STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE:	**THE NARRAGANSETT ELECTRIC**	**:**	
	COMPANY d/b/a RHODE ISLAND	**:**	
	ENERGY DISTRIBUTION	**:**	**DOCKET NO. 22-13-NG**
	ADJUSTMENT CHARGE	**:**	**DOCKET NO. 22-20-NG**
	and GAS COST RECOVERY	**:**	

ORDER

On August 1, 2022 and September 1, 2022, The Narragansett Electric Company d/b/a Rhode Island Energy (RIE 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, 2022.[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 October 5, 2022, RIE 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 testimony, schedules, rate factors, and bill impact analyses. The resulting incremental increase sought for recovery under the DAC was approximately $66.6 million, while the incremental

[1] All filings in this docket are available at the PUC offices located at 89 Jefferson Boulevard, Warwick, Rhode Island or at https://ripuc.ri.gov/Docket-22-13-NG and https://ripuc.ri.gov/Docket-22-20-NG.
[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] The Narragansett Electric Company'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 The Narragansett Electric Company to calculate the seasonal BTU content based upon the prior six-month experience for the equivalent season, which The Narragansett Electric Company 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.

increase sought for recovery under the GCR was approximately $19.2 million, for a total cost increase of approximately $85.8 million.

The Rhode Island Attorney General filed Motions to Intervene and became a party in both dockets when no objections to either motion were filed.

In response to the initial filings, the Division of Public Utilities and Carriers (Division) filed memoranda and direct testimony addressing the Company's proposed rate factors, incentive payment requests, and other issues on September 29, 2022. The filings recommended that the Commission approve the proposed rate factors and incentive payments and made several other recommendations.

After the Division filed its position in both dockets docket, the Company filed supplemental responses. After conducting a consolidated evidentiary hearing on October 11, 2022, the Commission conducted an Open Meeting on October 28, 2022 in which it deliberated on the Company's DAC and GCR proposals. It approved recovery of the costs associated with all of the Company's proposed DAC and GCR factors.[4] The Commission also ordered the Company to reduce the $14.00 customer charge on the bills of the low-income rate classes for the months of January, February, and March 2023 or to provide an equivalent uniform credit on those customers' bills if its billing system was not able to easily implement the reduction.

WITNESSES PRESENTING TESTIMONY

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

[4] The approved factors are attached hereto as Appendix A.

1. Peter R. Blazunas provided testimony to describe the reconciliation of the various components of the DAC and to propose new factors to become effective November 1, 2022. He provided supplemental testimony to update his original testimony and present a bill impact analysis of the proposed revisions.

2. Nathan Kocon, Stephanie A. Briggs, and Jeffrey D. Oliveira provided joint testimony to present the Company's FY 2022 Annual Reconciliation filing for the Gas ISR Plan, including the actual spending for the period April 1, 2021 through March 31, 2022 and the Adjusted Capital Additions In-Service in FY 2022. The testimonies also provided detailed information regarding the major spending variances for this period and updated revenue requirement associated with actual capital spending and tax deductibility percentages.

3. Jeffrey D. Oliveira 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. Stephanie A. Briggs provided testimony to describe the Company's gas earnings subject to the Company's Earnings Sharing Mechanism for the 12-month period ending December 31, 2022.

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

1. Elizabeth D. Arangio, Samara A. Jaffe, and James M. Stephens 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 2022-2023 GCR period.

2. Paul J. Hibbard provided testimony with an analysis of current natural gas and liquified natural gas market conditions that have affected supply costs for the coming year commencing on November 1, 2022.

3. Ryan M. Scheib provided testimony to calculate the GCR factors proposed for effect November 1, 2022.

4. 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.

5. 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, 2021 through March 31, 2022 and to provide an exhibit illustrating the impact of the current financial hedges for November 2022 through October 2023 in the GPIP.

Both the Company and the Division presented witnesses at the evidentiary hearing that adopted the pre-filed testimony and responded to inquiries about the filed documents.

THE 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.[5] As part of the DAC filing, RIE 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 or decreases 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 Environmental Response Cost (ERC) factor; 3) a Pension Adjustment factor; 4) an Arrearage Management Adjustment factor; 5) an Earnings Sharing Mechanism (ESM) factor; 6) a Low Income Discount Recovery (LIDR) factor; 7) a Service Quality Plan factor; 8) a Revenue Decoupling Adjustment (RDA) factor; 9) a rate class specific Infrastructure, Safety, and Reliability (ISR) factor; 10) two Reconciliation factors for last year's DAC factors;[6] and 11) 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.[7]

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[5] 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.

[6] The two reconciliations are the "Revenue Decoupling Adjustment Reconciliation" and the "ISR Reconciliation."

[7] The two factors relating to revenue decoupling are not grossed up by the uncollectible rate.

The Narragansett Electric Company's August 1, 2022 DAC filing and September 1, 2022 Supplemental filing provided testimony and support for a net rate increase of approximately $66.6 million, when all the components are taken into account. The Company proposed to recover the cost increases through a DAC factor of $0.2473 per therm for the Residential and Small and Medium Commercial and Industrial (C&I) customers, $0.2188 per therm for the Large and Extra-Large C&I customers, and $0.2232 per therm for Residential Low Income customers. After including the annual ISR component that varied from credits ranging from $0.0017 per therm to $0.0146 per therm depending on customer class, the final DAC rates proposed by the Company ranged from $0.3805 per therm for Small Commercial and Industrial customers to $0.2394 per therm for the Extra-Large High Load C&I customers. For all residential heating and non-heating customers the Company proposed a final DAC rate of $0.3716 per therm.[8] Firm throughput which is used to calculate many of the factors was identified as 39,896,251 Dth.[9]

The Company proposed a System Pressure factor of $0.1720 per therm for an estimated $68.7 million in hourly peaking fixed costs from the November 1, 2022 through October 31, 2023 period.[10] In direct testimony filed on September 29, 2022 by its consultant, Jerome D. Mierzwa of Exeter Associates, Inc, the Division found the Company's removal of $68.66 million in hourly peaking costs from the GCR filing and including those costs in the System Pressure Factor to be reasonable and recommended approval. In Docket No. 5180, 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. That contract and a 5,000 Dth per day

[8] Blazunas Supp. DAC Test. Sch. PRB-1S (Sept. 1, 2022). The Company filed one supplement to the August 1, 2022 filing and schedules. 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] Blazunas DAC Test. at 25 (Aug. 1, 2022).
[10] Blazunas DAC Test. at 4, Sch. PRB-1S, PRN-2S (Sept. 1, 2022).

Everett gas supply contract have expired and been replaced with a 25,000 Dth per day gas supply contract to fill the Dracut FT capacity, the costs of which have been moved from the GCR to the DAC. 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 the 2022-2023 winter season, and if so, remove those costs from the 2023 GCR reconciliation process and include them in the DAC reconciliation process.[11]

The Company did not propose funding the AGT factor, which was a funding mechanism in the Company's gas distribution tariffs that provided 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 that the factor be cancelled and directed the Company to file an amended tariff reflecting the removal of the provision.[12]

The Company proposed the following factors, of which the Division recommended approval after finding them to be appropriate: 1) $0.0010 per therm for Environmental Response Costs to recover the incremental cost of $438,725;[13] 2) $0.0078 per therm for Pensions and Postretirement Benefits Other than Pensions to recover the incremental cost of $3,143,609;[14] 3) $0.0002 per therm for the Arrearage Management Adjustment to recover the incremental cost of $112,061;[15] 4) $0.0273 per therm for the FY 2022 RDM Adjustment factor to recover an under-recovery of $7,804,264;[16] 5) ($0.0016) for a Service Quality Factor to credit customer for the

[11] Mierzwa GCR Test. at 23-24 (Sept. 29, 2022).
[12] Docket No. 5165, Order No. 24275. Blazunas DAC Test. at 18 (Aug. 1, 2022).
[13] Blazunas DAC Test. at 6-7, Sch. PRB-1S, PRB-3; Annual Environmental Report for Gas Service (Jul. 29, 2022); Morgan Mem. at 3-4 (Sept. 29, 2022).
[14] Blazunas DAC Test. at 7-8, Sch. PRB-1S; PRB-4; Oliveira/Allen DAC Test. at 5-9 and Schedules (Aug. 1, 2022); Mancini Mem. at 4 (Sept. 29, 2022).
[15] Blazunas DAC Test. at 8-12, Sch. PRB-1S, PRB-5; Morgan Mem. at 4.
[16] Blazunas DAC Test. at 12-13, Sch. PRB-1S, PRB-6; RDM Reconciliation Filing (July 1, 2022); Morgan Mem. at 4-5.

$675,000 penalty the Company incurred for performance in meter testing;[17] 6) $0.0000 per therm for the Earnings Sharing Mechanism factor because the Company's return on equity was below the earnings sharing threshold;[18] 7) $0.0132 per therm for the Reconciliation factor for all Residential and Small and Medium C&I rate classes and $0.0121 per therm for the Large and Extra-Large rate classes to recover $5,138,820;[19] 8) $0.0000 per therm for a FY 2021 RDM Reconciliation applicable to Residential and Small and Medium D&I rate classes because the $5,751 under-recovery was too small to create a factor which will be carried over to next year's filing;[20] 9) $0.0236 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 $9,014,612;[21] and 10) ($0.0004) per therm for a Storm Net Revenue factor calculated to credit $168,824 to customers.[22]

To reconcile its ISR costs, which recover the incremental revenue requirement for the Company's capital investments for the applicable period, RIE proposed credit factors ranging from ($0.0017) to ($0.0146) per therm.[23] The Commission previously approved a budget of $173.25 million for the Company's ISR Plan in Docket No. 5099. The ISR Reconciliation filing submitted by the Company on August 1, 2022 showed that it had actual spending of $161.42 million which was $11.83 million less than the approved budget.[24] The ISR Reconciliation filing calculated the actual revenue requirement at $30,279,322 reflecting a $7,962,565 decrease from the forecasted revenue requirement of $38,241,887 approved by the Commission in Docket No. 5099.[25] This

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[17] Blazunas DAC Test. at 14-15, Sch. PRB-1S, PRB-8; Service Quality Report (Jul. 29, 2022); Morgan Mem. at 5.
[18] Blazunas DAC Test. at 15, Sch. PRB-1S, Sch. PRB-11; Morgan Mem. at 5.
[19] Blazunas Supp. DAC Test. at 6-7, Sch. PRB-1S, PRB-9S (Sept. 1, 2022); Morgan Mem. at 6.
[20] Blazunas DAC Test. at 19-24, PRB-1S, PRB-10; Morgan Mem. at 6.
[21] Blazunas Supp. DAC Test. at 5-6 (Sept. 1, 2022), PRB 1S Revised, PRB-12S Revised (Oct. 20, 2022); Morgan Mem. at 5-6. The Low-Income Discount Recovery factor provides a 25% discount to Rates 11 and 13 customers.
[22] Blazunas DAC Test. at 16-17, Sch. PRB-1S, PRB-13; Morgan Mem. at 6. .
[23] Blazunas Supp. DAC Test. Sch. PRB-1S, PRB-7S; Annual ISR Reconciliation (Aug. 1, 2022).
[24] Kocon ISR Reconciliation Test. at 5 (Aug. 1, 2022).
[25] Briggs/Oliveira ISR Reconciliation Test. at 5-6, Att. SAB/JDO-1, (Jul. 30, 2022).

resulted in an over-collection of the revenue requirement associated with the incremental forecasted costs in the ISR, equal to $4,536,037.[26] The updated actual revenue requirement of $30,279,322 was allocated among the applicable rate classes, resulting in the range of factors by rate class from ($0.0017) to ($0.0146) per therm.[27] The Company provided explanations for the variances in spending for the different programs. The primary driver of the decrease was underspending in some of the categories.[28] 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 $30,279,322 revenue requirement.[29]

THE GAS COST RECOVERY RATES

The GCR is an annual filing that allows RIE 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. The Company 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.

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[26] Blazunas DAC Test at 13-14 (Aug. 1, 2022).
[27] Blazunas DAC Test. Sch. PRB-1S.
[28] Kocon ISR Reconciliation Test. at 5-6.
[29] Mancini Mem. at 1-4.

In the September 1, 2022 GCR filing, RIE proposed the following: 1) a high load factor of $0.6315 per therm; 2) a low load factor of $0.7009 per therm; 3) an FT-2 Demand Rate Usage of $14.8192 Dth/Mth; and 4) an FT-2 Storage and Peaking for FT-1 firm transportation customers eligible for TSS of $1.1687 per dekatherm.[30]

RIE explained how it projected and calculated gas costs.[31] 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 5, 2022.[32] It noted that its total gas costs are $16 million lower than those forecasted in the Long Rang Plan. The lower costs are attributable to: 1) the increase in the supplier demand charges being offset by an increased fixed cost credit and 2) a decrease in gas commodity costs.[33] The Company presented a fiscal year 2022 Annual GCR Reconciliation balance of $11,659,178.[34]

The Company submitted testimony regarding the development of its 2022/23 sales forecast of 39,688,140 MMBtu which was slightly lower than last year.[35] It presented testimony about the Gas Procurement Incentive Plan (GPIP) and the Natural Gas Portfolio Management Plan (NGPMP). It noted that the impact of its current financial hedges for the November 2022 through October 2023 provided a $77,741,490 benefit to customers.[36] It noted no changes to the GPIP over the last year. The Company stated that it had purchased discretionary supply of 1,072,000 Dth which resulted in a $16,587 incentive for the Company.[37] The NGPMP produced total savings

[30] Blazunas GCR Test. Attach. PRB-1 at 1 (Sept. 1, 2022).
[31] Gas Supply Panel GCR Test. at 8-16 (Sept. 1, 2022), Att. GSP-1, Att. GSP-2, Att. GSP-3 (Sept. 1, 2022).
[32] *Id.* at 8.
[33] Gas Supply Panel GCR Test. at 17.
[34] Blazunas GCR Test. at 10, Att. PRB-2.
[35] Gas Load Forecasting Test. at 4-13, Att. GLF-1-GLF-5 (Sept. 1, 2022).
[36] Energy Portfolio Management Test. at 9 (Sept. 1, 2022).
[37] Energy Portfolio Management Test. at 5-9, Att. EPM-2, EMP-5 (Sept. 1, 2022).

of $12,922,064 of which $11,646,740 was customers' share. RIE asked the Commission to approve the remaining $1,275,323 as the Company's incentive.[38]

On October 5, 2022, RIE proposed a BTU factor of 1.031 for the six-month period November 2022 through April 2023.[39] In a memorandum dated October 7, 2022, the Division recommended approval of the proposed BTU factor as filed.[40]

On September 29, 2022, the Division filed the testimony of its consultant, Jerome D. Mierzwa. Mr. Mierzwa made a number of findings and recommendations. First, he recommended that RIE re-evaluate its current design day standard characterizing it as "extremely conservative and inconsistent with the observed practices of other LCSs" and that RIE present its re-evaluation in its next Gas Long-Range Resource and Requirements Plan.[41] He found that the practice of removing peak hour costs from the GCR and recovering them through the DAC to be reasonable.[42] He found that the Company should track the actual incremental variable costs it incurs to meet hourly peak demand, report those costs in its 2023 DAC and GCR filings, and if significant remove them from the GCR reconciliation process and include the costs in the DAC reconciliation process.[43]

Mr. Mierzwa discussed how the Division has continued to monitor the Company's advance hedge purchases and determined that ratepayers realize a significant benefit due to the program.

[38] Energy Portfolio Management Test. at 9-12, Att. EMP-3, EMP-4.
[39] Boyajian BTU Letter at 1 (Oct. 5, 2022).
[40] Mancini Mem. at 1 (Oct. 7, 2022).
[41] Mierzwa Test at 5, 8-16 (Sept. 29, 2022).
[42] Mierzwa Test. at 5, 16-23.
[43] *Id.* at 5, 23-24.

He did not express any concern with the incentive amounts sought by the Company for either the GPIP or the NGPMP.[44]

Lastly, Mr. Mierzwa noted that the Company's proposed factors were based on NYMEX forward curves as of the close of trading on August 5, 2022 which was $7.81 per Dth. Since that time, he stated that prices have decreased and as of the date of his testimony the average price for the winter 2022/2023 was $7.15 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.[45]

On October 5, 2022, RIE filed a letter from counsel responding to the Direct Testimony of Mr. Mierzwa. Counsel represented that the Company agreed to evaluate its analysis regarding the design day standard and to present its results in its next Gas Long Range Resource and Requirements Plan.[46] The Company, however, cautioned that consideration of other factors, such as operational factors, transmission capacity constraints, and market dynamics, also be taken into account during such evaluation.[47] On October 7, 2022, the Company filed a supplement to its response to the Direct Testimony of Mr. Mierzwa. Using updated NYMEX pricing, the Company's forecasted gas costs decreased by 2.6% for the 2022/2023 GCR year. The 2.6% decrease coupled with the bill credit negotiated by the Attorney General during the PPL acquisition of the Narragansett Electric Company resulted in more than a 5% decrease to the rates as originally filed from a 15% increase to a 9.6% increase.[48]

[44] *Id.* at 24.
[45] *Id.* at 6, 28.
[46] Boyajian Response Letter at 1 (Oct. 5, 2022).
[47] *Id.* at 1-2.
[48] Boyajian Supplement Letter (Oct. 7, 2022).

HEARINGS

Public Comment Hearing

On September 16, 2022, the Commission held a public comment hearing to take public comments on both (i) the natural gas increases resulting from the DAC and GCR rate changes, and (ii) a significant increase in electric rates in Docket No. 4978. Given the size of the combined increases, the hearing garnered considerable attention and interest from the public. Governor McKee, members of the General Assembly, and numerous members of the public offered comment and, at times, the hearing was emotionally charged. Many testified to their dire financial situations and inability to endure any increase in their monthly energy bills. The legislators spoke of the numerous calls received from constituents about the economic hardship they face, and numerous others commented on having to make a choice between paying energy bills or going hungry or cold.

Evidentiary Hearings

The Commission then held an evidentiary hearing on October 11, 2022 to hear evidence on both the proposed DAC and GCR factors in Docket Nos. 22-13-NG and 22-20-NG, respectively.

A panel of witnesses was presented to adopt their respective pre-filed testimonies and sponsored information requested responses relating to the DAC.

Mr. Blazunas explained the calculation of the DAC factors and noted that taking into account the Attorney General credit of $64.15 per customer and the updated NYMEX prices, residential customers would experience a decrease of approximately 4.4% from the 15% increase originally proposed.[49] He responded to questions about the RDM and provided an explanation of the revenue per customer calculation.[50] The Commission also questioned Mr. Kocon regarding the increase in the tool cost from what was originally budgeted. He noted that tools were wearing out more quickly and that when RIE was part of National Grid, it was able to share tools with that Company's Massachusetts operations. During that time, RIE would be charged the lending company employee's hourly rate for delivery, operation, and return of the tool to the Massachusetts affiliate. Since RIE did not share in ownership of the tools, Rhode Island customers would not incur any costs of acquiring those specific tools.[51]

Mr. Mancini testified that the Division recommended approval of the factors.[52]

The DAC panel was dismissed and a panel of witnesses supporting the GCR filing appeared to answer questions. 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.[53] She explained how updating the NYMEX price from August 5, 2022 to October 3, 2022 affected the calculations and reduced the original costs proposed.[54] She also described the reason that the increase in gas prices were not as dramatic as the increase in the price of electricity. One of the reasons noted was that underground storage facilities are filled during the summer and are not impacted by spot prices at the Algonquin city gate during winter months. She explained the procurement process beginning with the Company updating its forecast in June, then analyzing customer requirements to determine if resources are sufficient to meet those requirements, and

[49] *Id.* at 35-37.
[50] Hr'g at 30-34.
[51] Hr'g at 23-26, 37-39 (Oct. 11, 2022); Response to Record Request 1 (Oct. 21, 2022).
[52] *Id.* at 158.
[53] GCR Hr'g Tr. at 51 (Oct. 11, 2022)
[54] *Id.* at 51-52.

then contracting for supply.[55] When asked why the rates in Massachusetts were so much higher, Ms. Arrangio identified a number of factors, including the Company's gas supply portfolio, its volatility manager program, and different levels of storage and LNG inventory, as contributing to the difference.[56]

Ms. Jaffe was questioned about the status of the rate cases currently at FERC noting that the pending settlement will result in a refund being issued to customers.[57] She and Ms. Arangio testified about the Company's asset management arrangements and the bidding process.[58] Ms. Horowitz was questioned and testified about the design day.[59] Finally, Mr. Protano testified about the Company's hedging and how it differs from that in Massachusetts. He noted that the goal of hedging is to ultimately eliminate or adjust the volatility in the markets.[60]

At the end of the evidentiary hearings, the Division presented Mr. Mierzwa who opined that the Company should continue the hedging program. The Division also offered Mr. Mancini who testified that when the Company executes an accelerated hedge it notifies the Division, and the Division conducts a review of the hedge. Mr. Mancini stated that the Division recommended approval of the rates proposed by the Company.[61]

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.

[55] *Id.* at 58-61.
[56] *Id.* at 64-65.
[57] *Id.* at 67.
[58] *Id.* at 81-100.
[59] *Id.* at 103-24.
[60] *Id.* at 135, 145-56.
[61] *Id.* at 152-53.

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 RIE 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 in Schedule PVB-1S Revised were designed to recover costs that were reasonably incurred under the prevailing conditions. In addition, the Commission relied on the comprehensive review performed by the Division in evaluating the reasonableness of the costs. The Company proposed a $0.0000 factor for both the Revenue Decoupling Adjustment Reconciliation factor and the Earnings Sharing Mechanism factor which results in no net charge or credit on a customer's bill.

The Company filing was consistent with and reflected the inclusion of incremental fixed peaking costs in the DAC as had been approved by the Commission in Docket No. 5066. The significant increase to the System Pressure factor was the result of world events, in particular the war in Ukraine, which caused the price of natural gas including LNG to increase dramatically including the LNG at import terminals. Since the Company purchases LNG at an import terminal, the increase in demand charges has contributed to the significant increase in peak hour demand costs from last year's filing. Since the ISR programs underspent by a total of almost $12 million, reconciliation of the ISR resulted in all customers being credited an amount dependent on their rate class.

The Commission is satisfied based on its review of the various filings and the Division's recommendation that the proposed rates are properly calculated and are therefore approved.[62]

Approval of GCR Rates, Incentives, and BTU Factor

At its Open Meeting, the Commission unanimously approved the Company's proposed factors and rates, including (i) the High Load Factor of $0.6136 per therm (ii) the Low Load Factor of $0.6831 per therm, (iii) the FT-2 Firm Transportation Marketer Gas Charge of $14.8234 per Dth/Mth, and (iv) the Storage and Peaking Charge for FT-1 firm transportation customers eligible for TSS of $1.1691 per Dth, were calculated. The Commission also approved the GPIP incentive of $16,587, the NGPMP incentive of $1,275,323, and the BTU Factor of 1.031.

Mitigation Measures to Assist Low Income Customers

As noted above, during the combined public comment hearing when the Commission heard comments regarding both the proposed electric and natural gas increases, the Commission received numerous public comments, most of which discussed the hardship faced by customers caused by dramatically increasing utility rates, especially for those customers that have the most difficulty

[62] The approved rates are attached hereto as Appendix A.

paying their bills during a time of inflationary pressures not seen in decades in New England. Those comments were compelling.

Fortunately, all customers will receive a one-time credit of approximately $64 on their November bill, secured in the settlement between Attorney General Peter Neronha and the PPL Corporation regarding PPL's purchase of Narraganset Electric Company, which is the legal name of the gas and electric company.[63] For a typical standard or low-income heating customer using 845 therms per year, this bill credit decreased the rate impact from 15% to approximately 10%. In addition, during the PUC's review of the filing, RIE updated its forecast of supply costs to reflect recent changes in the natural gas market. This update lowered the expected bill impact from 10% to approximately 9% for standard residential heating customers and to approximately 8% for low-income heating customers.

While these two items reduced the impact on low-income heating customers to 8%, a majority of the Commission remained concern that the potential impact on the most vulnerable customers of energy costs for the winter still called for further relief. In Docket No. 4978, the Commission was able to approve two additional measures which significantly reduced the impact on the most vulnerable population in the state on winter electricity bills. One was the implementation of $3.8 million credit to the low-income rate class proposed by the Governor and the Office of Energy Resources.[64] These funds came from the Regional Greenhouse Gas Initiative. Unfortunately, there are limitations on how RGGI funds can be applied and dispersed, and those funds cannot be applied to offset the cost of natural gas service. Thus, no RGGI funds were available to mitigate the increase in gas costs. The second mitigation measure adopted by the

[63] *See* PUC Order 24496, Docket No. 22-07-GE (Sept. 16, 2022).
[64] This amount was later increased by an additional $1.5 million in a separate filing.

Commission in the electric docket, however, was to defer customer charges on residential bills. This latter measure was an option available to mitigate the impact on natural gas customer bills.

While the proposed increase in gas rates is not as significant as the increase in electric rates, the rising costs of living on the most economically vulnerable population can have a devastating effect on customers in the low-income rate classes. In an effort to reduce the impact of the natural gas increase on that population of the Company's natural gas service customers, a majority of the Commission voted to implement a customer charge deferral for the low-income natural gas service customers similar to the one that was approved approved by the Commission in Docket No. 4978 to mitigate the increase in electric bills.[65] Accordingly, the Company was ordered to reduce the current $14.00 customer charge to zero on each bill for the low-income rate classes, Rate 11 and Rate 13, for the months of January, February, and March 2023.[66]

The deferral of the customer charge does not deny the Company of its right to be reimbursed for the costs it incurred, but merely delays recovery. Assuming 24,547 low income heating and non-heating accounts,[67] and factoring in the 25% low income discount, the total cost is approximately $775,000,[68] which is small enough to be seamlessly recovered in future gas rates in a manner to be addressed by the Commission next year.[69] With the the credit secured by the Attorney General, the reduction resulting from the updated forecast, and the additional customer

[65] Commissioner Anthony abstained from this vote.
[66] If the Company's billing system is not able to easily implement this directive in a timely manner, the Commission allowed for the Company to implement this as an equivalent uniform credit on the customer bills adjusted for the effect of a low income discount of 25%.
[67] Docket No. 22-13-NG, Schedule PRB-6 at 14-16 (Aug 1, 2022). Account totals are as of March, 2022.
[68]The total cost was calculated by multiplying the 24,547 customers by the $14.00 customer charge and multiplying 75% of that total by 3.
[69] The Company is authorized to record a regulatory asset to recover the amount of the credit in the 2023 Distribution Adjustment Charge filing, in a manner to be determined by the Commission.

charge deferral, the annual impact on low-income customers was substantially mitigated from 15% to 5%.

Other Miscellaneous Directives

The Company also was ordered to continue to track variable costs incurred in meeting peak hour requirements, to report those costs in the 2023 DAC and, if significant, to allocate them from the GCR to the DAC. Lastly, the Commission is directing that future filings proposing changes to the DAC and GCR be consolidated in one proceeding, designated as a single docket, and heard together as one evidentiary case.[70] This will allow for a single set of numbered exhibits, data responses, and pre-filed testimony being presented to the Commission, thus streamlining the proceedings and avoiding duplication.

Accordingly, it is hereby

(24562) ORDERED:

1. The factors reflected in Attachment A – DAC/GCR Rates Table – are approved, effective for usage on and after November 1, 2022.

2. The Narragansett Electric Company d/b/a Rhode Island Energy is ordered to reduce the $14.00 customer charge to zero on each bill for the low-income rate classes Rate 11 and Rate 13 for the months of January, February, and March of 2023; provided, however, to the extent the Company's billing system cannot easily implement this directive in a timely manner, the Company may implement this as an equivalent uniform credit on the customer bills adjusted for the effect of a low-income discount of 25%. The Company is authorized

[70] The Company should continue to sequence the relevant filing components for both the DAC and GCR consistent with the current practice.

to record a regulatory asset to recover the amount of the credit in the 2023 Distribution Adjustment Charge filing, in a manner to be determined by the Commission.[71]

3. The calculations of ratepayer savings and corresponding incentive reflected in the Gas Procurement Incentive Annual Report provided in Schedule EPM-2 in the Gas Cost Recovery Docket relating to the period from April 1, 2021 through March 31, 2022, are approved.

4. The calculations of ratepayer savings and corresponding incentive reflected in the Natural Gas Portfolio Management Plan Annual Report provided in Schedule EPM-4 in the Gas Cost Recovery Docket relating to the period from April 1, 2021 through March 31, 2022, are approved.

5. The BTU factor of 1.031 per ccf is approved.

6. The Narragansett Electric Company d/b/a Rhode Island Energy will continue to track variable costs incurred in meeting peak hour requirements and report those costs in the 2023 DAC and, if significant, allocate them from the GCR reconciliation process and include them in the DAC reconciliation process.

[71] Commissioner Anthony abstained from this vote.

EFFECTIVE AT WARWICK, RHODE ISLAND ON NOVEMBER 1, 2022 PURSUANT TO AN OPEN MEETING DECISION ON OCTOBER 28, 2022. WRITTEN ORDER ISSUED JANUARY 10, 2023.

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.

APPENDIX A

DAC/GCR Rates Table -- Effective November 1, 2022

(a) Description of Factor	(b) Rate	(c) Type of Charge	(d) Source
DAC FACTORS (Docket No. 22-13-NG):			
System Pressure Factor	$0.1720	per therm	Sch. PRB-2S
Environmental Response Cost Factor	$0.0010	per therm	Sch. PRB-3, p. 1, Line 16
Pension & Post-Retirement Benefits Other than Pension Factor	$0.0078	per therm	Sch. PRB-4, p. 1, Line 14
Arrearage Management Adjustment Factor	$0.0002	per therm	Sch. PRB-5, p. 1, Line 4
Revenue Decoupling Factor	$0.0273	per therm	Sch. PRB-6, p. 1, Line 8
Service Quality Performance Factor	($0.0016)	per therm	Sch. PRB-8
DAC Reconciliation Factors:			
Residential and Small/Medium C&I	$0.0132	per therm	Sch. PRB-9S Line 17
Large and Extra-Large C&I	$0.0121	per therm	Sch. PRB-9S Line 29
Revenue Decoupling	$0.0000	per therm	Sch. PRB-9S Line 23
Earnings Sharing Mechanism Factor	$0.0000	per therm	Sch. PRB-11
Low-Income Discount Recovery Factor	$0.0234	per therm	Sch. PRB-12S Revised, p. 1, Line 3
Storm Net Revenue Factor	($0.0004)	per therm	Sch. PRB-13
ISR Reconciliation Factors			
Residential	($0.0146)	per therm	Sch. PRB-7S, p. 1, Line 3
Small	($0.0101)	per therm	Sch. PRB-7S, p. 1, Line 4
Medium	($0.0056)	per therm	Sch. PRB-7S, p. 1, Line 5
Large LL	($0.0093)	per therm	Sch. PRB-7S, p. 1, Line 6
Large HL	($0.0103)	per therm	Sch. PRB-7S, p. 1, Line 7
XL-LL	($0.0017)	per therm	Sch. PRB-7S, p. 1, Line 8
XL-HL	($0.0097)	per therm	Sch. PRB-7S, p. 1, Line 9
GCR FACTORS (Docket No. 22-20-NG):			
High Load Factor	$0.6136	per therm	Sch. PRB-1 Revised, p. 1, Line 6(d)
Low Load Factor	$0.6831	per therm	Sch. PRB-1 Revised, p. 1, Line 6(e)
Gas Marketer Transportation Factors:			
FT-2 Demand Rate	$14.8234	per dekatherm	Sch. PRB-5 Revised, p. 2, Line 21
Storage and Peaking Charge	$1.1691	per dekatherm	Sch. PRB-5 Revised, p. 3, Line 5