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

August 7, 2024

VIA HAND DELIVERY AND ELECTRONIC MAIL

Stephanie De La Rosa, 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>Rhode Island Energy Legal Brief</u>

Dear Ms. De La Rosa:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's legal brief 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

STATE OF RHODE ISLAND

PUBLIC UTILITIES COMMISSION

The Narragansett Electric Company d/b/a Rhode Island Energy Petition for Acceleration Of a System Modification Due to a Distributed Generation Project (Tiverton)	)	Docket No. 23-37-EL
The Narragansett Electric Company d/b/a Rhode Island Energy Petition for Acceleration Of a System Modification Due to a Distributed Generation Project (Nooseneck)	)	Docket No. 23-38-EL

MEMORANDUM OF LAW OF
THE NARRAGANSETT ELECTRIC COMPANY
D/B/A RHODE ISLAND ENERGY

The Narragansett Electric Company d/b/a National Grid ("Narragansett" or the "Company") hereby submits the following Memorandum of Law supporting its Petitions submitted in the above-referenced dockets on October 17, 2023. The Petitions were submitted pursuant to 810 RICR-00-00-1.11(A). Each Petition seeks findings by and approvals from the Rhode Island Public Utilities Commission (the "PUC") pursuant to R.I. Gen. Laws § 39-26.3-4.1 (the "Interconnection Statute") and Section 5.4 of RIPUC No. 2258 entitled The Narragansett Electric Company Standards for Connecting Distributed Generation ("Interconnection Tariff").

I. NATURE OF THE PROCEEDING

Dkt. 23-27-EL (Tiverton)

On July 21, 2021, the Company and Green Development, LLC ("Green") entered into an Interconnection Services Agreement ("ISA") for purposes of interconnecting Green's 11,791 kW photovoltaic systems located at 390 Brayton Road, Tiverton, RI 02878 ("Tiverton Projects") to the Company's electric power system ("EPS"). In September 2023, the ISA was amended to identify the scope of work change to reflect the customer procurement of the cable. The ISA includes construction of a dedicated circuit (33F6) out of the Tiverton Substation and the installation of approximately 21,000 feet of a manhole and duct system with 3 conductor 1000 kcmil SCU EPR cable (the "Tiverton Phase 1 Investments").[1] The Tiverton Phase 1 Investments were completed in December 2023 and serve the Tiverton Projects. Exhs. RIE Response to Division 5-3; RIE Joint Direct Testimony at 19.

The Company's capital investment plans reviewed by the Division of Public Utilities and Carriers (the "Division") and submitted to the PUC in Docket Nos. 5209, 22-53-EL, and 23-48-EL include system investments in the Tiverton area through calendar year ("CY") 2029. RIE Response to Record Request No. 4. Such system investments, "Tiverton Phase 2 Investments", include the need for installation of approximately 17,200 feet of three-phase primary from Brayton Road to the intersection of Lake Road/East Road and reconductoring ~5,700 feet of existing conductor on East Road. These investments are interconnected to and depend on the Tiverton Phase 1 Investments which are 21,000 feet of a manhole and duct system with 3 conductor 1000 kcmil SCU EPR cable to provide safe and reliable service to ratepayers. Exhs. RIE Joint Direct Testimony, at 13; RIE Joint Rebuttal Testimony at 7; RIE Response to Division 2-11. Accordingly, the Tiverton Phase 1 Investments are needed to serve both the Tiverton Projects and ratepayers using the Tiverton Phase 2 Investments. The need for the Tiverton Phase 1 Investments to serve ratepayers was identified during the Tiverton Area Study, which was started during the Impact Study Process and before the "ISA" was executed, however after the Company determined

[1] As discussed further below, "Tiverton Phase 1 Investments" are investments necessary for the interconnection of the distributed generation but also benefit the Company's customers. Tiverton Phase 2 Investments are those investments that extend beyond Green's point of interconnection and have been included in the FY 2024 and 2025 ISR Plans. Exh. RIE Joint Rebuttal Testimony, at 20; see also Tr. 1, at 172 (June 3, 2024)

the need for these investments to serve the Tiverton Projects. Tr. 1, at 232 (June 3, 2024). Moreover, given the timeframes allowed by the Company's Interconnection Tariff, the construction of the Tiverton Phase 1 Investments was required to be in service to Green prior to the timetable when such investments needed to be in service for ratepayers. As such, Green's need for the Tiverton Phase 1 Investments to serve the Tiverton Projects resulted in accelerating the timetable for installing such investments to serve ratepayers. For purposes of reviewing the Tiverton Petition, the Company refers herein to such investments as "Accelerated System Modifications."[2]

Rhode Island law includes statutory language governing this type of sequenced system investments that benefit both distributed generation customers and ratepayers. In 2017, the General Assembly passed legislation, codified as R.I. Gen. Laws § 39-26.3-4.1, governing instances where a specific system modification benefiting other customers has been accelerated due to an interconnection request (the "Interconnection Statute"). The Company's Interconnection Tariff also includes provisions addressing the allocation of costs between distribution companies and distributed generation developers associated with system investments. To effectuate the provisions of the Interconnection Statute, the Company is seeking certain determinations from the PUC related to the acceleration of the Tiverton Phase1 Investments, which stem from the Tiverton Projects, specifically:

(a) that the Tiverton Phase 1 Investments were accelerated due to the interconnection of the Tiverton Projects, and represent Accelerated System Modifications for purposes of determining to what extent costs may be shared between Green and ratepayers for such investments;

[2] This Memorandum of Law reflects the definitions of "System Modification", "Accelerated [System] Modification" and "System Improvement" used by the bench during the July 9, 2024 evidentiary hearing in this proceeding in its questions to Revity's witness, Mr. Palumbo. See Tr. 5, at 56-57 (July 9, 2024).

(b) that the Company's methodology to collect costs from Green for the Tiverton Phase 1 Investments and then reimburse the depreciated value of such investments to the Interconnecting Customer is reasonable;

(c) that the Accelerated System Modifications required to interconnect the Tiverton Projects will benefit both Green and ratepayers;

(d) that the Tiverton Phase1 Investments have been accelerated from the time they would otherwise be required to serve ratepayers;

(e) that such acceleration is due to Green's request to interconnect the Tiverton Projects;

(f) that Green shall fund the Tiverton Phase 1 Investments subject to repayment of the depreciated value of such investments, such depreciated value calculated as of the time the investments would have been necessary to serve ratepayers; and

(g) that the costs of the depreciated value of the Tiverton Phase 1 Investments shall be recovered from ratepayers through the Company's Infrastructure, Safety and Reliability ("ISR") Provision, RIPUC No. 2199 ("ISR Tariff"), beginning of April 1, 2025 through the ISR Factors, subject to the project being placed in service, the third party audit and verification being complete, and the project being fully reconciled during the Fiscal Year 2025 ISR Plan Year.

(h) that the Company shall issue repayment of the depreciated value of the Tiverton Phase 1 Investments to Green during the Fiscal Year 2025 ISR Plan Year once the Tiverton Project is placed in service, the third party audit and verification is complete, and the project is fully reconciled.

Dkt. 23-38-EL

Separate and distinct from the investments noted in the Company's Petition submitted in Dkt. 23-37-EL, on July 22, 2020, the Company and Green entered into an Interconnection Services Agreement ("Green ISA") for purposes of interconnecting Green's 20,000 kW photovoltaic systems located at 899 Nooseneck Hill Road, West Greenwich, RI 02817 ("Nooseneck Projects") to the Company's EPS, which was amended by the Company and Green Development on December 9, 2021, and December 16, 2022**.** The Green ISA includes construction 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 ("Green Development System Investments").

In addition, on May 16, 2022, the Company and Revity Energy LLC ("Revity") entered Interconnection Services Agreements ("Revity ISAs") for purposes of interconnecting Revity's 40.7 MW photovoltaic systems located at 18 Weaver Hill Road, West Greenwich, RI 02817 ("Robin Hollow Project") to the Company's EPS, which were 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 Energy Development Partners ("EDP") ("Studley Solar ISA") for purposes of interconnecting EDPs 9.2 MW Studley Solar Project located at 189 Weaver Hill Road, West Greenwich, RI 02817 ("Studley Solar Project") to the Company's EPS.[3] The Revity ISAs and the Studley Solar ISA include construction 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 "Revity System Investments") (collectively, the Green Development System Investments and the Revity System Investments are referred to as the "Nooseneck Investments").

The Company's capital investment plans reviewed by the Division and submitted to the PUC in Dockets 5098, 5209, 22-53-EL, 23-48-EL include system investments in the West Greenwich area through CY 2027. Such system investments, "Weaver Hill Investments", include the need for:

(1) Installing a transformer and one feeder at the Weaver Hill substation site.
(2) Extending the 3310 and 3311 lines underground for approximately 4,700 feet from the end of the existing duct bank on Weaver Hill Road, West Greenwich to a Rhode Island Energy owned property off Pole 64 Weaver Hill Road.

[3] On April 26, 2024, the Company informed the PUC that the ownership of Studley Solar Project transferred to Revity. See Tr. 2, at 3 (June 4, 2024).

(3) Installing 1 mile of spacer cable construction from the substation location to Pole 108 Victory Highway.

each to provide safe and reliable service to ratepayers and are interconnected to and dependent on the Nooseneck Investments. Exhs. RIE Joint Direct Testimony at 12-13; EJRS-7, at 30; RIE Joint Rebuttal Testimony at 7; RIE Response to Record Request No. 1. Accordingly, the Nooseneck Investments are needed to serve: (1) the Nooseneck Projects; (2) the Robin Hollow Projects, (3) the Studley Solar Project as well as ratepayers. The need for the Nooseneck Investments to serve ratepayers was identified during the Central Rhode Island West Area Study (the "Area Study" or "Central RI West Area Study"), which was started during the Impact Study Process and "ISA" process, however after the Company determined the need for these investments to serve the Nooseneck Projects, the Robin Hollow Projects and the Studley Solar Project.

Moreover, given the timeframes allowed by the Company's Interconnection Tariff, the construction of the Nooseneck Investments was required to be in service to Green and Revity prior to the timetable when such investments needed to be in service for ratepayers. As such, Green's need for the Nooseneck Investments to serve the Nooseneck Projects, and Revity's need for the Nooseneck Investments to serve the Revity Projects resulted in accelerating the timetable for installing such investments to serve ratepayers. For purposes of reviewing the Nooseneck Petition, the Company refers herein to such investments as "Accelerated System Modifications."

As noted above, the Interconnection Statute and the Interconnection Tariff address this type of sequenced system investments that benefit both distributed generation and ratepayers. To effectuate the provisions of the Interconnection Statute, the Company is seeking certain determinations from the PUC related to the acceleration of the Nooseneck Investments, which stem from the Nooseneck Projects, Robin Hollow Projects and Studley Solar Project, specifically

(a) that the Nooseneck Investments were accelerated due to the interconnection of the Nooseneck Projects, Robin Hollow Projects and Studley Solar Project, and represent Accelerated System Modifications for purposes of determining to what extent costs may be shared between Green, Revity and ratepayers for such investments;

(b) that the Company's methodology to collect costs from Green and Revity for the Nooseneck Investments and then reimburse the depreciated value of such investments to Green and Revity is reasonable;

(c) that the Nooseneck Investments required to interconnect the Nooseneck Projects will benefit Green and ratepayers;

(d) that the Nooseneck Investments required to interconnect the Robin Hollow Projects and Studley Solar Project will benefit Revity and ratepayers;

(e) that the Nooseneck Investments 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's interconnection request for the Nooseneck Projects, and Revity's interconnection request for the Robin Hollow Projects and Studley Solar Project;

(g) that Green and Revity shall respectively fund the Nooseneck Investments subject to repayment of the depreciated value of such investments, such depreciated value calculated as of the time the Nooseneck Investments would have been necessary;

(h) that the costs of the depreciated value of the Nooseneck Investments shall be recovered from distribution customers through the Company's ISR Tariff beginning April 1, 2025 through the ISR Factors, subject to the project being placed in service, the third party audit and verification being complete, and the project being fully reconciled during the Fiscal Year 2025 ISR Plan Year;

(i) that the Company shall issue repayment of the depreciated value of Nooseneck Investments to Green during the Fiscal Year 2025 ISR Plan Year once the Nooseneck Project is placed in service, the third party audit and verification is complete, and the project's cost is fully reconciled; and

(j) that the Company shall issue repayment of the depreciated value of Nooseneck Investments to Revity during the Fiscal Year 2025 ISR Plan Year once the Robin Hollow Projects and the Studley Solar Project are placed in service, respectively, the third party audit and verification is complete, and the projects costs are fully reconciled.

II. STANDARD OF REVIEW

Interconnection Statute

The Company asks the PUC to interpret the Interconnection Statute and Section 5.4 of the Interconnection Tariff. R.I. Gen. Laws § 39-26.3-4.1, in relevant part, states:

> (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 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 benefiting other customers shall be 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.

The Rhode Island Supreme Court has stated our "ultimate goal is to give effect to the purpose of the act as intended by the Legislature." Stebbins v. Wells, 818 A.2d 711, 715 (R.I.2003) (per curiam) (quoting Mottola v. Cirello, 789 A.2d 421, 423 (R.I.2002)). When an administrative agency interprets a regulatory statute that the General Assembly empowered the agency to enforce, a court reviewing the agency's interpretation of the statute as applied to a particular factual situation must accord that interpretation "weight and deference as long as that construction is not clearly erroneous or unauthorized." In re Lallo, 768 A.2d 921, 926 (R.I.2001) (quoting Gallison v. Bristol School Committee, 493 A.2d 164, 166 (R.I.1985)).

To be sure, when the language of the statute is clear and unambiguous, the court must interpret it literally, giving the words of the statute their plain and ordinary meanings. Labor Ready Northeast, Inc. v. McConaghy, 849 A.2d 340, 344-345 (R.I. 2004) citing Stebbins, 818 A.2d at 715. And "[a]n agency cannot modify the statutory provisions under which it acquired power, unless such an intent is clearly expressed in the statute." Id. quoting Little v. Conflict of Interest Commission, 121 R.I. 232, 236, 397 A.2d 884, 886 (1979). But when "the provisions of a statute are unclear or subject to more than one reasonable interpretation, the construction given by the agency charged with its enforcement is entitled to weight and deference as long as that construction is not clearly erroneous or unauthorized" Id. quoting In re Lallo, 768 A.2d at 926 (quoting Gallison, 493 A.2d at 166). This is true even when other reasonable constructions of the statute are possible. Id. citing Pawtucket Power Associates Limited Partnership v. City of Pawtucket, 622 A.2d 452, 456–57 (R.I.1993) "([D]eference will be accorded to an administrative agency when it interprets a statute whose administration and enforcement have been entrusted to the agency * * * even when the agency's interpretation is not the only permissible interpretation that could be applied.").

Interconnection Tariff

R.I.P.U.C No. 2258, Section 5.4(a) through (c) provide:

(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.

The Rhode Island Supreme Court has explained that "all tariffs should be interpreted in accordance with equity and good conscience regardless of the specific language in which they may be couched." Narragansett Elec. Co. v. Pub. Utilities Comm'n, 773 A.2d 237, 242 (R.I. 2001).

Similarly, applying principles of statutory interpretation by analogy, the "ultimate goal is to give effect to the purpose of the act as intended by the Legislature." Progressive Cas. Ins. Co. v. Dias, 151 A.3d 308, 311 (R.I. 2017); citing Cummings v. Shorey, 761 A.2d 680, 684 (R.I. 2000); GSM Industrial Inc. v. Grinnell Fire Protection Systems Co. 47 A 3d 264, 268 (R.I. 2012). Clear and unambiguous terms are interpreted according to their plain and ordinary meaning. Raiche v. Scott, 101 A.3d 1244, 1248 (R.I. 2014). "However, the plain meaning approach must not be confused with 'myopic literalism'; even when confronted with a clear and unambiguous statutory provision, 'it is entirely proper for us to look to the sense and meaning fairly deducible from the context.'" Id., quoting Alessi v. Bowen Court Condominium, 44 A.3d 736, (R.I. 2012); see also In re Brown, 903 A2d 147, 150 (R.I. 2006); O'Connell v. Walmsley, 156 A.3d 422, 426 (R.I.

2017); Ryan v. City of Providence, 11 A3d 68, 71 (R.I. 2011) ("it would be foolish and myopic literalism to focus narrowly on one statutory section without regard for the broader context.").

III. APPLICATION OF FACTS TO STATUTE/TARIFF

A. Need for Investments Subject to Reimbursement

1. Tiverton Investments

(a) By Green

The Impact Study found that the required system modifications necessary for the Tiverton Project to interconnect to the EPS, including substation and distribution line modifications. Exh. EJRS-1, at 51-52. The substation modifications identified included installing: (1) 1,200 15kV RMAG relayed breaker; nine (9) 15kV 1200A single blade disconnects; three (3) single-phase 333kVA regulators; one (1) bay of buss extension; cable terminations and disconnects for getaway; and approximately 100 ft of 3 phase feeder underground cable. Id. The distribution line modifications included installing approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from Tiverton Substation on Fish Road, Bulgarmarsh (Route RI-177), and Brayton Road and the installation of approximately 21,000 foot 4-way 5'' concrete-encased manhole & duct system. Id. at 52; Exh. EJRS-2, at 9.

(b) By Ratepayers

The Company's Area Study, provided as Schedule EJRS-3, found there were thermal issues, contingency response capabilities and voltage issues on the existing Tiverton circuits. Exh. RIE Joint Direct Testimony at 17. A summary of the need is provided below:

Normal Configuration – Thermal Loading:

- 1 of 4 circuits is predicted to be overloaded 100% to 101%.
- 2 of 4 circuits are predicted to be loaded between 95% and 100%.
- The remaining circuit is predicted to be loaded 88% to 89%.

Contingency Configuration – Thermal Loading:

- All four circuits have contingency loading risk greater than 16 megawatt hours.

Voltage Performance:

- Low voltage is predicted on 3 of 4 circuits.

Reliability Performance:

- 2 of 4 circuits with high 5-year average frequency and duration statistics

Exh. RIE Joint Rebuttal Testimony at 17; See also Exh. RIE Response to Division 1-9. The Company's FY 2024 ISR Plan and FY 2025 ISR Plan included investments to address these needs for funding. RIE Response to Record Request No. 4 (see Bates Pages 70, 75, 103 of the FY 2024 ISR Plan; Bates Pages 70, 86, 153-154 of the FY 25 ISR Plan).

The least cost option would be to create a new circuit and extend it south to serve load. This is the same solution Green constructed for its Tiverton Projects. The Area Study identified spend for this work over the FY2024 through FY2029 timeframe. The Company estimates the required work would have been completed and placed in service in FY 2029 without the DG project. Exh. RIE Joint Direct Testimony, at 19.

Importantly, the Area Study is not premised on the fact that Green is going to interconnect the Tiverton Project. Indeed, in Section 6.1 of the Area Study the Company states, "[i]f the DG project does not proceed, this 33F6 circuit will still be needed to address the area contingency loading concerns." Exh. EJRS-1, at 14. Further, the 336 feeder would have run through the same area as Green's Tiverton Project regardless of whether the project existed or not. The only material difference in solution cost was the difference between overhead and underground cable which Green is paying for. See Exh. RIE Response to Division 3-11.

The Company anticipates the identified System Improvements are unlikely to no longer be needed in the future given they were recommended to serve not only load but also to mitigate thermal (capacity) limits, contingency response capability, and voltage issues identified on the existing Tiverton circuits. Exh. RIE Response to Division 1-9.

2. Nooseneck Investments

(a) By Green

The Impact Study found that the Green Nooseneck Projects would require the following system modifications to interconnect to the EPS: (1) installation of a new tap recloser on proposed Pole #25-1 Hopkins Hill Road with Live line reclose blocking capabilities; (2) installation of ~31,300 circuit feet of 3-1/C 1000 kcmil SCU EPR underground cable in manhole and duct system; and (3) installation of ~2800 circuit feet of overhead 3-477 Bare AL Crossarm at the bridge crossings. Exh. EJRS-1, at 8.

(b) By Revity

The Impact Studies found that the Revity Projects would require the following distribution line work to interconnect to the EPS: install approximately 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; and install ~1500 circuit feet of 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road. Exh. EJRS-2, at 6.

The Impact Study also found that approximately 22,600 circuit foot line extension from Hopkins Hill Road to the facility and the following civil work was needed: installation of MH and duct system of approximately 3,000 feet; installation of a manhole and duct system of approximately 14,700 feet from 3-way manhole on Hopkins Hill Road to 3-way manhole at intersection of Nooseneck Hill Road/Weaver Hill Road; installation of manhole and duct system (~600 feet) from 3-way manhole at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road; installation of manhole and ducket system of approximately 100 feet from first 3-way MH on Weaver Hill Road (Revity Energy POI) to proposed 2-way MH on Customer property and installation of manhole and duct system of approximately 50 feet from 2-way MH on Customer property to proposed riser pole on Customer property. Exh. EJRS-1, at 7.

The Impact Study for the Studley project indicated distribution line work and civil work would be needed for the project to interconnect to the EPS. The Impact Study found the following distribution line work was necessary: 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; 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. Exh. EJRS-3, at 5.

For distribution civil work, the Studley project required installation of manhole 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; installation 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; installation of manhole 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; 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; installation of ~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; and 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 point of common coupling. Exh. EJRS-3, at 6.

The Impact Study noted there were ongoing projects in this area which might allow Revity and other customers (Green) to share in the costs of some of the system modifications. Exh. EJRS-2, at 8. The Revity projects were authorized to interconnect on December 23, 2023 and are completed and in-service. The Studley projects are expected to interconnect and go in-service in December 2024. Exh. RIE Response to Division 6-3.

(c) By Ratepayers

The Area Study, provided as Exhibit EJRS-7, found there were necessary upgrades for ratepayers needed in the Weaver Hill project area. The FY 2022, 2023, 2024, and 2025 capital plans all identified a need for upgrades to address reliability, contingency, capacity, or asset condition concerns. RIE Response to Record Request No. 1. A summary of the need identified in the Area Study 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

Exh. RIE Joint Rebuttal Testimony at 15. The Company's FY 23 ISR, FY 24 ISR Plan and FY 25 ISR Plan included investments to address these needs for funding. RIE Response to Record Request No. 1 (see Bates Page 36 of FY 23 ISR Plan; Bates Page 103, 105 of FY 24 ISR Plan; Bates Pages 70, 72, 82, 86, 153-154 of the FY 25 ISR Plan).

The Area Study identified the following solutions to address these 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. Exh. RIE Joint Rebuttal Testimony at 15.

The Area Study identified a forecasted overload of 104% summer normal loading through 2035 on the Hopkins Hill 63F6 feeder. The Coventry 54F1 also shows a high loading of 94% of summer normal through 2035. The least cost option to address these thermal loading issues is the installation of a modular substation at Weaver Hill. Exh. RIE Joint Direct Testimony, at 22. 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 beginning in FY 2027 without the DG project. Id. at 24.

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 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.

B. Estimated Costs/Timing of Reimbursement to Developer and Recovery from Ratepayers

1. For Tiverton

The Company provided estimated costs for Tiverton in its Response to Record Request No. 2-2 which is provided as Attachment 1 to this Memorandum of Law. Please note the calculation of costs in Record Request No. 2-2 does not include depreciation. The total potential reimbursement, not including depreciation, is estimated to be $13,990,189.

2. For Nooseneck

The Company provided estimated costs for Tiverton in its Response to Record Request No. 3 which is provided as Attachment 2 to this Memorandum of Law. Please note the calculation of costs in Record Request No. 3 does not include depreciation. The total potential reimbursement, not including depreciation, is estimated to be $14,052,290.

C. Proposed Allocation Methodology

1. For Tiverton

The Company is proposing to pay Green 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. Exh. RIE Joint Direct Testimony at 19. 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 2029 without the DG project. Since the Company would be paying Green 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. Id.

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. Id.; Exh. RIE Response to Division 4-2. For illustrative purposes in this recommend approach, the Company estimates that the total cost of the project related to system improvements that benefit distribution customers would be $14.66 million and that the project will be placed in service during FY 2025 and would have not been necessary until FY 2029 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 Green 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. Id. 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 2029 as estimated dates, respectively.

In the alternative, the Company is proposing to pay Green 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. Exh. RIE Joint Direct Testimony at 21-22. 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 2029 without the DG project. Id. at 22. As such, in this proposal the Company would pay Green in FY 2029 the final cost of the system modification less the depreciation of the asset from FY 2025 through FY 2028, in other words the depreciated value. Id.

The Company is recommending to pay developers when placed in service for a couple of 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. Id. at 21. 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. Id. Any time payment is delayed, for potentially years, there is risk ownership is transferred or legal statuses change making payment more complicated. Id. The Company has memorialized its cost sharing decision making into a decision tree to assist the Company in determining whether costs should be shared between interconnecting customers and the Company under Section 5.4 of the Interconnection Tariff. See RIE Response to Record Request No. 7.

2. For Nooseneck

The Company proposed the same cost allocation methodology described above where the Company would be to 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. Exhs. RIE Joint Direct Testimony at 24; RIE Response to Division 4-10. 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 beginning in FY 2027 without the DG project. Id. 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. Id.

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. Id. at 27. 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 beginning 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. Id.

The Company is recommending to pay developers when placed in service for a couple of 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. Id. at 26. 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. Id. Any time payment is delayed, for potentially years, there is risk ownership is transferred or legal statuses change making payment more complicated. Id. As noted above, the Company memorialized its cost sharing decision making into a decision tree to assist the Company in determining whether costs should be shared between interconnecting customers and the Company under Section 5.4 of the Interconnection Tariff. See RIE Response to Record Request No. 7.

D. Application of Tariff to Request for Cost Sharing

The Rhode Island Supreme Court has stated our "ultimate goal is to give effect to the purpose of the act as intended by the Legislature." Stebbins v. Wells, 818 A.2d 711, 715 (R.I.2003) (per curiam) (quoting Mottola v. Cirello, 789 A.2d 421, 423 (R.I.2002)). The intent of the R.I. Gen. Laws § 39-26.3-4.1 is clear – to facilitate the interconnection of distributed generation in Rhode Island. The Interconnection Statute is silent as to the timing of when an accelerated modification must be completed. When interpreting the Interconnection Statute, the Commission must give weight to the purpose of the legislation which is to facilitate and foster interconnection in the state.

Moreover, the Rhode Island Supreme Court has explained that "all tariffs should be interpreted in accordance with equity and good conscience regardless of the specific language in which they may be couched." Narragansett Elec. Co. v. Pub. Utilities Comm'n, 773 A.2d 237, 242 (R.I. 2001). While the Company acknowledges the Interconnection Tariff includes a five-year period, a narrow application of the Interconnection Tariff will undermine the purpose of the Interconnection Tariff.

The Interconnection Tariff states that any "system modifications" benefiting other customers shall be included in rates as determined by the public utilities commission. Exh. RIE Joint Direct Testimony at 10. 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. Id. at 11.

As discussed at length above, the Tiverton and Nooseneck Investments benefit both the DG developers and the Company's customers. The Tiverton and Nooseneck Investments represent the type of mutually beneficial cost-sharing projects contemplated by Section 5.4(b) and (c) of the Interconnection Tariff. While the Interconnection Tariff notes a five-year period as of the date the Company begins the impact study, the Interconnection Statute is silent to such a time period. Exh. RIE Response to Division 2-11.

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 Interconnection Tariff, was five years. The Company notes that it now provides a 10-Year Long Range Plan. Exh. RIE Joint Rebuttal Testimony at 6-7.

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. Id. at 8. 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. Id. at 8-9.

The interconnection study process for sites similar to the sites considered in this Petition can span many years. (In this case, it is 3-5 years with one site's ISA still pending). Id. at 9. 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. Id.

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 Interconnection

Tariff and the intent of the Interconnection Statute. Id. 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. Id.

Given the overlap of benefits to all customers, fairness to the DG developers, and the fact that the investment has been identified with projected spend within the five-year timeframe, the Company supports categorizing this investment as an acceleration for purposes of cost sharing. Accordingly, the Company is seeking the approval of repayment of the shared costs and recovery from customers through the Infrastructure, Safety and Reliability Provision, RIPUC No. 2199.

IV. CONCLUSION

These dockets are an attempt to implement Rhode Island General Laws 39-26.3-4.1, specifically, Section (b). Section (b) states that if the PUC determines that a specific system modification benefiting other customers has been accelerated due to interconnection requests, 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 PUC. It also states that system modifications benefiting other customers shall be included in rates as determined by the PUC.

In these dockets, the Company has presented substantial evidence demonstrating the need for certain cable and duct bank investments that will benefit both ratepayers and the DG developers (i.e., interconnecting customers). The Company also presented its estimated costs for these shared investments in a proposed methodology that has the DG developers pay up front for these costs, given that they need them first, and then be reimbursed by the ratepayers, given the fact that these investments, as demonstrated by the Company, will also benefit them.

The Division has focused its attention in these dockets on two points: (1) the need for the Tiverton and Nooseneck investments for ratepayers; and (2) the Interconnection Tariff's language addressing a process by which the Company may determine whether an investment provides shared benefits to interconnecting customers and ratepayers. Regarding need, the Company ultimately has the responsibility to determine if investments are needed for customers, subject to review and approval by the PUC that those projects should be funded, and the Company has done so through its Area Studies and ISR Plans, as demonstrated on the records of these proceedings.

Regarding the Tariff, the language in Section 5.4(c) can and should be read as a process for when the Company would be determining whether a system modification would be considered an accelerated modification that potentially could be cost-shared. In the Company's opinion, however, the language in the Tariff should not be read to exclude other means of demonstrating the reasonableness of cost sharing. Presenting evidence of accelerated modifications through the process followed by the Company regarding the Tiverton and Nooseneck Investments should be as valid, for example, as amending an impact study to present the information there, as contemplated by the Tariff.

In addition, the PUC need not find that the five-year period included in the Tariff for the Company to determine if cost-sharing investments is warranted should exclude the Tiverton and Nooseneck Investments from cost sharing. As noted during the proceedings, the timetable necessary to study interconnection applications through the state and, as here, federal, study processes has expanded meaningfully since Section 5.4(c) was approved by the PUC. The language in Section 5.4(c) should not be used to constrain the PUC in determining an equitable outcome regarding cost-sharing between the DG developers and ratepayers.

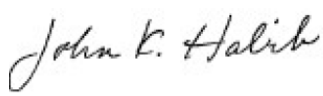
Accordingly, the Company respectfully requests that the PUC issue findings in these proceedings consistent with those presented in Section I, herein.

Respectfully submitted,

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

By its attorneys,

Andrew S. Marcaccio, #8168
Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263



John K. Habib, #7431
Keegan Werlin LLP
99 High Street, Suite 2900
Boston, MA 02110
(617) 951-1400

Dated: August 7, 2024

Attachment 1 to Legal Brief

SCHEDULE 8 - Updated PUC 2-3 Table
Updated 2024-06-20

	(a)	(b)	(c)		(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Description	**From**	**To**		**Costs per DIV 3-11**	**% For DG**	**% For Accel Mod**	**% For Sys Improve**	**System Modification (Soley Serve DG)**	**Accelerated Modification (Aligned With Study Recommendation)**	**System Improvement (Additional Ducts)**	**Allocation Method**
1	Sub-T DG Customer Cost Share			1								
2	Substation - New Feeder Position			2	$ 1,022,000	0.00%	100.00%	0.00%	$0	$1,022,000	$0	
3	Cable 15kV - New Install 33F6	Substation (Fish Rd)	Fish Rd/Bulgarmarsh Rd (177) Intersection	3	$ 745,882	0.00%	100.00%	0.00%	$0	$745,882	$0	
4	Duct Bank Civil Work & Cable Procurement	Substation (Fish Rd)	Fish Rd/Bulgarmarsh Rd (177) Intersection	4	$ 7,691,897	0.00%	69.13%	30.87%	$0	$5,317,300	$2,374,597	Duct Count - Mixed
5	Cable 15kV - New Install 33F6	Fish Rd/Bulgarmarsh Rd (177) Intersection	Bulgarmarsh Rd (177)/Brayton Rd Intersection	5	$ 364,834	0.00%	100.00%	0.00%	$0	$364,834	$0	
6	Duct Bank Civil Work & Cable Procurement	Fish Rd/Bulgarmarsh Rd (177) Intersection	Bulgarmarsh Rd (177)/Brayton Rd Intersection	6	$ 3,511,971	51.21%	32.70%	16.09%	$1,798,633	$1,148,426	$564,911	Ductbank Construction % - 4 way
7	Cable 15kV - New Install 33F6	Bulgarmarsh Rd (177)/Brayton Rd Intersection	Green Dev Site	7	$ 429,693	0.00%	100.00%	0.00%	$0	$429,693	$0	
8	Duct Bank Civil Work & Cable Procurement	Bulgarmarsh Rd (177)/Brayton Rd Intersection	Green Dev Site	8	$ 4,177,310	51.58%	32.38%	16.04%	$2,154,764	$1,352,591	$669,955	Ductbank Construction % - 4 way
				9	$ 17,943,586				$ 3,953,397	$ 10,380,726	$ 3,609,463	
				10					Total Potential Reimbursement		$ 13,990,189	

Attachment 2 to Legal Brief

Capex Only

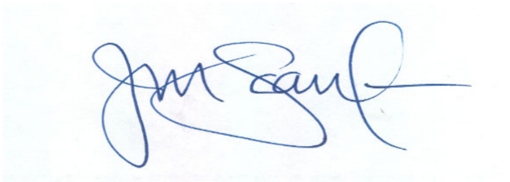
	(a)	(b)	(c)	(d)		(e)	(e1)	(f)	(g)	(h)	(i)	(j)	(k)
	Description	**From**	**To**	**Costs in Petition (PUC 1-1)**		**Updated Costs 6/2024**	**Allocation Method**	**% For DG**	**% For Accel Mod**	**% For Sys Improve**	**System Modification (Soley Serve DG)**	**Accelerated Modification (Aligned With Study Recommendtaion)**	**System Improvement (Additional Ducts)**
	Sub-T DG Customer Cost Share												
1	Cable 35kV - New Install 3309	3309 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)	$987,961	1	$ 1,281,331		100%			$1,281,331	$0	$0
2	Duct Bank Civil Work-Rev	3309 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)	N.A.	2	$ 3,188,415	Incremental Ductbank Construction % - 4 way	80%		20%	$2,550,732	$0	$637,683
3	Duct Bank Civil Work-GDP	3309 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)	N.A.	3	$ 177,654		100%			$177,654	$0	$0
4	Cable 35kV - New Install 3310	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)	$6,243,000	4	$ 2,629,370			100%		$0	$2,629,370	$0
5	Cable 35kV - New Install 3309	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)	$5,598,447	5	$ 2,629,370		100%			$2,629,370	$0	$0
6	3310 OH Line Work	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)		6	$ 281,730			100%		$0	$281,730	$0
7	Duct Bank Civil Work	3310 Riser (Hopkins Hill Rd)	Node A (Nooseneck/Weaver Hill)	$5,951,270	7	$ 5,951,270	Duct Count - 4 way	50%	50%	0%	$2,975,635	$2,975,635	$0
8	Cable 35kV - New Install 3310	Node A (Nooseneck/Weaver Hill)	GDP Site	$1,356,000	8	$ 2,159,823		100%			$2,159,823	$0	$0
9	Duct Bank Civil Work	Node A (Nooseneck/Weaver Hill)	GDP Site	$6,072,000	9	$ 5,894,601	Incremental Ductbank Construction % - 4 way	80%		20%	$4,715,681	$0	$1,178,920
10	Cable 35kV - New Install 3310	Node A (Nooseneck/Weaver Hill)	Revity Tap - Robin Hollow Site	$80,019	10	$ 98,191			100%		$0	$98,191	$0
11	Cable 35kV - New Install 3309	Node A (Nooseneck/Weaver Hill)	Revity Tap - Robin Hollow Site	$197,592	11	$ 98,191		100%			$98,191	$0	$0
12	Cable 35kV - New Install 3311	Node A (Nooseneck/Weaver Hill)	Revity Tap - Robin Hollow Site	$80,019	12	To be installed by RIE							
13	Duct Bank Civil Work	Node A (Nooseneck/Weaver Hill)	Revity Tap - Robin Hollow Site	$204,065	13	$ 925,669	Duct Count - 9 way	22%	22%	56%	$205,704	$205,704	$514,261
14	Cable 35kV - New Install 3310	Revity Tap - Robin Hollow Site	Revity Tap - Studley Solar	$493,453	14	$ 575,116			100%		$0	$575,116	$0
15	Cable 35kV - New Install 3311	Revity Tap - Robin Hollow Site	Revity Tap - Studley Solar	$493,453	15	To be installed by RIE							
16	Duct Bank Civil Work	Revity Tap - Robin Hollow Site	Revity Tap - Studley Solar	$1,258,404	16	$ 4,756,910	Duct Count - 6 way	0%	33%	67%	$0	$1,585,637	$3,171,273
17	Weaver Hill Substation			$3,800,000	17								
18	Cable 35kV - New Install 3310	Revity Tap - Studley Solar	Weaver Hill Sub	$623,618	18								
19	Cable 35kV - New Install 3311	Revity Tap - Studley Solar	Weaver Hill Sub	$623,618	19								
20	Duct Bank Civil Work	Revity Tap - Studley Solar	Weaver Hill Sub	$1,590,350	20								
21	Spacer Cable 15kV - New Install	Weaver Hill Sub	To New Circuits (63F6 Transfer)	$3,899,000	21								
22	Overhead 35kV - 3310 Tap	3310 Riser (Hopkins Hill Rd)	3310 Riser (Hopkins Hill Rd)		22	$ 198,771		0%	100%		$0	$198,771	$0
						$30,846,410					**$16,794,120**	**$8,550,153**	**$5,502,137**

N.A. = Not Applicable

Total Potential Reimbursement $14,052,290

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.



Joanne M. Scanlon

August 6, 2024
Date

Docket No. 23-38-EL Rhode Island Energy – Petition for Acceleration Due to DG Project – Weaver Hill Projects Service List updated 8/5/2024

Parties' Name/Address	E-mail	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew Marcaccio, Esq. Celia B. O'Brien, Esq. 280 Melrose Street Providence, RI 02907	AMarcaccio@pplweb.com; COBrien@pplweb.com; JScanlon@pplweb.com; SBriggs@pplweb.com; KRCastro@RIEnergy.com; ERussell@RIEnergy.com;	401-784-7263
John K. Habib, Esq. **Keegan Werlin LLP** 99 High Street, 29th Floor Boston, MA 02110	jhabib@keeganwerlin.com;	617-951-1400
Division of Public Utilities Leo Wold, Esq.	Leo.Wold@dpuc.ri.gov; Margaret.L.Hogan@dpuc.ri.gov; Christy.Hetherington@dpuc.ri.gov; John.bell@dpuc.ri.gov; Al.contente@dpuc.ri.gov; Paul.Roberti@dpuc.ri.gov; Ellen.golde@dpuc.ri.gov;	
Gregory L. Booth, PLLC 14460 Falls of Neuse Rd. Suite 149-110 Raleigh, N. C. 27614	gboothpe@gmail.com;	919-441-6440
Linda Kushner L. Kushner Consulting, LLC 514 Daniels St. #254 Raleigh, NC 27605	Lkushner33@gmail.com;	919-810-1616

William Watson	wfwatson924@gmail.com;	
Revity Energy LLC Nicholas L. Nybo, Esq. Revity Energy LLC & Affiliates 117 Metro Center Blvd., Suite 1007 Warwick, RI 02886	nick@revityenergy.com;	508-269-6433
Green Development LLC Seth H. Handy, Esq. HANDY LAW, LLC 42 Weybosset Street Providence, RI 02903	seth@handylawllc.com; conor@handylawllc.com;	401-626-4839
Kevin Hirsch Green Development, LLC 2000 Chapel View Blvd, Suite 500 Cranston, RI 02920	kh@green-ri.com; ms@green-ri.com; hm@green-ri.com; mu@green-ri.com;	
Green Development LLC Joseph A. Keough, Jr. KEOUGH + SWEENEY, LTD. 41 Mendon Avenue Pawtucket, RI 02861	jkeoughjr@keoughsweeney.com	401- 724-3600
File an original & 5 copies w/ PUC: Stephanie De La Rosa, Commission Clerk Public Utilities Commission 89 Jefferson Blvd. Warwick, RI 02888	stephanie.delarosa@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;	