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June 2, 2025

VIA HAND DELIVERY AND ELECTRONIC MAIL

Stephanie De La Rosa, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: The Narragansett Electric Company d/b/a Rhode Island Energy
Analysis to Comply with Energy Facility Siting Board's Decision and Order
Pre-filed Direct Testimonies of Daniel Aas and Lee Gresham

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), I have enclosed the pre-filed direct testimonies of Daniel Aas and Lee Gresham in the above referenced matter. Messrs. Aas and Gresham provide an analysis of measures and strategies designed to reduce demand on the natural gas distribution system on Aquidneck Island in compliance with the Energy Facility Siting Board's May 12, 2025 Decision and Order in Docket No. SB-2021-04.

Thank you for your attention to this matter. If you have any questions, please contact me at (401) 709-3359.

Sincerely,

Steven J. Boyajian

Enclosure

cc: Docket No. SB-2021-04 Service List

Certificate of Service

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

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Heidi J. Seddon

June 2, 2025
Date

SB-2021-04 The Narragansett Electric Company's Application for a License to Mobilize and Operate a Liquified Natural Gas (LNG) Vaporization Facility at Old Mill Lane (Portsmouth, RI)

Updated April 24, 2025

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PRE-FILED DIRECT TESTIMONY

OF

DANIEL AAS

June 2, 2025

Table of Contents

I. Introduction

Q. Please state your name, title, and business affiliation.

A. My name is Daniel Aas. I am a partner at Energy and Environmental Economics, Inc. ("E3"), located at 44 Montgomery Street, Suite 1500, San Francisco, CA, 94104.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company").

Q. Please state your qualifications and experience.

A. My qualifications are summarized in Schedule DA-2. I have seventeen years of experience in the energy industry, including eight years at E3 where my work has primarily been focused on heating sector transition analysis. I have led studies on heating sector transitions in states including California, Colorado, Illinois, Massachusetts, Maryland, Minnesota, New York, Oregon, Pennsylvania, and Washington state. I have also submitted testimony on heating sector transition topics to the Public Utilities Commissions of the states of Massachusetts, Colorado and Maryland.

In Rhode Island, I provided technical and strategic direction for the Technical Analysis Report submitted in the Rhode Island Public Utilities Commission's ("PUC") Investigation Into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the

Act on Climate in Docket No. 22-01-NG (the "Future of Gas" or "FOG"), which investigated pathways for the gas system to reduce emissions and the associated implications. On the topic of demand-side or non-pipeline alternatives ("NPAs") in particular, I recently conducted a detailed benefit-cost analysis for 11 NPAs in the San Francisco Bay area, supported a stakeholder process to develop NPA evaluation frameworks in Massachusetts, and am currently supporting a confidential East Coast utility in developing an NPA study and evaluation framework.

I have a Bachelor of Arts in Economics and Political Science from Whittier College, as well as a Master of Arts in Energy and Resources and a Master of Public Policy from the University of California, Berkeley.

Q. Have you previously testified before the PUC?

A. No.

II. <u>Purpose of Testimony</u>

Q. What is the purpose of your testimony?

A. The Energy Facility Siting Board ("EFSB"), in conditionally approving the Company's most recent permit application for Old Mill Lane ("OML"), ordered that the Company file with the PUC "a demand response/energy efficiency plan targeted specifically for Aquidneck Island with the objective of eventually eliminating the design-day peak hour capacity gap that has caused the gas capacity constraint on Aquidneck Island."[1] The ESFB required this to be completed and filed with the PUC by June 1, 2025. E3 was retained by the Company to conduct an analysis of alternative demand-side alternative scenarios to inform the Company's plans.

OML is a liquefied natural gas ("LNG") vaporization facility on Aquidneck Island that helps address two main challenges: (1) a gas capacity constraint, driven by the gap between design day demand and physical and contractual supply limits, and (2) capacity vulnerability due to the area's reliance on a single transmission pipeline and its location at the end of the Algonquin Gas Transmission ("AGT") pipeline. OML has helped address these challenges with portable LNG equipment to back up the pipeline supply of natural gas to the distribution system on Aquidneck Island. Per the EFSB order, the scope of this analysis focuses on addressing the first challenge, the capacity shortfall, with demand-side alternatives. The demand-side alternatives evaluated here do not address the second capacity vulnerability challenge given that issue is not a function of peak demand.

My testimony addresses the question of "What amount of technology investment and uptake would it take to mitigate the capacity shortfall?" This "technical potential" perspective examines demand-side alternatives under various resource portfolio

[1] In re *The Narragansett Electric Company Aquidneck Island Gas Reliability Project, Old Mill Lane, Portsmouth, RI*, Decision and Order, at 52 (May 12, 2025).

configurations, and it evaluates whether implementation of the portfolios may be feasible based on estimated costs, required customer adoption levels, and greenhouse ("GHG") emissions reduction potential. These represent a robust, though by no means exhaustive, set of considerations for the feasibility of the portfolios. My testimony does not include a recommendation for a specific demand-side alternative portfolio plan or program design to be pursued. Rather, it discusses the technological options and implementation challenges associated with the alternative demand-side measures evaluated.

Q. How is your testimony structured?

A. Section I of my testimony is the introduction and includes my background and qualifications. Section II explains the purpose and structure of my testimony. Section III provides an overview of the methodology and analytical framework that E3 used to assess demand-side alternatives to the capacity shortfall. This section outlines the overall approach (including customer segmentation, demand-side alternative selection, portfolio assembly, and evaluation across key metrics to be assessed as potential alternatives to OML as a solution to the natural gas demand-supply gap) as well as a comparison to the previously submitted study conducted by National Grid from September 2020. Section IV provides the key findings of the analysis, including the technical potential and portfolio adoption rates of each alternative by customer segment and the impacts of each alternative in terms of cost, feasibility, and emissions relative to each other and to OML. Section V provides conclusions on what would be needed to close the capacity gap through demand-side measures across different timeframes and the feasibility of successfully implementing the measures.

Q. Are you sponsoring any schedules as part of your testimony?

A. Yes, I am sponsoring the following schedules with my testimony, which were prepared by me or under my direct supervision:

- Schedule DA-1 Appendix of Data Sources
- Schedule DA-2 CV for Dan Aas

III. Methodology and Analytical Framework

Q. Please provide an overview of the analytical approach.

A. The analysis was conducted according to the five-step workflow outlined below:

- **Data Request and Model Development**
  - i. E3 obtained data from Rhode Island Energy and public sources to characterize demand-side measures and developed a model that combines those measures into demand reduction portfolios.
- **Customer Segmentation**
  - i. E3 segmented gas customers into groups that share key characteristics such as residential versus commercial customer classes, residential versus commercial building types, presence of gas space heating, and others.

- **Demand-Side Measure Selection and Evaluation**
  i. E3 selected measures based on estimated demand reduction potential, cost, and feasibility and evaluated the impacts of each measure for each customer segment.
- **Portfolio Development**
  i. E3 assembled the measures into portfolios that balance objectives such as cost, demand reduction potential, greenhouse gas emissions, and feasibility.
- **Portfolio Evaluation**
  i. E3 evaluated the portfolios to assess when the capacity gap is addressed, as well as across other key metrics including cost, emissions, and implementation feasibility.

<u>Data Request and Model Development</u>

Q. What data did you request from Rhode Island Energy?

A. E3 developed a request outlining the data necessary from Rhode Island Energy to complete a robust analysis, including both public and confidential information. Rhode Island Energy provided the requested data as available. Key inputs provided by Rhode Island Energy include customer billing data for the segmentation analysis and the forecasted design day gas demand. E3 then met with subject matter experts from Rhode Island Energy and the Navy, Rhode Island Energy's largest customer on Aquidneck Island, to evaluate and refine assumptions. Additional details on the data received from Rhode Island Energy versus public sources is provided in the in Schedule DA-1.

Q. What data did you derive from public sources?

A. E3 used public data to model the customer segments (e.g., space heating load shapes, average building square feet, etc.), measures (e.g., savings in space heating service demand, device efficiencies and costs, etc.), and other key inputs (e.g., emissions factors, natural gas and electricity prices, etc.) to inform evaluation metrics. Full details of these data sources and inputs are included in Schedule DA-1. E3 also used public Rhode Island Energy program data, such as from demand response filings, energy efficiency filings, and electrification incentive reports. For the key portfolio evaluation metrics, E3 relied upon the *Avoided Energy Supply Components in New England: 2024 Report* ("AESC") prepared by Synapse Energy Economics, and the *Rhode Island Investigation into the Future of Regulated Gas Distribution Business: Technical Analysis Report*, published by E3 in the Future of Gas docket, for equipment costs and efficiencies. Full details of these data sources and inputs are included in Schedule DA-1.

These sources represent the most recent and appropriate publicly available data at the time this analysis was conducted. However, they do not uniformly capture all recent policy developments and market trends. For example, the AESC does not reflect the recent Federal policy changes such as the rollbacks of offshore wind leases and potential changes to federal power plant rules, which could lead to portfolios with higher costs, emissions, or both. Due to these limitations, future electric system costs and emissions intensities should be considered extremely uncertain. Nevertheless, the AESC remains the most appropriate data source for avoided energy supply components, given its broad acceptance and applicability to similar demand-side evaluations in Rhode Island and the region. Additional detail is provided in Schedule DA-1.

Q. Please describe the core functionality of the model.

A. E3 developed a supply curve-based model that evaluates individual measures' impacts on gas demand reductions, emissions and several different cost perspectives. The model is designed to combine individual measures into alternative portfolios of demand reduction strategies. The model then returns the total demand reductions, emissions and costs for each portfolio.

Q. What cost perspectives does the model consider?

A. The model uses both the Societal Cost Test ("SCT") and the Utility Cost Test ("UCT"), with avoided cost components aligned with Rhode Island Cost Test conventions.[2] In addition, the model outputs the program incentive costs necessary to achieve the measure uptake modeled for each portfolio. Table 1 outlines the key components of each

[2] Components of the Docket 4600 framework are included and valued as applicable using the AESC or according to conventions discussed in prior filings: https://eec.ri.gov/wp-content/uploads/2023/09/04_2024-annual-plan_attachment-4_ri-test_9.7.2023.pdf

perspective. Information on the data sources used for each cost test is included in the Technical Appendix in Schedule DA-1.

Table 1: Cost Test Components

	[1]	**[2]**	**[3]**
	Component	**Societal Cost Test**[3]	**Utility Cost Test**[4]
[a]	Incremental Equipment Upfront Cost	Cost	Not Included
[b]	Utility Incentive	Not Included	Cost
[c]	Federal Incentive	Benefit	Not Included
[d]	Incremental Electric Bill	Not Included	Not Included
[e]	Avoided Gas Bill	Not Included	Not Included
[f]	Incremental Electric Supply	Cost	Cost
[g]	Incremental Electric Generation Capacity	Cost	Cost
[h]	Incremental Electric Transmission Capacity	Cost	Cost
[i]	Incremental Electric Distribution Capacity	Cost	Cost
[j]	Incremental Demand Reduction Induced Price Effect	Cost	Cost
[k]	Incremental Renewable Energy Credits	Cost	Cost
[l]	Avoided Gas Supply	Benefit	Benefit
[m]	Incremental Fuel Oil Supply	Cost	Not Included

[3] Calculated using 2 percent social discount rate.
[4] Calculated using 4.9 percent utility weighted average cost of capital for discount rate.

[n]	Avoided Supplier Risk	Benefit	Benefit
[o]	Incremental Administrative Costs	Cost	Cost
[p]	Avoided Greenhouse Gas Costs	Benefit	Not Included
[q]	Avoided Criteria Pollutants	Benefit	Not Included

Q. How does this analysis differ from National Grid's 2020 study?

A. E3 reviewed National Grid's Aquidneck Island Long-Term Gas Capacity Study from September 2020 (the "2020 Study") and identified four key differences compared to E3's current analysis conducted for Rhode Island Energy.

1. **Design Hour Capacity Gap**: The 2020 Study considered not only the demand gap but also included a contingency target to reflect the ability of OML to meet gas demand on Aquidneck Island in the event of a disruption to the AGT pipeline, making the total target two to three times higher in 2035. Conversely, E3's analysis focused only on the demand gap between forecast peak demand and contracted supply. The 2020 Study also assumed a larger future demand gap, driven by a higher peak demand forecast. This appears to reflect the conclusions of an older version of the Company's annual Gas Long-Range Resource Requirement Plan ("LRP"). To compare a specific year, the 2034/35 demand gap was projected at 310 dekatherms per hour (Dth/hr) with a total contingency target of over 600 Dth/hr in the 2020 study, whereas the E3 analysis

assumes a demand gap of 281 Dth/hr based on the latest design year forecast provided by Rhode Island Energy's forecasting team, with no additional contingency target.

2. **Electrification Uptake**: Comparing the scenarios with the highest levels of electrification (E3's No New Fossil scenario and the No Infrastructure scenario from the 2020 Study), E3's assumptions reflect one-third of the residential electrification and one-quarter of the commercial electrification relative to the **2020** Study. This is primarily due to large differences in the demand reductions targeted in each study (as discussed in the previous bullet), electrification sales share assumptions (E3's analysis capped at 60 percent versus 100 percent in the 2020 scenario), and timing of implementation (i.e., starting 2026 in E3 analysis versus 2020 in the 2020 Study).

3. **Electrification Costs**: E3's estimated incremental electrification costs for residential customers are two to three times **higher**, due to updated device costs inputs,[5] and higher assumed system tonnage requirements. Similarly, small commercial costs differ due to these key factors along with differences in customer segment definitions.

4. **Scope of Measures**: E3's analysis includes larger assumed C&I demand response (approximately 4 Dth/hr design **hour** reduction) as part of the lower cost and expanded electrification scenarios, while these measures achieved far lower reduction in the 2020

[5] See Schedule DA-1: APPENDIX OF DATA SOURCES for additional detail.

Study (i.e., the maximum Dth/hr reduction for large C&I measures assumed was 0.54 Dth/hr in the 2020 Study).

III.1 Customer Segmentation

Q. How did you segment the customers for the analysis?

A. E3's analysis focuses on Rhode Island Energy's customers on Aquidneck Island. The Company has approximately 14,500 gas customers on Aquidneck Island. Table 2 outlines customer rate classes with the corresponding number of customers and their annual usage from data provided by the Company.

Table 2: Customer Breakdown by Rate Category

		[1]	**[2]**	**[3]**	**[4]**	**[5]**	**[6]**
	Customer Type	Rate Category	Number of Customers	Percent of Total Customers	2024 Total Sales (Dth)	Percent of Total Sales	Rates
[a]	Residential	Heating	12,232	84.4%	938,012	47.3%	Rates 12, 13
[b]		Non-Heating	683	4.7%	9,819	0.5%	Rates 10, 11
[c]	Commercial & Industrial (C&I)	Small	1530	10.6%	528,210	26.6%	Rates 21, 22
[d]		Large	52	0.4%	507,237	25.6%	Rates 23, 24, 33, 34, 60
[e]	Total		14,497	100%	1,983,278	100%	

These customer groups were then further segmented by building type to reflect key variations in square footage, usage, load profiles, and measure adoption potential. Within the residential rate class, customers were segmented by single family homes versus multi-family homes, and large C&I was segmented into customers with and without existing backup heating equipment. Customers on the non-firm sales rate were excluded from this analysis because they are assumed to not contribute to the design day demand on Aquidneck Island. Non-heating residential customers were also excluded from this analysis as they are a very small share of residential sales and would have an even smaller relative contribution to design day load. Table 3 provides an overview of the customer segments used in this analysis, with the number of customers and average usage for each segment, which was calculated by averaging 2022-24 usage across all customers in the segment.

Table 3: Final Customer Segments

	[1]	**[2]**	**[3]**	**[4]**
[a]	Customer Type	Segment	Number of Customers	Average Per Customer Annualized Load (Dth/Yr)
[b]	Residential	Single Family Home	8,353	86
[c]		Multi-Family Home	3,879	64
[d]	Commercial & Industrial (C&I)	Small C&I	1,530	377
[e]		Large C&I with Existing Backup Heating Equipment	6	8280
[f]		Large C&I - No Existing Backup Heating Equipment	51	

Q. How did you forecast the capacity shortfall?

A. E3 defined the capacity shortfall, and the associated demand reduction target, by taking the difference between the AGT contracted supply (1,045 Dth/hr) and the modeled peak hour demand through 2035. E3 used the following approach to project demand growth through 2035:

- For 2025 through the 2028/29 heating season, E3 used the demand projection from the Rhode Island Energy's most recent LRP dated June 28, 2024 filed in Docket No. 24-27-NG the ("2024 LRP"), consistent with the plan's time horizon. In the 2024 LRP, the shortfall is projected to grow from 264 Dth/hr to 269 Dth/hr over this period.
- For 2029/30 through 2033/34, E3 used the demand projection from Rhode Island Energy's forecasting team from the second quarter of 2024. The shortfall is projected to grow to 279 Dth/hr over this period.
- For the 2034/35 season, E3 linearly extrapolated peak hour demand, based on the 2024/25 through 2033/34 peak hour demand growth trajectory, and assumed the same peak hour AGT contracted supply, thus increasing the capacity shortfall to 281 Dth/hr.

Q. How did you allocate each customer segment's contribution to the design hour load?

A. To estimate design day and hour loads for each customer segment, E3 used historical customer gas sales data provided by Rhode Island Energy and peak demand estimation methods based on heating degree day ("HDD") scaling of space heating demand. For a detailed description of Rhode Island Energy's normal and design demand forecast methodology, see sections III.B-III.G in the 2024 LRP. To calculate annual gas demand, E3 used historical customer gas sales data from 2022 to 2024 to develop a baseline annual usage by customer class, weighted by HDDs. For design hour demand by customer segment, E3 estimated the space heating share of annual gas demand by customer segment using the National Renewable Energy Laboratory (NREL) ResStock and ComStock building energy models for Rhode Island,[6] and scaled space heating demand by the ratio of design day HDDs to the average annual HDDs in 2022 to 2024. Non-space-heating end uses were assumed to have constant daily gas demand, thus contributing a small amount to design day load. Finally, this estimate was scaled by 4.3 percent to adjust from retail to wholesale volumes, using estimated unaccounted for gas ("UFG") from III.D.1 in the 2024 LRP. This method yields a more conservative estimate of potential per-customer peak load reduction, compared to the equivalent estimates from the 2020 Study, which used the same scalar to scale the entire annual gas demand. To convert design day load into design hour load, E3 multiplied design day load by 5 percent to estimate design hour usage, consistent with section III.F of the 2024 LRP. Table 4 shows the resulting design day and hour loads for each segment.

[6] See Schedule DA-1: APPENDIX OF DATA SOURCES for more details on data source.

Table 4: Customer Gas Usage

	[1]	**[2]**	**[3]**	**[4]**	**[5]**
[a]	Customer Type	Segment	Per Customer Design Day Load (Dth/day)	Total Design Day Load (Dth/day)	Per Customer Design Hour Load (Dth/hour)
[b]	Residential	Single Family Home	1.09	9,102	0.05
[c]		Multi Family Home	0.75	2,928	0.04
[d]	Commercial & Industrial (C&I)	Small C&I	4.00	6,119	0.20
[e]		Large C&I	82.69	4,217	4.13

III.2 Demand-Side Measure Selection and Evaluation

Q. Which demand-side alternative measures were selected for modeling?

A. E3 modeled three measure categories, which were selected based on their demand reduction potential, feasibility, and cost. The analysis prioritized measures that reduce space heating demand, which is the dominant driver of residential and commercial gas use in New England. On an annual basis, space heating accounts for 70.3 percent of household natural gas consumption, followed by water heating at 26.5 percent.[7] However, using NREL's ResStock model and a consistent peak day scaling approach to that described above, E3 estimates that space heating comprises 93 percent of residential peak day gas

[7] U.S. Energy Information Administration. *2020 Residential Energy Consumption Survey (RECS): Table CE5.2 Detailed household natural gas and propane end-use consumption – totals, 2020*. U.S. Department of Energy, 2023, https://www.eia.gov/consumption/residential/data/2020/.

demand, while water heating contributes just 6 percent. Other end uses, such as cooking and clothes drying, represent a negligible share of gas peak demand.

The space heating measures E3 evaluated include:

1. Gas Device Efficiency
   - This measure replaces existing gas space heating equipment at end-of-life with high efficiency furnaces and boilers. High efficiency furnaces and boilers address space heating, the largest source of peak demand from most customer types, but have relatively low demand reduction potential per unit installed compared to the other measures considered. This means that condensing furnaces and boilers are unlikely to be able to achieve sufficient demand reductions to close the capacity shortfall on their own. However, condensing furnaces and boilers are mature technologies and are generally cost effective, so they could be a component of a broader portfolio of measures to meet the capacity shortfall. High efficiency gas measures were assumed to be installed alongside basic building shell improvements that reduced heating demand by 11 percent for multi-family housing and 16 percent for single-family housing.[8]

[8] See Schedule DA-1: APPENDIX OF DATA SOURCES for equipment performance assumptions data source.

2. Electrification

- E3 evaluated cold climate air source heat pumps ("ASHPs") as a representative electrification measure. The modeled ASHPs were assumed to fully displace gas space heating demand and sized to meet the expected design hour peak demand without requiring backup heating, assuming capacity retention of 90 percent at the design day temperature.[9] An ASHP system size of 4 tons was assumed for single family homes, and 2.8 tons for multifamily homes. In comparison, the ASHPs adopted via Rhode Island's Clean Heat RI ("CHRI") program to date have been sized to meet lower peak loads, with 2.7 tons for partial displacement and 3.0 tons for full displacement; these customers may need to install larger heat pumps to meet design temperatures without using backup heating such as electric resistance heat.[10]
- ASHPs were assumed to be installed alongside basic building shell improvements that reduced heating demand by 11 percent for multi-family housing and 16 percent for single-family housing. These shell improvements improve the cost-effectiveness of the electrification measures but do not change the demand reduction potential, as electrification eliminates gas space heating demand with or without shell measures. E3 did not include building shell improvements in commercial and industrial buildings, where retrofit costs are higher and less certain.

[9] Mitsubishi Electric Trane HVAC US LLC., P-Series Catalog 2024, Hyper-Heating INVERTER, pg. 72.
[10] The Narragansett Electric Company d/b/a Rhode Island Energy, RIPUC Docket No. 24-29-NG, In Re: 2024 Distribution Adjustment Clause and Gas Cost Recovery Filing, Response to Commission's Third Set of Data Requests, Issued October 7, 2024.

Similar demand reductions could also be achieved using technologies such as ground-source heat pumps and networked geothermal systems, which have trade-offs in terms of electric system impacts, emissions, customer install costs and other factors.

- Hybrid heat pumps with backup gas furnaces or boilers were not included in this analysis, since the backup gas heating system would be in use during the design day and hours analyzed, thus reducing or eliminating the peak gas demand reduction.

3. Demand Response

- E3 modeled demand response for large C&I customers enabled by customer fuel switching to on-site back-up systems, such as a dual fuel boiler that can use either natural gas or heating oil. For the demand response measure, E3 segmented customers into customers with existing dual fuel systems and customers that would need new dual fuel systems. Existing systems take advantage of dual fuel boilers that are already installed at customer facilities. New systems would involve replacing an existing natural gas boiler with a dual fuel system or supplementing an existing natural gas boiler with a fuel oil system. Both segments are assumed to enroll in a demand response program that requires up to three calls per year, each with a duration of 24 hours. Residential and small C&I demand response programs were not modeled, due to low expected response from behavioral changes under design day conditions.[11]

Q. How were the measures evaluated?

A. The measures were applied to each customer segment and then evaluated across the following five criteria:

- **Costs**. E3 evaluated costs for each measure across each of the cost tests described in as addressed in Answer 0.
- **Design Hour Technical Potential**: E3 calculated the maximum possible demand reduction from each measure for each customer segment, assuming no feasibility constraints (e.g., customer acceptance, market barriers, etc.)
- **Emissions**: For greenhouse gas ("GHG") emissions, E3 estimated the net impact of the avoided direct combustion of gas, the incremental electric sector emissions from electrification measures, and the incremental combustion of fuel oil from customer backup systems during demand response events.
- **Implementation and Feasibility Risk**: Based on our market experience and professional judgement, E3 qualitatively assessed customer and stakeholder acceptance, policy hurdles and alignment, and durability of the measures for each customer segment.

[11] The Narragansett Electric Company d/b/a Rhode Island Energy. *2024 Winter Season Analysis: 2025 Gas Demand Response Pilot.* Rhode Island Public Utilities Commission, 2 October 2024.

III.3 Portfolio Development

Q. What portfolios of measures did E3 consider?

A. Table 5 outlines the three portfolios E3 considered: "Lower Cost", "Expanded Electrification", and "No New Fossil Fuel Equipment." The table shows the customer segment and measures in the first column and expected range of uptake in the body of the table.

Table 5: Portfolio Definition

	[1]	**[2]**	**[3]**	**[4]**
[a]	Measure	Lower Cost	Expanded Electrification	No New Fossil Fuel Equipment
[b]		*Emphasis on gas efficiency and demand response*	*Balance of electrification, gas efficiency, and demand response*	*Emphasis on electrification measures*
[c]	**All Customer Classes** Electrification	10% to 30% of annual equipment sales	30% to 50% of annual equipment sales	30% to 60% of annual equipment sales
[d]	**All Customer Classes** High Efficiency Gas	40% of annual sales	20% of annual sales	Zero customers
[e]	**Large C&I** Demand Response *Customer Funded*	50% to 100% of customers with existing backup heating equipment	50% to 100% of customers with existing backup heating equipment	50% to 100% of customers with existing backup
[f]	**Large C&I** Demand Response *Rhode Island Energy Funded*	8 to 15 customers provided with new backup heating equipment (dual fuel boilers)	3 to 6 customers provided with new backup heating equipment (dual fuel boilers)	Zero customers

Q. How were these portfolios identified?

A. E3 assembled the measures into portfolios considering trade-offs among cost, demand reduction potential, GHG emissions impacts, and feasibility.

- **Lower Cost**: this portfolio emphasizes lower cost measures, based on incentive costs and SCT results. It includes relatively high amounts of gas device efficiency because of the relative cost-effectiveness of those measures under the cost-effectiveness tests. In addition, it includes higher levels of gas demand response and lower levels of electrification relative to the other portfolios.
- **Expanded Electrification**: this portfolio emphasizes electrification alongside other strategies. It includes an increased role for electrification relative to the "Lower Cost" scenario, along with lower levels of gas device efficiency and demand response.
- **No New Fossil Fuel Equipment**: this portfolio assumes that no incentives are provided for new fossil fuel equipment, such as through gas device efficiency measures or supporting new dual fuel boilers. This portfolio has the highest level of electrification, no additional gas device efficiency and only includes gas demand response resources for customers that already have a dual fuel system.

Q. For electrification programs, how was customer measure uptake modeled and how were ranges for customer adoption rates and associated incentive levels determined?

A. E3 first calculated technical potentials to understand how much demand reduction could be hypothetically achieved for each measure and customer segment. E3 then developed ranges of customer adoption potential across different measures. To benchmark a range of electrification customer adoption potential, E3 reviewed outcomes from CHRI and Massachusetts' Mass Save program. CHRI offers a $750 per ton incentive that can be combined with an additional $350 per ton incentive from the utility, resulting in total incentives of approximately $3,300 per home for the average CHRI installation of a 3.0 ton system for a "full displacement" electrification. From October 2023 through February 2025 installation data, CHRI supported the installation of 4,324 heat pumps. Based on an assumed average gas furnace lifetime of 15 to 20 years, E3 estimates this adoption corresponds to an 11 percent annual sales share, which is calculated as the number of customers that adopt the technology divided over the expected total number of customers replacing their equipment in a given year. Based on CHRI data, approximately 4 percent of installations were "full displacement" and 7 percent were "partial displacement" electrification, with the latter indicating that customers retained gas heating equipment. Mass Save has offered higher incentives, up to $10,000 for full displacement air-source heat pumps. Using a similar method to our estimate for Rhode Island, E3 estimated that Mass Save has driven an average sales share of 15 percent — 7 percent full displacement and 8 percent partial displacement — among customers replacing their heating equipment.

In conducting this analysis, E3 found that closing the capacity gap would require significantly higher electrification adoption rates than have been achieved to date in either Rhode Island or Massachusetts, making achievement of these high adoption rates inherently speculative. Recognizing the uncertainty around achievable adoption beyond the levels seen in empirical data from Rhode Island and Massachusetts, E3 developed two electrification adoption rate scenarios: a Lower Customer Uptake case assuming up to 30 percent electrification adoption at equipment replacement, and a Higher Customer Uptake case assuming up to 60 percent adoption at equipment replacement, with all electrification assuming full displacement of gas heating. These values are several times greater than the combined sales shares of partial displacement and full displacement electrification achieved under either Mass Save or CHRI.

To estimate an electrification incentive level for the study, E3 compared the cost of installing an ASHP to that of a conventional gas furnace or boiler, using cost data from the FOG Technical Analysis. The resulting incentive is designed to eliminate any incremental upfront cost for customers choosing to electrify at the point of space heating equipment replacement.

Table 6 below summarizes incentive levels and sales shares from CHRI and Mass Save alongside the assumptions used in this study for single-family residential heating systems. E3 used the relationship between incentive levels and sales share to extrapolate how adoption would proportionally scale with higher incentives. It is notable that the incentives assumed for this study are more than twice as high as those seen in Rhode Island or

Massachusetts, as higher levels of incentives would be necessary to incent the level of electrification sales share targeted in the portfolios.

Table 6: Incentive and Adoption Levels for Residential Heat Pumps in this Study Compared to Empirical Values from RI and MA

	[1]	**[2]**	**[3]**
[a]	Program	Incentive	Electrification Sales Share
[b]	CHRI	$3,300 (average for full displacement)	8% (3% full, 5% partial)
[c]	Mass Save	Up to $10,000	15% (7% full, 8% partial)
[d]	This Study[12]	Multifamily: $10,500 Single Family: $20,500	30-50% (all full displacement)

Q. What other participant cost considerations did E3 evaluate for electrification?

A. In addition to considering upfront costs, E3 quantified the bill impacts of electrification measures. For all customer classes, E3 identified that electrification will result in higher customer bills relative to gas heating. A high-level example of a residential customer replacing their gas furnace with a heat pump illustrates the bill impacts challenge of electrification under current rate structures and levels in Rhode Island. Current volumetric residential winter electricity rates in Rhode Island are approximately ¢32/kWh, which translates to a cost of heat delivered of approximately $34/MMBTU, assuming an annual

[12] The incentive values shown reflect the incremental costs of heat pumps alone, and do not include the additional $1,900 to $3,600 incentives modeled for multifamily and single family building shell improvements respectively.

average coefficient of performance of 2.72 for an electric heat pump.[13] In comparison, current volumetric residential winter gas rates in Rhode Island are approximately $19/MMBTU, translating to a cost of heating delivered of approximately $23/MMBTU assuming an annual fuel utilization efficiency of 80 percent for a gas furnace. Table 7 shows annual heating bills for a gas customer compared to heating bills for an electric customer for representative residential and commercial customers. These bill increases, in addition to the higher upfront cost of electrification, corroborate that high incentives may be needed to encourage levels of electrification that are sufficient to meet the OML capacity gap.

Table 7: Annual Bill Impacts for Electrification Measures

	[1]	[2]	[3]	[4]
[A]	Measure	Gas Bill Decrease	Electricity Bill Increase	Net Bill Impact
[B]	Single Family - Electrification	-$1,350	$1,593	$243
[c]	Multifamily – Electrification	-$918	$1,149	$231
[d]	Small C&I - Electrification	-$4,395	$4,932	$538

[13] See Schedule DA-1: APPENDIX OF DATA SOURCES for retail energy price and equipment performance data sources.

Q. For gas efficiency programs, how did E3 identify a range of customer adoption rates and associated incentive levels?

A. E3 assumed high-efficiency gas furnaces for single family homes, and high-efficiency boilers for multifamily and C&I segments, with concurrent building shell improvements for residential customers. Like the electrification measures above, E3 assumed an incremental upfront cost incentive offered for these devices, relative to a standard gas furnace or boiler. Since these technologies are more commercially mature than the electrification measures mentioned above, E3 assumed up to 40% sales share for efficient gas measures in the Lower Cost portfolio, with a reduced sales share in the Expanded Electrification and No New Fossil Equipment portfolios, reflecting efforts to prioritize electrification measures over high-efficiency gas measures in those cases. Table 8 shows the expected bill savings for customers adopting the modeled gas efficiency measures.

Table 8: Annual Bill Impacts for Gas Efficiency Measures

	[1]	**[2]**	**[3]**	**[4]**
[a]	Measure	Gas Bill Decrease	Electricity Bill Increase	Net Bill Impact
[b]	Single Family – Efficient Gas	-$415		-$415
[c]	Multifamily – Efficient Gas	-$244		-$244
[d]	Small C&I – Efficient Gas	-$621		-$621

Q. For gas demand response programs, how did E3 identify a range of customer adoption rates and associated incentive levels?

A. E3 reviewed data from Rhode Island Energy's 3-hour Peak Period Demand Reduction ("PPDR") and 24-hour Extended Demand Reduction ("EDR") offerings, which ran as pilot demand response programs from 2018/2019 through 2024.[14] In addition, E3 interviewed Rhode Island Energy subject matter experts. The PPDR and EDR programs had low enrollment and inconsistent responses under the current incentive structure and participants have cited additional challenges particularly around staffing and O&M of their on-site backup fuel systems.

As with the electrification measures, E3 bounded the potential customer response to incentives with lower and higher customer response scenarios. E3 modeled an EDR style offering with three 24-hour calls a year. For large C&I customers with existing backup heating systems, E3 modeled the current program incentives of $700 per peak hour dekatherm capacity payment for peak season months and the $7 per dekatherm energy payment.[15] For customers provided with new dual-fuel boilers, E3 modeled a $450 per peak hour dekatherm capacity payment for the peak season months and the $7 per dekatherm energy payment. The lower capacity payment offered to these customers was

[14] The Narragansett Electric Company d/b/a Rhode Island Energy, *Docket No. 24-37-EE: 2025 Gas Demand Response Pilot Investment Proposal*, https://ripuc.ri.gov/Docket-24-37-EE.
[15] For context, the PPDR program offered a $250 per peak-hour dekatherm per month capacity payment with an energy payment of $50 per dekatherm.

determined by comparing the cost-effectiveness of demand reduction achieved across measures (i.e., the program cost per dekatherm per hour reduced), including the upfront cost incentive for new dual-fuel boilers. E3 estimated the cost of a new dual fuel system at $355,000 per customer,[16] although this would vary significantly in practice due to heterogeneity of large C&I customer demand.

The capacity enrollment assumed for all DR measures was set equal to the average design hour usage of that customer segment, with 100 percent participation across the day (design hour usage multiplied by 20 to estimate design day usage, in keeping with the peak load forecasting methods defined in Q3). E3 used the current program incentives as an indicative incentive level for this analysis but there is significant uncertainty around customer uptake, and the incentive level may need to be adjusted to incent additional enrollment and participation. Future efforts to determine incentive levels could involve conversations with the relatively small number of customers included in this measure.

Q. Please outline the incentives for each measure and associated demand reductions.

A. Table 9 below shows the assumed incentive payments and peak demand reductions by customer segments and measure.

[16] See Schedule DA-1: APPENDIX OF DATA SOURCES.

Table 9: Incentive Payment and Peak Demand Reductions by Customer Segment and Measure

	[1]	**[2]**	**[3]**	**[4]**
[a]	Customer Segment	Measure	Incentive Payment per Customer	Peak Demand Reduction per Customer (Dth/hr)
[b]	Single Family	**Electrification + EE**	*$24,033*	*0.05*
[c]		**High Efficiency Gas + EE**	*$5,883*	*0.01*
[d]	Multi Family	**Electrification + EE**	*$12,327*	*0.04*
[e]		**High Efficiency Gas + EE**	*$5,773*	*0.01*
[f]	Small Commercial	**Electrification**	*$30,182*	*0.18*
[g]		**High Efficiency Gas**	*$2,971*	*0.02*
[h]	Large C&I	**Electrification**	*$623,997*	*3.71*
[i]		**High Efficiency Gas**	*$61,425*	*0.45*
[l]	Large C&I	**Demand Response, with Existing Backup Heating Equipment**	*$700 per Dth/hr, $7/Dth energy,*	*4.13*
[m]		**Demand Response, with New Backup Heating Equipment**	*$450 per Dth/hr, $7/Dth energy, $355,386 for boiler*	*4.13*

IV. <u>Portfolio Evaluation</u>

Q. Please describe the results of the Lower Cost portfolio scenario.

A. Figure 1 shows the portfolios of demand reduction measures for the Lower Cost scenario under both the Lower Customer Uptake and Higher Customer Uptake cases. Table 10 shows key portfolio summary metrics for the Lower Cost Scenario under both the Lower Customer Uptake and Higher Customer Uptake cases.

Figure 1: Demand Reductions from the Lower Cost Portfolio Scenario

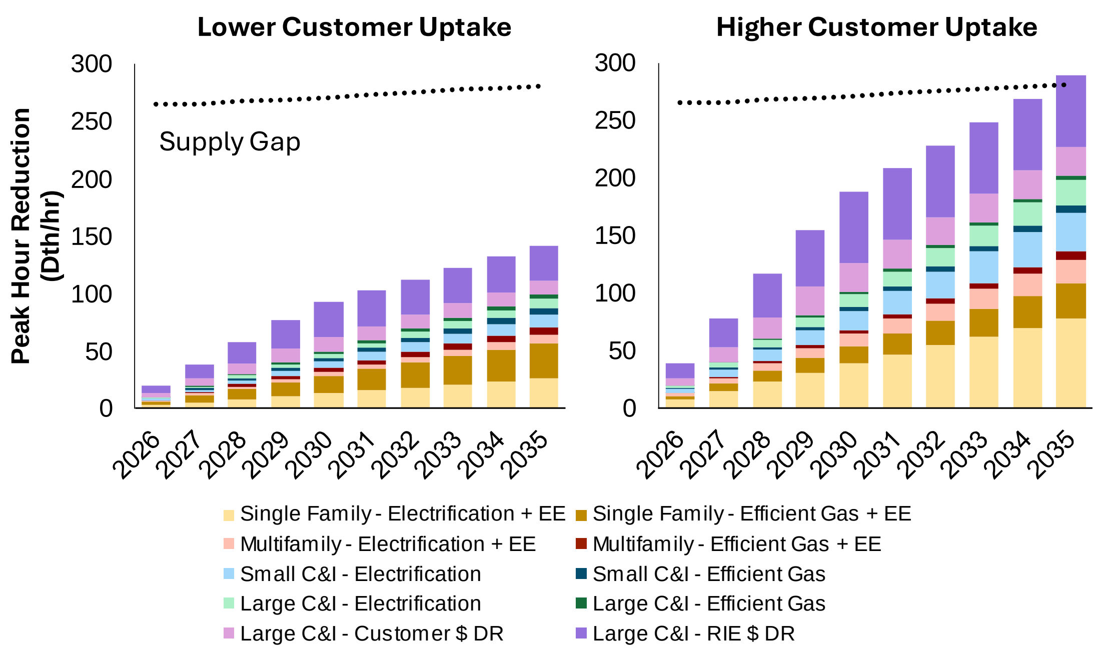

Table 10: Key Summary Metrics from the Lower Cost Portfolio Scenario

	[1]	[2]	[3]
[a]		**Lower Customer Uptake**	**Higher Customer Uptake**
[b]	**Percent of Residential Customer Electrification (Sales Share)**	10%	30%
[c]	**Percent of Residential Customer Efficient Gas (Sales Share)**	40%	40%
[d]	**Year Supply Gap Met**	Post 2035	2035
[e]	**Portfolio Cost (NPV $2025) Through Achievement Year**	N/A	$70M

For the Lower Cost scenario, the Higher Customer Uptake case achieves the demand reductions needed to meet the supply gap in 2035. Given the implied level of uptake is unprecedented and based on speculative conditions as discussed in A9, this outcome should be viewed as uncertain and unproven in practice. Under the assumptions in the Lower Customer Uptake case, the capacity gap would not be addressed by 2035.

Q. Please describe the results of the "Expanded Electrification" portfolio scenario.

A. Figure 2 shows the portfolios of demand reduction measures for the Expanded Electrification scenario under both the Lower Customer Uptake and Higher Customer Uptake cases. Table 11 shows key portfolio summary metrics for the Expanded Electrification scenario under both the Lower Customer Uptake and Higher Customer Uptake cases.

Figure 2: Demand Reductions from the Expanded Electrification Portfolio Scenario

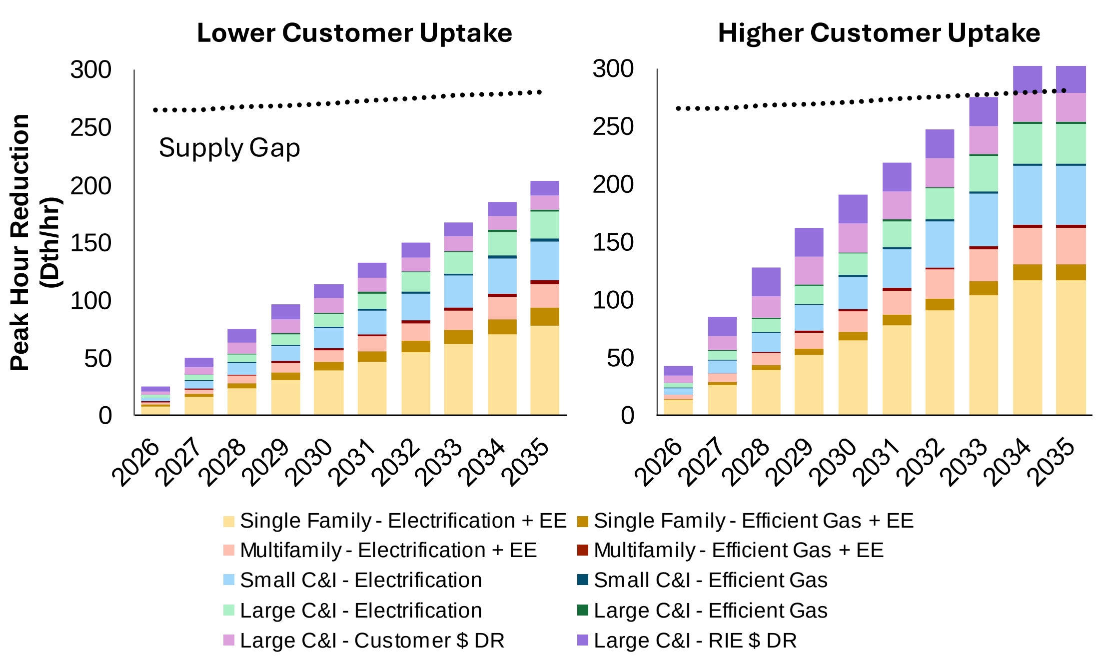

Table 11: Key Summary Metrics from the Expanded Electrification Portfolio Scenario

	[1]	[2]	[3]
[a]		Lower Customer Uptake	Higher Customer Uptake
[b]	Percent of Residential Customer Electrification (Sales Share)	30%	50%
[c]	Percent of Residential Customer Efficient Gas (Sales Share)	20%	20%
[d]	Year Supply Gap Met	Post 2035	2034
[e]	Portfolio Cost (NPV $2025) Through Achievement Year	N/A	$78M

For the Expanded Electrification scenario, the Higher Customer Uptake case achieves the demand reductions needed to meet the supply gap in 2034. Given the implied level of uptake is unprecedented and based on speculative conditions as discussed in A9, this outcome should be viewed as uncertain and unproven in practice. Under the Lower Customer Uptake case, the capacity gap would not be addressed by 2035.

Q. Please describe the results of the No New Fossil Fuel Equipment portfolio scenario.

A. Table 12 Figure 3 shows the portfolios of demand reduction measures for the No New Fossil Fuel Equipment scenario under both the Lower Customer Uptake and Higher Customer Uptake cases. Table 12 shows key portfolio summary metrics for the No New Fossil Fuel Equipment scenario under both the Lower Customer Uptake and Higher Customer Uptake cases.

Figure 3: Demand Reductions from the No New Fossil Fuel Equipment Portfolio Scenario

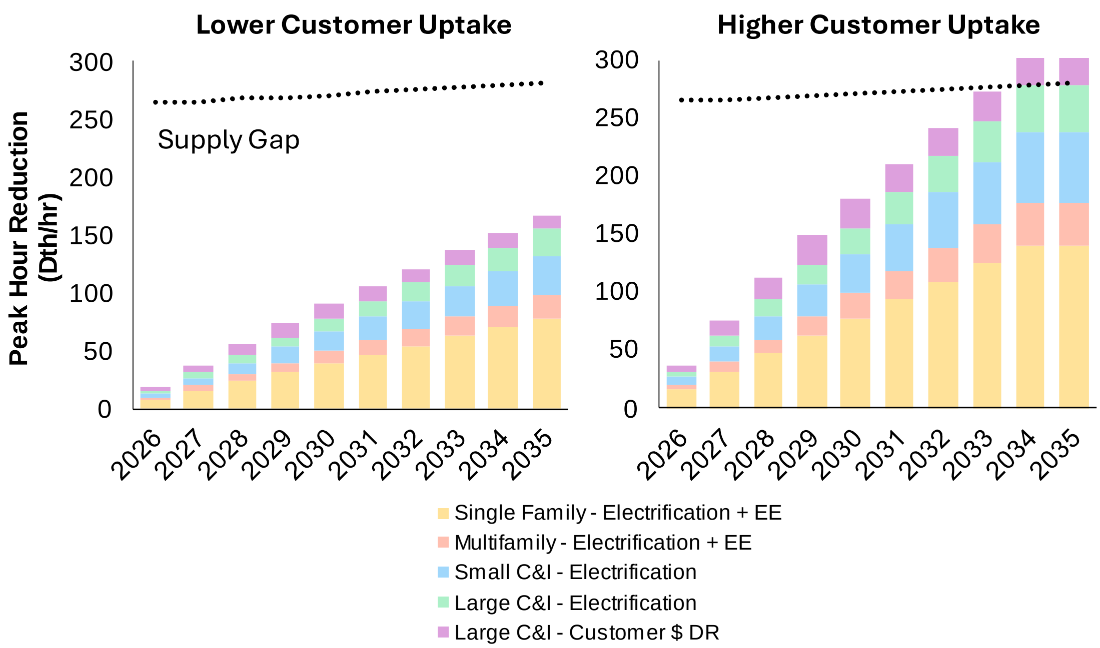

Table 12: Key Summary Metrics from the No Fossil Fuel Equipment Portfolio Scenario

	[1]	[2]	[3]
[a]		**Lower Customer Uptake**	**Higher Customer Uptake**
[b]	**Percent of Residential Customer Electrification (Sales Share)**	30%	60%
[c]	**Percent of Residential Customer Efficient Gas (Sales Share)**	0%	0%
[d]	**Year Supply Gap Met**	Post 2035	2034
[e]	**Portfolio Cost (NPV $2025) Through Achievement Year**	N/A	$80M

For the No New Fossil Fuel Equipment scenario, the Higher Customer Uptake case achieves the demand reductions needed to meet the supply gap in 2034. Given the implied level of uptake is unprecedented and based on speculative conditions as discussed in A9, this outcome should be viewed as uncertain and unproven in practice. Under the assumptions in the Lower Customer Uptake case, the gap would not be addressed by 2035.

Q. Please compare the results across scenarios.

A. Table 13 summarizes the results for each scenario under the Higher Customer Uptake case. A table of metrics for the Lower Customer Uptake case was not developed by E3 as none of the scenarios would address the capacity gap within the analysis horizon. The differences in portfolio costs are primarily driven by the level of electrification in each scenario, which is assumed to require relatively high incentives to support equally high levels of adoption. Electrification measures are also the biggest drivers of societal net costs, due to high upfront equipment costs, administrative costs (which are defined as a share of incentive costs), and electric system impacts (generation capacity and transmission). The same is true for the utility cost test, where incentives, administrative costs, and electric system impacts lead to high per-customer net costs. Thus, increasing shares of electrification across portfolios leads to increasing utility and societal net costs.

Table 13: Higher Customer Uptake Cases

	[1]	[2]	[3]	[4]
[a]		**Lower-Cost**	**Expanded Electrification**	**No New Fossil Equipment**
[b]	**Year Capacity Gap is Met**	2035	2034	2034
[c]	**Portfolio Incentive Cost (NPV $2025) Through Achievement Year**	$70M	$78M	$80M
[d]	**Portfolio Net Benefits (SCT)**	-$72M	-$105M	-$125M
[e]	**Portfolio Net Benefits (UCT)**	-$118M	-$148M	-$163M
[f]	**Number of Customers Impacted**	Residential: 4,800 Small C&I: 430 Large C&I: 35	Residential: 4,300 Small C&I: 390 Large C&I: 25	Residential: 3,700 Small C&I: 330 Large C&I: 15
[g]	**GHG Reduction, Short Tons (Snapshot of CO2 emissions reduced in 2035)**	10,220	11,170	11,250

It is important to note that the NPV values from the portfolio costs, UCT, and SCT are not directly comparable, as each test applies a different discount rate. The SCT uses a social discount rate of 2%, while the portfolio costs and UCT use a utility cost of capital discount rate of 4.9%. Given this difference, E3 advises interpreting the results of each cost test as a basis for comparing portfolios within the same test, rather than across tests.

Q. Please explain the emissions outcomes of each portfolio.

A. All three portfolios achieve a similar amount of emission reduction in 2035, equal to approximately 10 percent reductions relative to 2024 emissions from total gas sales on

Aquidneck Island. All scenarios rely heavily on electrification to close the capacity gap and see the largest share of emission reduction from electrification compared to reduction achieved by other measures. While electrification also reduces direct gas use, it also introduces incremental emissions from the electric grid, partially offsetting those savings. In contrast, efficient gas measures lower annual direct natural gas combustion and associated emissions, although displacing less natural gas usage annually compared to electrification. The modeled demand response measures see increases in emissions due to the greater emissions intensity of fuel oil assumed for backup heating use compared to natural gas; however, the increase in emissions in 2035 is at most approximately 120 short tons of CO_2, compared to 5,000 to 11,000 short tons of CO_2 avoided via efficient gas and electrification measures. E3 finds that electrification delivers greater emissions reductions on a per-unit basis due to greater annual displacement of gas, suggesting it may be a more scalable long-term GHG mitigation strategy than relying on gas efficiency alone. Furthermore, although it is standard practice to use the AESC values, as E3 has applied here, the hourly marginal emissions factors for electricity used in the AESC may overstate the incremental emissions from electrification, as electricity emissions factors specific to Rhode Island would be lower due to the state's statutory target of a 100 percent Renewable Energy Standard by 2033.[17]

[17] In keeping with Rhode Island Energy's 2025 Annual Energy Efficiency Plan, this analysis uses AESC 2024 regional (New England-wide) marginal emissions rates; regional electricity generation is not expected to be 100 percent renewable by 2033.

Q. Please describe the implementation and feasibility risks E3 identified for each measure.

A. Table 14 describes key implementation and feasibility risks that E3 considered qualitatively for each measure. The types of risk that E3 examined include:

- **Customer Acceptance**: this includes the extent to which a measure would require a substantial retrofit at a customer premise or adoption of a new or unfamiliar technology. Technologies that are riskier in terms of customer acceptance would likely require a combination of high incentives and market transformation in order to achieve scale.
- **Policy Hurdles and Alignment:** this reflects the alignment between a given measure and state policy goals. The 2021 Act on Climate set clear policy objectives for GHG emissions savings. However, there is a balance with other important policy goals, such as ensuring safe and reliable energy delivery, managing customer energy costs, supporting equity, and others. Under this broader consideration of policy objectives, each of the measures is supportive of some policy goals while being out of alignment with others. For example, electrification measures may be most aligned with the 2021 Act on Climate, if interpreted based on the per unit GHG emissions savings of each measure. However, the electrification measures considered here may have concerns regarding affordability and equity.
- **Reliability and Longevity:** This refers to the durability of gas peak demand savings that each measure can achieve, reflecting that some measures require

ongoing customer action (demand response) and participation to deliver those savings, while others do not (efficient gas, EE, electrification).

Table 14: Implementation and Feasibility Risks

Lower Risk Medium Risk Higher Risk

Measure	Customer Acceptance	Policy Hurdles & Alignment	Durability	Key Drivers
Efficient Gas + EE				Lower cost, and less extensive, retrofits required from a customer perspective. Lower gas peak demand reductions per customer and lower GHG savings.
Electrification + EE				Challenging economics for customers from upfront cost and bill perspectives. Durable gas peak demand and GHG reductions.
Existing Backup DR				Recent customer gas DR programs saw challenges with participation. Higher incentives may be needed to overcome the direct or indirect costs of fuel switching.
New Backup DR				Requires replacement of existing gas boilers with dual fuel alternatives. Potential for stakeholder pushback against new fossil fuel infrastructure.

There can be additional risks to consider, e.g.,

- *For multifamily housing, split incentives will be the largest challenge across all measures*
- *Full electrification can be challenging for residential housing due to additional retrofit requirements (electrical, ducts)*
- *DR programs require ongoing payments to maintain capacity savings*

Q. What are the results across scenarios with respect to the timing under which the capacity gap could be mitigated if the modeled customer adoption rates are achieved?

A. The scenarios and customer adoption cases assessed by E3 result in a range of outcomes with respect to when the capacity gap could potentially be addressed and the cost of doing so. In terms of the timing of addressing the gap, under the Higher Customer Uptake cases, the gap could – from a technical potential perspective – be addressed as soon as 2034. In cases that assume a lower, though still unprecedented, level of customer uptake, the capacity gap could not be closed until after 2035, with sufficient reductions not being achieved until 2048, 2040, and 2043 for the Lower Cost, Expanded Electrification, and No New Fossil Equipment portfolios respectively. If customer response remains at Mass Save levels (15 percent annual sales share), the No New Fossil equipment portfolio would not be able to close the capacity gap until post 2050.

Thus, even under very high incentive levels, a program may not successfully achieve the demand reduction levels needed by 2035. E3 emphasizes that the pace and scale of natural gas customer adoption of electrification measures in these scenarios is unprecedented via any set of policies, much less via utility incentive programs alone. This underscores the ambitious nature of these scenarios and the uncertainty around their feasibility.

Q. What other considerations have you noted with respect to the analysis results?

A. In most of the cases where analysis indicates there is the technical potential to achieve sufficient demand reductions to address the gap with alternatives, a significant share of those demand reductions come from demand response programs, including the installation of new dual fuel fossil fuel heating equipment in buildings. The only scenario in which those new demand response resources are not considered is the No New Fossil Equipment scenario, under the Higher Customer Uptake case, which in my view represents an unprecedented level of customer adoption and is among the most expensive cases considered. This means that in all other scenarios the gap is addressed, at least in part, by substituting one form of fossil fuel-based storage (gas) in favor of another (liquid fuel, such as heating oil).

Q. Did the analysis consider electric distribution system impacts of each portfolio?

A. Rhode Island Energy provided E3 with data related to Aquidneck Island's electric distribution system, including data for all 40 distribution feeders on Aquidneck Island. For each feeder, the data include 2024 peak load levels (MW), which we assume to reflect summer peak loads, as well as summer rated capacity (MW) and available summer headroom (MW, difference between rated capacity and 2024 peak load). E3 assumed that winter capacity is approximately 33 percent higher than summer capacity due to increased thermal ratings at cold temperatures and that current winter baseline peak loads are approximately 75 percent of current summer peak load (a conservative estimate due to air conditioning demand), an average of 32 percent of winter feeder capacity is currently being utilized across the 40 feeders. We then considered the additional winter peak load on each feeder from building electrification levels aligned with the No New Fossil Infrastructure, High Response case, which sees the highest level of electrification.

We find that no feeders are expected to exceed winter capacity from portfolio-driven electric peak demand growth, with capacity utilization expected to increase by 13 percent on average across the feeders. As a result, we find that all 40 existing feeders on Aquidneck

Island could accommodate this electrification load without triggering new electric distribution system costs. Given the available feeder capacity, we assume as well that distribution substations could also accommodate the electrification load.

An important caveat is that individual feeders may require upgrades if electrification uptake is concentrated in specific locations. This analysis assumed that the adoption of electrification matches the current distribution of loads across the Aquidneck Island distribution system. In addition, this analysis does not directly consider potential peak demand growth from future transportation electrification, nor from complete electrification of the Aquidneck Island building stock. Finally, these results may not be generalizable across the broader service territory, as other parts of the distribution system may have more limited electric distribution system capacity.

Q. What other considerations are there with respect to the role of gas or combustion of other fuels in meeting peak demands?

A. Work by E3[18] and others, including ISO-NE,[19] has demonstrated that large levels of heating electrification would drive the need for significant new firm electric generation capacity in the region. This analysis assesses the electric supply impacts of electrifying gas

[18] New Study from E3 and EFI Evaluates Electric Reliability and Innovation Opportunities under Deep Decarbonization Pathways in New England - E3
[19] a03_2025_01_23_pac_2024_economic_study_final_policy_results.pdf

demands on Aquidneck Island using the AESC. As a result, this study does not explore in detail the long-term resource adequacy implications of electrifying heating demand.

However, the previously mentioned regional studies that have examined the implications of heating electrification at scale offer useful lessons for this case. While renewables and storage can provide firm capacity to an extent, heating peak demands can be expected to occur alongside extended periods of low renewable production. Given that outcome, technologies that are not energy limited and available at full capacity except for during forced outages, also called 'firm', are needed. A number of clean (low or no GHG-emissions), firm technologies have been proposed, but none have been commercialized at meaningful scale except nuclear power. This raises the prospect that, even under a high renewables New England electricity system, natural gas peaking generation will be needed to maintain electric reliability during design day conditions. Notably, past work by E3 and ScottMadden[20] has indicated that, under scenarios of high electrification across the region, design day demands on the New England gas system may ultimately be similar or even increase.

Q. Are there any implementation concerns associated with these portfolios?

A. Yes, though the risks vary depending on the relative emphasis of different measures in each portfolio.

[20] 3.18.22 - Independent Consultant Report - Decarbonization Pathways.pdf

All three portfolios rely on unprecedented levels of electrification to achieve sufficient demand reductions to close the capacity gap. The largest risk to electrification related measures is customer acceptance due to the high costs and low sales share of these technologies. Overcoming this risk would likely require a combination of market transformation initiatives, incentives, and strategies like alternative cost allocation and rate mechanisms to manage bill increases. Despite those challenges, electrification would need to be an important component of any portfolio that closes the capacity gap on Aquidneck Island because of the large and durable peak demand reductions this strategy enables.

In contrast, portfolios that rely heavily on demand response using dual fuel boilers can pose different risks. For example, relying on fuel oil equipment can increase GHG emissions relative to natural gas and heavily incentivizing these measures could lock in use of higher emissions intensity fuels. Demand response programs also hinge on ongoing customer participation to ensure that savings persist, and past gas demand response programs in Rhode Island have had challenges in this regard.

Portfolios that lean heavily on efficiency show benefits in terms of cost, but efficiency alone is unlikely to be able to close the capacity gap. Efficient gas technologies reduce peak day demands, but less than electrification. While these can be a valuable measure within a broader portfolio, overreliance on gas efficiency measures may crowd out electrification, which would make achieving sufficient demand reductions to close the capacity gap challenging and potentially lock in higher GHG emissions. Renewable gases, such as renewable natural gas or hydrogen, could play a role and serve as a future decarbonization pathways, but their availability, cost, and scalability remain uncertain and were outside of the scope of this analysis.

Q. Did E3 distinguish between residential rate classes in its modeling? Why or why not?

A. E3 distinguished between residential heating and non-heating customers. As described in A2, residential non-heating customers were excluded from this analysis as they are a very small share of residential sales and would have an even smaller relative contribution to design day load. E3 did not directly distinguish between low-income and non-low-income customers in this analysis. Equity impacts are discussed in more detail in A26.

Q. What are the equity implications of potential implementation?

A. The Rhode Island Department of Environmental Management ("RIDEM") identifies the following green-shaded areas as "Environmental Justice" areas within Aquidneck Island.[21]

[21] Rhode Island Department of Environmental Management. *Environmental Justice*. Rhode Island Department of Environmental Management, https://dem.ri.gov/environmental-protection-bureau/initiatives/environmental-justice

According to RIDEM, an "Environmental Justice Focus Area" is a census tract that meets one or more of the following criteria: (i) Annual median household income is not more than sixty-five percent (65%) of the statewide annual median household income; (ii) minority population is equal to or greater than forty percent (40%) of the population; (iii) Twenty-five percent (25%) or more of the households lack English language proficiency; or (iv) Minorities comprise twenty-five percent (25%) or more of the population and the annual median household income of the municipality in the proposed area does not exceed one hundred fifty percent (150%) of the statewide annual median household income."[22]

[22] Ibid.

Characteristics of income and primary language have been linked to participation levels in energy efficiency programs and adoption of efficient electric heat pumps.[23]

Within Aquidneck Island, there are Environmental Justice areas in northwest Newport and west Middletown. One equity consideration of implementation is that these two Environmental Justice areas may be less likely to participate in any of the portfolios examined relative to the other areas within Aquidneck Island, all else equal. Potential equity concerns include: (1) if measure participation is lower, the Environmental Justice areas may receive proportionally lower benefits from the utility's investment in the portfolios, (2) if a larger share of customers in Environmental Justice areas are renters, this may further limit customers' ability to participate in the residential measures, which require replacing building equipment, and (3) the remaining cost burden of the gas distribution system may be borne proportionately more by Environmental Justice areas if more customers in other areas migrate away from the gas distribution system. If an ancillary goal of investment were to be to address these equity considerations, additional incentives or even compensation would likely be required that would increase the overall cost of each portfolio.

[23] Amann, Jennifer, Carolin Tolentino, and Dan York. *Toward More Equitable Energy Efficiency Programs for Underserved Households*. American Council for an Energy-Efficient Economy, May 2023. https://www.aceee.org/sites/default/files/pdfs/B2301.pdf

Considering the communities external to Aquidneck Island, equity considerations arising from such localized investment in Aquidneck Island relative to the rest of the State are: (1) whether it is fair and equitable to direct investment – particularly the cost premium of the portfolios – to one particular area and (2) whether it is appropriate to socialize this cost premium to the remaining customers in the service territory.

These equity considerations are within the purview of the utility (given its relationship with its customers), regulators, policymakers, legislators, and the public. By describing these equity considerations, E3 does not make a recommendation on the appropriate path forward, but rather comments on the potential linkages between these equity considerations and implementation of the portfolios modeled.

V. <u>Conclusion</u>

Q. What are your overall conclusions with respect to the cost and feasibility of closing the Aquidneck Island capacity gap using demand-side alternatives?

A. E3's finds that, although there exists the technical potential to close the Aquidneck Island capacity gap using demand-side alternatives, doing so may not be feasible in practice. Achieving the necessary reductions—especially through full electrification—would require customer adoption at unprecedented levels, far exceeding what current programs have achieved to date. Moreover, the modeled portfolios show significant net costs, ranging from $72 million to $125 million under the Societal Cost Test. These implementation and cost barriers make it challenging for the alternatives to feasibly close the capacity gap and raise uncertainty about the likelihood of doing so. However, if electrification and efficiency can be effectively scaled, perhaps in service of broader state goals such as meeting the Act on Climate targets, the incremental cost and challenge of also addressing the OML gap may be reduced.

Q. Does this conclude your testimony?

A. Yes.

Schedule DA-1

Appendix of Data Sources

Schedule DA-1: APPENDIX OF DATA SOURCES

Table 15: Data Sources

	[1]	**[2]**
	Input	Source *Publicly Available Unless Specified Otherwise*
[a]	Equipment costs	Residential measures: Informed by Technical Analysis Report in Docket 22-01-NG (“Future of Gas Docket”) Commercial measures: Energy Information. Administration (EIA), Technology Forecast Updates: Residential and Commercial Building Technologies (Reference Case), 2023.
[b]	Equipment efficiencies and performance	Technical Analysis Report in Docket 22-01-NG (“Future of Gas Docket”).
[c]	Baseline customer energy demand: annual and peak	Annual: historical customer data, 2022-2024. Design day and hour demand: see Q3.
[d]	Electrification customer energy demand: annual and peak	Annual: Baseline customer usage, scaled by relative annual average efficiencies of baseline and electric devices. Design day and hour demand: load shapes from National Renewable Energy Laboratory (NREL) ResStock and ComStock load shape libraries, Release 2. Hourly consumption scaled to meet annual load described above. • Residential shapes used ResStock Upgrade 2: High Efficiency cold-climate air-to-air heat pump with electric backup, TMY3. • Commercial shapes used ComStock, AMY 2018, Upgrade 7: Cold Climate Heat Pump Rooftop Unit Challenge, 2027 Specification.

[e]	Aquidneck Island design day demand and supply gap	Old Mill Lane contracted capacity and Aquidneck Island design hour demand sourced from Gas Long-Range Resource and Requirements Plan, Forecast Period 2024/25 to 2028/29, Exhibit 2. 2029/30 through 2033/34 design hour demand provided by RIE forecasting team, and 2034/35 forecast linearly extrapolated by E3.
[f]	Electric system avoided costs: generation capacity, losses, wholesale risk premium, demand reduction induced price effects, transmission, reliability, wholesale electric energy	AESC 2024, Synapse Energy Economics, CF 5 scenario.
[g]	Non-electric emissions factors	AESC 2021, Synapse Energy Economics, Emissions Factors for Non-Electric Sources.
[h]	Electric emissions factors	AESC 2024, Synapse Energy Economics, CF5 scenario.
[i]	Electricity and gas retail rates	Electricity: RIE retail rate sheets (residential A-16, residential LI A-60, and General for commercial) and "last resort service" commodity charges. Escalation from EIA Annual Energy Outlook 2025, Table 3. Gas: RIE retail rate sheets (residential Rate 12, small C&I Rate 21, and large C&I rate 33). Escalation from confidential regional E3 natural gas price forecast, informed by EIA Natural Gas Spot and Futures Prices (NYMEX) and Annual Energy Outlook.
[j]	Inflation Reduction Act federal incentives	Internal Revenue Service (IRS) Energy Efficient Home Improvement Credit.
[k]	Program costs (as % of incentive costs)	RIE 2025 Annual Energy Efficiency Plan, Attachment 5, Table 2, Energy Efficiency Program Budget. 10% assumed for demand response programs due to lower expected costs associated with lower number of participants.

able 16: Lifetime Societal Cost Test for each Measure ($NPV 2025/customer)[24]

		[1] = [3] + … + [15]	**[3]**	**[4]**	**[5]**	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**	**[11]**	**[12]**	**[13]**	**[14]**	**[15]**
		Net SCT	Incremental Capital Cost	Federal Tax Incentive	Gas Supply	Fuel Oil Supply	Electric Supply	Retail Supplier Risk	Renewable Energy Credit	Generation Capacity	Transmission Capacity	DRIPE	Administrative	Greenhouse Gas	Criteria Air Pollutant
[a]	Single Family – Electrification + EE	*$25,382*	*$20,897*	*-$3,137*	*-$7,905*	*$0*	*$5,100*	*-$224*	*$1,935*	*$2,437*	*$2,777*	*$355*	*$12,069*	*-$8,238*	*-$683*
[b]	Single Family - Efficient Gas + EE	*$287*	*$5,768*	*$0*	*-$2,688*	*$0*	*$0*	*-$215*	*$0*	*$0*	*$0*	*$0*	*$2,954*	*-$5,287*	*-$245*
[c]	Multifamily - Electrification + EE	*$10,966*	*$9,420*	*-$3,137*	*-$5,377*	*$0*	*$3,707*	*-$134*	*$1,395*	*$2,075*	*$2,365*	*$258*	*$6,190*	*-$5,333*	*-$463*
[d]	Multifamily - Efficient Gas + EE	*$2,850*	*$5,660*	*$0*	*-$1,796*	*$0*	*$0*	*-$144*	*$0*	*$0*	*$0*	*$0*	*$2,899*	*-$3,605*	*-$164*
[e]	Small C&I - Electrification	*$74,561*	*$21,947*	*-$1,992*	*-$35,777*	*$0*	*$30,146*	*-$450*	*$11,430*	*$38,016*	*$35,396*	*$2,303*	*$9,398*	*-$32,804*	*-$3,051*
[f]	Small C&I - Efficient Gas	*-$14,230*	*$2,913*	*$0*	*-$5,576*	*$0*	*$0*	*-$446*	*$0*	*$0*	*$0*	*$0*	*$925*	*-$11,536*	*-$510*
[g]	Large C&I - Electrification	*$1,519,037*	*$561,261*	*-$7,911*	*-$723,948*	*$0*	*$619,258*	*-$8,375*	*$231,279*	*$685,845*	*$638,584*	*$47,095*	*$194,294*	*-$656,767*	*-$61,578*
[h]	Large C&I – Efficient Gas	*-$286,263*	*$60,220*	*$0*	*-$112,837*	*$0*	*$0*	*-$9,027*	*$0*	*$0*	*$0*	*$0*	*$19,126*	*-$233,423*	*-$10,322*
[i]	Large C&I - Customer Funded DR	*$311,270*	*$0*	*$0*	*-$48,727*	*$176,267*	*$0*	*$10,203*	*$0*	*$0*	*$0*	*$0*	*$134,254*	*$37,430*	*$1,843*
[j]	Large C&I - RIE Funded DR	*$352,154*	*$107,536*	*$0*	*-$38,592*	*$139,603*	*$0*	*$8,081*	*$0*	*$0*	*$0*	*$0*	*$104,421*	*$29,644*	*$1,460*

[24] Positive value = cost, negative value = benefit. 2% discount rate, assuming 2026 install year.

Table 17: Lifetime Utility Cost Test for each Measure ($NPV 2025/customer)[25]

		[1] = [3] + … + [12]	**[3]**	**[4]**	**[5]**	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**	**[11]**	**[12]**
		Net Cost	Upfront Incentive	Annual Incentive	Gas Supply	Electric Supply	Retail Supplier Risk	RECs	Capacity	Transmission	DRIPE	Administrative
[a]	Single Family – Electrification + EE	*$37,819*	*$22,916*	*$0*	*-$6,349*	*$4,161*	*-$175*	*$1,514*	*$1,696*	*$2,033*	*$284*	*$11,738*
[b]	Single Family - Efficient Gas + EE	*$6,204*	*$5,610*	*$0*	*-$2,110*	*$0*	*-$169*	*$0*	*$0*	*$0*	*$0*	*$2,873*
[c]	Multifamily - Electrification + EE	*$20,850*	*$11,754*	*$0*	*-$4,319*	*$3,025*	*-$104*	*$1,091*	*$1,444*	*$1,731*	*$206*	*$6,021*
[d]	Multifamily - Efficient Gas + EE	*$6,850*	*$5,505*	*$0*	*-$1,365*	*$0*	*-$109*	*$0*	*$0*	*$0*	*$0*	*$2,820*
[e]	Small C&I - Electrification	*$92,371*	*$28,780*	*$0*	*-$26,911*	*$22,908*	*-$320*	*$8,369*	*$24,566*	*$24,135*	*$1,704*	*$9,140*
[f]	Small C&I - Efficient Gas	*-$664*	*$2,833*	*$0*	*-$4,071*	*$0*	*-$326*	*$0*	*$0*	*$0*	*$0*	*$900*
[g]	Large C&I - Electrification	*$1,786,504*	*$595,005*	*$0*	*-$544,538*	*$470,221*	*-$5,945*	*$169,340*	*$443,196*	*$435,422*	*$34,831*	*$188,972*

[25] Positive value = cost, negative value = benefit. 4.9% discount rate, assuming 2026 install year.

[h]	Large C&I – Efficient Gas	*-$11,799*	*$58,571*	*$0*	*-$82,381*	*$0*	*-$6,590*	*$0*	*$0*	*$0*	*$0*	*$18,602*
[i]	Large C&I - Customer Funded DR	*$1,041,427*	*$0*	*$981,680*	*-$35,575*	*$0*	*-$2,846*	*$0*	*$0*	*$0*	*$0*	*$98,168*
[j]	Large C&I - RIE Funded DR	*$901,980*	*$338,874*	*$508,771*	*-$28,176*	*$0*	*-$2,254*	*$0*	*$0*	*$0*	*$0*	*$84,764*

Table 18: Lower Cost Portfolio Cumulative Demand Reduction by Measure (Dth/hr)[26]

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
[a]	Single Family – Electrification + EE	*7.78*	*15.57*	*23.35*	*31.13*	*38.91*	*46.70*	*54.48*	*62.26*	*70.05*	*77.83*
[b]	Single Family - Efficient Gas + EE	*2.82*	*5.64*	*8.46*	*11.28*	*14.10*	*16.92*	*19.74*	*22.56*	*25.38*	*28.20*
[c]	Multifamily - Electrification + EE	*2.09*	*4.18*	*6.27*	*8.36*	*10.45*	*12.54*	*14.63*	*16.72*	*18.81*	*20.90*
[d]	Multifamily - Efficient Gas + EE	*0.62*	*1.23*	*1.85*	*2.46*	*3.08*	*3.69*	*4.31*	*4.92*	*5.54*	*6.16*
[e]	Small C&I - Electrification	*3.37*	*6.73*	*10.10*	*13.47*	*16.84*	*20.20*	*23.57*	*26.94*	*30.30*	*33.67*
[f]	Small C&I - Efficient Gas	*0.58*	*1.17*	*1.75*	*2.33*	*2.91*	*3.50*	*4.08*	*4.66*	*5.25*	*5.83*
[g]	Large C&I - Electrification	*2.27*	*4.54*	*6.81*	*9.08*	*11.36*	*13.63*	*15.90*	*18.17*	*20.44*	*22.71*
[h]	Large C&I – Efficient Gas	*0.37*	*0.74*	*1.11*	*1.48*	*1.85*	*2.22*	*2.59*	*2.96*	*3.34*	*3.71*
[i]	Large C&I - Customer Funded DR	*6.20*	*12.40*	*18.60*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*
[j]	Large C&I - RIE Funded DR	*12.40*	*24.81*	*37.21*	*49.61*	*62.02*	*62.02*	*62.02*	*62.02*	*62.02*	*62.02*

[26] Higher Uptake case, meeting demand gap in 2035.

Table 19: Expanded Electrification Portfolio Cumulative Demand Reduction by Measure (Dth/hr)[27]

		[1]	**[2]**	**[3]**	**[4]**	**[5]**	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
[a]	Single Family – Electrification + EE	*12.97*	*25.94*	*38.91*	*51.89*	*64.86*	*77.83*	*90.80*	*103.77*	*116.74*	*116.74*
[b]	Single Family - Efficient Gas + EE	*1.41*	*2.82*	*4.23*	*5.64*	*7.05*	*8.46*	*9.87*	*11.28*	*12.69*	*12.69*
[c]	Multifamily - Electrification + EE	*3.48*	*6.97*	*10.45*	*13.93*	*17.41*	*20.90*	*24.38*	*27.86*	*31.35*	*31.35*
[d]	Multifamily - Efficient Gas + EE	*0.31*	*0.62*	*0.92*	*1.23*	*1.54*	*1.85*	*2.15*	*2.46*	*2.77*	*2.77*
[e]	Small C&I - Electrification	*5.61*	*11.22*	*16.84*	*22.45*	*28.06*	*33.67*	*39.28*	*44.90*	*50.51*	*50.51*
[f]	Small C&I - Efficient Gas	*0.29*	*0.58*	*0.87*	*1.17*	*1.46*	*1.75*	*2.04*	*2.33*	*2.62*	*2.62*
[g]	Large C&I - Electrification	*3.79*	*7.57*	*11.36*	*15.14*	*18.93*	*22.71*	*26.50*	*30.28*	*34.07*	*34.07*
[h]	Large C&I – Efficient Gas	*0.19*	*0.37*	*0.56*	*0.74*	*0.93*	*1.11*	*1.30*	*1.48*	*1.67*	*1.67*
[i]	Large C&I - Customer Funded DR	*6.20*	*12.40*	*18.60*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*
[j]	Large C&I - RIE Funded DR	*8.27*	*16.54*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*

[27] Higher Uptake case, meeting demand gap in 2034.

Table 20: No New Fossil Equipment Portfolio Cumulative Demand Reduction by Measure (Dth/hr)[28]

		[1]	**[2]**	**[3]**	**[4]**	**[5]**	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**
		2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
[a]	Single Family – Electrification + EE	*15.57*	*31.13*	*46.70*	*62.26*	*77.83*	*93.39*	*108.96*	*124.52*	*140.09*	*140.09*
[b]	Single Family - Efficient Gas + EE	-	-	-	-	-	-	-	-	-	-
[c]	Multifamily - Electrification + EE	*4.18*	*8.36*	*12.54*	*16.72*	*20.90*	*25.08*	*29.26*	*33.44*	*37.61*	*37.61*
[d]	Multifamily - Efficient Gas + EE	-	-	-	-	-	-	-	-	-	-
[e]	Small C&I - Electrification	*6.73*	*13.47*	*20.20*	*26.94*	*33.67*	*40.41*	*47.14*	*53.87*	*60.61*	*60.61*
[f]	Small C&I - Efficient Gas	-	-	-	-	-	-	-	-	-	-
[g]	Large C&I - Electrification	*4.54*	*9.08*	*13.63*	*18.17*	*22.71*	*27.25*	*31.80*	*36.34*	*40.88*	*40.88*
[h]	Large C&I – Efficient Gas	-	-	-	-	-	-	-	-	-	-
[i]	Large C&I - Customer Funded DR	*6.20*	*12.40*	*18.60*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*	*24.81*
[j]	Large C&I - RIE Funded DR	-	-	-	-	-	-	-	-	-	-

[28] Higher Uptake case, meeting demand gap in 2034.

Table 21: Lower Cost Portfolio Lifetime Cost by Component[29]

		[1]	[2]
	Component	**Societal Cost Test** *($2025M NPV, 2% discount rate)*	**Utility Cost Test** *($2025M NPV, 4.9% discount rate)*
[a]	Incremental Equipment Costs	*$62*	*$0*
[b]	Federal Incentive	*-$7*	*$0*
[c]	Utility Upfront Incentive	*$0*	*$71*
[d]	Utility Annual Incentive	*$0*	*$14*
[e]	Gas Supply	*-$36*	*-$28*
[f]	Fuel Oil Supply	*$3*	*$0*
[g]	Electric Supply	*$19*	*$15*
[h]	Supplier Risk	*-$1*	*-$1*
[i]	RECs	*$7*	*$5*
[j]	Capacity	*$16*	*$11*
[k]	Transmission	*$16*	*$11*
[l]	DRIPE	*$1*	*$1*
[m]	Admin	*$35*	*$34*
[n]	GHGs	*-$43*	*$0*
[o]	Criteria Pollutants	*-$3*	*$0*
[p] = [a] + … + [o]	Net Cost	*$71*	*$133*

[29] Total SCT and UCT net costs shown in the following 3 tables do not match total portfolio costs shown in Table 13 as these costs reflect total installs from 2026 through 2035 but avoided cost streams for a 2026 install year. This is to avoid the distortionary effect of lower future costs due to NPV discounting. The total net costs shown previously reflect appropriately discounted costs for installs in each year of the analysis time horizon. Positive value = cost, negative value = benefit.

Table 22: Expanded Electrification Portfolio Lifetime Cost by Component[30]

		[1]	[2]
	Component	**Societal Cost Test** *($2025M NPV, 2% discount rate)*	**Utility Cost Test** *($2025M NPV, 4.9% discount rate)*
[a]	Incremental Equipment Costs	*$74*	*$0*
[b]	Federal Incentive	*-$10*	*$0*
[c]	Utility Upfront Incentive	*$0*	*$84*
[d]	Utility Annual Incentive	*$0*	*$9*
[e]	Gas Supply	*-$43*	*-$34*
[f]	Fuel Oil Supply	*$2*	*$0*
[g]	Electric Supply	*$28*	*$22*
[h]	Supplier Risk	*-$1*	*-$1*
[i]	RECs	*$11*	*$8*
[j]	Capacity	*$24*	*$16*
[k]	Transmission	*$24*	*$17*
[l]	DRIPE	*$2*	*$2*
[m]	Admin	*$42*	*$40*
[n]	GHGs	*-$46*	*$0*
[o]	Criteria Pollutants	*-$4*	*$0*
[p] = [a] + … + [o]	Net Cost	*$103*	*$163*

[30] Positive value = cost, negative value = benefit.

Table 23: No New Fossil Infrastructure Portfolio Lifetime Cost by Component[31]

		[1]	[2]
	Component	**Societal Cost Test** *($2025M NPV, 2% discount rate)*	**Utility Cost Test** *($2025M NPV, 4.9% discount rate)*
[a]	Incremental Equipment Costs	*$79*	*$0*
[b]	Federal Incentive	*-$12*	*$0*
[c]	Utility Upfront Incentive	*$0*	*$89*
[d]	Utility Annual Incentive	*$0*	*$6*
[e]	Gas Supply	*-$47*	*-$36*
[f]	Fuel Oil Supply	*$1*	*$0*
[g]	Electric Supply	*$34*	*$27*
[h]	Supplier Risk	*-$1*	*-$1*
[i]	RECs	*$13*	*$10*
[j]	Capacity	*$29*	*$19*
[k]	Transmission	*$29*	*$20*
[l]	DRIPE	*$2*	*$2*
[m]	Admin	*$45*	*$43*
[n]	GHGs	*-$45*	*$0*
[o]	Criteria Pollutants	*-$4*	*$0*
[p] = [a] + … + [o]	Net Cost	*$122*	*$179*

[31] Positive value = cost, negative value = benefit.

Schedule DA-2

CV of Dan Aas

Dan Aas

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Partner

Mr. Aas joined E3 in 2017 after ten years of work and study in energy and decarbonization policy including two graduate degrees, a Master of Public Policy and a Master of Arts in Energy and Resources, from the University of California, Berkeley. He is an expert on gas utility transition planning, utility decarbonization strategy, and regulatory innovation. At E3, Mr. Aas leads work at the intersection of technical modeling and policy design, advising utilities, state agencies, and other stakeholders on the future of gas utilities, future of heat, utility business models, and regulatory frameworks for deep decarbonization. His work integrates long-term emissions planning, energy system and financial modeling, and affordability analysis to assess how different technologies, customer decisions, and regulatory choices shape the path toward a low-carbon economy.

Mr. Aas has testified before utility commissions in Massachusetts, Colorado, and Maryland on issues related to gas decarbonization, non-pipeline alternatives, and multiyear planning frameworks. He has led dozens of studies evaluating decarbonization pathways, the financial implications for gas and electric utilities, and the regulatory tools needed to manage the transition. He co-led development of E3's RESHAPE model for simulating electric load impacts from diversified building electrification and contributed to E3's PATHWAYS model for long-term GHG mitigation planning. His recent work includes engagements focused on identifying the cost and feasibility of clean heat portfolios and mapping out opportunities to pursue targeted electrification and non-pipeline alternatives. Select projects at E3 include:

- **Eversource Climate Compliance Plan (2024-2025).** Supported Eversource Energy in developing its first ever Climate Compliance Plan (CCP). The CCP defines a set of initiatives, programs and regulatory mechanisms through which Eversource proposes to support Massachusetts clean energy and climate goals. The E3 team lead by Mr. Aas supported intensive engagement with SMEs throughout Eversource's organization to define key strategic objectives and then to translate those objectives into a comprehensive plan. The team then worked to achieve alignment with Eversource leadership perspectives and peer utility filings, and then provided technical writing and document production support for the CCP.
- **California Targeted Electrification Scale Analysis (2024).** Led a study commissioned by the Natural Resources Defense Council (NRDC) to evaluate the potential for targeted building electrification and gas decommissioning to reduce gas infrastructure costs in California. The analysis found that implementing a statewide targeted electrification strategy could avoid $15-26 billion in pipeline replacement costs by 2045. E3's findings supported NRDC's advocacy efforts and contributed to the passage of SB 1221, which directs the California Public Utilities Commission to establish priority decarbonization zones and pilot targeted electrification projects.
- **Vermont Public Service Department Clean Heat Study (2024).** Conducted technical analysis of the cost, availability, and lifecycle emissions of renewable fuels as part of Vermont's Clean Heat Potential Study. The study, developed in response to the state's Affordable Heat Act, aimed to

inform the design of a clean heat market, including which resources might be eligible and how to maximize benefits for customers.

- **Confidential Dual-Fuel Utility, Strategic Planning Support (2024).** Supported a dual-fuel utility in developing an internal study process to evaluate future gas and electric system needs. Provided strategic guidance on how to structure the analysis, apply best practices, and build internal capabilities to assess long-term decarbonization and infrastructure planning decisions.
- **Xcel Energy Natural Gas Innovation Act Compliance (2023–ongoing).** Supported Xcel Energy's compliance with Minnesota's Natural Gas Innovation Act by developing a portfolio of innovative GHG reduction strategies. Led financial and lifecycle emissions analysis to evaluate the cost-effectiveness and emissions impact of each strategy, informing regulatory filings and strategic planning under NGIA's innovation framework.
- **Xcel Energy Colorado Clean Heat Plan (2023-2024).** Led the technical analysis and regulatory strategy for Xcel Energy's Clean Heat Plan, which was approved by the Colorado Public Utilities Commission (CPUC) in response to SB 21-264. Developed direct testimony supporting E3's analysis, provided rebuttal testimony in response to stakeholder critiques, and served as an expert witness in oral testimony before the Commission. The approved $440 million plan prioritizes building electrification and demand-side management to achieve a 22% reduction in emissions by 2030. E3's Clean Heat Portfolio Model was used to evaluate supply- and demand-side clean heat resources, identifying hybrid electrification and heat pump water heaters as cost-effective strategies.
- **Ameren Scope 3 Emissions Feasibility Study (2023-2024).** Assessed the feasibility of reducing Scope 3 emissions across Ameren's supply chain, including upstream emissions from purchased fuels and downstream emissions from delivered energy products. Developed scenarios to quantify the costs, practical opportunities, and challenges of different emissions reduction pathways, providing strategic insights for Ameren's long-term decarbonization planning.
- **FortisBC Integrated Gas-Electric Planning Support (2023).** Advised FortisBC on the development of an integrated gas-electric planning framework to align with British Columbia's climate targets and policies. Provided technical feedback and strategic guidance on FortisBC's Kelowna Electrification Study, including improvements to the modeling of heat pump loads, cost assessments of electric system upgrades, and the study's framing within broader decarbonization strategies. The study was filed before the British Columbia Utilities Commission (BCUC) as part of FortisBC's regulatory planning efforts.
- **PG&E Targeted Electrification Study (2023).** Led a study identifying opportunities for targeted electrification across PG&E's entire service territory. Helped develop methodologies to assess where electrification could be most effective, supporting PG&E's internal analysis and strategic planning as well as PG&E's external communications and decision-making.
- **Confidential State Agency, Future of Gas Modeling and Strategic Support (2022–ongoing).** Led analysis of long-term decarbonization pathway scenarios and their financial impacts on gas utilities. Supporting the agency with strategic guidance on potential regulatory mechanisms, such as accelerated depreciation and reduced gas system expenditures, to enable transition goals. Developed an affordability analysis tool and evaluated the impacts of gas line extension policies and infrastructure repair costs on utility and customer outcomes.
- **California Energy Commission, *Future of Retail Gas in California's Low Carbon Future (2017-2020)*.** Led a California Energy Commission-funded study examining the implications of economy-wide decarbonization for the state's natural gas utilities and customers. The study compares electrification- and renewable natural gas-based pathways to decarbonize buildings. A key finding is that electrification is cost-effective in California from both societal and customer perspectives. The customer perspective was found to be critical for understanding the economics of gas

distribution in the context deep decarbonization: as customers exit the gas system, the average cost of service for remaining customers increases, further incentivizing customers to electrify. This feedback effect motivates the need for a managed gas transition strategy that is consistent with both meeting the state's climate objectives and protecting customers.

- **Exelon Utilities, *Decarbonization Strategy Analysis (2021-Present)*.** Co-leader of decarbonization pathways strategy analysis on behalf BGE and ComEd. The analysis explores strategies to leverage the company's electric and gas infrastructure to support achievement of net-zero GHG reduction targets across the states Exelon operates in. E3 found that direct electrification paired with renewable electricity is the primary driver of emissions reductions across the economy. However, E3 did identify that hydrogen and other renewable fuels could have important, complementary roles to electrification by providing firm capacity for electric generation, fuel for heavy-duty and long-distance freight transportation use-cases, industrial high temperature heat, and a niche role in the buildings sector.
- **Xcel Energy, *Net-Zero Vision for Gas (2021-2022)*.** Led a study where Xcel Energy engaged E3 to evaluate decarbonization scenarios consistent with its corporate goal of a 25% reduction gas emissions by 2030 and net-zero by 2050. E3 worked with Xcel to develop portfolios that trade of varying levels of direct emissions reductions versus reliance on negative emissions technologies. For the direct emissions reductions, E3 found that hybrid electrification strategies that use a heat pump for most of the year, backed-up by renewable gasses during the coldest hours of the year, was a core strategy in the cold climates Xcel Energy serves.
- **Massachusetts Local Distribution Companies, *DPU 20-80 Independent Consultant Report (2021-2022)***. Led an initiative where E3 was retained by the joint Massachusetts Local Distribution Companies to develop an independent analysis of decarbonization pathways for the state, identify the implications of the pathways for the utilities and their customers, and evaluate regulatory designs that would support the transition to decarbonization. E3 found that electrification was the primary driver of decarbonization in most scenarios, but that strategic use of gas lowered the challenge of achieving decarbonization when used alongside electrification. Hydrogen was found to have a limited role in the gas distribution system, but a potentially important role in providing firm generation during periods of cold weather in scenarios with high levels of electric heating.
- **Rhode Island Energy, *Act on Climate and RI PUC Support* (2022-Present)**. Supervising a project where E3 is assessing the impacts of Rhode Island's statewide net-zero GHG target for Rhode Island Energy and its customers. As part of this analysis, E3 has developed an assessment for the cost of delivered hydrogen to Rhode Island given the 45V Production Tax Credit established under the Inflation Reduction Act.
- **Washington State Department of Commerce, *Impact of Building Electrification on Consumer Owned Utilities* (2021-2022).** Supervised a project that evaluated the impacts of building electrification on consumer owned utilities in Washington State. E3 evaluated those impacts from a marginal cost basis, considering the impacts of a single customer adopting a building electrification package, as well as at a utility scale. E3 found that electrification was cost-effective for customers in new construction and in cases where a heat pump can replace both a furnace and an air conditioner. At the utility scale, E3 found that air-source heat pumps could substantially increase peak demands seen by consumer owned utilities, but that measures like building shell improvements, hybrid electrification and heat pump technology improvements could mitigate those impacts.
- **Puget Sound Energy, *Decarbonization Strategy Support* (2019-2023).** Led two projects that evaluate options for Puget Sound Energy (PSE) to reduce emissions from its natural gas system. The first project included a high-level scenario analysis of options that emphasized electrification.

That study found that a hybrid approach resulted in lower costs relative to an all-electric strategy. The second study supported a more granular analysis conducted in partnership with PSE's modeling teams. E3 developed a supply curve of renewable fuel options for PSE, including electrolytic hydrogen. As part of that, E3 worked with PSE's gas supply and engineering experts to reflect the physical characteristics of the company's system to refine our estimates of hydrogen blending potential.

- **Minnesota G21 Initiative, *Decarbonization of Gas End-Uses* (2021-2022).** Supervised a study that evaluated alternative strategies to decarbonize gas end-uses in Minnesota. Given the Minnesota's very cold climate, E3 found that full electrification would produce very large impacts on the state's electricity system. However, exclusive reliance on low-GHG fuels was found to be cost-prohibitive and would carry a substantial amount of risk given those fuels low-levels of commercialization. With that, E3 identified hybrid electrification as a key strategy to decarbonize building heating, but did identify a potentially larger role for hydrogen in reducing GHG emissions from high temperature industrial processes.

NATURAL RESOURCES DEFENSE COUNCIL San Francisco, CA
Consultant September 2016 – May 2017

- Produced policy analysis in support NRDC's distributed energy resources advocacy. Developed written regulatory comments that were block quoted in several CPUC decisions.

ENERGY INNOVATION, LLC San Francisco, CA
Policy Consultant 2016 – 2017

- Wrote a paper for the America's Power Plan series evaluating the impact of different performance-based regulation (PBR) designs on utilities' revenue and motivation to accomplish societal goals. This report added specificity to discussions of new regulatory models by illuminating the implications of PBR for utility decision-making on a project-by-project basis.

CALIFORNIA PUBLIC UTILITIES COMMISSION
OFFICE OF PRESIDENT PICKER San Francisco, CA
Graduate Student Intern *Summer 2015*

- Developed an analysis of regulatory models that better align electric utility incentives with changing electricity system technological trends, market structures and policy goals. Provided clarity on the various regulatory models labeled PBR and mapped out what forms of PBR may be aligned with California's energy policy goals.
- Reviewed proposed decisions and regulatory filings to advise President Picker on active energy related proceedings. Covered topics including grid modernization, grid integration, prudence reviews, and fuel-cost balancing accounts.

THE ENERGY FOUNDATION San Francisco, CA
Program Associate/ Senior Program Associate/ Staff Consultant 2011 – 2016

- Conduct policy issue research on a part-time basis to inform strategy development for, and implementation of, Energy Foundation's energy efficiency grant portfolio. Tasks have ranged from developing fundraising materials to reviewing grantee proposals.

- As a full-time employee effectively managed, and guided the strategic direction of, the $4 million energy efficiency portfolio grant portfolio during a period of significant senior staff turnover. Developed a strong knowledge of the policy and political barriers to deep energy efficiency commitments. Synthesized and prioritized strategies from a diverse set of over 40 advocacy groups to ensure that energy efficiency policies were successfully defended, implemented and improved in 35+ states.
- Effectively told the story of the energy efficiency program's strategy in writing, in presentations and in funder meetings. On two separate occasions, my work played a key role in unlocking at-risk funding, totaling over $1.2 million, for the industrial energy efficiency initiative.
- Worked to bolster the effectiveness of an energy efficiency advocate network by facilitating technical assistance and consulting expertise for grantees, making connections between groups conducting complementary work, and organizing an annual conference where over 150 experts shared best practices in energy efficiency regulatory policy and politics.
- Produced high quality written and visual materials to effectively communicate the energy efficiency program's progress and challenges to a diverse set of audiences including board members, Energy Foundation colleagues and external advisors.
- Demonstrated a commitment to internal process improvement by leading work to implement new Program Team budget spreadsheets that enable more coordinated grantmaking. Served as an effective manager of three program budgets, ensuring that all internal spending deadlines were met.

TETRA TECH EM, INC. Bothell, WA
Energy Analyst June 2008 – July 2010

- Calculated the greenhouse gas abatement potential of power sector-oriented, state-level climate policy options in four states (FL, IL, MI, OH). Assisted in the management of stakeholder processes to ensure quantitative work was credible to a broad set of interest groups, businesses and decision makers.
- Worked on a variety of environmental consulting projects including greenhouse gas inventory verifications, food chain modeling in remediation projects, environmental impact statements, environmental site assessments, and environmental justice initiatives.

Education

University of California, Berkeley Berkeley, CA
Master of Public Policy, Master of Arts in Energy and Resources May 2017

Whittier College Whittier, CA
B. A. Economics and Political Science May 2008
Honors: Outstanding Economics Major, Distinction in Economics and Political Science Majors

University of Oxford Oxford, UK
Politics, Philosophy and Economics 2005 – 2006

PRE-FILED DIRECT TESTIMONY

OF

LEE GRESHAM

June 2, 2025

Table of Contents

I. Introduction and Qualifications

Q. Dr. Gresham, please state your full name and business address.

A. My name is Lee Gresham. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. By whom are you employed and in what capacity?

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company") as Head of Gas Regulatory Strategy within the External Affairs team. In this role, I am responsible for general regulatory matters, policy development, and filings, including providing strategic support to inform business decisions that advance safe, reliable, affordable natural gas distribution.

Q. Please describe your educational background and professional experience.

A. I graduated from the College of the Holy Cross with a Bachelor of Arts degree in Psychology and concentration in Pre-Medicine in 1999. In 2007, I graduated from Vermont Law School with a Juris Doctorate degree. In 2010, I received a Doctor of Philosophy degree in Engineering and Public Policy from Carnegie Mellon University. From 2010 to 2011, I was a Post-Doctoral Fellow with the Carbon Capture and Sequestration Regulatory Institute. I worked as a Senior Consultant at SAIC, Inc. in its Energy, Environment, and Infrastructure division from 2011 to 2012. From 2012 to 2018, I held roles of increasing responsibility as an Associate with The Brattle Group in the firm's utility practice. In 2019 I joined National Grid USA Service Company, Inc. as a Lead Analyst for the Utility of the Future team within the Regulatory and Customer Strategy departments where I worked closely with the Massachusetts Jurisdictional President and staff, leading efforts to reduce methane and carbon emissions, developing strategies to support National Grid's objectives regarding decarbonization-related investments in the gas system, and providing testimony regarding capital investments to enable National Grid's operating companies, including Boston Gas Company d/b/a National Grid and the former Colonial Gas d/b/a National Grid, to decarbonize the gas network.

Q. Have you previously testified before the Rhode Island Public Utilities Commission (the "PUC" or the "Commission")?

A. Yes. I provided pre-filed direct testimony for the Company's 2024-2026 Gas Demand Response Pilot SRP Investment Proposal in Docket No. 23-46-EE, 2025 Gas Demand Response Pilot SRP Investment Proposal in Docket No. 24-37-EE, and FY2026 Gas Infrastructure, Safety and Reliability Plan in Docket No. 24-55-NG.

II. Purpose and Structure of Testimony

Q. What is the purpose of your testimony?

A. I identify the reliability needs that are addressed by the liquified natural gas ("LNG") storage and vaporization facility at Old Mill Lane in Portsmouth (the "Facility") by the

Facility's provision of a back-up the supply of natural gas to the Company's natural gas distribution system on Aquidneck Island ("Distribution System"). I also and explain that the gap between available pipeline natural gas supply and customer demand on Aquidneck Island's natural gas distribution system cannot cost-effectively, nor reliably, be eliminated with energy efficiency, demand response, and electric conversion measures (referred to herein as "demand side alternatives" or "demand reduction alternatives").

Q. How is your testimony structured?

A. Section I is the Introduction. Section II presents the purpose and structure of my testimony. Section III briefly identifies the reliability needs addressed by the Facility. Section IV describes the energy efficiency, demand response, and electric heating conversion analysis performed by Energy and Environmental Economics, Inc. ("E3") for eliminating the gas capacity constraint on Aquidneck Island the Energy Facility Siting Board ("EFSB") required as a condition of approving the Company's license application for the Facility.[1] Section V presents the Company's conclusions regarding the demand side alternative measures evaluated.

Q. Are you sponsoring any schedules with your testimony?

A. No.

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[1] *In re The Narragansett Electric Company Aquidneck Island Gas Reliability Project, Old Mill Lane, Portsmouth, RI*, Decision and Order, at 52 (May 12, 2025).

III. Need for the Old Mill Lane LNG Storage and Vaporization Facility

Q. Please briefly describe the need for the OML Facility.

A. The Facility is needed to address two challenges that pose risks to the reiliability of the natural gas distribution system on Aquidneck Island that have been referred to as capacity constraint and capacity vulnerability. These related but distinct threats to reliability are described generally in the EFSB's Decision and Order in Docket No. SB-202-04 dated May 12, 2025 at pages 2 to 3.

IV. E3 Demand Side Alternatives Analysis

Q. For this filing, did the Company evaluate the potential for demand side alternatives to mitigate the capacity constraint on Aquidneck Island?

A. Yes. The EFSB ordered the Company to submit to the PUC "a demand response/energy efficiency plan targeted specifically for Aquidneck Island with the objective of eventually eliminating the design-day peak hour capacity gap that has caused the gas capacity constraint on Aquidneck Island."[2] E3 was retained by the Company to conduct an analysis of demand side alternative scenarios for addressing the capacity constraint. The demand side alternatives evaluated do not address the separate capacity vulnerability challenge identified during the EFSB proceeding.

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[2] *Id.*

Q. What demand side alternative measures did E3 evaluate?

A. As explained in Section III.2 of the pre-filed direct testimony of Daniel Aas, E3 slected measures based on estimated peak natural gas demand reduction potential. The three demand reduction measures included were: (1) efficient natural gas furnaces or boilers plus basic building shell upgrades for all customer classes; (2) cold-climate air source heat pumps ("ASHPs") plus basic building shell upgrades for all customer classes; and (3) demand response fuel switching by large commercial and industrial customers with on-site backup systems. These defined demand reduction measures were evaluated across three alternative portfolios that balance objectives such as cost, emissions, and implementation feasiblity. The net benefits of each portfolio through 2035 were compared to the continued operation of the Facility.

Q. What were E3's findings?

A. In the pre-filed direct testimony of Daniel Aas, E3 concludes, that while there is technical potential from demand side measures to address the capacity constraint, available pathways may not be feasible in practice. The pathways may not be feasible because realizing sufficient demand reductions within the next decade would require an unprecedented and unproven pace and scale of customer adoption and program participation, particularly for ASHPs, rendering forecasts of demand reduction speculative.

Moreover, the esimated program costs for Rhode Island Energy to address the capacity constraint with demand reduction alternative measures range from $70 million to $80 million, on a net present value ("NPV") basis. E3's analysis further concludes that the costs of addressing the capacity constraint with demand reduction alternatives far exceed the benefits, with societal net costs ranging from $75 to $125 million and utility net costs $118 to $163 million, both on a NPV basis.

V. Feasibility of Demand Side Alternatives Plan

Q. Does the Company view any of the demand reduction portfolios evaluated by E3 as viable alternatives to the Facility for purposes of addressing the capacity constraint on Aquidneck Island?

A. No. It is unlikely that the highly-speculative levels of customer adoption E3's analysis suggests are required to achieve the demand reduction necessary to eliminate the capacity constraint by 2035 are achievable. Moreover, a determination that the capacity constraint has been resolved requires elimination of the demand-supply gap in an enduring way that is actually observable through data gathered in periods of extreme cold. Consequently, even the achievement of the speculative levels of customer adoption set forth in E3's analysis may ultimately prove insufficient if observed customer demand after plan implementation exceeds what was forecasted in the process of plan development.

Furthermore, the exceptionally high net cost estimates for each portfolio are prohibitive and unjustifiable, particularly at a time when affordabilty is an increasing challenge for our customers. It is the Company's position that results of E3's study support the continued use of the Facility to ensure the safe, reliable, and affordable delivery of energy to customers on Aquidneck Island.

Q. Will the Company continue to evaluate and consider pursuing demand reduction as an alternative to reliance on the Facility to meet the capacity shortfall?

A. Yes. E3's analysis and the model it developed to evaluate altnerative demand reduction measures provide the Company with a framework for updating assumptions associated with those measures as more information becomes available. At this time, however, the cost to incentivize demand reduction measures on a scale sufficient to eliminate the Aquidneck Island natural gas demand-supply gap far exceeds the measurable benefits and achievement of the goal for which the Company commissioned alternative plans evaluated by E3 appears speculative.

Q. Does this conclude your testimony?

A. Yes.