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

Rhode Island Energy Petition for Acceleration Due to DG Project

Tiverton Projects

Pre-Filed Joint Testimony of:
Erica Russell Salk &
Stephanie A. Briggs

October 17, 2023

Submitted to:
Rhode Island Public Utilities Commission

RIPUC Docket No. 23-37-EL

Submitted by:

Rhode Island Energy™
a PPL company

Andrew S. Marcaccio, Counsel
PPL Services Corporation
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Phone 401-784-7263

Rhode Island Energy™
a PPL company

October 17, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-37-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project
Tiverton Projects

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the Company's Petition for Acceleration of a System Modification Due to a Distributed Generation Project in connection with the Tiverton Projects ("Petition"). In support of the Petition, the Company is submitting joint pre-filed testimony of Erica J. Russell Salk and Stephanie A. Briggs. The Petition is being filed in accordance with R.I. Gen. Laws § 39-26.3-4.1.

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

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 PROJECTS**	)	DOCKET NO. 23-37-EL

PETITION OF THE NARRAGANSETT ELECTRIC COMPANY FOR ACCELERATION OF A SYSTEM MODIFICATION DUE TO AN INTERCONNECTION REQUEST

1. Pursuant to 810-RICR-00-00-1.11(A),[1] The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company") hereby respectfully submits this petition (this "Petition") to the Public Utilities Commission ("PUC").

2. The PUC possesses the authority to grant the relief sought through this Petition 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").

<u>Recitals</u>

The Company submits this Petition in consideration of the following recitals:

WHEREAS, on July 21, 2021, the Company and Green Development, LLC ("Interconnection Customer") entered into an Interconnection Services Agreement ("ISA") for purposes of interconnecting the Interconnection Customer's 11,791 kW photovoltaic systems located at 390 Brayton Road, Tiverton, RI 02878 ("Tiverton Projects") to the Company's electric power system ("EPS");

WHEREAS, the Company's 5-year and beyond capital investment plan includes system investments in the Tiverton area through calendar year ("CY") 2029;

WHEREAS, the interconnection of the Tiverton Projects has accelerated the need for system investments in the Tiverton area;

[1] The Public Utilities Commission's Rules of Practice and Procedure are codified as 810-RICR-00-00-1.

WHEREAS, the specific system investments that require acceleration are the 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 ("System Improvements");

WHEREAS, absent the interconnection of the Tiverton Projects, the Company anticipated making the System Improvements by 2029;

WHEREAS, 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;

WHEREAS, the Interconnection Tariff also includes provisions governing the allocation of costs between distribution companies and distributed generation developers associated with system improvements;

WHEREAS, the Tiverton Projects have accelerated the need for the installation of the System Improvements; and

WHEREAS, to effectuate the provisions of R.I. Gen. Laws § 39-26.3-4.1, the Company is seeking certain determinations from the PUC related to the acceleration of the System Improvements stemming from the Tiverton Projects.

Additional Support

3. In conjunction with the filing of this Petition, the Company is submitting pre-filed joint direct testimony of Erica J. Russell Salk, PE, Rhode Island Energy, Manager, Customer Energy Integration, and Stephanie A. Briggs, Rhode Island Energy, Senior Manager, Revenue and Rates, in support of this Petition.

Relief Sought

4. Through this Petition, the Company is respectfully requesting the following findings and approvals from the PUC:

   (a) That the System Improvements (as defined in the Recitals) were accelerated due to the interconnection of the Tiverton Projects;

   (b) 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 Customer for System Improvements associated with the interconnection of the Tiverton Projects and then reimburse the depreciated value of such System Improvements to the Interconnecting Customer;

(c) That the System Improvements required to interconnect the Tiverton Projects will benefit both the Interconnecting Customer and the Company's distribution customers;

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

(e) That such acceleration is due to the Interconnection Customer's request to interconnect the Tiverton Projects;

(f) That the Interconnection Customer shall fund the System Improvements subject to repayment of the depreciated value of the System Improvements, such depreciated value calculated as of the time the System Improvements would have been necessary; and

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

5. In terms of timing, the Company is respectfully requesting the following approvals from the PUC:

   (a) That the costs of the depreciated value of the System Improvements shall be recovered from distribution customers beginning April 1, 2024, 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.

   (b) That the Company shall issue repayment of the depreciated value of the System Improvements to the Interconnection Customer during the Fiscal Year 2025 ISR Plan Year once the project is placed in service, the third party audit and verification is complete, and the project is fully reconciled.

[Signature page follows]

Respectfully submitted,

The Narragansett Electric Company
d/b/a **Rhode Island Energy**
By its attorney,

Andrew S. Marcaccio (#8168)
The Narragansett Electric Company
d/b/a Rhode Island Energy
280 Melrose Street
Providence, RI 02907
(401) 784-4263

Dated: October 17, 2023

PRE-FILED JOINT DIRECT TESTIMONY OF

ERICA J. RUSSELL SALK

AND

STEPHANIE A. BRIGGS

October 17, 2023

Table of Contents

I. Introduction

Erica J. Russell Salk

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 request that is the subject of the Petition was made by Green Development, LLC ("Green" or "Green Development" or "Interconnection Customer") in connection with 11,791 kW photovoltaic systems located at 390 Brayton Road, Tiverton, RI 02878 ("Tiverton Projects").

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

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

- Schedule EJRS-1 – Impact Study related to the Tiverton Projects
- Schedule EJRS-2 – Interconnection Services Agreement with Green Development related to the Tiverton Projects
- Schedule EJRS-3 – Tiverton Area Study

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 customer.

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 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

[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.

> 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 Weaver Hill 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 public utilities commission. 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 Interconnection Customer's Tiverton Projects are System Modifications that benefit the Interconnection Customer and distribution customers. As such, among other findings, the Company seeks PUC approval to apply the provisions of Section 5.4(b) and Section (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 construction of a dedicated circuit (33F6) out of Tiverton Substation and the installation of approximately 21,000 feet of a manhole and duct system with 3 conductor 1000 kcmil SCU EPR cable were accelerated due to the interconnection of the Tiverton Projects ("System Improvements");

(b) 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 Customer for System Improvements associated with the interconnection of the Tiverton Projects and then reimburse the depreciated value of such System Improvements to the Interconnecting Customer;

(c) That System Improvements described in our testimony required to interconnect the Tiverton Projects will benefit both the DG Projects and the Company's distribution customers;

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

(e) That such acceleration is due to Green Development's interconnection request for the Tiverton Projects;

(f) That Green Development 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

(g) 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. <u>DG Projects</u>

Q. Please describe Green's Tiverton Projects.

A. Green's Tiverton Projects include two adjacent sites, totaling 11.7MW in aggregate, to be constructed as standalone solar arrays participating in the Net Metering incentive. The Projects are scheduled to interconnect by the end of CY 23. The Tiverton projects will be fed off one express 12.47kV feeder position (33F6) out of the Tiverton substation. Green is constructing approximately 21,000 feet of a manhole and duct system with 3 conductor 1000 kcmil SCU EPR cable to their point of common coupling.

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

A. On March 26, 2019.

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

A. The Company began the Impact Study of the Tiverton Projects on June 6, 2019. The Impact Study attached hereto as Exhibit EJRS-1a. The Company completed a restudy on August 23, 2023 to update the scope of work to reflect customer procurement of the cable. The updated Impact Study is attached hereto as Exhibit EJRS-1b.

Q. Has an interconnection service agreement been executed for the Tiverton Projects?

A. Yes. On July 21, 2021, the Company entered into an Interconnection Services Agreement ("ISA") with Green Development. The ISA is attached hereto as Exhibit EJRS-2a. The Company provided an amendment to the ISA to Green Development in September 2023 to identify the scope of work change to reflect the customer procurement of the cable. The ISA amendment is attached hereto as Exhibit EJRS-2b.

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

A. The total cost of the Projects' System Modifications, excluding the civil manhole and duct system constructed by Green Development, was estimated at $5,162,952. Green Development estimated the civil manhole and duct system at $12,757,210 (for a cumulative total of $17,920,162). The civil self-build costs will be reviewed through a detailed third-party cost verification and audit to confirm the total cost. The project was estimated again in 2023 at $3,708,409 to update the scope by removing the cost of the cable as the DG customer opted to procure. The DG customer estimate for the self-build including the cost of the cable was estimated at $15,381,179 for a cumulative total of $19,089,588.

Q. Do the entirety of these System Modifications only benefit the Tiverton Projects?

A. No. The System Modifications benefit distribution customers, too. As described in the Tiverton Area Study which is attached hereto as Exhibit EJRS-3, the addition of a new feeder position and extension of the 33F6 would solve issues with thermal limits, contingency response capability, and voltage issues in the area. The scope of work 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 for the System Improvement, and the repayment to Green by the Company of such costs, subject to the terms of the Interconnection Statute and Interconnection Tariff.

V. System Improvements

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

A. The construction of a new 12.47kV feeder position out of Tiverton Substation and extension south to serve distribution customers to address thermal limits, contingency response capability, and voltage issues meet the definition of a System Improvement.

Q. How will the System Improvement for the Tiverton Projects benefit distribution customers?

A. As identified in the Area Study, the least cost option proposed to address thermal limits, contingency response capability, and voltage issues in the Tiverton area is to extend the proposed 33F6 circuit further south to serve load.

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

A. Yes. The extension of the proposed 33F6 circuit to address loading concerns is in the FY2023 Proposal, Docket No. 5209, filed on December 20, 2021. The Tiverton Area Study evaluated the issues and proposed solutions.

Q. How does interconnecting the Tiverton Projects accelerate the installation of System Improvements identified by the Company?

A. The Area Study identified thermal issues, contingency response capabilities, and voltage issues on the existing Tiverton circuits. The least cost option would be to create a new circuit and extend it south to serve load. This is the same proposed circuit that Green is constructing for the Tiverton Projects.

VI. Potential Benefits to Other Renewable Interconnection Customers

Q. Is the Company aware of other renewable interconnection customers that may benefit from the Tiverton Projects System Modifications?

A. No, the Company is not aware of other renewable interconnection customers that may benefit.

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?

A. The estimated total cost of the System Improvement that will be charged to Green is approximately $14.660M. This can be broken out into two categories: substation work and distribution line work. The estimate for the substation work to install a new breaker and feeder position is $1.022M. The estimate for the distribution line work, which includes both civil and electrical, is $13.638M. The scope of the distribution line work for Green Development's interconnection consisted entirely of an underground manhole and duct system along Fish Road, Route 177, and Brayton Road to accommodate the 11.7MW size. Had this DG project not moved forward, the scope of the distribution line work would have differed. The scope of work would have been to extend the 33F6 circuit from the Tiverton Substation underground on Fish Road to the intersection of Rt. 177, where the circuit would rise up and double circuit the existing 33F4 with 477 spacer cable and continue down Brayton Road. In other words, a portion of the job would be overhead instead of underground, and with a different cable type/rating. The Company estimated the scope of this work which came to $13.638M. The incremental cost associated with the customer DG project to go underground (i.e. the cost beyond $14.660M) is borne by the DG customer.

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

A. After the third-party cost verification and audit and upon final reconciliation, the Company would calculate the dollar value to reimburse to Green based on the costs associated with the shared portion of the work that benefits the distribution customers. The Company would determine the cost difference for the portion of the work where the scope would be different, and reimburse Green for the amount that it would have otherwise cost to run overhead.

Q. Will 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 Green 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 recommend approach would be that the Company would 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. 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.

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

A. Please see Schedule SAB-1 for the estimated depreciated value from FY 2025 through FY 2028 that would be paid to Green in FY 2025 of $13,038,604. 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 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. 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.

Q. Under the 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 recommended approach, the Company would include the depreciated value through FY 2028 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 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. 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. 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.

Q. Under the alternative approach, what is the amount that the Company estimates will be the depreciated value paid to Green in FY 2029?

A. Please see Schedule SAB-1 for the estimated depreciated value in FY 2029 of $13,038,604. 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 $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. 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.

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 alternative approach, the Company would include the depreciated value in the FY 2029 ISR revenue requirement at which time it would begin being recovered from distribution customers.

VIII. Assessment on Act on Climate

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.

VIII. Conclusion

Q. Does this complete your testimony?

A. Yes, it does.

<table>
<tr><td rowspan="4">nationalgrid</td><td rowspan="2">DISTRIBUTION PLANNING DOCUMENT
Interconnection Study</td><td>Doc. RI-27970782, RI-27970789</td></tr>
<tr><td>Page 1 of 42</td></tr>
<tr><td>Complex Generating Facility – RIPUC 2180</td><td>Version 7.0 04/01/2021</td></tr>
<tr><td>Green Development, LLC
11,791 kW/ 11,791 kVA of Inverter Based Photovoltaic
394 Brayton Road, Tiverton RI 02878</td><td>Final</td></tr>
</table>

System Impact Study
for Distributed Generation Interconnection to National Grid's 12.47kV System

DG WR:	RI-27970782	RI-27970789
DG Case#:	00206316	00206317
Applicant:	Green Development, LLC	Green Development, LLC
Address:	394 Brayton Road (Southern Array)	394 Brayton Road (Northern Array)
City:	Tiverton, RI	Tiverton, RI
DG kW/kVA:	3,368 kW / 3,368 kVA	8,423 kW / 8,423kVA
DG Type:	Inverter-Based Photovoltaic	Inverter-Based Photovoltaic
Feeder:	Tiverton 33F6 (Proposed Feeder)	Tiverton 33F6 (Proposed Feeder)

Table of Contents

Section **Page**

List of Tables

Definitions

The following is a list of acronyms/synonyms used in this Interconnection Study:

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESB – National Grid'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

NPCC – Northeast Power Coordinating Council

PCC – Point of Common Coupling (point of demarcation between the Customer and Company facilities)

Project – The interconnection of the Facility to the Company electrical power system.

Executive Summary

The Company has completed the Impact Study for the interconnection of Green Development LLC, ("Customer") 11,791 kW / 11,791 kVA Combined total, inverter based photovoltaic generator ("the Facility") , to its 12.47 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

The specific Projects consist of:

RI-27970782 (Case 206316) 3,368 kW / 3,368 kVA

RI-27970789 (Case 206317) 8,423 kW / 8,423 kVA

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:

Tiverton Substation (Section 2.2):

1. Add one 12.47kV express circuit position, on the No.2 bus (33F6)
   - Install one (1) 12.47 kV breaker
   - 3 single-phase regulators and additional substation equipment required
   - Install new getaway man-hole and duct system inside of the Tiverton Substation

Distribution (Section 2.2):

1. Install approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from the Tiverton Substation (located near Fish Road) to the Point of Common Coupling on Brayton Point Road.
   1. The Customer has requested responsibility for the required installation of approximately 1,100 feet of 9-way 5'', 1,100 feet 6-way 5'' and 17,800 feet of 4-way 5'' (~21,000 feet total) concrete-encased manhole & duct system. The Customer will be required to comply with Company Construction Standards and obtain approval by the Company prior to covering. See Appendix B for additional details

2. Point of Common Coupling (Appendix B-1):
   1. Install primary riser
   2. Install approximately seven (7) poles and 600 circuit feet of 3-477 AAC overhead conductor and associated equipment
   3. Install one (1) load break switch

4. Install one (1) recloser
5. Install two (2) primary metering assemblies

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 **$5,162,951.58** +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the Interconnection Service Agreement. Applicable cost sharing allocations, if any, will be calculated by the Company and provided in the Interconnection Service Agreement.

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 National Grid 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

RI-27970782, Case 00206316

The Customer proposes to install the following:

- One (1) Customer owned inverter skid with Four (4) TMEIC Solar Ware Ninja 842kW / 842kVA inverter-based DG. (3,368kW / 3,368kVA total)
- One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-660 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
- One (1) Customer owned 15 kV Pole-Mounted VIP378ER-125 recloser with a SEL 651R relay assembly
- One (1) Customer owned, Vector, Model #1984-45F, 15 kV gang-operated switch, with visible blades accessible to utility side

RI-27970789, Case 00206317

The Customer proposes to install the following:

- Two (2) Customer owned inverter skid with Three (3) TMEIC Solar Ware Ninja 842kW / 842kVA, and One (1) Customer owned inverter skid with Four (4) TMEIC Solar Ware Ninja 842kW / 842 kVA inverter-based DG (5,894kW / 5,894kVA total)
- One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-660 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
- Two (2) Customer owned 2,526 kVA, 12.47 kV wye-grounded primary-660 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
- One (1) Customer owned 15 kV Pole-Mounted VIP378ER-125 recloser with a SEL 651R relay assembly
- One (1) Customer owned, Vector, Model #1984-45F, 15 kV gang-operated switch, with visible blades accessible to utility side

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-lines (dated 03/23/2021).

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.

2.1.1 Assumptions

For certain components, data was not provided by the Customer, or was physically not available at the time of this Study. In order to proceed with the analysis certain assumptions were made based on past experience and engineering judgment. Assumptions are summarized in the following list. Should any of these assumptions be incorrect, the Customer must advise the Company immediately, as reevaluation of the Impact Study results will be required:

1. The analysis in this Study assumed a neutral reactor sized at 7 ohms at each of the interface transformers, see section 7.3.

2. The Customer has requested responsibility for the required installation of approximately 1,100 foot 9-way 5'', 1,100 foot 6-way 5" and foot 17,800 4-way 5" (~21,000 total) concrete-encased manhole & duct system. The Customer will be required to comply with Company Construction Standards and obtain approval by the Company prior to covering. See Appendix B for additional details
   - The Customer will be responsible for all civil work on public way and private property. Scope of work includes the permitting and construction of man-holes, pads, conduit system, all in accordance with Company standards, specifications, and requirements.
   - Estimates provided for the donated property tax item in Table 4 assumes the customer installing approximately 1,100 feet of 9-Way 5", 1,100 feet of 6-Way 5", and 17,800 feet of 9-Way 5" PVC-DB concrete encased duct bank, thirty-four (34) - manholes, and five (5) risers .See Appendix B for additional details
   - The Customer will be responsible for performing, any and all, temporary and permanent restoration.
3. The Customer decided not to proceed with the expansion of breaker and a half configuration at the Tiverton Substation. For this reason, the Customer will be only allowed to operate when Transformer #2 is in-service. During contingencies, maintenance, and other abnormal conditions the customer will be required to be disconnected from the EPS.
4. Customer proposed inverters are assumed to be power limited to 842 kW/ 842 kVA each.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is a new express feeder to the customer's site. This new feeder, feeder 33F6, will be a 12.47kV regulated, three-phase, 4 wire, wye, effectively-grounded, radial distribution circuit that will originate at the Company's Tiverton Substation, in Tiverton Rhode Island (the "Interconnecting Circuit"). The feeder will be regulated by way of a feeder voltage regulator at the substation.

Substation modifications include the following:

- Install (1) 1,200 15kV RMAG relayed breaker
- Install nine (9) 15kV 1200A single blade disconnects
- Install three (3) single-phase 333kVA regulators
- Install one (1) bay of buss extension
- Install cable terminations and disconnects for getaway
- Install approximately 100 ft of 3 phase feeder underground cable

- Install associated civil-duct work and civil construction inside of the Tiverton substation

Distribution line modifications include:

- Install 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.
- The Customer has requested responsibility for the required installation of approximately 21,000 foot 4-way 5'' concrete-encased manhole & duct system.

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 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)*
33F6	*0*	*0*	*11,791*	*11,791*
33F1	*4,790*	*613*	*0*	*5,403*
33F2	*368*	*29*	*0*	*397*
33F3	*1,132*	*6,860*	*0*	*7,992*
33F4	*971*	*7,510*	*0*	*8,481*
TOTAL	*7,261*	*15,012*	*11,791*	***34,064***

Table 1: Generation at the Substation and Interconnecting Circuit

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 proposed Pole #5 for RI-27970782 and Pole #7 for RI-27970789 all on Brayton Road, Tiverton Rhode Island. 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 National Grid right of way (R.O.W) is involved, then the Customer shall provide detailed drawings of any planned construction within any National Grid 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 National Grid'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 Global Information System ("GIS"). A field review of the area was performed on 04/30/2019.

The analysis considered cases at peak load 19,253 kVA @ 99.24% Lagging PF and net minimum load 3,454 kVA @ 91.83% Leading PF at time of maximum expected generation (9:00AM – 6:00PM) on Transformer # 2 at the Tiverton Substation.

Substation peak and minimum load values have been taken from the Company's historical load data that has been compiled over the past 12 months, from 04/01/2018 to 04/01/2019.

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. However, the substation is currently equipped with bi-directional metering, which were previously installed for reasons unrelated to DG work. Therefore, no additional work is required at the substation, and this Customer is not responsible for costs related to the existing substation equipment.

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 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.

Due to potential high generation to load ratios on the feeder and possible Load Rejection Over Voltage (LROV), the Customer must provide details, documentation, and any factory tests or pre-certifications for the mitigation of this condition. The Company reserves the right to request additional equipment on the Customer's Facility if required and/or Over Voltage set point or a modification of an existing setting to mitigate this condition. The clearing/de-energization time must satisfy the Transient Over Voltage Tolerance Curve in Figure 1.

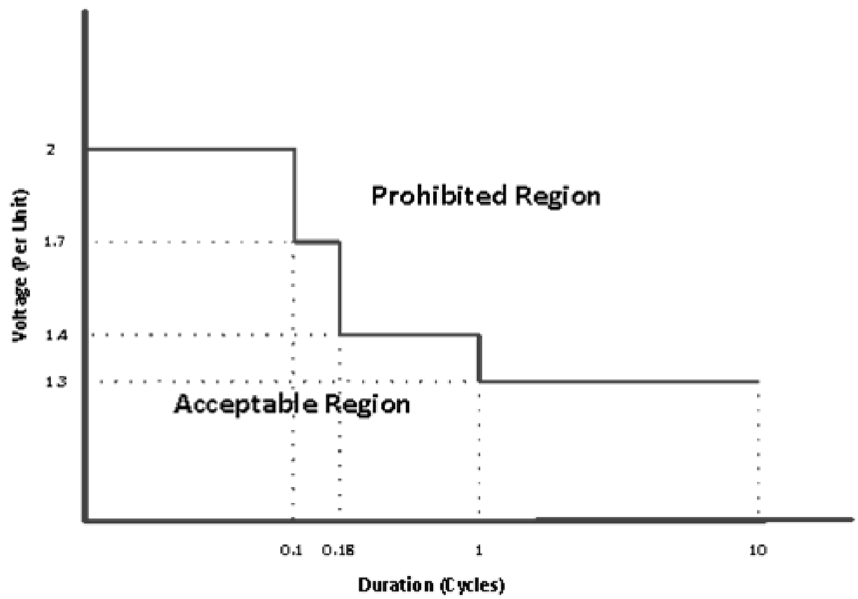


Figure 1: IEEE Transient Over Voltage Tolerance Curve

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.

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 there is potential for this site to cause voltage flicker on the interconnecting feeder, therefore more detailed analysis was required.

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 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.

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 unity power factor.
- The maximum output generation of the two projects stays at 11.8MW

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

[1] CYME Power Engineering Software, Version 7.1, Revision 02, Build 99, Copyright © 1986-2014, Cooper Industries, Ltd.

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 2 was considered on this feeder. Three-phase projects greater than 25kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Inverter Manufacturer	Inverter Model
0	All Projects <25kW Miscellaneous	All Projects <25kW Miscellaneous
11,791	Solar Ware Ninja	TMEIC

Table 2: 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 likely event. As a result, one (1) PCC recloser with reclose blocking will be required for both projects.

5.0 Transmission Assessments

National Grid Transmission Planning (NEP) studied the impact of the proposed project in accordance with ISO-NE Planning Procedure 5-6 “Scope of Study for System Impact Studies under the Generation Interconnection Procedures” and National Grid TGP28 “Transmission Planning Guide”. National Grid Transmission Planning determined there were no adverse impacts to the transmission system as studied.

This analysis is conducted in accordance with the following criteria:

- NERC Transmission Planning Standards TPL-001-4, “*Transmission System Planning Performance Requirements”*.
- Northeast Power Coordinating Council (NPCC) Directory 1, “*Design and Operation of the Bulk Power System*”.
- ISO New England Planning Procedure #3 (PP3) – “*Reliability Standards for the New England Area Bulk Power System*”.

- ISO New England Planning Procedure #5-6 (PP5-6) – *"Interconnection Planning Procedure for Generation and Elective Transmission Upgrades"*.
- National Grid Transmission Group Procedure (TGP) #28 – "*Transmission Planning Guide for the National Grid USA Service Company*".

National Grid will follow ISO NE PP 5-3 "Guidelines for Conducting and Evaluating Proposed Plan Applications Analyses (PPA)" and review all findings with appropriate Task Forces for concurrence of National Grid's findings. Upon Task Force concurrence National Grid will submit the PPA to Reliability Committee, for recommendation to ISO-NE. Thus the study findings are not considered final until letter of determination by ISO-NE is received by National Grid.

6.0 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. Refer to Section 2.1.1 for any assumptions made in the model.

6.1 Fault Detection at Substation (ESB 756D Section 6.2.2)

Addition of generation sources to distribution feeders can result in the backfeeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. The Company's typical 115kV-15kV class substation transformer has a delta connection on the transmission side and wye-grounded connection on the distribution side. Due to the transformer's configuration, it cannot contribute zero sequence ground fault current to single line to ground faults on a transmission line, and the voltage on the unfaulted phases rises significantly and rapidly. These overvoltages have potential to exceed insulation levels of the station and transmission line equipment, and maximum continuous operating voltage of surge arresters. Zero sequence voltage protection (commonly referred to as "$3V_0$") on the primary side of the transformer is required in order to detect these overvoltage conditions. This $3V_0$ protection will disconnect the generation from the substation transformer, and stop the generation and transformer from contributing to the transmission-side overvoltage condition.

Detailed analysis was completed to determine whether the interconnection of the Facility, in conjunction with existing connected facilities, may pose significant risk of

[2] ASPEN OneLiner V12.5, Build: 19177 (2015.01.28), Copyright © 1987-2013 ASPEN.

causing temporary over-voltage conditions to develop on the system during line to ground faults on the high side of the substation transformer. The load to generation match at the substation has been evaluated assuming minimum load, maximum generation, and one feeder out of service in order to determine if substation modifications are required.

For this Project, results indicate that the Facility poses a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer.

There was a project at the substation to install 3V0 on both the transformers under capital improvement project; therefore, the customer will not be responsible for any cost associated with the 3V0 installation.

6.2 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.

Pre-Project

System Impedance at PCC

Z1 = 0.2299 + j1.1026p.u.

Z0 = 2.1628 + j1.3118p.u

6.3 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 and will not upset existing device coordination on the feeder.

The Customer is responsible for ensuring that their own equipment is rated to withstand the available fault current according to the NEC and National Grid ESB 750, which specifies that the fault current should be no more than 80% of the device interrupting rating.

Any assumptions made in calculating the fault current shown in Table 5 are identified in Section 2.1.1

PRE PROJECT	Tiverton Sub @ 12.47 kV	PCC Amps @ 12.47 kV
3-phase (LLL)	7189	4171
Phase-Ground (LG)	7328	3212

POST PROJECT	Tiverton Sub @ 12.47 kV	PCC Amps @ 12.47 kV	Tiverton Sub I_{fault} @ SUB BUS	DELTA I_{fault} @ PCC
3-phase (LLL)	7835	4818	8.99%	15.51%
Phase-Ground (LG)	8357	4239	14.04%	31.97%

Table 3: Fault Duty

6.4 Substation Protective Device Modifications

Phase and Ground overcurrent elements are required for the at the new Tiverton 33F6 Circuit Breaker.

6.5 Area EPS Protective Device Coordination

The Project will require a Company owned recloser at the PCC.

7.0 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.

7.1 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 National Grid 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 National Grid. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when National Grid'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 National Grid’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.

7.2 Interconnecting Transformer (ESB 756D Section 7.3)

RI-27970782 Case 00206316

The documentation provided states the following interconnecting transformer:

One (1) 3,368 kVA, 12.47 kV wye-grounded primary, 660 V delta secondary with an impedance of 7.25% and X/R ratio of 10, with a neutral grounding reactor of 7 Ohms. The proposed transformer satisfies the requirements of the ESB.

RI-27970789 Case 00206317

The documentation provided states the following interconnecting transformers:

Two (2) 2,526 kVA, 12.47 kV wye-grounded primary, 660 V delta secondary with an impedance of 7.25% and X/R ratio of 10, with a neutral grounding reactor of 7 Ohms. The proposed transformer satisfies the requirements of the ESB.

One (1) 3,368 kVA, 12.47 kV wye-grounded primary, 660 V delta secondary with an impedance of 7.25% and X/R ratio of 10, with a neutral grounding reactor of 7 Ohms. The proposed transformer satisfies the requirements of the ESB.

7.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Company requires DG installations to be effectively grounded, which is defined in IEEE C62.92.1 section 7.1. Additionally, the Company requires that DG installations do not raise the overvoltage above 125% on the unfaulted phases during ground faults on the distribution circuits. Refer to IEEE C62.92.1 sections 6.3 and 7.1 for further details.

RI-27970782 & RI-27970789 (Case 00206316 and 00206317) :

The proposed configuration has been analyzed and found to meet the effective grounding requirements. The customer proposed a neutral grounding reactor, sized at 7 ohms, on each of the proposed interconnecting transformers.

The proposed grounding reactors are recommended to have a continuous current rating of no less than 100A.

7.4 Manual Generator Disconnecting Means (ESB 756D Section 7.4)

RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

The Customer provided documents satisfy the requirement of this Section of ESB 756D.

7.5 Primary Protection (ESB 756D Section 7.6 & 7.8)

RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

The following section relates to the primary means of protection by the Customer. This includes the inverter relay functionality.

7.5.1 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.

All inverter-based DER projects are required to have voltage and frequency settings and ride-through capability described in ESB 756D Section 7.6.11 and 7.8. This requirement is met.

7.5.2 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 showing acceptable internal relay setting as well as primary and backup relay settings in accordance with the aforementioned requirements.

7.5.3 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.

7.5.4 Primary Utility Restoration Detection (ESB 756D 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 shall provide settings and timing device information for review by the Company.

7.6 Secondary Protection

RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

The following section relates to the secondary means of protection, also referred to as redundant relaying.

7.6.1 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 pole top recloser for site protection.

7.6.2 Secondary Overcurrent Relay Elements (ESB 756D Section 7.6.10)

The Customer provided documents show ground overcurrent (51G) relay element and associated settings that satisfy the requirements of ESB 756D. The Customer provided the following settings for review by the Company:

RI-27970789, Case 00206317

51G – Ground

Customer Proposed: 210A (Primary) pickup, 2.0 Time Dial, U3 curve

RI-27970782, Case 206316

51G – Ground

Customer Proposed: 70A (Primary) pickup, 2.0 Time Dial, U3 curve

7.6.3 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. Relay make/model is included on the Customer single line.

7.6.4 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 showing acceptable internal relay setting as well as primary and backup relay settings in accordance with the aforementioned requirements.

7.6.5 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.

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.

7.6.6 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.

7.6.7 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.

7.6.8 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.

7.6.9 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.

7.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7)

Following a trip of the protective relay, a Utility Restoration Detection function shall prevent manual and automatic reclosing of the Customer's DG intertie device until the Customer's relay has detected that the Utility EPS has been within the voltage and frequency windows identified by IEEE 1547 section 4.2.6 for a minimum of five minutes. 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's one line diagram shows utility grade devices and settings to satisfy this requirement

7.6.11 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.

7.7 Customer Cabling

The Customer must provide a means for primary protection between the Generator disconnect switch and Customer owned transformer to protect the Customer cable. 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.

8.0 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.

9.0 Inspection, Compliance Verification, Customer Testing, and Energization Requirements

9.1 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.

9.2 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.

9.3 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.

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.

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

[3] Actual charges shall include the tax rate in effect at the time the charges are incurred.

10.0 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 4:

National Grid 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
NECO (Note #1) - Line Work, Customer Property	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Equipment at Point of Common Coupling Equipment for RI-27970782 , & RI-27970789 . See Note #2	$174,098.00	$174,098.00	$0.00	$0.00	$19,290.06	$193,388.06
SUBTOTAL	**$174,098.00**	**$174,098.00**	**$0.00**	**$0.00**	**$19,290.06**	**$193,388.06**

NECO - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Install approximately 21,000 circuit feet of cable. See Note #3	$3,176,122.00	$3,176,122.00	$0.00	$0.00	$351,914.32	$3,528,036.32
SUBTOTAL	**$3,176,122.00**	**$3,176,122.00**	**$0.00**	**$0.00**	**$351,914.32**	**$3,528,036.32**

NECO - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Install One Breaker Position at Tiverton Sub. See Note #4	$1,053,804.00	$1,053,804.00	$0.00	$0.00	$116,761.48	$1,170,565.48
Protective Device Changes. See Note # 5	$2,000.00	$0.00	$2,000.00	$0.00	$0.00	$2,000.00
SUBTOTAL	**$1,055,804.00**	**$1,053,804.00**	**$2,000.00**	**$0.00**	**$116,761.48**	**$1,172,565.48**

Civil Work (Company Portion)	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Approximate donated property tax. Note# 6	$0.00	$0.00	$0.00	$0.00	$75,679.72	$75,679.72
National Grid supervision and design support for Customer underground civil construction. See Note #7	$165,000.00	$165,000.00	$0.00	$0.00	$18,282.00	$183,282.00
SUBTOTAL	**$165,000.00**	**$165,000.00**	**$0.00**	**$0.00**	**$93,961.72**	**$258,961.72**

Witness Testing & EMS	Pre-Tax Total	Capital	O&M	Removal	NA	Total
Witness Testing For RI-27970782. See Note #8	$2,500.00	NA	$2,500.00	$0.00	$0.00	$2,500.00
Witness Testing For RI-27970789. See Note #8	$2,500.00	NA	$2,500.00	$0.00	$0.00	$2,500.00
EMS integration For RI-27970782 , & RI-27970789. See Note # 9	$5,000.00	NA	$5,000.00	$0.00	$0.00	$5,000.00
SUBTOTAL	**$10,000.00**	**$0.00**	**$10,000.00**	**$0.00**	**$0.00**	**$10,000.00**

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	$4,581,024.00	$4,569,024.00	$12,000.00	$0.00	$581,927.58	$5,162,951.58

Notes

1. Definition of abbreviation: NECO-Narragansett Electric Co.
2. Installation pole-mounted equipment including one (1) riser pole, one (1) load break switch , one (1) recloser, Two (2) metering assemblies , approximately 600ft of 3-Phase 477-AL OH conductor, 6 poles, and other required equipment.
3. Install Approximately 21,000 feet of 1000MCM CU 3-1/C EPR 15kV from the Tiverton Substation and along Fish Road, Bulgarmarsh Road (Route RI-177), and Brayton Road. Estimate does not include required manhole and duct civil construction (customer requested responsibility).
4. Install one (1) 12.47 kV circuit position of the Tiverton No.2 bus, including one (1) 1200 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, approximately 100ft of UG 3-phase-feeder cable, and additional substation equipment and civil construction inside of the Tiverton Substation.
5. Review and Implementation of protective device settings including field implementation and associated engineering review/documentation in Company tracking system(s)
6. Approximate donated property tax. Estimate assumes the customer installing approximately 21,000 feet of 5" PVC-DB concrete encased duct bank , thirty-four (34) - manholes, and five (5) risers. Note: Customer is responsible for performing, any and all, temporary and permanent restoration
7. National Grid supervision and design support for Customer driven underground civil construction. This cost includes: National Grid External Design/DPAM would need to prepare design package (Scope, Construction Specifications, Construction Standards/Drawings, Vendor Information, etc.), National Grid to review and approve Construction Drawings prepared by DG Developer , Full time inspector assigned to review and approve civil work.
8. Witness Testing including review of witness test documentation and manpower for attending witness test.
9. Integration of DG and EPS modifications into Company's Energy Management System (EMS).

Table 4: 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.[4] 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.

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 *ESB756C, 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

[4] Actual charges shall include the tax rate in effect at the time the charges are incurred.

11.0 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.

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.

12.0 Revision History

Version	Date	Description of Revision
1.0	02/22/2020	Draft
2.0	03/16/2020	Final
3.0	05/29/2020	Updated Study to reflect change in civil construction details (Customer)
4.0	11/10/2020	Updated Study to reflect change in civil construction details (Customer)
5.0	12/14/2020	Customer added a new application to the project
6.0	02/16/2021	The customer changed the size of the project
7.0	04/01/2021	Final

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.

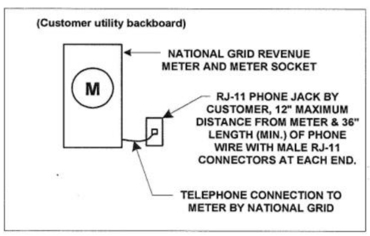


Figure 1A – Indoor Meter Installation
not to scale

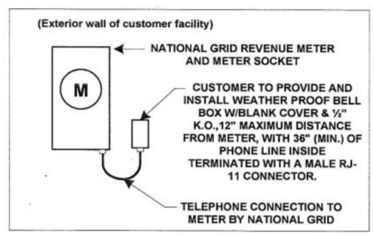


Figure 1B – Outdoor Meter Installation
not to scale

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).

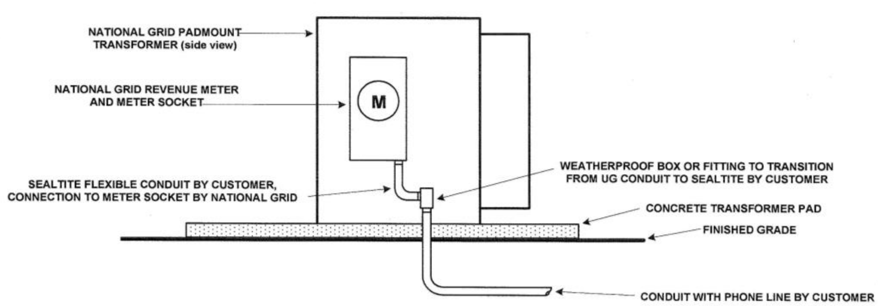


Figure A- 1: Revenue Meter Phone Line Installation Guide

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).

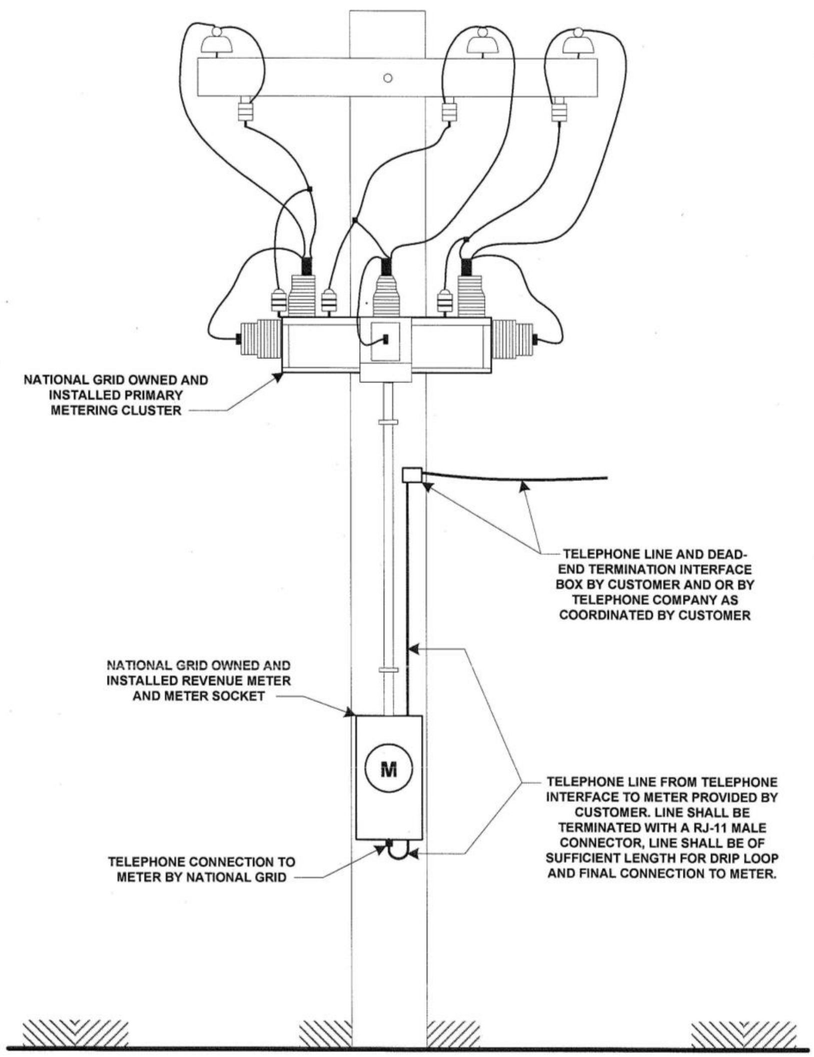


Figure A- 2: Revenue Meter Phone Line Installation Guide

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.

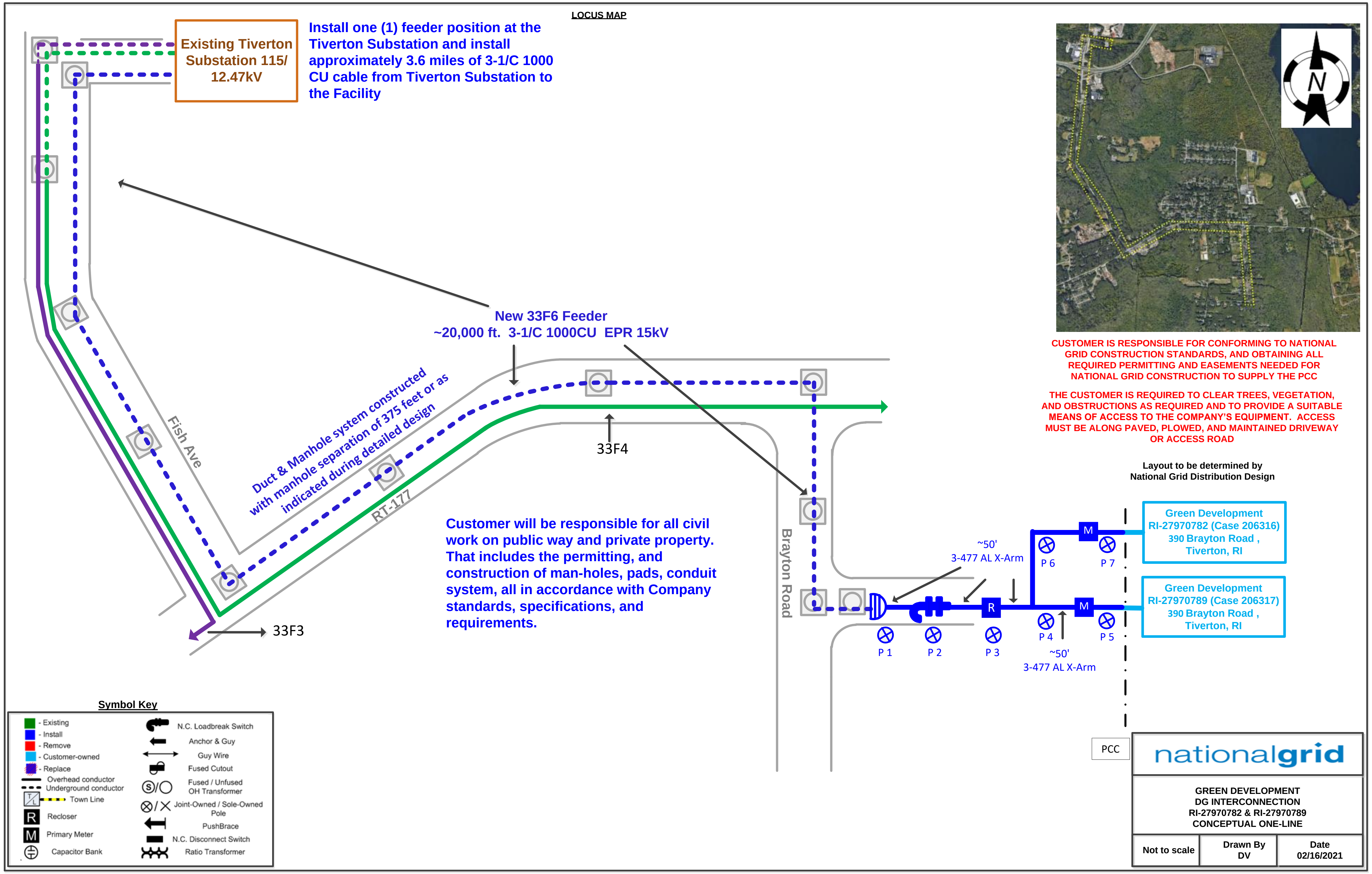


Figure B- 1: Mid-Line Modifications & PCC Configuration

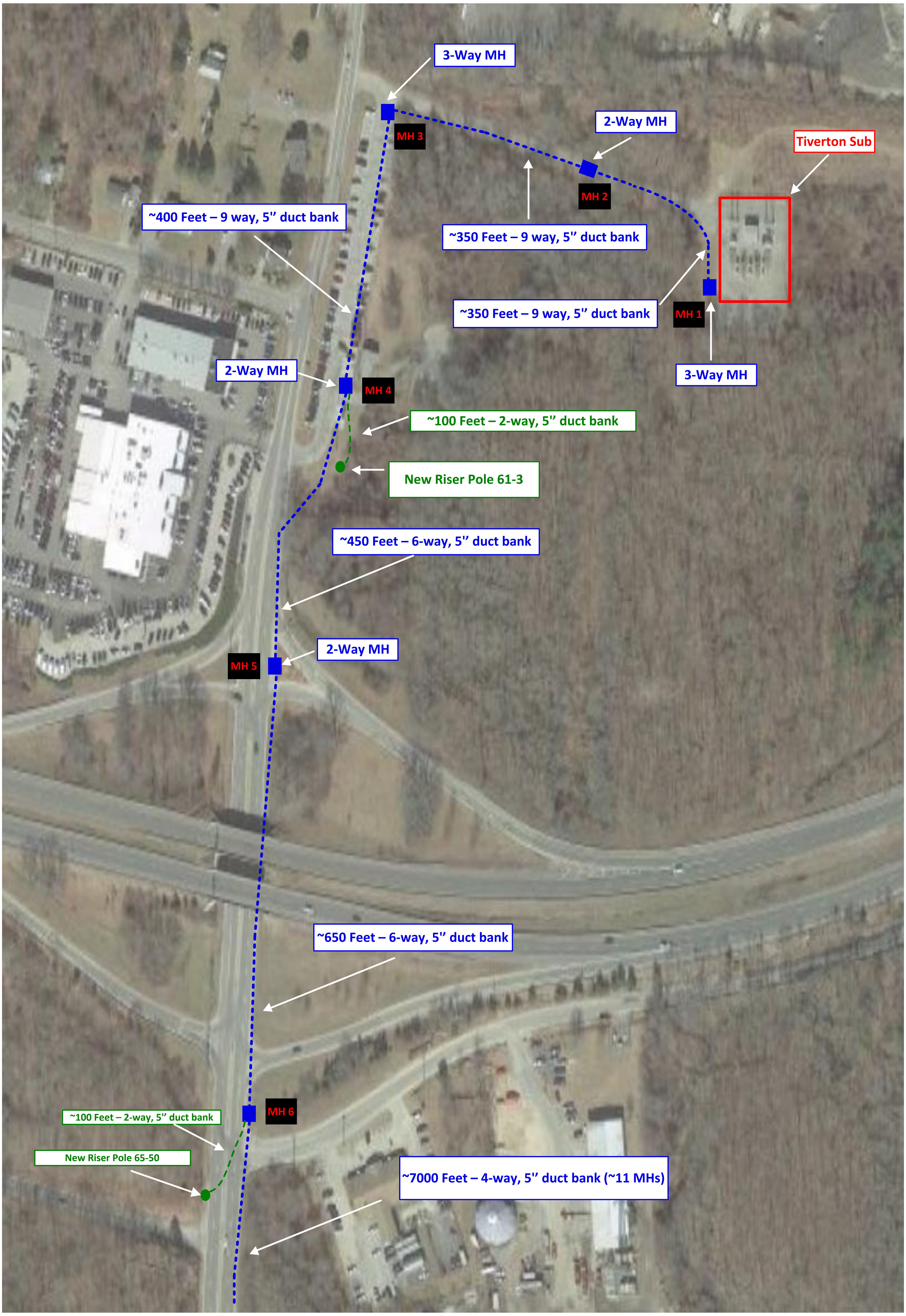


Figure B- 2: Civil Work (To be Completed by Customer)

Figure B- 3: Civil Work (To be Completed by Customer)

Figure B- 4: Civil Work (To be Completed by Customer)

Appendix C Customer Site and Single Line Diagram

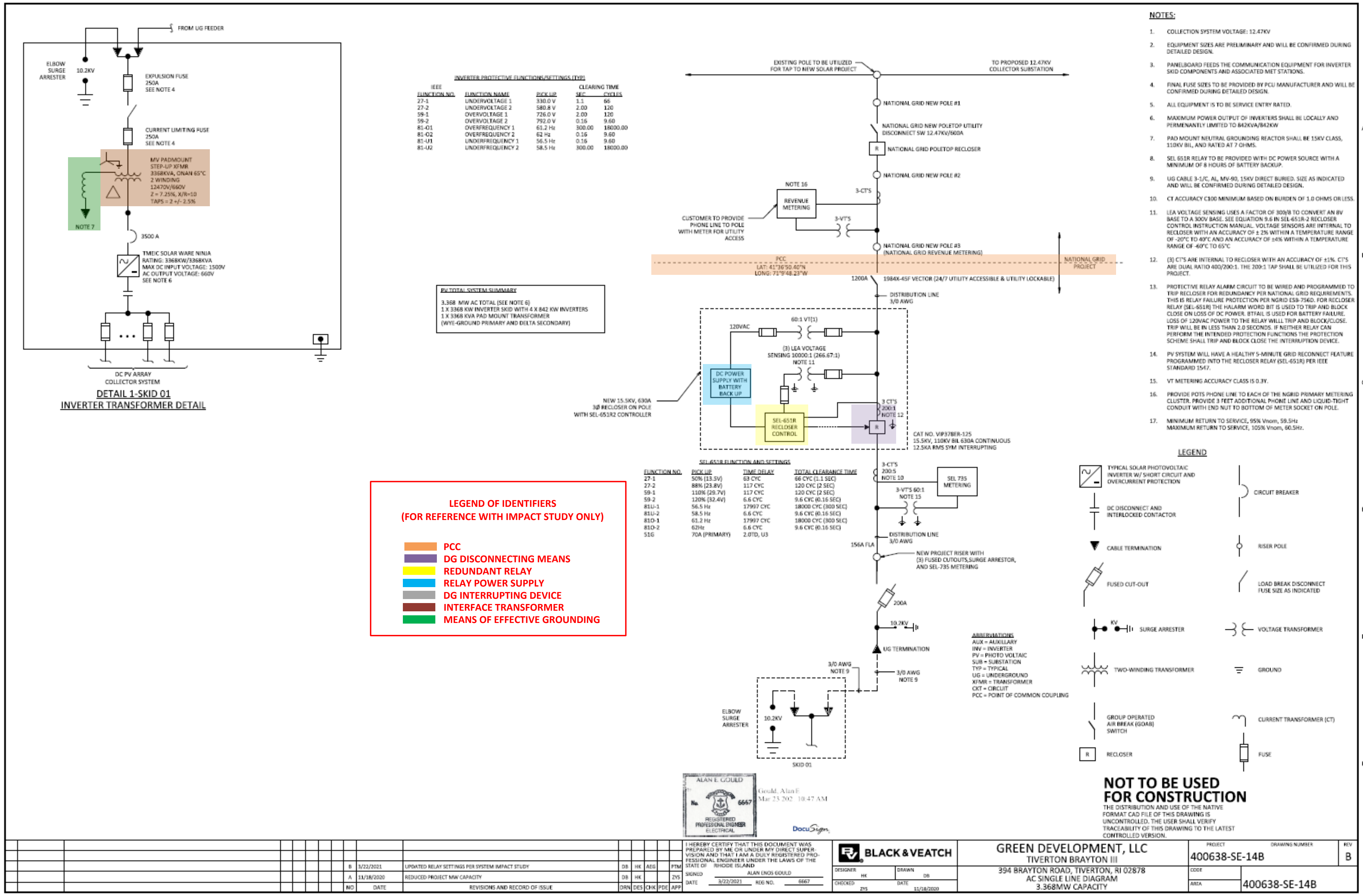


Figure C- 1: Project One-Line (RI-27970782 Case 00206316)

(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

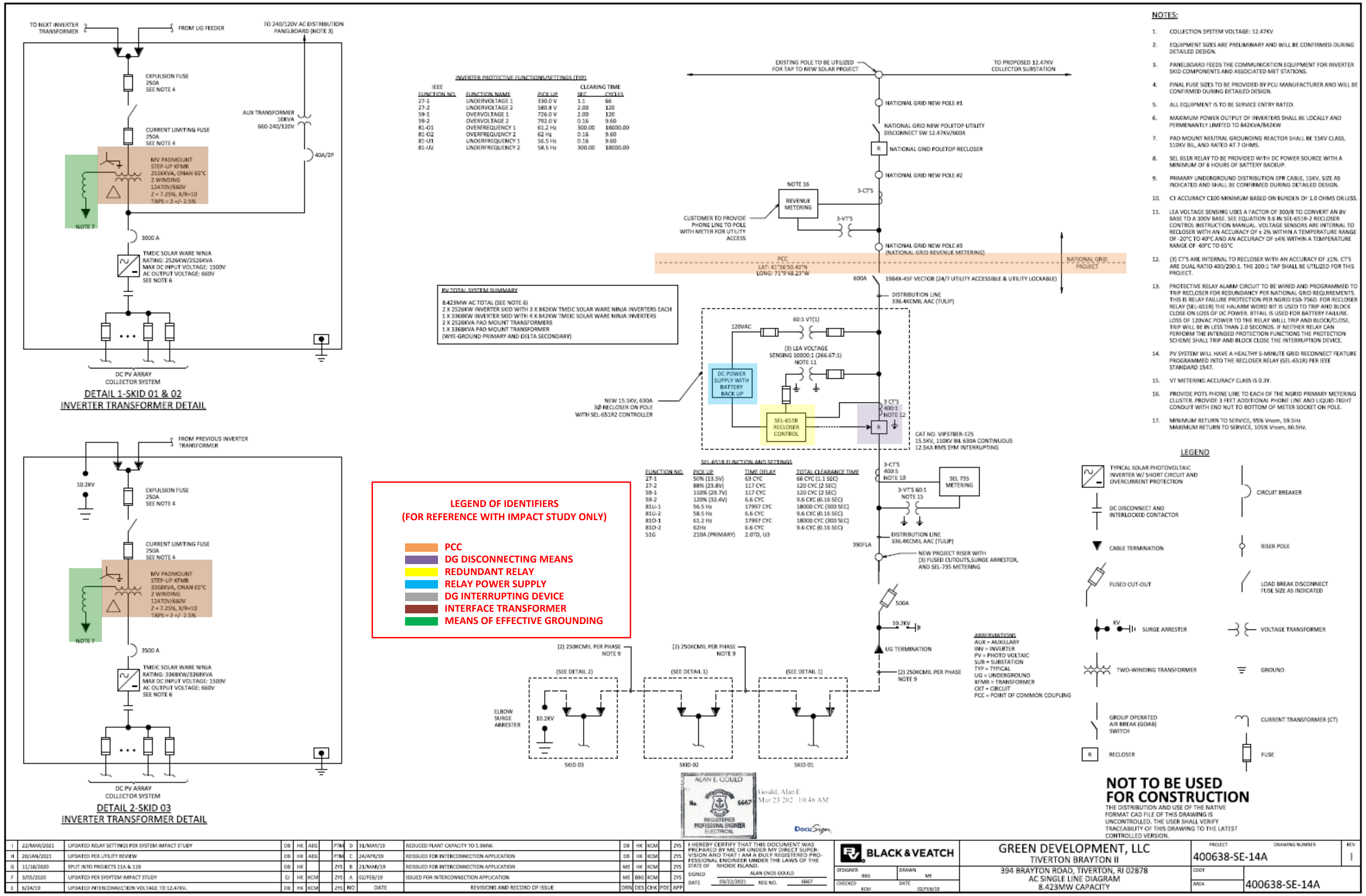


Figure C- 2: Project One-Line (RI-27970789 Case 00206317)
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

Figure C- 3: RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

System Impact Study
for Distributed Generation Interconnection to National Grid's 12.47kV System

DG WR:	RI-27970782	RI-27970789
DG Case#:	00206316	00206317
Applicant:	Green Development, LLC	Green Development, LLC
Address:	394 Brayton Road (Southern Array)	394 Brayton Road (Northern Array)
City:	Tiverton, RI	Tiverton, RI
DG kW/kVA:	3,368 kW / 3,368 kVA	8,420 kW / 8,420 kVA
DG Type:	Inverter-Based Photovoltaic	Inverter-Based Photovoltaic
Feeder:	Tiverton 33F6 (Proposed Feeder)	Tiverton 33F6 (Proposed Feeder)

Table of Contents

Section **Page**

List of Tables

Definitions

The following is a list of acronyms/synonyms used in this Interconnection Study:

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESB – National Grid'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

NPCC – Northeast Power Coordinating Council

PCC – Point of Common Coupling (point of demarcation between the Customer and Company facilities)

Project – The interconnection of the Facility to the Company electrical power system.

Executive Summary

The Company has completed the Impact Study for the interconnection of Green Development LLC, ("Customer") 11,788 kW / 11,788 kVA Combined total, inverter based photovoltaic generator ("the Facility") , to its 12.47 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

The specific Projects consist of:

RI-27970782 (Case 206316) 3,368 kW / 3,368 kVA

RI-27970789 (Case 206317) 8,420 kW / 8,420 kVA

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:

Tiverton Substation (Section 2.2):

1. Add one 12.47kV express circuit position, on the No.2 bus (33F6)
    - o Install one (1) 12.47 kV breaker
    - o 3 single-phase regulators and additional substation equipment required
    - o Install new getaway man-hole and duct system inside of the Tiverton Substation

Distribution (Section 2.2):

1. Install approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from the Tiverton Substation (located near Fish Road) to the Point of Common Coupling on Brayton Point Road.
    1. The Customer has requested responsibility for the required installation of approximately 1,100 feet of 9-way 5'', 1,100 feet 6-way 5'' and 17,800 feet of 4-way 5'' (~21,000 feet total) concrete-encased manhole & duct system. The Customer will be required to comply with Company Construction Standards and obtain approval by the Company prior to covering. See Appendix B for additional details

2. Point of Common Coupling (Appendix B-1):
    1. Install primary riser
    2. Install approximately seven (7) poles and 600 circuit feet of 3-477 AAC overhead conductor and associated equipment
    3. Install one (1) load break switch

4. Install one (1) recloser
5. Install two (2) primary metering assemblies

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 **$3,708,408.73** +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the Interconnection Service Agreement. Applicable cost sharing allocations, if any, will be calculated by the Company and provided in the Interconnection Service Agreement.

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 National Grid 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

RI-27970782, Case 00206316

The Customer proposes to install the following:

- One (1) Customer owned SMA Sunny Central 4000-UP-US derated to 3,368kW / 3,368kVA inverter-based DG
- One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-600 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
- One (1) Customer owned 15 kV Pole-Mounted Eaton Nova recloser with a SEL 651R relay assembly
- One (1) Customer owned, S&C Alduti-Rupter model #147412,15 kV gang-operated switch, with visible blades accessible to utility side

RI-27970789, Case 00206317

The Customer proposes to install the following:

- Two (2) Customer owned SMA Sunny Central 2660-UP-US derated to 2526kW / 2526KVA, and one (1) SMA Sunny Central 4000-UP-US derated to 3368kW / 3368KVA inverter-based DG (8,420kW / 8,420kVA total)
- One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-600 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
- Two (2) Customer owned 2,526 kVA, 12.47 kV wye-grounded primary-600 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
- One (1) Customer owned 15 kV Pole-Mounted Eaton Nova recloser with a SEL 651R relay assembly
- One (1) Customer owned, S&C Alduti-Rupter model #147412F, 15 kV gang-operated switch, with visible blades accessible to utility side

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-lines (dated 03/23/2021).

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.

RI-27970782, Case 00206316 is required to implement a 32 element in the customer relay to satisfy ESB756-2023 Section 7.6.13.1.

2.1.1 Assumptions

For certain components, data was not provided by the Customer, or was physically not available at the time of this Study. In order to proceed with the analysis certain assumptions were made based on past experience and engineering judgment. Assumptions are summarized in the following list. Should any of these assumptions be incorrect, the Customer must advise the Company immediately, as reevaluation of the Impact Study results will be required:

1. The analysis in this Study assumed a neutral reactor sized at 7 ohms at each

of the interface transformers, see section 7.3.

2. The Customer has requested responsibility for the required installation of approximately 1,100 foot 9-way 5'', 1,100 foot 6-way 5" and foot 17,800 4-way 5" (~21,000 total) concrete-encased manhole & duct system. The Customer will be required to comply with Company Construction Standards and obtain approval by the Company prior to covering. See Appendix B for additional details
   - The Customer will be responsible for all civil work on public way and private property. Scope of work includes the permitting and construction of man-holes, pads, conduit system, all in accordance with Company standards, specifications, and requirements.
   - Estimates provided for the donated property tax item in Table 4 assumes the customer installing approximately 1,100 feet of 9-Way 5", 1,100 feet of 6-Way 5", and 17,800 feet of 9-Way 5" PVC-DB concrete encased duct bank, thirty-four (34) - manholes, and five (5) risers .See Appendix B for additional details
   - The Customer will be responsible for performing, any and all, temporary and permanent restoration.
3. The Customer decided not to proceed with the expansion of breaker and a half configuration at the Tiverton Substation. For this reason, the Customer will be only allowed to operate when Transformer #2 is in-service. During contingencies, maintenance, and other abnormal conditions the customer will be required to be disconnected from the EPS.
4. Customer proposed inverters are assumed to be power limited to 842 kW/ 842 kVA each.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is a new express feeder to the customer's site. This new feeder, feeder 33F6, will be a 12.47kV regulated, three-phase, 4 wire, wye, effectively-grounded, radial distribution circuit that will originate at the Company's Tiverton Substation, in Tiverton Rhode Island (the "Interconnecting Circuit"). The feeder will be regulated by way of a feeder voltage regulator at the substation.

Substation modifications include the following:

- Install (1) 1,200 15kV RMAG relayed breaker
- Install nine (9) 15kV 1200A single blade disconnects
- Install three (3) single-phase 333kVA regulators
- Install one (1) bay of buss extension
- Install cable terminations and disconnects for getaway
- Install approximately 100 ft of 3 phase feeder underground cable

- Install associated civil-duct work and civil construction inside of the Tiverton substation

Distribution line modifications include:

- Install 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.
- The Customer has requested responsibility for the required installation of approximately 21,000 foot 4-way 5" concrete-encased manhole & duct system.

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 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)*
33F6	*0*	*0*	*11,788*	*11,788*
33F1	*4,790*	*613*	*0*	*5,403*
33F2	*368*	*29*	*0*	*397*
33F3	*1,132*	*6,860*	*0*	*7,992*
33F4	*971*	*7,510*	*0*	*8,481*
TOTAL	*7,261*	*15,012*	*11,788*	***34,061***

Table 1: Generation at the Substation and Interconnecting Circuit

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 proposed Pole #5 for RI-27970782 and Pole #7 for RI-27970789 all on Brayton Road, Tiverton Rhode Island. 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 National Grid right of way (R.O.W) is involved, then the Customer shall provide detailed drawings of any planned construction within any National Grid 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 National Grid'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 Global Information System ("GIS"). A field review of the area was performed on 04/30/2019.

The analysis considered cases at peak load 19,253 kVA @ 99.24% Lagging PF and net minimum load 3,454 kVA @ 91.83% Leading PF at time of maximum expected generation (9:00AM – 6:00PM) on Transformer # 2 at the Tiverton Substation.

Substation peak and minimum load values have been taken from the Company's historical load data that has been compiled over the past 12 months, from 04/01/2018 to 04/01/2019.

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. However, the substation is currently equipped with bi-directional metering, which were previously installed for reasons unrelated to DG work. Therefore, no additional work is required at the substation, and this Customer is not responsible for costs related to the existing substation equipment.

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 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.

Due to potential high generation to load ratios on the feeder and possible Load Rejection Over Voltage (LROV), the Customer must provide details, documentation, and any factory tests or pre-certifications for the mitigation of this condition. The Company reserves the right to request additional equipment on the Customer's Facility if required and/or Over Voltage set point or a modification of an existing setting to mitigate this condition. The clearing/de-energization time must satisfy the Transient Over Voltage Tolerance Curve in Figure 1.

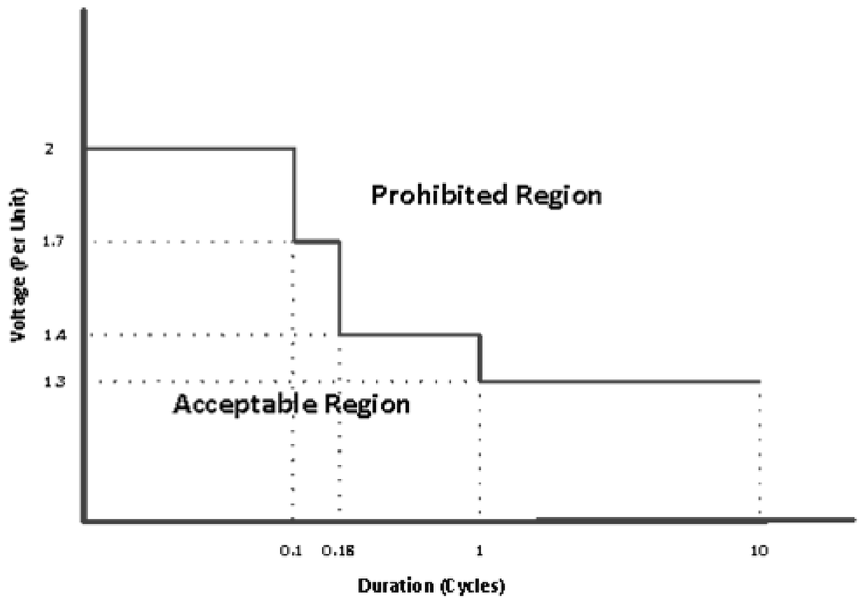


Figure 1: IEEE Transient Over Voltage Tolerance Curve

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.

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 there is potential for this site to cause voltage flicker on the interconnecting feeder, therefore more detailed analysis was required.

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 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.

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 unity power factor.
- The maximum output generation of the two projects stays at 11.8MW

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

[1] CYME Power Engineering Software, Version 7.1, Revision 02, Build 99, Copyright © 1986-2014, Cooper Industries, Ltd.

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 2 was considered on this feeder. Three-phase projects greater than 25kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Inverter Manufacturer	Inverter Model
0	All Projects <25kW Miscellaneous	All Projects <25kW Miscellaneous
11,788	SMA Sunny Central	2660-UP-US & 4000-UP-US

Table 2: 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 likely event. As a result, one (1) PCC recloser with reclose blocking will be required for both projects.

5.0 Transmission Assessments

National Grid Transmission Planning (NEP) studied the impact of the proposed project in accordance with ISO-NE Planning Procedure 5-6 “Scope of Study for System Impact Studies under the Generation Interconnection Procedures” and National Grid TGP28 “Transmission Planning Guide”. National Grid Transmission Planning determined there were no adverse impacts to the transmission system as studied.

This analysis is conducted in accordance with the following criteria:

- NERC Transmission Planning Standards TPL-001-4, “*Transmission System Planning Performance Requirements”*.
- Northeast Power Coordinating Council (NPCC) Directory 1, “*Design and Operation of the Bulk Power System*”.
- ISO New England Planning Procedure #3 (PP3) – “*Reliability Standards for the New England Area Bulk Power System*”.

- ISO New England Planning Procedure #5-6 (PP5-6) – *"Interconnection Planning Procedure for Generation and Elective Transmission Upgrades"*.
- National Grid Transmission Group Procedure (TGP) #28 – "*Transmission Planning Guide for the National Grid USA Service Company*".

National Grid will follow ISO NE PP 5-3 "Guidelines for Conducting and Evaluating Proposed Plan Applications Analyses (PPA)" and review all findings with appropriate Task Forces for concurrence of National Grid's findings. Upon Task Force concurrence National Grid will submit the PPA to Reliability Committee, for recommendation to ISO-NE. Thus the study findings are not considered final until letter of determination by ISO-NE is received by National Grid.

6.0 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. Refer to Section 2.1.1 for any assumptions made in the model.

6.1 Fault Detection at Substation (ESB 756D Section 6.2.2)

Addition of generation sources to distribution feeders can result in the backfeeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. The Company's typical 115kV-15kV class substation transformer has a delta connection on the transmission side and wye-grounded connection on the distribution side. Due to the transformer's configuration, it cannot contribute zero sequence ground fault current to single line to ground faults on a transmission line, and the voltage on the unfaulted phases rises significantly and rapidly. These overvoltages have potential to exceed insulation levels of the station and transmission line equipment, and maximum continuous operating voltage of surge arresters. Zero sequence voltage protection (commonly referred to as "$3V_0$") on the primary side of the transformer is required in order to detect these overvoltage conditions. This $3V_0$ protection will disconnect the generation from the substation transformer, and stop the generation and transformer from contributing to the transmission-side overvoltage condition.

Detailed analysis was completed to determine whether the interconnection of the Facility, in conjunction with existing connected facilities, may pose significant risk of

[2] ASPEN OneLiner V12.5, Build: 19177 (2015.01.28), Copyright © 1987-2013 ASPEN.

causing temporary over-voltage conditions to develop on the system during line to ground faults on the high side of the substation transformer. The load to generation match at the substation has been evaluated assuming minimum load, maximum generation, and one feeder out of service in order to determine if substation modifications are required.

For this Project, results indicate that the Facility poses a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer.

There was a project at the substation to install 3V0 on both the transformers under capital improvement project; therefore, the customer will not be responsible for any cost associated with the 3V0 installation.

6.2 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.

Pre-Project

System Impedance at PCC

Z1 = 0.2299 + j1.1026p.u.

Z0 = 2.1628 + j1.3118p.u

6.3 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 and will not upset existing device coordination on the feeder.

The Customer is responsible for ensuring that their own equipment is rated to withstand the available fault current according to the NEC and National Grid ESB 750, which specifies that the fault current should be no more than 80% of the device interrupting rating.

Any assumptions made in calculating the fault current shown in Table 5 are identified in Section 2.1.1

PRE PROJECT	Tiverton Sub @ 12.47 kV	PCC Amps @ 12.47 kV
3-phase (LLL)	7189	4171
Phase-Ground (LG)	7328	3212

POST PROJECT	Tiverton Sub @ 12.47 kV	PCC Amps @ 12.47 kV	Tiverton Sub I_{fault} @ SUB BUS	DELTA I_{fault} @ PCC
3-phase (LLL)	7835	4818	8.99%	15.51%
Phase-Ground (LG)	8357	4239	14.04%	31.97%

Table 3: Fault Duty

6.4 Substation Protective Device Modifications

Phase and Ground overcurrent elements are required for the at the new Tiverton 33F6 Circuit Breaker.

6.5 Area EPS Protective Device Coordination

The Project will require a Company owned recloser at the PCC.

7.0 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.

7.1 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 National Grid 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 National Grid. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when National Grid'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 National Grid'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.

7.2 Interconnecting Transformer (ESB 756D Section 7.3)

RI-27970782 Case 00206316

The documentation provided states the following interconnecting transformer:

One (1) 3,368 kVA, 12.47 kV wye-grounded primary, 600 V delta secondary with an impedance of 7.25% and X/R ratio of 10, with a neutral grounding reactor of 7 Ohms. The proposed transformer satisfies the requirements of the ESB.

RI-27970789 Case 00206317

The documentation provided states the following interconnecting transformers:

Two (2) 2,526 kVA, 12.47 kV wye-grounded primary, 600 V delta secondary with an impedance of 7.25% and X/R ratio of 10, with a neutral grounding reactor of 7 Ohms. The proposed transformer satisfies the requirements of the ESB.

One (1) 3,368 kVA, 12.47 kV wye-grounded primary, 600 V delta secondary with an impedance of 7.25% and X/R ratio of 10, with a neutral grounding reactor of 7 Ohms. The proposed transformer satisfies the requirements of the ESB.

7.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Company requires DG installations to be effectively grounded, which is defined in IEEE C62.92.1 section 7.1. Additionally, the Company requires that DG installations do not raise the overvoltage above 125% on the unfaulted phases during ground faults on the distribution circuits. Refer to IEEE C62.92.1 sections 6.3 and 7.1 for further details.

RI-27970782 & RI-27970789 (Case 00206316 and 00206317) :

The proposed configuration has been analyzed and found to meet the effective grounding requirements. The customer proposed a neutral grounding reactor, sized at 7 ohms, on each of the proposed interconnecting transformers.

The proposed grounding reactors are recommended to have a continuous current rating of no less than 100A.

7.4 Manual Generator Disconnecting Means (ESB 756D Section 7.4)

RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

The Customer provided documents satisfy the requirement of this Section of ESB 756D.

7.5 Primary Protection (ESB 756D Section 7.6 & 7.8)

RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

The following section relates to the primary means of protection by the Customer. This includes the inverter relay functionality.

7.5.1 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.

All inverter-based DER projects are required to have voltage and frequency settings and ride-through capability described in ESB 756D Section 7.6.11 and 7.8. This requirement is met.

7.5.2 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 showing acceptable internal relay setting as well as primary and backup relay settings in accordance with the aforementioned requirements.

7.5.3 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.

7.5.4 Primary Utility Restoration Detection (ESB 756D 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 shall provide settings and timing device information for review by the Company.

7.6 Secondary Protection

RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

The following section relates to the secondary means of protection, also referred to as redundant relaying.

7.6.1 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 pole top recloser for site protection.

7.6.2 Secondary Overcurrent Relay Elements (ESB 756D Section 7.6.10)

The Customer provided documents show ground overcurrent (51G) relay element and associated settings that satisfy the requirements of ESB 756D. The Customer provided the following settings for review by the Company:

RI-27970789, Case 00206317

51G – Ground

Customer Proposed: 210A (Primary) pickup, 2.0 Time Dial, U3 curve

RI-27970782, Case 206316

51G – Ground

Customer Proposed: 70A (Primary) pickup, 2.0 Time Dial, U3 curve

7.6.3 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. Relay make/model is included on the Customer single line.

7.6.4 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 showing acceptable internal relay setting as well as primary and backup relay settings in accordance with the aforementioned requirements.

7.6.5 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.

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.

7.6.6 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.

7.6.7 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.

7.6.8 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.

7.6.9 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.

7.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7)

Following a trip of the protective relay, a Utility Restoration Detection function shall prevent manual and automatic reclosing of the Customer's DG intertie device until the Customer's relay has detected that the Utility EPS has been within the voltage and frequency windows identified by IEEE 1547 section 4.2.6 for a minimum of five minutes. 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's one line diagram shows utility grade devices and settings to satisfy this requirement

7.6.11 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.

7.7 Customer Cabling

The Customer must provide a means for primary protection between the Generator disconnect switch and Customer owned transformer to protect the Customer cable. 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.

8.0 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.

9.0 Inspection, Compliance Verification, Customer Testing, and Energization Requirements

9.1 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.

9.2 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.

9.3 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.

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.

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

[3] Actual charges shall include the tax rate in effect at the time the charges are incurred.

10.0 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 4:

National Grid 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
NECO (Note #1) - Line Work, Customer Property	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Equipment at Point of Common Coupling Equipment for RI-27970782 & RI-27970789. See Note #2	$334,587.20	$319,675.25	$14,911.95	$0.00	$35,420.02	$370,007.22
SUBTOTAL	$334,587.20	$319,675.25	$14,911.95	$0.00	$35,420.02	$370,007.22

NECO - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Install approximately 21,000 circuit feet of cable. See Note #3	$1,707,665.02	$1,707,665.02	0.00	0.00	$189,209.28	$1,896,874.30
SUBTOTAL	$1,707,665.02	$1,707,665.02	$0.00	$0.00	$189,209.28	$1,896,874.30

NECO - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Install One Breaker Position at Tiverton Sub. See Note #4	$1,053,804.00	$1,053,804.00	$0.00	$0.00	$116,761.48	$1,170,565.48
Protective Device Changes. See Note # 5	$2,000.00	$0.00	$2,000.00	$0.00	$0.00	$2,000.00
SUBTOTAL	$1,055,804.00	$1,053,804.00	$2,000.00	$0.00	$116,761.48	$1,172,565.48

Civil Work (Custumer)	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Approximate donated property tax. Note# 6	$0.00	0.00	0.00	0.00	75,679.72	75,679.72
National Grid supervision and design support for Customer underground civil construction. See Note #7	$165,000.00	165,000.00	0.00	0.00	18,282.00	183,282.00
SUBTOTAL	$165,000.00	$165,000.00	0.00	$0.00	$93,961.72	$258,961.72

Witness Testing & EMS	Pre-Tax Total	Capital	O&M	Removal	NA	Total
Witness Testing For RI-27970782. See Note #8	$2,500.00	NA	$2,500.00	NA	NA	$2,500.00
Witness Testing For RI-27970789. See Note #8	$2,500.00	NA	$2,500.00	NA	NA	$2,500.00
EMS integration For RI-27970782 & RI-27970789. See Note # 9	$5,000.00	NA	$5,000.00	NA	NA	$5,000.00
SUBTOTAL	$10,000.00	$0.00	$10,000.00	$0.00	$0.00	$10,000.00

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	$3,273,056.22	$3,246,144.27	$26,911.95	$0.00	$435,352.51	$3,708,408.73

Notes

1. Definition of abbreviation: NECO-Narragansett Electric Co.
2. Installation pole-mounted equipment including one (1) riser pole, one (1) load break switch , one (1) recloser, two (2) metering assemblies , approximately 600ft of 3-Phase 477-AL OH conductor, 7 poles, and other required equipment.
3. Install 21,000 feet of 1000MCM CU 3-1/C EPR 15kV along Fish Road, Bulgarmarsh Road (Route RI-177), and Brayton Road. Estimate does not include required manhole and duct civil construction (customer requested responsibility). Cost of cable ($1,468,456.98) removed 8/9/2023
4. Install one (1) 12.47 kV circuit position of the Tiverton No.2 bus, including one (1) 1200 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, approximately 100fT of UG 3 phase feeder cable, and additional associated substation equipment and civil construction inside of the Tiverton Substation.
5. Review and Implementation of protective device settings including field implementation and associated engineering review/documentation in Company tracking system(s)
6. Approximate donated property tax. Estimate assumes the customer installing approximately 21,000 feet of 6-Way 5" PVC-DB concrete encased duct bank , thirty (30) - 2 way manholes, and two (2) risers. Note: Customer is responsible for performing, any and all, temporary and permanent restoration
7. National Grid supervision and design support for Customer driven underground civil construction. This cost includes: National Grid External Design/DPAM would need to prepare design package (Scope, Construction Specifications, Construction Standards/Drawings, Vendor Information, etc), National Grid to review and approve Construction Drawings prepared by DG Developer , Full time inspector assigned to review and approve civil work.
8. Witness Testing including review of witness test documentation and manpower for attending witness test.
9. Integration of DG and EPS modifications into Company's Energy Management System (EMS).

Table 4: 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.[4] 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.

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 *ESB756C, 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

[4] Actual charges shall include the tax rate in effect at the time the charges are incurred.

11.0 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.

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.

12.0 Revision History

Version	Date	Description of Revision
1.0	02/22/2020	Draft
2.0	03/16/2020	Final
3.0	05/29/2020	Updated Study to reflect change in civil construction details (Customer)
4.0	11/10/2020	Updated Study to reflect change in civil construction details (Customer)
5.0	12/14/2020	Customer added a new application to the project
6.0	02/16/2021	The customer changed the size of the project
7.0	04/01/2021	Final
8.0	08/09/2023	Removed cable cost of $1,468,456.98 from cost estimate
9.0	08/23/2023	Updated Customer Facility, PCC cost estimate and Appendix C Customer Single Line Diagram

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.

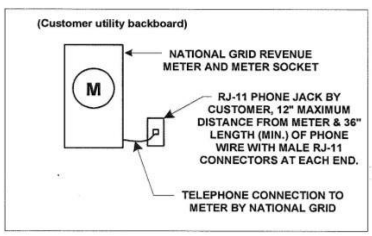


Figure 1A – Indoor Meter Installation
not to scale

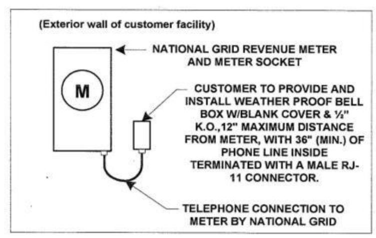


Figure 1B – Outdoor Meter Installation
not to scale

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).

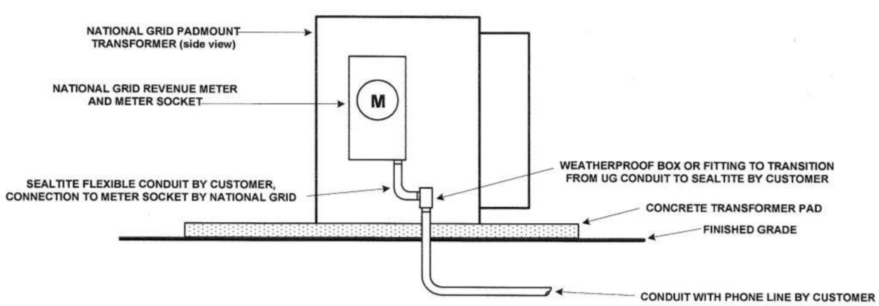


Figure A- 1: Revenue Meter Phone Line Installation Guide

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).

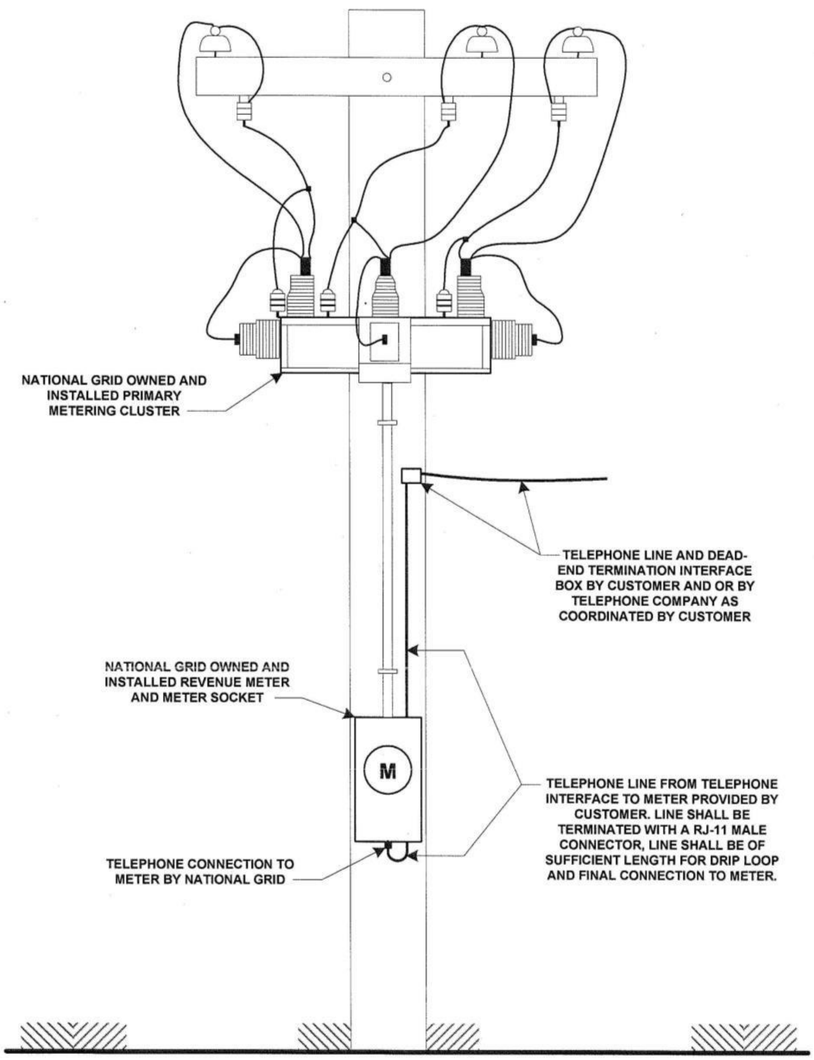


Figure A- 2: Revenue Meter Phone Line Installation Guide

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.

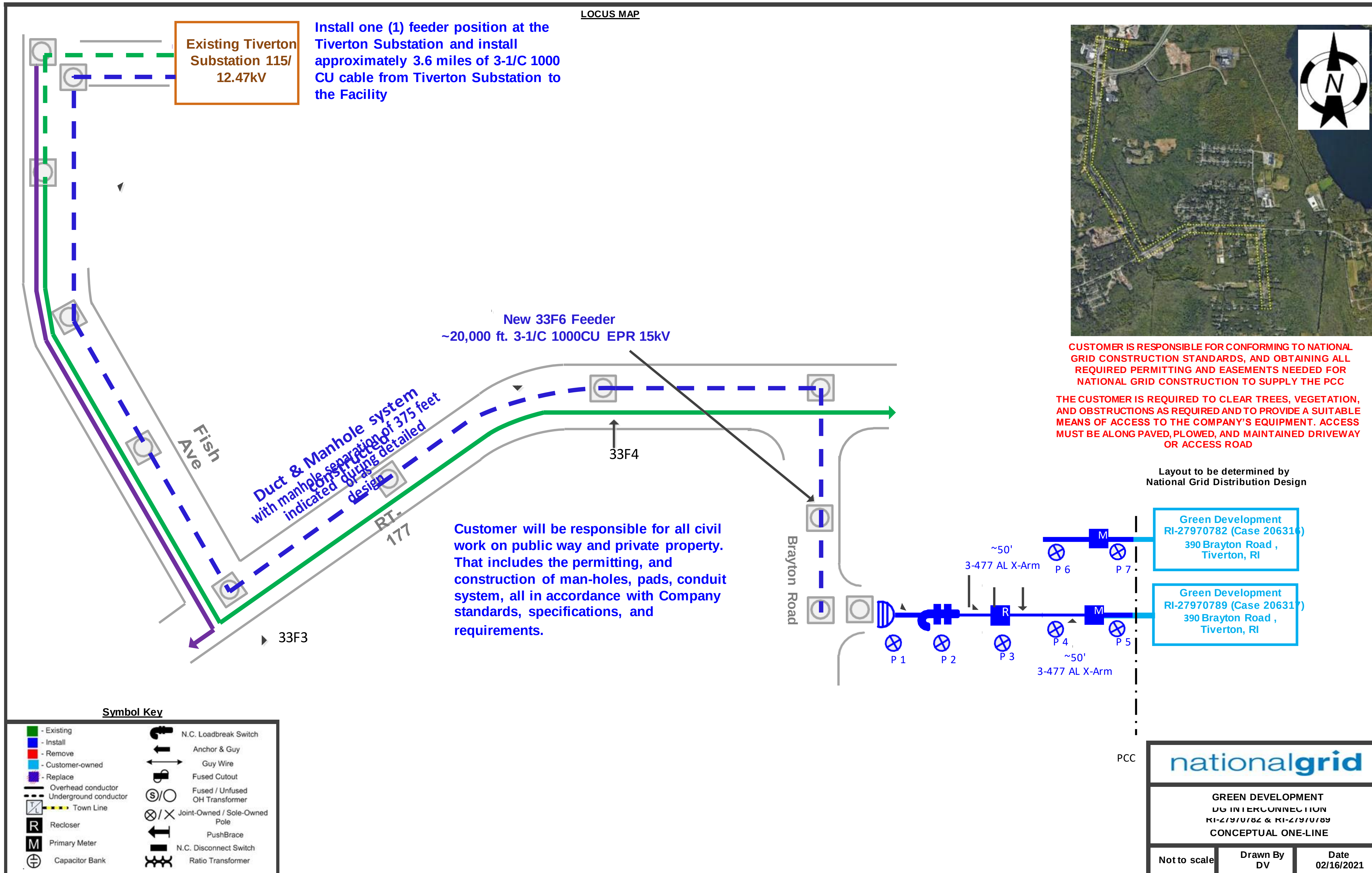


Figure B- 1: Mid-Line Modifications & PCC Configuration

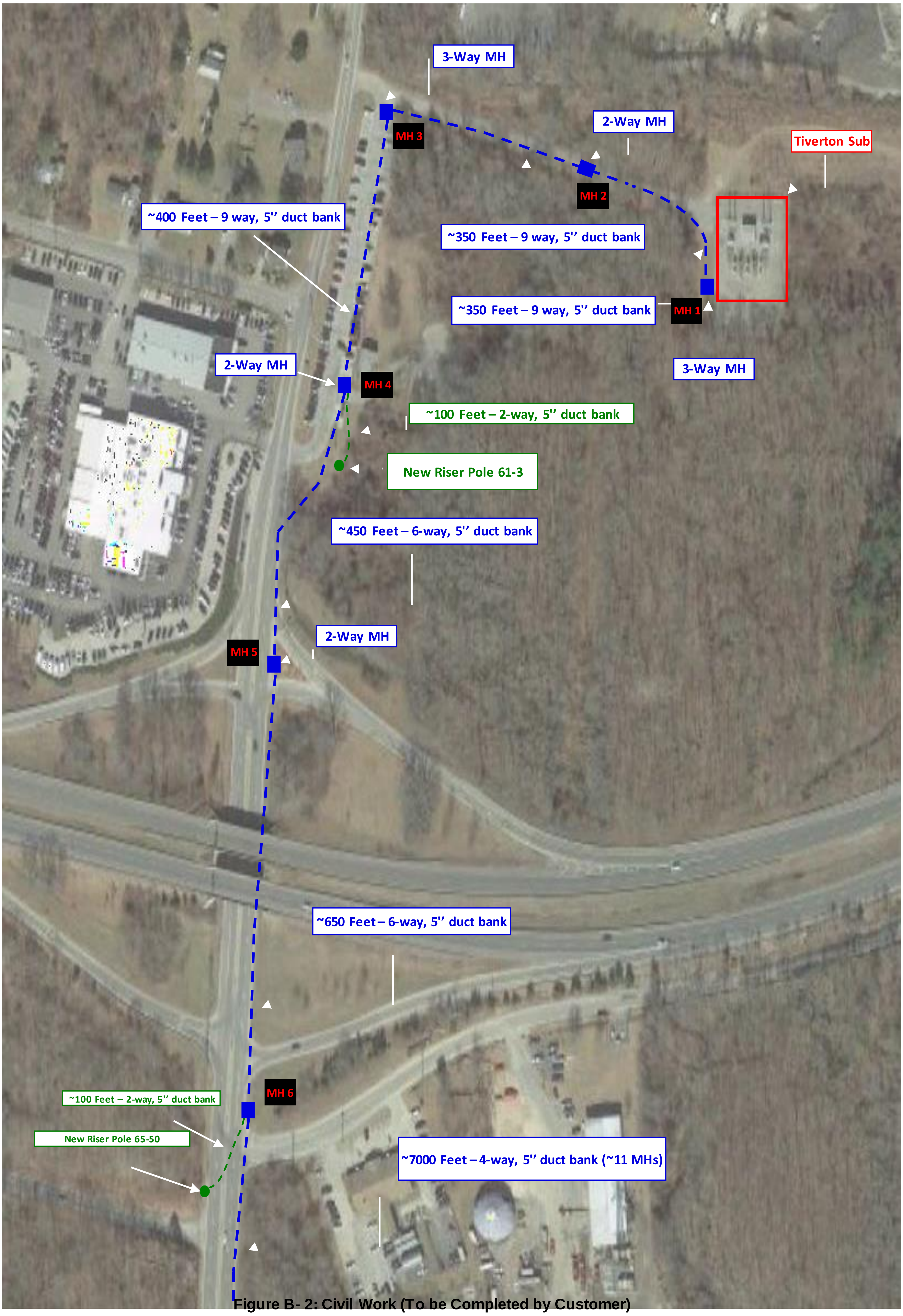


Figure B- 2: Civil Work (To be Completed by Customer)

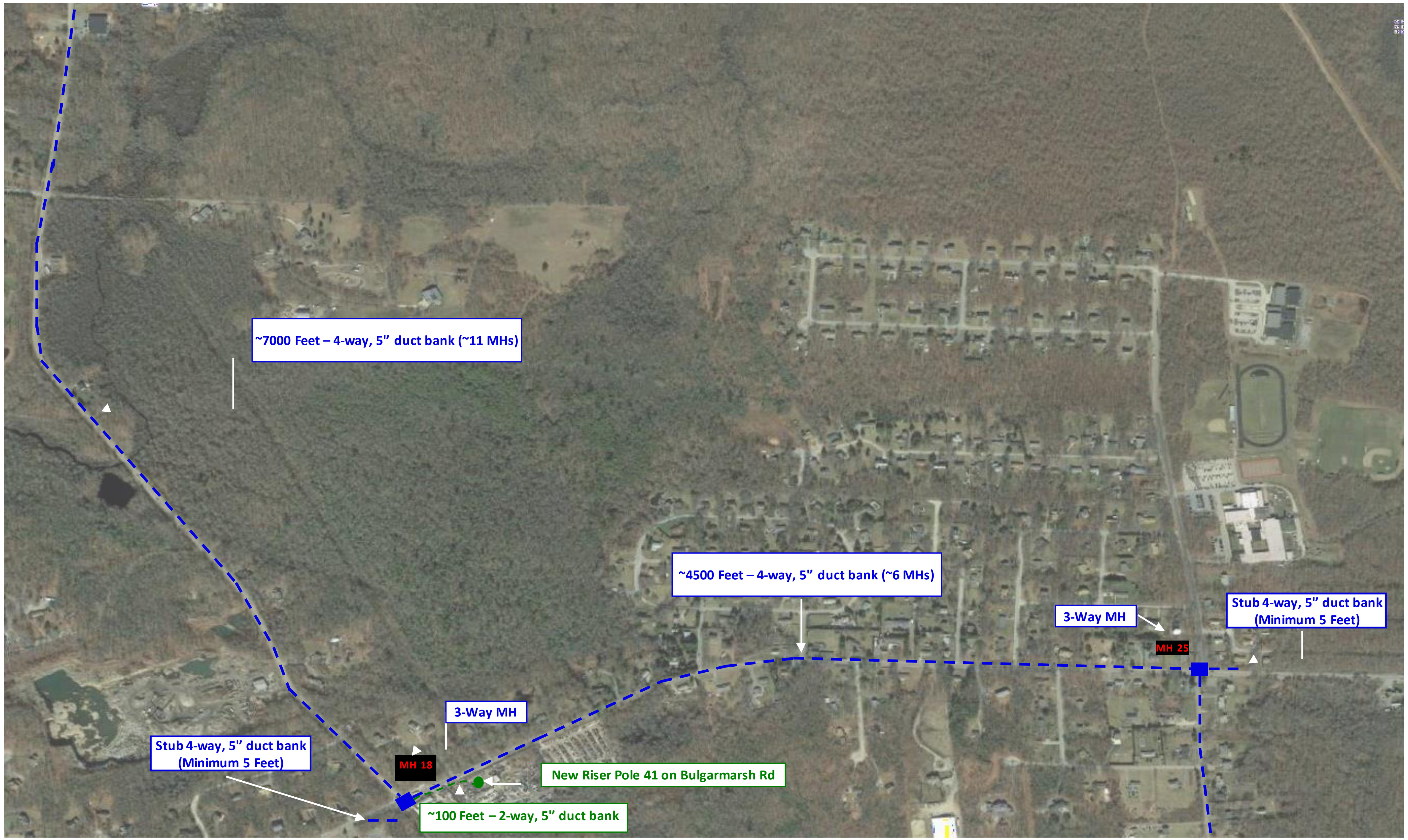


Figure B- 3: Civil Work (To be Completed by Customer)

Figure B- 4: Civil Work (To be Completed by Customer)

Appendix C Customer Site and Single Line Diagram

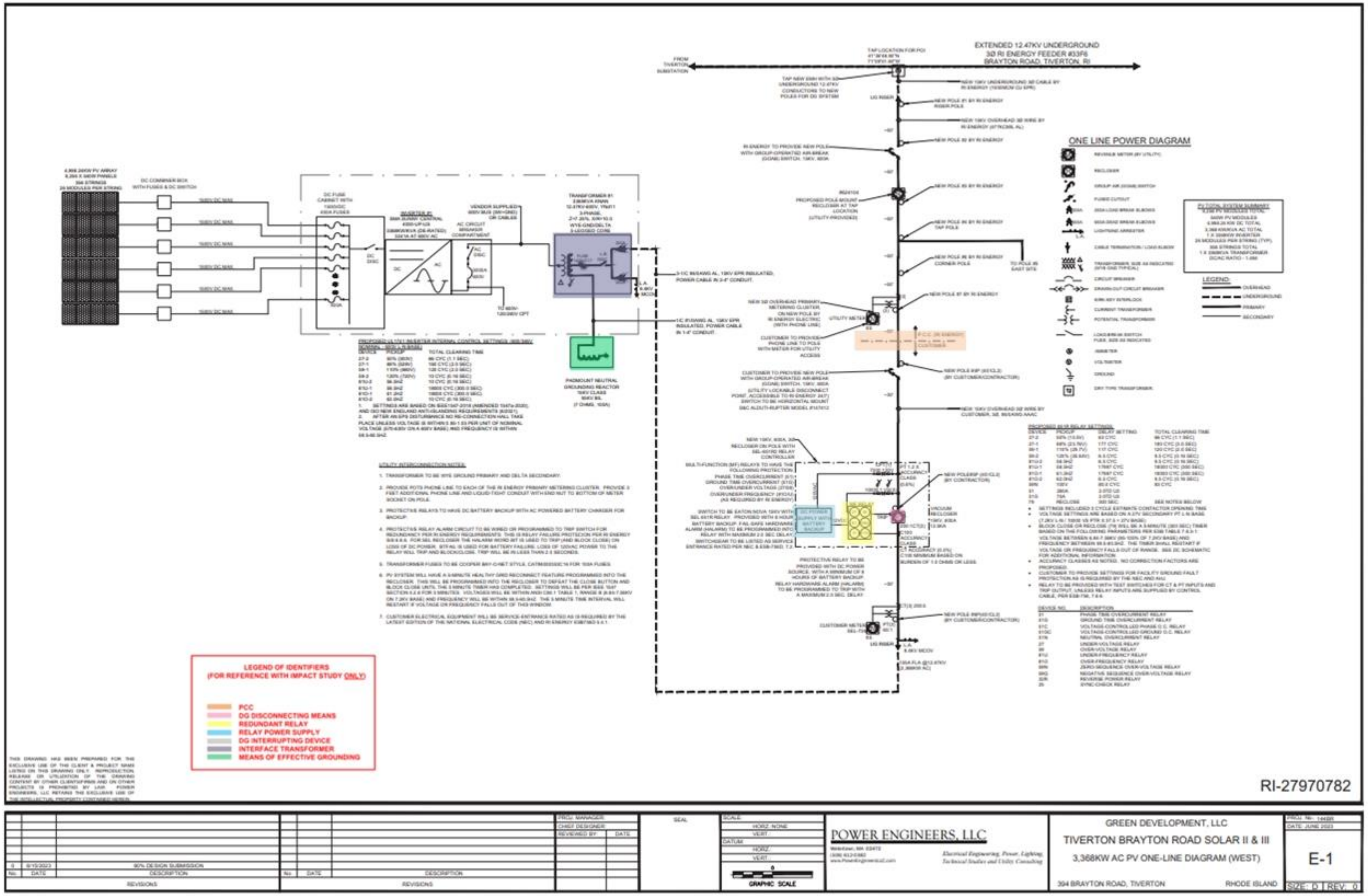


Figure C- 1: Project One-Line (RI-27970782 Case 00206316)
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

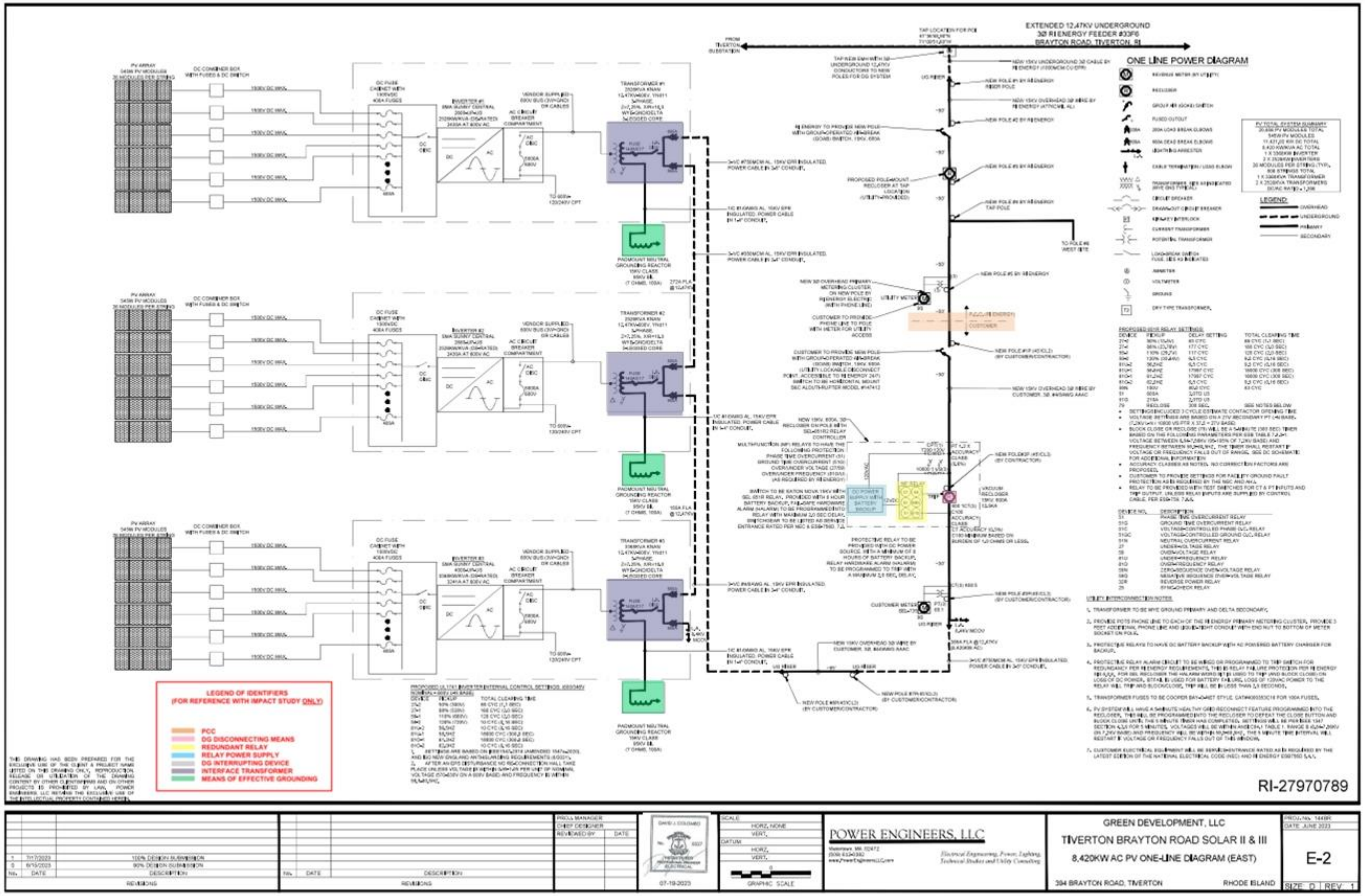


Figure C- 2: Project One-Line (RI-27970789 Case 00206317)
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

Figure C- 3: RI-27970782 & RI-27970789 (Case 00206316 and 00206317)

Exhibit H – Interconnection Service Agreement

1. **Parties**. This Interconnection Service Agreement ("Agreement"), dated as of July 22, 2021 ("Effective Date") is for application number "**27970789**" and Case Number "**206317**" is entered into, by and between **The Narragansett Electric Company (doing business as National Grid)**, a Rhode Island corporation with a principal place of business at **280 Melrose St., Providence, RI 02907** (hereinafter referred to as the "Company"), and **Green Development**, a **Limited Liability Corporation** with a principal place of business (or residence) at **2000 Chapel View Boulevard, Suite 500, Cranston, RI 02920** ("Interconnecting 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 EPS to be installed and operated by the Interconnecting Customer at **394 Brayton Road, Tiverton, RI 02878**. A description of the Facility is located in Attachment 1. If the Interconnecting Customer is not the Customer, an Agreement between the Company and the Company's Retail Customer, attached as Exhibit I 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 EPS 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 EPS 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.

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.

   5.1 Cost or Fee Adjustment Procedures. The Company will, in writing, advise the Interconnecting Customer in advance of any 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 EPS, 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 EPS or if operation of the Facility could cause damage to Company EPS 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 EPS 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 EPS, 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 EPS, and outages on the Company EPS. If the Interconnecting Customer demonstrates that the Company EPS 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 EPS, 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 EPS. This information will be treated as customer-confidential and only used for the purposes of meeting the requirements of Section 4.2.4 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 EPS or to the electric systems of others to which the Company EPS 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 EPS. 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 EPS when necessary for routine maintenance, construction and repairs on the Company EPS. The Company shall provide the Interconnecting Customer with a minimum of seven (7) 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 (7) 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 EPS; 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 EPS 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 EPS 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 forty five (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.

Exhibit H – Interconnection Service Agreement

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 EPS, 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 Company's written consent. Any assignment Interconnecting Customer purports to make without Company's written consent shall not be valid. Company shall not unreasonably withhold or delay its consent to Interconnecting Customer's assignment of this Agreement. Notwithstanding the above, Company's consent will not be required for any assignment made by 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.

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 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.

Exhibit H – Interconnection Service Agreement

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 and the Providence Plantations, or any other governmental subdivision thereof subject to the claims limits of R.I.G.L. 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 R.I.G.L. 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 R.I.G.L. 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 RI 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.

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 (3) 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:

National Grid
Attention: **Risk Management**
300 Erie Blvd West
Syracuse, NY 13202

12. Indemnification. Except as precluded by the laws of the State of Rhode Island and the Providence Plantations, 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.

Exhibit H – Interconnection Service Agreement

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:	**National Grid** Attention: **Distributed Generation** **40 Sylvan Road** **Waltham, MA 02451-1120** E-mail: **distributed.generation@nationalgrid.com**
If to Interconnecting Customer:	Green Development, LLC Attention: Mark DePasquale 2000 Chapel View Blvd Suite 500 Cranston, RI 02920 Phone: 401-295-4998 E-mail: **md@green-ri.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.

Exhibit H – Interconnection Service Agreement

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 of Default."

(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, any 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.

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 and the Providence Plantations 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.

Exhibit H – Interconnection Service Agreement

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.

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.

	Green Development, LLC:		The Narragansett Electric Company (d/b/a National Grid):
Name:	MARK P. DEPASQUALE	Name:	John C Kennedy
Title:	CEO	Title:	Manager
Date:	JULY 9, 2021	Date:	July 22, 2021
Signature:		Signature:	John C Kennedy

Exhibit H – Interconnection Service Agreement

Attachment 1: Description of Facilities, including demarcation of Point of Common Coupling

Interconnecting Customer has proposed a **8,423** kW photovoltaic system located at **394 Brayton Road, Tiverton, RI 02878.** The proposed Facility is an Independent Power Producer ("IPP"). Facilities will interconnect to the National Grid electric system via the Tiverton Substation, 12.47 kV distribution feeder 33F6, ("Point of Interconnection" or "POI").

a. **Description of proposed design/configuration:**

   a. Two (2) Customer owned inverter skid with Three (3) TMEIC Solar Ware Ninja 842kW / 842kVA, and One (1) Customer owned inverter skid with Four (4) TMEIC Solar Ware Ninja 842kW / 842 kVA inverter-based DG (5,894kW / 5,894kVA total)

   b. One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-660 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10

   c. Two (2) Customer owned 2,526 kVA, 12.47 kV wye-grounded primary-660 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10

   d. One (1) Customer owned 15 kV Pole-Mounted VIP378ER-125 recloser with a SEL 651R relay assembly

   e. One (1) Customer owned, Vector, Model #1984-45F, 15 kV gang-operated switch, with visible blades accessible to utility side

b. **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.

c. **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.

Attachment 2: Description of System Modifications

National Grid System Modifications required for the interconnection of **8,423** kW (AC) application as identified in the impact study are as follows:

On the Customer's property:
- Install primary riser
- Install approximately seven (7) poles and 600 circuit feet of 3-477 AAC overhead conductor and associated equipment
- Install one (1) load break switch
- Install one (1) recloser
- Install one (1) primary metering assembly

On the Company's distribution system:
- Install approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from the Tiverton Substation (located near Fish Road) to the Point of Common Coupling on Brayton Point Road.

At the Company's substation:
- Install one breaker position at the Tiverton substation
- Change protective devices

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 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. 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.

Attachment 3: Costs of System Modifications and Payment Terms

This application is one of two projects studied together with total system size of 11,791 kW. The Interconnecting Customer understands and agrees that, notwithstanding the costs detailed in this Agreement, if one of the applications (RI-27970782 & RI-27970789) does not move forward with the interconnection of a facility to the Company's electric power system, the total common modification costs will be re-estimated and reallocated among the remaining facilities, as determined by the Company in its sole discretion. Note the Company will not proceed with construction unless it has received adequate payment from all applicable customers within the group.

At present, System Modification Costs associated with both applications is: **$5,162,952** +/- 25% and itemized as follows:

At present, System Modification Costs associated with this application are: **$3,642,822** +/- 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: **$174,098** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970782 and RI-27970789. RI-27970789 will be responsible for 50% or **$87,049.**
- Total cost of common system modifications on the Company's distribution system as mentioned in Attachment 2 above is **$3,341,122** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970782 and RI-27970789. RI-27970789 will be responsible for 71.4% or **$2,385,561.**
- Total cost of common system modifications **(NECO)** at the distribution side of the Tiverton Substation as mentioned in Attachment 2 above is $1,053,804. (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970782 and RI-27970789. RI-27970789 will be responsible for 71.4% or **$752,416.**
- Cost of witness testing, engineering review, EMS Integration and implementation of protective device settings: **$5,000.**
- Tax gross-up adder on capital costs is or $415,496. (*A 2019 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 facility in the Group 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 Group, as determined by the Company in its sole 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.

Exhibit H – Interconnection Service Agreement

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 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. 2180):

- The first payment (5%) of **$182,141** is due when the Exhibit H-Interconnection Service Agreement is returned to the Company with Interconnecting Customer signature. The invoice, including payment instructions, will be sent to the Interconnecting Customer. Proof of payment is required.

- The second payment (5%) of **$182,141** is due within 15 business days from the receipt of the second payment invoice. The second invoice will be sent when National Grid reaches that point in design when long-lead time substation material items are ready to be ordered, or estimated on/around 10/11/2021. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

- The third payment (20%) of **$728,564** is due within 15 business days from the receipt of the third payment invoice. The third invoice will be sent when the Company reaches that point in design when long-lead time distribution line material items are ready to be ordered, or estimated on/around 01/24/2022. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

- The fourth and final payment (70%) of **$2,549,976** is due within 15 business days from the receipt of the fourth and final payment invoice. The fourth and final invoice will be sent when the Company reaches the construction start timeframe, or estimated on/around 06/01/2022. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

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 04/01/2021.

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.

Attachment 4: Special Operating Requirements, if any

The generating system may only normally generate onto the 33F6 feeder and National Grid's 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 National Grid's EPS, National Grid 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:

Exhibit H – Interconnection Service Agreement

a. National Grid's Standards for Interconnecting Distributed Generation (R.I.P.U.C. 2180), 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 National Grid-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 04/01/2021.

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 National Grid's EPS, National Grid 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 AC UTILITY DISCONNECT, accessible at all times by National Grid 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 AC UTILITY 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.

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 National Grid 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 National Grid. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when National Grid'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 National Grid's revenue meter is provided.

Exhibit H – Interconnection Service Agreement

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. National Grid'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 National Grid'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 National Grid 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, National Grid 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 National Grid 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.

21. The Company and the Interconnecting Customer have agreed that the Interconnecting Customer will perform the civil design for the manhole / duct system from Fish Road (Tiverton Substation) to Bulgarmarsh Road, and then to the Facilities (Brayton Road) and also the associated civil work, consistent with civil design plans approved by the Company. 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 submittal to the Company of the Interconnecting Customer' civil design plans for approval by the Company. The Interconnecting Customer agrees that 1) civil installation work performed and 2) all materials provided will be in strict conformance with the Company approved civil design plans.

Attachment 5: Agreement between the Company and the Company's Retail Customer

If the Company's Retail Customer (account holder) 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 National Grid ("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 nor will it be required to initiate any construction before it has received full payment from the Interconnecting Customer.

Attachment 6 - Appendix A: System Modifications Construction Schedule

Total Duration for engineering, permitting, procurement and construction of System Modification (Substation & Distribution System): 54[1] weeks to provide back-feed power to Customer

Milestone	Estimated Duration	Responsible Party
Company has received first payment	Start	Customer
Overhead and Underground Distribution System Modification Design (excluding underground manhole and duct bank system civil design provided by Interconnecting Customer and approved by Company which is required for Company to start its portion of the underground design)	21 weeks	Company
Secure and obtain any and all rights, consents environmental as well as non-environmental permits approvals and easement as are required for the Company's System Modifications on any Interconnecting Customer-owned property or any third party owned property **as well as for underground manhole and duct bank system on public way**)	8 weeks	Customer
Substation System Modification Design	43 weeks	National Grid
Secure and obtain any and all rights, consents, permits, approvals, and easements for the System Modifications on any Company owned property or within any public roadway (excluding underground man hole and duct bank system on public way)	16 weeks	National Grid
Distribution System Schedule Coordination and Construction (excluding construction of underground manhole and duct bank system on public way to be completed by Interconnecting Customer and supervised by Company appointed full-time civil inspectors)[1]	16 weeks	Company
Substation System Schedule Coordination and Construction (phased approach)	15 weeks	National Grid

* 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.
*Some milestones above will occur concurrently.
[1] Project schedule is dependent, among other things, on Interconnecting Customer delivering design and construction of underground manhole and duct bank system on time and to the satisfaction of National Grid
[2] Construction completion for civil underground manhole and duct bank system to be performed by Customer. Further, all Customer performed civil construction work shall be reviewed and approved by Company prior to backfilling by Customer.

Exhibit H – Interconnection Service Agreement

1. **Parties**. This Interconnection Service Agreement ("Agreement"), dated as of July 14, 2021 ("Effective Date") is for application number "**27970782**" and Case Number "**206316**" is entered into, by and between **The Narragansett Electric Company (doing business as National Grid)**, a Rhode Island corporation with a principal place of business at **280 Melrose St., Providence, RI 02907** (hereinafter referred to as the "Company"), and **Green Development**, a **Limited Liability Corporation** with a principal place of business (or residence) at **2000 Chapel View Boulevard, Suite 500, Cranston, RI 02920** ("Interconnecting 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 EPS to be installed and operated by the Interconnecting Customer at **394 Brayton Road, Tiverton, RI 02878**. A description of the Facility is located in Attachment 1. If the Interconnecting Customer is not the Customer, an Agreement between the Company and the Company's Retail Customer, attached as Exhibit I 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 EPS 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 EPS 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.

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.

   5.1 Cost or Fee Adjustment Procedures. The Company will, in writing, advise the Interconnecting Customer in advance of any cost increase for work to be performed up to a total amount of increase of 10% only. Any such changes to the

Exhibit H – Interconnection Service Agreement

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 EPS, 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 EPS or if operation of the Facility could cause damage to Company EPS 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 EPS 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 EPS, 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 EPS, and outages on the Company EPS. If the Interconnecting Customer demonstrates that the Company EPS 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 EPS, 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 EPS. This information will be treated as customer-confidential and only used for the purposes of meeting the requirements of Section 4.2.4 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 EPS or to the electric systems of others to which the Company EPS 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 EPS. 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 EPS when necessary for routine maintenance, construction and repairs on the Company EPS. The Company shall provide the Interconnecting Customer with a minimum of seven (7) 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 (7) 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 EPS; 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 EPS 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 EPS 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 forty five (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.

Exhibit H – Interconnection Service Agreement

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 EPS, 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 Company's written consent. Any assignment Interconnecting Customer purports to make without Company's written consent shall not be valid. Company shall not unreasonably withhold or delay its consent to Interconnecting Customer's assignment of this Agreement. Notwithstanding the above, Company's consent will not be required for any assignment made by 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.

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 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.

Exhibit H – Interconnection Service Agreement

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 and the Providence Plantations, or any other governmental subdivision thereof subject to the claims limits of R.I.G.L. 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 R.I.G.L. 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 R.I.G.L. 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 RI 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.

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 (3) 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:

National Grid
Attention: **Risk Management**
300 Erie Blvd West
Syracuse, NY 13202

12. **Indemnification**. Except as precluded by the laws of the State of Rhode Island and the Providence Plantations, 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.

Exhibit H – Interconnection Service Agreement

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:	**National Grid** Attention: **Distributed Generation** **40 Sylvan Road** **Waltham, MA 02451-1120** E-mail: **distributed.generation@nationalgrid.com**
If to Interconnecting Customer:	Green Development, LLC Attention: Mark DePasquale 2000 Chapel View Blvd Suite 500 Cranston, RI 02920 Phone: 401-295-4998 E-mail: **md@green-ri.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 of Default."

(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, any 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.

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 and the Providence Plantations 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.

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.

	Green Development, LLC:		The Narragansett Electric Company (d/b/a National Grid):
Name:	MARK P. DEPASQUALE	Name:	John Kennedy
Title:	CEO	Title:	Manager
Date:	July 9, 2021	Date:	July 14, 2021
Signature:		Signature:	John C Kennedy

Exhibit H – Interconnection Service Agreement

Attachment 1: Description of Facilities, including demarcation of Point of Common Coupling

Interconnecting Customer has proposed a **3,368** kW photovoltaic system located at **394 Brayton Road, Tiverton, RI 02878.** The proposed Facility is an Independent Power Producer ("IPP"). Facilities will interconnect to the National Grid electric system via the Tiverton Substation, 12.47 kV distribution feeder 33F6, ("Point of Interconnection" or "POI").

a. **Description of proposed design/configuration:**

   a. One (1) Customer owned inverter skid with Four (4) TMEIC Solar Ware Ninja 842kW / 842kVA inverter-based DG. (3,368kW / 3,368kVA total)

   b. One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-660 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10

   c. One (1) Customer owned 15 kV Pole-Mounted VIP378ER-125 recloser with a SEL 651R relay assembly

   d. One (1) Customer owned, Vector, Model #1984-45F, 15 kV gang-operated switch, with visible blades accessible to utility side

b. **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.

c. **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.

Attachment 2: Description of System Modifications

National Grid System Modifications required for the interconnection of **3,368** kW (AC) application as identified in the impact study are as follows:

On the Customer's property:

- Install primary riser
- Install approximately seven (7) poles and 600 circuit feet of 3-477 AAC overhead conductor and associated equipment
- Install one (1) load break switch
- Install one (1) recloser
- Install one (1) primary metering assembly

On the Company's distribution system:

- Install approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from the Tiverton Substation (located near Fish Road) to the Point of Common Coupling on Brayton Point Road.

At the Company's substation:

- Install one breaker position at the Tiverton substation
- Change protective devices

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 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. 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.

Attachment 3: Costs of System Modifications and Payment Terms

This application is one of two projects studied together with total system size of 11,791 kW. The Interconnecting Customer understands and agrees that, notwithstanding the costs detailed in this Agreement, if one of the applications (RI-27970782 & RI-27970789) does not move forward with the interconnection of a facility to the Company's electric power system, the total common modification costs will be re-estimated and reallocated among the remaining facilities, as determined by the Company in its sole discretion. Note the Company will not proceed with construction unless it has received adequate payment from all applicable customers within the group.

At present, System Modification Costs associated with both applications is: **$5,162,952** +/- 25% and itemized as follows:

At present, System Modification Costs associated with this application are: **$1,520,129** +/- 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: **$174,098** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for 50% or **$87,049.**
- Total cost of common system modifications on the Company's distribution system as mentioned in Attachment 2 above is **$3,341,122** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for 28.6% or **$955,561.**
- Total cost of common system modifications **(NECO)** at the distribution side of the Tiverton Substation as mentioned in Attachment 2 above is $1,053,804. (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for 28.6% or **$301,388.**
- Cost of witness testing, engineering review, EMS Integration and implementation of protective device settings: **$5,000.**
- Tax gross-up adder on capital costs is or $170,559. (*A 2019 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 facility in the Group 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 Group, as determined by the Company in its sole 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

Exhibit H – Interconnection Service Agreement

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. 2180):

- The first payment (5%) of **$76,006** is due when the Exhibit H-Interconnection Service Agreement is returned to the Company with Interconnecting Customer signature. The invoice, including payment instructions, will be sent to the Interconnecting Customer. Proof of payment is required.

- The second payment (5%) of **$76,006** is due within 15 business days from the receipt of the second payment invoice. The second invoice will be sent when National Grid reaches that point in design when long-lead time substation material items are ready to be ordered, or estimated on/around 10/11/2021. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

- The third payment (20%) of **$304,026** is due within 15 business days from the receipt of the third payment invoice. The third invoice will be sent when the Company reaches that point in design when long-lead time distribution line material items are ready to be ordered, or estimated on/around 01/24/2022. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

- The fourth and final payment (70%) of **$1,064,090** is due within 15 business days from the receipt of the fourth and final payment invoice. The fourth and final invoice will be sent when the Company reaches the construction start timeframe, or estimated on/around 06/01/2022. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

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 04/01/2021.

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.

Attachment 4: Special Operating Requirements, if any

The generating system may only normally generate onto the 33F6 feeder and National Grid's 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 National Grid's EPS, National Grid 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. National Grid's Standards for Interconnecting Distributed Generation (R.I.P.U.C. 2180), 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 National Grid-Owned EPS". ESB756D, available at: www.nationalgridus.com/non_html/shared_constr_esb756.pdf

Exhibit H – Interconnection Service Agreement

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 04/01/2021.
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 National Grid's EPS, National Grid 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 AC UTILITY DISCONNECT, accessible at all times by National Grid 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 AC UTILITY 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.
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 National Grid 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 National Grid. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when National Grid'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 National Grid'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. National Grid's Regional Control Center must first give permission to the customer to allow the operation of their system.

Exhibit H – Interconnection Service Agreement

17. Interconnecting Customer's protection scheme submitted for review must meet National Grid'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 National Grid 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, National Grid 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 National Grid 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.

21. The Company and the Interconnecting Customer have agreed that the Interconnecting Customer will perform the civil design for the manhole / duct system from Fish Road (Tiverton Substation) to Bulgarmarsh Road, and then to the Facilities (Brayton Road) and also the associated civil work, consistent with civil design plans approved by the Company. 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 submittal to the Company of the Interconnecting Customer' civil design plans for approval by the Company. The Interconnecting Customer agrees that 1) civil installation work performed and 2) all materials provided will be in strict conformance with the Company approved civil design plans.

Attachment 5: Agreement between the Company and the Company's Retail Customer

If the Company's Retail Customer (account holder) 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 National Grid ("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 nor 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 engineering, permitting, procurement and construction of System Modification (Substation & Distribution System): 54[1] weeks to provide back-feed power to Customer

Milestone	Estimated Duration	Responsible Party
Company has received first payment	Start	Customer
Overhead and Underground Distribution System Modification Design (excluding underground manhole and duct bank system civil design provided by Interconnecting Customer and approved by Company which is required for Company to start its portion of the underground design)	21 weeks	Company
Secure and obtain any and all rights, consents environmental as well as non-environmental permits approvals and easement as are required for the Company's System Modifications on any Interconnecting Customer-owned property or any third party owned property **as well as for underground manhole and duct bank system on public way)**	8 weeks	Customer
Substation System Modification Design	43 weeks	National Grid
Secure and obtain any and all rights, consents, permits, approvals, and easements for the System Modifications on any Company owned property or within any public roadway (excluding underground man hole and duct bank system on public way)	16 weeks	National Grid
Distribution System Schedule Coordination and Construction (excluding construction of underground manhole and duct bank system on public way to be completed by Interconnecting Customer and supervised by Company appointed full-time civil inspectors)[1]	16 weeks	Company
Substation System Schedule Coordination and Construction (phased approach)	15 weeks	National Grid

* 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.
*Some milestones above will occur concurrently.
[1] Project schedule is dependent, among other things, on Interconnecting Customer delivering design and construction of underground manhole and duct bank system on time and to the satisfaction of National Grid
[2] Construction completion for civil underground manhole and duct bank system to be performed by Customer. Further, all Customer performed civil construction work shall be reviewed and approved by Company prior to backfilling by Customer.

FIRST AMENDMENT TO
INTERCONNECTION SERVICE AGREEMENT

THIS FIRST AMENDMENT TO INTERCONNECTION SERVICE AGREEMENT (this "Amendment") dated ________________ ("Effective Date") amends the Interconnection Service Agreement dated 07/22/2021 for application RI-27970789 and Case Number "206317" by and between The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company) and Rhode Island Solar Renewable Energy IV, LLC (the "Customer") covering a distributed generation facility located at 394 Brayton Road, Tiverton, RI 02878 ("Agreement").

WHEREAS, on 09/27/2023, Customer sent Company Notices of Assignment of Interest in Interconnection Service Agreement indicating that Rhode Island Solar Renewable Energy IV, LLC had acquired the right, title and interest in the Interconnection Service Agreement;

WHEREAS, on 09/28/2023, Company consented to the Assignment of Interest in the Interconnection Service Agreement;

WHEREAS, Customer and the Company both desire to modify the Description of Facilities (Attachment 1) the Description of System Modifications (Attachment 2) and System Modifications Costs (Attachment 3);

NOW, THEREFORE, pursuant to Section 14 of the Agreement, for good and valuable consideration the receipt and sufficiency which are hereby acknowledged, the Company and the Interconnecting Customer (individually "Party" and together the "Parties") agree as follows:

1. **Defined Terms.** Capitalized terms used but not defined in this Amendment shall have the meanings ascribed to them in the Agreement or the Interconnection Tariff (defined below), as applicable.
2. **Standards for Interconnection of Distributed Generation**. The Interconnecting Customer shall be subject to and shall comply with the terms, conditions and requirements set forth in the Company's Standards for Interconnection of Distributed Generation tariff R.I.P.U.C. No. 2258 ("Interconnection Tariff"), as the same may be amended.
3. **Amendment to Agreement**. The Agreement is hereby amended as follows:
   a) **By striking Attachment 1 "Description of Facilities" in its' entirety, and replacing it with Attachment 1 attached hereto.**
   b) **By striking Attachment 2 "Description of System Modifications" in its' entirety, and replacing it with Attachment 2 attached hereto.**
   c) **By striking Attachment 3 "Cost of System Modifications" in its' entirety, and replacing it with Attachment 3 attached hereto.**

Attachment 1: Description of Facilities, including demarcation of Point of Common Coupling

Interconnecting Customer has proposed a **8,420** kW photovoltaic system located at **394 Brayton Road, Tiverton, RI 02878.** The proposed Facility is an Independent Power Producer ("IPP"). Facilities will interconnect to the National Grid electric system via the Tiverton Substation, 12.4 7 kV distribution feeder 33F6, ("Point of Interconnection" or "POI").

1. Description of proposed design/configuration for RI-27970789, Case 00206317 (Please see System Impact Study dated **08/23/2023** for additional details):
    a. Two (2) Customer owned SMA Sunny Central 2660-UP-US derated to 2526kW / 2526KVA, and one (1) SMA Sunny Central 4000-UP-US derated to 3368kW / 3368KVA inverter-based DG (8,420kW / 8,420kVA total)
    b. One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-600 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
    c. Two (2) Customer owned 2,526 kVA, 12.47 kV wye-grounded primary-600 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
    d. One (1) Customer owned 15 kV Pole-Mounted Eaton Nova recloser with a SEL 651R relay assembly
    e. One (1) Customer owned, S&C Alduti-Rupter model #147412F, 15 kV gang-operated switch, with visible blades accessible to utility side

2. Metering for RI-27970789, Case 00206317: 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.
3. PCC for RI-27970789, Case 00206317: 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 proposed Pole #7 for RI-27970789 on Brayton Road, Tiverton Rhode Island. 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.
    a. 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.

Attachment 2: Description of System Modifications

Rhode Island Energy System Modifications required for the interconnection of two applications (RI-27970782 & RI-27970789) studied together with total system size of 11,788 kW as identified in the System Impact Study dated **08/23/2023** are as follows:

On the Customer's property (Please see System Impact Study dated 08/23/2023 for additional details)**:**

1. Install primary riser
2. Install approximately seven (7) poles and 600 circuit feet of 3-477 AAC overhead conductor and associated equipment
3. Install one (1) load break switch
4. Install one (1) recloser
5. Install two (2) primary metering assemblies

On the Company's distribution system (Please see System Impact Study dated 08/23/2023 for additional details):

1. Install approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from the Tiverton Substation (located near Fish Road) to the Point of Common Coupling on Brayton Point Road.
    a. The Customer has requested responsibility for the required installation of approximately 1,100 feet of 9-way 5'', 1,100 feet 6-way 5'' and 17,800 feet of 4-way 5'' (~21,000 feet total) concrete-encased manhole & duct system. The Customer will be required to comply with Company Construction Standards and obtain approval by the Company prior to covering.
2. Customer will procure, store, and assume responsibility of cable until transfer of ownership to Rhode Island Energy.
3. Procurement of cable by the customer will adhere to all terms and conditions and associated standards provided on 08/05/2022.

At the Company's substation (Please see System Impact Study dated 08/23/2023 for additional details)**:**

1. Add one 12.47kV express circuit position, on the No.2 bus (33F6)
    a. Install one (1) 12.47 kV breaker
    b. 3 single-phase regulators and additional substation equipment required
    c. Install new getaway man-hole and duct system inside of the Tiverton Substation

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 prope1ty 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 prope1ty or within any public roadway as the Company determines necessary in its sole discretion ("Other Rights and Approvals"; together with Third Patty 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 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. 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. 2258, as amended from time to time.

Attachment 3: Costs of System Modifications and Payment Terms

This application is one of two projects studied together with total system size of 11,788kW. The Interconnecting Customer understands and agrees that, notwithstanding the costs detailed in this Agreement, if one of the applications (RI-27970782 & RI-27970789) does not move forward with the interconnection of a facility to the Company's electric power system, the total common modification costs will be re-estimated and reallocated among the remaining facilities, as determined by the Company in its sole discretion. Note the Company will not proceed with construction unless it has received adequate payment from all applicable customers within the group.

At present, System Modification Costs associated with both applications is: **$3,708,408.73** +/- 25% and itemized as follows:

At present, System Modification Costs associated with this application are: **$2,566,482.29** +/- 25% and itemized as follows:

- Total cost of common system modifications on the Interconnecting Customer's (or other private) property is **$334,587.20** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970789 will be responsible or **$167,293.60**.
- Total cost of common system modifications on the Company's distribution system is **$1,707,665.02** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970789 will be responsible for **$1,219,272.82**.
- Total cost of common substation modifications is **$1,053,804.00**. (Includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970789 will be responsible for **$752,416.06**.
- Total cost for distribution supervision and design for civil is **$165,000.00** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970789 will be responsible for **$117,810.00.**
- Total cost of witness testing, engineering review, EMS Integration, and implementation of protective device settings is **$12,000.00**. The cost for this will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970789 will be responsible for **$6,428.00.**
- Tax gross-up adder on capital costs is **$435,352.51**. The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970789 will be responsible for **$303,261.80**. A 2019 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 11.08% 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 facility in the Group 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 Group, as determined by the Company in its sole 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 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 will 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. 2180):

- The first payment of $182,141 was due when the Exhibit H-Interconnection Service Agreement was returned to the Company with Interconnecting Customer signature. Payment was received on 7/13/21.
- The second payment of $182,141 was due within 15 business days from the receipt of the second payment invoice. The second invoice was sent when the company reached that point in design when long-lead time substation material items were ready to be ordered. Payment was received on 10/18/21.
- The third payment of $728,564 was due within 15 business days from the receipt of the third payment invoice. Payment was received on 5/16/22.
- The fourth and final payment of **$1,473,636** is due within 15 business days from the receipt of the fourth and final payment invoice. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

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 08/23/2023. 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.

4. **Construction.** The Parties hereto agree that, once signed by both Parties, this Amendment modifies, supplements, and forms a part of the Agreement. Except as specifically modified and amended herein, all of the terms, provisions and requirements contained in the Agreement remain in full force and effect.

5. **Counterparts.** This Amendment may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute

one instrument. The delivery of this Agreement and of signature pages by facsimile or other electronic transmission (including a ".pdf" format data file) shall constitute effective execution and delivery of this Amendment as to the Parties and shall be deemed to be their original signatures for all purposes.

6. **Signatory Authority**. The Parties each represent and warrant that this Amendment is being signed by its duly authorized representative.

This Amendment shall be effective as of the Effective Date when fully executed, and shall be void with no further force or effect, or recourse to either Party, if not fully executed and returned to each Party on or before 10/23/2023.

IN WITNESS WHEREOF, the Parties hereto execute this **FIRST AMENDMENT TO INTERCONNECTION SERVICE AGREEMENT** under seal.

INTERCONNECTING CUSTOMER:	COMPANY:
Rhode Island Solar Renewable Energy IV, LLC	The Narragansett Electric Company, d/b/a Rhode Island Energy
By: ____________________________________	By: ______________________________
Name:	Name:
Its:	Its:
Duly authorized	Duly authorized
Date: ____________________	Date: ________________________

FIRST AMENDMENT TO INTERCONNECTION SERVICE AGREEMENT

THIS FIRST AMENDMENT TO INTERCONNECTION SERVICE AGREEMENT (this "Amendment") dated ________________ ("Effective Date") amends the Interconnection Service Agreement dated 07/14/2021 for application RI-27970782 and Case Number "206316" by and between The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company) and Rhode Island Solar Renewable Energy IV, LLC (the "Customer") covering a distributed generation facility located at 394 Brayton Road, Tiverton, RI 02878 ("Agreement").

WHEREAS, on 09/27/2023, Customer sent Company Notices of Assignment of Interest in Interconnection Service Agreement indicating that Rhode Island Solar Renewable Energy IV, LLC had acquired the right, title and interest in the Interconnection Service Agreement;

WHEREAS, on 09/28/2023, Company consented to the Assignment of Interest in the Interconnection Service Agreement;

WHEREAS, Customer and the Company both desire to modify the Description of Facilities (Attachment 1) the Description of System Modifications (Attachment 2) and System Modifications Costs (Attachment 3);

NOW, THEREFORE, pursuant to Section 14 of the Agreement, for good and valuable consideration the receipt and sufficiency which are hereby acknowledged, the Company and the Interconnecting Customer (individually "Party" and together the "Parties") agree as follows:

1. **Defined Terms.** Capitalized terms used but not defined in this Amendment shall have the meanings ascribed to them in the Agreement or the Interconnection Tariff (defined below), as applicable.
2. **Standards for Interconnection of Distributed Generation**. The Interconnecting Customer shall be subject to and shall comply with the terms, conditions and requirements set forth in the Company's Standards for Interconnection of Distributed Generation tariff R.I.P.U.C. No. 2258 ("Interconnection Tariff"), as the same may be amended.
3. **Amendment to Agreement**. The Agreement is hereby amended as follows:
   (a) **By striking Attachment 1 "Description of Facilities" in its' entirety, and replacing it with Attachment 1 attached hereto.**
   (b) **By striking Attachment 2 "Description of System Modifications" in its' entirety, and replacing it with Attachment 2 attached hereto.**
   (c) **By striking Attachment 3 "Cost of System Modifications" in its' entirety, and replacing it with Attachment 3 attached hereto.**

Attachment 1: Description of Facilities, including demarcation of Point of Common Coupling

Interconnecting Customer has proposed **a 3,368 kW** photovoltaic system located at **394 Brayton Road, Tiverton, RI 02878.** The proposed Facility is an Independent Power Producer ("IPP"). Facilities will interconnect to the National Grid electric system via the Tiverton Substation, 12.47 kV distribution feeder 33F6, ("Point of Interconnection" or "POI").

1. Description of proposed design/configuration for RI-27970782, Case 00206316 (Please see System Impact Study dated **08/23/2023** for additional details):
    a. One (1) Customer owned SMA Sunny Central 4000-UP-US derated to 3,368kW / 3,368kVA inverter-based DG
    b. One (1) Customer owned 3,368 kVA, 12.47 kV wye-grounded primary-600 V delta secondary transformer, with an impedance of 7.25% and X/R ratio of 10
    c. One (1) Customer owned 15 kV Pole-Mounted Eaton Nova recloser with a SEL 651R relay assembly
    d. One (1) Customer owned, S&C Alduti-Rupter model #147412,15 kV gang-operated switch, with visible blades accessible to utility side
    e. RI-27970782, Case 00206316 is required to implement a 32 element in the customer relay to satisfy ESB756-2023 Section 7.6.13.1.

2. Metering for RI-27970782, Case 00206316: 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.
3. PCC for RI-27970782, Case 00206316: 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 proposed Pole #5 for RI-27970782 on Brayton Road, Tiverton Rhode Island. 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.
    a. 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.

Attachment 2: Description of System Modifications

Rhode Island Energy System Modifications required for the interconnection of two applications (RI-27970782 & RI-27970789) studied together with total system size of 11,788 kW as identified in the System Impact Study dated **08/23/2023** are as follows:

On the Customer's property (Please see System Impact Study dated 08/23/2023 for additional details)**:**

1. Install primary riser
2. Install approximately seven (7) poles and 600 circuit feet of 3-477 AAC overhead conductor and associated equipment
3. Install one (1) load break switch
4. Install one (1) recloser
5. Install two (2) primary metering assemblies

On the Company's distribution system (Please see System Impact Study dated 08/23/2023 for additional details):

1. Install approximately 21,000 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable from the Tiverton Substation (located near Fish Road) to the Point of Common Coupling on Brayton Point Road.
    a. The Customer has requested responsibility for the required installation of approximately 1,100 feet of 9-way 5'', 1,100 feet 6-way 5'' and 17,800 feet of 4-way 5'' (~21,000 feet total) concrete-encased manhole & duct system. The Customer will be required to comply with Company Construction Standards and obtain approval by the Company prior to covering.
2. Customer will procure, store, and assume responsibility of cable until transfer of ownership to Rhode Island Energy.
3. Procurement of cable by the customer will adhere to all terms and conditions and associated standards provided on 08/05/2022.

At the Company's substation (Please see System Impact Study dated 08/23/2023 for additional details)**:**

1. Add one 12.47kV express circuit position, on the No.2 bus (33F6)
    a. Install one (1) 12.47 kV breaker
    b. 3 single-phase regulators and additional substation equipment required
    c. Install new getaway man-hole and duct system inside of the Tiverton Substation

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 prope1ty 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 prope1ty or within any public roadway as the Company determines necessary in its sole discretion ("Other Rights and Approvals"; together with Third Patty 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 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. 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. 2258, as amended from time to time.

Attachment 3: Costs of System Modifications and Payment Terms

This application is one of two projects studied together with total system size of 11,788 kW. The Interconnecting Customer understands and agrees that, notwithstanding the costs detailed in this Agreement, if one of the applications (RI-27970782 & RI-27970789) does not move forward with the interconnection of a facility to the Company's electric power system, the total common modification costs will be re-estimated and reallocated among the remaining facilities, as determined by the Company in its sole discretion. Note the Company will not proceed with construction unless it has received adequate payment from all applicable customers within the group.

At present, System Modification Costs associated with both applications is: **$3,708,408.73** +/- 25% and itemized as follows:

At present, System Modification Costs associated with this application are: **$1,141,926.44** +/- 25% and itemized as follows:

- Total cost of common system modifications on the Interconnecting Customer's (or other private) property is **$334,587.20** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata bas.is with RI-27970789 and RI 27970782. RI-27970782 will be responsible for **$167,293.60**.
- Total cost of common system modifications on the Company's distribution system is **$1,707,665.02** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for **$488,392.20**.
- Total cost of common substation modifications is **$1,053,804.00**. (Includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for **$301,387.94**.
- Total cost for distribution supervision and design for civil is **$165,000.00** (includes capital, removal, and O&M costs). The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for **$47,190.00**.
- Total cost of witness testing, engineering review, EMS Integration, and implementation of protective device settings is **$12,000.00**. The cost for this will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for **$5,572.00.**
- Tax gross-up adder on capital costs is **$435,352.51**. The cost for this modification will be shared on a pro-rata basis with RI-27970789 and RI 27970782. RI-27970782 will be responsible for **$132,090.70**. A 2019 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 11.08% 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 facility in the Group 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 Group, as determined by the Company in its sole 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 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 will 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. 2180):

- The first payment of $76,006 was due when the Exhibit H-Interconnection Service Agreement was returned to the Company with Interconnecting Customer signature. Payment was received on 7/13/21.
- The second payment of $76,006 was due within 15 business days from the receipt of the second payment invoice. The second invoice was sent when the company reached that point in design when long-lead time substation material items were ready to be ordered. Payment was received on 10/18/21.
- The third payment of $304,026 was due within 15 business days from the receipt of the third payment invoice. Payment was received on 5/16/22.
- The fourth and final payment of **$685,888** is due within 15 business days from the receipt of the fourth and final payment invoice. An invoice, including payment instructions, will be sent to the Interconnecting Customer.

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 08/23/2023. 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.

4. **Construction.** The Parties hereto agree that, once signed by both Parties, this Amendment modifies, supplements, and forms a part of the Agreement. Except as specifically modified and amended herein, all of the terms, provisions and requirements contained in the Agreement remain in full force and effect.

5. **Counterparts.** This Amendment may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute

one instrument. The delivery of this Agreement and of signature pages by facsimile or other electronic transmission (including a ".pdf" format data file) shall constitute effective execution and delivery of this Amendment as to the Parties and shall be deemed to be their original signatures for all purposes.

6. **Signatory Authority**. The Parties each represent and warrant that this Amendment is being signed by its duly authorized representative.

This Amendment shall be effective as of the Effective Date when fully executed, and shall be void with no further force or effect, or recourse to either Party, if not fully executed and returned to each Party on or before 10/23/2023.

IN WITNESS WHEREOF, the Parties hereto execute this **FIRST AMENDMENT TO INTERCONNECTION SERVICE AGREEMENT** under seal.

INTERCONNECTING CUSTOMER:	COMPANY:
Rhode Island Solar Renewable Energy IV, LLC	The Narragansett Electric Company, d/b/a Rhode Island Energy
By: ___________________________________	By: _____________________________
Name:	Name:
Its:	Its:
Duly authorized	Duly authorized
Date: ___________________	Date: _______________________

Rhode Island Energy™
a PPL company

Tiverton Area Study

Colin Sullivan

September 2021
Revision 1 – September 2022

Reviewed by: Ryan Constable — Date: 9/12/2022
Ryan Constable, Manager
Distribution Planning & Asset Management, RI Electric Operations

Approved by: Kathy Castro — Date: 9/12/2022
Kathy Castro, Director
Asset Management & Engineering, RI Electric Operations

Table of Contents

Pages

LEGEND	
Al	Aluminum wire or cable
ARP	Asset Replacement Program
Cal/cm^2	Calories/square centimeter
CAPEX	Capital expenditure (budget expenditure type)
CKAIDI	Circuit Average Interruption Duration Index
CKAIFI	Circuit Average Interruption Frequency Index
Cu	Copper wire or cable
DPG	Distribution Planning Guide rev 1, dated February 2011
EMS	Energy Management System
GIS	Geographic Information System
ISO	Independent System Operator
Kcmil or MCM	Thousand circular mils
kV	Kilovolts
LTC	Load Tap Changer
MVA	Megavolt Ampere
MVAR	Megavolt Ampere Reactive
MW	Megawatts
MWh	Megawatt hour
NE	New England
OH	Overhead
OPEX	Operations/Maintenance expenditure (budget expenditure type)
PT	Potential Transformer
RAPR	Remote Access Pulse Recorder
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
SN	Summer Normal Rating of Equipment
SE	Summer Emergency Rating of Equipment
Spca	Spacer Cable
UG	Underground
VCB	Vacuum Circuit Breaker

1. Executive Summary

A comprehensive study of the Tiverton/Little Compton 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, 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.

The first significant plan recommendation is to replace aging equipment at the Tiverton substation. Asset condition issues were identified with the 115kV switches, the 12.47kV breakers, and the regulators for the 33F1, 33F2 and 33F4 circuits. Animal protection issues were also identified at the substation.

The second significant plan recommendation is to extend the proposed 33F6 circuit, associated with a distributed generation interconnection, further south to serve load. Thermal (capacity) limits, contingency response capability, and voltage issues were identified on the existing Tiverton circuits. The addition of a new circuit with the capability to offload the existing circuits will resolve these issues and is the least cost option.

Various other recommendations of smaller scale are also made to resolve issues identified from the complete system evaluation.

The spending by fiscal year for all study recommendations is shown in Table 1.1 below.

Table 1.1: Cost Summary for all Tiverton Area Study Plans

	Total Spending Profile ($M)						
	FY24	FY25	FY26	FY27	FY28	FY29	Total
CapEx	$ 0.317	$ 0.950	$ 1.900	$ 1.900	$ 0.950	$ 0.317	$ 6.332
OpEx	$ 0.003	$ 0.009	$ 0.019	$ 0.019	$ 0.009	$ 0.003	$ 0.063
Removal	$ 0.024	$ 0.073	$ 0.146	$ 0.146	$ 0.073	$ 0.024	$ 0.488
Total	$ 0.344	$ 1.032	$ 2.065	$ 2.065	$ 1.032	$ 0.344	$ 6.883

Table 1.2: Total Cost with Amount That May Be Shared with Interconnecting Customer

	Total Spending Profile ($M)						
	FY24	FY25	FY26	FY27	FY28	FY29	Total
CapEx	$ 0.523	$ 1.568	$ 3.135	$ 3.135	$ 1.568	$ 0.523	$ 10.451
OpEx	$ 0.003	$ 0.010	$ 0.020	$ 0.020	$ 0.010	$ 0.003	$ 0.065
Removal	$ 0.024	$ 0.073	$ 0.146	$ 0.146	$ 0.073	$ 0.024	$ 0.488
Total	$ 0.550	$ 1.651	$ 3.301	$ 3.301	$ 1.651	$ 0.550	$ 11.004

2. Introduction

2.1 Purpose

A comprehensive study of the Tiverton/Little Compton 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), breaker operating capability, regulator operating capability, distribution arc flash review, reactive compensation performance, asset condition, and 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.

2.2 Problem

An initial system assessment based on the Annual Planning process and substation Asset Condition Reports revealed a variety of issues in the Tiverton/Little Compton area. Consultation with Operations personnel to review asset information was also conducted.

3. Background

3.1 Scope

3.1.1 Geographic Scope

The Tiverton study area consists of the towns of Tiverton, Little Compton, and a portion of Westport (Massachusetts). The study area is bounded by the ocean to its west and south, by Fall River (Massachusetts) to the north, and Westport (Massachusetts) to the east. The study area is shown geographically in Appendix 9.1.

3.1.2 Electrical Scope

Two 115kV transmission lines supply the Tiverton substation, which serves this area. The substation supply and nominal voltage are as follows:

- Tiverton #33 (115/12.47kV); supplied by L-14 and M-13

This substation is the source of 4 distribution feeders in the area that serve approximately 11,600 customers. A one-line diagram of the substation in the study area can be found in Appendix 9.2.

3.2 Area Load and Load Forecast

The study area is summer peaking and summer limited, during which the peak electrical demand is approximately 36.8MVA. This study used the 2021 forecast developed by National Grid, the "2021 Electric Peak (MW) Forecast". It utilized the 95/5 extreme weather scenario case after Distributed Energy Resource Impacts. This includes forecast impacts from distributed generation, energy efficiency, demand response, electric vehicles, and heating electrification. Table 3.1 shows the forecasted load growth rate for the study area from 2021 to 2035.

TABLE 3.1 – Forecasted Load Growth Rate from 2021 to 2035 for Study Area

Forecasted Growth						
2021	**2022**	**2023**	**2024**	**2025**	**2026-2030**	**2031-2035**
4.4%	-0.9%	-0.3%	0.3%	0.5%	0.2%	0.1%

Distributed Generation (DG)

The impacts of existing DG are included in the load readings and used as the foundation for analysis. Existing records showed three large DG sites (>500kW) in the study area. A review of the interconnection queue identified two additional large sites not yet interconnected. The study analysis considered both the scenario in which these in-queue projects do not proceed, and the scenario in which they do interconnect. Whether or not they proceed will not affect the plan recommendations, although one DG project, 11.8MW, would overlap with some of the plan recommendations (as further discussed in section 5.1). A map of the area large-scale distributed generation is shown in Appendix 9.3, and Table 3.2 below lists these projects.

TABLE 3.2 – Area Large-Scale Distributed Generation

Feeder	Queue Date	Case Number	Total Generator kWAC	DG Fuel Source	Connected Date
49_56_33F3	4/9/2018	178639	2,440	Solar	11/30/2020
49_56_33F4	6/26/2018	188903	1,826	Solar	12/29/2020
49_56_33F4	2/8/2019	207003	1,660	Solar	12/30/2020
49_56_33F6	3/26/2019	206316/206317	11,788	Solar	
49_56_33F4	3/23/2020	280574	1,000	Wind	

3.3 Active Projects

The completion of projects listed below was assumed and included in the foundation for analysis.

C084419, C084453 – Tiverton 33F4 Asset Replacement

- Initiated to address reliability issues on the Westport section of the circuit

C085653, C085806 – Brayton Road Solar

- Initiated to build a new circuit serve a proposed 11.8MW DG project to be located at 390 Brayton Road, Tiverton, RI

3.4 Limitations on Infrastructure Development

No significant limitations on infrastructure development were identified prior to plan development.

3.5 Assumptions & Guidelines

The analysis was performed using the Distribution Planning Guide (Rev 1, February 2011). The guides describe the normal and contingency analysis, as well as considerations for safety, the environment, reliability, reactive compensation, load balance, voltage, and efficiency. This guide was adopted by RI Energy from National Grid for use in distribution planning studies.

Arc Flash Information Tables were developed to supplement EOP G035 - Arc Flash Awareness and Mitigation and assist in the selection of appropriate PPE for compliance with OSHA regulations at 29 CFR 1910.269 and 1926 Subpart V. The incident energy and recommended work method in the information tables were assessed to determine if solutions were necessary through the area study. Arc flash calculations were performed using the IEEE 1584-2018 standards for underground (three-phase fault) calculations and using ArcPro for the overhead (single-line-to-ground fault) calculations.

The CYMdist 9.0 Revision 5.0 program was used to analyze radial three-phase unbalanced systems (distribution feeders). Databases are extracted from the GE-SmallWorld GIS System into a Microsoft Access format.

The ASPEN program was used to determine short circuit duty values at all substations.

4. Problem Identification

The following analysis considers transformer and feeder issues. There are no supply lines in the study area.

5. Thermal Loading

5.1.1 Normal Configuration - Thermal Loading

Table 4.1 shows the projected normal feeder loading on the distribution system for the limiting element of each circuit. By the end of the study period (2035) the 33F3 is the only feeder forecasted to exceed its summer normal (SN) capacity and another two are forecasted to be loaded above 90% of SN rating. Loading of all distribution mainline sections were analyzed using the CYME software.

There are no projected transformer overloads under normal configuration within the study period.

TABLE 4.1 - Projected Summer Normal Feeder Loading

Substation	Transformer	Feeder	2021 %SN	2035 % SN
TIVERTON 33	T1	33F1	97%	98%
TIVERTON 33		33F3	100%	101%
TIVERTON 33	T2	33F2	95%	96%
TIVERTON 33		33F4	88%	89%

The CYME three phase load flow program was used to identify distribution feeder elements /sections that may be overloaded. No issue

5.1.2 Contingency Configuration - Thermal Loading

A contingency analysis was performed for all transformers and feeders in the study area. This analysis calculates the load-at-risk 'exposure' or risk assuming a worst-case component failure. The assumptions made for this analysis include:

- A one-hour switching time to restore load up to emergency rating of neighboring feeders.
- Overhead failed component can be repaired within four hours, a cable can be repaired within 12 hours, and a substation transformer can be replaced within 24 hours.
- Some feeders are double circuited on the same pole plant, primarily near the substation. Since exposure is relatively small, a failure involving two feeders was not assumed in the calculations.
- The load-at-risk calculations utilize the summer emergency ratings of the equipment.

Table 4.2 shows the load-at-risk exposure for substation transformers and feeders in the area. There is no substation transformer in the area that is exposed to more than 240MWhr of risk described in the DPG and the most significant load at risk in the area is with loss of T2. All four feeders are exposed to more than the 16 MWhr risk which is primarily due to limited switching options available in the edge of RI Energy territory.

TABLE 4.2 – Transformer and Line Contingency Load-at-Risk

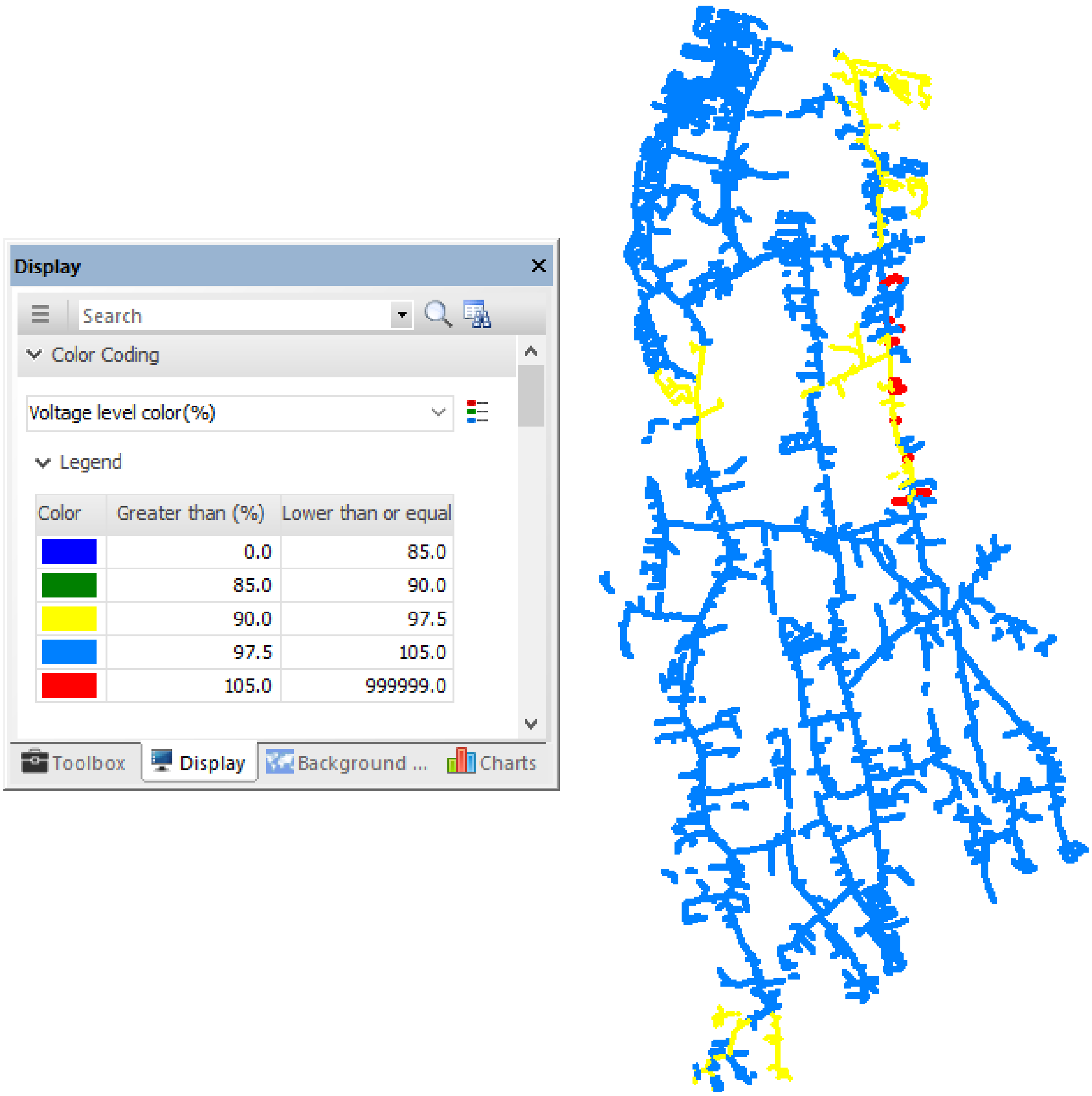
TIVERTON AREA			XFMR CONTINGENCY	LINE CONTINGENCY
Substation	Transformer	Feeder	'35 N-1 MWHrs	'35 N-1 MWHrs
Tiverton 33	T1	33F1	0.0	27.2
		33F3		28.8
	T2	33F2	3.4	26.1
		33F4		26.5

5.2 Voltage Performance

The CYME program models all three phases of each distribution feeder for its entire length starting at the substation. ANSI A/B voltage ranges are used to identify issues. ANSI A range is used for normal configurations and considers a +/-5% voltage band around nominal voltage. This equates to service voltage of 126V to 114V on a 120V base. Secondaries and services are not modeled. Therefore, a 3V drop in the distribution transformer and customer secondary wire can be assumed.

The results from CYME are shown in Figure 4.1. The 33F1 has 3.1 miles of mainline that does not meet distribution voltage criteria (due to low voltage during peak loading). The 33F3 has 1.6 miles of mainline that does not meet distribution voltage criteria (due to low voltage during peak loading). The 33F4 has 2.4 miles of mainline that does not meet distribution voltage criteria (due to low voltage during peak loading).

FIGURE 4.1 – Distribution Feeder Voltage Levels (Peak Loading)



5.3 Asset Condition

An asset condition assessment for the Tiverton substation was performed. A one-line diagram for the substation can be found in Appendix 8.2.

All issues were validated with Substation Operations, Substation Operations & Maintenance Services, and Asset Management. Below is a comprehensive summary of updated issues that includes various consultations with study team members.

- Equipment throughout the station does not meet the current minimum approach clearance requirements.
- The 115kV sacrificial motor operated airbreaks (MOABs) are deteriorated with problematic arcing horns.
- The 12.47kV VCB breakers are deteriorated and at the end of their design life cycle.
- The 33F1, 33F2 and 33F4 voltage regulators are deteriorated at the end of their design life cycle. (The 33F3 voltage regulators were replaced in 2017 and are in excellent condition.)
- The control house requires worker safety updates.
- The station lacks animal protection on terminators, bushing and general energized yard.

5.4 Additional Analysis

5.4.1 Reliability Performance

A reliability review was conducted to check feeder indices (CKAIDI and CKAIFI) against statewide targets. For calendar year 2021, the SAIFI and SAIDI targets for Rhode Island were 1.05 and 71.9 minutes, respectively. Table 4.5 below shows CKAIDI or CKAIFI performance over the past five years.

TABLE 4.5 – Study Area Reliability

SAIFI

Feeder	2016	2017	2018	2019	2020	5-Year Average
56-33F1	1.17	0.25	1.20	0.54	0.62	0.75
56-33F2	0.18	1.79	0.11	1.18	0.12	0.67
56-33F3	1.78	1.70	0.56	1.64	0.66	1.27
56-33F4	3.77	1.94	0.74	4.31	2.16	2.58

SAIDI

Feeder	2016	2017	2018	2019	2020	5-Year Average
56-33F1	126.6	20.1	77.7	24.6	33.8	56.6
56-33F2	6.5	142.4	11.4	47.0	14.2	44.3
56-33F3	122.6	114.4	52.4	74.1	69.5	86.6
56-33F4	531.0	158.0	77.7	213.1	131.2	222.2

The five-year averages exceeded the 2021 targets for both the 33F3 and 33F4. Tree-related issues were the main driver. Engineering Reliability Reviews (ERRs) were conducted for both circuits in FY20.

5.4.2 Arc Flash

On April 1, 2014, the United States Department of Labor's Occupational Safety and Health Administration ("OSHA") issued final rule 1910.269[1] requiring the employer to assess the workplace to identify employees exposed to hazards from flames or electric arcs. 1910.269 proposed compliance dates of January 1, 2015 and April 1, 2015 for completion of the hazard assessment and implementation of the assessment results

[1] Specifically, Appendix E to Subpart V in the final rule enables employers to readily select incident-energy calculation methods and input parameters that OSHA will consider reasonable and acceptable for compliance with subsection 1926.960.

respectively. As the industry adjusted to these new requirements and calculation methods, the dates were adjusted to March 31, 2015 and August 31, 2015.

As described above, arc flash regulations were issued and analysis methods were reviewed and adjusted during the course of this study. A review was performed using ASPEN fault current analysis and protection coordination values, with the IEEE1584-2018 calculation methodology for underground (three-phase) faults and ArcPro for overhead (single-phase) faults. Table 4.6 shows the results of this analysis with no study area feeders having incident energies above 8 calories per centimeter squared (cal/cm^2).

TABLE 4.6 – Arc Flash Calculations

IEEE1584-2018 (Underground) Calculation

Station Name	Feeder	Incident Energy (cal/cm^2)
TIVERTON 33	33F1	4.8
TIVERTON 33	33F2	7.1
TIVERTON 33	33F3	3.1
TIVERTON 33	33F4	2.4

ArcPro (Overhead) Calculation

Station Name	Feeder	Incident Energy (cal/cm^2)
TIVERTON 33	33F1	2.445
TIVERTON 33	33F2	4.061
TIVERTON 33	33F3	1.351
TIVERTON 33	33F4	1.784

5.4.3 Fault Duty/Short Circuit Availability

The ASPEN program was used to calculate single phase to ground and three phase short circuit duty values. These values were compared to the station breaker interrupting capabilities. Table 4.7 summarizes the results. The short circuit duty is less than the interrupting capability for all four breakers.

TABLE 4.7 – Fault Duty

Substation	Transf. ID	Breaker	kV Rating	Current Rating (A)	Max IC (kA)	Max Fault Current (A)		% Max 3PH	% Max 1LG
						3PH	1LG		
TIVERTON 33	1T	33F1	12.47	1200	20	6442	6552	32.2%	32.8%
TIVERTON 33	2T	33F2	12.47	1200	20	7369	7512	36.8%	37.6%
TIVERTON 33	1T	33F3	12.47	1200	20	6442	6552	32.2%	32.8%
TIVERTON 33	2T	33F4	12.47	1200	20	7369	7512	36.8%	37.6%

5.4.4 Reactive Compensation

The power factor performance review of the study area feeders was performed using CYME with PI data where available. Table 4.8 below identifies reactive compensation issues and possible actions. These actions may be refined during plan development as feeders may be reconfigured. Reactive compensation should also be included in any recommendation adding substation transformation.

Table 4.8 – Feeder Reactive Compensation Analysis

Substation	Feeder	PF at feeder head Before	Reactive Compensation Needs
Tiverton 33	33F1	90.87%	2400 KVAr
Tiverton 33	33F2	95.65%	1800 KVAr
Tiverton 33	33F3	98.56%	600 KVAr
Tiverton 33	33F4	99.45%	N/A

6. PLAN DESCRIPTION, COMPARISON, AND RECOMMENDATION

The study solutions are comprised of three plans to address the asset condition issues at the Tiverton substation, as well as a list of common items that are necessary in addition to the chosen plan. In combination, these sets of solutions address all the issues identified in Section 4. The following sections describe details of each plan, propose alternatives where relevant, and conclude with a comparison and recommendation.

6.1 Common Items

The following items are common to all solutions and are required in addition to the recommended Tiverton substation asset conditions solution. Marked up one-line diagrams detailing the scope of each solution can be found in Appendix 9.2 and cost estimates are shown below.

New Tiverton 33F6 Circuit

Construction of a dedicated circuit (33F6) is currently planned to serve an 11.8MW PV site at 390 Brayton Road (Tiverton, RI) under funding projects C085653 and C085806. This project is currently in the design phase, with an estimated completion date of 11/1/2022. If the DG project does not proceed, this 33F6 circuit will still be needed to address the area contingency loading concerns. The following work is planned to serve this DG site:

- Install one (1) 12.47 kV circuit position of the Tiverton No.2 bus, including one (1) 1200-amp 15kV relayed breaker, nine (9) 15kV 1200A single blade disconnects, three (3) single-phase 333kVA regulators, cable terminations and disconnects for getaway, approximately 100 feet of underground 3 phase feeder cable, and additional associated substation equipment and civil construction inside of the Tiverton Substation.
- Install approximately 21,000 circuit feet of 1000 kcmil CU 3-1/C EPR insulated 15kV cable from the Tiverton Substation and along Fish Road, Bulgarmarsh Road (Route RI-177), and Brayton Road. Estimate does not include required manhole and duct civil construction (currently to be installed by interconnecting customer).
- Review and Implementation of protective device settings including field implementation and associated engineering review/documentation in Company tracking system(s)
- National Grid supervision and design support for Customer underground civil construction

The DG developer is responsible for the costs below to serve their project. Cost sharing may apply to this portion of work once the 33F6 circuit is being used to serve load. This estimate does not include the civil work that is being performed by the DG developer.

	Distribution Total ($M)	Substation (D) Total ($M)	Total ($M)
CapEx	3.097	1.022	4.121
OpEx	0.000	0.002	
Removal	0.000	0.000	
Total	3.097	1.024	

Tiverton #33F6 Line Extension (Appendix 9.6.1)

To address the Load-at-risk violations detailed in Section 4.1.2, the 33F6 circuit will need to be extended further south to pick up loading from the other Tiverton circuits.

- Extend the 33F6 from the DG site at 390 Brayton Road to the intersection of Lake Road and East Road, including:
  - Installation of a riser and a recloser

- Upgrade ~17,200' of single-phase to three-phase 477 aluminum conductor
- Reconductor ~5,700' of existing 4/0 aluminum conductor along East Road to 477 aluminum conductor.

Spend	Total ($M)
CapEx	1.907
OpEx	0.063
Removal	0.211
Total	2.181

Total cost including costs that may be shared with interconnecting customers:

	Distribution Total ($M)	Substation (D) Total ($M)	Total ($M)
CapEx	5.004	1.022	6.302
OpEx	.063	0.002	
Removal	0.211	0.000	
Total	5.278	1.024	

33F6 Non-Wires Alternatives Considerations
Although the feeder extension is considered a common plan as it extends a circuit to be built for an interconnecting customer, a non-wires alternative (NWA) was explored for alleviating the feeder contingency planning criteria violation. A load reduction of 11.6MVA across all feeders would be needed to resolve this issue. This is approximately 30% of the area load, which is in excess of the 20% threshold in the NWA screening criteria. Additionally, the pending 11.8 MVA distributed generation interconnection was considered, but the solar generation load cycle was not aligned with the contingency need. Lastly, NWAs have been considered in this area over past years with varying results.

Tiverton #33F6 Voltage Performance
To keep the mainline voltage above 97.5% of nominal during peak loading conditions, a set of midline voltage regulators will need to be installed on the new 33F6 circuit.

- Install one (1) set of 3-333kVA voltage regulators near P29 East Road

Spend	Total ($M)
CapEx	0.100
OpEx	0.000
Removal	0.000
Total	0.100

Tiverton Reactive Compensation

Additional reactive compensation is required to bring the power factor at all feeder heads to above 98% during peak loading conditions. This requires the addition of four (4) 900 kVAR switched capacitor banks, and two (2) 600 kVAR switched capacitor banks. Table 5.1 shows the recommended capacitor amounts.

Table 5.1 – Capacitor Recommendations by Feeder

Substation	Feeder	PF at feeder head Before	PF at feeder head After	New Cap Bank(s)
Tiverton 33	33F1	90.87%	99.63%	(1) 600KVAr, (2) 900KVAr
Tiverton 33	33F2	95.65%	99.88%	(2) 900KVAr
Tiverton 33	33F3	98.56%	99.81%	(1) 600 KVAr
Tiverton 33	33F4	99.45%	99.45%	N/A

Capacitor locations were developed with assistance from the CYME Capacitor Placement module, with locations chosen to optimize voltage performance. These proposed locations are shown in Appendix 9.4.1.

Spend	Total ($M)
CapEx	0.180
OpEx	0.000
Removal	0.000
Total	0.180

Tiverton Reliability Solutions

Based on the engineering reliability reviews, the following items were recommended for reliability improvements on the 33F3 and 33F4:

- An infrared scan was performed on both the 33F3 and 33F4 on 3/14/19. This identified five locations on the 33F3 and one location on the 33F4 where equipment replacement was required.
- Tree trimming was completed on the 33F4; the RI sections were completed on 3/31/21, and the MA sections were completed on 5/7/21.
- Two projects were initiated for the MA portion of the 33F4 (C084419 and C084453). These will reroute the 33F4 mainline away from dead trees, install three CMRs, eliminate excessive splices, and upgrade the non-standard #4 aluminum wire.
- The 33F6 extension to address normal and contingency loading issues will also provide reliability benefits by sectionalizing the existing customer and providing new switching points.

6.2 Tiverton Asset Condition Option Comparison

Option 1 – Replace All Equipment with Asset Condition Issues

- Two (2) 115kV MOAB sacrificial airbreak switches
- Six (6) 12.47kV vacuum circuit breakers (VCB) breakers
- Three (3) sets of voltage regulators (33F1, 33F2, 33F4)
- Control house safety features
- Animal protection (guards on underground (UG) cable getaways, electric animal fence, transformer bushing guards)

	Distribution Total ($M)	Transmission Total ($M)	Total ($M)
CapEx	2.619	1.526	4.422
OpEx	0.000	0.000	
Removal	0.146	0.131	
Total	2.765	1.657	

Option 2 - Replace All Equipment with Asset Condition Issues, plus Installation of IEC 61850 Relaying

- Two (2) 115kV MOAB sacrificial airbreak switches
- Six (6) 12.47kV VCB breakers
- Three (3) sets of voltage regulators (33F1, 33F2, 33F4)
- Control house safety features
- Animal protection (guards on UG cable getaways, electric animal fence, transformer bushing guards)
- Install IEC 61850 relaying, substation monitoring, and new IEC 61850 control enclosure

	Distribution Substation Total ($M)	Transmission Substation Total ($M)	Total ($M)
CapEx	2.803	2.063	5.085
OpEx	0.000	0.000	
Removal	0.146	0.073	
Total	2.949	2.136	

Option 3 - Full station breaker-and-a-half metal clad switchgear rebuild

- One (1) pre-engineered metal-clad switchgear enclosure
- Two (2) 115/13.2kV (nameplate) 24/32/40MVA (Delta – Gnd Wye) transformers with online monitoring equipment

- Six (6) 115kV station class surge arresters (included with transformer).
- Six (6) 115kV capacitive-coupled voltage transformers (CCVTs).

	Distribution Total ($M)	Transmission Total ($M)	Total ($M)
CapEx	8.831	0.550	9.981
OpEx	0.054	0.004	
Removal	0.488	0.054	
Total	9.373	0.608	

6.3 Tiverton Asset Condition Recommended Option and Timeline

Replacing all equipment with asset condition issues is the least cost option and it is, therefore, the recommended option.

6.4 Recommended Option

6.4.1 Cash Flows That May Be Shared with DG Interconnecting Customer

Cash flows are shown below. These tables do not include any civil costs that are borne by the DG developer to serve the project on Brayton Road. Distribution line costs that may be shared:

	D-Line Spending Profile ($M)						
	FY24	FY25	FY26	FY27	FY28	FY29	Total
CapEx	$ 0.155	$ 0.465	$ 0.929	$ 0.929	$ 0.465	$ 0.155	$ 3.097
OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 0.155	$ 0.465	$ 0.929	$ 0.929	$ 0.465	$ 0.155	$ 3.097

Distribution substation costs that may be shared:

	D-Sub Spending Profile ($M)						
	FY24	FY25	FY26	FY27	FY28	FY29	Total
CapEx	$ 0.051	$ 0.153	$ 0.307	$ 0.307	$ 0.153	$ 0.051	$ 1.022
OpEx	$ 0.000	$ 0.000	$ 0.001	$ 0.001	$ 0.000	$ 0.000	$ 0.002
Removal	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 0.051	$ 0.154	$ 0.307	$ 0.307	$ 0.154	$ 0.051	$ 1.024

Total sharable costs:

	Total Spending Profile ($M)						
	FY24	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**Total**
CapEx	**$ 0.206**	**$ 0.618**	**$ 1.236**	**$ 1.236**	**$ 0.618**	**$ 0.206**	**$ 4.119**
OpEx	**$ 0.000**	**$ 0.000**	**$ 0.001**	**$ 0.001**	**$ 0.000**	**$ 0.000**	**$ 0.002**
Removal	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total	**$ 0.206**	**$ 0.618**	**$ 1.236**	**$ 1.236**	**$ 0.618**	**$ 0.206**	**$ 4.121**

6.4.2 Study Cash Flows

Study related distribution line costs:

	D-Line Spending Profile ($M)						
	FY24	FY25	FY26	FY27	FY28	FY29	Total
CapEx	$ 0.109	$ 0.328	$ 0.656	$ 0.656	$ 0.328	$ 0.109	$ 2.187
OpEx	$ 0.003	$ 0.009	$ 0.019	$ 0.019	$ 0.009	$ 0.003	$ 0.063
Removal	$ 0.011	$ 0.032	$ 0.063	$ 0.063	$ 0.032	$ 0.011	$ 0.211
Total	$ 0.123	$ 0.369	$ 0.738	$ 0.738	$ 0.369	$ 0.123	$ 2.461

Study related distribution substation costs:

Study related transmission substation costs:

	Substation (T) Spending Profile ($M)						
	FY24	FY25	FY26	FY27	FY28	FY29	Total
CapEx	$ 0.076	$ 0.229	$ 0.458	$ 0.458	$ 0.229	$ 0.076	$ 1.526
OpEx	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Removal	$ 0.007	$ 0.020	$ 0.039	$ 0.039	$ 0.020	$ 0.007	$ 0.131
Total	$ 0.083	$ 0.249	$ 0.497	$ 0.497	$ 0.249	$ 0.083	$ 1.657

Total study related costs:

	Total Spending Profile ($M)						
	FY24	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**Total**
CapEx	**$ 0.317**	**$ 0.950**	**$ 1.900**	**$ 1.900**	**$ 0.950**	**$ 0.317**	**$ 6.332**
OpEx	**$ 0.003**	**$ 0.009**	**$ 0.019**	**$ 0.019**	**$ 0.009**	**$ 0.003**	**$ 0.063**
Removal	**$ 0.024**	**$ 0.073**	**$ 0.146**	**$ 0.146**	**$ 0.073**	**$ 0.024**	**$ 0.488**
Total	**$ 0.344**	**$ 1.032**	**$ 2.065**	**$ 2.065**	**$ 1.032**	**$ 0.344**	**$ 6.883**

6.4.3 Total Cash Flows

	Total Spending Profile ($M)						
	FY24	**FY25**	**FY26**	**FY27**	**FY28**	**FY29**	**Total**
CapEx	**$ 0.523**	**$ 1.568**	**$ 3.135**	**$ 3.135**	**$ 1.568**	**$ 0.523**	**$ 10.451**
OpEx	**$ 0.003**	**$ 0.010**	**$ 0.020**	**$ 0.020**	**$ 0.010**	**$ 0.003**	**$ 0.065**
Removal	**$ 0.024**	**$ 0.073**	**$ 0.146**	**$ 0.146**	**$ 0.073**	**$ 0.024**	**$ 0.488**
Total	**$ 0.550**	**$ 1.651**	**$ 3.301**	**$ 3.301**	**$ 1.651**	**$ 0.550**	**$ 11.004**

7. Plan Considerations and Comparisons

7.1 Permitting, Licensing, Real Estate, and Environmental Considerations

A building permit will not be required for the electrical substation work under this scope. If night/weekend work is anticipated, additional coordination with the town will be required during final engineering to determine if the town has any limitations. Site plan review will not be required because the option does not fall under the criteria listed in the zoning ordinance (only necessary if constructing a building with at least 2,000 sq. feet.)

The substation is outside of the 500-year flood plain (noted as Unshaded Area of Minimal Flood Hazard Zone X) according to FEMA Flood Insurance Rate Map Number 4405C0043H, effective April 5, 2010. A review of the RIDEM ERM oil and hazardous materials (OHM) regulated facilities coverages indicates the substation is an underground storage tank site. Additional coordination with environmental compliance is required for any earth disturbing work proposed.

7.2 Planned Outage Considerations

Revising the station DC panel will require multiple temporary configurations for the cutover of the DC station service feeds. Multiple cutovers and temporary configurations will be required during the cutover of the transformer relaying and installation of the new breaker control and feeder protection relaying. Ongoing substation and transmission line work in the area associated with the 115kV M-13 and L-14 lines may affect outage availability. A coordinated outage planning effort is required to facilitate these installations.

8. Conclusions and Recommendations

The study identified several issues including normal and contingency loading issues, minor voltage concerns, asset condition concerns, reactive compensation need, and reliability issues. A comprehensive plan was developed with two main components. The first main component was station asset condition issues which will be addressed with a least cost plan to directly replace the equipment. The second main component was normal and contingency loading concerns addressed by extending the 33F6 feeder. This feeder solution extends a feeder to be installed for a distributed generation customer and helps mitigate reliability issues. The rest of the plan includes minor capacitor, regulator, and other reliability work. The total plan represents the least cost investments to address all the study issues.

9. Appendix

9.1 – Area Map

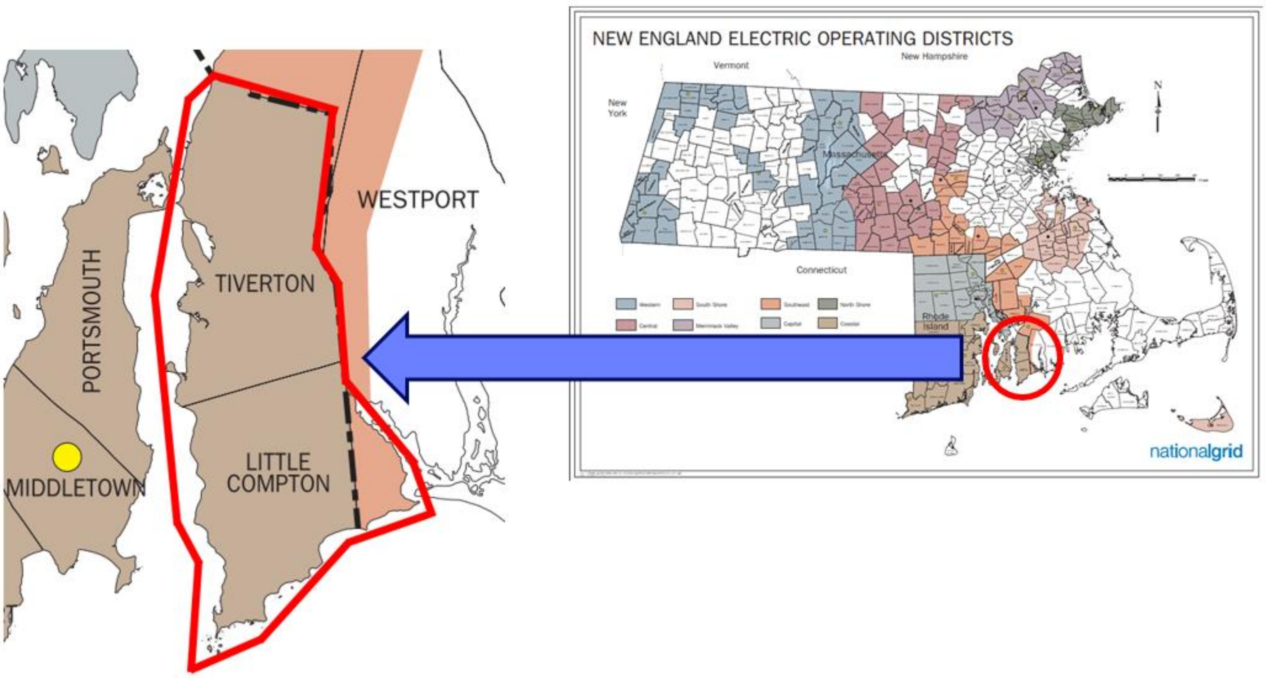
9.2 – One-Line Diagrams

9.3 – Area Large-Scale Distributed Generation

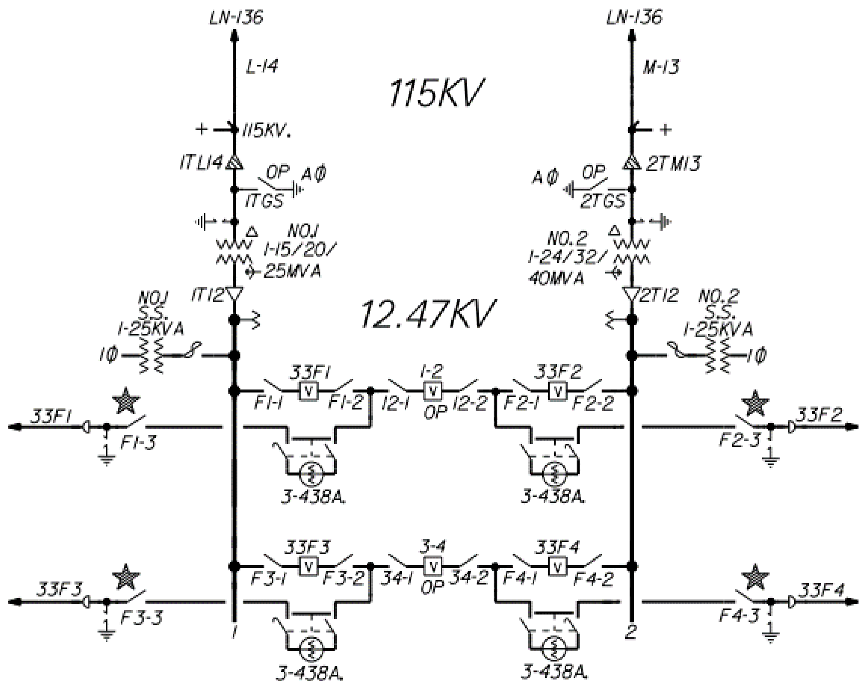
9.4 – Plan Development

9.5 – Non-Wires Alternative Criteria

9.1 Area Map


WESTPORT
TIVERTON
PORTSMOUTH
LITTLE COMPTON
MIDDLETOWN
NEW ENGLAND ELECTRIC OPERATING DISTRICTS
Vermont
New Hampshire
New York
Massachusetts
Connecticut
Rhode Island
nationalgrid

9.2 One-Line Diagram



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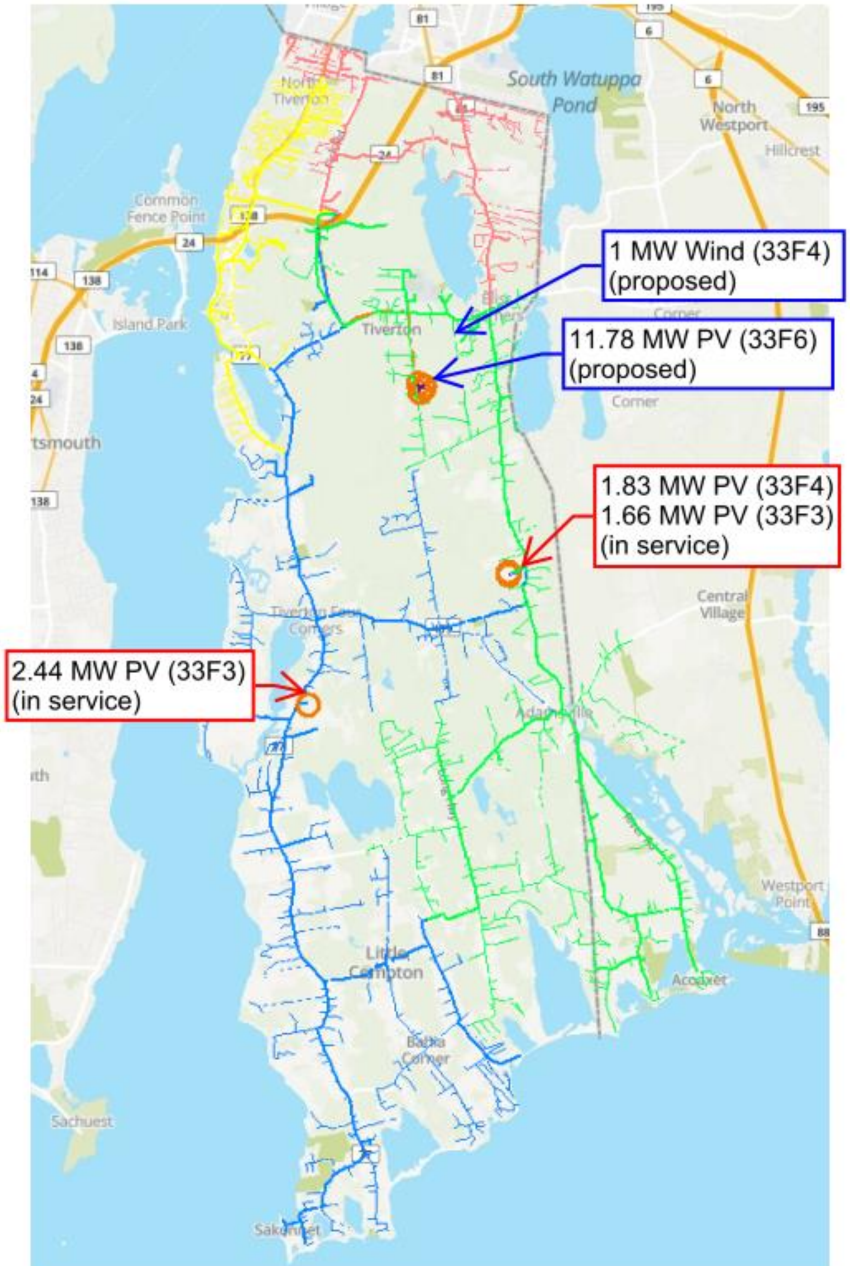
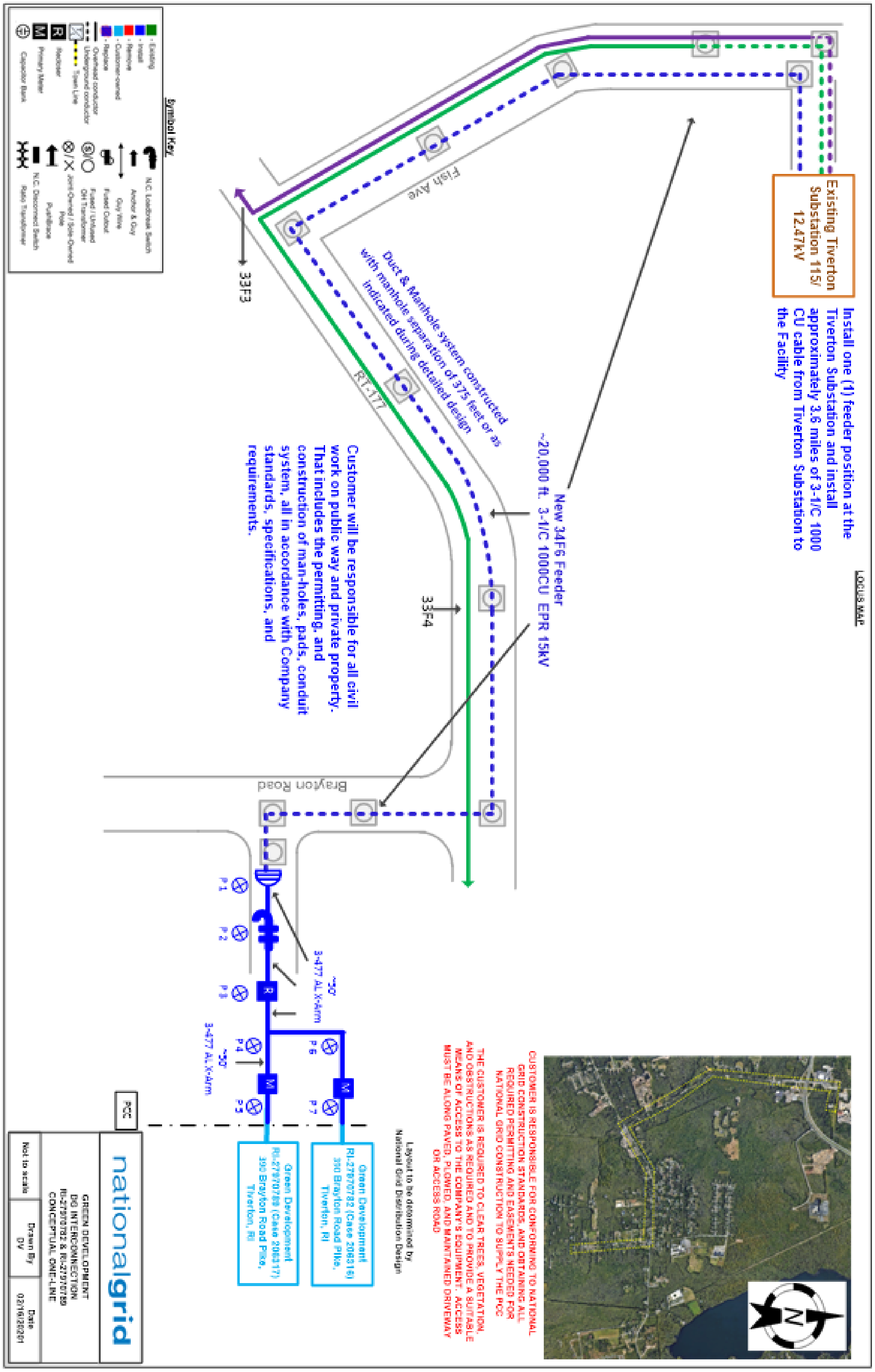
9.3 Area Large-Scale Distributed Generation

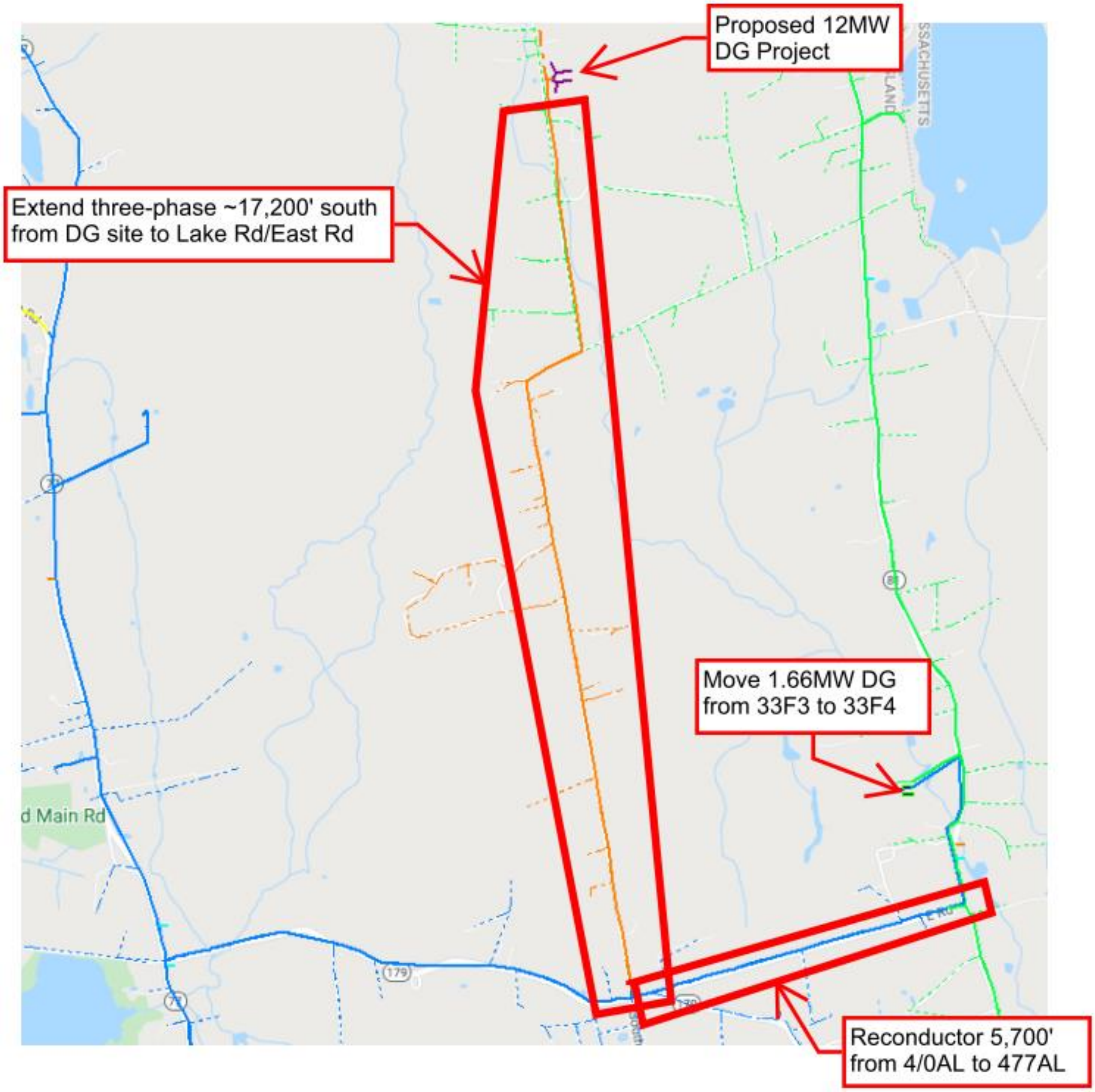


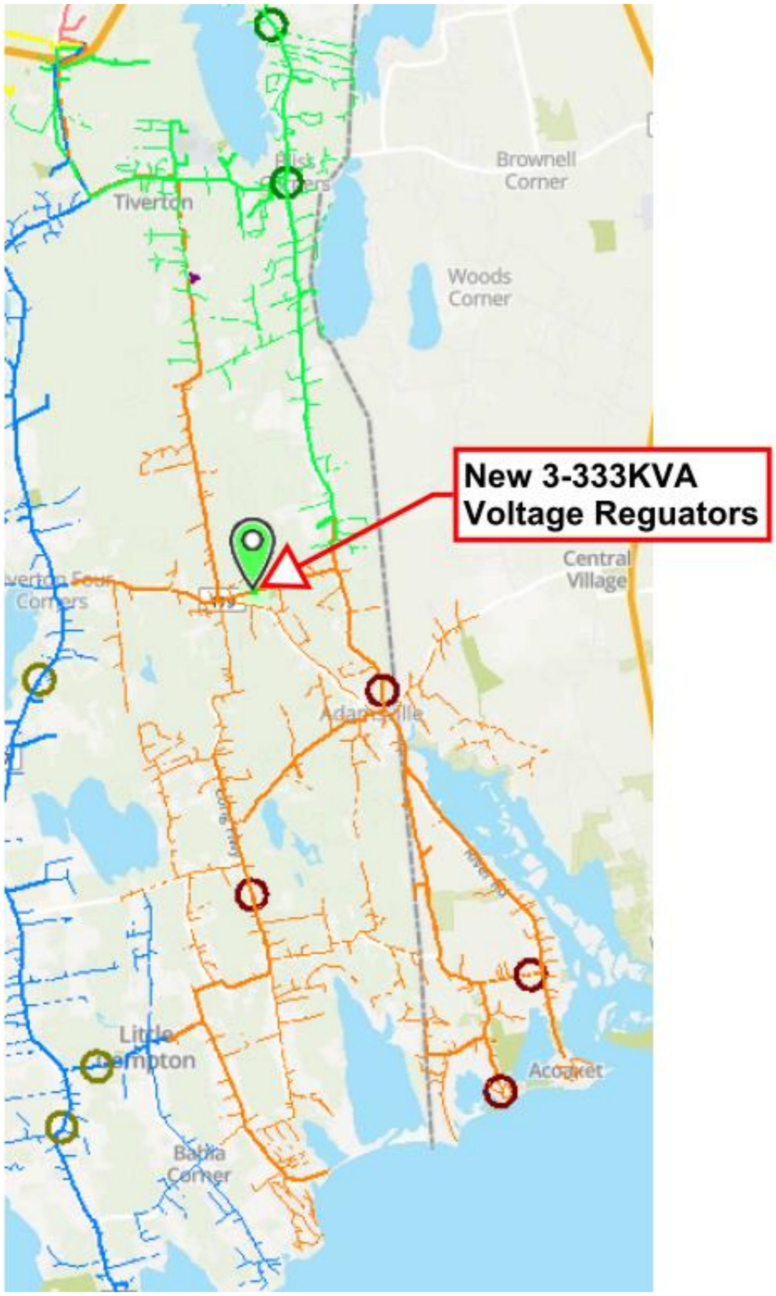
9.4 Plan Development

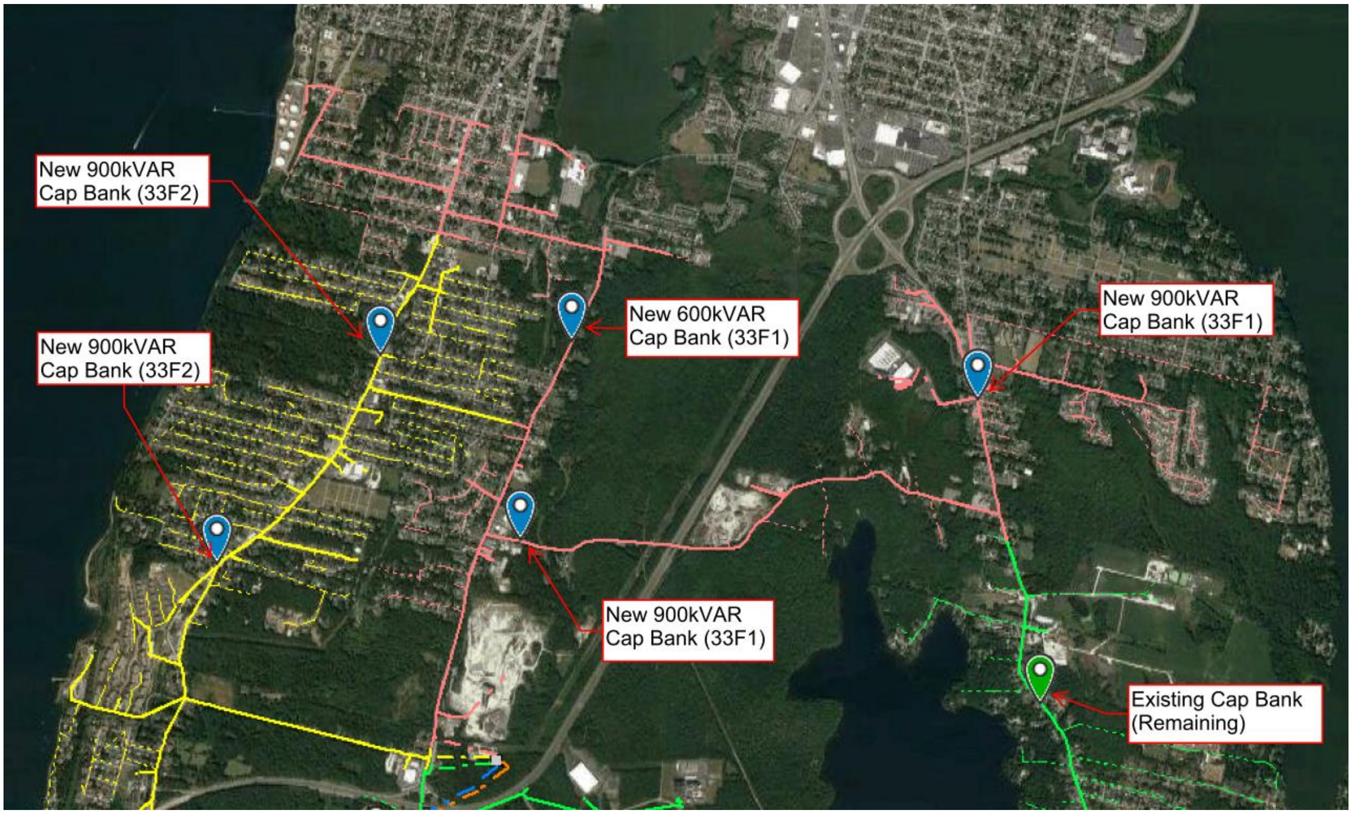
FIGURE 9.4.1 – COMMON LINE UPGRADES

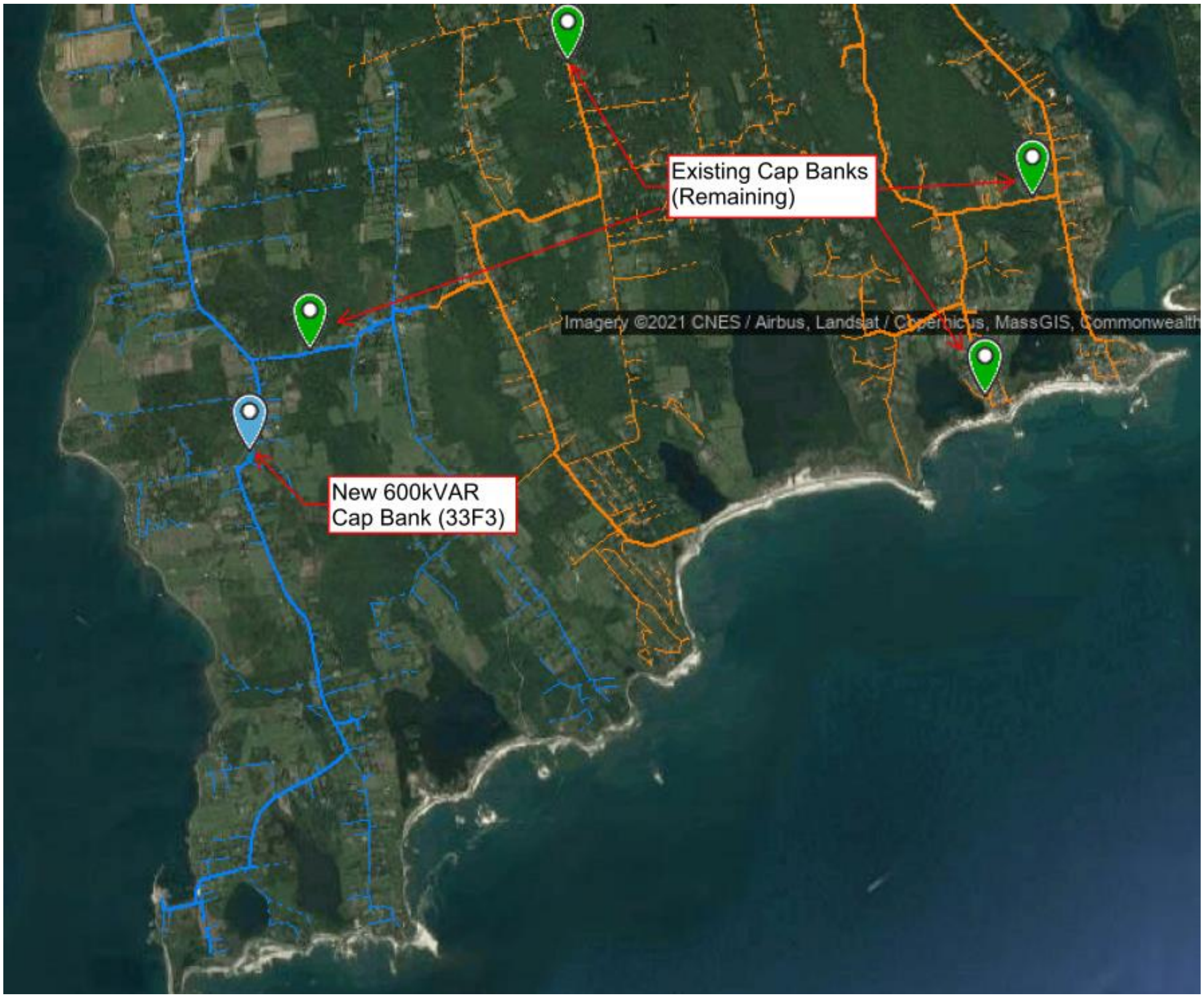


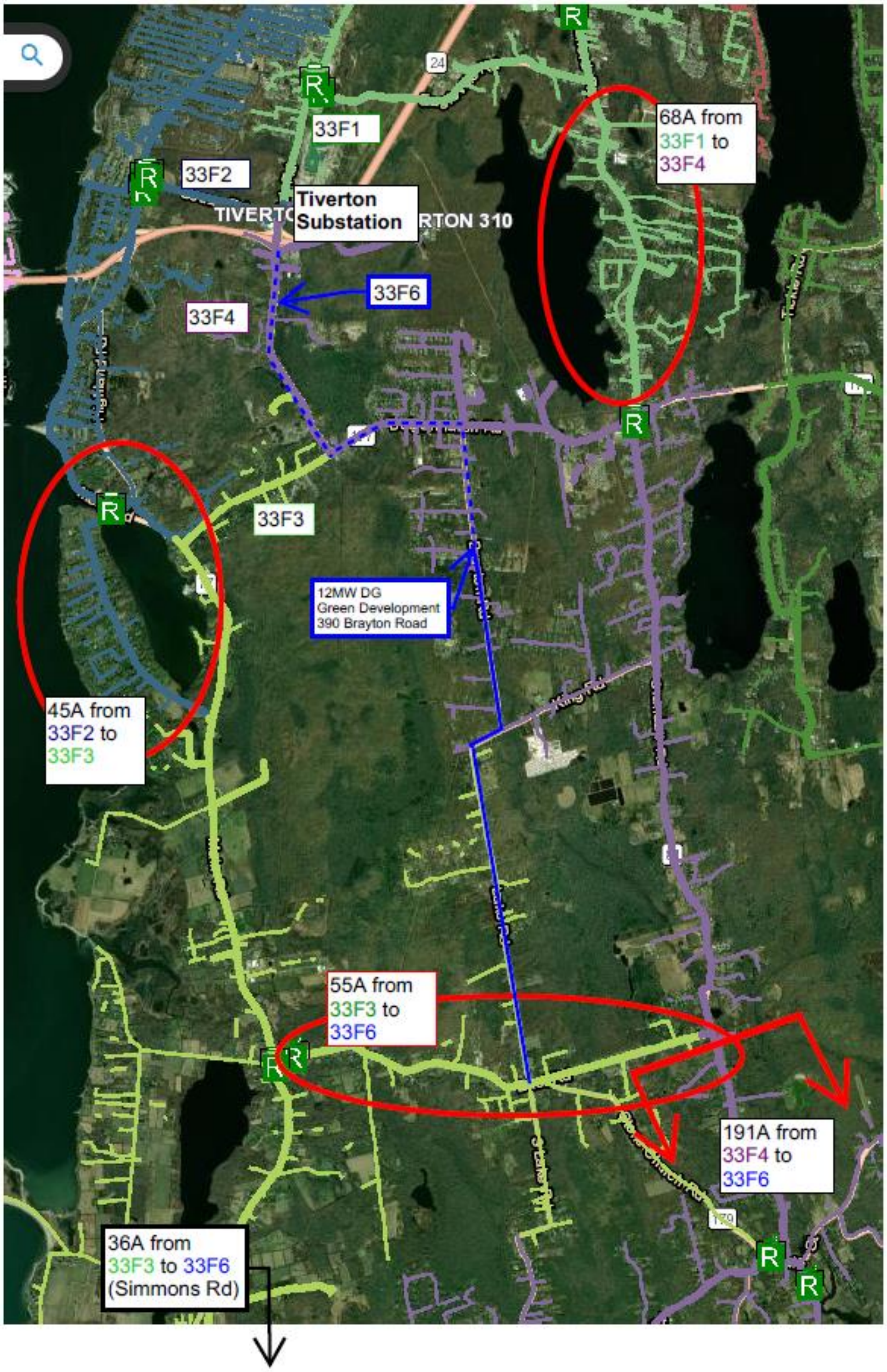
This document has been reviewed and does not contain Critical Energy/Electric Infrastructure Information

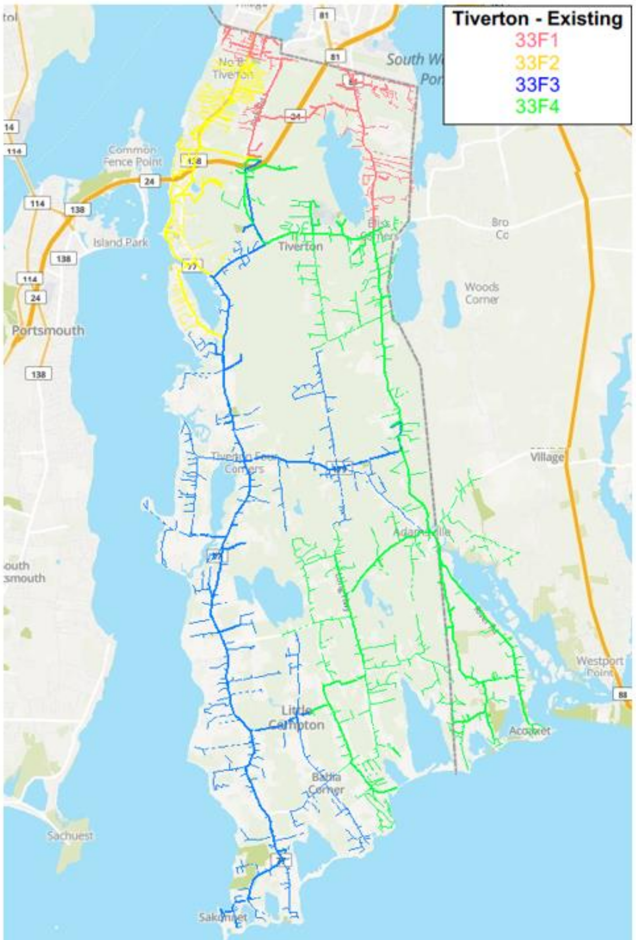

Proposed 12MW DG Project
Extend three-phase ~17,200' south from DG site to Lake Rd/East Rd
Move 1.66MW DG from 33F3 to 33F4
Reconductor 5,700' from 4/0AL to 477AL
d Main Rd


New 3-333KVA
Voltage Reguators
Tiverton
Brownell
Corner
Woods
Corner
Central
Village
Adamsville
Little
Compton
Acoaxet


New 900kVAR
Cap Bank (33F2)
New 600kVAR
Cap Bank (33F1)
New 900kVAR
Cap Bank (33F1)
New 900kVAR
Cap Bank (33F2)
New 900kVAR
Cap Bank (33F1)
Existing Cap Bank
(Remaining)


Existing Cap Banks
(Remaining)
New 600kVAR
Cap Bank (33F3)
Imagery ©2021 CNES / Airbus, Landsat / Copernicus, MassGIS, Commonwealth


68A from
33F1 to
33F4
33F1
33F2
Tiverton
Substation
TIVERTON 310
33F6
33F4
33F3
12MW DG
Green Development
390 Brayton Road
45A from
33F2 to
33F3
55A from
33F3 to
33F6
191A from
33F4 to
33F6
36A from
33F3 to 33F6
(Simmons Rd)


Tiverton - Existing
33F1
33F2
33F3
33F4

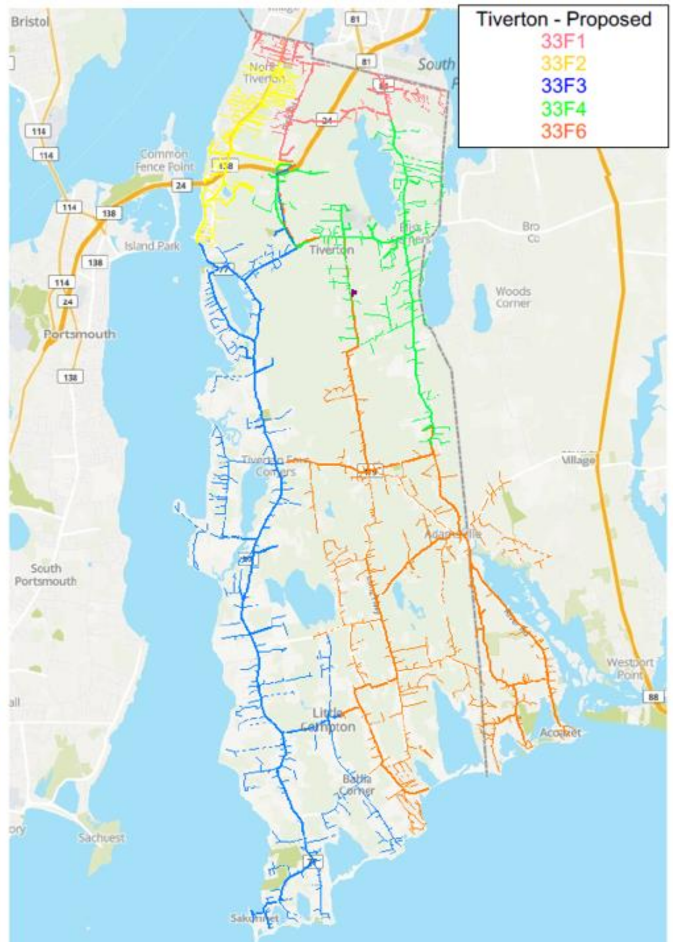
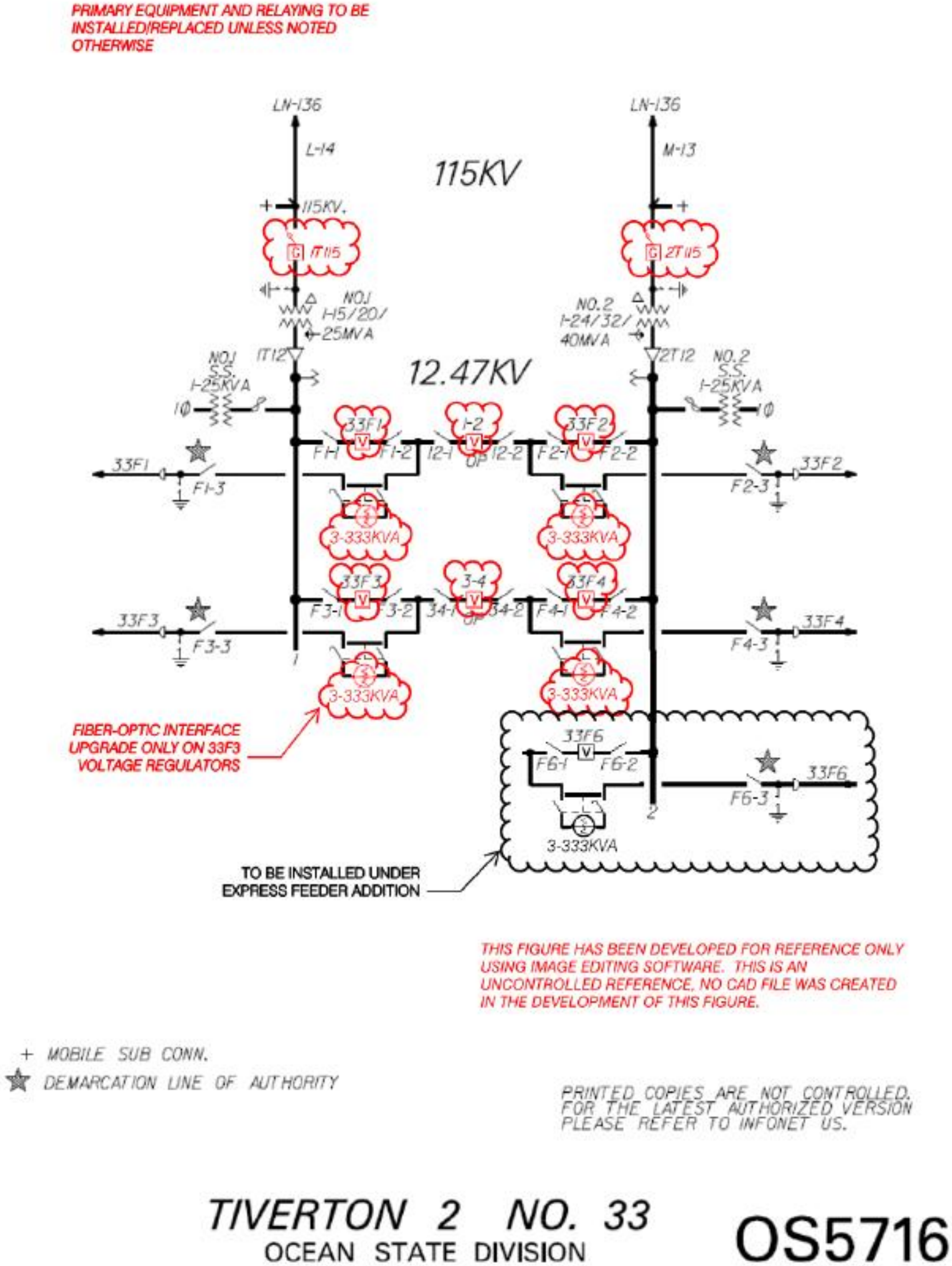
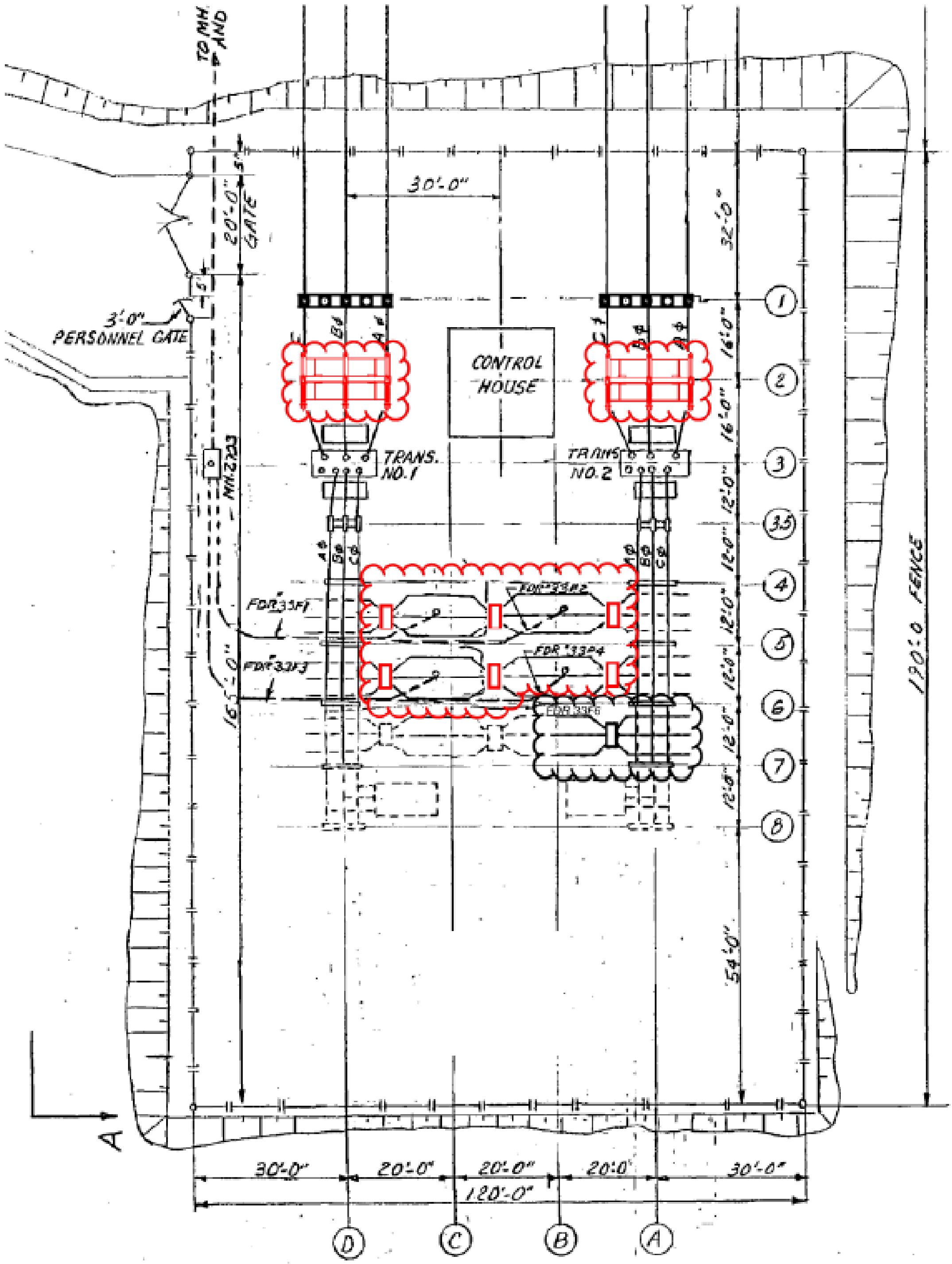

Tiverton - Proposed
33F1
33F2
33F3
33F4
33F6

FIGURE 9.4.2 – REPLACE EQUIPMENT WITH ASSET CONDITION ISSUES (OPTION 1)




TO MH AND
20'-0" GATE
30'-0"
32'-0"
3'-0" PERSONNEL GATE
CONTROL HOUSE
TRANS. NO.1
TRANS NO.2
MH.2323
FDR 33F1
FDR 33F2
FDR 33F3
FDR 33F4
FDR 33F6
16'-0"
12'-0"
54'-0"
165'-0"
190'-0" FENCE
30'-0"
20'-0"
20'-0"
20'-0"
30'-0"
120'-0"
D
C
B
A
A

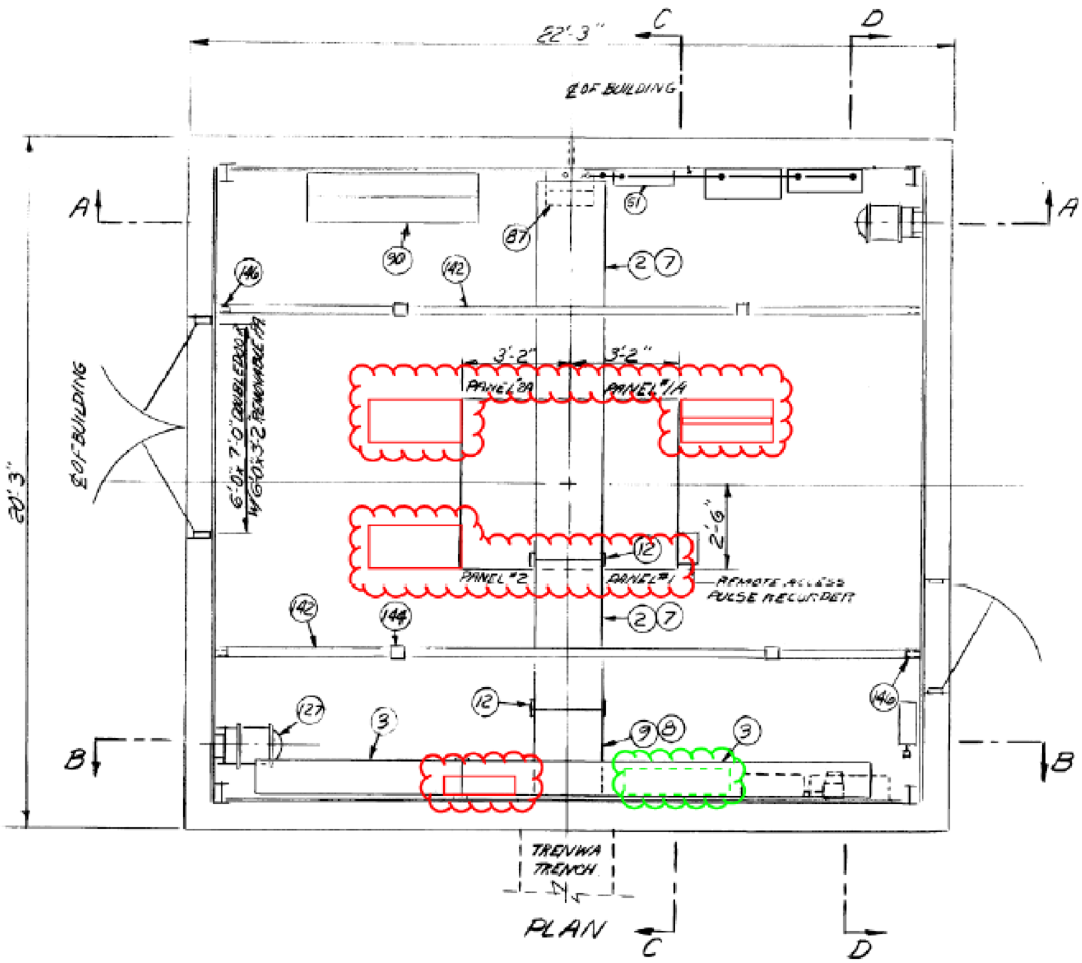
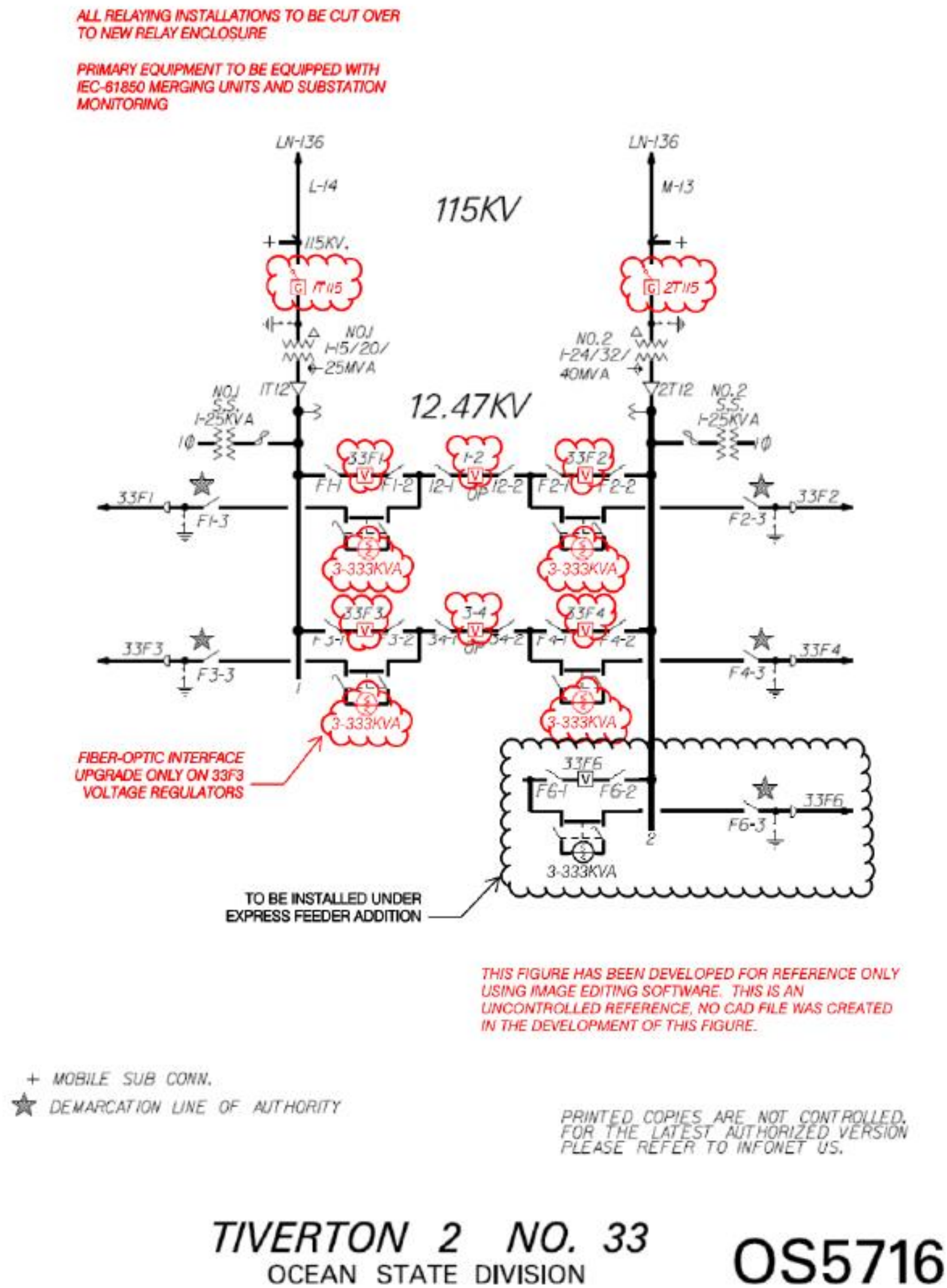

22'-3"
℄ OF BUILDING
20'-3"
℄ OF BUILDING
6'-0" x 7'-0" DOUBLE DOOR W/ 6'-0" x 3'-2" REMOVABLE TR
3'-2"
3'-2"
PANEL #2A
PANEL #1A
PANEL #2
PANEL #1
2'-6"
REMOTE ACCESS PULSE RECORDER
TRENWA TRENCH
PLAN

FIGURE 9.4.3 – REPLACE EQUIPMENT WITH ASSET CONDITION ISSUES AND INSTALL IEC 61850 RELAYING (OPTION 2)



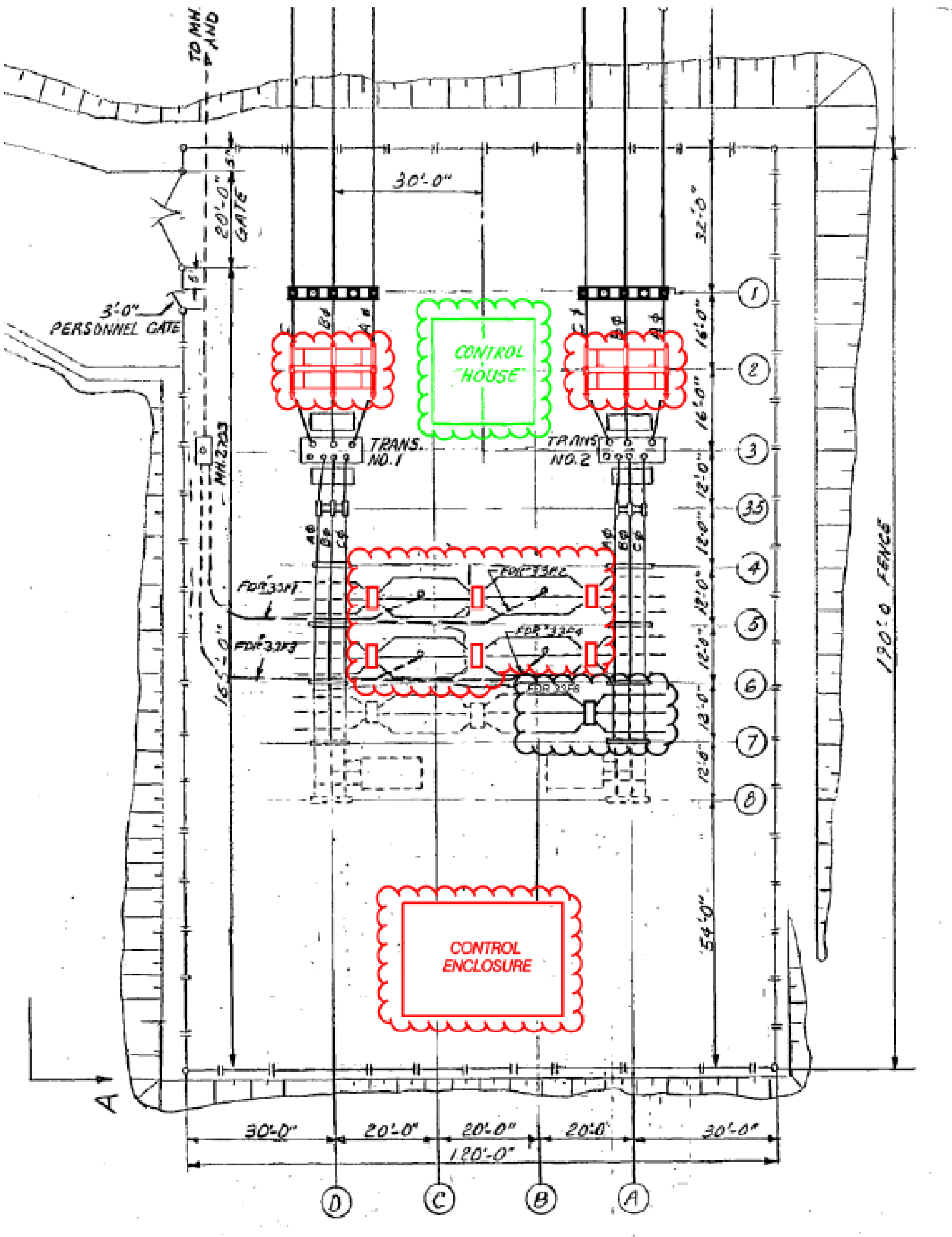
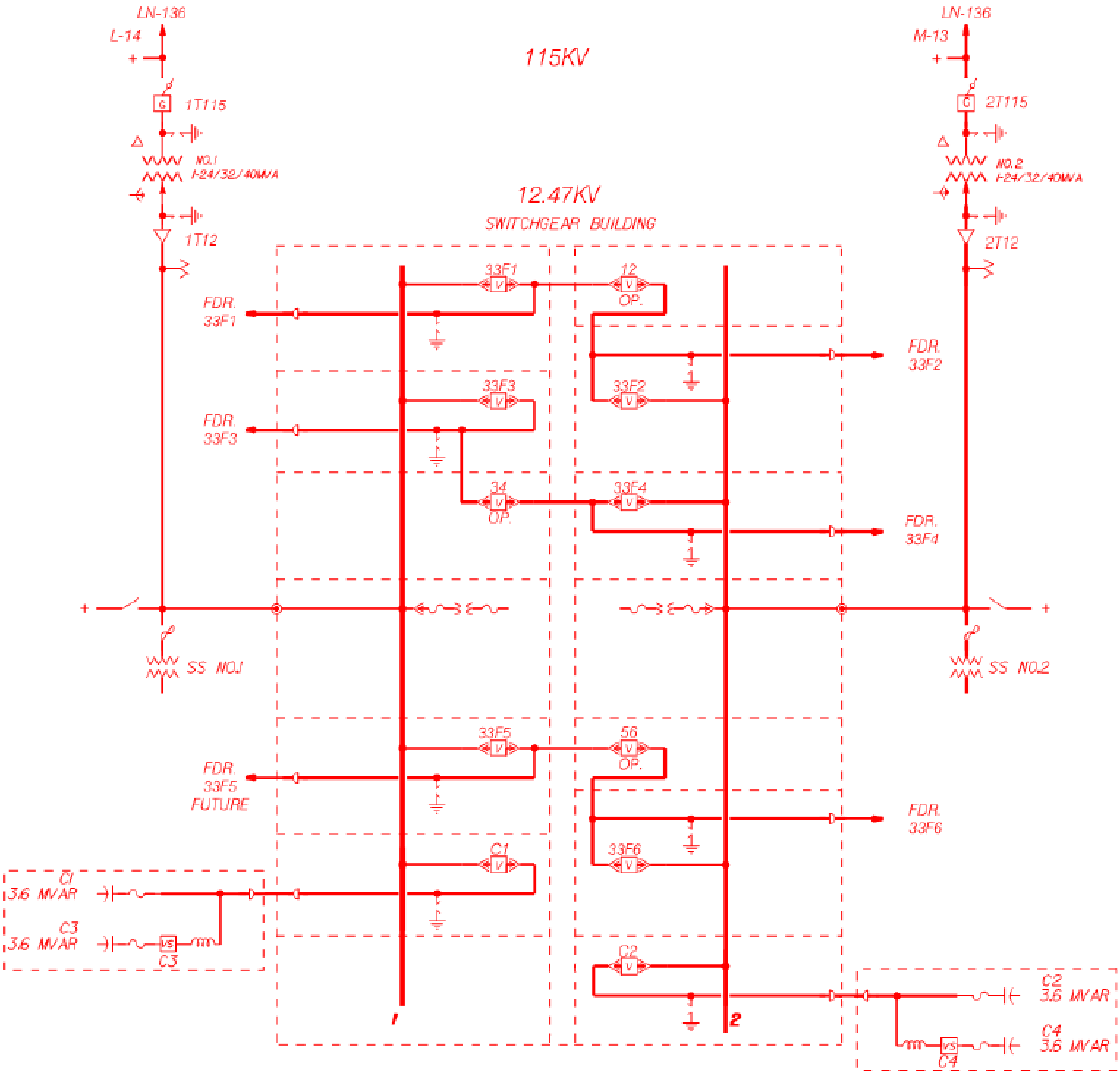
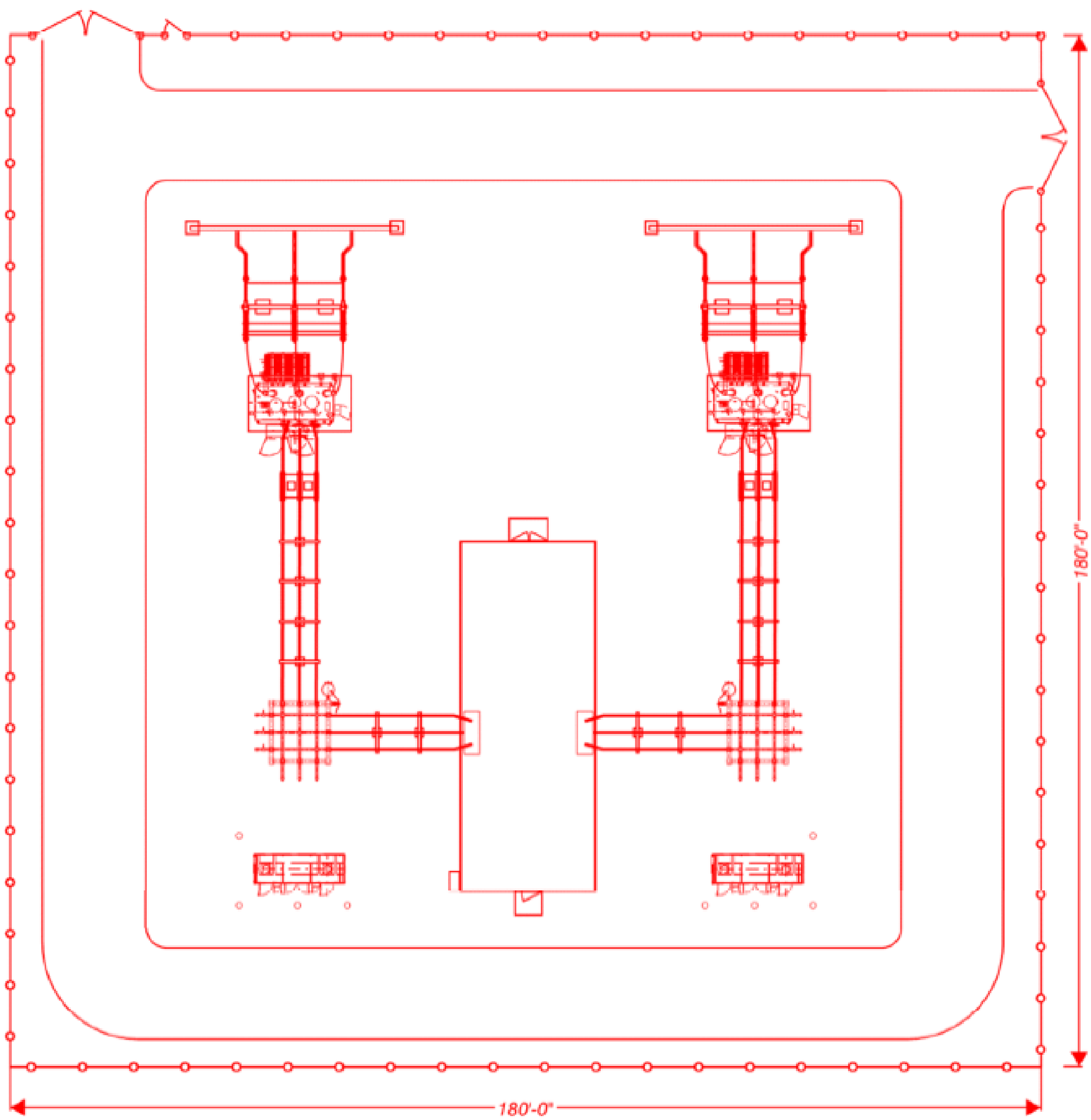
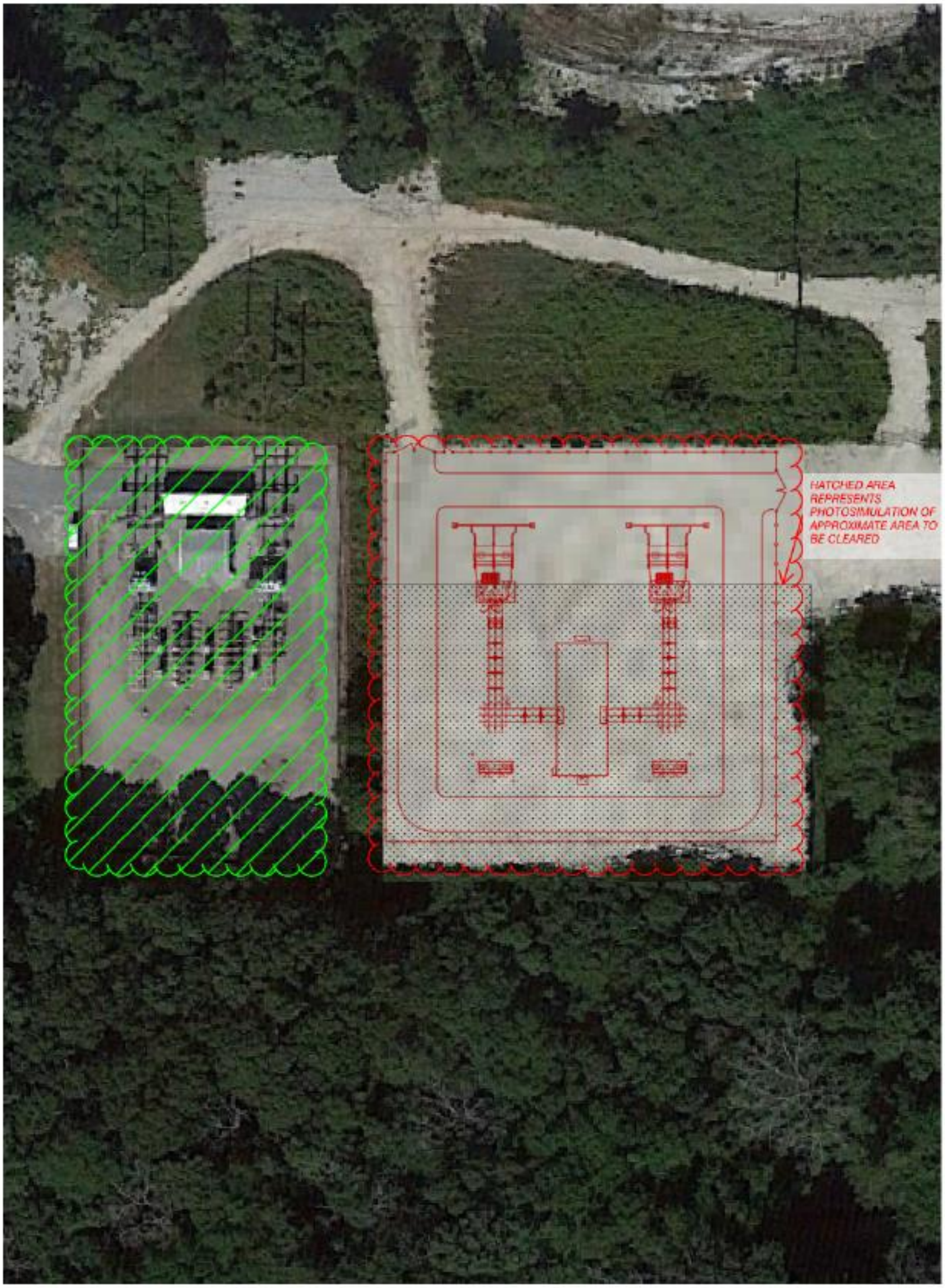

TO MH. AND
30'-0"
20'-0" GATE
32'-0"
3'-0" PERSONNEL GATE
CONTROL HOUSE
TRANS. NO. 1
TRANS NO. 2
MH. 2703
16'-0"
16'-0"
12'-0"
12'-0"
12'-0"
12'-0"
12'-0"
12'-0"
12'-0"
54'-0"
170'-0 FENCE
165'-0"
FDR 33F1
FDR 33F2
FDR 33F3
FDR 33F4
FDR 33F8
CONTROL ENCLOSURE
30'-0"
20'-0"
20'-0"
20'-0"
30'-0"
120'-0"
1
2
3
3.5
4
5
6
7
8
A
B
C
D

FIGURE 9.4.4 – FULL STATION REBUILD (OPTION 3)



THIS FIGURE HAS BEEN DEVELOPED FOR REFERENCE ONLY USING IMAGE EDITING SOFTWARE. THIS IS AN UNCONTROLLED REFERENCE, NO CAD FILE WAS CREATED IN THE DEVELOPMENT OF THIS FIGURE.


180'-0"
180'-0"


HATCHED AREA
REPRESENTS
PHOTOSIMULATION OF
APPROXIMATE AREA TO
BE CLEARED

9.5 Non-Wires Alternative Criteria

Where an issue has been identified, a Non-Wires Alternative may also be considered as an option to defer a transmission, sub-transmission, or distribution wires solution for a period of time. Considering Non-Wires Alternatives to every wires solution is not practical given the low cost of a large volume of potential wires solutions, the magnitude of load relief required in certain situations, the time to acquire Non-Wires Alternatives (and verify their availability) or instances where the issue is poor operating condition of the asset. As a result, Non-wires Alternatives are screened against the following four guidelines:

A. The Wires solution, based on Engineering judgment, will likely be more than $1M;
B. If load reduction is necessary, then it will be less than 20 percent of the total load in the area of the defined need;
C. Start of construction is at least 36 months in the future; and
D. The need is not based on Asset Condition.

The Narragansett Electric Company
d/b/a Rhode Island Energy
Petition for Acceleration Due to DG Project - Tiverton Project
Illustrative Depreciated Value at FY 2029

		(a)	(b)	(c)
(1)	Final Cost			14,660,000
(2)	FY 2025 Book Depreciation	3.16%	231,628	
	FY 2026 Book Depreciation	3.16%	463,256	
	FY 2027 Book Depreciation	3.16%	463,256	
	FY 2028 Book Depreciation	3.16%	463,256	
(3)	Cumulative Book Depreciation			1,621,396
(4)	Depreciated Value @ FY 2029			13,038,604

Notes:

(1)	Estimated final cost of project benefitting distribution customers
(2)(a)	Annual Book depreciation rate in FY 2024 ISR Plan
(2)(b)	Annual depreciation rate x Line (1)(c), FY 2025 is half year in year placed in service, FY 2026 forward use full rate
(3)	Sum of FY 2025 through FY 2028 Depreciation
(4)	Line 1(c) less Line 3