STATE OF RHODE ISLAND PUBLIC UTILITIES COMMISSION

IN RE: RHODE ISLAND ENERGY PETITION FOR ACCELERATION DUE TO DISTRIBUTED GENERATION PROJECT – WEAVER HILL PROJECTS	Docket No. 23-38-EL

<u>REVITY ENERGY LLC'S POST-HEARING MEMORANDUM</u>

Revity Energy LLC ("Revity"), by and through its undersigned attorney, hereby files this Post-Hearing Memorandum in support of Rhode Island Energy's (the "Company") October 17, 2023 Petition for Acceleration Due to DG Project (Weaver Hill Projects).[1]

The interconnection process places the distributed generation (DG) customer at the mercy of the Company in terms of the scope of work required to interconnect its projects. For the DG customer, the interconnection process is a take-it-or-leave-it proposition because, according to the Company, "if you want to be interconnected as a developer, you're going to either perform or pay for the performance of the scope of work" and the Company does not "allow DG customers to have any control over the scope of work * * *."[2] The Division agrees that DG customers "have to build to the [C]ompany's standards, whatever they are" and "the developer is stuck with that

[1] Revity is also a party to RIPUC Docket No. 23-37-EL per its December 7, 2023 Unopposed Motion to Intervene Pursuant to Rule 1.14 of the Rhode Island Public Utilities Commission Rules of Practice and Procedure. Revity has no financial interest in Docket No. 23-37-EL other than to the extent that the legal decision rendered in that matter may guide or otherwise impact the decision rendered in this matter and/or the policies and procedures governing renewable energy interconnection work in the future. Accordingly, with respect to Docket No. 23-37-EL, Revity restates its below analysis of Rhode Island law regarding renewable energy interconnection.

[2] 6/3/2024 TR at 222:4-19 (excerpts attached hereto as <u>Exhibit A</u>); 6/4/2024 TR at 163:10-13 (excerpts attached hereto as <u>Exhibit B</u>) ("MR. HANDY: Did Green ever have any choice about [whether] to build the upgrades in order to interconnect its project? MR. CONSTABLE: No."); *id*. at 223:15-19 ("MR. NYBO: So if you guys have it in your area study, your ISR, and the impact study says it needs to be done, it needs to be done. MR. CONSTABLE: Yes."); 6/5/2024 TR at 139:9-12 (excerpts attached hereto as <u>Exhibit C</u>) ("MR. HANDY: Do you understand that the company, the DG Developer had no choice in this context but to build what the company told them to build? MR. BOOTH: I would agree with that.").

standard."[3] In short, a DG customer must perform (or pay for) whatever the Company says that customer must perform (or pay for), otherwise the DG customer's project will not be interconnected. Furthermore, these upgrades must be donated by the DG customer to the Company "by operation of law" and "DG customers ha[ve] no say in that property being donated to Rhode Island Energy."[4] In short, the DG customer must build whatever the Company requires it to build and then donate that work to the Company.

The only reason why this regime is (marginally) tenable is that Rhode Island state law only permits the DG customer to be charged for system modifications "specifically necessary for and directly related to the interconnection."[5] This Commission has previously advised the General Assembly that (in the context of DG interconnection) the Rhode Island General Laws "ensure interconnecting customers pay only for modifications their projects require and ensure that ratepayers contribute to improvements that benefit them * * *."[6] The Commission has stated that, under the current legal regime, where the utility is required to "add or change equipment on its electric system solely to accommodate" a DG customer, "the costs of these modifications are charged to the interconnecting customer/developer."[7] But, according to the Commission, where "the utility makes other changes to the electric system as part of the same project where those changes are simply to improve the operation of the system and are necessary to provide safe and

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[3] Exhibit C at 110:5-13.
[4] Exhibit C at 55:19-56:1.
[5] R.I. Gen. Laws § 39-26.3-4.1(a) ("The electric distribution company may only charge an interconnecting, renewable-energy customer for any system modifications to its electric power system specifically necessary for and directed related to the interconnection.").
[6] Revity Ex. 4 in 23-38-EL & Revity Ex. 2 in 23-37-EL (April 12, 2022 PUC Letter to Corporations Committee) (attached hereto as Exhibit D). The Commission's position was in opposition to H 8028 pending before the House Corporations Committee which bill would have clarified the DG customer's interconnection obligations and installed an ombudsman to expeditiously adjudicate disputes that arise therefrom. The Commission objected on the basis that the Rhode Island General Laws were already crystal clear.
[7] Exhibit D.

reliable service to customers regardless of the addition of the renewable energy generator * * * these costs are already charged to all ratepayers."[8]

Yet and still, DG customers now find themselves potentially on the hook for nearly fifteen million dollars in interconnection costs which costs were ordered by the Company to provide safe, reliable service to ratepayers and these DG customers are stuck between the Division and the Company who are maligning each other's respective positions in this docket as "very misleading,"[9] "completely incorrect,"[10] "disingenuous"[11] and full of "misinterpretations and contradictions that are concerning."[12] The Division has no objection to the amounts spent on these upgrades[13] but nevertheless contends that the Company "should have come forward back in 2019 or 2020, long before the developers spent this money."[14] "The general body of ratepayers should not reimburse DG developers now for project work that the Company claims will only be installed after the tariff limitations period has expired, and in any event * * * will not be needed for years beyond the five-year period, if at all."[15]

When Section 5.4(c) was last amended in Docket No. 4763, the Division expressed concerns that the Company's proposed amendments to Section 5.4(c) would lead "to uncertainty

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[8] Exhibit D ("If the purpose of the bill is to ensure interconnecting customers pay only for modifications their projects require and ensure ratepayers contribute to improvements that benefit them, no changes need to be made to the current law.").
[9] April 17, 2024 Pre-filed Direct Testimony of Gregory L. Booth, PE at p. 8:4 (attached hereto as Exhibit E).
[10] May 9, 2024 Joint Rebuttal Testimony of Ryan Constable and Eric Wiesner at p. 13:5-13 (excerpts attached hereto as Exhibit F).
[11] Exhibit C at 103:25-104:1.
[12] Exhibit F at p. 12:3-16
[13] Exhibit C at 128:3-8; *id.* at 134:6-8 ("MR. HANDY: Does the Division object to the cost that the company, DG companies incurred to interconnect their projects? MR. BOOTH: The Division doesn't have an opinion one way or the other.").
[14] Exhibit C at 126:21-23.
[15] Exhibit F at p. 10:4-7.

regarding what is and what is not an accelerated project."[16] The Company addressed those concerns by stating that "the Company will honor any Accelerated Modification set forth in an Interconnection Service Agreement (ISA) even if the ultimate 'need' is later than forecasted in the Capital Plan to provide certainty to the DG developer community, provided the Company receives cost recovery for the remaining cost of the modification."[17] On January 4, 2019, the Commission approved amendments to Section 5.4(c) in Docket No. 4763 emphasizing that the Company "stated that in order to provide certainty to developers, the Company would honor any accelerated modification set forth in an interconnection service agreement even if the ultimate 'need' proves to be later than previously forecasted in the five-year capital plan."[18]

However, the DG developer community is now mired in uncertainty based on the Division's position in this proceeding.[19] The Division offers that these issues "should have been dealt with in the tariff better to protect the DG Developers and what they built" and "the tariff just doesn't have the specificity it should have * * *."[20] The Division's sentiments are cold comfort to Revity which is out $12.2 million in costs for upgrades dictated to it by the Company to provide safe and reliable service to the ratepayer.

[16] Division's March 28, 2018 Memorandum of Daymark Energy Advisors at p. 2 in Docket No. 4763 (attached hereto as Exhibit G).
[17] Company's April 27, 2018 Reply to Division's Memorandum at p. 2 in Docket No. 4763 (attached hereto as Exhibit H).
[18] PUC's January 4, 2019 Report and Order in Docket No. 4763 at p. 7 (attached hereto as Exhibit I).
[19] Indeed, the Division is specifically asking the Commission to send a message to the DG development community that reimbursement for grid upgrades required by the Company to provide safe, reliable service to ratepayers is not guaranteed. *See* Division's May 20, 2024 Objection to Motion for Summary Disposition by Green Development, Inc. at p. 3, n.10 ("There is no doubt that many other DG developers, with many millions of dollars in projects, are waiting 'in the wings' to learn if they, too, may receive interconnection cost recovery for their projects from ratepayers as 'System Improvements.'").
[20] Exhibit C at 125:23-126:1.

I. BRIEF STATEMENT OF THE FACTS

A. Revity's Robin Hollow Solar Project.

Revity's Robin Hollow Project includes 7 sites totaling 40.7 megawatts (MW) with 5.25 MW being fed off the 3310 circuit and 35.45 MW being fed off the 3309 circuit.[21] Revity's Robin Hollow Project entered the interconnection queue on October 18, 2019.[22] The Company began the impact study for the Robin Hollow Project on January 6, 2020.[23] The Company completed the Impact Study for Revity's Robin Hollow Project on April 21, 2021 which Impact Study reported that "the Project was found to be feasible with certain modifications to the existing Company System and operating conditions" and identified those System Modifications (to include the Modifications for which reimbursement is being sought).[24] On May 16, 2022, the Company and Revity entered into the Interconnection Service Agreement (ISA) for the Robin Hollow Projects (which ISAs were amended on July 29, 2022 and April 26, 2023).[25] The second amendment to the ISA included System Modifications totaling $3,494,272 excluding the civil manhole, duct system and electrical component.[26] Revity self-performed the manhole and duct bank system and a portion of the electrical work for the Robin Hollow Projects.

The record is clear that the Company "discussed with Green, Revity, and EDP the possibility of obtaining reimbursement from ratepayers for some of Green's, Revity's, and EDP's (now under Revity's control) expenditures for the Weaver Hill Project."[27] "As a condition to self-building, Green and Revity were required to build to the Company's standard including installing

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[21] October 17, 2023 Pre-Filed Joint Testimony of Erica Russell Salk & Stephanie A. Briggs at p. 14:18-20 (excerpts attached hereto as Exhibit J).
[22] Exhibit J at p. 15:8-9.
[23] Exhibit J at p. 15:18-20.
[24] Exhibit EJRS-2 to Company's Pre-Filed Testimony at pp. 6-10 of 70 (attached hereto as Exhibit K).
[25] Exhibit J at p. 16:12-15.
[26] Exhibit J at p. 17:9-12.
[27] Company's May 21, 2024 Responses to Div. 6-1 (attached hereto as Exhibit L).

extra duct to accommodate future needs" and the "basis being the Company would have included the extra duct work if it built the investment itself."[28] "Building out the extra duct work is consistent with how the Company treats both load and distributed generation customers and is good utility practice as it saves customers money over the long term" and this "extra duct work benefits all distribution customers and, had the work been performed by the Company, the Company would not have initially charged Green and Revity for the extra duct work and included it in the ISR reconciliation."[29]

In the first week of March 2023, the Company agreed to cost-sharing reimbursement for the ductbank and associated upgrades necessary for the Weaver Hill substation (subject to the Company filing a petition with the Commission).[30] During the May 31, 2023 monthly meeting, Revity and the Company discussed cost reimbursement for the Weaver Hill substation ductbank and associated upgrades and it was suggested that "[i]t seems that an equitable solution is in order to avoid preferential treatment of one developer over the other and arrive at a 50/50 reimbursement factor for both 3309 & 3310 cable installations if either one could be utilized."[31] During the June 28, 2023, August 23, 2023, September 20, 2023, November 27, 2023 and December 19, 2023 monthly meetings, Revity and the Company further discussed reimbursement of the Weaver Hill Substation ductbank and associated upgrades.[32] The Company has testified that "for the additional

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[28] Exhibit L.
[29] Exhibit L. The Company continued that "[g]iven the timing of the auditing of the duct bank costs and for administrative ease, the extra duct work was initially borne by Green and Revity through its self-build and requested reimbursement to Green and Revity for the extra duct work was included in the Petition for review and approval by the PUC." *Id*.
[30] May 22, 2024 Pre-Filed Surrebuttal Testimony of Ryan Palumbo at p. 3:3-9 (attached hereto as Exhibit M).
[31] Revity's June 4, 2024 Response to Commission's First Set of Data Requests at p. 9 of 53 (attached hereto as Exhibit N).
[32] Exhibit M at p. 3:12-18.

ducts * * * we had a confidence that we would figure out a way to get reimbursement done"[33] and the Company expressed that confidence to Revity.[34] From Revity's perspective, the "Company did a good job of letting us know that this cost-sharing is on the table, subject to the Commissioner approval" and "the way we understood it was that this is going to go through an audit process, a third party was going to come in to verify all the costs to make sure that they're true and accurate, that they're allocated to the right bucket, and then ultimately then the Commission will decide what the right number was * * *."[35]

Revity and its Company-approved subcontractors, Asplundh Construction, LLC (Asplundh) and Rosciti Construction Co., LLC (Rosciti), began self-performing the system upgrades required by the Company for the Weaver Hill Project on July 17, 2023 and Revity authorized Rosciti to begin underground work for the Weaver Hill Project on September 6, 2023.[36] Revity authorized Asplundh to begin overhead upgrade work on November 2, 2023.[37] Revity and Rosciti completed the statement of work for the civil manhole and duct bank work on November 7, 2023.[38] Revity and Asplundh completed all underground upgrade system work on or before November 30, 2023.[39] The Robin Hollow Projects were authorized to interconnect on December 23, 2023 and are completed and in service.[40]

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[33] Exhibit B at 203:19-22.
[34] Exhibit B at 206:15-18 ("MR. NYBO: And the company made that -- expressed that confidence to Revity? MR. CONSTABLE: Yeah. * * *.").
[35] 7/9/2024 TR at 33:20-34:2 (excerpts attached hereto as Exhibit O).
[36] Exhibit M at p. 15:1-7.
[37] Exhibit M at p. 15:7.
[38] Exhibit M at p. 15:8-9.
[39] Exhibit M at p. 15:9-10.
[40] Company's May 21, 2024 Responses to Div. 6-3 (attached hereto as Exhibit P); Exhibit O at 118:4-9.

B. Revity's Studley Solar Project.

In October of 2023, Revity acquired ownership and control of Studley Solar, LLC which was previously owned and controlled by Energy Development Partners ("EDP") which was developing a 9.2 MW site to be fed off the 3310 circuit.[41] The Studley Solar Project entered the interconnection queue on May 10, 2019.[42] The Company began the impact study for the Studley Solar Project on August 7, 2019.[43] The Company completed the Impact Study for the Studley Solar Project on September 20, 2022 which Impact Study reported that "the Project was found to be feasible with certain modifications to the existing Company System and operating conditions" and identified System Modifications.[44] The Company issued an ISA for the Studley Solar Project on April 14, 2023.[45] The Studley ISA included System Modifications totaling $8,437,085 excluding the civil manhole and duct system to be constructed by the developer.[46] The Company began a new impact study for the Studley Solar Project in early 2024 and the Company issued the revised impact study in June of 2024.[47] Revity is in the design and survey phase of the Studley Solar interconnection work.

II. CONTROLLING LAW

The Rhode Island General Laws dictate that the statutory interconnection standards "shall be construed liberally in aid of" the "expeditious completion of the application process for renewable distributed generation" which "is in the public interest."[48] The "electric distribution

[41] Company's April 26, 2024 Letter re: Updated Ownership and Control of Studley Solar Project from EDP to Revity (attached hereto as Exhibit Q)
[42] Exhibit J at p. 15:11-12.
[43] Exhibit J at p. 16:1-3.
[44] Exhibit K at pp. 6-10 of 70.
[45] Exhibit J at p. 16:12-15.
[46] Exhibit J at p. 17:14-17.
[47] Exhibit O at 91:1-2.
[48] R.I. Gen. Laws §§ 39-26.3-1, 39-26.3-5.

company may only charge an interconnecting, renewable-energy customer for any system modifications to its electric power system specifically necessary for and directly related to the interconnection."[49]

The Company's Petition asks that the Commission conclude that certain system upgrades should be reimbursed by the ratepayers as a "System Improvement" or an "Accelerated System Modification." The Narragansett Electric Company Standards for Connecting Distributed Generation (R.I.P.U.C. No. 2258) (the "Interconnection Tariff") defines a "System Improvement" as "[e]conomically justified upgrades determined by the Company in the Facility study phase for capital investments associated with improving the capacity or reliability of the EDS that may be used along with System Modifications to serve an Interconnection Customer."[50] The Tariff defines a "System Modification" as "[m]odifications or additions to Company facilities that are integrated with the Company EDS for the benefit of the Interconnecting Customer."[51]

Section 5.3 of the Interconnection Tariff states that the "Interconnecting Customer shall only pay for that portion of the interconnection costs resulting solely from the System Modifications required to allow for safe, reliable parallel operation of the Facility with the Company EDS; provided, however, the Company may only charge an Interconnecting Customer for System Modifications specifically necessary for and directly related to the interconnection, excluding modifications required on the Transmission infrastructure." Section 5.4(a) states that the "Company may combine the installation of System Modifications with System Improvements to the Company's EDS to serve the Interconnecting Customer or other customers, <u>but shall not</u>

[49] R.I. Gen. Laws § 39-26.3-4.1(a).
[50] Interconnection Tariff at § 1.2.
[51] *Id*.

include the costs of such System Improvements in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff."[52]

With respect to Accelerated System Modifications, Section 5.4(b) provides that "[i]n the event that the Commission determines that a specific System Modification of the electric distribution system benefits other customers and has been accelerated due to an interconnection request and orders the Renewable Interconnecting Customer to fund the modification, the Renewable Interconnecting Customer will be entitled to repayment of the depreciated value of the modification as of the time the modification would have been necessary as determined by the Commission." Section 5.4(c) states that "[t]he Company will consider a system modification to be an accelerated modification if such modification is otherwise identified in the Company's work plan as a necessary capital investment to be installed within a five-year period as of the date the Company begins the impact study of the proposed distributed generation (DG) project (defined as an Accelerated Modification)." Section 5.4(c) continues that "[t]he Company will identify the Accelerated Modification and the costs thereof in the impact study."

III. ARGUMENT

In response to PUC 2-4, the Company provided an attachment which "explains how estimated costs may be allocated across the various sections of the work" and proposes reimbursement of $4,016,349 for System Improvements and reimbursement of $10,541,062 for Accelerated System Modifications associated with the Weaver Hill interconnection infrastructure.[53] The Company testified that it cannot operate the Weaver Hill substation without

[52] Emphasis supplied.
[53] Company's May 28, 2024 Responses to PUC Data Requests (PUC 2-4) (attached hereto as Exhibit R). On June 21, 2024, the Company responded to Commission's Record Request No. 3 with an updated version of PUC 2-4 which proposes reimbursement of $8,550,153 for Accelerated System Modifications and reimbursement of $5,502,137 for System Improvements.

these System Improvements and Accelerated System Modifications.[54] The Division agrees that "the intent is that upgrades that have already been built are going to service load customers and the Weaver Hill substation * * *."[55] The Division does not oppose the reasonableness of the figures proposed by the Company in response to PUC 2-4.[56] The Company has testified that it is not "aware of any other examples where the Division has objected to acceleration of planned system improvements in association with interconnection of any customer load or otherwise * * *."[57]

The full amount of these System Improvements and Accelerated System Modifications should be awarded pursuant to R.I. Gen. Laws § 39-26.3-4.1 and Sections 5.3 and 5.4 of the Interconnection Tariff. Green has testified that it is entitled to $2.3 million of the $14.5 million reimbursement[58] and thus Revity is entitled to $12.2 million in reimbursement.

1. System Improvements cannot be charged to distributed generation customers.

With respect to the $4,016,349 in System Improvements, the Company agreed that the solar facilities in the area can operate without any of the System Improvements that the Company ordered the DG customers to install.[59] This work was ordered exclusively because it was needed for the Weaver Hill substation to benefit distribution customers.[60] The Interconnection Tariff

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[54] Exhibit B at 190:4-191:14.
[55] Exhibit C at 102:2-6.
[56] Exhibit C at 128:3-8; *id*. at 134:6-15 ("MR. HANDY: "Does the Division object to the cost that the company, DG companies incurred to interconnect their projects? MR. BOOTH: The Division doesn't have an opinion one way or the other. Q: So the Division doesn't object to the cost that the company incurred to interconnect their own projects? A: I think the DG folks make their own costs decisions. The Division has no role in that.").
[57] Exhibit B at 169:21-170:1.
[58] 6/6/2024 TR at 81:13-82:4 (excerpts attached hereto as Exhibit S) ("MR. NYBO: Okay. Is it fair to say that -- excuse me -- the $3.6 million that Green received from Rhode Island Energy that was paid by Revity reduces that 5.9 million to 2.3 million that Green needs cost reimbursement for Weaver Hill? MR. URSILLO: Correct, based on the numbers provided by Rhode Island Energy, yes, it would be the net of what was already reimbursed from Rhode Island Energy, and what the difference is. * * * Q: * * * [I]f the $14-and-a-half million was ultimately the cost reimbursement, Green's claim to that in Weaver Hill would be 2.3 million? A. Correct, roughly.").
[59] Exhibit B at 190:25-191:4.
[60] Exhibit B at 191:5-14.

plainly prohibits charging DG customers for System Improvements which the Tariff defines as "[e]conomically justified upgrades determined by the Company in the Facility study phase for capital investments associated with improving the capacity or reliability of the EDS * * *."[61] Clearly, the Tariff vests the Company with the plenary authority to determine what system upgrades are economically justified and the Company has exercised that authority with regard to the Weaver Hill substation.

The fact that the $4,016,349 in System Improvements is even open for debate is solely a function of the DG customers' self-performance of these Improvements. Had the DG customers not self-performed the System Improvements—and instead let the Company perform the System Improvements—there is no question that these DG customers could not have been charged for these costs.[62] Because the DG customers self-performed the work, they necessarily incurred the costs in the first instance. The Company agrees that "because of the self-build, there's a little bit of uncertainty here."[63] DG customers should not be punished for electing to self-perform the interconnection upgrades especially because the Company agrees that self-performance of these upgrades "was less expensive than what the costs would have been had the company performed all of the work."[64] "When Revity received the initial budgeting for [the Company's] scope of work relative to this project, we were looking at a number of 30 plus million dollars" but Revity, "in collaboration with Green Development * * * performed it all in for approximately $17,000,000"

[61] Section 5.4(a) of the Interconnection Tariff (emphasis supplied); Exhibit B at 166:25-167:16 ("MR. HANDY: So Green was required to do work planned to benefit other customers; correct? MR. CONSTABLE: The additional ducts, yes. Q: Under the premise that Rhode Island Energy would seek reimbursement? A: Yes. Q: And that was only because the project was self-built? A: Yes. Q: Green wouldn't have been required to fund and wouldn't be here if Rhode Island Energy had constructed the interconnection? A: Right. * * *").
[62] Exhibit A at 224:5-22.
[63] Exhibit B at 203:5-6.
[64] Exhibit B at 192:1-9.

saving "ratepayers close to $13, $14,000,000."[65] The Division agrees that there is no reason to "apply the tariff differently when a DG customer self-performs interconnection work as opposed to when it's the company performing the work and the DG customer is the paying Company * * *."[66]

The Rhode Island General Laws and the Interconnection Tariff both prohibit charging DG customers for System Improvements (as determined by the Company).[67] This Commission has stated that where "the utility makes other changes to the electric system as part of the same project where those changes are simply to improve the operation of the system and are necessary to provide safe and reliable service to customers regardless of the addition of the renewable energy generator * * * these costs are already charged to all ratepayers."[68] The DG customers must be reimbursed for the $4,016,349 in System Improvements.

2. ***The Company's Petition properly seeks cost recovery from ratepayers pursuant to Section 5.4(c) of the Interconnection Tariff to compensate Revity for Accelerated System Modifications required by the Company to be built by Revity during the interconnection of the Robin Hollow and Studley Solar Projects.***

System modifications are "[m]odifications or additions to Company facilities that are integrated with the Company EDS for the benefit of the Interconnecting Customer."[69] To be eligible for acceleration and ratepayer reimbursement, a system modification must meet the following conditions: (a) the modification must be identified in the Company's work plan as a necessary capital investment; (b) the modification must be installed within a five year period "as of the date" the Company begins the impact study; and (c) the system modification and the costs thereof must be identified in the impact study.

65 Exhibit O at 13:1-22.
66 Exhibit C 144:8-14.
67 R.I. Gen. Laws §§ 39-26.3-4.1(a) & (b); Interconnection Tariff at § 5.4(a).
68 Exhibit D.
69 Exhibit D.

a. Revity's system modifications were identified in the Company's past work plans as a necessary capital investment.

The System Modifications for which the Company is seeking acceleration are necessary for the service of a new Weaver Hill substation. The Division agrees that "the tariff puts on the company the decision of whether or not a capital investment is necessary"[70] and it is not the Division's role "to determine whether or not an investment is a necessary capital investment."[71] The Company has opined that "[i]f a capital project is mentioned in the Company's ISR Plan filing" the Company considers "the project 'identified in the Company's work plan as a necessary capital investment.'"[72] The Division has previously opined that the "ISR plan process is a better forum for establishing what constitutes a system modification" and the Company should be "identifying system modifications [or] system improvements is through the ISR plan process."[73] The Division concedes that "[i]t doesn't really matter whether the Division agrees whether these projects are needed or not for customers."[74] The natural conclusion of this evidence is that, if the Company identifies the work as a "necessary capital investment" in its ISR work plan, the work is eligible for acceleration and reimbursement regardless of the Division's position on the investment.

On December 21, 2020, years before Revity began its interconnection work, the Weaver Hill substation was identified by the Company in the Electric Infrastructure, Safety, and Reliability (ISR) Plan FY 2022 in Docket No. 5098.[75] In May of 2021, the Company transmitted to the Division the Central RI West Area Study which Study stated that "[t]wo (2) new substation

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[70] Exhibit C at 90:21-24.
[71] Exhibit C at 91:7-10.
[72] Company's February 15, 2024 Responses to Division 4-17 (attached hereto as Exhibit T).
[73] Exhibit C at 114:2-115:25.
[74] Exhibit C at 85:19-86:6; *id*. at 91:7-10 ("MR. HABIB: Not the Division's role here, correct, to determine whether or not an investment is a necessary capital investment? MR. BOOTH: That's correct.").
[75] Company's June 5, 2024 Response to Record Request No. 1 (attached hereto as Exhibit U).

locations were investigated to be utilized to build a modular substation/feeder to offload [the 63F6 and 54F1 feeders] – one at Weaver Hill Road, West Greenwich and one near Pine Hill Road, Exeter."[76] According to the Company, "the Division reviewed the Central RI West Area Study issues and recommendations in May of 2021 and made no comments regarding the analysis."[77] The Company continues that "the Division has had 4 opportunities over 3 years to comment on the details of the Central RI West Study and has failed to do so."[78] According to the Company, "once the area studies are completed, we'll have the discussion with the Division, and then, and then it'll move, depending on the needs identified in the study, into the ISR, into the ISR proposal."[79]

The Division concedes that it received the Central RI West Area Study in May of 2021 and began its review of the Study at that time but "the Division doesn't get into the details * * *."[80] The Division's witness agrees that the Weaver Hill circuit "has reliability issues and [no] ability to quickly switch load and outage"[81] so "outages may take a little longer"[82] but his "recollection

[76] Exhibit EJRS-7 to Company's Pre-Filed Testimony at p. 457 (attached hereto as Exhibit V); Exhibit C at 11:24-12:6 ("MR. CONSTABLE: * * * Weaver Hill substation, the central Rhode Island west area study recommended installing a new substation on Weaver Hill due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer in one feeder position, and installing a transformer in one feeder position, and installing distribution line work for feeders. So the scope is clearly defined.").
[77] Exhibit F at p. 12:14-15; Exhibit B at 213:15-214:9 ("MR. CONSTABLE: So when we do the area studies, this is actually, you know, part of the process where we actually seek Division comment so that we can get input onto the issue identification, the alternative analysis, and the recommendations. And so we do what we call a technical presentation. And so in that technical presentation, we will walk through how we identify the issues, how we evaluated the alternatives, and then what our ultimate recommendation was. MR. NYBO: Okay. And the Weaver Hill substation was fairly prominently included in that area study. MR. CONSTABLE: Yes. MR. NYBO: And your testimony is the division raised no issues about the Weaver Hill substation? MR. CONSTABLE: Yes. There was no comments.").
[78] Exhibit F at p. 13:1-3.
[79] Exhibit O at 113:5-9.
[80] Exhibit C at 103:15-104:4.
[81] Exhibit C at 152:16-18.
[82] Exhibit C at 154:2-3.

is that it is not the worst circuit on the entire system."[83] The Division does not contest "the need for this infrastructure to benefit customers at some point in the future" but maintains that "you don't need it today."[84] Ignored by the Division's analysis is the Town permitting requirements which dictate that the parties collaborate to "dig up the road once" so as to not "reallocate town resources, police detail, reroute school buses for six months just to do it again six months later, six months later, six months later."[85]

On December 20, 2021, in its ISR FY 2023 (in Docket No. 5209), the Company identified the need for the Weaver Hill substation as follows:

> Concerns: a number of circuits require reconductoring due to reliability, contingency, capacity, or asset condition concerns (2230 line, 54F1, 63F6, etc.); three stations require equipment replacement/upgrades due to asset condition concerns (Coventry, Hope and Division St).
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> Summary of Recommended Solutions:
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> * * *
>
> - Extend portions of the 35kV system and install a new modular substation at Weaver Hill Rd to relieve 54F1 and 63F6 circuits and address the Kent County 35kV system concerns.

The Division agrees that the Weaver Hill substation was identified by the Company as a "potential need" in the FY 2023 ISR.[86]

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[83] Exhibit C at 113:1-2. In response to Revity's question of whether "being the worst circuit in the area" would "be a reason that would justify system upgrades in that area for that circuit", Mr. Booth responded: "No, not if, not if the problem isn't so severe that you have to deal with it immediately." *Id*. 113:9-15. Mr. Booth did, however, agree that the Company is ultimately accountable "[i]f the Division recommends that a particular investment not be invested in for budgetary purposes or for need, and the company decided to agree with that decision and there was a safety or reliability problem related to that decision * * *." *Id*. at 98:19:99:2.

[84] Exhibit C at 83:10-84:2. Of course, it is the Company that is held accountable "if there is something that goes wrong with system reliability or safety * * *." *Id*. at 98:16-99:1 ("MR. HABIB: If the Division recommends that a particular investment not be invested in for budgetary purposes or for need, and the company decided to agree with that decision and there was a safety or reliability problem related to that decision, is the Division accountable for that decision, or is the company accountable for that decision? MR. BOOTH: The company is accountable * * *.").

[85] Exhibit O at 53:7-12.

[86] Exhibit C at 116:1-7.

On December 22, 2022, in its ISR FY 2024 (in Docket No. 22-53-EL), the Company again identified the need for the Weaver Hill substation as follows:

Problem:	There are predicted loading and voltage concerns on certain Hopkins Hill and Coventry substation feeders. The loading concerns include feeders predicted to be near or in excess of thermal ratings. The voltage concerns are similarly at or below guidelines. These same feeders are approaching contingency load-at-risk limits. Furthermore, many of the area feeders have circuit frequency and duration metrics above system averages.
Preferred Plan:	Install a new substation on Weaver Hill Rd. This work extension of the 3309 and 3310 lines from Nooseneck Hill and Weaver Hill Roads in West Greenwich to a Rhode Island Energy owned property on Weaver Hill Rd, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.
Alternate Plan:	Install a new substation on Bell Schoolhouse Road (Pine Hill substation). This work includes extension of the 3310 line from Route 3 north of Route 102 to a Rhode Island Energy owned property at the intersection of New London Turnpike and Bell Schoolhouse Road, Exeter referred to as Pine Hill substation. The work also includes the installation of a new 34.5 kV line from the new Wickford Junction substation to Pine Hill substation, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.[87]

The Division agrees that "the Weaver Hill substation was identified in the 2023 ISR plan as a necessary capital investment."[88]

The following year, on December 21, 2023, in its ISR FY 2025 (in Docket No. 23-48-EL), the Company identified the need for the Weaver Hill substation as follows: "The Central Rhode

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[87] Company's December 22, 2022 Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan (21-Month Filing April 2023-December 2024) (Book 1 of 2) at p. 95 (excerpts attached hereto as Exhibit W).

[88] Exhibit C at 116:20-23.

Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns" and "[t]his work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder."[89] The Division agrees that the "Weaver Hill substation was identified in the 2025 ISR plan as a necessary capital investment."[90]

According to the Company, "there was not debate around the Tiverton or the Weaver Hill projects in those ISR processes" and indeed, the Division "supported the inclusion of the Weaver Hill projects in the FY 2024 and FY 2025 ISR Plan filings."[91] Nevertheless, the Division maintains that "the improvements do not need to be included in an ISR Plan for capital improvement expenditure absent the DG project before 2035" and so "there should not be any reimbursement to the DG customers as proposed by the Company."[92]

It is patently inequitable for DG customers to be financially responsible for this internecine dispute between the Company and the Division regarding the propriety of the Company's ISR filings. This inequity is best evidenced by the following colloquy:

> MR. BOOTH: [I]f these dollars aren't in an ISR plan, haven't been approved in an ISR plan, had, in fact, been removed from the ISR plan, and the Division, who is one of the company witnesses in the ISR process that the Commission listens to says this isn't needed until 2035, my answer to you is a reasonable person would not assume that they would get those dollars instantly.
>
> MR. NYBO: Okay. So in that situation when those factors exist, a DG customer in this state can go to the company and say I'm not building your system modifications, because its outside five years, and because the Division has objected, we're not doing it. You're going to interconnect me nevertheless; we can do that?

---

[89] Company's December 21, 2023 Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan at p. 40 (excerpts attached hereto as Exhibit X).
[90] Exhibit C at 116:24-117:3.
[91] Exhibit F at p. 12:20-13:1; Exhibit B at 213:23-215:21; Exhibit C at 16:4-8 ("MR. WOLD: Mr. Constable, these document don't reflect the Division's pushback to the company regarding the ISR plan positions that the company takes, right? MR. CONSTABLE: There is no pushback on the Tiverton or Weaver Hill [projects].").
[92] Exhibit E at pp. 5:18-6:6.

MR. BOOTH: No. You're going to have to sit down with the company and work out the details.

MR. NYBO: In the future, would the Division join in those meetings and sit with the DG companies and explain to the company that they're being unreasonable by requiring DG customers to build unnecessary system modifications?

MR. WOLD: Objection.

MR. NYBO: What is the objection?

MR. WOLD: How does Mr. Booth know what the Division would or would not do in that hypothetical? First of all, that hypothetical, we would have to take that back to the administrator of the Division. Mr. Booth certainly at this stage would not have any basis or foundation for giving an opinion to answer that question.

MR. GERWATOWSKI: I'm going to sustain the objection.[93]

According to the Division, if system upgrades beyond those necessary to interconnect are included in the impact study because those upgrades have been identified as necessary to system reliability in previous ISR filings, the DG customer is left to meet with the Company in hopes of convincing the Company that it wrongfully included those upgrades in the impact study. But, even if the Division objected to the upgrades being included in the ISR filing, the Division will not commit to participating in those meetings. If the DG Customer cannot convince the Company that the upgrades were wrongfully included, the DG Customer must either abandon its project or be financially responsible for these upgrades despite the fact that those upgrades have nothing to do with the DG customer's project. This is the Division's position.

Mercifully, the Tariff does not brook that result. Section 5.4(c) of the Interconnection Tariff merely requires that the system modification be "identified" by the Company in its ISR work plan to qualify for acceleration and reimbursement. The Weaver Hill substation has been clearly and repeatedly identified by the Company in its ISR work plans since 2020. Indeed, it was by reviewing the Company's ISR work plans that the DG customers involved in this proceeding were able to

[93] Exhibit C at 118:18-119:25.

discover the Company's intentions to build the substation.[94] And it was only because DG customers discovered these intentions in 2022 that the Company began discussions with DG customers regarding cost reimbursement.[95] Section 5.4(c) does not require that the Company include the proposed development in the budget (although it did)[96] or that the Commission (or the Division) approve the proposal—it merely requires that the Company identify the System Modification "in the Company's work plan as a necessary capital investment."[97] Here, the Company has clearly identified the System Modifications in its work plan as necessary capital investments.

b. Revity's modifications were installed within a five-year period "as of the date" the Company began the impact study.

Section 5.4(c) states that the Company will consider a system modification to be an accelerated modification provided that it is "installed within a five-year period as of the date the Company begins the impact study" and that all accelerated modifications and the costs thereof must be included in the impact study. The Division's witness agreed that, under Section 5.4(c), "what needs to be completed within five years has to be identified in the impact study."[98] If an

[94] Exhibit O at 47:25-48:6; *id*. at 101:24-102:24.
[95] Exhibit O 144:1-145:21.
[96] Exhibit O at 168:5-11.
[97] It must also be noted that the Division has previously objected to DG Customers intervening to protect their interests in the Company's ISR Dockets. In ISR FY 2016 (Docket 4539), WED Coventry One, LLC, WED Coventry Two, LLC, WED Coventry Three LLC, WED Coventry Four, LLC, WED Coventry Five, LLC and WED Coventry Six, LLC filed a Motion to Intervene on February 10, 2015. The Division objected to the Motion to Intervene, on February 17, stating that "Mr. Booth has reviewed NGRID's ISR budgets for a number of years, is intimately familiar with NGrid's distribution system, and possesses consider legal, financial and technical expertise regarding the system's infrastructure needs and requirements" and so the Division "can easily and adequately assess the alleged interests (if any) espoused by WED that may require Commission consideration in the hearing process." February 17, 2015 Division Objection at p. 6 (attached hereto as Exhibit Y). Notably, in this pending docket matter, Mr. Booth testified (regarding this statement) that "I don't have a law degree, so I'm not sure why legal is in the sentence, but I have plenty of financial and technical expertise." Exhibit C at 122:18-20. The Commission denied WED's Motion to Intervene in Docket 5439.
[98] Exhibit C at 131:13-132:20.

upgrade is not included in the impact study (for example, the actual Weaver Hill substation) it does not need to be completed within five years.

With respect to Robin Hollow, the Company began the impact study on January 6, 2020.[99] Thus, Revity had until January 6, 2025 to complete the system modifications. All system modifications identified in the Robin Hollow impact study (for which the Company now seeks reimbursement) have been completed and the Robin Hollow Projects were authorized to interconnect on December 23, 2023.[100] The System Modifications for Robin Hollow were undoubtedly installed within a five-year period "as of the date" the Company began the impact study.

The timeline of the Studley Solar project is a bit more complicated. The Company began the impact study for the Studley Solar Project on August 7, 2019[101] but the Company did not complete the impact study until September 20, 2022.[102] Moreover, the Company began a new impact study for the Studley Solar Project in 2024 and the Company issued the revised Impact Study in June of 2024.[103] There have been two or three iterations of the Study Solar impact study since it was originally issued.[104] Comparing the original impact study to the 2024 impact study, "it's completely different, different equipment, the project size is different. So apples and oranges between the two."[105] The Company is "finalizing the ISA right now * * * [i]ncorporating those upgrades from the impact study" and Revity "will start construction this year."[106]

[99] Exhibit J at p. 15:18-20.
[100] Exhibit P; Exhibit O at 88:24-89:18.
[101] Exhibit J at p. 16:1-3.
[102] Exhibit K at pp. 6-10 of 70.
[103] Exhibit O at 91:1-2; *id*. at 93:6-12 ("The Studley solar project has just received its impact study back about a month ago. We are finalizing the ISA right now. So that's where the process stands. Incorporating those upgrades from the impact study. And we'll hopefully start -- will start construction this year.").
[104] Exhibit O at 91:18-22.
[105] Exhibit O at 91:14-17.
[106] Exhibit O at 93:6-12.

The Studley Solar impact study timeline highlights the flaw in the Division's absolutist approach regarding the five-year window because no construction can begin until the execution of an ISA.[107] The Company agrees that "the five-year period is difficult to apply in a black-and-white fashion in these petitions."[108] The ISA comes after the completion of both the regional transmission operator's Affected System Operator (ASO) study and the Company's impact study and "there could be a three- to four-year timeline from when an impact study starts and when an impact study * * * is actually delivered to the customer."[109] Indeed, it can take "three years before [an] impact study is even looked at" and "[i]t's not always one impact study" because "[i]t's very common in Rhode Island for projects to be restudied for a variety of reasons * * *."[110] "[Y]ou submit an application one year, and you wait three or four years, by that time, when you go to source that same equipment, its probably not available" and "any time you switch equipment like that, it usually requires a re-study of the impact study by the utility."[111] "[A] project will go through several impact studies before you finally get to an ISA."[112] For Studley Solar, the "impact study process took a number of years"[113] and has been revised a number of times. The start of the operative impact study should be the trigger date for the five-year period and so Revity has until 2029 to complete the system modifications identified in the revised Studley Solar impact study to qualify for acceleration.

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[107] Exhibit O at 23:13-17.
[108] Exhibit O at 119:24-120:1.
[109] Exhibit O at 18:2-5; Exhibit F at 9:10-16 ("The interconnection study process for sites similar to Weaver Hill's site considered in this Petition can span many years. (In this case, the three sites took 3 to 5 years with one site's ISA still pending). ISO-NE's Affected System Operator ('ASO') process can create similar timelines. Furthermore, the planning and full construction of projects identified within area studies can span many years considering the study time, the process time to introduce and request approval with an ISR Plan, and the practical design, procurement, and resourcing times.").
[110] Exhibit O at 17:15-18:11.
[111] Exhibit O at 18:15-19; 19:23-25.
[112] Exhibit O at 80:8-9.
[113] Exhibit O at 149:10-11.

c. Revity's modifications and costs were identified in its impact studies.

The Robin Hollow impact study lists the System Modifications necessary to interconnect the Robin Hollow project (including all Modifications for which the Company is proposing acceleration and reimbursement).[114] The costs of these System Modifications were listed in the Robin Hollow ISA.[115] The Studley Solar revised impact study lists the System Modifications necessary to interconnect the Studley Solar project (including all Modifications for which the Company is proposing acceleration and reimbursement).[116] The costs of these System Modifications were listed in the Studley Solar ISA.[117]

3. The Commission should endorse the duct count method over the incremental method because the former is easier to employ and reduces the amount of winner/loser scenarios and hearings to resolve unnecessary future disputes.

The Company concedes that interconnection reconciliation process in Rhode Island "is a bit of a black box."[118] On every project, Revity has difficulty discerning the costs that are properly attributable to its project from those costs that benefit the ratepayer.[119] The Company "has a responsibility to choose a methodology that makes sense and then defend it."[120] The Company proposed its methodology in its filing which contemplated "cost sharing for 100% of the electrical work on the common path associated with the 3310 circuit with a four-year depreciation and 100% of the common path portion of the underground civil duct bank with a four-year depreciation."[121]

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[114] Exhibit K at pp. 6-10.
[115] Exhibit EJRS-5 to Company's Pre-Filed Testimony at pp. 245-249 (attached hereto as Exhibit Z); Exhibit O at 190:20-191:13.
[116] Exhibit EJRS-3 to Company's Pre-Filed Testimony at pp. 142-143 (attached hereto as Exhibit AA).
[117] Exhibit EJRS-6 to Company's Pre-Filed Testimony at pp. 443-448 (attached hereto as Exhibit BB).
[118] Exhibit O at 45:11-12.
[119] Exhibit O at 104:22-105:15 ("MR. PALUMBO: To be frank, its every project. When we get a reconciliation report back, there's not enough detail or information for us to truly, you know, discern on whether or not these costs are justified or not, just whether there was a ratepayer benefit or if it was purely DG. So with every project, we kind of have a struggle.").
[120] Exhibit O at 63:18-20.
[121] Exhibit J at 23:13-16; Exhibit O at 64:23-24 ("MR. HABIB: We offer up the methodology that we put in the testimony.").

In the travel of this docket, however, the Company has proposed a combination of the "duct count" method and the "incremental" method. The Company contends that "both methods are reasonable."[122]

The Company agrees that the duct count method is "straightforward, black and white, and it seems to be the most fair method that can be utilized of the two."[123] The Company agrees that the "duct count" method is the "easier method."[124] When the Company is determining cost-sharing between DG developers, it employs the duct count method.[125] The Company agrees that the incremental method "is always going to have a loser" because "the deeper you go into a trench, the more risk and cost that you're going to run into on a per foot basis" and so "you can find that the second person in line is going to be responsible paying for that one-third, that additional 2 feet, but that additional 2 feet could be 50, 60 percent of the cost."[126] The Company agrees that there are "certainly instances where the second level work may be more expensive than the first level work because of ledge and water table issues" and so "the second level person will always, on the incremental method, have a smaller share of the cost-sharing * * *."[127] Accordingly, the incremental method raises a very consequential question: Which party is identified as the first-mover? The Company's tautological response is that "[i]t's basically the person going first."[128] If the Company determined that the ratepayer went first "the developer wouldn't have to pay anything for the benefit" of interconnection.[129]

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122 Exhibit O at 110:21.
123 Exhibit O at 37:5-8.
124 Exhibit O at 124:19-20.
125 Exhibit O at 132:15-133:6.
126 Exhibit O at 37:17-38:1.
127 Exhibit O at 127:1-13.
128 Exhibit O at 129:15.
129 Exhibit O at 131:7-21 ("MR. NYBO: Well, based on the hypo you gave, I may be putting my job at risk by saying this, but isn't that a bit unfair, that this developer in that case gets interconnection for free? Isn't

The record evidence is clear that the duct count method is the more even-handed and straightforward approach. The Commission should not endorse a cost-sharing method that "is always going to have a loser."[130] The Commission should endorse the duct count method as the appropriate paradigm for all future reimbursement petitions.

CONCLUSION

WHEREFORE, Revity respectfully requests that the Commission approve the Company's request to recover $10,541,062 from the distribution customers for Accelerated System Modifications incurred by DG customers (subject to a 2-year depreciation pursuant to Section 5.4 of the Tariff) and recover $4,016,349 for System Improvements incurred by the DG customers.

REVITY ENERGY LLC

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that an inequitable result from the incremental method? MR. CONSTABLE: It's simply the way the statutes and the tariffs and in [sic].").

[130] Exhibit O at 37:17-38:1.

Docket No. 23-38-EL
Rhode Island Energy – Petition for Acceleration Due to DG Project – Weaver Hill Projects
Service List updated 7/29/2024

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EXHIBIT A

STATE OF RHODE ISLAND

PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY D/B/A RHODE ISLAND ENERGY'S PETITION FOR ACCELERATION OF SYSTEM MODIFICATION DUE TO DISTRIBUTED GENERATION PROJECTS - TIVERTON PROJECT DOCKETS NO. 23-37-EL

HEARING

~ BEFORE ~

RONALD T. GERWATOWSKI, CHAIRMAN

ABIGAIL ANTHONY, COMMISSIONER

JOHN C. REVENS, JR., COMMISSIONER

JUNE 3, 2024

9:30 A.M.

Warwick, Rhode Island

Lisa L. Crompton, CSR, RPR

in more detail, dictated through the interconnection services agreement; correct?

MR. CONSTABLE: Yes.

MR. NYBO: Does the company allow DG customers to have any control over the scope of work to come back to the company and say we're not going to do that, you know, Items 1, 7, and 9, for example?

MR. CONSTABLE: Yeah. Not really. I mean, there are cases where we'll have discussions. But often, no.

MR. NYBO: Okay. So generally speaking, it is something of a take it or leave it proposition, if you want to be interconnected as a developer, you're going to either perform or pay for the performance of the scope of work that we had determined, we, the company, in the interconnection services agreement; fair?

MR. CONSTABLE: Yes.

MR. NYBO: I'm sorry. I cut you off.

MR. CONSTABLE: Sorry. Yes.

MR. NYBO: Okay. In both 23-37-EL, this docket, and 23-38-EL, tomorrow's docket, the DG customers self-performed certain to use this word about my client's work, but cheaper than if the company had performed it, as we sit here today.

MR. CONSTABLE: Fair.

MR. NYBO: Okay. If the company had performed all of the work in 23-37-EL, and I want to refer back to RIE Exhibit 13, which is that spreadsheet that we spent most of the morning with, if the company had, instead of self-performs, the company had performed the work, is it true that the costs listed in column J simply never would have been billed to the DG customer; correct?

MR. CONSTABLE: Yes.

MR. NYBO: Okay. So it is only by virtue of the customer's undertaking, electing to do self-performance, that that column J is even in play in this petition; right? Otherwise, it wouldn't have been billed to the customer, they never would have seen it; right?

MR. CONSTABLE: Yes.

MR. NYBO: So in some respects, by agreeing to self-perform, in this docket Green, tomorrow's docket Green and Revity, are

C E R T I F I C A T E

I, LISA L. CROMPTON, Registered Professional Reporter, hereby certify that the foregoing is a true and accurate transcription of my stenographic notes of the proceedings in this matter on the date and time specified in the caption hereof.

IN WITNESS WHEREOF I have hereunto set my hand this 12th day of June, 2024.

Lisa L. Crompton

LISA L. CROMPTON
REGISTERED PROFESSIONAL REPORTER
MY COMMISSION EXPIRES 1/22/2028

<u>EXHIBIT B</u>

In the Matter Of:

RHODE ISLAND PUBLIC UTILITIES COMMISSION

Docket No. 23-38-EL

HEARING

June 04, 2024

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Green's frustration in being in the middle of a dispute about whether or when these added upgrades it built and funded were necessary?

MR. HABIB: Objection. The witness is not going to be able to understand Green's frustration with any of this.

CHAIRMAN GERWATOWSKI: Do you want to rephrase?

MR. HANDY: I can withdraw.

Did Green ever have any choice about to build the upgrades in order to interconnect its project?

MR. CONSTABLE: No.

MR. HANDY: Did the company participate in Dockets 5205 and 5206?

MR. CONSTABLE: Yes.

MR. HANDY: Were you part of that?

MR. CONSTABLE: Yes.

MR. HANDY: Were these concerns about properly donating costs that could and could not be assessed to interconnecting renewable energy customers ever raised there?

MR. CONSTABLE: Absolutely.

MR. HANDY: Why haven't they

MR. CONSTABLE: Right. I'm raising awareness that self-build does create sort of a monetary transaction that didn't exist before and is hard to apply -- or hard to reconcile considering the tariff language.

MR. HANDY: Okay. So in your response to Division 6-1, you state that, as a condition to self-build and Green and Revity were required to build to the company standard including installing extra ducts to accommodate future needs. Do you need a minute to get there?

MR. CONSTABLE: I'm there.

MR. HANDY. Then I'll just keep reading.

And this extra duct work benefits all distribution customers, and had the work been performed by the company, the company would not have initially charged Green and Revity for the extra duct work and included it in the ISR.

Are you familiar with that response?

MR. CONSTABLE: Yup. Yes.

MR. HANDY: So Green was

required to do work planned to benefit other customers; correct?

MR. CONSTABLE: The additional ducts, yes.

MR. HANDY: Under the premise that Rhode Island Energy would seek reimbursement?

MR. CONSTABLE: Yes.

MR. HANDY: And that was only because the project was self-built?

MR. CONSTABLE: Yes.

MR. HANDY: Green wouldn't have been required to fund and wouldn't be here if Rhode Island Energy had constructed the interconnection?

MR. CONSTABLE: Right. We've explained this a couple of times. So -- We do this for load customers as well. So if we were to build, you know, a duct bank, say a 6-way duct bank, and the load customer was only using two of those ducts, we would basically do the proration at the time, and then the load customer would pay for their prorated portion of the duct banks.

MR. HANDY: Okay. Are you

ever accelerated upgrades needed to benefit other customers when it is interconnected load customers?

MR. CONSTABLE: I'm sure I could think of some cases. I can't think of any right now.

MR. HANDY: Is that fairly common that that happens?

MR. CONSTABLE: I wouldn't say it's common, but I also wouldn't say it's never happened.

MR. HANDY: Okay. And in that context, do you know whether the company seeks Commission approval for those upgrades?

MR. CONSTABLE: No, we do not.

MR. HANDY: Did you ever do a Docket 4600 analysis related to those upgrades?

MR. CONSTABLE: I do -- I doubt that we would have done a Docket 4600 related to that.

MR. HANDY: Are you aware of any other examples where the Division has objected to acceleration of planned system improvements in association with interconnection of any customer load or otherwise?

MR. CONSTABLE: No, I'm not.

MR. HANDY: Is it possible for us to make a record request about that?

CHAIRMAN GERWATOWSKI: So what would be the record request, please?

MR. HANDY: It would just be to request whether there are any instances of the Division opposing acceleration of system modifications in association with any other interconnection.

CHAIRMAN GERWATOWSKI: Mr. Habib?

MR. HABIB: Mr. chair, I don't think it's an appropriate record request to the company. If there's a record request on that topic, it probably should be to the Division.

CHAIRMAN GERWATOWSKI: Look. I think it's a, it's a question that's answerable. But the question is, would it be answered accurately. You can -- The company can only have an understanding -- I don't think it's reasonable to make them search through everything.

MR. HANDY: I understand. But I think you understand where I'm going with terminology across the board.

So I'm looking at PUC 2-4.

MR. CONSTABLE: Okay.

MR. NYBO: Column I. Would you agree that you cannot operate the solar facilities without the work, the expenses for which are reflected in column I?

MR. CONSTABLE: Correct.

MR. NYBO: Okay. Would you agree that you can operate the proposed Weaver Hill substation without the work reflected in column I?

MR. CONSTABLE: Yes, you can operate Weaver Hill -- Oh. Yes.

MR. NYBO: Okay. With respect to column J, would you agree that you cannot operate the solar facilities in this area without the expenses reflected in column J?

MR. CONSTABLE: Yes. Correct.

MR. NYBO: Would you also agree that you cannot operate the Weaver Hill substation without the work reflected in column J.?

MR. CONSTABLE: Also correct.

MR. NYBO: Okay. With respect

to column K, would you agree that you can operate the solar facilities in the area without the work reflected in column K?

MR. CONSTABLE: Yes.

MR. NYBO: Okay. And lastly, would you agree that you cannot operate the proposed Weaver Hill substation without the work reflected in column K?

MR. CONSTABLE: Well, column K is additional ducts. So technically, electrically, you could operate Weaver Hill without column K. However, if the company was to install the facilities for serving Weaver Hill, it would include column K.

MR. NYBO: Okay. Understood.

I'm going to go over, sort of retread over a few points, one or two, that you and I discussed yesterday with respect to the Tiverton docket. I appreciate the discussion about consolidation this morning, so I have -- many of the questions I was going to ask, but I think there's an area or two that I do need to carry over into West Greenwich.

Yesterday, you testified, Mr. Constable, that as the figures stand today, for the additional ducts.

MR. NYBO: Pursue them here in the Commission?

MR. CONSTABLE: So again, because of the self-build, there's a little bit of uncertainty here. So again, they could happen in this petition. They could happen through the normal course of an ISR process.

MR. NYBO: Did you make it clear to Revity that there was a chance there would be no reimbursement or was the company's, you know, caveat that they had to pursue to the Commission in either of the forums you mentioned, one of -- the amount you'll be reimbursed depends on what the Commission says?

MR. CONSTABLE: I don't know specifically if we explained a certainty. We've explained about how this petition is subject to the Commission. But for the additional ducts, I would say that, you know, we, you know, we had a confidence that we would figure out a way to get reimbursement done.

MR. NYBO: Okay. Did you ever -- Did the company -- When I say "you," by the way, I hope you mean -- I hope you know I that Revity may not be entitled to any cost sharing depending on what the Commission said.

MR. CONSTABLE: I'm not sure of specifics, but the company has always represented that the accelerated modifications associated with the area studies are subject to Commission review and approval.

MR. NYBO: Okay. What about system improvements, then?

MR. CONSTABLE: So system improvements we would expect that we would pursue through either, we can make a decision here or do the normal ISR process. We would expect that reimbursement does occur for those.

MR. NYBO: Okay. And the company made that -- expressed that confidence to Revity?

MR. CONSTABLE: Yeah. So I think there's a level of confidence. You know, I don't want to put a hundred percent certainty on it, but there's a level of confidence there.

MR. NYBO: Okay. I've read the Division's position as well. So you know, level of confidence would be tampered a bit by reading that. If only a bit.

MR. NYBO: Central Rhode Island West. On Page 12, lines 14 through 15, you state, quote, the Division reviewed the central Rhode Island West area study issues and recommendations in May of 2021 and made no comments regarding the analysis, end quote; correct?

MR. CONSTABLE: Yes.

MR. NYBO: Can you provide some more detail regarding, you know, how did the Division receive that area study, what was the review, were there discussions between the company and the Division regarding that area study?

MR. CONSTABLE: Yes. So when we do the area studies, this is actually, you know, part of the process where we actually seek Division comment so that we can get input onto the issue identification, the alternative analysis, and the recommendations. And so we do what we call a technical presentation. And so in that technical presentation, we will walk through how we identify the issues, how we evaluated the alternatives, and then what our ultimate recommendation was.

MR. NYBO: Okay. And the Weaver Hill substation was fairly prominently included in that area study?

MR. CONSTABLE: Yes.

MR. NYBO: And your testimony is the division raised no issues about the Weaver Hill substation?

MR. CONSTABLE: Yes. There was no comments.

MR. NYBO: Okay. On Page 12, I'm looking at lines, starting on line 20 and I'm going to run onto Page 13, but the sentence I'm interested in is, quote, the Division also supported the inclusion of the Weaver Hill projects in the FY 2024 and FY 2025 ISR plan filings. Did I read that correctly?

MR. CONSTABLE: Yes.

MR. NYBO: Okay. Can you provide some more explanation of how and when the Division -- well, I guess you say when, but how the Division quote-unquote supported the inclusion of the Weaver Hill project?

MR. CONSTABLE: So in any ISR process, we have a consultation period with the Division that basically spans the fall into the

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MR. CONSTABLE: Yes.

MR. NYBO: Okay. Can you provide some more explanation of how and when the Division -- well, I guess you say when, but how the Division quote-unquote supported the inclusion of the Weaver Hill project?

MR. CONSTABLE: So in any ISR process, we have a consultation period with the Division that basically spans the fall into the early winter of any year. Right; so... It starts generally around October and goes through December. And in that we'll review the contents of the ISR and seek Division, you know, input onto, you know, the items that are actually in the ISR plan. There's also some documents that we provide which are called pre-filed documents that include some additional details on each project. And so based on the consultation with the Division, we will then make our filing to the Commission in December, you know, towards the end of December in any year.

And so when we make the ISR filing, after that consultation, we consider the Division to support the filing, and then that carries through the ISR process which, you know, has a series of data requests and ultimately results in the Commission hearing in March where the Division again has an opportunity to comment and ask questions, additional details on anything within the ISR.

And so, you know, you know, so we included that statement in our rebuttal. Mr. Wold has commented that that statement is perhaps too strong. So we use the term from the DG customer to satisfy the company that the DG customers is correct, the additional work is not appropriate at this time, not appropriately accelerated, what would be a DG customer have to do to convince the company of that?

MR. CONSTABLE: I do not know. Right; so... The company doesn't require the DG customer to do additional work, you know, on whims for -- you know, it's the good utility practice of establishing the additional ducts or associated woodwork in our work plan.

MR. NYBO: Okay.

MR. CONSTABLE: Yeah.

MR. NYBO: So if you guys have it in your area study, your ISR, and the impact study says it needs to be done, it needs to be done.

MR. CONSTABLE: Yes.

MR. NYBO: Okay. Last question. Between the start of an impact study and the start of construction, can you just walk me through every step that needs to occur before either the DG customer can start construction or in a circumstance the company does the

C E R T I F I C A T E

I, LISA L. CROMPTON, Registered Professional Reporter, hereby certify that the foregoing is a true and accurate transcription of my stenographic notes of the proceedings in this matter on the date and time specified in the caption hereof.

IN WITNESS WHEREOF I have hereunto set my hand this 12th day of June, 2024.

Lisa L. Crompton

LISA L. CROMPTON
REGISTERED PROFESSIONAL REPORTER
MY COMMISSION EXPIRES 1/22/2028

EXHIBIT C

In the Matter Of:

RI PUBLIC UTILITIES COMMISSION

D 23-37-EL & D 23-38-EL

HEARING

June 05, 2024

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concerns, a number of circuits require reconductoring (sic) due to reliability, contingency, capacity or asset condition concerns. Now, that statement covers a number of the area study issues, but it does include the 54F1 and 53F6, which are the circuits that are relieved and addressed by the Weaver Hill substation.

Then in the recommended solutions, there's a third bullet that says extend portions of the 35kV system and install a new modular substation at Weaver Hill Road to relieve 54F1 and 53F6 circuits and address the Kent County 35kV system concerns.

Q. Thank you. Then moving on to fiscal year 2024, could you explain what was included in the budget?

A. Again, included in the budget in multiple lines for roughly $1.5 million, the first is the Weaver Hill Road D sub project and then the Weaver Hill Road feeder D Line. Weaver Hill substation is under the system capacity and performance category; it's also in Attachment 3. Then there is a chart on Bates Page 103 that also includes the reference to these projects. Then on Bates Page 105, we explain specifically the scope.

Weaver Hill substation, the central Rhode Island west area study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer in one feeder position, and installing distribution line work for feeders. So the scope is clearly defined.

Now, at that time I want to note that we were contemplating using the 3309 line. After further review, we determined that we could not use the 3309 line, and now we're using the 3311 line, which we talked about over the past few days. There is also the Docket 4600 analysis that we talked a little bit about yesterday.

Then there is a series of data requests, Division 1-20-2 -- well, that's the attachment and the response to Division 1-20. A fact sheet, again, was provided that explains the issues and the recommended plan and the cash flows. I think that's it for fiscal year '24.

Q. Thank you. Again, in fiscal year '25 there was more budget included in the plan; is that correct?

A. Fiscal year '25 was $1.1 million. Again, it's in Attachment 3, Line 7, Bates Page 86. It's in Attachment 5 again in the long-range plan.

Specific references, I'm not going to repeat it parties as well. Does anybody at this moment actually have some questions about this? Division, first.

EXAMINATION BY MR. WOLD

Q. Mr. Constable, these documents don't reflect the Division's pushback to the company regarding the ISR plan positions that the company takes, right?

A. There is no pushback on the Tiverton or Weaver Hill products.

Q. For 2025, you've already testified that the company took what was filed in the Division filing for the extension for the Weaver Hill and Tiverton projects and took it out of the ISR plan; isn't that correct?

A. That is not correct.

Q. You did take it out of the project, because the filing that you made with the Division included all the inspection, all the sums for the work that you're alleging to have accelerated in this case. Then you agreed with the Division that it would be taken out of the filing when you made the filing with the PUC, correct?

A. The numbers that were taken out as a result of consultation with the Division are related to the reimbursements that are the subject of this petition.

Q. That's right.

the Division on February 20, 2024, does that generally comport with your recollection?

A. Yes.

Q. So when Mr. Booth and the Division submitted all of the statements that Attorney Wold just read, all of Green's work on the Weaver Hill project had been completed as of that date, correct?

A. Yes.

Q. All of Revity's work on the Weaver Hill interconnection upgrades had been completed as of that date, correct?

A. Yes.

Q. Would it be a fair statement, perhaps, to slightly amend what you had said about pushback before, that the Division had never given any pushback to these projects prior to the project being completed?

A. Yes.

Q. As we sit here today, all of the upgrades, they have been by operation of law, I think, donated to Rhode Island Energy, correct?

A. Yes.

Q. They are Rhode Island Energy's property?

A. Yes.

Q. The DG customers had no say in that property

being donated to Rhode Island Energy?
A. Yes.
Q. So if the DG customers are not reimbursed for all of this work that they did, they have no ability to control how this property that they built is ultimately used; it's your property; you control it?
A. Yes.
Q. I want to clarify one point from yesterday that I asked you about on PUC 2-4. It's that big spreadsheet that we spent so much time on. I'm sure you have it.
A. Yes.
Q. The total all number down at the bottom, the $30,647,639 figure --
A. Yes.
Q. Yes, I believe you testified that includes all costs and expenses related to the construction of the upgrades identified to the far left; do I remember that correctly?
A. I know we talked a little bit about it, so there's the $30.6 million that is the total of the column above. Then we talked about including the Weaver Hill substation cost to the left. Then I think we got to about $36 million.
Q. You are right. That $30 million figure does

about whether or not the infrastructure in question that is serving the Tiverton substation and the Nooseneck projects are needed for customer benefit; would you agree to that?

A. No. Let me clarify that. It's not a question of need. It's a question of the timing of the need. So the company has characterized this, I think, pretty clearly. That there is a potential for these problems. They don't exist today. So you don't need it today.

All these areas are being served adequately, reliably, safely today without the advancement of Weaver Hill or Tiverton. It's an issue of when is it needed and how do these two projects fit within the scope of the whole system and all the projects.

I want to be very clear. If we were sitting here without the Tiverton and Weaver Hill interconnection work complete, built, so it started in 2019 and parts of this are built. We were just looking at this on a blank slate, no DGs at all, what I'm saying is the Division would not support either project now because we've got a litany of far more important projects.

Q. Fair enough. Let me just stop you there. Are you suggesting that you do not contest the need for this infrastructure to benefit customers at some

point in the future?
A. I think that's fair. I don't know what -- I mean, our best estimate right now, assuming load forecasts, that's 2035, or some period slightly beyond that is the actual need.
Q. Fair enough.
A. Do I think the Tiverton project, 33F6 circuit will eventually get built, or the Tiverton substation and circuits to tie into Hopkins in Coventry, I do think that will eventually happen.
Q. And benefit distribution customers?
A. For the benefit of distribution customers, that's correct.
Q. That's great. That's very helpful. I appreciate it. You believe that is the Division's position also?
A. Yes, I do. I think we're trying to articulate when we think that is.
Q. Fair enough. Ultimately, is it the Division's probability, is it the final discrimination of the Division to determine whether or not capital investment is necessary for distribution customers? Does the Division get to make that decision ultimately?
A. No, the Commission makes that decision.

Division puts forth its report, its opinions, what it agrees or disagree with through the collaboration process. I sit up here and answer Commission questions, but the Division doesn't make that decision. The Commission does.

Q. That's good to hear. A lot of, a lot has been made about the opinions of the Division about the need for this infrastructure for customer benefits. It sounds like what you're saying is the Division agrees that this infrastructure that we're talking about that is serving Tiverton and the Nooseneck projects, that benefits those projects, will also benefit customers at some point in the future; you just stated that is the Division's position, correct?

A. Yes.

Q. Ultimately, and I say this with respect because you have so much experience in this space, sir, it doesn't really matter that the Division makes an opinion about need, does it? It doesn't really matter whether the Division agrees whether these projects are needed or not for customers; it's the Commission's job, correct?

A. No doubt about it. The tariff is very clear in 5.4 that the Commission makes that determination.

Q. Very good. Ultimately -- I'm even going to go farther and go a little bit out on a limb. Ultimately, even if the Commission did not approve spending for a particular investment through the ISR and revenue decoupling plan, do you agree the company could make that investment on its own timetable at the risk of not getting cost recovery?

A. I think that's been articulated pretty clearly by the Commission. I would concur with that. That if the company wants to spend money and take a risk of rate case recovery, every utility in the country does that.

Q. That's very good. Now I'm going to take you to the tariff. Do you have it in front you, the interconnection tariff?

A. I can get it.

Q. That would be great, thank you. I want to get you to Section 5.4C.

A. I'm there.

Q. I want to start at even a bit of a higher level. I want to start with the statute that was the basis for this section of tariff. I know you're familiar with this. It's Title 39-36.3-4.1 and sub B. I'll read it. It's very short.

If the Public Utilities Commission determines that a specific system modification benefitting other application of the tariff says this work, this potential work is beyond five years.

Q. Okay, thank you. You actually got me to where I want to go next. That's helpful. I am now going to turn back to Section 5.4C; do you have that in front of you?

A. Yes.

Q. I stipulate that there is language in the tariff that talks about the five-year period. So I'm not asking a question about the five-year period right now. I want to talk to you about the beginning of the sentence. I'm reading this, tell me if I'm reading it incorrectly.

The company will consider a system modification to be an accelerated modification if such modification is otherwise identified in the company's work plan as a necessary capital investment. I want to stop there. Do you agree that I read that part of the sentence properly?

A. Yes.

Q. Do you agree that the tariff puts on the company the decision of whether or not a capital investment is necessary?

A. Yes.

Q. It doesn't mention -- you seem to be wanting to adhere to the tariff, which is admirable. It doesn't say the Division will consider a system modification to be an accelerated modification if such modification is otherwise identified in the company's work plan as a necessary capital investment, correct?

A. Correct.

Q. Not the Division's role here, correct, to determine whether or not an investment is a necessary capital investment?

A. That's correct.

Q. Very good.

A. That's the way the statute, or the way the tariff reads.

Q. Very good. Also, I'm going to ask you again not as a lawyer. This only requires ninth grade English. It does not say the company will only consider a system modification to be an accelerated modification if such modification is otherwise identified in the company's work plan as a necessary capital investment, correct?

A. Correct.

Q. So it's fairly open-ended, this sentence, in terms of the determination of whether or not a capital investment is necessary for purposes of the reimbursement of sharing of cost per the tariff; the to adhere to the tariff, which is admirable. It doesn't say the Division will consider a system modification to be an accelerated modification if such modification is otherwise identified in the company's work plan as a necessary capital investment, correct?

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A. Correct.

Q. So it's fairly open-ended, this sentence, in terms of the determination of whether or not a capital investment is necessary for purposes of the reimbursement of sharing of cost per the tariff; the

Q. What is the main objection by the Division to the company's proposal?

A. Number one, that there shouldn't be any dollars, because these accelerated projects are out past the five years stated in the tariff. But additionally, that neither of these projects, if you look at a plan without the DG projects advancing, would be out to 2035 or beyond.

Q. You agree that ultimately it's the decision of the company and obligation of the company to provide safe and reliable service to its customers, correct?

A. That's the company's obligation. The Commission approves the budget to meet that obligation.

Q. If there is something that goes wrong with system reliability or safety, the Division doesn't get held accountable for that, correct?

If the Division recommends that a particular investment not be invested in for budgetary purposes or for need, and the company decided to agree with that decision and there was a safety or reliability problem related to that decision, is the Division accountable for that decision, or is the company accountable for that decision?

A. The company is accountable. I think the Division catches heat, just like everybody else.

Q. Not in the same way that the company would from that situation, correct, sir? Does the Division get a lot of letters when the lights go out?

A. I think the Division gets plenty of calls.

MS. HABIB: Thank you. I'm going to pause. The company has no further questions at this time.

MR. GERWATOWSKI: It's 12:00. Usually I do an hour. I'm going to do a 45-minute lunch break today. I know we have -- Mr. Booth, do you have a flight?

(OFF THE RECORD)

(LUNCH BREAK)

MR. GERWATOWSKI: So we're back on the record. We finished, the company finished their questions, so we're returning to Green Development.

MR. HANDY: We're going after Revity on this, if that's okay.

MR. GERWATOWSKI: Did you flip a coin?

EXAMINATION BY MR. NYBO

Q. Thank you, chairman. Good afternoon, Mr. Booth.

A. Good afternoon.

upgrades don't go to the Weaver Hill station yet.

Q. Okay. But the intent is that upgrades that have already been built are going to service load customers and the Weaver Hill substation; are you aware of that?

A. That's correct.

Q. Okay. So my question is, when is the first time the Division learned that work needed to serve the future Weaver Hill substation was being actually performed, it was being built?

A. Again, I would have to go back and look at the ISRs. I think it would have been the 2024 ISR.

Q. So this year is the first time the Division knew that there was actually upgrades that were being actively installed to service the Weaver Hill substation?

A. No. The 2024 ISR plan was handled in 2022.

Q. Fair point, fair point. Okay. You reviewed the company's pre-filed rebuttal testimony that was dated May 9, 2024?

A. Yes.

Q. This is actually a section that Attorney Wold reviewed with you. It's on Page 12, if you would like to look, or you can take my word for what I'm about to read, but it's on Page 12.

The company stated that, quote, The Division reviewed the central Rhode Island west area study issues and recommendations in May of 2021 and made no comments regarding the analysis. Do you recall that statement in the company's rebuttal testimony?
A. Yes.
Q. Do you agree with that statement?
A. No.
Q. What part do you disagree with?
A. In May of 2021 is the first that the company presented that area study summary to us. So we actually then took that and started reviews as it relates to the ISR plan. So at that point in time we hadn't even reviewed it.
Q. Okay. Let me just unpack that a bit. You agree that the company presented you with the central Rhode Island west area study in May of 2021?
A. Yes.
Q. The Division began its review of that area study once it was presented with it in May of '21?
A. That's correct.
Q. I assume you disagree with the company's characterization that the Division made no comments regarding the analysis; you disagree with that?
A. Yes. I mean, I think this is somewhat

disingenuous. These area studies ultimately feed the long-range plan. The projects in the area studies do not, you know, the Division doesn't get into the details, nor does the company get into the details of the project until it comes into an ISR plan for budgeting.

So the area studies are not approved by the Division. The Division takes them in, receives the area studies. But from the outset the recommendation of the Division was to complete a systemwide area long-range plan, and the area studies feed that long-range plan, which we just got in the ISR 2025. We've been pushing back about that because of the significant amount of work they're trying to advance in the first five years.

The area studies simply are a worst-case to make sure that an ISR project would not have early obsolescence. It really, from the Division's perspective, it only feeds the ultimate long-range plan as to what the total system is doing. You can't pull it out of context.

Q. Okay. So is the Division reviewing the area study when it received the area study in May of 2021; does it begin its review?

A. Yes. The Division takes it in and reviews

Q. Is it your understanding that the DG Developers have any ability to refuse to build a system modification ordered by the company through an interconnection service agreement?

A. No. The developers, DG Developers are going to have to build to the company's standards, whatever they are. So that could be more ducts, larger conductor, deeper depths, whatever the company's standard is, because the company is going to ultimately have to operate and maintain it.

Every utility has a set of standards they want to follow. So you're right, the developer is stuck with that standard.

Q. Okay. The way this should work and does work in the Division's mind is that if a DG customer/developer wants to interconnect a new project, it has to build or pay for the building of system modifications, whatever they may be as identified by the company and the impact study in the ISA, right?

A. Well, the alternative would be they build what they feel is necessary for them, have a different point of common coupling, and they own and operate that facility themselves. So some DG customers own transmission or subtransmission for distribution

A. My recollection is that is not the worst circuit on the entire system. That's the worst circuit out of this particular area, but not of the entire system.

Q. Sure. The statement says the worst area circuit?

A. Right. It's the worst circuit in this area. It's nowhere near the worst circuit on the system.

Q. It being the worst circuit in the area, would that be a reason that would justify system upgrades in that area for that circuit?

A. No, not if, not if the problem isn't so severe that you have to deal with it immediately. That you have other circuits you need to deal with first.

Q. Your resume indicates that you participated in a great many dockets here in front of the Rhode Island PUC. I just want to discuss a few of them. Do you recall participating in Docket 5077, which was filed on October 22, 2020?

A. What docket is that?

MR. NYBO: Sure, I'll refresh your recollection. May I show the witness a document, and everybody else?

MR. GERWATOWSKI: Identify what it is

you're going to show him.

MR. NYBO: Absolutely. It's a January 8, 2021 letter with Mr. Booth's letterhead that was filed in Docket Number 5077, titled Standards For Connecting Distributed Generation.

MR. GERWATOWSKI: Mr. Wold, do you want to see that?

MR. WOLD: I'm trying to call it up on my computer here.

MR. GERWATOWSKI: Do you want to mark this for identification?

MR. HARRINGTON: Yes. Weaver Hill or Tiverton?

MR. NYBO: The docket is Weaver Hill.

MR. HARRINGTON: We'll mark it as Revity Exhibit 4.

MR. GERWATOWSKI: We have it marked as Revity 4 in the Weaver Hill docket.

(EXHIBIT 4 REVITY MARKED)

Q. Mr. Booth, does that appear to be your letterhead on the letter?

A. It is.

Q. The last page appears to contain your signature?

A. It does.

Q. Do you recall participating in this docket, writing this letter, anything about this docket?

A. Vaguely.

Q. Let's turn to Page 4, 4 of 5.

A. I'm there.

Q. I'll represent to you that this portion of the letter is discussing potential changes to Section 5.4 of the tariff dealing with system modifications, system improvements. I want to look at the first full paragraph there.

It begins, quote, The ISR plan process is a better forum for establishing what constitutes a system modification. Those changes to the system for the benefit of the interconnecting customer and a system improvement, those changes that benefit the overall system used to provide service to the consumers; do you see that?

A. Yes.

Q. Do you agree with that as you sit here today?

A. I do.

Q. The manner in which the company, in your opinion, should go about getting, identifying system modifications for system improvements is through the ISR plan process?

A. That is the process in Rhode Island.

Q. The Weaver Hill substation was identified by the company as a necessary capital investment in the 2023 ISR plan process, correct?
A. It wasn't put in the budget, but yes, it was a potential identified project.
Q. It was a potential identified project?
A. Correct.
Q. Those are the words that the 2023 ISR used to refer to the Weaver Hill substation?
A. I don't have all the words memorized, but it was, it was not an approved substation project.
Q. But it was identified by the company in the 2023 ISR plan, correct?
A. As a potential need.
Q. Okay. So if I look there, I'll find the word potential?
A. I'll have to go back and look. That's my recollection. They always identified Weaver Hill and the potential problems that drive the need.
Q. Okay. It was identified, the Weaver Hill substation was identified in the 2024 ISR plan as a necessary capital investment, correct?
A. Correct.
Q. Weaver Hill substation was identified in the 2025 ISR plan as a necessary capital investment,

correct?

A. That's correct, with pushback from the Division.

Q. Understood. So from the DG customer perspective, reading the testimony here, that the ISR process is the better forum for identifying necessary capital improvements, and then seeing that the Weaver Hill substation was identified, not once, not twice, but three times, wouldn't that draw a DG customer to believe that the project had complied with Section 5.4 of the tariff?

MR. WOLD: Objection.

MR. GERWATOWSKI: What's the objection?

MR. WOLD: How does he know what a DG customer would or would not believe?

MR. GERWATOWSKI: Rephrase the question.

Q. Sure. Given your testimony -- excuse me, your letter here, that the ISR process is the better forum to determine these issues that we're here discussing today, and given the fact that the company had identified the Weaver Hill substation as a necessary capital investment in the 2023 ISR, the 2024 ISR, and the 2025 ISR, wouldn't that lead a reasonable person to conclude that the Weaver Hill substation had complied with Section 5.4 of the tariff?

A. No, because it's beyond the five years, number one. Two, because it's been characterized by the Division as not needed until 2035. So I wouldn't say a reasonable person would conclude that. It fits 5.4C.

Q. Section 5.4 mentions the Division's role in this?

A. No.

Q. So then why would it matter to the 5.4 inquiry what the Division feels about this project?

A. Because you asked what a reasonable person would expect. So if I got a project, an accelerated modification, it wouldn't be in five years, isn't proposed to be in five years from the date of the impact study as spelled out in 5.4.

First off, I would say gosh, if it's beyond that, maybe I'm not going to get this, you know, if I use tariff language. Number two, if all these dollars aren't in an ISR plan, haven't been approved in an ISR plan, had, in fact, been removed from the ISR plan, and the Division, who is one of the company witnesses in the ISR process that the Commission listens to says this isn't needed until 2035, my answer to you is a reasonable person would not assume that they would get those dollars instantly.

Q. Okay. So in that situation when those factors exist, a DG customer in this state can go to the company and say I'm not building your system modifications, because it's outside five years, and because the Division has objected, we're not doing it. You're going to interconnect me nevertheless; we can do that?

A. No. You're going to have to sit down with the company and work out the details.

Q. In the future, would the Division join in those meetings and sit with the DG companies and explain to the company that they're being unreasonable by requiring DG customers to build unnecessary system modifications?

MR. WOLD: Objection.

MR. NYBO: What is the objection?

MR. WOLD: How does Mr. Booth know what the Division would or would not do in that hypothetical? First of all, that hypothetical, we would have to take that back to the administrator of the Division. Mr. Booth certainly at this stage would not have any basis or foundation for giving an opinion to answer that question.

MR. GERWATOWSKI: I'm going to sustain the objection. Maybe there is a way you can rephrase not sure where the legal expertise comes from. This is the first I've seen this sentence.

Q. You don't agree with the Commission's -- excuse me, the Division's representation to the Commission in that sentence?

A. I don't have a response one way or the other. This is the first I've seen this legal document. I would have to study this whole document. I don't like taking single sentences out of context of a document.

Q. Well, unfortunately, I'm going to ask you to comment on this one single sentence. It's about you, Mr. Booth, I think, unless there is another Mr. Booth. You know, this sentence has made characterizations about your expertise. I think you are the best person to ask if those characterizations are correct.

A. I am.

Q. Okay.

A. I don't have a law degree, so I'm not sure why legal is in the sentence, but I have plenty of financial and technical expertise.

Q. Okay. The purpose of this discussion was, by the Division, was to tell the Commission that the Division was capable of protecting Green Development's interest in the 2025 ISR filings?

MR. GERWATOWSKI: 2025?

I don't mind asking the questions about whether, the fundamental question about whether the Division can represent that the renewable generator's interest, but in the context of 2015, I didn't think it's fair.

Q. Okay. Sir, do you have an opinion -- strike that. You understand that the crux of this docket is the question of whether DG customers, Revity and Green, having expended significant financial resources, are going to receive reimbursement for a portion of those funds that it had outlaid over the past few years; you understand that's the purpose?

A. I do.

Q. Do you have any opinion about how the DG customers here could have better protected their interest, could have proceeded in a more prudent fashion so as not to be in this position?

A. Well, since I've been involved, at least, in some of the interconnection tariff development, and the fact that I said I was concerned about this whole issue of accelerated modifications and when they're going to take place, you know, I raised, the Division raised that concern some time back.

I think the tariff should have been dealt with in the tariff better to protect the DG Developers and what they built better. I think the tariff just doesn't have the specificity it should have, so we're stuck here with the Commission, with the Commission having to make other interpretations, either exactly like the tariff language or differently. That's unfortunate.

That was part of the concern that the Division voiced some time back, just wasn't dealt with.

Q. Okay. But the tariff says what it says?

A. It says what it says.

Q. My question is, under the current tariff is there a way in your mind that DG Developers could have proceeded that would avoid us being in the situation we're in right now, short of not building the projects?

A. Yes. We'll assume -- that didn't make any sense. You know, the DG Developers and the company should have come to a much more specific resolution during the impact study process, and since it didn't match up, even the company admits it doesn't, the tariff doesn't really have language to help them out to make this clear. It should have come forward back in 2019 or 2020, long before the developers spent this money.

Q. Okay. So if we had submitted this petition earlier, prior to when we actually started spending,

constructed; do you dispute that?
A. No.
Q. Do you, setting aside the fact that you don't think the ratepayers should have to pay for it, do you dispute that the amounts charged for the various upgrades on this large spreadsheet were unreasonable?
A. No. The dollar amounts that we're looking at are reasonable or in magnitude for the work completed.
Q. You've heard testimony, I'm sure, about discussions between the company and the DG customers regarding reimbursement over the last few years; they've been referenced from time to time. Have you heard about those discussions?
A. Yes.
Q. Do you dispute at all that the company has, in fact, had those discussions with the DG customers?
A. I would hope they did.
Q. Do you dispute that distribution customers will ultimately use some portion of the system upgrades that have been constructed for the Weaver Hill projects?
A. At some point they will.
Q. Your testimony, I think, in your pre-filed is that the system modifications need to be completed within five years of the start of the impact study; is

there is no system, there is no acceleration of the system modification, because there isn't one.

Q. Look at the second sentence of 5.4C. It reads, The company will identify the accelerated modification and the cost thereof in the impact study; do you see that?

A. Yes.

Q. Okay. Correct me if I'm wrong, I read that to say what needs to be completed within five years has to be identified in the impact study; is that a fair reading?

A. That's how I would read it.

Q. So if you're saying the substation is part of what needs to be completed within five years, I assume you also believe that the substation is included in the impact study as a system modification?

A. The system modification associated with that project. So they identified the 35kV line. That is part of the overall system modification that was not planned until well beyond the five-year period.

Q. Even if the impact study makes no mention of the substation?

A. That's right. It doesn't have to.

Q. Which it doesn't, but we are required to build that substation within five years of the impact study, which makes no mention of a substation, to be eligible for reimbursement under 5.4C; that's your testimony?

A. No. You don't have to build it. The project, in this case the whole Weaver Hill project that's being accelerated, that project, if the acceleration of that project doesn't fall within five years, then there is not a reimbursement. Because if we're only looking at a section of the 35kV line, there is no system, accelerated system modification.

Q. So if DG customers build everything that is required of them in the impact study, they built that all within five years --

A. Okay.

Q. -- and the company does not end up building the substation until year seven or eight, your testimony is that the DG customers are out of luck with respect to everything they built within the five-year period?

A. That's how I'm reading this.

Q. Okay.

A. That was my concern back years ago when I said there was a problem with this entire process, because you're looking out into the future, and somebody is trying to guess when might I build it well

Q. So the Division's position isn't that these projects should not have been interconnected, correct?
A. That is not --
Q. That is not the Division's position?
A. That is not the Division's position.
Q. Okay. Does the Division object to the cost that the company, DG companies incurred to interconnect their projects?
A. The Division doesn't have an opinion one way or the other.
Q. So the Division doesn't object to the cost that the company incurred to interconnect their own projects?
A. I think the DG folks make their own cost decisions. The Division has no role in that.
Q. Okay. Are you familiar, you're familiar with this chart that we've been discussing and the information?
A. Absolutely, for hours and hours of it.
Q. Is it the Division's position that the improvements listed in, under System Improvements in the far right-hand column of these charts, should have been considered necessary to interconnect the distributed generation projects?
A. I'm not sure I understand your question.

customer?
Q. Mr. Booth, do you understand that we're talking about $21 million here? That is in addition to what the company has charged to the DG customer for the interconnection of its project; do you understand that?
A. I understand that we're talking about a lot of dollars.
Q. Do you understand that the company, the DG Developer had no choice in this context but to build what the company told them to build?
A. I would agree with that.
Q. Is it your position that the DG Developer should incur all of the costs that the company required for it to build this project, regardless of whether it was necessary to interconnect the distributed generation customer?
A. Well, I guess we're, the debate is --
MR. WOLD: Mr. Handy, he is trying to answer. Let him answer the question. I would ask the Chair --
MR. HANDY: The problem is that we're qualifying answers, and there is a yes or no to this question.
MR. BOOTH: There is not a yes-or-no

MR. HANDY: Thank you. I have no further questions.

MR. NYBO: Mr. Chair, would you indulge me one more question? I had it here, and I skipped over it, one additional question?

MR. GERWATOWSKI: Go ahead.

FURTHER EXAMINATION BY MR. NYBO

Q. Mr. Booth, do you believe there's any reason to treat, to apply the tariff differently when a DG customer self-performs interconnection work as opposed to when it's the company performing the work and the DG company is paying the company; is there any reason to treat those two instances differently?

A. I don't believe they should.

MR. NYBO: Thank you. Thank you, Mr. Chair. I appreciate it.

MR. GERWATOWSKI: I want to come back to a series of questions that Mr. Handy was asking about system improvements. You weren't here for the first couple of hearing dates. It was very important to distinguish the terminology and pay attention to the tariff definitions. In the tariff itself, I don't know if you happen to have a copy of it --

MR. BOOTH: I do.

MR. GERWATOWSKI: If you look at

though it didn't, and we didn't have any DG connections and the company had come forward with, let's say the example of Weaver Hill, you were saying that you would have -- I'm not going to put words in your mouth.

The way I was understanding, you would recognize there was a need to address some form of voltage or reliability issue. You were saying at least in the interim other lower-cost method options, whether it's nine wires alternative or some other less expensive capital investment, that would delay the installation of the, delay the construction of the substation. So you were pushing it off beyond the period of time that they were saying they wanted to install it.

Am I understanding that correctly?

MR. BOOTH: Yes. It's really -- let me first talk about Tiverton.

MR. GERWATOWSKI: Okay.

MR. BOOTH: Tiverton, there were some low voltage issues. That when you open up the sign model and look at it, you balance the load on each phase. These low voltage issues go away. You take the load in Massachusetts and let National Grid serve themselves, and you take that away, then all of a sudden in Tiverton you've done just some operational things, few thousand dollars, not even a million.

Now Tiverton doesn't rise to the level that it needs anything done. There's not a capacity concern. Reliability is poorer than what the Commission asked for the average system, but there are lots of circuits that don't meet the average system. It's not, it's just slightly worse than the goal.

You say, gosh, let me look at how far out do I go? Well, I can get to 2035 with a low growth, and I don't need to do anything with 33F6, because I don't have a problem to solve. I can spend a little bit of money, do a few things, don't have to do $19 million worth of construction to fix a non-problem.

Weaver Hill is all about reliability and contingency, doesn't really have serious capacity. You know, it's not more than 100 percent loaded, just has reliability issues and not the ability to quickly switch load and outage. So if I look at that versus 58 circuits on the system that really are bad, 21 of them are way over 100 percent, I would do these circuits that are really in trouble long before I do Weaver Hill.

So that's the analysis and view that the Division is coming from, assuming we don't have any DG at all. That this project just wouldn't get advanced.

MR. GERWATOWSKI: The difficulty we're having, we have no choice but to try to do this, is to try to speculate on what would have happened, even though it's never going to happen because circumstances have changed. So you have to start speculating on what information we have today.

I thought it sounded like you were saying other things would have been done in between now and 2035, other than going forward with the project.

MR. BOOTH: It wouldn't be that you would do nothing between now and 2035, but other things would need to be done, some investment taken by the company in both of those instances. For instance, the tree reliability issue would be dealt with better vegetation management.

MR. GERWATOWSKI: Between now and 2035, would actions have to be taken maybe in capital investments being made, other than the actual project, in order to solve the need, reliability or safety need?

MR. BOOTH: Not at Weaver Hill, because it would not rise to the top of the list of all the feeders that have to be fixed. It would be down the list. You wouldn't get to it until 2035.

It's a contingency issue, not a real thermal system. It's not the system is going to fail, or the customers aren't going to get adequate service. It's simply an issue of outages may take a little longer.

MR. GERWATOWSKI: This allocation of dollars, is it not enough dollars to spend on it, you mean? So you make a choice to do others before you do that one?

MR. BOOTH: Yes. The company -- yes, I mean, you do the worst portion of the system first. So if you got 58 of those locations to deal with, you deal with those first before you got to Weaver Hill, because Weaver Hill doesn't rise to a concern at this point in time.

It's not a system failure concern. It's just a potential for slightly worse reliability. It's only a potential. It doesn't even exist today.

MR. GERWATOWSKI: Are there issues out in the Weaver Hill area that a utility, if it had the funds available, would normally want to undertake to try to improve service or enhance it?

MR. BOOTH: Yes. I think the company would like to enhance the service on all its feeders, at least the ones that don't meet the reliability goals.

MR. GERWATOWSKI: Okay, all right. Thank

C-E-R-T-I-F-I-C-A-T-E

I, ELIZABETH GREELEY, a Notary Public, do hereby certify that I am expressly approved as a person qualified and authorized to take depositions pursuant to Rules of Civil Procedure of the Superior Court; especially, but without restriction thereto, under Rule 28 of said Rules; that the witness was sworn by me; that the transcript contains a true record of the proceedings.

Reading and signing of the transcript was not requested by any parties involved upon completion of the hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 17th day of June, 2024.

Elizabeth Greeley

____

ELIZABETH GREELEY, NOTARY PUBLIC
CERTIFIED COURT REPORTER
MY COMMISSION EXPIRES: 04/07/2026

<u>EXHIBIT D</u>

HB 8028
PUC
Oppose

STATE OF RHODE ISLAND

Public Utilities Commission

89 Jefferson Boulevard
Warwick, Rhode Island 02888
(401) 941-4500

Chairman Ronald T. Gerwatowski
Commissioner Abigail Anthony
Commissioner John C. Revens, Jr.

April 12, 2022

The Honorable Joseph J. Solomon, Jr.
Chair, House Corporations Committee
State House
Providence, RI 02903

Re: House Bill 8028 – Distributed Generation Interconnection

Dear Chair Solomon:

I am submitting the following comments on behalf of the Public Utilities Commission (PUC) on House Bill 8028, amending the Distributed Generation Interconnection law. This bill (1) appears to be an attempt to shift costs from developers onto ratepayers; (2) raises potential reliability and safety concerns; (3) removes negotiated timing and damage provisions that could increase risk to developers and ratepayers; and (4) mandates requirements that are already or could be addressed regulatorily. Several changes in the bill not only expose National Grid's ratepayers to the risk of higher and unnecessary costs imposed on their electric bills, but it may increase the cost of meeting the goals of the Act on Climate. For these reasons, the PUC recommends against passage of this bill.

If the purpose of the bill is to ensure interconnecting customers[1] pay only for modifications their projects require and ensure ratepayers contribute to improvements that benefit them, no changes need to be made to the current law. For this reason, we believe the bill is attempting to redefine the categories of costs that should be properly borne by interconnecting customers. The addition of a larger renewable generator requires the utility to add or change equipment on its electric system solely to accommodate the generator.[2] These are called system modifications and the costs of these modifications are charged to the interconnecting customer/developer. Sometimes, the utility makes other changes to the electric system as part of the same project where those changes are simply to improve the operation of the system and are necessary to provide safe and reliable service to customers regardless of the addition of the renewable energy generator.

[1] By way of background, the term interconnection means the connection of any customer to the electric system. As relates to this bill, it is the connection of the renewable generator to the electric system. Small renewable energy systems can often connect to the electric system without necessitating changes to the electric system.

[2] Absent the new renewable generator, the electric system is providing safe and reliable service to customers without the need for any upgrade.

These are called system improvements and these costs are already charged to all ratepayers. This bill appears to be an attempt to artificially expand the definition of system improvements to shift costs currently and properly borne by renewable energy customers/developers to all other customers.

The proposed amendments will also lead to more disputes over how the costs related to interconnections are classified. While the interconnection process works largely without PUC involvement now, these new parameters will likely require the PUC to conduct case-by-case reviews to determine whether the changes to the electric system are properly system modification costs or system improvement costs. This may cause delays in interconnections.

The PUC is aware there may be a perception that the current allocation of costs for interconnections which require renewable developers to pay for the cost of system upgrades necessary for the project to operate on the system is an economic impediment to the development of renewable energy in Rhode Island. This perception, however, is not supported by the data. The current interconnection law and statutory ratepayer-funded compensation programs are supporting the robust development of renewable energy in Rhode Island by providing ample compensation to renewable energy project developers and their interconnecting customers while also providing appropriate price signals where a project would be causing higher costs to the electric system. Thus, instead of solving a perceived impediment to development, the law would be simply increasing the profit margins for developers on the backs of ratepayers and potentially subsidizing uneconomic development.

It is worth considering the unprecedented growth of renewable development in Rhode Island before amending the interconnection law. In the Spring of 2021, Solar Energy Industries Associated (SEIA) reported that Rhode Island had about 374 megawatts (MW) of solar power installed with another 775 MW in the interconnection queue. At the time, the website Clean Technica ranked Rhode Island 12th in the country on a per-capita basis. And when measuring solar capacity per square mile, Rhode Island ranked third (if the District of Columbia is included), according to National Grid and confirmed by a Providence Journal analysis.[3]

The most recent SEIA data through the fourth quarter of 2021 indicates that Rhode Island has 555.4 MW of solar installed.[4] This represents a 48% increase in less than a year. In addition, National Grid has recently reported that as of early December 2021, it had 688 MW of renewable energy projects under review, including all renewable energy types.[5] This suggests that the interconnection law as currently written is not thwarting the development of renewable energy in Rhode Island. Considering the high level of renewable energy investment backed by the compensation provided through the ratepayer funded Renewable Energy Growth Program and Net Metering credits, when a developer is faced with a price signal that renders a project uneconomic, that should not be seen as a failure in the interconnection process, but instead, that ratepayers are better off spending their money on other sources of renewable energy.

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[3] Alex Kuffner, *Solar power bill might have cost ratepayers $54 million or more*, PROVIDENCE JOURNAL, Jul. 17, 2021. https://www.providencejournal.com/story/news/2021/07/17/solar-bill-vetoed-governor-could-have-cost-ratepayers-54-million-more/7991702002/

[4] https://www.seia.org/state-solar-policy/rhode-island-solar

[5] Net metering projects accounted for 568.497 MW under review while Renewable Energy Growth Program projects accounted for 119.544 MW. (Docket No. 5202).

In addition to the impact of the cost increases to ratepayers, the bill includes new language allowing a third-party contractor, not under the control of the utility, to work on the utility side of the electric system. This may adversely affect the utility's ability to ensure safe and reliable service and would make Rhode Island an outlier. The Division of Public Utilities and Carriers is addressing this concern in its letter so we will not reiterate their points.

The bill also removes several provisions of the law that were negotiated in 2017 that properly balance the interests of the interconnecting renewable energy customer, the utility, and all ratepayers. Several of the changes improperly shift additional risk onto the utility and its ratepayers. This shift may lead to unexpected adverse consequences for interconnecting customers as well.

While the PUC would welcome additional assistance and resources in the review of interconnection disputes, similar to the support provided to the ombudsperson in Massachusetts, the ombudsperson role as described in the bill is overly broad and would conflict with the broad policies in place to ensure safety and reliability of service to all customers that is set out in R.I. Gen. Laws § 39-1-27.

Also notable, several of the components of the bill have either already been addressed in the tariff on file with the PUC, are currently under review in docketed matters, or would be better addressed in a regulatory proceeding. For example, based on the interconnection bill from last year, the PUC has sought comments on the developers' concerns with the final cost accounting. Two developers provided constructive comments which will assist PUC staff in developing recommendations for PUC action. This is only one of the issues currently under consideration.

Please feel free to contact me with any questions at 401-780-2147 or cynthia.wilsonfrias@puc.ri.gov.

Sincerely,

Cynthia G. Wilson-Frias
Chief of Legal Services

cc: Committee Members
Representative Cardillo

EXHIBIT E

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

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

Docket No. 23-38-EL

RE: Petition for Acceleration Due to
DG Project – Weaver Hill Projects

PREFILED DIRECT TESTIMONY OF

Gregory L. Booth, PE
President, Gregory L. Booth, PLLC
On Behalf of the Rhode Island Division of Public Utilities and Carriers

April 17, 2024

Prepared by:
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Prefiled Direct Testimony of

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

On Behalf of the Rhode Island Division of Public Utilities and Carriers
Docket No. 23-38-EL

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DIRECT TESTIMONY OF GREGORY L. BOOTH, PE

I. INTRODUCTION

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

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

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

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

Q. WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

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

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. I am an active member of the National Society of Professional Engineers ("NSPE"), the Professional Engineers of North Carolina ("PENC"), the Institute of Electrical and Electronics Engineers ("IEEE"), American Public Power Association ("APPA"), American Standards and Testing Materials Association ("ASTM"), the National Fire Protection Association ("NFPA"), and Professional Engineers in Private Practice ("PEPP"). I have also served as a member of the IEEE Distribution Subcommittee on Reliability and as an advisory member of the National Rural Electric Cooperative Association ("NRECA")-Cooperative Research Network, which is an organization similar to EPRI.

Q. PLEASE BRIEFLY DESCRIBE YOUR EXPERIENCE WITH ELECTRIC UTILITIES.

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

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

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

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

A. I have testified before the Federal Energy Regulatory Commission ("FERC") and numerous state commissions, including in Connecticut, Delaware, Florida, Georgia, Maine, Maryland, Massachusetts, Minnesota, New Jersey, North Carolina, Pennsylvania, South Carolina and Virginia. Attached is Exhibit GLB-1 Gregory L. Booth Curriculum Vitae.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. The purpose of my testimony is to address the Petition of Narragansett Electric Company d/b/a as Rhode Island Energy ("Company" or "RIE") for Acceleration of a System Modification Due to Distributed Generation Project; Weaver Hill Project dated October 17, 2023 (the "Petition"). The Distributed Generation interconnection requests that are the subject of the Petition were made by Green Development, LLC ("Green" or "Green Development"), Revity Energy, LLC ("Revity"), and Energy Development Partners ("EDP"). The Company and Green Development entered into an Interconnection Service Agreement ("Green ISA") on July 22, 2020 related to a 20,000 kW photovoltaic system located at 899 Nooseneck Hill Road, West Greenwich, Rhode Island 02817 ("Nooseneck Projects") which was amended by the Company and Green Development on December 9, 2021 and December 16, 2022. On May 16, 2022, the Company and Revity entered into an Interconnection Service Agreement ("Revity ISA") for the purpose of interconnecting Revity's 40.7 MW photovoltaic system located at 18 Weaver Hill Road, West Greenwich, Rhode Island 02817 ("Robin Hollow Project") to the Company's Electric Power System ("EPS"), which was amended by the Company and Revity on July 29, 2022 and April 26, 2023. On April 14, 2023, the Company issued an Interconnection Service Agreement to EDP ("EDP ISA") for the purpose of interconnecting EDP's 9.2 MW Studley Solar Project located at 189 Weaver Hill Road, West Greenwich, Rhode Island 02817 ("Studley Solar Project") to the Company's EPS. My analysis, testimony and recommendations are presented on behalf of the Division and are intended to equitably apply the tariff in order to protect the integrity of the tariff and the ratepayers.

III. OVERVIEW AND SYSTEM IMPROVEMENTS

Q. WHAT HAS THE COMPANY STATED AS ITS BASIS FOR FILING THE PETITION?

A. The Company's stated basis is R.I. Gen Laws §39-26.3-4.1, entitled *Interconnection Standards* (the "Interconnection Statute"), and Section 5.4 of RIPUC No. 2258, entitled *The Narragansett Electric Company Standards for Connecting Distributed Generation* (the "Interconnection Tariff" or "Tariff").

Q. DO YOU AGREE THE INTERCONNECTION TARIFF SHOULD APPLY TO THIS FILING?

A. Yes.

Q. DO YOU AGREE WITH THE COMPANY'S METHOD FOR APPLYING THE TARIFF?

A. I do not agree with the Company's method of applying the Interconnection Tariff.

Q. BEFORE DISCUSSING THE DETAILS OF YOUR ANALYSIS AND WHY YOU DISAGREE WITH THE COMPANY'S METHOD OF APPLYING THE TARIFF, WOULD YOU PROVIDE AN OVERVIEW OF YOUR ANALYSIS AND DISAGREEMENTS?

A. Yes. I have performed an assessment of the Weaver Hill Project including reviewing ISR Plan materials, Area Study materials, system engineering models, and area peak loads which the Company relied upon to determine the need and timing of system improvements considered in this Petition. In its original Area Study, the Company proposed Weaver Hill to alleviate overloads on Hopkins Hill 63F6 ("Hopkins Hill") and Coventry 54F1 ("Coventry") feeders projected at 104 percent and 94 percent loaded respectively in 2035 (page 29). However, the load has been declining since the time the Area Study was performed, eliminating any near-term need for the Weaver Hill project. My assessment indicates the system improvements in the Weaver Hill Area do not need to be installed within five years from the time the Company began the Impact Study of the proposed Nooseneck Projects (Green Development); Robin Hollow Project (Revity); and Studley Solar Project (EDP). The Impact Studies were started April 1, 2019, January 6, 2020 and August 7, 2019 respectively. Under the Company's proposal, the Weaver Hill project installation would not occur before 2027 or well beyond the five years from the start of the Impact Studies.

Q. CONTINUING YOUR OVERVIEW, WOULD YOU DISCUSS THE ISR PLAN AND AREA STUDY AS IT RELATES TO WEAVER HILL?

A. The FY 2024 ISR Plan, filed in 2022, included the first engineering work for the Weaver Hill project and by that time all the impact and interconnection studies had been finalized. What this means is the DG was already the precipitating reason for the Weaver Hill project. There is not a baseline Area Study case for the Weaver Hill project with existing loads and no DG. Based on existing data and analysis, my opinion is that the improvements do not need to be included in an ISR Plan for capital improvement expenditure absent the DG projects before 2035, particularly considering the decline in loading on Hopkins Hill and Coventry feeders. Loading data from RIE in FY 2025 ISR Plan materials[1] indicate much lower loads with Hopkins Hill projected at 88 percent in 2024 and Coventry at 84 percent with little or no future load growth. The Company's previously projected overloads have

[1] FY 2025 ISR Plan, Docket 23-48-EL, Attachment DIV 1-2.

not materialized. My analysis determined the Weaver Hill project would not be required until 2035 or later, which would be nearly fifteen years after the DG impact studies commence. This is well beyond the reimbursement eligibility period of five-years as established in the Tariff (Petition, page 9). This means that under the Interconnection Tariff, there should not be any reimbursement to the DG customers as proposed by the Company. The Company, however, has taken a more liberal view of tariff's intent while ignoring the actual Interconnection Tariff language. The Company disregards the tariff language and proposes reimbursement anyway. The Company's recommendation represents a deviation from its own Interconnection Tariff. I will discuss in detail my assessment and how I reached my conclusion and recommendation.

Q. DO YOU HAVE ANY DISAGREEMENT WITH THE SYSTEM IMPROVEMENTS PROPOSED BY THE COMPANY?

A. Yes. Considering the existing loads and nearly flat load growth and the fact that there is no overload now, any minor growth issues can be addressed with power factor correction using capacitors and voltage correction using voltage regulators. These are prudent interim solutions when the issues are not immediate and would cost a fraction of what the Company proposes in this Petition. Furthermore, the peak loads on both circuits are projected to exceed 100 percent capacity ratings for a very short period of time if they do develop at all, occurring as little as one hour in a year (DIV 2-5). Capital investments of a few hundred thousand dollars is much more appropriate than millions for a problem which may not occur at all and, if it does, the duration would be very short. Additionally, the existing and near term ISR Plans have many more critical projects to be advanced before the Weaver Hill project. The Weaver Hill project is required exclusively to accommodate the DG. The Company should not pay for any portion of that differential under any circumstances.

Q. DOES THE COMPANY APPROPRIATELY APPLY SECTION 5.4 OF THE INTERCONNECTION TARIFF TO THE WEAVER HILL PROJECT?

A. No. The Company provides Section 5.4 language in its testimony (pages 8-11) and follows with its rationale on its applicability, mainly that "the System Improvements that have been accelerated by the Green Development's Weaver Hill Projects are System Modifications that also benefit Revity, and EDP" (page 12). The Company specifically petitions that "Green Development, Revity, and EDP shall fund the System Improvements subject to repayment of the depreciated value of the System Improvement as of the time the System Improvement would have been necessary" (page 14). The Company contends that the Project should be "accelerated". which is that the "modification is otherwise identified in the Company's work plan as a necessary capital investment to be installed within a five-year period as of the date the Company begins the impact study of the proposed distributed generation (DG) project (defined as an Accelerated Modification)". (Interconnection Tariff, Section 5.4.c). As stated earlier, the Company commenced the three Impact Studies on April 1, 2019, January 6, 2020 and August 7, 2019. The Weaver Hill project, even if implemented as the Company identified in its Area Study with higher loads than are actually occurring, will not be installed until 2027 or later. The installation date for the Weaver Hill project is well beyond the five-year limitations period that determines if a capital investment is "accelerated" under the plain language of Section 5.4 of the Interconnection Tariff. DG reimbursement, therefore, is not available.[2]

Q. THE COMPANY STATES ON PAGE 21 OF ITS PETITION THAT THE WEAVER HILL ROAD SUBSTATION IS IN THE FY 2023 ISR PLAN DOCKET 5209 AND

[2] The Company, itself, does not take its petition very seriously. In its petition, the Company "proposes that it would begin recovering depreciation and return from distribution customers *in FY 2025 through the ISR plan revenue requirement."* (Petition, Page 24, lines 16-18). Since making that request, the Company and Division agreed that the Company will forego its requested relief, reserving its right to recover it in an unspecified future proceeding.

THAT THE CENTRAL RI WEST AREA STUDY EVALUATED THE ISSUES AND PROPOSED THE SOLUTION. IS THAT AN ACCURATE CHARACTERIZATION?

A. I find that characterization very misleading. The Weaver Hill substation and sub-transmission construction were not FY 2023 ISR Plan projects but only referenced as a potential future project. However, the FY 2023 ISR Plan was filed December 20, 2021 during the finalization of the Central RI West Area Study which is dated September 2022. It would have been speculative to include the Weaver Hill project in the FY 2023 ISR Plan. While the Area Study does show Weaver Hill as a solution for a potential 2035 problem, the project would not be constructed now since there are much less expensive interim solutions and the actual loads and overloading are not occurring at this time or in the near term. Absent the DG projects, there is nothing causing Weaver Hill substation to be advanced at this time.

Q. ON PAGE 22 OF THE PETITION THE COMPANY IN ITS TESTIMONY DISCUSSES OVERLOADING WHICH WILL EXIST IN 2035 AND THAT WEAVER HILL SUBSTATION IS THE LEAST COST SOLUTION FOR THIS 2035 OVERLOAD. IS THAT ACCURATE CONSIDERING TODAY'S INFORMATION?

A. No. The Company discusses the Hopkins Hill feeder loading at 104 percent but it is only 88 percent today and is not expected to increase much beyond that by 2035. It is important to note that the Area Study indicated Hopkins Hill feeder 63F6 would be loaded to 102 percent in 2020 and yet now it is only expected to be loaded to 88 percent in 2024. Exaggerated overload conditions are also being put forth by the Company for the Coventry feeder 54F1. The Area Study showed it to be loaded to 93 percent in 2020 and yet now it is expected to be loaded to 84 percent in 2024. Actual peak loads for both feeders have declined from 2021 and 2023 (see response to DIV 2-2). The present-day facts are clear. There is not an imminent overload concern on either feeder and will not be until 2035 and beyond. This is most certainly more than five-years after the 2019 and 2020 impact studies were started.

Q. THE COMPANY ON PAGE 24 OF ITS TESTIMONY STATES THE PROJECT WILL BE COMPLETED IN FY 2025 BUT WOULD HAVE BEEN COMPLETED IN FY 2027 WITHOUT THE DG PROJECTS. THE COMPANY ALSO PROPOSES PAYING THE DEVELOPERS AT THE TIME THE PROJECT IS PLACED IN SERVICE. DO YOU AGREE WITH THIS?

A. I do not. First, absent the DG projects, as I have stated earlier, the Weaver Hill substation would have been delayed well beyond 2027 to 2035 or later. The year 2027 in service date, if even achieved, is more than five years after the 2019 start of the Impact Study, and thus outside the Tariff.

Q. THE WEAVER HILL PROJECT WILL NOT BE INSTALLED WITHIN THE FIVE-YEAR LIMITATIONS PERIOD AS REQUIRED BY THE INTERCONNECTION TARIFF. DO YOU AGREE WITH THE COMPANY'S RATIONALE FOR PROPOSING DG REIMBURSEMENT WHEN THE PROJECT DEVIATES FROM THE TARIFF'S REQUIREMENTS?

A. I do not. The Interconnection Tariff language was developed to balance infrastructure development and cost responsibility by establishing specific timelines when investments can be considered for cost sharing. Loosely applying the standards, regardless of the level of perceived benefits, leads to premature system investments and requires the expenditure of capital that could otherwise be used for imminent and more critical projects.

My analysis is the product of applying the Interconnection Tariff's plain language and its obvious meaning. The Interconnection Tariff provides the regulatory-approved processes and requirements that govern when DG projects, like these DG projects, are to receive accelerated treatment. The general body of ratepayers should not reimburse DG developers now for project work that the Company claims will only be installed after the tariff limitations period has expired, and in any event, based on my analysis, will not be needed for years beyond the five-year period, if at all.

Q. IN THE COMPANY'S RESPONSE TO DIVISION DATA REQUEST DIV 3-4, IT STATES "THERE ARE MANY CASES WHERE PROJECT ACCELERATION CAN STILL PROVIDE BENEFITS AHEAD OF THE NEED DATE." DO YOU AGREE WITH THIS STATEMENT?

A. While I agree this statement is accurate, it has no applicability in the Tariff. The Tariff sets out standards for considering reimbursement which is not a test of whether a project that was accelerated provides benefits ahead of the need date. The Tariff reimbursement requires the determination of the need date and if the project is intended within five years of the start of an Impact Study, then reimbursement is applied. The fact that a project may provide benefits ahead of the need date is irrelevant in determining when a Distributed Generator is eligible for reimbursement under the Tariff.

Q. IN THE COMPANY'S RESPONSE TO THE DIVISION'S DATA REQUEST DIV 3-1, IT INDICATES THE DATE THAT A SYSTEM ISSUE IS INCLUDED IN AN ISR PLAN IS NOT THE EARLIEST DATE THAT THE INVESTMENT IS NEEDED. DO YOU CONCUR WITH THAT POSITION TAKEN BY THE COMPANY?

A. I do not concur with that position. First, just because the Company may desire a project be included in the ISR Plan does not mean it is actually needed at that time. Second, the project desired by the Company may not be the least expensive solution. Third, there may be other solutions which will extend the date the project is needed allowing the Company to determine if the future load requiring the project actually materializes. Lastly, the Company and Division collaborate on the ISR Plan and the Commission provides a final approval of a particular plan and budget. Affordability and risks are added components of the final decision which very often push projects such as the Weaver Hill project out well beyond the Company's preferred early, but not justified, completion date. Therefore, the date for a project implementation must consider when it is most likely to be incorporated into an ISR Plan and not the earliest date the Company may desire the project for risk reduction or revenue enhancement.

IV. AREA STUDY AND ISR PLAN ANALYSIS

Q. PLEASE BRIEFLY DESCRIBE YOUR ANALYSIS PROCESS.

A. I have been involved in the ISR Plan process on behalf of the Division since its inception. I have been involved in the analysis and conferences with the Company concerning every aspect of the ISR Plan process, Area Studies performed from 2014 to 2021, and the recently delivered Long-Range Plan in the FY 2025 ISR Plan filing. The Division, much like the Company, uses Area Studies to assist in development of the ISR Plan discretionary capital projects. The study outcomes are not considered sanctioned capital investments by the Division or approved capital investments by the Commission, but rather a level of guidance for many ISR Plan projects. While these studies provide a view of the future needs and are consolidated in a Long-Range Plan, they do not establish what will become acceptable in future ISR Plans. To be clear, the Long-Range Plan is not an approved capital investment plan but rather the Company's strategic view of future needs based on stressing the system beyond most likely loading levels. The actual loads and system conditions are dynamic and constantly changing. Projects proposed in the Area Studies and Long-Range Plan must be carefully assessed based on existing loads, forecasts and conditions before being advanced. The Division has not completed the Long-Range Plan analysis process and will have further conferences with the Company. My annual ISR Plan review includes evaluating the need and prioritization of proposed projects, including those driven by Area Studies. I rely on numerous information sources for my review and assessment including my first-hand knowledge of the past and present ISR Plans, Area Studies together with their CYME engineering models, field assessment of substations with asset condition issues, asset condition reports, and system reliability and loading analyses. All this analysis forms a basis of certain criticality for existing and future projects, with a focus on identifying projects justified for implementation now based on actual system conditions versus those that can be deferred. The ISR Plans are based on this analysis, a collaborative process with the Company, and a balance of criticality with affordability and risk assessment and tolerance. All the Company's proposed work cannot be accomplished immediately, nor is it affordable to do so.

Q. HOW DO THE AREA STUDY AND ISR PLAN ANALYSES RELATE TO THE WEAVER HILL PETITION?

A. The Company's Petition states, among other things, that the interconnection of the DG project has accelerated the Weaver Hill project; suggests the need for system investments in the Weaver Hill area; that the Company's 5-year and beyond capital investment plan includes system investments in the Weaver Hill area through calendar year 2027; and opines that absent the interconnection of the DG projects, the Company anticipates making the system improvements by 2027. The Company relies on these submittals to justify its proposed DG reimbursement. I used the Company's Central Rhode Island West Area Study and Weaver Hill project assumptions to assess the actual need and timing of the system improvement that is the subject of the Petition. To do this I evaluated system actual loads, forecasted loads, and engineering models to confirm whether system conditions would require the stated improvements. I then evaluated the criticality of the system issues requiring the improvement, comparing the need for the investment against other discretionary work to determine if the Company's anticipated completion of the project by 2027 will be necessary.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE NEED AND TIMING OF THE SYSTEM IMPROVEMENT IDENTIFIED AS THE WEAVER HILL PROJECT?

A. The system improvement identified in the Company's Area Study and Petition are new 34.5 kV sub-transmission lines proposed to interconnect DG customers which the Company would then utilize to feed the Weaver Hill modular substation. The Area Study is premised on the fact that the DG customers are going to interconnect; therefore, the Company does not have an Area Study including the base case for Weaver Hill substation that assumes the DG customers do not exist. I prepared a feeder loading analysis which the Company contends is what mandates the Weaver Hill project. The actual loads are far below the Company's projections. It appears the Company is forecasting loads to be increasing at unrealistic rates to place excess load on the two purported overloaded circuits. This then suggests thermal overload and low voltage, and a risk to customer service and reliability which does not exist.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF THE NEAR-TERM REQUIREMENT FOR THE WEAVER HILL MODULAR SUBSTATION AND 35 KV LINE TO SERVE THE SUBSTATION?

A. The projected loads in the Area Study driving the need for the Weaver Hill project are far in excess of existing loads and are not realistic projections. For example, RIE projected overloads in 2022 and 2023 on Hopkins Hill circuit when the actual circuit loads were 87 percent and 77 percent respectively (see response to DIV 2-2). The projected loads of 544 and 549 amperes for 2022 and 2023 were actually only 459 and 409 amperes, and thus some 26 percent below the projections. On the surface, it appears RIE is significantly over projecting load level in order to overbuild the system capacity.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF YOUR LONG-TERM REQUIREMENT FOR THE WEAVER HILL PROJECT?

A. There is very little projected load growth and most likely no load growth on the Hopkins Hill or Coventry circuits. That means voltage or loading violations are very unlikely through the end of the study period or 2035. Therefore, the Weaver Hill project absent the DG projects would not be incorporated into an ISR Plan before 2035.

Q. WHY NOT SOLVE ANY POTENTIAL CRITERIA VIOLATIONS NOW WITH THE WEAVER HILL PROJECT?

A. Voltage and power factor violations exist on many of the RIE feeders. Capacitors and voltage regulators are inexpensive and rapid deployment solutions which can solve many short-term issues should they arise. In addition, the Company's projected overloading of the circuits is not occurring now and load is actually declining, making a near term solution unnecessary. There are many asset condition substation projects which should take priority in the ISR Plans over any Weaver Hill project in the near term, particularly since the actual loads are not dictating any immediate action on the two circuits.

Q. YOU MENTIONED PRIORITIZING SUBSTATION ASSET CONDITION PROJECTS. CAN YOU EXPLAIN YOUR REASONING?

A. Yes. The Company identified a minimum of sixteen (16) substations which have substantially deteriorated assets. Most of the equipment and infrastructure is obsolete and unreliable, creating both safety and reliability concerns. The Division and its consultant visited these substations to verify the level of asset condition and the priority of stations for significant improvement projects. These stations represent a significant level of capital investment over the next five plus years. The substations serve a large number of customers and have a much higher priority than marginal loading and reliability issues on two feeders that the Weaver Hill project would be intended to solve. Thus, the substation projects will result in budgetary pressure to further delay single circuit marginal or even declining issues, particularly when these reliability issues can be solved with relatively inexpensive short-term solutions.

Q. ARE THERE ANY OTHER BUDGETARY PRESSURES WHICH WOULD FURTHER DICTATE DELAYING THE WEAVER HILL PROJECT ABSENT THE GENERATION INTERCONNECTIONS?

A. Yes. There are long-standing programs such as the UG Program which is addressing the upgrades to the underground duct bank system in areas, such as Providence, which are approaching or are more than 100 years old. Additionally, there is a URD program which involves direct buried vintage cable replacement and numerous other long standing asset condition programs which have far higher criticality than two feeders with marginal or no overloading issues now or projected in the near term. Tariff and engineering concerns aside, the Commission should not compromise major asset condition programs to advance the Weaver Hill project far ahead of its need.

V. RECOMMENDATIONS AND CONCLUSIONS

Q. WHAT CONCLUSIONS HAVE YOU REACHED?

A. The Weaver Hill project even with the DG projects would not be constructed and in service until well beyond the five-year window after the impact studies were started. The Weaver Hill project absent the DG projects would not be required in an ISR Plan until 2035 or beyond. The Company has stated in its testimony that the decision is driven by public policy and its assumption that the DG developers will be able to reinvest the capital and install additional distributed generation, however this is speculative as there is no restriction on how the funds could be used by developers, The following is a summary of the timelines as contained in Company exhibits EJRS-1; EJRS-2 and EJRS-3. The Nooseneck Project Impact Study started 4/1/2019 and was finalized 6/29/2020. The Robin Hollow Project Impact Study started 1/6/2020 and was finalized 4/21/2021. The Studley Solar Project Impact Study started 8/7/2019 and was finalized 9/20/2022. In its testimony on page 24, line 14, the Company says the Weaver Hill project would have been completed and placed in service in FY 2027 without the DG project. Whereas, on page 22 lines 3 through 5 of the Company's testimony it indicates the Area Study identified overloads or near overloads in 2035. The load does not warrant the Weaver Hill project until 2035 or later. The Company's timeline indicates the Weaver Hill Project is beyond the Tariff five-year period for reimbursement based on the start date of any one of the three Impact Studies. There is no scenario in which the DG projects qualify for reimbursement.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. The Company's Petition should be denied in its entirety.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

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 17th day of April, 2024.

____
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
STATE OF RHODE ISLAND
No. 8078
REGISTERED
PROFESSIONAL ENGINEER
(ELECTRICAL)

Gregory L. Booth, PE

<u>EXHIBIT F</u>

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Rhode Island Energy™
a PPL company

May 9, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-38-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project – Weaver Hill Project
Joint Rebuttal Testimony

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's joint pre-filed rebuttal testimony of Eric Wiesner and Ryan Constable in the above-referenced docket.

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

Sincerely,

Andrew S. Marcaccio

Enclosure

cc: Docket No. 23-38-EL Service List

JOINT REBUTTAL TESTIMONY

OF

RYAN CONSTABLE

AND

ERIC WIESNER

Table of Contents

I. <u>Introduction</u>

<u>Eric Wiesner</u>

Q. Mr. Wiesner, please state your name and business address.

A. My name is Eric Wiesner. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Mr. Wiesner, by whom are you employed and in what position?

A. I am employed by The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company" or "Rhode Island Energy" or "RIE") as the Director of Asset Management and Engineering. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Mr. Wiesner, please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Electric Engineering from Virginia Polytechnic Institute and State University (Virginia Tech) in Blacksburg, Virginia, in 2009 and a Master of Engineering in Electrical and Computer Engineering from Worcester Polytechnic Institute in Worcester, Massachusetts, in 2015. I am a Registered Professional Engineer in Rhode Island, number 14219. I worked at American Power Conversion from 2009 to 2010, after which time I joined the National Grid Service Company ("NGSC"). From 2010 to 2012, I worked in the Distribution Design department supporting distribution line capital projects and programs. From 2012 to 2015, I worked in the Substation Engineering department supporting capital projects such as substation rebuilds, greenfield substations, and supporting responses to equipment failures. From 2015 to 2016, I joined General Dynamics Electric Boat as an Engineer supporting the electrical power system on various submarines. I returned to NGSC in 2016 and rejoined the Substation Engineering department performing the same type of work as I had performed from 2012 to 2015. From 2016 to 2020, I worked in the Substation Operations and Maintenance department as a field supervisor where I oversaw the day-to-day operations and maintenance of substations in Central Massachusetts. From 2020 to 2022, I rejoined the Substation Engineering department as the Manager where I oversaw the execution of substation capital projects and programs. In 2022, I joined Rhode Island Energy as the Regional Engineering Manager as described above and, on March 4, 2024, I became Director of Asset Management and Engineering.

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

A. Yes. I have previously testified before the PUC in support of the Company's Fiscal Year ("FY") 2025 Electric Infrastructure Safety and Reliability ("ISR") Plan in Docket No. 23-48-EL.

Ryan Constable

Q. Mr. Constable, please state your name and business address.

A. My name is Ryan M. Constable. My business address is 280 Melrose Street, Providence, Rhode Island 02907.

Q. Mr. Constable, by whom are you employed and in what position?

A. I am employed by Rhode Island Energy as an Engineering Manager in the Distribution Planning and Asset Management Department. In my position, I am responsible for planning and oversight of projects and programs that ensure a safe and reliable electric distribution system.

Q. Mr. Constable, please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, New York, in 1993 and a Certificate of Industrial Management and Power Engineering from Worcester Polytechnic Institute in Worcester, Massachusetts, in 2000. I am a Registered Professional Engineer in Massachusetts, number 41632. I worked at NGSC from 1994 to 2000 and again from 2010 to May 24, 2022, after which time I joined Rhode Island Energy in my current position.

I have held various positions of increasing responsibility in the area of Distribution Planning. From 1994 to 1998, I was a Project Engineer responsible for the design and maintenance of the electric infrastructure serving commercial and residential customers in southeastern Massachusetts. During the period from 1998 to 2000, I was a Planning Engineer conducting long-range electric system studies. From 2010 to 2011, I worked as a Principal Engineer in the Utility of the Future department developing the Worcester Smart Energy Solution Pilot. In 2011, I became the Manager of Distribution Planning and Asset Management – New England, directing a ten-person team to conduct annual planning activities, perform long-range planning studies, and develop regulatory filings. In 2017, I became the Acting Director of that department.

From 2000 to 2010, I worked for three independent transmission development companies, TransEnergie U.S., Cross Sound Cable Company, and Brookfield Renewable Power.

Q. Have you previously testified before the PUC?

A. Yes. I have previously testified before the PUC in support of the Company's FY 2025 Electric ISR Plan in Docket No. 23-48-EL; FY 2024 Electric ISR Plan in Docket No. 22-53-EL; FY 2023 Electric ISR Plan in Docket No. 5209; FY 2022 Electric ISR Plan in Docket No. 5098; and the Company's FY 2020 and FY 2023 Electric ISR Plan

Reconciliation Filings. I have also participated in technical sessions as part of Docket No. 23-34-EL (ISR Planning and Budget Processes).

II. Purpose and Structure of Joint Reply Testimony

Q. What is the purpose of this testimony?

A. The purpose of this testimony is for the Company to respond to the following filings that were submitted in this proceeding: (i) Pre-filed direct testimony of Gregory L. Booth, PE on behalf of the Division of Public Utilities and Carriers ("Division") submitted on April 17, 2024; and (ii) Pre-filed direct testimony of Mathew Ursillo on behalf of Green Development, LLC ("Green") submitted on April 17, 2024 (dated April 10, 2024); and (iii) Pre-filed direct testimony of Ryan Palumbo on behalf of Revity Energy LLC ("Revity") submitted on April 10, 2024.

Q. How is this testimony structured?

A. This testimony is broken up by topic. Specifically, through this testimony, the Company responds to the following topics:

- Tariff Application (Section III)
- Central Rhode Island West Area Study (Section IV)
- ISR Materials (Section V)
- Conclusion (Section VI)

III. Tariff Application

Q. Why should the PUC reject Mr. Booth's narrow interpretation of Section 5.4 of RIPUC No. 2258 entitled The Narragansett Electric Company Standards for Connecting Distributed Generation ("Interconnection Tariff" or "Tariff")?

A. As explained in this rebuttal testimony, the intent of the Interconnection Tariff is to align with the scope and duration of the Company's distribution work plan and, from a practical standpoint, it would be challenging to identify a significant distributed generation ("DG") project that could be fully installed within five years from the start of an Impact Study.

Q. What is the rationale behind the five-year look forward period referenced in Section 5.4 of the Interconnection Tariff?

A. The applicable statute, R.I. Gen. Laws § 39-26.3-4.1 (the "Interconnecting Statute"), is silent as to the timeframe over which a System Modification[1] might be considered accelerated. The rationale behind the five-year look forward period in the Interconnection Tariff is to set a timeframe that aligns with the scope and duration of the Company's distribution work plan, which at the time the acceleration provisions were incorporated into the Tariff, was five years. The Company notes that it now provides a 10-Year Long Range Plan.

[1] The Interconnecting Statute references a System Modification "benefiting other customers." A System Modification that "benefits other customers" can be considered a System Improvement as defined by the Tariff.

Q. What is the Company's basis for the rationale described above?

A. In Docket No. 4763, the Company responded to a record request issued by the PUC stating that the look forward period is five years from the date the impact study begins "to align with the Company's distribution work plan."[2] Emphasis added.

Q. Does the Company consider the Accelerated Modification[3] that is the subject of the Petition[4] to be aligned with the Company's distribution work plan? If so, please explain why.

A. Yes. The Company views the installation of approximately 17,000 feet of a manhole and duct bank system along Division Street and Nooseneck Hill Road, West Greenwich, and the installation of approximately 17,000 feet of three conductor 1000 kcmil EPR insulated Cu cable to extend the 3310 line, and the installation of just under one mile of a manhole and duct bank system and three conductor 500 kcmil EPR insulated CU cable to extend the 3310 line along Weaver Hill Road (the "Weaver Hill Work") as an Accelerated Modification that was anticipated and continues to be needed within the FY 2024 through FY 2028 period as identified in the Central Rhode Island West Area Study

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[2] See the Company's response to Record Request No. 5 in Docket No. 4763. https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4763-NGrid-RR%282-23-18%29.pdf

[3] The Company will consider a System Modification to be an "Accelerated Modification" if such modification is otherwise identified in the Company's work plan as a necessary capital investment to be installed within a five -year period as of the date the Company begins the impact study of the proposed distributed generation project.

[4] The Company's Petition for Acceleration of a System Modification Due to Distributed Generation Project – Weaver Hill Projects dated October 17, 2023.

(the "Area Study" or "Central RI West Area Study"). The Central RI West Area Study was completed in September 2022. The Area Study's identified spend for the Weaver Hill Work is over the timeframe of FY 2024 though FY 2028. The Company began the Impact Studies associated with the Weaver Hill Work in April 2019 (FY 2020); August 2019 (FY 2020); and January 2020 (FY 2020); and identified spend stemming from the Central RI West Area Study four years later, in FY 2024.

Q. Mr. Booth's opinion is that the Accelerated Modification does not need to be included in an ISR Plan for nearly 15 years. Hypothetically, if an investment was 15 years out from being needed within an ISR Plan, would the Company consider it an Accelerated Modification?

A. As an initial matter, the Company does not agree with the Division's opinion regarding the need for the infrastructure that is being accelerated. The Weaver Hill Work was anticipated and continues to be needed within the FY 2024 though FY 2028 period as explained later in this testimony. However, if an investment is not needed for 15 years, the Company agrees that the project would be outside of the Company's five-year plan, which is the basis for the acceleration provisions in the Interconnection Tariff, and would not be considered by the Company for reimbursement as an Accelerated Modification.

Q. What insights or observations has the Company obtained from its ongoing review of DG interconnections and associated study timelines?

A. Since the Interconnection Tariff was amended to effectuate the statutory acceleration provisions, the scope, scale, and timelines for interconnections have become more complex both at state and federal levels. Accordingly, the Company looks at the surrounding circumstances of each project and the intent of the Interconnection Tariff and Interconnection Statute to determine whether to petition the PUC for reimbursement to the DG developer of an Accelerated Modification.

The interconnection study process for sites similar to Weaver Hill's site considered in this Petition can span many years. (In this case, the three sites took 3 to 5 years with one site's ISA still pending.). ISO-NE's Affected System Operator ("ASO") process can create similar timelines. Furthermore, the planning and full construction of projects identified within area studies can span many years considering the study time, the process time to introduce and request approval with an ISR Plan, and the practical design, procurement, and resourcing times.

As a result of timelines not contemplated during the development of the Interconnection Tariff, the Company notes a substantial conflict with a narrow interpretation of the Tariff and the intent of the Interconnection Statute. A narrow interpretation of the Tariff may result in limited to no opportunity for shared cost under the statutory acceleration provisions, which is inefficient for distribution planning and infrastructure construction that may be beneficial to both distribution customers and interconnecting customers.

The Company offers these specific observations for (i) Green's 20,000 kW photovoltaic systems located at 899 Nooseneck Hill Road, West Greenwich, RI 02817 ("Nooseneck Project"); (ii) Revity's 40.7 MW photovoltaic systems located at 18 Weaver Hill Road, West Greenwich, RI 02817 ("Robin Hollow Project"); and (iii) Revity's 9.2 MW Studley Solar Project located at 189 Weaver Hill Road, West Greenwich, RI 02817 ("Studley Solar Project").[5] The Nooseneck, Robin Hollow, and Studley Solar Projects are collected referred to as the "Weaver Hill Projects":

1. The Central RI West Area Study was started during the Impact Study process, approximately one year after start, and prior to the first Interconnection Services Agreement ("ISA") execution.
2. The Central RI West Area Study substantially finished after the Nooseneck Project but prior to the execution of the first version of the ISAs for the Robin Hollow and Studley Solar Projects. The ISA for the Studley Solar Project has not yet been executed.
3. The Central RI West Area Study identified a number of system issues with variable timing from immediate to forecasted.

[5] See correspondence from the Company dated April 26, 2024 which memorializes an update in ownership and control of the Studley Solar Project from Energy Development Partners ("EDP") to Revity.

4. Regardless of system issue timelines, the Study recommendation must consider regulatory and practical project execution timelines.
5. Considering regulatory and practical project execution timelines, the Study recommendation would have started near DG interconnection finish and the Study recommendation would have finished within five years of the DG interconnection finish.
6. The system and customers will benefit from electrical facilities installed by the Weaver Hill Projects well within five years from interconnection.

IV. <u>Central Rhode Island West Area Study</u>

Q. What is the purpose of an area study?

A. Area studies are detailed and comprehensive reviews of various regions throughout the Company's' service territory. Significant work goes into developing each area study. The studies typically address issues in a 10- to 15-year window and typically start five to seven years after the last study was completed. The studies may be prompted by findings exceeding the Company's planning criteria, asset condition issues, large new customer load requests, or acute reliability issues. To date, the Company has completed all 11 Rhode Island area studies and reviewed results with the Division.

Q. Is the process Mr. Booth described in his testimony to essentially invalidate the Central RI West Area Study concerning?

A. Yes. There are a number of misinterpretations and contradictions that are concerning. The Central RI West Area Study was a comprehensive and detailed study that took approximately 14 months to complete and was completed by engineering in consultation with operations personnel. Mr. Booth indicated that "the load has been declining since the time the Area Study was performed, eliminating any near-term need for the Weaver Hill project" In doing so, he incorrectly interpreted the forecast and dismissed other important factors as explained in the testimony below.

Q. Were the Central RI West Area Study recommendations reviewed by the Division?

A. Yes. The Division's claim that the Central RI West recommendations are suddenly unnecessary is contrary to other communications with and statements by the Division. The Division reviewed the Central RI West Area Study issues and recommendations in May of 2021 and made no comments regarding the analysis. Despite this fact and RI Energy's response to DIV 4-3 explaining study versions, Mr. Booth states: "However, the FY 2023 ISR Plan was filed December 20, 2021 during the finalization of the Central RI West Area Study which is dated September 2022. It would have been speculative to include the Weaver Hill project in the FY 2023 ISR Plan." It was not speculative and appropriate to include the work as it had been reviewed by the Division. The Division also supported the inclusion of the Weaver Hill projects in the FY 2024 and FY 2025 ISR

Plan filings. In addition to the analysis mistakes detailed below, the Division has had 4 opportunities over 3 years to comment on the details of the Central RI West Study and has failed to do so.

Q. From a needs standpoint, is the Central RI West Area Study premised on the fact that the Weaver Hill Projects would be interconnected?

A. Mr. Booth indicated that the "The FY 2024 ISR Plan, filed in 2022, included the first engineering work for the Weaver Hill project and by that time all the impact and interconnection studies had been finalized. What this means is the DG was already the precipitating reason for the Weaver Hill project." This statement is completely incorrect as the Central RI West Study recommendation does not serve the DG and so it is impossible for the DG to be the precipitating reason for the new station and feeder. This explanation is in the Company's response to Division 2-4.

Q. Did the Weaver Hill Projects create the need identified in the Central RI West Area Study?

A. No. The needs for the new station and feeder are identified in the Central RI West Area Study.

Q. Why should Mr. Booth's reanalysis of the Central RI West Area Study and opinion that the Weaver Hill Work would not go into an ISR Plan for 15 years be dismissed?

A. Mr. Booth bases his opinion on 'nearly flat growth' since the study was conducted. The Division requested a number of CYME models with attempts to find a lower load level without considering the full load picture. For instance, the 2023 load levels were low. However, the peak was in September and should be used with caution. A similar case occurred during the 2014 and 2015 summer peaks, which were also low and the Company did not adjust the work plan. This was proven appropriate as the 2016 summer was a hot summer with a high peak load. This event occurred during Mr. Booth's time reviewing the yearly ISR Plans and the Division and Mr. Booth raised no comments and were seemingly unaware. The Company is not claiming the Division or Mr. Booth should be involved in the nuances of forecasting, but this is an example that demonstrates how they are typically unaware of these details. His opinion on deferral for 15 years should also be dismissed because he dismisses the reliability issues associated with some of the longest feeders in RI Energy's territory and is not factoring emerging contingency issues on the 54F1 circuit as noted in the Company's response to Division 5-2.

Q. Could you summarize the needs contained within the Central RI West Area Study?

A. The Central RI West Area Study was provided in this docket as Exhibit EJRS-7 attached to the Pre-Filed Joint Testimony of Erica Russell Salk & Stephanie A. Briggs. Sections 4.2.1 Normal Configuration – Thermal Loading, 4.3 Voltage Performance, and 4.4.1 Reliability Performance describe the needs identified within the study. A summary is presented below.

- **Normal Configuration – Thermal Loading:**
    - 63F6 is predicted to be overloaded 102% to 104%.
    - 54F1 is predicted to be loaded between 93% to 94%.

- **Voltage Performance:**
    - 54F1 and 63F6 have low voltage issues.

- **Reliability Performance:**
    - 63F6 and 54F1 with high 5-year average frequency and duration statistics

Q. Based on the needs summarized above, did the Company take a comprehensive approach when planning for a solution?

A. Yes, and that comprehensive solution was developed through a process that included collaboration with the Division. Of all the presentations and filings made regarding the recommended Central RI West solution as of the date the Petition was filed, the Company had not received any negative comments regarding the thoroughness of the analysis or the reasonableness of the solution.

Q. What are the overload conditions for the Hopkins Hill feeder 63F6? Please explain.

A. 2.3 miles of spacer cable is predicted to be overloaded on the 63F6 per the Company's response to Division 2-3. Mr. Booth states that "The Company discusses the Hopkins Hill feeder loading at 104 percent but it is only 88 percent today". However, Mr. Booth attributes this to reduced load growth and changing forecasts and is not factoring actual events and operating issues. First, the main reason the 63F6 has a lower load level is that the Company switched load away from the 63F6 to another area feeder in a temporary fashion to mitigate the possible overload. The feeders in this area have various unique issues resulting in unsustainable switching configurations. Secondly, because the area circuits are electrically strained, the Company is considering shifting new load that is required by a public entity in this area to the sub-transmission system. This would require additional investment for effective grounding and voltage regulation. As the system operator, the Company has visibility and understands the actual planning and operational needs of the RI electric system. While the Company attempts to keep the Division updated on system operations, it is difficult to fully relay and understand the issues through data requests.

Q. If not for the Central RI West Study projects, how would the Company address that exposure?

A. Due to the vegetation in this area, there is no ability to install a larger conductor. The length and voltage issues on the circuits in this area preclude feeder reconfiguration.

Although not considered in the study because it would not address all issues, a possible alternative to the loading concerns would be to underground the 2.3 miles at a cost of $10-$15 million. This concept would not address the voltage and reliability issues.

Q. By approving this Petition, will the Division and PUC be locked into all Area Study solutions?

A. No. Area Study solutions may evolve over time as more information becomes available. While the Company recognizes that investments will be examined through the ISR proceedings and petitions such as this one, it is important to acknowledge that the area study and long-range plan process has been vetted and is a good process for identifying ISR projects and the potential of overlap between system needs and DG interconnection efforts. In this case, the Company believes the needs and solution identified through the Central RI West Area Study remain valid.[6]

[6] In this case, the Company believes the needs and solution identified through the Central RI West Area Study remain valid today. However, even if circumstances changed since the Central RI West Area Study, the Company stated, at the time the Interconnection Tariff was amended to include the acceleration provisions, "that in order to provide certainty to developers, the Company would honor any accelerated modification set forth in an interconnection service agreement even if the ultimate 'need' proves to be later than previously forecasted in the five-year capital plan." See PUC Report and Order No. 23379 in Docket No. 4763 at Page 7.

V. <u>ISR Materials</u>

Q. When did the Weaver Hill Work first show up in an ISR, including 5-year plan within the ISR?

A. The Company first introduced the Weaver Hill project in the five year plan within the FY 2023 ISR Plan. The Company first included spend on the Weaver Hill project in the FY 2024 ISR Plan Filing. The Company notes that the scope has evolved since this ISR Plan, as explained in the Company's response to DIV 4-9.

VI. <u>Conclusion</u>

Q. Is PUC approval of the Petition consistent with the Interconnection Statute?

A. Yes.

Q. Does this conclude this testimony?

A. Yes, it does.

Certificate of Service

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

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

Andrew S. Marcaccio, Esq.

May 9, 2024
Date

Docket No. 23-38-EL Rhode Island Energy – Petition for Acceleration Due to DG Project – Weaver Hill Projects
Service List updated 2/7/2024

Parties' Name/Address	E-mail	Phone
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File an original & 5 copies w/: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107

EXHIBIT G

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

Rhode Island Division of
Public Utilities and Carriers
89 Jefferson Blvd.
Warwick RI 02888
(401) 941-4500

March 28, 2018

Luly Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, R.I. 02888

In Re: Docket No. 4763 – National Grid's Standards for Connective Distributed Generation RIPUC No. 2180

Dear Luly,

Please find for filing with the Commission, an original and nine (9) copies of the State of Rhode Island Division of Public Utilities and Carriers, (the "Division") Comments relating to the request by the Commission to the Division to comment on responses #3 and #4 of National Grid's to Commission Record Requests filed on February 23, 2018.The Division conditionally accepts this proposal set forth in response to #3 of National Grid's responses to Commission Record Request filed on February 23, 2018 provided however, the Division reserves the right to respond after reasonable time has transpired for National Grid to implement the process described in response to PUC RR # 3 in order for the Division to more fully determine the reasonableness of the number of daily pre-interconnection applications reviewed. Further, attached hereto are the Comments of Carrie Gilbert of Daymark Energy Advisors on behalf of the Division with respect to Commission Record Request #4 for review and consideration by the Commission

I appreciate your anticipated cooperation in this matter.

Very truly yours,

Jon G. Hagopian, Esq.
Deputy Chief Legal Counsel

MEMORANDUM

TO: RHODE ISLAND PUBLIC UTILITIES COMMISSION

FROM: PHIL DIDOMENICO AND CARRIE GILBERT—DAYMARK ENERGY ADVISORS ON BEHALF OF THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

DATE: MARCH 28, 2018

SUBJECT: DOCKET NO. 4763 – NATIONAL GRID'S TARIFF ADVICE STANDARDS FOR CONNECTING DISTRIBUTED GENERATION RIPUC NO. 2180

On February 23, 2018 National Grid provide responses to record requests that were issued at the Commission's evidentiary hearing on January 25, 2018. In this memo we summarize our view of the Company's response to question #4 regarding the proposed treatment of a depreciation credit as it relates to the determination of interconnection costs for Renewable Interconnecting Customers.

The process outlined by the Company defines an accelerated modification as any modification that has previously been identified in its 5-year Capital Work Plan whose in-service date is moved up or accelerated by the proposed renewable project. Further, the Company proposes that the Interconnecting Customer is responsible for the identified accelerated modification costs less the depreciated value of modification costs reconciled to actual costs based on the date of installation.

Generally, the process outlined would serve to reduce the interconnection cost impact for new renewables where the need for system modification has been previously identified in the Company's 5-year Capital Plan but there are a few areas that merit awareness.

- The process outlined would benefit from a detailed hypothetical example that delineates each of the steps proposed;
    - Justification process that outlines how projects are added to the 5-year Capital Plan, what level of "other" customers defines a need?
    - How the modification cost will be estimated?
    - How depreciation will be calculated and applied?

- This process will do nothing to limit free riders that take advantage of the accelerated modification. A possible variation might include adjusting the original, planned, greater-good, in-service date should a second renewable resource require interconnection for the purpose of recalculating depreciation and assigning costs.
- The outer years of a five-year Capital Plan tend to vary significantly as new information is accumulated from year-to-year, the specific projects, project scope and their associated costs are all highly variable which potentially leads to uncertainty regarding what is and what is not an accelerated project.
- The process envisions a true-up to actual costs based on the actual in-service date. The uncapped nature of the true-up cost adds another layer of uncertainty for project proponents. Once an estimated cost has been provided in the ISA consideration should be given to treating it as a not-to-exceed cost with any overage subject to disqualification or general rates allocation at the Commission's discretion.

Subject to the limitations articulated in this memo we do not find the proposed treatment of depreciation for the purpose of calculating a "depreciation credit" for accelerated modification projects unreasonable.

EXHIBIT H

nationalgrid

Jennifer Brooks Hutchinson
Senior Counsel

April 27, 2017

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 4763 - Standards for Connecting Distributed Generation, RIPUC No. 2180
National Grid's Reply to Division Memorandum

Dear Ms. Massaro:

Enclosed please find 10 copies of National Grid's[1] Reply to the Rhode Island Division of Public Utilities and Carriers' Memorandum dated March 28, 2018 in the above-referenced docket, which includes a hypothetical example regarding the calculation of depreciation, as requested in Commission counsel's March 29, 2018 e-mail.

Thank you for your attention to this filing. Please contact me if you have any questions concerning this matter at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosures

cc: Docket 4763 Service List
Jon Hagopian, Esq.
John Bell, Division

[1] The Narragansett Electric Company d/b/a National Grid.

280 Melrose Street, Providence, RI 02907
T: 401-784-7288 ■ jennifer.hutchinson@nationalgrid.com ■ www.nationalgrid.com

Certificate of Service

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

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

___________________________________ April 27, 2018

Joanne M. Scanlon Date

Docket No. 4763 – National Grid - Standards for Connecting Distributed Generation, RIPUC No. 2180
Service List updated 12/27/17

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File an original & 9 copies w/: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107
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National Grid's Reply to the Division of Public Utilities and Carriers' March 28, 2018 Memorandum

The Company provides the following response to the Division of Public Utilities and Carriers' (Division) Memorandum regarding the Company's response to Record Request #4 concerning the proposed treatment of a depreciation credit as it relates to the determination of interconnection costs in connection with an Accelerated Modification.

In its Memorandum, the Division makes the following statements:

- The process outlined would benefit from a detailed hypothetical example that delineates each of the steps proposed (p.1);

    - **Justification process that outlines how projects are added to the 5-year Capital Plan, what level of "other" customers defines a need?**

      Response: The justification process for adding projects to the capital plan has been part of the Infrastructure, Safety and Reliability (ISR) filing process for a number of years, and the Company is not proposing any change to that process.

    - **How the modification cost will be estimated?**

      Response: The modification cost would be estimated at today's costs. See Company's response below for the cost calculation.

    - **How depreciation will be calculated and applied?**

      Response: The Company provides the following hypothetical example that delineates the steps for application of the depreciation credit:

      This example assumes that a $100,000 upgrade, identified in the Company's five-year capital plan (Capital Plan), is moved from year four to year one as a result of a Distributed Generation (DG) customer request for an interconnection. The Company will apply the net present value (NPV) of the investment based on the original planned installation date of five years from the present, and take the difference from this calculation to the NPV of the investment of moving the installation to one year from the present to determine the cost the customer will pay for the Accelerated Modification. The Company uses a discount rate of 8.41%. In this example, the customer would pay the Company $19,845 for the Accelerated Modification.

Table 1 below is a summary of the calculation of the depreciation and the DG customer's share of the cost of the Accelerated Modification.
Please see Attachment 1 to this response for a detailed calculation of this hypothetical example.

Table 1 – Depreciation Calculation

	NPV	Year 1	Year 2	Year 3	Year 4	Year 5
Initial Anticipated Timing of Capital Plan System Modification	$72,397	$0	$0	$0	$100,000	$0
Earlier Timing of DG Accelerated Modification	$92,242	$100,000	$0	$0	$0	$0
Interconnecting Customer Cost	$19,845					

- This process will do nothing to limit free riders that take advantage of the accelerated modification. A possible variation might include adjusting the original, planned, greater-good, in-service date should a second renewable resource require interconnection for the purpose of recalculating depreciation and assigning costs. (Division Memorandum, p. 2)

  Response: The Company does adjust planned work under its Capital Plan through the annual ISR process as conditions change over time, and would consider this in the event multiple projects come forward at a similar time.

- The outer years of a five-year Capital Plan tend to vary significantly as new information is accumulated from year-to-year, the specific projects, project scope and their associated costs are all highly variable which potentially leads to uncertainty regarding what is and what is not an accelerated project. (Division Memorandum, p. 2)

  Response: Due to this new requirement the Company will honor any Accelerated Modification set forth in an Interconnection Service Agreement (ISA) even if the ultimate "need' is later than forecasted in the Capital Plan to provide certainty to the DG developer community, provided the Company receives cost recovery for the remaining cost of the modification.

- The process envisions a true-up to actual costs based on the actual in-service date. The uncapped nature of the true-up cost adds another layer of uncertainty for project proponents. Once an estimated cost has been provided in the ISA consideration should be given to treating it as a not-to-exceed cost with any overage subject to disqualification or general rates allocation at the Commission's discretion. (Division Memorandum, p. 2)

Response: The process for true-ups of system modification costs is governed by the interconnection tariff and should be the same for DG customers with Accelerated Modifications. There is no different risk or uncertainty under this process for DG customers with Accelerated Modifications because the process for estimating these modification costs and determining actual costs is the same for all DG customers (the only difference is that a DG customer with an Accelerated Modification is only paying a portion of these estimated costs based on the formula set forth in the Company's response above). As such, the estimated costs for these Accelerated Modifications should not be treated as not-to-exceed costs.

The Narragansett Electric Company
Illustrative Calculation of Cost of Accelerated Modification Project

			NPV (a)	Year 1 (b)	Year 2 (c)	Year 3 (d)	Year 4 (e)	Year 5 (f)
(1)	Initial Anticipated Timing of Capital Plan System Modification		$72,397	$0	$0	$0	$100,000	$0
(2)	Earlier Timing of DG Accelerated Modification		$92,242	$100,000	$0	$0	$0	$0
(3)	Interconnecting Customer Cost	(2) - (1)	$19,845					
(4)	Discount Rate	page 2	8.41%					

The Narragansett Electric Company
Weighted Average Cost of Capital

			Ratio (a)	Rate (b)	Weighted Rate (c)
(1)	Long Term Debt		49.95%	4.96%	2.48%
(2)	Short Term Debt		0.76%	0.79%	0.01%
(3)	Preferred Stock (COP)		0.15%	4.50%	0.01%
(4)	Common Equity (COC)		49.14%	9.50%	4.67%
(5)	Total		100.00%		7.17%
(6)	Income Tax Gross-Up	21%	((COP + COC) ÷ (1-21%) x .21) = FIT		1.24%
					8.41%

Per Docket 4323, updated for reduced corporate federal income tax rate effective January 1, 2018
pursuant to the Tax Cuts and Job Act.

<u>EXHIBIT I</u>

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY	**:**	
d/b/a NATIONAL GRID'S STANDARDS FOR CONNECTING	**:**	**DOCKET NO. 4763**
DISTRIBUTED GENERATION	**:**	

REPORT AND ORDER

I. Overview

On June 30, 2017, Governor Raimondo signed into law amendments to the Distributed Generation Interconnection Standards, for effect July 1, 2017.[1] On October 31, 2017, to reflect the amendments, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) filed with the Public Utilities Commission (PUC or Commission) proposed changes to RIPUC 2163, its tariff governing interconnection of distributed generation projects (DG Interconnection Tariff).[2] As explained by National Grid, the changes were designed to, among other things, limit the ways in which the Company can charge renewable energy customers for system modifications to interconnect to the electric distribution system.

Specifically, the statutory amendments prohibited the Company from charging an interconnecting renewable energy customer for system modifications that are not directly related to the interconnection, except in certain limited circumstances. The amended law allowed for limited reimbursement of system modification costs to the interconnecting renewable energy customer if the PUC found that those modifications benefitted other customers and had been accelerated. It also allowed for contributions from subsequent non-residential interconnecting renewable energy customers where those subsequent customers relied on the earlier system modifications for interconnection. Additionally, it also placed certain timeframes on the Company to complete the

[1] R.I. Gen. Laws § 39-26.3-4.1.
[2] Tariff Advice Filing, RIPUC 2180; http://www.ripuc.org/eventsactions/docket/4763-NGrid-DGTariffAdvice(10-31-17).pdf.

application process and system modifications, and enabled the replacement of an existing renewable energy resource with limited study time and system modification costs.[3] In addition to new tariff language to reflect the intent of the statutory amendments, the Company also proposed additional amendments to the DG Interconnection Tariff, characterized as "clean-up" language. The Company also mandated use of a pre-application report as a screening tool for certain proposed interconnecting facilities.[4]

The PUC conducted a Technical Session on November 28, 2017. The Division of Public Utilities and Carriers (Division) and Office of Energy Resources (OER) responded to PUC discovery. The Division, in its comments of December 28, 2017, recommended approval of the revised tariff, RIPUC 2180. At a hearing held on January 25, 2018, additional information was sought through record requests. On September 6, 2018, the PUC approved RIPUC 2180, with modifications that required additional notifications to interconnecting customers of delays, reporting of certain information to the PUC, and a final accounting of interconnection costs within the tariff. The PUC also sought to clarify how a new provision of the law relating to "accelerated" system modifications would operate. On October 31, 2018, the Company filed a compliance tariff incorporating the PUC's changes. The compliance tariff was approved by the PUC at an Open Meeting on November 20, 2018.

II. Outstanding Issues and PUC-Ordered Modifications

The PUC found most of National Grid's original proposed changes to the DG Interconnection Tariff to be consistent with the amended law and to be reasonable. Following the hearing and

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[3] *Id.* at Cover Letter, 2.

[4] The Office of Energy Resources intervened in this matter. New Energy RI, a collaborative of renewable energy developers and other occasional stakeholders, attempted to intervene but, on January 3, 2018, the Commission determined that the motion to intervene was late and the movant had failed to show good cause for intervention. http://www.ripuc.org/eventsactions/minutes/010318.pdf. The PUC, indicated, however, that it would consider New Energy RI's filings as public comment.

submission of responses to record requests, there were four outstanding issues to be considered by the PUC: (1) whether certain language of the tariff on pre-application reports was too vague; (2) how the mechanics of the provision on "accelerated" system modification costs would work; (3) whether the "final accounting" provisions should be included in the body of the tariff as well as in attachments; and (4) whether, given the timelines in the tariff, it was reasonable to only require notification to customers of delays to System Modifications and not to other aspects of the tariff.[5] The following sections summarize the issues and the PUC's findings.

A. Pre-Application Reports

Pre-application reports are non-binding reports containing certain information specific to a proposed facility's interconnection location. Upon request, the Company will provide that interconnecting customer a pre-application report prior to the customer applying for interconnection. The Company provided a request form as an attachment to the DG Interconnection Tariff. In its original filing, the Company proposed modifications to the tariff's pre-application reports section as set out below. Pre-application reports would now be required for projects sized at 250 kW or greater instead of at 500 kW or greater. The Company also proposed to limit the number of pre-application reports that could be requested in a one-week period from a single applicant. Finally, National Grid no longer unequivocally committed to a 10-business day response period.

> **3.2 Pre-Application Reports**
> Prior to submitting an Interconnection Application through either the Expedited or Standard Process (see Sections 3.3 and 3.4), all Interconnecting Customers with Facilities that are 250 kW or greater must request and receive a Pre-Application Report from the Company. <u>An Application for Facilities 250 kW or greater will not be deemed to be complete without a Pre-Application Report</u>. The Pre-Application Form is provided in Exhibit B. The Pre-Application

[5] The PUC ruled on three of the outstanding items. On the fourth, addressing notification to customers of delays to System Modifications and not to other aspects of the tariff where there are timelines, the PUC reviewed National Grid's analysis of the statutory construction of the section and commented that it appeared the Company's interpretation was reasonable. However, the PUC took no votes on this matter, but approved the tariff with National Grid's original language included.

> Report is optional at the election of the Interconnecting Customer for those Facilities that are less than 250 kW. There is no fee for either a mandatory or optional Pre-Application Report.
>
> Following the submission for either a mandatory or optional Pre-Application Report, the Company shall provide the Report within 10 Business Days assuming a reasonable number of applicants under review. The Pre-Application Report produced by the Company is non-binding, and, if the Interconnecting Customer wishes to proceed, the Interconnecting Customer must still successfully apply to interconnect to the Company's EPS. No person or entity, or affiliate or agent thereof, may request more than ten (10) Pre-Application Reports in any one-week period. (changes underlined)

At the technical session, National Grid witness John Kennedy, Manager, Customer Energy Integration, New England, explained that projects as small as 200kW have recently triggered system upgrades at the transmission level as support for the lower threshold.[6] The PUC questioned whether the language "assuming a reasonable number of applicants under review" was too vague to be enforced in the future. National Grid submitted a record response stating that it could reasonably process approximately ten pre-application reports on a daily basis, or fifty per week.[7] The Division submitted a letter indicating that if the more specific language were included in the tariff, the Division could conditionally accept National Grid's response subject to further review after the limitation had been in place for a period of time.

After consideration of the parties' responses, the PUC accepted National Grid's original language, noting that as part of the Amended Settlement Agreement reached between the parties to Docket No. 4770 and approved by the PUC, the Company had been allowed additional funds to increase the number of full-time equivalent employees dedicated to interconnection work.[8] As a result, the PUC surmised that the definition of a "reasonable number of applicants under review" may

[6] Tech. Session Tr. at 43 (Nov. 28, 2017).
[7] National Grid Response to RR-3 (Feb. 23, 2018).
[8] *See* Docket No. 4770 (In re: Application of The Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates), Amended Settlement Agreement at 16; http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-AmendedSettlement(Redlined)_8-10-18.pdf.

evolve to a larger number than the Company has currently estimated. Thus, the PUC chose to accept the less specific language originally proposed by National Grid.

The PUC, however, required National Grid to include language in the tariff requiring notification to an interconnecting customer if there would be a delay in providing a pre-application report. In the future, if there are complaints about delays, the Division will review the reasonableness of the Company's actions under the tariff. Additionally, the PUC directed the Company to report to the PUC annually on the weekly average minimum and maximum number of pre-application reports and the number of delays due to the number of pending request exceeding a reasonable number of applicants under review. In its compliance filing, the Company included a filing date of March 1 annually. This will coincide with similar reporting requirements in the Docket No. 4770 decision.

B. Mechanics of "Accelerated" System Modifications

Section 5.4 of the DG Interconnection Tariff was modified to address the 2017 statutory requirement providing that:

> If the public utilities commission determines that a specific system modification benefiting other customers has been accelerated due to an interconnection request, it may order the interconnecting customer to fund the modification subject to repayment of the depreciated value of the modification as of the time the modification would have been necessary as determined by the public utilities commission. Any system modifications benefiting other customers shall be included in rates as determined by the public utilities commission.[9]

National Grid's original proposal simply copied the statutory language into the DG Interconnection Tariff. While this was consistent with the law, it did not adequately address the mechanics of the operation of this provision. For example, there was no indication of the timeframe over which something might be considered accelerated. Nor was there any discussion of the methodology for charging the renewable interconnecting customer for the accelerated modification

[9] R.I. Gen. Laws § 39-26.3-4.1(b).

costs. Following the January 25, 2018, hearing during which this issue was explored,[10] on February 23, 2018, National Grid filed its response to a record request seeking new proposed tariff language to describe the mechanics of this provision.

In its response, National Grid provided language that defined an acceleration of a system modification. It would constitute a modification that had otherwise been identified in the Company's capital work plan, necessary to be installed within a five-year period, as of the date the Company begins the impact study of the proposed distributed generation project. Once an accelerated system modification is identified, the Company will charge the renewable interconnecting customer for the estimated identified accelerated modification costs less the depreciated value. Following completion of the actual costs based on the date of asset installation, the Company will reconcile the actual costs with the previously estimated costs. All interconnection services agreements subject to this provision will be filed with the PUC. The Company also included a provision to allow a renewable interconnecting customer to petition the PUC directly if it believes the Company has incorrectly charged the renewable interconnecting customer for an accelerated modification.[11]

On March 28, 2018, the Division submitted a Memorandum from its consultants Phil DiDomenico and Carrie Gilbert, of Daymark Energy Advisors, summarizing their review of National Grid's proposed language. Finding the Company's proposal to be "not unreasonable," the consultants nonetheless, sought certain clarifications for the record, including a hypothetical example of the calculations. On April 27, 2018, National Grid filed responses to the consultants' questions together with a hypothetical example of the calculation of an interconnecting customer's cost of the accelerated modification.[12]

[10] Hr'g. Tr. at 69-81.
[11] National Grid Response to RR-4 (Feb. 23, 2018).
[12] DiDomenico and Gilbert Mem. at 1-2 (Mar. 28, 2018).

First, the Company explained that it would use the Electric Infrastructure, Safety, and Reliability process for including and adding projects to the five-year capital plan. Second, the Company indicated that a modification cost would be estimated at present cost. Third, National Grid provided the steps it would follow to apply the depreciation credit. Fourth, to address a Division concern that the Company's process would not limit free ridership from taking advantage of the accelerated modification, the Company would consider adjustments to its capital plan work if multiple projects sought interconnection at a similar time. Fifth, the Company responded to the consultants' concern that the outer years of a five-year plan tend to vary significantly as additional yearly data is collected, which could lead to uncertainty regarding what is an accelerated project. National Grid stated that in order to provide certainty to developers, the Company would honor any accelerated modification set forth in an interconnection service agreement even if the ultimate "need" proves to be later than previously forecasted in the five-year capital plan. Finally, in response to the consultants' concerns that there was no cap on the reconciliation of actual costs to estimates, the Company noted that this was the same treatment as other system modification costs and should remain as proposed for consistency among all interconnecting customers.[13]

The Division filed no additional comments on this section. The PUC found that the proposed tariff language filed on February 23, 2018, was consistent with the statutory language and adequately addressed the mechanics of the provision. The explanation provided by National Grid in response to the Division's consultants' concerns was sufficient to support the propriety of the language of the tariff. This does not mean the language is perfect. As with any new provision, it is possible that once the accelerated modification is calculated for the first time, there may need to be adjustments for future projects. The PUC will review any such proposed adjustments, if necessary. In addition,

[13] National Grid Reply at 1-3 (Apr. 27, 2017 [sic]) (Received Apr. 27, 2018).

interconnecting customers have the option of filing with the PUC for review of a specific project to which it believes an accelerated modification calculation should have been applied. This provides an additional protection for interconnecting customers and a balance for all National Grid customers from whom the remaining accelerated costs will be recovered.

C. Location of "Final Accounting" Provisions

An issue raised by New Energy RI in its comments was the location of the "Final Accounting" requirement. The existing tariff included language in the attachments about providing a final accounting to interconnecting customers. These attachments include sample forms that are executed by the Company and interconnecting customers as part of the interconnection process. New Energy RI posited that the final accounting requirement should also be in the body of the tariff for clarity.[14] The Company noted that the attachments are incorporated into the tariff and adding them to the body was unnecessary. However, the Company also indicated that it would have no objection to including the provisions in the body of the tariff if the PUC determined it was necessary to do so.[15]

The PUC found that the final accounting provision should be located both in the body of the tariff as well as in the attachments. While the attachments have been incorporated into the tariff, it is the body of the tariff that explains how the interconnection process works. In comments, counsel for New Energy RI posited that it would provide clarity to consumers to include the final accounting language in the body[16] and the Company had no objection to doing so upon direction by the PUC. Any burden to the Company of including additional language in the tariff is outweighed by the opportunity to provide additional clarity to interconnecting customers seeking to understand the tariff.

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[14] Tech. Session Tr. at 129-30 (Nov. 28, 2017).
[15] National Grid Response to RR-4 (Dec. 22, 2017).
[16] Tech. Session Tr. at 130.

III. Compliance Tariff

On October 31, 2018, National Grid submitted a revised tariff as a compliance filing that reflected the modifications ordered by the PUC at its September 6, 2018 Open Meeting. On November 20, 2018, the PUC approved the compliance filing finding that it properly incorporated the modifications made during the earlier decision. The effective date of the tariff was September 6, 2018. The effective date of the amendments to the Distributed Generation Interconnection Standards law was July 1, 2017. That is the date National Grid was required to begin applying the statutory changes. The DG Interconnection Tariff sets forth the approved processes.

Accordingly, it is hereby

(23379) ORDERED:

1. The Narragansett Electric Company d/b/a National Grid's Standards for Connecting Distributed Generation, RIPUC No. 2180, cancelling RIPUC No. 2163, filed on October 31, 2017, is hereby approved for effect September 6, 2018, with the following modifications:
    a. Amend Section 3.2 to state that the Company shall immediately advise interconnecting customers if there will be a delay in providing pre-application reports due to the number of pending requests.
    b. Amend the tariff to include a requirement that the Company report to the Public Utilities Commission annually on the weekly average minimum and maximum number of pre-application reports and the number of delays due to the number of pending requests exceeding a reasonable number of applicants under review.
    c. Amend the tariff to include final accounting language in the body of the tariff.
    d. Amend Section 5.4 to state: The Company will consider a system modification to be an accelerated modification if such modification is otherwise identified in the

Company's work plan as a necessary capital investment to be installed within a five-year period as of the date the Company begins the impact study of the proposed distributed generation (DG) project (defined as an Accelerated Modification). The Company will identify the Accelerated Modification and the cost thereof in the impact study. The Renewable Interconnecting Customer will be responsible for the identified Accelerated Modification costs less the depreciated value (Modified Costs), which Modified Costs will be estimated in the interconnection service agreement (ISA). Upon reconciliation, final labor, material and depreciation values will be provided based on the actual date of asset installation. The Company will file with the Commission all executed ISAs for Renewable Interconnecting Customer DG projects with an identified Accelerated Modification by July 1 of each year. Renewable Interconnecting Customers may also petition the Commission directly if the Renewable Interconnecting Customer believes it has been incorrectly charged for an Accelerated Modification under Section 5.4. In these cases, the Renewable Interconnecting Customer shall be responsible to pay for the cost of the system modification pursuant to the ISA, unless and until a determination has been made by the Commission. In all cases, the Company will be entitled to recover the costs of any unpaid portion of an Accelerated Modification(s) in rates.

2. The Narragansett Electric Company d/b/a National Grid's Standards for Connecting Distributed Generation, RIPUC No. 2180, cancelling RIPUC No. 2163 compliance filing, submitted on October 31, 2018, is hereby approved for effect September 6, 2018.

EFFECTIVE AT WARWICK, RHODE ISLAND, ON SEPTEMBER 6, 2018, PURSUANT TO OPEN MEETING DECISIONS ON SEPTEMBER 6, 2018 AND NOVEMBER 20, 2018. WRITTEN ORDER ISSUED JANUARY 4, 2019.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Marion S. Gold, Commissioner

Abigail Anthony, Commissioner

NOTICE OF RIGHT OF APPEAL: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the PUC may, within seven (7) days from the date of the order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or order.

EXHIBIT J

PRE-FILED JOINT DIRECT TESTIMONY OF

ERICA J. RUSSELL SALK

AND

STEPHANIE A. BRIGGS

October 17, 2023

Table of Contents

I. <u>Introduction</u>

<u>Erica J. Russell Salk</u>

Q. Could you please state your full name and business address?

A. My name is Erica J. Russell Salk, and my business address is 280 Melrose Street, Providence, Rhode Island, 02907.

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

A. I am Manager of Customer Energy Integration ("CEI") for the Narragansett Electric Company d/b/a Rhode Island Energy ("Rhode Island Energy or the "Company), an indirect wholly owned subsidiary of PPL Corporation ("PPL").

Q. What are your principal responsibilities in that position?

A. As Manager of CEI, I provide oversight to the team responsible for all distributed generation ("DG") interconnection applications. This includes all simple, expedited, and standard applications. As a customer facing team, we work with the DG developers focusing on implementation to shepherd their projects through the process from application to interconnection.

Q. Could you please describe your educational background and professional experience?

A. In 2011, I graduated from Trinity College with a Bachelor of Science Degree in Electrical

Engineering. In 2013, I received a Master of Science in Electrical Engineering from Brown University. In 2015, I earned a Graduate Level Certificate in Power Systems Engineering from Worcester Polytechnic Institute. I am also a licensed Professional Engineer in the State of Rhode Island. I worked at National Grid Service Company ("NGSC") from 2013-2022. At NGSC, I primarily worked in Protection Engineering as a Senior Engineer and additionally held the roles of Technical Advisor to the Senior Vice President of Electric Process & Engineering, and Engineering Manager of IEC-61850 & Protection Policy and Support. In June 2022, I joined Rhode Island Energy in my current position.

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

A. Yes. I testified on February 8, 2023, at the hearing for the 2023 Renewable Energy Growth Program in Docket No. 22-39-REG and on October 5, 2023 at the hearing for the Company's Proposal for Administration of Excess Net Metering Credits in Docket No. 23-05-EL. Additionally, for the Company's Proposal for Administration of Excess Net Metering Credits in Docket No. 23-01-EL, I submitted joint pre-filed direct testimony, participated in a Technical Session, and submitted joint rebuttal testimony. I have also participated in meetings facilitated by PUC staff in Docket Nos. 5205 and 5206 related to the administration of DG interconnections.

<u>Stephanie A. Briggs</u>

Q. Could you please state your full name and business address?

A. My name is Stephanie A. Briggs, and my business address is 280 Melrose Street, Providence, Rhode Island, 02907.

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

A. I am employed by PPL as a Senior Manager Revenue and Rates.

Q. What are your principal responsibilities in that position?

A. My current duties include revenue requirement and rates responsibilities for PPL's Rhode Island distribution operations including for the Company.

Q. Could you please describe your educational background and professional experience?

A. In 2000, I received a Bachelor of Arts degree in Accounting from Bryant College. In 2004, I was hired by NGSC as a Senior Analyst in the Accounting Department. In this position, I was responsible for supporting the books and records of Niagara Mohawk Power Corporation d/b/a National Grid. In 2009, I was promoted to Senior Analyst in the Regulatory Accounting Group. In this capacity, I supported the accounting of regulatory assets and deferrals in accordance with National Grid's rate plans and agreements. In 2011, I was promoted to Lead Specialist for Revenue Requirements responsible for supporting New York revenue requirements. In 2017, I was promoted to Director of Revenue Requirements for New York. In July 2020, I became Director of Revenue Requirements for New England. On May 25, 2022, PPL Rhode Island Holdings, LLC, a wholly owned indirect subsidiary of PPL, acquired 100 percent of the outstanding shares of common stock of the Company from National Grid (the "Acquisition"), at which time I assumed my current position.

Q. Have you previously testified before the PUC or any other regulatory commission?

A. Yes. I provided pre-filed direct testimony in numerous dockets including the Company's 2022 Annual Retail Rate Filing, Docket No. 5234, the Company's 2021 Performance Incentive Mechanism Factor Filing, as part of Docket No. 4770, the Fiscal Year 2022 Electric Infrastructure, Safety and Reliability Plan Annual Reconciliation Filing, Docket No. 5098, the Company's 2022 Distribution Adjustment Charge Filing, Docket No. 22-13-NG, the Company's Advanced Metering Functionality Business Case, Docket No. 22-49-EL, the Company's Fiscal Year 2024 Electric Infrastructure, Safety, and Reliability Plan, Docket No. 22-53-EL, Fiscal Year 2024 Gas Infrastructure, Safety, and Reliability Plan, Docket No. 22-54-NG, the Company's 2023 Electric Revenue Decoupling Mechanism Reconciliation Filing, Docket No. 23-16-EL, the Company's 2023 Residential Assistance Recovery filing, Docket No. 23-17-EL, and most recently in the Company's 2023 Distribution Adjustment Charge Filing, Docket No. 22-23-23-NG. I also have testified before the Massachusetts Department of Public Utilities and New York

Public Service Commission on behalf of National Grid's affiliates as a revenue requirement witness in various proceedings.

II. Purpose

Q. What is the purpose of this testimony?

A. The purpose of our testimony is to support the Petition of The Narragansett Electric Company for Acceleration of a System Modification Due to an Interconnection Request dated October 17, 2023 (the "Petition"). The interconnection requests that are the subject of the Petition were made by (1) Green Development, LLC ("Green" or "Green Development") in connection with 20,000 kW photovoltaic systems located at 899 Nooseneck Hill Road, West Greenwich, RI 02817 ("Nooseneck Projects"); (2) Revity Energy, LLC ("Revity") in connection with 40.7 MW photovoltaic systems located at 18 Weaver Hill Road, West Greenwich, RI 02817 ("Robin Hollow Project"); and (3) Energy Development Partners ("EDP") in connection with 9.2 MW Studley Solar Project located at 189 Weaver Hill Road, West Greenwich, RI 02817 ("Studley Solar Project"). Collectively, Green Development, Revity, and EDP are referred to herein as the "Interconnecting Customers".

Q. Are there any schedules provided in support of your testimony?

A. Yes. Erica J. Russell Salk is sponsoring the following supporting schedules:

- Exhibit EJRS-1 – Nooseneck Impact Study

- Exhibit EJRS-2 – Robin Hollow Impact Study
- Exhibit EJRS-3 – Studley Solar Impact Study
- Exhibit EJRS-4 – Nooseneck Interconnection Services Agreement with Green
- Exhibit EJRS-5 – Robin Hollow Interconnection Services Agreement with Revity
- Exhibit EJRS-6 – Studley Solar Interconnection Services Agreement with EDP
- Exhibit EJRS-7 – Area Study
- Exhibit EJRS-8 – Audit

Stephanie A. Briggs is sponsoring the following supporting schedules:

- Schedule SAB-1 – Illustrative Depreciated Value

III. Background

Q. Could you summarize the estimated impact that this Petition will have on distribution customers?

A. This Petition will impact rate payers in two beneficial ways; one is the benefit of the accelerated solution, and the other is that the cost to the ratepayers will be a discounted amount from what they otherwise would have had to pay given the depreciation or "acceleration" fee that is borne by the DG customers.

Q. What is the basis for filing the Petition?

A. The Company is filing the Petition in accordance with R.I. Gen. Laws § 39-26.3-4.1 entitled Interconnection Standards (the "Interconnection Statute") and Section 5.4 of RIPUC No. 2258 entitled The Narragansett Electric Company Standards for Connecting Distributed Generation (the "Interconnection Tariff").

Q. Based on your understanding, which provisions of the Interconnection Statute are applicable?

A. The following provisions of the Interconnection Statute are applicable:

(a) The electric distribution company may only charge an interconnecting, renewable energy customer for any system modifications[1] to its electric power system specifically necessary for and directly related to the interconnection.

(b) If the public utilities commission determines that a specific system modification benefiting other customers has been accelerated due to an interconnection request, it may order the interconnecting customer to fund the modification subject to repayment of the depreciated value of the modification as of the time the modification would have been necessary as determined by the public utilities commission. Any system modifications[2] benefiting other customers shall be

[1] The Interconnection Tariff defines a "System Modification" as "Modifications or additions to Company facilities that are integrated with the Company's [Electric Distribution System] for the benefit of the Interconnecting Customer."

[2] As noted herein, the Company interprets this language, and similar language in Section 5.4(c) of the Company's Interconnection Tariff to apply to "System Improvements" as defined in the Company's Interconnection Tariff.

included in rates as determined by the public utilities commission.

(c) If an interconnecting, renewable energy customer is required to pay for system modifications and a subsequent renewable energy or commercial customer relies on those modifications to connect to the distribution system within ten (10) years of the earlier interconnecting, renewable energy customer's payment, the subsequent customer will make a prorated contribution toward the cost of the system modifications that will be credited to the earlier interconnecting, renewable energy customer as determined by the public utilities commission.

Q. Based on your understanding, is Section 5.2 of the Interconnection Tariff applicable?

A. Yes. Section 5.2 states:

> The Interconnecting Customer shall be responsible for all costs associated with the installation and construction of the Facility and associated interconnection equipment on the Interconnecting Customer's side of the PCC, less any System Improvements.

Q. Based on your understanding, is Section 5.4 of the Interconnection Tariff applicable?

A. Yes. Section 5.4 states:

(a) The Company may combine the installation of System Modifications with System

Improvements to the Company's EDS to serve the Interconnecting Customer or other customers, but shall not include the costs of such System Improvements in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff. Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any System Modifications necessary to the Affected Systems.

(b) Effective for Renewable Interconnecting Customer Applications filed on or after July 1, 2017, in the event that the Commission determines that a specific System Modification of the electric distribution system benefits other customers and has been accelerated due to an interconnection request and orders the Renewable Interconnecting Customer to fund the modification, the Renewable Interconnecting Customer will be entitled to repayment of the depreciated value of the modification as of the time the modification would have been necessary as determined by the Commission. Subsequent Renewable Interconnecting Customers will be responsible for prorated payments within ten (10) years of the earlier Renewable Interconnecting Customer's payment toward System Modifications.

(c) The Company will consider a system modification to be an accelerated modification if such modification is otherwise identified in the Company's work plan as a necessary capital investment to be installed within a five-year period as of the date the Company begins the impact study of the proposed distributed generation (DG) project (defined as an Accelerated Modification). The Company will identify the Accelerated Modification and the cost thereof in the impact study. The Renewable Interconnecting Customer will be responsible for the identified Accelerated Modification costs less the depreciated value (Modified Costs), which Modified Costs will be estimated in the interconnection service agreement (ISA). Upon reconciliation, final labor, material and depreciation values will be provided based on the actual date of asset installation in the same price categories as originally proposed in the ISA to the customer so that a comparison can be made. The Company will file with the Commission all executed ISAs for Renewable Interconnecting Customer DG projects with an identified Accelerated Modification by July 1 of each year.

Q. Has the PUC ruled on the acceleration of a system modification due to an interconnection request since the enactment of R.I. Gen. Laws § 39-26.3-4.1?

A. No. This Petition and the Tiverton Petition will be the first two requests for approval of potential accelerations of a "system modification".

Q. Does the Company interpret the Interconnection Statute and Interconnection Tariff as allowing the Company to collect costs from an Interconnecting Customer for a System Modification that benefits both an Interconnecting Customer and distribution customers and then reimburse that Interconnecting Customer for such costs?

A. Yes. As noted above, the Interconnection Tariff states that any "system modifications" benefiting other customers shall be included in rates as determined by the PUC. The Interconnection Tariff provides additional detail regarding separation of costs by separately defining:

(a) "System Modifications" as "Modifications or additions to Company facilities that are integrated with the Company's [Electric Distribution System] for the benefit of the Interconnecting Customer; and

(b) "System Improvements" as "Economically justified upgrades determined by the Company in the Facility study phase for capital investments associated with improving the capacity or reliability of the [Electric Distribution System] that may be used along with System Modifications to serve an Interconnection Customer."

The Interconnection Tariff also implements the principle of separation of costs in Section 5.2 by requiring, the Interconnecting Customer to be responsible for all costs associated with the installation and construction of its Facility and associated interconnection equipment on the Interconnecting Customer's side of the Point of Common Coupling, less any System Improvements.

Q. Does the Interconnection Tariff clearly define the process by which the Company should determine whether a "System Improvement" has been accelerated?

A. The Interconnection Tariff does not precisely address this process. As noted above, Sections 5.4(b) and (c) of the Interconnection Tariff describe a process for accelerated "System Modifications" but does not use the term "System Improvements". As described herein, in this instance, the System Improvements that have been accelerated by the Green Development's Weaver Hill Projects are System Modifications that also benefit Revity, and EDP. As such, among other findings, the Company seeks PUC approval to apply the provisions of Section 5.4(b) and (c) of the Interconnection Tariff that address "System Modifications" to the "System Improvements" described herein.

Q. What specific findings are the Company seeking with this Petition?

A. The Company is seeking the following findings:

(a) That the installation of approximately 17,000 feet of a manhole and duct bank system along Division Street and Nooseneck Hill Road, West Greenwich and the installation of approximately 17,000 feet of three conductor 1000 kcmil EPR insulated Cu cable to extend the 3310 line (the "Green Development System

Improvements”) were accelerated due to the interconnection of the Nooseneck Projects;

(b) That the future the installation of just under one mile of a manhole and duct bank system and three conductor 500 kcmil EPR insulated CU cable to extend the 3310 line along Weaver Hill Road (the “Robin Hollow and Studley Solar System Improvements”) will be accelerated to do the future interconnection of the Robin Hollow Projects and Studley Solar Project (collectively, with the Green Development System Improvements, the “System Improvements”);

(c) That the Company may apply each of the provisions of Section 5.4 of the Interconnection Tariff to derive the methodology to collect costs from the Interconnecting Customers for System Improvements associated with the interconnection of the Nooseneck, Robin Hollow, and Studley Solar Projects and then reimburse the depreciated value of such System Improvements to the Interconnecting Customers, as appropriate;

(d) That the System Improvements described in our testimony required to interconnect the Nooseneck, Robin Hollow, and Studley Solar Projects will benefit both the DG Projects and the Company’s distribution customers;

(e) That such System Improvements have been accelerated from the time they would otherwise be required to serve the Company’s distribution customers;

(f) That such acceleration is due to Green Development's interconnection request for the Nooseneck Projects, Revity's interconnection request for the Robin Hollow Projects, and EDP's interconnection request for the Studley Solar Project;

(g) That Green Development, Revity, and EDP shall fund the System Improvements subject to repayment of the depreciated value of the System Improvement as of the time the System Improvement would have been necessary; and

(h) That the costs of the depreciated value of the System Improvement shall be recovered from distribution customers through the Company's Infrastructure, Safety and Reliability Provision, RIPUC No. 2199 ("ISR Tariff").

IV. DG Projects

Q. Please describe Green Development's Nooseneck Projects.

A. Green Development's Nooseneck Projects include two adjacent 10MW sites, constructed as standalone solar arrays participating in the Net Metering incentive. The projects interconnected in December of 2022 and are fed off the 3310 circuit.

Q. Please describe Revity's Robin Hollow Project.

A. Revity's Robin Hollow Project includes 7 sites totaling 40.7MW, to be constructed with an estimated connection timeframe of end of calendar year 2023. Site E, 5.25MW will be fed off the 3310 circuit, and 35.25MW will be fed off the 3309 circuit.

Q. Please describe EDP's Studley Solar Project.

A. EDP's Studley Solar Project consists of one 9.2MW site to be fed off the 3310 circuit. The Company issued an ISA to EDP on April 14, 2023 which has not yet been executed.

Q. When did the Nooseneck Projects enter the interconnection queue?

A. On February 12, 2019.

Q. When did the Revity Robin Hollow Projects enter the interconnection queue?

A. On October 18, 2019.

Q. When did the EDP Studley Solar Project enter the interconnection queue?

A. On May 10, 2019.

Q. When did the Company begin the Impact Study of the Nooseneck Projects?

A. The Company began the Impact Study of the Nooseneck Projects on April 1, 2019. The Weaver Hill Impact Study attached hereto as Exhibit EJRS-1.

Q. When did the Company begin the Impact Study of the Robin Hollow Projects?

A. The Company began the Impact Study of the Robin Hollow Projects on January 6, 2020. The Robin Hollow Impact Study attached hereto as Exhibit EJRS-2.

Q. When did the Company begin the Impact Study of the Studley Solar Projects?

A. The Company began the Impact Study of the Studley Solar Project on August 7, 2019. The Studley Solar Impact Study attached hereto as Exhibit EJRS-3.

Q. Has an interconnection service agreement been executed for each project?

A. Yes. On July 22, 2020, the Company entered into an Interconnection Services Agreement ("ISA") with Green Development (the "Green ISA"). The Company and Green Development have also entered into amendments to the ISA on December 9, 2021, and December 16, 2022. The Green ISA and amendments are attached hereto as Exhibit EJRS-4.

On May 16, 2022, the Company entered into an ISA with Revity (the "Revity ISA"). The Company and Revity have also entered into amendments to the ISA on July 29, 2022, and a second amendment was issued to Revity on April 26, 2023. The Revity ISA and amendments are attached hereto as Exhibit EJRS-5.

The Company issued an ISA to EDP on April 14, 2023 (the "EDP ISA"). The EDP ISA is attached hereto as Exhibit EJRS-6.

Q. What is the estimated total cost of the Nooseneck Projects System Modifications?

A. As noted in the second amendment to the Green ISA, the total cost of the Projects' System Modifications, excluding the civil manhole and duct system constructed by Green Development, was estimated at $4,883,571. Following construction, the costs associated with the civil manhole and duct system were reviewed through a detailed third-party cost verification and audit to confirm the total cost of $12,023,525. The final costs still need to be reconciled for the electrical component performed by the Company.

Q. What is the estimated total cost of the Robin Hollow Projects System Modifications?

A. As noted in the second amendment to the Revity ISA, the total cost of the Projects' System Modifications, excluding the civil manhole and duct system and electrical component to be constructed by Revity is estimated at $3,494,272.

Q. What is the estimated total cost of the Studley Solar Projects System Modifications?

A. As noted in the EDP ISA, the total cost of the Projects' System Modifications, excluding the civil manhole and duct system to be constructed by EDP, was estimated at $8,437,085.

Q. Do the entirety of these System Modifications only benefit the Nooseneck, Revity, and EDP Projects?

A. No. The System Modifications include the installation of a manhole and duct system and extension of the 3310, a portion of which will provide benefits to the Company's distribution customers. The portion of the manhole and duct system that will benefit the Company's distribution customers meets the definition of a "System Improvement" provided in the Company's Interconnection Tariff. The Company's Petition seeks findings relating to the up-front payment of costs by Green Development, Revity, and EDP for the System Improvement, and the repayment to Green Development, Revity, and EDP by the Company of such costs, subject to the terms of the Interconnection Statute and Interconnection Tariff.

V. <u>Benefits to Revity and EDP from Green Development Construction</u>

Q. What benefits will Revity and EDP receive from Green Development's construction of System Modifications to interconnect the Nooseneck Projects?

A. Yes. Regarding the Nooseneck Projects, Revity has a 40.7MW project in construction now and EDP has a 9.2MW project in the interconnection queue that would benefit from a portion of the manhole and duct system and a share of the 3310 cable constructed by Green Development.

For the Robin Hollow Projects, Revity is self-performing the work for a manhole and duct system and a portion of the electrical work. EDP's 9.2 MW Study Solar Project will subsequently benefit from the work performed by Revity, in addition to the Company through acceleration.

Q. Please describe these projects.

A. Green Development constructed a 28,568 foot manhole and duct system which cost $12,023,525. The common path to Green Development, Revity, EDP, and the Company is 15,006 ft, or 52% of the total length from manhole 21a to manhole 44 and cost $5,951,270. The Kent County 3310 cable was extended from the corner of Hopkins Hill Road and Division Street to the POI on Green Development's property. A portion of that cable is part of the common path between Green Development, Revity, EDP, and the Company. Once the project is fully reconciled, the total costs incurred would be evaluated for cost sharing between Green, Revity, and EDP based on a MW pro rata share. Six of the seven Revity sites will interconnect to the 3309 line which are not subject to cost sharing with any other Developer or the Company. One site will interconnect to the 3310. EDP's interconnection will be on the 3310.

Q. Will these projects share in the costs of the System Modifications?

A. Absent the acceleration, these projects would otherwise share in the costs of the System Modifications. The Company is progressing under that premise and has included cost sharing estimates in each Developer's ISA. Pending the outcome of the Petition, the Company would reimburse Green Development, Revity, and EDP, as appropriate.

Q. How will this cost sharing affect the cost that may be borne by distribution customers, if the PUC approves the Company's petition?

A. As described above, the Company is working with the Developers to facilitate cost sharing once the work is completed, and the costs are verified through a third-party audit. That has been completed for the Nooseneck manhole and duct system. The Company presented an ISA to EDP on April 14, 2023 which includes the cost share payment amount, to be paid upon execution. The Company presented an amended ISA to Revity on April 26, 2023, to update the cost share payment, to be paid upon execution. Pending the outcome of the Petition, the Company will reimburse Green, Revity, and EDP as appropriate. Depending on timing, if the outcome of the Petition is known prior to Revity and EDP paying Green, the Company will reimburse only Green. Otherwise, the Company would reimburse each Green, Revity, and EDP based on the allocations they paid.

VI. System Improvements

Q. Please describe in detail the manhole and duct system which the Company has determined meets the definition of a "System Improvement" provided in the Company's Interconnection Tariff?

A. A portion of the manhole and duct system that was constructed by Green Development has been identified as a System Improvement. This portion is just over three miles, from the intersection of Hopkins Hill Road and Division Street to the intersection of

Nooseneck Hill Road and Weaver Hill Road in West Greenwich. This stretch consists of 25 manholes of varying type, depending on the engineering design (e.g. 2-way, 3-way, etc.) and three phase conductor 1000 kcmil EPR insulated CU cable. Both the Robin Hollow project presently in construction, and then the Studley Solar EDP project, will extend this manhole and duct system and 3310 cable down Weaver Hill Road by just under a mile. The Robin Hollow Projects will also benefit EDP and distribution customers, and the EDP project would also benefit distribution customers.

Q. How will the System Improvement for the Nooseneck, Revity, and EDP Projects benefit distribution customers?

A. As identified in the Central RI West Area Study, which is attached hereto as Exhibit EJRS-7, the least cost option proposed to address thermal loading issues in the area is to build a new substation on Weaver Hill Road by extending the sub transmission facilities that are installed for the Nooseneck, Robin Hollow, and Studley Solar Projects.

Q. Are the System Improvements identified in the Company's Electric Infrastructure, Safety and Reliability Plan ("ISR")?

A. Yes. The installation of a new modular substation at Weaver Hill Road is in the FY2023 Proposal, Docket No. 5209, filed on December 20, 2021. The Central RI West Area Study evaluated the issues and proposed solutions.

Q. How does interconnecting the Nooseneck, Robin Hollow, and Studley Solar Projects accelerate the installation of System Improvements identified by the Company?

A. The Area Study identified a forecasted overload of 104% summer normal loading in 2035 on the Hopkins Hill 63F6 feeder. The Coventry 54F1 also shows a high loading of 94%of summer normal in 2035. The least cost option to address these thermal loading issues is the installation of a modular substation at Weaver Hill. This installation would utilize the manhole and duct system and 3310 cable as an alternate supply, a portion of which was constructed to interconnect the Nooseneck Projects and will be constructed to interconnect Robin Hollow and Studley Solar Projects.

VII. Costs to be Paid and Reimbursed

Q. What is the total cost of the System Improvement (the part that benefits distribution customers) that will be charged to Green Development, Revity and EDP?

A. This can be broken down into several components: the civil component that was constructed by Green Development plus the electrical component built by the Company; the civil & electrical portion built by Revity and the electrical portion built by the Company; the civil portion to be built by EDP and the electrical portion to be built by the Company. The cost share portion of what Green Development constructed is $5,951,270. The actual cost to the Company for the electrical component will not be determined until all work orders are closed and the project is fully reconciled. As seen in the Nooseneck

System Impact Study, the full portion of the 3310 work was estimated at $4,267,200. It is estimated that about 62.5% of that total (based on distance) would be subject to cost share at $2,667,000. As seen in the Studley Solar Impact Study, the estimated cost of the full portion of the 3310 electrical work is $6,243,617.

Q. How does the Company propose to calculate the dollar amount to reimburse?

A. The third-party audit confirmed a total of cost $12,023,525 to build the duct bank, of which $5,951,270 are subject to 100% cost share with the Company based on acceleration. The customer self-performed the civil underground construction of the Company's design for the duct bank to interconnect to the 3310 circuit. Based on the area study, the least cost option proposed to address thermal loading issues in the area is to build a new substation on Weaver Hill Road by extending the sub transmission that is installed for the DG projects. The Company is proposing cost sharing for 100% of the electrical work on the common path associated with the 3310 circuit with a four-year depreciation and 100% of the common path portion of the underground civil duct bank with a four-year depreciation. A copy of the audit is attached hereto as Exhibit EJRS-8.

Q. Did the third-party audit also analyze the accuracy and validity of the costs for potential reimbursement to Green?

A. Yes.

Q. Is the Company proposing a methodology to pay the developers and recover costs from distribution customers?

A. Yes, the Company is providing a recommendation as explained below and is also providing an alternative option for the PUC to consider in this Petition.

Q. Please describe the Company's recommended approach to recovering costs from distribution customers and reimbursing the developer.

A. The recommended approach would be that the Company would pay the developers for the specific system improvements that benefitted distribution customers, less the estimated depreciated value, at the time that the project is placed in service, the third party audit and verification is complete, and the project is fully reconciled. The Company is estimating that the work will be completed and placed in service during FY 2025, but would have been completed and placed in service in FY 2027 without the DG project. Since the Company would be paying the developers at the time the investment was placed in service in FY 2025, the Company proposes that it would begin recovering depreciation and return from distribution customers in FY 2025 through the ISR plan revenue requirement.

Q. Under the recommended approach, what is the amount that the Company estimates will be paid to the developers in FY 2025?

A. Please see Schedule SAB-1 for the estimated depreciated value from FY 2025 through FY 2026 that would be paid to the developers in FY 2025 of $12,926,368. The final cost of the system improvement would be determined after the project is placed in service, the third party audit and verification is complete, and the project is fully reconciled. For illustrative purposes in this recommended approach, the Company estimates that the total cost of the project related to system improvements that benefit distribution customers would be $13,569,565 million and that the project will be placed in service during FY 2025 and would have not been necessary until FY 2027 if not for this DG project. For purposes of calculating an illustrative annual depreciation amount, the Company applied the annual depreciation rate from the Company's most recent FY 2024 ISR Plan. The final depreciated value that would be paid to the developers would be based on actual depreciated value at the time which could differ from the illustrated amount on Schedule SAB-1 due to changes in depreciation rates that could occur before the payout. In addition, the actual dates of in-service and payout would be used to calculate the depreciated value, but for purposes of this petition, the Company used FY 2025 and FY 2027 as estimated dates, respectively.

Q. Under this recommended approach, how will the costs of the System Improvements be recovered from distribution customers?

A. The Company is seeking approval with this Petition to ultimately include any System Improvement costs at the depreciated value in its ISR factors, subject to approval by the PUC. In this proposal, the Company would include the depreciated value through FY 2026 in the FY 2025 ISR revenue requirement at which time it would begin being recovered from distribution customers.

Q. Why is the Company recommending to pay developers when the investment is placed in service?

A. The Company is recommending this approach for several reasons. From a public policy standpoint, the Company believes paying the developers sooner rather than later promotes the purposes of the Distributed Generation Interconnection Act, R.I. Gen. Laws § 39-26.3-1 et seq. Once developers receive payment, they will be able to reinvest that capital and install additional distributed generation in the State. From an administrative standpoint, waiting to pay the developers may create challenges. Any time payment is delayed, for potentially years, there is risk ownership is transferred or legal statuses change making payment more complicated.

Q. Please describe the alternative approach.

A. The alternative approach would be that the Company would pay the developers for the specific system improvements that benefitted distribution customers, less the depreciated value, at the time that improvements would have been necessary had it not been for the DG project. In this instance, the Company is estimating that the work will be completed and placed in service during FY 2025, but would have been completed and placed in service in FY 2027 without the DG project. As such, in this proposal the Company would pay the developers in FY 2027 the final cost of the system modification less the depreciation of the asset from FY 2025 through FY 2026, in other words the depreciated value.

Q. Under the alternative approach, what is the amount that the Company estimates will be the depreciated value paid to the developers in FY 2027?

A. Please see Schedule SAB-1 for the estimated depreciated value in FY 2027 of $12,926,368. The final cost of the system improvement would be determined after the project is placed in service, the third party audit and verification is complete, and the project is fully reconciled. For illustrative purposes in this proposal, the Company estimates that the total cost of the project related to system improvements that benefit distribution customers would be $13,569,565 million and that the project will be placed in service during FY 2025 and would have not been necessary until FY 2027 if not for this DG project. For purposes of calculating an illustrative annual depreciation amount, the Company applied the annual depreciation rate from the Company's most recent FY 2024 ISR Plan. The final depreciated value that would be paid to the developers would be based on actual depreciated value at the time which could differ from the illustrated amount on Schedule SAB-1 due to changes in depreciation rates that could occur before the payout. In addition, the actual dates of in-service and payout would be used to calculate the depreciated value, but for purposes of this petition, the Company used FY 2025 and FY 2027 as estimated dates, respectively.

Q. Under the alternative approach, how will the costs of the System Improvements be recovered from distribution customers?

A. The Company is seeking approval with this Petition to ultimately include any System Improvement costs at the depreciated value in its ISR factors, subject to approval by the PUC. In this proposal, the Company would include the depreciated value in the FY 2027 ISR revenue requirement at which time it would begin being recovered from distribution customers.

VIII. <u>Assessment on Act on Climate</u>

Q. What are the potential impacts of the proposed Petition in relation to the Act on Climate's requirements?

A. The 2021 Act on Climate, R.I. Gen. Laws §42-6.2-1 et seq., mandates a statewide, economy-wide 45% reduction in greenhouse gas emissions by 2030 relative to 1990 emissions levels, 80% by 2040, and shall be net-zero emissions by 2050. The Company has assessed that approval of this Petition positively influences the Act on Climate mandates by reasonably charging Interconnection Customers only for incurred costs solely due to their project, and incentivizing continued development of distributed generation connections.

IV. <u>Conclusion</u>

Q. Does this complete your testimony?

A. Yes, it does.

EXHIBIT K

Executive Summary

The Company has completed the Combined Impact Study, for the interconnection of Revity Energy, ("Customer") 40,700 kW/kVA combined inverter based photovoltaic, ("the Facility"), to its 34.5 kV distribution system, ("the Project"), and presents the conclusions of the study herein. Site designations are provided in the Definitions section above.

The interconnection requirements specified are exclusive to this project and are based upon the most recent information submitted by the Customer, which is attached for reference in Appendix C. Any further design changes made by the Customer post IA without the Company's knowledge, review, and/or approval will render the findings of this report null and void.

System Modifications

In general, the Project was found to be feasible with certain modifications to the existing Company System and operating conditions, which are described in detail in the body of this Study. Significant modifications include:

Site A, Site B, Site C, Site D, Site F, Site G: Kent County 3309

- Approximately 22,600 circuit foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work: (Section 2.2 & Appendix B)
  - Install ~20,100 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
  - Install ~700 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from the 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road (Revity Energy POI).
  - Install ~200 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road (Revity Energy POI) to a 2-way MH on Customer property.
  - Install ~100 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from 2-way MH on Customer property to proposed riser pole on Customer property.
  - Install ~1500 circuit feet of 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.

- Approximately 22,600 circuit foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2 & Appendix B)
  - Install MH and duct system (~3000 feet) from proposed riser pole on Hopkins Hill Road to 3-way MH on Hopkins Hill Road (to be self-built by Customer).

  - Install MH and duct system (~14,700 feet) from 3-way MH on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road.
    - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road (Revity Energy POI).
    - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
  - Install MH and duct system (~100 feet) from first 3-way MH on Weaver Hill Road (Revity Energy POI) to proposed 2-way MH on Customer property (to be self-built by Customer).
  - Install MH and duct system (~50 feet) from 2-way MH on Customer property to proposed riser pole on Customer property (to be self-built by Customer).
- Implement live line reclose blocking on the existing recloser at Pole #10, Hopkins Hill Road, Coventry, RI. (Section 4.1)
- Add Load encroachment settings to the Kent county T7 Directional Overcurrent Relay. (Section 5.4)
- Install ~410 feet of 3-1/c-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry. (Section 2.2, 5.5 & Appendix B)
- Change settings of the recloser at Pole #10, Hopkins Hill Road, Coventry, RI. (Section 2.2 & 5.5)
- Install ~1,100 circuit feet of 3-477 AAC, one (1) 35 kV load break switch, one (1) 35 kV recloser, two disconnect switches and six (6) primary meters along with six (6) disconnect switches at the PCC. (Appendix B)

Site E: Kent County 3310

Note: These system modifications are subject to less costly alternatives involving reduced scope and cost sharing. Applicability of these alternative modifications are dependent on the timely progression of this project and alignment of material procurement with an associated project which is also dependent on this UG system installation. The alternative would include the installation of 1000 kcmil CU EPR 35 kV Cable upfront and eliminate the need to remove the 500 kcmil CU EPR 35 kV Cable.

Alternative #1

Note: Due to other ongoing projects, this option is available to the Customer if the ISA is executed by a date to be specified in the ISA.

1. Approximately ~19,200circuit foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work: (Section 2.2 & Appendix B)
    - Install ~16,800 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet of 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road (Revity Energy POI).
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~200 circuit feet of 3-500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road (Revity Energy POI) to a 2-way MH on Customer property
    - Install ~100 circuit feet of 3-500 kcmil CU EPR 35 kV cable from the 2-way MH on Customer property to proposed riser pole on Customer property
    - Install ~1400 circuit feet of 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
2. Approximately ~19,200 circuit foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2 & Appendix B)
    - Install MH and duct system (~14,900 feet) from proposed riser on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
        - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
    - Install MH and duct system (~600 feet) from 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road (Revity Energy POI).
        - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.

- Install MH and duct system (~100 feet) from first 3-way MH on Weaver Hill Road (Revity Energy POI) to proposed 2-way MH on Customer property (to be self-built by Customer).
- Install MH and duct system (~50 feet) from 2-way MH on Customer property to proposed riser pole on Customer property (to be self-built by Customer).

3. Add Load encroachment settings to the Kent county T7 Directional Overcurrent Relay (Section 5.4)
4. Change the settings of the 3310 breaker at Kent County Substation. (Section 5.4)
5. Install ~410 feet of 3-1/c-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry. (Section 2.2, 5.5 & Appendix B)
    - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
6. Install ~250 feet of 3-1/c-477 AL Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers and one (1) primary meter at the PCC.

Alternative #2

Note: Due to other ongoing projects, this option will be required if the ISA is not executed by a date to be specified in the ISA.

1. Approximately 19,200 circuit foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work: (Section 2.2 & Appendix B)
    - Remove ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
    - Install ~16,800 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
    - Install ~700 circuit feet of 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road (Revity Energy POI).
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~200 circuit feet of 3-500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road (Revity Energy POI) to a 2-way MH on Customer property.
    - Install ~100 circuit feet of 3-500 kcmil CU EPR 35 kV cable from the 2-way MH on Customer property to proposed riser pole on Customer property.

- Install ~1400 circuit feet of 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

2. Approximately 19,200 circuit foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2 & Appendix B)
   - Install MH and duct system (~14,900 feet) from proposed riser on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
     - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
     - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
   - Install MH and duct system (~600 feet) from 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road (Revity Energy POI).
     - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
   - Install MH and duct system (~100 feet) from first 3-way MH on Weaver Hill Road (Revity Energy POI) to proposed 2-way MH on Customer property (to be self-built by Customer).
   - Install MH and duct system (~50 feet) from 2-way MH on Customer property to proposed riser pole on Customer property (to be self-built by Customer).
3. Add Load encroachment settings to the Kent county T7 Directional Overcurrent Relay (Section 5.4)
4. Change the settings of the 3310 breaker at Kent County Substation. (Section 5.4)
5. Install ~410 feet of 3-1/c-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry. (Section 2.2, 5.5 & Appendix B)
   - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
6. Install ~250 feet of 3-1/c-477 AL Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers and one (1) primary meter at the PCC.

EXHIBIT L

Division 6-1

Request:

Has the Company[1] ever discussed with Green, Revity, EPD and/or any other person or entity, either formally or informally, about the possibility of obtaining reimbursement from ratepayers for some or all of Green's, Revity's and/or EPD's expenditures for all or any part of the Weaver Hill Project[2]?

If so, (a) provide all written communications, *i.e.*, e-mails, correspondence, *etc.* reflecting the discussions and (b) describe in detail the discussions that occurred to the extent they are not reflected in the written communications provided.

Response:

Yes, the Company has discussed with Green, Revity, and EDP the possibility of obtaining reimbursement from ratepayers for some of Green's, Revity's, and EDP's (now under Revity's control) expenditures for the Weaver Hill Project. As indicated in the Company's response to Division 6-2, the only formal arrangements that came out of the discussions are the Interconnection Service Agreements ("ISA"s) attached as Exhibit EJRS-4, Exhibit EJRS-5, and Exhibit EJRS-6 to the Pre-Filed Direct Testimony of Erica Russell Salk and Stephanie A. Briggs.

The Company notified the Customers that it would file a Petition with the Public Utilities Commission ("PUC") seeking reimbursement to Green, Revity, and EDP (now under Revity control) from ratepayers for work identified in the Central RI West Area Study which benefits distribution customers and has been accelerated. R.I. Gen. Laws § 39-26.3-4.1 was the basis for the Company's reasoning to file the Petition. The Company informed Green, Revity, and EDP (now under Revity control) that the Petition was subject to review and approval of the PUC.

In this case, Green and Revity elected to self-build. As a condition to self-building, Green and Revity were required to build to the Company's standard including installing extra duct to accommodate future needs. The basis being the Company would have included the extra duct work if it built the investment itself. Building out the extra duct work is consistent with how the Company treats both load and distributed generation customers and is good utility practice as it saves customers money over the long term. This extra duct work benefits all distribution customers and, had the work been performed by the Company, the Company would not have initially charged Green and Revity for the extra duct work and included it in the ISR

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[1] As used herein, the term "Company" means RIE and National Grid, including any of their affiliates.
[2] Includes the Nooseneck Project, the Robin Hollow Project and the Studley Solar Project.

Division 6-1, page 2

reconciliation. Given the timing of the auditing of the duct bank costs and for administrative ease, the extra duct work was initially borne by Green and Revity through its self-build and requested reimbursement to Green and Revity for the extra duct work was included in the Petition for review and approval by the PUC.[3]

[3] Company counsel spoke with Division counsel to let the Division know the Engineering Team checked their emails and did not find any emails with the Customers discussing reimbursement from ratepayers. The Company believes the same applies to its Customer Energy Integration Team; however, the email search was ongoing and Division counsel indicated the ongoing email review is not necessary at this time.

EXHIBIT M

PRE-FILED SURREBUTTAL TESTIMONY OF RYAN PALUMBO

ON BEHALF OF REVITY ENERGY LLC

MAY 22, 2024

Prepared by:

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Q. Please state the reasons for this surrebuttal testimony?

The purpose of this surrebuttal testimony is to respond to the April 10, 2024 Pre-Filed Testimony of Matthew Ursillo (provided on behalf of Green Development LLC) ("Green Pre-Filed Testimony"), the April 17, 2024 Pre-Filed Direct Testimony of Gregory L. Booth, PE (provided on behalf of the Rhode Island Division of Public Utilities and Carriers) ("Division Pre-Filed Testimony"), and the May 9, 2024 Joint Pre-Filed Rebuttal Testimony of Eric Wiesner and Ryan Constable (provided on behalf of The Narragansett Electric Company d/b/a Rhode Island Energy ("Company Pre-Filed Rebuttal Testimony").

Q. Have you reviewed the Pre-Filed Testimony to which you are responding?

Yes, I have.

Q. In the Green Pre-Filed Testimony, Mr. Ursillo stated that during Green's interconnection process, Green "was informed by the Company that in order to do so it would be required to make upgrades necessary to serve other customers."[1] Did Revity have a similar experience during its interconnection process for the Weaver Hill Projects?

Yes. The Company required Revity to make certain upgrades necessary to serve other customers including to (1) overbuild a 9-way duct bank instead of a 6-way duct bank on Weaver Hill Road from Manhole 5 to Manhole 6 to support an additional feeder for the Company's substation; (2) perform an additional 400 to 450 feet of excavation of an additional depth of 1.5 feet to 2.5 feet; (3) perform supplemental blasting, hammering and rock

[1] Green Pre-Filed Testimony at p. 6:3-5.

processing; and (4) procure additional conduit, concrete, labor and materials to perform items (1), (2) and (3).

In the first week of March of 2023, the Company agreed to cost-sharing reimbursement for the ductbank and associated upgrades necessary for the Weaver Hill substation. The Company agreed to begin conducting monthly meetings with Revity to discuss the scheduling and progress of system upgrades for the Weaver Hill Projects and the substation. During the March 2023 monthly meeting, the Company and Revity discussed cost-sharing for the Weaver Hill substation and the timing for when the Company would file the petition to approve the reimbursement. During the August 23, 2023 monthly meeting, Revity and the Company discussed the Company's petition for Weaver Hill Substation cost-sharing reimbursement and the Company stated that its rates and regulatory groups were "crunching numbers" and that cost recovery would not be achievable until April 2024. During the September 20, 2023 monthly meeting, Revity and the Company discussed the Weaver Hill substation cost sharing. During the November 27, 2023 monthly meeting, Revity and the Company discussed the Weaver Hill substation cost sharing and the meeting minutes reflect that the Company had filed the Petition on October 17, 2023 and "cost recovery [is] pending RI PUC decision." On December 19, 2023, Revity and the Company again discussed the Weaver Hill substation cost sharing.

Q. In the Division Pre-Filed Testimony, Mr. Booth testified that the "Tariff reimbursement requires the determination of the need date and if the project is intended

within five years of the start of an Impact Study, then reimbursement is applied."[2] Do you agree?

No. Section 5.4(c) of the Tariff states that the "Company will consider a system modification to be an accelerated modification if such is otherwise identified in the Company's work plan as a necessary capital investment to be installed within a five-year period as of the date the Company begins the impact study of the proposed distributed generation (DG) project (defined as an Accelerated Modification)." The upgrades must be identified in the Company's ISR filing as a necessary capital investment (which these upgrades were) and the upgrades must be installed within a five-year period (which these upgrades were). Section 5.4 of the Tariff makes no reference to when the project is "intended" and the only "project" referenced in Section 5.4 is the DG project.

Q. In the Green Pre-Filed Testimony, Mr. Ursillo stated that the planned System Improvements at issue here were included in prior Company Infrastructure Safety and Reliability (ISR) filings.[3] Do you agree?

Yes. The Company's December 20, 2021 Electric Infrastructure, Safety, and Reliability (ISR) Plan FY 2023 Proposal (Docket No. 5209) identified concerns and recommended solutions for Central RI West:

Concerns: a number of circuits require reconductoring due to reliability, contingency, capacity, or asset condition concerns (2230 line, 54F1, 63F6, etc.);

[2] Division Pre-Filed Testimony at p. 10:14-16.
[3] Green Pre-Filed Testimony at p. 8:8-11.

three stations require equipment replacement/upgrades due to asset condition concerns (Coventry, Hope and Division St).

Summary of Recommended Solutions:

- Replace equipment identified at Coventry #54, Hope #15, and Division St. #61 to address safety and asset condition issues.
- Replace equipment at Anthony, Natick, and Warwick Mall, and complete reconductoring on the 2230 and 2232 23kV lines to address the Drumrock 23kV system concerns.
- Extend portions of the 35kV system and install a new modular substation at Weaver Hill Rd to relieve 54F1 and 63F6 circuits and address the Kent County 35kV system concerns.[4]

The Commission approved the Company's ISR Plan effective April 1, 2022. In the Division's Pre-Filed Testimony (on pages 7-8 of 17) in the pending matter, Mr. Boothe testified as follows:

Q. THE COMPANY STATES ON PAGE 21 OF ITS PETITION THAT THE WEAVER HILL ROAD SUBSTATION IS IN THE FY 2023 ISR PLAN DOCKET 5209 AND THAT THE CENTRAL RI WEST AREA STUDY EVALUATED THE ISSUES AND PROPOSED THE SOLUTION. IS THAT AN ACCURATE CHARACTERIZATION?

[4] Company's December 20, 2021 Electric Infrastructure, Safety, and Reliability Plan FY 2023 Proposal (Book 1 of 2) at p. 36.

> A. I find that characterization very misleading. The Weaver Hill substation and sub-transmission construction were not FY 2023 ISR Plan projects but only referenced as a potential future project. However, the FY 2023 ISR Plan was filed December 20, 2021 during the finalization of the Central RI West Area Study which is dated September 2022. It would have been speculative to include the Weaver Hill project in the FY 2023 ISR Plan. While the Area Study does show Weaver Hill as a solution for a potential 2035 problem, the project would not be constructed now since there are much less expensive interim solutions and the actual loads and overloading are not occurring at this time or in the near term.[5]

The 2023 ISR Plan filed by the Company in December of 2021 clearly stated the concerns regarding the Central RI West and the recommended extending "portions of the 35kV system and install a new modular substation at Weaver Hill Rd to relieve 54F1 and 63F6 circuits and address the Kent County 35kV system concerns." These solutions were proposed two and a half years ago, the Commission approved the ISR Plan (effective April 2022) and the Company required Revity to implement those solutions in order to be allowed to interconnect its Weaver Hill Projects. The Company's December 22, 2022 Proposed FY 2024 Electric Infrastructure, Safety and Reliability Plan (ISR) (Docket No. 22-53-EL) expanded on the problems and proposed solutions in Central RI West:

> **Problem:** There are predicted loading and voltage concerns on certain

[5] Division Pre-Filed Testimony at pp. 7:21-8:12.

Hopkins Hill and Coventry substation feeders. The loading concerns include feeders predicted to be near or in excess of thermal ratings. The voltage concerns are similarly at or below guidelines. These same feeders are approaching contingency load-at-risk limits. Furthermore, many of the area feeders have circuit frequency and duration metrics above system averages.

Preferred Plan: Install a new substation on Weaver Hill Rd. This work extension of the 3309 and 3310 lines from Nooseneck Hill and Weaver Hill Roads in West Greenwich to a Rhode Island Energy owned property on Weaver Hill Rd, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.

Alternate Plan: Install a new substation on Bell Schoolhouse Road (Pine Hill substation). This work includes extension of the 3310 line from Route 3 north of Route 102 to a Rhode Island Energy owned property at the intersection of New London Turnpike and Bell Schoolhouse Road, Exeter referred to as Pine Hill substation. The work also includes the installation of a new

> 34.5 kV line from the new Wickford Junction substation to Pine Hill substation, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.[6]

The Company's December 21, 2023 Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan (Docket No. 23-48-EL) provided as follows:

- *Weaver Hill Road Substation* – The Central Rhode Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder.[7]

Revity materially relied on the Company's filings and the Commission's approval of the 2023 ISR Plan insofar as Revity has incurred millions of dollars in costs to construct the System upgrades ordered by the Company.

Q. Had the Company's prior December 20, 2021 ISR Plan FY 2023 Proposal been rejected by the Commission in Docket No. 5209, how (if at all) would that have changed Revity's approach to the interconnection of its Weaver Hill Projects?

[6] Company's December 22, 2022 Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan (21-Month Filing April 2023-December 2024) (Book 1 of 2) at p. 95.
[7] Company's December 21, 2023 Proposed FY 2025 Electric Infrastructure, Safety, and Reliability Plan at p. 40.

If the Commission had denied the Company's recommendation to build the Weaver Hill substation and associated infrastructure upgrades in 2022, Revity would have refused to incorporate the upgrades in its ISA scope of work and insisted that its Weaver Hill Projects be interconnected without those upgrades. If the Company had refused to proceed with the interconnection absent those upgrades, Revity would have availed itself of its rights under Section 5.4(d) of the Tariff which provides that "Renewable Interconnecting Customers may also petition the Commission directly if the Renewable Interconnecting Customer believes that it has been incorrectly charged for an Accelerated Modification under Section 5.4."

Q. Are there any other Commission Docket matters which inform Revity's positions in this matter?

Yes. On October 31, 2017, the Company filed its Tariff Advice to amend the Standard for Connecting Distributed Generation Tariff (R.I.P.U.C. 2180) adding "a provision to Section 5.4, Separation of Costs to distinguish between costs for system improvements to the Company's EPS to serve the interconnecting customer and other customers, and the costs for system modifications."[8] On March 28, 2018, the Division filed a Memorandum in Docket No. 4763 stating that Section 5.4 "will do nothing to limit free riders that take advantage of the accelerated modification" and "[t]he outer years of a five-year Capital Plan tend to vary significantly as new information is accumulated from year-to-year, the specific projects, project scope and their associated costs are highly variable which potentially leads to

[8] Company's October 31, 2017 Letter to Division in Docket No. 4763 at p. 3.

uncertainty regarding what is and what is not an accelerated project."[9] On April 27, 2018, the Company filed a Reply to the Division's March 28 Memorandum responding to these concerns stating that "the Company will honor any Accelerated Modification set forth in an Interconnection Service Agreement (ISA) even if the ultimate 'need' is later than forecasted in the Capital Plan to provide certainty to the DG developer community, provided the Company receives cost recovery for the remaining cost of the modification."[10] On January 4, 2019, the Commission issued its Report and Order in Docket No. 4763 approving the Company's Tariff Advice subject to certain modifications.

On October 22, 2020, the Commission opened Docket No. 5077 considering the Company's Tariff Advice to revise the Standards for Connecting Distributed Generation (R.I.P.U.C. No. 2244) including further revision to Section 5.4. On January 8, 2021, Gregory Booth filed a letter with the Commission regarding Docket No. 5077 and, with respect to Section 5.4, stated that the "ISR Plan process is a better forum for establishing what constitutes a System Modification – those changes to the system for the benefit of the interconnecting customer, and a System Improvement – those changes that benefit the overall system used to provide service to the Company's customers" and the "ISR Plan process already addresses certain capital projects which benefit distributed energy resources and are appropriately socialized because they cannot be effectively directly assigned."[11] In the Division Pre-Filed Testimony in this matter, Mr. Booth now testifies that "just because the Company may desire

[9] March 28, 2018 Memorandum of Daymark Energy Advisors in Docket No. 4763 at p. 2.
[10] Company's April 27, 2018 Reply in Docket No. 4763 at p. 2.
[11] Booth's January 8, 2021 Letter in Docket No. 5077 at p. 4.

a project be included in the ISR Plan does not mean it is actually needed at that time."[12] In his January 8, 2021 letter filed in Docket No. 5077, Mr. Booth stated that "I would support System Modification[s] being classified as System Improvement[s] by the Company, if each project could be directly identified and linked to a specific project contained in a previously filed five-year Area Study, subject to final approval for inclusion in rates through the ISR Plan process."[13] On February 2, 2021, the Company filed its Reply Comments to the Division's Comments in Docket No. 5077 and, responding to Mr. Booth's comment regarding Section 5.4, stated that "Mr. Booth considers the ISR process to be a better forum for establishing what constitutes a System Modification and notes that the ISR Plan process already addresses certain capital projects that benefit DG are appropriately socialized" and further stating that "the Company would look to fund some portion of a System Modification through an upcoming ISR in the event that a portion of the System Modification benefited the Rhode Island customer base at large."[14]

For years, the Division has taken the position that system upgrades need to be approved through the ISR Plan process to avoid "uncertainty regarding what is and what is not an accelerated project." The Company has stated that it "will honor any Accelerated Modification set forth in an Interconnection Service Agreement (ISA) even if the ultimate 'need' is later than forecasted in the Capital Plan to provide certainty to the DG developer community, provided the Company receives cost recovery for the remaining cost of the modification." The

[12] Division Pre-Filed Testimony in Docket No. 23-38-EL at p. 11:1-2.
[13] Booth's January 8, 2021 Letter in Docket No. 5077 at p. 4.
[14] Company's February 2, 2021 Reply Comments to Division Comments in Docket No. 5077 at pp. 7-8.

Company and the Division consider the ISR Plan process to be the better forum for establishing what constitutes a System Modification compared to a System Improvement and the Company, through its December 20, 2021 Electric Infrastructure, Safety, and Reliability (ISR) Plan FY 2023 Proposal (Docket No. 5209), identified the Weaver Hill substation and associated infrastructure as capital system upgrades necessary for the safety and reliability of the grid in the Central Rhode Island area.

Q. In the Company Pre-Filed Rebuttal Testimony, Messrs. Wiesner and Constable testified that "it would be challenging to identify a significant distributed generation ('DG') project that could be fully installed within five years from the start of an Impact Study" because the "interconnection study process for sites similar to Weaver Hill's site considered in this Petition can span many years", the ASO "process can create similar timelines" and "the planning and full construction of projects identified within area studies can span many years considering the study time, the process time to introduce and request approval with an ISR Plan, and the practical design, procurement, and resourcing times."[15] Do you agree?

Yes, I agree. For example, on December 5, 2018, the Company issued its System Impact Study for Distributed Generation Interconnection to the Company's 12.47 kV System for Revity affiliated Natick Solar LLC's (f/k/a Southern Sky Renewable Energy Rhode Island, LLC) 6.250 MW system on Phenix Avenue in Cranston, Rhode Island. Natick Solar began the municipal planning process for the proposed development on November 9, 2018, Natick Solar

[15] Company Pre-Filed Rebuttal Testimony at pp. 6:7-9; 9:10-16.

received master plan approval for the development from the Cranston Plan Commission on February 11, 2019 but, since then, the proposed development has been delayed by four Superior Court appeals.[16] At the time of this testimony, the proposed development is being reviewed by the Rhode Island Superior Court in *Natick Solar LLC, et al. v. Michael E. Smith, et al.*, PC-2023-05457.

As another example, on April 29, 2021, the Company issued its System Impact Study for Distributed Generation Interconnection to the Company's 34.5 kV System for Revity's 10.225 MW system on 35 Frontier Road in Ashaway, Rhode Island. The ASO No. 2 Study for Western Rhode Island began on April 13, 2020 and included Revity's Frontier project. The ASO No. 2 Study was completed on January 30, 2021 and the associated Proposed Plan Applications were presented at the February 16, 2021 NEPOOL RC meeting and were approved by ISO-NE on March 4, 2021. Revity's proposed Frontier system was continued to the ASO No. 3 Study for Westen Rhode Island which began on August 17, 2021. Revity received Development Plan Review approval from the Hopkinton Planning Board on October 21, 2020. Revity's approval was subject to review by the Rhode Island Superior Court in *Revity Energy LLC v. Hopkinton Zoning Board of Review, et al.*, WC-2021-0526 which review concluded on February 2, 2023. In January of 2024, the Company reported that its timeline to complete ASO Study No. 3 was June 2024. ASO Study No. 3 involves 117 MWs of solar interconnection and it would be highly unlikely that interconnection service agreements could be finalized and the

[16] *Holly Zevon, et al. v. Southern Sky Renewable Energy RI Natick Ave – Cranston LLC, et al.*, PC-2019-6129; *Daniel Zevon, et al. v. Carl Swanson et al.*, PC-2021-06995; *Holly Zevon, et al. v. Ronald Rossi, et al.*, PC-2022-02502; *Natick Solar LLC, et al. v. Michael E. Smith, et al.*, PC-2023-05457.

interconnection work would be completed by April of 2026. Revity agrees with the testimony of Messrs. Wiesner and Constable in the Company's Pre-Filed Rebuttal Testimony, "[a] narrow interpretation of the Tariff may result in limited to no opportunity for shared cost under the statutory acceleration provisions, which is inefficient for distribution planning and infrastructure construction that may be beneficial to both distribution customers and interconnecting customers."[17]

Furthermore, Revity has had experience with Company system upgrades for which the equipment has years-long lead times (as one example, a synchronous condenser) which further delay installation beyond the developer's control.

Lastly, Section 5.4(c) of the Tariff states that the Company must identify System Modifications in the Impact Study. The Division's interpretation of cost reimbursement would require the developer to begin installation when the impact study is commenced; however, the developer does not know what system modifications are being required until the impact study is completed.

Q. In the Division Pre-Filed Testimony, Mr. Booth testifies that the "Weaver Hill project, even if implemented as the Company identified in its Area Study with higher loads than are actually occurring, will not be installed until 2027 or later" and the "installation date for the Weaver Hill project is well beyond the five-year limitations period that determines if a capital investment is 'accelerated' under the plain language

[17] Company Pre-Filed Rebuttal Testimony at pp. 9:20-10:2.

of Section 5.4 of the Interconnection Tariff" and "DG reimbursement, therefore, is not available."[18] Do you agree?

No. Mr. Booth states that "the Weaver Hill substation would have been delayed well beyond 2027 to 2035 or later" and the "year 2027 in service date, if even achieved, is more than five years after the 2019 start of the Impact Study, and thus outside the Tariff."[19] As for the System Improvements required for the Weaver Hill Projects, the Interconnection Tariff has no time limitation for the reimbursement of System Improvements. As for System Modifications required for the Weaver Hill Projects, Section 5.4(c) of the Tariff states that the "Company will consider a system modification to be an accelerated modification if such modification is otherwise identified in the Company's work plan as a necessary capital investment to be installed within a five-year period as of the date the Company begins the impact study of the proposed distributed generation (DG) project (defined as an Accelerated Modification)" and the "Company will identify the Accelerated Modification and the cost thereof in the impact study." The only work that needs to be completed within the five-year window is the work identified in the Impact Study. The Weaver Hill substation was not identified as part of the scope of work. The Company/Revity Impact Study required Revity to perform certain System Modifications and those Modifications were all completed within a five-year window.

[18] Division Pre-Filed Testimony at p. 7:15-20.
[19] Division Pre-Filed Testimony at p. 9:12-14.

Q. Please detail the timeline for Revity's self-performance of the interconnection system upgrades required by the Company for the Weaver Hill Project.

Revity and its Company-approved subcontractors, Asplundh Construction, LLC (Asplundh) and Rosciti Construction Co., LLC (Rosciti), began self-performing the system upgrades required by the Company for the Weaver Hill Project on July 17, 2023 and Revity authorized Rosciti to begin underground work for the Weaver Hill Project on September 6, 2023. Revity authorized Asplundh to begin overhead upgrade work on November 2, 2023. Revity and Rosciti completed the statement of work for the civil manhole and duct bank work on November 7, 2023. Revity and Asplundh completed all underground upgrade system work on or before November 30, 2023. Revity and Rosciti returned on April 24, 2024 to complete road milling, paving and stripping.

Attached are Exhibits RPP-1 and RPP-2 identifying the system upgrades performed in the Weaver Hill area by Revity, Green and the Company.[20] RPP-1 and RPP-2 do not contain every upgrade that was ultimately required by the Company for the Weaver Hill Projects interconnection.

Q. Does this conclude your testimony?

Yes.

[20] The map reflected in Exhibit RPP-1 comes from Figure B-2 of the September 20, 2022 Energy Development Partners Interconnection Study (attached as Exhibit EJRS-3 to the Company's October 17, 2023 Pre-Filed Joint Testimony of Erica Russell Salk and Stephanie A. Briggs (Page 172). The map reflected in Exhibit RPP-2 comes from Figure B-2 of the April 21, 2021 Revity Energy Interconnection Study (attached as Exhibit EJRS-2 to the Company's October 17, 2023 Pre-Filed Joint Testimony of Erica Russell Salk and Stephanie A. Briggs (Page 123)).

EXHIBIT N

PUC 1-1

Request:

All meeting minutes in Revity Energy LLC's possession reflecting discussions between Rhode Island Energy and Revity Energy regarding reimbursement of costs in connection with the Weaver Hill Projects.

Response:

Meeting minutes reflecting discussions between Rhode Island Energy and Revity Energy regarding reimbursement of costs in connection with the Weaver Hill Projects are attached hereto as PUC-1-1-1.

Revity Energy – RI Energy

Meeting Agenda

Procurement

1. Revity is seeing components that are currently only being sold to utilities. Revity would like to fine tune the procurement scope in this job to see what RIE has in inventory.

Equipment/Material	Location	Area	Feeder
Disconnect Switch for 3309 POI Riser	Pole P35-1	POI/PCC	3309
Disconnect Switch for 3310 POI Riser	Pole P5-1	POI/PCC	3310
Disconnect Switch for Project 1 PCC	Pole P35-22	POI/PCC	3309
Disconnect Switch for Project 2 PCC	Pole P35-19	POI/PCC	3309
Disconnect Switch for Project 3 PCC	Pole P35-7	POI/PCC	3309
Disconnect Switch for Project 4 PCC	Pole P35-16	POI/PCC	3309
Disconnect Switch for Project 6 PCC	Pole P35-10	POI/PCC	3309
Disconnect Switch for Project 7 PCC	Pole P35-13	POI/PCC	3309
Fused overhead transformer bank for 3309 POI Recloser - 1 of 2	Pole P35-3	POI/PCC	3309
Fused overhead transformer bank for 3309 POI Recloser - 2 of 2	Pole P35-5	POI/PCC	3309
Fused overhead transformer bank for 3310 POI Recloser - 1 of 2	Pole P5-5	POI/PCC	3310
Fused overhead transformer bank for 3310 POI Recloser - 2 of 2	Pole P5-3	POI/PCC	3310
Gang-operated load break switch for 3309 POI	Pole P35-2	POI/PCC	3309
Gang-operated load break switch for 3310 POI	Pole P5-2	POI/PCC	3310
Overhead 1/0 AL wire between poles (~150 circuit feet, ~450 of wire)	3310 POI/PCC Poles	POI/PCC	3310
Overhead 477 AL wire between poles (~560'circuit feet, ~1680 of wire)	3309 POI/PCC Poles	POI/PCC	3309
Pole Hardware (crossarms, insulators, arresters, etc.)	POI/PCC Poles	POI/PCC	3309/3310
Anchors and Guy Wire	POI/PCC Poles	POI/PCC	3309/3310
1/0 Triplex Secondary Cable for Transformer Banks	POI/PCC Poles	POI/PCC	3309/3310
Disconnect Switch for 3309 HH Riser Recloser	Pole P10-2-51	Hopkins Hill Rd	3309
Fused overhead transformer bank for 3309 HH Riser Recloser - 1 of 2	Pole P10-2-50	Hopkins Hill Rd	3309
Fused overhead transformer bank for 3309 HH Riser Recloser - 2 of 2	Pole P9-2-50	Hopkins Hill Rd	3309
Loadbreak Switch for HH Riser Recloser	Pole P9-2-51	Hopkins Hill Rd	3309
Overhead 795 AL bare wire between poles (~200 circuit feet, ~600 of wire)	3309 HH Riser Poles	Hopkins Hill Rd	3309
Pole Hardware (crossarms, insulators, arresters, etc.)	3309 HH Riser Poles	Hopkins Hill Rd	3309
Anchors and Guy Wire	3309 HH Riser Poles	Hopkins Hill Rd	3309
1/0 Triplex Secondary Cable for Transformer Banks	3309 HH Riser Poles	Hopkins Hill Rd	3309
Recloser for 3309 HH Riser	Pole P10-2	Hopkins Hill Rd	3309
Primary metering for Project 1	Pole P35-23	POI/PCC	3309
Primary metering for Project 2	Pole P35-20	POI/PCC	3309
Primary metering for Project 3	Pole P35-8	POI/PCC	3309
Primary metering for Project 4	Pole P35-17	POI/PCC	3309
Primary metering for Project 5	Pole P5-26	POI/PCC	3310
Primary metering for Project 6	Pole P35-11	POI/PCC	3309
Primary metering for Project 7	Pole P35-14	POI/PCC	3309
Recloser for 3309 POI	Pole P35-4	POI/PCC	3309
Recloser for 3310 POI	Pole P5-4	POI/PCC	3310
Three(3) H splices for 3310 in MH 3456 A	Manholes	Weaver Hill	3310
Cold shrink straight splices (3 per MH, 7 MHs, 21 total)	Manholes	Hopkins Hill Rd	3309
Cold shrink straight splices (3 per MH, 24 MHs, 72 total)	Manholes	Divison/Weaver Hill	3309
Cold shrink straight splices (3 per MH, 1 MH, 3 total)	Manholes	Weaver Hill	3309
Cold shrink straight splices (3 per MH, 1 MH, 3 total)	Manholes	Weaver Hill	3310

NOOSENECK ROAD/DIVISION ROAD COST SHARING

1. Discussion Topics for Entrust Report:

REDACTED

2. RI Energy – Weaver Hill sub-station costs sharing:
   a. When will RIE file with PUC to get this approved? How long will the approval take?

3. EDP – Weaver Hill/Studley Farm project:

REDACTED

4. RI Energy's request of Revity to advance pay costs sharing obligation:
   a. Revity is willing to advance pay its costs sharing responsibility once all mitigating factors have been accounted for (see all comments above) to reduce the cost sharing $ amount.
   b. We would like to see a similar acceleration effort from EDP.

WEAVER HILL ROAD/HOPKINS HILL ROAD COST SHARING

1. Revity EPC, LLC will hire sub-contractors on a Fixed Price structure to install the Weaver Hill Road and Hopkins Hill Road ductbank installation of approximately 3,800 LF.
    a. Detail costs reports for labor hours, machine time, materials procurement, etc. will only be necessary for in case by case instances such as change orders. (3rd party arms-length sub-contract at a market-based price).
    b. inspection requirements: If RIE requires daily inspections before concrete is poured and ductbank trench is backed filled Revity wants assurances that a RIE inspector will be readily available. If RIE does not have available inspectors for timely inspections Revity suggests hiring a 3rd party sub-contractor/consultant that acts on RIE's behalf.

2. Inspection requirements:
    a. Does RIE have a readily available inspector to be ready to start inspections within the next 30/45 days?
    b. Is a 3rd party inspector needed?

RI ENERGY COSTS RECONCILIATION BUDGET/ACTUAL COSTS TRANSPARENCY

REDACTED

[redacted]

Revity Energy – RI Energy

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RI ENERGY COSTS RECONCILIATION BUDGET/ACTUAL COSTS TRANSPARENCY

REDACTED

[redacted]

[redacted]

MEETING AGENDA

Revity Team Members & RI Energy Team Members

Meeting Date: Wednesday, May 31, 2023
Time: 1:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Bassey Iro, Andrew Hogan, Thomas Cappobianco, Erica Russell Salk, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy
Meeting Topics & Notes(in red):

- **Weaver Hill interconnect status**
    - **RI Energy procurement items**

REDACTED

- **Shore Road, Johnston**

REDACTED

[redacted]

[redacted]

REDACTED

- **Laten Knight Road**

REDACTED

[redacted]

[redacted]

REDACTED

If time allows:

Weaver Hill

- Cost Reimbursement from Weaver Hill sub-station
  - Reference Erica's email dated May 26th. It seems that an equitable solution is in order to avoid preferential treatment of one developer over the other and arrive at a 50/50 reimbursement factor for both 3309 & 3310 cable installations if either one could be utilized.
  - Discussion – a separate meeting will be coordinated to discuss Cost Reimbursement.

- Revity procurement items
  - Status of effort.
- Manhole – RIE inspector demanding/requiring drainage grates – not specified in approved plans. Non-issue now due to Andrew's efforts.
  - What authority does inspector have to make demands outside of approved design? Andrew reviewed process/instance where inspector may call a halt to job/days work while a design issue may be resolved.

[redacted]

[redacted]

MEETING AGENDA w/Notes

Revity Team Members & RI Energy Team Members

Meeting Date: Wednesday, June 28, 2023
Time: 1:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Erica Salk, Andrew Hogan, Nelson Antunes, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Note: Prior Monthly Meeting notes included for reference.

Meeting Topics:

- Weaver Hill interconnect status
  - RI Energy procurement items
    - Status of long lead items;

      REDACTED

      - Meters: 7 required. Ordered ? lead time ? Andrew to chase down.
    - Status of general materials

      REDACTED
  - ISA Amendments

[redacted]

[redacted]

REDACTED

Revity EPC start ductbank construction on Hopkins Hill Road.

REDACTED

  - Entrust

REDACTED

  - Petition by RI Energy
    - Filed? Rates and Regulatory groups crunching numbers. Still working on it. Further comments may be submitted.

- Shore Road, Johnston

REDACTED

- 7 Mile Road – Reconciliation

REDACTED

- Laten Knight Road

REDACTED

- ASO 3 status

REDACTED

[redacted]

[redacted]

REDACTED

If time allows:

- In the near future; customer RTU information/equipment changeouts required – Ngrid to PPL control system changeout. More to come
-

Meeting Date: Wednesday, May 31, 2023
Time: 1:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Bassey Iro, Andrew Hogan, Thomas Cappobianco, Erica Russell Salk, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Meeting Topics & Notes(in red):

- **Weaver Hill interconnect status**

REDACTED

[redacted]

[redacted]

REDACTED

- **Shore Road, Johnston**

REDACTED

- **Laten Knight Road**

REDACTED

[redacted]

[redacted]

REDACTED

- ***Entrust Ductbank audit report:*** REDACTED

REDACTED

If time allows:
Weaver Hill
- Cost Reimbursement from Weaver Hill sub-station
  - Reference Erica's email dated May 26th. It seems that an equitable solution is in order to avoid preferential treatment of one developer over the other and arrive at a 50/50 reimbursement factor for both 3309 & 3310 cable installations if either one could be utilized.
  - Discussion – a separate meeting will be coordinated to discuss Cost Reimbursement.

- Revity procurement items
  - Status of effort.

[redacted]

[redacted]

- Manhole – RIE inspector demanding/requiring drainage grates – not specified in approved plans. Non-issue now due to Andrew's efforts.
  - What authority does inspector have to make demands outside of approved design? Andrew reviewed process/instance where inspector may call a halt to job/days work while a design issue may be resolved.

[redacted]

[redacted]

MEETING AGENDA w/Notes

Revity Team Members & RI Energy Team Members

Meeting Date: Wednesday, June 28, 2023
Time: 1:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Erica Salk, Andrew Hogan, Nelson Antunes, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Note: Prior Monthly Meeting notes included for reference.

Meeting Topics:

- Weaver Hill interconnect status
    - RI Energy procurement items

REDACTED

- Status of general materials

REDACTED

- ISA Amendments

[redacted]

[redacted]

REDACTED

- Revity EPC start ductbank construction on Hopkins Hill Road.
  - REDACTED
- Entrust
  - REDACTED
- Petition by RI Energy
  - Filed? Rates and Regulatory groups crunching numbers. Still working on it. Further comments may be submitted.

- Shore Road, Johnston

REDACTED

- 7 Mile Road – Reconciliation

REDACTED

- Laten Knight Road

REDACTED

- ASO 3 status

REDACTED

[redacted]

[redacted]

REDACTED

If time allows:

REDACTED

Meeting Date: Wednesday, May 31, 2023
Time: 1:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Bassey Iro, Andrew Hogan, Thomas Cappobianco, Erica Russell Salk, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Meeting Topics & Notes(in red):

- **Weaver Hill interconnect status**

REDACTED

[redacted]

[redacted]

REDACTED

- **Shore Road, Johnston**

REDACTED

- **Laten Knight Road**

REDACTED

[redacted]

[redacted]

- Revity has exclusivity agreement to purchase this project

REDACTED

- ***Entrust Ductbank audit report:*** REDACTED

REDACTED

If time allows:
Weaver Hill

- Cost Reimbursement from Weaver Hill sub-station
  - Reference Erica's email dated May 26th. It seems that an equitable solution is in order to avoid preferential treatment of one developer over the other and arrive at a 50/50 reimbursement factor for both 3309 & 3310 cable installations if either one could be utilized.
  - Discussion – a separate meeting will be coordinated to discuss Cost Reimbursement.

- Revity procurement items
  - Status of effort.

[redacted]

[redacted]

- Manhole – RIE inspector demanding/requiring drainage grates – not specified in approved plans. Non-issue now due to Andrew's efforts.
    - What authority does inspector have to make demands outside of approved design? Andrew reviewed process/instance where inspector may call a halt to job/days work while a design issue may be resolved.

[redacted]

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[redacted]

RI Energy / Revity Energy Monthly Meeting

Agenda

Meeting Date: Wednesday, August 23, 2023
Time: 1:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Kathy Castro, Dan Glenning, Erica Russell Salk, Bassey Iro, Sean Kane, Ralph Palumbo, Ryan Palumbo, John Kennedy

Notes:
1) Meeting notes included below in colored font.
2) Closed items will be removed from the next meeting's agenda.

Meeting Topics:

- Weaver Hill / Robin Hollow interconnect status
  - RI Energy procurement items

REDACTED

[redacted]

[redacted]

REDACTED

[redacted]

- Status of general materials

[redacted]

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[redacted]

- Splice Kits leadtime/delivery date still in question? REDACTED

REDACTED

- Re-opened : ISA Amendments –

REDACTED

- Revity EPC Civil Construction

REDACTED

- Entrust

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filed? Rates and Regulatory groups crunching numbers. Still working on it. Further comments may be submitted. Status Quo as of 7/26/2023. Same for August.
    - Petition filing pending. Cost recovery not achievable until April 2024.

- Frontier Road/Main St

[redacted]

[redacted]

REDACTED

- Shore Road, Johnston

REDACTED

[redacted]

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[redacted]

- 7 Mile Road – Reconciliation

REDACTED

- Tracking Items:
  - Sometime in the future customer RTU information/equipment changeouts required – Ngrid to PPL control system changeout. More to come. Per Erica.

If time allows:

[redacted]

[redacted]

RI Energy / Revity Energy Monthly Meeting

Agenda

Meeting Date: Tuesday, September 19, 2023
Time: 1:30PM – 2:30PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Kathy Castro, Erica Russell Salk, Bassey Iro, Sean Kane, Ryan Constable, Jed Ferris, Dan Glenning, Denise Ducimo, Ralph Palumbo, Ryan Palumbo, John Kennedy

Note:
1) Closed items will be removed from the next meeting's agenda.

Strategic Discussion:

REDACTED

Project Related:

- Weaver Hill / Robin Hollow Interconnect Status

REDACTED

[redacted]

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[redacted]

REDACTED

REDACTED

- Revity EPC Civil Construction - Update

REDACTED

    - Entrust

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
    - Filing Status: Pending.

[redacted]

[redacted]

  - Cost recovery not achievable until April 2024.

- Frontier Road/Main St

REDACTED

Removed from Agenda going forward:

- Shore Road, Johnston – Covered during weekly meeting updates.

REDACTED

- 7 Mile Road – Reconciliation – Covered during weekly meeting updates.

REDACTED

- Tracking Items: - – Covered during weekly meeting updates.

REDACTED

[redacted]

[redacted]

- Frontier Road - REDACTED

REDACTED

[redacted]

[redacted]

RI Energy / Revity Energy Monthly Meeting

Agenda & Meeting Notes

Meeting Date: Tuesday, September 19, 2023
Time: 1:30PM – 2:30PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Kathy Castro, Erica Russell Salk, Bassey Iro, Sean Kane, Ryan Constable, Jed Ferris,, Denise Ducimo, Ralph Palumbo, Ryan Palumbo, John Kennedy, Dan Parent (Stations Eng'g), Chris Szmodis(Transmission Eng'g)

Note:
1) Closed items will be removed from the next meeting's agenda.
2) Sept 19 meeting notes in green.

Strategic Discussion:

REDACTED

Project Related:

- Weaver Hill / Robin Hollow Interconnect Status
    - RI Energy procurement items

REDACTED

[redacted]

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REDACTED

- Status of general materials

REDACTED

- Revity EPC Civil Construction - Update

REDACTED

[redacted]

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
    - Filing Status: Petition to be filed October 1, 2023. No change to content.
        - Cost recovery not achievable until April 2024.

- Frontier Road/Main St

REDACTED

[redacted]

REDACTED

- Hopkins Hill Road

REDACTED

Removed from Agenda going forward:

- Frontier Road

REDACTED

[redacted]

[redacted]

RI Energy / Revity Energy Monthly Meeting

Agenda & Meeting Notes

Meeting Date: Wednesday, October 25, 2023
Time: 2:00PM – 3:00PM
Place: RI Energy Providence Office – RI-Prov Room E2.225 Point Judith
Attendees: Kathy Castro, Erica Russell Salk, Bassey Iro, Sean Kane, Nick Neilsen, Ryan Constable, Jed Ferris, Denise Ducimo, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy, Dan Parent (Stations Eng'g), Chris Szmodis(Transmission Eng'g)

Note:
1) Closed items will be removed from the next meeting's agenda.
2) Sept 19 meeting notes in green.

Strategic Discussion:
- Long Lead Items

REDACTED

Project Related:
- Weaver Hill / Robin Hollow Interconnect Status
  - RI Energy procurement items

REDACTED

[redacted]

REDACTED

- Status of general materials

REDACTED

- Revity EPC Civil Construction - Update

REDACTED

- Entrust

REDACTED

[redacted]

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REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filing Status: Petition to be filed October 1, 2023. No change to content.
    - Cost recovery not achievable until April 2024.

- Frontier Road/Main St

REDACTED

[redacted]

REDACTED

- Hopkins Hill Road

REDACTED

Removed from Agenda going forward:

- Frontier Road

REDACTED

[redacted]

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[redacted]

Agenda

Meeting Date / Time: Monday, November 27, 2023 / 2:00PM – 3:00PM
Location: RI Energy Providence Office – Board Room
Attendees: Kathy Castro, Erica Russell Salk, Sean Kane, Nick Neilsen, Ryan Constable, Jed Ferris, Denise Ducimo, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Strategic Discussion:

REDACTED

Project Related:

REDACTED

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filing Status: Filed on October 17, 2023.
  - Cost recovery pending RI PUC decision.

- Frontier Road/Main St

REDACTED

[redacted]

[redacted]

Agenda

Meeting Date / Time: Tuesday, December 19, 2023 / 9:30AM – 10:30AM
Location: RI Energy Providence Office – Board Room
Attendees: Kathy Castro, Erica Russell Salk, Sean Kane, Nick Neilsen, Ryan Constable, Jed Ferris, Denise Ducimo, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Strategic Discussion:

REDACTED

Project Related:

- Weaver Hill / Robin Hollow Interconnect Status

REDACTED

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filing Status: Filed on October 17, 2023.
  - Cost recovery pending RI PUC decision.

- Jenckes Hill Solar

REDACTED

- Frontier Road/Main St

REDACTED

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REDACTED

- Shore Drive Reconcilliation Status

REDACTED

[redacted]

[redacted]

Agenda

Meeting Date / Time: Tuesday, January 16, 2024 / 10:00AM – 11:00AM
Location: RI Energy Providence Office – Board Room
Attendees: Kathy Castro, Erica Russell Salk, Sean Kane, Nick Neilsen, Ryan Constable, Jed Ferris, Denise Ducimo, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Project Related Priorities:

- Frontier Road/Main St

REDACTED

[redacted]

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[redacted]

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filing Status: Filed on October 17, 2023.
  - Cost recovery pending RI PUC decision.
  - New Hearing date?

- Jenckes Hill Solar

REDACTED

- Weaver Hill / Robin Hollow Interconnect Status

REDACTED

[redacted]

[redacted]

REDACTED

[redacted]

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[redacted]

Agenda

Meeting Date / Time: Wednesday, February 28, 2024 / 2:00PM – 3:00PM
Location: RI Energy Providence Office – Board Room
Attendees: Kathy Castro, Erica Russell Salk, Sean Kane, Ryan Constable, Jed Ferris, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Project Related Priorities:

- Frontier Road/Main St

REDACTED

- Studley

REDACTED

- Shore Drive Reconciliation Status -

REDACTED

[redacted]

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filing Status: Filed on October 17, 2023.
  - Cost recovery pending RI PUC decision.
  - New Hearing date?

- Weaver Hill / Robin Hollow Status

REDACTED

- Ross Simons Drive (aka Sharpe Drive)

REDACTED

Strategic Discussion:

REDACTED

[redacted]

[redacted]

Agenda

Meeting Date / Time: Wednesday, March 27, 2024 / 2:00PM – 3:00PM
Location: RI Energy Providence Office – Board Room
Attendees Invited: Eric Weisner, Erica Russell Salk, Sean Kane, Ryan Constable, Jed Ferris, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Project Related Priorities:

- Frontier Road/Main St

REDACTED

- Studley

REDACTED

- 7 Mile Reconciliation/FAR ?

REDACTED

[redacted]

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[redacted]

- Shore Drive Reconciliation Status

REDACTED

- Petition by RI Energy for Weaver Hill Substation Cost Sharing
  - Filing Status: Filed on October 17, 2023. Cost recovery pending RI PUC decision.
  - New Hearing date? **Discussion?**

- Weaver Hill / Robin Hollow Status

REDACTED

- Ross Simons Drive (aka Sharpe Drive)

REDACTED

Strategic Discussion:

REDACTED

[redacted]

Agenda

Meeting Date / Time: Wednesday, April 24, 2024 / 2:00PM – 3:00PM
Location: RI Energy Providence Office – Board Room
Attendees Invited: Eric Weisner, Erica Russell Salk, Sean Kane, Ryan Constable, Jed Ferris, Dan Glenning, Ralph Palumbo, Ryan Palumbo, John Kennedy

Strategic Discussion:

- **National Grid/ Rhode Island Energy Transition**

REDACTED

- **ASO Study**

REDACTED

[redacted]

[redacted]

Project Related Priorities:

- **Frontier Road/Main St**

REDACTED

- **Studley**

REDACTED

- **Petition by RI Energy for Weaver Hill Substation Cost Sharing**
  - Cost recovery pending RI PUC decision.
  - **Discussion?**

- **Weaver Hill / Robin Hollow**
  - Reconciliation Status - Following. FAR due May 15, 2024. Payment due June 29, 2024
    - Discussion: **Final Accounting Report to separate Weaver Hill Substation Cost Sharing component from remainder of Project components. The petition process would only delay the cost sharing component of FAR. - ~~Confirmed by Erica.~~**
    - Revity noted: **the final accounting report will follow normal process. Only payment delay, if any, would be associated with the cost sharing component (Weaver Hill Substation) reconciliation payment. Erica responded 4/5: I disagree – there would be no payment delay. I mentioned that this project will be reconciled following the normal process comparing the costs collected with the actuals for the study costs and system mods. If the PUC rules that there is acceleration of work, then Revity would be reimbursed by the Company. That is independent of the project reconciliation.**
    -
  - Entrust Solutions

[redacted]

REDACTED

[redacted]

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<u>EXHIBIT O</u>

In the Matter Of:

RI PUBLIC UTILITIES COMMISSION

23-37-EL

HEARING

July 09, 2024

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When Revity received the initial budgeting for their scope of work relative to this project, we were looking at a number of 30 plus million dollars. You know, fast forward to today, in collaboration with Green Developments, I think we performed it all in for approximately $17,000,000.

So the decision to accelerate these improvements and incorporate them into the self-performance work of Revity and Green Development, to me, was extremely justified on the economic side and it saved ratepayers close to $13, $14,000,000.

That was briefly touched upon, but I wanted to just emphasize that point.

Q. So just so I'm clear here, the savings from the 30 plus million dollars to the $17,000,000, it's your testimony that that savings was a result of self-performance by developers?

A. Assumably, yes. The work that we did, all the costs came in apples to apples scope of 17 plus or minus million dollars.

Q. Okay. And I should just back up. This is briefly discussed in your testimony, but I think it's helpful.

study.

And at that point, you're required to do two things: You sign an impact study agreement and you pay an impact study payment, which is approximately $10,000 per application, depending on the system size.

And then, assuming you get to that point, and you beat the ASO study, the impact study then gets to the company and it just sits there. Your project goes on hold. And you know, the company does that because the results of an ASO study could alter the results of an impact study on the distribution side. So it makes sense, it's logical why they do that.

But the point is, a project could have applied for an impact study let's say last year. ASO 3 has already started. Right? And they have to wait a whole year at that impact study stage just for the ASO study to start, and then they could be looking at, if history repeats itself, another three years before that impact study is even looked at. So then, as an ASO study is starting to come to a close and the utility has a better idea of what those upgrades may or may not look like, then at that point they start the impact study.

Point being, there could be a three- to four-year timeline from when an impact study starts and when an impact study, you know, is actually delivered to the customer.

And I think it's important to note that a project could go through several impact studies. It's not always one impact study. It's very common in Rhode Island for projects to be restudied for a variety of reasons, some outside of our control. And you know, ASO is a good example of that.

When -- In a rapidly evolving industry, technology is confidently becoming obsolete. So when you submit an application one year, and you wait three or four years, by that time, when you go to source that same equipment, it's probably not available. And we're running into that left and right.

More applicable to this case, Robin Hollow, the Robin Hollow project had its most recent re-study or impact study start in 2023, completed in 2023 as well, and that was due to the current ASO study that was going on here. Robin was an ASO 2 project. Right now, we're in ASO 3.

For some reason, during the ASO 3 process, during all the updates and model assessments, something triggered models in ASO 2 and ASO 1 to not function properly. So the utility would reach out to the developer and ask them correct those models so they can incorporate into their study and progress forward, which we did for Robin in 2023 prior, thankfully, to starting construction last year.

And when we took those models back, it's a, kind of a hand-holding effort from the inverter manufacturer. We have to hold their hands, because they have all the key information that goes into these models that can really swing the things left to right.

So when we went back to the manufacturer, in this example, they said they're actually discontinuing this specific inverter, they can't support any model updates, and the only way for us to get a working model now to the utility is to switch our equipment entirely. So the any time you switch equipment like that, it usually requires a re-study of the impact study by the utility. So we went through that

last one was three or four years ago.
Q. Just staying with my timeline question here. After the ASO study is finished, and after the impact study is finished, what's the next step?
A. Assuming that the customer has no comment to the impact study, then they deliver a draft ISA.
Q. Interconnection Service Agreement.
A. Correct. And assuming we have no comments for that, they'll deliver an executable version that we'll sign, and then we'll start making payments, get to construction, so on and so forth.
Q. So it's only until you have an executed interconnection service agreement, which comes after the impact study, which comes after the ASO study, that construction can actually start.
A. That is correct. Yes. The utility, whether they're -- whether it's self-performed or they have performed, no construction is going to begin until those initial payments were made in the ISA.
Q. There was -- I don't know if there was testimony or discussion or both back in June about a decision tree methodology that could be adopted to perhaps streamline what has become something

bit more.

What were the two different methodologies?

A. I apologize. I just wanted to make one more thing kind of clear in that prior topic.

Q. Sure.

A. Can we go back to that for one second?

Q. Of course.

A. This process, as I was stating with the original petition, was kind of the understanding that what we were going into during this process.

The utility did a good job of letting us know that this cost-sharing is on the table, subject to the Commissioner approval. So that was, that was communicated to us in this process.

From our perspective, it wasn't a matter of whether it was going to be something or nothing. The way that we understood it was that this is going to go through an audit process, a third party was going to come in to verify all the costs to make sure that they're true and accurate, that they're allocated to the right bucket, and then ultimately then the

Commission will decide what the right number was, was what our interpretation into this. Right or wrong.

We worked with that third party. Again, their scope was to, you know, make sure that these costs were justified, but they were also responsible for, you know, making sure that the costs were put in the right bucket. So every month, during construction, we would submit very detailed accounting invoices for all of our costs for that period, and then, in addition to that, we would break out the portion that was applicable to cost-sharing, as we understood it, which was as its written in the original petition right here.

And they would provide feedback if something was out of whack, but we received no comments. We received, you know, overall utility feedback that, you know, no news is good news, and we went on that path month after month thinking that that was the approach here.

So just reiterating the thought going into this, the cost-sharing being on a hundred percent of the civil work under the common path as opposed to an 80/20 split or person in line would pay the first 4 feet two-thirds and the following customer or ratepayer would pay the one-third.

The preferred method on Revity's side is the duct count method. It's straightforward, black and white, and it seems to be the most fair method that can be utilized of the two.

We've hit on this topic a couple different times in the path I think briefly in those administrative interconnection dockets, 5205, 5206, we were talking about the right way to cost-share, and the duct count method was the only method discussed at that time.

But the incremental duct bank percentage seems like -- is always going to have a loser. And the reason I say that is, because the deeper you go into a trench, the more risk and cost that you're going to run into on a per foot basis.

So you can find that the second person in line is going to be responsible paying for that one-third, that additional 2 feet, but that additional 2 feet could be 50, 60 percent briefly hit on in 5205 and 5206, because at the time, Revity had concerns, we were sharing upgrades with a large load customer in the area that needed them, and the, you know, I think the reconciliation process as a whole, you know, wasn't clear enough where we could say, okay, you know, that reimbursement makes sense or Revity owing this made sense. So it required a lot of questions, conversations, which ultimately I think led to us doing 5205, 5206. But the reconciliation process I think as a whole for customers is a bit of a black box.

Q. I think Mr. Constable was quite forthcoming in answering my questions about how this process plays out when the company has told the DG developer that work needs to be done or expenses need to be incurred for interconnection and the scope of work.

Is it your experience, as I think Mr. Constable testified, that really the company directs that issue and dictates to the DG customer what the scope of work will be and how much work needs to be done to interconnect the project?

A. That's correct. Whether we self-perform or the DG customers. I think everybody would agree with that.

In the process of an impact study or the interconnection service agreement, will the company come to the DG developer and say, hey, we're also doing this non-DG upgrade in the area? Will they identify that for you?

A. We've never seen anything like that identified, I should say far in advance. Obviously, at some point the company came to us and said, hey, Revity, there's going to be accelerated system modifications and system improvements for this project. But you know, this Weaver Hill substation was identified back in -- I don't know -- was a concept in 2020. And you know, we hear of it in 2023. So without a developer doing their due diligence and truly tracking the ISR process, which is a complicated process in itself, there's no bulletin that goes out to developers to say, hey, here are the five areas that we're planning upgrades over the next two years or anything like that.

Q. In this case, how did Revity come to learn about the Weaver Hill substation?

A. Through the ISR process. We had a

co-developer that we were working with relative to this process that identified it several years ago, and the conversations started to happen. So that was how it was brought to our attention, and then we obviously dove into the ISR filing and saw the same thing.

Q. You're aware that the interconnection tariffs, and you've participated I think in this, -- correct me if I'm wrong -- allow for developer to raise a dispute to the Commission if it has an issue with the cost being charged to developer?

A. I am aware of that.

Q. Do you have any knowledge of whether, while going through a dispute -- Does the company require that you pay the disputed amount to continue with your interconnection even though you are disputing the amount?

A. Yes. In an example like that, you're either going to, you know, go along with what they're looking for. If it was a disputed amount, as an example, we're either going to pay that and move forward or we're not going to pay it and just going to fight about it, everything would sit on pause until...

overlooked is that it wasn't just a decision out of convenience, but this was a requirement by the local municipalities. When all this was going on, they actually put it into the conditions of approval for the projects in town that, okay, if you guys all want to connect here, you need to collaborate and you need to dig up our roads once, we're not going to reallocate town resources, police detail, reroute school buses for six months just to do it again six months later, six months later, six months later.

So at the time, Green Development was kind of the first one in line here, so they came in, and the town wasn't unfamiliar with the project, but it was probably their first subservice interconnection that they had to deal with. So green Development gets their project approved with that plan, and then fast forward just a few short months later, here comes Robin Hollow and here comes Studley in front of those same boards, and we're saying, hey, we also need to dig up the road for our interconnection and we're going on similar paths. Well, at that point the municipality that the -- Mr. Bianco was looking for what the cost-sharing would look like assuming that alternative methodology. Is that incorrect?

CHAIRMAN GERWATOWSKI: Well, okay. I guess the difficulties we're having is that the response didn't say that. That would help, too. But maybe we didn't articulate it well enough. But I just wanted to make sure that I certainly wasn't understanding it that we were asking you to go change your methodologies.

MR. HABIB: Not -- And my understanding here is not to change it because you found a flaw in the original methodology, but that you were looking at an alternative approach for cost-sharing.

CHAIRMAN GERWATOWSKI: Well, let me put it this way: This is not our methodology. This is your methodology, and the company has a responsibility to choose a methodology that makes sense and then defend it. If we're asking questions about it is because we're inquiring as to the reasonableness of what you did. But we're not asking you to do a methodology. You have to propose it, and you have to put it in front of us, and then you have to defend the reasonableness of it. And I don't like it if the company is trying to shift it and say it's our responsible to do it. And I think that's probably what I'm reacting to. Well, it was the Commission that asked us to do it, it wasn't us, it was the Commission. And it's not. Because I think I've seen a little bit of trend in this docket that seems to be doing that. I want to make sure that that's not going to -- it isn't, you know, what's happening here with what's been proposed. So that's the part that I'm reacting to.

MR. HABIB: That's not the case, Mr. Chairman.

CHAIRMAN GERWATOWSKI: Okay. All right.

MR. HABIB: I'm similarly trying to ask Revity whether they are thinking that this alternative methodology for which are challenging was something that they think Rhode Island Energy was offering up as the methodology for cost allocation in this case. It is not. We offer up the methodology that we put in the testimony. That's the point I was trying to make.

that has the applicable upgrades or
modifications that are discussed here.
Q. And you're not using the 8/19/20 date or the
1/06/20 date; is that correct?
A. That's correct.
Q. And why aren't you using those particular dates?
A. Because these impact studies -- Like I said,
a project will go through several impact studies
before you finally get to an ISA.
Q. So you're picking and choosing which impact
study you want --
A. I'm interpreting that the impact study that
is applicable in the ISA with the accurate
modification should be the impact study that's
in question.
Q. And the tariff states that it's when the company
begins the impact study of the proposed DG
project; correct?
A. Correct.
Q. You mentioned in your, I believe it's your
direct testimony, on Page 12, you talk about the
company's alternative approach and you do not
recommend that the Commission adopt that
approach. Do you recollect that testimony?
A. I can try to pull it up now. But generally,

Q. When was the last impact study issued?
A. June 2024.
Q. If Revity -- Revity now owns the Studley project, the Revity affiliate?
A. Correct.
Q. If Revity wanted to do the interconnection work based on the original 2019 impact study, for whatever reason, do you have any idea whether the company would allow us to do that?
A. They would not allow us to do that.
Q. Okay. What are the major differences between the original Studley impact study and the 2024 revised impact study?
A. From a project specification, it's completely different, different equipment, the project size is different. So apples and oranges between the two.
Q. And there have been a number of iterations of the Studley Solar impact study.
A. I believe so. At least, at least two. I believe maybe even three. Like I said, couple different factors that held that out.
MR. NYBO: Okay. That's all I have, Mr. Chair. Thank you.
CHAIRMAN GERWATOWSKI: So we're

going to have questions. We'll take a break right now for 10 minutes. It's 11:10, so we'll restart at 11:20.

By the way, before you go off the record, we're planning on taking lunch around somewhere between noon and 12:30, at a good stopping point.

(Recess taken at 11:13 a.m. Proceedings resumed at 11:27 a.m.)

CHAIRMAN GERWATOWSKI: So back on the record.

Mr. Palumbo, I have a few questions I wanted to follow up on with you. I'm going to ask the company the same question about project status, but I'd like to ask, get your understanding of the status of the projects that are now owned by Revity that pertain to the Weaver Hill proceeding.

So what's your understanding of what the status is of the projects?

A. For the Revity project, -- excuse me -- for the Revity project specifically?

Q. Yes.

A. So Robin Hollow owned by Revity is fully operational today. So that construction has been complete, both on site and off site, off site being the utility work, and that has been the case since December of 2023.

CHAIRMAN GERWATOWSKI: Okay.

A. The Studley solar project has just received its impact study back about a month ago. We are finalizing the ISA right now. So that's where that process stands. Incorporating those upgrades from the impact study. And we'll hopefully start -- will start construction this year.

CHAIRMAN GERWATOWSKI: Now Studley already has an ISA, doesn't it?

A. I don't know off the top of my head. I'd have to go back and check.

CHAIRMAN GERWATOWSKI: I had a reference, a response to Record Request 8 from the company, that indicated Studley Solar had date of September 11th, 2023.

A. That may be the case.

CHAIRMAN GERWATOWSKI: Are you -- an amendment --

A. That's correct. Proposed an amendment, and the amendment will reflect all the changes that the company and its ratepayers. And so I'm what I'm interested to know is, when Revity first had conversations with Rhode Island Energy or its predecessor when the National Grid owned it, about the sharing with the ratepayers, not the sharing among the developers. Do you understand my question?

A. Yes, I do. The reimbursement sharing.

CHAIRMAN GERWATOWSKI: Yes.

A. The exact dates, I don't recall off the top of my head. But this -- It became a real conversation with Rhode Island Energy sometime early 2023, was when we were talking about it. Now, Revity, EDP, and maybe Green Development, -- I won't speak for them -- did identify this Weaver Hill substation in prior ISR plans, and questions were asked prior but they weren't -- I don't think there was any substantive information that the utility had to offer at the time. I don't know if it was in a concept phase or what. And I don't have the exact dates of those conversations, but they predated the 2023 conversation.

CHAIRMAN GERWATOWSKI: So that was going to be my next question, there was a rents in your testimony about someone looking at the ISR discovery, there was a Weaver Hill project, and then discussions followed. I'm not trying to put words in your mouth, but I'm trying to understand. Are you saying that none of you realize there was a possibility of doing sharing for accelerated system modifications until someone saw it in the ISR or did conversations occur before that?

A. No. You're correct. So it was Frank Epps, the owner of EDP, brought it to our attention a couple of years ago. And at the time, it obviously -- it caused us to ask the question, because it mentioned the specific lines that we're talking about for the Robin Hollow project. It was, then it was 3309 and it was 3310. Since then, it has changed to 3310 and 3311. But that was how it was identified to us through Frank, and then that caused us to go in and go do our even due diligence, start looking at the ISR plans. And to be honest, it was the first time we dove in to an ISR plan in detail. So it led us down this path.

CHAIRMAN GERWATOWSKI: So I'll

ahead.

EXAMINATION BY MR. NYBO:

Q. When did Revity's interconnection work begin? Month.

A. For the Robin Hollow, I'm going to say spring of 2023.

Q. Did Revity learn about the Weaver Hill project through this ISR discussion that we've been hearing about prior to Revity beginning that work?

A. We knew of that work prior to starting our construction. We knew that they were going to be common upgrades. What we did not know is -- We didn't have a cost-sharing conversation with the utility until after we started construction.

MR. NYBO: Okay.

CHAIRMAN GERWATOWSKI: Anybody else have any questions for Mr. Palumbo?

MR. HANDY: I might just ask quickly.

EXAMINATION BY MR. HANDY:

Q. I mean, this kind of gets to the transparency issue you talked a little about. I just wonder, do you have other examples of projects where you've had difficulty discerning, you know, what costs were properly attributable to your projects and what costs were better attributed to other customer benefit? I mean, are there any other specific examples of that --

A. I think, to be frank, it's every project.

CHAIRMAN GERWATOWSKI: Can you talk towards the microphone?

A. Yes. I apologize.

To be frank, it's every project. When we get a reconciliation report back, there's not enough detail or information there for us to truly, you know, discern on whether or not these costs are justified or not, just whether there was a ratepayer benefit or if it was purely DG. So with every project, we kind of have a struggle. That's how we spinned off into 5205, 5206.

Q. This may help to have specific -- Do you have any specific illustrations?

A. One specific example that we experienced last year, we interconnected a project in Johnston on Shore Drive. And around that same time, a very large load customer was being commissioned on a similar path and they had similar upgrades. We didn't share a feeder, but we shared common infrastructure, such as poles and other

spreadsheet we were talking about today.
A. Got it.
Q. And is that the company -- Is what is reflected in that spreadsheet, is that the company's position of how the costs should be allocated amongst ratepayers and developers?
A. Yes.
Q. And you heard Revity's position today explaining an alternative method to sharing costs among ratepayers and developers; correct?
A. Yes.
Q. And could you just explain why you think that your position in this Record Request 3 is more appropriate than Revity's position?
A. So we think that the method presented in Record Request 3 is more a fair method, thinking about the, how the uses of the equipment and then how the construction actually occurs.
Q. Thank you. Would you say both methods are reasonable?
A. Yeah, both methods are reasonable.
Q. Thank you. And I'm going to go back to Mr. Booth's testimony. Do you recall Mr. Booth's suggestion that 2035 is the appropriate need date for when the Weaver Hill

that's sort of the primary, primary method, that a project goes from need identification, alternative development, and then ultimately into the ISR.

And so once the area studies are completed, we'll have the discussion with the Division, and then, and then it'll move, depending on the needs identified in the study, into the ISR, into the ISR proposal. Many times it's because of near term needs are identified, it goes in near right away, and then there's other times where it'll be, you know, again, based on the area study identification, it'll go into the ISR at basically the appropriate time.

Q. And so putting prioritization aside. In this case, what is the need date for Tiverton and Weaver Hill?

A. So the technical need dates are, right now, the contingency issue, reliability issues exist right now, there's voltage issues that exist right now. From a practical need date, it's per the area studies. Right; so... The practical need date is 2028 and 2029 for Weaver Hill and Tiverton.

Q. And going back to the Division's testimony.

soon, and then I'm not sure when that's expected to be finished. But that's part of the Revity/Studley solar work.
Q. Now, you heard the testimony that Robin Hollow solar, it's connected to the national -- Rhode Island Energy electric system; correct?
A. Yes.
Q. And it's operating; correct?
A. Yes.
Q. But the solution from the customer's perspective and from the company's perspective to solve the systemic problems that you mentioned, that hasn't been done; correct?
A. Right. That's the, that's the sort of the point behind the accelerated modification, yes.
Q. And the systemic solution that the company, Rhode Island Energy, planned for in its work plan, in its ISR, that won't -- those solutions won't be completed until, as you testified, 2028; correct?
A. Yes. Those are the study and service dates. I also testified that we are looking at opportunities to accelerate. But from a standpoint of need, and then, you know, a practical need date considering construction,

that was -- those were the dates that I provided before, the 2028, 2029, and then we are looking at opportunities to accelerate the construction itself.

Q. And when you look at Section 5.4 of the tariff, and it talks about the company's work plan, that -- those date that you mentioned, 2028 for completion of the systemic solution, that's consistent with what the company identified in its ISR plans in 2023 and 2022; correct?

A. Yes.

Q. And the impact statement for the -- that were identified in the petition that were first started in 2019 and 2020, those impact statements, if we use that -- those as a starting point, and we take five years forward from those dates, the systemic solutions that the company has indicated are not yet done, those are outside that five-year window; correct?

A. Yes. They're greater than that five-year period. And you know, there's, there's -- again, like if you think about -- we've talked about how that five-year period is difficult to apply in a black-and-white fashion in these petitions. But yes.

MR. WOLD: Thank you.

That's all I have.

CHAIRMAN GERWATOWSKI: Mr. Handy, do you have any?

MR. HANDY: Yeah. I have a few questions.

EXAMINATION BY MR. HANDY:

Q. I'm just going to limit it to the information that was produced in response to the record request, since I've already asked you questions about your other testimony, and it really specifically has to do with the revised reimbursable cost numbers and the different methodologies that have been discussed here today. Just a few questions.

It looks like you revised Table PUC 2-4, and you capped the accelerated modification costs based on a hypothetical estimate cost, if you had gone overhead with the cabling. Is that -- I'm talking about Tiverton.

A. Yes.

Q. Is that what you did?

A. Yes.

Q. So you're basically, in Schedule 5A, you're there might have been additional costs, but then there's going to be -- you know, the company's also thinking about establishing a method that can carry on even beyond these petitions. And so, again, if you think about it from an overall perspective, we think it's the fairest way.

Q. And I appreciate that. I mean -- And I think that Revity was testifying to the fact that we're trying to find a methodology that applies easily across the board and won't raise disputes, et cetera. And their position, as I understood it, was that the, you know, the utility, the duct bank count allocation method was just clearer and easier to assess. Do you have an opinion? I mean, it seems to me that it's clearer when you don't have to get into issues like what the added depth cost, et cetera.

A. It's -- Just counting the duct bank method is an absolutely and easier method. Right? Simply counting the ducts and dividing. However, when we were reviewing the individual sections and the individual work, and we started thinking about how the -- you know, who is actually using what and how the construction proceeds, again,

Q. Okay. And I think you agreed that there's certainly instances where the second level work may be more expensive than the first level work because of ledge and water table issues; right?
A. Yes.
Q. So the second level person will always, on the incremental method, have a smaller share of the cost-sharing; right?
A. Yes.
Q. But in many -- In some instances, they will be responsible for a great -- their work will be -- cost more than the initial person; right?
A. Some instances, yes.
Q. Okay. And you made reference to, you know, police detail, sort of what I might call overhead costs that are required by opening the road up at all; right?
A. Yes.
Q. Those costs are necessary regardless of the first or second person; right?
A. Yes.
Q. Okay. How do we determine -- Well, let me back up. In a lot of instances the first person in, under the incremental method, is going to get sort of a raw deal there, because they are

putting in two ducts requires curb to curb paving in many places these days. Right; so... Again, like the paving doesn't change, even if you're going deeper and stuff like that.

And so, again, that incremental construction method is intended to be fair, because that first person would have paid the majority of the costs anyway.

Now, yes, there is some nuances where, in certain cases, you can run into ledge, you can run into watering, and so forth. So you know, we have to admit that.

Q. How do we decide who the first person is? How do you decide who the first person is?

A. It's basically the person going first. Right; so... In this particular case, these DG developers clearly went first. Right; so... Their projects were identified, their scopes were identified, even prior to the study starting. Right; so... And then during the study, right --

Q. I'm sorry to interrupt. What study? When you say "prior to the study." We have a lot of studies going on. I just want to be clear.

A. I'm sorry. Prior to the area studies

A. No. There was a hypothetical that we talked about in one of the previous sessions where, if the company went first and installed extra ducts, and a developer came, would the company be obligated to let the developer use those additional ducts. The answer's yes.
Q. And based on the incremental method, if that were employed, the developer wouldn't have to pay anything for the benefit.
A. Correct.
Q. Okay. Well, based on the hypo you gave, I may be putting my job at risk by saying this, but isn't that a bit unfair, that this developer in that case gets interconnection for free? Isn't that an inequitable result from the incremental method?
A. It's simply the way the statutes and the tariffs and in.
Q. Well, the statute and the tariff doesn't talk about incremental method verse the duct count method; right?
A. But the way that the statute and the tariffs are written for DG interconnection is, we have to give, we have to give existing capacity to the developers. Right; so... If there is

existing capacity in the system, we can't charge the developers for it because it already existed for the system. Right? And you can't charge a developer for something that's used for the system. Right; so... we already installed it for the system, and then, therefore, you can't charge the developer for it. Right? But they get to use it. Right; so... And in that hypothetical, the developer gets a really good deal.

Q. So that's not a function of the employment of the incremental method. That's a function of the operation of state law.

A. Yes.

Q. Okay. When there is developer to developer cost-sharing, do we use the duct bank method or the incremental method?

A. We use -- We're going to go through that actual conduit decision tree. Right? And you can actually get to both. Right? Now, in most cases -- I got to think about this. We probably have to go through a couple examples. But fairly certain you would get to a conduit, the conduit split method, developer to developer. We'd have to go through some cases and apply --

Q. Did you say the conduit split method?
A. Yeah.
Q. All right. So that's a third method?
A. No. That's the -- I'm sorry. The duct count method.
Q. Oh, okay.
A. The duct count method.
Q. Because I thought there was a method that's been employed in the past that is based on the megawatt size of the respective projects.
A. That's for electrical components.
Q. Okay.
A. So for electrical components where you're sharing a cable or a wire, you divide by megawatts. Right? But for physical components like -- And so the idea is, if you have a 10 megawatt site and a 5 megawatt site, they still need the conduit. Right? There isn't one uses only part of the conduit and the only uses so much -- you know, so there is no megawatt share for physical components.
So for physical components, you kind of just base it on usage and then you do assignments or these split allocation methods. But for electrical components, we use a megawatt

agree with Mr. Palumbo's recollection that the first discussions between the company and Revity about the cost-sharing potential started in the spring of 2023?
A. Yes. When we were debating it internally and then ultimately starting to introduce it into the ISR, we were not involving the developers.
Q. Okay.
A. We did not intentionally include the developers.
Q. Thank you. Okay. You've jumped a few questions of mine, but I appreciate you shortcut to where I wanted to go.
Why did you not include the developers?
A. I think it was just because it was new and we were figuring it out. Right; so... It wasn't an intention, like an intentional oversight and, you know, we -- you know, we were just introducing it because we knew that, you know, we'd have to have talks with the Division and the Commission to sort of figure out the process and figure out how all this works. So it was just, you know, what we thought was the first step.

Q. So what happened to lead the company to decide it's time to talk to developers about this? There must have been something that occurred that you guys said, all right, now it's time to talk to the developers.
A. So in certain cases, the developers actually came to us. Right; so... Frank Epps actually came to us. Matt Ursillo actually came to us when he saw Tiverton in one of the of the ISRs. And so that started conversations. And then we had the -- and some of those conversations I think -- you know, I'm not certain about this, but some form of conversations led to those dockets in 2022, regarding DG cost allocation, and I can't remember the docket numbers, but there was two dockets we discussed in 2022.
Q. Okay. So really the cause of you guys starting discussions with developers -- and forgive me for this turn of phrase. I mean nothing by it. But the cat was out of the bag? Some of the developers -- And really, I'm not trying to ascribe it any like -- I'm just saying, it was sort of brought to you as opposed to you guys making a decision, okay, it's time to bring the developers into the -- the developers came to

you guys.
A. Yeah. And it may appear that it was like a cat -- but that was the not the intention at all.
Q. I didn't mean it that way.
A. Like the first step was, we should probably go talk to the Division and the Commission. Right; so... That was it.
Q. Understood. I was just curious if there -- if something had occurred -- I assume something did occur that led you guys to start these discussions with developers, and I think I'm hearing that, what occurred was, certain of the developers sort of figured out for themselves or at least were getting curious about it so we're asking you about it.
A. Right. So in this particular case, because it was all new -- Right? I'm not saying that's the way it's going to happen in the future. But in this particular case, because of the newness and so forth, that's the way it happened.
MR. NYBO: Okay. Could I have one moment, Mr. Chair.
(PAUSE)
MR. NYBO: Thank you very much.

A. Yeah. We couldn't, because the area study wasn't started and wasn't, you know, wasn't completed.

CHAIRMAN GERWATOWSKI: But didn't you know at that point whether or not you even had a project that you -- you had no idea that you had a project that was going to be occurring at that time?

A. Yeah. And this is why it's complicated. Right; so... The impact study process took a number of years. Right? And it's not a moment in time. And so for a significant portion of the impact study process, the area study wasn't started and the solution wasn't determined. Right; so... That's a majority of the impact study process, including some of the revisions. Then there's a point in time where the study's done, the company now knows that there's a project, and now it's -- there's sort of a question of what do we do next. Right? We have these impact studies that were developed without this, we have this, we have this sort of tariff process and statute process, which we still need to, you know, in some respects figure out, and so the decision was made to sort of pursue

A. So the accelerated modifications are -- So at that time, the DG developers installed and paid for what is becoming the accelerated modifications.

CHAIRMAN GERWATOWSKI: So nowhere in the ISR are there any budget references to any of the accelerated modifications.

A. We had them in the fiscal year 2025 budget that would have been in attachment 3, but in conferences with the Division, we removed them.

CHAIRMAN GERWATOWSKI: What about in 2024?

A. They were not there.

CHAIRMAN GERWATOWSKI: And what about 2023?

A. Not there.

CHAIRMAN GERWATOWSKI: That's what I meant. You never had the accelerated modification cost in any of the filings with the Commission.

A. Because, yeah, because we had to figure this out. Right? We --

CHAIRMAN GERWATOWSKI: I'm just looking for a yes or no answer. But -- Okay.

Modifications?
A. Yes.
Q. And then it --
CHAIRMAN GERWATOWSKI: What Bates page is that?
MR. NYBO: Yup. Now I'm on 351, Chairman.
Q. So this attachment title is Description of System Modifications.
A. Yes.
Q. And then it proceeds for a number of pages to articulate various scopes of work under that rubric of system modification; correct?
A. Right.
Q. So is none of this work -- Was none of this work required for the Weaver Hill substation?
A. No. There is work in this scope that was required for Weaver Hill substation. It wasn't identified as an accelerated modification here.
Q. Okay. So there is work listed in this ISA that falls under accelerated modification on our spreadsheet that we now have that is articulated in this description here.
A. Yes.
Q. Okay. It's just not specifically called out as

an accelerated modification.
A. Yes.
Q. Okay. And is that distinction true of work described in the impact study as well?
A. Yes.
Q. Okay. So your testimony was simply that those documents do not use the phrase "accelerated modification."
A. Yes.
Q. But they do list things that ultimately the company is asking be found to be accelerated modification.
A. Yes.
MR. NYBO: Okay. Thank you.
That's all I have, Mr. Chair.
CHAIRMAN GERWATOWSKI: Anything else from anyone?
Good.
The witnesses, you'll be excused, but you can just sit there, because I don't think you're going to be here much longer, unless there's closing statements.
I know that there was some desire expressed by counsel for briefs, and that's -- And I never want to say no if the

C E R T I F I C A T E

I, LISA L. CROMPTON, Registered Professional Reporter, hereby certify that the foregoing is a true and accurate transcription of my stenographic notes of the proceedings in this matter on the date and time specified in the caption hereof.

IN WITNESS WHEREOF I have hereunto set my hand this 12th day of July, 2024.

Lisa L. Crompton

LISA L. CROMPTON
REGISTERED PROFESSIONAL REPORTER
MY COMMISSION EXPIRES 1/22/2028

<u>EXHIBIT P</u>

Division 6-3

Request:

Please provide the Company's best estimate of the date(s) when (a) the Robin Hollow Projects (Revity) and (b) the Studley Solar Project (EPD) will be "completed and placed in service" and provide a detailed description of the physical status of each project as of the date of your response.

Response:

The Robin Hollow Projects were authorized to interconnect on December 23, 2023 and are completed and in-service. The Studley Solar Projects are expected to interconnect and go in-service in December 2024.

The area study Weaver Hill Projects are expected to be completed and in-service as follows:

- Subtransmission
    - Substantial completion is estimated for middle to late calendar year 2027 with final completion by March 2029. The subtransmission work should go into service when the substation goes into service between mid to late calendar year 2027 and early calendar year 2029.
- Substation
    - Substantial completion is estimated for middle to late calendar year 2027 with final completion by March 2029. The substation work should go into service when energized and serving customers.
- Distribution Line
    - Projects of this type go into service shortly after specific equipment is installed, energized, and used by customers. While the total project completion date is currently March 2029, portions of the project will be in service prior to that date.

As of the date of this response, the work orders are in design with site delineation and cultural reviews in progress.

EXHIBIT Q

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Rhode Island Energy™
a PPL company

April 26, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-38-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project - Weaver Hill Project

Updated Ownership and Control of Studley Solar Project from EDP to Revity

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), this letter memorializes an update in ownership and control of the Studley Solar Project from Energy Development Partners ("EDP") to Revity Energy LLC ("Revity"). At the evidentiary hearing for the above-referenced docket, the Company's witnesses plan to testify to the updates described below and adopt any updated exhibits.

Background

On October 17, 2023, the Company filed a petition with the Public Utilities Commission ("PUC") for Acceleration of a System Modification Due to a Distributed Generation Project in connection with the Weaver Hill Projects ("Petition"). The Company also submitted joint pre-filed testimony of Erica J. Russell Salk and Stephanie A. Briggs in support of the Petition ("Joint Pre-Filed Testimony"). At the time of submittal, the Weaver Hill Projects consisted of three interconnection customers: Green Development, LLC ("Green"), EDP, and Revity. Since that time, Revity presented documentation to the Company reflecting its ownership and control of Studley Solar, LLC, which was previously EDP's portion of the Weaver Hill Projects.[1] This letter memorialized that Studley Solar, LLC is now wholly owned and controlled by Revity or its affiliate.

Updated References in the Petition and Joint Pre-Filed Testimony

Now that Revity possesses control and ownership over the Studley Solar Project, references to EDP in the Petition and the Joint Pre-Filed Testimony should refer to Revity,

[1] A legal form reflecting the update was uploaded to the Company's system on January 5, 2024.

except for references to the Company's engagement with EDP prior to Revity taking control and ownership of the Studley Solar Project.

<u>Updated Exhibit EJRS-6 (an exhibit to the Pre-Filed Joint Testimony)</u>

As an exhibit to the Joint Pre-Filed Testimony (<u>Exhibit ERJS-6</u>), the Company included an interconnection services agreement for the Studley Solar Project ("Studley Solar ISA") which was executed while still under EDP control. The executing interconnecting party to the Studley Solar ISA was Studley Solar, LLC and, while ownership and control over the LLC has been updated, there has been no change to that LLC as the executing party (other than its updated address). Accordingly, an updated ISA is not required to be executed by Revity. However, the Company and Revity are negotiating a revised Studley Solar ISA to reflect current project updates. Those revisions are not expected to materially impact the requested approvals contained within the Petition. When a revised ISA is executed, the Company will file as "<u>Exhibit ERJS-6B</u>." The Company anticipates that the updated Studley Solar ISA will be executed in advance of the evidentiary hearing.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket No. 23-38-EL Service List

EXHIBIT R

PUC 2-4[1]

Request:

PUC 1-4 includes a map with a various dotted lines which represent construction shared by developers and RIE. PUC 1-1 provides the scope of "system modification subject to Petition" by developer. (Each subpart should include a table - see example below 2-3.c).

a. Box 3309 states, in part, ductbank part of shared cost with RIE. First, please confirm this is the only portion of costs subject to the petition with the remainder of items in that box. Second, please explain how the Company allocated the cost of the shared ductbank between itself and the developer, including an itemization of the cost for that portion resulting solely from the System Modifications required to allow for safe, reliable, parallel operation of the Facility with the Company EDS, an itemization of the cost of that portion the Company is claiming to be an accelerated Modification, and the cost the Company believes is an economically justified upgrade that may be used along with System Modifications to serve an Interconnecting Customer. Please label as System Modification and System Improvement, as applicable. Please relate the costs for the work in Box 3309 back to the relevant table in the response to PUC 1-1 and Rebuttal Testimony at 7. (Provide totals where appropriate and use the most recent numbers available, noting any changes from previously filed numbers).

b. Box 3310 states, in part, "From Riser to Node A. UG Cable and Ductbank both shared by DG developers and RIE." First, please explain how the Company allocated the cost of the shared ductbank between itself and the developers, including an itemization of the cost for that portion resulting solely from the System Modifications required to allow for safe, reliable, parallel operation of the Facility with the Company EDS, an itemization of the cost of that portion the Company is claiming to be an accelerated System Modification, and the cost the Company believes to be an economically justified upgrade that may be used along with System Modifications to serve an Interconnecting Customer. Please label as System Modification and System Improvement, as applicable. Please relate the costs for the work in Box 3310 back to the relevant table in the response to PUC 1-1 and Rebuttal Testimony at 7. (Provide totals where appropriate and use the most recent numbers available, noting any changes from previously filed numbers).

c. Box 3311 states, in part, Ductbank part of shared cost with RIE. First, please explain how the Company allocated the cost of the shared ductbank between itself and the developer, including an itemization of the cost for that portion resulting solely from the System

[1] The Company's response begins on page 2.

PUC 2-4, page 2

Modifications required to allow for safe, reliable, parallel operation of the Facility with the Company EDS, an itemization of the cost of that portion the Company is claiming to be an accelerated System Modification, and the cost the Company believes to be an economically justified upgrade that may be used along with System Modifications to serve an Interconnecting Customer. Please label as System Modification and System Improvement, as applicable. Please relate the costs for the work in Box 3311 back to the relevant table in the response to PUC 1-1 and Rebuttal Testimony at 7. (Provide totals where appropriate and use the most recent numbers available, noting any changes from previously filed numbers).

Scope (See, e.g., Dkt. No. 5209, RR-11, page 6)	System Modification (%)	Accelerated System Modification (%)	System Improvement (%)	Cost ($)

Response:

Attachment PUC 2-4 explains how estimated costs may be allocated across the various sections of the work. The costs are itemized as follows:

- System Modifications – Portion of the cost assigned to the developers to allow for safe, reliable, parallel operation of the Facility with the Company EDS

- Accelerated Modification - Portion of the cost the Company believes is an economically justified upgrade that is aligned with area study recommendations and system needs.

- System Improvement – Portion of the cost not included in the category above but reasonably required at the time of construction for system purposes such as additional spare ducts.

The costs are presented using the format shown in the response to Division 4-9, which also includes information related to PUC 1-1. Generally, the costs associated with the items originally contemplated in the Petition have reduced from about $13.57 million to $10.54 million. However, the Company has now included additional possible reimbursement associated with additional ducts which is estimated at approximately $4.02 million. This brings the total possible reimbursement to $14.56 million.

Prepared by or under the supervision of: Ryan Constable

PUC 2-4, page 3

a. The Company confirms that only the ductbank is a shared cost for the 3309 box in the map included in the response to PUC 1-4. An estimated allocation method is included in the attachment.

b. An estimated allocation method is included in the attachment.

c. An estimated allocation method is included in the attachment.

Capex Only For locations, refer to PUC 1-4-1 Map

Description	From	To	Area Study	EDP SIS	Revity SIS	GDP SIS	FY23 ISR	FY24 ISR	FY25 ISR	Costs in Petition (PUC 1-1)	Updated Costs 5/2024	% For DG	% For Accel Mod	% For Sys Improve	System Modification (Soley Serve DG)	Accelerated Modification (Aligned With Study Recommendtaion)	System Improvement (Additional Ducts)
Sub-T DG Customer Cost Share																	
Cable 35kV - New Install 3309	3309 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)	N.A.	N.A.	$716,048	N.A.	N.A.	N.A.	N.A.	$987,961	$ 1,281,331	100%			$1,281,331	$0	$0
Duct Bank Civil Work-Revity	3309 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)	N.A.	N.A.	Self Build - No Cost	N.A.	N.A.	N.A.	N.A.	N.A.	$ 3,188,415	80%		20%	$2,550,732	$0	$637,683
Duct Bank Civil Work-Green	3309 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)	N.A.	N.A.	Self Build - No Cost	N.A.	N.A.	N.A.	N.A.	N.A.	$ 177,654	100%			$177,654	$0	$0
Cable 35kV - New Install 3310	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)	$5,280,108	$4,479,108	$5,204,291	$2,325,114	0	0	0	$6,243,000	$ 2,629,370		100%		$0	$2,629,370	$0
Cable 35kV - New Install 3309	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)	$6,211,892	N.A.	$5,204,291	N.A.	N.A.	N.A.	N.A.	$5,598,447	$ 2,629,370	100%			$2,629,370	$0	$0
3310 OH Line Work	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)									$ 281,730		100%		$0	$281,730	$0
Duct Bank Civil Work	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)	$8,186,000	$15,361,827	$16,136,861	Self Build - No Cost	0	0	0	$5,951,270	$ 5,951,270	33%	33%	33%	$1,983,757	$1,983,757	$1,983,757
Cable 35kV - New Install 3310	Node A (Nooseneck/Weaver Hill)	Green Dev Site	N.A.	N.A.	N.A.	$1,502,298	N.A.	N.A.	N.A.	$1,356,000	$ 2,159,823	100%			$2,159,823	$0	$0
Duct Bank Civil Work	Node A (Nooseneck/Weaver Hill)	Green Dev Site	N.A.	N.A.	N.A.	Self Build - No Cost	N.A.	N.A.	N.A.	$6,072,000	$ 5,894,601	80%		20%	$4,715,681	$0	$1,178,920
Cable 35kV - New Install 3310	Node A (Nooseneck/Weaver Hill)	Revity - Robin Hollow Site	$80,019	$158,086	$183,681	N.A.	0	$77,023	$77,595	$80,019	$ 98,191		100%		$0	$98,191	$0
Cable 35kV - New Install 3309	Node A (Nooseneck/Weaver Hill)	Revity - Robin Hollow Site	N.A.	N.A.	$183,681	N.A.	N.A.	N.A.	N.A.	$197,592	$ 98,191	100%			$98,191	$0	$0
Cable 35kV - New Install 3311	Node A (Nooseneck/Weaver Hill)	Revity - Robin Hollow Site	$80,019	N.A.	N.A.	N.A.	0	$77,023	$77,595	$80,019	To be installed by RIE						
Duct Bank Civil Work	Node A (Nooseneck/Weaver Hill)	Revity - Robin Hollow Site	$204,065	$542,182	Self Build - No Cost	N.A.	0	$196,423	$197,884	$204,065	$ 925,669	53%	23%	23%	$493,690	$215,989	$215,989
Cable 35kV - New Install 3310	Revity - Robin Hollow Site	Revity - Studley Solar (former EDP)	$493,453	$974,865	N.A.	N.A.	0	$474,972	$478,505	$493,453	$ 575,116		100%		$0	$575,116	$0
Cable 35kV - New Install 3311	Revity - Robin Hollow Site	Revity - Studley Solar (former EDP)	$493,453	N.A.	N.A.	N.A.	0	$474,972	$478,505	$493,453	To be installed by RIE						
Duct Bank Civil Work	Revity - Robin Hollow Site	Revity - Studley Solar (former EDP)	$1,258,404	Self Build - No Cost	N.A.	N.A.	0	$1,211,274	$1,220,284	$1,258,404	$ 4,756,910	0%	100%		$0	$4,756,910	$0
Weaver Hill Substation			$3,800,000				$3,800,000	$3,658,000	$3,685,000	$3,800,000							
Cable 35kV - New Install 3310	Revity - Studley Solar (former EDP)	Weaver Hill Sub	$623,618	N.A.	N.A.	N.A.	$0	$600,262	$604,727	$623,618							
Cable 35kV - New Install 3311	Revity - Studley Solar (former EDP)	Weaver Hill Sub	$623,618	N.A.	N.A.	N.A.	$0	$600,262	$604,727	$623,618							
Duct Bank Civil Work	Revity - Studley Solar (former EDP)	Weaver Hill Sub	$1,590,350	N.A.	N.A.	N.A.	$0	$1,530,789	$1,542,175	$1,590,350							
Spacer Cable 15kV - New Install	Weaver Hill Sub	To New Circuits (63F6 Transfer)	$700,251	N.A.	N.A.	N.A.	$125,000	$770,000	$3,899,000	$3,899,000							
											$ 30,647,639				$ 16,090,227	$ 10,541,062	$ 4,016,349

N.A. = Not Applicable

Total Potential Reimbursement **$ 14,557,411**

Cost Basis		Quantity	Unit of Measure	Unit Cost	Capex	Opex	Removal	Total
Cable 35kV - New Install	SU-UG Cbl 1000ft 1000MCM Cu 3-1/C 35KV EPR	17.9	1000 ft	$133,772	$2,394,518.80	$0	$0	$2,394,518.80
Duct Bank Civil Work	Duct Bank Civil Work - 6X6" (Asphalt). Total =100 LF.	90	EA	$33,925	$3,053,250.00	$0	$0	$3,053,250.00
Spacer Cable 15kV - New Install	SU-SPCR CBL 477 MILE 2ND CKT 15KV 25 PCT POLES ELEC SET	2	MI	$399,407	$700,251.00	$40,825	$57,738	$798,814.00
					$6,148,019.80	**$40,825.00**	**$57,738.00**	**$6,246,582.80**

Sub-T DG Customer Cost Share

Cost Basis		Quantity	Unit of Measure	Unit Cost	Capex	Opex	Removal	Total
Cable 35kV - New Install 3310	SU-UG Cbl 1000ft 1000MCM Cu 3-1/C 35KV EPR	16.8	1000 ft	$314,292	$5,280,108	$2,297	$3,216	$5,285,622
Cable 35kV - New Install 3309	SU-UG Cbl 1000ft 1000MCM Cu 3-1/C 35KV EPR	19.9	1000 ft	$312,155	$6,211,892	$2,703	$3,784	$6,218,378
Duct Bank Civil Work	Duct Bank Civil Work - 6X6" (Asphalt). Total =100 LF.	170	EA	$48,153	$8,186,000.00	$0	$0	$8,186,000
					$19,678,000	**$5,000**	**$7,000**	**$19,690,000**

Total	**$25,936,582.80**
Dline + Dsub	$29,736,582.80

Cost Basis - D-Sub

NECO - Substation Work (D-Sub)	Capital	O&M	Removal	Total
Install a 7.5/9.375 MVA transformer and one modular feeder position to be supplied by the 3311 preferred and 3310 alternate.	$ 3,800,000.00	$ -	$ -	$ 3,800,000.00
	$ 3,800,000.00	$ -	$ -	$ 3,800,000.00

EXHIBIT S

In the Matter Of:

RI PUBLIC UTILITIES COMMISSION

D 23-37-EL & D 23-38-EL

TRANSCRIPT OF PROCEEDINGS

June 06, 2024

ESQUIRE
DEPOSITION SOLUTIONS

800.211.DEPO (3376)
EsquireSolutions.com

Q. You are aware of the fact that, in the course of the performance here of the interconnection build-out, that Revity was required to pay roughly $3.6 million to Rhode Island Energy to pay for certain upgrades that Green was performing; am I correct in that?
A. Correct.
Q. Am I correct that Green received that roughly $3.6 million payment from Rhode Island Energy -- just let me finish; I know you know where I am going.
A. Sorry.
Q. -- prior to these proceedings?
A. Correct.
Q. Okay. Is it fair to say that -- excuse me -- the $3.6 million that Green received from Rhode Island Energy that was paid by Revity reduces that 5.9 million to 2.3 million that Green needs cost reimbursement for Weaver Hill?
A. Correct, based on the numbers provided by Rhode Island Energy, yes, it would be the net of what was already reimbursed from Rhode Island Energy, and what the difference is.
Q. Okay. So if the -- looking at PUC 24, and I know we are going to get an updated version of this, and I have chicken scratch all over here from testimonial updates that we've had, but I'm just going

to go with the original version, if the $14-and-a-half million was ultimately the cost reimbursement, Green's claim to that in Weaver Hill would be 2.3 million?

A. Correct, roughly.

Q. Thank you. Let me talk about the discussions that Green had with the Company regarding cost reimbursement. I think you agreed with either Attorney Habib or Attorney Wold, perhaps both of them, that the Company was clear with Green that there would need to be a regulatory review process prior to reimbursement; correct?

A. Correct.

Q. Okay. Was Green's understanding of that -- did the Company provide any level of detail about what that regulatory review would look like to Green?

A. As I said, this was a process over a period of time. We were going through the dispute resolution process, so I didn't know if the -- it would come out of that process. I know, as we came toward the end of these petitions being filed, it was finally decided that they would submit petitions for these costs that could not be shared with other developers.

Q. Okay. Was Green's understanding of what the regulatory process would be, was Green's understanding that this would be more of a review, for lack of a

C E R T I F I C A T E

I hereby certify that the foregoing is a true, accurate, and complete transcription of my notes as taken at the above-entitled hearing, dated June 21, 2024.

Nancy S. Caron

NANCY S. CARON
NOTARY PUBLIC
STATE OF RHODE ISLAND

NANCY S. CARON, C.S.R., NOTARY PUBLIC
MY COMMISSION EXPIRES 07/30/2025

EXHIBIT T

Division 4-17

Request:

If a capital project is mentioned in the Company's ISR Plan filing but not included in the Company's proposed ISR Plan budget that accompanies the Plan, does the Company consider the project "identified in the Company's work plan as a necessary capital investment"? Explain.

Response:

If a capital project is mentioned in the Company's ISR Plan filing but not included in the proposed plan budget, the Company does consider the project "identified in the Company's work plan as a necessary capital investment". The Company includes information in its ISR Plan, such as area study summaries and a five-year plan, to provide visibility to investments that have been identified and needed in future years.

EXHIBIT U

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

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

Rhode Island Energy™
a PPL company

June 5, 2024

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket No. 23-38-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project
Weaver Hill Projects
<u>Response to Record Request No. 1</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's response Record Request No. 1 issued at the evidentiary hearings in the above-referenced docket.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 23-38-EL Service List

Record Request No. 1

Request:

Please indicate every place in the Electric ISR Plans where Weaver Hill projects were identified.

Response:

The Company has outlined below where the Weaver Hill work was identified in the Fiscal Year ("FY") 2022, FY 2023, FY 2024, and FY 2025 Electric Infrastructure, Safety, and Reliability ("ISR") Plans.

FY 2022 ISR PLAN
Docket No. 5098

On Bates Page 150 of the Proposed FY 2022 Electric Infrastructure, Safety, and Reliability Plan ("FY 22 ISR Plan"),[1] the Company responded to a Division Data Request referenced as R-III-9.

FY 2023 ISR PLAN
Docket No. 5209

Budget Inclusions:
The Company did not include a budget in the Proposed FY 2023 Electric Infrastructure, Safety, and Reliability Plan ("FY 23 ISR Plan").[2] A forecast of $150,000 for FY 2024 was included in Attachment 3 on Bates Page 81 of the FY 23 ISR Plan.

References within Filing:
The Company highlighted the Area Study findings on Bates Page 36 of the FY 23 ISR Plan which reads as follows:

[1] The FY 22 ISR Plan may be accessed at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5098-NGrid-ElectricISR-FY2022%28Book2of-2%29-%2812-21-2020%29.pdf.
[2] The FY 23 ISR Plan may be accessed at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5209-NGrid-Book1-Electric-ISR-FY2023-Plan-%28PUC-12-20-21%29.bates.pdf

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Record Request No. 1, page 2

FY 2023 ISR PLAN
Docket No. 5209

"Concerns: a number of circuits require reconductoring due to reliability, contingency, capacity, or asset condition concerns (2230 line, 54F1, 63F6, etc.);
three stations require equipment replacement/upgrades due to asset condition concerns (Coventry, Hope and Division St)."

Summary of Recommended Solutions:

- Replace equipment identified at Coventry #54, Hope #15, and Division St. #61 to address safety and asset condition issues.
- Replace equipment at Anthony, Natick, and Warwick Mall, and complete reconductoring on the 2230 and 2232 23kV lines to address the Drumrock 23kV system concerns.
- Extend portions of the 35kV system and install a new modular substation at Weaver Hill Rd to relieve 54F1 and 63F6 circuits and address the Kent County 35kV system concerns."

FY 2024 ISR PLAN
Docket No. 22-53-EL

The proposed budget for Weaver Hill was approved as part of the FY 24 ISR Plan and is included in the totals in the Company's Compliance Filing for Electric Rates Effective April 1, 2023 that was submitted on March 30, 2023 ("FY 24 Compliance Filing").[3]

Budget Inclusions ($1,507,000):

- C085412 - Weaver Hill Rd DSub, C088009 Weaver Hill Rd. SubT Extension, and C085414 Weaver Hill Rd Feeder DLine are on Attachment 2 of the Supplemental Budget

[3] The FY 24 Compliance Filing may be accessed at: https://ripuc.ecms.ri.gov/sites/g/files/xkgbur841/files/2023-03/RIE-Compliance-April1-2023-Rates.pdf.

Record Request No. 1, page 3

FY 2024 ISR PLAN
Docket No. 22-53-EL

- Weaver Hill Substation is under System Capacity & Performance category on Attachment 3 of the FY 24 Supplemental Budget.
- Chart 17 on Bates Page 103 of the Proposed FY 2024 Electric Infrastructure, Safety, and Reliability Plan ("FY 24 ISR Plan").[4]

*This reference was made prior to the change from calendar year to fiscal year for the ISR filing.

References within Filing:

- Chart 7 on Bates Page 75 of the FY 24 ISR Plan which reads as follows:

Project	Respective Planning Area Study
Southeast (aka Dunnell Park)	Legacy Project - Blackstone Valley North
Dyer Street - Indoor Substation	Legacy Project - Providence System Area Study
Providence Study Projects - Phase 1-4	Providence
Apponaug Substation	Central Rhode Island East
Phillipsdale Substation	East Bay
Centredale Substation	Northwest Rhode Island
Tiverton Substation	Tiverton
Aquidneck Island (Newport projects)	Legacy Project - Newport
New Lafayette Substation	South County East
Warren Substation	East Bay
East Providence Substation	East Bay
Nasonville Substation	Northwest Rhode Island
Weaver Hill Road Substation	Central Rhode Island East

[4] The FY 24 ISR Plan may be accessed at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-01/2253-RIE-ook1-ElecISR-RevBates2%201-4-23.pdf.

Record Request No. 1, page 4

FY 2024 ISR PLAN
Docket No. 22-53-EL

- The Company also highlights the proposed work on Bates Page 105 of the FY 24 ISR Plan:

  "Weaver Hill Substation – The Central Rhode Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder."

- Docket 4600 analysis of the project begins on Bates Page 150 of the FY 24 ISR Plan.

Data Requests

- The Central Rhode Island West Area Study was provided as Attachment DIV 1-20-2 in DIV 1-20.
- A fact sheet was provided in RR#19 that outlines proposed work (RR# 19-11)

FY 2025 ISR PLAN
Docket No. 23-48-EL

Please refer to Attachment RR#1 for the pertinent pages of the approved budgets in the Company's Compliance Filing for Electric Rates Effective April 1, 2024 that was submitted on March 27, 2024 ("FY 25 Compliance Filing").[5]

Budget Inclusions (1,105,000):

- Chart 10 Bates Page 70 of the FY 2025 Electric Infrastructure, Safety, and Reliability Plan ("FY 25 ISR Plan") [6]
- Attachment 2, Lines 9-11 Bates Page 82 of the FY 25 ISR Plan

[5] The full FY 25 Compliance Filing may be accessed at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-03/RIEnergy-Compliance-Apr1-2024-Rates_3-27-24_0.pdf.
[6] The FY 25 ISR Plan may be accessed at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2024-01/2348-RIE-Book1-ElecISRPlan_12-21-23.pdf

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Record Request No. 1, page 5

FY 2025 ISR PLAN
Docket No. 23-48-EL

- Attachment 3 Line 7 Bates Page 86 of the FY 25 ISR Plan
- Attachment 5 Long Range Plan Bates Page 153 of the FY 25 ISR Plan
- Attachment 5 Long Range Plan Bates Page 154 of the FY 25 ISR Plan*

*This value was related to the work subject to the petition and was removed from the FY 2025 ISR Filing to the Commission.

References within Filing

- Bates Page 72 of the FY 25 ISR Plan which reads as follows:

  "Weaver Hill Road Substation – The Central Rhode Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder."

Data Requests

The Company included cash flows associated with Weaver Hill in various data requests including:

- DIV 1-12
- PUC 2-5
- PUC 3-5
- PUC 3-12
- PUC 5-2
- PUC 6-3

The Company also provided sanctioning information on the project in DIV 1-24.

Testimony

The Company provided Reply Testimony related to the Tiverton and Weaver Hill petitions on page 22 of 42.

COMPLIANCE (3/26/2024)

Attachment 3 - Five-Year Budget with Details

$000's

Line Number	Spending Rationale	Category	Docket 22-53-EL: FYTD Actuals 12/31/23	Docket 22-53-EL: Preliminary FY 2024 Q3 Forecast	Docket 22-53-EL: FY 2024 Budget	5 Year Investment Plan - Capital Spending: FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	Major Project - Details: Major Project - Current Phase	Current Sanction - CAPEX only	Initial Estimate - CAPEX only	Date of Last Sanction	Est'd Constr Start	Est'd Constr End	Capital Spending through FY 2023
1	**Non-Discretionary**																
	Customer Request /																
2	Public Requirement	New Business - Commercial	8,745	11,025	9,093	9,366	9,647	9,937	10,235	10,542							
3		New Business - Residential	5,471	7,212	7,212	7,428	7,651	7,880	8,117	8,361							
4		Public Requirements	1,953	1,249	1,249	3,140	3,234	3,331	3,431	3,531							
5		Transformers and Related Equipment	6,776	8,350	5,000	8,000	8,000	8,000	8,000	8,000							
6		Meters and Meter Work	1,036	2,089	2,605	2,533	430	100	100	100							
7		Distributed Generation	5,781	1,000	1,000	1,000	1,000	1,000	1,000	1,000							
8		Third Party Attachments	(732)	331	280	288	297	306	315	324							
9		Land and Land Rights	329	500	500	515	530	546	562	579							
10		Outdoor Lighting	352	813	575	592	610	628	647	666							
11	**Total Customer Request/Public Requirement**		**29,710**	**32,568**	**27,514**	**32,862**	**31,399**	**31,728**	**32,407**	**33,103**							
12	Damage / Failure	Damage /Failure	9,920	12,545	10,940	11,268	11,606	11,954	12,313	12,682							
13		Reserves	-	-	979	1,008	1,038	1,070	1,102	1,135							
14		Failed Assets	2,619	4,340	1,323	2,537	1,972	-	-	-							
15		Storms	3,176	3,662	1,950	3,000	3,000	3,000	3,000	3,000							
16	**Total Damage/Failure**		**15,716**	**20,547**	**15,192**	**17,813**	**17,616**	**16,024**	**16,415**	**16,817**							
17	**Total Non-Discretionary**		**45,426**	**53,116**	**42,706**	**50,675**	**49,015**	**47,752**	**48,822**	**49,921**							

The Narragansett Electric Company
d/b/a Rhode Island Energy
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			Docket 22-53-EL			5 Year Investment Plan - Capital Spending					Major Project - Details						
Line Number	Spending Rationale	Category	FYTD Actuals 12/31/23	Preliminary FY 2024 Q3 Forecast	FY 2024 Budget	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	Major Project - Current Phase	Current Sanction - CAPEX only	Initial Estimate - CAPEX only	Date of Last Sanction	Est'd Constr Start	Est'd Constr End	Capital Spending through FY 2023
1	**Discretionary**																
2	Asset Condition																
3	Separately Tracked Major	Dyer Street Substation	1,861	2,553	-	15	-	-	-	-	Construction	$10,658	$10,842	Apr-21	Sep-21	FY 2025	$14,651
4		Admiral St 12 KV Substation	-	-	-	5,513	2,500	-	-	-	Construction	$12,831	$12,831	Aug-21	Sep-21	FY 2026	$2,731
5		Providence Area LT Study Projects (Ph 1A,1B,2,4)	17,685	25,783	24,314	-	-	-	-	-	--	--	--	--	--	--	--
6		Kingston Equipment Replacement	-	-	-	400	3,361	8,403	1,681	2,961	Study Phase	--	$16,805	--	Oct-25	FY 2029	$0
7		Phillipsdale Substation D Sub	-	-	-	100	5,728	7,240	1,448	324	Study Phase	--	$6,025	--	Oct-25	FY 2029	$0
8		Apponaug Substation	-	-	-	150	1,120	1,980	1,750	700	Study Phase	$5,700	$3,800	Jul-23	FY 2026	FY 2029	$0
9		Hospital #146 Equipment Replacement	-	-	-	320	2,064	2,680	296	-	Study Phase	$5,360	$5,359	Dec-23	FY 2026	FY 2028	$0
10		Merton #51 Equipment Replacement	-	-	-	-	816	2,449	4,082	816	Study Phase	--	$8,164	--	FY 2027	FY 2029	$0
11		Southeast Substation	327	327	66	-	-	-	-	-	Construction	$11,244	$9,000	Jun-19	Oct-19	FY 2025	$15,198
12		Auburn 115/12.4kV Substation (D-Sub)	-	-	-	-	-	832	1,663	4,989	Study Phase	--	$6,590	--	FY 2028	FY 2029	$0
13	Subtotal - Separately Track Major Projects		19,873	28,663	24,380	6,498	15,589	23,583	10,919	9,790							
14	Other	Underground Cable Replacement	4,231	4,281	5,500	5,500	6,000	6,000	6,000	6,500							
15		URD Cable Replacement	5,321	6,496	6,276	5,000	5,411	5,723	5,823	5,500							
16		Blanket Projects	4,298	5,686	5,220	6,177	6,338	6,504	6,676	6,850							
17		I&M	257	476	3,000	1,530	1,530	1,530	1,530	1,530							
18		Substation Spare Transformers				540	2,480	7,436	8,186	6,825							
19		Substation Breakers & Reclosers	1,231	1,231	437	196	440	-	-	-							
20		Other Area Study Projects - BSVS	1,058	1,058	-	781	1,556	2,457	2,280	1,156							
21		Other Area Study Projects - CRIE	27	27	-	50	75	35	293	315							
22		Other Area Study Projects - CRIW	-	-	-	1,883	6,317	10,196	3,730	390							
23		Other Area Study Projects - East Bay	-	-	-	100	505	570	570	190							
24		Other Area Study Projects - Newport	194	194	-	446	1,189	802	-	-							
25		Other Area Study Projects - NWRI	135	135	-	500	3,007	2,725	1,432	250							
26		Other Area Study Projects - Providence	-	-	-	492	5,396	6,575	4,630	4,630							
27		Other Area Study Projects - SCW	-	-	-	-	-	-	1,029	2,297							
28		Tiverton Substation	60	60	-	75	393	786	786	393							
29		Providence Area LT Supply & Distrib Study	-	-	-	20,382	10,580	7,064	-	-							
30		Reserve	-	-	-	-	1,000	1,000	1,000	1,000							
31		Batteries / Chargers	31	227	230	195	387	319	100	-							
32		Recloser Replacements	1,209	1,209	1,300	-	-	-	-	-							
33		UG Improvements and Other	2,732	2,809	1,383	700	565	-	-	-							
34	Subtotal - Other Projects and Programs		20,783	23,889	23,346	44,547	53,169	59,722	44,065	37,826							
35	**Total Asset Condition**		**40,656**	**52,552**	**47,726**	**51,045**	**68,758**	**83,305**	**54,984**	**47,617**							
36	Non-Infrastucture																
37		General Equip & Telecom Blanket	(805)	536	700	712	724	737	750	764							
38		Verizon Copper to Fiber	11	26	1,000	180	75	-	-	-							
39	**Total Non-Infrastructure**		**(793)**	**562**	**1,700**	**892**	**799**	**737**	**750**	**764**							

The Narragansett Electric Company
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1	System Capacity & Performance																
2	Separately Tracked Major	East Providence Substation (D Sub + D Line)	720	976	1,330	-	-	-	-	-	--	--	--	--	--	--	--
3		East Providence Substation (D Sub)	-	-	-	2,685	2,309	2,952	-	-	Preliminary Eng'g	$6,000	$6,000	Feb-17	Apr-24	Oct-26	$892
4		Warren Substation (D Sub + D Line)	1,915	2,381	1,969	-	-	-	-	-	--	--	--	--	--	--	--
5		Chase Hill Second Half of Station	-	-	-	-	1,006	2,012	1,006	1,006	Study Phase	--	$5,030	--	FY 2027	FY 2029	$0
6		Nasonville #127 Sub (D-Sub)	-	-	-	3,566	3,100	489	-	-	Study Phase	$10,786	$13,325	Jul-23	FY 2026	FY 2027	$0
7	Subtotal - Separately Track Major Projects		2,635	3,357	3,299	6,251	6,415	5,453	1,006	1,006							
8	Other	Aquidneck Island	1,189	1,327	1,038	-	-	-	-	-							
9		New Lafayette Substation	197	361	750	910	5,886	151	-	-							
10		Warren Substation	-	-	-	1,800	2,943	747	111	-							
11		Nasonville Substation (D Sub + D Line)	1,346	2,338	1,912	-	-	-	-	-							
12		East Providence Substation (D Line)	-	-	-	3,600	2,700	2,051	-	-							
13		Weaver Hill Road Substation	419	665	1,507	1,105	3,054	3,475	2,496	1,229							
14		3V0	201	217	1,095	186	540	-	-	-							
15		EMS/RTU	(15)	(15)	658	135	1,147	2,350	750	-							
16		Overloaded Transformer Replcmts	1,118	1,500	1,500	1,500	1,500	1,500	1,500	1,500							
17		Blanket Projects	5,209	5,639	2,490	2,605	2,725	2,851	2,983	3,072							
18		Other Area Study Projects - BSVS	120	120	400	680	681	968	-	-							
19		Other Area Study Projects - CRIW	366	845	1,371	1,441	1,125	1,125	675	-							
20		Other Area Study Projects - East Bay	-	-	-	84	378	378	-	-							
21		Other Area Study Projects - Newport	-	-	-	793	976	461	-	-							
22		Other Area Study Projects - NWRI	775	1,185	1,933	108	128	-	-	-							
23		Other Area Study Projects - SCE	-	-	-	1,684	6,404	333	-	-							
24		Other Area Study Projects - SCW	101	137	364	927	4,101	3,909	2,576	1,147							
25		Tiverton D-Line	130	130	109	328	656	656	328	440							
26		Reserve	-	-	-	-	1,000	1,000	1,000	1,000							
27		CEMI-4	1,072	1,221	1,230	1,230	1,230	1,230	1,230	-							
28		ERR	-	-	-	-	-	-	-	-							
29		Distrib Automation Recloser Program	-	-	-	-	-	-	-	-							
30		ADMS/DERMS Advanced	-	-	-	-	-	3,159	1,568	-							
31		DER Monitor/Manage	-	-	-	-	-	2,288	4,043	-							
32		Electromech Relay Upgrades	-	-	-	1,234	603	1,267	2,513	1,263							
33		Fiber Network	-	-	-	200	-	-	-	-							
34		VVO - Smart Capacitors and Regulators	235	235	-	400	8,439	6,701	6,701	6,701							
35		Mobile Substation	-	-	-	1,278	3,834	7,668	-	-							
36		Other projects and programs	(1,686)	(1,451)	541	478	100	100	100	100							
37	Subtotal - Other Projects and Programs		10,776	14,453	16,898	22,706	50,150	44,369	28,575	16,452							
38	**Total System Capacity & Performance**		**13,411**	**17,810**	**20,197**	**28,957**	**56,565**	**49,822**	**29,581**	**17,458**							

			Docket 22-53-EL			5 Year Investment Plan - Capital Spending					Major Project - Details						
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1	**Total Discretionary excluding AMF**		**53,275**	**70,924**	**69,623**	**80,894**	**126,122**	**133,864**	**85,315**	**65,839**							
2	Advanced Metering Functionality																
3		Meter Costs	-	-	-	28,725	61,795	4,212	-	-							
4		Network Costs	-	-	-	4,479	8,374	1,985	-	-							
5		System Costs	-	-	-	11,487	13,280	7,597	-	-							
6		Program Costs	-	-	-	3,502	3,502	1,751	-	-							
7	**Total AMF**		**-**	**-**	**-**	**48,192**	**86,950**	**15,544**	**-**	**-**							
8	**Total Discretionary including AMF**		**53,275**	**70,924**	**69,623**	**129,086**	**213,073**	**149,408**	**85,315**	**65,839**							
9	**Total Capital Spending including AMF**		**98,700**	**124,040**	**112,329**	**179,761**	**262,088**	**197,160**	**134,137**	**115,759**							
10	**Total Capital Spending excluding AMF**		**98,700**	**124,040**	**112,329**	**131,569**	**175,137**	**181,616**	**134,137**	**115,759**							
					-												
11	**O&M Spend**																
12		Vegetation Management	8,304	13,950	13,950	13,075											
13		VVO/CVR	173	400	400	365											
		I&M - Opex Related to Capex	173	400	400	200											
14		I&M - Inspections & Replairs Related Costs	459	550	338	500											
15	**Total O&M**		**9,109**	**15,300**	**15,088**	**14,140**											

Certificate of Service

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

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

____

Joanne M. Scanlon

June 5, 2024

Date

Docket No. 23-38-EL Rhode Island Energy – Petition for Acceleration Due to DG Project – Weaver Hill Projects Service List updated 5/21/2024

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File an original & 5 copies w/: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; John.Harrington@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov; Kristen.L.Masse@puc.ri.gov;	401-780-2107
Frank Epps, EDP	Frank@edp-energy.com;	

EXHIBIT V

1. EXECUTIVE SUMMARY

A comprehensive study of the Central RI West area was performed to identify existing and potential future distribution system performance concerns. System evaluation included comparison of equipment loading to thermal (capacity) limits, contingency response capability (Distribution Planning Criteria), voltage performance (ANSI A/B requirements), breaker operating capability, regulator operating capability, distribution arc flash review, reactive compensation performance, asset condition, system reliability, safety, and environmental issues. The recommendations provide a comprehensive solution to address all the system performance concerns existing and anticipated in the study area through 2035.

An alternative analysis was conducted to determine the facilities necessary to address the identified issues providing best system performance at the least cost. The alternative analysis considered Non-Wire Alternatives (NWA) in addition to traditional wire solutions.

There are several common items necessary to address safety and asset condition issues at various substations - specifically, Coventry #54, Hope #15, and Division St. # 61. These projects include replacements of transformers, air breaks, lightning arresters, regulators, and various other pieces of equipment at each substation due to age and reliability concerns. Common items also include the reconductor of sections of five (5) feeders (Coventry 54F1, Division St. 61F2, Chase Hill 155F8, Natick 29F1, and New London 150F6) to address a combination of overloaded line sections, asset condition issues, and outage issues. Finally, there is a common project to create a backup tie to the Warwick Mall.

A primary area of concern addressed within this study is the Drumrock 23kV system. The primary drivers of concern in this area are asset condition issues at the Anthony #64, Warwick Mall #28, and Natick #29 substations. Asset condition issues are similar to those addressed at the common item substations including the need to replace transformers, air breaks, circuit breakers, regulators, lightning arresters, and various other equipment. The option to add four (4) additional feeders at the New London Substation and remove all equipment at Anthony #64, Warwick Mall #28, and Natick #29 substations was investigated but the least cost option, and therefore recommended plan, is to replace the necessary equipment with asset condition issues at the named substations instead.

The final area of concern addressed within this study is the Kent County 34.5kV system with a summer normal overload at Hopkins Hill (63F6) as well as a highly loaded feeder at Coventry (54F1). Two (2) new substation locations were investigated to be utilized to build a modular substation/feeder to offload these two feeders – one at Weaver Hill Road, West Greenwich and one near Pine Hill Road, Exeter. The least cost recommended option is the Weaver Hill Road option to extend the 3309 and 3310 lines from Nooseneck Hill and Weaver Hill Roads, West Greenwich to a Rhode Island Energy owned property off pole #64 Weaver Hill Road and install a 7.5/9.375 MVA transformer and one modular feeder position to be supplied by 3309 preferred/3310 alternate with distribution line work for a new feeder to be made up of parts of Coventry 54F1 and Hopkins Hill 63F6.

This Document Contains Critical Energy/Electric Infrastructure Information (CEII) – DO NOT DISTRIBUTE or COPY

EXHIBIT W

Docket 4600 Benefit-Cost Framework

Project Name:	Weaver Hill Substation
Area Study:	Central RI West

Problem: There are predicted loading and voltage concerns on certain Hopkins Hill and Coventry substation feeders. The loading concerns include feeders predicted to be near or in excess of thermal ratings. The voltage concerns are similarly at or below guidelines. These same feeders are approaching contingency load-at-risk limits. Furthermore, many of the area feeders have circuit frequency and duration metrics above system averages.

Preferred Plan: Install a new substation on Weaver Hill Rd. This work includes extension of the 3309 and 3310 lines from Nooseneck Hill and Weaver Hill Roads in West Greenwich to a Rhode Island Energy owned property on Weaver Hill Rd, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.

Alternate Plan: Install a new substation on Bell Schoolhouse Road (Pine Hill substation). This work includes extension of the 3310 line from Route 3 north of Route 102 to a Rhode Island Energy owned property at the intersection of New London Turnpike and Bell Schoolhouse Road, Exeter referred to as Pine Hill substation. The work also includes the installation of a new new 34.5 kV line from the new Wickford Junction substation to Pine Hill substation, installation of a new transformer and one modular feeder position, and installation of distribution line equipment to transfer portions of the Coventry 54F1 and Hopkins Hill 63F6 circuits.

Summary of Benefit - Cost Analysis

Preferred Plan	
Benefit Cost Ratio	0.67
Net Benefit/Cost	$ (14,860,000)
Alternate Plan	
Benefit Cost Ratio	0.58
Net Benefit/Cost	$ (26,180,000)

Refer to following pages for detailed Docket 4600 Benefit - Cost analysis

1. All cost and benefit calculations are based on a 20 year period net present value, with the cost calculations taking into consideration revenue requirements.

2. All reliability benefit calculations are based on the US Department of Energy Interruption Cost Estimate (ICE) Calculator, which provides residential and commercial customer interruption costs.

3. All energy saving calculations are based on CME Group future Peak/Off peak prices and AESC REC values and escalations factors.

4. CO2 reduction calculations are based on Regional Greenhouse Gas Initiative (RGGI) values.

5. The NOX/SOX benefits were calculated using U.S. Environmental Protection Agency technical support documents for particulate matter and AESC generic generation unit characteristics.

EXHIBIT X

- *Weaver Hill Road Substation* – The Central Rhode Island West Area Study recommended installing a new substation on Weaver Hill Road due to overload concerns. This work will include extending the 3309 and 3310 lines for 1.7 miles, installing a transformer and one feeder position, and installing distribution line work for a new feeder.

- *3V0 Program* – As DG penetration levels continue to increase, the need for zero sequence overvoltage ("3V0") protection is more necessary. The addition of DG to distribution feeders can result in the flow of power in the reverse direction on feeders and, at times, through the substation transformer onto the high voltage transmission system. To enable a more rapid response to DG interconnections, the Company proactively installs 3V0 protective devices in substations on a priority basis.

- *Substation EMS/RTU (SCADA) Additions Program* – The Company is proposing to continue the EMS/RTU program to improve reliability performance, increase operational effectiveness, and provide data for asset expansion or operational studies at Wampanoag and West Greenville Substations.

- *Overloaded Transformer Replacements* – This program proposes to replace or upgrade overloaded transformers to alleviate existing overloads and ensure reliability.

- *Blanket Projects* – In addition to specific projects, the Company also establishes blanket projects to ensure that local field engineering and operations can resolve system and equipment loading and reliability issues in an efficient and effective manner. The amount of funding in the blanket project is reviewed and approved each year based on the results of annual capacity planning and reliability reviews, historical trends in the volume of work required, input from local Operations, and forecasted impacts of inflation. The individual work requests have a value of less than $500,000 in value. The current year's spending is monitored monthly.

  The Company has included $1.7 million of FY 2023 recloser plant additions to FY 2025's Target Plant Additions shown on Chart 11. As noted in the Company's September 22, 2023 Letter titled Settlement Between The Narragansett Electric Company d/b/a Rhode Island Energy and the Division of Public Utilities and Carriers on FY 2023 Spending, the Company removed the plant additions and cost of removal from its FY 2023 revenue requirement and has reviewed the work with the Division.

- *Other Area Study Projects* – Individual projects have been established for System Capacity work coming out of Area Studies. The majority of the work is engineering, design, and initial procurement of materials. The individual projects are itemized on

EXHIBIT Y

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

NATIONAL GRID'S ELECTRIC INFRASTRUCTURE, SAFETY & RELIABILITY PLAN FOR 2016	)))	Docket No. 4539

DIVISION OF PUBLIC UTILITIES AND CARRIER'S OBJECTION TO WED'S MOTION TO INTERVENE AND DIVISION'S MOTION TO STRIKE

The Division of Public Utilities and Carriers ("Division") hereby objects to the motion to intervene that WED One Coventry One, LLC, WED Coventry Two, LLC, WED Coventry Three, LLC, WED Coventry Four, LLC, WED Coventry Five, LLC and WED Coventry Six, LLC ("WED") has filed in this proceeding, and moves to strike the Objection that WED has also filed in response to NGrid's 2016 Electric ISR Plan. In support of its objection and motion, the Division submits the accompanying memorandum of law.

Respectfully submitted,

DIVISION OF PUBLIC UTILITIES
AND CARRIERS
By its attorneys,

PETER F. KILMARTIN
ATTORNEY GENERAL

Leo J. Wold, # 3613
Assistant Attorney General
150 South Main Street
Providence, RI 02903
401-274-4400, ext. 2218

CERTIFICATE OF SERVICE

I certify that a copy of the within objection and motion was forwarded to the Service List in the above matter on the 19 day of February, 2015.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

NATIONAL GRID'S ELECTRIC INFRASTRUCTURE, SAFETY & RELIABILITY PLAN FOR 2016	)))	Docket No. 4539

DIVISION'S MEMORANDUM OF LAW IN SUPPORT OF ITS OBJECTION TO WED'S MOTION TO INTERVENE AND DIVISION'S MOTION TO STRIKE

I. INTRODUCTION

WED One Coventry One, LLC, WED Coventry Two, LLC, WED Coventry Three, LLC, WED Coventry Four, LLC, WED Coventry Five, LLC and WED Coventry Six, LLC ("WED") have filed a motion to intervene in this proceeding, contending that the WED satisfies the requirements of Rule 1.13(b). WED Motion at 1.[1] The Division opposes WED's participation here on the grounds that WED does not possess standing to participate in the pending matter as a full party and that the motion does not comply with the requirements of Rule 1.13(b). It necessarily follows that WED's motion to intervene must be denied and that its objection—filed concurrently with the motion to intervene—must be stricken from the Record.

---

[1] Rule 1.13(b) of the Commission's Rules of Practice and Procedure identifies the standard that "any person claiming a right to intervene or an interest that of such nature that intervention is necessary or appropriate" must satisfy in order to be granted intervenor status in a Commission proceeding. In pertinent part, Rule 1.13(b) provides that an intervention will be granted when the person possesses: (1) a right conferred by statute, (2) an interest which may be directly affected and which is not adequately represented by existing parties and as to which the movants may be bound by the Commission action in the proceeding, or (3) any other interest of such nature that movant's participation may be in the public interest.

II. ARGUMENT

A. WED DOES NOT POSSESS STANDING TO PARTICIPATE AS A FULL PARTY IN THE PENDING MATTER.

In order for a litigant to participate in a proceeding as a full party, the litigant must possess standing, *i.e.*, the litigant must have sustained injury in fact, economic or otherwise. Newport Elec. Corp. v. Public Utilities Comm'n, 454 A.2d 1224 (R.I. 1983). Only "actual" or "threatened legal injury" is sufficient to satisfy this threshold legal requirement. Blackstone Valley Chamber of Commerce v. Public Utilities Comm'n, 452 A.2d 931, 934 (R.I. 1982). Thus, a plaintiff claiming only a "[m]ere 'interest in a problem,' no matter how longstanding the interest and no matter how qualified the organization is in evaluating the problem, is not sufficient by itself to render the organization 'adversely affected' or 'aggrieved.'" In Re: Town of New Shoreham Project, 19 A.3d 1226, 1227 (R.I. 2011). When a litigant lacks standing, no matter how well-intentioned, it will be error for the deciding body to permit the litigant to intervene. ABAR Assoc. v. Luna, 870 A.2d 990, 997 (R.I. 2005); In Re: Stephanie B., 826 A.2d 985, 991 (R.I. 2003); West Warwick School Committee v. Souliere, 626 A.2d 1280, 1284 (R.I. 1993).

In its motion to intervene, the sole contention that could conceivably support a claim of standing is that WED "received an interconnection impact study for . . . six projects including a charge of almost $13 million to interconnect the project, over $12 million was for capacity improvements to National Grid's distribution system." WED Motion at 1. That WED received a statement or estimate of a lawful charge to connect to NGrid's distribution system at some point in the future can hardly be considered "actual" or "threatened legal injury" to WED. Rather, it is no more than an expression of WED's desire to obtain ratepayer funds through NGrid's 2016 ISR budget to help subsidize the cost of interconnection. Much more "is needed" to establish standing when an alleged injury from government inaction is asserted, not by the regulated entity, but by "someone else." Lujan v Defenders of Wildlife, 504 U.S. 555, 562 (1992). Thus, when a plaintiff is not himself the object of the government action or inaction he challenges, "standing is . . . ordinarily 'substantially more difficult' to establish." Id. WED "goes beyond the limit . . . and into pure speculation and fantasy," to claim that it is "appreciably harmed" by a mere claimed interest in NGrid's 2016 ISR budget when it has no "specific connection" to that budget process. Id. at 567. The Commission should deny WED's motion to intervene and strike its objection for lack of standing alone.

B. WED DOES NOT SATISFY ANY OF THE CRITERIA OF RULE 1.13(b).

In applying Rule 1.13(b), the Commission has taken a "more cautious" approach to granting intervention motions ever since the Rhode Island Supreme Court's decision in In Re: Island Hi-Speed Ferry, LLC, 746 A.2d 1240 (R.I. 2000). See Narragansett Electric Company d/b/a National Grid Proposed Standard Offer Service Rate Reduction, Docket No. 3739, Order No. 18794 at 12 (2006). In Hi-Speed, the Court questioned the wisdom and appropriateness of permitting a competitor to intervene to contest an applicant's rate application. Island Hi-Speed, 746 A.2d at 1246. The concerns expressed by the High Court in Hi-Speed and subsequently by the Commission in Narragansett Electric apply equally as well in the pending matter.

1. **<u>WED Does Not Possess A Right To Intervene Conferred By Statute</u>.**

In its Motion to Intervene, WED has not claimed a right to intervene conferred by statute. For obvious reasons, WED cannot satisfy this criterion, and no further discussion of its merits is required.

2. **<u>WED Does Not Possess An Interest Which May Be Directly Affected And Which Is Not Adequately Represented By Existing Parties</u>.**

a. <u>No Interest Directly Affected</u>

WED summarily contends that "its interests are directly affected by this proceeding and WED is not adequately represented by the existing parties." <u>WED Motion</u> at 1. Nowhere in its motion, however, does WED explain or identify how Rule 1.13(b)'s criteria are satisfied. Nor is WED's claimed interest in fact a real interest at all. Rather, it is simply a disingenuous attempt of WED to transfer its duly-tariffed financial responsibility to pay for interconnection costs onto ratepayers.

At issue in the pending matter is NGrid's proposed "reconcilable allowance for anticipated capital investments and other spending relating to maintaining safety and reliability of NGrid's electric distribution system for fiscal year 2016," <u>NGrid 2016 Plan Correspondence Dated October 7, 2014</u>, and whether NGrid's management decisions regarding the same are "reasonably needed." <u>See</u> G.L. § 39-1-27.7.1(d). Currently, customers such as WED that desire to interconnect to NGrid's distribution network are required to pay for the cost of interconnection themselves. R.I.P.U.C. No 2078 provides as follows:

5.2 Interconnection Equipment Costs

The Interconnecting Customer shall be responsible for all costs associated with the installation of the Facility and associated interconnection equipment on the Interconnecting Customer's side of the PUC.

5.3 System Modification of Costs

The Interconnecting Customer shall also be responsible for all costs reasonably incurred by Company attributable to the proposed inter-Connection project in designing, constructing, operating and maintaining the System Modifications…

WED, of course, is fully aware of these legally binding financial responsibilities. In correspondence addressed to the Rhode Island House Corporations Committee WED opines that "interconnection cost . . . are the biggest impediment to the benefits of our new energy economy." This legislation (H5131) "seeks to fix that problem prohibit[ing] the utility from charging interconnecting customers for electric power system upgrades…" Handy Law Letter Dated January 29, 2015 at 2. The Commission and Pascoag Utility District have also acknowledged the current state of the law. See Letter from PUC Counsel Dated January 29, 2015 at 1 ("…this bill attempts to shift certain electric distribution upgrade costs associated with interconnecting distributed generation projects from the developer to all ratepayers…"); Letter from Pascoag Utility District re: H5131 at 1 (the bill "shifts the cost-burden of an interconnecting renewable customer to all other ratepayers of the system…"). Since WED and similar third parties, rather than ratepayers, are currently required to pay for interconnection costs (and have admitted as much), WED simply has no legally cognizable interest which it may advance before the Commission in the pending matter. Intervention pursuant to Rule 1.13(b)(2) is not permitted under such circumstances.

b. *Adequate Representation by Existing Party*

Regardless of WED's claim to an interest which may be directly affected, WED never contends in its motion that the Division cannot adequately represent its alleged interest before the Commission. The Division, in fact, possesses ample expertise to assess whether it is reasonable and/or appropriate, as WED claims, that "interconnection" costs for renewable projects should be incorporated into the 2016 ISR budget. In the pending matter, the Division has retained an independent, expert consultant, Gregory Booth of PowerServices, Inc., to review NGrid's filing. Mr. Booth has reviewed NGrid's ISR budgets for a number of years, is intimately familiar with NGrid's distribution system, and possesses considerable legal, financial and technical expertise regarding the system's infrastructure needs and requirements. The Division, therefore, can easily and adequately assess the alleged interests (if any) espoused by WED that may require Commission consideration in the hearing process.

The Superior Court concurs with this analysis, holding that prospective third party intervenors are barred from intervening in proceedings to air their concerns when there are specialized administrative agencies in place that may assess and resolve (if necessary) those same concerns. In Block Island Ferry Services, LLC, *et al.* v. Rhode Island Fast Ferry, Inc., *et al.,* PC 2013-5322, the Division denied a third party claimant from intervening in a CPCN proceeding on the basis that the granting of CPCN to the applicant could detrimentally impact safety and/or service and interfere with docking schedules. The Superior Court upheld the Division's ruling, recognizing that CRMC and the Harbormaster (like the Division and Commission here relative to WED's alleged concerns) "are more familiar and better equipped to decide and regulate details having to do with dockage and local traffic issues and both represent the public interest." Permitting intervention in such circumstances, the Court held, "would be duplicative, time consuming and . . . a waste of time…" Id. at 7.

The same rationale applies to the pending matter. WED has attempted to intervene in a proceeding where there exists an administrative agency, the Division, that can just as easily review and assess WED's alleged concerns. Moreover, WED can place its position in the non-evidentiary record through public comment, and the Commission can always query the Division's expert regarding his opinions regarding those same concerns at hearing. To allow WED to intervene and litigate issues that have been considered by the Division and its expert consultant in assessing the reasonableness of NGrid's 2016 ISR budget would be "duplicative" and "time consuming" as well as "a waste of time."

3. **<u>WED's Intervention In This Proceeding Is Not In The Public Interest.</u>**

The only remaining rationale that can conceivably support WED's intervention in the pending proceeding is WED's claim that its participation "may be in the public interest." While Rule 1.13(b)(3) does not define what matters the Commission should deem "in the public interest," legal precedent makes it abundantly clear that the mere assertion of laudable public interest ends does not necessarily sanction that litigant's participation in a Commission proceeding as a full party. Under Rule 1.13(b)(3), participation that is in "public interest" must do more than achieve the same result that the Commission could arrive at with the assistance of existing parties or through its own reasoned decision-making. <u>In Re: Island Hi-Speed Form of Regulation and Review of Rates</u>, Docket No. 3495, Order No. 17452 at 8 (2003). Vague and non-specific calls for additional review that will further "the public interest" do not demonstrate the requisite interest that would support intervention under Rule 1.13(b)(3). <u>Narragansett Electric</u>

Company d/b/a National Grid Proposed Standard Offer Service Rate Reduction, *supra* at 12.

In the pending matter, WED identifies a number of areas of inquiry which it contends will vindicate the Commission's granting WED's motion to intervene: job creation, stable energy pricing, reduced energy costs, a sustainable Rhode Island economy and environmental benefits. All are laudable goals to be sure; however, none of these vague and non-specific ends have anything to do with the merits of the pending docket. WED's intervention in this matter, then, will not advance any particular interest—public or otherwise. Nor will WED's intervention advance any interest that is different from what the Commission could consider with the Division's participation alone. WED's claim of intervention pursuant to Rule 1.13(b)(3) fails as well.

III. CONCLUSION

For the foregoing reasons, the Division requests that the Commission deny WED's Motion to Intervene and strike WED's Objection to NGrid's proposed 2016 ISR Plan.

Respectfully submitted,

DIVISION OF PUBLIC UTILITIES
AND CARRIERS
By its attorneys,

PETER F. KILMARTIN
ATTORNEY GENERAL

Leo J. Wold, # 3613
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401-274-4400, ext. 2218

CERTIFICATE OF SERVICE

I certify that a copy of the within memorandum of law was forwarded to the Service List in the above matter on the 17 day of February, 2015.

Exhibit Z

Exhibit H – Interconnection Service Agreement

Attachment 2: Description of System Modifications

Rhode Island Energy System Modifications required for the interconnection of 8750kW (AC) application as identified in the impact study are as follows:

On the Customer's property:

- Install ~1,100 circuit feet of 3-477 AAC,
- One (1) 35 kV load break switch
- One (1) 35 kV recloser
- Two disconnect switches
- Six (6) primary meters along with six (6) disconnect switches at the PCC.
- Install Twenty three (23) poles include project numbers for the 6 sites

On the Company's distribution system:

- Install 20,100 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road. .
- Install ~700 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from the 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road (Revity Energy POI).
- Install ~200 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road (Revity Energy POI) to a 2-way MH on Customer property.
- Install ~100 circuit feet of 3-1000 kcmil CU EPR 35 kV cable from 2-way MH on Customer property to proposed riser pole on Customer property.
- Install ~1500 circuit feet of 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
- Install ~410 feet of 3-1/c-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry
- Implement live line reclose blocking and settings change at pole 10 Hopkins Hill Road, Coventry, RI

Civil construction (designed and installed by others) ("Third Party Ductbank"):

- Installation of (4) - 3 way manholes, (21) - 2 way manholes, (89 feet) - 2 way, 6" PVC - DB concrete encased duct bank, (14,309 feet) 4 way, 6" PVC - DB concrete encased duct bank, and associated equipment. For estimating purposes, permanent restoration for civil work is assumed to be twelve (12) feet in width. Note: Should additional permanent restoration (i.e. Curb to curb or centerline to curb) be required, the cost of civil construction could increase.

Civil construction (work anticipated to be completed by Revity) ("Revity Ductbank")

- Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road (Revity Energy POI).
- Install duct system (~600 feet) between previously constructed 3-way MH on Hopkins Hill Road and previous constructed 3-way MH at the intersection of Hopkins Hill Road and Division Road. Rhode Island Energy to provide civil design including drawings to Customer to construct this portion.
- Install MH and duct system (~100 feet) from first 3-way MH on Weaver Hill Road (Revity Energy POI) to proposed 2-way MH on Customer property (to be self-built by Customer). Customer to provide civil design including drawings per Distributed Generation: Minimum Self-Performance Requirements to construct this portion.
- Install MH and duct system (~50 feet) from 2-way MH on Customer property to proposed riser pole on Customer property (to be self built by Customer) . Customer to provide civil design including drawings to construct this portion per Distributed Generation: Minimum Self-Performance.
- Install MH and duct system (~3000 feet) from proposed riser pole on Hopkins Hill Road to 3-way MH on Hopkins Hill Road. Customer to provide civil design including drawings to construct this portion per Distributed Generation: Minimum Self-Performance Requirements.
- The Interconnecting Customer will perform the civil construction for the manhole / duct system consistent with civil design plans provided by the Customer and approved by the Company per the per Distributed Generation: Minimum Self-Performance Requirements. A kick-off meeting will be held and coordinated by the Company to 1) review and convey all of the Company's civil design parameters and requirements, and 2) coordinate the schedule

for the Interconnecting Customer civil construction . The Interconnecting Customer agrees that 1) civil installation work performed and 2) all materials provided will be in strict conformance with the Company provided civil design plans.

At the Company's substation:

- Add Load encroachment settings to the Kent County T7 Directional Overcurrent relay

It will be the responsibility of the Interconnecting Customer, at its sole cost and expense, to secure and obtain in favor of itself and the Company, the following: any and all rights, consents, permits, approvals, and easements (free and clear from any encumbrances), as are required for the Company's System Modifications on any Interconnecting Customer-owned property or any third-party owned property ("Third Party Rights and Approvals"). The Interconnecting Customer shall use the Company's standard form when obtaining all Third Party Rights and Approval, as applicable. The Company will seek to obtain, at the Interconnecting Customer's sole cost and expense, any and all rights, consents, permits, approvals, and easements for the System Modifications on any Company owned property or within any public roadway as the Company determines necessary in its sole discretion ("Other Rights and Approvals"; together with Third Party Rights and Approvals referred to as "System Modification Required Approvals"). The Interconnecting Customer and the Company will fully cooperate with each other in obtaining the Other Rights and Approvals. The Company shall not be required to accept any System Modification Required Approvals that are not in form or on terms satisfactory to the Company in its sole discretion, or that impose additional liabilities or costs on the Company. The Company shall not be required to appeal or challenge the denial of any System Modification Required Approvals or the imposition of any unsatisfactory term or condition, however, the Interconnecting Customer shall be allowed to appeal the imposition of any unsatisfactory terms or conditions associated with Third Party Rights and Approvals. The Company shall not be obligated to commence the construction of the System Modifications unless and until it has received all System Modification Required Approvals in accordance with this provision, and Sections 5 and 15 of this Agreement, above, and the Company's Terms and Conditions for Distribution Service, tariff R.I.P.U.C No. 2180, as amended from time to time.

Exhibit H – Interconnection Service Agreement

Attachment 3: Costs of System Modifications and Payment Terms

This application is one of **seven projects** studied together with total system size of 40,700 kW (the "Related Projects"). This application's size is 8,750**kW** and is 21.5**%** of the total aggregated Related Project size. The Interconnecting Customer understands and agrees that, notwithstanding the costs detailed in this Agreement, if one of the Related Project applications (RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253, RI-29048531) does not move forward with the interconnection of a facility to the Company's electric power System, the total common modification costs on the Company's System will be re-estimated and reallocated among the remaining Related Projects, as determined by the Company in its reasonable discretion. Note the Company will not proceed with construction unless it has received adequate payment from all applicable customers within the Related Projects group.

The total Company System Modification Costs (excluding the THIRD PARTY DUCTBANK and REVITY DUCTBANK) that will be performed by the Company and are associated with all Related Project applications are: **$9,602,158** (+/- 25%). As of the ISA execution date, the System modification cost responsibility for this ISA is **$1,952,743.**

In order to safely and reliably interconnect the Related Projects, the THIRD PARTY DUCTBANK and REVITY DUCTBANK must also be constructed. The total third party estimate provided to construct the THIRD PARTY DUCTBANK is **$11,761,595** as of the date of this agreement. The Company will facilitate the sharing of costs of the THIRD PARTY DUCTBANK with all parties that occupy a common path of the THIRD PARTY DUCTBANK based on the distance of the common path and a pro rata megawatt share of the common path. The common path that will be occupied by all parties of the THIRD PARTY DUCTBANK is 52.0% of the total path. Based on that percentage; the Company will facilitate the sharing of an estimated **$6,116,029.** The pro rata megawatt share of this amount for all Related Project applications referenced herein is 67.05% of this figure or **$4,555,167** including tax. This application's cost responsibility for the THIRD PARTY DUCTBANK will be **$979,361** (such amount, the "Interconnecting Customer's Cost Share Amount").

Upon completion of construction of the THIRD PARTY DUCTBANK, Company will request the entity constructing the THIRD PARTY DUCTBANK to provide a cost summary (including a detailed accounting ledger for each line item presented on the cost summary) with the following supporting information: vendor name, date/dates of service, detailed description of service, copy of the cancelled check(s), and associated contract/purchase order/timeslip/certified payroll/etc. documents. Upon the receipt of all required documentation, the Company will audit and verify the proposed costs incurred by the third party and will adjust the Interconnecting Customer Cost Share Amount to reflect such reconciliation (which adjustment shall be reflected in an amended interconnection service agreement) for cost line items that, in whole or inpart, do not qualify as an approved cost.

The Company will audit and verify the actual costs incurred to construct the REVITY DUCTBANK, and agrees that it will facilitate the sharing of such costs with all future parties (excluding the Related Projects) that occupy a common path of the REVITY DUCTBANK based on the distance of the common path and a pro rata megawatt share, and that any such cost sharing amount that is collected by the Company shall be disbursed to Revity Energy LLC.

The parties acknowledge and agree that the ability of the Company to assign and collect from an interconnecting customer any costs incurred by a third party in connection with its self-performance of interconnection work has been challenged in Docket No. 5235 (the "Petition"), which currently is pending before the Rhode Island Public Utilities Commission ("RIPUC"). Accordingly, the Company and Interconnecting Customer agree that Interconnection Customer's payment of the Interconnecting Customer Cost Share Amount, and any collection of costs from a third party by the Company of the REVITY DUCTBANK costs, is expressly subject to any final ruling by the RIPUC on the Petition, and that the Company shall refund to Interconnection Customer any Interconnection Customer Cost Sharing Amount if and to the extent required by the RIPUC.

The Company System Modification Costs associated with this application (which do not include the THIRD PARTY DUCTBANK) are: **$1,952,743** (+/- 25%) and itemized as follows:

- Total cost of common system modifications on the Interconnecting Customer's (or other private) property as mentioned in Attachment 2 above: **$784,147** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253. RI-29048593, and the Interconnecting Customer will be responsible for 24.7% share or **$193,684.**
- Total cost of common system modifications on the Company's distribution System, specifically 3309 cable pulling as mentioned in Attachment 2 above is **$6,106,255** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253. RI-29048593, and the Interconnecting Customer will be responsible for 24.7% share or **$1,508,245.**
- Total cost of common system modifications **(NECO)** at the distribution side of the Kent County Substation as mentioned in Attachment 2 (Load encroachment) above is **$17,600** (includes capital, removal, and O&M costs). The cost for this modification

will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253, RI-29048531. RI-29048593 will be responsible for 21.5% share or **$3,784.**

- Total cost of the donated property taxes associated with the REVITY DUCTBANK construction self-performed by Customer civil construction is **$69,554.** The cost for the donated property will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253, RI-29048531. RI-29048593 will be responsible for 21.5% or **$14,594.**

- Total cost of Rhode Island Energy Supervision associated with the REVITY DUCTBANK construction self-performed by Customer is **$165,000.** The cost for the Supervision will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253, RI-29048531. RI-29048593 will be responsible for 21.5% share or **$35,475.**

- Total cost of common system modifications on the Company's distribution System, specifically protective device settings as mentioned in Attachment 2 above is **$1,600** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253. RI-29048593 will be responsible for 21.5% share or **$344.**

- Cost of witness testing, engineering review, EMS Integration and implementation of protective device settings: **$3,494.**

- Tax gross-up adder on capital costs is or **$193,123**. (*A 2021 tax rate of 11.08% is expected to apply to contributions in aid of construction ("CIAC") payments received by The Narragansett Electric Company from the Interconnecting Customer, and a 2019 tax rate of 9.90% is expected to apply to CIAC payments associated with substation modifications for interconnections. The calculation of the tax gross-up adder is included in this cost estimate on the basis of tax guidance published by the Internal Revenue Service, but tax rates and decisions are ultimately subject to IRS discretion. By signing this agreement, the Interconnecting Customer understands and agrees that the tax has been estimated for convenience and that the Interconnecting Customer remains liable for all tax due on CIAC payments, payable upon the Company's demand.*

The Interconnecting Customer understands and agrees that, notwithstanding the costs detailed in this Agreement, if any other Related Project does not move forward with its interconnection to the Company's electric power system, the Facility's interconnection may need to be restudied, and the System Modification costs will be re-estimated for the Facility and for the Related Projects, as determined by the Company in its reasonable discretion. In such a case, the Interconnecting Customer shall be responsible for the full amount of any study costs and increase in the costs in order to continue with the Facility's interconnection under this Agreement, including its pro-rata share of any re-estimated and re-allocated costs.

The System modification costs were developed by the Company with a general understanding of the project and based upon information provided by the Interconnecting Customer in writing and/or collected in the field. The cost estimates were prepared using historical cost data, data from similar projects, and other assumptions, and while they are presumed valid for 60 business days from the date of the Impact /Group Study, the Company reserves the right to adjust those estimated costs as authorized under this Agreement, the Tariff, or by law and to require the Interconnecting Customer to pay any such additional costs.

The Total System Modifications Costs and the Facility System Modification Costs do not include any costs for Third Party Rights and Approvals (as defined in Attachment 2) or any Verizon system modification costs and charges (and fees for services related thereto), for which the Interconnecting Customer may be directly responsible. These costs, to the extent applicable, are in addition to the Total System Modifications Costs and the Facility System Modification Costs and must be paid directly by the Interconnecting Customer to the appropriate third party

ISO-NE Planning Study
Rhode Island Energy Transmission Planning has studied the impact of the proposed project in accordance with the ISO New England Inc. (ISO-NE) Planning Procedure 5-6 "Scope of Study for System Impact Studies under the Generation Interconnection Procedures" and Rhode Island Energy TGP28 "Transmission Planning Guide." Rhode Island Energy Transmission Planning has determined that there are no adverse impacts to the transmission system.

ISO-NE Operating Requirement
This is part of a group of generating Facilities within close proximity, as determined by ISO-NE, which equals or exceeds an aggregate of 5MW and will be required to comply with ISO-NE's requirements, including Operating Procedure No. 14. Prior to the Company providing Authorization to Interconnect, the Interconnecting Customer will be required to provide evidence that it has complied with

all applicable ISO-NE registration requirements. Additionally, ISO-NE may determine that there are additional system upgrade costs.

Additional costs may be involved if the required pole work takes place in Telephone Company Maintenance Areas. These costs will be billed directly to the Interconnecting Customer from the Telephone Company.

EXHIBIT AA

Rhode Island Energy a PPL company	DISTRIBUTION PLANNING DOCUMENT Interconnection Study	Doc. RI-28228074 Case #00197003 Page 1 of 39
	Complex Generating Facility - R.I.P.U.C. 2180	Version 3.0 9/20/2022
	Energy Development Partners 9,200 kW / kVA rating, Inverter Based Photovoltaic 189 Weaver Hill Road, West Greenwich, RI	FINAL

Revised System Impact Study for Distributed Generation Interconnection to Rhode Island Energy's 34.5 kV System

DG WR:	RI-28228074
DG Case#:	00197003
Applicant:	Energy Development Partners
Address:	189 Weaver Hill Road
City:	West Greenwich, RI
DG kW/kVA:	9,200 kW / kVA
DG Type:	Inverter Based Photovoltaic
Feeder:	3310, Kent County Substation

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Rhode Island Energy™ a PPL company	DISTRIBUTION PLANNING DOCUMENT Interconnection Study	Doc. RI-28228074 Case #00197003
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	Complex Generating Facility - R.I.P.U.C. 2180	Version 3.0 9/20/2022
	Energy Development Partners 9,200 kW / kVA rating, Inverter Based Photovoltaic 189 Weaver Hill Road, West Greenwich, RI	FINAL

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List of Tables

Definitions

The following is a list of acronyms/synonyms used in this Interconnection Study:

BESS – Battery Energy Storage System

Company – Rhode Island Energy

Customer – The interconnecting customer of this project

DG – Distributed Generation

DER – Distributed Energy Resources

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESB – Rhode Island Energy's Electrical Service Bulletin

Facility – The distributed generating facility for this project, including all related appurtenances and equipment.

IA – Interconnection Application

Interconnecting Circuit – Circuit to which the Facility will connect.

ISA – Interconnection Service Agreement

ISO-NE – Independent System Operator of New England

MH - Manhole

NPCC – Northeast Power Coordinating Council

PCC – Point of Common Coupling (point of demarcation between the Customer and Company facilities)

PF – Power Factor

P_{lt} – Long term flicker emission limit

Project – The interconnection of the Facility to the Company electrical power system.

P_{st} – Short Term flicker emission limit

P.U – Per Unit

PV - Photovoltaic

RTU – Remote Terminal Unit

Executive Summary

The Company has completed the Revised Impact Study, for the interconnection of Energy Development Partners, ("Customer") a 9,200 kW / kVA Inverter based photovoltaic, ("the Facility"), to its 34.5 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

The interconnection requirements specified are exclusive to this project and are based upon the most recent information submitted by the Customer, which is attached for reference in Appendix C. Any further design changes made by the Customer post IA without the Company's knowledge, review, and/or approval will render the findings of this report null and void.

System Modifications

In general, the Project was found to be feasible with certain modifications to the existing Company System and operating conditions, which are described in detail in the body of this Study. Significant modifications include:

1. Distribution line work (Section 2.2, Appendix B):
    - Install ~16,100 feet of 3-1/c 1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
        - Prior analysis has shown that this project requires the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable in this section. The costs provided in this study are for the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable. Another Customer has paid for the installation of 3-1/c 1000 kcmil Cu EPR 35 kV cable.
    - Install ~700 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road.
    - Install ~4100 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
    - Install ~200 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
    - Install ~1,400 feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

2. Distribution Civil Work (Section 2.2, Appendix B):
   - Install MH and duct system (~14,300 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road.
     - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
     - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
   - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road.
     - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
   - Install MH and duct system (~3700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road (to be self-built by Customer).
   - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property (to be self-built by Customer).
3. Add Load encroachment settings to the Kent county T7 Directional Overcurrent Relay (Section 5.4)
4. Install ~410 circuit feet of 3-477 AL Bare Conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) 35 kV disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry, RI. (Section 2.2 & 5.5, Appendix B)
   - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
5. Install ~250 feet of 3-477 AL Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers and one (1) primary meter at the PCC. (Appendix B)

Cost Estimate

Refer to the Cost Estimate table in Section 9.0 for a listing of major modifications and associated costs. The total estimated planning grade cost of the work associated with the interconnection of the Facility, is $24,545,166 +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the final Interconnection Service Agreement.

Special Operating Requirements

The Customer is required to comply with the following special operating requirements in order to interconnect to the Company EPS:

1. The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS. (Section 3.4)

1.0 Introduction

The Customer has requested interconnection of a Facility to the Company's existing infrastructure.

The analysis utilized Customer provided documentation to examine the effects on the Company system when the new Facility is connected. The results identify required modifications to the Customer one line diagram(s) and Company infrastructure in order to accommodate the interconnection. As such, the interconnection of the Facility has been evaluated under specific conditions. Should the Customer make any changes to the design, other than those identified in this study, it may require additional time for review, and possibly additional cost.

In accordance with the R.I.P.U.C. 2180 tariff and the Company's ESB series, the Company has completed an Impact Study to determine the scope of the required modifications to its EPS and/or the Facility for providing the requested interconnection service.

Analysis will be performed in accordance with applicable reliability standards and study practices, and in compliance with the applicable codes, standards, and guidelines listed in the Company's *Electric System Bulletin No. 756 Appendix D: Distributed Generation Connected to Rhode Island Energy Distribution Facilities Per The Rhode Island Standards for Interconnecting Distributed Generation ("ESB756D")* to determine the incremental impact and any potential adverse impacts associated with the interconnection of the Facility to the EPS.

2.0 Project Description

2.1 Customer Facility

The Customer proposes to install the following:

- Two (2) Customer owned SMA 4600-UP-US, three phase inverters for an assumed total of 9,200 kW / kVA of inverter-based PV.
- Two (2) Customer owned 4,600 kVA, 34.5 kV wye-ground, 600 V delta secondary padmounted interface transformer with an impedance of Z =5.75% along with X/R ratio of 11.
- One (1) Customer owned padmounted switchgear 35kV, 600A, 200 kV BIL G&W Viper recloser with SEL-651R relay assembly with 8-hour battery backup.
- One (1) Customer owned GOAB switch, S&C Model #147513, 200 kV BIL, 40kA with a Visible, lockable blades and utility accessible 24/7.

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 09/28/2021).

Any advanced inverter functionality other than that specifically called out on the Customer documentation and/or outlined herein shall be subject to additional study before being enabled.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is 3310, a 34.5 kV unregulated, three-phase, 3 wire, wye, ungrounded, radial, sub-transmission circuit that originates out of the Company's Kent County Substation, in West Greenwich, RI (the "Interconnecting Circuit"). This circuit is located overhead on Division Street, approximately 3.9 miles from the proposed Facility. This Line Extension will include the following work:

- Distribution Line Work (Section 2.2, Appendix B):
  - Install ~16,100 feet of 3-1/c 1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road
    - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Prior analysis has shown that this project requires the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable in this section. The costs provided in this study are for the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable. Another Customer has paid for the installation of 3-1/c 1000 kcmil Cu EPR 35 kV cable.
  - Install ~700 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Weaver Hill Road to the first 3-way MH on Weaver Hill Road.
  - Install ~4100 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.

- Install ~200 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
- Install ~1,400 feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
- Install ~410 feet of 3-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

- Distribution Civil Work (Section 2.2, Appendix B):
  - Install MH and duct system (~14,300 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road
    - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are expected.
  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road
    - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are expected.
  - Install MH and duct system (~3,700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road (to be self-built by Customer).
  - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property (to be self-built by Customer).

An underground line extension originating from the overhead line on Hopkins Hill Rd will be required to reach the proposed Facilities. There is one river that will need to be crossed with overhead conductors alongside the bridge. The Big River Bridge was not constructed to allow for installation of concrete encased ducts.

The Customer shall perform civil work from the first 3-way Manhole on Weaver Hill Road to the proposed riser pole on Customer property. Civil work scope performed by the Customer will require Company review and approval of the proposed plans, as well as Company review and approval of the ductbank prior to covering.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL (kW)*
3309	165	0	0	*165*
3310	434	24,248	9,200	*33,882*
3311	30,284	23,795	0	*54,079*
3312	2,735	4,049	0	*6,784*
TOTAL	*33,618*	*52,092*	*9,200*	**94,910**

Table 1: Generation at the Substation and Interconnecting Circuit

- There is one (1) existing recloser on the circuit, none of which are in between the substation and the facility, summarized in Table 2. Refer to Section 5 for further discussion on any required modifications.

Location	Status	Mid-line recloser, or existing DG project PCC recloser	In between Facility and Substation
Pole #18-1, Hopkins Hill Road, West Greenwich	In Service	Mid-line	No

Table 2: Recloser Locations

- There are no existing capacitor banks installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

- There are no existing regulators installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

2.3 Interconnection

Refer to the interconnection diagram in Appendix B for approximate PCC location.

Should the Customer elect to move forward with the Project, the Company's Design Personnel will specify the exact location of the Company's facilities and installation details. The Customer shall be responsible for obtaining all easements and permits required for any line extension not on public way in accordance with the Company's requirements.

The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

For this Project, the PCC is defined as the point where the Customer owned conductors terminate to the Company revenue meter, which is located at Pole #10-6, 189 Weaver Hill Road, West Greenwich, RI. The Customer must install their facilities up to the Company revenue meter. The Customer must provide sufficient conductor to allow the Company to make final connections at the meter pole. The Company will provide final connection of the Customer conductors to the Company meter.

If a Rhode Island Energy right of way (R.O.W) is involved, then the Customer shall provide detailed drawings of any planned construction within any Rhode Island Energy R.O.W., for the Company's review and subsequent approval, showing elevation grades of all phases of construction within the R. O. W. before any construction may begin. Plans and drawings must be submitted that meet all the Company's requirements before the interconnection process can move forward. These plans shall be submitted to Rhode Island Energy's R.O.W./Real-Estate group and the Transmission R.O.W. Engineering and construction group for review and comment before any construction can be allowed to move forward. There may be additional costs and subsequent delays involved with the review, and, or oversight of any construction in, or adjacent to, the Company's R.O.W., and if any Company owned facilities need modification as a result of the Customer's proposed construction. These costs will be in addition to, and outside of the scope of, this SIS. Failure of the Customer to reimburse the Company for these costs may delay or negate the interconnection process.

3.0 Power Flow Analysis

The power flow analysis was substantially performed using electrical system modeling software. A model of the Interconnecting Circuit, as described in Section 2.2, was developed based on data extracted from the Company's Geographical Information System ("GIS"). A field review of the feeder was performed on 09/25/2019.

The analysis considered cases at peak load (16,284 kVA @ 100% PF) and net minimum load (5,017 kVA @ 99.52% Lagging PF) at time of maximum expected generation (9:00AM – 6:00PM) on the circuit.

Circuit peak and minimum load values have been taken from the Company's historical load data that has been compiled over 12 months, from 1/1/2019 to 1/1/2020.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Analysis shows that the maximum potential generation exceeds the observed minimum load on the Kent County 34.5 kV bus. However, the substation is currently equipped with bi-directional metering which was previously installed for reasons unrelated to DG work. No additional work is required on the substation bulk power metering.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in steady state voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output, the voltage range at the PCC was within acceptable limits.

Customer provided manufacturer's test reports have been reviewed for 1.4PU pickup values with 1ms or less total clearing time. The proposed design has been found to meet the necessary requirements.

3.4 Flicker Analysis

The IEEE 1547 standard and IEEE 1453 flicker assessments were used to estimate whether or not this site would be likely to cause unacceptable voltage flicker on the interconnecting feeder. This method evaluates for both short term and long-term voltage flicker against IEEE1547-2018 Table 25 - DER Flicker Emission Limits.

Analysis shows that P_{st} and P_{lt} are within acceptable limits and no mitigation for voltage flicker is recommended.

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2015 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long-Term Dynamics module of CYME[1]. A long-term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6-hour period. Other significant DG existing or in process ahead of this Project were modeled at full output and modeled with the appropriate voltage fluctuation curve to simulate reasonable voltage fluctuations.

The generation profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate realistic power output from the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict voltage flicker under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether or not there is a readily apparent concern related to voltage flicker.

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

[1] CYME Power Engineering Software, Version 8.1, Revision 01, Build 115, Copyright © 1986-2017, Cooper Industries, Ltd.

Analysis shows that the predicted flicker and voltage fluctuations are expected to be acceptable, provided that the following conditions are met:

- The system modifications identified elsewhere in this study are implemented.
- The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS.

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 100kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
442	All Projects <100kW CERTIFIED
0	All Projects <100kW Non-CERTIFIED
740	CERTIFIED
3,500	CERTIFIED
9,200	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered a likely event. As a result, a PCC recloser with reclose blocking will be required. Additionally, live-line reclose blocking must be implemented at the following line reclosers summarized in Table 4.

Location	Status (Existing or New)
Pole #25-3, Hopkins Hill Road, Coventry, RI	New

Table 4: Recloser Locations

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C 2180 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation.

5.1 Fault Detection at Substation (ESB 756D Section 6.2.2)

Addition of generation sources to sub-transmission feeders can result in the back-feeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. Due to the Kent County T1, T2 and T7 supply transformer configurations, there is a path for zero sequence ground fault current to single line to ground faults on the transmission line. Therefore, the Facility does not pose a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Substation modifications related to $3V_0$ are not required.

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account existing system conditions, but not the impact of the Customer's new Facility.

[2] ASPEN OneLiner V12.5, Build: 19177 (2015.01.28), Copyright © 1987-2013 ASPEN.

Pre-Project

System Impedance at PCC

Z1 = 0.05 + j0.26 p.u.

Z0 = 0.65 + j1.38 p.u.

5.3 Fault Current Contributions

Table 5 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings. Mitigation strategies are required to accommodate the proposed Facility, as described in Sections 5.4 and 5.5.

The Customer is responsible for ensuring that their own equipment is rated to withstand the available fault current according to the NEC and Rhode Island Energy ESB 750, which specifies that the fault current should be no more than 80% of the device interrupting rating.

PRE PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)
3-phase (LLL)	21581	3999
Phase-Ground (LG)	24066	2346

POST PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)	DELTA I_{fault} @ SUB BUS	DELTA I_{fault} @PCC
3-phase (LLL)	21779	4199	1%	5%
Phase-Ground (LG)	24322	2478	1%	6%

Table 5: Fault Duty

5.4 Substation Protective Device Modifications

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study:

- Add load encroachment settings to the Kent County Transformer #7, 34.5 kV directional overcurrent relay (67)

5.5 Area EPS Protective Device Coordination

The Project will require a Company owned recloser at the PCC.

The existing device settings and associated time-current curves were evaluated for protective devices on the Interconnecting Circuit.

The protection coordination review of the area EPS revealed that the following modifications to the existing EPS protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study. Refer to Appendix B for system modification drawings:

- Install a recloser at the tap for the proposed line extension to the facility at Pole #25-3, Hopkins Hill Rd, Coventry, RI. (Appendix B-3)

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the Rhode Island Energy revenue meter. This may be accomplished with an analog/POTS (Plain Old Telephone Service) phone line (capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc.), or, in locations with suitable wireless service, a wireless meter.

Feasibility of wireless service must be demonstrated by Interconnecting Customer, to the satisfaction of Rhode Island Energy. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when Rhode Island Energy's retail tariff provides a mechanism for monthly billing for this service, the customer agrees to the addition of this charge to their monthly electric bill. Interconnecting Customer shall have the option to have this charge removed, if and when a POTS phone line to Rhode Island Energy's revenue meter is provided.

Refer to *Appendix A Figures A-1 and A-2 - Revenue Meter Phone Line Installation Guide).*

The Customer is advised to contact Generation and Load Administration (NewGenCoord@iso-ne.com) at ISO New England regarding all metering, communications circuits, remote access gateway (rig), financial assurance, paperwork, database updates, etc. that may be required for this Facility.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states the interconnecting transformer are two (2) Customer owned 4,600 kVA, 34.5 kV delta, 690 V delta secondary padmounted interface transformer with an impedance of Z =5.75% along with X/R ratio of 11.0.

The proposed transformer satisfies the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Facility is proposing to connect to a non-effectively grounded 34.5 kV circuit, and therefore does not require a means of effective grounding.

As a result, the customers proposed configuration satisfies the requirements of the ESB.

6.4 Manual Generator Disconnecting Means (ESB 756D Section 7.4)

The Customer provided documents satisfy the requirement of this Section of ESB 756D.

6.5 Primary Protection (ESB 756D Section 7.6 & 7.8)

The following section relates to the primary means of protection by the Customer. This includes the inverter relay functionality.

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable inverter relay settings in accordance with the aforementioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8. This requirement is met.

6.6 Secondary Protection

The following section relates to the secondary means of protection, also referred to as redundant relaying.

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a circuit breaker for site protection.

The Customer provided documents indicate an interrupting device on the high side (Customer 34.5 kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

6.6.2 Secondary Overcurrent Relay Elements (ESB 756D Section 7.6.10)

The Customer provided documents show a phase overcurrent (51) relay element and associated settings.

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

51 – Phase

Customer Proposed: 300A primary amps pickup, 2 second time delay, U4 curve.

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relays make/model is included on the Customer single line.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D. The Customer provided documents show neutral overvoltage (59N) that are unacceptable.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756C Section 7.6.11 and 7.8. This requirement is met.

The Customer provided one-line diagram shows acceptable settings for neutral overvoltage 59N protection.

59N – Neutral Overvoltage

Customer Proposed: $3V_0$ = 12.45 kV primary pickup (46.7 V), 0.8 second time delay.

6.6.6 Current Transformers (“CT”) (ESB 756D Section 7.6.4.1)

The Customer provided documents show current transformer with ratings listed, which satisfies this Section of ESB 756D.

6.6.7 Voltage Transformers (“VT”) and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show wye-grounded/wye-grounded VT’s and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer provided documents indicate a power supply for the redundant relay that satisfies the requirements of this section of ESB 756D.

The Customer has proposed a DC power supply. The Customer shall demonstrate in the witness test that the relay will trip if the DC voltage goes out of the normal operating range.

It is recommended that the power DC power supply be connected to the utility (source) side of the interrupting device in order to ensure power availability to close the interrupting device after an extended outage. This is a recommendation, for consideration by the Customer. It is not a requirement by the Company.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7 & 756C Section 7.8.3)

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting a minimum 5 minutes of healthy utility voltage and frequency. “Healthy Utility Voltage and Frequency” is defined by ESB 756D Table 7.8.3-1. The five-minute time interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five-minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer provided settings and timing device information is acceptable as shown.

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer's one line diagram shows devices and settings to satisfy this requirement.

6.7 Synchronizing Devices (ESB 756D Section 7.6.9 and 7.6.11.2)

Project is inverter based; therefore, synchronizing devices are not required.

6.8 Customer Cabling

The Company is not responsible for the protection of the Customer cable and primary protection for the Customer cable must be provided at the change of ownership.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

8.0 Inspection, Compliance Verification, Customer Testing, and Energization Requirements

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment.
- Inverter manufacturer cut sheet including method of island detection and UL certification.
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project.
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study.
- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme.
- The proposed testing procedure
- The proposed energization plan.
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft MA state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above identified time frames due to errors in the relay settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, is shown below in Table 6:

Rhode Island Energy System Modification	Conceptual Cost +/-25% Planning Grade Cost Estimate not including Tax Liability				Associated Tax Liability Applied to Capital	Total Customer Costs includes Tax Liability on Capital Portion
RIE - Civil Work	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Approximate donated property tax. See Note #1.	$0	$0	$0	$0	$82,718	$82,718
RIE Supervision and Design Support for Customer Underground Civil Construction. See Note #2	$165,000	$165,000	$0	$0	$18,282	$183,282
Distribution Civil work, 3310 circuit See Note #3 (Cost Sharing may be applicable)	$15,904,009	$15,904,009	$0	$0	$1,762,164	$17,666,173
SUBTOTAL	**$16,069,009**	**$16,069,009**	**$0**	**$0**	**$1,863,164**	**$17,932,173**
RIE - Line Work, Customer Property	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Equipment at Point of Common Coupling, 3310 Circuit. See Note #4	$310,038	$310,038	$0	$0	$34,352	$344,390
SUBTOTAL	**$310,038**	**$310,038**	**$0**	**$0**	**$34,352**	**$344,390**
RIE - Line Work, Mainline	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Distribution Line work, 3310 Circuit. See Note #5 (Cost Sharing may be applicable)	$5,621,801	$5,612,059	$5,272	$4,470	$621,816	$6,243,617
SUBTOTAL	**$5,621,801**	**$5,612,059**	**$5,272**	**$4,470**	**$621,816**	**$6,243,617**
RIE - Substation Work (Distribution Level)	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**9.90%**	**Total**
Add Load Encroachment to the Kent County T7 Directional Overcurrent Relay. (Cost Sharing may be applicable)	$16,000	$15,000	$1,000	$0	$1,485	$17,485
SUBTOTAL	**$16,000**	**$15,000**	**$1,000**	**$0**	**$1,485**	**$17,485**
Witness Testing & EMS	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**NA**	**Total**
Witness Testing. See Note #6	$2,500	NA	$2,500	NA	NA	$2,500

EMS integration. See Note #7	$5,000	NA	$5,000	NA	NA	$5,000
SUBTOTAL	**$7,500**	**$0**	**$7,500**	**$0**	**$0**	**$7,500**

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	**$22,024,348**	**$22,006,106**	**$13,772**	**$4,470**	**$2,520,818**	**$24,545,166**

Notes

1 Approximate donated property tax for the Customer installation of (1) - 3-way manhole, (5) - 2-way manholes, (100 feet) 2-way, 6" PVC - DB concrete encased ductbank, (3700 feet) - 4-way, 6" PVC - DB concrete encased ductbank and associated equipment. Customer is responsible for performing, any and all, temporary and permanent restoration.

2 RIE supervision and design support for underground civil construction performed by the Customer. The cost includes preparation of design package (Scope, Construction specifications, Construction standards/drawings, Vendor information, etc.…), review and approval of civil design drawings, and review and approval of civil construction by full-time RIE inspector.

3 Installation of (4) - 3 way manholes, (21) - 2 way manholes, (300 feet) - 2 way, 6" PVC - DB concrete encased duct bank, (14,000 feet) 4 way, 6" PVC - DB concrete encased duct bank, (600 feet) 6 way, 6" PVC - DB concrete encased duct bank and associated equipment. For estimating purposes, permanent restoration for civil work is assumed to be twelve (12) feet in width. Note: Should additional permanent restoration (i.e. Curb to curb or centerline to curb) be required, the cost of civil construction could increase.

4 Installation of pole-mounted equipment at the POI-PCC, including approxiamtely 250 feet of 3-477 Al Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers, one (1) primary meter, and associated equipment.

5 Extend the Kent County 3310, 34.5 kV circuit underground from proposed Pole #26-2, Hopkins Hill Road, West Greenwich, RI to the proposed DG facility located at 189 Weaver Hill Road, West Greewich, RI. (approximately 3.9 Miles). Estimate included in table above assumes installation of 3-1/c-500 kcmil CU EPR 35 kV cable, and associated equipment. Costs include one (1) bridge crossing with risers to 477 Al bare conductor, Installation of new tap recloser located on Hopkins Hill Road, West Greenwich, RI, and associated equipment.

6 Witness Testing including review of witness test documentation and manpower for attending witness test.

7 Integration of DG and EPS modifications into Company's Energy Management System (EMS)

Table 6: Cost Estimates

The planning grade estimate provided herein is based on information provided by the Interconnecting Customer for the study and is prepared using historical cost data from similar projects. The associated tax effect liability included is the result of an IRS rule, which states that all costs for construction collected by the Company, as well as the value of donated property, are considered taxable income.[3] This estimate is valid for ninety (90) calendar days from the issuance of this report, after which time it becomes void. If the Interconnection Customer elects to proceed with this project after the ninety (90) calendar days, a revised estimate may be required.

This interconnection application may result in costs charged to The Narragansett Electric Company (the Company) by an Affected System Operator (ASO). Please note that in addition to the payment obligation for your share of the cost of any transmission upgrades identified in an ASO Study or identified during the Distribution System Impact Study of your application, when

[3] Actual charges shall include the tax rate in effect at the time the charges are incurred.

your facility is energized you also will be assessed for the on-going carrying charges for the transmission upgrades (plus cost security before your facility is energized), as specified in your Interconnection Service Agreement. The on-going carrying charges include O&M, property taxes, and other carrying costs associated with transmission upgrades. The transmission upgrades and on-going carrying charges are calculated and charged to the Company by the ASO, in most instances the Company's transmission provider, New England Power Company (NEP), in accordance with the ASO's tariff (for NEP, Schedule 21-NEP, Attachment DAF, to the ISO-NE Open Access Transmission Tariff ("DAF Charges") and data from the FERC Form 1). You will be charged initially on an estimated basis for the transmission upgrade costs, which will be reconciled to actual costs. On-going carrying charges are calculated by multiplying the capital portion of the transmission upgrade costs by the transmission carrying charge rate in effect at the time. For NEP, the on-going carrying charge rate is subject to adjustment annually as estimated transmission upgrade costs are reconciled to actual costs. The current on-going carrying charge rate for NEP is 5.21%.

The estimated duration for the Company to complete construction of the System Modifications will be identified in the final Interconnection Service Agreement.

The project schedule may be impacted by the ability to have planned outages to allow work to take place on the distribution system. Outages will be contingent on the ability to support the load normally supplied by affected circuits. The schedule can also be impacted by unknown factors over which the Company has no control. The interconnection schedule is contingent on the Interconnecting Customer's successful compliance with the requirements outlined in this report and timely completion of its obligations as defined in *ESB756D, Exhibit 2: Company Requirements for Projects Not Eligible for the Simplified Process*. The schedule for the Company's work shall be addressed during the development, or after the execution, of the Interconnection Agreement.

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the final ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the final ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C. No. 2180, Section 3.4 Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	05/11/2021	Original Underground Study
2.0	01/31/2022	Over-head Restudy
3.0	09/20/2021	Fully Underground Design Restudy

Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION
If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

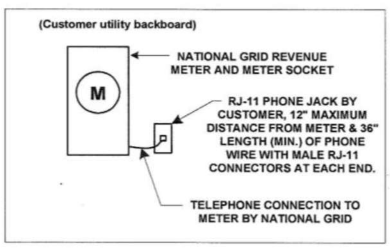

Figure 1A – Indoor Meter Installation
not to scale

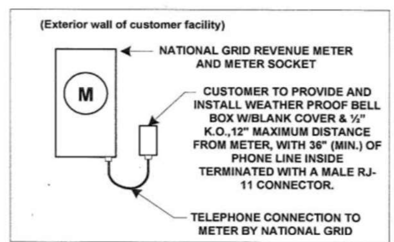

Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION
If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

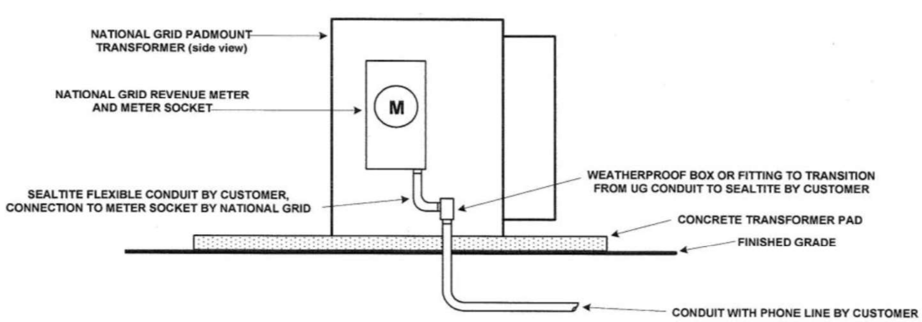

Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

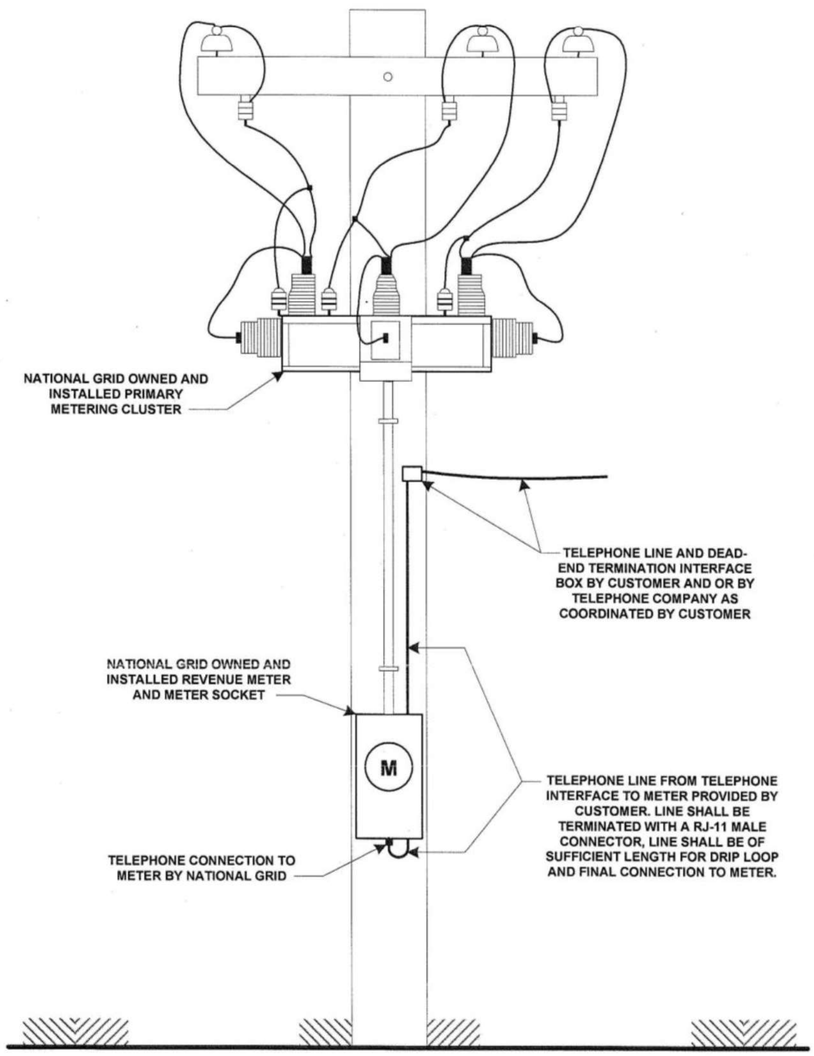

Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

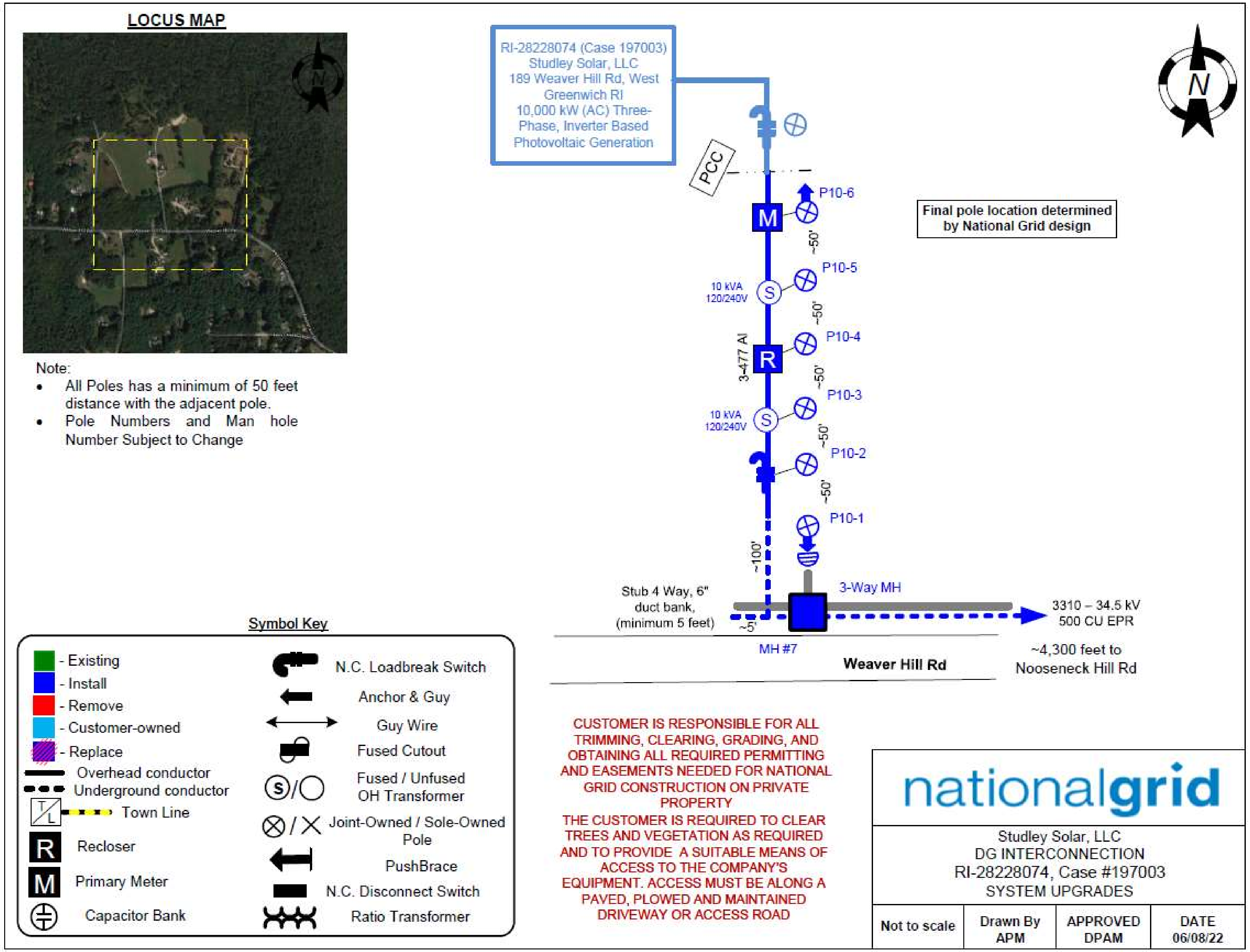

Figure B- 1: PCC Configuration

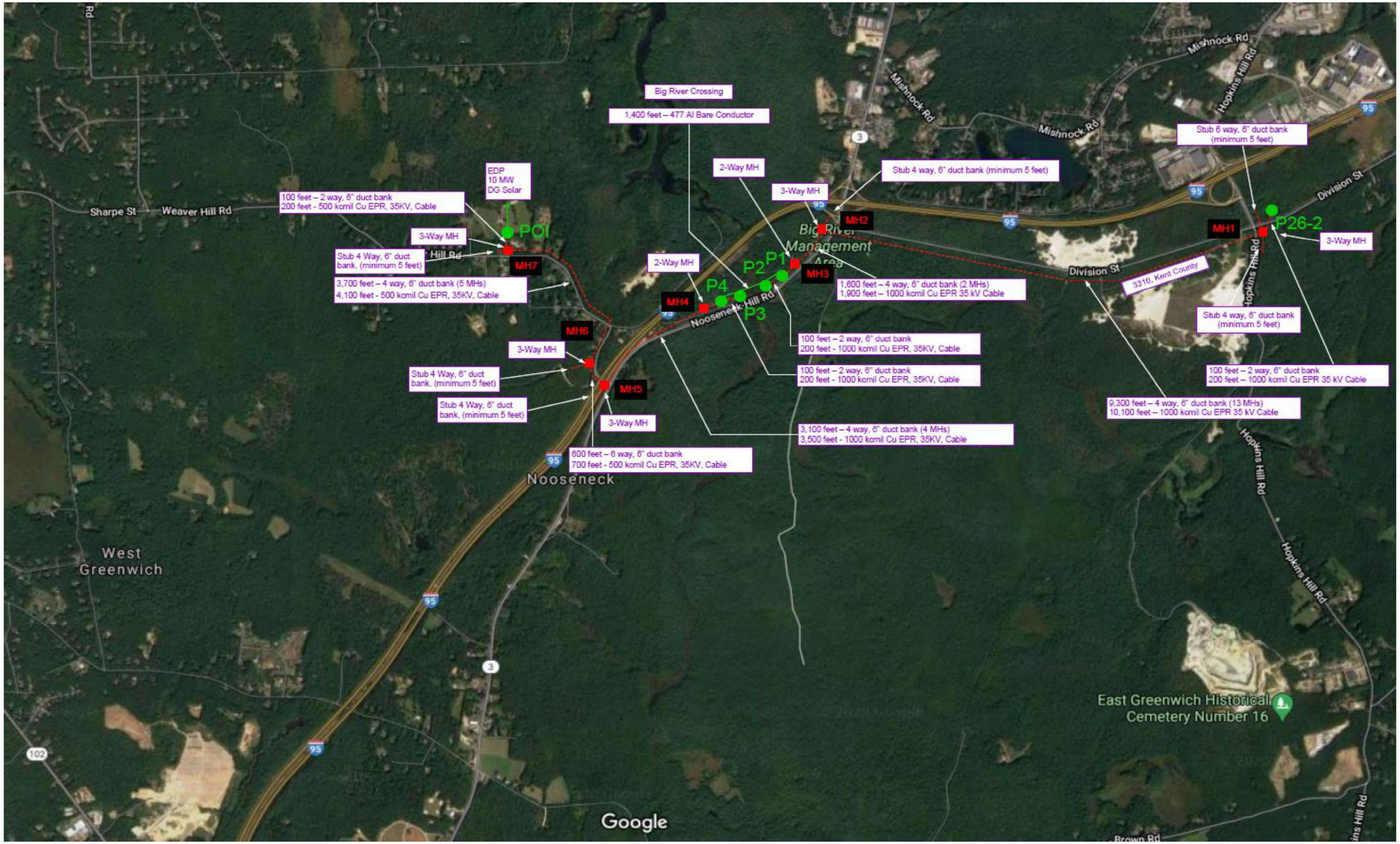

Figure B- 2: System Modification

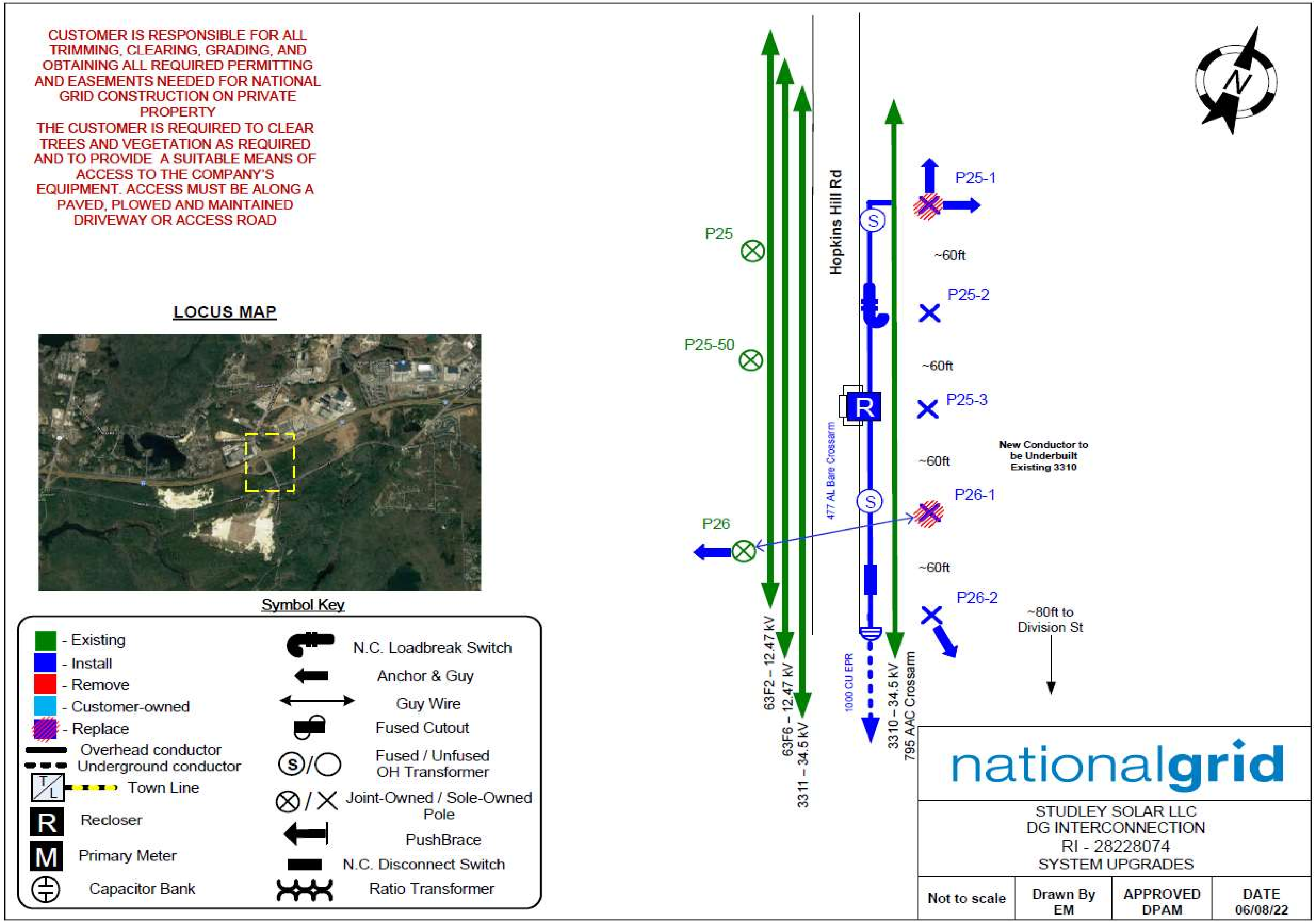

Figure B- 3: System Modification

Appendix C Customer Site and Single Line Diagram

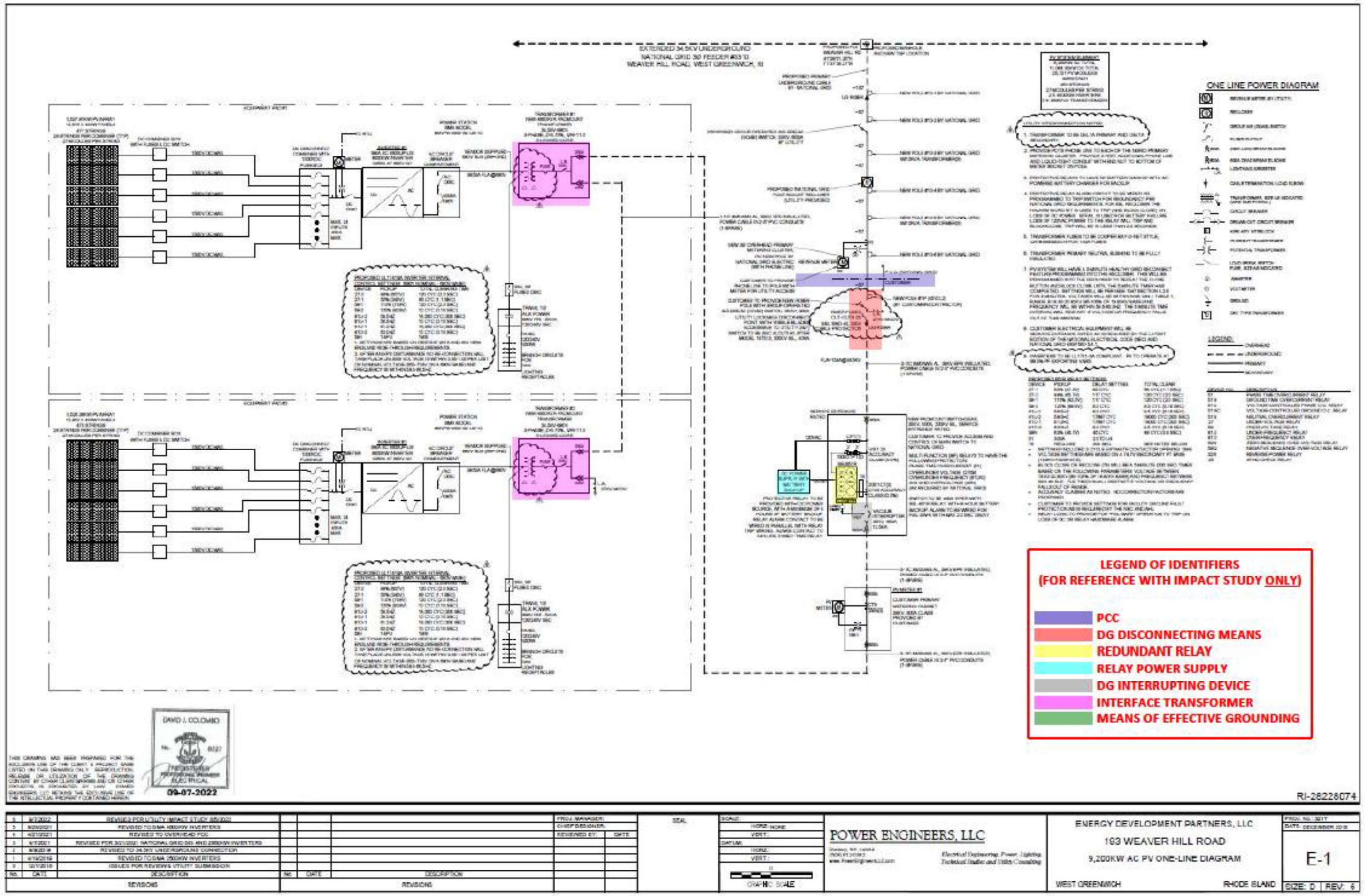

Figure C- 1: Project One-Line
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

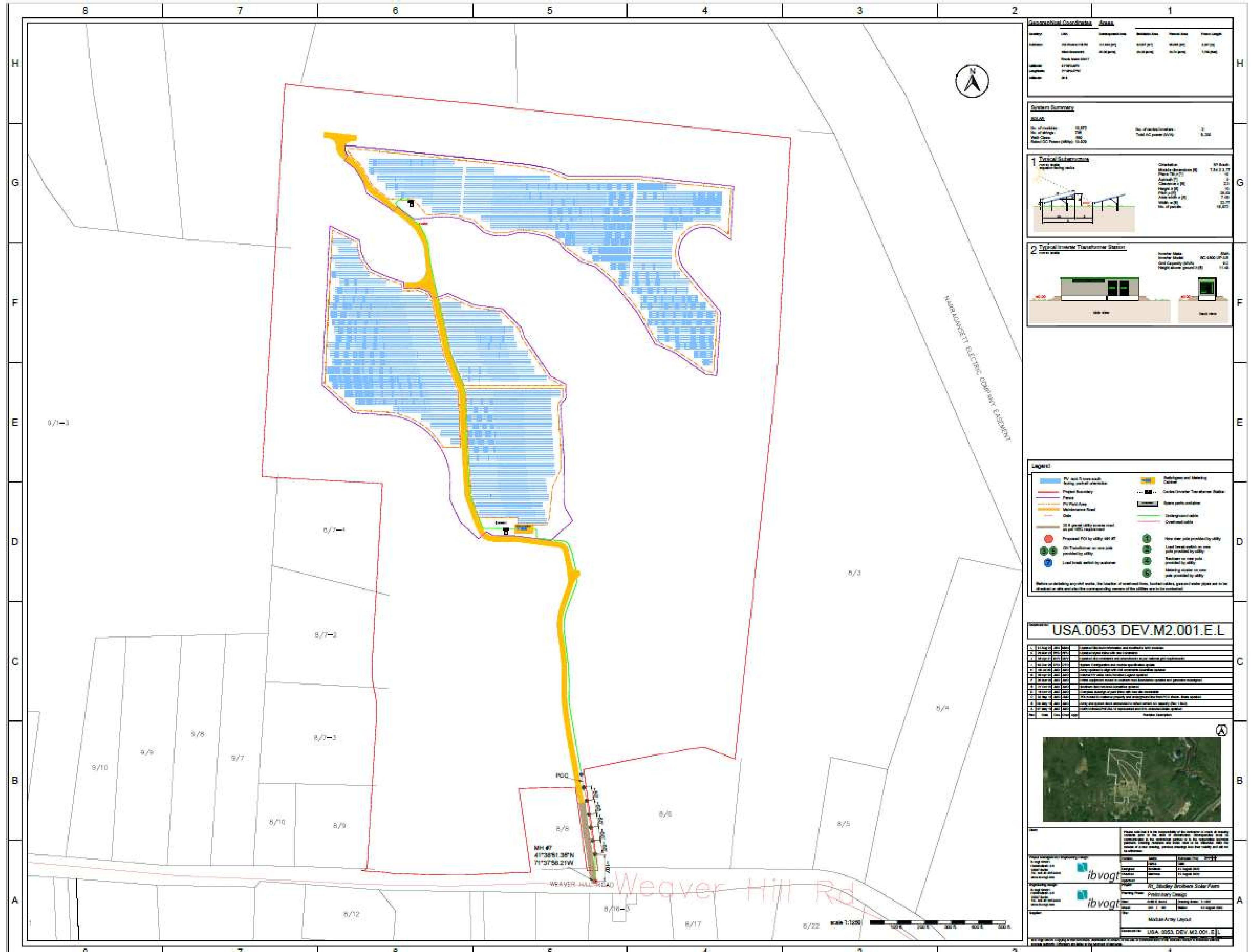

Figure C- 2: Project Site Plan

<u>EXHIBIT BB</u>

Exhibit H – Interconnection Service Agreement

1. **Parties**. This Interconnection Service Agreement ("Agreement"), dated as of 9/11/2023 ("Effective Date") is for application number "28228074" and Case Number "197003" is entered into, by and between **The Narragansett Electric Company (doing business as Rhode Island Energy** a Rhode Island corporation with a principal place of business at **280 Melrose St., Providence, RI 02907** (hereinafter referred to as the "Company"), and **Studley Solar**, a **LLC** with a principal place of business(or residence) at **189 Weaver Hill Road, West Greenwich, RI 02817** ("Interconnecting Customer" or "Customer"). (The Company and Interconnecting Customer are collectively referred to as the "Parties"). Terms used herein without definition shall have the meanings set forth in Section 1.2 of the Interconnection Tariff which is hereby incorporated by reference.

2. **Basic Understandings**. This Agreement provides for parallel operation of an Interconnecting Customer's Facility with the Company EDS to be installed and operated by the Interconnecting Customer at: **189 Weaver Hill Road, West Greenwich RI, 02817**. A description of the Facility is located in Attachment 2. If the Interconnecting Customer is not the Customer, an Agreement between the Company and the Company's Retail Customer, attached as Exhibit J to the Interconnection Tariff, must be signed and included as an Attachment to this Agreement.

   The Interconnecting Customer has the right to operate its Facility in parallel with the Company EDS immediately upon successful completion of the protective relays testing as witnessed by the Company and receipt of written notice from the Company that interconnection with the Company EDS is authorized ("Authorization Date").

3. **Term**. This Agreement shall become effective as of the Effective Date. The Agreement shall continue in full force and effect until terminated pursuant to Section 4 of this Agreement.

4. **Termination**.

4.1 This Agreement may be terminated under the following conditions.

4.1.1 The Parties agree in writing to terminate the Agreement.

4.1.2 The Interconnecting Customer may terminate this agreement at any time by providing sixty (60) days written notice to Company.

4.1.3 The Company may terminate this Agreement upon the occurrence of an Event of Default by the Interconnecting Customer as provided in Section 18 of this Agreement.

4.1.4 The Company may terminate this Agreement if the Interconnecting Customer either: (1) fails to energize the Facility within 12 months of the Authorization Date; or, (2) permanently abandons the Facility. Failure to operate the Facility for any consecutive 12 month period after the Authorization Date shall constitute permanent abandonment unless otherwise agreed to in writing between the Parties.

4.1.5 The Company, upon 30 days' notice, may terminate this Agreement if there are any changes in Commission regulations or state law that have a material adverse effect on the Company's ability to perform its obligations under the terms of this Agreement.

4.2 **Survival of Obligations**. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of termination. Sections 5, 10, 12, 13, and 25 as it relates to disputes pending or for wrongful termination of this Agreement shall survive the termination of this Agreement.

4.3 **Related Agreements**. Any agreement attached to and incorporated into this Agreement shall terminate concurrently with this Agreement unless the Parties have agreed otherwise in writing.

Kathy Castro

4.4

Exhibit H – Interconnection Service Agreement

5. **General Payment Terms**. The Interconnecting Customer shall be responsible for the System Modification costs and payment terms identified in Attachment 3 of this Agreement and any approved cost increases pursuant to the terms of the Interconnection Tariff. If the system modifications exceed $25,000, Attachment 3 will include a payment and construction schedule for both parties. Interconnecting Customers shall be directly responsible to any Affected System operator for the costs of any system modifications necessary to the Affected Systems.

5.1 Cost or Fee Adjustment Procedures. The Company will, in writing, advise the Interconnecting Customer in advance of any expected cost increase for work to be performed up to a total amount of increase of 10% only. Any such changes to the Company's costs for the work shall be subject to the Interconnecting Customer's consent. The Interconnecting Customer shall, within thirty (30) days of the Company's notice of increase, authorize such increase and make payment in the amount up to the 10% increase cap, or the Company will suspend the work and the corresponding agreement will terminate.

5.2 Final Accounting. The Company within ninety (90) business days after completion of the construction and installation of the System Modifications described in an attached exhibit to the Interconnection Service Agreement and all Company work orders have been closed, shall provide Interconnecting Customer with a final accounting report of any difference between the (a) Interconnecting Customer's cost responsibility under the Interconnection Service Agreement for the actual cost of such System Modifications and for any Impact or Detailed Study performed by the Company, and (b) Interconnecting Customer's previous aggregate payments to the Company for such System Modifications and studies. Costs that are statutorily-based shall not be subject to either a final accounting or reconciliation under this provision (e.g., statutorily set study fees for the ISRDG), but may be reconciled at any time only if the costs exceed the statutory fee, and the Company seeks to collect actual costs in accordance with the applicable statute. To the extent that Interconnecting Customer's cost responsibility in the Interconnection Service Agreement for the System Modifications and in the Impact and/or Detailed Study Agreements (as applicable) for the studies performed by the Company exceeds Interconnecting Customer's previous aggregate payments, the Company shall invoice Interconnecting Customer and Interconnecting Customer shall make payment to the Company within forty-five (45) days. To the extent that Interconnecting Customer's previous aggregate payments exceed Interconnecting Customer's cost responsibility under this applicable agreement, the Company shall refund to Interconnecting Customer an amount equal to the difference within forty- five (45) days of the provision of such final accounting report.

6. **Operating Requirements**

6.1 General Operating Requirements. Interconnecting Customer shall operate and maintain the Facility in accordance with the applicable manufacturer's recommended maintenance schedule, in compliance with all aspects of the Company's Interconnection Tariff. The Interconnecting Customer will continue to comply with all applicable laws and requirements after interconnection has occurred. In the event the Company has reason to believe that the Interconnecting Customer's installation may be the source of problems on the Company EDS, the Company has the right to install monitoring equipment at a mutually agreed upon location to determine the source of the problems. If the Facility is determined to be the source of the problems, the Company may require disconnection as outlined in Section 7.0 of the Interconnection Tariff. The cost of this testing will be borne by the Company unless the Company demonstrates that the problem or problems are caused by the Facility or if the test was performed at the request of the Interconnecting Customer.

6.2 No Adverse Effects; Non-interference. Company shall notify Interconnecting Customer if there is evidence that the operation of the Facility could cause disruption or deterioration of service to other Customers served from the same Company EDS or if operation of the Facility could cause damage to Company EDS or Affected Systems. The deterioration of service could be, but is not limited to, harmonic injection in excess of IEEE Standard 1547- 2003, as well as voltage fluctuations caused by large step changes in loading at the Facility. Each Party will notify the other of any emergency or hazardous condition or occurrence with its equipment or facilities which could affect safe operation of the other Party's equipment or facilities. Each Party shall use reasonable efforts to provide the other Party with advance notice of such conditions.

The Company will operate the EDS in such a manner so as to not unreasonably interfere with the operation of the Facility. The Interconnecting Customer will protect itself from normal disturbances propagating through the Company EDS, and such normal disturbances shall not constitute unreasonable interference unless the Company has deviated from Good Utility Practice. Examples of such disturbances could be, but are not limited to, single-phasing events, voltage sags from remote faults on the Company EDS, and outages on the Company EDS. If the Interconnecting Customer demonstrates that the Company EDS is adversely affecting the operation of the Facility and if the adverse effect is a result of a Company deviation from Good Utility Practice, the Company shall take appropriate action to eliminate the adverse effect.

6.3 Safe Operations and Maintenance. Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for, the facility or facilities that it now or hereafter may own unless otherwise specified in this Agreement. Each Party shall be responsible for the maintenance, repair and condition of its respective lines and appurtenances on their respective side of the PCC. The Company and the Interconnecting Customer shall each provide equipment on its respective side of the PCC that adequately protects the Company's EDS, personnel, and other persons from damage and injury.

6.4 Access. The Company shall have access to the disconnect switch of the Facility at all times.

6.4.1 Company and Interconnecting Customer Representatives. Each Party shall provide and update as necessary the telephone number that can be used at all times to allow either Party to report an emergency.

6.4.2 Company Right to Access Company-Owned Facilities and Equipment. If necessary for the purposes of the Interconnection Tariff and in the manner it describes, the Interconnecting Customer shall allow the Company access to the Company's equipment and the Company's facilities located on the Interconnecting Customer's or Customer's premises. To the extent that the Interconnecting Customer does not own all or any part of the property on which the Company is required to locate its equipment or facilities to serve the Interconnecting Customer under the Interconnection Tariff, the Interconnecting Customer shall secure and provide in favor of the Company the necessary rights to obtain access to such equipment or facilities, including easements if the circumstances so require.

6.4.3 Right to Review Information. The Company shall have the right to review and obtain copies of Interconnecting Customer's operations and maintenance records, logs, or other information such as, unit availability, maintenance outages, circuit breaker operation requiring manual reset, relay targets and unusual events pertaining to Interconnecting Customer's Facility or its interconnection with the Company EDS. This information will be treated as customer-confidential and only used for the purposes of meeting the requirements of Section 4.2.6 in the Interconnection Tariff.

7. Disconnection

7.1 Temporary Disconnection

7.1.1 Emergency Conditions. Company shall have the right to immediately and temporarily disconnect the Facility without prior notification in cases where, in the reasonable judgment of Company, continuance of such service to Interconnecting Customer is imminently likely to (i) endanger persons or damage property or (ii) cause a material adverse effect on the integrity or security of, or damage to, Company EDS or to the electric systems of others to which the Company EDS is directly connected. Company shall notify Interconnecting Customer promptly of the emergency condition. Interconnecting Customer shall notify Company promptly when it becomes aware of an emergency condition that affects the Facility that may reasonably be expected to affect the Company EDS. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, or the expected effect on the operation of both Parties' facilities and operations, its anticipated duration and the necessary corrective action.

7.1.2 Routine Maintenance, Construction and Repair. Company shall have the right to disconnect the Facility from the Company EDS when necessary for routine maintenance, construction and repairs on the Company EDS. The Company shall provide the Interconnecting Customer with a minimum of seven calendar days planned outage notification consistent with the Company's planned outage notification protocols. If the Interconnecting Customer requests disconnection by the Company at the PCC, the Interconnecting Customer will provide a minimum of seven days' notice to the Company. Any additional notification requirements will be specified by mutual agreement in the Interconnection Service Agreement. Company shall make an effort to schedule such curtailment or temporary disconnection with Interconnecting Customer.

7.1.3 Forced Outages. During any forced outage, Company shall have the right to suspend interconnection service to effect immediate repairs on the Company EDS; provided, however, Company shall use reasonable efforts to provide the Interconnecting Customer with prior notice. Where circumstances do not permit such prior notice to Interconnecting Customer, Company may interrupt Interconnection Service and disconnect the Facility from the Company EDS without such notice.

7.1.4 Non-Emergency Adverse Operating Effects. The Company may disconnect the Facility if the Facility is having an adverse operating effect on the Company EDS or other customers that is not an emergency, and the Interconnecting Customer fails to correct such adverse operating effect after written notice has been provided and a maximum of 45 days to correct such adverse operating effect has elapsed.

7.1.5 Modification of the Facility. Company shall notify Interconnecting Customer if there is evidence of a material modification to the Facility and shall have the right to immediately suspend interconnection service in cases where such material modification has been implemented without prior written authorization from the Company.

7.1.6 Re-connection. Any curtailment, reduction or disconnection shall continue only for so long as reasonably necessary. The Interconnecting Customer and the Company shall cooperate with each other to restore the Facility and the Company EDS, respectively, to their normal operating state as soon as reasonably practicable following the cessation or remedy of the event that led to the temporary disconnection.

7.2 Permanent Disconnection. The Interconnecting Customer has the right to permanently disconnect at any time with 30 days written notice to the Company.

7.2.1 The Company may permanently disconnect the Facility upon termination of the Interconnection Service Agreement in accordance with the terms thereof.

8. **Metering**. Metering of the output from the Facility shall be conducted pursuant to the terms of the Interconnection Tariff.

9. **Assignment**. Except as provided herein, Interconnecting Customer shall not voluntarily assign its rights or obligations, in whole or in part, under this Agreement without the Company's written consent. Any assignment that the Interconnecting Customer purports to make without the Company's written consent shall not be valid. The Company shall not unreasonably withhold or delay its consent to Interconnecting Customer's assignment of this Agreement. Notwithstanding the above, the Company's consent will not be required for any assignment made by the Interconnecting Customer to an Affiliate or as collateral security in connection with a financing transaction. In all events, the Interconnecting Customer will not be relieved of its obligations under this Agreement unless and until the assignee assumes in writing all obligations of this Agreement and notifies the Company of such assumption. The Interconnecting Customer must sign a consent agreement to complete the assignment to a new system owner and execute Exhibit I when the Interconnecting Customer is still going to be the retail delivery customer or property owner.

10. **Confidentiality**. Company shall maintain confidentiality of all Interconnecting Customer confidential and proprietary information except as otherwise required by applicable laws and regulations, the Interconnection Tariff, or as approved by the Interconnecting Customer in the Simplified or Expedited/Standard Application form or otherwise.

11. **Insurance Requirements**.

11.1 General Liability.

11.1(a) In connection with Interconnecting Customer's performance of its duties and obligations under the Interconnection Service Agreement, Interconnecting Customer shall maintain, during the term of the

Exhibit H – Interconnection Service Agreement

Agreement, general liability insurance with a combined single limit of not less than:

i. Five million dollars ($5,000,000) for each occurrence and in the aggregate if the Gross Nameplate Rating of Interconnecting Customer's Facility is greater than five (5) MW.

ii. Two million dollars ($2,000,000) for each occurrence and five million dollars ($5,000,000) in the aggregate if the Gross Nameplate Rating of Interconnecting Customer's Facility is greater than one
(1) MW and less than or equal to five (5) MW;

iii. One million dollars ($1,000,000) for each occurrence and in the aggregate if the Gross Nameplate Rating of Interconnecting Customer's Facility is greater than one hundred (100) kW and less than or equal to one (1) MW;

iv. Five hundred thousand dollars ($500,000) for each occurrence and in the aggregate if the Gross Nameplate Rating of Interconnecting Customer's Facility is greater than ten (10) kW and less than or equal to one hundred (100) kW, except for eligible net metered customers which are exempt from insurance requirements.

11.1(b) No insurance is required for a Facility with a Gross Nameplate Rating less than or equal to 50 kW that is eligible for net metering. However, the Company recommends that the Interconnecting Customer obtain adequate insurance to cover potential liabilities.

11.1(c) Any combination of General Liability and Umbrella/Excess Liability policy limits can be used to satisfy the limit requirements stated above.

11.1(d) The general liability insurance required to be purchased in this Section may be purchased for the direct benefit of the Company and shall respond to third party claims asserted against the Company (hereinafter known as "Owners Protective Liability"). Should this option be chosen, the requirement of Section 11.2(a) will not apply but the Owners Protective Liability policy will be purchased for the direct benefit of the Company and the Company will be designated as the primary and "Named Insured" under the policy.

11.1(e) The insurance hereunder is intended to provide coverage for the Company solely with respect to claims made by third parties against the Company.

11.1(f) In the event the State of Rhode Island, or any other governmental subdivision thereof subject to the claims limits of Rhode Island General Laws Chapter 9-31 (hereinafter referred to as the "Governmental Entity") is the Interconnecting Customer, any insurance maintained by the Governmental Entity shall contain an endorsement that strictly prohibits the applicable insurance company from interposing the claims limits of Rhode Island General Laws Chapter 9-31 as a defense in either the adjustment of any claim, or in the defense of any lawsuit directly asserted against the insurer by the Company. Nothing herein is intended to constitute a waiver or indication of an intent to waive the protections of Rhode Island General Laws Chapter 9-31 by the Governmental Entity.

11.2 Insurer Requirements and Endorsements. All required insurance shall be carried by reputable insurers qualified to underwrite insurance in Rhode Island having a Best Rating of "A-". In addition, all insurance shall, (a) include Company as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that Company shall not incur liability to the insurance carrier for payment of premium for such insurance; and
(d) provide for thirty (30) calendar days' written notice to Company prior to cancellation, termination, or material change of such insurance; provided that to the extent the Interconnecting Customer is satisfying the requirements of subpart (e) of this paragraph by means of a presently existing insurance policy, the Interconnecting Customer shall only be required to make good faith efforts to satisfy that requirement and will assume the responsibility for notifying the Company as required above.

11.3 Evidence of Insurance. Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Interconnecting Customer.

Exhibit H – Interconnection Service Agreement

The Interconnecting Customer is responsible for providing the Company with evidence of insurance in compliance with the Interconnection Tariff on an annual basis.

Prior to the Company commencing work on System Modifications and annually thereafter, the Interconnecting Customer shall have its insurer furnish to the Company certificates of insurance evidencing the insurance coverage required above. The Interconnecting Customer shall notify and send to the Company a certificate of insurance for any policy written on a "claims-made" basis. The Interconnecting Customer will maintain extended reporting coverage for three years on all policies written on a "claims-made" basis.

In the event that an Owners Protective Liability policy is provided, the original policy shall be provided to the Company.

11.4 All insurance certificates, statements of self-insurance, endorsements, cancellations, terminations, alterations, and material changes of such insurance shall be issued, updated and submitted yearly to the following:

The Narragansett Electric
Company Attention: Risk
Management
280 Melrose Street,
Providence RI, 02907

12. **Indemnification**. Except as precluded by the laws of the State of Rhode Island, Interconnecting Customer and Company shall each indemnify, defend and hold the other, its directors, officers, employees and agents (including, but not limited to, Affiliates and contractors and their employees), harmless from and against all liabilities, damages, losses, penalties, claims, demands, suits and proceedings of any nature whatsoever for personal injury (including death) or property damages to unaffiliated third parties that arise out of or are in any manner connected with the performance of this Agreement by that Party except to the extent that such injury or damages to unaffiliated third parties may be attributable to the negligence or willful misconduct of the Party seeking indemnification.

13. **Limitation of Liability**. Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including court costs and reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage or liability actually incurred. In no event shall either Party be liable to the other Party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever.

14. **Amendments and Modifications**. No amendment or modification of this Agreement shall be binding unless in writing and duly executed by both Parties.

15. **Permits and Approvals**. Interconnecting Customer shall obtain all environmental and other permits lawfully required by governmental authorities for the construction and operation of the Facility. Prior to the construction of System Modifications the interconnecting customer will notify the Company that it has initiated the permitting process. Prior to the commercial operation of the Facility the Customer will notify the Company that it has obtained all permits necessary. Upon request the Interconnecting Customer shall provide copies of one or more of the necessary permits to the Company.

16. **Force Majeure**. For purposes of this Agreement, "Force Majeure Event" means any event:

    a. that is beyond the reasonable control of the affected Party; and

    b. that the affected Party is unable to prevent or provide against by exercising commercially reasonable efforts, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war or terrorism, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lighting, storms, and other natural calamities; explosions or fire; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible. In no event will the unavailability or inability to obtain funds constitute a Force Majeure Event.

17. Notices.

17.1 Any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given on the date actually delivered in person or five (5) business days after being sent by certified mail, e-mail or fax with confirmation of receipt and original follow-up by mail, or any nationally-recognized delivery service with proof of delivery, postage prepaid, to the person specified below:

If to Company:	**Rhode Island Energy** **Attention: Distributed Generation** **280 Melrose Street, Providence RI, 02907** **CAP@RIEnergy.com**
If to Interconnecting Customer:	**Studley Solar, LLC** **260 West Exchange Street, Suite 102A** **Providence RI 02903** **401-349-1229 x700** **frank@edp-energy.com**

17.2 A Party may change its address for Notices at any time by providing the other Party Notice of the change in accordance with Section 17.1.

17.3 The Parties may also designate operating representatives to conduct the daily communications, which may be necessary or convenient for the administration of this Agreement. Such designations, including names, addresses, and phone numbers may be communicated or revised by one Party's Notice to the other.

18. Default and Remedies

18.1 Defaults. Any one of the following shall constitute "An Event ofDefault."

(i) One of the Parties shall fail to pay any undisputed bill for charges incurred under this Agreement or other amounts which one Party owes the other Party as and when due, and such failure shall continue for a period of thirty (30) days after written notice of nonpayment from the affected Party to the defaulting Party, or

(ii) One of the Parties fails to comply with any other provision of this Agreement or breaches any representation or warranty in any material respect and fails to cure or remedy that default or breach within sixty (60) days after notice and written demand by the affected Party to cure the same or such longer period reasonably required to cure (not to exceed an additional 90 days unless otherwise mutually agreed upon), provided that the defaulting Party diligently continues to cure until such failure is fully cured.

Exhibit H – Interconnection Service Agreement

18.2 **Remedies**. Upon the occurrence of an Event of Default, the affected Party may at its option, in addition to any remedies available under any other provision herein, do any, or any combination, as appropriate, of the following:

a. Continue to perform and enforce this Agreement;

b. Recover damages from the defaulting Party except as limited by this Agreement;

c. By written notice to the defaulting Party terminate this Agreement;

d. Pursue any other remedies it may have under this Agreement or under applicable law or in equity.

19. **Entire Agreement**. This Agreement, including any attachments or appendices, is entered into pursuant to the Interconnection Tariff. Together the Agreement and the Interconnection Tariff represent the entire understanding between the Parties, their agents, and employees as to the subject matter of this Agreement. Each Party also represents that in entering into this Agreement, it has not relied on any promise, inducement, representation, warranty, agreement or other statement not set forth in this Agreement or in the Company's Interconnection Tariff.

20. **Supercedence**. In the event of a conflict between this Agreement, the Interconnection Tariff, or the terms of any other tariff, Exhibit or Attachment incorporated by reference, the terms of the Interconnection Tariff, as the same may be amended from time to time, shall control. In the event that the Company files a revised tariff related to interconnection for Commission approval after the effective date of this Agreement, the Company shall, not later than the date of such filing, notify the signatories of this Agreement and provide them a copy of said filing.

21. **Governing Law**. This Agreement shall be interpreted, governed, and construed under the laws of the State of Rhode Island without giving effect to choice of law provisions that might apply to the law of a different jurisdiction.

22. **Non-waiver**. None of the provisions of this Agreement shall be considered waived by a Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

23. **Counterparts**. This Agreement may be signed in counterparts.

24. **No Third Party Beneficiaries**. This Agreement is made solely for the benefit of the Parties hereto. Nothing in the Agreement shall be construed to create any rights in or duty to, or standard of care with respect to, or any liability to, any person not a party to this Agreement.

25. **Dispute Resolution**. Unless otherwise agreed by the Parties, all disputes arising under this Agreement shall be resolved pursuant to the Dispute Resolution Process set forth in the Interconnection Tariff.

26. **Severability**. If any clause, provision, or section of this Agreement is ruled invalid by any court of competent jurisdiction, the invalidity of such clause, provision, or section, shall not affect any of the remaining provisions herein.

Exhibit H – Interconnection Service Agreement

27. **Signatures**. IN WITNESS WHEREOF, the Parties hereto have caused two (2) originals of this Agreement to be executed under seal by their duly authorized representatives.

	Studley Solar, LLC:		The Narragansett Electric Company (d/b/a Rhode Island Energy):
Name:	Frank A. Epps	Name:	Kathy Castro
Title:	Manager	Title:	Director Engineering and Asset Mgt.
Date:	September 11, 2023	Date:	September 19, 2023
Signature:	Frank A. Epps	Signature:	Kathy Castro

Business Use

Exhibit H – Interconnection Service Agreement

Attachment 1: Description of Facilities, including demarcation of Point of Common Coupling

Interconnecting Customer has proposed a **9,200** kW photovoltaic system located at **189 Weaver Hill Road, West Greenwich, RI 02817**. The proposed Facility is an Independent Power Producer ("IPP"). Facilities will interconnect to the Rhode Island Energy electric system via the Kent County Substation, 34.5 kV distribution feeder 3310, ("Point of Interconnection" or "POI").

Description of proposed design/configuration:

- Two (2) Customer owned SMA 4600-UP-US, three phase inverters for an assumed total of 9,200kW/kVA of inverter-based PV
- Two (2) Customer owned 4,600 kVA, 34.5kV wye-ground, 600V delta secondary pad-mounted interface transformer with an impedance of Z = 5.75% along with X/R ratio of 11
- One (1) Customer owned pad-mounted switchgear 35kV, 600A, 200kV BIL G&W Viper recloser with SEL-651R relay assembly with 8-hour battery backup
- One (1) Customer owned GOAB switch, S&C Model #147513, 200kV BIL, 40kA with visible, lockable blades and utility accessible 24/7

Metering: The company will install (1) pole-mounted primary meter, please refer to ESB 750 and ESB 756 Appendix D for service installation and primary meter installation.

PCC: The Company's Design Personnel will determine the exact location of the Company's facilities and the Customer's gang operated disconnect. The Customer's gang operated disconnect must be accessible by the Company's personnel at all times, and be capable of being locked open and tagged by Company personnel. The Point of Common Coupling (PCC) will be designated as the Customer's side of the Company's primary meter. The Interconnecting Customer must install their Facilities up to the Company revenue meter. The Interconnecting Customer must provide sufficient conductor to allow the Company to make final connections at the meter pole. The Company will provide final connection of the Interconnecting Customer conductors to the Company meter.

Exhibit H – Interconnection Service Agreement

Attachment 2: Description of System Modifications

Rhode Island Energy System Modifications required for the interconnection of 9,200 kW (AC) application as identified in the impact study are as follows:

On the Customer's property:

- Install ~250 feet of 3-477 AL Bare conductor
- Install one (1) 35 kV load break switch
- Install two (2) single-phase transformers
- Install one (1) primary meter

On the Company's distribution system:

Facility Specific Distribution Modifications

- Install ~4100 circuit feet 3-1/c 500 kcmil CU EPR 35 kV cable from the first 3-way manhole on Weaver Hill Road to the 3-way manhole at EDP 10 MW POI located at 189 Weaver Hill Road.
- Install ~200 feet of 3-1/c 500 kcmil CU EPR 35kV cable from the 3-way MH at EDP 10MW POI located at 189 Weaver-Hill Road to proposed riser pole on Customer property.

Common Distribution Modifications

- Install ~16,100 circuit feet of 3-1/c 1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way manhole at the intersection of Nooseneck Hill Road/Weaver Hill Road. (Previously installed by Green Development)
- Install ~700 circuit feet 3-1/c 500 kcmil CU EPR 35 kV cable from 3-way manhole at the intersection of Weaver Hill Road to the first 3-way manhole on Weaver Hill Road
- Install ~1,400 feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Rd
- Install ~410 circuit feet of 3-477 AL Bare Conductor, two (2) single phase transformers, one (1) 35kV recloser, one (1) 35kV disconnect switch, one (1) 35kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Rd, Coventry RI

Civil Construction (design and installation performed by third parties)

- Install MH and duct system (~14,300 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection on Nooseneck Hill Road/Weaver Hill Road
- Install manhole and duct system (~600 feet) from 3-way manhole at intersection Hill Road/Weaver Hill Road to first 3-way manhole on Weaver Hill Road.

To be designed and self-built by Customer

- Install MH and duct system (~3,700 feet) from the first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10MW POI located at 189 Weaver Hill Road (to be self-built by Customer).
- Install MH and duct system (~100 feet) from 3-way MH at EDP 10MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer Property

At the Company's substation:

Common substation modifications:

- Add load encroachment settings to the Kent County T7 Directional Overcurrent Relay

Exhibit H – Interconnection Service Agreement

It will be the responsibility of the Interconnecting Customer, at its sole cost and expense, to secure and obtain in favor of itself and the Company, the following: any and all rights, consents, permits, approvals, and easements (free and clear from any encumbrances), as are required for the Company's System Modifications on any Interconnecting Customer-owned property or any third-party owned property ("Third Party Rights and Approvals"). The Interconnecting Customer shall use the Company's standard form when obtaining all Third Party Rights and Approval, as applicable. The Company will seek to obtain, at the Interconnecting Customer's sole cost and expense, any and all rights, consents, permits, approvals, and easements for the System Modifications on any Company owned property or within any public roadway as the Company determines necessary in its sole discretion ("Other Rights and Approvals"; together with Third Party Rights and Approvals referred to as "System Modification Required Approvals"). The Interconnecting Customer will fully cooperate with the Company in obtaining the Other Rights and Approvals. The Company shall not be required to accept any System Modification Required Approvals that are not in form or on terms satisfactory to the Company in its sole discretion or that additional liabilities or costs on the Company. The Company shall not be required to appeal or challenge the denial of any System Modification Required Approvals or the imposition of any unsatisfactory term or condition. The Company shall not be obligated to commence the construction of the System Modifications unless and until it has received all System Modification Required Approvals in accordance with this provision, and Sections 5 and 15 of this Agreement, above, and the Company's Standards for Connecting Distributed Generation, tariff R.I.P.U.C No. 2258, and Terms and Conditions for Distribution Service, tariff R.I.P.U.C. No. 2243, as amended from time to time.

Business Use

Exhibit H – Interconnection Service Agreement

Attachment 3: Costs of System Modifications and Payment Terms

In order to safely and reliably interconnect this application, this Facility will utilize an already constructed ductbank, referred to herein as the 1st THIRD PARTY DUCTBANK. This 1st THIRD PARTY DUCTBANK has a length of 28,568 feet. Upon completion of construction of that ductbank, a third-party audit was conducted on the 1st THIRD PARTY DUCTBANK which verified the actual cost of $12,023,525. The Company will facilitate the sharing of costs of the 1st THIRD PARTY DUCTBANK with all interconnecting customers that occupy a common path of the 1st THIRD PARTY DUCTBANK based on the costs incurred on the common path and a pro rata megawatt share of the common path. The costs incurred on the common path were $5,892,962. EDP's pro rata megawatt share (9.2 MW of 69.9 MW) is 13.162%, costing $775,612. The Company will facilitate the sharing of costs to each prior interconnecting customer that occupies a common path of the ductbank.

A 2nd THIRD PARTY DUCTBANK, must also be constructed. This 2nd THIRD PARTY DUCTBANK is currently under construction by a separate interconnecting customer and has an approximate length of 600 feet that EDP will utilize for this application. The Company will facilitate the sharing of costs of the 2nd THIRD PARTY DUCTBANK with all interconnecting customers that occupy a common path of the 2nd THIRD PARTY DUCTBANK based on the costs incured of the common path and a pro rata megawatt share of the common path. The common path of the 2nd THIRD PARTY DUCTBANK will be occupied by the separate interconnecting customer and EDP and the pro rata megawatt share (9.2 MW of 49.9 MW) is 18.437%. The Company will facilitate cost sharing based on the cost incurred on the common path and a pro rata megawatt share once the ductbank is fully constructed and the costs are verified through an audit.

A 3,800-foot ductbank must be constructed along Weaver-Hill and will be used solely for this application; (the "EDP DUCTBANK"). The EDP DUCTBANK has a length of 3,800 feet, which EDP will self-build. The costs associated with this self-build are not included in the total estimated cost presented in Exhibit H.

During construction of the 2nd THIRD PARTY DUCTBANK, the Company will request the entity constructing the 2nd THIRD PARTY DUCTBANK to provide a cost summary (including a detailed accounting ledger for each line item presented on the cost summary) with the following supporting information: vendor name, date/dates of service, detailed description of service, copy of the cancelled check(s), and associated contract/purchase order/timeslip/certified payroll/etc. documents. Upon the receipt of all required documentation, the Company will hire a third party to perform an audit and verify the proposed costs incurred by the third party and will adjust the Interconnecting Customer Cost Share Amount to reflect such reconciliation (which adjustment shall be reflected in an amended interconnection service agreement) for cost line items that, in whole or in part, do not qualify as an approved cost.

The Company will hire a third party to perform an audit and verify the actual costs incurred to construct the EDP DUCTBANK and agrees that it will facilitate the sharing of such costs with all future parties that occupy a common path of the EDP DUCTBANK based on the distance of the common path and a pro rata megawatt share, and that any such cost sharing amount that is collected by the Company shall be disbursed to EDP LLC.

To the extent that any System Modification necessary to interconnect the Facility accelerates a System Improvement, a portion of the total costs associated with this application may be subject to cost sharing with the Company and the costs identified may be reimbursed in part or in whole, subject to approval by the Rhode Island Public Utilities Commission.

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

R.I.P.U.C. No. 2258

Exhibit H – Interconnection Service Agreement

At present, System Modification Costs associated with this application (excluding the EDP DUCTBANK) are: **$8,437,085**+/- 25% and itemized as follows:

Rhode Island Energy System Modification	Conceptual Cost +/-25% Planning Grade Cost Estimate not including Tax Liability				Associated Tax Liability Applied to Capital	Total Customer Costs includes Tax Liability on Capital Portion
RIE - Civil Work	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Approximate donated property tax. (See Note #1)	$0	$0	$0	$0	$82,718	$82,718
RIE Supervision and Design Support for Customer Underground Civil Construction.	$165,000	$165,000	$0	$0	$18,282	$183,282
Distribution Civil work, 3310 circuit (Cost Sharing applied. See Note #2)	$1,416,042	$1,416,042	$0	$0	$156,897	$1,572,939
SUBTOTAL	**$1,581,042**	**$1,581,042**	**$0**	**$0**	**$257,897**	**$1,838,939**

RIE - Line Work, Customer Property	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Equipment at Point of Common Coupling, 3310 Circuit.	$310,038	$310,038	$0	$0	$34,352	$344,390
SUBTOTAL	**$310,038**	**$310,038**	**$0**	**$0**	**$34,352**	**$344,390**

RIE - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Distribution Line work, 3310 Circuit. (Cost Sharing applied. See Note #3	$5,621,801	$5,612,059	$5,272	$4,470	$621,816	$6,243,617
SUBTOTAL	**$5,621,801**	**$5,612,059**	**$5,272**	**$4,470**	**$621,816**	**$6,243,617**

RIE - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
Add Load Encroachment to the Kent County T7 Directional Overcurrent Relay. (Cost Sharing applied. See Note #4	$2,400	$2,250	$150	$0	$238	$2,638
SUBTOTAL	**$2,400**	**$2,250**	**$150**	**$0**	**$238**	**$2,638**

Witness Testing & EMS	Pre-Tax Total	Capital	O&M	Removal	NA	Total
Witness Testing.	$2,500	NA	$2,500	NA	NA	$2,500
EMS integration.	$5,000	NA	$5,000	NA	NA	$5,000
SUBTOTAL	**$7,500**	**$0**	**$7,500**	**$0**	**$0**	**$7,500**

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	**$7,522,781**	**$7,505,389**	**$12,922**	**$4,470**	**$914,303**	**$8,437,085**

Exhibit H – Interconnection Service Agreement

- Note #1: Total cost of the approximate donated property tax is **$82,718**. The approximate donated property tax for the Customer installation of (1) – 3-way manhole, (5)- 2-way manholes, (100 feet) 2-way 6' PVC – DB concreate encased ductbank, (3700 feet) – 4-way, 6" PVC – DB concrete encased ductbank and associated equipment. Customer is responsible for performing, any and all, temporary and permanent restoration.

- Note #2: Total cost shared value of common system modifications on the Company's distribution system, specifically the installation of the manhole and duct system (1st THIRD PARTY DUCTBANK and 2nd THIRD PARTY DUCTBANK) is **$1,416,042** (includes capital costs). The common path of the 1st THIRD PARTY DUCTBANK utilized by all three parties cost $5,892,962 to build. The cost for this modification will be shared on a pro-rata basis with RI-2782578, RI-27888883, RI-29048593, RI-29018573, RI-29048568, RI-29048550, RI-29048531, RI-29048488, RI-25999253. RI-28228074 will be responsible for **13.162%** or **$775,612**. The common path of the 2nd THIRD PARTY DUCTBANK utilized by two parties is estimated at 600' and has an estimated cost share value of **$640,430**, shared with RI-29048593, RI-29018573, RI-29048568, RI-29048550, RI-29048531, RI-29048488, RI-25999253.

- Note #3: Total estimated value for distribution line work on the Company's distribution system on the 3310 circuit is **$5,621,801.** It is estimated that this application will be responsible for a cost share amount of **$2,295,104**. The cost for this modification will be shared on a pro-rata basis with RI-27825278, RI-27888883, RI-29048593, RI-29018574, RI-29048568, RI-29048550, RI-29048531, RI-29048488, RI-29599253. The cost-shared value is subject to change and will be determined once all prior projects of the aforementioned Work Request Numbers are fully interconnected and costs are reconciled.

- Note #4: Total cost of common system modifications (NECO) at the distribution side of the Kent County Substation as mentioned in Attachment 2 (load encroachment) above is **$16,000** (includes capital and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-29048593, RI-29048574, RI-29048568, RI-29048550, RI-29048488, RI-29599253, RI-29048531, RI-27780479, RI-27780375, and RI-28228074. RI-28228074 will be responsible for **15%** or **$2,400**.

- Tax gross-up adder on capital costs is **$914,303**. (*A 2023 tax rate of 11.08% is expected to apply to contributions in aid of construction ("CIAC") payments received by The Narragansett Electric Company from the Interconnecting Customer, and a 2013 tax rate of 9.90% is expected to apply to CIAC payments associated with substation modifications for interconnections. The calculation of the tax gross-up adder is included in this cost estimate on the basis of tax guidance published by the Internal Revenue Service, but tax rates and decisions are ultimately subject to IRS discretion. By signing this agreement, the Interconnecting Customer understands and agrees that the tax has been estimated for convenience and that the Interconnecting Customer remains liable for all tax due on CIAC payments, payable upon the Company's demand.*

The system modification costs were developed by the Company with a general understanding of the project and based upon information provided by the Interconnecting Customer in writing and/or collected in the field. The cost estimates were prepared using historical cost data, data from similar projects, and other assumptions, and while they are presumed valid for 60 business days from the date of the Impact /Group Study, the Company reserves the right to adjust those estimated costs as authorized under this Agreement, the Tariff, or by law and to require the Interconnecting Customer to pay any such additional costs.

The Total System Modifications Costs and the Facility System Modification Costs do not include any costs for Third Party Rights and Approvals (as defined in Attachment 2) or any Verizon system modification costs and charges (and fees for services related thereto), for which the Interconnecting Customer may be directly responsible. These costs, to the extent applicable, are in addition to the Total System Modifications Costs and the Facility System Modification Costs and must be paid directly by the Interconnecting Customer to the appropriate third party.

Exhibit H – Interconnection Service Agreement

ISO-NE Planning Study
Rhode Island Energy Transmission Planning has studied the impact of the proposed project in accordance with the ISO New England Inc. (ISO- NE) Planning Procedure 5-6 "Scope of Study for System Impact Studies under the Generation Interconnection Procedures" and Rhode Island Energy TGP28 "Transmission Planning Guide." Rhode Island Energy Transmission Planning has determined that there are no adverse impacts to the transmission system.

ISO-NE Operating Requirement
This is part of a group of generating Facilities within close proximity, as determined by ISO-NE, which equals or exceeds an aggregate of 5MW and will be required to comply with ISO-NE's requirements, including Operating Procedure No. 14. Prior to the Company providing Authorization to Interconnect, the Interconnecting Customer will be required to provide evidence that it has complied with all applicable ISO-NE registration requirements. Additionally, ISO-NE may determine that there are additional system upgrade costs.

Additional costs may be involved if the required pole work takes place in Telephone Company Maintenance Areas. These costs will be billed directly to the Interconnecting Customer from the Telephone Company.

Payment Terms:

System Modifications Costs may be paid in full if less than $25,000, or if greater than $25,000 in scheduled payments (per Section 5.5 of R.I.P.U.C No. 2258):

- The first payment (5% plus 1st THIRD PARTY DUCTBANK cost share) of **$934,054.55** is due when the first invoice is received after Exhibit H - Interconnection Service Agreement is returned to the Company with Interconnecting Customer signature. The invoice also includes the total cost share amount the Interconnection Customer owes for the 1st THIRD PARTY DUCTBANK, see note #2 above. The invoice, including payment instructions, will be sent to the Interconnecting Customer. Proof of payment is required.
- The second payment (20%) of **$633,770.19** is due within 15 business days from the receipt of the second payment invoice. The second invoice will be sent approximately 12 weeks from the signing of the ISA, when the electrical and civil design have been completed by both Customer and company which his estimated to be around 11/6/2023. An invoice, including payment instructions, will be sent to the Interconnecting Customer.
- The third payment (75%) of **$2,376,638.23** is due within 15 business days from the receipt of the third payment invoice. The third invoice will be sent when Rhode Island Energy has completed the design and when the long-lead time material items are ready to be ordered, or no later than 10/13/2023. An invoice, including payment instructions, will be sent to the Interconnecting Customer.
- A fourth payment (2nd THIRD PARTY DUCTBANK cost share) of **$118,629.19** that is associated with this application's cost sharing responsibility for the 2nd THIRD PARTY DUCTBANK will be due after the 2nd THIRD PARTY DUCTBANK is constructed, and the costs are audited/verified.
- The 3310 Cable, Note #3 above, is being cost-shared on a pro rata share MW basis between RI-27825278, RI-27888883, RI-29048593, RI-29018574, RI-29048568, RI-29048550, RI-29048531, RI-29048488, RI-29599253. The cost for this modification may be subject to, upon final reconciliation an additional cost of **3,695,295.03** to cover the actual cost of the 3310 Cable in the event the aforementioned Work Requests do not interconnect.

If the design of the System Modifications changes during the design as a result of permitting or access issues, the company reserves the right to adjust the cost of the Systems Modifications prior to issuing the second and final invoice.

A more detailed breakdown of estimated costs may be found within the System Impact Study dated 9/20/2022

The physical construction of system modifications will not commence until full payment is received. Nothing herein shall prevent the Interconnecting Customer from making any payment, or the full payment, due to the Company earlier than the dates provided above. Funds received may be immediately expended or committed as determined by the Company in its sole discretion.

Exhibit H – Interconnection Service Agreement

Attachment 4: Special Operating Requirements, if any

The generating system may only normally generate onto the 3310 feeder and Rhode Island Energy Regional Control Center must first give permission to the Interconnecting Customer to allow the operation of their system. The generator may not be allowed to operate with the local electrical power system (EPS) in an abnormal state. To ensure the safe and reliable operation of Rhode Island Energy's EPS, Rhode Island Energy may choose to disconnect the customer at the PCC when abnormal system conditions develop and/or circuit reconfiguration takes place on the EPS.

1. The Interconnecting Customer is required to adhere to the following standards which are incorporated in their entirety by reference:
   a. Rhode Island Energy Standards for Interconnecting Distributed Generation (R.I.P.U.C. 2258), available at: http://www.nationalgridus.com/non_html/RI_DG_Interconnection_Tariff.pdf
   b. Electric System Bulletin 750 "Specifications for Electrical Installations". ESB 750, available at: http://www.nationalgridus.com/non_html/shared_constr_esb750.pdf
   c. Electric System Bulletin 756 "Requirements for Parallel Generation Connected to a Rhode Island Energy - Owned EPS". ESB756D, available at: www.nationalgridus.com/non_html/shared_constr_esb756.pdf
2. The Interconnecting Customer is required to address any outstanding requirements (that are not explicitly addressed herein), which are described in the most recent application review memo and/or study report (which is hereby incorporated in its entirety) provided by the Company on or prior to the Effective Date of this Interconnection Service Agreement.
   a. If the Effective Date of this Interconnection Service Agreement precedes the issuance of a required Detailed Study by the Company, the Interconnecting Customer is also required to address any outstanding requirements described in the Detailed Study Report upon its issuance.
3. Interconnecting Customer shall adhere to the requirements identified in the Impact Study dated 9/20/2022
4. Interconnecting Customer shall provide Compliance Documentation, including photographs, as requested by, and to the satisfaction of, the Company.
5. Interconnecting Customer may not be allowed to operate with the local EPS in an abnormal state. To ensure the safe and reliable operation of Rhode Island Energy EPS. Rhode Island Energy may disconnect the Customer at the PCC when abnormal system conditions develop and/or circuit reconfiguration takes place on the EPS.
6. Per section 6.4 of this agreement, Interconnecting Customer shall provide an external ACUTILITY DISCONNECT, accessible at all times by Rhode Island Energy personnel.
7. Interconnecting Customer's AC UTILITY DISCONNECT switch shall be labeled "AC UTILITY DISCONNECT".
8. The AC UTILITY DISCONNECT shall be gang operated, have a visible break when open, be rated to interrupt the maximum generator output and be capable of being locked open, tagged and grounded on the Company side by Company personnel. The visible break requirement can be met by opening the enclosure to observe the contact separation. The Company shall have the right to open this disconnect switch in accordance with the Interconnection Tariff. The switch has to be installed at the DR output on the current carrying lines. Shunt mechanisms are not permitted.
9. If the ACUTILITY DISCONNECT switch is not adjacent to the meter and/or PCC, Interconnecting Customer shall provide a permanent plaque locating the switch.
10. All plaques as described in NEC 705.10, 705.12 (7), 690.56, 692.4 and 705.70 shall be installed, as applicable.
11. All Interconnecting Customer-Owned meters shall be labeled "CUSTOMER-OWNED METER"
12. Interconnecting Customer shall install a permanent plaque or directory at the revenue meter and at the PCC with a warning about the generator(s) installed.

Exhibit H – Interconnection Service Agreement

13. Interconnecting Customer shall be responsible for providing necessary easements and/or environmental and/or municipal permits, as requested by the Company.

14. For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the Rhode Island Energy revenue meter. This may be accomplished with an analog/POTS (Plain Old Telephone Service) phone line (capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc.), or – in locations with suitable wireless service, a wireless meter. Feasibility of wireless service must be demonstrated by Interconnecting Customer, to the satisfaction of Rhode Island Energy. If approved, a wireless -enabled meter will be installed, at the customer's expense. If and when Rhode Island Energy's retail tariff provides a mechanism for monthly billing for this service, the customer agrees to the addition of this charge to their monthly electric bill. Interconnecting Customer shall have the option to have this charge removed, if and when a POTS phone line to Rhode Island Energy's revenue meter is provided.

15. For systems with redundant relaying, Company witness testing will be required. Customer shall develop, and provide for approval, a functional test procedure, including settings for relaying scheme. Witness test plan must be approved by Company prior to scheduling Company personnel for witness test.

16. Interconnecting Customer may only generate onto the feeder referenced in the Impact Study. Rhode Island Energy's Regional Control Center must first give permission to the customer to allow the operation of their system.

17. Interconnecting Customer's protection scheme submitted for review must meet Rhode Island Energy's specific protection requirements. Interconnecting Customer shall submit a PE stamped one-line, including relay settings, that meets the requirements specified within this document to Rhode Island Energy for review and approval, before a Witness Test plan can be reviewed. Please refer to "Expedited/Standard Process Completion Documentation Checklist", per Company's website for additional required documentation.

18. In order to minimize the impact of the proposed generation on the EPS and area customers, Rhode Island Energy will require that the reactive contribution of the PV interconnection be maintained between a 99% leading and lagging power factor at the PCC during the normal operation of the PV array. In addition, The PV interconnection shall not contribute to greater than a 3.0% change in voltage on the Rhode Island Energy EPS under any conditions.

19. The Customer shall be responsible for obtaining all easements and permits required for any line extension not on public way in accordance with the Company's requirements. The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

20. The Interconnecting Customer is responsible for coordinating with Verizon for any Verizon work. These costs will be billed directly to the customer from Verizon. It will be the responsibility of the customer to obtain any and all easements and required permitting for work that takes place on private property.

Exhibit H – Interconnection Service Agreement

Attachment 5: Agreement between the Company and the Company's Retail Customer

If the Company's Retail Customer (accountholder) is not the owner(and/or operator) of the Facility, then Exhibit I - Agreement Between the Company and the Company's Retail Customer - shall be signed by the Company's Retail Customer and executed by the Company and shall be considered part of this Interconnection Service Agreement. It shall be the responsibility of the Interconnecting Customer to notify the Company if the Exhibit I associated with this application changes.

Attachment 6: System Modifications Construction Schedule

Below is an estimated construction schedule. This schedule is conceptual and shows the duration of the facility's milestones from a "start-date" to an "in-service" date, in calendar days. This conceptual schedule is based upon assumptions and knowledge regarding the project, the site, and activities as of the date of the impact study. These estimations of construction time frames and total duration do not include any time that the Company's performance is on hold, delayed, or interrupted, including, without limitation, while waiting on information or on the performance of obligations by the Interconnecting Customer and/or third parties (including, without limitation, Verizon, ISO-NE, Railroad), as a result of unknown environmental and/or permitting issues, events of force majeure, and/or as a result of required transmission outages.

The start-date for this construction schedule is deemed to have occurred once: (1) the Interconnection Service Agreement ("ISA") has been executed (i.e., signed) by both Rhode Island Energy ("Company") and the Interconnecting Customer ("Customer"); and (2) the first payment has been submitted by the Customer to the Company, provided , however, that the Company shall not be required to provide any services or order any equipment without receiving adequate payment therefore from the Interconnecting Customer n or will it be required to initiate any construction before it has received full payment from the Interconnecting Customer.

Exhibit H – Interconnection Service Agreement

Attachment 6 - Appendix A: System Modifications Construction Schedule

Total Duration for Construction: 124 weeks

Milestone	Estimated Duration	Responsible Party
First Payment	**Start**	**Customer**
EDP Civil Design	3 weeks	Customer
RIE Civil Design Review	3 Weeks	RIE
EDP Electrical Design	3 weeks	Customer
RIE Electrical Design Review	3 weeks	RIE
Second Payment		**Customer**
Secure Required Permits/Easements and Petition for Rhode Island Energy Work	16 weeks	RIE and Customer
Procurement	52 weeks	Customer
Submit Final Payment	**As per ISA**	
Customer Construction	29 weeks	Customer
RIE Construction	7 weeks	RIE
Witness Testing & Completion Documents	4 weeks	RIE/Customer
Meter Installation & ATI	4 weeks	RIE/Customer

* Milestones may be contingent on Verizon schedule and/or ISO-NE approval of outages. Customer is responsible to coordinate directly with Verizon. This schedule does not include any Design or Construction Time required by Verizon.
** This schedule is contingent on the construction of the manhole and duct bank system. If Rhode Island Energy is required to design and construct this manhole and duct bank system, this schedule will change.