



STATE OF RHODE ISLAND

DIVISION OF PUBLIC UTILITIES & CARRIERS

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February 20, 2026

*Via Electronic Mail*

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

**RE: Docket No. 25-54-EL – Rhode Island Energy's Proposed FY2027 Electric Infrastructure, Safety, and Reliability Plan**

Dear Ms. De La Rosa:

On behalf of the Division of Public Utilities and Carriers, attached please find the pre-filed testimony of the Division's expert in this matter, Gregory L. Booth, PE, for filing in the above-entitled docket.

Please note that the Division is not commenting on the Company's proposed revenue requirements calculations or proposed ISR rate factors at this time because of the Division's significant disagreement with RI Energy's proposed budget. The Division will review and comment on these matters as part of the compliance phase of this docket when a final budget has been approved.

Thank you for your attention to this submission.

Very truly yours,

/s/ Gregory S. Schultz

Gregory S. Schultz  
Chief of Legal Services

Enclosure

cc: 25-54-EL Service List  
Linda George, Esq., Division Administrator

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

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

Docket No. 25-54-EL

RE: FY 2027 Electric Infrastructure,  
Safety, and Reliability Plan

**PREFILED DIRECT TESTIMONY OF**

**Gregory L. Booth, PE**

**Representing Gregory L. Booth, PLLC  
On Behalf of Rhode Island Division of Public Utilities and Carriers**

**February 20, 2026**

Prepared by:  
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**Prefiled Direct Testimony of**

**Gregory L. Booth, PE, President  
Representing Gregory L. Booth, PLLC**

**On Behalf of Rhode Island Division of Public Utilities and Carriers  
Docket No. 25-54-EL**

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1                                   **DIRECT TESTIMONY OF GREGORY L. BOOTH, PE**

2   **I. INTRODUCTION**

3   **Q. PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR**  
4   **EMPLOYER.**

5   A. My name is Gregory L. Booth. My company is Gregory L. Booth, PLLC ("Booth, PLLC"),  
6   with mailing address 14460 Falls of Neuse Road, Suite 149-110, Raleigh, North Carolina  
7   27614.

8   **Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?**

9   A. I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers  
10   ("Division").

11   **Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?**

12   A. I graduated from North Carolina State University in Raleigh, North Carolina in 1969 with  
13   a Bachelor of Science Degree in Electrical Engineering, and was inducted into the North  
14   Carolina State University Department of Electrical and Computer Engineering Alumni  
15   Hall of Fame in November 2016. I am a registered professional engineer in twenty-three  
16   (23) states, including Rhode Island, as well as the District of Columbia. I am a registered  
17   land surveyor in North Carolina. I am also registered under the National Council of  
18   Examiners for Engineering and Surveying.

19   **Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?**

20   A. I am an active member of the National Society of Professional Engineers ("NSPE"), the  
21   Professional Engineers of North Carolina ("PENC"), the Institute of Electrical and  
22   Electronics Engineers ("IEEE"), American Public Power Association ("APPA"), American  
23   Standards and Testing Materials Association ("ASTM"), the National Fire Protection

1 Association (“NFPA”), and Professional Engineers in Private Practice (“PEPP”). I have  
2 also served as a member of the IEEE Distribution Subcommittee on Reliability and as an  
3 advisory member of the National Rural Electric Cooperative Association (“NRECA”)-  
4 Cooperative Research Network, which is an organization similar to EPRI.

5 **Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH ELECTRIC**  
6 **UTILITIES.**

7 A. I have worked in the area of electric utility and telecommunication engineering and  
8 management services since 1963. I have been actively involved in all aspects of electric  
9 utility planning, design and construction, including generation, transmission, and  
10 distribution systems, and North American Electric Reliability Corporation (“NERC”)  
11 compliance.

12 **Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE THE RHODE**  
13 **ISLAND PUBLIC UTILITIES COMMISSION?**

14 A. Yes. I have testified before the Rhode Island Public Utilities Commission (“Commission”)  
15 on numerous matters, including Docket Nos. 2489, 2509, 2930, 3564, 3732, 4029, 4218,  
16 4237, 4307, 4360, 4382, 4770/4780, 4473, 4483, 4513, 4539, 4592, 4614, 4682, 4783,  
17 4857, 4915, 4995, 5077, 5098, 5209, 5235, 25-41-EL, D-11-94, D-17-45, D-21-09, and D-  
18 25-19. My testimony in Rhode Island has included filed and live testimony on previous  
19 Electric Infrastructure, Safety and Reliability Plan Fiscal Year Proposal filings by National  
20 Grid and later Rhode Island Energy in Docket Nos. 4218, 4307, 4382, 4473, 4539, 4592,  
21 4682, 4783, 4915, 4995, 5098, 5209, 22-53-EL, 23-48-EL, and 24-54-EL.

22 **Q. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT IN OTHER**  
23 **JURISDICTIONS?**

1 A. I have testified before the Federal Energy Regulatory Commission (“FERC”) and  
2 numerous state commissions, including in Connecticut, Delaware, Florida, Georgia,  
3 Maine, Maryland, Massachusetts, Minnesota, New Jersey, North Carolina, Pennsylvania,  
4 South Carolina and Virginia.

1 **II. PURPOSE OF TESTIMONY**

2 **Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?**

3 A. The purpose of my testimony is to introduce *Exhibit GLB-2*, Report of Gregory L. Booth,  
4 PE (“Report”) on the review of Rhode Island Energy’s (“RIE” or “Company”) Proposed  
5 FY 2027 Electric Infrastructure, Safety and Reliability Plan (“FY 2027 ISR Plan”) and Full  
6 Plan provided to the Division on October 31, 2025 (“ISR Plan”). My testimony will briefly  
7 summarize the process between the Division and RIE, in which RIE and the Division  
8 attempted to mutually agree on the proposed FY 2027 ISR Plan filed with the Commission  
9 by RIE on December 22, 2025. I explain why the Division could not reach an agreement  
10 with RIE on the ISR Plan, discuss the Division’s reasons for disagreeing with RIE’s intent  
11 to advance planned capital projects outside of the ISR Plan which were historically  
12 included in the ISR Plan, and outline the Division’s concerns regarding the Company’s  
13 proposed investment strategy of higher capital spending levels. I present the Division’s  
14 areas of consensus which are limited to non-discretionary capital spending and Vegetation  
15 Management expenses. I demonstrate how the Company can achieve a more reasonable  
16 near and long-term capital investment plan by shifting lower priority projects. My  
17 testimony also summarizes certain details of my Report in *Exhibit GLB-2* and summarizes  
18 the Division’s recommendations.

1 **III. ISR PLAN EVALUATION PROCESS AND NON-CONSENSUS POSITION**

2 **Q. WOULD YOU BRIEFLY OUTLINE THE PROCESS WHICH LEADS TO THE**  
3 **DIVISION'S LACK OF SUPPORT OF THE RIE ISR PLAN FILED IN THIS**  
4 **DOCKET?**

5 A. Yes, I will first start with a broader overview and then provide details. Historically, the  
6 Company and Division recognized that the statutory 60-day negotiation period was  
7 insufficient to adequately address all issues and details, including allowing the Company  
8 time to respond to the Division's extensive data requests. For that reason, the Company  
9 had historically provided the proposed ISR Plan in August or September providing both  
10 parties at least 90 days for review of the annual plan. More recently, the Company has been  
11 filing in mid-October, thus providing a shortened review and negotiation period. For this  
12 plan, RIE filed a partial plan on October 17, 2025, and the remaining revenue requirement  
13 section of the plan on October 31, 2025. The process was further complicated by the fact  
14 that the Company has elected to progress several significant customary ISR Plan projects  
15 outside of the ISR Plan. These include the Phillipsdale Substation, power transformer  
16 spares, mobile substations, volt-var optimization program advancement and others. The  
17 Division and Company have substantially different views of these customary ISR Plan  
18 projects, many of which have been identified in Area Studies as part of a system-wide  
19 effort to methodically upgrade the Company's system. This has further complicated the  
20 ISR Plan process and made reaching a consensus for FY 2027 virtually impossible because  
21 RIE did not provide details and cost estimates for the planned projects it intends to advance  
22 outside of the ISR Plan. This means the solution set for safety and reliability and capital  
23 budget impact being presented within an ISR Plan is incomplete. The Division suggested

1 that the Company re-prioritize and integrate all projects into a single ISR Plan to meet the  
2 initially proposed budget level, but RIE provided no response to the Division’s proposal  
3 which was intended to bring us closer to consensus and an agreed to ISR Plan.

4 **Q. CAN YOU ELABORATE ON THE DIVISION’S ISR PLAN REVIEW PROCESS**  
5 **AND HOW THE PROJECTS AND PROGRAMS BEING ADVANCED OUTSIDE**  
6 **OF THE ISR PLAN PROCESS WERE CONSIDERED?**

7 A. Yes. When evaluating a proposed ISR Plan, the Division looks at the Area Studies, Long-  
8 Range Plan (“LRP”), ISR Plan and all the associated capital projects holistically. That is  
9 to say, the capital improvement projects required for infrastructure, safety and reliability  
10 should all be considered in the same context of need, scope, cost, timing and affordability.  
11 In prior years, the ISR Plan and LRP included every proposed capital project offering with  
12 transparency in the integrated planning process. Complete and comprehensive plans also  
13 offered the opportunity for the Division and Commission to review individual project  
14 details, understand interrelationships, and most importantly, get a complete picture of cost  
15 and ratepayer affordability. For the FY 2027 proposed ISR Plan, the Company indicated  
16 that it will be advancing what had previously been considered ISR Plan projects outside of  
17 the ISR Plan. The Company excluded these “non-ISR” projects from the ISR Plan and the  
18 LRP. During the review process, the Company did not provide details or budgetary  
19 information on the planned projects outside of the ISR Plan other than the general timing.  
20 The only information provided in the Company’s December 22, 2025, filing was a general  
21 reference and a footnote listing the projects. Therefore, the Division had neither insight  
22 into these projects nor the ability to consider their impact in the context of the overall ISR  
23 Plan.

1 **Q. HOW DOES THE PROPOSED BUDGET IN THE ORIGINAL OCTOBER FILING**  
 2 **COMPARE TO THE FINAL FILING IN DECEMBER?**

3 A. The Company filed an overall ISR Plan budget, excluding AMF, of \$136.4 million on  
 4 October 31, 2025, and a final proposed ISR Plan budget of \$135.8 million on December  
 5 22, 2025. The budgets were primarily the same but excluded any non-ISR Plan spend. The  
 6 Company’s AMF budget increased over that time. A summary comparison follows:

	(a)	(b)	(c)	(d)
Line Number	<b>FY 2027 ISR Plan Proposed Capital Budget (\$000)</b>	<b>RIE Initial Proposed 10-17-25</b>	<b>RIE Proposed 12-22-25</b>	<b>Variance</b>
1	Total Capital Spending excluding AMF	\$136,356	\$135,820	(\$536)
2	AMF	\$15,281	\$17,879	\$2,598
3	Total Capital Spending including AMF	\$151,637	\$153,699	\$2,062

8 **Q. WHY IS THE COMPANY ADVANCING PROJECTS OUTSIDE OF THE ISR**  
 9 **PLAN AND IS THE DIVISION IN AGREEMENT?**

10 A. The Company in its filing with the Commission contends advancing previously planned  
 11 projects outside of the ISR Plan is in keeping with the Commission’s feedback and FY  
 12 2026 ISR Plan Order in Docket 24-54-EL. The Division disagrees and finds the Company’s  
 13 position contrary to the intent of the Revenue Decoupling statute. Furthermore, the  
 14 Commission has gone to great lengths in holding the Company accountable for developing  
 15 fully justified ISR Plans that consider ratepayer affordability. In fact, the Commission’s  
 16 Orders in 24-54-EL reduced the requested capital spending due in part because of the lack  
 17 of affordability. It is the Division’s position that moving planned projects outside the ISR  
 18 Plan was not the intent of the of the Commission’s Orders. As discussed in more detail  
 19 later in my testimony, the combination of the spend in the ISR Plan and advancing projects  
 20 outside the ISR will dramatically increase capital spending and customer costs over the

1 next five years which conflicts with the Commission’s objective to limit increased  
2 spending when there are so many other pressures on utility rates.

3 **Q. WITNESS LAFOND ON PP. 15-17 OF HIS TESTIMONY SUGGESTS THAT THE**  
4 **PROJECTS PROPOSED OUTSIDE OF THE ISR PLAN ARE REQUIRED**  
5 **SAFETY AND RELIABILITY INVESTMENTS AND THAT MAKING THOSE**  
6 **INVESTMENTS IS SUPPORTED BY THE COMMISSION’S FY 2026 ISR PLAN**  
7 **ORDER. DO YOU AGREE?**

8 A. No. As I previously discussed, the Commission reduced the Company’s FY 2026 ISR Plan  
9 budget finding that many projects were unjustified for inclusion or not needed for safety  
10 and reliability given the Company’s acceptable reliability performance. The Commission  
11 stated, in part, that “Nothing in this order prohibits the Company from making needed  
12 investments and seeking cost recovery in its next rate case.”<sup>1</sup> This clause appears to be the  
13 basis of Witness LaFond’s support for progressing a significant level of projects outside of  
14 the ISR Plan. I do not agree that the Commission was authorizing or encouraging the  
15 Company to develop and execute two portfolios of projects that would customarily be  
16 included in a single ISR Plan. It is my belief that the Commission’s language was designed  
17 to ensure that the Company understood it always had the right and likely the duty to  
18 advance emergent projects that arise unexpectedly during a plan year in order to maintain  
19 safety and reliability. It was not intended as a mechanism for the Company to avoid having  
20 projects scrutinized as part of a comprehensive ISR Plan or to advance Area Study planned  
21 projects outside the ISR Plan.

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<sup>1</sup> Report and Order No. 25470, Docket No. 24-54-EL at pp. 15-16 (July 17, 2025).

1 **Q. CAN THE DIVISION OR COMMISSION REASONABLY EVALUATE AN ISR**  
2 **PLAN THAT EXCLUDES RELATED CAPITAL INVESTMENTS?**

3 A. No. If the Company withholds any planned project work being advanced for reliability and  
4 safety purposes from the Division and the Commission, a comprehensive picture of the  
5 solution set for safety and reliability and capital budget impact being presented within an  
6 ISR Plan is incomplete. That means the solutions presented within the ISR Plan may be  
7 unnecessary based on work outside of the ISR Plan that may very well be solving existing  
8 needs of safety and reliability. An ISR Plan review and concurrence simply cannot occur  
9 with incomplete information.

10 **Q. WHAT IS THE DIVISION'S ESTIMATE OF THE COMPANY'S PROPOSED**  
11 **SPEND OUTSIDE OF THE ISR PLAN PROCESS?**

12 A. Although RIE did not provide forecasted budgets, I have estimated that annual spending  
13 on discretionary capital projects outside the ISR would approach \$20 to \$55 million per  
14 year over the next four years. These amounts would drive investments to approximately  
15 \$200 million in some years, which are levels the Company previously reached when  
16 including significant AMF spend. The estimates were derived through the Company's  
17 forecasts for the projects when they were included in previous ISR Plan attachments and  
18 prior LRPs but are now excluded in both for FY2027. In the table below, I provide a list of  
19 the projects proposed to advance outside the ISR Plan with a budgetary spending level per  
20 year derived from information in prior ISR Plan filing materials. These estimates are likely  
21 lower than what the actual cost will be since they are derived from older data and have not

1           been escalated to today’s costs<sup>2</sup> or scope for each project and program. While the Company  
 2           did not provide the Division cost detail, they recently responded to the PU1-5 indicating  
 3           FY 2027 capital spending outside the ISR Plan is estimated at \$40 million. Since the  
 4           Company still has not provided the detail per project or any justification, it may be that the  
 5           spending outside the ISR Pan could even exceed the Company’s latest estimate.

Line Number	(a) RIE FY 2027 Proposed 5 Year Investment Plan - Capital Spending ISR and Non-ISR Project Estimates (\$000)	(b)	(c)	(d)	(e)	(f)	(g)
		FY 2027	FY 2028	FY 2029	FY 2030	FY 2031	5-yr Total
1	<b>ISR Spending</b>						
2	Total ISR Capital Spending including AMF	153,699	152,400	155,169	147,788	150,379	<b>759,435</b>
3	Total ISR Capital Spending excluding AMF	135,820	152,400	155,169	147,788	150,379	<b>741,556</b>
4	<b>Non-ISR Estimates*</b>						
5	Division St Substation	750	3,000	1,250	-	-	<b>5,000</b>
6	Phillipsdale Substation D Line	2,000	61	-	-	-	<b>2,061</b>
7	Auburn Conversion D Line	5,192	11,632	9,042	-	-	<b>25,866</b>
8	Spare Transformers	10,550	18,184	10,850	10,250	4,200	<b>54,034</b>
9	Phillipsdale Substation D Sub	5,500	5,500	4,500	891	-	<b>16,391</b>
10	Auburn Substation D Sub	1,057	2,112	6,336	832	-	<b>10,337</b>
11	Staples #112 Reliability 112W43	1,000	-	-	-	-	<b>1,000</b>
12	Staples #112 Reliability 112W44	1,807	-	-	-	-	<b>1,807</b>
13	Mobile Substations	-	7,670	-	-	-	<b>7,670</b>
14	VVO/CVR	3,000	6,700	6,700	9,600	Non-ISR	<b>26,000</b>
15	Total Non-ISR Capital Spending	30,855	54,859	38,678	21,573	4,200	<b>150,165</b>
16	<b>Grand Total ISR + Non-ISR Projects inc. AMF</b>	<b>184,554</b>	<b>207,259</b>	<b>193,848</b>	<b>169,361</b>	<b>154,579</b>	<b>909,601</b>
17	<b>Grand Total ISR + Non-ISR Projects excl. AMF</b>	<b>166,675</b>	<b>207,259</b>	<b>193,848</b>	<b>169,361</b>	<b>154,579</b>	<b>891,722</b>

\* RIE did not provide forecasts for Non-ISR spending.

Estimates based on FY 2026 ISR Plan, LRP and various data points.

6  
 7   **Q.     THE COMPANY IN ITS RESPONSE TO DIVISION DATA REQUEST DIV 1-5**  
 8   **STATED: “INDEED, THE COMPANY BELIEVES THE INVESTMENTS MADE**  
 9   **OUTSIDE OF THE ISR SHOULD OTHERWISE BE ELIGIBLE FOR RECOVERY**  
 10 **THROUGH THE ISR, AND THE DIVISION AGREED WITH THOSE**

<sup>2</sup> For example, escalating dated project estimates using Handy Whitman which is a published set of indices for the various utility plant accounts in the FERC uniform system of accounts. These indices allow the calculation of historical increased cost by FERC utility plant account or for entire segments such as distribution or transmission.

1           **INVESTMENTS THAT IT EXAMINED IN THE COMPANY’S FY 2026**  
2           **PROPOSAL.” DO YOU CONCUR WITH THAT CHARACTERIZATION?**

3    A.    No, I do not. The Division did not concur with all the projects now being advanced outside  
4           the ISR Plan. The Division has specifically outlined its disagreement with the Company’s  
5           spare transformer program in terms of scale and when the cost should be incorporated into  
6           rates. Furthermore, the Division finds the advancing of projects outside the ISR Plan  
7           process unacceptable while also being disruptive to any overall infrastructure, safety and  
8           reliability analysis process by not disclosing the total capital program investment levels. In  
9           doing so, RIE has rendered the ISR Plan statute and process unnecessary. Additionally, the  
10          Division never made any such indication of concurrence to forego controlled spending by  
11          the Company. In fact, the Division presented separate testimony in previous ISR Plans  
12          about capital spending controls in order to protect ratepayer affordability.

13   **Q.    WHAT DO YOU BELIEVE ARE SOME OF THE CONSEQUENCES OF THE**  
14          **COMPANY ADVANCING SUBSTATIONS AND OTHER MAJOR PROGRAMS**  
15          **OUTSIDE THE HISTORICAL ISR PLAN PROCESS?**

16    A.    The primary concern with the Company advancing customary ISR Plan and Area Study  
17          capital projects outside the ISR Plan is whether RIE is complying with statutory  
18          requirements and Commission guidance aimed at invoking annual budgets and limiting  
19          unnecessary project acceleration. The Company’s actions bring additional consequences  
20          besides the obvious expenditure of tens of millions of dollars lacking any stakeholder  
21          analysis and concurrence from the Division. These include but are not necessarily limited  
22          to:

- 1           1) The Company will be allowed to circumvent the ISR Plan review process and  
2           requisite justification.
- 3           2) The system being built in FY 2027 and beyond for safety and reliability may be  
4           overbuilt for conditions which may not arise for years or decades. The capital and  
5           O&M budget in the ISR Plan are intended to reflect investments necessary to meet  
6           the safety and reliability requirements in an affordable cost justified manner. If tens  
7           of millions are being spent on additional projects outside the ISR Plan then that  
8           basic premise must be assumed incorrect.
- 9           3) The Company's action means that the Division is evaluating ISR Plan capital  
10          projects for a system which is not the actual system which will exist. Thus, project  
11          solutions within the ISR Plan may not be appropriate because other solutions are  
12          advanced outside the ISR Plan but are not reflected in the ISR Plan holistic analysis  
13          or cost justified otherwise.
- 14          4) The reality is that the Company is advancing the LRP at a much more rapid pace  
15          than is being communicated or justified through the intended ISR Plan process.
- 16          5) The Company's actions of moving many planned Area Study projects outside the  
17          ISR Plan process circumvents the ISR Plan process.
- 18          6) The Company moves analysis of many planned Area Study projects outside the ISR  
19          Plan and forces them to be evaluated as part of a much larger and more complicated  
20          general rate case process. This overly complicates a rate case and dilutes the time  
21          for real meaningful analysis of those projects not advanced through the ISR Plan.  
22          Furthermore, it begins setting a precedent which could theoretically allow RIE to

1           reduce the ISR Plan budget significantly and move capital projects through the  
2           retail rate process, completely circumventing the ISR Plan statutory requirements.

3 **Q.   HOW WOULD YOU CHARACTERIZE DISCUSSIONS AND ATTEMPTS TO**  
4 **REACH MUTUAL AGREEMENT DURING THE REVIEW PROCESS BETWEEN**  
5 **THE DIVISION AND RIE?**

6 A.   In October, the Company provided its proposed budget for the upcoming FY 2027 Plan  
7   year and also submitted its 10-year LRP as a component of the ISR Plan document. The  
8   LRP is an area in which the Division had hoped there would be continuing discussions  
9   since the Division does not accept the LRP as currently presented. The key area of  
10   divergence is the pace of project execution. RIE proposes completing the majority of its  
11   substation related work by FY 2030 as opposed to the Division's position that much of the  
12   work can be deferred into the next 5 years without affecting the Company's ability to meet  
13   its regulatory reliability targets. The Company continues to propose an aggressive pace of  
14   investment and has exacerbated the issue by providing less transparency in proposed spend.  
15   Very early into the review process, the Division expressed concerns with the Company's  
16   plans to advance projects outside of the ISR Plan which were neither identified nor  
17   quantified. The Company ultimately revealed the list of projects and general timing in  
18   response to DIV 1-5 but did not provide budgets. Based on prior planning documents, it  
19   became clear that if the Company progressed both ISR Plan and non-ISR projects, capital  
20   spending (excluding AMF) would approach \$170 million in FY 2027 versus the \$136.4  
21   million ISR plan budget initially presented by the Company. Capital spend would then  
22   reach \$200 million or more in the following years. This is four times the FY 2012 ISR Plan  
23   and twice the ISR Plan spending in the years just prior to the PPL acquisition in 2022. The

1 Division stated its concerns with overall spend, affordability and the inability to perform a  
2 comprehensive review without full visibility of the total capital spending plan. The  
3 Division supported an overall ISR Plan budget of \$136.4 million as initially proposed by  
4 the Company and suggested that projects could be deferred or modulated which would  
5 allow some non-ISR projects to be incorporated in the ISR, producing the desired holistic  
6 plan. The Company did not offer adjustments. The Division went a step further and  
7 provided the Company with a list of potential projects that could be deferred or  
8 implemented over a longer time period based on my findings. If considered, the Company  
9 could potentially incorporate higher priority non-ISR projects within the ISR Plan, stay  
10 within the targeted budget, and forgo executing a separate portfolio. RIE did not respond  
11 to the Division on the proposed compromised position nor did RIE offer an alternate  
12 position to the Division before filing its proposed FY 2027 ISR Plan on December 22,  
13 2025. Therefore, discussions culminated in non-consensus.

14 **Q. WITNESS LAFOND IN HIS TESTIMONY ON PAGE 20 CHARACTERIZED THE**  
15 **PROCESS AS ONE IN WHICH THE DIVISION DID NOT RECOMMEND ANY**  
16 **CHANGES TO THE ISR PLAN OTHER THAN THIRD-PARTY**  
17 **ATTACHMENTS. IT APPEARS YOU ARE INDICATING THE DIVISION DID**  
18 **MAKE A PROPOSAL. COULD YOU EXPLAIN THIS SIGNIFICANT**  
19 **DIFFERENCE BETWEEN WHAT YOU ARE SAYING AND MR. LAFOND'S**  
20 **TESTIMONY?**

21 A. As previously stated, the Division proposed RIE move capital spending proposed outside  
22 the ISR Plan within the plan and limit the FY 2027 budget to \$136.4 million which was the  
23 initial proposed budget without AMF. This position was discussed and although the

1 Division did not make targeted adjustments, it offered the Company an opportunity to re-  
2 evaluate project risks and priorities to accomplish the objective of developing a single,  
3 holistic ISR Plan. The Division followed up by providing the Company with a list of  
4 substation projects that could be reasonably deferred or modulated based on my  
5 assessment. The proposed list included ISR and non-ISR<sup>3</sup> projects based on information  
6 from previous ISR Plans, and my technical evaluations. The substation list was a starting  
7 point, knowing the Division must rely on the Company's input and active participation in  
8 these adjustments. Instead, the Division's proposal was not accepted. What this means is  
9 that if only the currently proposed non-ISR Plan projects are advanced outside the ISR,  
10 there will be an increase in total capital spending over what is proposed in the ISR Plan of  
11 up to \$50 million per year. This is certainly understated considering the fact the most  
12 recently filed retail rate case Docket 25-45-GE includes several expensive substation and  
13 distributed generation interconnection project investments that have already occurred  
14 outside the ISR Plan.

15 **Q. YOU DISCUSSED A PROPOSAL THAT RIE MODULATE PROJECT SPEND TO**  
16 **MEET THE DIVISION'S BUDGET TARGET AND ALSO DEVELOP A SINGLE**  
17 **HOLISTIC ISR PLAN THAT INCLUDES PRIORITY NON-ISR PROJECTS.**  
18 **HOW DO YOU PROPOSE THAT NON-ISR SPARE TRANSFORMER AND**  
19 **MOBILE SUBSTATION PURCHASES BE TREATED?**

20 A. The Division has not supported the Company's plan to purchase a significant number of  
21 spare transformers, many of which were available to the Company under National Grid  
22 ownership. The Division and Company were to continue discussions and potentially agree

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<sup>3</sup> The Company provided a list of non-ISR projects in DIV 1-6 response.

1 on the magnitude of purchases and recovery mechanism. Now the Company has removed  
2 spare transformer purchases from the ISR Plan and LRP, effectively ceasing meaningful  
3 discussions. Based on this change and our prior evaluations and conclusions, the Division  
4 recommends that spare transformer purchases can occur outside of the ISR Plan, however  
5 there should be no cost recovery unless and until the time the unit is placed in service.  
6 Further, cost recovery should be based on the depreciated value of the spare transformer.  
7 This recommendation provides ratepayers with access to spare transformers at no cost until  
8 a unit is actually used on the Rhode Island system for an emergency, consistent with  
9 arrangements under National Grid ownership. It also provides ratepayer protection by  
10 avoiding a scenario where RIE purchases excessive levels of spare transformers and  
11 receives cost recovery in the short term but well before the unit is used and useful. In short,  
12 the Division's recommendation will encourage the Company to better align spare  
13 transformer purchases with system needs without unduly burdening ratepayers.  
14 Additionally, the Division's position is that mobile substations are a transitional cost since  
15 the equipment was available to the Company under National Grid ownership. The Division  
16 has previously agreed with the Company on the level of planned purchases and supports  
17 those investments outside of the ISR Plan.

18 **Q. THE COMPANY HAS ALSO PROPOSED VOLT-VAR OPTIMIZATION AND**  
19 **CONSERVATION VOLTAGE REDUCTION (“VVO/CVR”) INVESTMENTS**  
20 **OUTSIDE OF THE ISR PLAN. DO YOU SUPPORT MOVING THESE**  
21 **INVESTMENTS WITHIN THE ISR PLAN?**

22 A. The VVO/CVR program is not for safety or reliability but when implemented on select  
23 feeders, it provides a net power cost benefit to customers. The program was previously

1 presented as part of the Company's Grid Modernization Plan and was not approved for full  
2 advancement. The Company's VVO/CVR pilots have demonstrated that the expected  
3 benefits were achieved, and I have consistently been supportive of the program. The  
4 Division's position is that if the Company proposes to continue implementing VVO/CVR,  
5 it should seek approval of a separate and comprehensive program to be included in a future  
6 ISR Plan, similar to what was developed for AMF. The Division does not support  
7 VVO/CVR investments outside of the ISR Plan without requisite justification, including a  
8 benefit-cost analysis and program execution commitments for review and potential  
9 approval by the PUC.

10 **Q. IN PAST ISR PLAN FILINGS, YOU HAVE INCLUDED A TABLE SHOWING**  
11 **THE COMPANY'S ORIGINAL PROPOSAL AND THE ADJUSTED CONSENSUS**  
12 **POSITION OF THE DIVISION AND COMPANY. DO YOU HAVE A SIMILAR**  
13 **TABLE FOR THIS FILING?**

14 A. No. The Division and Company were unable to reach a consensus position, therefore I did  
15 not include the table. While there were slight differences between the original and final  
16 proposed ISR Plan budgets, the filings were principally the same and any variances were  
17 the result of the Company's internal adjustments and not consultation with the Division.

18 **Q. DESPITE THE INABILITY TO REACH A CONSENSUS POSITION, DID THE**  
19 **DIVISION AGREE WITH PROPOSED CAPITAL BUDGETS IN ANY**  
20 **CATEGORY OF SPEND?**

21 A. Yes. The Division did concur with the non-discretionary categories of Customer  
22 Service/Regulatory and Damage and Failure. The Division and RIE, after extensive  
23 discussions, reached a compromise position on the Third-Party Attachments. The Division

1 proposed a significantly more rigorous process of engineering for the make ready analysis  
2 which would involve existing attaching entities sharing in a much greater portion of the  
3 make ready costs. Additionally, the FCC clarifications would be utilized to further offset  
4 costs which RIE was otherwise planning on imposing on the electric ratepayer. Attached  
5 to my report is the proposed process which would be utilized and serves as the basis of the  
6 Division's concurrence to move the Third-Party Attachments outside the Consolidated Soft  
7 Budget Limit category and resolving the cost inclusion in the reconciliation process.

8 **Q. YOUR REPORT INDICATES THAT DURING THE CONFERENCES IT**  
9 **BECAME VERY EVIDENT THE PPL PHILOSOPHY IS DIFFERENT THAN**  
10 **NATIONAL GRID. WOULD YOU ELABORATE?**

11 A. Certainly. The differences became apparent over the last two ISR Plans filed by RIE, and  
12 now with its recent plan and proposal to advance upwards of \$50 million a year of planned  
13 capital projects outside the ISR Plan RIE is moving away from the concept of affordability  
14 and is not attempting to accept and manage risk as has been done for decades in Rhode  
15 Island. RIE indicated early on that the PPL risk assessment and risk tolerance was different  
16 than National Grid's. My observation is that the Company is inclined to increase or  
17 accelerate investments to offset perceived risks. RIE also takes a more aggressive stance  
18 on reliability performance. For example, RIE not only wants to meet and exceed regulatory  
19 reliability metrics, but the Company also wants to be "best in class" by making additional  
20 investments to further improve its already very good reliability performance by adopting  
21 much lower internal reliability indices. RIE has made a real effort to also explain some of  
22 its philosophy differences and enhancements, including in areas such as vegetation  
23 management, system protective coordination and advancement of technology such as

1 FLISR reclosers (defined also as self-healing circuits) and its optimistic reliability goals.  
2 The Division and RIE have not completely reached consensus on all the philosophy  
3 changes, including the level of capital spend A \$153.7 million ISR Plan with something  
4 approaching \$50 million of capital spending outside the ISR Plan is still a capital spending  
5 impact on ratepayers approaching \$200 million. Ratepayers will be just as adversely  
6 impacted whether the massive capital spending is inside or outside the ISR Plan.

1 **IV. INFRASTRUCTURE INVESTMENT AND JOBS ACT (“IIJA”) ISSUES**

2 **Q. RIE HAS DISCUSSED IN THIS ISR PLAN THAT IT ACCEPTED THE IIJA**  
3 **FUNDING AWARD. WHAT ARE THE DIVISION’S CONCERNS WITH THE**  
4 **COMPANY’S COMMITMENTS FOR FUNDING?**

5 A. The Company reports that it accepted the IIJA award from the U.S. Department of Energy  
6 (“DOE”) for Smart Grid investments and “certain work in the FY 2027 ISR Plan and  
7 previous years’ Plans are eligible for IIJA reimbursement.” RIE further states that “The  
8 Company is in the process of submitting a reimbursement request for services performed  
9 in the first budget period of the award which is October 2024 through September 2025.”<sup>4</sup>  
10 The Division’s previous review of the award in the FY 2026 ISR Plan proceedings raised  
11 several concerns that linger. The most critical matter is that RIE would be liable for  
12 investing \$283 million<sup>5</sup> in order to receive \$50 million in government funding, or eighteen  
13 percent (18%) share of the total cost which the Division does not support. The Company  
14 also reports that it will defer or moderate the pace of some future IIJA investments to reflect  
15 regulatory outcomes in prior ISR Plan proceedings. Complete details have not been  
16 provided and the Company’s commitments to the DOE for funding and trajectory of future  
17 spend remain unclear. Since the investments are mostly embedded in projects, both within  
18 and outside of the ISR Plan, there is no practical way to determine if they are resolving a  
19 system need in the most cost-effective manner, or simply desired by the Company. The  
20 Division had hoped that the Company would have clearly identified and justified IIJA  
21 investments, strategically incorporating those investments within a holistic LRP that

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<sup>4</sup> FY 2027 ISR Plan, Section 2, Bates p. 109.

<sup>5</sup> RIE response to DIV 6-10; Investments include \$224 million for operational technology (OT), \$1 million for project management, and \$58 million for information technology (IT) that PPL has already implemented.

1 informed a modulated ISR Plan. Despite RIE contending that ISR Plan and IJJA  
2 investments are moderated, the Division's expectations have not and will not be met,  
3 particularly if spending is merely shifted to non-ISR projects. It is impractical for the  
4 Division to endorse ISR Plan discretionary projects and spending levels that include  
5 incremental spending for grid modernization projects that have not been justified which  
6 are then further expanded by the Company outside of the ISR Plan with no justification or  
7 transparency.

1 **V. PROJECT ADVANCEMENT PROCESS**

2 **Q. DO YOU HAVE ANY CONCERNS ABOUT RIE'S PROJECT ADVANCEMENT**  
3 **PROCESSES AND WHAT CONSENSUS THE DIVISION IS ACTUALLY**  
4 **REACHING WITH THE COMPANY WHEN IT AGREES TO PROJECT**  
5 **ENGINEERING?**

6 A. Yes. Over the past several ISR Plans, it has become very apparent that RIE believed that  
7 when the Division approved a project's engineering, that meant the entire project was  
8 approved for advancement at any scope, cost and pace desired by the Company. That belief  
9 is far from what the Division's expectations were, as it was only agreeing to engineering  
10 advancement. The Division has continued to reiterate to RIE during each ISR Plan that  
11 approval for engineering is not agreement on an undefined scope or cost. The Division has  
12 been advocating in each ISR Plan for a significantly improved engineering, scoping and  
13 cost estimating process for RIE, however our request has not been satisfied yet Final project  
14 scopes and costs are often far different than originally developed by the Company in its  
15 Area Study. A more defined phase to review engineering study results prior to project  
16 implementation is necessary but not currently provided. The Division must be satisfied that  
17 the proposed project and implementation timeline are cost-effective and reasonable given  
18 the Company's holistic capital spending LRP. RIE should not expect funding for a project  
19 based on study grade cost estimates and analysis. Detailed engineering, scoping and cost  
20 estimates are mandatory before capital spending beyond the engineering phase advances.  
21 The Commission also reinforced these concerns, explaining in its FY 2026 ISR Plan Order  
22 that it believed that RIE completed its most accurate level of project cost estimate prior to

1       procuring equipment, but that was a misunderstanding.<sup>6</sup> The Commission even paused  
2       projects to allow time to better understand estimating and project progression. The Division  
3       fully expected it would have productive discussions with RIE to establish a better  
4       understanding and, hopefully, achieve a commitment for an earlier completion of  
5       engineering, so before a project is advanced, there is a detailed and reasonable scope, plan,  
6       engineering detail and accurate cost estimate. My decades of experience with many utilities  
7       has indicated detailed engineering, scoping and cost estimates completed in advance of  
8       major equipment purchases and contract executions is the most common way of project  
9       planning and advancement, which is far different than what RIE is currently doing.

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<sup>6</sup> FY 2026 ISR Plan Order, page 7.

1 **VI. CAPITAL BUDGET GUIDANCE AND LONG-RANGE PLAN**

2 **Q. BOTH YOUR TESTIMONY AND REPORT PRESENT A PICTURE OF A**  
3 **DRAMATIC UPWARD TRAJECTORY OF INCREASING CAPITAL SPENDING.**  
4 **HOW DOES THE DIVISION EVALUATE MODULATING RIE'S CAPITAL**  
5 **SPENDING PROGRAM TO FOCUS ON AFFORDABILITY WITHOUT UNDULY**  
6 **COMPROMISING SAFETY AND RELIABILITY?**

7 A. I have worked in many jurisdictions and with many utility clients on guidelines and  
8 parameters to assess the reasonableness of an electric utility's level of capital investment  
9 plan, considering a balance of system need, reliability performance and ratepayer impacts.  
10 Historically, the Company maintained a focus on capital spending cost containment. More  
11 recently, RIE has proposed advancing discretionary capital projects at a very rapid pace.  
12 The trajectory is evident when considering prior LRPs that included all potential ISR Plan  
13 projects, however the trend is now obscured by the removal of projects and costs from the  
14 filed plan or long-term projections. The Company's investment pace comes even when  
15 load growth is well below projections. Despite achieving superior reliability results, RIE  
16 has adopted its own much more aggressive reliability targets while moving towards a low  
17 risk tolerance level. RIE has continued to focus on advancing projects to create  
18 contingencies for outages when none had previously existed or were considered necessary.  
19 RIE focuses on complex solutions to eliminate risks instead of lower cost options to  
20 reasonably manage risk. While these goals may be admirable, they are not reasonable or  
21 affordable. The Division used its guidance methodology combined with engineering  
22 studies, analysis from the Company, and known additional areas of need such as the  
23 advancement of AMF to establish a level of capital spending which may be considered as

1 reasonable. My report provides further details on the guidance. More modulated plans  
2 similar in nature to past plans of National Grid fit well with the guidance method utilized  
3 by the Division. Those plans generally always resulted in consensus. RIE has been moving  
4 away from a more modulated capital spending philosophy and its FY 2027 ISR Plan and  
5 the level of capital spending outside the ISR Plan is a dramatic move towards excessive  
6 annual capital spending on the system. The Division plans to continue to use as one of its  
7 many tools, its capital budgetary guidance methodology combined with its other analysis  
8 processes as detailed in FY 2026 by William Watson, PhD. and myself to determine  
9 reasonable budget levels.

10 **Q. HAVE YOU INDEPENDENTLY EVALUATED ADJUSTMENTS TO ACHIEVE**  
11 **CAPITAL SPENDING WITHIN THE DIVISION'S DESIRED BUDGET**  
12 **GUIDANCE?**

13 A. Yes. By re-prioritizing substation work I am able to demonstrate that both the FY 2027  
14 ISR Plan budget and modulated LRP can be reasonably achieved within the Division's  
15 desired budget guidance. I used the Company's filed 5-Year Capital Spending Plan and the  
16 LRP for the following 5 years as the basis since my adjustments affect future years. I then  
17 considered non-ISR substation related projects put forth by the Company using my own  
18 estimated costs. Spare transformers, mobile substations and VVO/CVR were excluded  
19 based on the Division's recommendation discussed earlier in my testimony. Next, I  
20 deferred early lifecycle and lower priority substation projects. I also adjusted system  
21 capacity and performance substation projects where load has not developed as projected  
22 and the solutions could be deferred. Consensus categories of spend were not adjusted.  
23 Through these steps I was able to develop a FY 2027 ISR Plan that somewhat exceeds the

1 Division’s support for a total ISR Plan budget of approximately \$136 million but it is well  
 2 below the capital expenditure proposed by the Company when including non-ISR projects.  
 3 This analysis is a starting point and there are additional areas of adjustment to be explored

Line Number	(a) FY 2027 ISR Plan Capital Spend (\$000)	(b) RIE Proposed 12-22-25	(c) Division Adjustment through Project Deferrals
1	Non-Discretionary	\$54,915	\$54,915
2	Non-Infrastructure	\$410	\$410
3	Asset Condition	\$29,750	\$29,750
4	System Capacity	\$24,361	\$21,345
5	<b>Consolidated Soft Budget Limit</b>	<b>\$109,436</b>	<b>\$106,421</b>
6	Separately Tracked Major Projects	\$22,084	\$26,979
7	Third Party Attachments	\$4,300	\$4,300
8	<b>ISR Capital Spending (excluding AMF)</b>	<b>\$135,820</b>	<b>\$137,700</b>
9	<b>Non-ISR Projects</b>	\$30,855	\$0
10	<b>Grand Total Capital Spending (excluding AMF)</b>	<b>\$166,675</b>	<b>\$137,700</b>

4 should the Company engage. The following table illustrates the results of the Division’s  
 5 project adjustments with additional details provided in my report.

6

7 **Q. HOW DO YOUR PROPOSED PROJECT DEFERRALS IMPACT THE**  
 8 **COMPANY’S LONG-RANGE PLAN?**

9 A. By shifting lower priority projects, I created a more levelized annual investment strategy  
 10 than proposed by the Company. A key adjustment was deferring approximately \$50 million  
 11 of substation work from the first 5 years into the second 5 years of the planning horizon.  
 12 The resulting LRP is far closer to what the Division has been requesting of the Company  
 13 for several years. A high-level summary of my analysis below shows a more tempered  
 14 spend over the long term which is also better aligned with an illustrative budget target

1 assuming 3% annual escalation. Where necessary, small-scale adjustments can be applied  
 2 to align with budget guidance. Future years are below the target considering excess  
 3 reserves for unidentified projects in the Company’s LRP that are not shown here.

Line Number	(a) Long Range Plan Capital Spend (\$M)*	(b) FY27	(c) FY28	(d) FY29	(e) FY30	(f) FY31	(g) 5-yr Total	(h) FY32	(i) FY33	(j) FY34	(k) FY35	(l) FY36	(m) 10-Yr. Total
1	<b>RIE Proposed ISR + Non-ISR</b>	153	175	176	142	124	770	117	120	123	127	131	1,389
2	<b>Division Adjusted-Project Deferrals</b>	138	145	142	148	147	720	142	134	131	132	131	1,389
3	<i>Illustrative Budget Target (3% esc.)</i>	<i>136</i>	<i>140</i>	<i>144</i>	<i>149</i>	<i>153</i>		<i>158</i>	<i>162</i>	<i>167</i>	<i>172</i>	<i>177</i>	

4 \* Excludes Spare Transformers, Mobile Substations and VVO/CVR

5 **Q. WHY IS YOUR ANALYSIS IMPORTANT IN CONSIDERING THE DIVISION’S**  
 6 **LIMITED SUPPORT FOR THE FY 2027 ISR PLAN?**

7 A. My analysis emphasizes that the Company has flexibility in executing discretionary  
 8 investments for safety and reliability over the short and long term. I have provided an  
 9 example of how that flexibility can be leveraged in developing a more reasonable capital  
 10 investment plan that takes ratepayer affordability into consideration. The Division’s  
 11 position is that the Company should be able to achieve this objective considering all  
 12 discretionary capital investments, not just a partial portfolio as presented in the proposed  
 13 FY 2027 ISR Plan. The Company did not appear willing to work towards this objective in  
 14 the discussions with the Division which was a major factor in limiting Division  
 15 concurrence to non-discretionary spend. I firmly believe that if the Company’s proposed  
 16 discretionary ISR Plan budget is denied in full, RIE would utilize more robust system  
 17 assessments and risk analysis to re-prioritize projects due to the delay of cost recovery, and  
 18 the end result would be an investment plan that is more aligned with the Division’s  
 19 objectives.

1 **VII. CONCLUSION**

2 **Q. DO YOU AND THE DIVISION SUPPORT THE PROPOSED RIE FY 2027**  
3 **ELECTRIC ISR PLAN BUDGET FOR \$135.8 MILLION EXCLUDING AMF, AND**  
4 **\$153.7 MILLION INCLUDING AMF, IN CAPITAL EXPENDITURES?**

5 A. No. The Company filed a proposed ISR Plan and indicated that, in addition to the spend  
6 proposed in the ISR plan, it will be advancing what had previously been considered ISR  
7 Plan projects outside of the ISR Plan. By the Division's estimate, the Company's non-ISR  
8 project spend would add nearly \$31 million of discretionary spend in FY 2027 making the  
9 Company's total capital investment approach \$167 million excluding AMF. The Division  
10 does not support the Company's strategy to pursue two separate portfolios of planned  
11 investments for safety and reliability and strongly withholds concurrence for an overall  
12 plan that would result in capital investment levels that far exceed \$135.8 million and would  
13 ultimately reach capital spending at or above \$200 million per year excluding AMF.

14 **Q. WHAT IS THE DIVISION'S RECOMMENDATION IF THE COMPANY**  
15 **CONTINUES TO SEEK APPROVAL OF ITS FY 2027 ISR PLAN BUDGET AS**  
16 **PROPOSED AND ALSO ADVANCES PLANNED PROJECTS OUTSIDE OF THE**  
17 **ISR PLAN?**

18 A. The Division recommends that the FY 2027 ISR Plan approval be limited to only non-  
19 discretionary spend of \$59.2 million. Of this, the Division supports separately tracking and  
20 reconciling \$4.3 million for Third-Party Attachments subject to the Company meeting  
21 Recommendation No. 1 below. The resulting Consolidated Soft Budget Limit would be  
22 \$54.9 million excluding the Third-Party Attachment budget. This would allow the  
23 Company to recover ongoing costs to meet its statutory or regulatory obligations within

1 the ISR Plan and simultaneously progress discretionary projects outside of the ISR Plan  
2 without regard to the overall spending guidance put forth by the Division and also the  
3 Commission. The Company would maintain full latitude and flexibility in executing its  
4 desired investment strategy outside of the ISR Plan but would ultimately be held  
5 accountable to justify that spend in a rate case. At that time, stakeholders will have an  
6 opportunity to retrospectively evaluate the Company's comprehensive investment plan  
7 which is not the Division's preference but is a better alternative than attempting to achieve  
8 advance concurrence when the Company only delivers a partial plan.

9 **Q. DOES THE DIVISION CONCUR WITH THE COMPANY'S PROPOSED**  
10 **OPERATIONS AND MAINTENANCE BUDGETS?**

11 A. The Division agrees with the Company's proposed \$12.9 million in expenditures for the  
12 Vegetation Management Program. The Division withholds concurrence of the Company's  
13 proposed \$1.4 million in O&M expenses related to the I&M Program, which is a  
14 discretionary program, since agreement was not reached on any discretionary budget.

15 **Q. WHAT ARE THE RECOMMENDATIONS YOU HAVE MADE IN YOUR**  
16 **REPORT *EXHIBIT GLB-2?***

17 A. I have added a recommendations related to Third-Party Attachments and continue to  
18 endorse thirteen (13) recommendations included in my previous ISR Plan report. These  
19 recommendations are summarized in the following list and are provided with additional  
20 discussion in the Recommendations section of my Report.

- 21
- 22 1. The Company shall develop and put forth for Division review an acceptable process to  
23 manage third-party pole attachment requests that incorporate equitable cost sharing

1 arrangements by March 31, 2026. The process shall include a requirement for complete  
2 record retention that documents the need for, and cost assignment of, all make ready work  
3 in a manner that can be examined to validate costs incurred by the Company.

4 2. The Company shall continue developing Area Studies and future study documents  
5 supporting Asset Replacement and System Capacity and Performance programs and  
6 projects as applicable to include, at a minimum:

- 7 • The traditional elements included in the Company's current studies including, but not  
8 limited to, purpose and problem statement, scope and program description, load  
9 forecast methodologies, condition assessment/criticality rankings, alternatives  
10 considered, solution, cost estimate and timeline. Additionally, the AMF data shall be  
11 integrated into the engineering models to enhance the accuracy of these models and  
12 project development. Initial project cost estimates should be developed with a -  
13 25%/+50% tolerance, or better, and adjusted for inflation.
- 14 • Discussion on the impact to related Company initiatives, Commission programs, the  
15 various pilot projects, or other requirements driven by SRP, Distribution System  
16 Planning ("DSP"), Heat Maps, and emerging initiatives.
- 17 • A detailed comparison of recommendations to Area Studies to determine if solutions  
18 are aligned with study outcomes, noting adjustments required to avoid redundancy in  
19 planning.
- 20 • An evaluation of potential incremental investments that support the Company's long  
21 -term grid modernization strategy. This includes description of technology or  
22 infrastructure investment, cost-benefit to traditional safety and reliability objectives,  
23 and additional operational benefits achieved, if implemented. Grid modernization

1 investments should be closely correlated with all ISR Plan investments, including  
2 both recurring and newly proposed programs.

- 3 • A robust non wires alternative (“NWA”) evaluation for projects passing initial  
4 screening that clearly identifies alternatives considered, costs, and benefits.
- 5 • The Company shall submit and present the outcome of each completed or revised  
6 Area Study to the Division.

7 3. The Company shall correlate Area Studies to each other for the development of a holistic  
8 system LRP in order to increase the level of support and transparency for the capital budget  
9 which further informs the ISR Plan. Completed Area Studies shall be used to re-prioritize  
10 and sequence all solutions and major projects in the LRP. The LRP shall be developed in  
11 a manner recognizing that a reasonable plan must incorporate ratepayer affordability and a  
12 reasonable level of company risk acceptance. The Company shall submit a report with  
13 updates on modeling activities, holistic system LRP development and revision of each  
14 current and future planned Area Study status at least 120 days prior to filing its FY 2028  
15 ISR Plan Proposal, but in any event no later than August 31, 2026.

16 4. The Company shall maintain and file with each proposed ISR Plan its holistic 10-year LRP  
17 as contemplated in these Recommendations to include all strategic capital investments. The  
18 LRP should demonstrate the strategic alignment and between various planning and project  
19 evaluation processes including but not limited to, the SRP plans, Area Studies, ISR Plan,  
20 non-wires alternatives options, grid modernization plans, and internal Design Criteria. The  
21 LRP must be adequately supported and accompanied by a level of detail that allows  
22 stakeholders to sufficiently validate the need, timing and level of proposed investment in

1 relation to ratepayer affordability. It shall also reflect the demand reduction which may  
2 transpire from the SRP program advancements.

3 5. The Company shall not include spend in the ISR Plan for initiatives or programs that are  
4 subject to Commission review and/or approval prior to the program progressing through a  
5 regulatory proceeding.

6 6. The Company shall present new programs, major projects, or material modifications to  
7 existing programs to the Division in advance of including the programs in the ISR Plan.  
8 The Company shall produce requisite justification at a level of detail to sufficiently validate  
9 the need, timing and level of proposed investment, including a benefit-cost analysis. The  
10 Company shall also propose a methodology to separately track, measure and validate  
11 program costs and benefits. Requisite justification and accompanying information shall be  
12 provided in advance of the FY 2028 ISR Plan Proposal filing, and in any event no later  
13 than August 31, 2026.

14 7. The Company shall continue to provide a detailed budget for System Capacity &  
15 Performance and Asset Condition in order to allow for transparency on a project level basis  
16 for the current and future 4-year period. The budget shall be provided in advance of the FY  
17 2028 ISR Plan Proposal filing, and in any event no later than August 31, 2026.

18 8. The Company shall submit an evaluation of future proposed Asset Condition projects as  
19 compared to the Company's LRP in advance of the FY 2028 ISR Plan Proposal filing, and  
20 in any event no later than August 31, 2026.

21 9. The Company shall continue to submit its detailed substation capacity expansion plans and  
22 load projections, and include an evaluation of proposed projects against the Company's

1 LRP in advance of the FY 2028 ISR Plan Proposal filing, and in any event no later than  
2 August 31, 2026.

3 10. The Company shall continue to monitor and report on work performed under  
4 Damage/Failure, I&M, and related Asset Replacement Blanket programs to validate proper  
5 classifications. The Company shall continue to provide quarterly reporting on  
6 Damage/Failure expenditures to include the details of completed projects by operating  
7 region. The Company will separately identify Level I projects repaired as a result of the  
8 I&M program.

9 11. The Company shall complete a systemwide protective coordination study, demonstrating  
10 the need, the location, and/or the manner in which reclosers will be coordinated in advance  
11 of progressing major recloser additions. The Division and Company will work to develop  
12 a mutually acceptable study format and content. The memorandum which the Company  
13 has already agreed to deliver before advancing reclosers and most particularly the FLISR  
14 schemes may substantially address the Division's needs.

15 12. The Company shall continue to submit an overall cost-benefit analysis for Cycle Pruning  
16 and Risk Reduction work within the Vegetation Management Program for the Division's  
17 review prior to submitting the Company's FY 2028 ISR Plan Proposal, and in any event  
18 no later than August 31, 2026.

19 13. The Company shall provide continuous and timely updates on ISR Plan team members and  
20 responsibilities, material changes to Company guidelines, standards or processes that affect  
21 distribution planning, or any proposed changes to the ISR Plan process. The Company  
22 shall, at minimum, provide updates at quarterly presentations of the quarterly reports.  
23

1 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

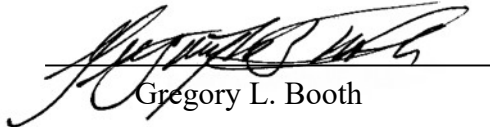
2 A. Yes

**AFFIDAVIT OF GREGORY L. BOOTH, PE**

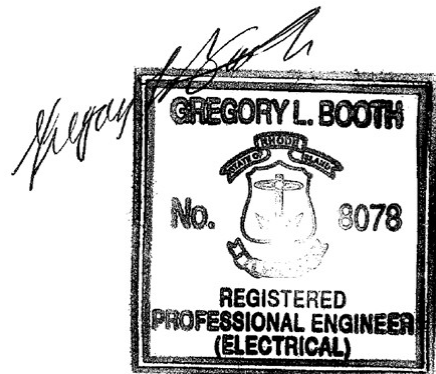
Gregory L. Booth, does hereby depose and say as follows:

I, Gregory L. Booth, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 20th day of February, 2026.

  
Gregory L. Booth

I hereby certify this document was prepared by me or under my direct supervision. I also certify I am a duly registered professional engineer under the laws of the State of Rhode Island, Registration No. 8078.



Gregory L. Booth, PE

**RESUME OF  
GREGORY L. BOOTH, PE, PLS  
President  
Gregory L. Booth, PLLC**

Gregory L. Booth is a registered professional engineer with engineering, financial, and management services experience in the areas of utilities, industry private businesses and forensic investigation. He has been representing over 300 clients in some 40 states for more than 50 years. Mr. Booth was inducted into the North Carolina State University Electrical and Computer Engineering Alumni Hall of Fame in November of 2016 based on his accomplishments in the field of engineering.

Mr. Booth has been accepted as an expert before state and federal regulatory agencies, including the Federal Energy Regulatory Commission, Colorado Public Utility Regulatory Authority, Connecticut Public Utilities Regulatory Authority, Delaware Public Service Commission, Florida Public Service Commission, Georgia Public Service Commission, Maine Public Utilities Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Minnesota Department of Public Service Environmental Quality Board, the New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, North Carolina Utilities Commission, Pennsylvania Public Utility Commission, Rhode Island Public Utilities Commission, South Carolina Office of Regulatory Staff, and the Virginia State Corporation Commission,. Mr. Booth has provided expert witness services on over 500 tort case matters, and over 50 regulatory matters. Investigation and testimony experience includes areas of wholesale and retail rates, utility acquisition, territorial disputes, electric service reliability, right-of-way acquisition and impact of electromagnetic fields and evaluation of transmission line options for utility commissions.

He has been accepted as an expert in both state and federal courts, including Colorado, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Puerto Rico, South Carolina, Texas, Virginia, West Virginia, Virgin Islands, and Wisconsin, and numerous Federal Court jurisdictions. Mr. Booth has extensive experience serving as an expert witness before state and federal courts on matters including property damage, forensic evaluation, fire investigations, fatality, and areas of electric facility disputes and Occupational, Safety and Health Administration violations and investigations together with National Electrical Code and National Electrical Safety Code and Industry Standard compliance.

The following pages provided are the education and experience from 1963 through the present, along with courses taught and publications.

**RESUME OF  
GREGORY L. BOOTH, PE, PLS**

Mr. Booth is a Registered Professional Engineer with engineering, financial, and management experience assisting local, state, and federal governmental units; rural electric and telephone cooperatives; investor-owned utilities, industrial customers and privately owned businesses. He has extensive experience representing clients as an expert witness in regulatory proceedings, private negotiations, and litigation.

**PROFESSIONAL  
EDUCATION:**

NORTH CAROLINA STATE UNIVERSITY; Raleigh NC, Bachelor of Science, Electrical Engineering, 1969 and over 1,000 professional development hours

**PROFESSIONAL  
HONORS:**

Inducted into North Carolina State University Department of Electrical and Computer Engineering Alumni Hall of Fame in November 2016.

**REGISTRATIONS:**

Registered as Professional Engineer in Alabama, Arizona, Colorado, Connecticut, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, North Carolina, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Texas, Commonwealth of Virginia, West Virginia, and Wisconsin; Professional Land Surveyor in North Carolina Council Record with National Council of Examiners for Engineering and Surveying

**EXPERIENCE:**

1963-1967  
Technician  
Booth & Associates, Inc.

Transmission surveying and design assistance, substation design assistance; distribution staking; construction work plan, long-range plan, and sectionalizing study preparation assistance for many utilities, including Cape Hatteras EMC, Halifax EMC, Delaware Electric Cooperative, Prince George Electric Cooperative, A&N Electric Cooperative; assistance generation plant design, start-up, and evaluations.

1967-1973  
Project Engineer  
Booth & Associates, Inc.

Transmission line and substation design; distribution line design; long-range and construction work plans; rate studies in testimony before State and Federal commissions; power supply negotiations; all other facets of electrical engineering for utility systems and over 30 utilities in 10 states.

1973-1975  
Professional Engineer  
Booth & Associates, Inc.  
1975-1994  
Executive Vice President  
Booth & Associates, Inc.

Directed five departments of Booth & Associates, Inc.; provided engineering services to electric cooperatives and other public power utilities in 23 states; provided expert testimony before state regulatory commissions on rates and reliability issues; in accident investigations and tort proceedings; transmission line routing and designs, generation plant designs; preparation and presentation of long-range and construction work plans; relay and sectionalizing studies; relay design and field start-up assistance; generation plant designs; rate and cost-of-service studies; reliability studies and analyses; filed testimony, preparation and teaching

of seminars; preparation of nationally published manuals; numerous special projects for statewide organizations, including North Carolina EMC. Work was provided to over 130 utility clients in 23 states, PWC of the City of Fayetteville, NC, Cities of Wilson, Rocky Mount and Greenville are among the utilities in which I have provided engineering services in North Carolina during this time frame. Services to industrial customers include Texfi Industries, Bridgestone Firestone, Inc and many others.

1994-2004  
President  
Booth & Associates, Inc.

Responsible for the direction of the engineering and operations of Booth & Associates, Inc. for all divisions and departments. The engineering work during this time frame has continued to be the same as during 1974 through 1993 with the addition of greater emphasis on power supply issues, including negotiating power supply contracts for clients; increased involvement in peaking generation projects; development of joint transmission projects, including wheeling agreements, power supply analyses, and power audit analyses. The work during this time frame includes providing services to over 200 utility clients across the United States, including NCEMC and NRECA. Acquired by Utility Services Associates (C. W. Wright, Inc.) in 2002. Served on safety committee.

2005-August 2019  
President  
PowerServices, Inc.

Providing engineering and management services to the electric industry, including planning and design and utility acquisition. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serving as an expert witness in state and federal regulatory matters and state and federal court. . Served on the PowerSecure International safety committee.

2008-August 2019  
President  
UtilityEngineering, Inc.

Providing engineering and management services to the electric industry, including planning and design and utility acquisition. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serving as an expert witness in state and federal regulatory matters and state and federal court.

2016-2019  
Southern Company  
President of Engineering  
Subsidiaries PowerServices,  
Inc. & UtilityEngineering, Inc.

Providing engineering and management services to the electric utility industry, including planning and design and utility acquisition. Providing forensic engineering, product evaluation, fire investigations, accident investigation, serving as an expert witness in state and federal matters and state and federal courts. Served on the Southern Company safety committee and was part of executive management team.

2004-Present  
President  
Gregory L. Booth, PLLC

Providing engineering and management services to the electric industry, including planning and design. Providing forensic engineering, product evaluation, fire investigations and accident investigation, serving as an expert witness in state and federal regulatory matters and state and federal court.

**WORK AND  
EXPERTISE:**

**ELECTRIC UTILITIES:**  
(more than 300 clients)

- All aspects of utility planning, design and construction, from generation, transmission, substation and distribution to the end user.
- Utility acquisition expert, including providing condition assessment, system electrical and financial valuation, electrical engineering assessment, initial Work Plan and integration plans, acquisition loan funds, testimony, assessment and consulting services for numerous electric utility acquisitions. Utility clients for acquisition projects include Winter Park, FL acquisition of Progress Energy, FL, system in the City limits, A & N Electric Cooperative acquisition of the Delmarva Power & Light Virginia jurisdiction, Shenandoah Valley Electric Cooperative acquisition of Allegheny Energy Virginia jurisdiction, Rappahannock Electric Cooperative acquisition of Allegheny Energy Virginia jurisdiction, and numerous other past and currently active electric utility acquisitions. Regulatory expert testimony in PPL acquisition of Narragansett Electric Company in Rhode Island.
- System studies, including long-range and short-range planning, sectionalizing studies, transmission load flow studies, system stability studies (including effects of imbalance and neutral-to-earth voltage), environmental analyses and impact studies and statements, construction work plan, power requirements studies, and feasibility studies.
- Fossil, hydro, microgrid, wind, and solar generation plan analysis, design, and construction observation.
- Transmission line design and construction observation through 230 kV overhead and underground, including interface with DOT and other utilities.
- Switching station and substation design and construction observation through 230 kV.
- Distribution line design and staking, overhead and underground, including interface with DOT and other utilities.
- Design of submarine cable installations. (Transmission and distribution)
- Supervisory control and data acquisition system design, installation and operation assistance.
- Load management system design, installation and operation assistance.
- Computer program development.
- Load research and alternative energy source evaluation.
- Field inspection, wiring, and testing of facilities.
- Relay and energy control center design.
- Mapping and pole inventories.
- Specialized grounding for abnormal lightning conditions.

- Ground potential rise protection.
- Protective system/relay coordination.
- Grid Modernization Plan development, regulatory testimony, and implementation
- Pole Attachment Agreements, rate design, and testimony
- Virtually every aspect of utility engineering excluding on Nuclear and coal fire plant design.

**UTILITY OPERATIONS:**

- Storm assessment services., including interface with DOT and other utilities
- Regulatory testimony on storm response.
- Storm Response Plan development.
- Operations, including outage management and Call Centers.
- Outage management and operations enhancement services and testimony.
- Vegetation management plans.
- Utility work order inspections and construction certifications.

**GENERATION DESIGN /  
FAILURE ANALYSES:**

- Intermediate and peaking generation (gas and oil fired through 400 MW).
- Peaking generation (diesel and gas through 10,000 kW)
- Wind generation.
- Solar (PV) generation.
- Hydroelectric generation.
- Microgrid, including energy storage.

**TELECOMMUNICATION:  
UTILITIES:**

- Subscriber and trunk carrier facilities design.
- Stand-by generation and DC power supplies
- DC-AC inverters for interrupted processor supplies.
- Plant design and testing.
- Fiber optics and other transmission media.
- Microwave design.
- Pole attachment designs and make-ready design.
- Pole Attachment Agreements and rental rates calculations.
- Regulatory testimony.

**FINANCIAL SERVICES:**

- Long-term growth analyses and venture analyses.
- Lease and cost/benefit analyses.
- Capital planning and management.
- Utility rate design and service regulations.
- Cost-of-Service studies.
- Franchise agreements.
- Corporate accounting assistance.
- Utility Commission testimony (State and Federal)

**FORENSIC ENGINEERING:**

- Compliance with NESC, NEC, OSHA, IEEE, ANSI, ASTM and other codes and industry standards, including DOT standards.
- Equipment and product failure and analysis and electrical accident investigation (high and low voltage equipment).
- Stray voltage, electrical shocking, and electrocution investigations.
- Building code investigations.
- New product evaluation.
- MCC, MDP failure analysis and arc flash analysis
- Electrical fire analysis

**INDUSTRIAL/ELECTRICAL ENGINEERING:**

- Building design (commercial and industrial).
- Building code application and investigation. (NFPA and NEC)
- Electric thermal storage designs for heating, cooling, and hot water.
- Standby generation and peaking generation design.
- Electric service design (residential, commercial, and industrial).

**INSTRUCTIONAL SEMINARS AND TEXT:**

- Seminars taught on arc flash hazards and safety, including National Electrical Safety Code regulations for utilities.
- Courses taught on Distribution System Power Loss Evaluation and Management.
- Courses taught on Distribution System Protection.
- Text prepared on Distribution System Power Loss Management.
- Text prepared on Distribution System Protection.
- Seminars taught on substation design, NESC capacitor application, current limiting fuses, arresters, and many others electrical engineering subjects.
- Courses taught on accident investigations and safety.
- Courses taught on Asset Management.
- Courses taught on OSHA and Construction Safety.

**TESTIMONY AS AN EXPERT:**

- Concerning rate and other regulatory issues before Federal Energy Regulatory Commission and state commissions in Colorado, Connecticut, Delaware, Florida, Georgia, Maine, Maryland, Massachusetts, Minnesota, New Jersey, New Hampshire, North Carolina, Pennsylvania, Rhode Island, South Carolina, and Virginia.
- Concerning property damage or personal injury before courts in Colorado, Delaware, District of Columbia, Florida, Georgia, Kansas, Maryland, Minnesota, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Puerto Rico, South Carolina, Texas, Virginia, West Virginia, Virgin Islands, and Wisconsin.

**FIELD ENGINEERING:**

- Transmission line survey and plan and profile.
- Distribution line staking.
- Property surveying.
- DOT highway relocation design.
- Relay and recloser testing.
- Substation start-up testing.
- Generation acceptance and start-up testing.
- Ground resistivity testing.
- Work order inspections.
- Operation and maintenance surveys.
- Building inspection and service facility inspection.
- Construction Management
  - Generation
  - Transmission
  - Substation
  - Distribution
  - Building Electrical Installations
  - GSA construction projects
  - NASA construction projects
  - University construction projects

**PROFESSIONAL ORGANIZATIONS:**

- a. National Society of Professional Engineers (NSPE)
- b. Professional Engineers in Private Practice (PEPP)
- c. National Council of Examiners for Engineering & Surveying (NCEES)
- d. Professional Engineers of North Carolina (PENC)
- e. National Fire Protection Association (NFPA)
- f. Associate Member of the NRECA
- g. NRECA Cooperative Network Advisory Committee (NRECA-CRN)
- h. The Institute of Electrical and Electronics Engineers (IEEE) Life Member (Distribution sub-committee members on reliability)
- i. American Standards and Testing Materials Association (ASTM)
- j. Occupational Safety and Health Administration (OSHA) Certification
- k. American Public Power Association (APPA)
- l. American National Standards Institute (ANSI)

**STATE OF RHODE ISLAND  
PUBLIC UTILITIES COMMISSION**

**REPORT OF**

**Gregory L. Booth, PE  
President, Gregory L. Booth, PLLC  
On Behalf of Rhode Island Division of Public Utilities and Carriers  
Concerning  
The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed  
FY 2027 Electric Infrastructure, Safety, and Reliability Plan  
Docket No. 25-54-EL**

**February 20, 2026**

Prepared by:  
Gregory L. Booth, PE  
14460 Falls of Neuse Road, Suite 149-110  
Raleigh, North Carolina 27614  
(919) 441-6440  
gboothpe@gmail.com

***PREFACE***

*Gregory L. Booth, PLLC was engaged by the State of Rhode Island, Division of Public Utilities and Carriers (“RIDPUC”) to evaluate the Electric Infrastructure, Safety and Reliability (“ISR Plan” or “Plan”) Plan FY 2027 Proposal submitted by Rhode Island Energy. As part of the review of the plan, numerous data requests were submitted and responses provided by Rhode Island Energy. Additionally, meetings and conferences were held with Rhode Island Energy and their key personnel involved in the development of the Plan. The Legislative Act amending Chapter 39-1 “Revenue Decoupling”, §39-1-27.7.1, provided Rhode Island Energy the right to file an ISR Plan for the prospective fiscal year and receive considerations for the Plan. The statute provides for evaluation by the Division, and for Rhode Island Energy and the Division to attempt to reach an agreement on a proposed plan and submit a mutually agreed upon Plan. The following report describes the process and position reached between the Division and Rhode Island Energy.*

**REPORT OF**  
**Gregory L. Booth, PE**  
**President, Gregory L. Booth, PLLC**  
**On Behalf of Rhode Island Division of Public Utilities and Carriers**  
**Concerning**  
**The Narragansett Electric Company d/b/a Rhode Island Energy's Proposed**  
**FY 2027 Electric Infrastructure, Safety, and Reliability Plan**  
**Docket 25-54-EL**

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## **I. INTRODUCTION**

Gregory L. Booth, PLLC (“Division Consultant”<sup>1</sup>) was engaged by the Rhode Island Division of Public Utilities and Carriers (“Division”) to assist in the evaluation of the initial Rhode Island Energy (“RIE” or “Company”) Electric Infrastructure, Safety, and Reliability Plan FY 2027 Proposal dated October 17, 2025,<sup>2</sup> and the final Electric Infrastructure, Safety, and Reliability Plan FY 2027 Proposal dated December 22, 2025 filed with the Public Utilities Commission (“Commission”) in Docket 25-54-EL (the “ISR Plan” or “Plan”). This is the fourth ISR Plan developed and filed by the Company since PPL’s acquisition of The Narragansett Electric Company, previously owned by National Grid. The evaluation followed the same process of analysis completed for each ISR Plan filed from FY 2012 through FY 2026 with the exception of requiring additional assessment of capital projects being advanced out the ISR Plan, which I refer to as “non-ISR projects” throughout this report. The non-ISR projects are comprised of a significant number of investments historically included in the ISR Plan that RIE is now advancing outside of the ISR Plan. This report explains the Division’s evaluation and process in which RIE and the Division attempted to mutually agree on a final proposed plan. This process, as provided for in Chapter §39-1-27.7.1 of the General Laws entitled “Revenue Decoupling”, is for the Company, prior to the start of each fiscal year, to submit its ISR spending plan and consult with the Division regarding said Plan. In my testimony and this report as an exhibit to my testimony, I discuss areas of consensus and areas of disagreement, including RIE’s advancement of ISR projects outside the proposed ISR Plan. By excluding these projects from the ISR Plan, the Company did not present an integrated view of planned projects for safety and reliability and also

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<sup>1</sup> For the purposes of this report, reference to “Division Consultant”, “I” and “my” are interchangeable.

<sup>2</sup> The Company submitted Sections 1 through 3 of the initial Plan on October 17, 2025, and Sections 4 through 6 on October 31, 2025.

obscured the fact that capital investments would be well above the proposed ISR Plan budget level. The Division and RIE did not reach mutual agreement on a proposed ISR Plan or resolve areas of non-consensus. The Company filed its proposed FY 2027 ISR Plan with the Commission on December 22, 2025. that principally reflected its initially proposed FY 2027 ISR Plan dated October 17, 2025. Variances between the initial and final proposed ISR Plan budget levels were the result of the Company's internal adjustments and not resulting from any areas of consensus with the Division.

The Company's October 17, 2025, FY 2027 ISR Plan followed very closely the format of previous submittals but with revised budget categories to align with the Commission's budgetary framework. The Company now includes all capital projects and programs, whether non-discretionary or discretionary, under a Consolidated Soft Budget Limit. Major Projects are separately tracked and are subject to individual soft budget limits. Vegetation Management and other Operations & Maintenance ("O&M") expenses are also separately reported and subject to a budget limit. The remaining category of spending is AMF. For the FY 2027 ISR Plan, extensive discussions were held to address new Federal Communications Commission ("FCC") rules and the impact on RIE's cost obligations to accommodate Third-Party Attachments within the non-discretionary category. The Division proposed that RIE adopt a significantly more rigorous process to manage attachment requests including methods to appropriately assign costs to communication companies. The Company and Division mutually agreed to move Third-Party Attachments outside of the Consolidated Soft Budget Limit and resolve the cost inclusion in the reconciliation process. This consultation consensus is predicated on a very specific and rigorous make-ready attachment process.

The Division performed its evaluations by reviewing the Company's pre-file planning information, Area Studies, and the proposed ISR Plan. The pre-file planning information was limited to the Company's most recent version of its 10-year Long-Range Plan ("LRP"). The Division has historically found the LRP unacceptable in terms of the level of capital investment proposed in the first five years, particularly considering the Company's excellent reliability and lack of load growth. The LRP has been a continual topic of discussion between the Division and the Company with no consensus being reached. The FY 2027 ISR Plan discussions were complicated by the fact that the Company elected to progress several significant customary ISR Plan projects outside of the ISR Plan. These projects included the Phillipsdale Substation, power transformer spares, mobile substations, volt-var optimization program advancement and others. The Division and Company took a substantially different view of these projects, many of which have been identified in Area Studies as part of a system-wide effort to methodically upgrade its system. During the review process, the Company provided a list of projects being advanced outside the ISR but it did not provide any details or budgetary information on the planned projects. Therefore, the Division was unable to consider the impact of these projects and capital spending in the context of the overall ISR Plan. With RIE moving significant planned capital projects outside the ISR Plan it made reaching a consensus for FY 2027 virtually impossible. Furthermore, the Division observed that RIE is advancing capital projects, from prior ISR Plans, in its 2025 retail rate case filing. The Company's failure to deliver complete and comprehensive plans denied the Division the opportunity to get a complete view of the expected utility investments that are reasonably needed to maintain safe and reliable distribution service over the short and long term, validate project interrelationships and justification, and also get a complete picture of cost and ratepayer affordability. This was a primary basis for the Division's inability to reach mutual

agreement on the proposed FY 2027 ISR Plan. The Division proposed a solution to the significant lack of consensus, however RIE did not respond. There are also outstanding issues that the Division raised concerning past ISR Plan proceedings that were discussed without resolution. The topics include but are not limited to the Company's LRP and accelerated pace of discretionary projects, impacts on affordability, incurring significant project capital commitment and spend prior to final project scope, design and engineering, the purchase and recovery of spare power transformers and mobile substations, and advancing Infrastructure Investment Jobs Act ("IIJA") eligible projects with minimal or no federal reimbursement. These issues were contributing factors in the Division's lack of concurrence with the Company's ISR Plan as proposed, and they are relevant to the overall assessment and ongoing recommendations. I address these outstanding issues in more detail in my report as topics of non-concurrence.

The Division's 60-day evaluation of the proposed Plan included a significant number of data requests, submitted on October 27, 2025. The Company provided rolling responses, and a series of conferences were established to discuss select ISR Plan spending rationale and major topics such as Third-Party Attachment procedures, project risk assessments and prioritization, Area Study project pace and investment levels, non-ISR Plan spend transparency, and ratepayer affordability. There were no adjustments offered through the course of discussions despite the Division's concerns and recommendation that the Company re-prioritize and defer discretionary projects, particularly major substation work, to achieve a single ISR Plan that included non-ISR projects within the Company's proposed ISR Plan budget level. The Company did not respond and proceeded to file its final Proposed FY 2027 ISR Plan on December 22, 2025. The evaluation and analysis included the actions and procedures detailed in Appendix 1. The data requests and responses referred to above, excluding those that are considered confidential or critical energy

infrastructure information, have been submitted to the Commission by RIE in the Company's filing as Book 3 of 3. Area Studies with finalized reports are available on the Company's portal.

The Company's initial proposed FY 2027 capital investment plan, excluding AMF, was \$136.4 million or four percent (4%) higher than the FY 2026 ISR Plan budget of \$130.9 million. The Company proposed incremental increases in various spending categories while also progressing a significant number of Area Study substation projects. RIE continues Advanced Metering Functionality ("AMF") deployment under Docket 22-49-EL which added \$15.3 million to the initial proposed FY 2027 ISR Plan budget for a total proposed capital investment plan of \$151.6 million. Overall spending was strategically managed to a budget reflecting a more moderate investment plan than proposed by the Company in FY 2025 or FY 2026, yet it did not reflect non-ISR projects. In the Division's estimate, non-ISR projects would add nearly \$31 million of spend in FY 2027 for a total capital investment plan exceeding \$167 million and \$182 million including AMF. The Company filed its final proposed ISR Plan on December 22, 2025 totaling \$135.8 million. AMF spend is projected at \$17.9 million for a grand total of \$153.7 million. This excludes the estimated \$31 million of FY 2027 capital spending for non-ISR Plan projects which are briefly referenced in the Company's testimony<sup>3</sup> but not presented otherwise. This level is in comparison to historical annual capital spending just above \$100 million while achieving reliability performance that met or was superior to regulatory thresholds. Following is a comparison of the Company's October 17, 2025 initial proposal and its December 22, 2025 proposed budget by Spending Rational and Category, including proposed capital for the AMF

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<sup>3</sup> FY 2027 ISR Plan, Book 1, Bates pp. 15-17: Witness LaFond addresses the Company's intention to progress certain projects outside of the ISR Plan.

program which was authorized under Docket 22-49-EL. For reference, the proposed ISR Plan is also summarized by Budget Framework approved by the Commission in the FY 2025 ISR Plan.

	(a)	(b)	(c)	(d)	(e)
	<b>FY 2027 ISR Plan Proposed Capital Budget by Spending Rationale (\$000)</b>	<b>RIE Initial Proposed 10-17-25</b>	<b>RIE Adjustments</b>	<b>RIE Proposed 12-22-25</b>	<b>% of Total Budget</b>
1	Customer Request / Public Requirement	\$ 39,835	\$ (5,100)	\$ 34,735	26%
2	Third Party Attachments (Cust /Public Requirement)	\$ -	\$ 4,300	\$ 4,300	3%
3	Damage/Failure	\$ 21,164	\$ (984)	\$ 20,180	15%
4	<b>Subtotal Non-Discretionary</b>	<b>\$ 60,999</b>	<b>\$ (1,784)</b>	<b>\$ 59,215</b>	<b>44%</b>
5	Non-Infrastructure	\$ 410	\$ -	\$ 410	0.3%
6	Asset Condition	\$ 31,606	\$ (1,856)	\$ 29,750	22%
7	System Capacity & Performance	\$ 23,913	\$ 448	\$ 24,361	18%
8	Separately Tracked Major Projects	\$ 19,428	\$ 2,656	\$ 22,084	16%
9	<b>Subtotal Discretionary</b>	<b>\$ 75,357</b>	<b>\$ 1,248</b>	<b>\$ 76,605</b>	<b>56%</b>
10	<b>Proposed Capital Spending Budget - ISR*</b>	<b>\$ 136,356</b>	<b>\$ (536)</b>	<b>\$ 135,820</b>	
11	Advanced Metering Functionality (AMF)	\$ 15,281	\$ 2,598	\$ 17,879	
12	<b>FY 2027 Capital Spending Including AMF*</b>	<b>\$ 151,637</b>	<b>\$ 2,062</b>	<b>\$ 153,699</b>	
13	Consolidated Soft Budget Limit	\$ 116,929	\$ (7,492)	\$ 109,436	
14	Separately Tracked Major Projects	\$ 19,428	\$ 2,656	\$ 22,084	
15	Third Party Attachments (Cust /Public Requirement)	\$ -	\$ 4,300	\$ 4,300	
16	<b>Proposed Capital Spending Budget - ISR*</b>	<b>\$ 136,356</b>	<b>\$ (536)</b>	<b>\$ 135,820</b>	

*\*Excludes an estimated \$31 million in additional non-ISR capital projects*

The remaining sections of this report address the Division’s area of consensus which was limited to non-discretionary capital projects and the non-consensus areas comprised of all discretionary capital spending categories and associated O&M.<sup>4</sup> I discuss why agreement was not reached and explain the Division’s position by examining how the Company’s proposed FY 2027 ISR Plan and non-ISR project investment strategy has intensified several unresolved issues that have been brought forth in prior ISR Plan reviews. I separately address the Vegetation

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<sup>4</sup> In the December 22, 2025 FY 2027 ISR Plan filing, RIE included a separate category in its Discretionary budget as authorized by the Commission under Docket 22-49-EL. The Company proposed a \$17.9 million AMF capital budget. The Division did not perform a detailed assessment of AMF spend in the FY 2027 ISR Plan review since the Division participated in, and supported, AMF implementation and costs in the AMF docket. The analysis in this report excludes the AMF capital budget.

Management Program and the Division's agreement with the Company's proposed funding levels. I conclude with specific recommendations and offer conditions of ISR Plan approval for Commission consideration.

**II. CAPITAL BUDGET CONSENSUS**

The major area of Division consensus is the Company’s proposed non-discretionary budget comprised of Customer Request/Public Requirements and Damage/Failure categories. The spending in these categories is by nature customer driven or required due to imminent needs or emergencies. There is low probability that projects would be related to remaining discretionary spend, particularly non-ISR projects. The Division determined that non-discretionary spend could be reasonably isolated and appropriately reviewed unlike the proposed discretionary spend driven by both the ISR and non-ISR projects which were not comprehensively disclosed. For the non-discretionary spending rationales, the proposed FY 2027 ISR Plan included \$59.2 million. This compares to a FY 2026 ISR Plan budget and forecast of \$51.7 million and \$60.3 million. The Company’s FY 2026 performance and proposed FY 2027 budgets for non-discretionary spend are as follows:

	(a)	(b)	(c)	(d)	(e)
	<b>ISR Plan Capital Budget Non-Discretionary (\$000)</b>	<b>FY 2026 Q2 Budget</b>	<b>Variance over/(under)</b>	<b>FY 2026 Q2 Forecast</b>	<b>FY 2027 Proposed</b>
1	Customer Request/Public Requirement	\$31,503	\$2,772	\$34,275	\$39,035
2	Damage Failure	\$20,217	\$5,821	\$26,038	\$20,180
3	<b>Total Non-Discretionary</b>	<b>\$51,720</b>	<b>\$8,593</b>	<b>\$60,313</b>	<b>\$59,215</b>

**A. Customer Request/Public Requirements Category**

For FY 2027 the Company proposed \$39 million for Customer Request/Public Requirements compared to a FY 2026 ISR Plan budget of \$31.5 million and forecast of \$34.3 million as follows:

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	(a)	(b)	(c)	(d)	(e)
	<b>ISR Plan Capital Budget Customer Request/Public Requirement (\$000)</b>	<b>FY 2026 Q2 Budget</b>	<b>Variance over/(under)</b>	<b>FY 2026 Q2 Forecast</b>	<b>FY 2027 Proposed</b>
1	Distributed Generation	\$1,000	(\$0)	\$1,000	\$1,000
2	Land and Land Rights	\$450	(\$217)	\$233	\$450
3	Meters and Meter Work	\$430	\$212	\$642	\$1,260
4	New Business - Commercial	\$11,854	\$3,909	\$15,763	\$14,286
5	New Business - Residential	\$7,500	\$0	\$7,500	\$7,715
6	Other	\$0	\$0	\$0	\$0
7	Outdoor Lighting	\$300	\$265	\$565	\$300
8	Public Requirements	\$1,669	(\$2,936)	(\$1,267)	\$1,725
9	Third Party Attachments	\$300	\$1,764	\$2,064	\$4,300
10	Transformers and Related Equipment	\$8,000	(\$224)	\$7,776	\$8,000
11	<b>Total Customer Request/Public Requirement</b>	<b>\$31,503</b>	<b>\$2,772</b>	<b>\$34,275</b>	<b>\$39,035</b>

The Company establishes budgets based on historical spending, known projects, and forecasted economic conditions including inflation. For FY 2026, the Company projects overspend of \$5.8 million. A contributing factor continues to be higher New Business Commercial work forecasted at \$3.9 million above budget. The Company is reimbursed for a portion of spending, so amounts are net of contributions in aid of construction. There may be timing differences that affect variances across fiscal years as well. The Company increased the FY 2027 budget for New Commercial to levels closer to the FY 2026 forecast. The Division accepted the proposed budget but notes that actual spend may be adjusted at ISR Plan reconciliation where the Company incorporates system improvements in new business work. In this case, the system improvements represent investments at the discretion of the Company and not required by the customer. The Company's FY 2026 projected spend for Transformers and Related Equipment is close to the forecasted budget of \$8 million, which is the same as the FY 2027 budget. This differs from the FY 2025 Plan, which was \$7.9 million above budget which prompted the Commission to direct the Company to conduct an audit of transformer and related equipment expenditures to evaluate

procurement processes, inventory practices, and installation.<sup>5</sup> The Company's audit was filed on February 13, 2026.<sup>6</sup> Although the Division accepted the FY 2027 budget of \$8 million, this category of spend may incur separate adjustments based on the Division's complete review of the audit findings.

One area that prompted extensive discussions and potential adjustment was Third-Party Attachments. This category covers the Company's costs to accommodate communication attachments on its solely and jointly owned poles. In Rhode Island, communication attachments are guided by the FCC along with a combination of utility and state requirements. The FCC implemented rule changes in 2023 with subsequent clarifications aimed at limiting situations when a communications company can be charged for pole modifications to accommodate a new attachment, or "make-ready" work. For instance, a limited interpretation of the FCC rulings and clarifications suggests that a new attacher cannot be charged for a pole replacement where there are existing loading or clearance violations, making the pole owner responsible for the cost. This is the exact interpretation that RIE has adopted which would result in over \$4 million of make ready costs shifted from communication companies to electric ratepayers each year and a dramatic increase in non-discretionary spend now and into the future. According to the Company the cost estimate is driven by one communication company planning broadband expansion in Newport. RIE indicates that the costs of complying with the FCC rulings and cost sharing are outside the control of the Company.<sup>7</sup>

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<sup>5</sup> Docket 23-48-EL, FY 2025 ISR Plan Reconciliation Report and Order No. 25551, p. 11.

<sup>6</sup> Docket 23-48-EL, FY 2025 ISR Plan Reconciliation, Corporate Audit Services Report RIE Distribution Transformers.

<sup>7</sup> FY 2027 ISR Plan, Section 2, Bates p. 104.

The Division disagrees with the Company and its plans to absorb all the cost of the make-ready work, in many scenarios the costs would historically be assigned to the attachers. The Company's position is based on its incomplete interpretation of FCC rulings while not considering the non-delegable duty of the existing attaching entities to have designed and installed all its facilities in compliance with the NESC and under the responsible charge of its professional engineer. The Division and RIE had multiple discussions on this issue, and I prepared and provided the Company with a position paper outlining related FCC rulings and clarifications and also Rhode Island statutes that supported an alternate interpretation than derived by the Company. This included a recommended pole attachment process that the Company could apply and equitably assign costs between attachers and the Company, mitigating unjustified cost burdens on Rhode Island ratepayers. The position paper is provided in Appendix 2.

After extensive discussions, the Company agreed to review their internal processes and incorporate modifications. While the Company works out the process details, the Division accepted RIE's proposal to remove \$4.3 million for Third-Party Attachments from the Consolidated Soft Budget Limit due to the unpredictability of future work and customer reimbursements. The Division's agreement is conditioned on the Company putting forth an acceptable process to manage pole attachments that incorporates equitable cost sharing arrangements. The Division also expects that RIE will maintain detailed records in a manner that can be examined to determine whether costs were appropriately assigned. This will be critical at each ISR Plan reconciliation including FY 2026 where the Company already projects \$1.7 million in overspend due to its FCC rule interpretation. My final observation is that third party pole attachment cost is within the control of the Company despite RIE's assertion because the Company determines cost assignment. The Company does not control attachment applications but if the

Company fails to incorporate a robust process, it will incur more costs than justified which are passed onto ratepayers. The process is controllable and if not properly managed, ratepayers will be bearing a significant cost to enable broadband expansion in the state of Rhode Island which already ranks fifth highest among states in terms of internet coverage, speed and availability.<sup>8</sup>

The Division accepted the remaining categories resulting in a total of \$39 million for Customer Requests/Public Requirements. Of this, the Division proposes that \$34.7 million be subject to the Consolidated Soft Budget Limit and that \$4.3 million for Third-Party Attachments be separately tracked. The Company proposes to seek recovery of Third-Party Attachment costs during the FY 2027 reconciliation if and when projects materialize as anticipated. The Division is in agreement with the condition that the Company meet the Division's Recommendation No. 1 provided in Section VI.

**B. Damage/Failure Category**

The proposed FY 2027 ISR Plan included \$20.2 million in the Damage/Failure category for non-discretionary costs to replace equipment that unexpectedly fails or becomes damaged. Of this, \$12.3 million is designated for smaller scale and unidentified Blanket work, \$2.6 million to address specific equipment failures, and \$5.2 million for storms. This compares to a FY 2026 ISR Plan budget and forecast of \$20.2 million and \$26 million, respectively.

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<sup>8</sup> <https://broadbandnow.com/Rhode-Island>.

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	(a)	(b)	(c)	(d)	(e)
	<b>ISR Plan Capital Budget Damage/Failure (\$000)</b>	<b>FY 2026 Q2 Budget</b>	<b>Variance over/(under)</b>	<b>FY 2026 Q2 Forecast</b>	<b>FY 2027 Proposed</b>
1	Damage /Failure Blanket Projects	\$12,020	\$2,720	\$14,740	\$12,340
2	Failed Assets - Specific Projects	\$3,697	\$3,101	\$6,798	\$2,640
3	Storms	\$4,500	\$0	\$4,500	\$5,200
4	<b>Total Damage Failure</b>	<b>\$20,217</b>	<b>\$5,821</b>	<b>\$26,038</b>	<b>\$20,180</b>

The Company considers Damage/Failure work unplanned but necessary, and budget variances are highly correlated to large equipment damage and storm activity. The Company continues to incur expenses over budget in this category with an overall FY 2026 variance projected at \$5.8 million. The Failed Asset budget, which includes continued spending for previously failed major assets, is forecasted at \$3.1 million over budget in FY 2026. Contributing factors include emerging projects that were unidentified in the original budget including vault work, a failed RTU, and the Pontiac Ave. substation transformer failure. The budget for Failed Assets relies on historical trends with further adjustments for anticipated costs. For FY 2027, the budget accounts for the failed transformer replacement costs for Hopkins Hill and Pontiac substations. As of the second quarter, storm work was forecasted to meet the FY 2026 budget, but that position could change depending on weather events through the remainder of the fiscal year. The storm budget of \$5.2 million for FY 2027 was escalated from the \$4.5 million budget in FY 2026.

Elements of Damage Failure which are unrelated to major storms or clear equipment failures are also budgeted based on historical work and the Company anticipates exceeding its \$12 million budget in FY 2026. These projects and their associated costs have been steadily increasing. For FY 2027, the Division supported the Company's proposed budget of \$12.3 million for smaller scale work in Damage/Failure.

This brings the total non-discretionary categories of Customer Request/Public Requirements and Damage/Failure to \$54.9 million, excluding \$4.3 million for Third-Party Attachments. The Division concurred with each of the Company's proposed categories of spend and budget and agreed to separately track and reconcile spending for Third-Party Attachments. The Division did not concur with any additional categories of capital spending or budgets in the Company's proposed FY 2027 ISR Plan. Therefore, the recommended Consolidated Soft Budget Limit for FY 2027 is \$54.9 million with an additional \$4.3 million for Third-Party Attachments to be separately tracked and reconciled.

**III. CAPITAL BUDGET NON-CONSENSUS**

The area of non-consensus related to the remaining proposed FY 2027 ISR Plan Capital Budget which included customary discretionary spending for ongoing programs and projects in the Non-Infrastructure, Asset Condition, System Capacity & Performance, and Separately Tracked Major Projects categories totaling \$76.6 million. This compares to a FY 2026 ISR Plan budget of \$79.2 million and forecasted spend of \$76.7 million. For FY 2027, the Company also elected to progress several significant customary ISR Plan projects outside of the ISR Plan. Although the project details were not presented or discussed by the Company, the Division estimates that if executed, the Company’s non-ISR projects would add \$31 million to the proposed FY 2027 ISR Plan levels based on analysis of costs associated with these projects as they were incorporated in prior ISR Plan filings and LRP documents. For example, the Phillipsdale substation and spare power transformers had been proposed but removed from the FY 2026 ISR Plan filing. The Company’s FY 2026 performance, proposed FY 2027 ISR Plan budgets and estimate for non-ISR projects for discretionary spend are as follows:

	(a)	(b)	(c)	(d)	(e)
	<b>ISR Plan Capital Budget Discretionary (\$000)</b>	<b>FY 2026 Q2 Budget</b>	<b>Variance over/(under)</b>	<b>FY 2026 Q2 Forecast</b>	<b>FY 2027 Proposed</b>
1	Asset Condition	\$29,696	\$4,500	\$34,196	\$29,750
2	Non-Infrastructure	\$400	\$0	\$400	\$410
3	System Capacity & Performance	\$23,779	(\$5,437)	\$18,342	\$24,361
4	Separately Tracked Major Projects	\$25,320	(\$1,568)	\$23,752	\$22,084
5	<b>Total Discretionary</b>	<b>\$79,195</b>	<b>(\$2,505)</b>	<b>\$76,690</b>	<b>\$76,605</b>
6	<b>Non-ISR Projects</b>				<b>\$30,855</b>
7	<b>Grand Total Discretionary</b>				<b>\$107,460</b>

The Division and Company took a substantially different view of the non-ISR projects, many of which have been identified in Area Studies as part of a system-wide effort to methodically upgrade its system. The Company’s investment strategy would effectively advance two related

portfolios of projects but only allow the Division to review one of those portfolios in the ISR Plan. The Division requested project details for non-ISR projects including projected level of spend, but RIE was unwilling to provide any information other than a project list absent any specifics such as annual capital spending, timeline of execution, quantity of equipment purchases and scope and engineering details. That means the Division's estimate of annual non-ISR capital spending impact could be significantly understated. The Division strongly disagreed with the Company's approach and in a last attempt to reach concurrence on ISR Plan spending, the Division recommended that the Company re-prioritize and defer discretionary projects, particularly major substation work, to achieve a single ISR Plan that included non-ISR projects within the Company's proposed budget level. This proposal included a list of projects which the Division found could be deferred without taking on unreasonable risk or impacting the excellent system reliability. RIE provided no response to the Division's proposal which was intended to bring us closer to consensus and an agreed to ISR Plan. The Division's review concluded in a position of non-consensus for all discretionary capital spend. Since a component of discretionary spend is the Inspection & Maintenance ("I&M") Program, the Division also withholds concurrence of the Company's proposed \$1.4 million in O&M expenses related to the I&M Program.

In prior years, I presented an itemized detail of the Company's proposed discretionary budget to explain areas of adjustment, concurrence and non-concurrence. I discussed how programs and particularly multi-year substation projects were evaluated to determine alignment with Area Study outcomes, project prioritization, and the justification to advance the project within the current ISR Plan. My reviews consistently highlighted deficiencies with the Company's planning process and lack of justification to advance projects at a rapid pace creating significant upward pressure on rates and affordability. Many significant and ongoing issues identified in prior

ISR Plan reviews have not been resolved but are now further exacerbated by the Company's FY 2027 ISR Plan and associated non-ISR projects. For FY 2027, instead of a project-by-project detailed review, I will revisit the larger outstanding issues as they relate to the proposed ISR Plan which will also serve to explain and support the Division's non-consensus position.

**A. Long-Range Plan, ISR Plan Development and Non-ISR Projects**

The Company presented its 10-year LRP which includes investments that are proposed or will be included in the ISR Plan. The Company explains that the LRP "is intended to give stakeholders a complete view of the Company's proposed strategy to safely, reliably, and cost-effectively meet expected load growth, methodically replace aged infrastructure, maintain system resiliency, manage increasing distributed energy resource deployment, and implement statutorily or regulatory required programs."<sup>9</sup> I have reviewed and commented on prior versions of the LRP expressing concern with the rapid advancement of projects and alarming levels of spend when compared to historical investments. For example, if RIE had implemented the LRP presented in FY 2026, the Company would have doubled its capital investments over the next five years when compared to investment levels under National Grid. My previous assessment was that the Company fell short of the Division's expectations by proposing a capital investment plan that was unacceptable in terms of the pace and spending level over the next five years. I have consistently recommended that RIE modulate spending by stretching project implementation which is crucial during years of additional capital needs such as AMF implementation. System Capacity projects could be deferred considering the lack of load growth and other discretionary spend for reliability could be tempered given RIE's excellent system reliability performance. The Division's baseline

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<sup>9</sup> FY 2027 ISR Plan, Section 2, Bates p. 75.

expectation was and continues to be that the Company fully justify the pace and timing of investments while balancing ratepayer affordability. The Division finds the LRP and RIE strategies to be unaffordable and not focused on projects needed to provide for a safe and reliable electric distribution system.

In the FY 2026 ISR Plan proceedings the Commission was critical of the Company's investment philosophies of accelerated spend which evolved from "maintaining safety and reliability"<sup>10</sup> to achieving reliability standards that exceed the regulatory standards. The Commission's decision went on to state that "in the absence of evidence of deteriorating performance, the Commission cannot support increased spending at the pace proposed by the Company when there are so many other pressures on utility rates and, particularly in the face of Division frustration with the even higher proposals made to them each year before the filing is even made to the Commission."<sup>10</sup> The Commission was clearly concerned with unjustified spend putting upward pressure on rates. Ultimately, the Commission approved a lower FY 2026 ISR Plan budget than proposed by the Company which excluded budgets for specific ISR Plan projects.<sup>11</sup>

For FY 2027, RIE presented its LRP explaining that development started with the same soft budget limit approved in FY 2026 which was escalated by 3% and adjusted for major items. The Company also "deferred and sequenced a number of projects to attempt to meet a soft budget limit in line with the FY 2026 order."<sup>12</sup> The total FY 2027 LRP budget, which informs the ISR Plan, was presented at \$155 million which was well below the \$227 million that RIE previously proposed in its FY 2026 ISR Plan. On the surface it appeared that the Commission and Division's

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<sup>10</sup> FY 2026 ISR Plan, Report and Order No. 25470, p. 13.

<sup>11</sup> FY 2026 ISR Plan budget allocation removed for Apponaug, Phillipsdale, Centredale, Hospital Substation, Kingston Substations, DARP, Fiber Study, Damage/Failure Reserves and new VVO/CVR projects. Auburn, Merton and Chase Hill Substation found premature to include in ISR for cost recovery. (Orders No. 3, 4, 5 and 6)

<sup>12</sup> FY 2027 ISR Plan, Attachment 5-Long Range Plan, Section 2.1.

priority of balancing capital spend and ratepayer affordability was resonating with the Company. However, the Company's LRP was only a partial view of planned capital investments for safety and reliability since it planned to progress multiple projects outside the ISR Plan which were not initially presented. Upon Division request, the Company provided a list of its non-ISR projects<sup>13</sup> all of which had previously been included or proposed in an ISR Plan including Phillipsdale, Auburn and VVO/CVR that were not funded in FY 2026. The Company provided the year of projected spend for each project but excluded associated budgets. I derived an independent estimate using the Company's forecast for the projects when they were included in previous LRPs and ISR Plan attachments. My analysis below projects that RIE will spend over \$150 million on non-ISR projects in the next 5 years,<sup>14</sup> making the total 5-year LRP spend closer to \$900 million as opposed to the \$750 million that RIE represented.

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<sup>13</sup> DIV 1-6 response (see Attachment DIV 1-6).

<sup>14</sup> In DIV 4-20 response, RIE forecasts non-ISR project plant in service totaling \$157 million from FY 2027 through FY 2030. Although specific projects are not provided, the total validates the estimated \$150 million in this report.

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Line Number	(a)	(b)	(c)	(d)	(e)	(f)	(g)
	<b>RIE FY 2027 Proposed 5 Year Investment Plan - Capital Spending ISR and Non-ISR Project Estimates (\$000)</b>						<b>5-yr Total</b>
1	<b>ISR Spending</b>						
2	Total ISR Capital Spending including AMF	153,699	152,400	155,169	147,788	150,379	<b>759,435</b>
3	Total ISR Capital Spending excluding AMF	135,820	152,400	155,169	147,788	150,379	<b>741,556</b>
4	<b>Non-ISR Estimates*</b>						
5	Division St Substation	750	3,000	1,250	-	-	<b>5,000</b>
6	Phillipsdale Substation D Line	2,000	61	-	-	-	<b>2,061</b>
7	Auburn Conversion D Line	5,192	11,632	9,042	-	-	<b>25,866</b>
8	Spare Transformers	10,550	18,184	10,850	10,250	4,200	<b>54,034</b>
9	Phillipsdale Substation D Sub	5,500	5,500	4,500	891	-	<b>16,391</b>
10	Auburn Substation D Sub	1,057	2,112	6,336	832	-	<b>10,337</b>
11	Staples #112 Reliability 112W43	1,000	-	-	-	-	<b>1,000</b>
12	Staples #112 Reliability 112W44	1,807	-	-	-	-	<b>1,807</b>
13	Mobile Substations	-	7,670	-	-	-	<b>7,670</b>
14	VVO/CVR	3,000	6,700	6,700	9,600	Non-ISR	<b>26,000</b>
15	Total Non-ISR Capital Spending	30,855	54,859	38,678	21,573	4,200	<b>150,165</b>
16	<b>Grand Total ISR + Non-ISR Projects inc. AMF</b>	<b>184,554</b>	<b>207,259</b>	<b>193,848</b>	<b>169,361</b>	<b>154,579</b>	<b>909,601</b>
17	<b>Grand Total ISR + Non-ISR Projects excl. AMF</b>	<b>166,675</b>	<b>207,259</b>	<b>193,848</b>	<b>169,361</b>	<b>154,579</b>	<b>891,722</b>

\* RIE did not provide forecasts for Non-ISR spending.

Estimates based on FY 2026 ISR Plan, LRP and various data points.

The Division asked the Company how stakeholders would get complete view of the expected utility investments that are reasonably needed to maintain safe and reliable distribution service over the short and long term if projects were executed outside the ISR Plan. The Company generally responded that a list of the projects without associated budgets would provide the Commission and the Division with a holistic view.<sup>15</sup> The Company's response went on to discuss that RIE would make any investments it determines are prudent and reasonably needed but cannot be funded under approved ISR budget caps. The Company's position is that the Revenue Decoupling law provides the Division and Commission with granular visibility and real-time review of the Company's proposed investments but projects outside the ISR should not get the same analysis. The Company also asserted that its decision to advance projects outside the ISR is

<sup>15</sup> DIV 1-5 response.

unrelated to whether projects in the ISR meet the standard for inclusion and should be approved. RIE intends to present non-ISR projects to the Division and Commission for review when the Company seeks cost recovery in a future rate case filing, but those projects will not be subject to the same review process and standard as ISR projects.

The Company's decision and position on progressing a portfolio of traditional ISR Plan capital projects outside of the ISR Plan process raises significant concerns. As a first and primary point, I strongly disagree that stakeholders will have the "holistic view of the Company's electric distribution system planning for safety and reliability" that RIE claims is available. That is impossible when the Company is obscuring significant investments and denying a detailed review of projects that are related to the ISR Plan. I reject the Company's assertion that projects advancing outside the ISR Plan are unrelated to decisions regarding projects within the ISR Plan. There are direct and obvious links, particularly for multi-year Area Study projects. A project such as Phillipsdale which is now proposed outside the ISR Plan is part of a comprehensive solution identified in the East Bay Area Study. If the interrelated Area Study solutions are evaluated and advanced in the ISR Plan, the Division must also have the opportunity to perform the same detailed assessment to justify progressing Phillipsdale. Considering that Phillipsdale substation was but one of the projects removed by the Commission from the FY 2026 ISR Plan filed budget, it is apparent that RIE is now attempting to remove a significant number of expensive Area Study and infrastructure, safety and reliability projects from review by the Division and presumably from the Commission as well.

Second, the Company's action means that the Division is evaluating ISR Plan capital projects for a system which is not the actual system which will exist. Thus, project solutions may not be appropriate because other solutions are advanced outside the ISR Plan but are not reflected

in the ISR Plan holistic analysis. The Division is therefore evaluating a partial investment plan in the ISR Plan process and full concurrence is impossible if the Company is simultaneously advancing a separate but related portfolio of projects which are part of infrastructure supporting safety and reliability.

Third, the Company's investment structure circumvents the ISR Plan review process and requisite justification. RIE will be making significant discretionary capital investments, estimated at over \$150 million, that normally fall within the ISR Plan but asserts that those projects "are not subject to the same review process and standard."<sup>16</sup> The Company's actions mean that the future system being built in 2027 for safety and reliability is absolutely being overbuilt for conditions which will not arise for years or decades in the future. It also allows the Company to increase the pace and expand the scope of projects beyond what has been communicated to the Division without additional scrutiny. I'm concerned that the non-ISR actual spend will be higher than estimated due to projects being in preliminary phases or the fact that the Company can advance additional undisclosed projects.

Fourth, advancing a separate portfolio of non-ISR projects generates massive costs that the Company will attempt to pass to consumers in a rate case. This upward pressure on utility rates defeats the concept of ratepayer affordability. The Commission has been clear that the Company can make investments and seek recovery in a future rate case, but regulatory lag does not address ratepayer affordability. The fact that RIE has proposed lower budgets in the ISR Plan but will add incremental and unquantified investments must be viewed in whole. The Company declined to produce the expected non-ISR project spend which prevents scrutiny of ratepayer affordability. This structure completely dismantles the ISR Plan process and statute.

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<sup>16</sup> DIV 1-5 response.

Lastly, the Company moves analysis of many planned Area Study projects outside the ISR Plan and forces them to be evaluated as part of a much larger and more complicated retail rate case process. This overly complicates a retail rate case and dilutes the time for real meaningful analysis of those projects not advanced through the ISR Plan. Furthermore, it begins setting a precedent which would theoretically allow RIE to reduce the ISR Plan to nearly zero and move all capital projects through the retail rate process, completely circumventing the ISR Plan statutory requirements.

The Company is offering to limit the ISR Plan budget but is simultaneously advancing significant spend outside the ISR that will ultimately impact ratepayer affordability concerns. The Company is also circumventing the need to produce adequate justification and achieve stakeholder agreement prior to advancing non-ISR projects which is a gateway to higher capital spending levels. The Division remains highly concerned with the Company's rapid advancement of projects and alarming levels of spend when compared to historical investment. These issues and particularly the absence of a complete and acceptable LRP that includes all planned capital investments led to the Division's non-concurrence of the FY 2027 ISR Plan.

## **B. Infrastructure Investment and Jobs Act ("IIJA") Funding**

In the FY 2026 ISR Plan proceeding, the Company discussed its acceptance of an award under Department of Energy's ("DOE") IIJA Grid Resilience and Innovative Partnerships Funding Opportunity, Smart Grid Topic. Under the agreement, RIE was obligated to invest \$283 million over 5 years to receive \$50 million, or an eighteen percent (18%) Government share. Along with select IT initiatives, the Company proposed Operational Technology ("OT") investment categories including reclosers, relays, smart capacitors and regulators, and fiberoptic which are largely RIE's grid modernization plan. There was some uncertainty as to the exact amount that RIE would have

to invest along with other questions on investment periods, funding guarantees over the investment horizon, and timing of IJJA funding relative to ISR Plan cost recovery. The Division withheld its support for the investments given the significant level of commitment that the Company would have to make to receive a small reimbursement.

The Company now reports that it is in the process of submitting a reimbursement request for investments in the first budget period which ended September 2025.<sup>17</sup> The Company explained that it updated its LRP to defer or moderate the pace of some IJJA investments to reflect regulatory outcomes in prior ISR Plan proceedings and will modify the original award to account for those changes.<sup>18</sup> In both the ISR Plan and LRP, eligible investments are incorporated in projects or programs but not specifically delineated as IJJA investments. The Company also makes IJJA investments as part of non-ISR projects that would normally progress in an ISR Plan.<sup>19</sup> For the period of October 2024 through March 2027, the Company estimates that it will make IJJA eligible investments of nearly \$19 million in the ISR Plan and over \$10 million outside of the ISR Plan, possibly receiving 18% reimbursement. The Company's true commitments to the DOE for funding and trajectory of future spend remain unclear. Since the investments are mostly embedded in projects, there is no practical way to determine if they are resolving a system need in the necessary most cost-effective manner, or simply desired by the Company. I would expect the Company to take a tempered approach for IJJA investments within the ISR Plan since the Consolidated Soft Budget Limit places some guardrails on discretionary spending. But funding an IJJA project takes budget headroom that could be earmarked for a more emergent priority. Alternately, if IJJA investments are incorporated in non-ISR projects, there is no transparency and certainly no

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<sup>17</sup> DIV 4-12 response.

<sup>18</sup> DIV 4-13 response.

<sup>19</sup> DIV 4-16 response contains a table of projects that include IJJA investments.

accountability for ratepayer affordability. The Company stated that it would not modify its proposed capital investment plans if IJJA reimbursement was not available.<sup>20</sup> The Company is unwavering in its commitment to make grid modernization investments regardless of IJJA funding level, certain project benefits or cost impact to ratepayers.

This brings to light the dilemma facing the Division in reaching agreement on discretionary spending in an ISR Plan. If the Division disagrees with, or the Commission does not approve the pace or level of spending for an IJJA eligible investment within the ISR Plan, the Company can shift the project outside the ISR Plan at its discretion.<sup>21</sup> This is demonstrated by the estimated \$26 million that RIE plans for VVO/CVR (smart capacitors and regulators) as non-ISR projects which I address in more detail in Section III.E. Once outside the ISR plan, there is no transparency in need or timing and certainly no cost control. The Division had hoped that the Company would have clearly identified and justified IJJA investments, strategically incorporating those investments within a holistic LRP that informed a modulated ISR Plan. Despite RIE contending that ISR Plan and IJJA investments are moderated, the Division's expectations have not and will not be met particularly if spending is merely shifted to non-ISR projects. It is impractical for the Division to endorse ISR Plan discretionary projects and spending levels that include incremental spend for grid modernization projects that have not been justified which are then further expanded by the Company outside of the ISR Plan with no justification or transparency.

A final outstanding issue with IJJA funding is how and when the Company will recover the cost of projects that receive federal reimbursement. The Company suggests that it will place ISR Plan eligible investments in service and depending on the timing of receipt of IJJA funding,

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<sup>20</sup> DIV 4-15 response.

<sup>21</sup> DIV 4-7 response.

the reimbursement amount will be reflected in an upcoming ISR Plan reconciliation filing or a future ISR filing would be adjusted.<sup>22</sup> This process has not been tested since the Company is just now seeking reimbursement for the first budget period. The Division will address the Company's request to recover costs for both IT and OT investments that have been placed in service but also receive federal reimbursement when brought forth in ISR Plan reconciliation, an ISR Plan filing, or a rate case, as applicable.

### **C. Major Project Approvals and Execution Lifecycle**

Within my historical ISR Plan reviews, I have discussed multiple concerns with the Company's progression of discretionary multi-year projects from inception to completion. The issues start when the Company first presents a project for inclusion in an ISR Plan budget. The Division typically concurs with initial funding to advance engineering with the expectation that the Company will produce a more accurate picture of scope, project design, proposed implementation time and budget to be used in evaluating the project within future ISR Plans. The Division's agreement on engineering and subsequent Commission approval does not constitute agreement of the project and budget in future years. The Company and Division are not aligned with this concept as the Company interprets Commission approval to commence a project (engineering and permitting) to mean it is approved through completion.<sup>23</sup> RIE acknowledges that an approved project remains subject to review through the course of the project's lifecycle and that the Company must still be able to show that spending is needed.<sup>23</sup> However, this objective is all but impossible to achieve without more defined phases between engineering approval, engineering completion, and project execution which are controlled by the Company.

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<sup>22</sup> DIV 4-9 response.

<sup>23</sup> DIV 4-21 response.

The primary factor preventing the desired project review phases is the Company's practice of advancing project implementation and major equipment purchases based on planning documents and very preliminary engineering before completing a final scope, all permitting, final engineering, and a refined cost estimate. This precludes Division review based on realistic cost estimates and the ability to assess the need and justification based on enhanced factors expected after development of a scope, permitting and engineering is completed. It is common for the Company to move projects from preliminary design to construction within the same ISR Plan year. The Company's rapid progression of project execution provides no opportunity for the Company or stakeholders to validate system need, ensure that the optimal solution is advanced based on finalized costs, and confirm the reasonableness of the implementation and timeline considering a holistic capital plan and ratepayer impacts. Adding to this, the Company incurs significant major equipment costs well before a project has progressed through detailed engineering, permitting and final design. Advanced purchases establish a targeted in-service date since a project must be constructed to accept the major equipment upon delivery. Therefore, the Company's purchasing practices effectively sets the project implementation schedule prior to final scope development and absent Division review. The Division would have a small window of opportunity to suggest an alternative schedule, if provided that opportunity at all. Purchasing major equipment before design and scope are complete can also lead to significant waste and cost overruns. It is well documented that the Company always exceeds project budgets. Despite the Division's request for more accurate estimates for major substation projects and the need to achieve a construction grade estimate (+/-10%) for Division review before commencing equipment purchases and construction, the Company has not incorporated improvements. There are at least three Separately Tracked

Major Projects in construction that have not achieved a construction grade estimate<sup>24</sup> which is a metric required to track projects under the Commission’s budget framework. The Dyer Street substation project is a classic example of how the RIE process is significantly flawed. RIE was advancing the substation at a site that turned out to be unusable and it had to be constructed in a totally different manner at a completely different site. This was avoidable had the company completed the scoping, permitting and engineering and enhanced cost estimate as continually proposed by the Division.

The Division has expressed concerns with the Company’s practices for many years and anticipated resolving the issues through mutual cooperation. The Company has not indicated it is willing to change its project execution philosophies, purchasing strategies, or plans for rapid implementation. In fact, by moving traditional ISR Projects outside of the ISR, the Company is taking the opposite position and obscuring all project details including major Area Study projects which are customarily reviewed in depth. These unresolved issues have now become a factor in the Division’s lack of concurrence with the Company’s proposed ISR Plan discretionary spending.

#### **D. Spare Power Transformers & Mobile Substations**

The Company indicated that spare power transformer purchases were planned as non-ISR spending. The topic of spare power transformer purchases has been addressed in prior ISR Plan reviews and continues to be an area of concern for the Division. The Division has not supported the Company’s plan to purchase a significant number of spare transformers, many of which were available to the Company under National Grid ownership. The Division and Company were to continue discussions and potentially agree on the magnitude of purchases and recovery

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<sup>24</sup> FY 2027 ISR Plan, Section 2, Attachment 3-Five Year Budget with Details: Admiral Street, East Providence, and Warren Substations.

mechanism. Now the Company has removed spare transformer purchases from the ISR Plan and LRP, effectively ceasing meaningful discussions. Given the Company's current actions and based on prior evaluations and conclusions, the Division recommends that spare transformer purchases can occur outside of the ISR Plan conditioned on the Company agreeing that costs would not be recovered unless and until the time the unit is placed in service. Cost recovery would be based on the depreciated value of the spare transformer. This recommendation provides ratepayers with access to spare transformers at no cost until a unit is actually used on the Rhode Island system for an emergency, consistent with arrangements under National Grid ownership. It also provides ratepayer protection by avoiding a scenario where RIE purchases excessive levels of spare transformers and receives cost recovery in the short term but well before the units are used and useful. In short, the Division's recommendation will encourage the Company to better align spare transformer purchases with system needs without unduly burdening ratepayers. If RIE cannot make this commitment, the Division will need to re-address its position and a path forward. Additionally, the Division's position is that mobile substations are a transitional cost since the equipment was available to the Company under National Grid ownership. The Division has previously agreed with the Company on the level of planned purchases and supports those investments outside of the ISR Plan. RIE would request rate recovery at a later time and in the manner it has requested other transitional capital costs.

**E. Volt Var Optimization/Conservation Voltage Reduction (VVO/CVR)**

The Company plans to make VVO/CVR investments as part of its non-ISR portfolio. In my report, I discussed that VVO/CVR utilizes smart regulators and capacitors which are IJJA eligible investments. The VVO/CVR program is not for safety or reliability but when implemented on select feeders, it provides a net power cost benefit to customers. The program was previously

presented as part of the Company's grid modernization plan and was not approved for full advancement. The Company's VVO/CVR pilots have demonstrated that the expected benefits were achieved, and I have consistently been supportive of the program. The Division's position is that if the Company proposes to continue implementing VVO/CVR, it should seek approval of a separate and comprehensive program to be included in a future ISR Plan, similar to what was developed for AMF. The Division does not support VVO/CVR investments outside of the ISR Plan without requisite justification, including a benefit-cost analysis and program execution commitments, for review and potential approval by the Commission.

#### **IV. CAPITAL BUDGET GUIDANCE**

As part of discussions aimed at reaching agreement on the FY 2027 ISR Plan, the Division proposed that the Company develop a single ISR Plan that includes non-ISR spending to meet a total budget of \$136 million. This budget level is consistent with the methodology I presented in the FY 2026 ISR Plan proceedings. During the hearing, the Commission expressed the opinion that the Division's guidance formula was appropriate for the Division to use in its analysis and negotiations with the Company.<sup>25</sup> The guidance is derived by taking the Company's 10-year average discretionary spend restated to the current year using the Gross Domestic Price Implicit Price Deflator ("GDP Deflator") and escalating that amount by 2.5% to produce an expected budget.<sup>26</sup> For FY 2027, this results in discretionary spending of nearly \$74 million. Adding the Company's proposed non-discretionary budget of \$59 million produces a total budget guidance of \$133 million which is reasonably close to the Company's originally proposed spending level of \$136 million (excluding AMF). I also provided the Company with a list of potential substation projects that could potentially be deferred to achieve this objective. The Company did not respond.

To demonstrate that a more modulated near and long-term investment plan can be achieved, I independently evaluated ISR Plan and non-ISR project adjustments to meet capital spending within the Division's desired budget guidance. By re-prioritizing Area Study projects and substation work, I was able to produce a FY 2027 ISR Plan budget within the Division's desired guidance and a more levelized annual investment strategy than proposed by the Company.

The steps are:

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<sup>25</sup> Docket 24-54-EL, FY 2026 ISR Plan Report and Order, p.14.

<sup>26</sup> See Docket 24-54-EL, FY 2026 ISR Plan, Prefiled Direct Testimony of William F. Watson, PHD, Exhibit WFW-2 for Budget Guidance Formula methodology.

1. I used the Company's filed 5-Year Capital Spending Plan<sup>27</sup> and the LRP<sup>28</sup> for the following 5 years as the basis since my adjustments affect future years.
2. I considered non-ISR substation related projects put forth by the Company using my own estimated costs. These are presented in Section III.A of my report.
3. Spare transformers, mobile substations and VVO/CVR were excluded based on the Division's recommendation discussed earlier in my testimony.
4. Reserves incorporated by the Company were removed, assuming the placeholders are used for deferred spend or would create budget headroom in future years.
5. I deferred early lifecycle projects based on the status presented by the Company in its 5-Year Capital Spending Plan. I deferred lower priority substation projects based on my assessment of asset condition priorities. I also adjusted system capacity and performance substation projects where load has not developed as projected and the solutions could be deferred.
6. Consensus categories of spend (non-discretionary) were not adjusted.

The following table describes each project shift:

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<sup>27</sup> FY 2027 ISR Plan, Section 2, Attachment 3-Five Year Budget with Details (Bates pp. 116-119).

<sup>28</sup> FY 2027 ISR Plan, Section 2; see Attachment 1-Detailed Long Range Plan within Attachment 5 (Bates pp. 145-148).

**Area Study Project Adjustments**

<b>Project(s)</b>	<b>Rationale</b>	<b>Yrs. of Shift</b>
Merton Tiverton Wood River	Projects in Study Phase - early life cycle and lower priority.	4
Weaver Hill	Load is not developing as projected and site issues unresolved.	3
Chase Hill	2nd half of station. Final Eng. March 2027.	2
Anthony	Final eng. July 2027. Kingston #131 is an alternative for deferral.	1
Apponaug	One failed transformer replaced. Defer remaining work.	1
Auburn (Non-ISR)	Lower priority - status unknown.	3
Division (Non-ISR)	Lower priority - status unknown.	3
Phillipsdale (Non-ISR)	Incorporated in ISR FY27-FY30	0
Staples Reliability	Incorporated in ISR FY27	0

The resulting FY 2027 ISR Plan is \$138 million which is slightly above the Division’s guidance but below the capital expenditure proposed by the Company when including non-ISR projects. By shifting Area Study projects, I was able to reduce the initial 5-year LRP investment level by \$50 million and when spreading that amount over the following 5-years, the average annual budget is \$134 million which provides RIE latitude to add projects. This analysis is a starting point. There are other factors that have not been considered such as reductions to discretionary IJIA investments. The following table compares the results of the project adjustments against the Division’s illustrative budget guidance, assuming 3% annual escalation.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
	<b>Long Range Plan Capital Spend (\$M)*</b>	<b>FY27</b>	<b>FY28</b>	<b>FY29</b>	<b>FY30</b>	<b>FY31</b>	<b>5-yr Total</b>	<b>FY32</b>	<b>FY33</b>	<b>FY34</b>	<b>FY35</b>	<b>FY36</b>	<b>10-Yr. Total</b>
1	<b>RIE Proposed ISR + Non-ISR</b>	153	175	176	142	124	770	117	120	123	127	131	1,389
2	<b>Division Adjusted-Project Deferrals</b>	138	145	142	148	147	720	142	134	131	132	131	1,389
3	<i>Illustrative Budget Guidance (3% esc.)</i>	136	140	144	149	153		158	162	167	172	177	

\* Excludes Spare Transformers, Mobile Substations and VVO/CVR

I offer this analysis to emphasize the Company’s flexibility in executing discretionary investments for safety and reliability over the short and long term. I have provided an example of how that flexibility can be leveraged in developing a more reasonable capital investment plan that takes ratepayer affordability into consideration. The Company did not appear willing to achieve this objective in the FY 2027 ISR Plan discussions with the Division. I firmly believe that if the

Company's proposed discretionary ISR Plan budget is denied in full, RIE would utilize more robust system assessments and risk analysis to re-prioritize projects due to the delay of cost recovery, and the end result would be an investment plan that is more aligned with the Division's objectives. The Division has always been prepared to work towards a balanced solution.

**V. VEGETATION MANAGEMENT**

The Company proposes Vegetation Management expenditures of \$12.9 million in FY 2027 compared to a \$13.8 budget and forecasted spending in FY 2026. The Vegetation Management Program, which includes customary programs, risk reduction enhancements, and tree growth regulator treatments was not adjusted.

	(a)	(b)	(c)
	<b>ISR Plan O&amp;M Budget Vegetation Management (\$000)</b>	<b>FY 2026 RIE Budget &amp; Forecast</b>	<b>FY 2027 RIE Proposed</b>
1	Cycle Pruning (with Enhanced Trimming)	9,100	8,100
2	Cycle Trimming Treatment (TGR)	43	100
3	Risk Reduction Work - on cycle	1,050	1,330
4	Risk Reduction - off cycle (formerly EHTM)	250	250
5	Sub-T (off & on road)	550	570
6	Police/Flagman Detail	1,100	1,050
7	Pockets of Poor Performance	30	-
8	Core Activities*	1,700	1,500
9	<b>Total Vegetation Management</b>	<b>13,823</b>	<b>12,900</b>

*\*Customer Requests, Emergency Response, etc.*

Consistent with historical budgets, the major spending component is Cycle Pruning budgeted at \$8.1 million. The Company has moved from a prescriptive four-year pruning cycle and although circuits remain scheduled on a fixed timeline or rotation, the work is informed by data analytics to identify risks and develop specific workplans for each circuit based on actual vegetation health and conditions. The Company applies analytics to pinpoint the annual feeder list for circuit clearing as opposed to a feeder list based solely on geography and not system conditions. Enhanced clearance specifications are applied to targeted areas to reduce future cycle trim costs and tree-related outages. Proposed work in FY 2027 includes all of the circuits in Pawtucket, Bristol, Warren, and many in Warwick. The Company proposed a lower budget than FY 2026 since planned work is in urban and suburban areas with less tree canopy. RIE also proposes

continuation of tree growth regulator (“TGR”) treatments based on trial results from FY 2025. Although the Division concurs with the budget to continue TGR applications in FY 2027, the Company should put forth a definitive timeline, scope and cost for proposed TGR treatments, along with how performance will be measured and reported to determine program effectiveness.

Once feeders are identified for cycle trimming, the Company also applies On-Cycle Risk Reduction by examining the circuit in advance using data and field observation to identify areas where tree-related outage risks are high. Crews complete prescribed work during the cycle trim schedule to avoid interim return trips. The 34FI feeder in Foster and Scituate were part of the FY 2026 work plan and identified as requiring more trimming in FY 2027.

The Company’s Off-Cycle Risk Reduction for hazard tree removals due to pest infestation continues at a \$250,000 budget level that remains unchanged from FY 2026. Sub-transmission clearing work continues at a slightly higher budget. To address trouble areas, RIE is utilizing LiDAR (light detection and ranging) technology that provides high resolution images to determine vegetation encroachment which is superior to ground patrolling. The Company notes that large DG customers have been added to sub-transmission, adding outage exposure due to increased line miles, which in turn increases the need for more intensive vegetation management.<sup>29</sup> This area of increased spending should be evaluated to ensure that incremental costs due to DG interconnections are properly allocated. The Company has eliminated the budget for Pockets of Poor Performance since the work is being performed during on-cycle risk reduction. Lastly, traffic control measures are budgeted at just over \$1 million driven by the need for traffic control since FY 2027 planned circuits are in congested areas. The Company continues to require vendor bids

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<sup>29</sup> FY 2027 ISR Plan, Section 2, Bates p. 156.

for cycle trim work to include traffic control in the pricing instead of a pass-through cost in an effort to ensure that vendors manage costs effectively.

The Company has revised its Vegetation Management Standards in compliance with the Vegetation Management for Electric System Reliability Act (“Act”) enacted in 2024.<sup>30</sup> The Act requires that vegetation management standards and practices address several areas including conditions related to clearing on and around rights of ways, municipal notifications, educational outreach “right tree, right place” program, website development to access standards and customer service contacts, compliance with state arborist licensing, and a property owner approval process to remove danger trees. The Division reviewed and approved the Company’s revised standards to take effect on April 1, 2026, conditioned on the Company establishing the “right tree, right place” program and website.<sup>31</sup> I evaluated the proposed Vegetation Management Standards and Practices and testified in the docketed proceeding finding that after incorporating modifications, RIE complied with the law. The Company’s current program follows best management practices and with recent enhancements, communication and coordination with municipalities and customers will improve. The Company will also have a greater opportunity to remove hazard trees outside of trim zones, offering another level of risk mitigation.

Trees remain the leading cause of customer interruptions and I strongly endorse efforts to address the root cause of outages as opposed to restoration investments that only minimize the number of customers affected but do not eliminate the source. I have previously commented on the importance of vegetation management, since protecting core distribution facilities from the dangers of falling limbs and trees will be more critical as grid connected technologies are deployed

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<sup>30</sup> R.I. Gen. Laws §39-34-1.

<sup>31</sup> Docket No. D-25-15, Rhode Island Energy Vegetation Management Standards and Practices, Decision and Order effective September 14, 2025.

that rely on an intact and functioning system to provide intended benefits. There are no cost-effective substitutes for robust vegetation management and the Company's proactive approach, balanced with cost management, continues to be integral to system reliability. The Company has consistently reported improved reliability in areas of the system undergoing cycle clearing or hazard tree removals and is augmenting practices with data-analytics that are expected to drive further improvements. Although the Company indicates recent unfavorable trending in tree related outages due to high activity days such as tornado events, analysis suggests that positive results are consistently observed during the second and third year after a circuit is maintained. The Division expects that RIE will continue preparing and delivering a Vegetation Management Program Cost-Benefit Analysis in advance of each ISR Plan filing. The Division concurs with RIE's proposed Vegetation Management Program and spend.

**VI. SUMMARY AND RECOMMENDATIONS**

For FY 2027, RIE initially proposed an electric ISR Plan Capital Budget of \$136.4 million, a Vegetation Management Program at \$12.9 million, and I&M Program Operations and Maintenance Expenses of \$1.4 million. The Company included \$15.3 million in capital expenditures for AMF implementation, resulting in a proposed FY 2027 ISR Plan grand total Capital Budget of \$151.6 million. The Company also indicated that it will be advancing what had previously been considered ISR Plan projects outside of the ISR Plan. According to the Division's estimate, the Company's non-ISR project spend would add nearly \$31 million of discretionary spend in FY 2027 making the Company's total capital investment exceed \$167 million. The Company also put forth an LRP that indicated a rapid pace of discretionary project implementation over the next five years. If executed with proposed non-ISR projects, the Company would drive annual capital spending to levels at or above \$200 million.

The Division's primary concerns with the initial proposed FY 2027 ISR Plan were the Company's omission of non-ISR projects and the lack of transparency. RIE did not to deliver a comprehensive plan which denied the Division the opportunity to get a complete view of the expected utility investments that are reasonably needed to maintain safe and reliable distribution service over the short and long term, validate project interrelationships and justification, and also get a complete picture of cost and ratepayer affordability. The Division proposed that RIE re-prioritize projects and put forth a single holistic plan to meet its proposed ISR Plan capital budget, but the Company did not respond. The Company filed a final proposed FY 2027 ISR Plan on December 22, 2025 that principally reflected its initially proposed plan, comprised of \$135.8 million in capital spending and \$17.9 for AMF for a grand total Capital Budget of \$153.7 million.

The Company did not revise its plans to progress an estimated \$31 million in non-ISR projects, which would push the total capital investment level above \$184 million.

My review of the Company's proposed FY 2027 ISR Plan and LRP has established that the Company's capital investment plan does not balance system need, reliability performance and ratepayer impacts. Historically, the Company maintained a focus on capital spending cost containment. More recently RIE has proposed advancing discretionary capital projects at a very rapid pace. The trajectory is evident when considering prior LRPs that included all potential ISR Plan projects which the Company now obscures by removing projects and costs outside of any filed plan or long-term projections. The Company's accelerated investment pace comes even when load growth is well below projections. Despite achieving superior reliability results, RIE has adopted its own much more aggressive reliability targets while moving towards a nearly zero risk tolerance level. RIE has continued to focus on advancing projects to create contingencies for outages when none had previously existed or were considered necessary. RIE focuses on complex solutions to eliminate risks instead of lower cost options to reasonably manage risk. The Division does not believe that these goals are reasonable or needed to achieve acceptable reliability.

These concerns have been identified and raised by the Division over multiple ISR Plan proceedings and are further exacerbated by the Company's decision to simultaneously advance a separate but related portfolio of projects outside of the ISR Plan. The Division does not support the Company's FY 2027 ISR Plan as proposed. The area of Division concurrence is limited to the proposed FY 2027 non-discretionary capital budget of \$59.2 million. Of this, the Division supports separately tracking and reconciling \$4.3 million for Third-Party Attachments subject to the Company meeting the Division recommendation below. The Division also supports the proposed FY 2027 Vegetation Management Program expenses of \$12.9 million.

**Recommendations**

1. The Company shall develop and put forth for Division review an acceptable process to manage third-party pole attachment requests that incorporate equitable cost sharing arrangements by March 31, 2026. The process shall include a requirement for complete record retention that documents the need for, and cost assignment of, all make ready work in a manner that can be examined to validate costs incurred by the Company.
2. The Company shall continue developing Area Studies and future study documents supporting Asset Replacement and System Capacity and Performance programs and projects as applicable to include, at a minimum:
  - The traditional elements included in the Company’s current studies including, but not limited to, purpose and problem statement, scope and program description, load forecast methodologies, condition assessment/criticality rankings, alternatives considered, solution, cost estimate and timeline. Additionally, the AMF data shall be integrated into the engineering models to enhance the accuracy of these models and project development. Initial project cost estimates should be developed with a -25%/+50% tolerance, or better, and adjusted for inflation.
  - Discussion on the impact to related Company initiatives, Commission programs, the various pilot projects, or other requirements driven by SRP, Distribution System Planning (“DSP”), Heat Maps, and emerging initiatives.
  - A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning.

- An evaluation of potential incremental investments that support the Company’s long - term grid modernization strategy. This includes description of technology or infrastructure investment, cost-benefit to traditional safety and reliability objectives, and additional operational benefits achieved, if implemented. Grid modernization investments should be closely correlated with all ISR Plan investments, including both recurring and newly proposed programs.
  - A robust non wires alternative (“NWA”) evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.
  - The Company shall submit and present the outcome of each completed or revised Area Study to the Division.
3. The Company shall correlate Area Studies to each other for the development of a holistic system LRP in order to increase the level of support and transparency for the capital budget which further informs the ISR Plan. Completed Area Studies shall be used to re-prioritize and sequence all solutions and major projects in the LRP. The LRP shall be developed in a manner recognizing that a reasonable plan must incorporate ratepayer affordability and a reasonable level of company risk acceptance. The Company shall submit a report with updates on modeling activities, holistic system LRP development and revision of each current and future planned Area Study status at least 120 days prior to filing its FY 2028 ISR Plan Proposal, but in any event no later than August 31, 2026.
4. The Company shall maintain and file with each proposed ISR Plan its holistic 10-year LRP as contemplated in these Recommendations to include all strategic capital investments. The LRP should demonstrate the strategic alignment and between various planning and project evaluation processes including but not limited to, the SRP plans, Area Studies, ISR Plan, non-

wires alternatives options, grid modernization plans, and internal Design Criteria. The LRP must be adequately supported and accompanied by a level of detail that allows stakeholders to sufficiently validate the need, timing and level of proposed investment in relation to ratepayer affordability. It shall also reflect the demand reduction which may transpire from the SRP program advancements.

5. The Company shall not include spend in the ISR Plan for initiatives or programs that are subject to Commission review and/or approval prior to the program progressing through a regulatory proceeding.
6. The Company shall present new programs, major projects, or material modifications to existing programs to the Division in advance of including the programs in the ISR Plan. The Company shall produce requisite justification at a level of detail to sufficiently validate the need, timing and level of proposed investment, including a benefit-cost analysis. The Company shall also propose a methodology to separately track, measure and validate program costs and benefits. Requisite justification and accompanying information shall be provided in advance of the FY 2028 ISR Plan Proposal filing, and in any event no later than August 31, 2026.
7. The Company shall continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to allow for transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2028 ISR Plan Proposal filing, and in any event no later than August 31, 2026.
8. The Company shall submit an evaluation of future proposed Asset Condition projects as compared to the Company's LRP in advance of the FY 2028 ISR Plan Proposal filing, and in any event no later than August 31, 2026.

9. The Company shall continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's LRP in advance of the FY 2028 ISR Plan Proposal filing, and in any event no later than August 31, 2026.
10. The Company shall continue to monitor and report on work performed under Damage/Failure, I&M, and related Asset Replacement Blanket programs to validate proper classifications. The Company shall continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.
11. The Company shall complete a systemwide protective coordination study, demonstrating the need, the location, and/or the manner in which reclosers will be coordinated in advance of progressing major recloser additions. The Division and Company will work to develop a mutually acceptable study format and content. The memorandum which the Company has already agreed to deliver before advancing reclosers and most particularly the FLISR schemes may substantially address the Division's needs.
12. The Company shall continue to submit an overall cost-benefit analysis for Cycle Pruning and Risk Reduction work within the Vegetation Management Program for the Division's review prior to submitting the Company's FY 2028 ISR Plan Proposal, and in any event no later than August 31, 2026.
13. The Company shall provide continuous and timely updates on ISR Plan team members and responsibilities, material changes to Company guidelines, standards or processes that affect distribution planning, or any proposed changes to the ISR Plan process. The Company shall, at minimum, provide updates at quarterly presentations of the quarterly reports.

## **APPENDIX 1**

**Appendix 1**  
**FY 2027 ISR Plan Evaluation Actions and Procedures**

Item No.	Date	Actions and Procedures <i>(Conference calls included the Division, Division consultants, and RIE)</i>
1	June 18, 2025	Conference call was held to discuss the FY 2025 ISR Plan Q3/Q4 ISR Plan Reports and additional planning enhancements.
2	September 12, 2025	RIE submitted its FY 2027 10-year Long-Range Plan (“LRP”) for investments that are or will be included in the Electric ISR Plan.
3	October 17, 2025	RIE filed Sections 1, 2 and 3 of its proposed FY 2026 ISR Plan with a capital budget of \$136.4 million and \$15.3 million for AMF, for a total proposed budget of \$151.7million.
4	October 27, 2025	The Division provided the First Set of Data Requests to the Company.
5	October 31, 2025	RIE filed the remaining Sections 4, 5 and 6 of its proposed FY 2026 ISR Plan.
6	November 6, 2025	Conference call was held to discuss Third Party Attachments, New Business, I&M, the LRP and project deferrals/investments outside the LRP, and risk.
7	November 12, 2025	Conference call was held to discuss overall Area Study project execution and prioritization, Commercial New Business, Electromechanical relay replacements, and the status of multiple Asset Condition substation projects.
8	November 17, 2025	RIE provided its first batch of responses to the Division’s First Set of Data Requests.
9	November 19, 2025	The Division provided the Second Set of Data Requests to the Company.
10	November 19, 2025	RIE provided its second batch of responses to the Division’s First Set of Data Requests.
11	November 20, 2025	Conference call was held to discuss pole attachment and make ready cost allocation, I&M, energy forecasting and planning, and annual capacity reviews. The Division requested details on ISR projects and costs being implemented outside the plan and RIE offered to only list projects and time horizons.
12	November 20, 2025	RIE provided its third batch of responses to the Division’s First Set of Data Requests.
13	November 21, 2025	RIE provided its fourth batch of responses to the Division’s First Set of Data Requests.
14	November 25, 2025	The Division provided the Third Set of Data Requests to the Company.
15	December 4, 2025	Conference call was held to discuss pole attachment process changes and FCC compliance, vegetation management, status and scope changes for major substation upgrades, and deliverables for final design and engineering.
16	December 8, 2025	RIE provided its first batch of responses to the Division’s Second Set of Data Requests and its first batch to the Division’s Third Set of Data Requests.
17	December 10, 2025	RIE provided a complete set of responses to the Division’s Second Set of Data Requests.
18	December 11, 2025	Conference call was held to discuss non-consensus and Division recommendation that RIE re-prioritize projects and put forth a revised ISR Plan that includes non-ISR projects to meet the total initial proposed budget.

**Appendix 1**  
**FY 2027 ISR Plan Evaluation Actions and Procedures**  
**(Continued)**

19	December 12, 2025	The Division provides RIE with a list of potential substation projects that can be deferred or re-prioritized in developing a revised ISR Plan.
20	December 16, 2025	RIE provided a complete set of responses to the Division's First Set and Third Set of Data Requests.
21	December 22, 2025	RIE filed its Proposed FY 2027 Electric Infrastructure, Safety, and Reliability Plan
22	January 12, 2026	The Division provided the Fourth Set of Data Requests to the Company.
23	January 26, 2026	RIE provided its first batch of responses to the Division's Fourth Set of Data Requests.
24	January 28, 2026	RIE provided its second batch of responses to the Division's Fourth Set of Data Requests.
25	January 30, 2026	RIE provided a complete set of responses to the Division's Fourth Set of Data Requests.

## **APPENDIX 2**

**Appendix 2**  
**RIDPUC POLE ATTACHMENT POSITION PAPER**  
**November 18, 2025**

**I. Background**

For decades, communication companies have been granted the right to attach to electric utility poles to provide services. Third-party communication attachments on the Rhode Island Energy (RIE) electric system are guided by a combination of utility, state and federal standards designed to maintain the safety and the integrity of pole infrastructure. From a cost perspective, if a new attachment on a pole makes the pole unserviceable, the attaching entity customarily bears the cost of necessary modifications (“make-ready”). This cost-causation philosophy has allowed RIE to fund communication attachment work within ISR Plans that appropriately assign costs to third parties without unduly burdening electric ratepayers. The pole attachment process has supported an extensive communication system across the state and proven positive for Rhode Island which ranks highly for both broadband access and speed.<sup>32</sup>

Despite the widespread coverage in Rhode Island, communication companies continue to expand broadband which is resulting in significantly more pole attachment requests. Discussions with RIE as part of the ISR Plan process indicate that the Company’s interpretation of recent Federal Communications Commission (FCC) rulings would increase the annual costs to accommodate these new attachers. The Company projects the need to expend \$4 million annually for third party pole attachments for work that previously was accomplished for less than \$200,000. This \$4 million would be imposed on the electric rate payer. Furthermore, based on RIE discussions the \$4 million increase is driven by what appears to be a significant expansion of broadband by one or more companies. The cost increase is due to RIE’s expectation that the Company would in most cases be fully responsible for bringing existing poles into compliance and that new attachers would not be charged for make-ready. The Company’s proposed ISR Plan pole attachment budgets beginning with FY 2027 is much higher than historical budgets. RIE has taken a position that will impose costs on electric ratepayers even though they are not the cost causers. In response, the Division has prepared the following position on the pole attachment process and cost to be charged to attaching entities. The document is organized by presenting key FCC clarifications and differences with RIE’s position, highlighting state requirements and code standards that pre-empt FCC rulings, discussing RIE’s pole attachment process and recommending steps that the Company

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<sup>32</sup> Rhode Island has ninety-nine percent service coverage, multiple providers, and ranks within the top ten best states for broadband.  
[RI Broadband Map](#)  
[Broadband state rankings](#)

should incorporate in its pole attachment process.<sup>33</sup> By adopting these recommendations, it is the Division’s position that the Company will be in compliance with state law, NESC standards and FCC directives while avoiding unjustified ratepayer cost burdens.

## **II. FCC Rulings and Clarifications**

The FCC establishes rules pertaining to pole attachment and specifically cost causation and cost sharing when a new attachment requires pole replacements. In recent years, the FCC has implemented several rule changes aimed to accelerate broadband deployment by streamlining regulations and improving pole access.<sup>34</sup> RIE in its proposed FY 2027 ISR Plan filing references a related 2023 FCC order that “prohibits the Company from charging third-party broadband installers in “any situation where the pole already requires replacement before a new attachment request is made, including when poles are out of compliance with current safety and utility construction standards.””<sup>35</sup> The Company claims that the FCC order will lead to additional capital costs since the Company, and not the new attacher, will now absorb the cost for a significant number of pole replacements due to existing NESC violations which are predominately a lack of pole strength to accommodate all attaching facilities.

The underlying FCC rule pertaining to modification costs is 47 CFR § 1.1408(b) which states that:

The costs of modifying a facility shall be borne by all parties that obtain access to the facility as a result of the modification and by all parties that directly benefit from the modification. Each party described in the preceding sentence shall share proportionately in the cost of the modification. A party with a preexisting attachment to the modified facility shall be deemed to directly benefit from a modification if, after receiving notification of such modification as provided in subpart J of this part, it adds to or modifies its attachment. Notwithstanding the foregoing, a party with a preexisting attachment to a pole, conduit, duct or right-of-way shall not be required to bear any of the costs of rearranging or replacing its attachment if such rearrangement or replacement is necessitated solely as a result of an additional attachment or the modification of an existing attachment sought by another party. If a party makes an attachment to the facility after the completion of the modification, such party shall share proportionately in the cost of the modification if such modification rendered possible the added attachment.

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<sup>33</sup> The observations and recommendations within this document address the pole attachment request process. The Division anticipates that RIE will separately adjust the terms, conditions and cost sharing under joint pole ownership agreements to reflect process changes in addition to updating the pole attachment rate (FCC) to be charged to attaching entities.

<sup>34</sup> FCC 47 CFR Part 1, WC Docket No. 17-84, Accelerating Wireline Broadband Deployment by Removing Barriers to Infrastructure Investment

<sup>35</sup> Proposed FY 2027 ISR Plan, Section 2, page 26.

The rule was intended to address cost causation and cost sharing principles including cases where utilities and other attachers use modifications as an opportunity to bring their own facilities into compliance with safety or other requirements. The ambiguity of the rule and particularly the term “necessitated solely” has led to multiple FCC clarifications through subsequent Declaratory Orders.<sup>36</sup> For instance, the FCC has clarified that a party using a modification to bring facilities into compliance would be responsible for its share of the modification cost, and further reaffirmed the interpretation that new attachers “are not responsible for the costs associated with bringing poles or third-party equipment into compliance with current safety and pole owner construction standards to the extent such poles or third-party equipment were out of compliance prior to the new attachment.”<sup>37</sup> Exactly when a new attacher is solely responsible for a pole replacement remained undefined. The FCC did provide examples of when a pole replacement *is not* necessitated solely by an attachment request. The non-exhaustive and illustrative examples include:<sup>38</sup>

- (1) a pole replacement is required pursuant to applicable law;
- (2) the current pole fails engineering standards, such as those contained in the NESC; or
- (3) the current pole already is on the utility’s internal replacement schedule.

A limited interpretation of the FCC rulings and clarifications suggest that a new attacher cannot be charged for a pole replacement where there are existing violations, and this is the exact interpretation that RIE has adopted. However, on August 26, 2025, the FCC issued further clarification adding context regarding cost causation and cost sharing.<sup>39</sup> The FCC Report and Order language (*with emphasis* below) explains circumstances where a new attacher would be responsible for pole replacement costs, or alternately, all attaching entities that benefit from improvements would share in the cost.

**Basis for charging new attacher (Federal Register 90, page 41740):**

However, we grant clarification insofar as we provide here an important caveat to the internal construction standards determination and associated example. We note that an important element of the internal construction standards determination is the capacity, or the lack thereof, on the existing pole. We clarify that, for purposes of the internal construction standards determination, when a utility is determining capacity on a pole to see whether a pole replacement is necessary, the relevant utility construction standards to consider are limited to the current standard and the standard immediately

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<sup>36</sup> Due to the complexities of the pole attachment process, the FCC has issued multiple Declaratory Orders and clarifications. This document is intended to highlight essential findings relative to cost causation and cost sharing and is not intended to chronicle and summarize related filings.

<sup>37</sup> WC Docket No. 17-84, Third Report and Order, Appendix B, Section 5.

<sup>38</sup> November 22, 2023 FCC Fact Sheet, Third Further Notice of Proposed Rulemaking – WC Docket No. 17-84, pp. 22-23.

<sup>39</sup> WC Docket No. 17-84, Fifth Report and Order, Federal Register/Vol 90, No. 163, p. 41740.

preceding that current standard. (We thus reject EEI’s argument that the internal construction standards determination requires the utility to figure out “which of the many previous iterations of an electric utility’s construction standards would be applicable” when a pole is replaced following a new attachment request.) *That is, assuming a pole lacks capacity for a requested new attachment under the utility’s new construction standard, but capacity would exist under its immediately preceding construction standard, the resulting pole replacement would not be “necessitated solely” by a new attachment request. By contrast, if the pole lacks capacity under both the new and immediately preceding construction standards, then application of § 1.1408(b) means that the new attachment request is the cause of the pole replacement, i.e., it is “necessitated solely” by the new attachment.* The clarification we offer today can be administered easily and also limits unreasonable actions to delay pole replacements in order to force new entrants to bear the entire cost of a pole replacement. To the extent this was not clear from the Declaratory Ruling, we hereby clarify accordingly.

**Basis for cost sharing (Federal Register 90, page 41741):**

However, as the Commission explained in the Declaratory Ruling, it agreed with the Bureau’s analysis in the 2021 Pole Replacement Declaratory Ruling that *when the cost-allocation and cost causation provisions in § 1.1408(b) are read together, they “stand for the proposition that parties benefiting from a modification share proportionately in the costs of that modification, unless such modification is necessitated solely as a result of an additional or modified attachment of another party, in which case that party bears the cost of the modification.”* The Commission further clarified that “it would be contrary to the Commission’s rules and policies to require a new attacher to pay the entire cost of a pole replacement when a pole already requires replacement . . . at the time a request for a new or modified attachment is made.”

When considering the original rulings and subsequent clarifications it is evident that under certain conditions a new attacher would be responsible for a pole replacement if the current pole is non-compliant which contradicts RIE’s position that charging a new attacher is prohibited. In the alternative case where a new attacher is not responsible, the FCC has repeatedly clarified that all parties benefiting from the modification, in this case a pole replacement to remedy non-compliance, would bear the cost of the modification. This means that RIE should be assigning pole replacement costs to *all* attaching entities, including the new attacher. These limited examples do not address other cost assignment situations such as a new attacher solely causing non-compliance, non-compliant existing attachments, replacing poles that have failed the utility’s pole inspection test, etc. To capture the numerous scenarios and fully comply with FCC rulings, RIE must expand and incorporate additional steps in its pole attachment process which are discussed in Section V of this document. Absent these changes, significant and unjustified costs would be imposed on ratepayers, which the Division opposes.

### **III. Rhode Island State Law and National Electrical Safety Code (“NESC”)**

It is critical to note that while FCC rulings and interpretation are important considerations in the pole attachment process, they cannot supersede the state of Rhode Island requirements and NESC standards. Design and construction of systems in Rhode Island which may affect the health, safety and welfare of the public must be designed under the responsible charge of a professional engineer licensed in the state of Rhode Island. Statute §23-27.3-128.2.1 along with General Laws Chapter §5-8 and Administrative Code 430 R.430 RICR-00-00-1.8 all work in unison to require professional engineering including by communication companies when designing and installing facilities on electric utility poles or poles owned by others. This means, when a communication company places facilities on poles belonging to another party the communication company is responsible for engineering that installation which must be in full compliance with the NESC. The Rhode Island Public Utilities Commission expects each public utility to construct, operate and maintain its plant, structures, equipment and lines in accordance with standard practice which is the NESC per Title 815 Chapter 30 paragraph 1.8 which in turn establishes the electric utility construction standard as discussed by the FCC in its clarification. That means any strength or clearance violations of the NESC that would not exist without the communication attachment is a violation by the communication company and its responsibility to remedy and not the responsibility of the electric rate payer or RIE.

### **IV. RIE’s Pole Attachment Process**

The Division understands that RIE is using the PPL methodology for pole attachment engineering assessment. RIE is going to each pole and determining its suitability for a new attachment including analyzing the clearance requirements and strength requirements. RIE stated in a conference that if a pole does not have sufficient strength requirements as a result of existing facilities before a new attachment is made, then RIE plans on absorbing all the cost of the make ready work. The Company’s position is based on its interpretation of FCC rulings while not considering the non-delegable duty of the existing attaching entities to have designed and installed all its facilities in compliance with the NESC and under the responsible charge of its professional engineer. The Division finds that the FCC rulings, as clarified, are not being utilized by RIE thus driving up the ISR Plan budget for pole attachments. RIE does not appear to consider that the strength deficiency may often have been caused by another pole attaching entity including its overlashing of prior facilities with or without an application. RIE is taking the position that since it did not identify the fact that existing communication company attachments compromised the pole strength then RIE and its ratepayers must absorb all the cost to remedy violations. RIE is not considering cost allocation to all attachers that benefit from improvements, including the new attacher. RIE’s position on make ready costs is not consistent with the state law and FCC clarification.

**V. Recommended Pole Attachment Process**

It is the Division's position that RIE can meet the FCC rulings and clarifications, particularly when combined with the requirement for professional engineering design, by incorporating the following steps in its pole attachment process.

- 1) An attaching entity such as a communication company on a RIE or jointly owned pole would be responsible for the professional engineering associated with that installation. If RIE provides those engineering services, then the communication company requesting to make the attachment is solely responsible for the cost of those services.
- 2) When RIE performs its make ready engineering and determines a pole is currently satisfactory for service but must be replaced in order to accommodate the new communication facilities attachment then the new communication company is responsible for the entire cost of the necessary make ready work.
- 3) When RIE performs make ready engineering and determines a pole is currently not satisfactory for service under the current or immediately preceding construction standards, then RIE must determine if the pole would be satisfactory for service if there were no communication attachments on the pole. If the pole is satisfactory for service without communication attachments, either the causer of the NESC violation must incur the cost to remedy the deficiencies or if multiple communication companies are determined to be responsible the cost to remedy the deficiencies would be shared equally among all attaching entities since they benefit from the modification.

If a taller or stronger larger class pole is required for the new attaching communication company than would be required to remedy the NESC violations absent the addition of the new communication company attachment, then the new attaching company shall incur the cost of that difference, and the other parties only incur the cost of what would have been a less expensive remedy. In no event should the electric rate payer be imposed with this cost. The Division finds that to be consistent with the FCC clarifications as noted above.

- 4) To the extent RIE elects to absorb the make ready cost as may be determined under 3 above, the Division's position is those costs would not be recoverable through electric rates or the ISR Plan reconciliation process.
- 5) To the extent a pole through the inspection process of the wood pole was determined to have a strength of less than 67 percent of its original required strength per the NESC, the pole replacement is then the responsibility of either RIE exclusively if not a jointly owned pole or the responsibility of the joint owners of the pole. This provision applies only when a pole fails the wood pole inspection test due to rot, infestation or other wood product deterioration.