The Narragansett Electric Company
d/b/a Rhode Island Energy

Proposed FY 2026 Gas Infrastructure, Safety, and Reliability Plan

Responses to Division Data Requests Sets 2 and 3

December 20, 2024

Docket No. 24-55-NG

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
AMarcaccio@pplweb.com

280 Melrose Street
Providence, RI 02907
Phone 401-784-4263

Rhode Island Energy™
a PPL company

December 4, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2026 Gas Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 2

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's responses to the Division's Second Set of Data Requests in the above-referenced matter.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: John Bell, Division
Al Mancini, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.

Division 2-1

Request:

Referring to Section 3, Attachment 1, Page 35, Lines 24 and 29, please provide documentation supporting the Property Tax Expense for End of FY 2023 and End of FY 2024.

Response:

Please see Attachment DIV 2-1 for the requested information.

Fiscal year 2023 Property Tax Expense can be found on Attachment DIV 2-1, Page 1, Line 14, Column (p) and FY 2024 Property Tax Expense can be found on Attachment DIV 2-1, Page 2, Line 13, Column (p).

Prepared by or under the supervision of: Jeffrey Oliveira

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		National Grid					PPL									
		Apr-22	May-22	Jun-22			Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Total
(1)	C4081400				Glad	(Multiple Items)										
(2)																
(3)	**Sum of Amount in local currency**	**Column Labels**			**Sum of Monetary Amount**											
(4)		**FY 2023**					**CY 2022**	**CY 2022**	**CY 2022**	**CY 2022**	**CY 2022**	**CY 2022**	**CY 2023**	**CY 2023**	**CY 2023**	**Grand Total**
(5)	**Row Labels**	**1**	**2**	**3**	**SRC**	**Journal Line Ref**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	
(6)	**TRAN**	**1,406,475.34**	**1,409,110.85**	**1,425,950.79**	**TRAN**		**1,336,195.98**	**726,034.18**	**1,316,703.60**	**1,307,889.39**	**1,314,337.88**	**1,368,303.88**	**1,323,073.11**	**1,332,848.48**	**1,333,054.47**	**15,599,977.95**
(7)		1,407,290.79	1,410,046.58	1,426,841.58	**7505**								1,335,393.00	1,335,393.00	1,335,393.00	8,250,357.95
(8)	5220SC4315M01				**7512**									(2,628,089.79)	0.00	(2,628,089.79)
(9)	5360SC4315M01	(815.45)	(935.73)	(890.79)	**7512**	C4081400	1,336,195.98	726,034.18	1,316,703.60	1,307,889.39	1,314,337.88	1,368,303.88	(12,319.89)	2,625,545.27	(2,338.53)	9,977,709.79
(10)	**ELEC**	**2,796,285.87**	**2,812,849.95**	**2,815,808.23**	**ELEC**		**2,946,078.84**	**2,980,491.37**	**2,885,521.54**	**2,873,501.47**	**2,865,780.93**	**2,903,957.32**	**2,877,961.59**	**2,886,873.49**	**2,887,058.58**	**34,532,169.18**
(11)		2,797,011.70	2,813,689.82	2,816,607.72	**7503**								2,889,181.00	2,889,181.00	2,889,181.00	17,094,852.24
(12)	5220SC4315M01				**7511**									(5,732,169.20)	0.00	(5,732,169.20)
(13)	5360SC4315M01	(725.83)	(839.87)	(799.49)	**7511**	C4081400	2,946,078.84	2,980,491.37	2,885,521.54	2,873,501.47	2,865,780.93	2,903,957.32	(11,219.41)	5,729,861.69	(2,122.42)	23,169,486.14
(14)	**GAS**	**2,709,101.62**	**2,716,514.05**	**2,959,909.47**	**GAS**		**4,824,694.77**	**3,166,915.89**	**3,067,305.51**	**3,081,956.00**	**3,067,316.72**	**3,283,377.71**	**3,136,780.49**	**3,141,611.21**	**3,141,711.54**	**38,297,194.98**
(15)		2,709,495.06	2,716,969.30	2,960,342.84	**7504**								3,142,862.00	3,142,862.00	3,142,862.00	17,815,393.20
(16)	5220SC4315M01				**7513**									(6,170,933.42)	0.00	(6,170,933.42)
(17)	5360SC4315M01	(393.44)	(455.25)	(433.37)	**7513**	C4081400	4,824,694.77	3,166,915.89	3,067,305.51	3,081,956.00	3,067,316.72	3,283,377.71	(6,081.51)	6,169,682.63	(1,150.46)	26,652,735.20
(18)	**Grand Total**	**6,911,862.83**	**6,938,474.85**	**7,201,668.49**	**Grand Total**		**9,106,969.59**	**6,873,441.44**	**7,269,530.65**	**7,263,346.86**	**7,247,435.53**	**7,555,638.91**	**7,337,815.19**	**7,361,333.18**	**7,361,824.59**	**88,429,342.11**

from the Company's General Ledger

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
				Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Total
(1)	Report Filter:															
(2)	(Year = 2023, 2024) And ({Accounting Period} = 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12) And ({Business Unit} = 75100, 75200, 75300, 75400) And (Account (ID) Like "40811")															
(3)																
(4)	**Sum of Monetary Amount**															
(5)				**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2023**	**CY 2024**	**CY 2024**	**CY 2024**	**Grand Total**
(6)	**SRC**	**Journal Line Ref**	**JE#**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**1**	**2**	**3**	
(7)	**TRAN**			**1,333,612.47**	**1,333,612.47**	**1,333,612.47**	**1,333,606.78**	**1,337,690.29**	**2,246,555.12**	**1,436,633.00**	**1,436,633.00**	**1,453,530.33**	**1,761,313.00**	**1,761,313.00**	**1,761,313.00**	**18,529,424.93**
(8)	**7505**		JES307	1,335,393.00	1,335,393.00	1,335,393.00	1,335,393.00	1,335,393.00	2,246,555.12	1,436,633.00	1,436,633.00	1,453,530.33	1,761,313.00	1,761,313.00	1,761,313.00	18,534,255.45
(9)	**7512**	C4081400	NEC100	(1,780.53)	(1,780.53)	(1,780.53)	(1,786.22)	2,297.29								(4,830.52)
(10)	**ELEC**			**2,886,746.65**	**2,886,746.60**	**2,886,746.65**	**2,886,762.03**	**2,891,628.20**	**4,860,520.52**	**3,108,219.00**	**3,108,219.00**	**3,144,776.61**	**3,810,677.00**	**3,810,677.00**	**3,810,677.00**	**40,092,396.26**
(11)	**7503**		JES307	2,889,181.00	2,889,181.00	2,889,181.00	2,889,181.00	2,889,181.00	4,860,520.52	3,108,219.00	3,108,219.00	3,144,776.61	3,810,677.00	3,810,677.00	3,810,677.00	40,099,671.13
(12)	**7511**	C4081400	NEC100	(2,434.35)	(2,434.40)	(2,434.35)	(2,418.97)	2,447.20								(7,274.87)
(13)	**GAS**			**3,141,560.09**	**3,141,560.07**	**3,141,560.09**	**3,141,568.32**	**3,144,153.66**	**5,224,979.15**	**3,374,208.00**	**3,374,208.00**	**2,976,275.13**	**3,867,276.00**	**3,867,276.00**	**3,867,276.00**	**42,261,900.51**
(14)	**7504**		JES307	3,142,862.00	3,142,862.00	3,142,862.00	3,142,862.00	3,142,862.00	5,224,979.15	3,374,208.00	3,374,208.00	2,976,275.13	3,867,276.00	3,867,276.00	3,867,276.00	42,265,808.28
(15)	**7513**	C4081400	NEC100	(1,301.91)	(1,301.93)	(1,301.91)	(1,293.68)	1,291.66								(3,907.77)
(16)	**Grand Total**			**7,361,919.21**	**7,361,919.14**	**7,361,919.21**	**7,361,937.13**	**7,373,472.15**	**12,332,054.79**	**7,919,060.00**	**7,919,060.00**	**7,574,582.07**	**9,439,266.00**	**9,439,266.00**	**9,439,266.00**	**100,883,721.70**

from the Company's General Ledger

Division 2-2

Request:

Referring to Section 3, Attachment 1, Page 35, Lines 35 and 40, please explain why the Effective Prop Tax Rate decreases from the End of FY 2024 to End of FY 2025 and then increases from the End of FY 2025 to End of FY 2026.

Response:

The Effective Property Tax Rate for each "Plan" year filing is based on the Company's last actual property tax rate as of the Plan filing date. This rate is trued-up in the Company's reconciliation filing when the Company reports the actual net plant amounts and actual property tax expense. The Effective Property Tax Rate for fiscal year 2025 is an estimate based on the Company's fiscal year 2023 Effective Tax Rate, and the Effective Property Tax Rate for fiscal year 2026 is an estimate based on the Company's fiscal year 2024 Effective Tax Rate. Both of these rates are estimates and will be trued-up in the Company's reconciliation filings.

Andrew S. Marcaccio, Counsel
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280 Melrose Street
Providence, RI 02907
Phone 401-784-4263

Rhode Island Energy™
a PPL company

December 12, 2024

VIA ELECTRONIC MAIL AND HAND DELIVERY

Stephanie De La Rosa, Clerk
Division of Public Utilities and Carriers
89 Jefferson Boulevard
Warwick, RI 02888

RE: Rhode Island Energy's Proposed Fiscal Year 2026 Gas Infrastructure, Safety, and Reliability Plan
Responses to Division Data Requests – Set 3

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed are the Company's responses to the Division's Third Set of Data Requests in the above-referenced matter.

Please note that Attachments DIV 3-3-2, DIV 3-4-2, DIV 3-5, DIV 3-6-1 through 6 are considered confidential. The confidential versions will be sent via a secured link and are subject to the universal Non-Disclosure Agreement between the Company and the Division. The Company will review the attachments for CEII. Once its review is complete, the Company will release the public versions of those attachments.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: John Bell, Division
Al Mancini, Division
Christy Hetherington, Esq.
Margaret L. Hogan, Esq.
Kyle Lynch, Esq.
Mark Simpkins, Esq.
Leo Wold, Esq.

Division 3-1

Request:

The Company states on Bates page 12 that, "When the Company includes the DTA impact to rate base in its expense versus capital comparison, the Company can demonstrate using net present value calculations that expensing versus capitalizing paving costs is harmful to customers over time." Please provide that demonstration with all supporting documentation and calculations.

Response:

Please see Attachment DIV 3-1, Pages 1-17, for the supporting documentation and calculations showing the revenue requirement ("RR") at net present value ("NPV") impact to customers over time when paving costs are expensed versus capitalized. Page 1 is a summary of the comparison calculations by year where Column (d) reflects the increase or decrease in the RR at NPV when expensing versus capitalizing paving costs, Column (h) reflects the NPV of the RR when paving costs are expensed and Column (m) reflects the NPV of the RR when paving costs are capitalized. The discount rate for the NPV calculations matches the pre-tax rate of return used in the RR calculations discussed below.

The remaining pages use the Infrastructure, Safety and Reliability RR framework to perform the calculations. To keep the calculations simple, the only inputs reflected are 1) the amount of paving costs, 2) the depreciation rate, 3) the tax rate, 4) the pre-tax rate of return and 5) the capital repairs deduction rate. Pages 2-8 reflect the RR calculations when $12 million of paving costs are expensed. Pages 9-17 reflect the RR calculations when $12 million of paving costs are capitalized.

It is important to note that when paving costs are expensed, a new book-to-tax temporary difference ("temporary difference") results because paving costs must continue to be capitalized for tax purposes. On Page 5, which reflects the computation of tax depreciation, this new temporary difference is reflected on Lines 2, 8 and 22. The temporary difference is reflected on Line 2 because it is subject to the repairs deduction rate. The temporary difference is reflected on Line 8 to calculate the originating deferred tax impact (i.e., a deferred tax asset or a reduction in a deferred tax liability) in the year paving costs are incurred. The temporary difference is reflected on Line 22 to capture the increase in tax basis net of the repairs tax deduction, which will depreciate over the tax life of the asset and will reverse the originating deferred tax. The total impact of this new temporary difference in year 1 is reflected on Page 5, Line 32, which is then reflected on Page 2, Line 10 and is used to calculate deferred taxes on Pages 2, Line 16. A credit amount on Pages 2-4, Lines 10 and 11, signifies a deferred tax asset will be calculated, which will increase rate base and will create additional harm to the customer.

Prepared by or under the supervision of: Natalie Hawk

Attachment DIV 3-1

As requested by the Division, the Company is providing the information in an Excel file as Attachment DIV 3-1.

Prepared by or under the supervision of: Natalie Hawk

Division 3-2

Request:

Please provide a detailed explanation of why the Company's estimate for Group A - Main Replacement & Rehabilitation categories have increased 41% from FY2025 ($107,703) to FY 2026 ($152,302)?

Response:

After spending less than budget for many of the last several years, the Company shifted its replacement strategy at the beginning of FY2024 to target the projects that represented the highest risk, rather than a strategy that balanced higher risk with more overall mileage. The Company was not as fully prepared to support this new strategy, and found it necessary to work a project mix that was heavily weighted towards long, larger diameter main work. This type of work, due to many different factors, from traffic management to material handling, is significantly more expensive than shorter, smaller diameter main work. This more expensive work mix resulted in the Company overspending on the types of projects which now make up budget Group A. These extra costs required the Company to stop project work undertaken by outside contractors for the final month of the year to limit overspend.

While preparing the FY2025 budget, the Company identified higher risk main work that could be undertaken at lower cost, while still expecting a larger than normal percentage of expensive projects. The expectation was that the unit cost, on a dollars per mile basis, for Group A work would revert closer to the previously observed mean, yet remain higher than it had been prior to the change in replacement strategy. However, over the early part of FY2025, it became clear that project spend was outpacing budget, and the Company undertook a comprehensive analysis of cost drivers. It was found that costs had risen more than anticipated across all major project elements including: contractor labor, materials, traffic management, paving, internal labor, and others. More than just the particular work mix, the entire cost of installing mains and services had risen in step with inflation seen across the rest of the economy. The Company has once more curtailed external spend on outside contractors in an attempt to limit overspending on Group A in FY2025.

The Company's observation of generally rising costs was used to inform the FY2026 ISR proposal for Group A projects. The Company also recognized that its existing contracts with outside labor were set to expire at the end of FY2025. The expiring agreements were originally three-year contracts under which two one-year extension options were exercised, meaning that it has been five years since the last negotiation and bid process has taken place. The Company understood through informal discussions with its contract labor force that it should expect a steep change in the pricing offered to conduct mains and services work in FY2026 and beyond. The Company built assumptions regarding these cost increases into the FY2026 ISR plan proposal to the Division. In the meantime, the competitive bid process for FY2026 contracts, while not yet completed, has progressed and the Company's estimates have largely been confirmed.

In summary, the combination between the Company shifting to higher risk projects, which often take place under more expensive circumstances than lower risk projects and are more expensive, along with the delayed realization of the same inflationary factors seen by the rest of the economy at large has driven the cost of conducting projects like those in budget Group A significantly higher than in the past.

Division 3-3

Request:

Please update each project under the category "Gas System Reliability" in East Providence, Providence, North Providence, Lincoln and Johnston (FY 2026 Gas ISR Plan Bates Pages 22-23). In your update, please include the following information:

a. A description and construction schedule for each project;
b. The total costs of each project;
c. Identify when the costs for the various Projects have been and/or will be incurred relative to the construction schedule; and
d. A site plan for each project.

Response:

a. Project Descriptions and Schedules

  - WO #90000231875 (Greenwich Avenue, East Providence) – This project is a low-pressure to high-pressure conversion as well as the first phase of a multi-year project to connect a single feed 99 psig system in East Providence with the larger 99 psig system near Dey Street. This project includes the installation of 1.8 miles of modern high-pressure gas main to retire 1.4 miles of low-pressure gas main, 0.3 miles of which are leak prone pipe and the remaining 1.1 miles are existing plastic that is not rated for high-pressure use. The scope includes modern high-pressure conversion for (146) existing customers. The goal is to complete 50 percent of the project during FY2025, carry over 35 percent into FY2026 with final restoration on or before FY2027.

  - WO #90000234523 (Waterman Avenue, North Providence) – This project will integrate two separate 35 psig systems. The scope requires the installation of 0.7 miles of 12" high-pressure plastic gas main. This project is proposed to start in FY2025 and continue work through final restoration in FY2026.

  - WO #90000234616 (Allandale Avenue, Johnston) – This project is related to the Waterman Avenue, North Providence project described above. This project will further integrate two separate 35 psig systems, and provide a backfeed to a small area of the 35 psig systems on the west side a 12 inch coated steel 35 psig main in Allendale Avenue. The project was proposed in FY2025; however, resources were not available. Therefore it will carry over into the FY2026 construction season.

Division 3-3, page 2

- WO #90000231856 (Beverly Drive, Lincoln) – This project is proposed to convert a low-pressure extremity of the distribution system to high-pressure. The project was proposed in FY2025; however, resources were not available to complete the project. Therefore it will carry over into the FY2026 construction season.

- WO #90000224932 (Roger Williams Avenue, East Providence) – This project is a main extension from the existing 99 psig line in Roger Williams Avenue towards the border of Pawtucket and East Providence (Riverside) for future 99 psig to 35 psig and 99 psig to 18 psig regulator stations to support an 18 psig low point in Pawtucket, as well as adding another 35 psig regulator station to a current single feed 35 psig system. The project was proposed in FY2025; however resources were not available. Therefore, the project will carry over into the FY2026 construction season.

New work proposed for FY2026 is as follows:

- WO #90000235056 (Boyd Avenue, East Providence) – This will be the second phase of the East Providence 99 psig system integration and a continuation of the 99 psig main installed under Greenwich Avenue, East Providence (as described above). This project will extend the 99 psig system down Wampanoag Trail and set up for the following phase to continue north of the end of the Greenwich Avenue 99 psig towards the separate 99 psig system by Waterman Avenue at Pawtucket Avenue. This project is proposed to start and complete in FY2026.

- WO # 90000237055 (Pawtucket Ave, East Providence) – This will be phase three of the East Providence 99 psig system integration and a continuation of the 99 psig main installed under Greenwich Avenue and Boyd Avenue, East Providence to continue north towards the separate 99 psig system by Waterman Avenue at Pawtucket Avenue. This project is proposed to start and complete in FY2026.

- WO # 90000190386 (Hartford Avenue, Providence) – This project in Olneyville will provide reliability by looping two disconnected sections on the 99 psig system. The scope includes 0.4 miles of new high-pressure main install and enables 21 existing low-pressure services to be converted to modern high-pressure. The existing parallel low-pressure gas main must remain in service because it is a central artery to the area. An additional benefit of this project is that Gas Control will gain flexibility to increase supply to Providence from the Smithfield and Cranston Take Stations (TGP Lateral) and lower demand from Wampanoag Trail Take Station (AGT Lateral) if necessary to balance the daily supply portfolio. This project is proposed to start and complete in FY2026 ahead of the Onleyville downtown development plan anticipated to begin in FY2027.

Prepared by or under the supervision of: Brandon Flynn

- WO # 90000216897 (Harris Avenue, Providence) – This project in Olneyville will provide reliability by looping a third disconnected lateral on the 99 psig system. The scope includes 0.2 miles of new high-pressure main install and enables (5) existing low-pressure services to be converted to modern high-pressure. The existing parallel low-pressure gas main must remain in service because it is a central artery to the area. An additional benefit of this project is that Gas Control will gain flexibility to increase supply to Providence from the Lincoln and Scott Road Take Stations (TGP Lateral) and lower demand from Wampanoag Trail Take Station (AGT Lateral) if necessary to balance the daily supply portfolio. This project is proposed to start and complete in FY2026 ahead of the Onleyville downtown development plan anticipated to begin in FY2027.

The following projects are slated for FY2027 and may be advanced in FY2026 as backup work, if needed:

- WO # 90000139822 (Scenery Lane, Johnston) – This project will eliminate a single feed 35 psig system by connecting it to the regional system with 0.4 miles of new main install. There is no gas main retirement or service transfers associated with this scope of work. The current system has one stand-alone regulator station that will be retired as part of this work scope. The schedule for this project has not yet been confirmed. It is currently listed as a backup project for FY2026.

- WO # Pending (Winter Street @ Railroad Street, Lincoln) – This project targets the remaining low-pressure single feed system in the Manville area of Lincoln. The project requires approximately 1.0 miles of new high-pressure gas main in order to retire the existing low-pressure system and convert approximately 200 customers to high-pressure. The current system has one stand-alone regulator station that will be retired as part of this work scope. The schedule for this project has not yet been confirmed. It is currently listed as a backup project for FY2026.

b. and c. Please see Attachment DIV 3-3-1 for the requested information.

d. Please see Attachment DIV 3-3-2 for the requested site plans. Please note that Attachment DIV 3-3-2 contains critical energy infrastructure information ("CEII") and is being provided pursuant to a non-disclosure agreement with the Division. When filed with the Public Utilities Commission the Company will provide a redacted version of Attachment DIV 3-3-2 and an unredacted confidential version subject to a motion for protective treatment.

RI Energy Gas System Reliability – DIV 3-3-1

FY Project	WO #	Related WO#s	Town	Street	Installation Miles	Abandonment Miles	Leak-Prone Miles	Non Leak-Prone Miles	# of Services	FY25 Forecast	FY26 Proposed Budget	FY27 (Carryover from FY26)	In Service	Aband
Carryover FY25	90000231875	90000235056, 90000237055, MSR 90000233734	EPV	Greenwich Ave	0.0	2.1	0.7	1.4	146	$2.37	$1.92	$0.82	FY25	FY26
Carryover FY25	90000234523	90000234616	NPV	Waterman Ave	0.6	0.0	0.0	0.0	0	$0.79	$0.74	$0.18	FY26	N/A
Carryover FY25	90000234616	MSR 90000234523	JOH	Allandale Ave	0.4	0.2	0.2	0.0	0	N/A	$0.45	$0.11	FY26	FY26
Carryover FY25	90000231856	MSR 90000211503	LNC	Beverly Dr	0.0	0.9	0.5	0.4	56	$0.34	$0.32	$0.08	FY26	FY26
Carryover FY25	90000224932	MSR 90000236859	EPV	Roger Williams Ave	0.9	0.0	0.0	0.0	0	N/A	$1.35	$0.35	FY26	N/A
FY26	90000235056	90000231875, 90000237055	EPV	99# System Integration P2	0.5	0.0	0.0	0.0	0	N/A	$0.99	$0.25	FY26	N/A
FY26	90000237055	90000231875, 90000235056	EPV	99# System Integration P3	2.1	2.0	0.0	2.0	181	N/A	$0.90	$2.7	FY26	FY26
FY26	90000190386	90000216897	PVD	Hartford Ave	0.4	0.0	0.0	0.0	21	N/A	$0.85	$0.21	FY26	N/A
FY26	90000216897	90000190386	PVD	Harris Ave	0.2	0.0	0.0	0.0	5	N/A	$1.82	$0.45	FY26	N/A
FY26 Backup	WR# 51633032		JOH	Scenery Ln	0.4	0.0	0.0	0.0	0	N/A	$0.69	$0.3	FY27	N/A
FY26 Backup	WR# 51637404		LNC	Winter St @ Railroad St	1.0	1.1	1.0	0.2	204	N/A	N/A	$1.71	FY27	FY28
FY27	future projects	-	-	-	-	-	-	-	-	-	-	$4.65		
										FY26 Budget	**$10.02**			

REDACTED

Attachment DIV 3-3-2

Attachment DIV 3-3-2 contains critical energy infrastructure information ("CEII").

Prepared by or under the supervision of: Brandon Flynn

Division 3-4

Request:

Please provide the following information regarding the Low-Pressure System Elimination (Proactive) program:

a. An update on current FY 2025 projects including construction progress and costs;

b. Construction details and the estimated cost for each project proposed in the FY 2026 budget; and

c. A site plan for each proposed project.

Response:

a. Please see Attachment DIV 3-4-1 for an update on construction progress and costs for projects in Low-Pressure System Elimination (Proactive) program during FY25. Note that all FY25 projects are multi-year projects for which construction and spending will carry over into FY26 and make up the majority of the FY26 budget, so the descriptions in section B will be a summary of the FY25 projects as they carry into FY26.

b. In addition to the information provided in Attachment DIV 3-4-1, please see project details below. Please refer to Attachment DIV 3-4-2 for the full estimated cost of each project.

   - **WO #90000239809 (Tuckerman Avenue, Middletown):** This project and Wolcott Avenue (listed below) were originally identified as separate work scopes, each under a different program budget, however the projects have now been combined into one new work order to streamline construction. Middletown restricts access to the streets until after Labor Day therefore fall and winter seasonal work is required. Progress was made during the spring and the intent is to complete 30 percent of the total project each year with final restoration and paving completed on or before FY27. The work is contingent upon the completion of the temporary regulator station and there were re-designs in FY25 that pushed off the continuation of the project.

   - **WO #90000221104 (Wolcott Avenue, Middletown):** As mentioned above, this project has been combined with the Tuckerman Avenue project to streamline construction. This work order is no longer active.

   - **WO #90000239809 (Charles St, Providence):** This project is on track to complete the majority of the installation, gas in, and service transfers in FY25 and will complete the work as well as restoration in FY26.

- **WO #90000235353 (Privilege Street, Woonsocket):** This project is forecasted to be 20 percent complete in FY25, with the installation of new main and preparation for service transfers in winter 2024-25. The Company forecasts that 60 percent of the work and spend will occur in FY26 and the remaining 20 percent of work, mainly restoration, will be completed in FY27. This project is being completed in parallel with the progression of Social Street (below), which is prioritized to be ahead of Rhode Island Department of Transportation (RIDOT) paving in FY27.

- **WO #90000237699 (Tiffany Street, North Providence):** This project is on track to be 80 percent complete during FY25 with final restoration carrying over into FY26.

- **WO #90000234969 (East Street, Woonsocket):** This project has been deferred to an undetermined future year due to moratorium paving restrictions in the neighborhood.

- **WO #90000235554 (Mitris Boulevard, Woonsocket):** This project was not able to begin during FY25 and will carry over to the FY26 workplan with restoration on or before FY27.

- **WO #90000238318 (Morton Street, Johnston):** Similar to Mitris Boulevard, this project was not able to start during FY25 and will carry over to the FY26 workplan with restoration on or before FY27.

- **WO #90000239843 (Social Street, Woonsocket):** This project is being completed in close coordination with RIDOT and the Town of Woonsocket. The Company's goal is to complete 40 percent of the project during FY25 and finalize the project in FY26 prior to the RIDOT paving scheduled for the following Spring (i.e., FY27).

c. Please see Attachment DIV 3-4-2 for the requested site plans. Please note that Attachment DIV 3-4-2 contains critical energy infrastructure information ("CEII") and has been produced pursuant to a non-disclosure agreement with the Division. When filed with the Public Utilities Commission, the Company will provide a redacted copy of Attachment DIV 3-4-2 and an unredacted confidential version subject to a motion for protective treatment.

Prepared by or under the supervision of: Brandon Flynn

RI Energy LP Elimination– DIV 3-4-1

FY Project	WO #	Related WO#s	Town	Street	Installation Miles	Abandonment Miles	Leak-Prone Miles	Non Leak-Prone Miles	# of Services	FY25 Forecast	FY26 Proposed Budget	FY27 (Carryover from FY26)	In Service	Aband
Carryover FY25	90000244323	90000221104, 90000229980	MDT	Tuckerman Ave	2.9	2.9	0.2	2.7	204	$1.06	$1.23	$1.23	FY26	FY27
Carryover FY25	90000238318	MSR 90000237914	JOH	Morton Ave	0.7	0.7	0.1	0.6	43	N/A	$0.94	$0.23	FY26	FY27
Carryover FY25	90000239809	MSR 90000214976	PVD	Charles St	0.0	0.6	0.5	0.1	207	$1.79	$0.52	N/A	FY25	FY26
Carryover FY25	90000235353	Reliability 90000180671 (FY24),MSR 90000226113 (FY25),MSR 90000236076 (FY25),	WSO	Privilege St	0.5	2.1	0.7	1.4	175	$0.69	$2.10	$0.72	FY26	FY27
Carryover FY25	90000237699	MSR 90000236254, FY25	NPV	Tiffany St	0.0	1.5	0.3	1.2	148	$1.52	$0.44	N/A	FY25	FY26
Carryover FY25	90000239843	MSR 90000226113	WSO	Social St	0.0	0.0	0.0	0.0	0	$1.46	$2.54	N/A	FY26	N/A
Carryover FY25	90000235554	MSR 90000235508	WSO	Mitris Blvd	0.3	0.6	0.5	0.1	17	N/A	$0.27	$0.07	FY26	FY27
FY26	WR# 51622485	N/A	WWK	Harrison Ave	0.6	0.6	0.0	0.6	40	N/A	$0.97	$0.24	FY26	FY27
FY27	Future Projects	-	-	-	-	-	-	-	-	-	-	$8.1	-	-
										FY26 Budget	**$9.00**			

Attachment DIV 3-4-2

Attachment DIV 3-4-2 contains critical energy infrastructure information ("CEII").

Prepared by or under the supervision of: Brandon Flynn

Division 3-5

Request:

Please provide the following information regarding the Petty's Avenue Lining Project within the Proactive Main Rehabilitation – Large Diameter Pipe Rehabilitation program,

a. Construction details and timeline for the project.
b. Identify when the costs will be incurred relative to the construction schedule.
c. A detailed site plan for the project.

Response:

a. Pre FY2025: Prior to FY2025, there had been no construction activity relating to the Petteys Avenue lining projects, only initial engineering design and planning.

   FY2025: To date, there has been no construction activity relating to the Petteys Avenue lining projects. For the remainder of FY2025, the plan is to start the lining preparation work which includes relaying the onsite main servicing #550-562 Hartford Avenue (approximately 620 feet of 2 inch 10# PE to be relayed with approximately 620 feet of 2 inch 99# PE and 9 service relays) and relaying and transferring 43 services off of the two mains to be lined (36 inch LP cast iron and 16 inch 10# cast iron) to the existing parallel 12 inch 99# coated steel main in Petteys Avenue. This preparation work is required to allow for the shutdown of the two mains to be lined.

   FY2026: For construction in FY2026, the plan is to complete the lining preparation work slated to start in late FY2025. Engineering design will be finalized for the two lining projects and the materials required for the lining projects will be ordered.

   FY2027: In FY2027, approximately 1,800 feet of 16 inch 10# cast iron and 2,050 feet of 36 inch LP cast iron will be lined.

   FY2028: Final restoration is planned to be completed in FY2028.

b. Pre FY2025: To date, approximately $0.05 million has been spent on preliminary engineering and planning for the Petteys Avenue lining projects.

   FY2025: The lining preparation work to take place in late FY2025 carries an estimated cost of approximately $0.375 million.

   FY2026: The completion of the lining preparation work as well as the ordering of the materials and engineering design costs for the two lining projects to be constructed in

FY2027 carries an estimated cost of approximately $1.80 million ($0.10 million associated with the completion of the lining preparation work and $1.70 million associated with the lining materials and engineering design).

FY2027: The completion of the two lining projects in FY2027 is estimated to cost between $3.50 million and $4.00 million. Please note this is a level 1 estimate. Full engineering design for these projects is expected to be completed in FY2026.

FY2028: The restoration of Petteys Avenue will cost approximately $0.15 million and is expected to be completed in FY2028 after the lining projects are finalized. Please note this is a level 1 estimate.

c. Please refer to Attachment DIV 3-5 for a site plan of the Petteys Avenue lining projects.

Attachment DIV 3-5

Attachment DIV 3-5 contains critical energy infrastructure information ("CEII").

Prepared by or under the supervision of: Corey Hogg

Division 3-6

Request:

Please provide the following information regarding the Replace Pipe on Bridges program:

a. An update on current FY 2025 projects including construction progress and costs;
b. Construction details and estimated costs for each project proposed in the FY 2026 budget; and
c. A site plan for each proposed project.

Response:

a. For FY25, the costs and progress on projects within the Replace Pipe on Bridges program are as follows:

90000218701 - Lonsdale Avenue Bridge in Pawtucket: This was an FY24 project that involved the replacement of 210 feet of 12-inch gas main on the Lonsdale Avenue Bridge, which crosses Interstate 95 in Pawtucket. Work on the project commenced in December 2023. The majority of the project was completed before the close of FY24; however, some tasks, including valve installation, service transfers, and restoration, extended into FY25. The project has now been fully completed. $0.478 million was charged to the FY25 budget under the Replace Pipe on Bridges program.

90000240883 - Manton Avenue Tar Bridge in Providence: The scope of work for this project initially involved the replacement of approximately 50 feet of 12-inch gas main at the Manton Avenue Tar Bridge, which spans the Woonasquatucket River. The design for this replacement was completed, and the proposal was to relocate the gas main to the west side of the bridge. This proposed location required two easements to establish the foundations necessary for supporting the pipe on both sides of the river.

Attempts were made to contact both property owners regarding the easements; however, there was no response to the inquiries. The project cannot proceed as a Replace Pipe on Bridges project without these easements. Although the Company explored the possibility of relocating the gas main to the east side of the bridge, this option was not viable due to the presence of an underground electric duct bank, which left insufficient space to properly tie in the gas main. As a result, the project was redesigned. Rather than replacing the gas main across the bridge, the revised plan involves reinforcing the gas infrastructure around the block from Delaine Street to Valley Street and Westminster Street. This reinforcement work does not fall under the Replace Pipe on Bridges program but will instead be included in another program the FY26 work plan.

Prepared by or under the supervision of: Barry Foster

The total cost for the initial design phase on the Manton Avenue Tar Bridge replacement project, amounts to $0.017 million.

Please see Attachment DIV 3-6-1 for a site plan for this project.

90000219817 - Goat Island Bridge in Newport: This FY25 project involves the replacement of approximately 1,160 feet of 4-inch gas main crossing the Goat Island Bridge, with construction originally anticipated to begin in January 2025. The design has been completed, and materials have been ordered. In October 2024, three construction bids were received, all of which exceeded the Company's estimate. The estimated cost for the contractor was approximately $1 million, while the bids received were $1.35 million, $2.1 million, and $3.45 million. Given the late timing in the fiscal year and the potential for cost overruns beyond the project's budget, the decision was made to defer the project to FY26. To date, the cost incurred for this project in FY25 is $0.041 million, which covers design expenses. The budget for this project increases to $2.6 million for FY26.

Please see Attachment DIV 3-6-2 for a site plan for this project.

90000245040 - Glenbridge Avenue Bridge in Providence: This project was initially targeted for design in FY25 design and construction in FY26/27. The Company has two gas mains installed on a Company owned trestle crossing Woonasquatucket River in Providence, a 36-inch main and a 16-inch main. The trestle is independent from the city owned roadway bridge which is to the east. The trestle spans approximately 200 feet in length and is 32 feet above the water. The Company originally planned to relocate the gas mains and remove the trestle. A new utility bridge was proposed to be constructed approximately 40 feet west of the roadway bridge where two new gas mains would be installed. However, from a construction perspective, the new location presents challenges, particularly in terms of setting up equipment and the need for significant tree trimming. As a result, the Company is currently redesigning the river crossing. The Company has reached out to the City of Providence to explore the possibility of attaching both gas mains to the city-owned roadway bridge. In parallel, the Company is conducting a bridge inspection to assess the structural integrity of the trestle.

Please see Attachment DIV 3-6-3 for a site plan for this project.

90000235779 - Hamlet Avenue Bridge in Woonsocket: This pipe on bridge project is part of the Cumberland Hill Road Reactive Project which also includes two other main replacement projects in the area. The entire project is included in the FY25 workplan and is currently in progress. The planned sequence of work begins with the replacement of the two gas mains, followed by the replacement of pipe on the Hamlet Avenue bridge. The bridge work is subject to specific time constraints. In April 2024, the Company determined there was a risk of not being able to complete the proposed replacement in time to establish gas flow back across the bridge by the next heating season. As a result, the Hamlet Avenue Bridge gas main replacement has been deferred to FY26. This project is budgeted at $1.6 million, with $0.004 million spent in FY25.

Please see Attachment DIV 3-6-4 for a site plan for this project.

b. The construction details and estimated costs for each project proposed in the FY 2026 budget are as follows:

90000245040 - Glenbridge Avenue Bridge in Providence: As noted in part a. above, the Glenbridge Avenue project is currently undergoing redesign. The Company is proposing to relocate the 36-inch and 16-inch gas mains to the city-owned bridge. In parallel, an inspection of the trestle is being conducted to assess its structural integrity. The project is scheduled to span FY26 and FY27, with a total budget of $6.5 million.

Please see Attachment DIV 3-6-3 for a site plan for this project.

90000245155 - River Street Bridge in Woonsocket: This FY26 project involves the replacement of approximately 220 feet of 10-inch gas main over Blackstone River in Woonsocket. A recent bridge inspection revealed corrosion at both abutments. At the same time, RIDOT is going to be rehabilitating the River Street Bridge in Woonsocket, which will include cleaning and painting the superstructure, deck removal and the replacement of sidewalks and expansion joints. The Company will coordinate with RIDOT to replace the gas main while the deck is being removed. The current budget for the River Street Bridge gas main replacement is $1.5 million.

Please see Attachment DIV 3-6-5 for a site plan for this project.

90000245825 - Greystone Avenue bridge in North Providence: Due to RIDOT removing the top decking to the Greystone Avenue Sluiceway Bridge, the Company will relocate the gas main under the river using Horizontal Directional Drill ("HDD") as the method of installation. RIDOT's plan to remove the bridge deck is currently on hold, pending a petition by North Providence and Johnston for bridge replacement. The decision could impact the method of the Company's proposed gas main crossing. If RIDOT proceeds with the bridge replacement, the Company may relocate the gas main back onto the new bridge. However, if RIDOT opts to remove the deck, the gas main will be relocated under the river by HDD. The current project budget is $2 million.

Please see Attachment DIV 3-6-6 for a site plan for this project.

Attachments DIV 3-6 (1 through 6)

Attachments DIV 3-6 (1 through 6) contain critical energy infrastructure information ("CEII").

Prepared by or under the supervision of: Barry Foster

Division 3-7

Request:

Provide a detailed cost summary of all three phases of the Atwells Avenue Main Replacement Project.

Response:

Please refer to Attachment DIV 3-7 for the requested cost summary.

Prepared by or under the supervision of: Corey Hogg

Attachment DIV 3-7

$(millions)

	A	B	C	D	E	F	G	H	I
1	**Section #**	**FY2019**	**FY2020**	**FY2021**	**FY2022**	**FY2023**	**FY2024**	**FY2025***	**Total**
2	**Section 1**	$0.00	$0.32	$5.17	$1.15	$2.75	$0.06	$0.00	$9.45
3	**Section 2**	$0.08	$0.59	$0.50	$0.00	$0.00	$0.00	$0.00	$1.17
4	**Section 3**	$0.00	$0.00	$0.02	$0.01	$0.00	$1.08	$0.86	$1.96
5	**Total**	$0.08	$0.91	$5.69	$1.16	$2.75	$1.14	$0.86	$12.59
6	*FY2025 costs are updated through the end of October								

Division 3-8

Request:

Please update each project under the category "LNG" (FY 2026 Gas ISR Plan Pages 33-34). In your update please include the following information:

a. A description and construction schedule for each project;

b. The total costs of each project; and

c. Identify when the costs for the various Projects have been and/or will be incurred relative to the construction schedule.

Response:

a. Project Description

- **Exeter Tank Switchback Stairs:** Install switchback stair on the LNG tank with compliant handrails and tie off points. The new prefabricated stairs will ensure safe access. Project will undergo design and procurement on long lead time material in FY25 followed by construction in FY26.

- **Cumberland BOG Recovery Manifold:** Install boil off gas ("BOG") recovery manifold to capture BOG gas during cool down of portable LNG storage trailers and normal BOG generated from stored LNG. New manifold will be designed and fabricated to facilitate trailer connections. This initiative supports achievement of the Act on Climate's mandated by reducing emissions and improving sustainability. FY25 will focus on engineering and design, with install planned for FY26.

- **Exeter Emergency Generator Upgrade & Uninterruptible Power Supply ("UPS"):** Install emergency generation and UPS to ensure power reliability. This upgrade will support the additional load from newly installed boil off gas compressors and heat tracing for Hi-Ex Foam impoundment basins that will ensure uninterrupted functionality during power outages and enhancing site reliability. FY25 will focus on engineering and design, with installation planned for FY26.

- **LNG Blanket:** Addresses miscellaneous site needs across all LNG facilities, ensuring ongoing operational reliability and flexibility.

- **Cumberland Boiler Platform:** Construct new platform to provide safer and easier access for boiler maintenance and operations, install is planned for FY26.

- **Cumberland Critical Spares:** Procure and stock critical spare parts to minimize downtime and ensure uninterrupted operations.

- **Exeter Critical Spares:** Procure and stock critical spare parts to minimize downtime and ensure uninterrupted operations.

- **Cumberland Supplemental Portable Storage:** Procurement of additional pump trailers also known as "queens" to enhance LNG storage capacity and provide flexibility for temporary or emergency operations. Procurement in FY25, followed with closing costs in FY26.

- **Cumberland Water Main:** Replace existing water main to address recurring leaks and ensure a reliable water supply for site operations. FY25 will focus on installation and FY26 will support closing costs.

- **Exeter Boiloff Compressor 2 Upgrade:** This project will install two new BOG compressors at the Exeter LNG Plant. The installation of the new compressors will increase the BOG system reliability by having three (3) 50% duty capacity compressors. Engineering and design were completed in FY24, FY25 focused on installation and FY26 spending will be for closing costs.

Division 3-8, page 3

b. and c.

Please see the following table for the total forecasted project spending and the distribution of that spending relative to the project construction schedule.

	A	B	C	D	E	F
1	**Investment Name**	**Total Project Cost (in $M)**	**Prior FY25 Spend (in $M)**	**FY25 Forecast Spend (in $M)**	**FY26 Spend (in $M)**	**FY26 Activity**
2	Exeter Boiloff Compressor 2 Upgrade	$ 11.45	$ 8.56	$ 2.88	$ 0.01	Closing Costs in FY26
3	Cumberland Supplemental Portable Storage/Equipment	$ 13.11	$ 8.46	$ 4.60	$ 0.05	Closing Costs in FY26
4	Exeter Tank Switchback Stairs	$ 2.94	$ 0.04	$ 0.40	$ 2.50	Construction in FY26
5	Cumberland BOG Recovery Manifold	$ 2.61	$ 0.43	$ 0.18	$ 2.00	Construction in FY26
6	Exeter Emergency Generator Upgrade & UPS	$ 1.97	$ -	$ 0.90	$ 1.07	Construction in FY26
7	Cumberland Water Main	$ 0.55	$ 0.10	$ 0.45	$ 0.01	Closing Costs in FY26
8	Cumberland Boiler Platform	$ 0.21	$ -	$ -	$ 0.21	Construction in FY26
10	LNG Blanket	[redacted]	[redacted]	$ 0.51	$ 0.75	Procure in FY26
11	Cumberland Critical Spares	[redacted]	[redacted]	$ 0.41	$ 0.16	Procure in FY26
12	Exeter Critical Spares	[redacted]	[redacted]	$ 0.41	$ 0.16	Procure in FY26

Note: Highlighted projects in the table above are blanket programs with fluctuating yearly budget based on planned work. Therefore, total project cost and prior spend are not applicable to accommodate these variations.

Division 3-9

Request:

Please provide the following information for the "Pressure Regulating Facilities" Work, *i.e.,* construction for 5 to 8 new stations, engineering for 5 future stations, abandonment of one to four stations, and design and engineering for future work at 12 stations:

a. A description and construction schedule for each station Project;

b. The total costs of each Project; and

c. Identify when the major costs for the various Projects have been and/or will be incurred relative to the construction schedule.

Response:

a. Project Descriptions and Construction Schedules

Below is a description of the pressure regulating facilities projects proposed by the Company. For the project schedules, please see column (H) in part c. of this response.

1. **3362 Kingstown Road (North Kingston) -** Installation of a three layer, dual-run prefabricated regulator station to replace the existing station. The inlet pressure is 99 PSIG, and the outlet pressure is 35 PSIG.

2. **Atwood Avenue @ 1401 Plainfield Street (Johnston) -** Installation of a three layer, dual-run prefabricated regulator station to replace the existing station. The inlet pressure is 99 PSIG, and the outlet pressure is 35 PSIG.

3. **New River Road @ Cottage Street (Lincoln) -** Installation of a three layer, dual-run prefabricated regulator station to replace the existing station. The inlet pressure is 99 PSIG, and the outlet pressure is 60 PSIG.

4. **Point Street @ Beacon Avenue (Providence) -** Abandonment of the 99 PSIG to low pressure ("LP") involves the decommissioning and safe removal of all operational components, while adhering to environmental and regulatory compliance standards.

5. **Post Road @ Byron Boulevard (Warwick) -** Abandonment of the 35 PSIG to LP involves the decommissioning and safe removal of all operational components, while adhering to environmental and regulatory compliance standards.

Division 3-9, page 2

6. **Silver Spring Street @ Metcalf Street (Providence) -** Abandonment of the 99 PSIG to LP involves the decommissioning and safe removal of all operational components, while adhering to environmental and regulatory compliance standards.

7. **Weeden Street @ Smithfield Avenue (Pawtucket) -** Installation of a three layer, dual-run prefabricated regulator station to replace the existing station. The inlet pressure is 60 PSIG, and the outlet pressure is LP.

8. **Providence Street @ Toll Gate Road (West Warwick) -** Installation of a three layer, dual-run prefabricated regulator station to replace the existing station. The inlet pressure is 99 PSIG, and the outlet pressure is 35 PSIG.

9. and 10. **Hartford Avenue @ Petteys Avenue (RIS-024.5) LP and Hartford Avenue @ Petteys Avenue (RIS-024.3) (Providence) -** This project involves the consolidation of two stations into a single, dual-run, three-layer prefabricated vault. The new station will reduce pressure from the 99 PSIG system to 10 PSIG. Construction is scheduled to span two years, with installation planned for FY26 and the station to be operation ("gassed in") by FY27. Upon completion RIS-024.5 will be replaced, and RIS-024.3 will be abandoned.

11. **Hartford Avenue @ Petteys Avenue (RIS-024.1) Dey St Line (Providence) -** Installation of a three layer, dual-run prefabricated regulator station to replace the existing station. The inlet pressure is 60 PSIG, and the outlet pressure is LP.

12. **Walcott Avenue @ St. Georges (Middletown) -** This project involves a one-way feed that requires the installation of a temporary pressure regulator station to ensure uninterrupted service during the systems transition from LP customers to HP. The installation will take place FY26, with decommissioning and abandonment anticipated for FY27. Once main installation is completed temporary station and original above ground station will be decommissioned and abandoned respectively.

13. **Future Project Design and Procurement** – This budget allocation provides funding during FY26 for engineering design work and the procurement of long lead materials required for upcoming projects for FY27.

Division 3-9, page 3

b. Total Project Estimates

	A	B	C	D
1	**Station Name**	**Town**	**Project Type**	**Total Cost ($M)**
2	Walcott Ave @ St Georges	MIDDLETOWN	Replacement	$1.00
3	3362 Kingstown Rd (Waites Corner)	NORTH KINGSTOWN	Replacement	$1.20
4	Atwood Ave @ 1401 Plainfield St	JOHNSTON	Replacement	$1.35
5	New River Rd @ Cottage St	LINCOLN	Replacement	$1.10
6	Point St @ Beacon Ave	PROVIDENCE	Abandonment	$0.05
7	Post Rd @ Byron Blvd	WARWICK	Abandonment	$0.05
8	Silver Spring St @ Metcalf St	PROVIDENCE	Abandonment	$0.05
9	Weeden St @ Smithfield Ave	PAWTUCKET	Replacement	$1.20
10	Providence St @ Toll Gate Rd	WEST WARWICK	Replacement	$1.20
11	Hartford Ave @ Petteys Ave (Holder 19) 18" Line	PROVIDENCE	Replacement	$1.20
12	Hartford Ave @ Petteys Ave (Holder 19) Dey St Line	PROVIDENCE	Abandonment	$0.02
13	Hartford Ave @ Petteys Ave (Holder 19) LP	PROVIDENCE	Replacement	$1.20
14	Future Project Design and Procurement	N/A	Design	$0.52

c. Construction Schedule and Costs

	A	B	C	D	E	F	G	H
1	**Station Name**	**Project Type**	**Total Cost ($M)**	**To Date Spend ($M)**	**FY25 Spend ($M)**	**Remaining FY25 Spend ($M)**	**FY26 Spend ($M)**	**Activity**
2	Walcott Ave @ St Georges	Replacement	$1.00	$0.78	$0.023	$0.00	$0.23	Construction of temporary station in FY26
3	3362 Kingstown Rd (Waites Corner)	Replacement	$1.20	$0.08	$0.044	$0.33	$0.79	Construct new station in FY26
4	Atwood Ave @ 1401 Plainfield St	Replacement	$1.35	$0.36	$0.04	$0.31	$0.67	Construct new station in FY26 (pending an easement)
5	New River Rd @ Cottage St	Replacement	$1.10	$0.16	$0.02	$0.02	$0.92	Construct new station in FY26
6	Point St @ Beacon Ave	Abandonment	$0.05	$0.00	$0.00	$0.01	$0.04	Design & decommissioning in FY26
7	Post Rd @ Byron Blvd	Abandonment	$0.05	$0.00	$0.00	$0.01	$0.05	Decommissioning in FY26
8	Silver Spring St @ Metcalf St	Abandonment	$0.05	$0.01	$0.005	$0.00	$0.04	Decommissioning in FY26
9	Weeden St @ Smithfield Ave	Replacement	$1.20	$0.46	$0.01	$0.00	$0.74	Construct new station in FY26
10	Providence St @ Toll Gate Rd	Replacement	$1.20	$0.06	$0.05	$0.30	$0.84	Construct new station in FY26
11	Hartford Ave @ Petteys Ave (Holder 19) 18" Line	Replacement	$1.20	$0.01	$0.01	$0.32	$0.86	Construct new station in FY26
12	Hartford Ave @ Petteys Ave (Holder 19) Dey St Line	Abandonment	$0.02	$0.00	$0.00	$0.00	$0.02	Design in FY26
13	Hartford Ave @ Petteys Ave (Holder 19) LP	Replacement	$1.20	$0.60	$0.03	$0.01	$0.50	Construct new station in FY26
14	Future Project Design and Procurement	Replacement	$0.52	$0.00	$0.00	$0.00	$0.52	Procurement of long lead material and future design in FY 26

Division 3-10

Request:

Please provide the following information for the Scott Road Take Station Project (FY 2026 Gas ISR Plan Bates Page 37):

a. An updated construction schedule for the Project;
b. A description of the Project;
c. Itemize the major costs of the Project;
d. Identify when the major costs for the Project that have been and/or will be incurred relative to the construction schedule; and
e. Explain why total costs for the project have increased from FY 2025 estimate.
f. A site plan of the Project.

Response:

a. Construction Schedule

Fiscal Year (FY) 2025: Construction of the new regulator station was completed, including the installation of a new regulator building with dual runs, and three layers of overpressure protection, a Data and Acquisition ("DAC") building, odorant system, and a new hydronic heating system with redundancy. The station was successfully brought online, addressing issues of high velocity, noise, and vibration while meeting updated regulatory and reliability standards.

FY26: During FY26 the Company will focus on abandoning the old infrastructure, improving site drainage with a storm water management system and completing environmental compliance requirements. Additional work will include fencing, paving, curbing, and landscaping.

b. Project Description

The Scott Road Gate Station, originally built in 1956, featured a dual run setup with two layers of overpressure protection. The station serves 29,040 customers. The project scope involves rebuilding the station with a new regulator building that includes dual run, three layers of over protection, a DAC building, an odorant system, and a new hydronic heating system. The station has a history of high velocity, noise and vibration, pressure inconsistencies and previously lacked three layers of protection. While the heating system is redundant, one of the heaters lacked the latest approved control package. This upgrade addresses the requirement for records that are traceable, verifiable and complete, implements industry best practice of implementing three layers of over protection, and mitigates concerns about asset condition, reliability, and supply delivery.

Division 3-10, page 2

Construction for the rebuild, including installation and gas-in, was completed in FY25. In FY26, the Company will shift its focus to the abandonment of the old infrastructure and the installation of the storm management system to improve site drainage and environmental compliance.

c. Itemized cost of project

	A	B
1	**Category**	**Total Project Forecasted Spend ($M)**
2	Contractors/ Consultants	$ 7.224
3	Materials	$ 3.680
4	Internal Labor	$ 0.795
5	Inspection and oversight	$ 0.330
6	New KM Flow Signal+ KM Oversight	$ 0.235
7	Stormwater Management	$ 2.600
8	Overhead	$ 2.195
9	**Scott Rd Rebuild TOTAL**	**$17.059**

d. Spend Distribution

FY25 Costs: Most of the costs, including mechanical systems, electrical installations, and regulator runs, were incurred during FY25 for the station rebuild and commissioning.

FY26 Costs: Costs associated with site restoration, stormwater management, and abandonment of the old infrastructure will be incurred during FY26.

Project Name	FY25 Activity	FY26 Activity	Total Cost ($M)	Forecasted Spend FY25 ($M)	FY26 Cost ($M)
Scott Rd Rebuild	Construction	Restoration, Abandonment, and Stormwater management install	$17.059	$10.517	$3.524

Division 3-10, page 4

e. Increase of Total Cost

The total costs for the Scott Road Gate Station Rebuild Project have increased from the FY25 estimate due to several factors. Actual contractor costs were significantly higher than estimated. Increased spending on consultants was primarily due to additional preliminary site exploration, design changes, and scope additions. Material costs rose because of design changes including an increase in pipe size (from 12" to 16"), regulator size (6" to 8"), and the three-outlet valve (to 16"). Internal labor requirements were adjusted based on comparable projects like Tiverton. Inspection costs increased due to updated rates for third party welding and non-destructive examination services. A new KM flow signal line was added to accommodate SCADA room requirements identified during project development. Lastly, the inclusion of the stormwater management project to address runoff issues reflects the additional increase in budget. The table below provides an increase in spend breakdown by category.

	A	B	C
1	**Category**	**Initial 2024 Estimate ($M)**	**Current Estimate ($M)**
2	Contractors/ Consultants	$ 3.739	$ 7.224
3	Materials	$ 2.896	$ 3.680
4	Internal Labor	$ 0.584	$ 0.795
5	Inspection and oversight	$ 0.148	$ 0.330
6	New KM Flow Signal + KM Oversight	$ -	$ 0.235
7	Stormwater Management	$ -	$ 2.600
8	Overhead	$ 1.346	$ 2.195
9	**Scott Rd Rebuild TOTAL**	**$ 8.713**	**$17.059**

Prepared by or under the supervision of: Vanessa Valencia

Division 3-10, page 5

f. Project Site Plan

Please note, the figures below contain critical energy infrastructure information ("CEII") and have been produced pursuant to a non-disclosure agreement with the Division. When filed with the Public Utilities Commission, the Company will provide a redacted copy this response and an unredacted confidential version subject to a motion for protective treatment.

Figure 1: Existing Conditions with Proposed Overview

Contains CEII

Division 3-10, page 6

Figure 2: New Station (A) with new inlet piping (C) and new outlet piping (B).

Contains CEII

REDACTED

Division 3-10, page 7

Figure 3: New Inlet Interconnect with Kinder Morgan (C) and Outlet Tie In to Scott Rd (B).

Contains CEII

Division 3-11

Request:

Please provide an updated risk ranking of all 15 take stations discussed on Bates page 35-37. Include stations that materials have been verified and those that are in the scope for retesting and/or replacement of equipment.

Response:

In fiscal year 2025 the Company progressed with station rebuilds at the Laten Knight Take Station and Scott Road Take Station, both of which are now operational, and all materials at these sites are now verified. Previously completed sites include the Crary Street Take Station, Dey Street Take Station (2018), and Tiverton Take Station (2022) where all materials have now been verified. Future planned take station rebuilds include the Putnam Pike Take Station (2026) and the Wampanoag Trail Take Station (2028).

Per 49 CRF 192 at least 50 percent of take station components are required to be verified by FY2029 and 100 percentFY2036. Compliance is measured based on total site footage across all take stations. The Company remains on track to meet this regulatory requirement.

The tables below provide further details:

Table A provides the updated risk raking for all gate stations, reflecting the most recent assessment done in FY2024. The table includes 14 stations instead of 15 stations because the station at Cowesett Avenue is a regulator station, not a take station. It is risk ranked among other regulating stations. However, due to increase in pressure to 200PSIG during its completion, verification of materials was required.

Table B outlines completed, in progress, and scheduled projects and includes the percentage of total footage across all take stations, which amount to a combined 3,173 square feet.

Table C lists the stations that remain to be tested and includes the percentage of total footage across all take stations and outlines the number of components at the remaining stations that still require verification.

Prepared by or under the supervision of: Vanessa Valencia

Division 3-11, page 2

Table A: FY2024 Take Station Risk Ranking

	A	B
1	**Station Name**	**Total Risk Score**
2	**Worst condition (for reference)**	106
3	Westerly TS	30
4	Wampanoag Trail TS	24
5	El Paso (TGT1) 68 Scott Rd	22
6	30 Allens Ave (Manchester St TS)	21
7	Duke (AGT) 4317 Diamond Hill Rd	18
8	Warren Take Station	17
9	67 Laten Knight Rd TS	17
10	374 Putnam Pike TS	17
11	27 Dey St TS	16
12	El Paso (TGT2 116) 600 George W	16
13	135 Old Mill Ln TS	15
14	30 Allens Ave (Crary St TS)	14
15	1084 Wallum Lake Rd TS	14
16	Tiverton TS	13

Division 3-11, page 3

Table B: Project Status Overview for Take Station

	A	B	C	D
1	**Location**	**Material Verification Status**	**Footage**	**% of Total Footage**
2	Crary Street, Providence	Complete - 2017	493	13%
3	Dey Street, East Providence	Complete - 2018	259	7%
4	Cowesett Avenue, West Warwick	Complete – 2022	676	18%
5	Main Road, Tiverton	Complete - 2022	122	3%
6	Laten Knight Road, Cranston	Complete - 2024	241	6%
7	Putnam Pike, Smithfield	Scheduled - 2026	188	5%
8	Scott Road, Cumberland	Complete - 2024	526	14%
9	Wampanoag Trail, East Providence	Scheduled - 2028	177	5%

Division 3-11, page 4

Table C: Take Station Material Verification and Testing Summary

	A	B	C	D	E	F	G
1	**Station Location**	**Total Station Components**	**Components To Review and/or Test**	**Total Footage**	**Footage without Pressure Test**	**Footage to be Tested**	**% of Total Footage Needing Testing**
2	Diamond Hill Road, Cumberland	109	81	197	71	138	4%
3	George Washington Hwy, Lincoln	183	129	445	6	317	8%
4	Manchester Street, Providence	206	206	411	411	411	11%
5	Old Mill Lane, Portsmouth	46	38	89	89	74	2%
6	Wallum Lake Road, Burrillville	20	7	15	0	15	<1%
7	Brown Street, Warren	11	7	10	0	10	<1%
8	Canal Street, Westerly	*N/A – Rhode Island Energy takes ownership at 75 psig / %SMYS at ~ 4.19% assuming Grade A*					

Division 3-12

Request:

How many additional miles of leak prone main abandonment are associated with the additional funding ($9.787 M) for the "Main Replacement (Mandated) – Leak Prone Pipe (PHMSA)"?

Response:

The Company estimates that it will install 4.1 miles and abandon 2.5 miles of additional leak prone pipe for the proposed $9.787M PHMSA budget. Approximately 1.6 additional miles, relating to the initial 4.1 miles, is expected to be abandoned in the following fiscal year.

Prepared by or under the supervision of: Phil LaFond

Division 3-13

Request:

Provide a breakdown by miles of all operating pressures within the Company's distribution system.

Response:

Please see the table below for the requested information.

	(a)	(b)
1	**Pressure**	**Miles of Main**
2	Low Pressure	1,016.36
3	5#	36.94
4	7#	17.86
5	8#	23.7
6	10#	47.29
7	18#	17.99
8	21#	14.73
9	25#	117.23
10	35#	1,134.58
11	55#	76.32
12	60#	340.34
13	75#	1.12
14	99#	368.77
15	200#	9.15
16	350#	0.25
17	750#	0.01
18	975#	0.11

Prepared by or under the supervision of: Corey Hogg

Division 3-14

Request:

The Company's 2022 SIR reveals that as of 2011 yearend, there were 191,690 total services (Bates page 135 of FY 2025 Gas ISR) throughout the distribution system. The 2023 SIR reveals that there are 195,158 total services as of 2023 yearend.

a. Why did the total service count only increase by 3,468 during that same period when the Company's 2022 SIR (Bates page 117 of FY 2025 Gas ISR) reveals that there were 9,153 growth services installed from 2012 through 2016 and the Company's 2023 SIR Bates page 116 reveals that there have been 9,023 growth services installed from 2017 through 2023?

b. In Response to Div 1-14 RIE states that it currently has 205,209 active services. Please reconcile the 205,209 number with the figure in the 2023 SIR that states there are 195,158 total services as of 2023 yearend.

Response:

The Company acknowledges and is aware of the referenced anomalies with its service inventory data. In calendar year 2018, the Company's GIS system was transferred from Smallworld to ArcGIS. On Bates page 135 of the FY2025 Gas Infrastructure, Safety and Reliability plan, the reported total number of services in the Company's system dropped from 197,147 in 2018 to 193,491 in 2019, a difference of approximately 3,650. None of the personnel directly responsible for compiling that dataset is still employed by Rhode Island Energy; however, there are notes within historical files which indicate that the GIS transition was the reason for many data anomalies in 2018 and 2019.

The Company transitioned to a new GIS system in August of 2024 after the end of the Transition Services Agreement with National Grid. Because of this transition, many reporting tools which had existed in the past had to be rebuilt and mapped with the new GIS system. Through the process of rebuilding the service inventory reporting tool used to compile data for both the System Integrity Report and the PMSA F7100 Gas Distribution Annual Report, a data issue was discovered within the GIS and the code of the old reporting tool which appears to have caused many services to be left out of the service inventory.

The Company is actively working to rebuild its service inventory reporting tool for use in developing the 2024 System Integrity Report and PHMSA F7100 Gas Distribution Report. The 205,209 service count submitted in response to data request Division 1-14 was taken from the GIS system and is believed to be accurate based upon what the Company has learned up to this point through the process of rebuilding the service inventory reporting tool.

Prepared by or under the supervision of: Barry Foster

Division 3-14, page 2

On page 54 of the Company's 2023 System Integrity Report, the total number of services in the system as of 2016 is shown to be approximately 196,000, which is prior to the suspected 2018/2019 data issue due to the first GIS transition described above. On page 59 of the Company's 2023 System Integrity Report, the total number of growth services installed between 2017 and 2023 is approximately 9,000. The sum of these two numbers is approximately 205,000 which lends further confidence to the 205,209 number given in response to Division 1-14.

Prepared by or under the supervision of: Barry Foster

Division 3-15

Request:

The Company has stated that it is transitioning to a new software/model for risk ranking its remaining inventory of leak prone pipe.

a. Provide the name and Company that created the software.

b. Give a timeline of implementing the new software.

c. Provide an overview of the software and explain the key inputs that the software evaluates to create a risk score.

Response:

a. The new software is called Lighthouse and is provided by JANA Corporation (JANA).

b. The current estimated timeline to implement the new software is as follows:

  - Calendar Year ("CY") 2024 – The Company worked with JANA to provide asset and historical leak data for the entire distribution system using CY 2023 information. This information was scrubbed to remove as many unknowns as possible, such as missing installation dates, material size, type or operating pressure. This data was run through the Lighthouse application and a draft set of results returned. The Company is currently working to create geospatial maps to visually represent the results.

  - CY 2025 – The Company will provide JANA up to date CY 2024 asset and leak data and JANA will balance the model with the actual results. The rebalanced results will be used to predict future risks.

  - CY 2026 – The Company will evaluate the rebalanced model to determine accuracy and applicability, if appropriate to transition away from Company's on-going practice to follow current risk ranking.

c. The Lighthouse software statistically predicts the probability of future failures for the Company's distribution system assets using all asset information and leak history that is input. The predictive results are divided into potential hazards by Leak Grades 1, 2 and 3 given location, threat and asset type. This information is then used in conjunction with a consequence of failure score based upon Health & Safety, Economic Loss, Regulatory, Environmental and Corporate scenarios to develop a risk score for the asset. All scores are returned as the base risk results for that year, which can used to model various outcomes by implementing risk remediation programs.

Prepared by or under the supervision of: Barry Foster

Division 3-16

Request:

What metrics does the company use to evaluate its progress/effectiveness ($/mi installed, $/mi retired, reduction in leaks per system mile, $/leak reduced/system mile)?

Response:

The Company uses a number of different metrics to evaluate the progress and effectiveness of the Leak Prone Pipe replacement program. As detailed on Page 4 of its annual System Integrity Report, the Company considers Leak Receipts, Leak Receipts Rate, Total Leak Backlog, LPP Main and Service Inventory, Main Leak Repair Rate, Cast Iron Main Break Rate, Unprotected Steel Main Corrosion Leak Rate, and Service Leak Rate. Additionally, the Company tracks the cost per mile of main abandonment for benchmarking and planning purposes.

Prepared by or under the supervision of: Phil LaFond

Division 3-17

Request:

Which of the above metrics does RIE believe give the best representation of the main and service replacement programs accomplishments? Please explain.

Response:

The Company relies upon the quantity, that is miles, of leak prone pipe abandoned as the best indicator of the main and service replacement programs' accomplishments. In 2023, 96.2 percent of all leaks that occurred on the Company's distribution system occurred on leak prone pipe. Because the vast majority of leaks occurred on assets that represent only 29.6 percent of the overall main inventory, it is abundantly clear that best way to reduce leaks, which is ultimately the major purpose of the mains and services replacement program, is to reduce leak prone main.

Prepared by or under the supervision of: Phil LaFond

Division 3-18

Request:

How will high risk mains planned for replacement be ranked if RIE moves to a neighborhood replacement method (will they adopt a hybrid system)?

Response:

The Company is still using its current procedure, ENG04030, for project prioritization as it looks to increase the size of its main replacement projects from smaller scale single street replacements to larger scale "neighborhood" style replacements. The prioritization scores for each project calculated using ENG04030 are based on specific lengths of main, defined as L_{calc} in the procedure and commonly referred to as the leak cluster length. The leak cluster length is the length of main within the project scope displaying the leak activity of greatest concern. The leak cluster length is subject to the judgement of the engineer calculating the prioritization score for each project and can be as great as the total length of leak-prone main being replaced down to a minimum of 500 feet (unless the total project length is less than 500 feet, in which case the leak cluster length can be reduced to match the lesser relay length). The prioritization score calculated for the leak cluster length is then applied to the entire project scope built out around the segment of concern.

While not every segment within a project scope may be exhibiting leak activity, by exercising engineering judgement when selecting additional segments for inclusion in a neighborhood type main replacement, those which are included are typically of the same material and similar vintage and due to being in close geographical proximity are likely subject to the same conditions such as soil type, water table, etc. Additionally, by expanding project scopes, it increases the likelihood that there may be high pressure available in the vicinity of the project to allow for a project scope to include a low-pressure to high-pressure conversion. Along with the elimination of leak-prone pipe, the elimination of low-pressure systems is another risk the Company is actively trying to remediate, so creating projects to address two separate risks at once is advantageous.

By switching to neighborhood style replacements, there will be no changes to the ENG04030 procedure. Segments with high prioritization scores will still be targeted for replacement and scores will still be calculated in the same manner – by selecting a leak cluster length and grouping in other nearby leak-prone pipe segments to create a practical project scope. The change will come in larger project scopes being put together by bundling in a greater number of nearby leak-prone mains with the identified high priority segments than have been in years past.

Prepared by or under the supervision of: Corey Hogg

Division 3-19

Request:

Using a neighborhood replacement methodology, will RIE be using a model to risk rank each neighborhood and if so, what will be the parameters of the model?

Response:

As indicated in the Company's response to data request Division 3-18, the Company still plans to use its current procedure, ENG04030, to prioritize its main replacement projects.

The latest revision of ENG04030 was provided as Attachment DIV 1-17-1.

Division 3-20

Request:

In the current risk model for segment replacements, are weightings used and please provide a list of the characteristics and their current weightings?

Response:

ENG04030 takes into account a variety of factors to produce prioritization scores for segments including:

- Leak History – 10-year lookback
  - Status of Leaks: Open or Previously Repaired
  - Leak Grade: 1, 2A, 2 or 3
  - Type of Leak Repair: Broken Main, Corrosion, Service, Joint repair, etc.
- Location of segment: Nearby Schools/Hospitals, Residential, etc.
- Nearby Public Works Activity: Paving, Road Reconstruction, etc.
- Flood Zone Status
- Size/Pressure Upgrade/Reinforcement

For a more comprehensive overview of the formulas used to calculate the prioritization scores and how all of the aforementioned factors are weighted within those formulas, please refer to the latest revision of ENG04030, provided as Attachment DIV 1-17-1.

Prepared by or under the supervision of: Corey Hogg

Division 3-21

Request:

What would be the anticipated improvement in replacement efficiency if RIE adopted a program of neighborhood replacements except certain circumstances, such City-State Construction, local road repaving, identified threats, major failures, etc.)?

Response:

The efficiencies of adopting a neighborhood replacement approach can be categorized into two groups depending upon whether the project will enable a low to high pressure system upgrade.

All neighborhood replacements offer the following benefits and efficiencies:

1. Safety and Reliability
    a. Replacing mains of the same inventory (i.e., vintage, material and geographic location), of similar risk.
2. Cost
    a. Larger scope of work reduces contractor mobilization cost.
    b. Larger scope of work reduces the numbers of live main connections per project.
    c. Larger scope of work reduces the number of projects, resulting in less administrative work.
3. Minimization of Construction Disturbance
    a. Replacement of all the mains in the area eliminates the need to return to the area in the future.
    b. Minimizing construction disturbance will improve relations with the general public and municipalities.
    c. Larger scope of work reduces the number of projects. As a result, it will decrease the demand on municipalities in terms of review, permitting and approvals.

Division 3-21, page 2

In addition, when possible, projects involving low pressure to high pressure system upgrades will offer the followings additional efficiencies:

1. Safety and Reliability
   a. For systems with pressures higher than 25 PSIG, two layers of pressure protection are added to each customer.

   b. Upgrading low pressure systems to high pressure improves reliability since high pressure systems have line pack. For example, a 2" plastic 99 psig main contains five times the volume of gas within a 100 foot section of pipe when compared to the equivalent length of 2" low pressure main. High pressure systems are equipped to handle flow disruptions during power outages due the line packing.

2. Cost
   a. Upgrading low pressure systems to high pressure allows for the installation of smaller diameter mains which are less expensive and easier to install. This results in a cost reduction for materials and labor, and also a reduction in project duration.

   b. Smaller diameter pipes will have less conflicts with other utilities.

   c. Shorter construction duration will reduce the hours required of police details.

   d. With enough low pressure to high pressure conversations, low pressure regulator stations can be eliminated, resulting in reduced annual maintenance and future replacement cost.

Division 3-22

Request:

Please provide a short narrative of how the proposed PHMSA leak and repair regulation will affect how RIE handles system leaks.

Response:

The proposed PHMSA leak detection and repair ("LDAR") regulations will affect how the Company handles system leaks in four significant ways:

1. The proposed LDAR regulations would increase the frequency of certain required surveillances and set forth new surveillance requirements following events, such as heavy rain or freezing, that might affect gas migration in the ground.
2. The proposal changes how leaks are graded, classifying Grade 1 leaks as any leak that is an existing, probable, or future hazard to persons, property, or the environment. The non-discretionary nature of this proposal will likely result in many more Grade 1 leak discoveries.
3. The required monitoring frequency of non-Grade 1 leaks would be increased from six months to 30 days for Grade 2 leaks and from annually to semi-annually for Grade 3 leaks.
4. Repair due dates for non-Grade 1 leaks are shortened from 12 to six months for Grade 2 leaks and from no repair required to two years for newly discovered leaks, or to five years if the leak will be remedied through a main replacement project.

These rules taken together will increase the amount of time and money the Company must spend on surveillance and monitoring of leaks and would force the Company to consider whether to repair existing Grade 3 leaks or whether the Company could defer a repair through the replacement of the main segments within the required time.

In addition to the changes listed above, PHMSA's proposed LDAR regulations would establish a performance standard requiring operators of gas pipelines subject to regulation under 42 C.F.R. Part 192 to demonstrate, by conducting engineering tests and analyses, that their suite of leak detection equipment, procedures, and analytics are capable of detecting all leaks above a minimum concentration threshold when measured in close proximity to the pipeline. PHMSA proposes to require that leakage surveys be performed using commercially available advanced technology and practices consistent with the proposed performance standard. PHMSA also proposes to require a minimum sensitivity for leak detection equipment used in leakage surveys and leak investigations. This standard is likely to require the Company to purchase new and additional leak detection equipment.

Prepared by or under the supervision of: Phil LaFond

Division 3-23

Request:

What criteria will RIE use to select main segments for proposed abandonment for decarbonization?

Response:

Please see Attachment DIV 3-23, which is the Company's Gas Segment Decommissioning criteria filed on July 24, 2024 in Docket No. 23-49-NG regarding the Company's Fiscal Year 2025 Gas Infrastructure, Safety and Reliability Plan.

Pages 27 to 32 of Attachment DIV 3-23 set forth the gas and electric technical criteria that the Company would employ to evaluate segments of the gas system for decommissioning.

Generally, these criteria are broken down into three categories:

1) Risk Reduction / System Vulnerability
2) Geography
3) Program Integration

If a segment of the gas system satisfies the criteria, the Company's gas engineering group must also evaluate the segment to determine whether it decommissioning is hydraulically feasible so that decommissioning of the segment will not jeopardize reliability.

Prepared by or under the supervision of: Brandon Flynn

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Rhode Island Energy™
a PPL company

July 24, 2024

VIA ELECTRONIC MAIL

Luly Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 23-49-NG – The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed FY 2025 Gas Infrastructure, Safety, and Reliability Plan
<u>Response to Commission's Directive Regarding Gas Segment Decommissioning Criteria</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company"), enclosed is Rhode Island Energy's response to the Public Utilities Commission's ("Commission") directive, from its March 26, 2024 open meeting, that the Company file proposed, "criteria for segment decommissioning that could potentially be used to systematically rank or score segments of the gas distribution system."

To address the Commission's directive, Rhode Island Energy utilized its decarbonization framework and technical expertise to develop an illustrative list of gas and electric technical criteria that could potentially be utilized to rank segments. As an overarching consideration, the Company notes that any potential gas segment decommissioning pilot project must be hydraulically feasible and not jeopardize the safety and reliability of the Company's natural gas and electric distribution systems.

To provide context to the Company's submission, the enclosed PowerPoint presentation begins with an introduction of the proposed technical criteria and a summary of the Company's decarbonization framework, within which the criteria must be evaluated. This framework consists of a three-step process of analysis and learning, piloting of opportunities, and deployment at scale. The presentation slides also present a summary of certain research associated with gas segment decommissioning efforts of other gas distribution companies. Based upon those reported experiences and the Company's knowledge of the characteristics of its gas and electric distribution systems, the presentation (starting on Slide 22) offers a deeper discussion of the set of technical criteria that could potentially be utilized to rank segments.

In addition to the gas and electric technical criteria developed by the Company, any potential gas segment decommissioning pilot project would need to evaluate other critical metrics and factors such as customer and cost implications; equity, regulatory/legislative policy objectives; and economic impacts, as summarized on Slide 4.

Lastly, as proposed on Slide 5 and on Slides 9-13, the Company believes that there is no single technology or implementation strategy that can be relied upon to decarbonize natural gas end uses. Rather, decarbonization will require a portfolio of technologies and implementation strategies, which in addition to gas segment decommissioning, includes but is not limited to: energy efficiency / demand response; renewable natural gas; hydrogen; and integrated planning. The Company proposes to use this decarbonization framework to evaluate each technology and implementation strategy, together with its respective opportunities, challenges, and uncertainties.

The Company appreciates the opportunity to present the technical criteria and decarbonization framework for potential gas segment decommissioning to the Commission for their review and consideration.

Thank you for your attention to this matter. If you have any questions, please contact me at 401-316-7429.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

cc: Docket No. 23-49-NG 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

Heidi J. Seddon

July 24, 2024
Date

Docket No. 23-49-NG- RI Energy's Gas Infrastructure, Safety and Reliability (ISR) Plan 2025 - Service List 2/28/2024

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Decarbonization Framework – Gas Segment Decommissioning

July 24, 2024

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Presentation – Table of Contents

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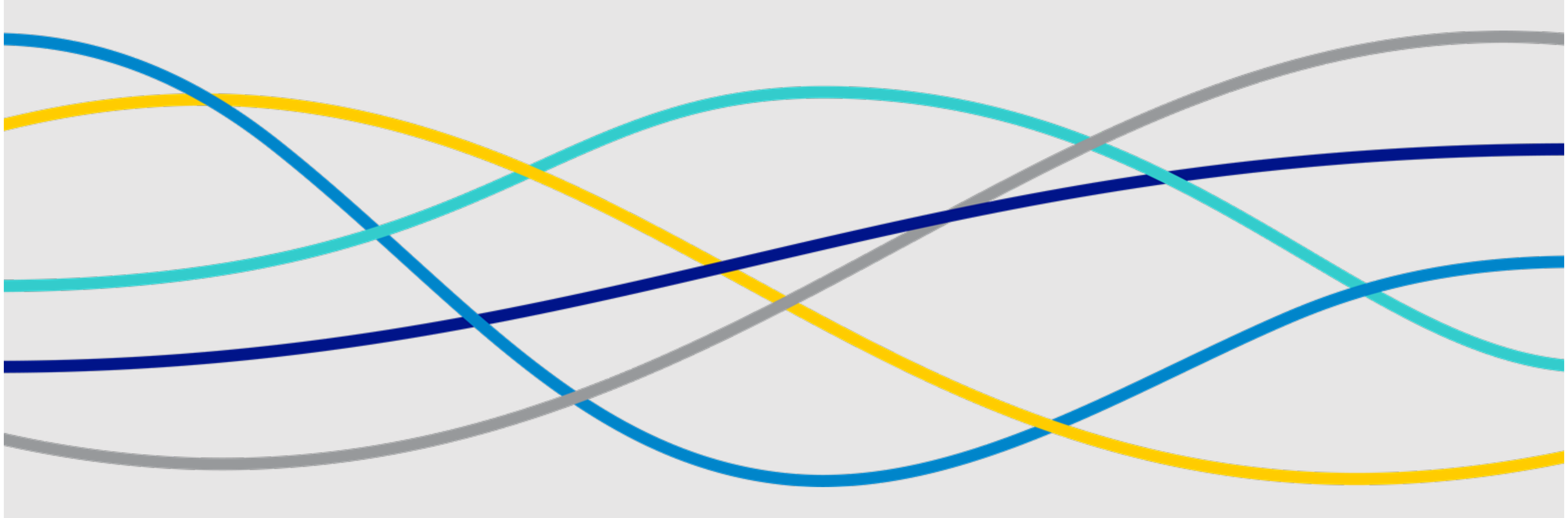

Executive Summary

Introduction

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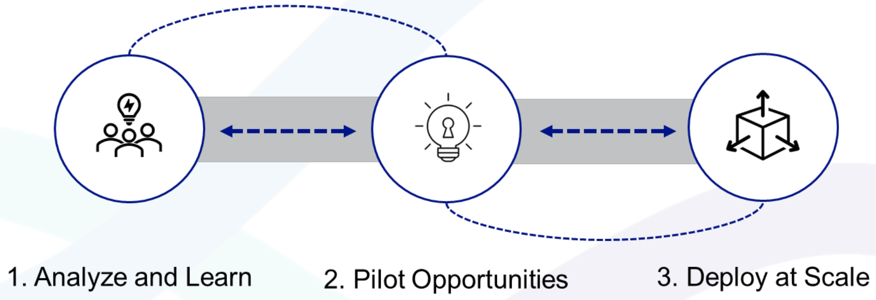
- At its March 26, 2024, Open Meeting in Docket No. 23-49-NG regarding the Rhode Island Energy ("RIE" or the "Company") FY2025 Gas Infrastructure, Safety and Reliability ("ISR") Plan the Public Utilities Commission (the "Commission") directed the Company to propose criteria for segment decommissioning that could potentially be used to systematically rank or score segments of the gas distribution system.
- The Company is submitting this presentation in compliance with the Commission's Open Meeting directive. The proposed criteria, considerations, and concepts presented herein represent an illustrative framework for ranking segments of the natural gas distribution system for potential decommissioning.
- This presentation does not include a broader evaluation of other factors which include, but are not limited to, the following:
  - Customer demographics (e.g., customer type, counts)
  - Customer affordability (e.g., upfront investments and on-going energy costs)
  - Customer gas use (e.g., customer appliances and processes, gas use volume)
  - Regulatory/legislative policy changes (e.g., changes to existing tariffs)
  - Economic impacts of decommissioning a segment
  - Equity (e.g., environmental justice communities)
  - Customer engagement and communication

Background and Context

- RIE is committed to providing safe, reliable, and cost-effective energy to our customers and communities.
- The Company supports and is actively engaged in efforts to assist the state in meeting the carbon reduction targets set forth in Rhode Island’s Act on Climate.
- The Company believes that there is no single technology or implementation strategy that can be relied upon to decarbonize natural gas end uses.
  - Decarbonization will require a portfolio of technologies and implementation strategies (*see table below*).
  - Each technology and implementation strategy has its own set of opportunities, challenges, and uncertainties.
- To assist with the evaluation and review of decarbonization strategies and policies, RIE developed a three-step decarbonization framework:



1. Analyze and Learn
2. Pilot Opportunities
3. Deploy at Scale

Potential Technologies

- EE / Demand Response
- Hybrid Heating
- Renewable Natural Gas
- Hydrogen
- Gas Segment Decommissioning
- Networked Geothermal
- Integrated Planning
- Targeted Electrification
- Carbon Capture

Initial Observations and Next Steps

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- RIE has applied its three-step decarbonization framework to develop a preliminary conceptual approach to evaluating gas segment decommissioning:
  1. Analyze and Learn
     - Because gas segment decommissioning has only been tested in the U.S. on a very limited basis, lessons learned from utilities and customers in other jurisdictions will continue to help inform and refine RIE's approach.
  2. Pilot Opportunities
     - Any potential gas segment decommissioning project must be hydraulically feasible and not jeopardize the safety and reliability of the overall RIE gas and electric systems.
     - RIE has identified preliminary gas and electric technical criteria that can be used to evaluate the feasibility of potential gas segment decommissioning pilot projects (as summarized on slide 7).
     - Evaluation of other critical factors (e.g., customer and cost implications; regulatory/legislative policy objectives; economic impacts; and equity) must be completed, in collaboration with other stakeholders in Rhode Island, to prioritize and proceed with any pilot opportunities.
  3. Deploy at Scale
     - Deployment at scale will depend on timing and results of the prior two steps.
- RIE believes decarbonization will require a portfolio of technologies and implementation strategies and will apply its three-step decarbonization framework to evaluate and review other strategies, including but not limited to: EE / demand response; renewable natural gas; hydrogen; and integrated planning.
- The evaluation and review of decarbonization strategies and policies is an iterative process that will continue to be refined and enhanced as we learn from others and gain experience in Rhode Island.

Gas Segment Decommissioning – Proposed Technical Criteria

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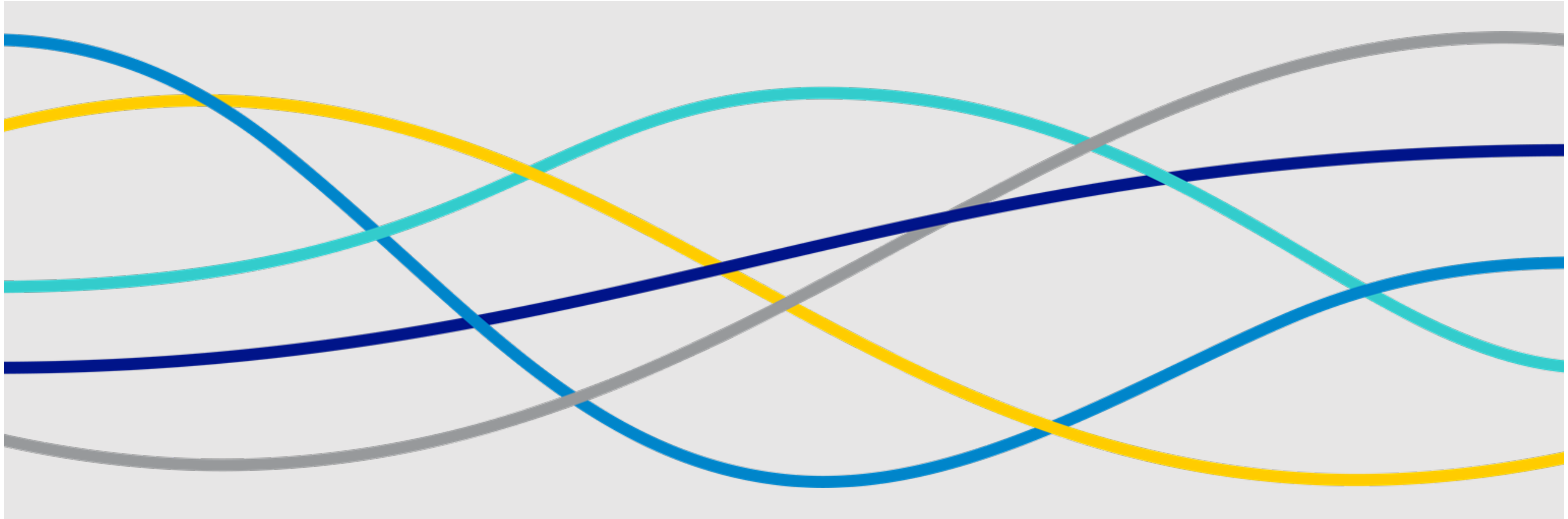
- The Company provides the following preliminary list of gas and electric engineering or operational technical metrics to evaluate the feasibility and risks associated with the potential decommissioning of segments of the gas distribution system.
  - Gas Technical Criteria:
    - Any gas segment decommissioning project must:
      - Be hydraulically feasible; and
      - Not jeopardize the safety and reliability of the overall RIE gas system.
    - Risk Reduction/System Vulnerability Considerations
      - Leak Prone Pipe
      - Low Pressure Systems
      - Capacity Constrained Systems
      - Single Feed Gas Systems
    - Geography Considerations
      - System Extremities
      - Flood Prone Areas
    - Program Integration Considerations
      - Gas ISR
      - On-going Gas Operations
  - Electric Technical Criteria:
    - Any gas segment decommissioning project must:
      - Consider the level and shape of the incremental electric load, as well as the associated timing; and
      - Not jeopardize safety and reliability of the overall RIE electric system.
    - Risk Reduction/System Vulnerability Considerations
      - Scale and Scope
      - Overhead Lines
      - System Design
      - Available Capacity
    - Geography Considerations
      - High Reliability/High Voltage Performance Areas
      - Proximity to Mainline/Substations
    - Program Integration Considerations
      - Electric ISR
      - On-going Electric Operations
- These technical criteria are subject to the considerations and other factors identified herein.



RIE Decarbonization Framework

RIE Guiding Principles

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RIE is committed to assisting the state in achieving the statewide climate mandates, and supporting the Commission's efforts in this endeavor, while ensuring a balanced and affordable transition for Rhode Island households and businesses, communities, and employees. The following long-standing principles will guide RIE's decarbonization framework:

Safety and Reliability

Ensure safe and reliable energy delivery to meet diverse customer needs

Energy Affordability

Provide affordable energy solutions while recognizing our broad range of customer segments

Customer Choice

Preserve customer options and choice for energy equipment

Community Stewardship

Promote Rhode Island economic well-being, sustainability, and corporate citizenship

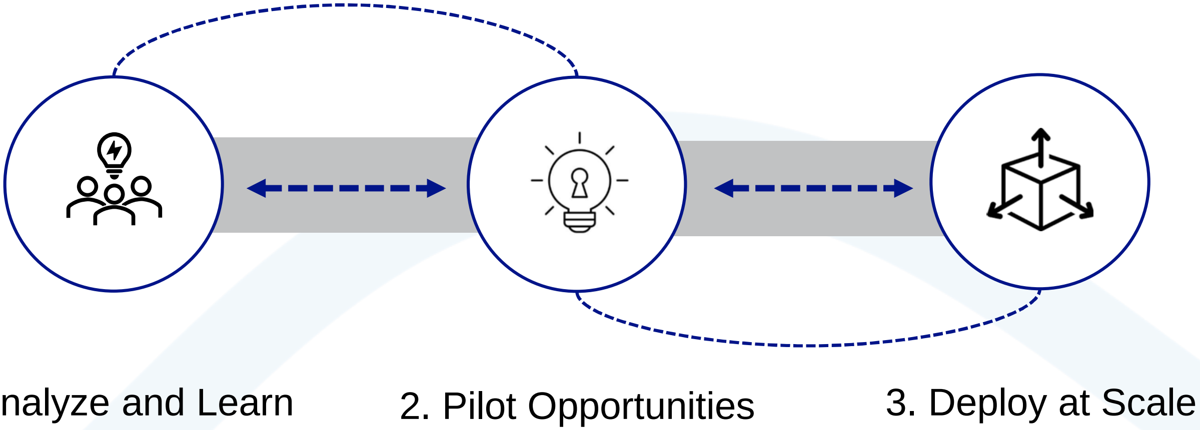
Technology/ Innovation

Leverage technology innovation and maintain option to pivot with technological advances

These guiding principles will enable RIE to support the state's decarbonization transition.

RIE Decarbonization Framework

RIE proposes to use the following three-step decarbonization framework.



1. Analyze and Learn
2. Pilot Opportunities
3. Deploy at Scale

The RIE decarbonization framework is an iterative process that (i) requires revision and establishment of regulatory policies and mechanisms, and (ii) maintains the option to pivot as technologies advance and/or new solutions emerge.

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1. Analyze and Learn – Rhode Island Focused Outcomes

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From Customers and Value Chain Partners (e.g., HVAC contractors)

- Market research – residential, commercial, and industrial
- State demographics, housing stock, employment trends research
- Supply chain bandwidth / Investment requirements

From Other Utilities, including RIE Affiliates

- Decarbonization policies and strategies assessed and implemented
- Metrics and results
- Lessons learned

From Wholesale Suppliers and Alternative Heating Providers (e.g., oil and propane)

- Products and services being marketed or under development
- Decarbonization research and technology investments
- Opportunities to partner / Leverage prior experience

Research and analysis will inform pilot opportunities for Rhode Island.

2. Pilot Opportunities – Rhode Island Focus

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Identify and Prioritize

- Leverage observations and findings from Analyze and Learn phase
- Feasibility/Risk Assessment
    - Natural gas system
    - Electric grid
- Customer Implications
    - Affordability
    - Equity
    - Equipment choice
    - Engagement and communication
- Regulatory/Legislative

Structure and Develop

- Scope and objectives
- Milestones
- Schedule/timeline
- Budget
- Cost recovery
- Rate design
- Reporting requirements
- Roll-out strategy

Pilot and Monitor

- Collect data
- Manage and monitor operational performance of program(s)
- Track progress and performance (carbon savings)
- Anticipated vs. realized costs (capital and O&M)

Evaluate Results and Learn

- Evaluate program and outcomes
- Document and communicate lessons learned regarding:
    - Customer engagement (e.g., communication, education, decision-making, financial impact)
    - Customer implications (e.g., reliability)
    - Infrastructure development
    - Costs
    - Carbon savings
    - Necessary changes and enhancements to the regulatory construct

Results of the pilot opportunities will permit assessment of deployment of programs on a larger scale.

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3. Deploy at Scale

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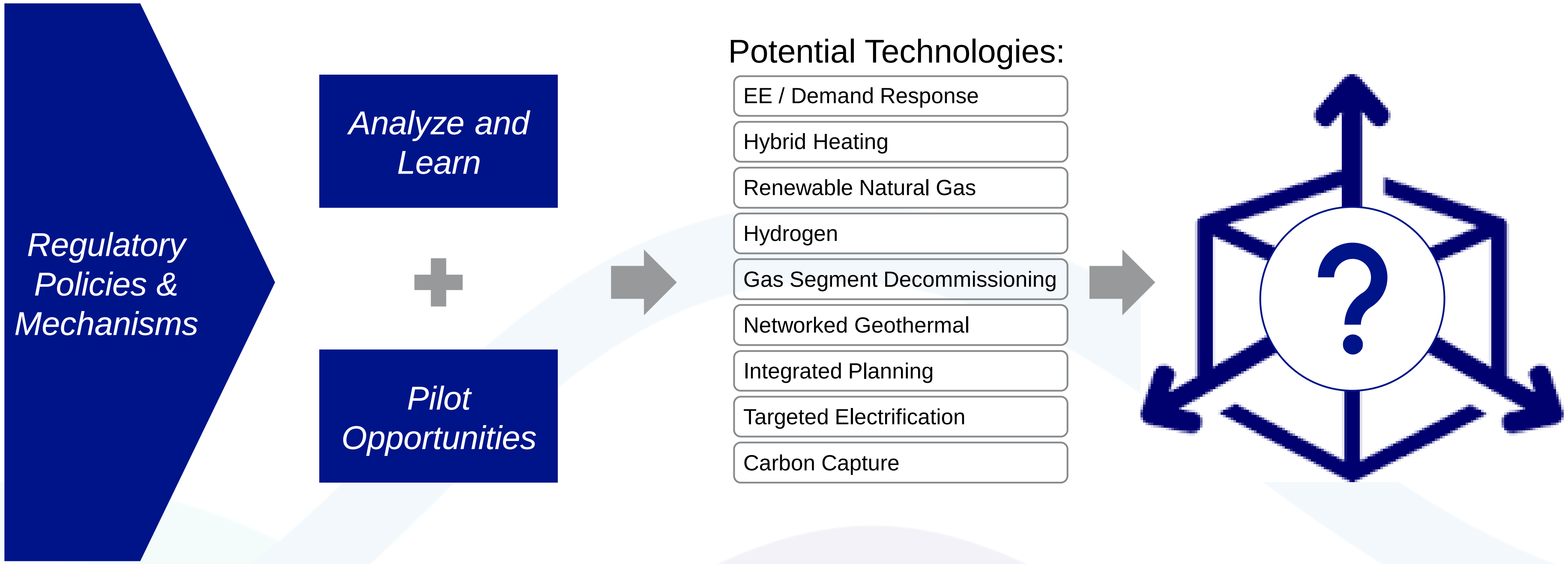

Regulatory Policies & Mechanisms

Analyze and Learn

\+

Pilot Opportunities

Potential Technologies:

- EE / Demand Response
- Hybrid Heating
- Renewable Natural Gas
- Hydrogen
- Gas Segment Decommissioning
- Networked Geothermal
- Integrated Planning
- Targeted Electrification
- Carbon Capture

While continuing to focus on safety, reliability, and affordability, deploy the most effective pilots on a wider scale at appropriate pace to support statewide climate goals.

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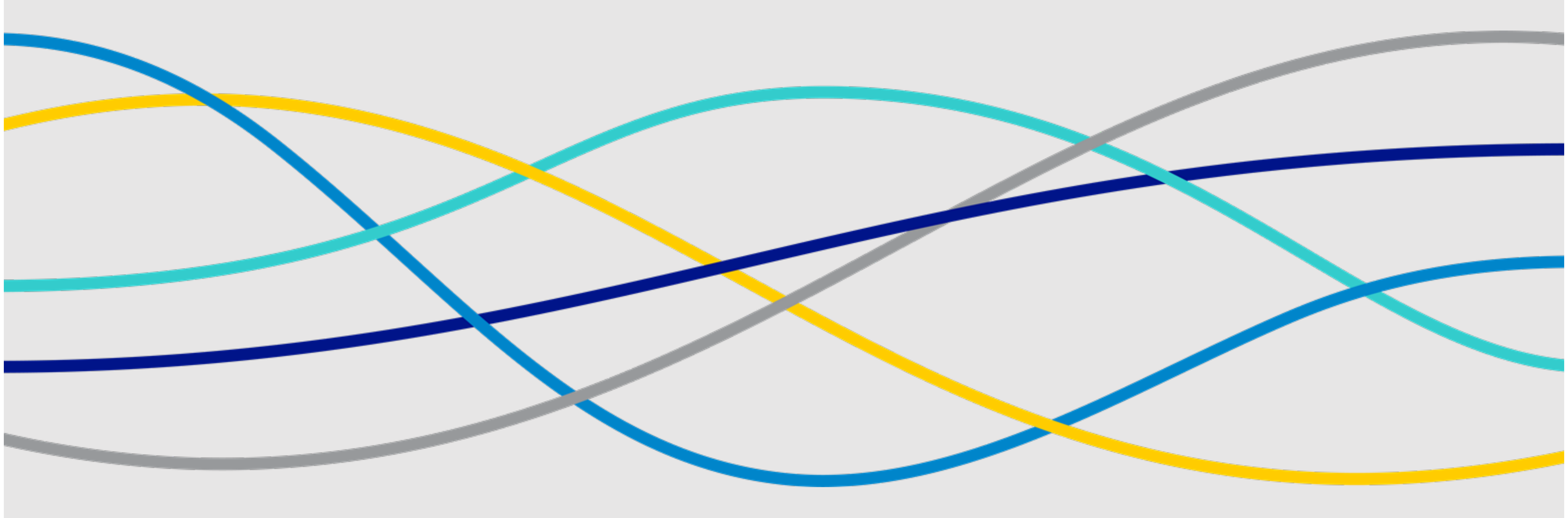

Natural Gas Segment Decommissioning

Working Definition - Gas Segment Decommissioning

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- **Feasibility**
  - Only on those segments of the distribution system where decommissioning would not result in degradation of the Company's ability to provide safe and reliable service.
  - Only on those segments that do not adversely impact costs for existing customers.
- **Customer**
  - Existing gas customers on a shared pipeline segment would be required to change, on a coordinated schedule, their natural gas appliances (heating systems, water heaters, stoves, generators, etc.) and/or natural gas processes to appliances and processes that operate using an alternate energy source, including implementing any needed building retrofits.
  - Subject to Commission approval, once a gas segment is decommissioned, regulated gas tariff service would no longer be available to those customers.
  - Consideration would need to be given to treatment of applications for service on mains targeted for decommissioning. Options include a right to deny service to applicants or to condition service on the applicants' agreement to disconnect from service if needed to facilitate decommissioning.
- **Utility**
  - Once all customers on a particular gas segment perform these conversion activities, the gas distribution system segment would be abandoned in accordance with federal and state regulations.

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Step 1. Analyze and Learn – Gas Segment Decommissioning

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From Customers and Value Chain Partners (e.g., HVAC contractors)

- Market research – residential, commercial, and industrial
- State demographic, housing stock, employment trends research
- Supply chain bandwidth / Investment requirements

From Other Utilities, including RIE Affiliates

- Lessons Learned: National Grid (NY); Pacific Gas & Electric ("PG&E") (CA); Southern California Gas ("SoCalGas") (CA)
- Key Takeaways from Gas Segment Decommissioning Experiences

From Wholesale Suppliers and Alternative Heating Providers (e.g., oil and propane)

- Products and services being marketed or under development
- Decarbonization research and technology investments
- Opportunities to partner / Leverage prior experience

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Lessons Learned: National Grid (NY)

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- National Grid has performed decarbonization analyses on multiple projects, but has only had one successful implementation:
  - In 2022, National Grid identified a project involving 19 homes – each directly served by a connection to gas transmission infrastructure, or “farm tap” – that required new natural gas regulator equipment.
  - Of these 19 customers, five expressed interest but only three moved forward with full electrification.
  - The NPA resulted in the retirement of 586 feet of gas pipe and avoidance of three new regulators.
  - As implemented, the total cost to electrify the three customers was approximately $350,000, which included full electrification with a geothermal heating system installed.

National Grid Key Learnings From Project Analyses

As customer count per segment increases, likelihood of 100 percent adoption rapidly declines

Customers whose appliances are operational and/or recently purchased are not focused on replacement at this time, and are reluctant to accept the disruption associated with equipment replacement

Cost of electrifying is not clear, including utility and operating costs after converting

Lack of trust in incentives and concerns about relying on electric heating in winter.

Source: National Grid, NY DPS C-24-G-0323, Direct Testimony of Gas Infrastructure and Operations Panel, May 2024

Lessons Learned: PG&E (CA)

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PG&E has noted several challenges with targeted electrification and strategic decommissioning:

- **Customers**
  - PG&E's targeted electrification projects have affected fewer than five customers at a time
  - Reflects the challenge of reaching unanimous agreement on electrification
- **Costs**
  - PG&E: "Expense spend needed for electrification must be competitive with capital or expense required for gas project"
  - Average cost per residential conversion was $38,000; average cost per C&I customer was $78,000
- **Funding**
  - Significant funding gap for the upfront costs of electrifying buildings, even after accounting for existing incentives
  - PG&E: "Little flexibility around use of rate case funds. Limited pool of expense dollars that could be used for conversions"

PG&E: Why do customers decline electrification opportunities?

- Affinity with their gas appliances
- Not familiar with alternative energy options
- Concerns with reliability (wildfire concerns)

> ***"Without addressing these barriers, targeted electrification will remain unpredictable, costly, and rare"***
>
> \- PG&E (September 2021)

Source: PG&E's Alternative Energy Program, PG&E Strategy to Retire Gas Infrastructure via Electrification, September 15, 2021

Lessons Learned: PG&E Criteria for Decommissioning

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PG&E provided the following criteria to identify and target segments of the gas system for decommissioning:

Risk Reduction	▪ Includes age of pipe, safety, asset condition, local environmental hazards, and material types
Feasibility	▪ Are customers willing to switch to alternative energy sources? Is the type of customer able to transition to an alternative source? ▪ How many customers and type of customers will be involved in each decommissioning project? ▪ Are there construction or permitting concerns?
Affordability	▪ What are the near- and long-term costs to affected gas and electric customers? ▪ Cost neutrality of the project when compared to non-decommissioning ▪ Correlates to customer density and gas usage
Reliability and Resiliency	▪ Reliability and resiliency of energy system
Geography	▪ Consideration of location of pipe to be decommissioned, in relation to the overall gas system ▪ Tail ends of pipeline systems

Source: CPUC, R.20-01-007, Gas Infrastructure Workshop 2, January 24, 2022, at p. 27

Lessons Learned: SoCalGas Criteria for Decommissioning

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SoCalGas provided the following criteria to identify and target segments of the gas system for decommissioning:

Pipeline Diameter	▪ Areas served by small diameter pipelines are more likely to be viable for decommissioning than areas served by larger diameter pipelines ▪ Large diameter pipelines (e.g., greater than 2”) are typically installed in locations where they support interconnected distribution networks and/or large (and likely difficult-to-electrify) customers
Material and Vintage	▪ Consider the age and material of distribution assets to help identify and prioritize assets with higher risk factors
Pipeline Interconnectedness	▪ Focus on distribution assets that have known, well-bounded, and limited impacts, such as single-feed pipelines with a terminal end serving small residential customers with limited gas end-uses ▪ Focusing on single-feed assets that will limit amount of adverse reliability impacts
Meter Size and Historical Usage	▪ The variety of meter sizes that are served by a distribution asset directly, or indirectly by a dependent distribution asset, is an indicator of the variety and intensity of gas end-uses, and accordingly the complexity of pursuing an alternative to pipeline gas service ▪ Identifying small meters with relatively low usage can be an indicator on the likelihood of simpler and more limited number of gas appliances
Cost Optimization	▪ Prioritize areas of the gas system that are facing high operating and/or safety investment costs relative to customers and demand served
Operating Pressure	▪ Decommissioning should be limited to pipelines operating below 60 psig ▪ While SoCalGas does operate some pipelines categorized as "distribution" that operate above 60 psig, these pipelines generally serve a multitude of customers and/or directly serve large, difficult-to-electrify customers, and would likely not be candidates for NPAs

Source: Joint Opening Comments of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) on Staff Gas Infrastructure Decommissioning Proposal, February 24, 2023

RIE Key Takeaways from Decommissioning Research

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- Gas segment decommissioning has been tested in the U.S. on a very limited basis
    - Small-scale projects in New York and California
- Limited number of customers and facilities
    - No more than five customers
- Significant focus on customer education and communication to support coordinated decision-making
- Requires substantial upfront customer costs
    - On-premises construction, appliance and installation costs
- Non-pipeline solutions must address multiple barriers
    - Obligation to serve, customer preferences for gas end-use equipment, lack of familiarity with non-pipeline solutions, affordability concerns, and aligning gas infrastructure replacement timelines with timelines for a customer’s own equipment turnover
- Requires long lead time and coordination with other tariff requirements
- Requires more focus on integrated gas and electric planning

Step 2. Pilot Opportunities – Gas Segment Decommissioning

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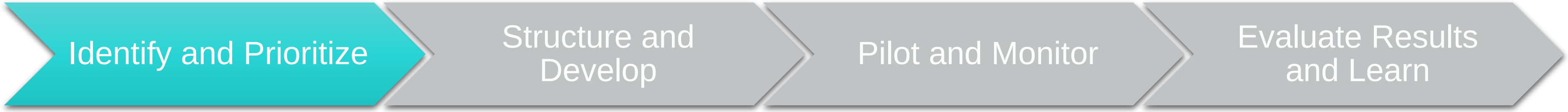
- The Commission directed the Company to propose criteria for segment decommissioning that could potentially be used to systematically rank or score segments of the gas distribution system. To develop the preliminary list of criteria, the Company relied on the learnings from other utilities and RIE's technical expertise.
- The Company identified both gas and electric engineering or operational technical metrics for potential pilot projects.
  - The application of the proposed technical criteria will require close collaboration and planning between the RIE gas and electric teams.
  - Identification of natural gas segments that fit these technical criteria will be a manual and time intensive process.
- These proposed gas and electric technical criteria are just one consideration in developing a pilot program for gas segment decommissioning.
- The identification of gas segments that could be decommissioned as a pilot project will require not only the application of the technical criteria but also a broader evaluation, which will include among other factors: customer demographics and customer cost implications, as well as potential regulatory policy and legislative changes.
  - By way of example, to decommission a segment of main, all customers on that segment need to reach unanimous agreement to exit the gas system on a coordinated schedule.
  - The broader evaluation will require collaboration from other Rhode Island stakeholders.

Step 2. Pilot Opportunities – Gas Technical Criteria



- Leverage observations and findings from Analyze and Learn phase
- **Feasibility/Risk Assessment**
  - **Natural gas system**
  - Electric grid
- Customer Implications
  - Affordability
  - Equity
  - Equipment Choice
  - Engagement and communication
- Regulatory / Legislative

Key Considerations:

- Any potential gas segment decommissioning project must:
  - **Be hydraulically feasible**; and
  - Not jeopardize the **safety and reliability** of the overall RIE gas system.

Technical Criteria to Evaluate Feasibility	Site A	Site B	Site C	Site D	Site E
▪ **Risk Reduction / System Vulnerability** ▪ Leak prone pipe ▪ Low Pressure systems ▪ Capacity Constrained systems ▪ Single feed gas systems					
▪ **Geography** ▪ System extremities ▪ Flood prone areas					
▪ **Program Integration** ▪ Gas ISR ▪ On-going Gas Operations					

Key Elements of RIE's Gas Technical Criteria

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Subject to the key considerations identified on the prior slide (i.e., hydraulically feasibility; and must not jeopardize safety and reliability) the Company outlines the following gas technical criteria:

Risk Reduction / System Vulnerability	Leak Prone Pipe ("LPP")	▪ LPP is one of the highest risk assets on the Company's natural gas system	▪ Focus on material type, leak activity, and condition of distribution assets to prioritize segments ▪ Highest risk LPP should primarily be addressed through continued main replacement due to urgency to abandon
	Low Pressure ("LP") Systems	▪ LP systems do not offer over-pressure protection (regulator) at the meter and are more susceptible to an outage during a temporary low-pressure event	▪ Identify LP system segments, which are susceptible to water infiltration and freezing during extreme cold weather events, to prioritize segments with higher risk factors
	Capacity Constrained Systems	▪ Capacity constrained areas on the system are typically subject to load growth and have undersized infrastructure to support that growth	▪ Consider constraints on the gas system, which may be associated with a service pipe, a segment of main, a regulator station feeding an area/system, or general upstream area with supply issues
	Single Feed Gas Systems	▪ Single feed systems present varying degrees of risk depending on the nature of the single point of failure and the number of customers that could be affected by a potential failure	▪ Prioritize single feed systems based on variables including size, number of customers, regulator station configuration, and other key considerations, including bridge and culvert crossings

Key Elements of RIE's Gas Technical Criteria (cont.)

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Geography	System Extremities	▪ Gas segments that are located at the extremities/tail ends of the Company's gas system	▪ Consider location and interconnectedness of pipe in relation to the overall gas system, particularly LPP at extremities, low points or locations with poor pressure, and dead-end streets to prioritize segments
	Flood Prone Areas	▪ Areas requiring Contingency Plans for storm events and segments at lower elevation points and/or near waterways, which are at risk of water intrusion into the pipe, regulator stations, vents, and general equipment	▪ Identify and prioritize gas segments that are susceptible to losing service due to flood conditions
Program Integration	Gas ISR	▪ Approved Gas ISR investments and associated operational activity will continue to be managed by the Company	▪ Efforts to identify and decommission certain segments of the gas distribution system should complement existing programs within the Gas ISR to ensure a holistic strategy exists that meets the needs of all RIE customers
	On-going Gas Operations	▪ Leak repair, compliance work, station investments and maintenance, and other construction work for safety and reliability will continue to be identified and addressed by the Company	▪ Identify and re-prioritize gas segments to reflect recent work

Step 2. Pilot Opportunities – Electric Technical Criteria

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Identify and Prioritize | Structure and Develop | Pilot and Monitor | Evaluate Results and Learn

- Leverage observations and findings from Analyze and Learn phase
- **Feasibility/Risk Assessment**
  - Natural gas system
  - **Electric grid**
- Customer implications
  - Affordability
  - Equity
  - Equipment Choice
  - Engagement and communication
- Regulatory / Legislative

Key Considerations:

- Any potential gas segment decommissioning project must:
  - **Consider the level and shape of the incremental electric load**, as well as the associated timing; and
  - Not jeopardize **safety and reliability** of the overall RIE electric system.

Technical Criteria to Evaluate Feasibility	Site A	Site B	Site C	Site D	Site E
▪ **Risk Reduction / System Vulnerability** ▪ Scale and Scope ▪ Overhead Lines ▪ System Design ▪ Available Capacity					
▪ **Geography** ▪ High Reliability/High Voltage Performance Areas ▪ Proximity to Mainline/Substations					
▪ **Program Integration** ▪ Electric ISR ▪ On-going Electric Operations					

Key Elements of RIE's Electric Technical Criteria

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While these technical criteria will be adapted, aligned, or broadened to reflect potential gas decommissioning pilot projects, the following is an initial list of criteria that would likely be utilized in addition to the key considerations identified on the prior slide (i.e., incremental electric load requirements; and must not jeopardize safety and reliability):

Risk Reduction / System Vulnerability	Scale and Scope	▪ The scale of any potential project will impact feasibility and reliability considerations, with smaller scale projects likely to encounter fewer technical challenges and larger scale deployments requiring additional considerations	▪ Identify the scale and scope of electrical grid and energy source impacts of any gas segment decommissioning pilot project(s) ▪ Projects that are less than 50 kilowatts are considered smaller in scale and would require more limited analysis
	Overhead Lines	▪ Conversions adjacent to undersized overhead lines are likely to require less time and costs to replace/upgrade vs. underground lines	▪ Identify capacity/size of adjacent overhead lines relative to the potential gas segment decommissioning pilot project(s)
	System Design	▪ Conversions on a radial system area are likely to be less complicated than networked system areas	▪ Identify the design of the electric distribution system relative to the potential gas segment decommissioning pilot project(s)
	Available Capacity	▪ Conversions in a location that is lightly loaded or has high capacity infrastructure will require less infrastructure	▪ Identify capacity availability of adjacent electrical infrastructure (e.g., transformer) relative to potential gas segment decommissioning pilot project(s)

Key Elements of RIE’s Electric Technical Criteria (cont.)

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Geography	High Reliability/ High Voltage Performance Areas	▪ Conversions in these areas increases the probability of long-term success by avoiding areas with other electric system issues that can influence the customers’ overall perception	▪ Identify High Reliability/High Voltage Performance locations relative to the potential gas segment decommissioning pilot project(s)
	Proximity to Mainline/Substations	▪ Conversions within close proximity to Mainline/Substations increases the likelihood that electric system capacity exists and could reduce upgrade costs	▪ Identify Mainline/Substation locations relative to the potential gas segment decommissioning pilot project(s)
Program Integration	Electric ISR	▪ Electric investments associated with gas decommissioning opportunities will be progressed through the typical Electric ISR process	▪ Electric infrastructure investments that are driven by the decommissioning of certain segments of the gas system could complement existing programs within the Electric ISR process
	On-going Electric Operations	▪ Asset replacements/upgrades for safety and reliability will continue to be identified and addressed by the Company	▪ Leverage assets already targeted for replacement/upgrade to create a comprehensive plan to support electrification

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Division 3-24

Request:

Has RIE joined any organizations working on reducing the carbon footprint of their natural gas system, and if so, what were the proposed solutions, and if not, why not?

Response:

The Company is an active member of the American Gas Association ("AGA") and the Northeast Gas Association ("NGA"). Both AGA and NGA are actively engaged in educating and advising its members on advancing practical, near-term solutions and the associated investments for facilitating the continued safe, reliable, and affordable delivery of energy to customers while achieving ambitious decarbonization goals. AGA has performed a comprehensive analysis of multiple pathways that exist to help natural gas distribution utilities reach a net-zero greenhouse gas emissions future. Consistent with the results of the Technical Analysis performed for the "Future of Gas" Docket (Docket No. 22-NG-01) in Rhode Island, AGA has concluded there is no single pathway to net-zero, and planning and implementation must include highly localized factors such as geography, energy demands, resources, and weather.

Examples of the range of emissions reduction strategies for natural gas systems include reducing gas demand, largely through existing and expanded building and appliance efficiency programs; reducing system emissions from methane leaks through improved and advanced leak detection, measurement, and repair and replacement measures; decarbonizing the gas supply through the utilization of biomethane and hydrogen; and leveraging negative or offsetting emission technologies carbon capture and emissions offsets.

For additional information, please see Attachment DIV 3-24, which is a February 2022 study prepared for the AGA by ICF entitled *Net-Zero Emissions Opportunities for Gas Utilities*.

Prepared by or under the supervision of: Lee Gresham

Attachment DIV 3-24

The Company is providing the link associated with this attachment as it is unable to produce a .pdf copy or a paper copy due to permissions applied to this document.

https://www.aga.org/wp-content/uploads/2022/02/aga-net-zero-emissions-opportunities-for-gas-utilities.pdf

Prepared by or under the supervision of: Lee Gresham

Division 3-25

Request:

What new technologies has RIE investigated and piloted to reduce leaks and/or reduce costs for main and service replacements? Please provide a list and narrative on how each one was used and what the outcome was? If none, why?

Response:

The Company is an active member of the American Gas Association and the Northeast Gas Association and works with other member trade partners to stay current on new technologies and techniques that the Company can consider adopting to benefit its ratepayers. The Company is not currently aware of any new technologies for reducing leaks or reducing the cost of main and service replacement.

The Company will continue to look for technological solutions to both of these challenges, but believes that continuing to abandon leak prone pipe and implementing non-technological efficiencies will continue to be the best way to reduce leaks.

Prepared by or under the supervision of: Phil LaFond

Division 3-26

Request:

What additional steps beside doing leak repairs and main and service replacements (including some main abandonment) can RIE do to reduce its carbon footprint and what are the costs and benefits?

Response:

As stated in Rhode Island Energy's response to DIV 3-28, it is the Company's position that no single technology or implementation strategy can currently be leveraged to reliably or cost-effectively decarbonize *natural gas end uses*, and that the most effective approach for reducing greenhouse gas emissions associated with the *natural gas distribution* system is through the continued replacement of leak-prone pipe. As new data emerges and technical and economic uncertainties are reduced, the Company may be in a better position to explore nuances associated with *natural gas distribution* and *end use* decarbonization strategies and deploy the most promising technologies to meet climate targets while remaining primarily focused on safety, reliability, and affordability for all customers.

To advance the effort beyond leak repairs and the replacement of leak prone pipe, the Company has taken the following steps to pursue reducing the carbon footprint of the distribution system:

1. The Company participated in a free demonstration with ULC Technologies, LLC. The demonstration involved the use of a drawdown compressor to transfer natural gas from an isolated section of gas main to an active section of the main. On May 23, 2024, 3,165 SCFG of natural gas was the recovered from 3,600 feet of 16" 10 PSIG gas main in 18 minutes. Past practice has been venting to the atmosphere. In the Spring of 2025, the Company is planning to contract with ULC to perform a similar drawdown 2 miles of 12" 200 PSIG in East Providence. The Company is evaluating purchasing this equipment for future internal use. The estimated cost for this equipment is approximately $215,500.

2. The Company's electric and gas engineering groups have formed an integrated planning team to consider segments of the gas system that could potentially be abandoned with affected customers' equipment converted to electric or alternative energy. The integrated team of engineers is working to identify candidates based on a set of criteria that are provided as Attachment DIV 3-23. The Company does not currently have data to generate cost benefit analysis associated with this effort.

3. The Company is planning to perform a feasibility study in fiscal year 2026 on the potential of a hydrogen blending project within the Company's service territory. The feasibility study will include system review, technology options, potential customer impact, permitting requirements, and cost benefit analysis.

Prepared by or under the supervision of: Laeyeng Hunt

Division 3-27

Request:

What costs and benefits would RIE encounter if it did hydrogen blending of natural gas and what technology hurtles would be encountered?

Response:

The Company does not have a full understanding of the costs and benefits of hydrogen blending within its distribution system for its natural gas customers at this time. Analyses performed in connection with the Public Utilities Commission's Investigation Into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate (Docket No. 22-01-NG) and the Heating Sector Transformation Initiative (Executive Order 19-06) provide a starting point for understanding potential costs and benefits of hydrogen blending in the state.[1] The Company anticipates that some of the identified costs and benefits, to some degree, would be applicable to hydrogen blending in its territory.

The Company will be conducting a hydrogen blending feasibility study in fiscal year 2026. The feasibility study will include system review, technology options, potential customer impact, permitting requirements, and cost benefit analyses.

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[1] *See* E3 Technical Analysis Report submitted April 2024 in Docket No. 22-01-NG; Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050, May 7, 2020, prepared for the Rhode Island Office of Energy Resources and Division of Public Utilities and Carriers, available at https://energy.ri.gov/sites/g/files/xkgbur741/files/documents/HST/RI-HST-Final-Pathways-Report-5-27-20.pdf.

Prepared by or under the supervision of: Laeyeng Hunt

Division 3-28

Request:

In RIE's opinion what is the most cost-effective method to reduce the carbon footprint and/or the amount of greenhouse gases (GHG).

Response:

The most effective approach for reducing greenhouse gas emissions associated with the *natural gas distribution* system itself is through the continued replacement of leak-prone pipe.

It is the Company's opinion, as set forth in greater detail in Attachment DIV 3-28-1,[1] supported by the results of the Technical Analysis[2] performed for the Public Utilities Commission's Investigation Into the Future of the Regulated Gas Distribution Business in Rhode Island in Light of the Act on Climate (Docket No. 22- 01-NG) which is attached as Attachment DIV 3-28-2, that no single technology or implementation strategy can currently be leveraged to reliably or cost-effectively decarbonize *natural gas end uses* incrementally or in totality (on a gross or net basis). Rather, decarbonization will likely require a portfolio of potential technologies and implementation strategies, each with its own set of opportunities, challenges, and uncertainties. Identifying an optimal combination of potential technologies and implementation strategies is not feasible at this time given the limited experience – both in Rhode Island and jurisdictions across the United States – with the decarbonization measures considered in the Technical Analysis.

Nevertheless, the Company recognizes the Technical Analysis provides certain results regarding the relative impact of decarbonization technologies and implementation strategies for *natural gas end uses* that are helpful as a starting point for identifying safe, reliable, and cost-effective decarbonization methods. For example, the Technical Analysis emphasizes that energy efficiency is a critical component of decarbonization across strategy that might be pursued.[3] The Technical Analysis also shows that the Continued Use of Gas scenario – a scenario that includes significant energy efficiency and electrification[4] in addition to biomethane and hydrogen – represents the lowest overall costs for customers regardless of whether they remain on the gas system or choose to migrate to electric technologies. Customer bill impacts for residential,

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[1] Rhode Island Energy Comments on E3's Final Technical Report submitted on August 23, 2024 in Docket No. 22-01-NG.

[2] E3 Technical Analysis Report submitted April 2024 in Docket No. 22-01-NG.

[3] *Id.* at 33.

[4] The Continued Used of Gas scenario assumes 25 percent of buildings convert to all-electric heat pumps and an additional 30 percent of buildings convert to hybrid heating systems.

commercial, and industrial customers, as well as upfront costs, are lowest in the Continued Use of Gas scenario.[5]

The Technical Analysis serves as the initial step in exploring the implications of certain decarbonization pathways for the *natural gas distribution system* and *natural gas end uses*; however, the modeling results cannot be viewed in isolation and need to be augmented with (i) learning opportunities from monitoring industry developments; and (ii) the testing and deployment of a wide variety of innovative resources in Rhode Island. As new data emerges and technical and economic uncertainties are reduced, the Company may be in a better position to explore nuances associated with *natural gas distribution* and *end use* decarbonization strategies and deploy the most promising technologies to meet climate targets while remaining primarily focused on safety, reliability, and affordability for all customers.

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[5] Attachment DIV 3-28-2, at 70 and 93. Figure 40 and Figure 41 illustrate that the Continued Use of Gas scenario results in the most affordable gas delivery rates for residential and large C&I customers. Figure 57 illustrates that upfront costs associated with decarbonization measures are lowest for gas customers.

Lee Gresham
Head of Gas Regulatory Strategy
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280 Melrose Street
Providence, RI 02907

Rhode Island Energy™
a PPL company

August 23, 2024

VIA ELECTRONIC MAIL

Matt Nelson, Principal
Apex Analytics, LCC
2500 30th Street, Suite, 207
Boulder, CO 80301
(508) 964-7264

RE: Docket No. 22-01-NG - Investigation into the Future of the Regulated Gas Distribution Business in Rhode Island In Light of the Act on Climate
Rhode Island Energy Comments on E3's Final Technical Report

Dear Mr. Nelson:

On behalf of Rhode Island Energy,[1] I am writing to submit the Company's comments on E3's Final Technical Report. Should you have questions or need any additional information, please don't hesitate to reach out.

Sincerely,

Lee Gresham

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[1] The Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy" or the "Company").

I. Executive Summary

The Rhode Island Public Utilities Commission (the "Commission") opened Docket No. 22-01-NG ("the Docket") to examine the effect of the Rhode Island Act on Climate (the "Act") on the regulated gas distribution business in Rhode Island. To better understand the implications of the Act on Rhode Island Energy's ("RIE" or the "Company") gas distribution system and its customers, Energy and Environmental Economics, Inc. ("E3") prepared a Technical Analysis Report ("Technical Analysis" or the "Report") that summarized the results and implications of certain decarbonization scenarios.

While the Company appreciates the work done by the Technical Working Group, E3, and Apex Analytics LLC in developing the Technical Analysis scope and E3 with developing the assumptions and associated results, the Company urges caution in interpreting the results of the Report, as those results include assumptions not grounded in empirical data or practical realities. Nor does the modeling approach reflect the wide range of potential outcomes inherent in the magnitude of changes contemplated in the Technical Analysis. Therefore, the Company believes that the report should be viewed as a starting point for future policy development, rather than a definitive guide.

In this context, the Company provides the following observations and comments on the Technical Analysis Report:

Technical Analysis Relies on Important Assumptions that are Illustrative and Unsupported

- **Illustrative Assumptions Lead to an Unrealistically Narrow Range of Potential Outcomes**: Key assumptions, such as customer adoption of deep-shell retrofits, are point estimates that do not consider how a wide range of other outcomes would impact electric peak demands and electric infrastructure requirements. Other key assumptions, such as the heavy reliance of heat pump adoption across all but one scenario, diminish the differentiation in outcomes and overlook alternative technologies or implementation strategies.

- **Illustrative Assumptions are Not Grounded in Practicality or Experience:** The Technical Analysis assumes that up to 50 percent of the pipeline replacements may be avoidable under a "managed" mandated transition. However, this assumption is not based on any practical experience or data and involves the elimination of customer choice and control over equipment decisions.
- **Illustrative Assumptions Do Not Account for Economic, Technical, or Marketplace Realities:** Total resource costs across high electrification and staged electrification scenarios show minimal ranges in costs, with variations of approximately +/- 10 percent despite assuming unprecedented levels of electrification while having little to no practical experience or data.
- **Illustrative Assumptions Do Not Account for Customer Preferences:** The hybrid electrification with delivered fuels backup scenario does not account for significant customer experience complications as well as cost-effectiveness uncertainties.

Technical Analysis has Limited Usefulness for Policy Making Purposes

- **Limited Evaluation of how Regulatory Policies could Address Continued Use of the Gas System:** The assumption that gas customers will face "untenable long-term gas delivery rates" due to customers transitioning to electric heat does not account for any potential reexamination of current cost recovery strategies, such as accelerated depreciation.
- **Limited Evaluation of Safety and Reliability Implications:** The absence of an evaluation of the safety and reliability differences among scenarios raises several concerns and arbitrarily minimizes the reliability benefits of the gas system.
- **Limited Transparency of Benefit-Cost of Specific Decarbonization Strategies**: Scenarios lack transparency on the cost-effectiveness and emissions reduction effectiveness of individual strategies, such as comparing hybrid electrification and full electrification on the basis of cost per carbon reduction. The report also omits a detailed discussion on the

technology costs, customer adoption, and performance of the technologies included in each scenario.

Continued Use of Gas Scenario Supports a Least-Cost, Most-Reliable Path

- **Affordability:** Customer bill impacts for residential, commercial, and industrial customers, as well as upfront costs, are lowest in the Continued Use of Gas scenario under both unmanaged and managed transitions.

The Technical Analysis serves as a starting point to explore the implications of certain decarbonization pathways; however, the modeling results cannot be viewed in isolation and need to be augmented with (i) learning opportunities from monitoring industry developments; and (ii) the testing and deployment of a wide variety of innovative resources in Rhode Island. As new data emerges and technical and economic uncertainties are reduced, the Commission, Company, and stakeholders, may be in a better position to explore nuances associated with natural gas decarbonization strategies and deploy the most promising technologies to meet climate targets while remaining primarily focused on safety, reliability, and affordability for all customers.

Looking forward, there should be more focus on decarbonization strategies that are actionable in the near-term; affordable and practical for Rhode Island's households, businesses, and essential institutions; account for customer choice considerations; ensure safe, reliable, and cost-effective energy delivery; and support economic development and growth in Rhode Island.

II. Introduction

Rhode Island Energy appreciates the opportunity to provide the following comments to the Commission regarding E3's Technical Analysis Report filed with the Commission on May 1, 2024.

In the context of the Rhode Island Act on Climate (the "Act"), the Commission opened the Docket to examine the effect of the Act on the regulated gas distribution business in Rhode Island. The Technical Analysis is one component of a broader scoping document issued by the Commission in Docket No. 22-01-NG.

As the Technical Analysis demonstrates, there is no single technology or implementation strategy that can be relied upon to decarbonize natural gas end uses. Rather, decarbonization will require a portfolio of potential technologies and implementation strategies, each with its own set of opportunities, challenges, and uncertainties. Identifying an optimal combination of potential technologies and implementation strategies is not feasible at this time given the limited experience with the decarbonization measures considered in the Technical Analysis, not only in Rhode Island but also across the Unites States.

As such, the Technical Analysis should be viewed with caution. The Technical Analysis includes decarbonization technologies and implementation strategies that rely on assumptions not grounded in practical realities. Nor does the modeling approach reflect the wide range of potential outcomes inherent in the magnitude of changes contemplated in the Technical Analysis. While the modeling approach should be based on a very wide range of assumptions and potential outcomes to reflect the limited experience with the various assumptions, the Technical Analysis in many cases reflects a very narrow band of assumptions and potential outcomes and thus should be viewed with some caution for future policy development.

Nevertheless, the Company recognizes the Technical Analysis provides certain results regarding the relative impact of decarbonization technologies and implementation strategies that are helpful as a starting point for future policy development. For example, the Technical Analysis shows that the Continued Use of Gas scenario – a scenario that includes significant electrification – represents the lowest overall costs for customers regardless of whether they remain on the gas system or choose to migrate to electric technologies.[2]

To that end, in order to develop policy recommendations, the Commission need not select a particular decarbonization technology or implementation strategy as defined in the Technical Report. Rather, the Commission should continue to focus on safety, reliability, and affordability, while developing an inclusive regulatory framework focused on the public interest that ensures equity and provides fair consideration of the growing availability of current and future technologies capable of meeting the state's clean energy objectives. In addition, t an important next step to inform that objective is to design, develop, fund, and implement pilot programs to better understand the opportunities, challenges, uncertainties, feasibility, and customer implications of potential decarbonization technologies and implementation strategies.

III. Specific Comments on the Technical Analysis Report

A. Model Design Relies on Unsupported and Illustrative Assumptions

Key assumptions in the Technical Analysis often lack grounding in practical experience and data, as none of the decarbonization scenarios represented in the report have been widely tested or implemented at the scale contemplated, and as a result do not adequately account for uncertainties. The limited use of sensitivity analyses for key assumptions diminishes the robustness of scenario results and, therefore, diminishes the Technical Analysis's effectiveness in providing comprehensive modeling results to guide future policy discussion. The Company offers the following observations and comments:

Key Assumptions Lack Grounding in Practical Experience

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[2] The Continued Used of Gas scenario assumes 25 percent of buildings convert to all-electric heat pumps and an additional 30 percent of buildings convert to hybrid heating systems.

Certain key assumptions, such as customer adoption of deep-shell retrofits and shifting electric load from the on-peak to off-peak periods, are point estimates that do not consider how a wide range of other outcomes would impact electric peak demands and the requirement for incremental electric generation, transmission, and distribution infrastructure investment.[3] Other assumptions, such as artificially limiting the supply of biomethane resources available to Rhode Island, are illustrative and unsupported by real-world experience. Utilizing such assumptions in the Technical Analysis narrows the range of potential outcomes while limiting the opportunity to consider alternative solutions to achieving carbon reduction targets.

For example, the Technical Analysis allocates supply of biomethane and renewable diesel to Rhode Island based on the proportion of biomass resources produced in the eastern United States.[4] There is no practical experience or data to show that such an assumption is reasonable. To the contrary, natural gas supplies today are allocated to markets willing and able to pay for the cost of access to and deliverability from natural gas supply markets across North America.

The Company has contracts with interstate pipeline companies that provide access to and deliverability from supply markets throughout the United States and Canada. The contracts provide the Company with access to and deliverability from key natural gas supply markets, such as Texas, Louisiana, and Western Canada.[5] These same contracts provide the Company with access to and deliverability from potential United States and Canadian renewable natural gas ("RNG") supply markets as well.

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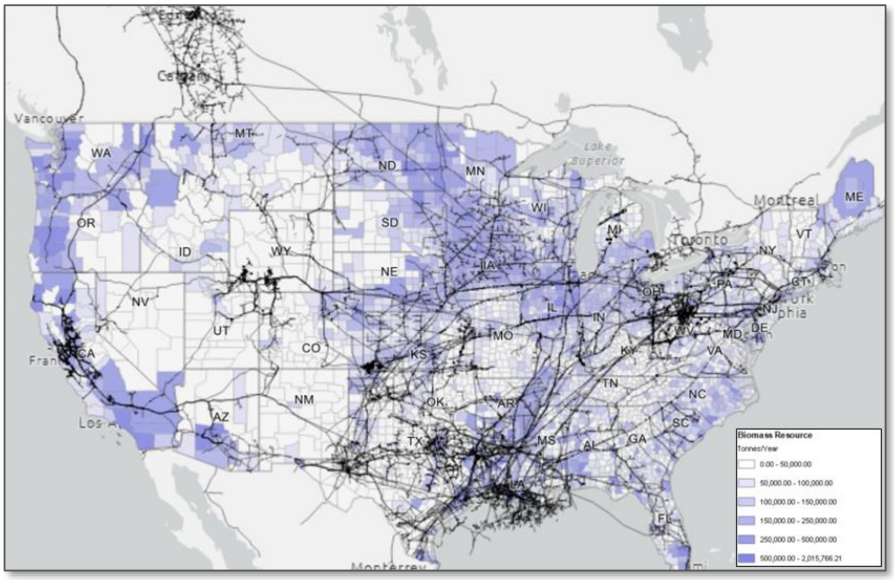
[3] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 33. All decarbonization scenarios assume a nearly 35% adoption of deep-shell retrofits by 2050 in the residential section. Page 75 of the report notes that E3 assumed that 50% of home light-duty vehicle charging, 25% of water heating, and 4% of space heating loads could be avoided during the identified peak load hour.

[4] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 103

[5] S&P Capital IQ. Pipeline companies include but are not limited to Texas Eastern Transmission, Algonquin Gas Transmission, Eastern Gas Transmission and Storage, Tennessee Gas Pipeline Company, Transcontinental Gas Pipe Line Company, Iroquois Gas Transmission System, Portland Natural Gas Transmission System, and TransCanada Mainline

Figure 1 (below) shows the footprint for North American gas pipelines substantially overlaps with the footprint of potential United States RNG supply markets.

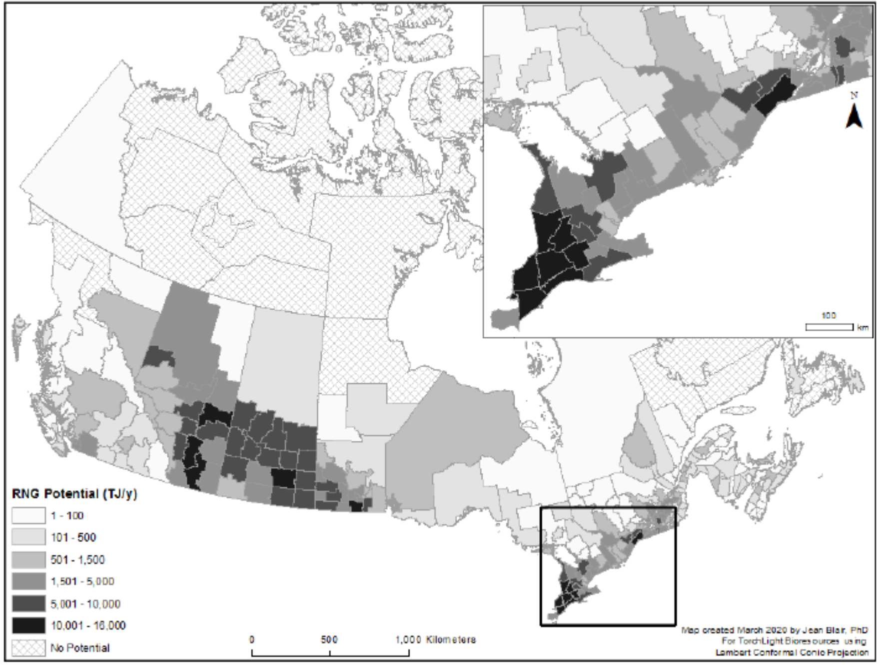
Figure 1: Biomass Resources and Natural Gas Operating Pipelines



Source: S&P Capital IQ

In addition, the North American gas pipelines provide widespread access to and deliverability from potential Canadian RNG supply markets, as shown in Figure 2 (below). Figure 2 shows the footprint for the Canadian gas pipelines in Figure 1 substantially overlaps with the footprint of potential Canadian RNG supply markets.

Figure 2: Total Conventional RNG Production Potential in Canada



Source: TorchLight Bioresources, RNG Feedstock Potential in Canada, 2020, at p.30

The Company's access to and deliverability from RNG supply market can be expanded. The Company's contracts with interstate pipelines provide access via interconnections to other interstate pipelines including those that have access to and deliverability from additional potential RNG supply markets.

For example, one of the interstate pipelines with which the Company contracts, Texas Eastern Transmission L.P., has an interconnection with Rockies Express Pipeline LLC, which provides access to and deliverability from markets in Kansas, Nebraska, and Illinois – states with high concentrations of biomass feedstocks.[6] Expanded access to and deliverability from potential United States and Canadian RNG supply markets provides the Company and Rhode Island's homes and businesses the opportunity to seek additional RNG supply resources at potentially lower costs to meet Rhode Island's climate goals.

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[6] E3, TWG Meeting #4: Renewable Gas Modeling, November 1. 2023. Slide 14

Managed Transition Costs Are Unsupported and Illustrative

The Technical Analysis relies on an assumption that up to 50 percent of the pipeline replacements may be avoidable under managed transition.[7] This assumption is not based on any practical experience or data – it is merely conjecture.[8] In order for managed transition projects to be successful, 100 percent of affected customers need to transition all gas heating equipment and appliances to electric end-uses. In practice, the challenge of persuading groups of customers to reach unanimous agreement on electrification has limited the participation and impact of managed transition approaches.[9] In fact, no utility in the United States has successfully implemented a managed transition with greater than five customers.[10]

In addition, the Technical Analysis relies on an assumption that operation and maintenance costs on the gas system could be reduced by nearly 35 percent by 2050 under managed transition.[11] Again, the assumption is not based on any practical experience or data. Consequently, the Technical Analysis results have limited usefulness in guiding the upcoming policy discussion. Notably, the assumptions do not fully consider the implications on the safety and reliability of the distribution system, such as the loss of secondary feeds.

Moreover, managed transition results in no meaningful difference in residential customer delivery rates, as shown in Figure 3 (below).

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[7] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 11. The Continued Use of Gas Scenario under a managed transition is equivalent to the reference case.

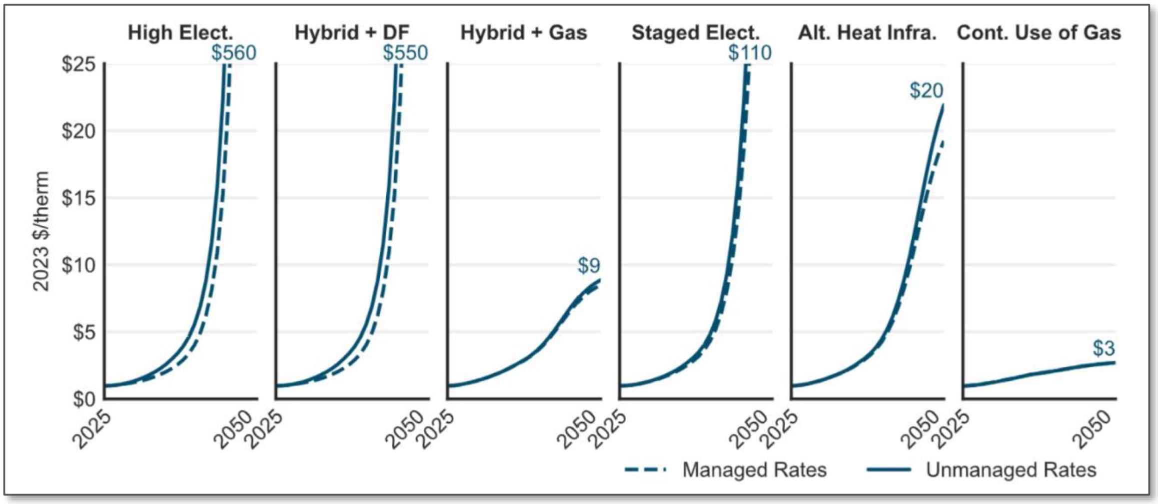
[8] See p. 67-68 of Technical Analysis Report. E3 states that pilot projects are beginning in several jurisdictions to assess the potential benefits of a managed transition for utilities and customers, but these are currently limited in scope and scale. E3 then states that there is limited data and examples of the costs and benefits of managed transition projects.

[9] Consolidated Edison Company of New York, NY DPS Docket No. 19-00318, NPA Annual Report 2023, filed November 17, 2023; Pacific Gas & Electric; RMI-National Grid Research: Emerging Opportunities in Planning for U.S. Gas System Decarbonization, May 2024, at p. 11, RMI - National Grid: NPA Report

[10] PSC of District Columbia, Case No. 1175, Order No. 22003, filed June 12, 2024, at p. 17

11 E3, Presentation on Technical Analysis Report, April 25, 2024, Slide 17

Figure 3: Residential Delivery Rates Under Unmanaged and Managed Transitions

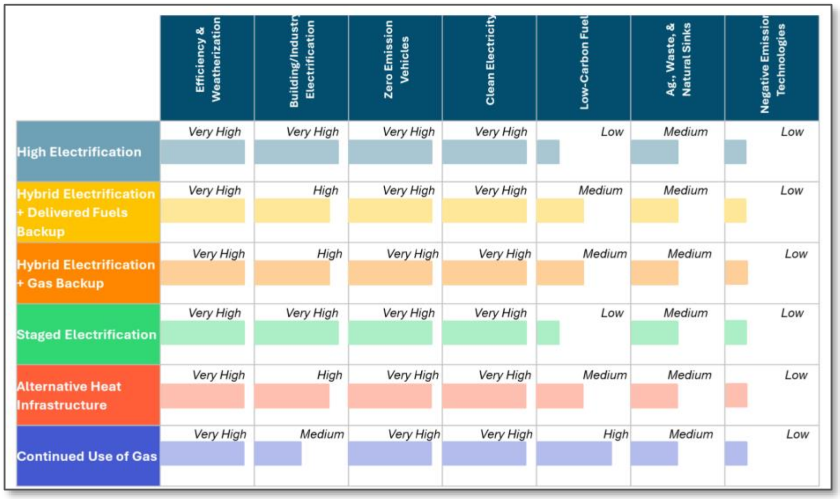


Source: E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 70

<u>Scenario Parameters Are Not Distinctive</u>

The Technical Analysis reflects decarbonization scenarios or pathways that have few distinguishing parameters, leading to limited differentiation of outcomes, as shown in Figure 4 (below).

Figure 4: Overview of Scenario Parameters



	Efficiency & Weatherization	Building/Industr Electrification	Zero Emission Vehicles	Clean Electricity	Low-Carbon Fuel	Ag., Waste, & Natural Sinks	Negative Emissio Technologies
High Electrification	Very High	Very High	Very High	Very High	Low	Medium	Low
Hybrid Electrification + Delivered Fuels Backup	Very High	High	Very High	Very High	Medium	Medium	Low
Hybrid Electrification + Gas Backup	Very High	High	Very High	Very High	Medium	Medium	Low
Staged Electrification	Very High	Very High	Very High	Very High	Low	Medium	Low
Alternative Heat Infrastructure	Very High	High	Very High	Very High	Medium	Medium	Low
Continued Use of Gas	Very High	Medium	Very High	Very High	High	Medium	Low

Source: E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 33

The Figure shows decarbonization scenarios as employing similar technologies and implementation strategies. For example, Figure 4 shows the Technical Analysis relies heavily on heat pump installations across all but one scenario, demonstrating significant commonality in the scenarios.[12] The heavy reliance on heat pumps not only diminishes the differentiation in outcomes but also overlooks alternative technologies or implementation strategies that could contribute to a more diverse and resilient approach to decarbonization, such as carbon capture. Exploring a wider range of technologies and implementation strategies could have provided a more robust evaluation of potential pathways for achieving gas decarbonization.

Sensitivity Analyses Do Not Reflect Significant Uncertainty in Electrification Scenarios

The cost ranges presented in the high electrification and staged electrification scenarios do not reflect the significant uncertainties in costs with respect to renewable energy generation, investments in the electric system needed to achieve these levels of electrification, the required capital expenditures for electrification end-use equipment, and the incremental operating costs

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[12] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 48

of the electric end-use equipment. As shown in Figure 5 (below), the total resource costs across high electrification and staged electrification scenarios show minimal ranges in costs, with variations of approximately +/- 10 percent despite the scenarios having little to no practical experience or data.[13]

The limited variability in cost ranges is particularly concerning given the unprecedented scale of electrification assumed within the scenarios. These assumptions hinge on the concurrent execution of decarbonization policies throughout the ISO New England region,[14] coupled with substantial investments in transmission and distribution infrastructure.[15] The impact of these multiple demands for new intermittent energy supply, and the resulting impact on the availability, resource adequacy, and intermittency of the energy supply to meet both peak and baseload requirements, are not considered in the Technical Analysis. Further, permitting, construction, and material costs present significant challenges – cost and otherwise – to the electrification buildout that are simply not adequately reflected in the report.

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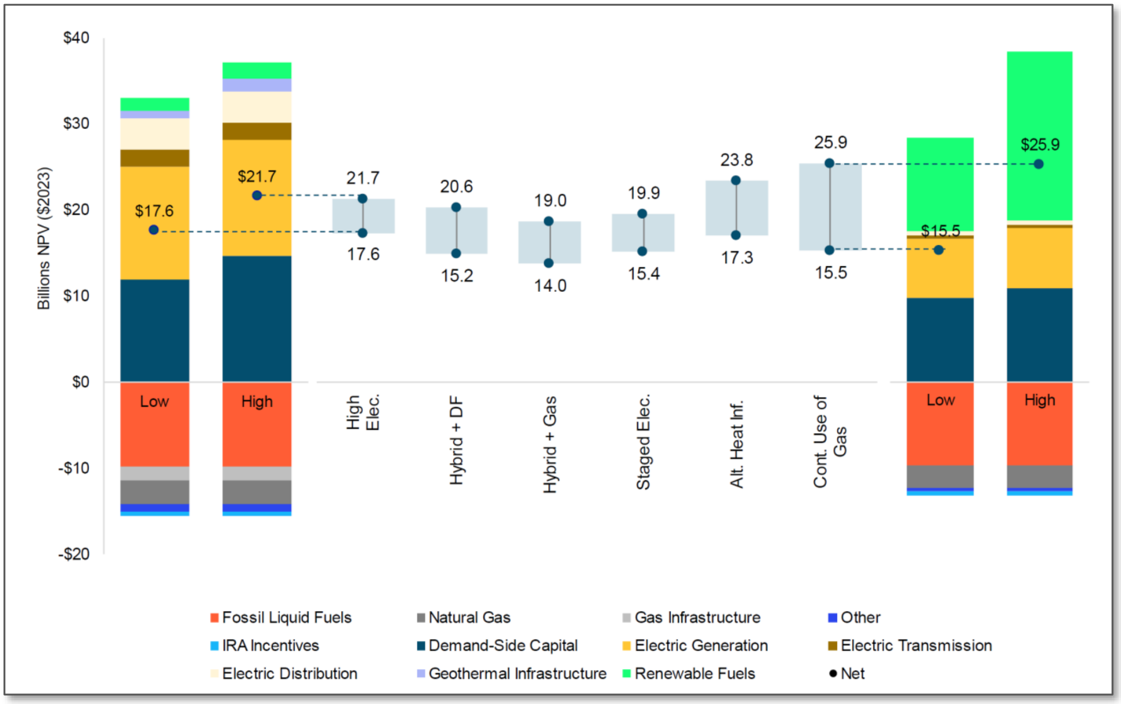
[13] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 80 & 83
[14] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 102
[15] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 107-108

Figure 5: Total Resource Cost Range for High Electrification and Continued Use of Gas



Source: E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 83

Electrification scenarios face significant economic and technical challenges that are not reflected in the range of cost assumptions in Technical Analysis. For example, multiple United States East Coast offshore wind projects have been cancelled or delayed due to financing challenges, with the total cost of an offshore wind project increasing by more than 30 percent over the past two years.[16] National Fuel in New York withdrew its application for a networked geothermal pilot due to issues related to cost, program participation, and technical constraints.[17] Additionally, the

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[16] S&P Capital IQ, Demand for US East Coast offshore wind remains despite gust of disruptions, January 30, 2024

[17] New York DPS, Docket C-23-G-0627, Direct Testimony Of Energy Services & Sustainability Panel, October 31, 2023, at p. 32

construction budget for Eversource's networked geothermal pilot in Massachusetts has increased 84 percent from its original estimate.[18]

Further, while the Technical Analysis assumes Rhode Island achieves carbon neutrality in the electric grid, there is no sensitivity analysis performed to measure the impact of not achieving this assumption – or achieving it, but at much higher costs.[19] The generation and transmission systems serving Rhode Island also serve adjacent markets, which have similar decarbonization goals. The impact of these aggregate demands for new intermittent energy supply, storage of this intermittent energy supply to meet both peak and baseload requirements, and the resulting impact on power prices have not been sufficiently evaluated. Achieving carbon neutrality in the electric grid will require unprecedented regional activity to build renewable generation and transmission on the scale needed to meet decarbonization goals. The Technical Analysis assumes that carbon neutrality will be met by 2033 but does not evaluate the aggregate implications across the region.

The uncertainty of electric space heating demand on the distribution system has not been sufficiently evaluated either, as shown in Figure 6 (below). The Figure summarizes Puget Sound (Washington) Energy's heat pump load analysis and shows that as temperatures fall, standard heat pumps supplemented with backup electric resistance heating can lead to both substantial increases and variability in power demand. The uncertainty associated with peak demand impacts on the distribution system highlights the need for assumptions that reflect a broader cost range.

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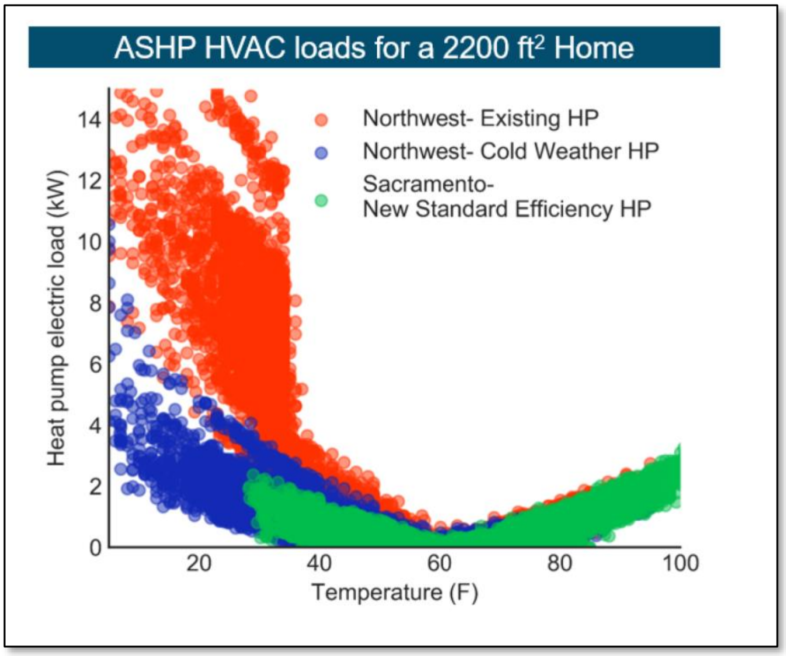
[18] Eversource Energy – D.P.U. 21-53 Phase II Quarterly Report (filed May 27, 2022) presented 2020 Updated Filing Total Project Cost of $10,562,000. Eversource Energy Geothermal Demonstration Project March 2024 Progress Report presented updated Total Project Cost of $19,480,900.

[19] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 45

Figure 6: Puget Sound Energy Heat Pump Load Analysis



Source: WA UTC, D-UG-220067, Exh. JJJ-1T, p. 44

Given the absence of sensitivity parameters related to renewable energy development and electrical grid infrastructure costs to potentially meet new and variable peak demand requirements driven by the electrification of space heating, transportation, and other residential and commercial end uses, any long-term cost comparisons to natural gas heating system costs cannot reasonably inform policy decisions.[20]

Cost Range for Delivered Fuels Backup Scenario Does Not Reflect Uncertainties

Hybrid electrification with delivered fuels backup involves a two-step process where existing gas customers must first transition to delivered fuels before eventually converting to whole-home electric heating. This approach introduces significant customer experience complications and

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[20] Table 6 of the E3 Technical Analysis Report does not include any sensitivities associated with renewable electric generation, transmission, or distribution

cost-effectiveness uncertainties, which should be reflected in a broader range of costs. However, the current projections do not adequately account for these complexities (i.e., removal and installation of multiple heating systems), potentially underestimating the financial and logistical challenges involved.

Further, alternative fuels are not subject to the same regulation by the Commission as natural gas. As a result, the same protections and benefits associated with regulated natural gas service, including the requirements for safe and reliable service, tariff rules for how the Company may charge customers for their gas distribution service, and other customer protections (such as those for income-eligible customers and protected classes), do not apply to propane or fuel oil providers, thus, potentially exposing customers converting to these alternative fuels to higher costs and less reliable service. The absence of regulated protections in this two-step process, in which existing gas customers first transition to delivered fuels before eventually converting to electric heating, could also lead to increased customer dissatisfaction and resistance, further complicating the shift to electrification.

B. Scenarios and Simplifying Assumptions Limit the Credibility and Usefulness of This Study for Policy Making Purposes

The decarbonization scenarios rely on simplifying assumptions that create concerns regarding the safety and reliability of the gas system. The Company offers the following observations and comments:

Gas Affordability Is Negatively Impacted by Regulatory Assumptions

The Technical Analysis notes that under the current regulatory framework, gas customers will face “untenable long-term gas delivery rates” as a result of customers transitioning to electric heat.[21] However, this outcome is a function of the regulatory assumptions within the model and

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[21] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 110

does not account for any potential reexamination of current cost recovery strategies, such as accelerated depreciation.

Understanding how costs associated with decarbonization could be addressed is an unresolved issue that must be further explored. For example, cost allocation methodologies could evolve, and gas transition costs could be recovered from sources beyond gas customers, such as electric customers who will benefit from increased electric load.

For example, in a recent Colorado demand-side management proceeding, the Colorado Public Utilities Commission adopted Public Service's proposal to allocate costs 50/50 to the electric and natural gas utilities for measures and programs that seek to electrify existing natural gas end-uses.[22]

Scenarios Do Not Capture Full Safety and Reliability Impacts

The Technical Analysis states that each scenario is modeled to ensure a safe and reliable energy system per existing gas and electric standards and thus safety and reliability are not evaluated as criteria that differ between scenarios raises several concerns.[23] First, there are inherent differences in reliability levels between gas and electric systems that merit consideration, particularly given that essential customer heating requirements will rely on the electric system under the electrification scenarios. Second, the transition to renewable generation is only beginning, raising potential concerns that are not yet well understood. Third, the Technical Analysis's modeling of a "managed" transition, which includes reduced pipeline replacement and lower O&M costs, introduces additional safety and reliability uncertainties. Lastly, existing electric reliability standards have not been designed or evaluated in the context of the electric grid serving most transportation and space heating needs. These measures could negatively impact the reliability of the overall energy system (i.e., increasing concentration risk by reducing resource diversity as significantly more end-use applications are electrified), complicating the

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[22] Proceeding No. 22A-0309EG, Decision No. C23-0413 ¶ 213.

[23] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 39

assurance of a safe and dependable energy supply during a time in which consumers may depend more heavily on the electric system for space heating and transportation needs.

The absence of an evaluation of the safety and reliability differences between scenarios minimizes the research findings in the Technical Analysis. In its Literature Review for Puget Sound, the Technical Analysis notes that studies investigating natural gas decarbonization commonly show that gas can be particularly important in supporting electric reliability and delivering heat during cold-snaps.[24] Further, in its initial Rhode Island Stakeholder Meeting presentation, the Technical Analysis notes that a potential advantage of renewable gas relative to other decarbonization pathways is its reliability.[25] Recognition of the reliability impacts of the gas system and then the failure to incorporate such considerations into the scenario modeling calls into question the comparability of reliability standards across scenarios.

Scenario Limitations

The Technical Analysis models six scenarios that each contain a combination of decarbonization strategies and technologies.[26] While the scenarios provide a starting point to broadly understand the magnitude of decarbonization costs, the scenarios do not provide transparency into the cost-effectiveness and emissions reduction effectiveness of individual strategies, such as comparing hybrid electrification and full electrification on the basis of cost per carbon reduction. Further, the report does not include a detailed discussion on the technology costs, customer adoption, and performance of the technologies included in each scenario.

The use of scenarios based on combinations of technologies offers little transparency on practical, near-term actions the Company can take to support Rhode Island's climate goals.

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[24] E3, Puget Sound Energy GRC Settlement Study: Regional Context, Literature Review (Updated DRAFT), June 2023, Slide 8

[25] E3, Introduction to Modeling Decarbonization Scenarios, Rhode Island Future of Gas – Stakeholder Meeting, May 30, 2023, Slide 21

[26] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 4

Further, the scenarios leave unanswered many questions regarding individual decarbonization strategies, such as:

- Where have decarbonization strategies been pursued or implemented? Are those jurisdictions similar to Rhode Island in relevant demographics, winter heating requirements, industrial base, housing inventory, and energy growth?
- What has been the effectiveness of those decarbonization strategies in supporting climate goals?
- What have been the impacts of those decarbonization strategies on customers (residential, commercial, and industrial), the utility workforce, and economic development?
- Have there been unintended consequences resulting from the pursuit or implementation of such decarbonization strategies?

A more transparent and effective approach would be to learn from pilot programs underway across North America – and in particular those regions similar to Rhode Island – as well as to launch targeted pilot programs in Rhode Island. The pilot programs would be evaluated over a range of weather and operating conditions to assess safety and reliability of service, the customer experience, emissions reductions, cost-effectiveness, and potential scalability. The pilot programs would foster collaboration and knowledge-sharing among the Company, industry groups, state agencies, and other stakeholders, laying the groundwork for the expansion of successful programs. Further, pilot programs would generate important customer and utility learnings to better understand the nuances of the best use of resources.

C. Continued Use of Gas Scenario Supports a Least-Cost, Most-Reliable Path

Table 1 of the Technical Analysis report presents the cumulative net present value (NPV) of total resource costs and total cost of ownership by 2050.[27] However, the Table overlooks the

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[27] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 11

immediate financial considerations that influence customer decision-making, such as upfront costs to convert technologies. Energy affordability is a paramount concern for Rhode Island customers, who often base their choices on upfront costs of end-use energy consuming equipment and the immediate costs of utility service.

In this context, the Continued Use of Gas pathway, which assumes 25 percent of buildings adopt all-electric heat pumps and 30 percent converts to hybrid heating with gas or delivered fuel backup, emerges as the most affordable option for customers. Customer bill impacts for residential, commercial, and industrial customers, as well as upfront costs, are lowest in the Continued Use of Gas scenario under both unmanaged and managed transitions.[28]

Moreover, if electricity rates exceed forecasts, customers on electrification pathways may face unexpected financial strain. As shown in Figure 7, cost estimates of residential electric rates presented in the Technical Analysis report exhibit minimal variability, limiting the robustness of the analysis and failing to comprehensively account for all affordability implications. Therefore, any prospect of a transition away from the continued use of natural gas should carefully weigh the affordability needs of customers to avoid unintended economic consequences.

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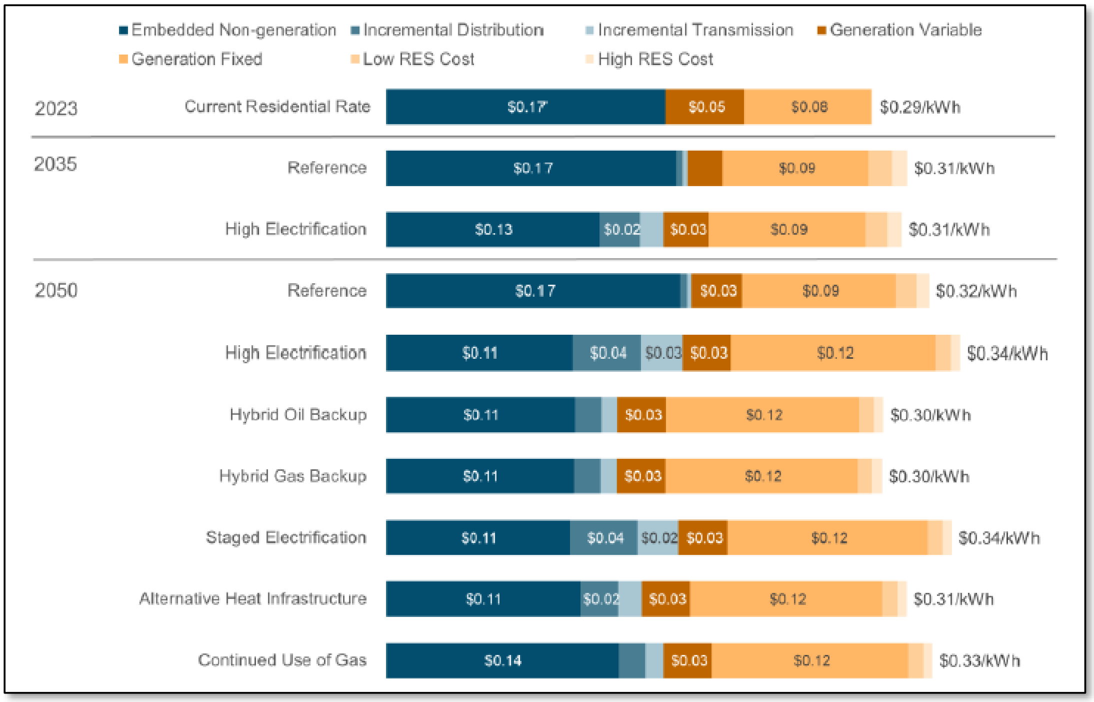
[28] E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 70 & 93. Figure 40 and Figure 41 illustrate that the Continued Use of Gas scenario result in the most affordable gas delivery rates for residential and large C&I customers. Figure 57 illustrates that upfront costs associated with decarbonization measures are lowest for gas customers.

Figure 7: Residential Electric Rates by Scenario and

Impact of Renewable Energy Standard



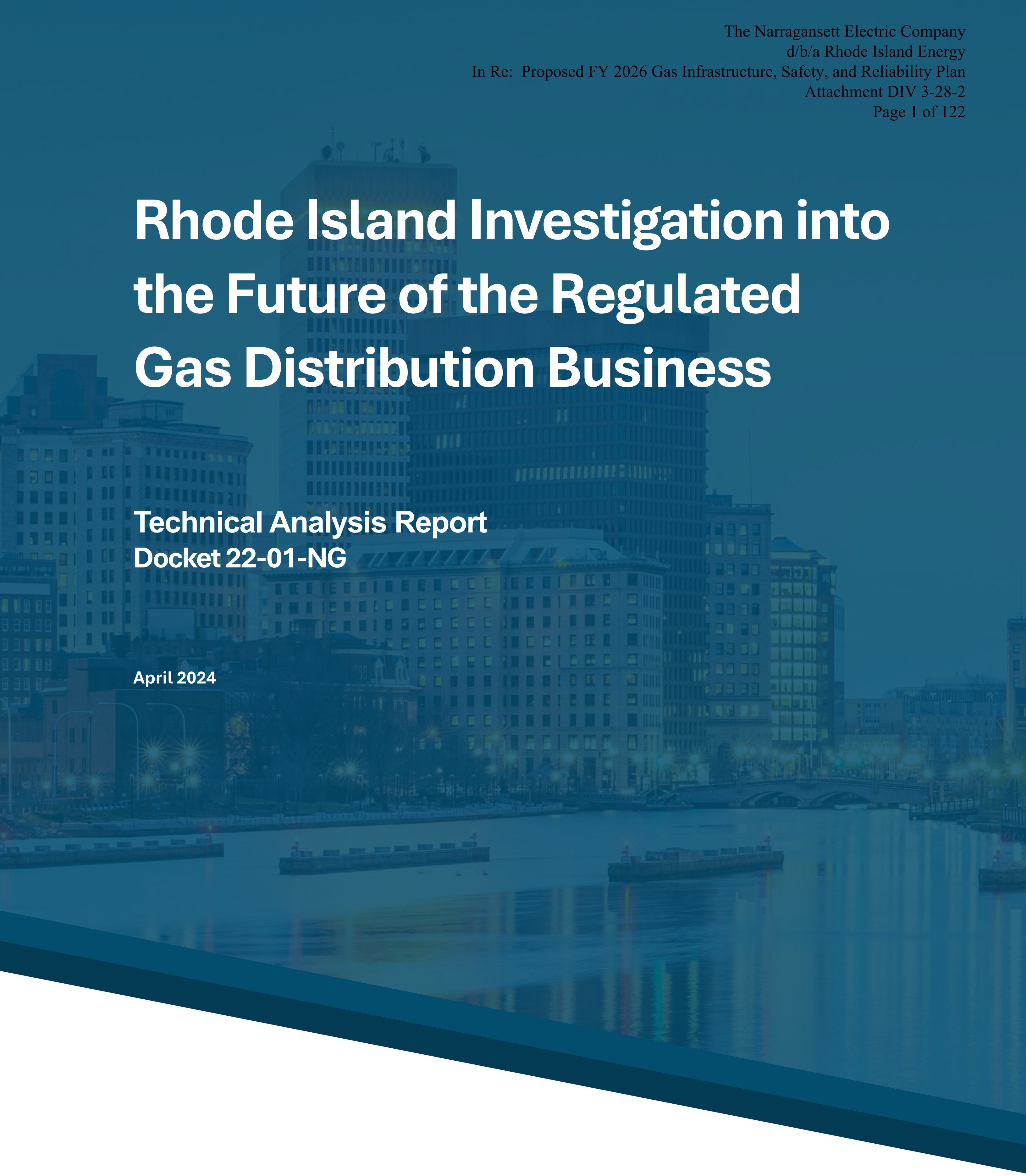
Source: E3, Technical Analysis Report, RIPUC Docket 22-01-NG, p. 79

IV. Conclusion

The Company views the Technical Analysis report as a missed opportunity to inform Rhode Island's future policies for the regulated gas distribution business. The document offers little guidance on practical, near-term actions the Company can take to support Rhode Island's climate goals. The report also includes little detailed discussion on individual strategies within scenarios that would help focus the upcoming policy discussion on regulatory initiatives to support achieving the climate goals.

As detailed in the Technical Analysis, much remains unknown about Rhode Island's path to net zero across all sectors. While the Technical Analysis serves as a starting point to explore the implications of certain decarbonization pathways, the modeling results cannot be viewed in isolation and need to be augmented with (i) learning opportunities from monitoring industry developments; and (ii) the testing and deployment of a wide variety of innovative resources in Rhode Island. As new data emerges and technical and economic uncertainties are reduced, the Commission, Company, and stakeholders, may be in a better position to explore nuances related to natural gas decarbonization strategies and deploy the most promising technologies to meet climate targets while maintaining affordability for all customers.

Looking forward, there must be more focus on decarbonization strategies that are actionable in the near-term; affordable and practical for Rhode Island's households, businesses, and essential institutions; account for customer choice considerations; ensure safe, reliable, and cost-effective energy delivery; and support economic development and growth in Rhode Island. In addition, an inclusive framework based on the public interest is the appropriate analytical instrument for assessing various decarbonization polices. This type of decarbonization framework will be more comprehensively outlined in the Company's policy development comments, which will serve as an input to Apex Analytics' Policy Report.



Rhode Island Investigation into the Future of the Regulated Gas Distribution Business

Technical Analysis Report
Docket 22-01-NG

April 2024

Energy+Environmental Economics

Energy and Environmental Economics (E3) is an analytically driven consulting firm focused on the transition to clean energy resources with offices in San Francisco, Boston, New York, Calgary, and Denver. Founded in 1989, E3 delivers analysis that is widely utilized by governments, utilities, regulators, and developers across North America. E3 completes roughly 350 projects per year, all exclusively related to the clean energy transition, across our three practice areas: Climate Pathways and Electrification, Integrated System Planning, and Asset Valuation, Transmission, and Markets. The diversity of our clients – in their questions, perspectives, and concerns – has provided us with the breadth of experience needed to understand all facets of the energy industry. We have leveraged this experience and garnered a reputation for rigorous, unbiased technical analysis and strong, actionable strategic advice.

Study authors: Niki Lintmeijer, Tory Clark, Stephanie Kinser, Molly Bertolacini, Kenzie Schwartz, Bill Wheatle, Charles Li, Dan Aas, Sean Smillie

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Acknowledgements

E3 would like to thank the Rhode Island Public Utilities Commission, Rhode Island Energy, Apex Analytics, the members of the Stakeholder Committee, and the members of the public who provided feedback and input on the Technical Analysis scope and results. E3 in particular would like to thank the members of the Technical Working Group who provided critical input and feedback on the assumptions and methodology underlying this study.

The results and conclusions of this report are the responsibility of the study authors and do not necessarily reflect the views of others, including members of the Stakeholder Committee, Technical Working Group, or organizations that provided funding to support this report.

Table of Contents

Table of Figures

Table of Tables

Executive Summary

In the context of Rhode Island's Act on Climate ("the Act") that requires the state to achieve net-zero economy-wide emissions by mid-century, the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG ("the Docket") to investigate the effect of the Act on the regulated gas distribution business in Rhode Island. The PUC required Rhode Island Energy (RIE), the largest provider of gas and electric service in the state, to retain a third-party consultant to perform a Technical Analysis that identifies options to reduce emissions from the gas distribution system and to understand the implications of these options. RIE retained Energy and Environmental Economics, Inc. (E3) to identify and model decarbonization scenarios that comply with the Act and to draft a report summarizing the technical analysis findings and implications.

This report presents E3's independent findings from the Technical Analysis. The findings are informed by analysis of decarbonization scenarios compliant with the Act that were developed in close collaboration with a Stakeholder Committee and Technical Working Group formed by the PUC.

Decarbonization Scenarios

E3, in consultation with the Stakeholder Committee and with final direction and approval from the PUC, designed six economy-wide decarbonization scenarios that each present distinct pathways to achieving the Act's climate targets of 45% by 2030, 80% by 2040, and net zero by 2050, compared to 1990 levels:

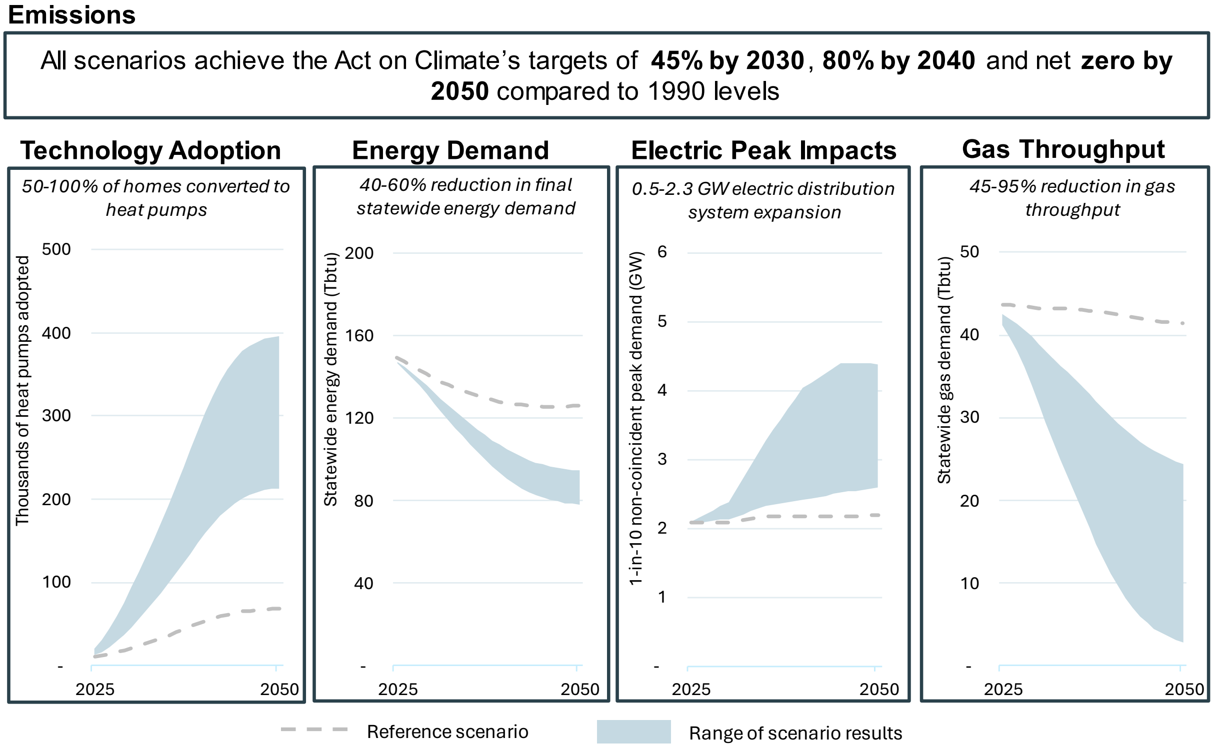
- A **High Electrification** scenario, designed to assess the impact of pursuing a full-electrification pathway that transitions Rhode Island away from gas infrastructure;
- A **Hybrid Electrification with Delivered Fuels Backup** scenario, designed to assess the statewide impact of hybrid electrification while evaluating potential net benefits of avoiding gas infrastructure;
- A **Hybrid Electrification with Gas Backup** scenario, designed to assess the statewide impact of hybrid electrification while leveraging existing gas infrastructure in the long term;
- A **Staged Electrification** scenario, designed to leverage existing infrastructure and mitigate customer impacts in the near term while achieving long term electrification;
- An **Alternative Heat Infrastructure** scenario, designed to assess how networked geothermal systems can support decarbonization in Rhode Island, while providing an alternative to gas investments;
- A **Continued Use of Gas** scenario, designed to assess how existing gas infrastructure can support decarbonization, evaluating the effect of and potential limit to remaining fossil gas and renewable fuels.

In addition, E3 developed a reference scenario to evaluate the impact of existing policies and trends on emissions reductions in Rhode Island. The scenarios evaluate emissions reductions across all sectors of the economy, while holding key emissions reductions in non-heating sectors constant to allow for comparisons across heating sector transformations. Importantly, these scenarios are not forecasts and are not intended to pick a preferred solution. Instead, scenario analysis allows for the identification of commonalities, differences, and key implications for near- and long-term planning that are meant to inform the Docket's policy and regulatory discussions. The scenarios do not model economic consumer behavior that results in meeting the Act but are instead based on a "backcasting" approach that assesses the necessary actions to comply with the Act. The probability that consumer behavior will follow these necessary actions is not modeled within the scope of this work. Lastly, it is important to note that the decarbonization scenarios developed are not optimizations; instead, each scenario is meant to answer "what if" questions about the future of Rhode Island's energy system, rather than determine the optimal – or least-cost – path to decarbonization.

Technical Findings from Decarbonization Scenarios

Key technical findings from the decarbonization scenario analysis are shown in Figure 1 and described below.

Figure 1. Key Technical Findings from Decarbonization Scenarios



Emissions

All scenarios achieve the Act on Climate's targets of **45% by 2030**, **80% by 2040** and net **zero by 2050** compared to 1990 levels

- **Emissions:** While existing policies and trends achieve 40% emissions reductions by 2030 compared to 1990 levels, additional mitigation measures are required to comply with the Act on Climate. All decarbonization scenarios modeled by E3 achieve the Act's targets.

Sensitivity analysis demonstrates that scenarios with higher levels of renewable fuels[1] may have higher remaining emissions under alternative emissions accounting frameworks.

- **Technology adoption:** Energy efficiency and building electrification are a critical component of gas system decarbonization. Across scenarios, between 50-100% of buildings are assumed to electrify to comply with the Act's targets. In the industrial sector, all scenarios include significant levels of efficiency and varying levels of industrial electrification, while leaving a role for pipeline gas for "hard-to-decarbonize" applications.
- **Energy demand:** All scenarios see transformational changes in the way Rhode Island uses energy. Across scenarios, final energy demand decreases between 40-60% by 2050, primarily as a result of efficiency and electrification. Rhode Island will see an increased demand for renewable fuels, driven by the Biodiesel Heating Act in the near term and to comply with emissions targets in the long term.
- **Electric system impacts:** By 2050 across scenarios, 40-60% of final energy demand is served by (renewable) electricity. The adoption of heat pumps and EVs lead to a need for significant system expansion, between 0.5-2.3 GW higher than today. Electric system peaks can be significantly mitigated through the use of hybrid backup systems or highly efficient networked geothermal systems.
- **Gas throughput:** Gas throughput declines between 45-95% across scenarios, primarily as a result of efficiency and electrification. Scenarios that keep a role for gas heating (Continued use of Gas, Hybrid with Gas Backup), see an increase in the use of renewable fuels.

Role and Use of the Gas System

All scenarios imply a transformation of the role and use of the gas distribution system. Four out of six decarbonization scenarios see a significant decline in gas customers driven by electrification; two scenarios require a change in the way gas system is used (Hybrid with Gas Backup) or in the portfolio of gas that RIE would need to procure (Continued Use of Gas). At the same time, under the current regulatory framework, costs of the gas system are expected to rise as a result of planned levels of capital expenditures through the Infrastructure, Safety and Reliability (ISR) program. The replacement of leak-prone pipe (LPP) required in the next decade to ensure safe and reliable gas service, as well as expected reinvestments after the ISR program cause annual revenue requirement to nearly double by 2050 in a reference scenario. Although there are variations in RIE's revenue requirement across scenarios by 2050, the combination of reduced throughput and increasing system costs under the current regulatory framework results in rapidly escalating delivery rates for residential, commercial and industrial customers in nearly all decarbonization scenarios, leading to untenable long-term gas delivery rates for scenarios with high levels of customer departures. Absent changes in policy, $2.6 billion in unrecovered rate base may still be present in 2050 in scenarios with high levels of customer departures.

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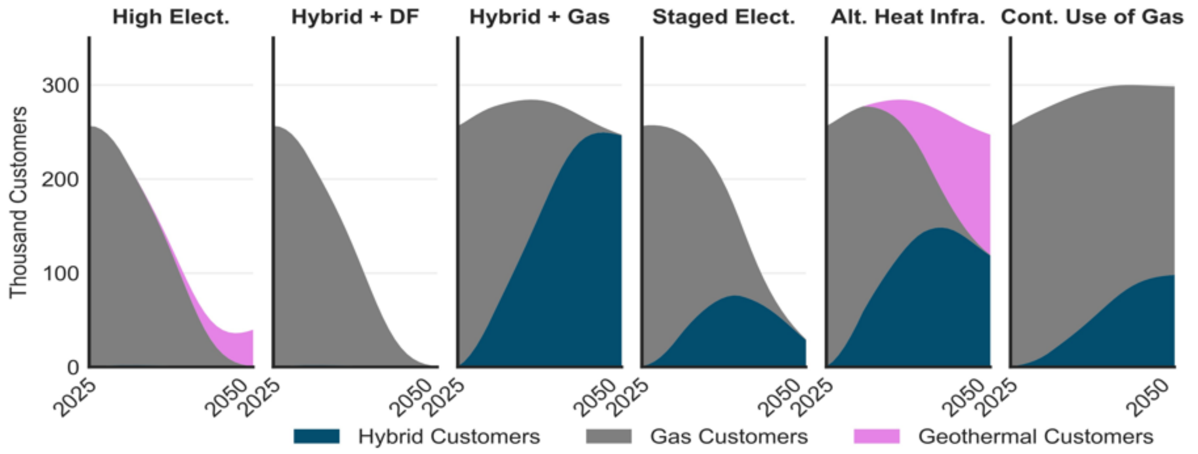
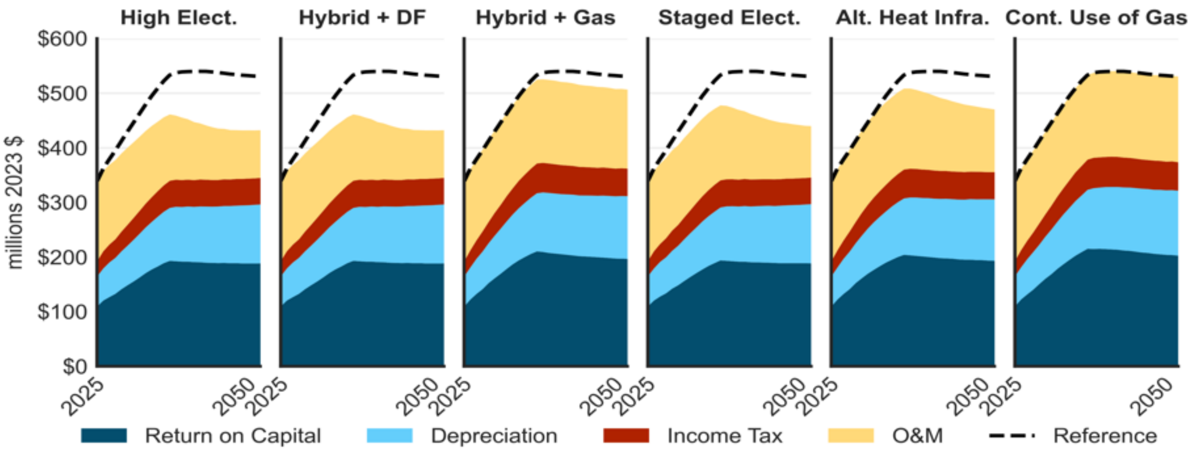
[1] E3 uses the term "renewable fuels" as an umbrella term encompassing a variety of emissions-compliant fuels. More context is provided in the main body of the report.

Figure 2. Gas Customers (Top), Revenue Requirement (Middle), And Residential Delivery Rates Across Scenarios (Bottom)

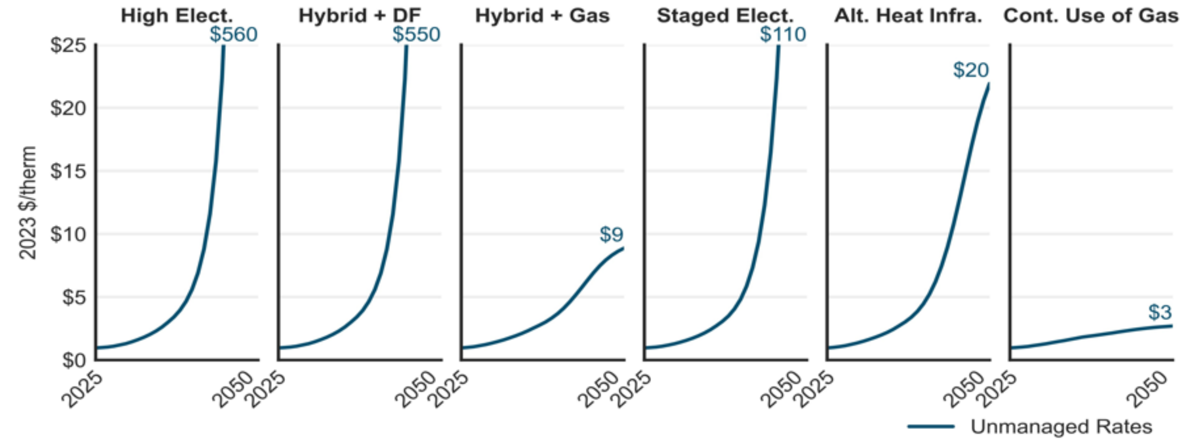
Gas Utility Customers



Gas Revenue Requirement



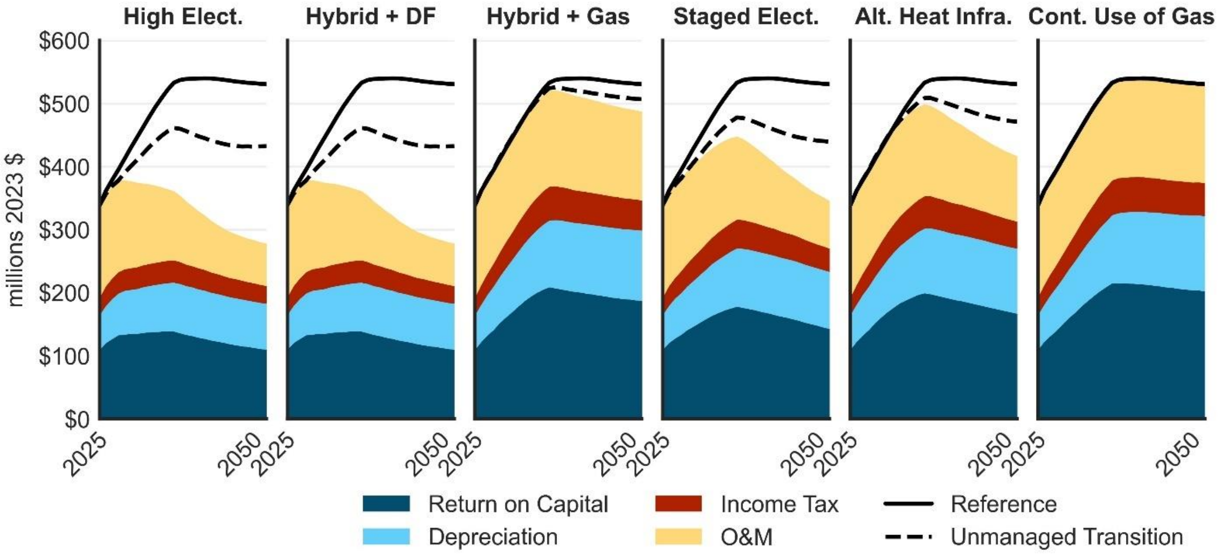
Residential Gas Delivery Rate



Impact of a Managed Transition

Through an illustrative analysis, E3 estimated the impact of a hypothetical managed transition, where electrification projects would occur in a targeted, neighborhood-scale manner, assuming these projects could avoid gas system reinvestment costs. This analysis found that *if* RIE could avoid up to 50% of capital replacements through targeted electrification, annual costs of the system could be reduced by up to 35% by 2050, while reducing potentially unrecovered rate base to $1.5 billion. Although a managed transition could avoid annual system costs, the impact on delivery rates in scenarios with high levels of electrification is relatively small. However, the level of reinvestment avoidance assumed in this analysis is unprecedented, and much more research is required to understand the technical feasibility of this approach.

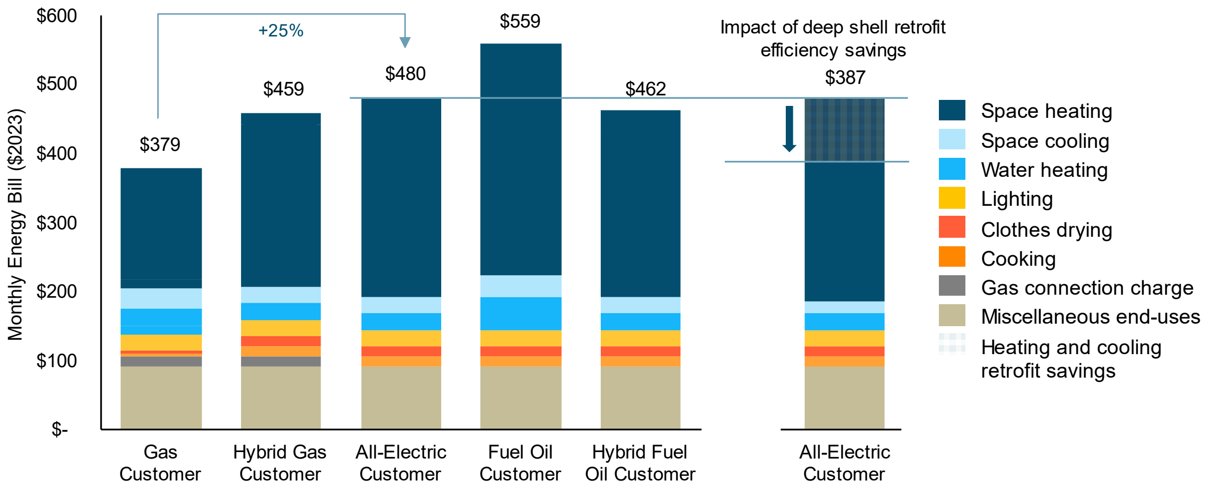
Figure 3. Revenue Requirement under a Managed Transition (note: based on illustrative cost avoidance assumptions)



Customer Implications and Affordability

Rhode Island currently has some of the highest electricity rates in the country. Today, as a result, gas customers transitioning to highly efficient all-electric heating will experience an approximately 25% increase in monthly energy bills. In addition, customers transitioning away from the gas system face significant upfront costs for electric appliances. Taken as a whole, the higher costs of electrification relative to natural gas today imply that additional programmatic and policy support is necessary to achieve the levels of customer electrification that was modeled to meet the requirements of the Act.

Figure 4. Residential Monthly Energy Bills in 2023



Counter to current conditions, electric heating becomes more cost-effective over time in comparison to gas heating in all scenarios, although the time of the "inflection point" differs. This outcome occurs because gas rate increases outpace electric rate increases as a result of two dynamics: 1) in scenarios where customers transition away from the gas system, the costs of the system are shifted to fewer remaining gas customers and 2) in scenarios where customers remain connected to the gas system, the commodity cost of gas increase through the procurement of renewable fuels.

Scenario Implications across Evaluation Criteria

The decarbonization scenarios analyzed for the Technical Analysis see different levels of benefits, risks and challenges across multiple evaluation criteria, as summarized in the table below. Overall, total resource costs fall within similar ranges across scenarios, but are lower for scenarios that leverage hybrid heating solutions and may further be reduced for scenarios that are able to avoid gas system reinvestments. All scenarios assume an increasing level of adoption of cleaner vehicles and home appliances that is significantly higher than it is today. It is important to note that scenarios that are able to avoid gas system investments through a "managed transition" require a change in how electrification technologies are adopted that is not modeled in detail in the Technical Analysis. Without interventions, customer adoption of home appliances is driven by choice and influenced by economic conditions. In a managed transition as modeled in the High Electrification, Hybrid with Delivered Fuels Backup and Staged Electrification scenarios, a top-down level of coordination is assumed where up to 3,000 customers adopt electrification technologies through a neighborhood-by-neighborhood approach, which has implications for customer choice. The likelihood that this type of coordinated strategy occurs is not modeled or assessed as part of the analysis and significant uncertainty exist around the feasibility and practicality of this approach.

In the scenarios as modeled, all decarbonized futures lead to long-term customer affordability challenges, both for customers adopting decarbonization solutions, as well as for customers who are faced with higher costs of the gas system as others electrify.

Scenarios with high levels of renewable fuels or networked geothermal systems (Alternative Heat Infrastructure, Continued Use of Gas) face high levels of cost uncertainty, partly due to the level of commercialization associated with these technologies. At the same time, both the use of renewable fuels and networked geothermal systems, as well as the use of hybrid heating technologies, significantly reduce the need for distribution system capacity upgrades that are required in a High Electrification scenario.

All scenarios may benefit from air quality improvements as the level of fuel combustion is significantly reduced to achieve the Act. These benefits are likely to be lower in the Continued Use of Gas scenario, which has the highest ongoing level of fuel combustion. Additionally, the Continued Use of Gas scenario is likely to require import of fuels from outside of New England compared to scenarios with higher levels of electrification that rely more heavily on in-region renewable electricity procurement. These scenarios additionally see potential positive impacts with regard to local economic development and workforce needs. Workforce needs on the gas system may be reduced over time, but these effects are likely to only occur in the long term.[2]

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[2] Note: Workforce impacts are not quantitatively shown on Table 1, but are contextualized qualitatively in the report.

Table 1. Assessment of scenarios across evaluation criteria

Criteria	Representative Metric		High Electrification	Hybrid w. DF Backup	Hybrid w. Gas Backup	Staged Electrification	Alternative Heat Infra	Cont. Use of Gas
Total Resource Costs	Net Present Value between 2023-2050, incremental to reference		$18-22 billion	$15-21 billion	$14-19 billion	$15-20 billion	$17-24 billion	$16-26 billion
	Illustrative NPV savings if up to 50% of gas CAPEX can be avoided[3]		-$1.7 billion	-$1.7 billion	-$0.1 billion	-$0.7 billion	-$0.4 billion	-$0.0 billion
Customer choice	Annual no. of targeted electrification customers (2035)	*Un-managed*	0	0	0	0	0	0
		Managed	~3,000	~3,000	0	~1,200	~700	0
Long-term affordability	2050 monthly total cost of ownership (TCO) for migrating customer		~ $700	~ $700	~ $700	~ $700	~ $800	~ $700
	2050 monthly TCO for non-migrating customer		> $3,000	> $3,000	~ $1,500	> $3,000	> $3,000	~ $700
	TCO "inflection year" for residential gas vs. all-electric customer[4]		2036	2037	2037	2036	2036	2046
Air Quality Impacts	Change in statewide fuel combustion between 2020-2050 (%)		-85%	-82%	-81%	-85%	-82%	-65%
Reliance regional fuel supply	Total annual volume of renewable fuel required by 2050 (TBtu)		11	15	15	11	13	33
Technology Readiness[5]	Likely range of Technology Readiness Levels required to achieve AoC		8-10	7-10	7-10	8-10	6-10	6-11
Electric System Expansion	Total increase in distribution system capacity by 2035 (GW)		1.2	0.5	0.4	0.5	0.4	0.2

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[3] Represents reduction in NPV if 50% of CAPEX can be avoided through managed transition, relative to the above row

[4] "Inflection year" is defined as the point in time where the TCO for an all-electric heating customer is lower than for a gas heating customer, under the current regulatory framework.

[5] E3 uses the Technology Readiness Level (TRL) scale defined by the International Energy Agency (IEA), where 1 refers to the lowest level of technology commercialization and 11 to the highest level of technology commercialization.

Scenario Commonalities and Additional Study Needs

Despite differences across scenarios in the transformation of the heating sector and associated use and role of the gas system, E3 distills several key commonalities across scenarios related to the gas distribution system as the state moves towards achieving the climate targets:

- **Energy efficiency.** To achieve the Act, all scenarios rely on significant energy efficiency measures, such as building shell retrofits, that far exceed the state's rate of adoption today.
- **Building electrification.** Building electrification is a significant component of gas system decarbonization across scenarios. Heat pump adoption levels in the next decade are 5-10 times higher than today's levels of adoption.
- **Renewable energy generation and electric system expansion.** Achieving the state's 100% Renewable Energy Standard (RES) in combination with significant levels of electrification in all scenarios leads to increases in loads and peaks that are likely to require investment in and expansion of the electric grid.
- **Affordability issues with decarbonization scenarios.** All scenarios rely on decarbonization measures that increase customer costs, especially with regard to gas-to-electric conversions. The adoption of decarbonization measures at the scale required to achieve the Act implies the need for policy development to mitigate these costs.
- **Long-term impacts on gas customer bills.** All scenarios lead to an increase in rates for customers on the gas system, either through customers exiting the gas system or through the costs of renewable fuels. These results underline an important area of focus for the policy development phase of the proceeding.
- **Opportunities for electrification of delivered fuels heating.** In contrast to gas customers, customers currently using delivered fuels as main source of heating, primarily located in the western part of the state, see a decrease in monthly energy bills with adoption of efficient electric heating, implying a near-term opportunity for emissions reductions.
- **Significant uncertainty related to renewable fuels.** All scenarios rely on some volume of renewable fuels to comply with the existing Biodiesel Heating Act or the Act on Climate. The Technical Analysis demonstrates significant uncertainty associated with the availability, costs and efficacy of renewable fuels. This highlights the need for ways to mitigate uncertainty that can be addressed in the policy development phase of the Docket.

E3 identified four primary outstanding technical questions on the implementation and technical feasibility associated with decarbonizing the gas system that require further study:

- **Technical feasibility related to a managed transition.** The assumptions E3 used to estimate the impact of avoided gas system costs are illustrative and not based on input from RIE. The magnitude of gas system cost avoidance assumed in this study is unprecedented. Additional research is required to quantify to what extent gas infrastructure projects can technically and cost-effectively be avoided through targeted electrification in Rhode Island.
- **Technical feasibility related to networked geothermal systems.** Networked geothermal systems have the potential to reduce electric peak system impacts but, at the scales modeled in this study, come at an incremental cost to other electrification strategies. Additional research is needed to identify use cases where networked geothermal would see

a cost advantage relative to all-electric or hybrid electrification. Research is also required to understand the geological feasibility of these systems and to identify parts of the state where they can provide the highest level of benefit.

- **Technical feasibility related to delivered fuels backup.** The Hybrid with Delivered Fuels Backup scenario demonstrates benefits with regard to electric peak mitigation while at the same time allowing for targeted electrification projects that may avoid gas system costs. However, the concept of using delivered fuels as a backup for winter heating needs, especially for customers currently connected to the gas system, is novel and requires further study, for example with regard to backup conversion costs, customer practicality and supply chain impacts.
- **Workforce impacts.** A detailed study investigating the impacts of the Act on Climate on the workforce in Rhode Island, both related to the gas distribution system and to the broader clean energy transition, was beyond the scope of the Technical Analysis. Additional investigation into the jobs and skills necessary to facilitate the transformations outlined in this study is necessary to understand the challenges, opportunities and potential gaps associated with Rhode Island's workforce as the state transitions to a net zero economy.

1. Introduction

On April 14, 2021, Governor Dan McKee signed into law the Act on Climate ("the Act"), which mandates the state of Rhode Island to achieve climate targets of 45% greenhouse gas (GHG) emissions reductions by 2030, 80% by 2040, and net-zero by 2050, compared to 1990 levels. These targets represent mandatory, enforceable goals that position the state to address and mitigate the impacts of climate change, requiring a transformation of energy use across all sectors of the economy.

In the context of the state's climate commitment, on June 9, 2022, the Rhode Island Public Utilities Commission (PUC) opened Docket 22-01-NG ("the Docket") to investigate the effect of the Act on Climate on the regulated gas distribution business in Rhode Island.[6] The final scope of the Docket was released in January 2023 and followed by a stakeholder process with the aim to gather *"clear recommendations from stakeholders on the future of the gas system in light of the Act".*[7]

The scope required Rhode Island Energy (RIE) to retain a third-party consultant to perform a Technical Analysis that identifies options to reduce emissions from the gas distribution system and to understand the implications of these options. RIE retained Energy and Environmental Economics, Inc. (E3) to identify and model decarbonization scenarios that comply with the Act and to draft a report summarizing the technical analysis findings and implications.

Docket Process

At the start of the Docket, the PUC established a Stakeholder Committee comprised of RIE, state agencies, business representatives, environmental organizations and consumer advocates to provide input and recommendations on the scope and outcome of various phases of the Docket. The PUC retained Consultant Apex Analytics, LLC. to facilitate the stakeholder process and guide the development of the Policy Development phase in the second half of 2024. An overview of the Docket's process is provided in Figure 5 below.

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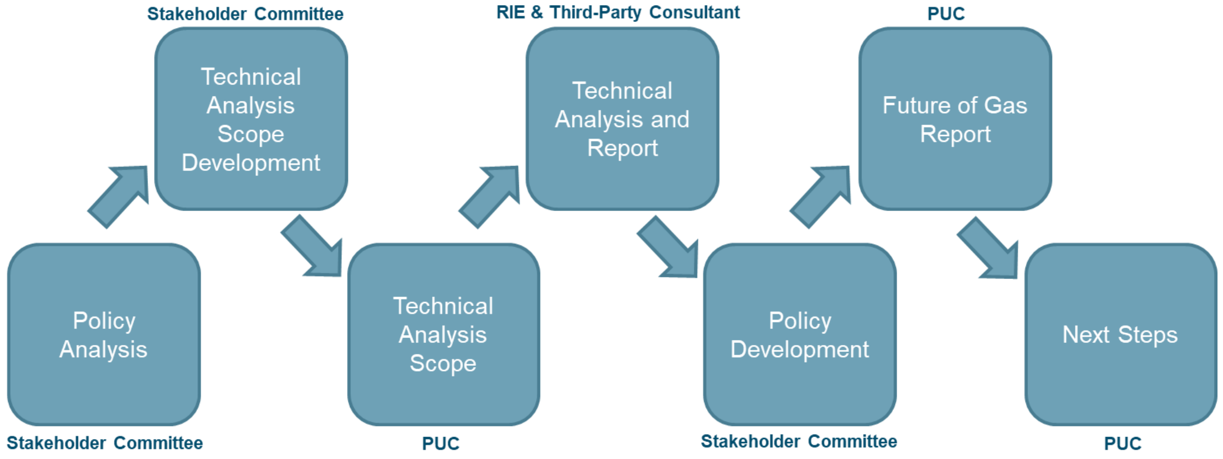
[6] State of Rhode Island Public Utilities Commission. Notice of Commencement of Docket. Docket No. 22-01-NG. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-08/22-01-NG-Notice_6-9-22.pdf

[7] State of Rhode Island Public Utilities Commission. Proceeding Scope at 1. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/22-01-NG_FoG_Scope.pdf

Figure 5. Docket 22-01-NG Process



The Technical Analysis will be used by the Stakeholder Committee and the PUC in the Policy Development phase, with the aim of developing recommendations and next steps regarding the regulated gas distribution business in Rhode Island. As described in the scope, a Technical Analysis is "*necessary to create information useful to understanding what actions and options for emissions reductions are effective and to identify the potential benefits and costs of these actions and options".*[8] To validate foundational assumptions around modeling inputs and methodology, the PUC established a Technical Working Group (TWG) comprised of subject matter experts. The TWG provided input, feedback and recommendations with regard to E3's modeling framework and assumptions. A total of 8 TWG meetings were prepared and facilitated by E3 and held on a bi-weekly basis between September 2023 and January 2024. An overview of TWG members is provided in Table 2. An overview of topics discussed with the TWG is provided in Appendix A.5.

***Table 2. Technical Working Group Members** (*TWG alternates, sharing 1 seat)*

Name	Organization
Lee Gresham	Rhode Island Energy
Nicholaz Vaz	RI Attorney General
Dean Murphy	Brattle, on behalf of RI Office of Energy Resources
Paul Roberti	RI Division of Public Utilities and Carriers
John Willumsen	RI Department of Labor & Training
Craig Pickell	Bullard Abrasives
Samuel Ross	NV5, on behalf of RI Energy Efficiency & Resource Management
Joseph Poccia	RI Department of Environmental Management
Mike Walsh*	Groundworks Data, on behalf of Sierra Club, Conservation Law Foundation
Ben Butterworth*	Acadia Center

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[8] State of Rhode Island Public Utilities Commission. Proceeding Scope at 2. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/22-01-NG_FoG_Scope.pdf

Scope of Technical Analysis

The scope of the Docket includes a list of comprehensive questions for the Technical Analysis to consider and address, summarized in the table below.

Table 3. Overview of Docket Questions related to Technical Analysis

Docket question	Docket sub questions	Addressed in Report
1. What infrastructure and non-infrastructure options exist for reducing emissions from the gas system?	a) Which have been explored in previous and current studies and which have not? b) What updates to the examinations in previous studies, including key assumptions, should be updated and/or considered for sensitivity testing?	Decarbonization Pathways Technical Results (Chapter 4) - Technology adoption levels, impact on gas and electric system
2. What scenarios for (all) sector-level emissions will allow the state to meet the emissions reduction mandates of the Act?	a) What is the appropriate baseline for the economy and for the gas system? b) In terms of different timing and extent of emissions reductions, what is the implication of these scenarios on the gas system? c) Does the feasibility of options for reducing gas system emissions change between these differences in timing and extent in these scenarios?	Decarbonization Pathways Technical Results (Chapter 4) - Emissions
3. What outputs of the Technical Analysis will inform the Policy Development phase?	a) What effects of decarbonization should be tracked between scenarios? For example, benefits, costs, rate impacts, inclusion and participation, reliability factors, impacts on other sectors, etc. i. What mechanisms of cost recovery should be examined? b) Which effects can be directly tracked, and which must be indirectly inferred by tracking related factors or proxies? c) From which points-of-view do we wish to track the effects of decarbonization? For example, the point-of view of society, the state, the EC4, residents, utility ratepayers, gas system ratepayers, etc. d) How much detail about how changes in the gas system will impact other sectors is necessary to model in order to answer key questions?	Decarbonization Pathways Assessment & Implications (Chapter 5)

4. What assumptions and inputs are critical to the outputs of the Technical Analysis?	a) Does current knowledge about these assumptions warrant testing alternative assumptions? b) Does current knowledge about these inputs warrant performing sensitivity analyses?	Decarbonization Pathways Technical Results (Chapter 4) – Sensitivity analyses
What statutory, regulatory, or stakeholder requirements and/or preferences exist that represent constraints on possible pathways for reducing gas system emissions consistent with the Act.		*To be discussed in Policy Development phase*
What final scenarios, including alternative testing and sensitivity ranges, should be included in RIE's scope for the Technical Analysis the company will perform?		Scenario Development (Chapter 3)

About this Report

This Technical Analysis Report provides E3's analysis of a set of decarbonization scenarios compliant with the Act that were developed in collaboration with the Stakeholder Committee. Through the analysis of decarbonization scenarios, E3 provides the findings and implications of options to reduce GHG emissions from the gas distribution system, addressing the questions raised by the PUC in the Docket as outlined above. Although the focus of the Docket is on the gas distribution system in particular, the Technical Analysis reviews the statewide transformations required in order to comply with the Act, to be able to understand the role of the gas system in achieving statewide emissions reductions.

This report was developed by E3 and provides E3's independent assessment of the role of Rhode Island's gas distribution system in achieving the state's climate goals. E3's findings are informed by discussions with and feedback from the Stakeholder Committee and TWG.

This report consists of 6 chapters. Chapter 2 provides an overview of energy and emissions in Rhode Island and the characteristics of natural gas distribution in the state today. Chapter 3 describes the approach towards the Technical Analysis used by E3, introducing E3's modeling framework, scenario development and an overview of sensitivity analysis and evaluation criteria. Chapter 4 includes the key technical results of the decarbonization scenarios modeled by E3, distinguishing impacts on emissions, technology adoption, energy demand, the gas system and the electric system. Implications of these scenarios across evaluation criteria are further assessed in Chapter 5. Finally, chapter 6 provides an overview of key study takeaways and recommendations for further research.

2. Overview of Energy and Emissions in Rhode Island

Understanding the fundamentals of energy distribution in the state, as well as the composition of energy demand and, in particular, gas use by customers in Rhode Island, is essential to identifying the potential options to reduce emissions and the impact of these options. Both the gas and electric distribution system in Rhode Island are operated and maintained by a single utility, RIE. Delivered fuels, such as distillate fuel oil and propane, are supplied to homes and businesses by independent delivery service companies. These fuels—electricity, gas, and delivered fuels —are the primary fuels utilized for the purpose of heating in Rhode Island. Decarbonization efforts are expected to alter the heating fuel mix, their demand, and the impact on the distribution of fuels in the state in the next decades.

Energy Demand in Rhode Island

The State of Rhode Island counts 1.1 million inhabitants and consumed approximately 152 TBtu of energy in 2021.[9],[10],[11] The Transportation sector is the largest consumer of energy in the state, accounting for 36% of state's energy consumption, primarily relying upon gasoline and diesel to power on-road vehicles. The Residential sector is the second largest energy-consuming sector in Rhode Island, accounting for 31% of energy demand in 2021, mostly comprising of natural gas, diesel, and electricity used for building end-uses. The Commercial sector made up 21% of the state's energy consumption in 2021, with consumption driven primarily by the use of electricity and natural gas. Industry was the lowest-consuming sector in Rhode Island, accounting for 13% of energy consumption in 2021.

Approximately 23% of total energy consumption, or 41 TBtu, represents natural gas consumed for residential, commercial, and industrial purposes. Space and water heating are the primary uses for natural gas in the residential and commercial sectors, and plastics and metals-based durables manufacturing are the primary uses of natural gas in the industrial sector.

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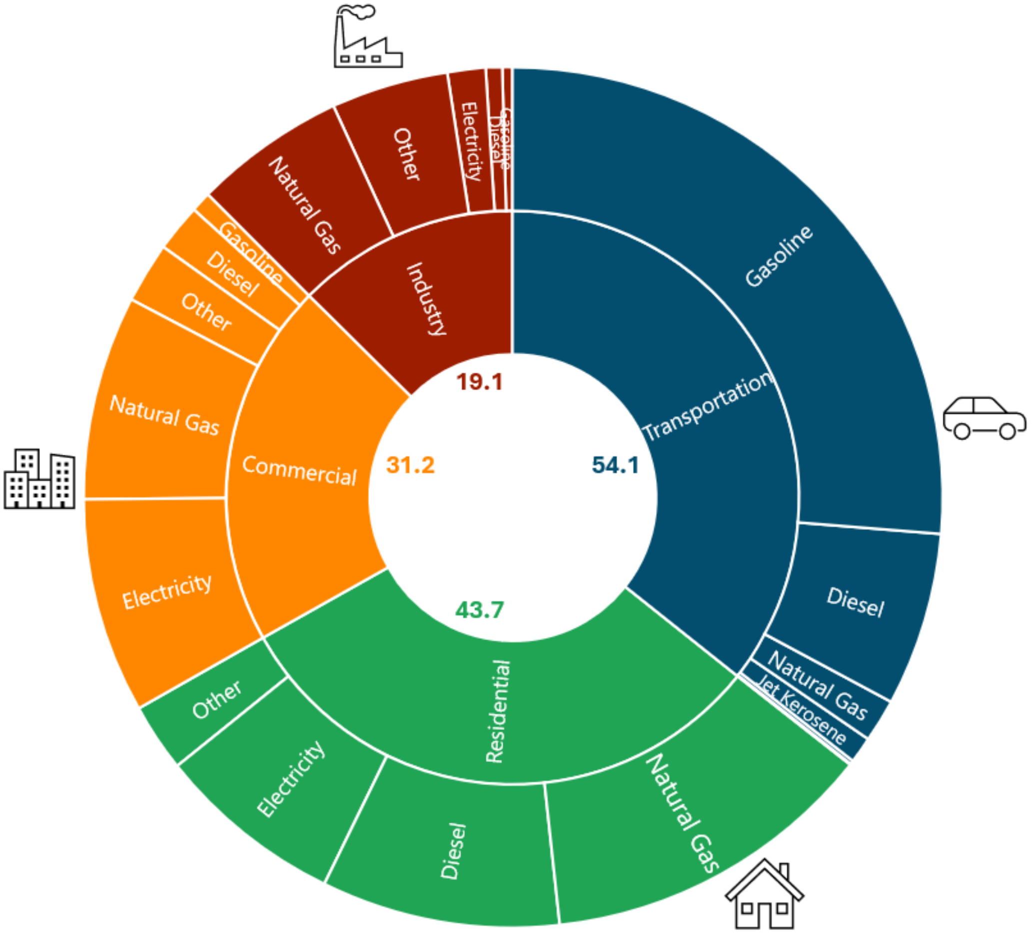
[9] Energy demand total does not include electric power losses.
[10] U.S. EIA State Energy Data System (SEDS). 2021. https://www.eia.gov/state/seds/seds-data-complete.php?sid=US#Consumption.
[11] The energy demand totals listed in this chapter are from 2021 as it is the latest year of publicly available data from SEDS.

Figure 6. Energy Consumption by End Use in Rhode Island in 2021 (TBTU)[12]



Residential and commercial heating demand is driven by the composition of heating fuels used in the state's building stock. In 2018, Rhode Island had over 400,000 occupied residential housing units and 302 million square feet of commercial building space.[13,14] As shown in Figure 7, over half the building stock is heated by natural gas, while the remaining building stock is primarily heated by distillate fuel oil or electricity.

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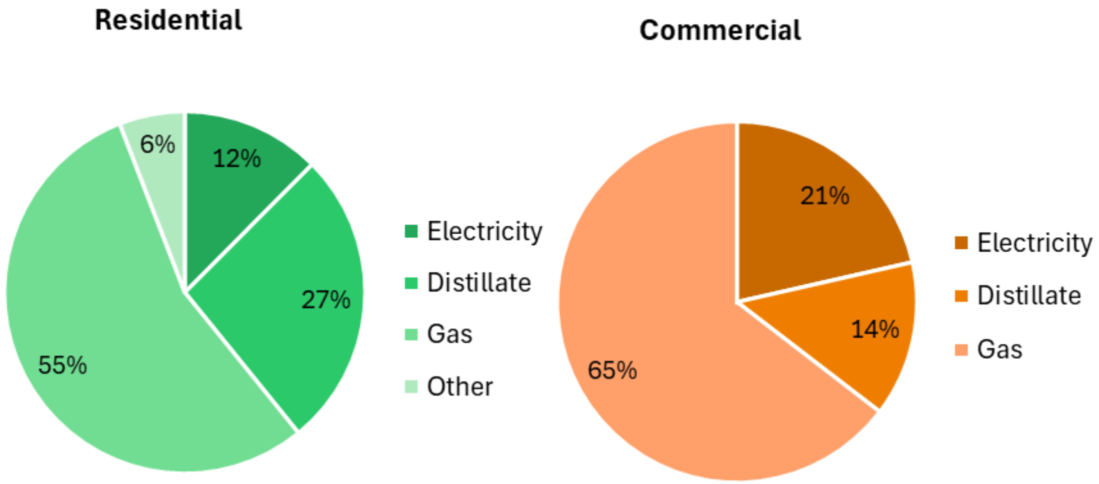
[12] U.S. EIA State Energy Data System (SEDS). 2021. https://www.eia.gov/state/seds/seds-data-complete.php?sid=US#Consumption.

[13] Residential housing units come from the American Community Survey, U.S. Census Bureau. 2018. https://data.census.gov/table?q=DP04&g=040XX00US44&y=2018.

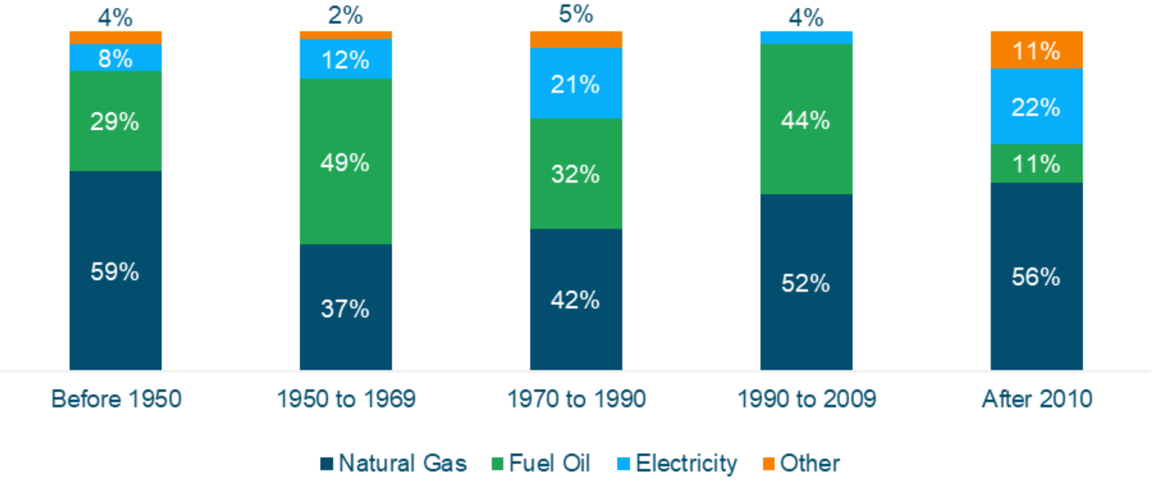
[14] Commercial square footage comes from the Office of Energy Resources (OER) and Division of Public Utilities and Carriers (DPUC) Heating Sector Transformation Report.2020. https://energy.ri.gov/HST.

Figure 7. Space Heating Stock Share in 2021[15]



The primary heating system installed in residential buildings has varied over time, as illustrated by the heating fuels used by housing vintages (see Figure 8).[16] Natural gas systems have been the primary heating system installed in most decades and have grown over time, whereas the number of distillate fuel oil systems declined in homes built after 2010. Electric heating, including less efficient resistance heating and more efficient non-resistance heating through heat pumps, has always made up a relatively small portion of heating systems installed in the building stock but has increased in market share since 2010.

Figure 8. Heating Fuel Use by Housing Vintage[17]



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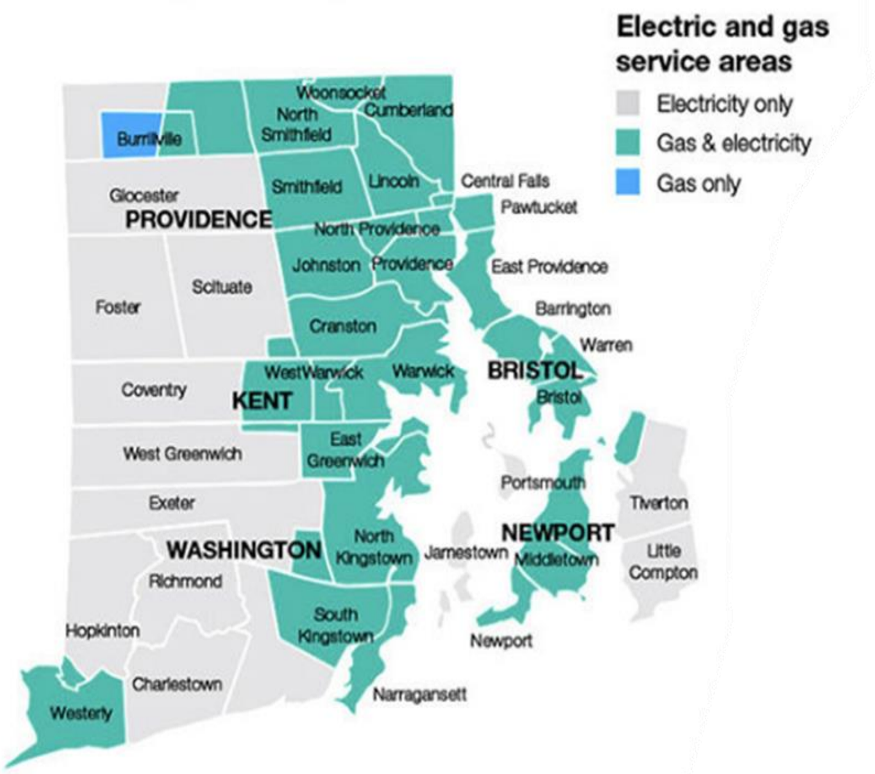
[15] Other category includes LPG furnaces and wood stoves.
[16] EIA, 2020 Residential Energy Consumption Survey (RECS)
[17] EIA, 2020 Residential Energy Consumption Survey (RECS)

Distribution of Energy in Rhode Island

RIE operates the electric and gas distribution systems in Rhode Island, providing electricity service to most of Rhode Island and natural gas service to parts of the state, primarily in the eastern half of the state (see Figure 9). RIE serves over 500,000 electric customers and over 270,000 natural gas customers.[18,19] While the number of electric customers in the state has shown relatively limited growth over the past 10 years, mostly as a result of low levels of population growth, the number of gas customers has been rising steadily. From 2010 to 2020, RIE's gas customer base grew by approximately 0.9% annually, exceeding population growth and primarily reflecting fuel oil conversions to natural gas.[20]

Unlike electricity and natural gas distribution, the distribution and sale of fuel oil and propane are not regulated. Most customers receive fuel oil and propane from local retail distributors, but some large commercial and industrial customers purchase fuel directly from wholesale distributors.[21]

Figure 9. Rhode Island Energy Service Territory[22]



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[18] U.S. EIA State Energy Data System (SEDS). 2021. https://www.eia.gov/state/search/#?5=126&6=134&2=220.
[19] U.S. EIA Natural Gas Data. 2024. https://www.eia.gov/dnav/ng/ng_cons_num_dcu_sri_a.htm.
[20] Ibid.
[21] Ibid.
[22] RIE Gas Operations 101, 1/24/2024.

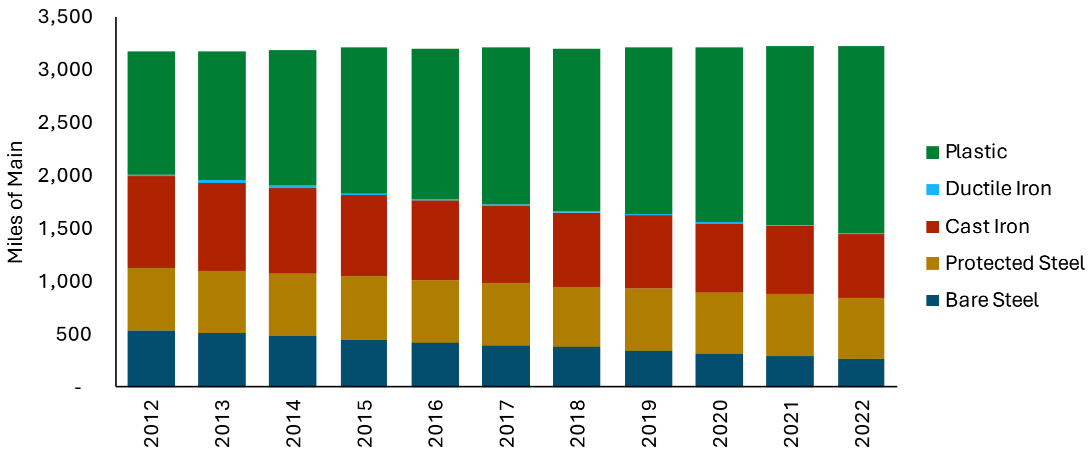
Natural Gas Distribution System

RIE operates the natural gas distribution system in Rhode Island and maintains approximately 3,200 miles of main and 194,000 service pipelines.[23] The company delivers approximately 40 Tbtu annually to a mix of residential, commercial, and industrial customers.[24]

RIE's gas distribution system is a winter peaking system, following seasonal demand for space heating. To meet customer demand, RIE supplies gas via pipeline transportation, underground storage, and peaking resources. Most of the pipeline gas is supplied from the Algonquin and Tennessee interstate pipelines. Its underground storage resources include eleven injection-withdrawal storage assets with 65,200 dekatherms (Dth) of maximum daily withdrawal quantity.[25] RIE's peaking resources to meet the periods of highest customer gas demand include on-system liquefied natural gas (LNG) assets and portable LNG facilities, with 802,000 Dth of gross storage capacity and 119,000 Dth of vaporization capacity.[26]

RIE maintains some of the oldest distribution pipeline infrastructure in the U.S.[27] Historically, a large part of the gas infrastructure was comprised of cast iron and unprotected steel, which is considered leak-prone pipe (LPP). Since 2012, RIE accelerated the replacement of LPP under its Infrastructure, Safety, and Reliability (ISR) program, with the primary goal to replace cast iron and unprotected steel pipe with plastic pipe. In 2012, 48% of the distribution system consisted of LPP. By the end of 2022, 27% of the system consisted of LPP, leaving approximately 860 miles of LPP still to be replaced.[28]

Figure 10. Miles of Distribution Main by Material



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[23] The Narragansett Electric Company Proposed FY 2024 Gas Infrastructure, Safety, and Reliability Plan.

[24] Presentation by RIE during Docket Stakeholder Committee. RIE Gas Operations 101. 1/24/2024.

[25] The Narragansett Electric Company Gas Long-Range Resource and Requirements Plan for the Forecast Period 2022/23 to 2026/27, p. 67.

[26] The Narragansett Electric Company Gas Long-Range Resource and Requirements Plan for the Forecast Period 2022/23 to 2026/27, p. 23.

[27] Presentation by RIE during Docket Stakeholder Committee. RIE Gas Operations 101. 1/24/2024.

[28] Ibid.

Electric Distribution System

RIE provides electric service to over 500,000 residential, commercial, and industrial customers. The number of electric annual RIE customers has grown by approximately 0.3% annually from 2010 to 2020.[29] RIE's residential customers represent 88% of its customer count and 43% of its sales volume; RIE's commercial customers account for 12% of its total customers and 48% of its sales volume. Industrial delivery customers make up 0.3% of total customer count and 9% of its sales volume.[30]

RIE's electric distribution infrastructure includes over 6,000 miles of distribution lines, 420 feeders, and 60 substations.[31] Under Rhode Island's Renewable Energy Standard (RES), retail energy suppliers, including RIE, must procure enough renewable electricity to meet 100% of their customers' consumption by 2033, or pay an alternative compliance penalty.[32]

In recent years, Rhode Island has seen a significant increase in the adoption of distributed energy resources (DERs), including solar installations, electric vehicle (EV) charging stations, and battery storage systems. RIE makes budget proposals for grid investments to support load growth and the changing demands of electric customers through annual ISR filings with the PUC.

Currently, RIE's electric system is summer peaking, designed for a peak demand of approximately 2,000 MW and an average demand of 1,000 MW. The all-time highest peak demand was 1,985 MW in August 2006.[33] Over the next 15 years, the company expects the annual peak to increase by approximately 0.2% primarily due to load growth from electrification.[34]

Delivered Fuels

Fuel oil and propane are used by about one third of Rhode Islanders for space and water heating in buildings, meeting almost 40% of Rhode Island's heating demand.[35] The majority of these delivered fuels customers are located in the western part of Rhode Island where RIE does not provide gas service. Fuel oil and propane are shipped to Rhode Island via six marine import terminals in East Providence, Providence, and Tiverton and then delivered by truck to end-users.[36]

Emissions in Rhode Island Today

The latest Rhode Island GHG Inventory was released in October 2023 and published data on 2020 emissions levels in the state. In 2020, Rhode Island emitted approximately 9 million metric tons of carbon dioxide equivalent ($MMTCO_2e$), representing an economywide emissions reduction of 20%

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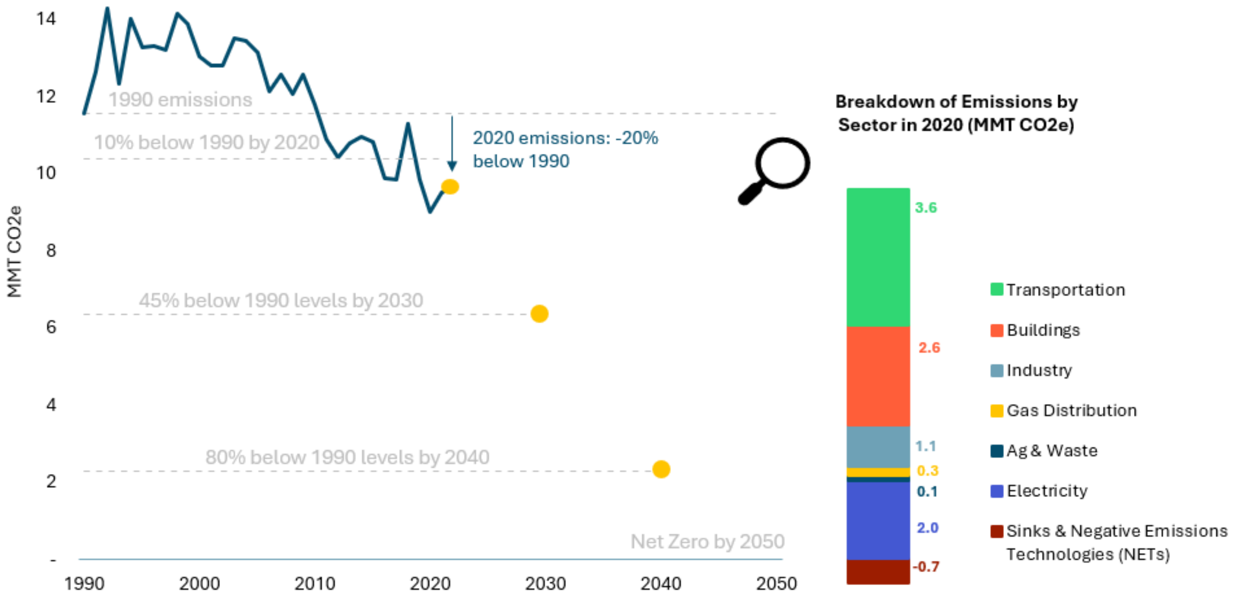
[29] U.S. EIA State Energy Data System (SEDS). 2021. https://www.eia.gov/state/search/#?5=126&6=134&2=220.
[30] U.S. EIA State Energy Data System (SEDS). 2021. https://www.eia.gov/state/search/#?5=126&6=134&2=220.
[31] "The Narragansett Electric Company Electric Infrastructure, Safety, and Reliability Plan FY 2023 Proposal Book 1 of 2."
[32] P.L. 2022, Ch. 218, § 1, effective June 27, 2022; P.L. 2022, Ch. 226, § 1, effective June 27, 2022
[33] Narragansett Electric Company, 2021 Electric Peak (MW) Forecast, 15-Year Long-Term, 2021 to 2036, at p. 4.
[34] Ibid., at p. 5, 27, & 29
[35] EIA, 2020 Residential Energy Consumption Survey (RECS)
[36] State of Rhode Island Office of Energy Resources, "Oil (Heating Only)".

from 1990 levels, thus achieving the Act on Climate's 2020 emission reduction mandate to reduce 10% below 1990 levels (Figure 11).[37] Overall, the transportation sector was the highest emitting sector, with nearly 40% of total emissions stemming from both on- and off-road sources in 2020. Electricity consumption was the second largest source of emissions in 2020, making up about 21% of total emissions and representing fossil fuel-generated power in the region. Combustion of fossil fuels in buildings comprised about 27% of total emissions in Rhode Island in 2020, primarily from natural gas and oil furnaces and boilers. The remaining emissions in Rhode Island stemmed from the industrial sector, gas distribution, agriculture, and waste.[38]

Figure 11. Historical and 2020 Emissions Breakdown in Rhode Island[39]



Rhode Island's GHG Accounting Framework

The Rhode Island 2020 GHG Inventory primarily relies upon the Environmental Protection Agency (EPA)'s emissions accounting framework reported in the State Inventory Tool (SIT). The accounting framework assumes a 100-year Global Warming Potential (GWP) based on the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5).[40] The GWP is a metric of how much a given gas, such as methane (CH_4) or nitrous oxide (N_2O), will contribute to global warming compared to carbon dioxide (CO_2) over a certain time period. By definition, CO_2 has a GWP of 1 so that it can be used as the reference gas.[41] GWPs enable the comparison between different gases by

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[37] Source: https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf

[38] Ibid.

[39] The categories in this chart are those used by E3 in the Technical Analysis modeling. The categories may vary slightly from those used in the RI GHG Inventory.

[40] IPCC AR5: https://www.ipcc.ch/assessment-report/ar5/

[41] Source: https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

putting all climate pollution effects into a single metric – in this case based on a 100-year time horizon. AR5 GWPs used by the RI 2020 GHG Inventory are shown in Table 4 below.

Table 4. IPCC AR5 GWPs

Pollutant	AR5 Global Warming Potential (GWP)
CO_2	1
CH_4	28
N_2O	265

Other key factors in Rhode Island's current emissions accounting methodology include:

- **Consumption-based electricity accounting.** The electric sector uses a consumption-based emissions accounting method. A consumption-based framework accounts for all emissions associated with electricity used within the state, rather than generated within the state.[42]
- **Net Zero GHG accounting.** The current netting methodology in Rhode Island involves summarizing all GHG sources and then subtracting all GHG sinks, rather than netting for individual GHGs.[43]
- **Renewable fuels**. Renewable fuels are considered carbon neutral in Rhode Island's current GHG emissions accounting methodology, and current emissions from biodiesel usage in the state are not reported.[44] More details on emissions associated with renewable fuels can be found in the textbox below.

In the Technical Analysis, the treatment of renewable fuels follows the Rhode Island accounting framework, which means that the use of renewable fuels is assumed to lead to gross GHG emissions reductions, effectively assuming all greenhouse gas emissions from renewable fuels have an emissions factor of zero. Through sensitivity analysis, E3 explores the impact of Rhode Island adopting alternative accounting frameworks that would treat the emissions factor from renewable fuels as non-zero, accounting for upstream and lifecycle emission associated with the combustion of fuels in the state, as detailed further in Chapter 3.

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[42] https://dem.ri.gov/sites/g/files/xkgbur861/files/programs/air/documents/ghg-memo.pdf

[43] Net Zero GHG accounting was confirmed by RI Department of Environmental Management (RIDEM) on the Stakeholder Committee.

[44] Rhode Island 202 GHG Emissions Inventory. https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf

Emissions associated with renewable fuels

Rhode Island considers emissions associated with renewable fuels as carbon neutral, which is in line with the treatment of emissions from biogenic sources used by the Environmental Protection Agency (EPA) and guidance from the Intergovernmental Panel on Climate Change (IPCC).[45] Some biogenic emissions in Rhode Island's inventory are reported for informational purposes, but those emissions are not counted towards the sum of gross emissions in the state. Although the combustion of biomass and biofuels in Rhode Island result in GHG emissions in the state, it is assumed that biogenic sources absorb a similar amount of CO2 *from the atmosphere* over their lifetime to what they release *into the atmosphere* at the point of combustion. Since EPA's national inventory includes an estimation of carbon sequestration resulting from biogenic sources, biogenic CO2 emissions are indirectly captured within the land-use, land-use change and forestry sector of the national inventory, even though these emissions might ultimately take place in different sectors or across different state borders.[46]

Many stakeholders in and outside of Rhode Island have cautioned the current treatment of biogenic emissions as carbon neutral, stating the complexity and uncertainty associated with lifecycle emissions. EPA acknowledges this complexity and notes that *"technical, policy and legal contexts may change over time that could lead to revisiting the treatment of biogenic emissions as necessary."*[47] In addition, the Rhode Island Department of Environmental Management (RIDEM) in its latest inventory recognizes the ongoing international controversy surrounding GHG accounting for energy generated from biogenic sources and continues to collaborate with stakeholders on a more robust framework.[48]

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[45] See: https://www.epa.gov/sites/default/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf; IPCC 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 1, Chapter 8

[46] https://www.epa.gov/sites/default/files/2018-04/documents/biomass_policy_statement_2018_04_23.pdf

[47] Ibid.

[48] 2020 Rhode Island GHG Emissions Inventory. Available at: https://dem.ri.gov/sites/g/files/xkgbur861/files/2023-10/2020%20RI%20GHG%20Emissions%20Inventory%20Summary.pdf

3. Technical Analysis Approach

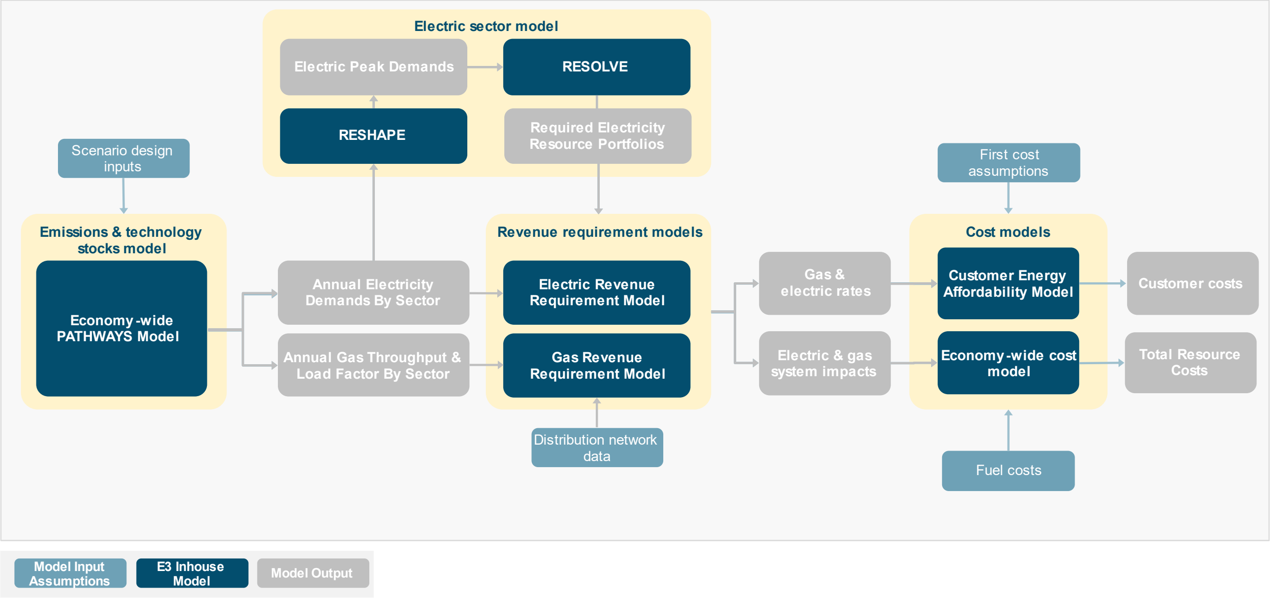
Modeling Framework

The Technical Analysis was developed using E3's in-house modeling framework designed to evaluate the impact of decarbonization targets on the state of Rhode Island, Rhode Island's gas distribution system and Rhode Island residents. The framework combines a variety of models that together assess the impact of distinct decarbonization pathways that achieve the Act on Climate on emissions, technology adoption, fuels, electric system impacts and gas system impacts, as well as evaluation criteria such as costs and affordability. The modeling framework consists of 4 model categories:

- **Rhode Island emissions and technology stock model:** E3 used the economy-wide PATHWAYS model to assess emissions and energy use over time. This model considers emissions and energy use across all sectors in Rhode Island and determines the impact of changes in technology stock on energy use and emissions.
- **Electric sector model:** E3 used a combination of RESHAPE and RESOLVE to assess impacts of scenarios on the electric sector. RESHAPE assesses the impacts of building electrification on annual and hourly electric loads, incorporating 40 years of historical weather data. RESOLVE is E3's electric sector capacity expansion model that assesses optimized electric sector portfolios in the ISO-NE area to maintain electric sector reliability.
- **Revenue requirement models:** E3 used an in-house, long-term (through 2050) revenue requirement framework that assesses the relationships between changing gas supply costs, throughput, capital investment, cost allocation and more on utility revenue requirements and rates. A less detailed, top-down revenue requirement model was used to assess in-state electric sector impacts and rates.
- **Cost models:** E3 uses a Customer Energy Affordability Model to calculate equipment retrofit costs and monthly energy and gas bills over time, using the rates calculated in the Revenue Requirement models. The Economy-wide cost model is used to assess the impact of pathways on total incremental resource costs for the state of Rhode Island.

A visualization of these categories that outlines the relationship between the models is provided in Figure 12. A detailed description of the models and assumptions is provided in Appendix A.

Figure 12. E3's Modeling Framework



Scenario Development

The scenarios described in this report represent distinct, plausible futures for how Rhode Island could meet its climate targets over the next several decades. Each scenario is designed to evaluate a unique combination of decarbonization strategies in order to meet Rhode Island's GHG reduction targets. The scenarios were developed in conjunction with the Stakeholder Committee and Technical Working Group with final direction and approval from the PUC, with the goal of answering key research questions related to the actions Rhode Island can take to achieve decarbonization across the whole economy, emphasizing, in particular, the role of natural gas distribution and the heating sector.

The decarbonization scenarios modeled for the Technical Analysis are not forecasts; instead, the pathways are modeled through a "backcasting" approach. Backcasting in this context means that E3 designed a key end-state outcome – statewide and sector-specific emissions reductions by 2030, 2040 and 2050 – and assessed the necessary changes in stock and fuel use over time in order to achieve that end-state outcome. While the scenarios are then compared against each other across multiple evaluation criteria, the intention is not to pick a preferred solution amongst scenarios. Instead, scenario analysis allows for the identification of commonalities, differences, and key implications for near- and long-term planning that can be incorporated into policy and regulatory design.

In addition, it is important to note that the decarbonization scenarios developed are not optimizations; instead, each scenario is meant to answer "what if" questions about the future of Rhode Island's energy system, rather than determine the optimal – or least-cost – path to decarbonization. Aside from the electric sector modeling framework that does optimize for least-cost electricity portfolios, the scenarios do not optimize for the most cost-effective solutions.

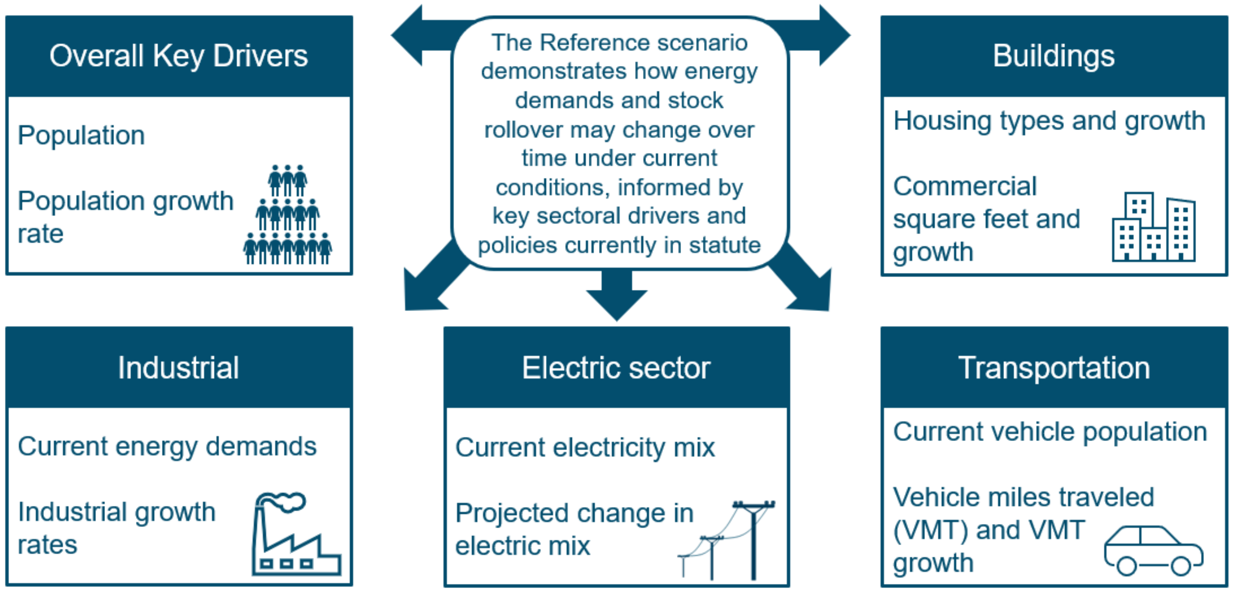
Scenarios are developed using a bottom-up accounting method, built upon detailed assumptions around building and heating characteristics, customer demographics, energy efficiency programs, emissions accounting framework, and the current regulatory landscape.

Input assumptions, especially key assumptions that have a driving impact on the outcome of the analysis, were discussed in detail with the TWG and iterated on through discussions and feedback. Throughout the TWG process, E3 shared an Excel-spreadsheet with draft input assumptions for TWG review and incorporated TWG feedback through multiple iterations of the document. The final overview of input assumptions used in the Technical Analysis is provided as a separate appendix to this report (Appendix B).

Reference Scenario

In order to understand the impact of existing policies on state energy demands, GHG emissions, and progress toward decarbonization goals, E3 first constructed a reference scenario, which captures the dynamics of all existing conditions and policies that are currently on-the-books in Rhode Island with the exception of the Act on Climate. The goal of this scenario is to estimate the path the state is on with respect to energy and GHG emissions before layering on additional actions needed to meet the GHG targets laid out in the Act. Specifically, the reference scenario is intended to identify the magnitude and scope of additional mitigation needs, after considering the impact of existing policies on emissions and energy demands. The energy consumption and emissions in the reference scenario are informed by key sectoral drivers in Rhode Island, such as population, housing units, and vehicle population (see Figure 13).

Figure 13. Reference Scenario Key Sectoral Drivers



The Reference scenario demonstrates how energy demands and stock rollover may change over time under current conditions, informed by key sectoral drivers and policies currently in statute

Detailed assumptions and data sources for key drivers are included in Appendix A.1. In addition to these key drivers, the reference scenario includes any policies that are currently in statute in Rhode Island, such as:

- **Rhode Island Biodiesel Heating Oil Act of 2013/2021:** All building (residential and commercial) oil customers receive heating oil with a 10% biodiesel blend in July 2023, increasing to 50% by 2030.[49]
- **Federal Energy Conservation Standards for Consumer Furnaces:** All new gas furnace sales must be 95% fuel efficient by 2029.[50]
- **Rhode Island's Renewable Energy Standard (RES):** Rhode Island's electric grid will be powered by 100% renewable energy by 2033, including interim targets (36% electricity from renewable sources by 2025, 74% electricity from renewable sources by 2030, among others). The RES is not a production target; it requires utility companies to procure clean energy projects, purchase renewable energy certificates (RECs), or pay an alternative compliance payment that is typically above the market price of RECs .[51]

The reference scenario also includes assumptions around the role of efficiency and the pace of decarbonization in the buildings and transportation sectors under existing conditions.

- **Building envelopes and weatherization**. Based on data provided by NV5, it is anticipated that in the reference scenario nearly 60% of residential buildings and about 10% of commercial buildings will undergo light-touch weatherization retrofits by 2050.[52] Light-touch retrofits include basic weatherization upgrades, such as glazing and partial air sealing, and are expected to reduce heating energy service demand by approximately 15%.[53]
- **Building electrification**. A modest level of heat pump growth (25% residential space heating stocks and 15% of commercial are heat pumps by 2050) was included in the reference scenario, primarily driven by electric resistance conversions and existing federal/state heat pump incentives (e.g. Inflation Reduction Act, Clean Heat RI, Rhode Island Energy Rebates).[54,55,56]
- **Transportation electrification**. Advanced Clean Cars II (ACCII) and Advanced Clean Trucks (ACT) policies were <u>not</u> incorporated into the reference scenario based on discussions with the Stakeholder Committee and Technical Working Group, in order to allow for a better comparison of the isolated impacts of the regulation compared to impacts occurring from natural demand drivers. The reference scenario assumes that electric vehicle penetration

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[49] http://webserver.rilin.state.ri.us/BillText/BillText21/HouseText21/H5132A.pdf; http://webserver.rilin.state.ri.us/BillText/BillText21/SenateText21/S0357A.pdf

[50] https://www.regulations.gov/document/EERE-2014-BT-STD-0031-4107

[51] http://webserver.rilin.state.ri.us/BillText/BillText22/HouseText22/H7277A.pdf; http://webserver.rilin.state.ri.us/BillText/BillText22/SenateText22/S2274Aaa.pdf

[52] NV5 is an engineering consulting firm with deep energy efficiency expertise. The firm was a representative in the Technical Working Group on behalf of RI Energy Efficiency & Resource Management and provided data and forecasts on building envelope adoption in Rhode Island.

[53] Detailed assumptions can be found in Appendix A.1.

[54] https://www.whitehouse.gov/cleanenergy/

[55] https://cleanheatri.com/

[56] https://www.rienergy.com/media/ri-energy/pdfs/energy-efficiency/ri_electric_heating-cooling_form.pdf

would reach 10% by 2030, as targeted by Rhode Island's Executive Climate Change Coordinating Council (EC4) in the 2022 Climate Update[57], with anticipated penetration primarily driven by current rebate programs, such as DRIVE EV.[58]

Decarbonization Scenarios

In addition to a reference scenario, E3 designed six decarbonization scenarios, each presenting a distinct pathway to achieving climate targets in Rhode Island. All scenarios comply with Rhode Island's Act on Climate, which requires a net emissions reduction target of 45% below 1990 levels by 2030, 80% below 1990 levels by 2040, and net zero by 2050.[59] Each scenario was designed to answer unique research questions on the role of different strategies to mitigate GHG emissions and the future of natural gas in Rhode Island:

- **High Electrification**: What is the impact of pursuing a full electrification decarbonization pathway that transitions Rhode Island away from gas infrastructure?
- **Hybrid with Delivered Fuels Backup**: What is the impact of hybrid electrification with delivered fuels (i.e., the use of an electric heat pump with a delivered fuel-powered furnace or boiler to be used during the coldest conditions)? What is the net benefit of avoiding gas infrastructure/decommissioning?
- **Hybrid with Gas Backup:** What is the impact of hybrid electrification with gas (i.e., the use of an electric heat pump with a gas-powered furnace or boiler to be used during the coldest conditions)? How can Rhode Island leverage existing gas infrastructure to reduce electric sector build out?
- **Staged Electrification:** How can Rhode Island leverage existing infrastructure and mitigate customer impacts in the near-term, while allowing for a managed transition and achieving long-term electrification?
- **Alternative Heat Infrastructure:** How can highly efficient heating systems (e.g., networked geothermal) support decarbonization in Rhode Island? What is their net impact? Can they provide an alternative to gas investments?
- **Continued Use of Gas:** How can existing gas infrastructure support decarbonization? What is the effect of and potential limit to remaining fossil gas and renewable fuels such as biomethane, hydrogen and other emissions-compliant fuels??

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[57] https://climatechange.ri.gov/media/1261/download?language=en.

[58] DRIVE EV is an electric vehicle rebate project that provides incentives to Rhode Island residents and businesses to adopt electric vehicles. https://drive.ri.gov/.

[59] Gross emissions represent the total amount of greenhouse gases that enter the atmosphere; net emissions reductions account for the balancing or offsetting of emissions that occurs through negative emissions technologies (NETs) and the Land Use, Land Use Change, and Forestry (LULUCF) sector.

Delivered Fuels as Backup

The use of delivered fuels as a hybrid heat pump backup fuel option to mitigate electric system peak impacts in winter is a relatively new concept suggested by the Stakeholder Committee that has not yet been studied in detail elsewhere in the United States. Following this concept, customers currently using delivered fuels as their main source of heating *or* customers that currently use gas as a main source of heating would adopt all-electric heat pumps, while installing or keeping a furnace or boiler that uses fuel oil, propane or another form of delivered fuel that does not rely on networked infrastructure. A potential advantage of the concept for existing gas customers is that networked infrastructure, such as gas pipelines, can be decommissioned with less impact on customers or the electric grid. Uncertainty exists around the extent to which required tank storage is feasible on customer premises and around the impact of the above-ground delivery of fuels, such as truck movements. These uncertainties are not investigated in the Technical Analysis and require further study.

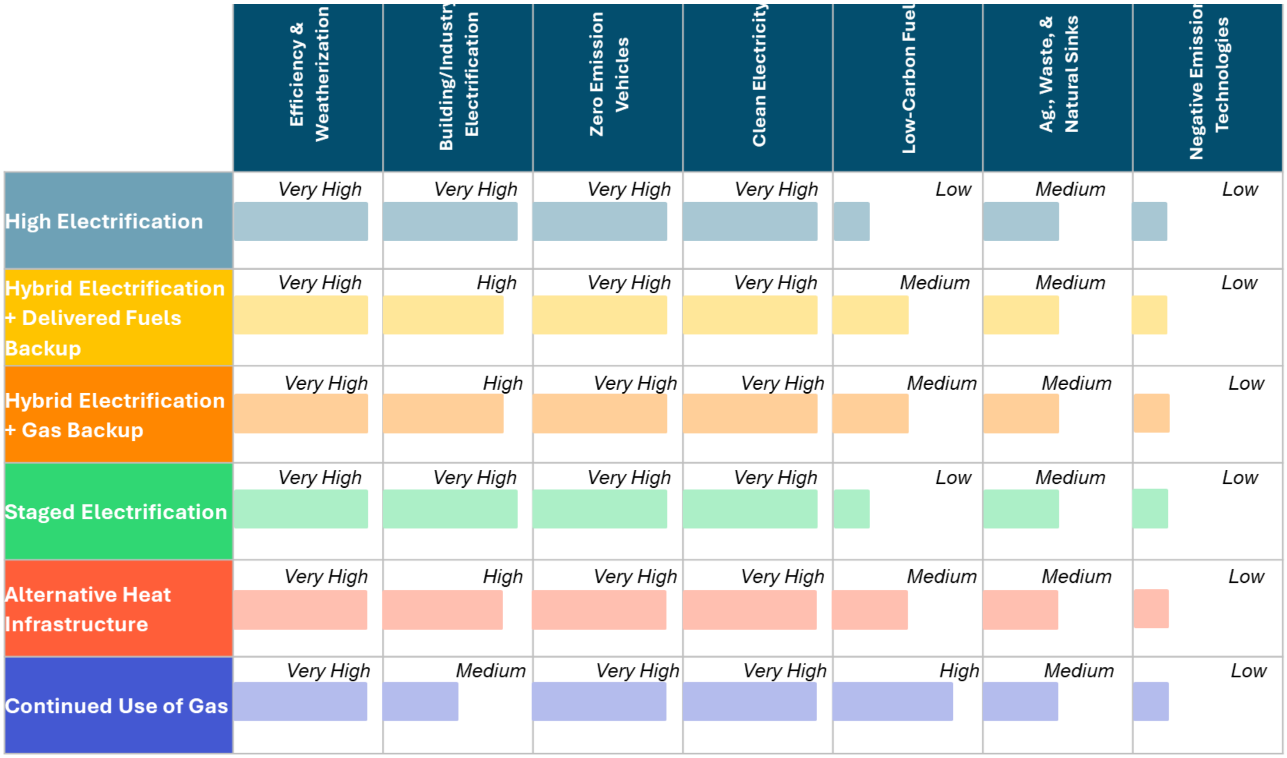
Throughout this report, E3 uses the term delivered fuels as an umbrella term covering all non-regulated fuels such as propane and fuel oil. In our modeling framework, a fuel oil furnace or boiler was used as a proxy to define the impacts of the concept for all types of delivered fuel conversions. However, the conversion to propane may result in advantages over fuel oil given the emissions impact of propane over fuel oil. In addition, converting to the use of a propane boiler or furnace may be possible with limited adaptations required to an existing gas furnace or boiler. For example, in a “staged” transition, customers with an existing gas furnace or boiler could make burner-tip adjustments to their appliances by switching from gas to propane fuel while installing a partial load electric heat pump. These customers could then transition to whole-home electric heating later in time, at the end-of-life of their furnace or boiler. This conversion could avoid the upfront cost of installing a new boiler or furnace for backup use, although it is important to note that this concept primarily applies to scenarios that see a longer-term transition to whole-home electric heating, such as the Staged Electrification scenario. E3 explores the impact of avoided backup system costs as a sensitivity in the Technical Analysis.

In each of these scenarios, the role and use of the gas system is expected to change through fuel switching, efficiency or timing of technology adoption. Some pathways, such as Hybrid with Gas Backup and Continued Use of Gas keep a role for the gas system while others, such as High Electrification and Hybrid with Delivered Fuels Backup – move away from using the gas system over time. In these scenarios, the gas system is eventually expected to decommission where feasible.

Key scenario parameters

Given this study's emphasis on the role of the natural gas system in statewide decarbonization objectives, the Technical Analysis primarily focuses on mitigation strategies within the heating sector. As a result, the scenarios vary in levels of electrification and reliance on renewable fuels while keeping other factors mostly constant across scenarios to allow for comprehensive comparisons. However, each sector plays an important role in Rhode Island's path to net zero, even if many parameters are aligned across scenarios. The high-level scenario parameters are shown in the figure below.

Figure 14. Overview of Scenario Parameters



	Efficiency & Weatherization	Building/Industr Electrification	Zero Emission Vehicles	Clean Electricity	Low-Carbon Fuel	Ag., Waste, & Natural Sinks	Negative Emissio Technologies
High Electrification	Very High	Very High	Very High	Very High	Low	Medium	Low
Hybrid Electrification + Delivered Fuels Backup	Very High	High	Very High	Very High	Medium	Medium	Low
Hybrid Electrification + Gas Backup	Very High	High	Very High	Very High	Medium	Medium	Low
Staged Electrification	Very High	Very High	Very High	Very High	Low	Medium	Low
Alternative Heat Infrastructure	Very High	High	Very High	Very High	Medium	Medium	Low
Continued Use of Gas	Very High	Medium	Very High	Very High	High	Medium	Low

Note: there may be minor variation across scenarios to account for rounding/balancing of final GHG targets.

- **Efficiency and Weatherization.** Efficiency and weatherization assumptions are kept constant across all scenarios. It is assumed that about 60% of residential buildings and nearly 10% of commercial buildings will undergo light-touch weatherization retrofits by 2050. All decarbonization scenarios additionally assume a nearly 35% adoption of deep-shell retrofits by 2050 in the Residential sector. Other types of efficiency are also assumed to improve over time in Rhode Island, such as technology performance, behavioral conservation, and industrial efficiency. Details on all efficiency parameters and results can be found in Chapter 4 and Appendix A.1.
- **Building/Industry Electrification.** Given the Technical Analysis' focus on the heating sector, levels of building and industrial electrification vary significantly across scenarios. Depending on the design of each scenario, different levels of electrification and industry are deployed.

Scenarios that explore the impact of high electrification and gas decommissioning include high levels of heat pump adoption in buildings and the industrial sector electrifies as much as technically feasible. For scenarios that are meant to show the impact of continued reliance on the natural gas system, fewer heat pumps are adopted in buildings and industry relies more heavily on low-carbon fuels instead of electrification. Additionally, a larger share of the heat pumps adopted in those scenarios are systems with gas backup.

- **Zero Emission Vehicles**. Zero-emission vehicle (ZEV) adoption levels are held constant across all scenarios. The light-duty vehicle (LDV) and medium- and heavy-duty vehicle (MHDV) electrification trajectories are largely driven by the adoption of ACCII and ACT in Rhode Island.
- **Clean Electricity.** Electric sector assumptions are held constant across all scenarios, although the variations in building electrification will lead to different levels of load growth. Like the reference scenario, all decarbonization scenarios comply with Rhode Island's RES. The decarbonization scenarios also account for electric sector targets outside of the RES, including the ambition to add 600-1000 additional MW of offshore wind to the state's clean energy portfolio.[60,]
- **Renewable Fuels.** Given the Technical Analysis' focus on the role of the natural gas system, levels of renewable fuels vary across scenarios. Scenarios that rely on higher levels of electrification and gas system decommissioning require lower blends of renewable fuels into the remaining fuel mix by 2050 to reach emissions targets. Scenarios that maintain a larger use of the natural gas system by 2050 require higher levels of renewable fuel blends in order to reach emissions targets. As described in the textbox below, E3 uses the term renewable fuels as an umbrella term considering all types of emissions-compliant fuels.
- **Ag., Waste, & Natural Sinks.** Parameters around agriculture, solid waste, wastewater, and natural carbon sinks are held constant across scenarios. Overall, these sectors make up a very small component of Rhode Island's economywide emissions. Like the reference scenario, it is assumed that agricultural emissions will remain flat over time, as reflected in historical trends from the Rhode Island GHG Inventory and due to the difficulty to decarbonize. Also aligned with the reference scenario, solid waste emissions are assumed to phase out to zero emissions by 2040 after the Central Landfill is closed in 2048, consistent with the 2016 Rhode Island GHG Reduction Plan.[61] Unlike in the reference scenario, it is assumed that carbon sequestration will remain mostly flat through 2050 due to no net forest, wetland, or cropland loss (in line with the 2016 Rhode Island GHG Reduction Plan).[62] No net losses in forestland assumes the adoption of conservation measures and that new developments will be built denser and on already-developed lands.

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[60] In 2022, Governor Dan McKee signed a bill that required a request for proposals for up to 600-1,000 MW of offshore wind capacity. Although the initial bid responses were rejected, additional RFPs have been announced. See: S 2583. State of Rhode Island. General Assembly 2022. http://webserver.rilin.state.ri.us/BillText/BillText22/SenateText22/S2583.pdf; Rhode Island Energy's Long-Term Clean Energy Procurement 2023 OSW RFP: https://ricleanenergyrfp.com/2023-osw-rfp/

[61] https://climatechange.ri.gov/sites/g/files/xkgbur481/files/documents/ec4-ghg-emissions-reduction-plan-final-draft-2016-12-29-clean.pdf

[62] Ibid.

- **Negative Emissions Technologies (NETs).** The use of NETs to meet emissions targets is held constant across all scenarios.[63] NETs are used as a final measure to align emissions across all sectors with the net zero target by 2050.

Renewable fuel emissions compliance

E3 modeled a role for renewable fuels in transportation, buildings, and industry, detailed further in Chapter 4. It is likely that Rhode Island will need to become a net importer of renewable fuels to decarbonize end uses that are challenging to electrify as described in more detail in Chapter 5. The availability, efficacy and costs associated with these fuels is uncertain. E3 captured some of this uncertainty through sensitivity analysis, but additional detail on the role and implications of using renewable fuels in the state warrants further policy discussion.

Some members of the Technical Working Group have suggested that other forms of emissions compliance mechanisms could fulfill the same role as renewable fuels. An example would be offsetting fossil fuel combustion through negative emissions technologies such as direct air capture (note that this is not reflected in the modeling). The latest National Climate Assessment states that further research is required to better understand whether producing and burning physical low-carbon fuels is lower in costs and more sustainable than managing emissions from fossil fuels through carbon dioxide removal from the atmosphere.[64] In Rhode Island's current accounting framework, such a method would contribute to the *net* emissions target as long as the carbon dioxide removal takes place within state borders. More discussion and clarity is required to understand the scope and eligibility of these options and their relation to the state's accounting framework.

Acknowledging the uncertainty associated with the availability, costs and efficiacy of renewable fuels, E3 uses the term "renewable fuels as" an umbrella term encompassing emissions-compliant fuels without specifically prescribing their source. A similar approach is taken for the calculation of costs associated with renewable fuels (described in Appendix A) that uses a simplified "marginal cost of abatement" compliance approach with low and high bounds without detailing the cost of production of different type of fuels. Additional considerations and implications of the reliance on out-of-state fuels are described in Chapter 5.

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[63] There may be minor variation across scenarios to account for rounding and balancing of final GHG targets.

[64] Davis, S.J., R.S. Dodder, D.D. Turner, I.M.L. Azevedo, M. Bazilian, J. Bistline, S. Carley, C.T.M. Clack, J.E. Fargione, E. Grubert, J. Hill, A.L. Hollis, A. Jenn, R.A. Jones, E. Masanet, E.N. Mayfield, M. Muratori, W. Peng, and B.C. Sellers, 2023: Ch. 32. Mitigation. In: Fifth National Climate Assessment. Crimmins, A.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, B.C. Stewart, and T.K. Maycock, Eds. U.S. Global Change Research Program, Washington, DC, USA. https://doi.org/10.7930/NCA5.2023.CH32

Detailed scenario parameters for space heating purposes

Each scenario primarily focuses on how the deployment of different types of space heating technologies (see Table 5) and the use of renewable fuels[65] in buildings and industry might shape Rhode Island's future energy landscape.

Table 5. Key Narrative and Space Heating (Residential and Commercial) Technology Assumptions for Each Scenario

Scenario Name	**Key Scenario Narrative (focused on heating sector transformations)**	**Key[66] Space Heating Technologies**					
		ASHP/Electric Boilers[67,68]	GSHP[69]	Hybrid HP/Boilers w/DF[70]	Hybrid HP/Boilers w/Gas	Networked Geo.	Eff. Gas Furnace
High Electrification	The High Electrification scenario focuses on high levels of efficiency and deployment of primarily all-electric heating in buildings. A small number of buildings keep a backup heating source. The industrial sector electrifies as much as technically feasible.	●	●				
Hybrid Electrification with Delivered Fuels (DF) Backup	The Hybrid with Delivered Fuels Backup scenario focuses on high levels of efficiency and deployment of primarily hybrid heat pumps with delivered fuels as backup in buildings. A modest number of buildings convert to all-electric heating. The industrial sector electrifies as much as technically feasible.			●			
Hybrid Electrification with Gas Backup	The Hybrid with Gas Backup scenario focuses on high levels of efficiency and deployment of primarily hybrid heat pumps with gas as backup in buildings. A small number of buildings convert to all-electric heating. The industrial sector converts to a mix of electrification and renewable fuels (e.g., hydrogen).				●		

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[65] See textbox above.

[66] Note this table does not show *all* space heating technologies deployed in each scenario. The table is simply meant to highlight the technologies of primary focus in each pathway.

[67] ASHP: Air Source Heat Pump

[68] In the Commercial sector, buildings undergoing electrification convert to either an electric boiler or an ASHP, depending on the existing technology type (boiler vs. furnace). Further details can be found in Chapter 4.

[69] GSHP: Ground Source Heat Pump

[70] HP: Heat Pump; DF: Delivered Fuels

Staged Electrification	The Staged Electrification scenario focuses on a staged transition for buildings starting with a ramp up of hybrid heat pumps in the near-term (both gas and delivered fuels). By the mid-2030s, buildings and industry begin to convert to all-electric where possible.	●	●	●	●		
Alternative Heat Infrastructure	The Alternative Heat Infrastructure scenario focuses on a mix of networked geothermal systems, all-electric heating, and hybrid HPs in buildings. The industrial sector converts to a mix of electrification and renewable fuels (e.g., hydrogen).	●			●	●	
Continued Use of Gas	The Continued Use of Gas scenario focuses on a mix of high-efficiency gas appliances and hybrid heat pumps in buildings. The industrial sector converts to a mix of electrification and dependence on renewable fuels (e.g., hydrogen). The gas system continues to serve customers all year.				●		●

Sensitivity Analysis

The scenario approach used by E3 is assumptions-driven and, as any outlook towards 2050, is inherently uncertain across factors related to costs, consumer behavior, technology development and other factors. To account for key uncertainties, E3 incorporated sensitivity analyses in its modeling framework across a number of key parameters that are likely to have a meaningful impact on the results of the analysis. In particular, E3 incorporated two types of sensitivities:

1. Sensitivities impacting ***the level and pace of emissions reductions***, such as technology adoption parameters, efficiency assumptions and assumptions regarding the accounting of GHG emissions;
2. Sensitivities impacting ***the costs of the transition***.

The table below provides an overview of the sensitivities included in this analysis. A detailed overview of assumptions related to sensitivity analyses is provided in Appendix A.1.

Table 6. Overview of Sensitivity Parameters

Sensitivity analysis	Scope	Expected insights
Sensitivities impacting the level and pace of emissions reductions		
Higher levels of ***cold climate heat pumps efficiency performance***	• Modeled as a sensitivity on building sector energy demands and electric capacity needs. • Modeled for the High Electrification scenario only.	Potential electric sector impacts resulting from the adoption of higher efficiency technology.
Lower levels of transportation electrification, e.g.,	• Modeled as a sensitivity onto transportation sector technology adoption levels	Potential impacts to the heating sector resulting

slower pace of adoption than required by ACCII.	• Modeled for the High Electrification scenario only.	from the slower adoption of electric vehicles.

Different GHG accounting frameworks, including higher GWPs, upstream fuel emissions and zero emissions benefit from biofuels	• Modeled as a sensitivity onto fuel emissions factors through 3 options:
	  ○ Lifecycle emissions associated with fuels
	  ○ 20-year GWP
	  ○ No emissions benefits from renewable fuels
	• Modeled for all scenarios
		Potential risks associated with higher reliance on biofuels

Sensitivities impacting the costs of the transition.		
Elements of a managed transition, i.e. ***targeted electrification and gas decommissioning*** on gas system investments, rates, and resource cost.	• Modeled as a sensitivity onto gas sector costs (avoidance of leak-prone pipe replacement) • Modeled for all scenarios	Potential level of cost savings on the gas system that can be achieved per scenario if electrification takes place through a managed approach.
Cost of ***cold-climate air source, ground-source and hybrid heat pumps***	• Modeled as low/high bounds on heat pump capital and installation costs	Potential impact of varying cost input assumptions on total resource costs and the comparison of cost risks across scenarios.
Cost of ***networked geothermal systems***	• Modeled as low/high bounds on networked geothermal installation capital costs (excluding behind-the-meter costs)	
Cost of ***renewable fuels***	• Modeled as low/high bounds on the compliance cost of fuel for renewable natural gas, diesel, and gasoline	
Cost of ***Renewable Energy Certificates (RECs)***	• Modeled as low/high bounds on the cost of purchasing RECs to comply with the 100% RES standard	
Cost of ***avoiding hybrid electrification backup use***	• Modeled as an additional sensitivity onto the cost of Air Source Heat Pumps (ASHPs) with backup use (<u>not included in low/high bounds</u>) • Modeled for scenarios that use ASHP with backup use	Potential impact of a "staged" approach to backup use where customers keep existing furnaces or boilers as backup

Overview of Evaluation Criteria and Metrics

To assess the implications and feasibility of the modeled decarbonization scenarios, E3 together with the Stakeholder Committee defined a set of key evaluation criteria. Evaluation criteria can be used as an objective measure to assess benefits, risks and challenges associated with pathways, without choosing a preferred set of pathways or weighing one criterion more heavily over another. In particular, the evaluation criteria in this analysis are used to distill commonalities and shared opportunities and risks that can be taken into account by policymakers in the policy development phase of this docket.

E3 assessed pathways across a combination of both quantitative and qualitative factors. An overview of evaluation criteria and associated metrics is provided in the table below.

Table 7. Overview of Evaluation Criteria and Metrics used to Assess Implications of Decarbonization Pathways

Criteria	Definition	Based on metric
Quantitatively assessed		
Scenario Costs	Statewide total cost (cost of fuels, capital costs, electric/gas system costs, etc.) associated with AoC compliance and associated cost of abatement	• Cumulative incremental Net Present Value (NPV) and annual total resource costs of pathways compared to reference scenario • $/tonne CO2e abated by subsector
Customer affordability	Total cost of ownership for individual customers adopting decarbonization measures	• Monthly total bills for customers adopting heating technologies (“migrating customers”)
	The effect of customer migrations on the remaining costs for customers on the gas system	• Monthly total bills for customers <u>not</u> adopting decarbonized heating technologies (“non-migrating customers”)
Qualitatively assessed		
Customer choice	The extent to which customers are able to choose their preferred heating solution	• Estimated number of targeted electrification projects in 2035
Workforce impacts	The extent to which scenarios impact the need for a difference workforce in the state	• Not based on quantitative metrics (described qualitatively only)
Reliance on Regional Fuel Supply	Reliance on level of renewable fuel that, given Rhode Island’s footprint, will likely need to be imported from out of state	• Annual volume of renewable fuels
Technology Readiness	The extent to which a pathway relies on commercially available technologies	• “Technology readiness level” (TRL) range that will be required in each scenario to comply with AoC.
Pace of electric system expansion	The pace and scale of electric sector infrastructure needs	• Near-term (up to 2035) transmission and distribution (T&D) investments and new installation of electric generation resources (e.g. offshore wind).

Notably, each scenario is modeled to reflect a safe and reliable energy system in Rhode Island per existing gas and electric standards, while achieving similar levels of greenhouse gas reductions. As such, safety and reliability are not evaluated as criteria that differ between scenarios.

4. Decarbonization Pathways – Technical Results

This chapter details the results of Technical Analysis, describing each decarbonization scenario's impact on emissions, technology adoption, energy demand, the gas system, and the electric grid. Additional implications across evaluation criteria for each pathway will be discussed in Chapter 5.

Impact on Emissions

A primary component of reaching the targets set out in Rhode Island's Act on Climate is the mitigation of GHG emissions across Rhode Island's economy. As such, a key focus of this study is determining what decarbonization measures will need to be taken in all sectors of the economy in order to achieve Rhode Island's climate goals and what level of emissions reductions these measures can achieve.

Reference Scenario Emissions

While Rhode Island's 2020 emissions showed a 20% reduction in emissions compared to a 1990 baseline, 2020 was not a standard year due to the COVID-19 pandemic. COVID-19 caused a dip in normal activities, such as driving to work, leading to abnormally low energy demand. With the economy's rebound from the pandemic and return to normal activities, energy usage data available from EIA for 2021 and 2022 implies that Rhode Island can expect emissions to increase again in the next two years (Figure 15), with 2022 emissions landing about 15% below 1990 levels. After 2022, current economywide conditions and existing policies are expected to lead to ongoing emissions reductions in the reference scenario.

Overall, the reference scenario achieves a 40% emissions reduction by 2030 (% relative to 1990), a 55% reduction by 2040, and 57% emissions reduction by 2050, as shown in Figure 15. Emissions reductions are driven by a combination of measures across the economy:

- **Transportation**. The transportation sector in the reference scenario achieves a 28% sectoral emissions reduction by 2030, 43% emissions reduction by 2040, and 45% reduction by 2050 compared to 1990 levels. Reductions are driven by an increase in EV penetration consistent with historical levels and targets set by EC4, reaching approximately 10% of LDV stocks by 2030 and 37% of LDV stocks by 2050. Zero-emission MHDVs grow modestly over the next three decades. There is overall growth in Vehicle Miles Traveled (VMT) per vehicle, but a decline in total number of vehicles due to population decreases across the state. The reference scenario does not include impacts of adoption of ACCII/ACT.
- **Buildings**. The buildings sector achieves a sectoral emissions reduction of 35% by 2030, 41% by 2040, and 45 by 2050, compared to 1990 levels. The reductions are driven by modest heat pump adoption, with about 5% of customers adopting heat pumps by 2030 and about 10-15% of customers adopting heat pumps by 2050. It is also anticipated that a portion of delivered fuel customers will convert to gas heating at a pace aligned with historical levels in the reference scenario. Customers that remain on fuel oil will have a 50% biodiesel blend in

their fuel by 2030, continuing at the same rate until 2050, per the Biodiesel Heating Act. Energy efficiency also plays a role in building sector reductions, with weatherization retrofits reaching nearly 60% adoption by 2050.

- **Industry**. Combustion emissions from heating in the industrial sector increase in the reference scenario due to projected industrial growth, reaching about 7% sectoral increase by 2030, 12% increase by 2040, and 18% by 2050, compared to 1990 levels. Other non-combustion industrial process emissions decrease slightly, primarily due to the reduction in hydrofluorocarbons (HFCs) in alignment with the Kigali Amendment to the Montreal Protocol.[71]
- **Gas distribution**. Rhode Island's gas distribution sector will experience a sectoral emissions reduction of 48% by 2030, 64% by 2040, and 63% by 2050 compared to 1990 levels. Emissions reductions are driven by RIE's Leak Prone Pipe replacement schedule out to 2035. Note that the gas distribution category in Rhode Island's Inventory only accounts for emissions resulting from methane leakages in the distribution phase and does not include emissions resulting from the combustion of gas, or upstream (out-of-state) emissions.
- **Agriculture & waste**. After 2020, there are no emissions reductions assumed in the agricultural sector due to hard-to-decarbonize end-uses and historical trends. By 2048, solid waste emissions are phased down to zero after the Central Landfill is expected to close in 2038, which is consistent with the 2016 RI GHG Reduction Plan. Overall, waste emissions decrease by 64% in 2030, 65% in 2040, and 70% in 2050 compared to 1990 levels.
- **Electricity**. The largest contribution to reference scenario emissions reductions in Rhode Island are expected in the electric sector with 77% sectoral emissions reduction in 2030, 100% reduction in 2040, and 100% reduction in 2050, compared to 1990 levels. The large reduction in the electric sector is driven by Rhode Island RES, which requires 100% renewable energy procurement or REC purchases by 2033. This means that after 2033, all electricity in Rhode Island is considered zero-emission.
- **Sinks and NETs.** There is a slight reduction in sequestration from carbon sinks by 2050 due to deforestation assumptions as laid out in the RI 2020 Forest Action Plan. No NETs are utilized in the reference scenario.[72]

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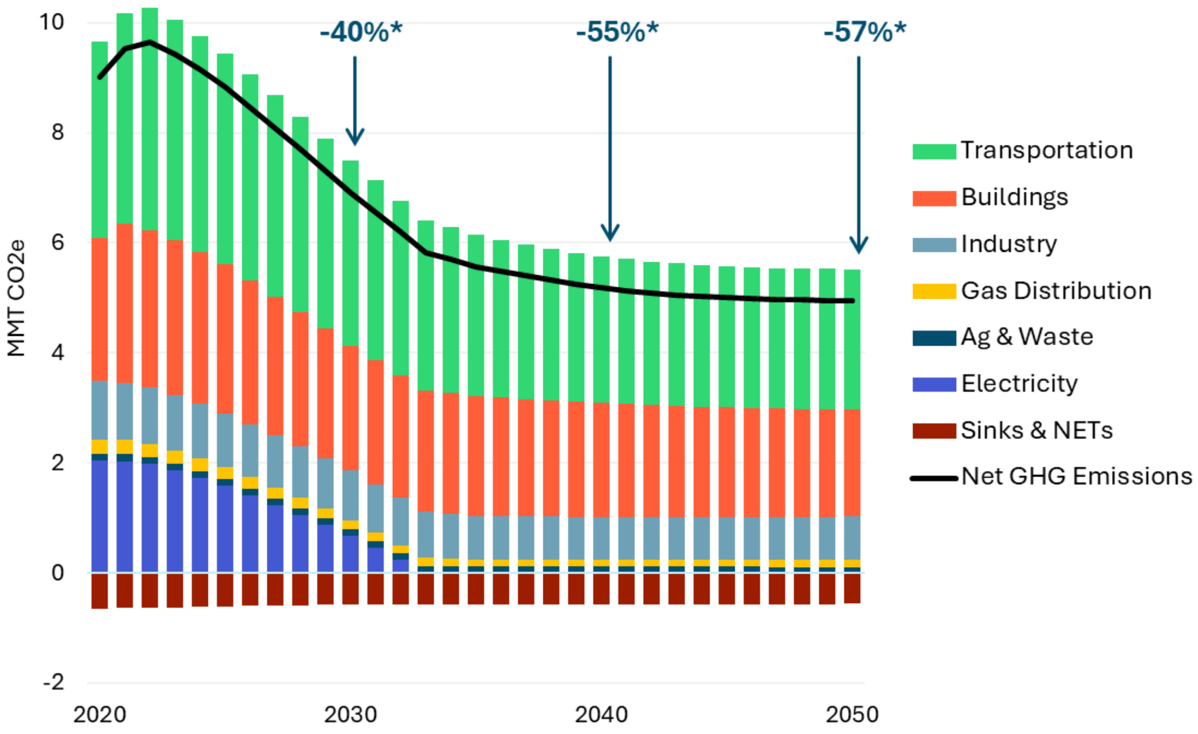
[71] https://www.state.gov/u-s-ratification-of-the-kigali-amendment/

[72] Rhode Island Department of Environmental Management and Division of Forest Environment. 2020 Forest Action Plan. https://dem.ri.gov/sites/g/files/xkgbur861/files/programs/bnatres/forest/pdf/forest-action-plan/forest-action-plan.pdf

Figure 15. Reference Scenario GHG Emissions 2020-20250



* compared to 1990 GHG emissions levels

Despite the progress made in the Reference scenario under existing policy mechanisms, additional measures will be required to achieve Rhode Island's Act on Climate mandate by 2030, 2040, and 2050. The Reference scenario misses emissions targets by .55 MMT CO2e in 2030, 2.87 MMT CO2e in 2040, and 4.95 MMT CO2e in 2050, indicating that more aggressive mitigation action will be needed, particularly in the buildings. transportation, and industrial sectors in later years. Achieving compliance with 2040 and 2050 targets will require acceleration of mitigation measures between 2025 and 2040, especially considering the significant lag time between annual sales increases and subsequent changes to stock penetration.

Methane leakage from the gas distribution system

Following EPA guidance and aligning with the methodology from the state's GHG Inventory, methane leakage in the state of Rhode Island is estimated using reported gas consumption and emissions factors associated with different material types of gas distribution mains and services. This methodology assumes that as natural gas is distributed to end-use customers, a certain percent of gas leaks into the atmosphere in the form of methane (CH4), therefore contributing to GHG emissions. In Rhode Island's accounting framework, the impact of methane leakage on emissions is calculated for in-state emissions only (excluding out-of-state supply chain impacts) over a 100-year time period (using a 100-year GWP).

Distribution system materials such as cast iron and unprotected steel, that today make up about 30% of mains in Rhode Island, are considered "leak-prone" and therefore have a significantly higher emissions factor than material types such as plastic and protected steel. Therefore, as RIE continues to replace leak-prone-pipe as part of its ISR program, emissions from the gas distribution system are expected to decline under the state's accounting framework.

Recent studies have indicated that leakage from oil and gas systems may be higher than currently reported through inventories. For example, Weller et al. (2020) estimated that national methane emissions from the gas distribution system were approximately five times greater than reported through EPA inventories.[73] A study published in PNAS in 2021 found that atmospheric methane measurements in the Boston area over 8 years were three times larger than calculated by usage-based inventories, observing no changes in emissions despite efforts to replace leak-prone pipes.[74]

It is important to note that detailed measurement reports of methane leakage associated with the distribution system are currently lacking. The only widely available measure of potential leaks reported by utilities is called "Lost and Unaccounted for Gas (LAUF)", which represents the difference between gas purchased and gas sold. However, studies have criticized the LAUF metric, arguing that it includes noise created by differences in the timing of measurements, variations in temperatures, meter inaccuracies and accounting errors.[75]

The uncertainty related to methane leakage, including potential impacts from unreported sources such as gas meters and indoor appliances, warrants continuous consideration and focus for further study.

Decarbonization Scenario Emissions

All decarbonization scenarios are designed to meet the emissions targets defined by Rhode Island's Act on Climate under Rhode Island's current GHG accounting framework. In addition, as a result of keeping most non-heating measures constant across scenarios, all pathways reach similar gross emissions in 2030, 2040, and 2050 by sector (see Table 8). That is, the gross emissions levels in 2040 in the residential sector for the High Electrification pathway is equal to the gross emissions levels in 2040 in the residential sector for the Continued Use of Gas pathway, but the primary measures employed to achieve those emissions reductions vary across pathways.

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[73] Weller, Z., Hamburg, S., von Fisher, J. (2020). A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems. *Environ. Sci. Technol.* 2020, 54, 14, 8958–8967

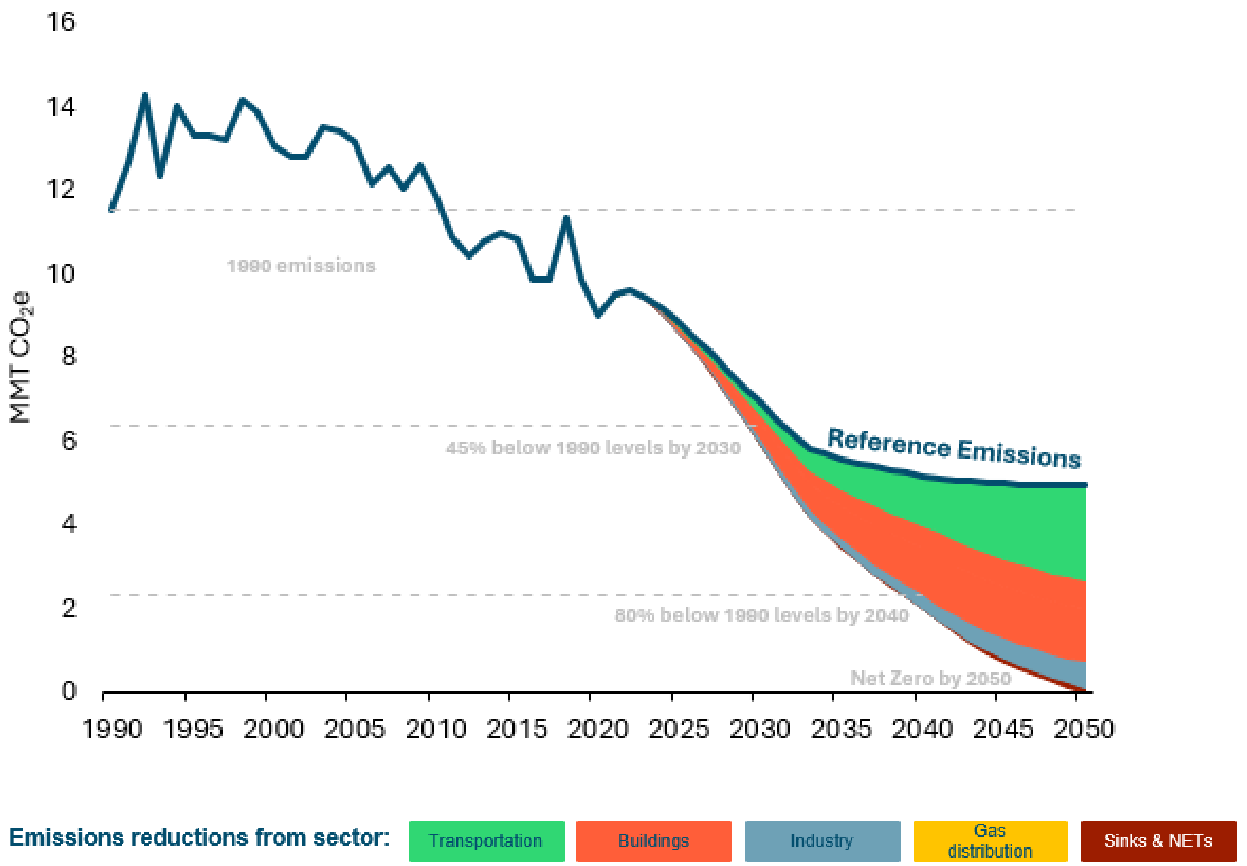
[74] Sargent, M., Floerchinger, C., McKain, K., Wofsy, S. 2021. Majority of US urban natural gas emissions unaccounted for in inventories. Proc Natl Acad Sci U S A. 2021 Nov 2;118(44):e2105804118. doi: 10.1073/pnas.2105804118

[75] See, for example: National Bureau of Economic Research (2018). Price regulation and environmental externalities: evidence from methane leaks. https://www.nber.org/system/files/working_papers/w22261/w22261.pdf

Table 8. Gross Sectoral Emissions Reductions by 2050

Sector	Emissions Reductions Compared to 1990 Baseline Across All Scenarios (%)
Transportation	-94%
Buildings	-100%
Industry	-84%
Gas Distribution	-63%
Agriculture & Waste	-66%
Electricity	-100%

Figure 16. Emissions Reductions in All Mitigation Scenarios



- **Transportation**. Across all decarbonization scenarios, transportation sector emissions decrease by 94% below 1990 levels by 2050. Emissions reductions are driven by Rhode Island's compliance with ACCII, which requires that 100% of new LDV sales are zero-emission by 2035, and ACT, which requires an aggressive increase in MHDV ZEV sales by 2035, with specific sales shares driven by truck class.

- **Buildings**. Across all decarbonization scenarios, building sector emissions decrease nearly 100% below 1990 levels by 2050. The specific measures that drive these emissions reductions vary by scenario. For scenarios with high levels of electrification, all-electric and hybrid heat pump adoption contributes significantly to emissions reductions – particularly after 2033 when the electric grid is carbon neutral. In the High Electrification and Alternative Heat Infrastructure scenarios, networked geothermal also plays a role in driving down emissions by 2050. Renewable fuels are blended into remaining fuel supply at varied levels across scenarios, with higher levels in the scenarios that maintain a larger reliance on natural gas by 2050. In the Continued Use of Gas scenario, a significant share of emissions reductions is attributable to the use of renewable fuels.
- **Industry**. Across all decarbonization scenarios, emissions associated with industrial activities decrease by approximately 84% below 1990 levels. The industrial sector decarbonizes through electrification or fuel-switching (e.g., dedicated hydrogen) within specific subsector processes, as feasible. Subsector processes that are considered to have high electrification potential include those where energy is used for conventional boilers, cogeneration, CHPs, and HVAC. Hard-to-electrify end-uses are those in which energy is used for high-temperature process heat.
- **Gas distribution**. Across all decarbonization scenarios, emissions associated with the gas distribution system decrease 63% below 1990 levels due to reduced methane leakage from Rhode Island Energy's LPP replacement program.
- **Agriculture & waste**. Across all decarbonization scenarios, emissions from agriculture and waste decrease by approximately 66% below 1990 levels. Agriculture, waste, and wastewater emissions follow the same trajectory in decarbonization scenarios as in the reference scenario.
- **Electricity**. Across all decarbonization scenarios, the electricity sector reaches 100% gross emissions reductions by 2033. There are no additional emissions reductions from the electric sector compared to the reference scenario, given compliance with the RES is consistent. However, variations in electric load growth across scenarios will result in differences in the amount of renewable energy procured, as further discussed in Chapter 4.
- **Sinks & NETS**. Across all decarbonization scenarios, natural carbon sinks provide about 0.61 MMT CO2e reduction by 2050. Carbon sequestration from natural sinks is slightly higher in mitigation scenarios than Reference, because it is assumed that there is no net forest, wetland, or cropland loss after 2030, in line with the 2016 RI GHG Reduction plan. About 0.15 MMT CO2e of NETs are used across all scenarios to reach AoC emissions targets without relying on expensive low-carbon fuel blending.

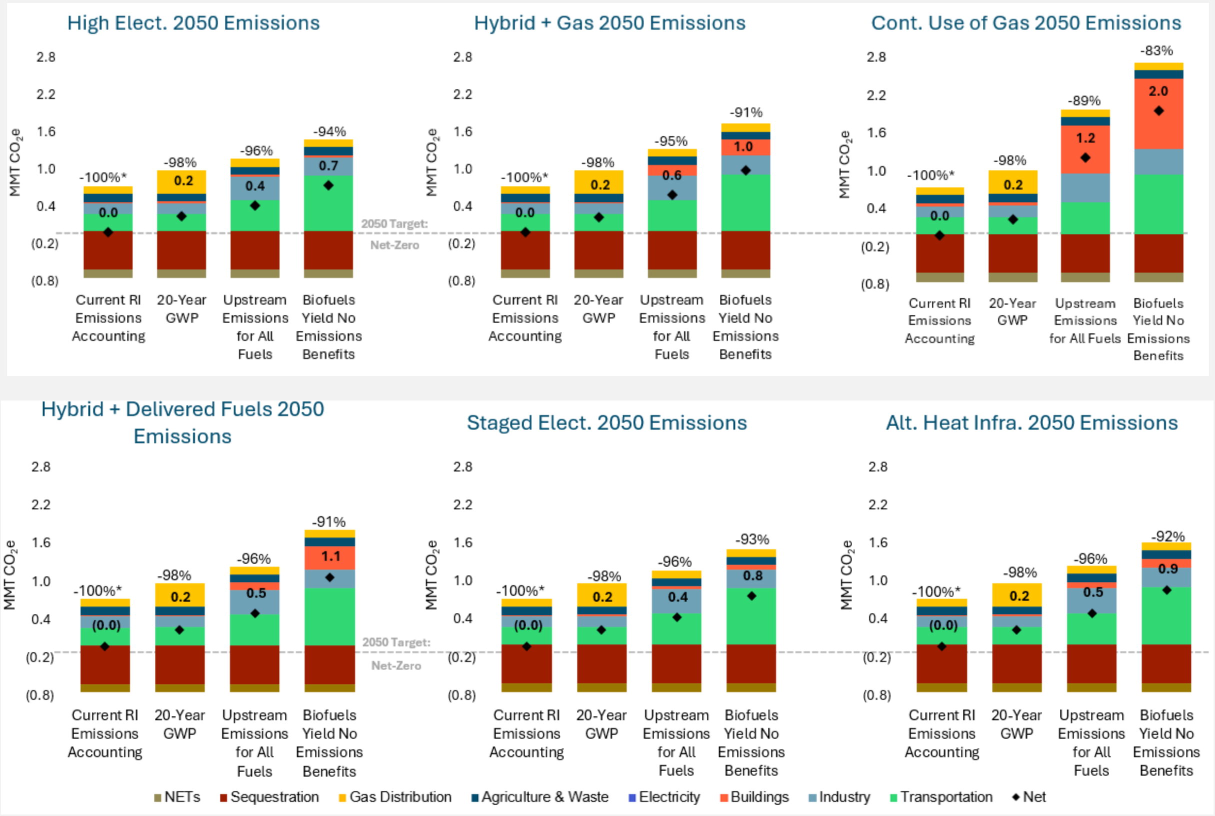
GHG emissions accounting methodology sensitivities

This study uses the Rhode Island state emissions inventory as its primary basis for developing an emissions baseline and emissions accounting. Through sensitivity analysis, E3 estimated the impact on remaining emissions if Rhode Island were to adopt alternative GHG accounting frameworks, including different GWP parameters, upstream emissions and zero emissions benefits associated with renewable fuels. This analysis finds that pathways that rely on higher levels of renewable fuels would have larger emissions impacts under all sensitivities:

- **20-year GWP**. If Rhode Island adopted an accounting framework that uses a 20-year GWP rather than 100-year (as is current practice in New York and Maryland), across most scenarios the state would miss AoC 2050 targets by approximately 2%. This is primarily due to methane leakages from the gas distribution system carrying an approximately 3x higher impact using a 20-year GWP. These impacts are similar across scenarios but would differ if future gas infrastructure replacements are avoided or parts of the system can be decommissioned. Note that this analysis assumes the level of methane leakage derived from the current emissions accounting framework.
- **Upstream emissions for all fuels.** The current GHG accounting methodology does not consider upstream (out-of-state) emissions for fossil fuels or renewable fuels. If Rhode Island was to consider upstream emissions for both fossil and renewable fuels, scenarios that rely on higher levels of fuels, such as Continued Use of Gas, would fall short of the 2050 target by 11%. Scenarios that rely on higher levels of electrification (e.g. High Electrification, Staged Electrification) would fall short of the 2050 AoC targets by 4%.
- **Renewable fuels have no emissions benefit.** Under the existing emissions accounting framework, Rhode Island considers renewable fuels to be carbon neutral, assuming that these fuels take up an equal amount of CO2 of their lifetime as they combust at end-of-life. As a bounding exercise recommended by the TWG, E3 estimated the impact on emissions if, hypothetically, the combustion of renewable fuels emitted the same levels of emissions as their fossil counterparts. This analysis finds that under this assumption, all scenarios would fall short of the 2050 targets, but to varying extents. Scenarios that rely on higher levels of electrification (e.g. High Electrification, Staged Electrification) would miss 2050 AoC targets by 6%, while the Continued Use of Gas pathway would miss targets by 17%.

Overall, under different emissions accounting frameworks, the pathways that utilize higher levels of renewable fuels would leave higher levels of emissions by 2050. The assumptions that were used to calculate these results are outlined in Appendix A.1.

Figure 17. Remaining Emissions in 2050 Under Alternative Accounting Frameworks



Impact on Technology Adoption

Mitigation scenarios achieve the Act on Climate through a distinct mix of technology adoption in the residential and commercial sectors, a large ramp-up of zero-emission vehicles in the transportation sector, and a mix of efficiency, electrification, and low-carbon fuel switching in the industrial sector. While the specific mix of technologies varies based on the key research question of each scenario, a rapid shift toward decarbonized technology adoption will be required across all pathways in order to reach Rhode Island's ambitious climate goals.

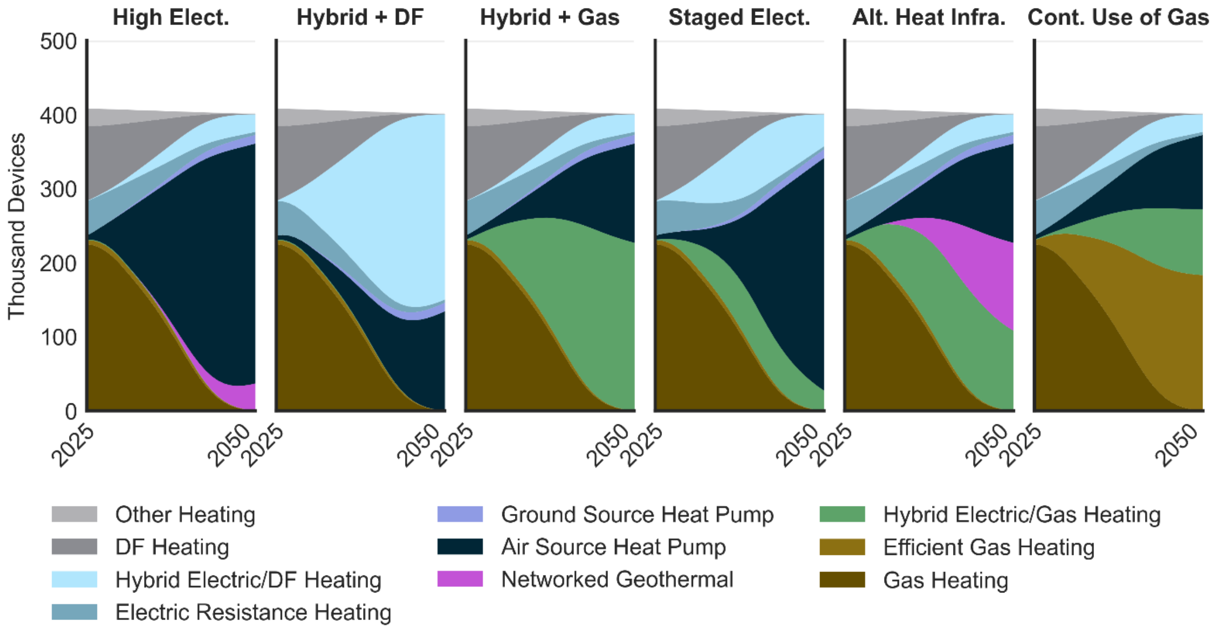
Adoption Of Heating Technology In The Building Sector

Across all pathways, there is a significant transformation in the way both residential and commercial buildings use energy. All end-uses – such as space heating, water heating, cooking, and clothes drying – undergo a notable transition from fossil-fuel powered equipment to decarbonized technologies. While space heating is the largest focus of the Technical Analysis, all building end-uses will experience significant shifts between today and 2050. Across all scenarios, water heating, cooking, and clothes drying transition to all-electric or efficient gas equipment at approximately the same pace as space heating conversions, with the technology transitions specific to each scenario's key research question. The focus of the rest of this chapter is on space heating; space heating is the building end-use that consumes the most energy, thus the transformation of how buildings are heated is a critical component in the future of Rhode Island's natural gas system and in the path to decarbonizing Rhode Island's economy.

Figure 18 below shows how space heating technology will change over time in the residential sector under all six scenarios. Figure 18 below shows how space heating technology will change over time in the residential sector under all six scenarios. Although building electrification occurs within all pathways, the level and composition of electrification varies:

- The High Electrification, Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup, Staged Electrification, and Alternative Heat Infrastructure achieve similar levels of electric space heating, utilizing a mix of different heat pump technologies. Electrification in the High Electrification and Staged Electrification pathways is made up of primarily all-electric ASHPs by 2050. Buildings in the Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup pathways have the same total number of heat pumps in 2050 as High Electrification, but the electrification relies on hybrid heat pumps with either delivered fuel or gas backup.
- The Alternative Heat Infrastructure pathway has the same total number of heat pumps as the High Electrification pathway, but about 30% are comprised of networked geothermal systems. In this pathway, it is assumed that approximately 145,000 of total residential gas customers would transition to networked geothermal systems between 2027 and 2050, with investments prioritized in moderate to high population density areas.
- The Continued Use of Gas pathway assumes 25% of buildings adopt all-electric heat pumps, and 30% converts to hybrid heating with gas or delivered fuel backup. Remaining buildings are expected to adopt efficient gas heating appliances.

Figure 18. Residential Household Space Heating Equipment Adoption[76]



In order to reach the goals laid out in the Act on Climate, Rhode Island will need to significantly increase annual adoption of decarbonized heating technologies. In scenarios focused on higher levels of electrification, annual heat pump sales exceed 25,000 devices in 2040, nearly five times higher compared to the reference scenario and approximately ten times higher than today's adoption levels. Scenarios with lower levels of electrification still see adoption levels by 2040 that are twice as high compared to the reference scenario, and five times higher compared to today's annual heat pump sales.

Figure 19 below shows how space heating technology stocks will change over time in the commercial sector under all six mitigation pathways. The transition of commercial space heating equipment is similar to the transition in the residential sector within the same pathway, with differences primarily in the ratio between electric boilers and heat pumps, where commercial buildings with existing gas or oil boilers convert to electric boilers rather than ASHPs when undergoing electrification.[77]

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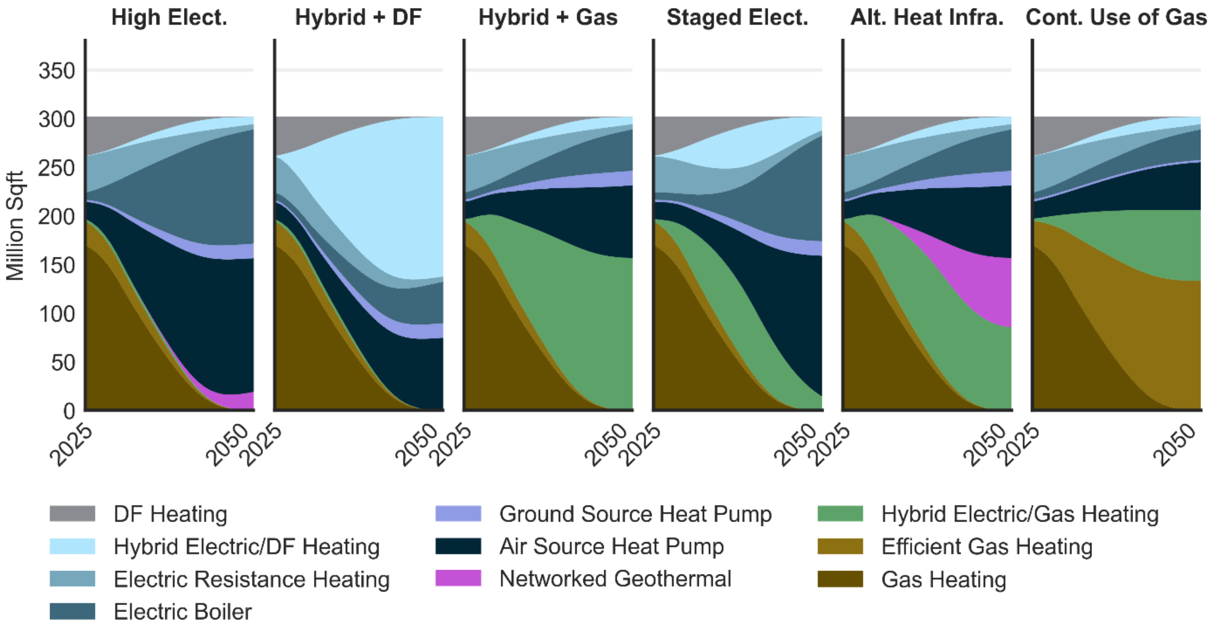
[76] "Other Heating" includes LPG furnaces and wood stoves.

[77] E3 set an expert-guided cutoff that a heater must be below 50-tons to be electrifiable to a heat pump. From E3's review of the Commercial Buildings Energy Consumption Survey (CBECS), no commercial boilers were below 50-tons. Therefore, E3 determined that commercial buildings with fossil fuel-powered boilers would electrify to electric boilers rather than ASHPs.

Figure 19. Commercial Space Heating Equipment Adoption



Energy Efficiency and Weatherization

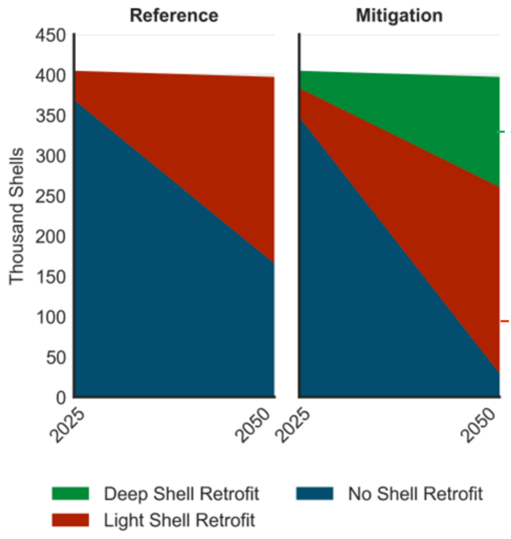
Energy efficiency is a critical component of all decarbonization strategies and will play an important role in Rhode Island's path to net zero emissions. As described in Appendix A.1, the Technical Analysis incorporates many forms of energy efficiency measures across multiple sectors, such as weatherization and building shell retrofits, building electrification, technology performance improvements, appliance standards and in-kind high-efficiency replacements (e.g., lighting upgrades), behavioral conservation and smart devices (e.g. programmable thermostats and lighting timers), and industrial manufacturing efficiency.

The rest of this section primarily focuses on the role of building energy efficiency, with a particular emphasis on weatherization and building shell adoption in decarbonizing the heating sector.

Energy efficiency in buildings – such as weatherization measures to improve the performance of a building envelope – directly reduces heating requirements, energy consumption, and electric load impacts of electrification, which can significantly reduce the need for additional electric infrastructure buildouts and/or the quantity of renewable fuels required. Building energy efficiency already plays a key role in Rhode Island's heating sector transformation through existing energy efficiency programs. For example, the EnergyWise Single Family Program (EWSF) assisted over 3,000 customers with energy efficiency measures – such as lighting and weatherization – in 2019 and the EnergyWise Income Eligible and Multifamily Program has served hundreds of multifamily facilities across Rhode Island with measures such as common area and in-unit lighting.[78,79] Given the impact of existing energy efficiency programs and the potential for future expansion, aggressive assumptions around weatherization adoption are incorporated into the reference scenario in addition to all decarbonization pathways.

Building shell and envelope assumptions deployed in the reference and decarbonization scenarios were supported by research from NV5, a technical engineering and consulting firm that leads the Technical Consultant team for the Rhode Island Energy Efficiency and Resource Management Council (EERMC) and represented EERMC on the TWG. Leveraging industry expertise and the Rhode Island Energy Efficiency Market Potential Study Refresh, NV5 developed set of assumptions regarding weatherization adoption rates under both reference and decarbonization scenario conditions for E3 to utilize in the Technical Analysis.[80] Adoption rates varied by building type (single family, multifamily, commercial) and fuel type (natural gas, oil, propane). Overall, it is estimated that nearly 60% of Rhode Island's residential building stock will undergo light-touch energy efficiency retrofits by 2050 in the reference scenario, whereas decarbonization scenarios install an additional 35% of deep shell retrofits in residential homes (see Figure 20).

Figure 20. Building Shell Adoption Over Time



A deep shell involves comprehensive upgrades, such as full envelop building insulation

A deep shell retrofit represents an approximate **30%** reduction in space heating service demand

A light shell retrofit includes basic weatherization upgrades, such as glazing and partial air sealing

A light shell retrofit represents an approximate **15%** reduction in space heating service demand

Energy efficiency in buildings, such as the weatherization measures discussed above, building electrification, technology performance improvements, appliance standards, and behavioral conservation lead to significant reductions in energy demand in buildings, as shown in Figure 21.

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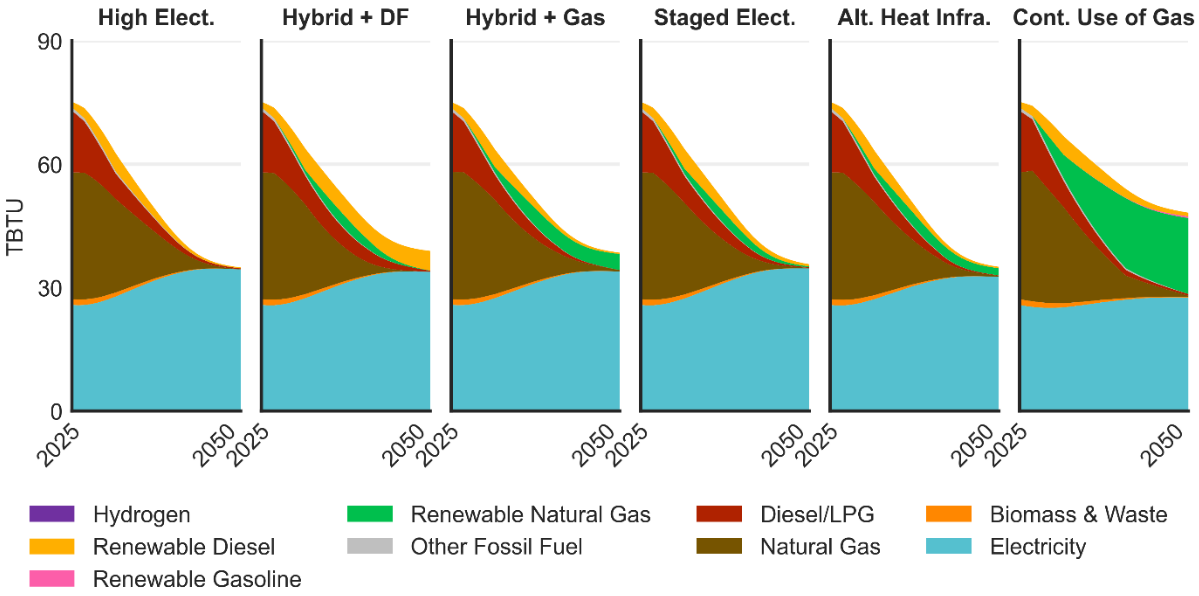
[78] Source: https://rieermc.ri.gov/wp-content/uploads/2020/10/ng-ri-ewsf-impact-and-process-comprehensive-report_final_04sept2020.pdf

[79] Source: https://rieermc.ri.gov/wp-content/uploads/2020/10/ng-ri-mf-impact-and-process-comprehensive-report_final_04sept2020.pdf

[80] Additional data sources listed include: NREL Data Lake, C&I Building Demographic Data, MA Clean Energy and Climate Plan, RIE/National Grid Program Performance Data

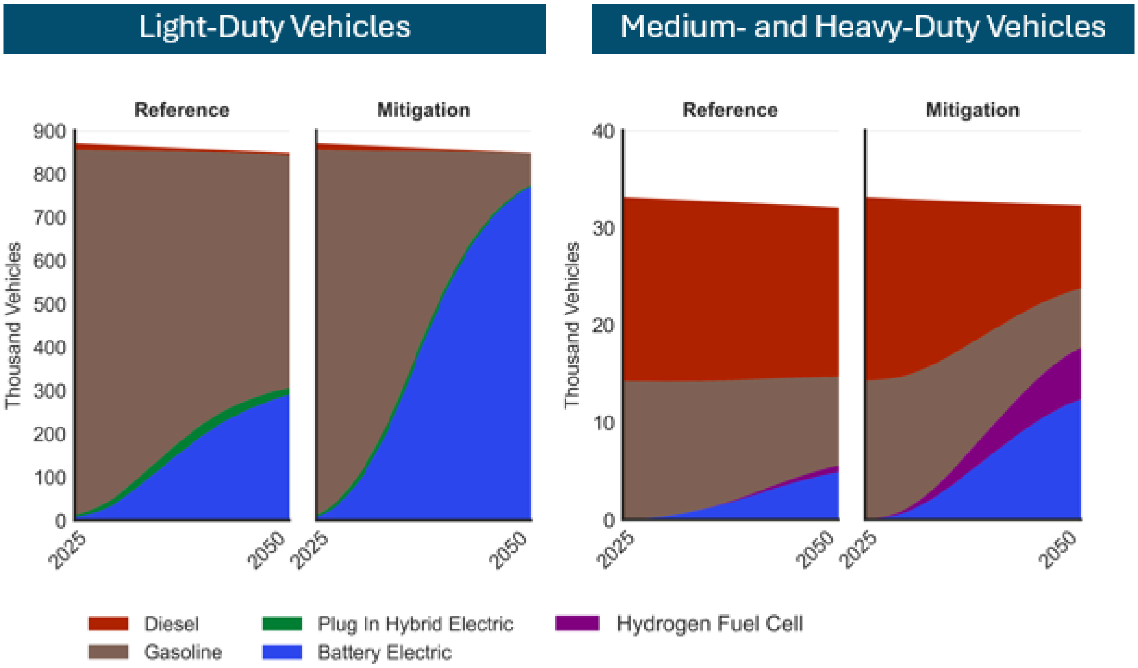
Figure 21. Energy Demand Reductions in Buildings as a Result of Efficiency and Electrification Measures



Transportation Sector Technology Adoption

Across all decarbonization scenarios, the Transportation sector experiences a drastic transition away from internal combustion engine (ICE) vehicles to zero-emission cars and trucks, as required by ACCII and ACT (see Figure 22). ACCII requires that 100% of new LDV sales will be ZEVs by 2035; in line with ACCII requirements, E3 assumed that the majority of LDV ZEVs will be battery electric by 2035, with a small portion of plug-in hybrid. ACT requires an aggressive increase in MHDV ZEV sales by 2035, with specific sales shares driven by truck class. While MHDVs will also transition away from ICE vehicles as required by ACT, MHDVs will experience lower levels of electrification than LDVs, with a modest portion converting to hydrogen fuel cell vehicles instead (also classified as ZEVs under ACT). Where MHDVs are not able to fully electrify, remaining fuel demand is blended with low-carbon fuel alternatives, such as renewable diesel.

Figure 22. LDV and MHDV Stocks Over Time

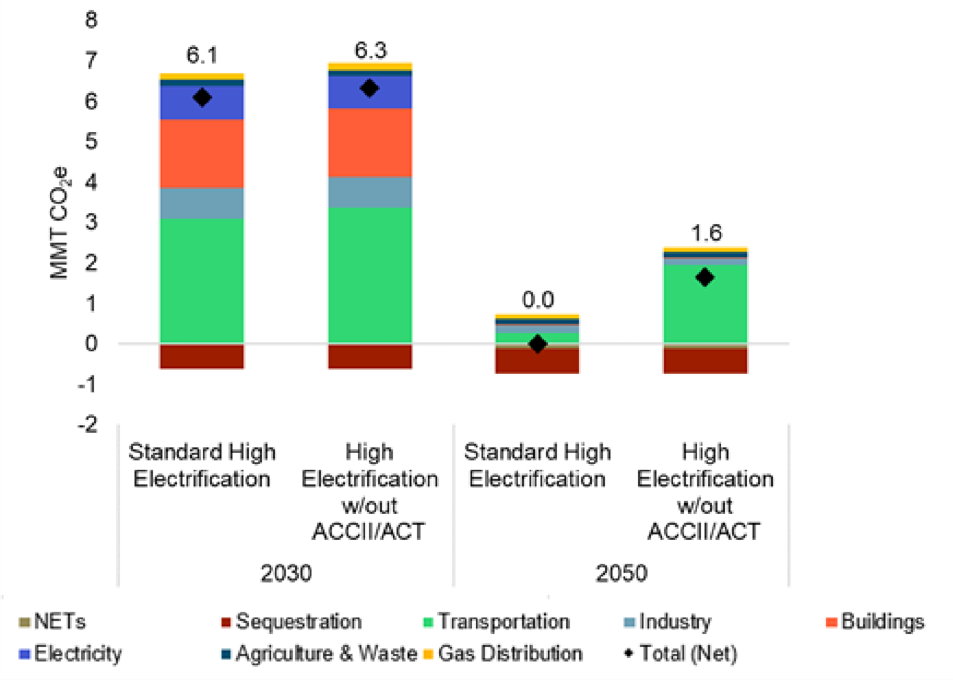


If the transportation sector does not electrify at the pace of ACII/ACT, more action will be required in other sectors.

A key assumption in all decarbonization pathways is that Rhode Island will achieve compliance with ACCII and ACT, leading to significant emissions reductions in the transportation sector. E3 modeled a sensitivity onto this assumption that explores the action required in other sectors if the transportation sector does not electrify at the place of ACCII/ACT. It is important to note that E3 did not model or assess the probability of Rhode Island meeting or not meeting the ACCII/ACT targets.

The sensitivity analysis shows that if achievement of ACCII/ACT is delayed, Rhode Island will require deeper measures to reach AoC targets, primarily in the long term. The 2030 AoC target can be met with accelerated building sector measures that are already required to facilitate longer term climate goals. For example, High Electrification would meet the 2030 target even if ACCII/ACT follows a slower trajectory in the short term. This is due to accelerated action in the buildings sector that was modeled in the Technical Analysis in order to set the state up for reaching longer-term emissions targets. However, by 2050, High Electrification will have approximately 1.65 MMT CO2e remaining in 2050 without achievement of ACCII/ACT, thus missing the AoC target by about 14% (see Figure 23). If EV penetration is consistent with historical levels and the EC4 target (10% of stocks by 2050) instead of ACCII/ACT, RI will not meet the 2040/2050 AoC targets without higher renewable fuel blending or deeper measures in other sectors. In High Electrification, the buildings sector is completely electrified. Thus, if the ACCII/ACT is not achieved, higher renewable fuel blending in the Transportation sector will be required. In other mitigation pathways, deeper building electrification measures can be adopted if the ACCII/ACT is not met.

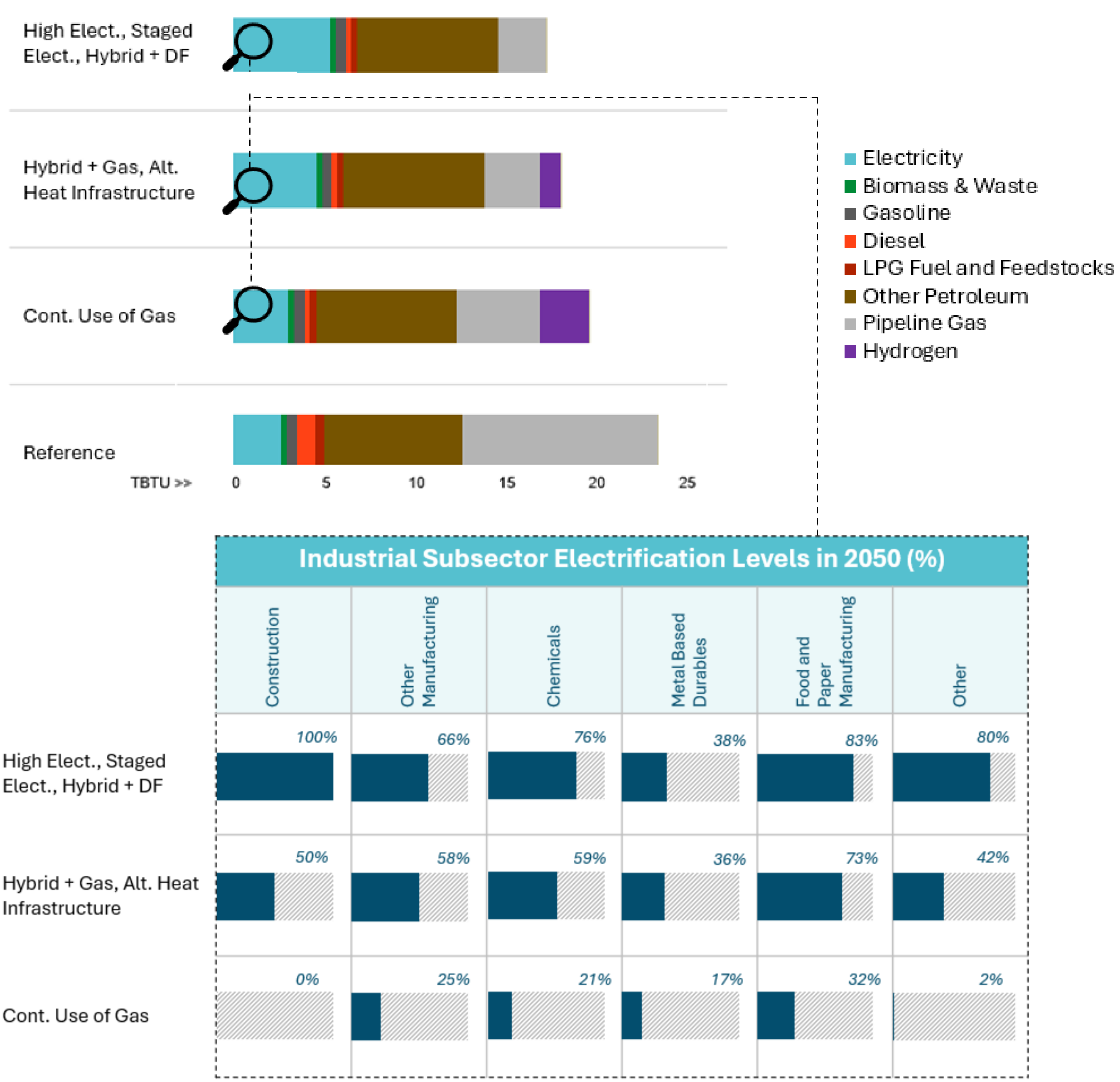
Figure 23. Remaining Emissions with and without ACCII/ACT (High Electrification Pathway)



Industrial Sector

Despite consistent levels of assumed economic growth, energy demand in the industrial sector declines across all scenarios (Figure 24) driven by continued efficiency improvement and varied reliance on electrification vs. fuel-switching. Scenarios with a larger focus on electrification and gas pipeline decommissioning (e.g., High Electrification, Staged Electrification, and Hybrid with Delivered Fuels Backup) electrify industrial end-uses as much as is technically feasible, while relying on renewable fuels – such as renewable natural gas – only in hard-to-electrify subsectors. Scenarios that rely more heavily on the maintenance of the gas system (e.g., Hybrid with Gas Backup, Alternative Heat Infrastructure, and Continued Use of Gas) electrify a smaller portion of industrial subsector processes, with a higher focus on pipeline gas – supplied by renewable fuels – and adoption of dedicated hydrogen.

Figure 24. Industrial Energy Demand (TBTU) and Subsectoral Electrification Levels in 2050



E3 used the Manufacturing Energy Consumption Survey (MECS) to determine the type and quantity of energy used by industrial subsectoral processes today. Subsector processes that are considered to have high electrification potential include those where energy is used for conventional boilers, cogeneration, CHPs, and HVAC. Hard-to-electrify end-uses are those in which energy is used for high-temperature process heat. Some processes, such as on-site transportation and machinery have less certain electrification potential. For the processes with less certain electrification potential, assumptions on levels of electrification varied by scenario (see Appendix A.1 for details).

Impact on Energy Demand

Statewide Energy Demand

The Technical Analysis shows that in order to reach climate targets, Rhode Island will need to significantly transform how it produces, supplies, and uses energy within all sectors of the economy. Across all pathways, final energy demand decreases between 40-50% compared to today by 2050 as a result of weatherization, appliance efficiency, and electrification, as seen in Figure 25 and Figure 26. Today, Rhode Island's energy system relies primarily on petroleum and natural gas, but by 2050 the reliance shifts to electricity and renewable fuels across all decarbonization scenarios. None of the pathways fully eliminate gas; those with high levels of electrification leave some gas usage in the industrial sector, while those with lower levels of electrification continue to rely on gas in buildings.

By 2050, 40-60% of final energy demand is served by electricity; scenarios with high levels of electrification see nearly doubling of electric load by 2050 compared to today's levels. By 2050, 50-70% of the fuel mix across pathways consists of renewable fuels, although the total amount of fuel is significantly reduced. In order to comply with state policy – such as the Biodiesel Heating Oil Act – and Act on Climate targets, the use of renewable fuels is required across all pathways, with the highest levels in the pathways with the lowest levels of electrification. Hybrid with Delivered Fuels Backup sees the highest level of renewable diesel adoption, while the Continued Use of Gas pathway utilizes the most renewable natural gas and hydrogen.

Figure 25. Statewide Energy Consumption Over Time by Fuel Type

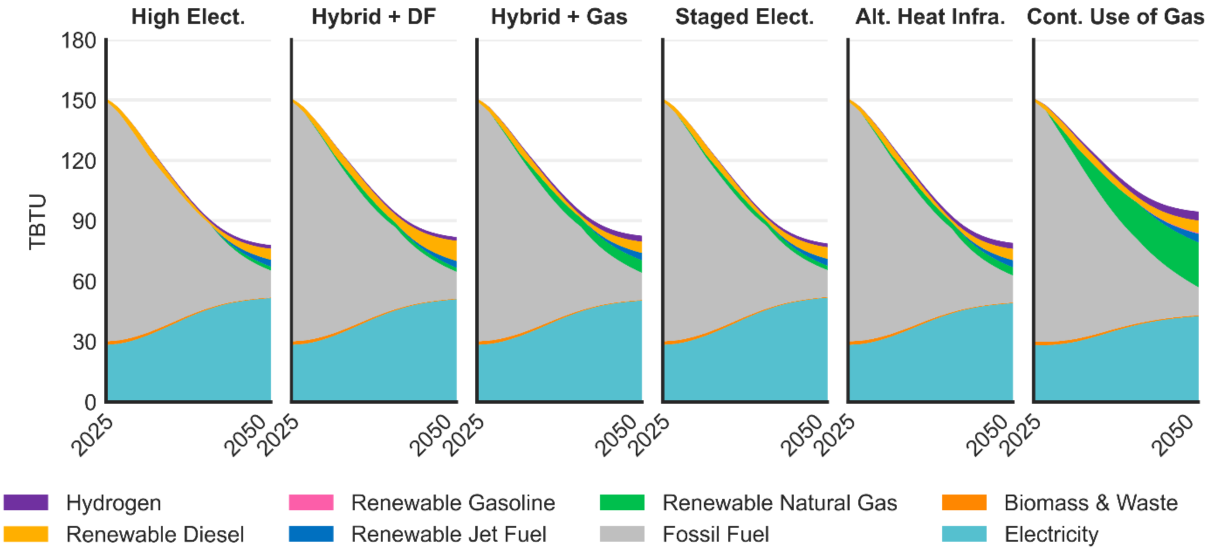
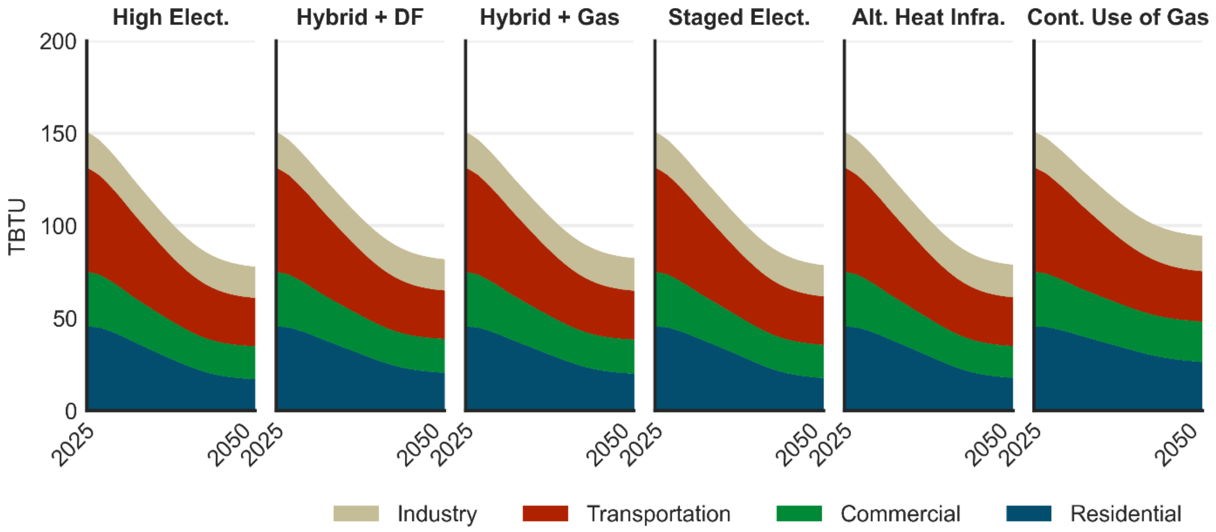


Figure 26. Sectoral Energy Consumption Over Time

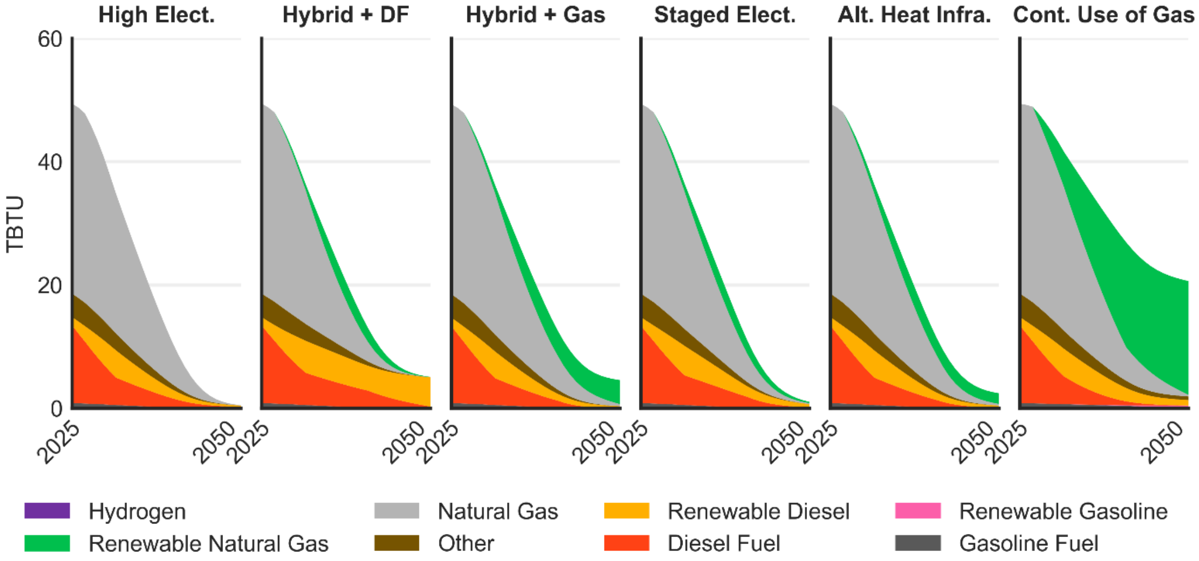


Use of Renewable Fuels in the Buildings Sector

Following Rhode Island's GHG accounting framework, the Technical Analysis assumes that the combustion of renewable fuels contribute to gross emissions reductions. For simplicity, E3 refers to these types of fuels as renewable natural gas, renewable diesel or renewable gasoline, acknowledging that the source of the fuel may vary depending on factors as availability, policy and market mechanisms. From a technical perspective, renewable fuels can be derived through anaerobic digestion or gasification using various sources of biomass (forest residues, municipal solid waste, landfill gas, etc.) or synthetically using renewable hydrogen and captured carbon dioxide. The availability, commercialization and cost of these different production methodologies differs widely.

Renewable fuels are expected to play an increasingly important role in the buildings sector across scenarios. In the near-term in all scenarios, renewable diesel gradually replaces the use of fuel oil for heating purposes to comply with the Biodiesel Heating Act. In addition, all scenarios except for High Electrification start to blend in small amounts of renewable natural gas as a way to reduce emissions. Longer term, renewable natural gas is primarily used as a supply-side measure in the Continued use of Gas scenario, and to a lesser extent in the Hybrid with Gas Backup scenario. In contrast, the Hybrid with Delivered Fuels Backup scenario relies more heavily on renewable diesel to supply heat on cold winter days. Further implications of the use of renewable fuels are discussed in Chapter 5.

Figure 27. Transition to Renewable Fuels in the Building Sector across Scenarios



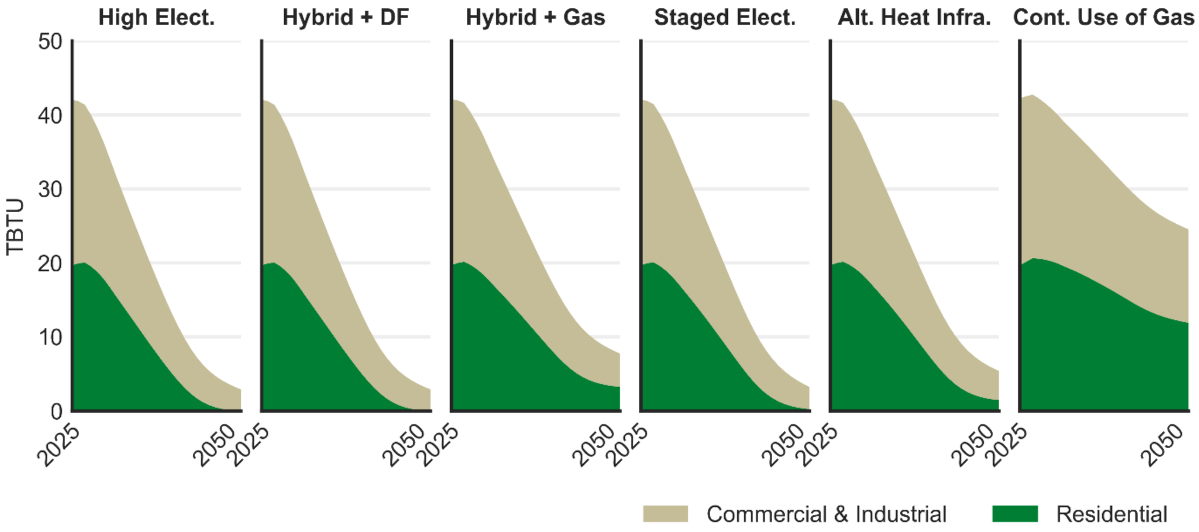
Impact on the Gas System

Each of the scenarios results in a transformation of the gas system, either through demand-side measures in the form of electrification or through supply-side measures in the form of renewable gas blending. These decarbonization strategies have different impacts on the role and the use of the gas delivery system and gas supply. Some pathways, such as High Electrification and Hybrid with Delivered Fuels Backup, see a complete phase out of natural gas for residential and commercial customers, while other pathways rely on gas infrastructure to meet peak space heating needs in buildings during the coldest hours of the year (Hybrid with Gas Backup) or continue to use the gas system to deliver a blend of renewable gases (Continued Use of Gas) to achieve Rhode Island's climate goals.

Transformation Of Gas Throughput And Customer Base

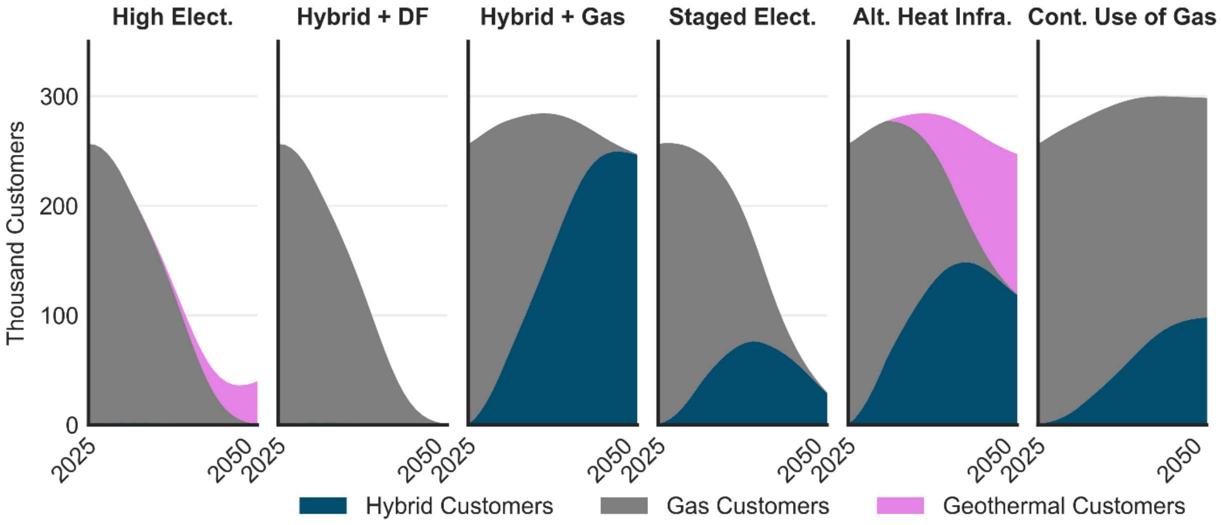
The decarbonization scenarios see a substantial decline in delivered gas volumes; across all pathways, gas throughput decreases between 45-95% by 2050 because of efficiency and electrification, as shown in Figure 28. Some levels of gas throughput remain in the commercial and industrial sectors, particularly to deliver gas to "hard-to-decarbonize" applications in the industrial sector. The Continued Use of Gas pathway maintains the highest level of gas throughput but still sees declines compared to today due to efficiency improvements in buildings and levels of hybrid electrification. Pathways with high levels of electrification, such as High Electrification and Hybrid with Delivered Fuels Backup, reduce gas throughput to almost zero by 2050, whereas pathways relying on hybrid gas heating systems require some gas supply by 2050, but at much reduced levels compared to today's supply.

Figure 28. Gas Throughput by Sector across Decarbonization Scenarios



The transition of the gas customer base (Figure 29) is a key variable across decarbonization pathways. Scenarios with high levels of electrification, such as High Electrification, Hybrid with Delivered Fuels and Staged Electrification, see a steep decline in the gas customer base as customers convert to all-electric appliances. Pathways with hybrid heating solutions with gas backups and networked geothermal maintain similar levels of customers, either on the gas system directly or as networked geothermal customers. It is assumed that networked geothermal customers will be customers of a utility-type entity that would invest in and build the geothermal systems. Finally, the Continued Use of Gas pathway sees an increase in the number of gas customers, primarily as a result of fuel oil-to-gas conversions.

Figure 29. Gas Utility Customers across Decarbonization Scenarios

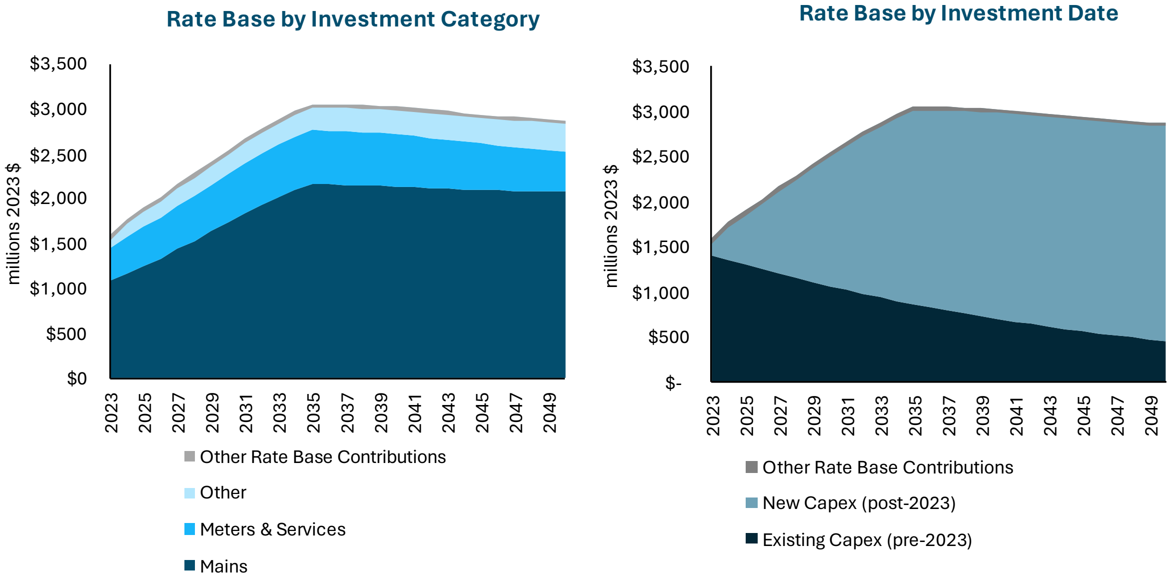


Gas Revenue Requirement

Given the varying roles of the gas distribution system to deliver gas and serve customers under different pathways, E3 analyzed the capital costs of replacing and maintaining gas system infrastructure and the operational & maintenance (O&M) costs of serving customers.

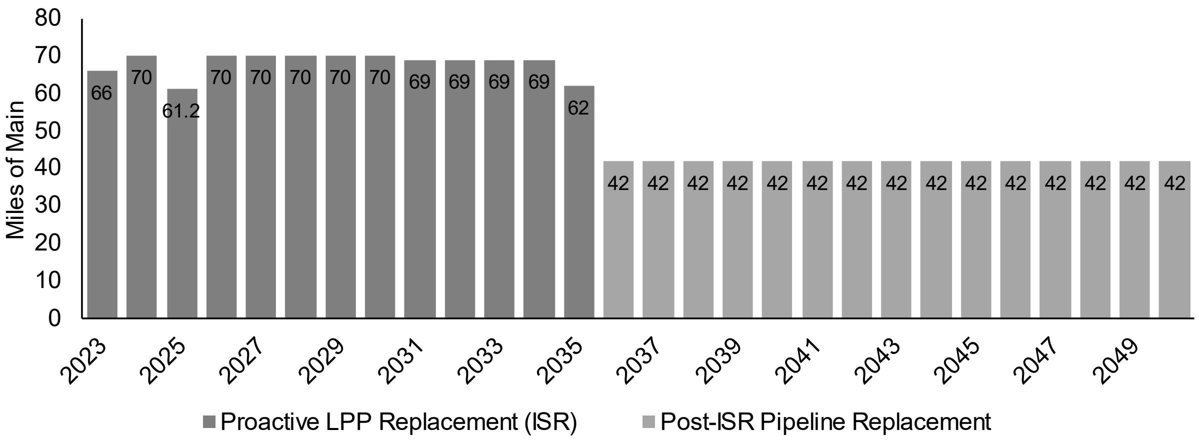
E3 forecasted RIE's rate base — the total value of RIE's assets — by assessing investments already on the books and evaluating future capital costs required to replace existing infrastructure and build new infrastructure (see Figure 30). E3 categorizes RIE's capital investments that make up its rate base into three categories: Mains, Meters & Services, and Other. The Mains category includes investments in main distribution pipeline, which is largely comprised of RIE's investment in LPP replacement. Meters & Services includes investments in service lines that directly connect mains to customers' homes and businesses and the meters that serve these customers. The "Other" asset category reflects additional, non-pipeline capital investments, such as regulator station upgrades, LNG facilities and office equipment. Other rate base contributions include construction works in progress, materials and supplies, cash working capital, deferred tax, and several other small contributing categories.

Figure 30. Rate Base under Reference Scenario



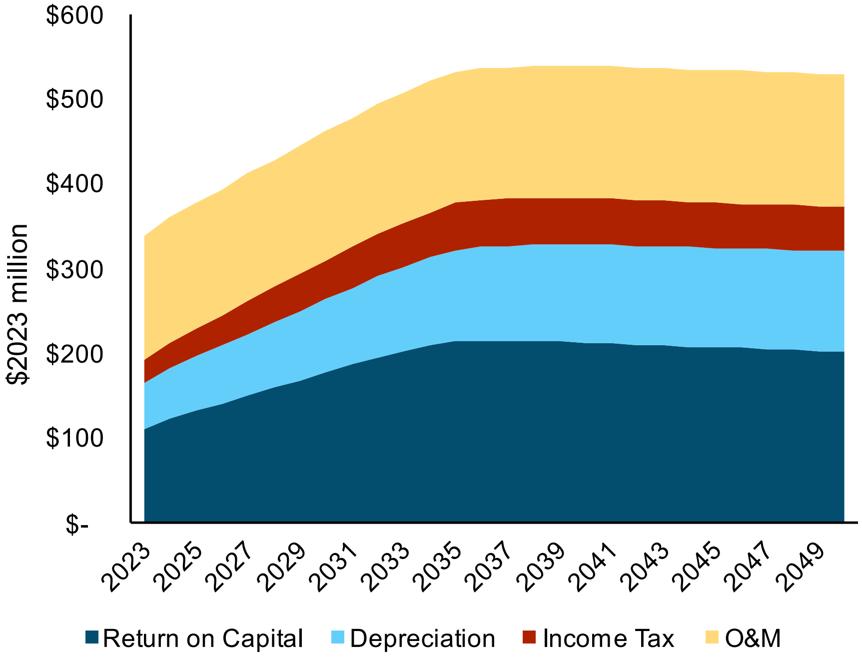
Much of RIE's recent and forecasted gas system investment stems from the ISR program, which encompasses LPP replacement. These investments are included in the Mains component in Figure 30. Figure 31 shows the number of main pipeline miles that RIE expects to replace through 2050. RIE plans to replace approximately 70 miles of LPP per year until 2035 and then expects to reduce the replacements to approximately 42 miles per year through 2050, mostly representing the replacement of plastic mains. Under the current regulatory framework, the investments are estimated to be the same across decarbonization pathways.

Figure 31. Projected Miles of Pipeline Main Replacement



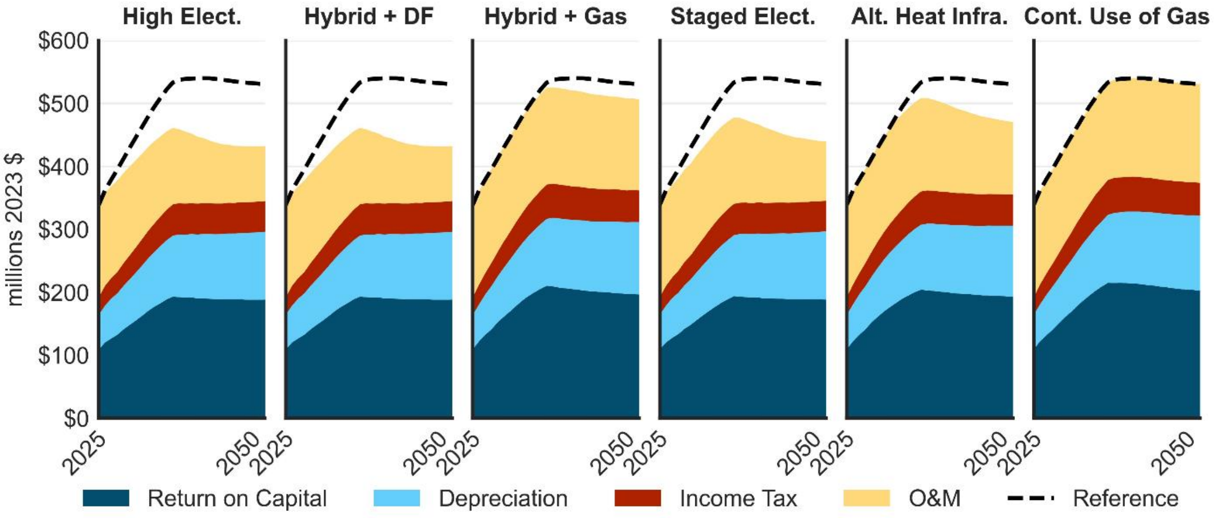
The investments planned under the ISR program, additional infrastructure investments, and investments in new customer connections contribute to RIE's rate base, on which RIE earns a return. In addition to RIE's return on capital, depreciation expense, income tax, and O&M expenses make up RIE's revenue requirement (see Figure 32), which is forecasted to grow under the reference scenario, primarily because of future capital expenditures. In addition to RIE's return on capital, depreciation expense, income tax, and O&M expenses make up RIE's revenue requirement (see Figure 32), which is forecasted to grow under the reference scenario, primarily because of future capital expenditures.

Figure 32. Revenue Requirement under Reference Scenario



Under the current regulatory framework, capital investments required to maintain the distribution system, such as the those under the ISR program, are forecast to be the same across decarbonization pathways. However, the differences in gas customer counts alter the infrastructure investments designated for new customers and the O&M costs required to serve those customers. Customer additions require service and meter infrastructure investments and sometimes main line extensions. Customer additions and departures result in varying O&M expenses reflecting the variable costs to serve customers. Figure 33 shows how the revenue requirement differs across pathways due to customer additions and departures. This figure shows that scenarios that do not assume additional customer connections, such as High Electrification and Hybrid with Delivered Fuels, reduce annual costs of the gas system by approximately 24% by 2050 compared to a reference scenario.

Figure 33. Revenue Requirement under Decarbonization Scenarios



Impact On Delivery Rates

RIE's revenue requirement is recovered through customer delivery rates where the majority of costs are recovered through a volumetric charge. At the highest level, this means that the total costs of the gas system are divided by gas throughput on the system to determine the costs for a customer *per unit of gas used.*[81] Although there are variations in RIE's revenue requirement across scenarios, all scenarios experience a decline in gas throughput while the costs of the system continue to rise. Under the current regulatory framework, this dynamic results in rapidly escalating long-term gas delivery rates for residential, commercial, and industrial customers in nearly all decarbonization scenarios. As shown in Figure 34, gas delivery rates rise substantially, especially after 2035, in pathways where gas throughput declines dramatically.

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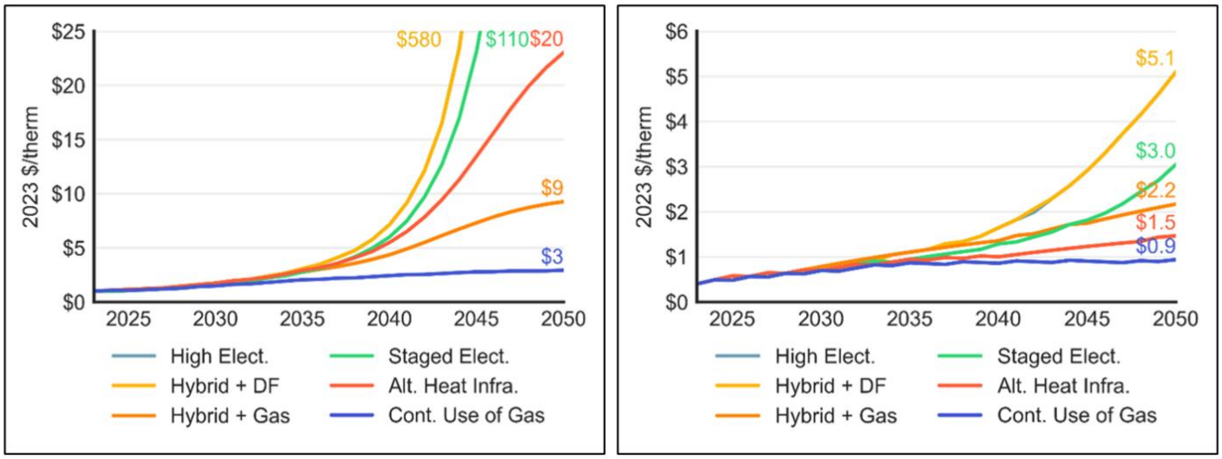
[81] A more detailed explanation of how gas rates are determined is provided in Appendix A.2.

Figure 34. Gas Rates across Decarbonization Scenarios. Left: residential rates. Right: commercial and industrial (C&I) rates



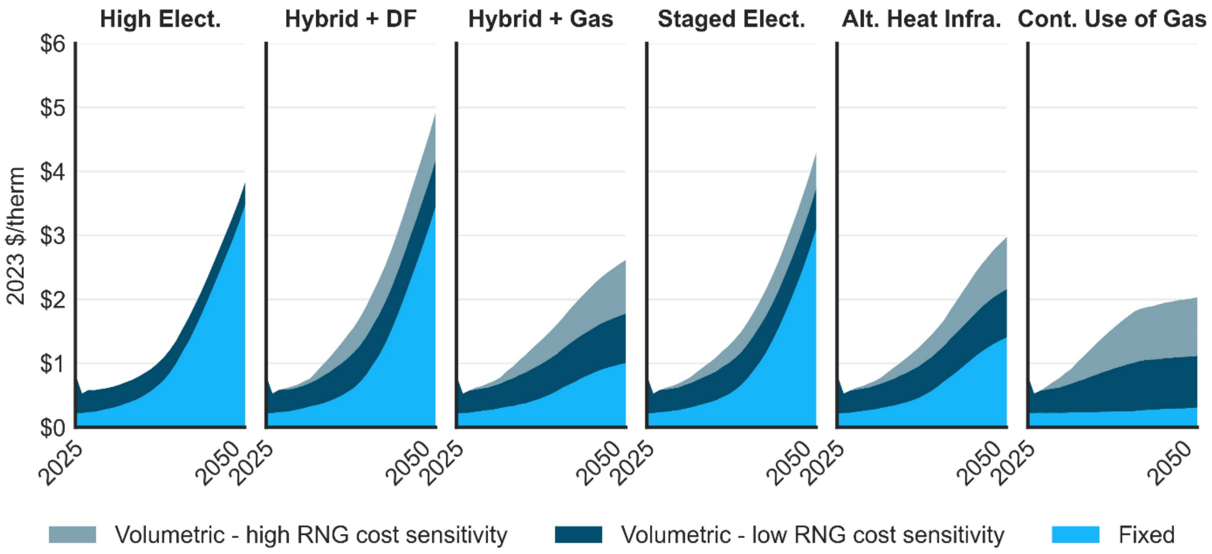
Variable Costs Of Gas

Variable costs of gas, which include commodity costs of gas and the fixed cost of transportation and storage, are passed through to customers and are not included in RIE's revenue requirement. Fixed transportation and storage costs are assumed to remain the same across scenarios since the infrastructure is required to transport any amount of gas that is still needed on the system. On the other hand, the cost of gas varies significantly across scenarios and depends on the amount of renewable fuels blended into the system.

The commodity rates that customers ultimately pay depend on the scenario's fixed transportation and storage cost and variable commodity costs, as well as gas throughput. In all scenarios, the commodity costs are expected to rise (see Figure 35). In scenarios with high levels of electrification, transportation and storage rates increase as the costs are spread among fewer customers, leading to higher commodity rates. This assumes that despite reducing gas volumes, RIE would continue to pay long-term contracts for capacity on the system. The extent to which the costs of such contracts can be reduced is uncertain.

In pathways relying on high levels of renewable gas, such as Continued Use of Gas, the volumetric component of commodity rates is forecasted to rise substantially resulting in higher rates, especially after 2040 when levels of renewable gas are expected to increase. However, the impact of declining gas throughput on fixed transportation costs has a more substantial effect on rates than does the cost of renewable gas, resulting in significantly higher rates in the High Electrification, Hybrid with Delivered Fuels Backup, and Staged Electrification pathways. In these scenarios, as the fixed costs of transportation are socialized over fewer units (gas throughput), costs per unit are expected to go up. Similar to the dynamic regarding gas delivery rates, this raises an issue that needs to be addressed in the policy development phase of the docket.

Figure 35. Variable Costs of Gas (commodity costs and transportation & storage costs) under Decarbonization Scenarios

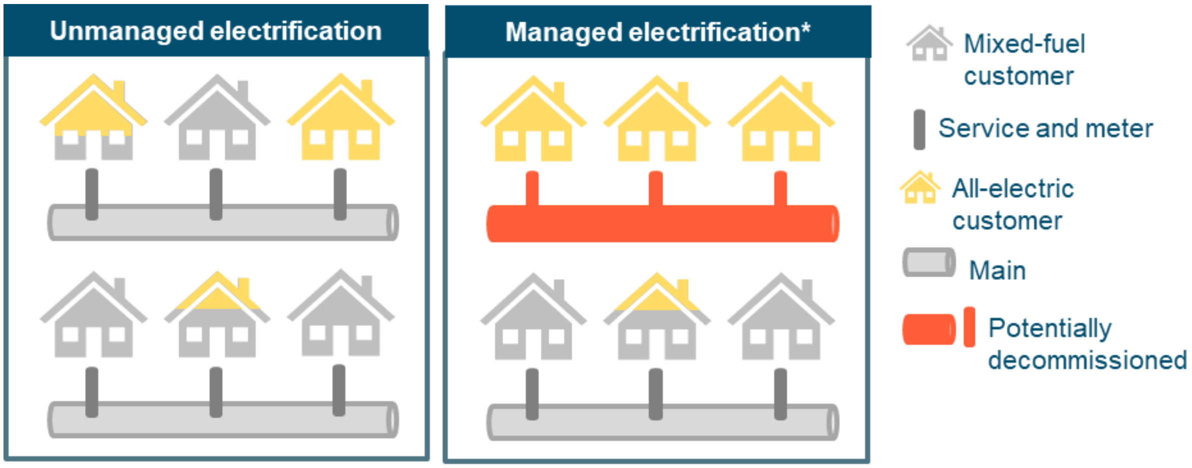


Impacts of a Managed Transition

What is a managed transition?

Although the term "managed transition" is not used consistently in the industry, E3, with input from the TWG, refers to the concept as a set of coordinated, long-term planning strategies deployed in the gas distribution system that align with climate goals and minimize adverse impacts on customers, while safeguarding affordability, safety, and reliability. A managed transition includes targeted deployment of non-GHG emitting heating technologies that minimize or avoid gas system investments, as well as the necessary policy reforms that facilitate these strategies. In the Technical Analysis, E3 uses the term managed transition to indicate the avoidance of gas distribution system infrastructure resulting from targeted electrification projects. With a managed transition approach, RIE would target specific geographic areas for complete building electrification in order to decommission the gas pipeline in that location, avoiding gas pipeline replacement reinvestments (see Figure 36). Although such a strategy requires significant policy and regulatory reform, the Technical Analysis primarily assesses the impacts of the strategy on the gas system and its customers. The question of which types of policies or regulatory strategies are needed to achieve a managed transition, are to be discussed in the Policy Development phase of this Docket. In addition, more detailed engineering questions associated with the technical feasibility of the concept require further study, as outlined in Chapter 6.

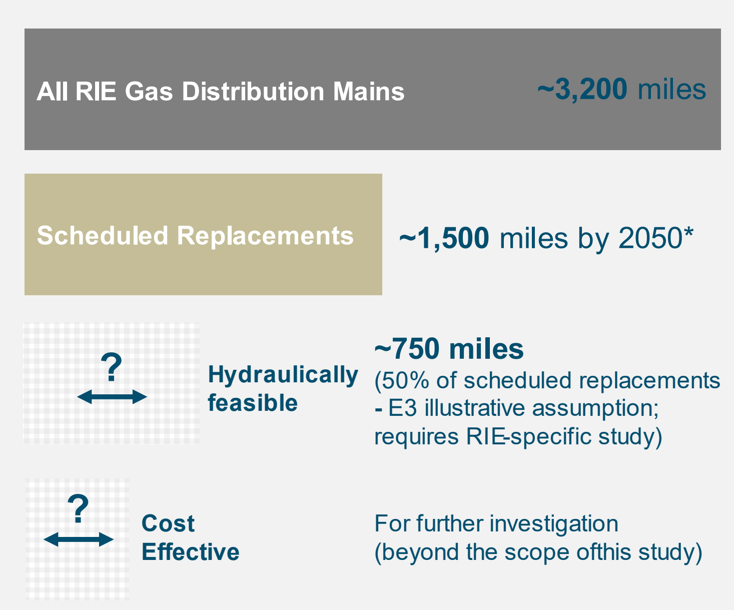
Figure 36. Electrification under an Unmanaged and a Managed Approach



*Also referred to as "**targeted/zonal electrification and gas decommissioning**"

In the Technical Analysis, E3 conducted sensitivity analysis to explore the potential impact of a managed transition on the gas revenue requirement and, ultimately, delivery rates. Only pipeline that is fully depreciated and scheduled to be replaced will result in avoided capital investment if decommissioned. This means that E3 only considers pipelines that are assumed to reach their end-of-life between now and 2050 as candidates for targeted electrification projects, representing approximately half of all gas distribution mains on the system (see Figure 37). Additionally, to decommission a gas pipeline, it must be considered "hydraulically feasible", meaning that the gas system maintains the minimum allowable pressures and gas flows and maintains secondary feeds to ensure safe and reliable service to customers that remain on the gas system. In the managed transition sensitivity, E3 assumes that a maximum of 50% of scheduled pipeline replacements can be avoided each year beginning in 2027. This assumption is illustrative; further study is required to understand how much of the system could be feasibly and cost-effectively decommissioned.

Figure 37. Assumptions Regarding The Number Of Distribution System Miles That Can Be Avoided In A Managed Transition. Note: The "hydraulic feasibility" assumptions are illustrative and require further study.



** Based on RIE's estimation of replacement miles between 2023-2050 (see* Figure 10*). Represents all cast iron and unprotected steel, plus additional post-2035 plastic mains that are expected to reach end of life.*

Managed Transition studies outside of Rhode Island

Although the concept of a managed transition as defined in this study is relatively novel in the United States, several regions have started to investigate the impact and potential benefits of the concept. In December 2023, E3 released a study regarding a benefit-cost analysis of targeted electrification and gas decommissioning in California commissioned by the California Energy Commission.[82] Evaluating eleven candidate sites in the cities of Oakland, San Leandro, and Hayward, representing 1,500 total utility customers, this study found that all eleven projects would generate lifecycle net benefits associated with targeted decommissioning, even after accounting for the costs of electrification. In Massachusetts, Groundwork Data performed a technical analysis for strategic gas decommissioning and grid resiliency in the City of Holyoke.[83] This study demonstrates that a non-pipeline strategy, particularly on low-density streets, can be a cost-effective strategy with significant levels of avoided gas system costs.

Pilot projects are beginning in several jurisdictions to assess the potential benefits of a managed transition for utilities and customers, but these are currently limited in scope and scale. For example, PG&E's pilot project with East Bay Community Energy in California is assessing how

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[82] E3 (2023). Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California

[83] Groundwork Data (2023). Equitable Energy Transition Planning in Holyoke Massachusetts - A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency.

targeted electrification and gas decommissioning for 105 gas customers can provide gas system savings while meeting the needs of the local community.[84] Currently in the research phase, the project team has developed a site selection framework and completed a cost-benefit analysis indicating net benefits in specific locations where new gas infrastructure can be avoided. PG&E is moving forward with a pilot program, but the project reflects a small portion of the utility's overall distribution system and customer base. While pilot projects are taking root, there is limited data and examples of the costs and benefits of managed transition projects, and additional pilot projects and analysis are needed to understand the potential to avoid gas system costs.

In estimating an illustrative figure for the potential avoidance of capital replacement costs, E3 draws from several studies that assess the potential for avoided gas system costs, shown in the table below. Not all these studies are based on empirical evidence on hydraulic feasibility or the scale of potential gas system savings.

Table 9. Managed Transition Avoided Capex Assumptions

Study	Managed Transition Assumptions	Source/Notes
MA D.P.U. 20-80 (2021)	All Scenarios: 50% avoided main replacements (illustrative)	Appendix 1: Modeling Methodology[85]
PG&E Neighborhood Scale Electrification Projects (2024)	~45% hydraulic feasibility of scheduled mains replacements	PG&E Presentation. [86] Assumes 30% of projects are feasible by 2030 and 60% by 2045
NY ConEd Long-Term Plan (2023)	Hybrid Electrification: 31% avoided CAPEX Deep Electrification: 64% avoided CAPEX	Gas System Long-Term Plan Update Appendices[87] Estimate updated based on revised appendices using weighted average avoided investments from 2026-2043
NY Orange & Rockland Long-Term Plan (2023)	Hybrid Electrification: 16% avoided CAPEX Deep Electrification: 58% avoided CAPEX	Gas System Long-Term Plan Update Appendices[88] Estimate updated based on revised appendices using weighted average avoided investments from 2026-2043

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[84] E3 and Gridworks (2023). Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California.

[85] Massachusetts 20-80 Future of Gas Independent Consultant Report (2021). Appendix 1. https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Appendix%201%20(Modeling%20Methodology).pdf

[86] PG&E Presentation during Building Decarbonization Coalition seminar on Jan 25, 2024. https://buildingdecarb.org/wp-content/uploads/BDC-Presents-Neighborhood-Scale-Slides.pdf

[87] ConEd and O&R (2023). Gas System Long-Term Plan Update Appendices. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b10E81C8C-0000-C315-BC56-6BA86F5A265A%7d

[88] Ibid.

Impacts of a Managed Transition on Rate Base, Revenue Requirement and Delivery Rates

By avoiding some of the pipeline replacement costs under a managed transition, the rate base (see Figure 38) and the resulting revenue requirement (see Figure 39) is reduced in every pathway except Continued Use of Gas, which must maintain the entire gas system. In the High Electrification and Hybrid with Delivered Fuels Backup pathways, the rate base decreases by approximately 40% by 2050 since these pathways see the most gas customers leave the system, creating the greatest opportunity to electrify customers and decommission pipeline.

Figure 38. Rate Base under an Unmanaged and Managed Transition

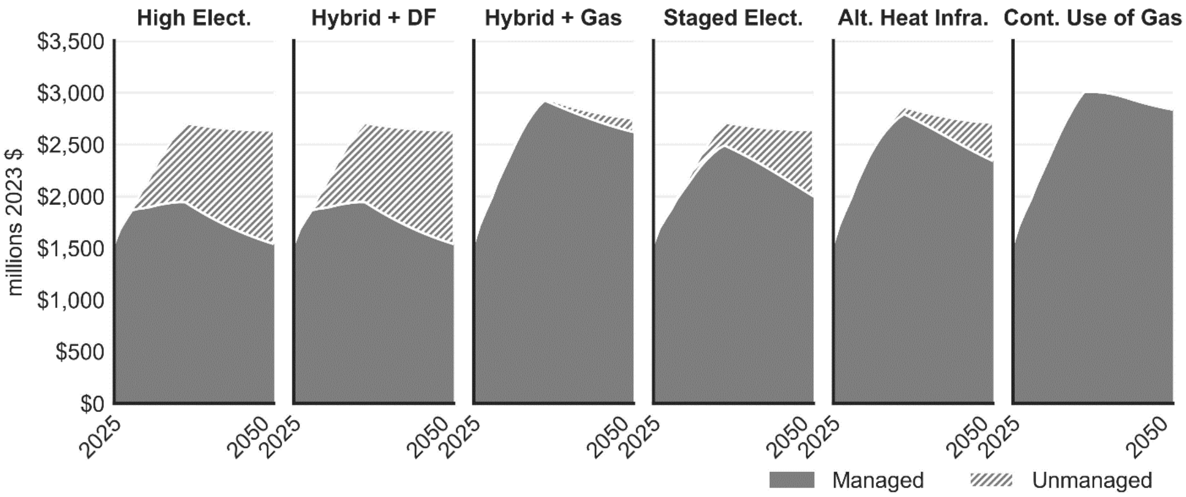
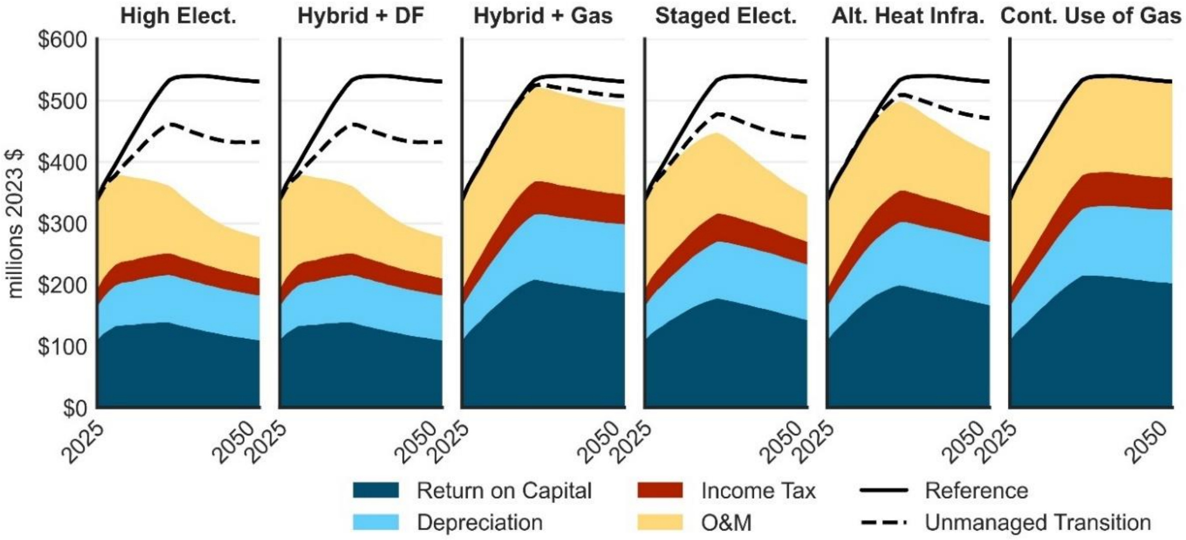


Figure 39. Revenue Requirement under a Managed Transition (note: based on illustrative cost avoidance assumptions)



While the managed transition sensitivity has a sizeable impact on gas rate base and revenue requirement, as well as on statewide total resource costs as described further in Chapter 5, it does not lead to meaningful differences in customer delivery rates, especially for residential customers. The significant decline in gas throughput still causes rates to increase substantially in the long-term. Rates still increase greatly for commercial customers under the managed transition sensitivity, however there is a lesser impact especially for pathways with the highest rates of electrification.

Figure 40. Residential Delivery Rates under Unmanaged and Managed Transitions

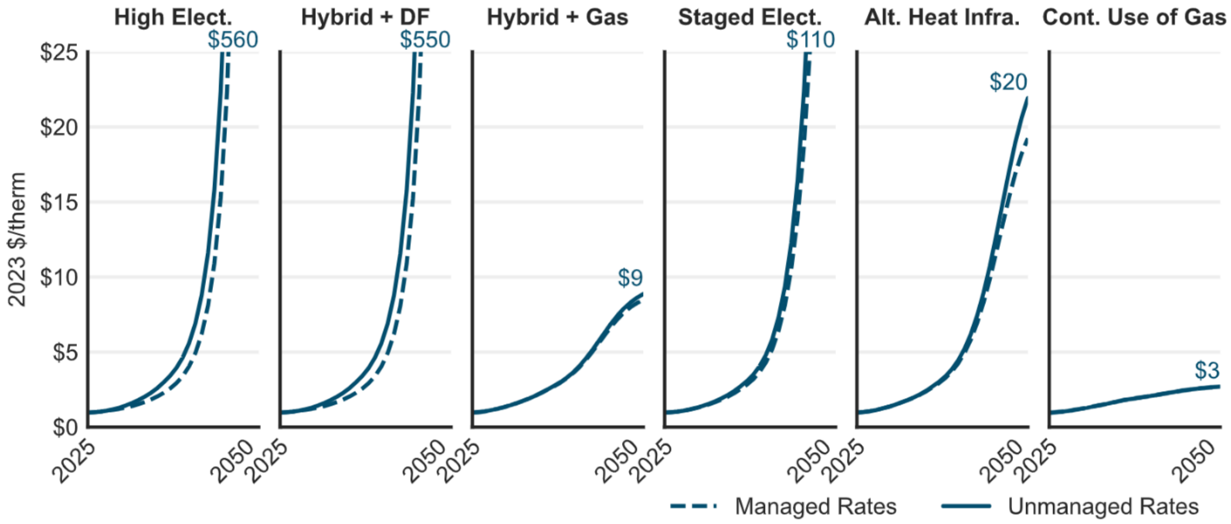
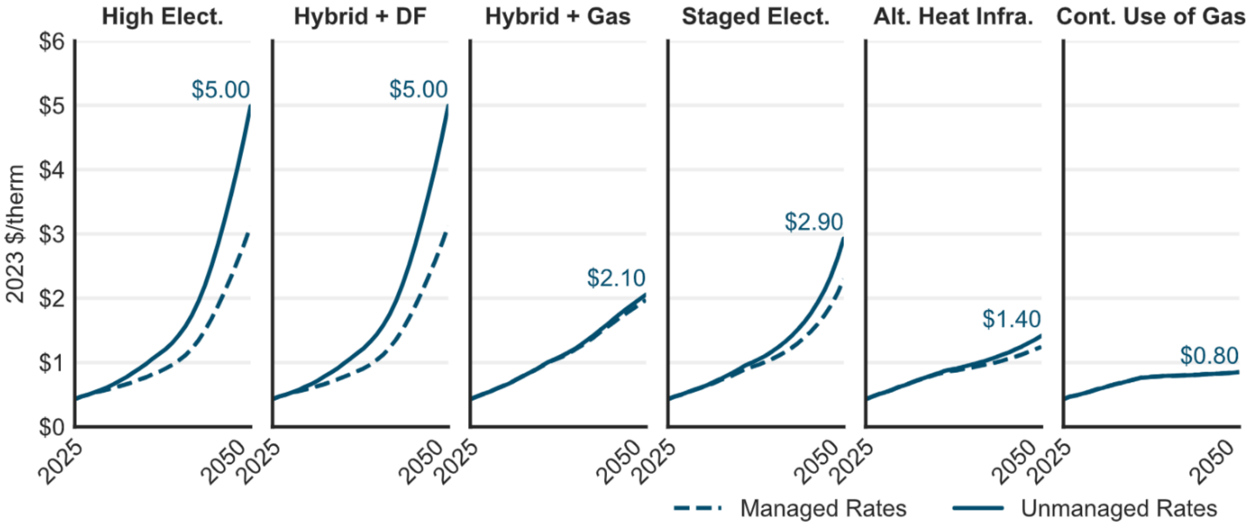


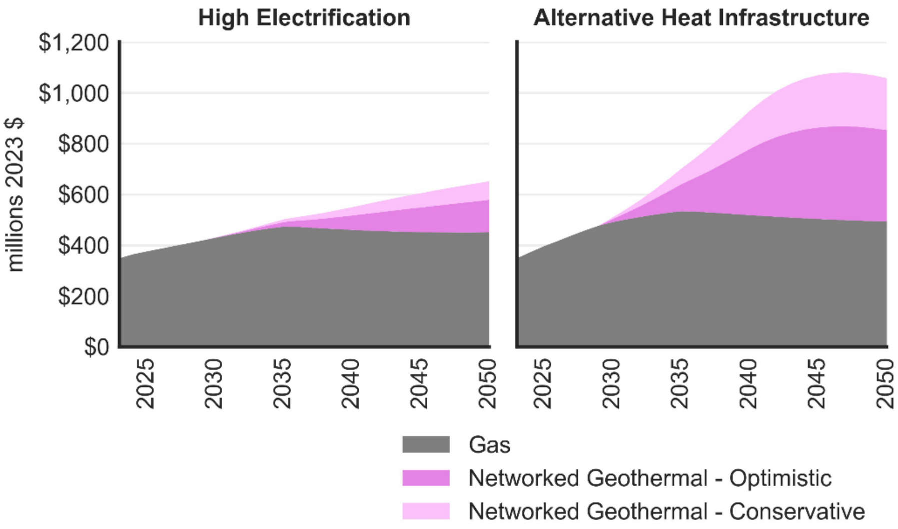
Figure 41. Large C&I Delivery Rates under Unmanaged and Managed Transition



Networked Geothermal Systems

Two decarbonization scenarios, High Electrification and Alternative Heat Infrastructure, include the transition of some of the gas customer base to networked geothermal systems. E3 assumes that the costs of installing networked geothermal infrastructure (not including appliances on customer premises) will be financed and recovered by a utility-type entity under cost-of-service regulation similar to the current gas system cost recovery. E3 estimated the revenue requirement based on the investment required for networked geothermal and added this to the gas revenue requirement in both the High Electrification and Alternative Heat Infrastructure scenarios (see Figure 42). Note that the costs of the gas system in this figure are provided for reference and comparison purposes only, not implying that networked geothermal systems would need to be installed by RIE.

Figure 42. Networked Geothermal Revenue Requirement Addition to Gas Revenue Requirement (gas system costs shown without managed transition assumptions)



The concept of networked geothermal systems as applied in the Technical Analysis is relatively novel, and the costs of installing these systems are uncertain. More research is required to understand the feasibility and cost-effectiveness of the systems, as further described in Chapter 6.

About Networked Geothermal Systems

Similar to the concept described by HEET in its Geothermal Networks Feasibility Study (2019), E3 refers to a networked geothermal system as an underground connection of pipes and pumps that transfer heat and cooling from the ground to buildings in a shared loop network.[89] A networked geothermal system moves heat in the ground and excess heat from other buildings to a home or business that needs heating, resulting in an efficient heating system. In the Technical Analysis, E3 assumes that networked geothermal systems achieve a constant coefficient of performance (COP) of 6, compared to between 0.90 – 1 for gas furnaces and approximately 3 for ASHPs. A

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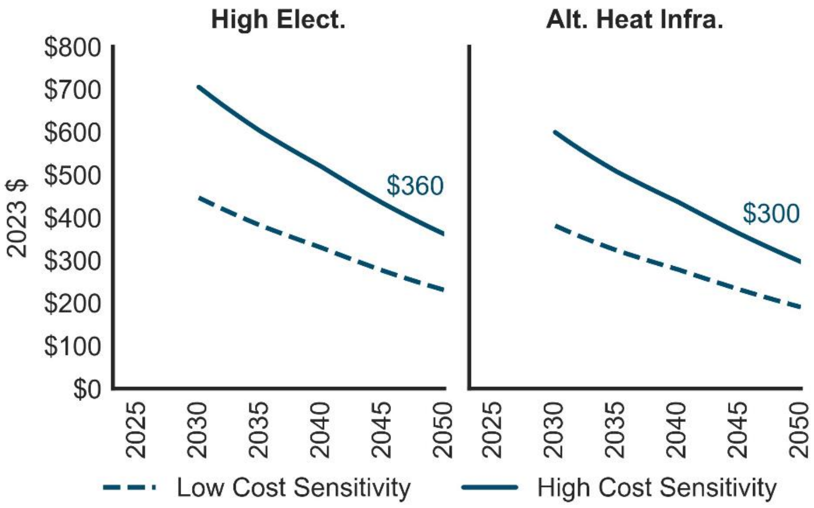
[89] HEET and BuroHappold. Geothermal Networks 2019 Feasibility Study (2019). https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/656f8ad67bbc7df081e3fe17_Buro-Happold-Geothermal-Network-Feasibility-Study.pdf

networked geothermal system additionally transfers heat out of buildings to provide cooling, making it valuable in winter and summer seasons.

The transfer of heat across buildings in the shared loop means that it is beneficial to connect buildings with diverse heating loads. For example, grocery stores have large cooling loads, whereas homes have smaller heating and cooling loads that track the seasons. Grouping these buildings in a single system can enable these loads to be balanced across the network.

In this report, E3 assumes that the revenue requirement for networked geothermal will be recovered by networked geothermal customers, resulting in a monthly networked geothermal connection charge (see Figure 43). The connection charge begins in 2030 when the networked geothermal system is assumed to be installed and declines over time as more customers are added to the system. However, it is important to note that the means to finance and recover costs for a networked geothermal system may be designed in multiple ways. Such alternative options are not reflected in the costs on Figure 43.

Figure 43. Residential Monthly Networked Geothermal Connection Charge

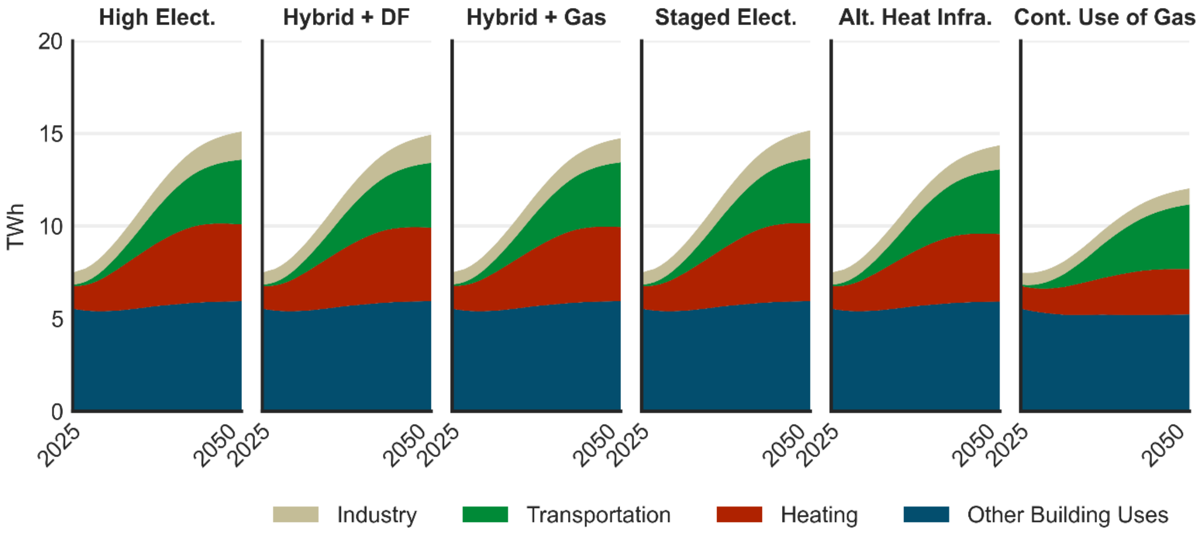


Impact on the Electric System

Load Growth And Electric System Peak Impacts

The electric sector is expected to serve nearly double the annual system load by 2050, regardless of scenario. Shown in Figure 44, the primary drivers of annual load growth across all mitigation scenarios are transportation and heating electrification. LDVs make up the bulk of transportation loads and are a result of Rhode Island successfully meeting ACCII targets.

Figure 44. Annual Load Growth across Decarbonization Scenarios

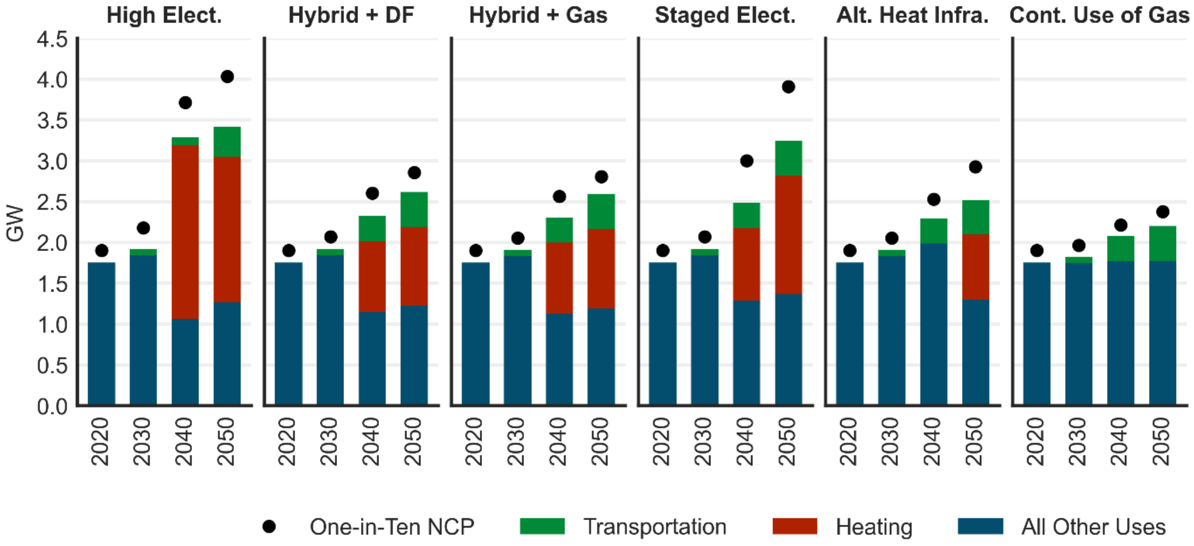


The differences in annual load growth between mitigation scenarios is primarily driven by the level and kind of heating electrification. Annual load growth is the slowest in the Continued Use of Gas scenario because of lower general levels of heating electrification. The Hybrid and Alternative Heat Infrastructure scenarios rely on high penetrations of hybrid heating or highly efficient whole-building heating (through networked geothermal systems), resulting in moderate levels of heating load growth. Finally, the High and Staged Electrification scenarios rely on high penetrations of whole-building ASHPs, leading to the highest heating load growth by 2050.

Electric-sector reliability is driven by its ability to serve large electric demands under extreme weather conditions. These peak loads were estimated using weather data across the 40 weather years from 1979 to 2018. Two types of peak loads were estimated in this study:

- **Median, or 50/50, coincident peaks.** Median peaks are considered the “average” peak load. These peak loads result when high loads across multiple sectors coincide to produce high, system-wide demand. Note that, in general, the coincident peak does not occur simultaneously with any one sector’s peak. This peak, paired with a planning reserve margin, is important to estimate generator-level reliability.
- **One-in-ten, or 90/10, noncoincident peaks.** One-in-ten peaks are more extreme than 90% of all peaks calculated using the 1979-2018 weather year data. Unlike the above coincident peaks, the one-in-ten noncoincident peaks were calculated as the sum of the per-sector peak loads. This peak is important to ensure appropriate transmission and distribution sizing.

Figure 45. Post-Flexibility Median (50/50) Coincident Peak Loads By Contribution And 1-In-10 (90/10) Noncoincident Peak Loads. Heating electrification contributions to the peak indicate a transition to winter peaking.[90]



Peak loads are often driven by weather, with summer peaks today largely driven by air conditioning loads. Electrification of heating leads to an increase in winter peaks as space heating needs increase with colder temperatures. The amount of heating electrification and the type of technology underlying heating electrification drive the extent to which winter peaks increase, and determine whether Rhode Island's electric system remains "summer peaking", or transitions to "winter peaking". Figure 45 shows that nearly all scenarios, except Continued of Use of Gas, result in a significant contribution of heating electrification to the annual system peak in the state starting in the 2030s or 2040s, indicated by the "heating" category on the figure. This demonstrates that in those scenarios, Rhode Island is expected to transition to a winter peaking system, where the winter peak is driven by the need for electricity to satisfy space heating demands.

Those scenarios (High Electrification and Staged Electrification) relying on high penetrations of whole-building ASHPs have the highest peak load growth, with median peaks nearly doubling by 2050. This effect results from the fact that the efficiency of ASHPs decreases as the outdoor air temperature drops, leading to relatively significant levels of electric system peak impacts in winter. In contrast, scenarios with hybrid heating or very efficient whole-building heating have slower peak growth since those scenarios avoid the impact of cold winter peaks. In the scenarios with high levels of hybrid heating (Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup), winter peaks are avoided through gas and/or delivered fuel backup systems in cold hours of the year. In the Alternative Heat Infrastructure scenario, winter peaks are avoided through both the use of hybrid heat pumps and the use of networked geothermal systems that show significant, weather-independent

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[90] The peak heating contribution in the High Electrification scenario decreases from 2040 to 2050 as the median peak load shifts from cold, low LDV-charging morning hours to slightly warmer, high LDV-charging evening hours.

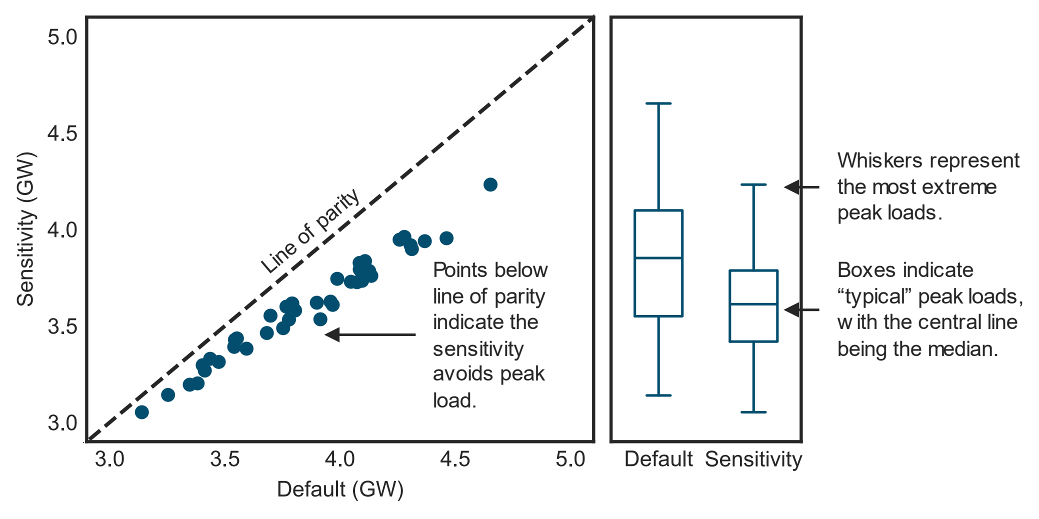
efficiency benefits. These scenarios also demonstrate that hybrid and efficient heating can mitigate peak load impacts under more extreme weather conditions, as shown by the 1-in-10 noncoincident peaks.

Load flexibility is an important component in mitigating peak load growth. Load flexibility can take the form of an electric vehicle delaying charging until after an evening peak or buildings pre-heating or cooling prior to an extreme weather event. E3 assumed that 50% of home light-duty vehicle charging, 25% of water heating, and 4% of space heating loads could be avoided during the identified peak load hour. While not shown in Figure 45, load flexibility reduced both the median coincident and the one-in-ten noncoincident peaks between 350-450 MW across all decarbonization scenarios.

Impact of higher efficiency heat pumps on peak loads

E3 evaluated the effect of high heat pump efficiency for the High Electrification scenario. In this sensitivity, E3 substituted modeled whole-home heat pumps, which were sized to meet the 99th percentile of heating demands and supplemented by electric resistance, with high efficiency heat pumps with no electric resistance backup. The effect of these heat pumps were then evaluated by calculating the system peaks across weather years 1979-2018 and comparing them to those peaks from the High Electrification scenario, the results of which are contained in Figure 46. The results show that substituting high efficiency heat pumps can reduce median peak loads by 250-300 MW up to 500 MW under the most extreme conditions.

Figure 46. High Electrification 2050 System Peak Loads Under Default And High Efficiency Heat Pump Sensitivity Assumptions For Weather Years 1979-2018.



Note: Each point represents peak loads for the sensitivity and default for a given weather year. Box-and-whisker plots summarize peak load distribution under both sets of assumptions.[91]

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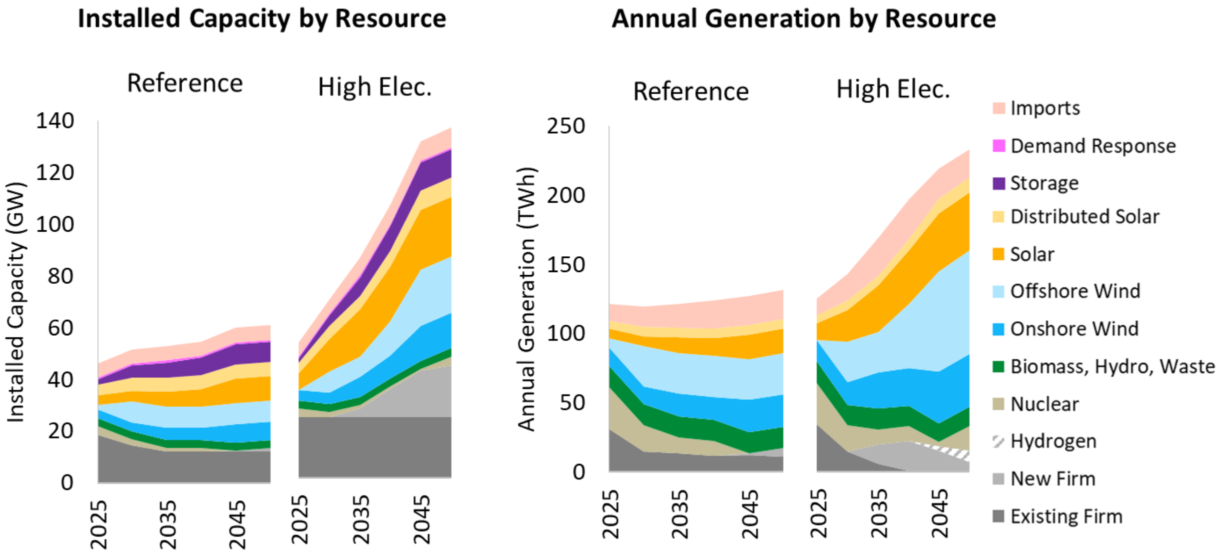
[91] Results on the line of parity would indicate that the sensitivity produces peak loads consistent with the default assumptions.

Capacity & Generation Needs On The ISO New England System

To serve the increasing electric demand across all scenarios, the New England electric system is expected to see transformational changes in generation and capacity. E3 modeled the entire ISO New England for generation capacity expansion considering the current clean and renewable energy policies across all states in New England, including the Rhode Island's 100% Renewable Energy Standard by 2033. As shown in Figure 47, renewables will become a major source of electricity across all scenarios in New England, including in the reference scenario. In the High Electrification scenario, substantial increase in renewables lead to nearly 3x higher installed capacity needs by 2050, dominated by wind and solar. The need for firm (gas) capacity drops in the reference scenario due to relatively flat load profiles, while new firm capacity is required in the other scenarios to reliably serve increasing demand from electrification. The ISO New England-wide cost of generation was scaled down to Rhode Island in each scenario using its share of annual electric demand in the entire ISO.

Figure 47. Installed Capacity and Generation Mix across ISO New England (GW)



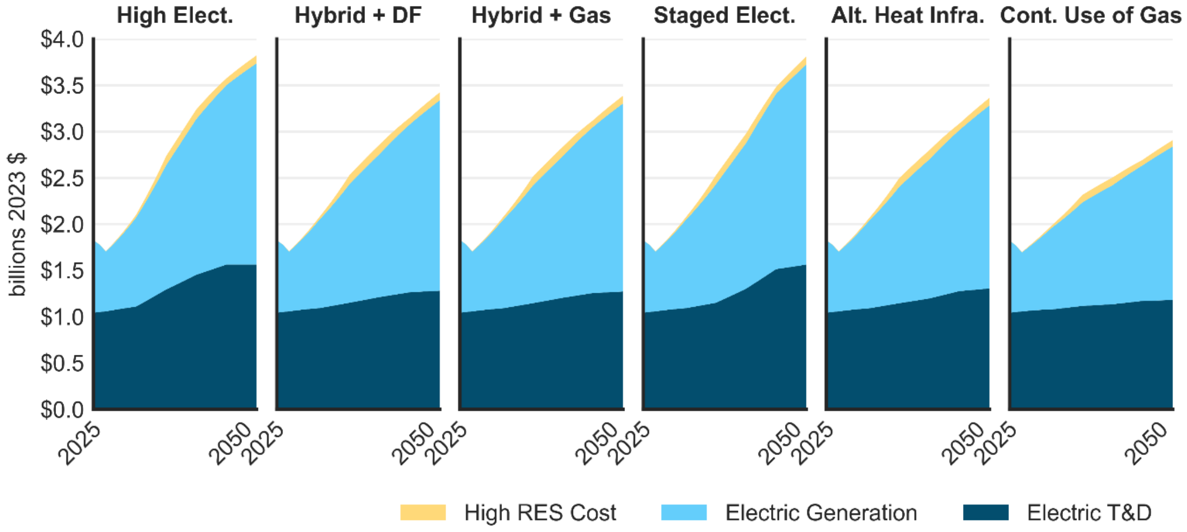
Cost Of Electric Service In Rhode Island

Total cost of electric service in Rhode Island approximately doubles by 2050 due to increased renewable generation and capacity needs (Figure 48). This is driven by higher electric demand, which increases both generation and transmission and distribution (T&D) infrastructure costs to serve the demand, and higher cost of electric generation to meet the 100% Renewable Energy Standard.

Achieving 100% RES by 2033 increases the cost of generation in Rhode Island over the average cost in ISO New England. On average, approximately 60% of the total generation will be from renewable sources across the entire ISO New England by 2033 if all states achieve their renewable and clean energy targets. In this study, it is assumed that Rhode Island needs to pay a premium to meet the 100% RES in addition to the average renewable generation mix achieved in ISO New England. This premium will be paid via purchases of RECs, represented in two bounding scenarios with $31/MWh on the low end and $51/MWh on the high end. Figure 48 shows that the $51/MWh high-end RES sensitivity would add an additional $64-87 million per year in Rhode Island across all scenarios compared to the low-end sensitivity, relative to the average cost of generation in ISO New England.

Average cost of generation increases from $104/MWh in 2023 to approximately $150/MWh in 2050 across all scenarios, driven by increasing capacity need from electrification and higher penetration of renewables. Increasing cost of building renewable resources in recent years further contributes to the cost increase from 2023 to 2050. For example, recent market prices show that average cost of new solar installations increased by at least 20% from 2021, while offshore wind prices increased by at least 33% from 2020.[92]

Figure 48. Current and 2050 Total Cost of Electric Service (2023$ Billion)



Scenarios with higher levels of electric heat pump adoption, such as the High Electrification scenario and the Staged Electrification scenario, see higher levels of T&D spending in the long term due to heat pump capacity needs. The Continued Use of Gas scenario, on the contrary, shows lowest cost of generation and T&D spendings due to lower levels of electrification.

Impacts on electric rates

Rhode Island experienced a steep increase in 2022-2023 electric rates driven by higher natural gas prices, mostly resulting from natural gas supply chain constraints. As shown in Figure 49, in the near-term, E3 assumes that the residential rate follows natural gas market price trends, leading to a reduction in rates in the next two or three years. Beyond 2025 in all scenarios, the costs of electricity are expected to remain higher than the rate of inflation. With electric load increasing over time, rate impacts are mitigated as costs are shared over more load. However, in real dollars (excluding impacts of inflation), rates still increase by 17% between 2023-2050 driven by higher costs for renewable generation, transmission and distribution.

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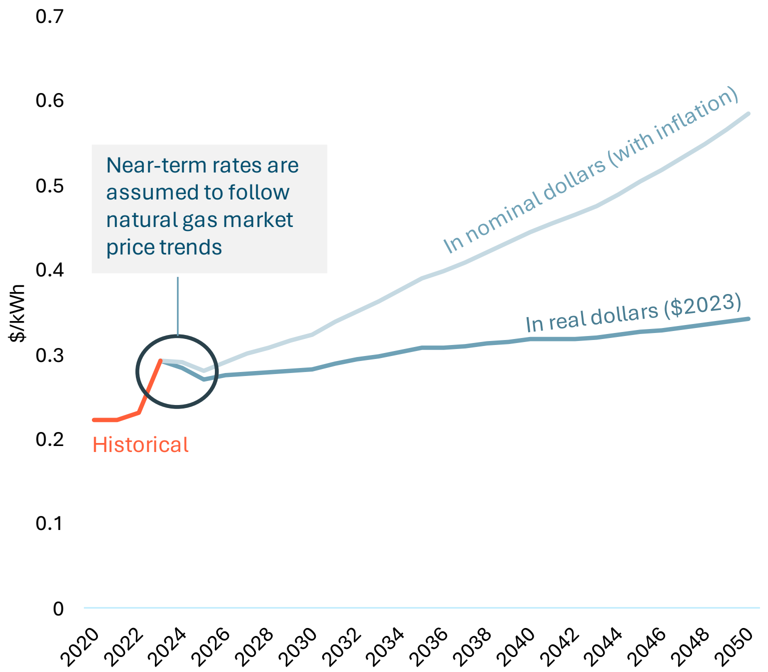
[92] Renewable resource costs are based on the 2023 NREL Annual Technology Baseline and recent market trend, including federal tax credit impacts from the Inflation Reduction Act of 2022.

Figure 49. Rhode Island Historical and Projected Residential Rates in High Electrification Scenario



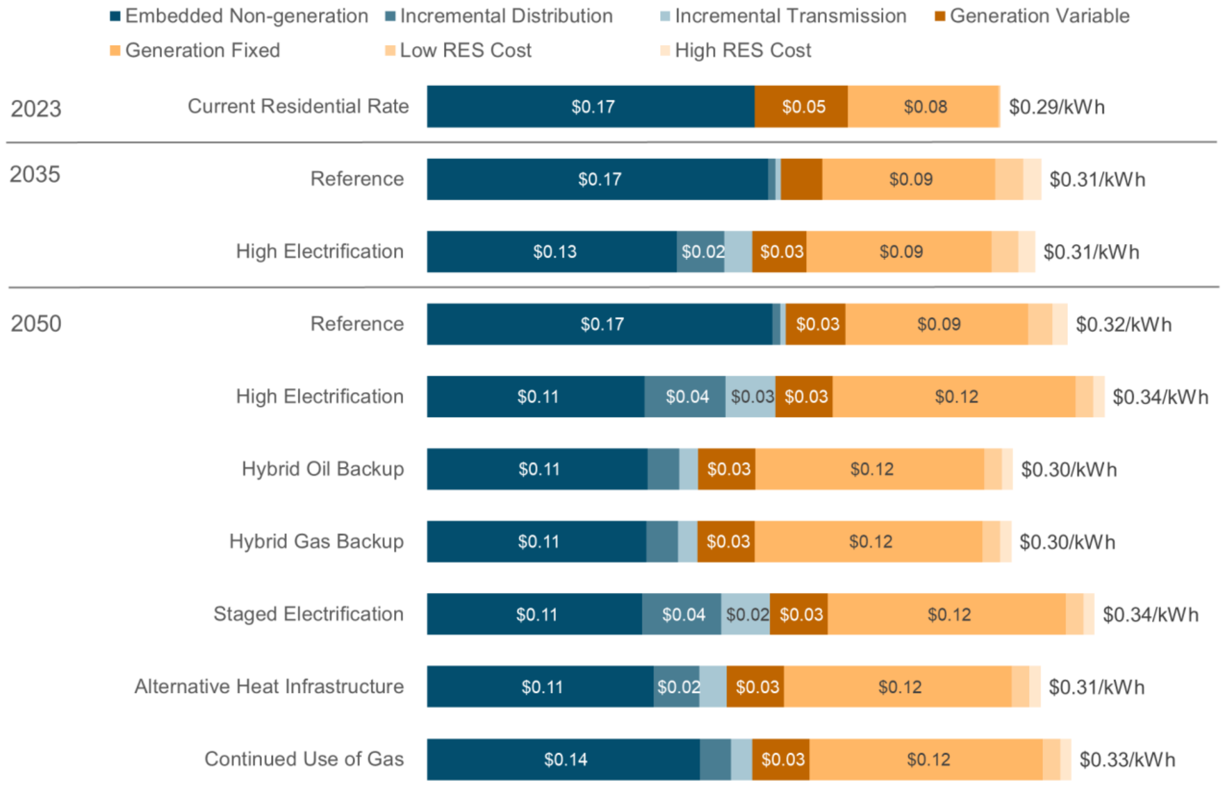
Across all scenarios, electric rate increases are mitigated through load growth to some extent. When spreading the total cost of service over the total load, cost of service increases are largely offset by increased loads, especially for scenarios with high load factors. As shown in Figure 50, in the scenarios with higher levels of electric heat pump adoptions (i.e. High Electrification scenario and Staged Electrification scenario), higher heating load from all-electric heat pumps requires more capacity resources per MWh increase in load to ensure system reliability, thus driving up rates. In scenarios where hybrid heat pumps take up a larger share (i.e. Hybrid with Delivered Fuels Backup scenario and Hybrid with Gas Backup scenario), alleviated peak impacts reduce the need for capacity resources, increasing scenario load factors and therefore lowering the cost per MWh to serve electrification load. The Continued Use of Gas scenario sees relatively high rates due to lower levels of load increase with similar Renewable Energy Standard requirements.

Electricity rates modeled in the Technical Analysis

In the Technical Analysis, E3 modeled average electricity rates through a statewide approach that identifies total electric system costs (including generation, transmission, and distribution costs) and total electric load. At the highest level, this means that the total annual costs of service in Rhode Island are allocated to different customer classes (residential, commercial and industrial) and divided by the annual electric load from those classes. This means that the electricity rates depicted on Figure 49, Figure 50 and as used in the customer bill analysis in Chapter 5 show systemwide average rates or "unit costs" by customer class. These rates are not reflective of specific rate design structures or rate components that individual customers may see on their bill. For example, customers participating in net metering would see a net reduction in electricity rates and bills that is not reflected in this average unit cost metric. In addition, the rate components depicted on Figure 50 represent average generation, distribution and transmission costs associated with decarbonization and do not necessarily reflect real-world wholesale market dynamics, nor do they reflect the impact of potential long-term procurement contracts that may influence customer rates.

For residential electric rates, Figure 50 shows that achieving RES increases rates by ¢1.3-2.3/kWh by 2035. Unit costs of RES, by 2050, are lower in mitigation scenarios due to load growth (¢0.9-1.5/kWh). The implications of electric rate increases across scenarios and the impact on customer affordability are further discussed in Chapter 5.

Figure 50. Residential Electric Rates by Scenario and impact of Renewable Energy Standard (RES)



5. Decarbonization Pathways – Assessment and Implications

The decarbonization scenarios analyzed for the Technical Analysis see different levels of benefits, risks and challenges. This chapter describes key implications of scenarios across a set of evaluation criteria, as introduced in Chapter 3. The evaluation criteria and associated metrics were defined together with the Stakeholder Committee and TWG.

Table 10 provides an overview of key metrics assessed across multiple evaluation criteria that demonstrate differences and commonalities across scenarios. The evaluation criteria are discussed in detail in the section below. Additionally, not shown in the table, E3 provides qualitative considerations with regard to workforce impacts in this chapter.

Table 10. Assessment of Evaluation Criteria

Criteria	Representative Metric		High Electrification	Hybrid w. DF Backup	Hybrid w. Gas Backup	Staged Electrification	Alternative Heat Infra	Cont. Use of Gas
Total Resource Costs	Net Present Value between 2023-2050, incremental to reference		$18-22 billion	$15-21 billion	$14-19 billion	$15-20 billion	$17-24 billion	$16-26 billion
	<u>Illustrative</u> NPV savings if up to 50% of gas CAPEX can be avoided[93]		-$1.7 billion	-$1.7 billion	-$0.1 billion	-$0.7 billion	-$0.4 billion	-$0.0 billion
Customer choice	Annual no. of targeted electrification customers (2035)	*Un-managed*	0	0	0	0	0	0
		Managed	~3,000	~3,000	0	~1,200	~700	0
Long-term affordability	2050 monthly total cost of ownership (TCO) for migrating customer		~ $700	~ $700	~ $700	~ $700	~ $800	~ $700
	2050 monthly TCO for non-migrating customer		> $3,000	> $3,000	~ $1,500	> $3,000	> $3,000	~ $700
	TCO "inflection year" for residential gas vs. all-electric customer[94]		2036	2037	2037	2036	2036	2046
Air Quality Impacts	Change in statewide fuel combustion between 2020-2050 (%)		-85%	-82%	-81%	-85%	-82%	-65%

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[93] Represents reduction in NPV if 50% of CAPEX can be avoided through managed transition, relative to the above row

[94] "Inflection year" is defined as the point in time where the TCO for an all-electric heating customer is lower than for a gas heating customer, under the current regulatory framework.

Reliance regional fuel supply	Total annual volume of renewable fuel required by 2050 (TBtu)	11	15	15	11	13	33
Technology Readiness[95]	Likely range of Technology Readiness Levels required to achieve AoC	8-10	7-10	7-10	8-10	6-10	6-11
Electric System Expansion	Total increase in distribution system capacity by 2035 (GW)	1.2	0.5	0.4	0.5	0.4	0.2

Total Resource Costs

Total resource costs by pathway are determined based on the incremental costs of a scenario compared to the reference scenario. This metric provides an understanding of the costs of additional efforts required for the state of Rhode Island to comply with the Act on Climate, on top of the efforts already underway through existing policies and trends. Total resource costs include all energy-related decarbonization costs, including demand-side capital (costs to install appliances, purchase vehicles, etc.), gas infrastructure, electric infrastructure, geothermal infrastructure, and the cost of fuels. The social costs of carbon and other societal benefits, such as health impacts, are not included in this evaluation.

Due to the uncertain nature of the costs associated with the transition over a time horizon of 30 years, the analysis considers a range of cost sensitivities for key input parameters, as described in Chapter 3. The key findings related to total resource costs are therefore presented as ranges of costs. More detail on the costing approach is provided in Appendix A.4.

Cumulative Resource Costs across Scenarios

Across scenarios, the cumulative incremental total resource costs, expressed in NPV between 2023-2050, vary from $14.0B to $17.6B with low-bound cost input parameters and $19.0B to $25.9B with high-bound cost input parameters. These figures exclude the impact of a managed transition (see textbox below), or the impact of potentially higher efficiency heat pumps that were analyzed as separate sensitivities. Driven by uncertainty around the future cost of renewable fuels, the high-bound cost parameters show higher levels of variation across scenarios. Scenarios with high reliance on renewable fuels, such as the Continued use of Gas scenario, are therefore at higher risk of exposure to more costly renewable fuels.

Across both low- and high-bound cost assumptions, scenarios that leverage hybrid heating technologies, including Hybrid with Delivered Fuels Backup, Hybrid with Gas Backup and Staged Electrification show lower overall costs. These scenarios avoid electric system investments while also reducing dependence on fuels compared to scenarios that rely more heavily on fuels as the

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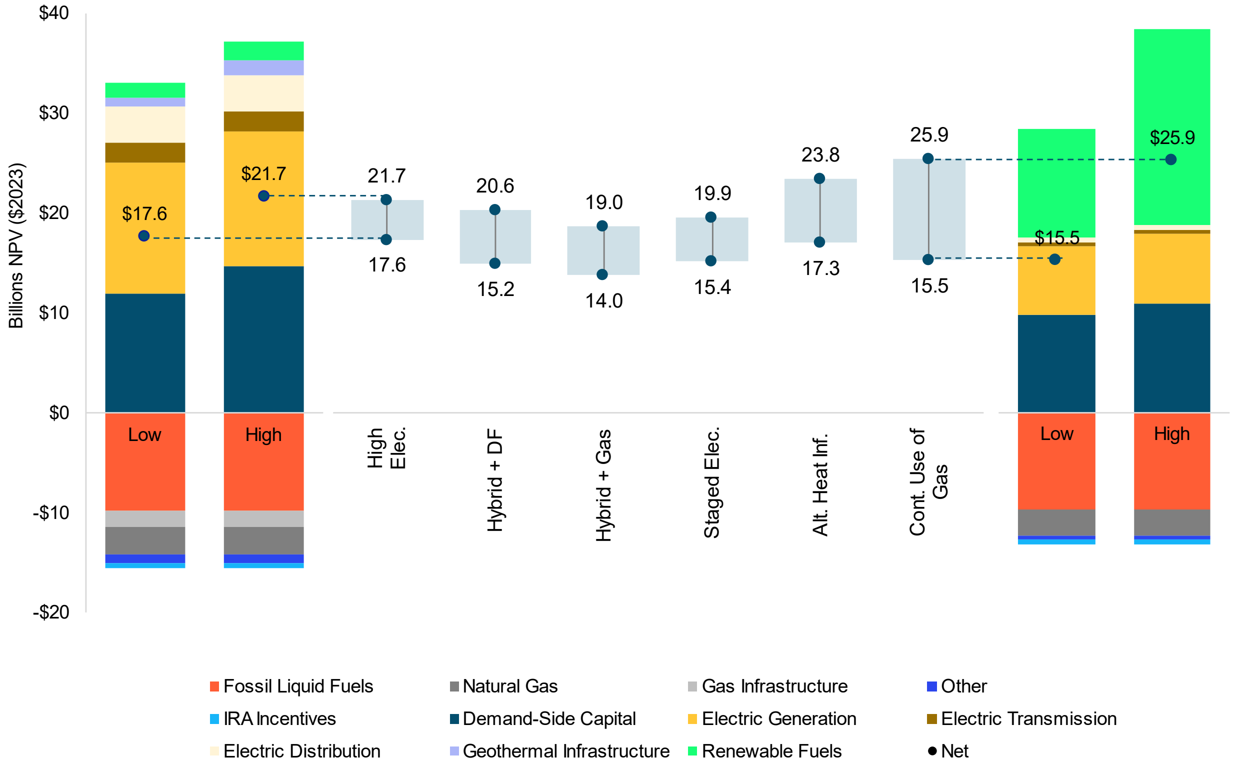
[95] E3 uses the Technology Readiness Level (TRL) scale defined by the International Energy Agency (IEA), where 1 refers to the lowest level of technology commercialization and 11 to the highest level of technology commercialization.

primary heating solution, such as Continued Use of Gas. However, scenarios that leverage hybrid heating solutions show higher levels of risk associated with the cost of renewable fuels compared to scenarios that rely more heavily on electrification, such as the High Electrification scenario.

Figure 51 shows the range of net present value total incremental resource costs across scenarios, with a breakdown by component for the High Electrification and Continued Use of Gas scenarios. This figure shows the total statewide costs of decarbonization measures across scenarios relative to the reference scenario, accounting for both savings and costs of fuels, demand-side capital, electric system, gas system and networked geothermal system costs, incorporating potential savings from Inflation Reduction Act (IRA) incentives. All resource costs are shown on a net present value basis, representing the cumulative incremental costs of the transition between 2023-2050, discounted with a factor of 1%.

Figure 51 demonstrates that although total resource costs fall in a similar range across scenarios, the breakdown of costs varies widely: In the High Electrification scenario for example, the largest cost components are associated with the buildout of electric system infrastructure; in the Continued Use of Gas scenario, the largest cost component represent the costs of renewable fuels. In addition, the High Electrification scenario shows a cost reduction related to gas infrastructure as a result of lower customer connection costs associated with new gas infrastructure compared to a reference scenario. Both scenarios show similar levels of costs associated with demand-side capital, as well as similar levels of cost savings due to the reduction of fossil fuel use.

Figure 51. Range of Net Present Value Total Resource Cost by Scenario using Low and High Cost Input Parameters – breakdown of Components for High Electrification and Continued Use of Gas

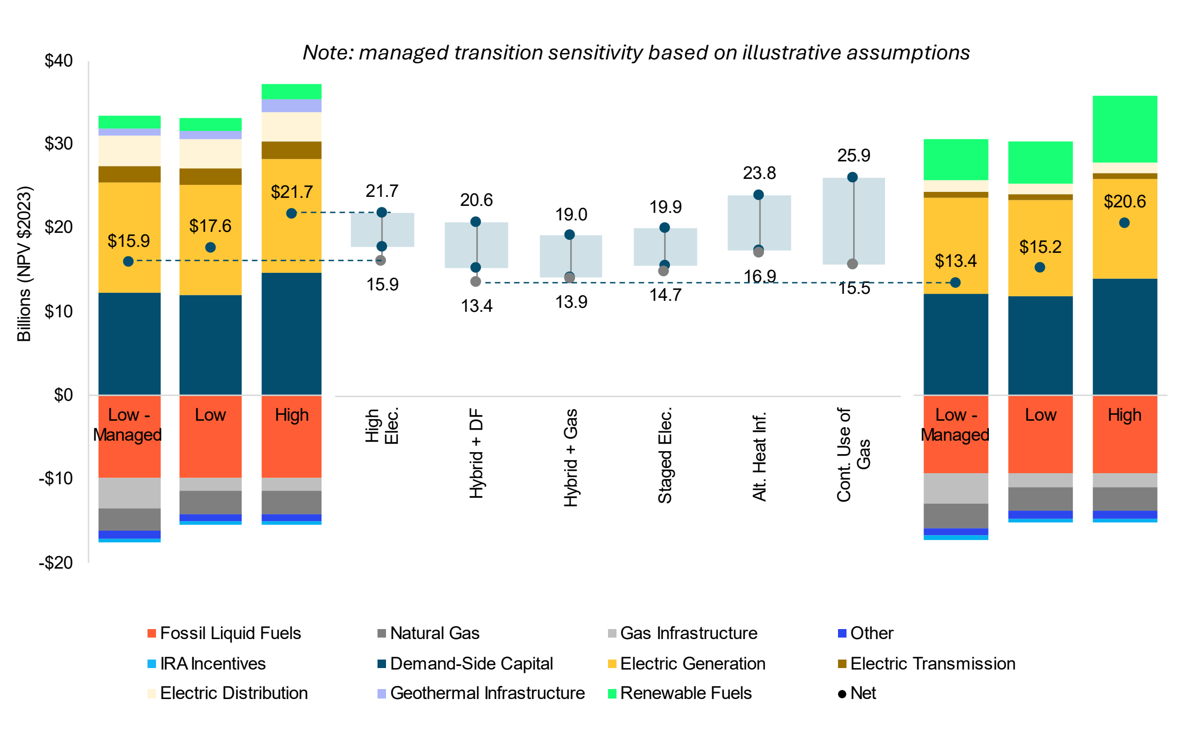


Impact of a managed transition on total resource costs

In scenarios that are able to avoid long-term gas infrastructure, a managed transition can further reduce total resource costs. For illustrative purposes E3 assumed that a maximum of 50% of annual gas capital expenditures can be avoided in scenarios that allow for targeted electrification, which reduces annual gas revenue requirement as described in Chapter 4. Based on this illustrative assumption, total resource costs decline by approximately $1.7 billion in both the High Electrification and Hybrid with Delivered Fuels scenarios. The Staged Electrification scenario sees a reduction in total resource costs of $0.7 billion, as this scenario has less opportunity to avoid gas infrastructure in the near term when most of the leak-prone pipe replacements are due.

The total resource cost reductions assessed in this analysis incorporate both the savings in gas infrastructure resulting from avoided capital expenditures, as well as increased costs related to the early retirement of heating equipment in customer homes. The latter category is relatively small compared to the savings of infrastructure, assuming that in an *unmanaged transition*, the same customers would have electrified their heating equipment later in time. The costs associated with early retirement therefore only reflect the costs of adopting electric heating equipment a few years earlier in time. Regardless, since electric heating equipment is significantly more expensive than gas heating equipment, a managed transition still includes challenges associated with the upfront cost of customer equipment. In addition, a cost-benefit assessment incorporating both gas infrastructure avoidance and customer heating equipment will vary on an individual street level, as this assessment is highly dependent on the density of streets.

Figure 52. Range of Net Present Value Total Resource Cost by Scenario under a Managed Transition – breakdown of Components for High Electrification and Hybrid with Delivered Fuels.



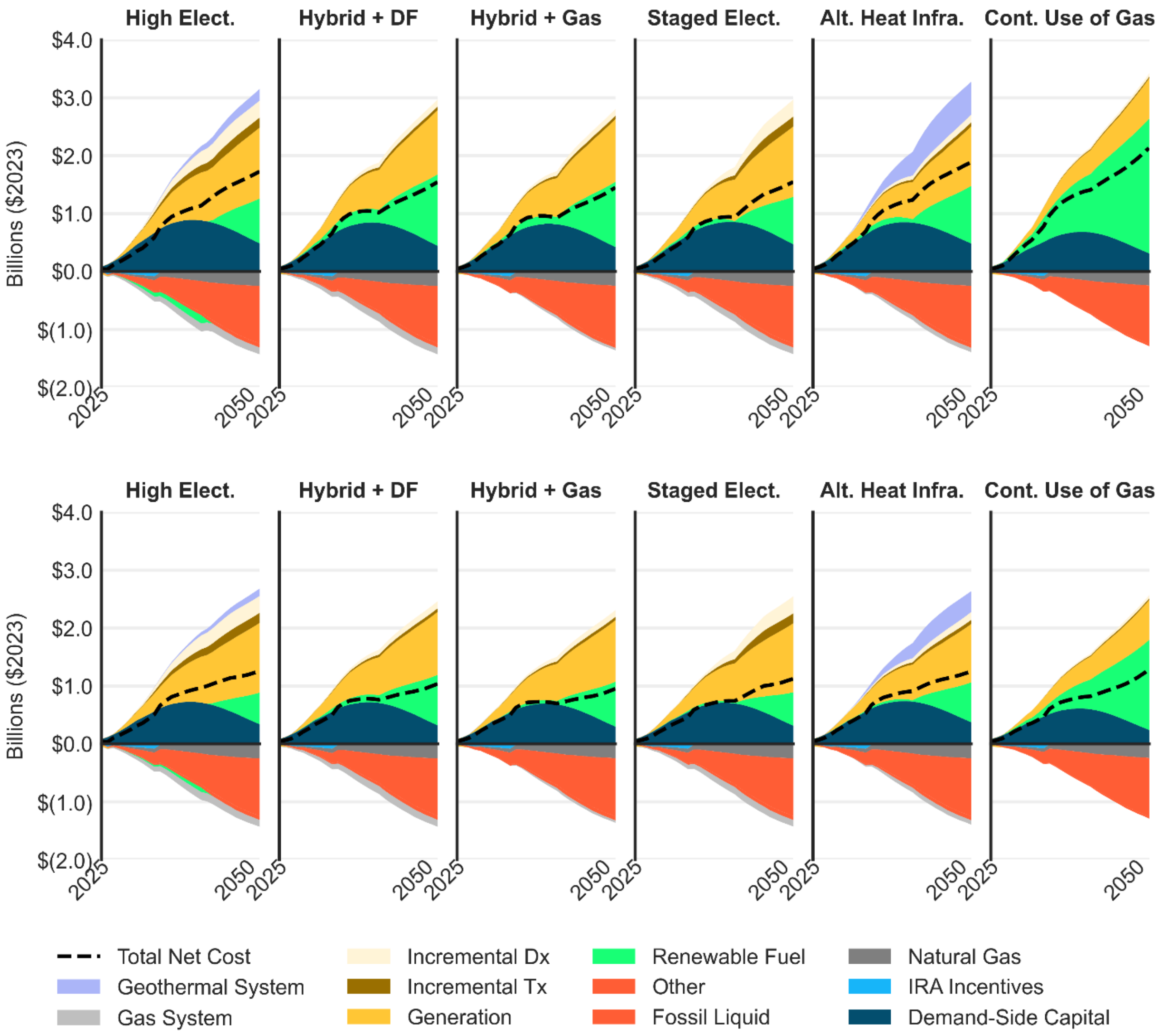
The extent to which total resource costs can be reduced as a result of a managed gas transition highly depends on the extent to which near-term capital expenditures on the gas system can be avoided. As E3 primarily relied on illustrative assumptions for this analysis, much more research is needed to better understand the opportunity associated with avoiding gas infrastructure.

As shown in Figure 53, the annual costs of the transition increase over time, with the majority of annual costs accounted for beyond the 2030s. In the near term, total costs are weighed more heavily towards demand-side capital accounting for the costs of heat pumps and electric vehicles, shifting to a combination of demand-side capital, electric system, and renewable fuels costs in the long term. This is due to two primary reasons:

- The use of renewable fuels increases only later in time to comply with Rhode Island's increasingly stringent emissions targets. With demand for renewable fuels increasing, the costs of renewable fuels are expected to increase and more expensive resources are expected to be required to meet growing demand.
- Incremental costs of the electric system are expected to be lower in the near term as the cost of renewable generation make up a lower portion of total electric system costs and more headroom is available on the system to interconnect distributed generation. As the RES

becomes more stringent and the available headroom on the system declines, the costs of generation, transmission and distribution are expected to go up.

Figure 53. Annual Incremental Costs. Top: high-bound cost input assumptions. Bottom: low-bound cost input assumptions.



Impact of avoidance of hybrid backup installation costs on total resource costs

In the Technical Analysis, E3 assumes that customers that convert to hybrid electrification bear the costs of both all-electric appliances, such as ASHPs, as well as the costs of a backup system (i.e. gas or delivered fuel furnace or boiler). Although most customers have existing furnaces or boilers, it is reasonable to assume that in a long-term transition, these furnaces or boilers need to be replaced at end-of-life similar to other appliances.

However, in some cases customers may be able to benefit from existing furnaces or boilers with minimal additional investments, for example through burner-tip adjustments for conversion to propane use. In these cases, it is assumed that a customer would transition to all-electric appliances later in time as their furnace or boiler reaches end of life, or that a customer would significantly extend the lifetime of their backup system. E3 explored the potential total resource cost savings that can be achieved if the cost of hybrid backup systems can be avoided. This sensitivity analysis found a total cumulative incremental saving $1.1B for the Staged Electrification scenario. It is reasonable to assume that this benefit would mostly be applicable to the Staged Electrification scenario that transitions to all-electric heating in the long term, but a similar benefit may be seen in the Hybrid with Delivered Fuels backup scenario or Hybrid with Gas Backup scenarios for customers that are able to retain existing backup systems without replacement for additional years of useful life, before replacing the backup system or transitioning to a fully electric heating system.

Cost Uncertainty Analysis

As noted in Chapter 3, E3 accounted for uncertainties in incremental resource costs through sensitivity analysis using both low-bound and high-bound cost parameters for key input assumptions. Using these sensitivity parameters, E3 performed a cost uncertainty assessment based on the theory of “regret analysis.” Regret analysis helps inform whether a finding of lower costs for particular decarbonization measures or scenarios is robust to various sensitivities.[96] “Regret” is defined as the extra cost of a given scenario for each sensitivity above the lowest cost scenario within that sensitivity.

The tables below shows two variations of costs across scenarios. Table 11 (top) shows the incremental total resource costs of scenarios relative to the reference case isolated by sensitivity parameter. For example, the “high heat pump costs” column represents the total resource costs in a worldview where *only* the costs of heat pumps represent conservative input parameters, holding all other parameters constant at low-bound cost input parameters. Comparing the costs in this column to the “low cost sensitivity” column on the left allows us to view the impact of potential higher costs of heat pumps in isolation, providing insight into the risks associated with higher costs of heat pumps. Table 12 (bottom) shows the additional costs of a given scenario above the lowest cost scenario within each sensitivity column. A regret of zero indicates that the scenario was the lowest cost scenario within that sensitivity column. For example, in the “high heat pump costs” sensitivity, all scenario costs are shown as incremental to the Hybrid with Gas Backup scenario as that scenario shows the lowest costs within that column.

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[96] Based on Decision Theory: Peterson M. An Introduction to Decision Theory. Cambridge University Press, 2013

Table 11. Incremental Total Resource Costs By Scenario, Isolated By Sensitivity Parameter (in $2023 billion cumulative NPV costs).

Sensitivity → *(in $2023 billion)*	Low cost sensitivity	Managed Transition	High heat pump costs	High REC costs	High RNG costs	High networked geo costs	High cost sensitivity
High Electrification	**$17.7**	$15.9	$20.4	$18.1	$18.0	$18.3	**$21.7**
Staged Electrification	**$15.4**	$14.7	$17.9	$15.8	$17.0	$15.4	**$19.9**
Alt. Heat Infrastructure	**$17.4**	$17.0	$19.3	$17.7	$19.5	$19.6	**$24.0**
Continued Use of Gas	**$15.5**	$15.5	$16.8	$15.6	$24.6	$15.5	**$25.9**
Hybrid with Gas Backup	**$14.0**	$13.9	$16.2	$14.3	$16.6	$14.0	**$19.0**
Hybrid with DF Backup	**$15.2**	$13.4	$17.4	$15.5	$18.1	$15.2	**$20.6**

Table 12. Sensitivity Analysis Across Scenarios And Sensitivities (in $2023 billion cumulative NPV costs). Costs are shown as incremental to the lowest cost scenario per sensitivity.

Sensitivity → *(in $2023 billion)*	Low cost sensitivity	Managed Transition	High heat pump costs	High REC costs	High RNG costs	High networked geo costs	High cost sensitivity
High Electrification	$3.7	$2.5	$4.3	$3.7	$1.5	$4.2	$2.7
Staged Electrification	$1.4	$1.3	$1.8	$1.4	$0.4	$1.4	$0.8
Alt. Heat Infrastructure	$3.4	$3.6	$3.2	$3.4	$2.9	$5.6	$4.9
Continued Use of Gas	$1.5	$2.1	$0.6	$1.3	$8.0	$1.5	$6.8
Hybrid with Gas Backup	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.0
Hybrid with DF Backup	$1.2	$0.0	$1.2	$1.2	$1.6	$1.2	$1.6

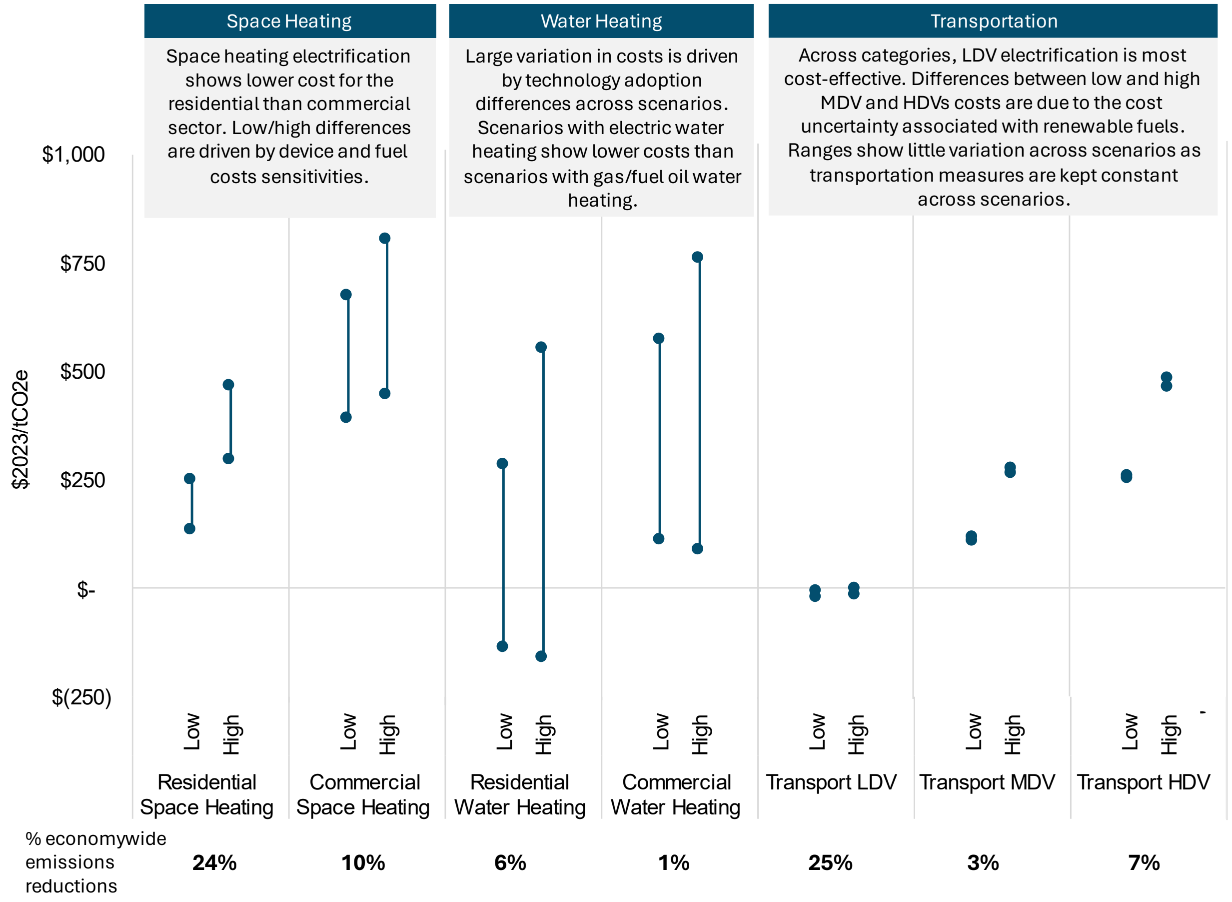
The sensitivity analysis shows that the costs of renewable fuels and the costs of networked geothermal systems demonstrate the highest levels of incremental costs. Scenarios that rely more heavily on renewable fuels or networked geothermal systems therefore imply higher levels of risk than scenarios with lower reliance on these components. The scenarios that rely more heavily on hybrid solutions, such as Hybrid with Gas Backup, Hybrid with Delivered Fuels Backup, and Staged Electrification demonstrate lowest levels of cost uncertainty across all sensitivity parameters (indicated by relatively low levels of regret across rows). It is important to note that this analysis only considers uncertainty across the parameters selected for sensitivity analysis, and is dependent on the value of input specific input assumptions, as detailed in Appendix B.

Cost of Abatement

In addition to analyzing incremental total resource costs by scenario, E3 evaluated the costs of GHG abatement associated with decarbonization of key subsectors in the building and transportation sector. In this analysis, abatement costs are defined as the incremental costs to avoid one metric ton of CO2e compared to a reference scenario. Costs include all components incorporated in the total resource costs analysis (see section Appendix A.4). This type of analysis provides insight into the relative cost-effectiveness of decarbonization measures and can therefore inform potential low-regret, near-term policy decisions. It is important to note, however, that in the longer term, all subsectors need to abate GHG emissions in order to comply with the Act on Climate.

Figure 54 shows a range of average abatement costs by subsector, where the range is determined based on the values of abatement costs found across scenarios. Average abatement costs are defined as the cumulative (2023-2050) incremental resource costs per subsector (in net present value, accounting for all the cost categories associated with total resource costs), divided by the total GHG abatement in that subsector. This view is not technology-specific, but rather represents a portfolio of technology options dependent on the design of the scenario. For example, in the High Electrification scenario, the space heating subsector is primarily comprised of air source heat pumps, but includes other technologies as well. The figure below therefore primarily provides insight into the relative costs of one subsector over another as well as the variation in subsector costs by scenario, rather than insights into the cost-effectiveness of individual technologies.

Figure 54. Range Of Abatement Costs For Each Subsector Found Across Scenarios. Low = low-bound cost input parameters, High = high-bound cost input parameters.



Space heating electrification shows lower cost for the residential than commercial sector. Low/high differences are driven by device and fuel costs sensitivities.

Large variation in costs is driven by technology adoption differences across scenarios. Scenarios with electric water heating show lower costs than scenarios with gas/fuel oil water heating.

Across categories, LDV electrification is most cost-effective. Differences between low and high MDV and HDVs costs are due to the cost uncertainty associated with renewable fuels. Ranges show little variation across scenarios as transportation measures are kept constant across scenarios.

A few observations can be made from the figure:

- Across categories, electrification of LDVs is most cost-effective. The range in LDV costs shows little variation as transportation measures are kept constant across scenarios, with the majority of LDVs transitioning to electric vehicles.
- Decarbonization of MDVs and HDVs is less cost-effective than LDVs. Across scenarios, a higher part of the MDV and HDV stock is decarbonized through renewable fuels compared to the LDV stock. The differences between low and high MDV and HDVs costs are due to the cost uncertainty associated with renewable fuels.

- Decarbonization of space heating demonstrates lower costs for the residential sector than commercial sector. The differences between low and high parameters are driven by device and fuel costs sensitivities.
- There is significant variation in the abatement costs of water heating for both the residential and commercial sector. This variation is primarily driven by the differences in technology adoption across scenarios, since some scenarios (e.g. High Electrification, Staged Electrification) rely more heavily on adoption of heat pump water heaters, while other scenarios rely on water heating through renewable gas (Continued Use of Gas, Hybrid with Gas Backup) or renewable delivered fuels (Hybrid with Delivered Fuels Backup). In Figure 54, the low bound of the range is determined by scenarios that rely more heavily on adoption of heat pump water heaters, which implies that heat pump water heaters are relatively cost-effective decarbonization solutions. In contrast, the high bound of the range is determined by scenarios that rely more heavily on gas or delivered fuel water heating, which implies that these technologies are not a cost-effective solution to decarbonize water heating.

Customer Choice and Implications of a Managed Transition

As described in Chapter 4, the term managed transition in this report refers to the development of neighborhood-specific targeted electrification projects based on gas mains replacement schedules that result in the avoidance of gas system costs. In the scenarios modeled, the analysis assumes a 100% opt-in from customers. The likelihood of this outcome was not modeled or assessed, and implementing a managed transition strategy could require significant changes to customers options. The figure below shows that if 50% of pipeline replacements are avoidable, up to 3,000 customers per year need to electrify their heating system in a targeted manner between 2027-2035. For reference, initial pilot programs conducted by PG&E in California have to date electrified a total of 102 customers.[97] These “targeted conversions” only apply to scenarios with near-term gas system departures, such as High Electrification, Hybrid with Delivered Fuels Backup and Staged Electrification.

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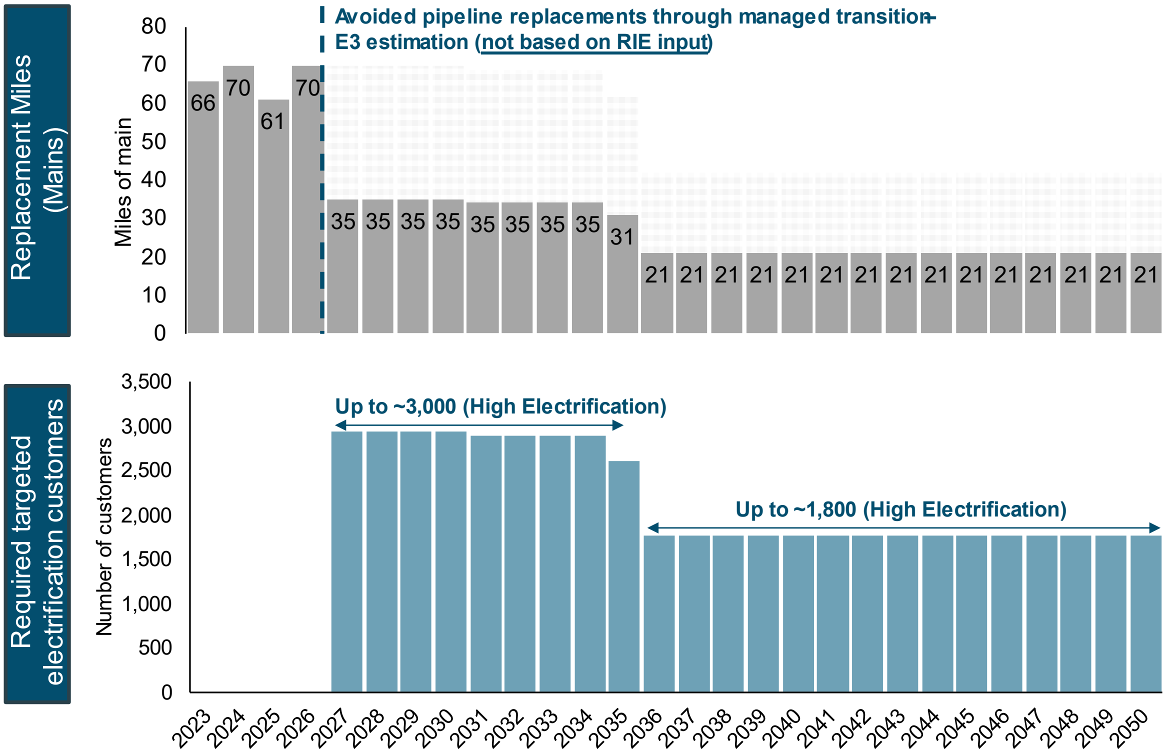
[97] Presentation by PG&E on The Building Decarbonization Coalition “Future of Building Decarbonization” workshop, page 21: BDC Presents Neighborhood Scale (buildingdecarb.org)

Figure 55. (Illustrative) Avoided Pipeline Replacement Assumptions And Implications For Number Of "Targeted" Customer Conversions



While a managed transition may avoid some investment in the gas system, it will require substantial top-down coordination and presents several risks, which are not modeled or addressed in detail as part of this study. A few considerations include:

- Obligation to serve: A managed transition strategy requires a 100% opt-in from customers or has significant implications for customer choice, as customers will need to agree to convert all gas appliances to electric and/or geothermal systems. Successful implementation of such projects may require regulatory reforms associated with obligations to serve.
- Community engagement. Achieving a 100% opt-in from customers will likely require significant levels of community engagement. Initial community engagement research by E3, Gridworks and East Bay Community Energy in California found that identifying the appropriate parties to interface with community members may prove difficult, as utilities and local governments are not always viewed as trusted parties and local organizations may have low bandwidth or expertise to engage on these issues.[98]
- Safety and reliability: Maintaining the safety and reliability of the gas distribution system is a core tenant of RIE's responsibilities and is necessary to continue to serve customers that remain on the gas system. A managed transition will require careful study to determine which segments of

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[98] E3, Gridworks and East Bay Community Energy (June 2023). Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California.

the distribution system can be safely decommissioned while maintaining sufficient gas flow and pressure to reliability deliver gas. These areas for further study are described in Chapter 6.

+ Cost-effectiveness: Converting customer gas appliances to electric appliances requires substantial upfront costs, especially when gas appliances may not be at the end of their useful life and fully depreciated. Balancing the benefits of potential avoided costs from decommissioning and the costs of customer electrification will be a key challenge in a managed transition. Some studies have found that targeted electrification projects result in net societal benefits, but the cost-effectiveness is highly dependent on factors such as electric distribution upgrade requirements, upfront equipment costs, and gas system density.[99] Cost-effectiveness could further be affected by the potential need to provide "buy-out" incentives in order to achieve a 100% opt-in from customers.
+ Funding gap: Regardless of societal benefits, additional funding will be needed to make targeted electrification cost-effective from a customer perspective. Studies show that the upfront costs of equipment still lead to a net cost from a participant perspective, especially as project upgrades need to occur before equipment end-of-life.[100] This means that there is a potential misalignment between societal benefits and customer benefits that needs to be addressed in order to make targeted electrification projects attractive for customers.

Affordability and Implications for Energy Burden

As demonstrated in Chapter 4, a reduction in gas demand leads to higher gas rates for remaining customers, which could lead to spiraling energy bills for gas customers. As the upfront costs for electrification are high, this effect could create equity issues as low-income customers are less likely to be able to afford electrification and are left on the gas system.

E3 evaluates customer affordability by assessing customer energy bills and levelized upfront costs for various customer types, such as a gas customer, an all-electric customer, a hybrid gas customer, and a hybrid delivered fuels customer. In addition to the impact of adopting new heating technologies on energy bills, E3 assesses the impact of weatherization measures on bills and the impact of upfront costs.

Cost Of Adopting Decarbonization Measures Today

Today, as illustrated on Figure 56, an all-electric customer adopting an ASHP and other electric appliances experiences approximately 25% higher monthly energy bills than a gas customer that uses gas as primary heating source. This increase is primarily driven by relatively high electricity rates compared to gas rates, as discussed in Chapter 4. Rhode Island has one of the highest electricity rates in the country today (0.29 $/kWh in 2023 compared to the approximately 0.15 $/kWh U.S. average[101]), which means that despite the efficiency of heat pumps, efficient electric heating does

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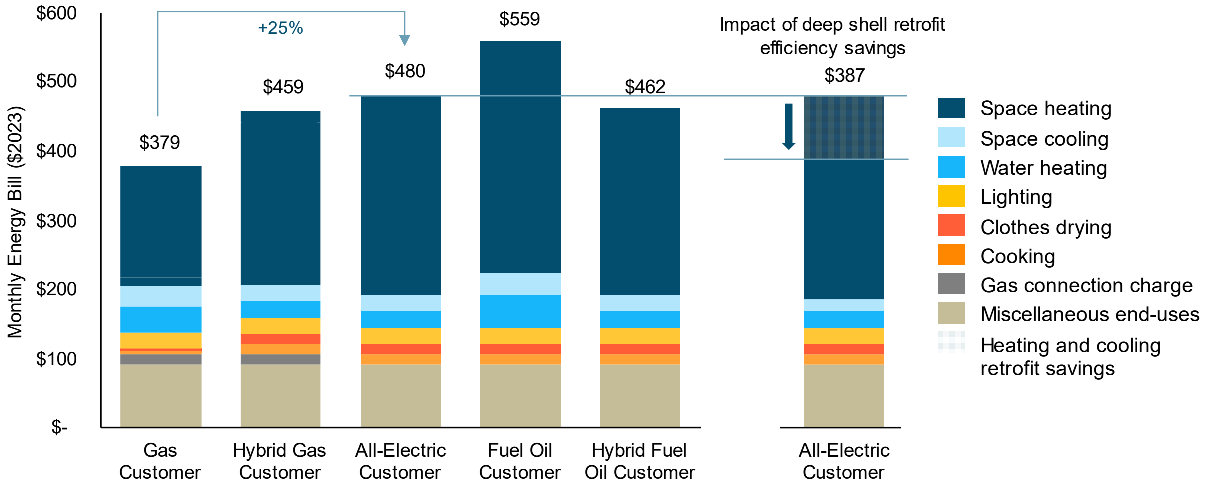
[99] See, for example: E3 - Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California;
[100] Ibid
[101] Based on EIA Table 5.6.A, Table 2.10

not lead to a reduction in energy bills for customers currently on gas heating. In contrast, efficient electric heating does lead to a significant reduction in bills for customers using delivered fuels as their primary source of heating, because of the high costs associated with delivered fuels. In addition, as illustrated on Figure 56, a customer transitioning from gas to electric heating and undergoing a deep shell weatherization retrofit that reduces energy consumption would experience monthly energy bills that are similar to a gas customer.

Figure 56. Residential Monthly Energy Bills in 2023



In addition to monthly energy bills, customers transitioning away from the gas system will face significant upfront costs for electric appliances. Purchasing ASHPs and other electric equipment today is more expensive than traditional gas appliances[102], leading to costs that are almost three times higher for an all-electric customer compared to a gas customer. Furthermore, building shell weatherization retrofits that achieve up to 30% energy savings in space heating and cooling are necessary investments to reach Rhode Island's climate goals. E3 estimates that a deep shell weatherization retrofit would cost approximately $20,000 for an average-sized single-family home, presenting a sizeable upfront cost barrier to customers (see Figure 57).[103]

Federal and state incentives can mitigate the affordability challenge for customers, but current incentives are insufficient to bring electric heating appliances to cost parity with their gas appliance counterparts. The Inflation Reduction Act (IRA) provides tax credits for heat pumps and weatherization upgrades until 2033. Rhode Island State offers rebates for heat pumps and an electric panel upgrade and RIE also provides incentives for heat pumps.

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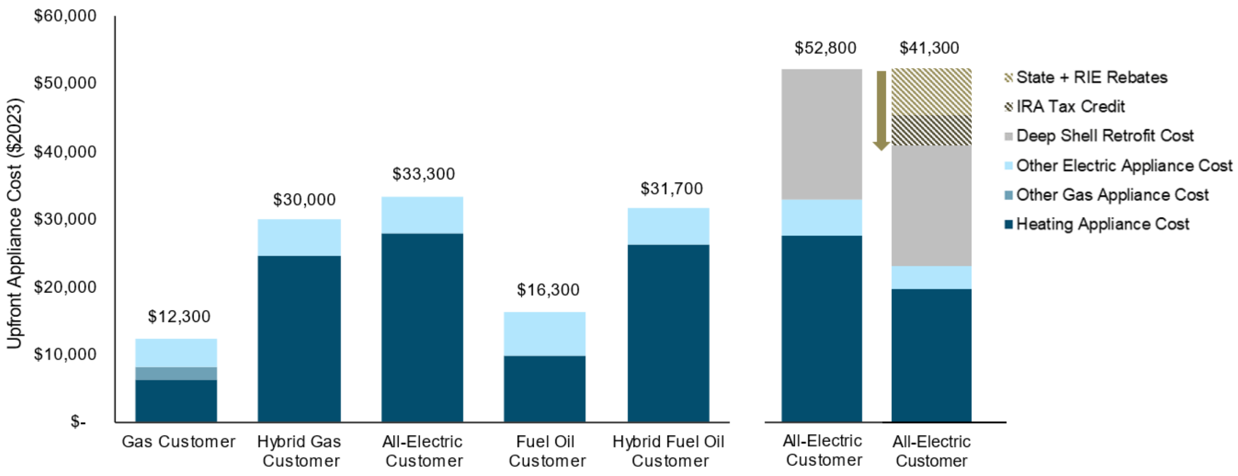
[102] E3 applies its default or base case cost assumption for ASHP and hybrid ASHPs in its energy bill calculations.

[103] Note that in the PATHWAYS analysis, by 2050 nearly 35% of customers are assumed to receive a deep shell retrofit, and 60% a "basic" (cheaper) shell retrofit. These numbers are similar across scenarios. A basic shell retrofit is expected to cost approximately $6,000 for an average-sized single-family home, leading to a 16% saving in heating service demand.

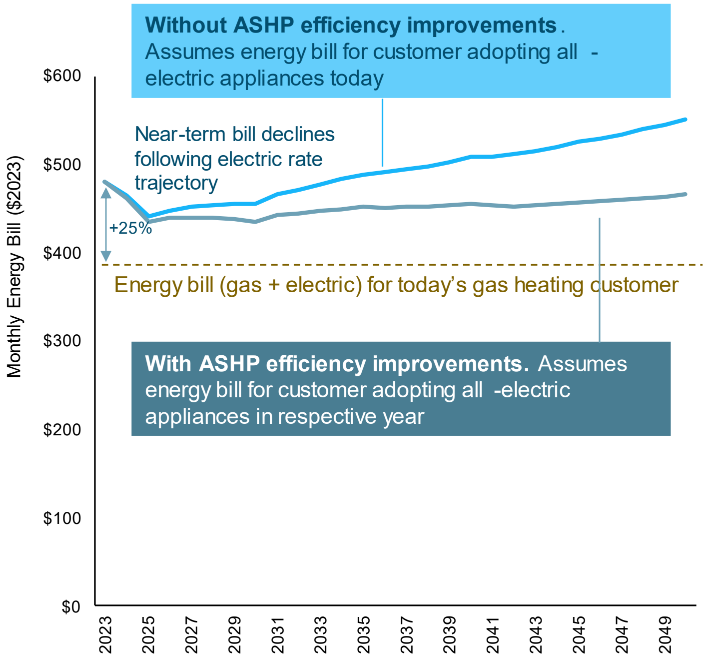
Figure 57. 2023 Upfront Appliance Costs associated with Decarbonization Measures



Costs Of Adopting Decarbonization Measures Over Time

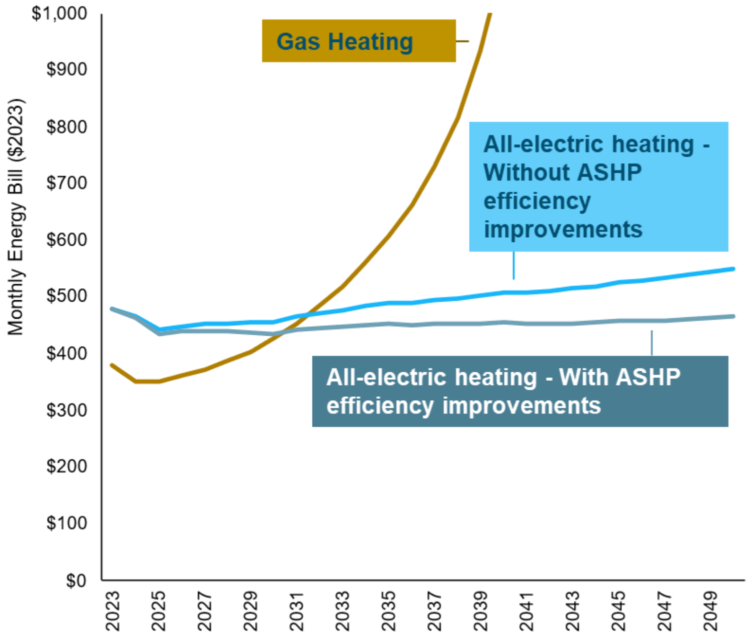
In all decarbonization pathways, energy bills increase as gas and electric rates are expected to rise. As electric rates increase, it becomes less attractive to adopt electric heat pump equipment, especially for customers adopting heat pumps in the near term with current levels of technology efficiency. However, as heat pump efficiencies are expected to improve over time, despite electric rate increases customers adopting heat pumps in later years will not experience significant energy bill increases from today’s level (see Figure 58).

Figure 58. Single Family Residential Monthly All-Electric Customer Bill under the High Electrification Scenario



As customers exit the gas system in a High Electrification scenario, adopting all-electric equipment becomes more cost-effective *in relative terms* in comparison to gas bills under the current regulatory framework. This dynamic is demonstrated on Figure 59, which shows the same electric heating customer energy bills as Figure 58 but adds a comparison to the energy bills for a customer that remains connected to the gas system in the High Electrification scenario. This figure shows that while electric heating bills remain relatively steady (assuming heat pump efficiency assumptions), the bills for a gas heating customer rise substantially because of delivery rate increases. As a result, all-electric heating becomes more cost-effective in relative terms compared to gas heating around the early 2030s.

Figure 59. Single Family Residential Monthly All-Electric Customer Bill compared to Gas Customer Bill under the High Electrification Scenario



The same dynamic is illustrated for all scenarios in Figure 60. This figure show that residential gas customers face spiraling gas rates and untenable energy bills in the long-term in all pathways except for Continued Use of Gas. Similarly, commercial customers experience spiraling gas rates, though to a lesser extent than residential customers (see Figure 61). Because of that dynamic, by the early 2030s it becomes more affordable for residential customers to electrify their homes as most of the costs of the gas system are shifted to fewer remaining gas customers. However, it is important to note that following these dynamics, all customer energy bills are expected to go up from today's levels.

Figure 60. Residential Monthly Energy Bills under Decarbonization Pathways

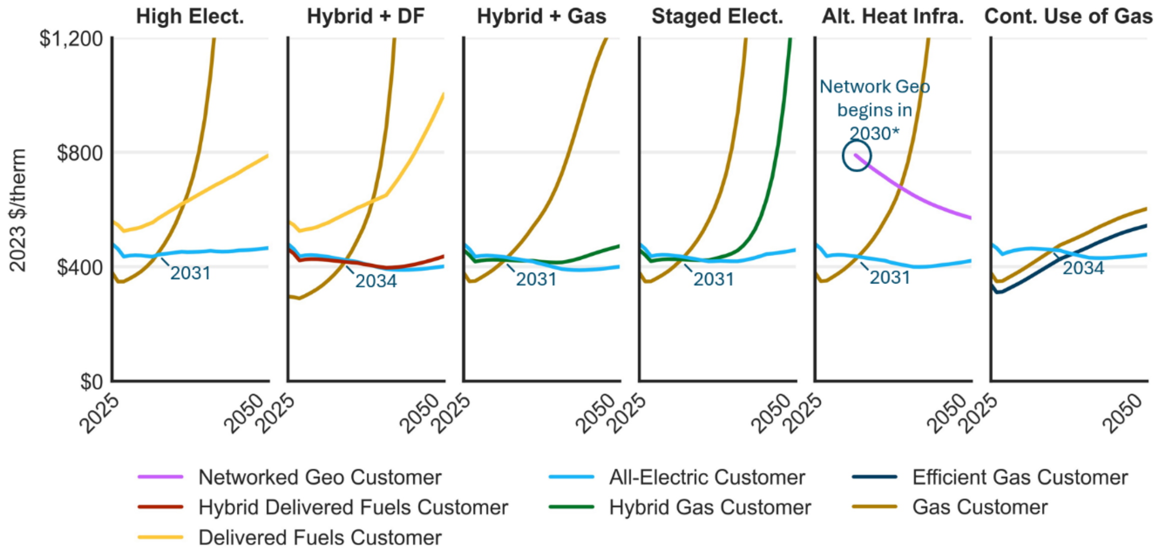
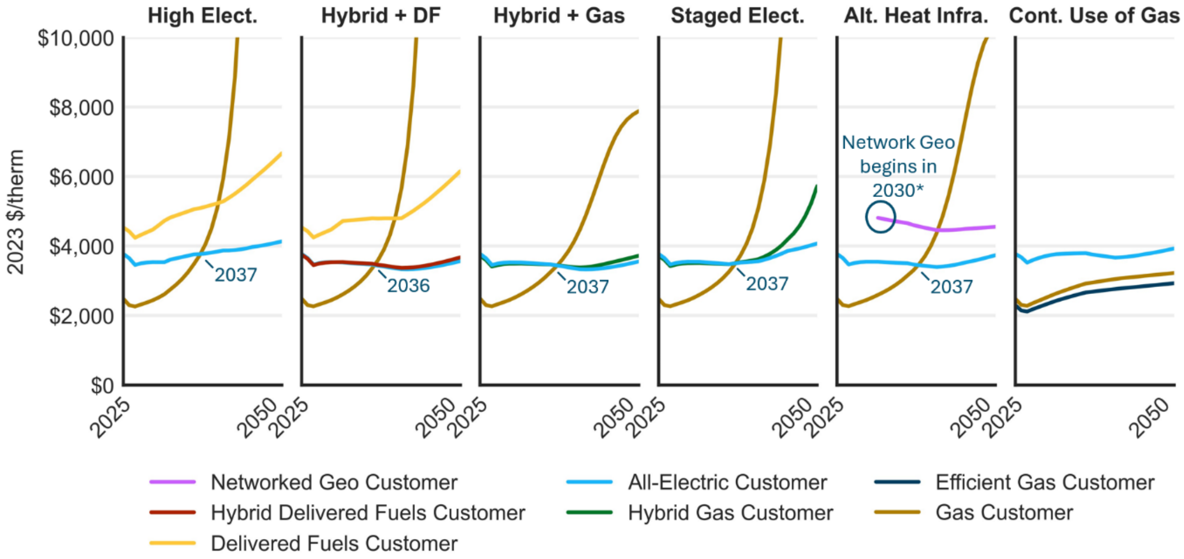


Figure 61. Small Commercial Monthly Energy Bills under Decarbonization Pathways



**Note: Networked geothermal systems are assumed to come online in 2030. Networked geothermal customers initially face very high energy bills as the system costs are spread among few customers. Over time, energy bills are forecasted to decline for these customers and to become more affordable than residential gas customer bills in 2038 in the Alternative Heat Infrastructure scenario.*[104]

While energy bills become more cost-effective for customers electrifying, the upfront cost of electric appliances push back the inflection point for when it becomes more affordable to be an all-electric

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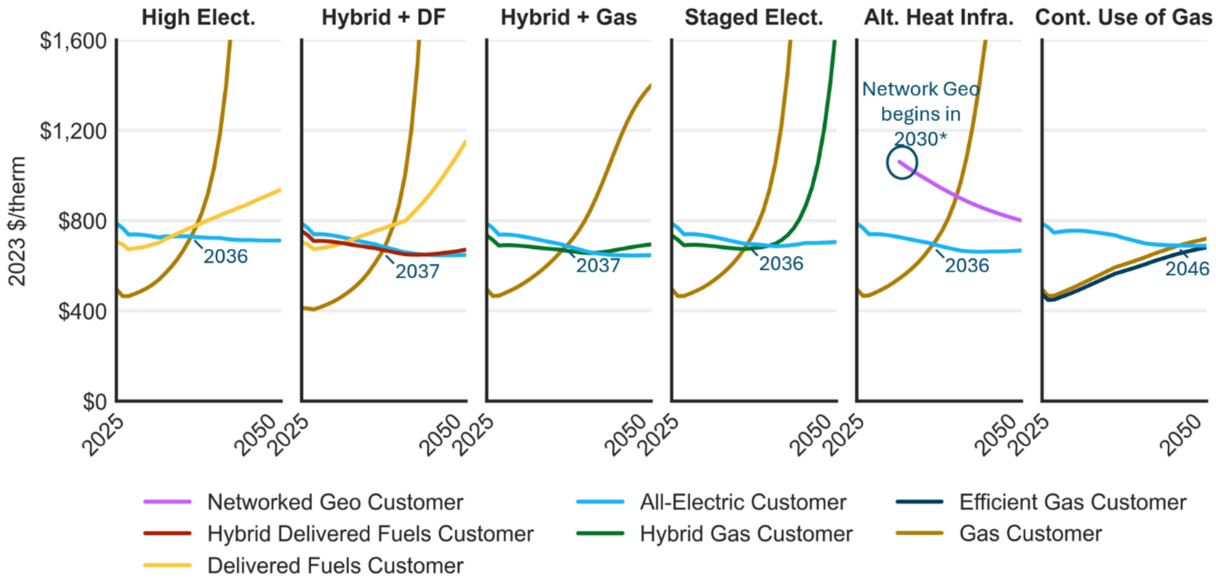
[104] The small commercial customer's electricity use is dominated by non-heating loads, emphasizing the impact of high electricity rates and limiting the bill savings from a networked geothermal heating system.

or hybrid customer rather than a gas heating customer. Total energy costs, shown in Figure 62, illustrate energy bills with *levelized* upfront costs included. The levelized costs in this analysis reflect the cost to pay back the appliances on a monthly basis over the appliances' lifetime *plus* interest, equivalent to a situation in which a customer would lease or finance the cost of equipment. Showing both energy bills and levelized upfront costs on a monthly basis provides a perspective on the total cost of ownership for customers that is associated with the adoption of decarbonization solutions. With the addition of upfront costs, the inflection point for when it becomes cheaper to transition to all-electric is moved the mid-2030s, assuming no changes to the regulatory paradigm that prevent gas rates to increase.

Figure 62. Residential Monthly Energy Costs (Energy Bills + Levelized Upfront Costs) including Gas to All-electric Inflection Year



Building shell weatherization retrofits save customers money on their energy bills by reducing the energy needed for space heating and cooling, however they add significant upfront costs. If customers adopt deep shell weatherization retrofits, they would experience similar total energy costs to those shown in Figure 62. The sizeable upfront costs are mostly balanced by the monthly energy bill savings customers would receive.

Energy Burden

Long-term affordability for gas customers is a particular challenge across all decarbonization pathways. There is a significant cost shift risk as customers transition off the gas system leaving fewer customers, likely low-to-moderate income customers, bearing the burden of gas system costs. This shift is especially apparent when considering customer energy burden, the percentage of a customer's gross income that is spent on household energy bills.

Today, a gas customer experiences an energy burden of 5.7%, which is expected to increase over time across all scenarios, as a result of increased gas delivery rates or an increase in the variable costs of gas.[105] On the other hand, all-electric and hybrid customers do not experience significant changes in energy burden. Today, an all-electric customer experiences an energy burden of 7.2%, reflecting 25% higher energy bills than gas customers. Hybrid delivered fuels and hybrid gas customers face a current energy burden of approximately 6.9% each. In the High Electrification scenario, all-electric customers' energy burden would decline to 5.9% by 2050, reflecting the adoption of more efficient technology over time. Hybrid delivered fuels customers' and hybrid gas customers' energy burdens would similarly dip to 5.6% and 6.1% by 2050 in the Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup scenarios, respectively. However, due to spiraling gas rates, gas customers left on the system face a skyrocketing energy burden in scenarios with high electrification. For example, gas customers face an energy burden of over 700% by 2050 in the High Electrification scenario. The energy bills clearly place an untenable burden on customers that will need to be mitigated. Even in the Continued Use of Gas scenario, efficient gas customers face a 25% higher energy burden (7.2%) in 2050 than they do in 2023 as a result of changes in the variable costs of gas.

Workforce Impacts

A detailed quantitative workforce impact assessment was beyond the scope of the Technical Analysis. Instead, E3 provides qualitative considerations on the potential benefits or challenges to the Rhode Island workforce resulting from decarbonization scenarios. More comprehensive models and studies that analyze the impact of decarbonization on the local economy and jobs do exist and are recommended for use in further study. For example, New York's Scoping Plan included modeling of the jobs impacts of net zero decarbonization scenario,[106] and Massachusetts developed a Clean Energy Workforce Needs Assessment aligning workforce needs with the state's decarbonization goals.[107]

In E3's qualitative review of workforce impacts, two types of impacts were considered:

- The impact of decarbonization scenarios on the gas distribution workforce, given the focus of the Docket on the gas distribution system.
- The impact of decarbonization scenarios on the broader workforce, specifically related to jobs required to install building shell weatherization packages, heat pumps, and other distributed energy resources.

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[105] Energy burden is calculated for a customer making the area median income of approximately $80,000 in 2023 and with an annual income growth rate of 0.60%. U.S. Census Bureau. QuickFacts Rhode Island. https://www.census.gov/quickfacts/fact/table/RI,US/INC110222

[106] Chapter 7. Just Transition of New York's Scoping Plan (2022). Available online: https://climate.ny.gov/resources/scoping-plan/

[107] Available online: https://www.masscec.com/resources/massachusetts-clean-energy-workforce-needs-assessment

Gas Distribution System

The decarbonization scenarios assessed in the Technical Analysis have different impacts on the role and use of the gas system, with likely differences in the associated workforce. Whereas Continued Use of Gas and Hybrid with Gas Backup keep the gas distribution system maintained in the long term, the other scenarios see a decline in gas infrastructure use. These scenarios are likely to see a reduction in the long-term need to operate and maintain the distribution system, with potential consequences for the workforce. In E3's revenue requirement model by 2050, RIE's operations and maintenance expenses associated with the gas distribution system are reduced by approximately 40% in scenarios with high levels of electrification compared to today as a result of customer departures, and over 50% with high levels of electrification in a managed transition. However, studies have indicated that even in scenarios focusing on long-term electrification, there are labor requirements associated with decommissioning of the gas system that require a temporary increase in workforce.[108,109] In addition, in all scenarios with gas throughput declines, there is an ongoing need to perform safety and reliability activities, which means that any changes to the gas distribution system workforce are likely to only materialize in the long term as segments from the system are decommissioned. As investigated by Economy League and the Building Electrification Institute in the City of Philadelphia, the transition to decarbonization takes decades, and current gas workers are not at risk of losing their job in the near term.[110]

Broader Job Impacts From Decarbonization

Many studies have analyzed the impact of achieving a net zero economy on employment in the United States. For example, Decarb America found that decarbonizing the US economy will create a net increase of over 2 million jobs by mid-century, primarily driven in the near-term by the energy efficiency sector because of the ready access to efficiency technologies.[111] According to the 2023 Rhode Island Clean Energy Industry Report, Rhode Island employed 14,511 clean energy workers in 2022, with just over half of jobs in the energy efficiency technology sector.[112] Before the COVID-19 pandemic, all clean energy sectors, including energy efficiency, efficient heating and cooling, renewable energy, clean transportation and solar and wind, saw significant increases in year-over-year employment, and post-COVID numbers have started to pick up again.[113]

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[108] Oliphant, Elizabeth. Electrification Impact Assessment: A Preliminary Analysis of the Utility Costs & Staffing Impact to Electrify All SingleFamily Residences in Palo Alto. https://www.cityofpaloalto.org/files/assets/public/agendas-minutes-reports/agendas-minutes/utilitiesadvisory-commission/archived-agenda-and-minutes/agendas-and-minutes-2020/11-04-2020-special/id-11639-item-no-3.pdf. Accessed January 8, 2021.

[109] Economy League and the Building Electrification Institute (2023). Philadelphia Building Decarbonization Workforce Impacts and Opportunities. https://www.economyleague.org/resources/philadelphia-building-decarbonization-workforce-impacts-and-opportunities

[110] Ibid

[111] Decarb America (2022). Employment Impacts in a Decarbonized Economy. https://decarbamerica.org/wp-content/uploads/2022/06/Employment-Impacts-in-a-Decarbonized-Economy.pdf

[112] BW Research (2023). 2023 Rhode Island Clean Energy Industry Report. https://energy.ri.gov/sites/g/files/xkgbur741/files/2024-01/2023%20Clean%20Jobs%20Report.pdf

[113] Ibid

In the Technical Analysis, the increase in decarbonization technologies is unprecedented across scenarios in Rhode Island. This includes adoption of efficient heating and cooling technologies such as heat pumps, electric vehicles, renewable energy, and energy efficiency measures such as weatherization. For example, the scenarios see an increase in heat pump adoption 5 to 10 times higher than today's adoption of heat pumps and levels of building shell retrofits that far exceed participation levels from current energy efficiency programs in the state. Although not quantified in this study, these adoption levels imply a significant growth of the clean energy workforce across all scenarios in the next decades to ensure successful implementation. In the workforce analysis of the New York Scoping Plan, over half of the jobs added before 2030 were in buildings, with the largest increases in residential HVAC and building shell installations.[114]

In Massachusetts, MassCEC projected a growth in a clean energy workforce of 37% by 2030 while highlighting eight key gaps in the workforce needed to meet future occupational needs of the clean energy transition.[115] These gaps include additional needs for electricians, HVAC installers, electric power line installers, construction laborers, building inspectors, insulation workers, cost estimators and pipelayers, plumbers, pipefitters and steamfitters. More research is needed to understand the extent to which Rhode Island currently has the workers and skills necessary to install the decarbonization technologies as required to comply with the Act.

Air Quality

In addition to greenhouse gases, the combustion of fuels (including renewable fuels) produces emissions of pollutants, such as PM 2.5 and Nox, that negatively impact air quality. In the state of Rhode Island and elsewhere across North America, air quality impacts are associated with tailpipe emissions in the transportation sector, and combustion of gaseous and liquid fuels in the electricity, industrial and buildings sector. In addition to health impacts from outdoor tailpipe emissions, studies have demonstrated implications from indoor combustion of fuels on public health. For example, Gruenwald et al. (2023) found a relationship between the use of indoor gas stoves for cooking and in increased risk of asthma among children.[116] Historically, emissions of pollutants like PM 2.5 have been disproportionally concentrated in low-income and/or minority areas.[117]

A detailed quantification of the direct impacts of the scenarios on air quality benefits was beyond the scope of this work. Models that quantify these types of dynamics do exist; for example, the co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) estimates health

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[114] Chapter 7. Just Transition of New York's Scoping Plan (2022). Available online: https://climate.ny.gov/resources/scoping-plan/

[115] MassCEC (2023). Powering the Future: A Massachusetts Clean Energy Workforce Needs Assessment. Available online: https://www.masscec.com/sites/default/files/documents/Powering%20the%20Future_A%20Massachusetts%20Clean%20Energy%20Workforce%20Needs%20Assessment_Final.pdf

116 Gruenwold, T., Seals, B., Knibbs, L. and Hosgood III, D. "Population Attributable Fraction of Gas Stoves and Childhood Asthma in the United States". Int. J. Environ. Res. Public Health 2023, 20(1), 75.

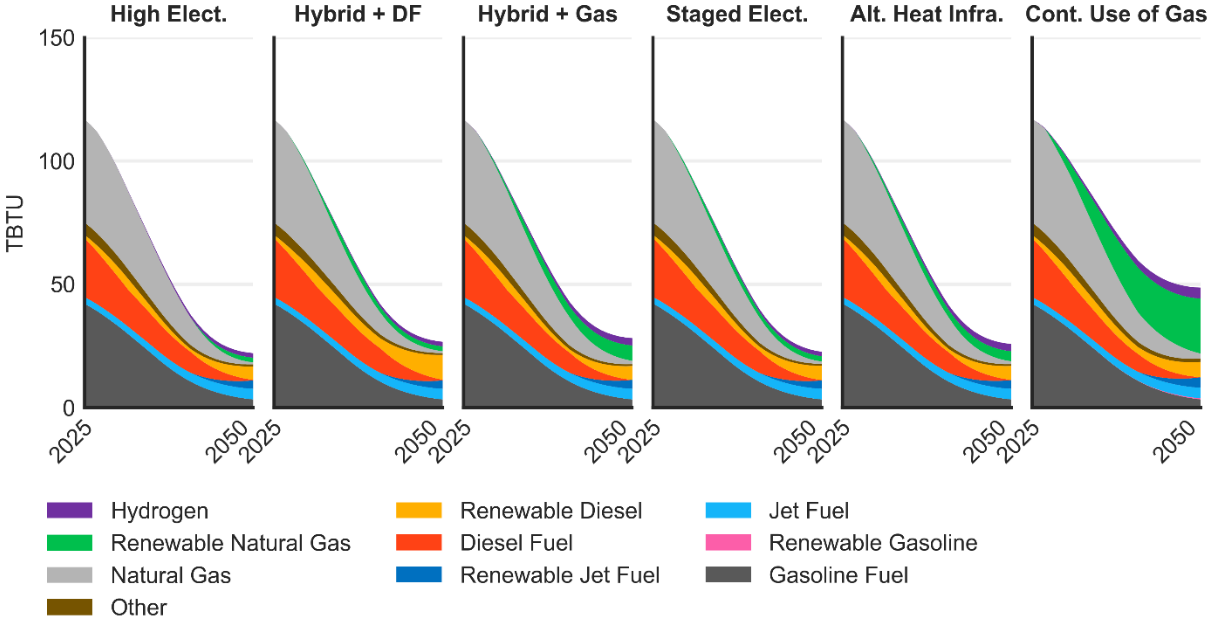
117 See, for example: Tessum, Christopher W., et al. "PM2. 5 polluters disproportionately and systemically affect people of color in the United States." Science Advances 7.18 (2021): eabf4491

impacts of changes in air pollution emissions as a result of decarbonization measures at granular level. In the Technical Analysis, E3 assumes that the reduction of fuel combustion has a directly positive impact on air quality in the state of Rhode Island and therefore, the reduction in fuel combustion, including renewable fuels, across scenarios is used as a proxy to qualitatively determine the effects of scenarios on air quality. This analysis is done at the statewide level – additional research that assesses impacts on a regional basis would provide more insights into the extent to which emissions reductions directly benefit low-income disadvantaged communities (LIDACs).

Figure 63 shows the combustion of fuels across scenarios over time, which shows the reduction in fuel combustion across all sectors. These figures show that fuel combustion declines significantly in all scenarios, which is primarily due to the high levels of efficiency and electrification in the transportation and buildings sector. Statewide, the combustion of fuels reduces between 65-85% across scenarios, with the highest level of combustion left in the Continued Use of Gas scenario mostly as the result of differences in the building sector. In the buildings sector specifically, shown earlier in Chapter 4, the highest levels of combustion take place in the Continued Use of Gas scenario, followed by the Hybrid with Gas Backup and Hybrid with Delivered Fuels scenarios that leave combustion of fuels to serve heating demands in winter.

The overall decline In combustion across scenarios implies that complying with the Act on Climate has an overall positive impact on air quality and ultimately, health in the state of Rhode Island. Scenarios with higher levels of electrification are likely to see higher levels of benefits than scenarios that leave higher levels of combustion of fossil or renewable fuels.

Figure 63. Fuel Combustion across Scenarios Over Time



Reliance on Regional Fuel Supply

The decarbonization scenarios included in the Technical Analysis show variations in the type of energy used as input fuels in the heating sector, and therefore differ in where energy supply is coming from. Scenarios that rely on electrification source energy supply from an increasing share of renewable electricity, whereas scenarios that rely on renewable fuels source energy supply from a variety of emissions-compliant sources, including biomass resources to produce renewable biofuels and hydrogen produced through renewable electricity. The evaluation of reliance on regional fuel supply provides two types of insights:

- The extent to which Rhode Island will depend on national and international market dynamics that determine the supply and costs of fuels. Given its size in the market, Rhode Island is likely to be a “price taker”, having little influence over demand and supply dynamics in the broader market, and therefore is at risk of exposure to market fluctuations outside of the state’s (and region’s) control.
- The extent to which the transformation of energy supply may lead to local economic development opportunities. Studies have demonstrated a positive relation between renewable energy production and economic development[118], which indicates that reducing dependency on fuels beyond state and regional borders may lead to economic opportunities. Note that there are also other considerations to take into account that indicate risks associated with this dependency, for example as described below in the evaluation criterion on the pace of electric system expansion.

Renewable Electricity Generation

In the electricity sector, load increases need to be met with electricity generation within or connected to the ISO-NE system. In addition, the Rhode Island RES defines eligible renewable resources as generation units that are within the ISO-NE control area, or generation units that are able to prove that the energy produced by the generation unit is delivered into the ISO-NE area for consumption by New England customers.[119] This means that as Rhode Island achieves its 100% RES goal by 2033, all load increases from electrification of heating sources need to be met by renewable electricity generation within the ISO-NE region. Although the RES does not prescribe that generation needs to occur within the state, the RES within Rhode Island and adjacent New England states will ultimately balance demand for and supply of renewable electricity within the New England region.

Scenarios that rely on electrification of heating to achieve the Act on Climate, such as High Electrification, Staged Electrification and to some extent Hybrid with Gas Backup, Hybrid with Delivered Fuels Backup and Alternative Heat Infrastructure, will see a shift from dependency on out-of-state fuels, such as natural gas and delivered fuels, to more dependency on in-region electricity. Although this trend puts pressure on electric system requirements, especially for scenarios with high

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[118] See, for example: World Resources Institute (2022). Federal policy Building blocks to support a just and prosperous new climate Economy in the United States

[119] RI Gen. Laws § 39-26-5. http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-26/39-26-5.htm

levels of all-electric heat pump adoption, it is also more likely to lead to regional economic development opportunities than scenarios that continue to source fuels from out of region.

Renewable Fuels

Several studies estimate that New England is likely to have one of the lowest levels of biomass resources available for conversion into renewable fuels in the United States.[120] Scenarios that rely heavily on renewable fuels are therefore likely to source these fuels from out of region. While the import of fuels for energy purposes is common in Rhode Island today, this means that scenarios with higher levels of renewable fuels to serve heating demand are more likely to continue to rely on out-of-region resources in contrast to scenarios with higher levels of electrification that transition more strongly to in-region supply of energy for heating purposes. In particular, it is likely that the capital investments necessary to produce renewable fuels will occur out of region, while Rhode Island continues to rely on local infrastructure to deliver these fuels.

Both nationally and internationally, the supply of renewable fuels if sourced from biomass feedstocks is constrained by competition for critical land uses, which puts pressure on the availability and costs of resources as demand across sectors grows. Shown by the light gray bands in Figure 64, E3 estimated the maximum amount of biomethane that could be produced from biomass resources based on the 2016 DOE Billion Ton Report using different percentages of availability of biomass that could reasonably be allocated to the state of Rhode Island. These bands assume that a proportion of biomass resources produced in the eastern United States is entirely converted into biomethane or renewable diesel for use in Rhode Island.

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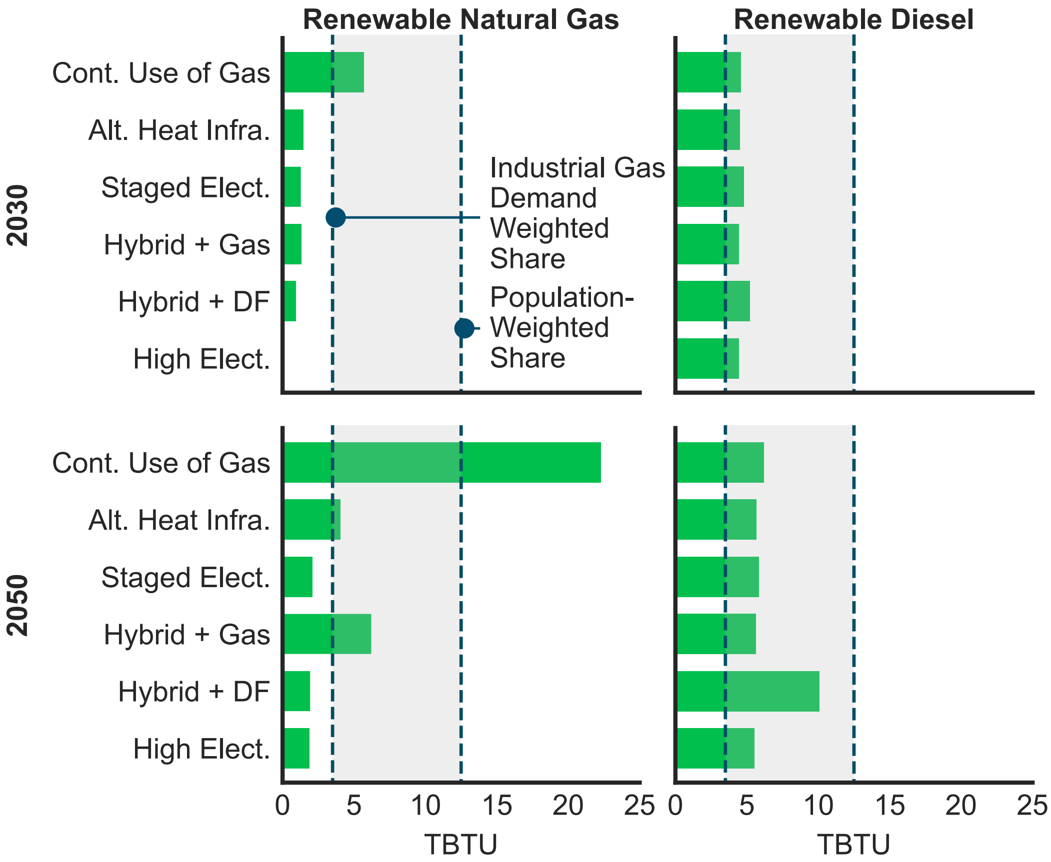
[120] See, for example: *US DOE (2016). Billion Ton Report;*
M.J. Bradley (2019). Renewable Natural Gas: Potential Supply and Benefits;
American Gas Foundation, prepared by ICF (2019). Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment.

Figure 64. Renewable Natural Gas and Renewable Diesel Demands for 2030 and 2050. The shaded bands represent the allocation of biomass to Rhode Island, converted into the indicated renewable fuel, based on different allocation methods.



Two primary considerations apply to scenarios that fall within or beyond the allocation range:

- **Reliance on non-commercialized fuels.** Scenarios with high demands for renewable fuels are likely to procure fuels sourced from non-biomass sources, such as synthetic natural gas or synthetic diesel. The production of these synthetic fuels requires production of green hydrogen as well as availability of a carbon-neutral source of CO2 from either biorefineries or direct air capture. These production methods have a relatively low level of commercialization today (see section on Technology Readiness).
- **Higher costs.** The amount of fuels that can be procured for use in Rhode Island will ultimately depend on market mechanisms. A regional or national market for renewable fuel credits may emerge that would broaden the range of eligible sources or regions. However, as seen in other regions, credit prices fluctuate based on demand and may significantly drive up the cost of renewable fuels.

Figure 64 demonstrates that out-of-state resources may be required for Rhode Island to meet its goals, particularly in those scenarios where Rhode Island relies heavily on the use of renewable fuels to meet its emissions targets. Scenarios that retain high levels of gas demands, particularly

Continued Use of Gas, may rely on currently non-commercialized fuels as early as 2030 resulting from constraints in availability of biomass resources. In addition, all scenarios rely on the use of renewable diesel to some extent, at minimum to comply with the Biodiesel Heating Act by 2030. The demand for renewable diesel may drive up the costs or need for synthetic fuels as competition across sectors and regions increases.

While the above results should not be interpreted as prescriptions or forecasts of renewable fuel demand or availability for the state, they do show increased risk of dependence on renewable fuels for the Continued Use of Gas scenario, and to a lesser extent the Hybrid with Gas Backup and Hybrid with Delivered Fuel Backup scenarios, in the long term. As maximal production of biomethane or renewable diesel in these scenarios is likely unable to satisfy renewable fuel demands by 2050, Rhode Island would need to procure other types of emissions-compliant fuels, such as synthetic fuels which have a lower level of commercialization today and are likely to be available at higher cost. Production of these fuels through primarily out-of-state capital investment will rely on market and policy dynamics that Rhode Island will have little control over.

The significant uncertainty associated with the availability and cost of renewable fuels, as well as the emissions impact of fuels under different accounting assumptions, suggest an increasing need for policies that mitigate risk associated with renewable fuels. Such policies can be discussed and addressed in the Policy Development phase of this proceeding.

Technology Readiness

The scenarios designed for the Technical Analysis rely on a number of decarbonization technologies, varying from heat pumps, to networked geothermal systems, to use of technologies required to produce renewable fuels. These technologies have varying levels of "technology readiness": While some technologies are commercially available and mature, others are still in demonstration phase. The level of commercialization or extent to which a technology is ready for large-scale deployment determines the risk associated with relying on a technology to achieve the emissions targets required to comply with the Act on Climate.

The International Energy Agency (IEA) has established a Technology Readiness Level (TRL) scale for decarbonization measures and keeps a detailed database of TRL levels of clean energy technologies.[121] In this framework, technologies with a TRL of 11 are ready to scale and fully commercialized, while options lower than that need Research and Development (R&D) and/or commercialization support, as outlined in the table below. E3 relied on IEA's TRL scale and assessment to evaluate the level of technology readiness of key measures used in the design of decarbonization scenarios.

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[121] See: https://www.iea.org/data-and-statistics/data-tools/etp-clean-energy-technology-guide

Table 13. IEA's Technology Readiness Level Scale with Clean Energy Technology Examples

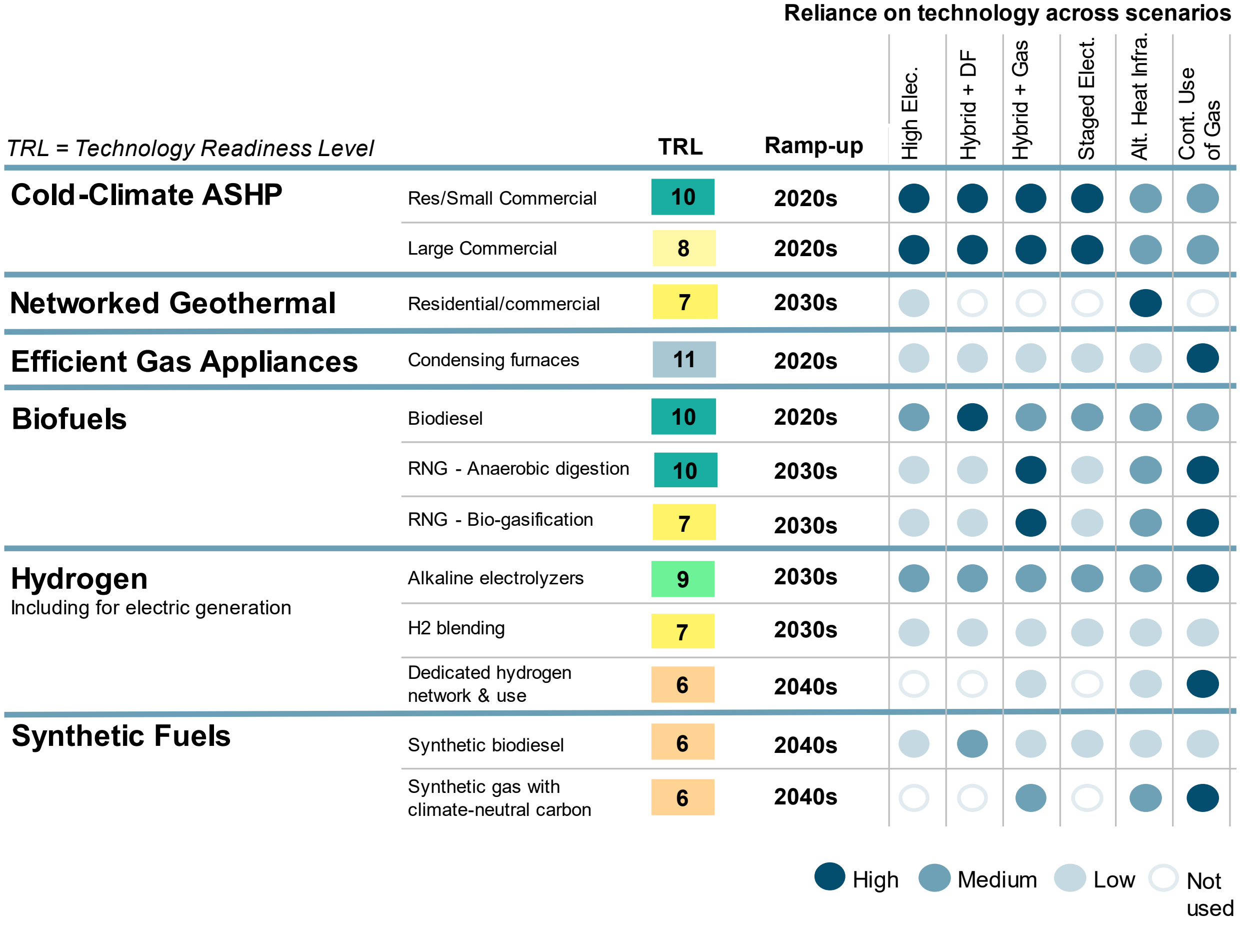
TRL	Category	Example
11	**Mature** – Proof of stability reached	High-efficiency gas furnaces
9-10	**Early adoption** – commercially available; further improvement and integration needed	Cold climate Air-Source Heat Pumps
7-8	**Demonstration** – pre-commercial or first-of-a-kind commercial deployment	Networked Geothermal Systems
5-6	**Large prototype** – Components or full prototype proven in conditions to be deployed	Biomass gasification and Fischer-Tropsch to produce biofuels
4	**Small prototype** – prototype proven in test conditions	Integrated heat pumps with storage for heating and cooling
1-3	**Concept** – application in idea or validation phase	Direct hydrogen combustion in jet turbines

In designing scenarios, E3 and other deep decarbonization researchers generally screen out technologies that are low (<5) on the TRL scale because of their speculative nature and the short time horizon of mid-century climate goals. Therefore, the scenarios designed for the Technical Analysis typically have a TRL of 5 or higher, but the time required for key technologies deployed across the scenarios to mature still varies.

Figure 65 provides an overview of the TRLs of key decarbonization technologies used across scenarios, their expected ramp-up of deployment in the scenarios and the reliance of scenarios on these technologies. This figure shows that the High Electrification and Staged Electrification scenarios largely rely on technologies with TRLs of 9 or higher, such as cold-climate air source heat pumps. The High Electrification scenario additionally sees some level of reliance on networked geothermal systems, which are deployed at a much larger scale in the Alternative Heat Infrastructure scenario. Given the fact that this scenario already sees significant ramp up of this technology by the late 2020s, this scenario has a relatively high risk that the technology would not be available at commercial scale in time for it to achieve the levels of emissions reductions as projected in this scenario.

The Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup scenarios are likely to rely to some extent on the use of synthetic fuels (biodiesel and gas respectively) that have relatively low levels of commercialization, depending on the availability of fuels as discussed in the previous section. However, the deployment of these technologies is likely only required later in time. It is important to note that if an alternative compliance mechanism for renewable fuels arises, this assessment is not strictly accurate. However, in such case, it is likely to assume that a negative emissions technology such as Direct Air Capture needs to be deployed (either in- or out-of-state) that has similar levels of technology readiness.

Figure 65. TRLs of Key Technologies and Reliance on Technology across Scenarios



TRL = Technology Readiness Level

				Reliance on technology across scenarios					
		TRL	Ramp-up	High Elec.	Hybrid + DF	Hybrid + Gas	Staged Elect.	Alt. Heat Infra.	Cont. Use of Gas
Cold-Climate ASHP	Res/Small Commercial	10	2020s	●	●	●	●	◐	◐
	Large Commercial	8	2020s	●	●	●	●	◐	◐
Networked Geothermal	Residential/commercial	7	2030s	◔	○	○	○	●	○
Efficient Gas Appliances	Condensing furnaces	11	2020s	◔	◔	◔	◔	◔	●
Biofuels	Biodiesel	10	2020s	◐	●	◐	◐	◐	◐
	RNG - Anaerobic digestion	10	2030s	◔	◔	●	◔	◐	●
	RNG - Bio-gasification	7	2030s	◔	◔	●	◔	◐	●
Hydrogen Including for electric generation	Alkaline electrolyzers	9	2030s	◐	◐	◐	◐	◐	●
	H2 blending	7	2030s	◔	◔	◔	◔	◔	◔
	Dedicated hydrogen network & use	6	2040s	○	○	◔	○	◔	●
Synthetic Fuels	Synthetic biodiesel	6	2040s	◔	◐	◔	◔	◔	◔
	Synthetic gas with climate-neutral carbon	6	2040s	○	○	◐	○	◐	●

● High ◐ Medium ◔ Low ○ Not used

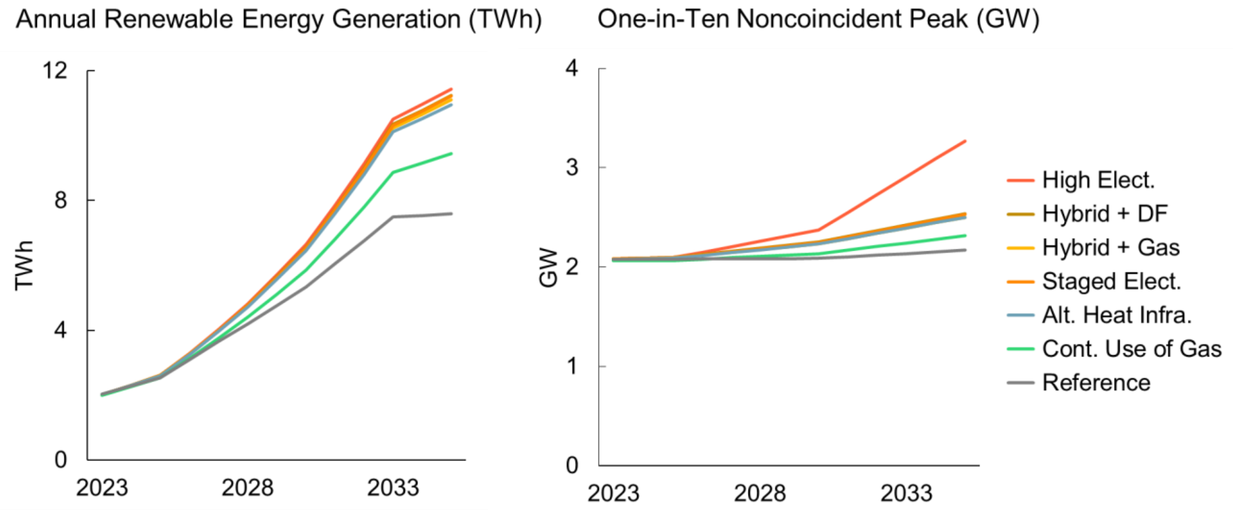
Pace of Electric System Expansion

All decarbonization scenarios include significant levels of electrification in transportation and buildings, leading to an unprecedented buildout in electric system infrastructure to meet new demands. All scenarios require significant renewable buildouts to comply with 100% RES and requirements from other states. To serve Rhode Island's increasing load and meet the 100% RES, as well as similar demands throughout the region, higher levels of incremental renewable generation are required especially in scenarios with high levels of heat pump adoption (Figure 66). Although Rhode Island is a relatively small player in ISO New England, the increasing demand for renewables will require building additional resources in the region. This will tap into the potential onshore wind resources that are relatively lower in cost but limited due to land constraints, as well as the solar or offshore wind resources that are more abundant but have experienced more than 20% cost increases or project cancellations in the last few years due to supply chain disruptions.

As renewable procurement ramps up in the near term and to support the higher peak demands from electrification, transmission and distribution (T&D) infrastructure needs to be significantly expanded (Figure 66). The increase in peak demand driving T&D upgrades is especially pronounced in the High

Electrification scenario which leads to a +/- 1 GW increase in required electric system capacity in the next decade.

Figure 66. Near-Term Pace of Electrification Shown as Changes in Renewable Energy Generation and One-in-Ten Noncoincident Peak (2023-2035)



Rhode Island already has a system peak that is twice as high as the average demand on the system, which means that the full capacity of the system is only utilized during periods of high demand. Increasing peak demands from electrification will require T&D system upgrades but at the same time, in most scenarios, will reduce the peak-to-average ratio under higher proportion of annual load growth, as more electricity is used throughout the year, including in non-peak hours. This increase in system utilization is expected to put downward pressure on average electric rates in the state. The reduction in peak-to-average ratios is especially profound in scenarios that are able to avoid system peaks, through the use of gas or delivered fuel heating as backups during the coldest hours of a year.

6. Key Study Takeaways

The Technical Analysis shows that achieving the Act on Climate in Rhode Island requires a transformation of energy use across all sectors in the state, and significantly impacts the use and role of the gas distribution system. This chapter provides key takeaways with regard to the questions raised in the Docket scope that may inform the policy development phase of the Docket, summarizing results of the Technical Analysis and implications across evaluation criteria. In addition, E3 provides an overview of commonalities across scenarios that may inform next steps, as well as outstanding technical questions and study needs that E3 identified over the course of the Technical Analysis process.

Summary of Technical Analysis Results

E3 modeled six decarbonization scenarios that present different options for reducing emissions from the gas system in Rhode Island. Each scenario allows the state to meet the emissions reductions mandate of the Act on Climate. The Technical Analysis results are summarized through 5 critical outputs: emissions, technology adoption, energy demand, gas system impacts and electric system impacts.

Emissions

The analysis shows that existing policies and trends, represented in a reference scenario, achieve 40% emissions reductions by 2030 compared to 1990 levels, which means that additional mitigation measures are required to achieve the Act on Climate. While reference scenario emissions reductions are largely driven by reductions in the electricity sector, the modeled decarbonization scenarios include accelerated measures in the Transportation and Buildings sector to comply with the Act. Under Rhode Island's GHG accounting framework, all decarbonization scenario modeled by E3 achieve the Act on Climate targets of 45% by 2030, 80% by 2040 and net zero by 2050, compared to 1990 levels. While the level of emissions reductions is identical across scenarios, emission reductions are achieved through distinct measures in the heating sector, with primary variations in building and industrial applications. Sensitivity analysis demonstrates that scenarios with higher levels of renewable fuels may have higher remaining emissions under alternative accounting assumptions. In addition, sensitivity analysis shows that a delayed achievement of the Advanced Clean Cars II and Advanced Clean Trucks rules in Rhode Island would require deeper and more accelerated measures primarily in buildings, with implications for the role and use of the gas system.

Technology Adoption

Although the six decarbonization scenarios achieve the Act on Climate through a distinct mix of technology adoption in the residential and commercial sector, the Technical Analysis demonstrates that energy efficiency and building electrification are a critical component of gas system decarbonization. Scenarios focused on higher levels of electrification, such as High Electrification, Staged Electrification, Hybrid with Delivered Fuels Backup and Hybrid with Gas Backup, require residential heat pump adoption levels by 2030 and 2040 that are nearly 10 times higher than today's adoption levels. Scenarios that rely more heavily on renewable fuels to achieve the Act still include a five times increase in heat pump adoption compared to today. There are significant cost barriers associated with these levels of heat pump adoption that were not modeled in the Technical Analysis through consumer or economic behavior. Achieving the adoption levels as modeled in the Technical Analysis that are needed to comply with the Act's goals therefore likely requires policy intervention. In the industrial sector, all scenarios include significant levels of efficiency and varying levels of industrial electrification. Industries that are harder to decarbonize, such as the chemical and metals-based industry as well other manufacturing processes using high temperature heat, leave a role for pipeline gas and see increased adoption of dedicated hydrogen.

Energy Demand

All scenarios see transformational changes in the way Rhode Island uses energy; across scenarios, final energy demand decreases between 40-50% by 2050, primarily as a result of efficiency and electrification. In addition, Rhode Island will see increased use of renewable fuels, through the Biodiesel Heating Act in the near term and to comply with emissions targets in the long term. By 2050, between 50-70% of the fuel mix across scenarios consists of renewable fuels, with the largest reliance in the Continued Use of Gas scenario. Gas throughput in Rhode Island declines in all scenarios: By 2050, gas throughput is reduced by 45% in the Continued use of Gas scenario and between 80-95% in all other scenarios as a result of efficiency and electrification.

Gas System Impacts

All scenarios imply a transformation in the role and use of the gas system in the next decades. While gas throughput and the number of customers connected to the gas system decline, the costs of the system under the currently regulatory framework are expected to rise. Planned levels of capital expenditures through the ISR program cause the annual gas revenue requirement to nearly double towards 2050, with variations across scenarios in the number of new gas connections assumed. Scenarios that do not assume additional customer connections (High Electrification, Hybrid with Delivered Fuels Backup, Staged Electrification) reduce annual costs by approximately 20% by 2050 compared to a reference scenario.

A managed transition that would include targeted deployment of non-GHG emitting heating technologies that minimize or avoid gas system investments, could significantly reduce the costs of the gas system. Using an illustrative assumption of a maximum of 50% avoided capital replacements through targeted electrification, a managed transition could reduce the costs of the gas system by up to 35% in scenarios that transition away from the gas system in the near term (High Electrification, Hybrid with Delivered Fuels, Staged Electrification). However, the level of coordination required for a managed transition is unprecedented and more research is needed to understand the technical feasibility of this approach.

Under the current regulatory framework, decarbonization scenarios that assume a high level of customer departures through electrification lead to untenable long-term gas delivery rates by recovering the costs of the gas system over fewer and fewer customers. Although a managed transition can save gas system costs on the system, these cost savings only partly mitigate the effect on long-term customer rates. Assuming customers are not able to bear the costs of the system in scenarios with high levels of customer departures, the gas distribution system is faced with a potentially total unrecovered rate base in 2050 of 2.6B (unmanaged). If RIE could avoid up to 50% of capital replacements in the next decades, the size of the rate base could be reduced to $1.5B.

Electric System Impacts

By 2050 across scenarios, 40-60% of final energy demand is served by electricity. Scenarios with high levels of electrification see nearly doubling of annual load by 2050 compared to today's levels. Scenarios with high adoption of heat pumps cause the Rhode Island electricity system to become winter peaking in the 2030s. In the High Electrification scenario, the adoption of ASHPs leads to median peak demand by 2050 of approximately 3.5 GW, nearly double the size of the system compared to today. This peak demand is mitigated by load flexibility (e.g. flexible vehicle charging), demand response, and smart devices (e.g. smart thermostats and lighting timers). These electric peaks can further mitigated by approximately 1 GW through the use of hybrid backup systems or the use of highly efficient electric heating systems, such as networked geothermal.

Renewables become a major source of generation in the New England and Rhode Island electricity portfolio. Total cost of electric service increases across all scenarios driven by higher electric demand and higher cost of electric generation to meet the 100% RES and similar requirements throughout the region. However, despite the costs of the electric system nearly doubling in scenarios with high levels of electrification, the costs of service increases are largely offset by increased loads, especially for scenarios with high load factors.

Scenario Implications

The decarbonization scenarios analyzed for the Technical Analysis see different levels of benefits, risks and challenges across multiple evaluation criteria. Key implications are summarized below.

- **Economy-wide costs vary from $14B to $26B NPV (2023-2050) across scenarios and cost sensitivities.** Across scenarios, the cumulative incremental total resource costs vary from $14.0B to $17.6B with low-bound cost parameters and $19.0B to $25.9B with high-bound cost parameters (NPV, 2023-2050). Scenarios with high reliance on renewable fuels, such as the Continued use of Gas scenario, and scenarios with higher levels of networked geothermal systems, such as Alternative Heat Infrastructure, see higher levels of cost risks. The scenarios that rely more heavily on hybrid solutions, such as Hybrid with Gas Backup and Hybrid with Delivered Fuels Backup, show lowest levels of cost across all sensitivity parameters. Staged Electrification also shows low levels of cost risk across the test sensitivities.
    - **A managed transition could help reduce total resource costs in Rhode Island, but the extent to which costs can be avoided is highly uncertain.** Based on an illustrative assumption of 50% capital expenditure avoidance on the gas system, the High Electrification and Hybrid with Delivered Fuels Backup scenarios both reduce total resource costs by $1.7B NPV relative to the modeled unmanaged transition.
- **Customer choice is a key consideration in scenarios assuming a managed transition.** Scenarios that are able to avoid capital reinvestments on the gas system through targeted

electrification assume that coordinated level of planning is possible with 100% opt-in from customers. Under these assumptions, the High Electrification and Hybrid with Delivered Fuels Backup scenarios require up to 3,000 customers per year to opt-in on voluntarily replacing their source of heating on a neighborhood-by-neighborhood basis. Implementing such projects is likely more complicated because of economics and other factors that influence customer choice. These considerations need to be addressed in the policy development phase of this Docket.

- **Energy affordability is a concern today and continues to be a challenge across all scenarios but for different reasons.** Under today's rates, customers using gas as their primary source of heating that adopt all-electric heating appliances experience approximately an increase of 25% in monthly energy bills. In addition, those customers are faced with significant upfront costs for electric appliances. At the same time, if customers exit the gas system as a result of electrification, the relative affordability of electrification improves as delivery costs of gas rise. Under the current regulatory framework, this poses a significant cost shift risk towards customers that are less likely to be able to afford electrification measures. Absent policy or regulatory changes, customers that remain on the gas system in the long term risk a significant increase in energy burden.
- **Air quality improves in all scenarios relative to today, especially in scenarios with higher levels of electrification.** Across the scenarios as modeled, fuel combustion declines by 65-85% in all scenarios as a result of high levels of efficiency and electrification. The overall decline in combustion across scenarios implies that complying with the Act on Climate has an overall positive impact on air quality and ultimately, health in the state of Rhode Island. All else equal, scenarios with higher levels of electrification are likely to see more air quality benefits than scenarios that leave higher levels of fuel combustion. A more detailed, quantitative analysis can help to further investigate the magnitude of these potential benefits.
- **Rhode Island will likely see an increase in clean energy workforce opportunities.** The level of adoption of clean energy technologies required to achieve the Act is unprecedented and far exceeds the level of adoption of clean energy technologies deployed today. Given that many technology installations need to happen in state, especially those related to the building sector, Rhode Island is likely to see an increased need for skilled workers. At the same time, four out of six scenarios may have a negative impact on the workforce in the gas sector, but those impacts are likely to occur only in the long term.
- **Reliance on out of region fuel supply will be higher in scenarios with lower levels of electrification.** Rhode Island likely needs to rely on out-of-region capital investments in and production of renewable fuels to meet the Act on Climate. Therefore, scenarios with higher levels of renewable fuels to serve heating demand are more likely to continue to rely on out-of-region resources in contrast to scenarios with higher levels of electrification that transition more strongly to in-region supply of energy for heating purposes. Although the in-region supply of electricity leads to constraints with regard to electric system expansion, this trend also leads to higher levels of local economic opportunities and reduced dependency on fluctuating market dynamics associated with fuels.
- **Technology readiness or state of commercialization is lower for advanced renewable fuels, networked geothermal systems and use of dedicated hydrogen in industry.**

Portfolios of decarbonization options that rely on lower technology readiness levels (TRL) measures carry additional risk over scenarios that rely on commercialized technologies. These risks are most prominent in the Continued Use of Gas scenario and Alternative Heat Infrastructure scenario, that rely on renewable fuels and networked geothermal systems respectively in order to meet Rhode Island's emissions targets.

- **Pace of electric system expansion is unprecedented across all scenarios, but is most pronounced in the High Electrification scenario.** All scenarios require significant renewable buildouts to comply with 100% RES. To serve increasing loads and meet rising peak demand from electrification, renewable generation and T&D infrastructure needs to be significantly expanded. The impact is especially pronounced in the High Electrification scenario which leads to a +/- 1 GW increase in required electric system capacity in the next decade.

Commonalities Across Scenarios

Despite differences across scenarios in the transformation of the heating sector and associated use and role of the gas system, E3 distills several key commonalities across scenarios that are essential to achieving near-term climate targets in the state. These commonalties may help inform the Policy Development phase of the Docket.

- **Energy efficiency.** To achieve the Act, all scenarios rely on significant energy efficiency measures, such as building shell retrofits, efficient industrial technologies, efficient appliance sales, efficient lighting, smart devices such as programmable thermostats, and managed electric vehicle charging, that far exceed the state's rate of adoption today.
- **Building electrification.** Building electrification is a significant component of gas system decarbonization across scenarios. Heat pump adoption levels in the next decade are 5-10 times higher than today's level of adoption.
- **Renewable energy generation and electric system expansion.** Achieving the 100% RES in combination with significant levels of electrification in all scenarios requires expansion of the electric grid. Rhode Island's electric system today experiences constraints that need to be addressed in order for the system to be able to handle the increase in loads and peaks expected to comply with the Act.
- **Affordability issues with decarbonization scenarios.** All scenarios rely heavily on decarbonization measures that increase costs from a customer perspective, both in terms of upfront and operational costs. The adoption of decarbonization measures at the scale required to achieve the Act implies the need for policy development to mitigate these costs.
- **Long-term impact on gas customer bills.** All scenarios lead to an increase in rates for customers on the gas system, either through the effect of customer departures, or through the increase in gas commodity costs as a result of renewable fuel procurement. These results point out an important area of focus for the policy development phase of the proceeding.
- **Opportunities for electrification of delivered fuels.** Although the focus of the Docket is on the implications of the Act on the gas distribution system, the Technical Analysis assessed the required transformations across the entire state, including the western half of Rhode

Island that primarily relies on delivered fuels today. All scenarios assume that delivered fuels customers adopt electric heating appliances. In contrast to gas customers, customers currently using delivered fuels for the main source of heating that adoption electric heating solutions see a decrease in monthly energy bills, which implies a significant near-term opportunity for emissions reductions.

- **Significant uncertainty related to renewable fuels.** All scenarios include a role for renewable fuels such as green hydrogen, renewable diesel in transportation, and renewable natural gas. As noted throughout this report, there is significant uncertainty associated with the availability and cost of renewable fuels, as well as the emissions impact of fuels under different accounting mechanisms. As all scenarios rely on renewable fuels to some extent, at minimum to comply with the Biodiesel Heating Act, there is an increasing need for ways to mitigate uncertainty that can be addressed in the policy development phase of the Docket.

Outstanding Technical Questions And Study Needs

The Technical Analysis raises key outstanding questions on the implementation and technical feasibility associated with decarbonizing the gas system. E3 identified two primary outstanding technical feasibility questions that require further study.

Technical Feasibility Related to a Managed Transition

As noted throughout this report, the assumptions E3 used to estimate the impact of avoided gas system costs are illustrative and not based on empirical evidence or data inputs from RIE. The order of magnitude of gas system cost avoidance assumed in this study is unprecedented, despite early pilots throughout the United States and beyond that have started to investigate the opportunity associated with targeted electrification. E3 distills three important research questions for further study that were beyond the scope of the Technical Analysis:

- ***What parts of RIE's system can be classified as "hydraulically feasible", i.e. can potentially be decommissioned while maintaining the gas flow, minimum allowable pressure and secondary feeds required to ensure safe and reliable service of other parts of the gas system?*** The Technical Analysis does not model the performance and operations of the gas system, nor does it provide a geographical representation of cost avoidance opportunities. Additional study by RIE is necessary to understand the magnitude of opportunity associated with targeted decommissioning.
- ***What parts of the gas system, if any, are cost-effective to electrify through targeted decommissioning?*** Other studies have identified the cost-effectiveness of targeted electrification through neighborhood-specific study of key parameters, such as system density, pipeline age, replacement costs, cost of electrification, etc.[122] This type of study is

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[122] See, for example: E3 - Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California; Groundwork Data - Equitable Energy Transition Planning in Holyoke Massachusetts - A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency.

necessary in Rhode Island to better understand the feasibility and opportunity associated with targeted electrification.

- ***What additional costs, if any, are associated with decommissioning of the gas system that are not yet captured in the current accounting of asset removal costs recovered by RIE in the annual revenue requirement?*** In E3's modeling framework, it is assumed that pipeline decommissioning and removal costs are already accounted for in the company's annual revenue requirement. Since the scale of decommissioning that is required in some scenarios is unprecedented, these assumptions require additional investigation.

Other implications associated with a managed transition, such as questions related to customer choice and the implications for different customer classes, require specific policy and regulatory intervention and are therefore to be addressed in the Policy Development phase of the Docket.

Technical Feasibility Related to Networked Geothermal Systems

Although networked geothermal systems have been installed in a handful of settings, such as campuses, and pilots in New England are underway that test the feasibility of the systems, additional study is required to understand the potential and technical feasibility of the scale of networked geothermal systems envisioned in the Alternative Heat Infrastructure scenario. Based on best available information today, networked geothermal systems have the potential to significantly reduce electric peak system impacts due to their highly efficient nature, but the systems also require substantial capital investments. The scale of the systems required in the Alternative Heat Infrastructure scenario implies a conversion of a large number of buildings at the same time. Additional research is required to understand the geological feasibility of these systems across the state, as well as to identify parts of the state where networked geothermal systems can provide the highest level of benefit.

Technical Feasibility Related to Delivered Fuel Backup Systems

The Hybrid with Delivered Fuels backup scenario demonstrates benefits with regard to electric peak mitigation while at the same time allowing for targeted electrification projects that may avoid gas system costs. However, the concept of using delivered fuels as a backup for winter heating needs, especially for customers currently connected to the gas system, is novel and requires further study. For example, it is unclear to what extent existing gas furnaces or boilers can be converted to propane systems with minimal adjustments, as explored through sensitivity analysis in this report. In addition, more insights are needed to understand if conversion to delivered fuels supply is a practical solution for customers in RIE's territory, given the tank storage required on customer premises. Lastly, E3 did not estimate any emissions impact from the in-state fuel delivery supply chain, such as increased truck movements that may occur as more customers transition away from networked gas towards delivered fuels.

Workforce Impacts

A detailed study investigating the impacts of the Act on Climate on the workforce in Rhode Island, both related to the gas distribution system and to the broader clean energy transition, was beyond the scope of the Technical Analysis. At the same time, as shown in this study through qualitative research, Rhode Island is likely to see an increase in clean energy workforce opportunities and the need for skilled workers, while the need for skilled workers on the gas distribution system may evolve in the long term. Additional investigation into the jobs and skills necessary to facilitate the transformations outlined in this study is necessary to understand the challenges, opportunities and potential gaps associated with Rhode Island's workforce as the state transitions to a net zero economy.

Division 3-29

Request:

In response to the above question, what would be the effect of such a method on the asset base of the gas system.

Response:

As stated in Rhode Island Energy's response to Division 3-28, it is the Company's position that no single technology or implementation strategy can currently be leveraged to reliably or cost-effectively decarbonize ***natural gas end uses***, and that the most effective approach for reducing greenhouse gas emissions associated with the ***natural gas distribution*** system is through the continued replacement of leak-prone pipe. As such, to opine on the effect of any decarbonization on the asset base of the gas system would be highly speculative. However, if one were to assume, for the sake of illustration, that a portfolio approach such as the Continued Use of Gas scenario examined in the Technical Analysis[1] for the "Future of Gas" Docket (No. 22-NG-01) – which reflects the lowest overall cost pathway for customers evaluated in the analysis – were pursued, there would be no incremental change in the asset base of the gas system.[2] To bookend this illustrative example, if the high levels of electrification assumed under the High Electrification scenario modeled in the Technical Analysis, reductions to gas system asset base would be relatively modest unless it is feasible to avoid replacing a substantial portion of the Company's leak-prone pipe inventory and decommissioning segments of the system after transitioning customers to electric heating.[3]

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[1] See Attachment DIV 3-28-2.

[2] Attachment DIV 3-28-2, at 69. Figure 38 illustrates no incremental changes in the gas system asset base under the Continued Use of Gas scenario as the entire gas system is maintained.

[3] As E3 emphasized in the Technical Analysis Report provided as Attachment DIV 3-28-2, such approach is currently hypothetical and requires further study to understand whether and to what extent the Company's gas system could be safely and cost-effectively decommissioned.

Prepared by or under the supervision of: Lee Gresham

Division 3-30

Request:

If RIE started a phased abandonment of the gas system, would the electric system be sufficiently robust to carry the additional load especially in the winter months when electric resistance space heating may be necessary.

Response:

On July 24, 2024, Rhode Island Energy filed a response to the Commission's Directive regarding gas segment decommissioning in Docket No. 23-49-NG regarding the Company's FY2025 Gas Infrastructure, Safety and Reliability Plan. The filing included development of an illustrative list of gas and electric technical criteria that could potentially be utilized to rank segments. Other concepts such as feasibility, safety, and reliability were also highlighted. As a result of this filing, as well as consultation with other industry and external stakeholders, Rhode Island Energy has initiated a combined gas/electric planning effort.

Preliminary analysis has indicated that if Rhode Island Energy started a phased abandonment of the gas system, the electric system initially would be sufficiently robust to carry the additional load. Initial gas conversion would be limited to small customer counts and small subsets of the gas system. The electric load increase for these subsets would be modest and accommodated by existing electric system capacity. Large scale gas conversions would require substantial customer participation, and if participation is obtained, it could result in stresses to the electric system as noted in the Company's Grid Modernization Plan (GMP) submitted on December 30, 2022 in Docket No. 22-56-EL. The GMP considered space heating electrification with a resistance heating component and identified when the electric system could shift from a summer peaking system to a winter peaking system.

Prepared by or under the supervision of: Ryan Constable