Order Rejecting Tariff Records and Directing to Show Cause" a rate increase proposed by Texas Eastern Transmission, LP, (TETCO) the proposed rate increase of which National Grid had included in its September 1, 2021 filing. The revision filed on September 10, 2021 affected only the Gas Supply Panel Testimony and Attachments. The testimony and attachments of the Gas Load Forecasting witnesses and John M. Protano filed on September 1, 2021 were unaffected.
[36] Gas Supply Panel GCR Test. at 7-15 (Sept. 1, 2021), Revised Att. GSP-1, Att. GSP-2, Att. GSP-3 (Sept. 10, 2020).
[37] *Id.* at 7.
[38] Gas Supply Panel GCR Test. at 16. The September 1, 2021 filing indicated a greater increase and one of the reasons as a result of the Texas Eastern Transmission, LLP anticipated rate increase.
[39] Scheib GCR Test. at 12, Att. RMS-2.

Embedded in the GCR Reconciliation balance was the GCR COVID deferral from Docket No. 5066.[40]

The Company submitted testimony regarding the development of its 2020/21 sales forecast of 40,084,553 MMBtu which was slightly higher than last year.[41] It presented testimony about the Gas Procurement Incentive Plan (GPIP) and the Natural Gas Portfolio Management Plan (NGPMP). It noted no changes to the GPIP over the last year. It stated that it had purchased discretionary supply of 2,453,000 Dth which resulted in a $20,648 incentive for the Company.[42] The NGPMP produced total savings of $9,043,353 of which $8,039,179 was customers' share. National Grid asked the Commission to approve the remaining $1,004,353 as the Company's incentive.[43]

On September 20, 2021, National Grid proposed a BTU factor of 1.030 for the six-month period November 2021 through April 2022.[44] In a memorandum dated October 21, 2021, the Division recommended approval of the proposed BTU factor as filed.[45]

On September 24, 2021, the Division filed the testimony of its consultant, Jerome D. Mierzwa. He noted how the Company had revised its September 1, 2021 filing to reflect the effects of the Federal Energy Regulatory Commission's "Order Rejecting Tariff Records and Directing to Show Cause" in Texas Eastern Transmission, LLP's application to increase rates docket which caused National Grid to file revised testimony on September 10, 2021. Mr. Mierzwa made a

[40] RMS-2 at 1, line 37, column (m).
[41] Gas Load Forecasting Test. at 4-12, Att. GLF-1-GLF-5 (Sept. 1, 2021). This throughput was also used to calculated DAC factors.
[42] Protano GCR Test. at 3-7, Att. JMP-2, JMP-5 (Sept. 1, 2021).
[43] Protano Test. GCR at 7-9, Att. JMP-3, JMP-4.
[44] Boyajian Letter at 1 (Sept. 20, 2021).
[45] Mancini Mem. at 1 (Oct. 21, 2021).

number of findings and recommendations. First, he found National Grid's proposal to remove peak hour costs of $6.69 million from the GCR and recover them through the DAC in this proceeding to be reasonable.[46] He found the Company's report that it incurred no incremental variable costs to be accurate and recommended that National Grid should track the actual incremental variable costs it incurs to meet hourly peak demand, report those costs in its 2022 DAC and GCR filings, and if significant remove them from the GCR reconciliation process and include the costs in the DAC reconciliation process.[47]

Mr. Mierzwa discussed National Grid's 20,000 Dth per day Everett gas supply contract and how the Commission in Docket No. 5066 ordered the Company to revisit whether those costs should be included in the System Pressure factor in the DAC if it chose to execute a replacement arrangement when that contract expires. Mr. Mierzwa noted that since the contract had not yet expired, the Company had not revisited the issue. He recommended that should National Grid execute a replacement agreement, it should evaluate whether the replacement agreement is necessary to meet design peak hour demands, and if it is the charges associated with the replacement should be included in the DAC.[48]

Mr. Mierzwa discussed how the Company was ordered in Docket No. 5066 to continue to work with the Division to develop data exchange protocols for the Natural Gas Portfolio Management Plan (NGPMP), that this was done, and how those protocols will provide additional transparency and more efficient auditing.[49] He did not express any concern with the incentive

[46] Mierzwa Test. at 5, 13 (Sept. 24, 2021)..
[47] *Id.* at 5, 13-14.
[48] *Id.* at 5, 13.
[49] *Id.* at 5-6, 15.

amounts sought by the Company for either the Gas Procurement Incentive Plan (GPIP) or the NGPMP.[50]

Mr. Mierzwa explained how the Company and the Division had collaborated regarding the Company's accelerated hedge purchase practices and how the Company had a policy of accelerating one-third of its mandatory purchases and making those purchases all on one day two years prior to the month of delivery. Mr. Mierzwa stated that the Company and the Division had conducted an analysis of other Local Distribution Company's hedging programs and analyzed National Grid's program against historical market prices. He stated that after review, both the Division and the Company determined that National Grid's accelerated hedging program was not unreasonable and concluded that National Grid should continue its current practice. He noted that the Division would continue to evaluate the value of the hedging practices to customers and determine if future change was necessary.[51]

Lastly, Mr. Mierzwa noted that the Company's proposed factors were based on NYMEX forward curves as of the close of trading on August 3, 2021 which was $4.13 per Dth. Since that time, he stated that prices have increased and as of the date of his testimony the average price for the winter 2020/2021 was $5.50 per Dth. He recommended that the Company update its rate projections if the price difference is material, e.g., 5%, to minimize any over/under-collection that may occur.[52]

[50] *Id.*
[51] *Id.* at 6, 16-17.
[52] *Id.* at 17-18.

HEARINGS

On September 14, 2021, the Commission held a public comment hearing. The Commission then held back-to-back evidentiary hearings on October 13, 2021 to hear evidence on the proposed DAC and GCR factors in Docket Nos. 5165 and 5180, respectively.

The DAC Hearing

During the hearing, the Commission questioned National Grid on a number of the proposed factors. The first was the Low-Income Discount Recovery factor. Specifically, the Commission inquired as to why the Company used a factor of 25% to calculate the total discount when depending on a customer's financial situation, the discount applied could be as high as 30%. Mr. Scheib justified the Company's use of 25% by noting that the large majority of customer receiving the discount, 80-85%, receive a 25% discount. He also noted that factoring in the small number that receive more than the 25% discount would not have a significant impact on the total estimated for the factor. He was unsure of the Company's practice on the electric side of operations but acknowledged that the Company's use a blended factor based on actual enrollments in the future would not be unreasonable. Mr. Scheib also testified that the Company had not considered the effects of the auto enrollment process, the first round of which he believes occurred in July, because the Company's forecast was created in June. He indicated that he could provide the anticipated increase in the gas low-income discount enrollment as a result of the auto enrollment plan.[53]

[53] DAC Hr'g Tr. at 15-26 (Oct. 13, 2021).

The next area of questioning was about the Company's ISR reconciliation. Mr. Kocon noted that the primary challenge the Company faced in FY 2021 associated with its main replacement work was the COVID pandemic. He explained that transferring to new mains and abandoning old mains requires the Company to enter customers premises and that due to safety concerns related to COVID, the Company was not able to do this for a prolonged period of time. And although throughout the course of the year, most customers allowed access to their premises, there were still some that did not. When questioned whether there were negative consequences with not meeting the replacement targets, Ms. Smith noted that the Company performs regular leak surveys to assess risk and will remediate quickly as an emergency. Mr. Kocon explained the process of replacing the main, how it goes into service, and what happens when the old main is still needed. Ms. Smith provided that the risk of leaks on the old main remains at the same level. She noted that there was still a benefit to putting the new main in service simultaneously. She testified that it was easier during the pandemic to do the work in the street, because there was less traffic and that by the time the Company was willing to go into customers' homes, more customers were willing to let them. She stated that the situation of not being able to achieve the target of abandonment was an oddity of the past year. Also contributing to not achieving the target was that some of the Company's employees either had COVID or had to quarantine because of exposure to someone with COVID.[54]

Mr. Moreira was questioned about his response to PUC 3-6 that asked the Company to indicate

> "whether or not [it] believes that continuation of the AGT program conflicts with the objectives of the recently enacted Act on Climate given that it is designed to promote the development of gas technologies that increase usage of natural gas delivered on the

[54] *Id.* at 27-41.

> company's system during periods of low demand which brings in more margin for the company."

Mr. Moreira's response was that "[t]he AGT program is not designed to increase the burning of natural gas by customers in the aggregate, but to find ways to optimize the manner in which natural gas is used" and that "the AGT program influences the demand for natural gas during certain months of the year to improve the utilization of the distribution system by increasing the company's load factor and thereby lower the average unit cost of natural gas supply services to all firm customers." The Commission questioned how the program lowers the average unit cost of gas for all customers. He claimed that if the load was flattened for all customers throughout the 12-month period, in the fall, the Company will be in a better position for a better price because it will have a more levelized load going into the heating season.[55]

Mr. Moreira was referred to witness testimony in Docket No. 5079 where another Company witness testified that

> "[t]he AGT program was established in Docket No. 2025 to promote the development of energy efficient natural gas technologies that increase utilization of natural gas during periods of low demand. Increase off-peak usage reduces the unit cost of gas delivery" – "of the gas delivery system for all customers by generating distribution revenue to support fixed costs associated with resources needed during peak periods."

Mr. Moreira acknowledged that the program can result in increased gas usage but clarified that by stating that it would depend on how much of the load was shifted to the summer versus the fall. When pressed, he admitted that his colleague's previous testimony in Docket No. 5079 was accurate when it indicated that the purpose of the program was to generate more distribution revenue there would have to be more gas usage, but qualified that by stating it would have to be looked at on a case-by-case basis where the Company actually shifted the load and stated in some

[55] *Id.* at 53-56.

instances there was not a shift but that just added use between April and September. Mr. Moreira was asked about the contradictory responses given by him and his colleague regarding the purpose of the program. Specifically, prior testimony from the Company asserted that the program is designed to increase the use of gas throughout the year, while Mr. Moreira stated that it is only designed to shift usage. But Mr. Moreira was unable to provide a satisfactory explanation.[56]

Mr. Mancini testified that the Division recommended approval of the factors. He noted that the Division is working with the Company to close the gap between the number of installed miles of main and abandoned miles of main.[57]

The GCR Hearing

At the outset of the GCR portion of the hearings, counsel for the Company asked witness Arrangio to explain the Company's response to Mr. Mierzwa's recommendation that the Company update its gas cost projections.[58] Ms. Arrangio stated that the Company had not updated its GCR filing, referencing the Company's past practices and that there are a number of factors that affect the calculation. She also alluded to the fact that the NYMEX has been "varying quite a bit." According Ms. Arrangio,

> "[T]ypically the company doesn't update its filing for these types of variables because it's not just the NYMEX, there are other factors that would be changing that would need to be updated as well. So typically [the Company] deal[s] with these variables in looking at it throughout the year, the GCR year and deal[s] with that, if needed, would provide a supplemental GCR filing if necessary."[59]

[56] *Id.* at 56-67.
[57] *Id.* at 73-76.
[58] GCR Hr'g Tr. at 14 (Oct. 13, 2021)
[59] *Id.* at 15-16.

On cross-examination by the Division, Ms. Arrangio further elaborated, stating:

> "So we have not done that calculation with today's NYMEX close because – so we don't know if that factor will be plus or minus five percent because part of the company's portfolio is hedged as well, so those factors – some of the hedging would offset expected increases in NYMEX pricing as well."[60]

She further acknowledged that the winter average NYMEX price closed at $5.42 per Dth, as of October 11.[61] Another Company witness, Mr. Schieb, also noted that the Company's tariff allows the Company to request an adjustment to its rates if the Company forecasts an under-recovery of more than five percent.[62] The Company also offered Mr. Stephen Longo as a witness to discuss its hedging program and the GPIP and NGPMP proposed incentives.[63]

During questioning, Ms. Arangio noted that the real drivers of cost increase in the GCR are the commodity costs.[64] Providing an update on the TETCO filing at FERC, Ms. Jaffe testified that after FERC had rejected TETCO initial filing, a month later, it filed a request for re-hearing of the original case and a new rate case to which the Company filed an objection. She stated that she expected a decision by the end of October.[65]

Near the end of the evidentiary hearings, the Division offered Mr. Mancini as a witness, who testified that he was satisfied that if additional costs were incurred through the winter months,

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[60] *Id.* at 16-17.
[61] *Id.* at 16- 17. The difference between the NYMEX price used to calculate the factor and the price on the date of hearing is $1.29 per Dth.
[62] *Id.* at 20. The Company's Gas Recovery Clause within its gas tariffs contains the following provision, quoted in pertinent part: "In the event of any change subsequent to the November effective date which would cause the estimate of the Deferred Gas Cost Balance to differ from zero by an amount greater than five percent (5%) of the Company's gas revenues, the Company may make a Gas Charge filing designed to eliminate that non-zero balance." RIPUC NG-GAS No. 101, Section 2, Gas Charge, Schedule A, Sheet 1, Ninth Revision (Gas Recovery Clause § 1.2).
[63] *Id.* at 20-21.
[64] *Id.* at 31.
[65] *Id.* at 36.

they could be reconciled next year. Mr. Mancini then stated that the Division recommended approval of the rates proposed by the Company.[66]

DECISION

Every year, the DAC and the GCR are filed in the fall to address a subset of costs incurred by the Company that are necessary for the provision of safe and reliable gas service and supply. The annual filings typically result in a change of rates effective November 1 for the coming winter period. In recent years, the costs of providing safe and reliable gas distribution service and natural gas supply have risen significantly, largely due to growing constraints on the various gas pipeline systems that transport natural gas to the delivery points in Rhode Island. When the utility makes a filing of this type, the Commission (and the Division, acting as the ratepayer advocate) review the reasonableness of the costs and, unless there is an evidentiary basis for a finding that the costs were not necessary or the Company acted imprudently, the costs are allowed to flow through rates. The Commission has no legal authority to deny recovery for most of the types of costs flowing through the DAC or the GCR solely on the grounds that a rate increase is not desirable or might have a detrimental impact on the economy. It is in that context, bounded by legal requirements, that the Commission considered the request by National Grid to recover its incremental gas-related costs addressed by the DAC and the GCR.

The DAC Factors

Regarding the Company's proposed DAC factors, the Commission found the Company's proposed rates reflected in Schedule RMS-1 Second Supplemental to be reasonable and appropriate. In addition, the Commission relied on the comprehensive review performed by the

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[66] *Id.* at 38-39.

Division in evaluating the reasonableness of the costs. The Company proposed a $0.0000 factor for both the Revenue Decoupling Adjustment factor and the Earnings Sharing Mechanism factor which results in no net charge or credit on a customer's bill.

Regarding the Low-Income Adjustment factor, National Grid's proposed $0.0180 per therm was calculated using a 25% discount. Noting that in some instances the discount is 30%, the Commission expressed concern that the factor could under-recover the amount necessary to satisfy the discount resulting in a greater amount to reconcile the following year. It noted that in the electric docket, the Company uses a blended percentage of eligibility based on historical data and ordered the Company to do the same in the DAC going forward.

The Advanced Gas Technology Program (AGT)

While the Company's AGT factor was set at zero, the Commission is concerned about the continued existence of the AGT mechanism in the tariff. The Commission notes that the AGT originated as National Grid's DSM program designed to increase gas usage during off peak periods.[67] Justification for the program was that if gas usage was increased during off peak periods, there would be no impact on capacity, instead generating more revenue which would help offset fixed costs and, in turn, lower the unit cost of gas.[68] In Docket No. 3859, National Grid's 2008 DAC filing, the Company changed the name of the DSM factor to the AGT factor to avoid confusion with the energy efficiency filing it made in Docket No. 3790 pursuant to R.I. Gen. Laws § 39-2-1.2.[69] The AGT program continued for many years. However, for the past few years, the Company has not had any projects to earmark for funding through the program. In Docket No.

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[67] *See* Order No. 19152, Docket 3859 at 3-4 (Dec. 18, 2007).
[68] *Id.* at 4.
[69] *Id.* R.I. Gen. Laws §39-2-1.2(e) states that "[e]ffective January 1, 2007, and for a period of sixteen (16) years thereafter, each gas distribution company shall include, with the approval of the commission, a charge per decatherm delivered to fund demand-side management programs…." *See* Docket No. 3859, Czekanski Test. at 6 (Aug. 1, 2007).

5040, the Commission ordered the Company to refund to ratepayers the approximately $700,000 balance in the fund. It is apparent to the Commission that the AGT program is not resulting in any benefits, is outdated, and has lost its purpose. Further, shifting gas usage to off peak hours is now part of the Company's energy efficiency program.

At the evidentiary hearing, the Company's witness acknowledged that the program can result in increased gas usage.[70] But the witness had stated in response to a data request that: "The AGT program is not designed to increase the burning of natural gas by customers in the aggregate, but to find ways to optimize the manner in which natural gas is used."[71] When pressed about this, the witness claimed that it would allow the Company to get better pricing for all end use customers by shifting usage to off-peak hours.[72] This response that such a shift benefits all customers, however, makes no sense because not all customers purchase gas from the Company. Thus, any market price impact on the Company's purchases – if large enough – would only impact firm gas sales customers. Yet, the program costs are recovered from all customers paying the DAC charges. In that regard, the claim that the AGT program is designed to obtain market pricing benefits appeared to the Commission to be a contrived justification asserted to save an outdated program, because it does not appear to ever have been asserted as a goal of the program since it was first proposed in 1996.

Further, the witness's statement that the program is not designed to increase the burning of natural gas is completely contradicted by assertions made by the Company going back to the origin of the program in Docket 2025,[73] as well as recent representations made by the Company in Docket

[70] DAC Hr'g Tr. at 58, 59, 63, 66.
[71] PUC 3-5; DAC Hr'g Tr. at 54-55.
[72] DAC Hr'g Tr. at 55.
[73] Commission Compliance Order No. 15023, Docket 2025 (1996), Appendix Compliance Settlement, Subsection C.

No. 5079, where the Company explained that the program is designed to increase gas distribution revenues to reduce the unit cost of gas delivery.[74]

In that regard, the fact that the program has been designed to increase gas usage is most important in the context of the recently passed Act on Climate, R.I. Gen. Laws § 42-6.2-1 *et seq.* Given this significant enactment of policy, many issues need to be addressed on the future of the gas system, including but not limited to, decarbonization of supply, obsolescence of new and existing gas infrastructure, and the allocation of stranded asset risk of infrastructure. Thus, continuation of a program with the primary objective of encouraging more gas usage to increase revenues to the utility is directionally inconsistent with the policy goals of the Act on Climate. For these reasons, the Commission ordered National Grid to file an amended tariff reflecting the removal of the AGT provisions from its gas tariffs. This removal is without prejudice to the Company making a future filing to implement new provisions, provided it can meet the evidentiary burden of showing how the implementation of any newly proposed program is consistent with the goals of the Act on Climate and not duplicative of any demand response programs that are currently being implemented through the Company's energy efficiency programs.

The COVID Deferral

As noted above, the combined increase of both the DAC and GCR on an average residential heating customer is 6.8%. This increase would have been smaller; however, last year the Commission ordered the Company to defer 50% of the proposed increase because of the economic uncertainty associated with the COVID pandemic. The Commission reasoned that the deferral would ease the financial challenges faced by many who were out of work and struggling to satisfy

[74] DAC Hr'g Tr. at 61; Docket No. 5079, PUC 2-1.

financial obligations noting that National Grid would be able to recover the deferred amount at a later date. The 50% deferred from last year was included in the current dockets, and the Commission found recovery of the deferred amounts to be reasonable at this time.

Forecasted Gas Costs and the Rising NYMEX Futures

The Commission notes that this filing came before the Commission at a time when natural gas prices in the market are rising rapidly from both global and domestic market forces that are beyond the control of Rhode Island and this Commission. Public statements from the United States Energy Information Administration indicated that it was forecasting a 30% increase in natural gas costs for this coming winter. However, the Company has a procurement plan to purchase the supplies necessary for its Rhode Island customers that to a certain degree can or mitigate the impact on ratepayers from short-term jumps and sharp increases that many in other parts of the country face. In this instance, the impact of both the DAC and the GCR factors on a typical residential heating customer is an increase of 6.8%.

While indications were that NYMEX futures were rising and the Division's witness recommended that the Company's projections be updated, the Company's witness, Ms. Arangio, testified that the Company does not typically update its filing because there are factors other than the NYMEX that need to be updated as well.[75] She also testified that the Company typically waits until all the factors become "more set" before determining whether any rate adjustment is appropriate.[76] The Division pressed this issue at the hearing,[77] but the Company did not appear to be concerned about the changes in the NYMEX futures and, in fact, acknowledged that it did not

[75] GCR Hr'g Tr. at 16.
[76] *Id.* at 19.
[77] *Id.* at 16-17.

even make any attempt to update its GCR factors in response to the concern raised by the Division on September 24 when its pre-filed testimony was filed.[78]

It is important to note that the Company has the expertise to forecast its expected cost incurrence, with all the relevant market data available to it. In that regard, the Company has the obligation to assure that the forecast it uses for its forward-looking cost-recovery request is reasonable and reliable, taking into account all the information known to the Company. While it was apparent that the NYMEX futures had increased significantly between August 3 (the date of the NYMEX used for the forecast)[79] and October 11 (two days before the evidentiary hearing),[80] the Company nevertheless expressed no concerns at the hearing that the Company would be exceeding the tariff-based threshold – i.e., a greater than 5% difference between a zero gas-cost balance and an under-recovery of costs for the relevant period.[81] Acceptance of the Company's rate proposals, however, in no way should be interpreted as a finding that the Company's decision not to update the projections upon which the rates were based was either reasonable or unreasonable, since the Commission did not have available all the data and information as of the date of the hearing to draw any conclusions as to the reasonableness of the Company's actions or inactions at the time of the Commission's decision and the Division withdrew its recommendation to update the factors after hearing the testimony of the Company.[82]

Approval of GCR Rates, Incentives, and BTU Factor

[78] *Id.* at 14-15.
[79] *Id.* at 15; Att. GSP-2.
[80] GCR Hr'g Tr. at 17.
[81] RIPUC NG-GAS No. 101, Section 2, Gas Charge, Schedule A, Sheet 1, Ninth Revision (Gas Recovery Clause § 1.2).
[82] GCR Hr'g Tr. at 38.

At its Open Meeting, the Commission unanimously approved the Company's proposed factors and rates, including (i) the High Load Factor of $0.5413 per therm (ii) the Low Load Factor of $0.6137 per therm, (iii) the FT-2 Firm Transportation Marketer Gas Charge of $11.8772 per Dth/Mth, and (iv) the Storage and Peaking Charge for FT-1 firm transportation customers eligible for TSS of $0.9323 per Dth, were calculated. The Commission also approved the GPIP incentive of $20,648, the NGPMP incentive of $1,004,353, and the BTU Factor of 1.030.

The Commission ordered National Grid to continue to work with the Division to monitor advance hedge purchases to ensure the Company will accelerate gas purchases when gas prices are low. Further, it ordered National Grid to continue to track variable costs incurred in meeting peak hour requirements, to report those costs in the 2022 DAC, and if significant to allocate them from the GCR to the DAC. Finally, it ordered the Company to track the incremental variable costs associated with the peak and if they are significant to include them in the 2022 DAC.

Accordingly, it is hereby

(24275) ORDERED:

1. A System Pressure factor of $0.0165 per therm is approved for usage on and after November 1, 2021.

2. An Environmental Response Cost factor of $0.0016 per therm is approved for usage on and after November 1, 2021.

3. A Pension and Post-Retirement Benefits other than Pensions factor of $0.0112 per therm is approved for usage on and after November 1, 2021.

4. An Arrearage Management Adjustment factor of $0.0005 per therm is approved for usage on and after November 1, 2021.

5. A Revenue Decoupling Adjustment factor of $0.0000 per therm is approved for usage on and after November 1, 2021.

6. The various ISR reconciliation factors and components as set forth in RMS-8S are approved for usage on and after November 1, 2021.

7. The various COVID deferral factors and components as set forth in RMS-15S are approved for usage on and after November 1, 2021.

8. A Service Quality Performance factor of ($0.0001) per therm is approved for usage on and after November 1, 2021.

9. Reconciliation factors of $0.0015 per therm for Residential and Small and Medium C&I customers and $0.0011 per therm for Large and Extra-Large C&I customers are approved for usage on and after November 1, 2021.

10. A Revenue Decoupling Reconciliation factor for 2021 of $0.0018 per therm is approved for usage on and after November 1, 2021.

11. An Earning Sharing Mechanism factor of $0.0000 per therm is conditionally approved subject to further review of the Company's Earnings Sharing Report for usage on and after November 1, 2021.

12. A Low-Income Discount Recovery factor of $0.0180 per therm is approved for usage on and after November 1, 2021.

13. In subsequent DAC filings, Narragansett Electric d/b/a National Grid shall determine a blended percentage of eligibility based on historical data and use that percentage in the calculation to determine the Low-Income Discount Recovery factor.

14. A Storm Net Revenue factor of ($0.0004) per therm is approved for usage on and after November 1, 2021.

15. The AGT factor is cancelled and the Narragansett Electric Company d/b/a National Grid shall file an amended tariff reflecting removal of the provisions.

16. A High Load Factor of $0.5413 per therm is approved for usage on and after November 1, 2021.

17. A Low Load Factor of $0.6137 per therm is approved for usage on and after November 1, 2021.

18. Gas Marketer Transportation factors of:

    a. $11.8772 per Dth/Mth for FT-2 Firm Transportation Marketer Gas Charge and

    b. $0.9323 per Dth for Storage and Peaking Charge

    are approved for usage on and after November 1, 2021.

19. The incentive of $20,648 for the Gas Procurement Incentive Plan, for the period April 1, 2020 through March 31, 2021, is approved.

20. The incentive of $1,004,353 for the Natural Gas Portfolio Management Plan, for the period April 1, 2020 through March 31, 2021, is approved.

21. The BTU factor of 1.030 per ccf is approved.

22. The Narragansett Electric Company d/b/a National Grid shall work with the Division to continue to monitor the advance hedge an to determine if any changes are necessary and to ensure the Company will accelerate gas purchases when gas prices are low.

23. National Grid shall revisit the Everett 20,000 Dth per day arrangement when the contract expires to determine whether the costs associated with meeting peak requirements should be included in the DAC and if so, include those costs in the 2022 DAC filing.

24. The Narragansett Electric Company d/b/a National Grid will continue to track variable costs incurred in meeting peak hour requirements and report those costs in the 2022 DAC and if significant, allocate them from the GCR to the DAC.

25. The Narragansett Electric Company d/b/a National Grid in each subsequent DAC and GCR filing shall include a 1-page schedule comparing the Total Combined Increase of DAC/GCR, as approved for the previous year, compared to the updated as filed increase for the current year.

EFFECTIVE AT WARWICK, RHODE ISLAND ON NOVEMBER 1, 2021 PURSUANT TO AN OPEN MEETING DECISION ON OCTOBER 26, 2021 AND NOVEMBER 1, 2021. WRITTEN ORDER ISSUED DECEMBER 16, 2021.

PUBLIC UTILITIES COMMISSION

Ronald T. Gerwatowski, Chairman

Abigail Anthony, Commissioner

John C. Revens, Jr., Commissioner

NOTICE OF RIGHT TO 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.