STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE:	**THE NARRAGANSETT ELECTRIC**	**:**	
	COMPANY d/b/a NATIONAL GRID	**:**	**DOCKET NO. 5040**
	DISTRIBUTION ADJUSTMENT	**:**	**DOCKET NO. 5066**
	CHARGE and GAS COST RECOVERY	**:**	

CORRECTED REPORT AND ORDER

On August 3, 2020 and September 1, 2020, 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, 2020.[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 18, 2020, 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 $21.1

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[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/5040page.html and http://www.ripuc.org/eventsactions/docket/5066page.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, while the incremental increase sought for recovery under the GCR was approximately $10.6 million, for a total cost increase of approximately $31.7 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 subsequent to the Division's memoranda and testimony that incorporated the Division's recommendations. On October 28, 2020, 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 most of the Company's proposed DAC factors and disallowed some costs associated with others. It approved recovery of all the costs associated with the Company's requests regarding the GCR. While approving cost recovery, however, a majority of the Commission ordered the Company to defer recovery of fifty (50) percent of the incremental cost increases until a later date, which it coined as the "COVID deferral."

DISTRIBUTION ADJUSTMENT CHARGE

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 factor; 8) a Service Quality Plan factor; 9) a Revenue Decoupling Adjustment (RDA) factor; 10) rate class specific Infrastructure, Safety, and Reliability (ISR) factor; 11) two Reconciliation factors 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 3, 2020 DAC filing, September 1, 2020 Supplemental filing, and two revisions filed on September 29, 2020 and October 9, 2020, respectively, provided testimony

[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.
[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.

and support for an aggregate rate increase of approximately $21.1 million, when all the components are taken into account. The Company proposed to recover the cost increases through a DAC factor of $0.0404 per therm for the Residential and Small and Medium Commercial and Industrial (C&I) customers, $0.0346 per therm for the Large and Extra-Large C&I customers, and $0.0240 per therm for Residential Low Income customers. After including the annual ISR component that varied from a credit of $0.0046 per therm to a charge of $0.0016 per therm depending on customer class, the final DAC rates proposed by the Company ranged from $0.2071 per therm for all Residential Non-Heating customers to $0.0483 per therm for the Extra-Large High Load C&I customers.[7] Firm throughput which is used to calculate many of the factors was identified as 39,648,231 Dth.[8]

Initially, the Company proposed a System Pressure factor of $0.0132 per therm for an estimated $5.2 million in hourly peaking fixed costs from the November 1, 2020 through October 31, 2021 period.[9] In a memorandum filed on September 23, 2020 by its consultants, Jerome D. Mierzwa and Lafayette Morgan, Jr. of Exeter Associates, Inc, the Division noted that the Company has two contracts that provide for the delivery of gas from Everett to National Grid, one for 5,000 Dth per day which was recently executed and one for 20,000 Dth per day that is expected to expire in 2022. The Division recommended that the fixed demand costs associated with the 5,000 Dth per day supply arrangement be reflected in the System Pressure factor. It reasoned that because the agreement was executed to meet peak hour requirements and would not have been necessary if the FT-1 marketers were not assigned capacity by National Grid, the costs associated with it should be borne by all customers and not only sales customers. The Division recommended that if the

[7] Second Rev. Supp. DAC Filing Sch. RMS/MJP-1S Second Revision (Oct. 9, 2020).
[8] Scheib and Pini DAC Test. at 10 (Aug. 3, 2020).
[9] Scheib and Pini Supp. DAC Test. at 5, Sch. RMS/MJP-1S, RMS/MJP-2S (Sept. 1, 2020).

Company executes a replacement arrangement for the 20,000 Dth per day supply arrangement set to expire in 2022, the contract be revisited to determine whether the fixed demand costs associated with it should also be reflected in the System Pressure factor. The Division also recommended including incremental variable costs associated with peak hour resources in the DAC if those costs are significant. It noted that currently the incremental variable costs would only be recovered from sales customers. However, since those costs are not known at the current time, the Division expressed that National Grid should report on them in next year's DAC filing, and if found to be significant, included in the reconciliation process.[10]

In the September 29, 2020 Revised Supplemental filing, National Grid agreed with the Division's recommendation to include the fixed costs in the Everett 5,000 Dth per day supply arrangement in the System Pressure factor. Reallocating the fixed costs from GCR to the DAC resulted in an increase in the System Pressure factor to $0.0215 per therm.[11] On October 9, 2020, the Company filed a Second Revised Supplement. It identified an error in the calculation of the fixed demand costs from the Everett 5,000 Dth per day supply arrangement that had been allocated to the DAC, which it corrected. The correction resulted in $6.1 million in total fixed costs for an adjusted proposed System Pressure factor of $0.0154 per therm.[12]

National Grid did not propose funding the AGT factor. The current balance in the AGT fund is $713,040. The interest that has accrued on the balance in the account between April 2019 and March 2020 is $21,498 which will be credited to ratepayers through the Reconciliation factor.[13] The Division noted that in the Company's response to Division Data Request 2-2,

[10] Mierzwa and Morgan Mem. at 3-4 (Sept. 23, 2020).
[11] Rev. Supp. DAC Filing at 1-2 (Sept. 28, 2020).
[12] Second Rev. Supp. DAC Filing at 1-2 (Oct. 9, 2020).
[13] Scheib and Pini DAC Test. at 7-8, Sch. RMS/MJP-1, RMS/MJP-3 (Aug. 3, 2020)

National Grid stated that it 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. The Company also said that it believes that the current methodology of calculating the potential customer's AGT incentive is complex and a major barrier to participation. It suggested that certain revisions to this calculation may enable a customer to progress its project to installation. The Division recommended continuing discussions to broaden the scope of the program to include funding for studies regarding the decarbonization of natural gas and that discussion include modifying the program to reduce barriers and increase customer participation.[14]

National Grid also proposed the following factors, of which the Division recommended approval after finding them to be appropriate: 1) $0.0024 per therm for Environmental Response Costs to recover the incremental cost of $961,315;[15] 2) $0.0022 per therm for Pensions and Postretirement Benefits Other than Pensions to recover the incremental cost of $924,808;[16] 3) $0.0015 per therm for the Arrearage Management Adjustment to recover the incremental cost of $600,436;[17] 4) $0.0005 per therm for the Reconciliation factor for all Residential and Small and Medium C&I rate classes and ($0.0018) per therm for the Large and Extra-Large rate classes to return a net reconciliation credit of ($38,361);[18] 6) ($0.0034) per therm for the FY 20 RDM Reconciliation factor to return a reconciliation credit of ($994,958) from the prior period;[19] 7)

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[14] Mierzwa and Morgan Mem. at 4-5 (Sept. 23, 2020), Div. 2-2. National Grid did not propose expanding the scope of the program to allow for decarbonization studies in the current Docket.
[15] Scheib and Pini DAC Test. at 9-10, Sch. RMS/MJP-1, RMS/MJP-4; Annual Environmental Report for Gas Service (Jul. 24, 2020); Mierzwa and Morgan Mem. at 5-6.
[16] Scheib and Pini DAC Test. at 10-11, Sch. RMS/MJP-1, RMS/MJP-5; Bell Mem. at 1-2 (Sept. 16, 2020).
[17] Scheib and Pini DAC Test. at 11-15, Sch. RMS/MJP-1, RMS/MJP-6; Mierzwa and Morgan Mem. at 6.
[18] Scheib and Pini DAC Test. at 11-15, Sch. RMS/MJP-1, RMS/MJP-6; Mierzwa and Morgan Mem. at 6. The $0.0018 per therm credit factor includes the $0.0005 per therm surcharge applicable to all rate classes.
[19] Scheib and Pini Supp. DAC Test. at 7-8, Sch. RMS/MJP-10S, RMS/MJP-11; Mierzwa and Morgan Mem. at 10. This amount is credited to all Residential and Small & Medium C&I customers.

$0.0161 per therm for the Low-Income Discount Recovery factor to recover the total annual cost of the discount provided to the low-income rate class of $6,119,893;[20] 8) ($0.0011) per therm for the Earnings Sharing Mechanism factor to return a credit of ($461,331);[21] and 9) setting the Storm Net Revenue factor at $0.0000 per therm which calculated to a credit of ($13,302) too small to set a rate and, thus, would be carried over to the next year's reconciliation.[22]

National Grid filed its Gas Revenue Decoupling Mechanism Reconciliation Filing on July 1, 2020. The report showed an under-recovery of $2,009,962.[23] The Company proposed a factor of $0.0069 per therm to recover the $2,009,962 under-collection of which the Division verified and recommended approval.[24]

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 ($0.0046) to $0.0016 per therm. The Commission previously approved a budget of $162.46 million for the Company's ISR Plan in Docket No. 4916. The ISR Reconciliation filing submitted by the Company on August 3, showed that it had actual spending of $154.28 million which was $8.18 million less than the approved budget. The ISR Reconciliation filing calculated the actual revenue requirement at $5,502,510, reflecting a decrease from the forecasted revenue requirement of $6,474,720 approved by the Commission in Docket No. 4916.[25] This resulted in a slight over-

[20] Second Rev. Supp. DAC Filing at 2, Sch. RMS/MJP-13 Second Revision; Mierzwa and Morgan Mem. at 11-12. This factor was updated from the $0.0162 per therm factor that the Division initially recommended approval of. The Low-Income Discount Recovery factor provides a 25% discount to Rates 11 and 13 customers.
[21] Scheib and Pini DAC Test. at 11-15, 17-18, 23-27 Sch. RMS/MJP-1, Sch. RMS/MJP-4; Mierzwa and Morgan Mem. at 6-8, 10-11.
[22] Scheib and Pini DAC Test. at 20, Sch. RMS/MJP-1, RMS/MJP-14; Mierzwa and Morgan Mem. at 12. Calculation of the factor after netting revealed an amount too small from which to derive a factor.
[23] Revenue Decoupling Revenue Decoupling Mechanism Reconciliation Filing (Jul. 1, 2020).
[24] Mierzwa and Morgan Mem. at 6-8.
[25] Little Test. at 4-18, Att. MAL-1, MAL-2 (Aug. 3, 2020).

collection of the revenue requirement associated with the incremental forecasted costs in the ISR, equal to ($972,209). The updated actual revenue requirement of $5,502,510 was allocated among the applicable rate classes, resulting in the range of factors by rate class from ($0.0046) to $0.0016 per therm. The Company provided explanations for the variances in spending for the different programs. A large portion of the total variance was due to delays in the issuance of road opening permits by the City of Providence for work other than emergency work which caused most of the City of Providence projects to be delayed. 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 $5,502,510 revenue requirement.[26]

National Grid incurred $531,782 in Service Quality Performance penalties during the first and second quarters. On July 17, 2020, the Company filed a Request for Relief from Penalty Because of Exogeneous Events requesting that it be relieved of a $91,008 first quarter penalty and that one of its second quarter penalties be reduced from $273,337 to $66,000. It proposed a credit factor of $0.0004 per therm for a Service Quality Performance factor. The proposed factor would credit customers for $167,383 in penalties and did not include either the $91,008 or the $273,337 penalty amounts from which the Company had previously requested relief. It justified not including these amounts in the calculation of the factor by asserting that the Commission had not yet ruled on its request for relief.[27] After the Commission requested legal briefs addressing the definition of "exogenous event", the Division engaged in discussions with the Company regarding the penalties and advised that subject to Commission approval, National Grid and the Division agreed to the waiver of the $91,008 penalty and a reduction of the $273,337 penalty to $120,472

[26] Mancini Mem. at 1-2 (Sept. 23, 2020).
[27] Scheib and Pini DAC Test. at 16-17 Sch. RMS/MJP-1, RMS/MJP-9 (Aug. 3, 2020); Scheib and Pini Supp. DAC Test. at 6, Sch. RMS/MJP-1S, RMS/MJP-9S.

resulting in a credit factor of $0.0007 per therm.[28] In National Grid's response to Division Data Request 2-4, the Company provided a recalculation of the Service Quality Performance factor that included all of the penalties assessed for the first and second quarters totaling $531,782. The recalculation resulted a credit factor of $0.0130 per therm.[29]

GAS COST RECOVERY

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 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.

On September 18, 2020, National Grid proposed a BTU factor of 1.029 for the six-month period November 2020 through April 2021.[30] The Division did not object to the Company's proposed factor. In the September 1, 2020 GCR filing, National Grid proposed the following: 1) a high load factor of $0.5178 per therm; 2) a low load factor of $0.5868 per therm; 3) an FT-2 Demand Rate Usage of $14.0154 Dth/Mth; and 4) an FT-2 Storage and Peaking for FT-1 firm

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[28] Mierzwa and Morgan Mem. at 8-10.
[29] Docket No. 5040, Div. 2-4.
[30] Pimentel Letter at 1(Sept. 10, 2020).

transportation customers eligible for TSS of $1.0542 per dekatherm.[31] On September 28, 2020, it revised the proposed factors to: 1) a high load factor of $0.5093 per therm; 2) a low load factor of $0.5757 per therm; 3) an FT-2 Demand Rate Usage of $12.3568 Dth/Mth; and 4) an FT-2 Storage and Peaking for FT-1 firm transportation customers eligible for TSS of $0.9294 per dekatherm.[32]

National Grid explained how it projected and calculated gas costs.[33] It noted that its total gas costs are $2.4 million higher than those forecasted in the Long Rang Plan. The higher costs are attributable to: 1) the increase in the Everett supply deal; 2) Columbia Gas Transmission's proposed fixed costs increases presently pending before FERC; and 3) an increase in the NYMEX and basis forward curves.[34] The Company described the changes to the Customer Choice Program and how the GCR factors were developed.[35] It identified a marketer surcharge of $689,850 and a 2019 credit of $188,452 for marketer total reconciliation.[36] It estimated an under-recovery of approximately $8.1 million at the end of the current GCR period.[37] Finally, the Company presented a fiscal year 2020 Annual GCR Reconciliation balance of $827,573.[38]

The Company submitted testimony regarding the development of its 2020/21 sales forecast of 39,648,231 which was slightly lower than last year.[39] Lastly, National Grid 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

[31] Scheib and Pini GCR Test., Sch. RMS/MJP-1 at 1, RMS/MJP-5 (Sept. 1, 2020).
[32] Scheib and Pini GCR Test., Sch. RMS/MJP-1-Revised at 1; RMS/MJP-5 (Sept. 28, 2020).
[33] Gas Supply Panel Test. at 7-17, Att. GSP-1- GSP-3 (Sept. 1, 2020).
[34] Gas Supply Panel Test. at 17-18.
[35] Gas Supply Panel Test. at 29-32; Scheib and Pini GCR Test. at 9-10.
[36] Scheib and Pini GCR Test. at 9-10, Att. RMS/MJP-7, RMS/MJP-1.
[37] Scheib and Pini GCR Test. at 12, Att. RMS/MJP-1.
[38] Scheib and Pini GCR Test. at 12, Att. RMS/MJP-2.
[39] Poe Test. at 4-12, Att. TEP-1-TEP-5 (Sept. 1, 2020). This throughput was also used to calculated DAC factors.

discretionary supply of 3,978,000 Dth which resulted in a $48,974 incentive for the Company.[40] The NGPMP produced total savings of $5,945,613 of which $5,251,051 was customers' share. National Grid asked the Commission to approve the remaining $694,561 as the Company's incentive.[41]

On October 7, 2020, the Division filed the testimony of its consultant, Jerome D. Mierzwa. Mr. Mierzwa noted that in the 2019 GCR filing, the Company was ordered to develop appropriate cost allocation procedures for incremental design peak hour costs, to evaluate current cost allocation procedures for interstate pipeline firm transportation capacity assigned to firm transportation customers and reflect modifications that address the allocation of fixed gas supply reservation charges, and to develop data exchange protocols for the GPIP and NGPMP so as to provide additional transparency to allow for more efficient auditing.[42]

Mr. Mierzwa made a number of recommendations. First, he recommended that National Grid's proposal to recover fixed costs associated with meeting peak hour requirements through DAC be approved. He noted that this was accomplished through the changes made to the Customer Choice Program and ensures that the Company's FT-1 customers also pay these costs since all customers benefit from the contracts associated with meeting peak hour demand.[43] National Grid agreed to include the fixed reservation charges associated with the Everett 5,000 Dth per day arrangement through the System Pressure factor in the DAC and agreed to revisit the other Everett contract when it expires should it choose to execute a replacement arrangement. In the Second Revised Filing made on October 9, 2020, the Company corrected an error in the costs of the fixed

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[40] Protano Test. at 3-6, Att. JMP-2, JMP-5 (Sept. 1, 2020).
[41] Protano Test. at 7-9, Att. JMP-3, JMP-4.
[42] Mierzwa Test. at 6 (Oct. 7, 2020).
[43] *Id.* at 9-12.

reservation charges in the Everett 5,000 Dth per day arrangement which resulted in total fixed costs of $6.1 million to be recovered through the System Pressure factor.[44]

Mr. Mierzwa also recommended that National Grid track variable costs incurred in meeting peak hour requirements and report those costs in the 2021 DAC filing. If significant, he stated that these costs should be reallocated from the GCR to the DAC to be recovered from all customers.[45] The Company agreed.[46] Mr. Mierzwa noted that he found the proposed modifications to the Company's Customer Choice Program to sufficiently address the concerns raised in Docket No. 4963.[47] Mr. Mierzwa also recommended that the Company continue to work with the Division to develop data exchange protocols for the NGPMP. He expressed that while the Division and the Company were successful in developing the protocols for the GPIP, the complexity and detail in the NGPMP data fields required more work.[48] He did not have any concern with the incentive amounts sought by the Company for both Plans.[49]

Mr. Mierzwa expressed concern with the Company's activity under the GPIP noting that its practice of accelerating about a third of its mandatory purchases and making them all on one day two years prior to the month of delivery was inconsistent with the objective of the GPIP to mitigate gas cost volatility. He suggested that the Company diversify the timing of its advance hedge purchases and limit the use of accelerated purchases to a period where the NYMEX prices

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[44] Att. GSP-1 Second Revision, Att. RMS/MJP-2S Second Revision (Oct. 9, 2020).
[45] Mierzwa Test. at 13.
[46] Docket No. 5066, Div. Data Request 3-5.
[47] Mierzwa Test. at 16.
[48] *Id.* at 17.
[49] *Id.*

are lower than average historical prices.[50] National Grid agreed to work with the Division to ensure that accelerated purchases are made when gas prices are low.[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 6, 2020. Since that time, he stated that prices have increased. He recommended that the Company update its rate projections if the price difference is material so to minimize any over/under-collection.[52] The Company responded that updating the factors is not necessary, because there is not likely to be an increase of greater than 5% resulting from the increase in NYMEX forward curve prices. It stated that hedging activities reduce the impact of changes in the forward curve prices. It noted that because of the pandemic, it is hesitant to propose a further increase that would only address a relative minor under-recovery. It committed to continued monitoring of the over/under-recovery and that if projected deferral exceeds 5% of total projected gas costs, it would likely come to the Commission for an adjustment to the factors.[53]

On September 22, 2020, the Commission held a combined hearing for the Gas and Electric Pension Adjustment factors. National Grid proposed a factor of $0.0022 per therm for which the Division recommended approval.[54] The Commission held evidentiary hearings on October 6, 2020 and October 21, 2020 to hear evidence on the other DAC and GCR factors. Prior to the commencement of the evidentiary hearings, the Commission heard a number of public comments

[50] *Id.* at 17-18.
[51] Webster Letter (Oct. 14, 2020).
[52] Mierzwa Test. at 19.
[53] Webster Letter (Oct. 14, 2020).
[54] Scheib and Pini DAC Test. at 10-11, Sch. RMS/MJP-1, RMS/MJP-5; Bell Mem. at 1-2 (Sept. 16, 2020).

objecting to the proposed increases and informing the Commission of various hardships being experienced and the financial effect that COVID was having on many of those who spoke.

DECISION

A. Cost Recovery

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.

This year, because of the COVID pandemic and its associated economic impacts on Rhode Islanders, the Commission received many comments asking the Commission to deny the rate increases associated with National Grid's filings. But, unfortunately, the Commission's authority is limited. 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.[55] It is in that context,

[55] This is similar to what occurs with National Grid's electric business and was recently addressed by the Commission in Docket 4935, when National Grid sought an increase in standard offer service. See Order No. 23915 at 9-10 (Sept. 29, 2020).

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.

Regarding the Company's proposed DAC factors, the Commission found the Company's request for cost recovery associated with all but four of the factors to be reasonable and appropriate. In addition, the Commission relied on the comprehensive review performed by the Division in evaluating the reasonableness of the costs.

For the System Pressure factor, the Commission unanimously approved the recovery of the costs upon which the proposed factor of $0.0154 per therm were based. Further, consistent with the Division's recommendation, the Commission ordered National Grid to revisit the Everett 20,000 Dth per day arrangement when the contract expires to determine whether costs associated with meeting peak requirements should be included in the DAC.

The Commission also ordered the Company to report on the incremental variable costs associated with peak hour resources in next year's DAC filing and if determined to be significant during the 2020/2021 winter season to include them in the reconciliation process. The Commission found that the balance in the AGT fund should be returned to ratepayers and ordered the refund of the entire balance of $713,000. It reasoned that because there have been no recent projects or any pending projects earmarked to use these funds, it could not justify allowing the balance to remain in the account especially during a time when so many people are struggling financially.

The Commission also discussed National Grid's proposed Service Quality Performance factor. The Commission unanimously agreed that the entire $531,782 penalty should be credited to ratepayers. The Commission noted that even though it had not ruled on the Company's request to waive a large portion of the penalties, it was presumptuous of the Company to assume that the

Commission would grant all or part of that request and to not include the full penalty amounts incurred in its initial filing. Finally, the Commission conditionally approved the proposed credit of ($461,331) arising out of the Earnings Sharing Mechanism, subject to further review of the Company's Earnings Report.

The Commission next considered the proposed GCR factors and unanimously approved recovery of the costs underlying the Company's proposal upon which (i) the High Load Factor of $0.5093 per therm (ii) the Low Load Factor of $0.5757 per therm, (iii) the FT-2 Firm Transportation Marketer Gas Charge of $12.3568 per Dth/Mth, and (iv) the Storage and Peaking Charge for FT-1 firm transportation customers eligible for TSS of $0.9294 per Dth, were calculated. The Commission also unanimously approved the GPIP incentive of $48,974, the NGPMP incentive of $694,561, and the BTU Factor of 1.029. It ordered the Company to continue to work with the Division to develop data exchange protocols for the NGPMP to provide additional transparency and for more efficient auditing. The Commission ordered National Grid to collaborate with the Division to develop a plan to diversify 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 2021 DAC, and if significant to allocate them from the GCR to the DAC. Finally, it ordered the Company to track the incremental costs associated with the peak and if they are significant to include them in the 2021 DAC.

After making the adjustments to the DAC factors, as indicated, the Company's request for an increase in the final DAC factor was reduced to $20,123,804. The total GCR increase was granted at $10,584,526. This resulted in a combined incremental increase of $30,708,330.

B. <u>The COVID Deferral</u>

While the Commission's authority to reject the recovery of prudently incurred costs is very limited, once it is determined that the costs are recoverable, the Commission does have the authority to determine the timing of recovery. With respect to timing, in any typical year, it is appropriate for most of the costs associated with the DAC and the GCR to be recovered during the winter period. This is appropriate because the vast majority of the consumption of natural gas being delivered by the Company occurs during the winter, when natural gas is used for heating purposes. Simply stated, how much a customer pays each month is determined by how much gas the customer consumes that month. The amount of gas consumed is measured by therms; the more therms consumed, the greater the cost. Once the DAC and GCR rates are set on November 1, they remain in effect for 12 months unless the Company requests a change, although most of the revenue needed by the Company to recover the costs it incurs is received during the winter months between November 1 and April 1. For that reason, setting the rates to take full effect for consumption on and after November 1 properly coincides with the time period when consumers are using most of the gas and causing most of the costs to be incurred. This matching of rate recovery to the time period of cost incurrence is related to the utility ratemaking principle of "cost causation." In other words, in typical circumstances the consumers causing the costs to be incurred should be responsible for paying the costs associated with their energy consumption, as close in time to when the costs are actually incurred. Since most of the costs are incurred during the winter, it is appropriate that consumers pay for the costs during the winter.

There is another reason why matching the rates to the winter period is ordinarily appropriate. This relates to the way in which the accounting for costs is addressed in the cost and revenue reconciliation process under the DAC and GCR tariff provisions. Specifically, if rates are set based on a forecast that over-estimates winter consumption, the rate will be set too low. In such case, the natural consequence is that there is an under-recovery of costs that must be recovered later. Conversely, if the forecast under-estimates winter consumption, the rates are set too high, and the utility recovers too much revenue that exceeds the costs.[56] In either case, the utility maintains a regulatory account with either a negative or positive balance, determined by a simple equation of "revenue minus costs." The balance then accrues interest at the Bank of America Prime Rate minus 200 basis points.[57] Thus, if there is a negative balance at the end of the winter period, the negative balance will accrue interest from which ratepayers will need to reimburse the Company the next time the DAC and/or GCR rates are re-set for the following winter period.[58]

Significantly, after the winter period, the lag between April and November is a time when gas consumption and associated revenue recovery remains low. In the case of the interest calculation applied to a large negative balance after the winter, this is analogous to having a credit card debt where only minimum monthly payments are made on the debt, resulting in the accrued interest growing the size of the debt. Given this effect, under normal circumstances it is in the best interest of ratepayers to avoid the build-up of a negative balance. Otherwise, over the course of 12 months, there is an accumulation of interest payments that result in ratepayers paying more for the service than if the costs were paid off during the high-consumption winter. For all of these reasons, in any *typical year*, the Commission allows a rate increase to go into full effect. But this is *not* a typical year. We are far from it. The world, the country, and the state are facing a potential second wave of the COVID pandemic which appears to be looming for this winter. Rhode Island faces

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[56] There are other variables as well that could affect the balance of revenue against costs, such as unexpected changes in the forecasted costs.
[57] The current approved interest rate in National Grid's Gas Tariff is the Bank of America Prime Rate minus 200 basis points, currently 1.25%. The interest rate also is often referred to "carrying charges." *See* Response to PUC Record Request 1 at 2.
[58] Interest accrues in the ratepayers' favor when there is an over-recovery.

the prospect of consumers continuing to work from home, school children not being able to attend school on regular schedules, and other effects which cause citizens to make a choice to stay at home when they ordinarily would be working elsewhere or involved in daily activities away from the home. When people stay home more often during the winter heating season, it likely means that they will be using even more natural gas than a typically cold winter, which will have an impact on the gas utility bills for the winter. Citizens, some of whom the Commission heard from during the public comment hearing, have lost their jobs or for other reasons are facing challenging financial circumstances from the COVID crisis and may have no other choice but to avoid paying the gas heating bill in order to cover other essential costs of living. Not paying a heating bill can be a logical short-term choice for many families, especially when consumers realize that there is a moratorium on shut offs. What results is that those utility customers who are struggling financially will build up arrearages on their gas utility bills because they have no other practical choice. Moreover, there are many families who currently owe large balances on bills incurred from usage last winter, which were not paid during the 2020 shutdown when there was a continuation of the emergency moratorium that extended well past the spring and into the summer.[59]

Considering all of what was set forth above, a majority of the Commission concluded that a different action was warranted for this winter period to address the combined increases of the DAC and GCR. The majority expressed concern that allowing the full rates to go into effect would increase the arrearages many have already accumulated. It also would make the situation financially worse for those who may have paid past bills, but now face a second wave of hardship as the winter season hits. In this context, it is a significant understatement to say that the COVID crisis is highly unusual. It is something that has never been experienced in the lifetimes of most

[59] *See* Order Nos. 23786, 23807, 23809, 23826, 23836, and 23866, Docket No. 5022.

people today. It is an experience where the timing of the full impact of the rate increase for the impending winter could make a difference on the financial challenges facing so many in the near term. This is not mere speculation. It is a reality that a majority of the Commission could not ignore. For this reason, the majority concluded that deferring half of the proposed rate increases at this time is needed, even if it creates the risk of accumulation of interest and postpones the recovery of half the costs to another day. Thus, while the combined increases requested from the DAC and GCR come to approximately $30.7 million, the majority found that reducing this amount by 50% is in the best interest of ratepayers. This equates to approximately $15.4 million, to be *deferred* into a "COVID Deferral" account.[60]

Certainly, the majority is mindful of the risks, but believes these risks do not outweigh the benefits of immediate relief. First, the estimated interest on the combined DAC and GCR "COVID Deferral" for one year is approximately $200,000.[61] While this is an incremental cost to ratepayers, the majority believes it is manageable. Second, the majority certainly recognizes that a deferral of $15.4 million inevitably means that any annual DAC and GCR rate increase for the winter of 2021-22 could be exacerbated. Moreover, the circumstances which may be faced one year from now are impossible to forecast with a reasonable degree of certainty. Nevertheless, there are various ways through which the COVID Deferral risk could be addressed next fall. If the forecasted costs for

[60] Recently, the Commission was faced with a question whether to defer all or part of a rate increase on the electric side of the business relating to standard offer supply service but declined to do so. Order No. 23648, Docket No. 4935, (Jun. 12, 2020). In the context of the electric rate increase, the Commission identified the risk of standard offer service customers leaving the service to take supply from retail suppliers under municipal aggregation offers, thereby stranding costs on other customers (see *id.* at p. 12 and n. 48). Unlike the electric side of the business, the make-up of the customer classes affected on the gas side is not likely to change materially from one winter to the next. In fact, non-residential customers taking gas service from the Company do not have retail choice, where they can opt for service from competitive suppliers. Thus, the risk of large groups of customers stranding costs on other customers in the near future that is present on the electric side is not materially present on the gas side of the business.

[61] The total amount deferred between the DAC and GCR was $15,354,164, as shown on compliance Schedule RMS/MJP-8 at 1(Oct. 29, 2020). At current rates, the cost of deferring $15,354,164 for twelve months would be approximately $200,000.

the winter of 2021-22 are extreme, the Commission could choose to amortize the remaining balance of the COVID Deferral over a period of years. Alternatively, it is conceivable that the forecasted costs for the winter of 2021-22 will be manageable. Similarly, it is possible that significant winter usage in 2020-21 could result in an overcollection of billed revenue under gas distribution rates which would result in a refund to consumers from the revenue decoupling mechanism that could partially offset the COVID Deferral. While there are risks, a majority of the Commission believes it is better to mitigate the imminent winter risk for 2020-21 from the pandemic. Relying on the ratemaking tool of amortizing the cost over a period of years is a preferable choice rather than allowing the rates to have their full effect for 2020-21, with the difficult COVID winter within view.[62]

Having drawn this conclusion, however, the majority is very mindful of not setting a precedent or creating public expectations for the future that could leave the impression that every time there is an undesirable rate increase, the Commission will avoid it by pushing off payments to another day. Here, the circumstances of the COVID crisis are extreme and likely a once-in-a-lifetime experience.[63] It is only because of the extreme nature of what is being experienced today that the majority is willing to break from past practice and opt for a deferral that eases the energy cost burden for consumers who will be relying upon natural gas heating for the winter ahead. By deferring 50% of the incremental combined increases instead of 100%, the majority is attempting to strike a balance between the need for mitigative relief and the risk of deferring too much for future recovery. The short-term relief from the COVID Deferral is designed to bring the

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[62] The majority is aware that the Division did not support a deferral and the Commission majority surmises that it related to the risks described earlier in this decision, but the Division's testimony did not provide any evidence or rationale to support its position.

[63] If this is not a one-time crisis that is eventually brought under control, we will all be confronted with a far greater crisis than just risks associated with the balance of the COVID Deferral account.

incremental increase in winter heating costs down to a manageable level while health authorities continue the valiant effort to bring the pandemic under control.

In the gas distribution context, the Commission traditionally measures impacts by the "annual" effect on typical heating customer bills.[64] Under the Company's original proposal, the typical residential heating customers would have seen an annual increase of $93.39 and the typical low income heating customer an increase of $68.47.[65] With the COVID Deferral, these annual impacts are lowered to $48.61 and $35.68, respectively.[66] Using a 6-month average effect on the typical residential heating and low income heating customers, the deferral lowers the impact from $12.62 per month and $9.25 per month, respectively, to $6.57 and $4.82 per month, respectively.[67] The resulting monthly amounts should be manageable for customers still able to pay their bills. For those who may not be able to pay their heating bills at all, this will lower the build-up of arrearages that could become overwhelming by the end of the winter.

The majority understands this is only a short-term fix for an immediate problem. Over the longterm, there also is a need for more longer-lasting solutions to manage costs and to address the potential re-design of rates. This is not an either/or proposition through which the majority is choosing a deferral instead of sustainable initiatives. Rather, it is a "both/and" proposition. The majority understands that both the effort to provide some short-term mitigation through the deferral, and consideration of more sustainable initiatives, are appropriate. And the Commission expects National Grid and the Division to consider such initiatives. For now, the majority believes

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[64] In contrast, impacts are typically measured by the typical residential monthly bill for changes in electric distribution rates.
[65] *See* PUC 2-1 at 1.
[66] *See* PUC 2-2, p. 6. It is worth noting that the difference does not translate precisely to 50% because the COVID Deferral reduces the total combined DAC & GCR incremental revenue by 50% which, in turn, is allocated to customer classes by relevant allocators. *See* Attachment PUC 3-5(e)(Section 2).
[67] The actual impact will depend upon usage which varies by customers. In addition, the Commission is mindful that the impacts for non-residential customers also can be significant and the deferral will mitigate those impacts as well.

COVID is such an all-encompassing crisis that business as usual must be put aside to mitigate the near-term financial burdens of winter heating costs during the pandemic.

In order to keep track of the status of the resulting under-collection caused by the COVID Deferral, the Commission ordered the Company to report on the status of the deferral no later than May 1 and with the 2021 DAC and GCR filing on September 1.

C. Compliance Filing

The Commission ordered the Company to make a compliance filing to calculate the new approved factors, including the implementation of the COVID Deferral which reflects all of its impacts. The compliance filing was made on October 29, 2020. In the compliance filing, the Company implemented the COVID Deferral by applying a negative COVID Deferral factor to the approved DAC and GCR factors, as shown in the compliance schedules, to achieve a 50% reduction in the proposed combined DAC and GCR increases of approximately $30.7 million. The resulting rates included in the compliance filing were reviewed, ratified, and approved by the Commission at an Open Meeting on November 4, 2020.[68]

Accordingly, it is hereby

(23967) ORDERED:

1. A System Pressure factor of $0.0154 per therm is approved for usage on and after November 1, 2020.

[68] A summary of the DAC and GCR factors are attached.

2. 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 2021 DAC filing.

3. National Grid shall report on the incremental variable costs associated with peak hour resources in the 2021 DAC filing and if determined to be significant during the 2020/2021 winter season include them in the reconciliation process.

4. An Advanced Gas Technology factor of ($0.0017) per therm is approved for usage on and after November 1, 2020.

5. An Environmental Response Cost factor of $0.0024 per therm is approved for usage on and after November 1, 2020.

6. A Pension and Post-Retirement Benefits other than Pensions factor of $0.0022 per therm is approved for usage on and after November 1, 2020.

7. An Arrearage Management Adjustment factor of $0.0015 per therm is approved for usage on and after November 1, 2020.

8. A Revenue Decoupling Adjustment factor of $0.0069 per therm is approved for usage on and after November 1, 2020.

9. The various ISR reconciliation factors and component as set forth in Appendix A are approved for usage on and after November 1, 2020.

10. A Service Quality Performance factor of ($0.0013) per therm is approved for usage on and after November 1, 2020.

11. Reconciliation factors of $0.0005 per therm for Residential and Small and Medium C&I customers and ($0.0018) per therm for Large and Extra-Large C&I customers are approved for usage on and after November 1, 2020.

12. A Reconciliation factor for 2020 of ($0.0034) per therm is approved for usage on and after November 1, 2020.

13. An Earning Sharing Mechanism factor of ($0.0011) per therm is conditionally approved subject to further review of the Company's Earnings Sharing Report for usage on and after November 1, 2020.

14. A Low-Income Discount Recovery factor of $0.0161 per therm is approved for usage on and after November 1, 2020.

15. A Storm Net Revenue factor of $0.0000 per therm is approved for usage on and after November 1, 2020.

16. A High Load Factor of $0.5093 per therm is approved for usage on and after November 1, 2020.

17. A Low Load Factor of $0.5757 per therm is approved for usage on and after November 1, 2020.

18. Gas Marketer Transportation factors of:

    a. $12.3568 per Dth/Mth for FT-2 Firm Transportation Marketer Gas Charge and

    b. $0.9294 per Dth for Storage and Peaking Charge are approved for usage on and after November 1, 2020.

19. The incentive of $48,974 for the Gas Procurement Incentive Plan, for the period April 1, 2019 through March 31, 2020, is approved.

20. The incentive of $694,561 for the Natural Gas Portfolio Management Plan, for the period April 1, 2019 through March 31, 2020, is approved.

21. The BTU factor of 1.029 per ccf is approved.

22. The Narragansett Electric Company d/b/a National Grid shall continue to work with the Division to develop data exchange protocols for the Natural Gas Portfolio Management Plan.

23. The Narragansett Electric Company d/b/a National Grid shall work with the Division to develop a plan to diversify advance hedge purchases to ensure the Company will accelerate gas purchases when gas prices are low.

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 2021 DAC and if significant, allocate them from the GCR to the DAC.

25. The Narragansett Electric Company d/b/a National Grid shall continue to track incremental costs associated with the peak and if those costs are significant include them in the 2021 DAC.

26. The Narragansett Electric Company d/b/a National Grid's Motions for Protective Treatment are granted for: Attachments GSP-1, RMS/MJP-2, RMS/MJP-5. GSP-1-

Revised, RMS/MJP-1-Revised, RMS/MJP-5-Revised, GSP-1-Second Revision, RMS/MJP-1-Second Revision, RMS/MJP-5-Second Revision, the Responses to DIV 1-1, DIV 1-2, DIV 1-5, DIV 1-6, DIV 1-15, DIV 1-21, DIV 1-27, DIV 1-28, DIV 2-3, DIV 2-5, DIV 2-6, DIV 2-8, DIV 2-9, DIV 2-10, and the Attachments to DIV 3-1 and DIV 3-9.

27. The Narragansett Electric Company d/b/a National Grid shall 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. The COVID Deferral amount shall be tracked and deferred until the Commission allows recovery in future rates.

EFFECTIVE AT WARWICK, RHODE ISLAND ON NOVEMBER 1, 2020 PURSUANT TO AN OPEN MEETING DECISION ON OCTOBER 28, 2020. CORRECTED WRITTEN ORDER ISSUED JANUARY 6, 2021.

PUBLIC UTILITIES COMMISSION

Ronald T. Gerwatowski

Ronald T. Gerwatowski, Chairperson

Marion S. Gold

Marion S. Gold, Commissioner

Abigail Anthony

*Abigail Anthony, Commissioner

*Commissioner Anthony dissented on the decision to defer 50% of the combined incremental increases. Her dissent is attached.

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.

Dissenting Opinion of Commissioner Anthony

I disagree with the majority's decision to defer recovery of the approved costs in the Gas Cost Recovery and Distribution Adjustment Charge filings. I echo the majority's concerns with affordability and that is why I accept the Division of Public Utilities and Carrier's position that a deferral will be more costly to the customers it is intended to help. The Division clearly and correctly identified that the deferral balance will accrue interest and the total costs will be higher when they come due to be paid. The Division offered testimony that a deferral is not in the best interest of customers, and I find that the Division's recommendation is consistent with ratemaking principles. The Commission should approve justified costs and set rates based on cost causation unless there is some generally accepted ratemaking principle to defer, such as rate shock. National Grid's proposal, while resulting in a rate increase, would not result in rate shock. This deferral has the potential to harm customers more at a time when the moratorium on shutoffs lifts and funding for assistance is depleted. This is not in the best interests of those customers who need the most help.

The Commission has other tools that it can use to address affordability in rates. For example, the Commission has extended the moratorium on utility terminations and recent information provided by National Grid in Docket No. 5022 and Docket No. 1725 has shown that it has not terminated service to any residential customers since March.[69] In addition, the Commission has approved increased discounts on the bills of income eligible customers, ordered the Company to provide flexible payment plans, and has approved arrearage management plans.

[69] RI PUC Docket 5022, PUC 4-8. National Grid indicates that as of October 13, 2020, no residential customers had received termination notices.

In the future, the Commission can continue its review of appropriate rate design mechanisms to balance the interests of all ratepayers with the utility.

To that end, during the Open Meeting in these matters, I urged the Commission to focus on reducing the real costs of the state's utility systems by seeking the least cost solutions to policy and utility system goals, and to pursue fairer rate design. I was encouraged by my fellow Commissioners' support of these principles.

National Grid - RI Gas
Summary of DAC Factors
Effective November 1, 2020

Section 1: DAC factor (not including annual ISR component) November 1, 2020 - October 31, 2021

	Description	Reference	Amount	Factor: Residential/ Small/ Medium C&I (a)	Factor: Large/ X-Large (b)	Factor: Residential Low Income (c)
(1)	System Pressure (SP)	RMS/MJP-2S Second Revision	$6,109,925	$0.0154	$0.0154	$0.0154
(2)	Advanced Gas Technology Program (AGT)	Compliance RMS/MJP-3	($713,040)	($0.0017)	($0.0017)	($0.0017)
(3)	Environmental Response Cost Factor (ERCF)	RMS/MJP-4	$961,315	$0.0024	$0.0024	$0.0024
(4)	Pension Adjustment Factor (PAF)	RMS/MJP-5	$924,808	$0.0022	$0.0022	$0.0022
(5)	Arrearage Management Adjustment Factor (AMAF)	RMS/MJP-6	$600,436	$0.0015	$0.0015	$0.0015
(6)	Service Quality Factor (SQP)	Compliance RMS/MJP-9	($531,728)	($0.0013)	($0.0013)	($0.0013)
(7)	Reconciliation Factor (R)	RMS/MJP-10S	($38,361)	$0.0005	($0.0018)	$0.0005
(8)	Earnings Sharing Mechanism (ESM)	RMS/MJP-12	($461,331)	($0.0011)	($0.0011)	($0.0011)
(9)	Low Income Discount Recovery Factor (LIDRF)	Compliance RMS/MJP-13	$6,110,727	$0.0161	$0.0161	n/a
(10)	Storm Net Revenue Factor	RMS/MJP-14	($13,302)	$0.0000	$0.0000	$0.0000
(11)	Subtotal	Sum [(1):(10)]	$12,949,448	$0.0340	$0.0317	$0.0179
(12)	Uncollectible Percentage	Dkt 4770	1.91%	1.91%	1.91%	1.91%
(13)	DAC factors grossed up for uncollectible	(11) ÷ [1-(12)]	$13,201,598	$0.0346	$0.0322	$0.0182
(14)	Revenue Decoupling Adjustment (RDA)	RMS/MJP-7	$2,009,962	$0.0069	$0.0000	$0.0069
(15)	Revenue Decoupling Adjustment Reconciliation	RMS/MJP-10S	($994,958)	($0.0034)	$0.0000	($0.0034)
(16)	DAC factor	(13)+(14)+(15)	$14,216,603	**$0.0381**	**$0.0322**	**$0.0217**

Section 2: DAC factors including annual ISR component & COVID Deferral Factor

		ISR Reconciliation w/o uncollectible (therms) (a)	Uncollectible Percentage (b)	ISR Reconciliation* (therms) (c) = (a) x [1+(b)]	Base DAC Component* (therms) (d)	DAC Component Subtotal Rates* (therms) (e) = (c) + (d)	ISR Component (therms)* (f)	COVID Deferral Factor (g)	November 1, 2020 DAC Rates* (therms) (h)
(17)	Res-NH	$0.0004	1.91%	$0.0004	$0.0381	$0.0385	$0.1663	($0.0099)	$0.1949
(18)	Res-NH-LI	$0.0004	1.91%	$0.0004	$0.0217	$0.0221	$0.1663	($0.0087)	$0.1797
(19)	Res-H	$0.0007	1.91%	$0.0007	$0.0381	$0.0388	$0.0742	($0.0296)	$0.0834
(20)	Res-H-LI	$0.0007	1.91%	$0.0007	$0.0217	$0.0224	$0.0742	($0.0284)	$0.0682
(21)	Small	$0.0016	1.91%	$0.0016	$0.0381	$0.0397	$0.0718	($0.0301)	$0.0814
(22)	Medium	($0.0002)	1.91%	($0.0002)	$0.0381	$0.0379	$0.0460	($0.0341)	$0.0498
(23)	Large LL	($0.0015)	1.91%	($0.0015)	$0.0322	$0.0307	$0.0440	($0.0107)	$0.0640
(24)	Large HL	($0.0046)	1.91%	($0.0046)	$0.0322	$0.0276	$0.0333	($0.0130)	$0.0479
(25)	XL-LL	($0.0004)	1.91%	($0.0004)	$0.0322	$0.0318	$0.0160	($0.0104)	$0.0374
(26)	XL-HL	($0.0012)	1.91%	($0.0012)	$0.0322	$0.0310	$0.0149	($0.0128)	$0.0331

*Factors Include Uncollectible Allowance

(a) RMS/MJP-8S
(b) Per Docket 4770
(d) Section 1, Line (16)
(f) FY21 ISR component per Docket 4996, Revised Section 4, Attachment 1R, Page 1
(g) Compliance RMS/MJP-16, Page 2, Col (d)

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

	Description	Source: Reference	Source: Line #	High Load[1]	Low Load[2]	FT-2 Mkter[3]
	(a)	(b)	(c)	(d)	(e)	(f)
(1)	Fixed Cost Factor - $/dktherm	RMS/MJP-1 Second Revision, pg 2	Line (17)	$2.0889	$2.7403	
(2)	Variable Cost Factor -$/dktherm	RMS/MJP-1 Second Revision, pg 3	Line (14)	$2.9076	$2.9076	
(3)	Total Gas Cost Recovery Charge- $/dktherm	(1) + (2)		$4.9965	$5.6479	
(4)	Uncollectible %	Docket 4770		1.91%	1.91%	
(5)	Total GCR Charge adjusted for Uncollectibles- $/dkdtherm	(3) ÷ [1 - (4)]		$5.0937	$5.7578	
(6)	GCR Charge on a per therm basis	(5) ÷ 10		$0.5093	$0.5757	
(7)	COVID Deferral Factor per therm	Compliance RMS/MJP-8, pg 2	Line (12) & (13)	($0.0153)	($0.0195)	
(8)	GCR Charge on a per therm basis	(6) + (7)		**$0.4940**	**$0.5562**	
(9)	Current rate effective 11/01/19 - $/therm	Docket 4963		$0.4736	$0.5302	
(10)	Increase / (Decrease) - $/therm	(8) - (9)		$0.0204	$0.0260	
(11)	Percent Increase	(9) ÷ (8)		4.3%	4.9%	

[1] Includes: Residential Non Heating, Large High Load and Extra Large High Load
[2] Includes: Residential Heating, Small C&I, Medium C&I, Large Low Load, Extra Large Low Load
[3] See RMS/MJP-5 Second Revision for calculation of FT-2 rate
(6): Truncated to 4 decimals.