

**STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION**

IN RE: THE NARRAGANSETT ELECTRIC :
COMPANY d/b/a RHODE ISLAND :
ENERGY DISTRIBUTION : **DOCKET NO. 25-22-NG**
ADJUSTMENT CHARGE :
and GAS COST RECOVERY :

ORDER

On July 31, 2025 and August 28, 2025, 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, 2025.¹ 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 15, 2025, RIE also filed its semi-annual BTU factor report.³ Subsequent to the initial DAC and GCR filings, the Company made supplemental filings to correct a number of

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-25-22-NG>. A number of subsequent filings were made to revise and correct errors in the schedules. The figures cited in this order are the most current corrected figures provided prior to the hearing even though the testimony is what was originally filed. Corrected schedules are identified as either supplemental, corrected, or revised.

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.

schedules. The resulting incremental decrease to the DAC was approximately \$42.10 million, while the incremental decrease to the GCR was approximately \$21.87 million. Netting the two categories of costs, this results in a total cost decrease of approximately \$63.97 million.⁴

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, the Infrastructure, Safety and Reliability (ISR) plan reconciliation filing, and other issues on October 1, 2025. The Division recommended that the Commission approve the proposed rate factors and incentive payments.

After conducting an evidentiary hearing on October 16, 2025, the Commission conducted an Open Meeting on October 27, 2025 during which it deliberated on the Company's DAC and GCR proposals. It approved recovery of the costs reflective of its decision for all of the Company's proposed DAC and GCR factors and incentives.⁵

WITNESSES PRESENTING TESTIMONY

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

1. Tyler Shields provided testimony, supplemental testimony, and schedules to describe the reconciliation of the various components of the DAC and to propose new factors to become effective November 1, 2025. He also provided supplemental and revised testimony and schedules to update his original testimony and factors presented and to present a bill impact analysis of the proposed revisions.

⁴ DAC-1S (Corrected).

⁵ These figures reflect the Company position prior to the Open Meeting decision and are set forth in Schedule DAC-1S Corrected p.2. The factors that were approved by the Commission are attached hereto as Appendix A.

2. Jeffrey D. Oliveira and George R. Sunder provided separate testimony and joint schedules 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. Mr. Oliveira also filed a corrected joint schedule to fix errors in the PBOP costs that were incorrectly calculated.
3. Jeffrey D. Oliveira 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, 2025 which included a discussion of the hold harmless credit for the purpose of supporting the conclusions in the earnings report.⁶
4. Philip LaFond, Jeffrey D. Oliveira, and Natalie Hawk provided individual testimony to present the Company's FY 2025 Annual Reconciliation filing for the Gas ISR Plan which included an updated calculation of the value of the hold harmless credit. Mr. LaFond presented the actual spending and details concerning the major spending variances for the specific categories for the for the period April 1, 2024 through March 31, 2025. He provided details concerning the work undertaken by the Company primarily related to the Leak Prone Pipe and Proactive Main Replacement and Rehabilitation categories and how that work contributed to the spending variances. Mr. Oliveira presented and updated the 2024 revenue requirement for the ISR reconciliation, providing supporting attachments. Ms. Hawk described the tax related adjustments to the revenue requirement and provided supporting attachments.⁷

⁶ Oliveira DAC-Earning Test. at 12-15 (July 31, 2025).

⁷ Hawk ISR Test. at NH-1 through NH-3 (Aug. 1, 2025).

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

1. Kim N. Dao provided testimony and attachments regarding estimated gas costs and items relating the Company's proposed GCR factors. Her testimony also discussed the Company's portfolio for 2025-2026 GCR period.
2. Timothy A. Jones provided testimony and attachments supporting the underlying retail and wholesale forecasts of customer requirements that are used to estimate the gas costs presented by the Company in the filing.
3. Tyler G. Shields presented testimony and attachments supporting the calculation of the GCR factors for the Company's firm service and transportation service customers proposed for effect November 1, 2025.
4. Terry J. Crupi, Jr.'s testimony discussed the results of the Company's Gas Procurement Incentive Plan (GPIP) for the period April 1, 2024 through March 31, 2025 and to provide an exhibit illustrating the impact of the current financial hedges for November 2024 through October 2025 in the GPIP.
5. James Stephens a provided separate testimony and attachments from his testimony regarding gas costs about the Natural Gas Portfolio Management Plan (NGPMP) for the period April 1, 2024 through March 31, 2025.

THE DISTRIBUTION ADJUSTMENT CHARGE

The DAC is filed annually to establish a rate that reconciles certain estimated distribution system and gas costs to actual 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.⁸ 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;⁹ and 11) a Storm Net

⁸ 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.

⁹ The two reconciliations are the "Revenue Decoupling Adjustment Reconciliation" and the "ISR Reconciliation."

Revenue factor. Most of the DAC factors are grossed up to include a 1.91% uncollectible percentage as approved in Docket No. 4770.¹⁰

The Company made a number of filings that relate to the DAC proposed rate changes, a July 31, 2025 DAC filing, an August 28, 2025 Supplemental DAC filing, and a September 16, 2025 Supplemental Revised Corrected Schedules filing. The Company also filed a Revenue Decoupling Mechanism Reconciliation filing on June 30, 2025, a Gas Environmental Report on July 25, 2025, and an Annual Service Quality Plan Report on July 31, 2025. These filings provided testimony and support for a proposed net rate decrease for the DAC of approximately \$42.10 million, when all the components are taken into account. The Company proposed to recover a DAC factor of \$0.0368 per therm for the Residential and Small and Medium Commercial and Industrial (C&I) customers, \$0.0177 per therm for the Large and Extra-Large C&I customers, and \$0.0132 per therm for Residential Low-Income customers. After including the annual ISR reconciliation factor (varying by rate classes from a credit of \$0.0420 per therm to a charge of \$0.0108 per therm), the final DAC rates proposed by the Company ranged from \$0.3733 per therm for Residential Heating and Residential Non-Heating customers to \$0.0977 per therm for the Extra-Large High Load C&I customers.¹¹ Firm throughput which is used to calculate many of the factors was identified as 39,371,417 Dth.¹²

The Company proposed the following factors, of which the Division recommended approval after finding them to be appropriate: 1) System Pressure \$0.0314 per therm to recover the incremental cost of \$12.4 million;¹³ 2) \$0.0004 per therm for Environmental Response Costs

¹⁰ The two factors relating to revenue decoupling are not grossed up by the uncollectible rate.

¹¹ Sch. DAC-1S Corrected (Sept. 16, 2025).

¹² Shields Supp. DAC Test. at 6 (Aug. 28, 2025).

¹³ Shields Supp. DAC Test. at 6, Sch. DAC 2-S Revised (Aug. 28, 2025); Mancini DAC/RDM Mem. at 3-4 (Oct. 3, 2024).

to reflect a credit of \$384,861 to be returned to customers;¹⁴ 3) (\$0.0271) per therm for Pensions and Postretirement Benefits Other than Pensions to credit the incremental cost of \$10,664,680;¹⁵ 4) \$0.0004 per therm for the Arrearage Management Adjustment to return the incremental cost of \$178,391;¹⁶ 5) \$0.0108 per therm for the FY 2024 RDM Adjustment factor to recover an under-recovery of \$3,127,111;¹⁷ 6) (\$0.0007) for a Service Quality Factor to credit customer for the \$310,695 in penalties the Company incurred for falling below service quality metrics plus a \$4,177 credit from the Storm Net Revenue factor;¹⁸ 7) \$0.0000 per therm for the Earnings Sharing Mechanism factor because the Company's return on equity was below the earnings sharing threshold;¹⁹ 8) (\$0.0076) per therm for the Reconciliation factor for all customers to credit an over-recovery of \$3,023,055, (\$0.0103) per therm for the Large and Extra-Large rate classes to credit an over-recovery of \$307,375 and includes the credit applicable to all rate classes,²⁰ 9) a Revenue Decoupling Adjustment Reconciliation factor of \$0.0056 per therm applicable only to Residential and Small & Medium C&I customers to recover \$1,578,381;²¹ 10) \$0.0233 per therm for the Low-Income Discount Recovery factor to recover the total annual cost of the discount provided to the

¹⁴ Shields DAC Test. at 7-9, Sch. DAC-3; Annual Environmental Report for Gas Service (Jul. 25, 2025); Mancini DAC/RDM Mem. at 4-5.

¹⁵ Oliveira Rev. DAC Test. at 5, Sch. JDO/GRS-1 Corrected (Aug. 28, 2025); Mancini DAC/RDM Mem. at 5-6.

¹⁶ Shields DAC Test. at 10-14, Sch. DAC-5; Mancini DAC/RDM Mem. at 6.

¹⁷ Shields DAC Test. at 14-15, Sch. DAC-6S, RDM Reconciliation Filing (Jun. 30, 2025); Mancini DAC/RDM Mem. at 6-7.

¹⁸ Shields DAC Test. at 16-17, Shields Supp. DAC Test. at 11, Sch. DAC-8S; Service Quality Report (Jul. 31, 2024); Mancini DAC/RDM Mem. at 8-9.

¹⁹ Oliveira DAC Test. at 16, Sch. JDO-1 (Jul. 31, 2025), Sch. DAC-11; Mancini DAC/RDM Mem. at 10. Mr. Oliveira's testimony and schedules included a hold harmless credit that the Company included as a reduction to rate base. Oliveira Earnings Test. at 12. Sch. JDO-1 at 5.

²⁰ Shields Supp. Rev. DAC Test. at 8-9, Sch. DAC-1S Corrected, Sch. DAC-9S Corrected; Mancini DAC/RDM Mem. at 9-10.

²¹ *Id.*

low-income rate class of \$8,763,262;²² and 11) \$0.0000 per therm for a Storm Net Revenue factor because the credit of \$26,786 is too small to calculate a factor.²³

To reconcile its ISR costs, which recover the incremental revenue requirement for the Company's capital investments for the applicable period, RIE proposed factors ranging from \$0.0108 to (\$0.0420) per therm which includes a 1.91% adjustment designed to permit the Company to recover revenue from unpaid customer bills that result in bad debt (i.e., uncollectibles).²⁴ The Commission previously approved a budget of \$180.24 million for the Company's ISR Plan in Docket No. 23-49-NG. The ISR Reconciliation filing submitted by the Company on August 1, 2025 showed that it had actual spending of \$199.94 million which was \$19.71 million more than the approved budget.²⁵ The ISR Reconciliation filing calculated the actual revenue requirement at \$74,578,868 reflecting a \$9,401,098 decrease from the forecasted revenue requirement of \$83,979,966 approved by the Commission.²⁶ Mr. Oliveria noted that the Company applied a hold harmless credit to rate base which reduced the revenue requirement by \$4,536,343. He provided that "the Company calculated a hold harmless adjustment...to provide customers an economically equivalent rate base credit to offset the rate base increase that resulted from the Company's asset purchase."²⁷ The ISR reconciliation resulted in an under-collection of the revenue requirement associated with the incremental forecasted costs in the ISR, equal to \$3,637,758.²⁸ The updated actual revenue requirement of \$74,578,868 was allocated among the

²² Shields Supp. DAC Test. at 9-10; Sch. DAC-1S Corrected, Sch. DAC-12S Corrected; Mancini DAC/RDM Mem. at 10. The Low-Income Discount Recovery factor provides a 25% discount to Rates 11 and 13 customers.

²³ The Company proposed to include the credit amount in the calculation of the Service Quality factor, which would return the amount to customers through that credit factor. Shields Supp. DAC Test. at 10-11, Sch. DAC-13S; Mancini DAC/RDM Mem. at 11.

²⁴ Shields DAC Test. at 15-16, Sch. DAC-1-S Corrected, Sch. DAC-7S Corrected; Annual ISR Reconciliation Filing (Aug. 1, 2025).

²⁵ LaFond ISR Reconciliation Test. at 4 (Aug. 1, 2025).

²⁶ Oliveira ISR Reconciliation Test. at 4, Att. JDO-1 Corrected, (Aug. 1, 2025).

²⁷ Id. at 14; Oliveira DAC Test. at 14.

²⁸ Shields at Sch. DAC-7S Corrected.

applicable rate classes, resulting in the range of factors by rate class from (\$0.0413) to \$0.0106 per therm, not including the uncollectible percentage.²⁹ Ms. Hawk also discussed the hold harmless credit and explained how it was calculated.³⁰ The Company provided explanations for the variances in spending for the different programs. Mr. LaFond provided greater detail regarding the overspending and the work related to the particular categories where the overspending occurred specifically identifying the three primary drivers as increased costs in replacing main, scope of change required for the Scott Road Take Station, and the unexpected receipt of meters.³¹ The Division filed a memorandum recommending approval of the Company's proposed factors. It opposed waiving the penalty for the overspend for and recategorization of the Scott Road Take Station project noting that the more than doubling of costs were foreseeable and that waiving the penalty and recategorizing the project would undermine the intent of the budgetary restraints previously established by the Commission. He did recommend allowing a waiver of the penalty for the overspend in the meters category stating that the Company had no control over when the meters were delivered. Regarding the revenue requirement, the Division found the budget underspending was reasonable and recommended no adjustment to the updated \$74,578,868 revenue requirement.³²

On October 10, 2025, Mr. LaFond filed Rebuttal Testimony disputing Mr. Mancini's recommendation that the Company not be granted a waiver of the penalty assessed for the Scott Road Take Station overspend which he asserted resulted from changes needed to the original design that were beyond the Company's control and necessitated after the FY 2025 Plan review

²⁹ Sch. DAC-1S Revised.

³⁰ Hawk ISR Test. at 9-13; Att. NH-1-NH-3 (Aug.1, 2025).

³¹ LaFond ISR Test. at 4.

³² Mancini ISR Mem. at 1-5 (Oct. 1, 2025).

process was underway and complete costs was assessment not complete until after the Commission had approved the FY 2025 Plan. He maintained that the Scott Road project should be recategorized, because after it began it became apparent that the project was a multi-year project that would exceed \$10 million. He noted that even if the Commission denies the current request to recategorize the Scott Road project, it should consider a mechanism to allow for recategorization of a project that has commenced.³³

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.

In the August 28, 2025 GCR filing, RIE proposed the following: 1) a high load factor of \$0.5775 per therm; 2) a low load factor of \$0.6342 per therm; 3) an FT-2 Demand Rate Usage of

³³ LaFond Rebuttal at 5 (Oct. 10, 2025).

\$12.2019 Dth/Mth; and 4) an FT-2 Storage and Peaking for FT-1 firm transportation customers eligible for TSS of \$0.9969 per dekatherm.³⁴

RIE explained how it projected and calculated gas costs.³⁵ 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 1, 2025.³⁶ It noted that its total gas costs are \$10.2 million lower than those forecasted in the 2025 Long-Range Resource and Requirements Plan (Long Range Plan). The lower costs are attributable to: 1) the decrease in the transportation and storage delivery costs by about \$2 million and 2) a decrease in total variable costs by approximately \$8.3 million because of decreases in gas commodity costs.³⁷

The Company submitted testimony regarding the development of its 2024/25 sales forecast of 39,163,011 Dth which was slightly higher than last year.³⁸ It presented testimony about the Gas Procurement Incentive Plan (GPIP) and the Natural Gas Portfolio Management Plan (NGPMP). It noted no changes to the GPIP over the last year. The Company stated that it had purchased discretionary supply of 3,100,000 Dth which resulted in a \$18,399 incentive for the Company.³⁹ The NGPMP produced total savings of \$19,778,501.47 of which \$18,091,791.39 was customers’ share. RIE asked the Commission to approve the remaining \$1,686,710.09 as the Company’s incentive.⁴⁰

³⁴ Shields Test. at Attach. TGS-1 Corrected, TGS-5 Corrected (Sept. 12, 2025).

³⁵ Dao GCR Test. at 4-13, Att. GSP-1, Att. GSP-2, Att. GSP-3 (Aug. 28, 2024).

³⁶ Dao GCR Test. at 4.

³⁷ *Id.* at 12-13.

³⁸ Jones GCR Test. at 3-15 (Aug. 28, 2025).

³⁹ Crupi Test. at 6-7, Att. GPIP-2 (Aug. 28, 2025).

⁴⁰ Stephens (NGPMP) Test. at 5-6, Att. NGPMP-2.

On October 15, 2025, RIE proposed a BTU factor of 1.031 for the six-month period November 2025 through April 2026.⁴¹ In a memorandum dated October 16, 2025, the Division recommended approval of the proposed BTU factor as filed.⁴²

On October 1, 2025, the Division filed the testimony of its consultant, Jerome D. Mierzwa who made a number of findings and offered recommendations. First, he recommended that the System Pressure factor in the DAC be approved subject to any adjustments determined to be appropriate with respect to incremental variable peak hour costs being allocated between DAC and GCR. He stated that the Company had not specifically quantified the variable costs incurred to meet hourly demands during the 2024-2025 winter season and asked that it do so in rebuttal testimony. He stated that should be done in the Company's rebuttal testimony. He found that the Company should track the actual incremental variable costs it incurs to meet hourly peak demand, report those costs in its 2025 DAC and GCR filings and, if significant, remove them from the GCR reconciliation process and include the costs in the DAC reconciliation process.⁴³ He did not express any concern with the incentive amounts sought by the Company for either the GPIIP or the NGPMP.⁴⁴

After expressing and detailing his concerns with the transportation imbalance cash out provisions, Mr. Mierzwa recommended that the Commission order the Company to revise the current provisions to eliminate the unreasonable impact of the current provisions on GCR

⁴¹ Boyajian BTU Letter at 1 (Oct. 15, 2025).

⁴² Mancini Mem. at 1 (Oct. 16, 2025).

⁴³ Mierzwa Test. at 5-6, 9-10 (Oct. 1, 2025).

⁴⁴ *Id.* at 6, 14-16.

customers. He recommended that the proposed rates be approved subject to any adjustment determined appropriate by the Commission.⁴⁵

On October 10, 2025, James Stephens filed Rebuttal Testimony in response to Mr. Mierzwa's concerns over the allocation of variable peak hour costs incurred during the winter of 2024/25 between the GCR and the DAC and the transportation imbalance cash out provisions. Mr. Stephens quantified the variable costs associated with the utilization of portable LNG assets noting that they were not included in the DAC 2024/25 reconciliation because they were not significant. He summarized the transportation imbalance cash out provisions and noted that the Company's application of the tariff provisions revealed a slightly lower amount than Mr. Mierzwa suggested and what was provided by the Company in Schedule TGS-2. He contributed the difference to timing differences of actual payments to marketers and prior period accounting adjustments. He expressed that the cash out value to marketers for the transportation imbalances cannot be viewed in isolation because they are managed in conjunction with the Company's gas supply for GCR customers through various approaches. He suggested that the Division and the Company engage in a collaborative process to determine if any changes to the tariff were necessary,⁴⁶

Mr. Mierzwa filed Surrebuttal Testimony agreeing with Mr. Stephens that the variable costs were not significant. Regarding the cash out provisions, he found the suggestion of engaging in a collaborative process to determine if any changes were necessary to be reasonable.⁴⁷

⁴⁵ *Id.* at 7, 16-20.

⁴⁶ Stephens Rebuttal at 2-17 (Oct. 10, 2025).

⁴⁷ Mierzwa Surrebuttal at 2-4 (Oct. 14, 2025).

HEARINGS

Public Comment Hearing

On September 9, 2025, the Commission held a public comment hearing to take comments from the public. The hearing was held in the evening both in person and virtually to afford anyone interested the opportunity to provide public comment.

Evidentiary Hearings

The Commission held an evidentiary hearing on October 16, 2025 to hear evidence on both the proposed DAC and GCR factors in Docket Nos. 25-22-NG.

Mr. Jones, Mr. Stephens, Ms. Dao, and Mr. Shields all appeared to answer questions regarding their prefiled testimony in the GCR portion of this docket. Mr. Stephens provided a high level overview of the approximate 21,000 Dths per day the Company expects from the planned enhancements to the Algonquin system starting in 2029. When questioned by the Chairman, Mr. Stephens identified the two low pressure points that would be addressed by the improvements to the Algonquin system and noted that not only would the improvements benefit Aquidneck Island but would also provide additional capacity to Cumberland.⁴⁸ He explained in detail the monthly balancing rules, how they work, are applied and are calculated, their connection to the NGPMP, and how at times, a marketer over-delivery can offset more expensive resources that the Company would have had to procure.⁴⁹

⁴⁸ Hr'g Tr. at 28-33 (Oct. 16, 2025).

⁴⁹ *Id.* at 35-49.

Mr. LaFond testified about the ISR Reconciliation. When questioned about the Company's requested waiver of the penalty assessed for the overspend for the Scott Road Take Station project, Mr. Lafond acknowledged a more than \$9 million increase from the original \$8.71 million cost of the project. He testified that some of the increased costs were known prior to the time the Commission issued its decision on the Gas ISR Plan. He was also questioned about the Company's request to waive the penalty for the overspend on Purchased Meters. He expressed that to his recollection meters were not a large part of the discussion when the categories and budget caps were created. He noted that if they were in a category with other items, the Company would have a better ability to manage an over/underspend.⁵⁰

Mr. Oliveria and Ms. Hawk both provided testimony regarding the hold harmless adjustment. Mr. Oliveria noted that the \$4,536,343 hold harmless credit was a reduction to rates. Upon questioning from the Chairman, he acknowledged that the hold harmless credit is designed to remove the profit that would have been recovered as a result of the acquisition choices made for tax purposes.⁵¹ Ms. Hawk explained the calculation.⁵²

Mr. Mierzwa testified on behalf of the Division. He stated that after review of the variable peak hour demand costs, he agreed that they were not significant and could be left in the GCR. He agreed with the Company's suggestion that the Division and the Company review the transportation imbalance cashout provision and determine whether revision was necessary.⁵³

Mr. Mancini was asked whether if there was a mechanism to recategorize the Scott Road Take Station the Division would oppose it. He testified that he did not think the Division would

⁵⁰ *Id.* at 64-76.

⁵¹ *Id.* at 89-90, 93-94.

⁵² *Id.* at 90-95 (emphasis added).

⁵³ *Id.* at 105-09.

be opposed to that. He also testified regarding the Company's filing of the BTU factor and noted that he reviews the calculation provided by the Company.⁵⁴

DECISION

Every year, the DAC and the GCR are filed in the fall to address a subset of costs incurred by the Company that are necessary for the provision of safe and reliable gas service and supply. The annual filings typically result in a change of rates effective November 1 for the coming winter period. In recent years, the costs of providing safe and reliable gas distribution service and natural gas supply have risen significantly, largely due to growing constraints on the various gas pipeline systems that transport natural gas to the delivery points in Rhode Island. When the utility makes a filing of this type, the Commission (and the Division, acting as the ratepayer advocate) review the reasonableness of the costs and, unless there is an evidentiary basis for a finding that the costs were not necessary or the Company acted imprudently, the costs are allowed to flow through rates. The Commission considered the request by RIE, including a review of the underlying gas-related costs addressed in the DAC and the GCR. In both matters, the Commission and the Division conducted extensive discovery issuing numerous data requests which the Company witnesses adopted under oath at the hearing. At an Open Meeting on October 27, 2025, the Commission approved the Company's proposed DAC and GCR factors.

The DAC Factors

Regarding the Company's proposed DAC factors, including the revenue requirement calculations and adjustments supporting those rate factors, the Commission finds the Company's proposed rates in Schedule DAC-1-S Corrected, attached hereto as Appendix A, are designed to

⁵⁴ *Id.* at 112-15.

recover costs that were reasonably incurred under the prevailing conditions. In addition, the Division evaluated the revenue requirement adjustments and reasonableness of the costs. The Commission relies upon the Division's recommendation for Commission approval.

Regarding the Company's request to waive the penalties associated with the overspend and recategorize for the Scott Road Take Station project, the Commission denies the request. The purpose of the ISR budget framework is to provide structure and is intended to hold the Company accountable to a budget cap. Since the ISR provides preferential treatment to the Company for capital spending, it is incumbent on the Company to manage this spending. The framework does not contemplate the Company seeking waivers from the formulaic way in which the framework operates.

The Scott Road Take Station project overspend was caused by increased costs in labor, paving, and redesign among other things which was the Company's responsibility to manage against other costs and time. The fact that the costs were not known until after the budget had been approved and were unforeseeable at the time of the initial planning indicates that the project may have been prematurely included in the ISR plan. Moreover, any requests to modify the framework or reclassify project categories should occur prior to the program year in the applicable ISR docket – not after the program fiscal year has been completed.

For the same reason, the Company's request for a waiver of the penalty imposed for overspend in the Purchased Meters category is likewise denied. If the Company believes that the framework in this category is too rigid, it may propose changes with adequate justification in the next ISR docket for prospective application.

Approval of GCR Rates, Incentives, and BTU Factor

The Commission unanimously approves the Company's proposed factors and rates, including (i) the High Load Factor of \$0.5775 per therm (ii) the Low Load Factor of \$0.6342 per therm, (iii) the FT-2 Firm Transportation Marketer Gas Charge of \$12.2019 per Dth/Mth, and (iv) the Storage and Peaking Charge for FT-1 firm transportation customers eligible for TSS of \$0.9969 per Dth, were calculated. The Commission also approves the GPIP incentive of \$18,399, the NGPMP incentive of \$1,686,710.09, and the BTU Factor of 1.031. The Commission is satisfied based on its review and recommendation of the Division that the factors and incentives were properly calculated.

Tracking of Variable Peak Hour Costs

The Commission also orders the Company as part of its filing each year to track the actual incremental variable costs it incurs in meeting peak hour requirements, to report those costs in the annual DAC filing and, if significant, to allocate them from the GCR to the DAC.

Monthly Imbalances

After discussion, the Company and the Division agreed that it would collaborate to determine whether modification was necessary to the transportation imbalance tariff and the Company's cash out provisions.

Accordingly, it is hereby

(25586) ORDERED:

1. The factors reflected in the DAC 1S Corrected page 3 filed September 16, 2025 and titled Summary of DAC and GCR Factors attached hereto as Appendix A, are approved effective for usage on and after November 1, 2025.
2. The calculations of ratepayer savings and corresponding incentive reflected in the Gas Procurement Incentive Annual Report provided in Attachment GPIIP-2 of the Testimony of Terry Crupi relating to the period April 1, 2024-March 31, 2025 are approved.
3. The calculations or ratepayer savings and corresponding incentive reflected in the Natural Gas Portfolio Management Plan provided in Attachment NGPMP-2 of the Testimony of James Stephens relating to the period from April 1, 2024 through March 31, 2025 are approved.
4. The BTU factor of 1.031 per ccf is approved.
5. As part of its annual filing, The Narragansett Electric Company d/b/a Rhode Island Energy shall track actual incremental variable costs incurred in meeting peak hour requirements and report those costs in the DAC filing and, if significant, reallocate them from the GCR reconciliation process and include them in the DAC reconciliation process.
6. The Company and the Division shall meet to determine whether the tariff cash out provisions the Company used to address monthly imbalances to transportation customers are appropriate and shall provide a report to the Commission with conclusions by February 1, 2026.

EFFECTIVE AT WARWICK, RHODE ISLAND ON NOVEMBER 1, 2025 PURSUANT TO AN OPEN MEETING DECISION ON OCTOBER 27, 2025. WRITTEN ORDER ISSUED JANUARY 22, 2026.

PUBLIC UTILITIES COMMISSION



Ronald T. Gerwatowski

Ronald T. Gerwatowski, Chairman

Abigail Anthony

Abigail Anthony, Commissioner

Karen M. Bradbury

Karen M. Bradbury, 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

The Narragansett Electric Company
d/b/a Rhode Island Energy
Summary of DAC & GCR Factors, As Filed
Effective November 1, 2025

Distribution Adjustment Charge (DAC) Factors		Rate	Type of Charge	Source (Docket No. 25-22-NG)
<i>(not including Uncollectible %)</i>				
(1)	System Pressure Factor	\$ 0.0314	per therm	Sch. DAC-2SR, Pg.1, Line (6)
(2)	Environmental Response Cost Factor	\$ 0.0004	per therm	Sch. DAC-3, Pg. 1, Line (18)
(3)	Pension Adjustment Factor	\$ (0.0271)	per therm	Sch. DAC-4C, Pg. 1, Line (14)
(4)	Arrearage Management Adjustment Factor	\$ 0.0004	per therm	Sch. DAC-5, Pg. 1, Line (4)
(5)	Service Quality Factor	\$ (0.0007)	per therm	Sch. DAC-8S, Pg. 1, Line (10)
(6)	<i>DAC Reconciliation Factors:</i>			
(a)	Reconciliation Factor (All Rate Classes)	\$ (0.0076)	per therm	Sch. DAC-9SC, Pg. 1, Line (16)
(b)	Reconciliation Factor (Large and Extra-Large C&I Only)	\$ (0.0103)	per therm	Sch. DAC-9SC, Pg. 1, Line (28)
(c)	RDA Reconciliation Factor (Residential, Small & Medium C&I Only)	\$ 0.0056	per therm	Sch. DAC-9SC, Pg. 1, Line (22)
(7)	Earnings Sharing Mechanism	\$ -	per therm	Sch. DAC-11, Pg. 1, Line (4)
(8)	Low Income Discount Recovery Factor	\$ 0.0233	per therm	Sch. DAC-12SC, Pg. 1, Line (3)
(9)	Storm Net Revenue Factor	\$ -	per therm	Sch. DAC-13S, Pg. 1, Line (8)
(10)	Revenue Decoupling Adjustment Factor	\$ 0.0108	per therm	Sch. DAC-6S, Pg. 1, Line (10)
(11)	<i>ISR Reconciliation Factors:</i>			
(a)	Residential	\$ (0.0104)	per therm	Sch. DAC-7SC, Pg. 1, Line (3)
(b)	Small	\$ (0.0413)	per therm	Sch. DAC-7SC, Pg. 1, Line (4)
(c)	Medium	\$ (0.0128)	per therm	Sch. DAC-7SC, Pg. 1, Line (5)
(d)	Large LL	\$ 0.0106	per therm	Sch. DAC-7SC, Pg. 1, Line (6)
(e)	Large HL	\$ (0.0178)	per therm	Sch. DAC-7SC, Pg. 1, Line (7)
(f)	XL-LL	\$ (0.0057)	per therm	Sch. DAC-7SC, Pg. 1, Line (8)
(g)	XL-HL	\$ 0.0038	per therm	Sch. DAC-7SC, Pg. 1, Line (9)
Gas Cost Recovery (GCR) Factors		Rate	Type of Charge	Source (Docket No. 25-22-NG)
(12)	High Load Factor	\$ 0.5775	per therm	Attachment TGS-1C, Pg. 1, Line (6)(d)
(13)	Low Load Factor	\$ 0.6342	per therm	Attachment TGS-1C, Pg. 1, Line (6)(e)
(14)	<i>Gas Marketer Transportation Factors:</i>			
(15)	FT-2 Demand Rate	\$ 12.2019	per dekatherm	Attachment TGS-5C, Pg. 2, Line (23)
(16)	Storage and Peaking Charge	\$ 0.9969	per dekatherm	Attachment TGS-5C, Pg. 3, Line (5)