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Rhode Island Energy™
a PPL company

February 15, 2024

VIA ELECTRONIC MAIL

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

RE: Docket No. 23-38-EL – The Narragansett Electric Company d/b/a Rhode Island Energy's Petition for Acceleration of a System Modification Due to Distributed Generation Project Weaver Hill Projects
Responses to Division Data Requests – Set 4

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed please find the Company's complete set of responses to the Division of Public Utilities and Carriers' ("Division") Fourth Set of Data Requests in the above-referenced docket.

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

Sincerely,

Andrew S. Marcaccio

Enclosures

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

Division 4-1

Request:

Please provide a copy of each System Impact Study for Energy Development Partners shown in the Revision History (Petition, page 166), specifically Versions 1.0 and 2.0.

Response:

Included please find:

Attachment DIV 4-1-1 – Energy Development Partners System Impact Study, Version 1.0, May 2021

Attachment DIV 4-1-2 – Energy Development Partners Revised System Impact Study, Version 2.0, January 2022

Attachment DIV 4-1-3 – Energy Development Partners Revised System Impact Study, Version 3.0, September 2022

Prepared by or under the supervision of: Ryan Constable

System Impact Study
for Distributed Generation Interconnection to
National Grid's 34.5 kV System

DG WR:	RI-28228074
DG Case#:	00197003
Applicant:	Energy Development Partners
Address:	189 Weaver Hill Road
City:	West Greenwich, RI
DG kW/kVA:	10,000 kW / kVA
DG Type:	Inverter Based Photovoltaic
Feeder:	3310, Kent County Substation

Table of Contents

Section **Page**

List of Tables

Table **Page**

Definitions

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

BESS – Battery Energy Storage System

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DER – Distributed Energy Resources

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

MH - Manhole

NPCC – Northeast Power Coordinating Council

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

PF – Power Factor

P_{lt} – Long term flicker emission limit

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

P_{st} – Short Term flicker emission limit

P.U – Per Unit

PV - Photovoltaic

RTU – Remote Terminal Unit

Executive Summary

The Company has completed the Impact Study, for the interconnection of Energy Development Partners, ("Customer") a 10,000 kW / kVA Inverter based photovoltaic, ("the Facility"), to its 34.5 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

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

System Modifications

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

1. Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work: (Section 2.2, Appendix B)
    - Install ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Weaver Hill Road to the first 3-way MH on Weaver Hill Road.
    - Install ~4100 circuit feet 3-500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
    - Install ~200 circuit feet 3-500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
    - Install ~1,400 circuit feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

2. Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2, Appendix B):
    - Install MH and duct system (~14,900 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road.

- Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
- Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.

  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road.
  - Install MH and duct system (~3700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
  - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.

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

Special Operating Requirements

The Customer is required to comply with the following special operating requirements in order to interconnect to the Company EPS:

1. The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS. (Section 3.4)

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 $ 28,784,633 +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the final 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

The Customer proposes to install the following:

- Four (4) Customer owned SMA 2660-UP-US, 2,667 kW / kVA derated to 2,500 kW / kVA, three phase inverters for a total of 10,000 kW / kVA of inverter-based PV.
- Four (4) Customer owned 2,660 kVA, 34.5 kV delta primary, 600 V wye-ungrounded secondary padmounted interface transformer with an impedance of Z =6% along with X/R ratio of 7.5.
- One (1) Customer owned padmounted switchgear 35kV, 600A, 200 kV BIL G&W Viper recloser with SEL-651R relay assembly with 8-hour battery backup.
- One (1) Customer owned GOAB switch, S&C Model #147513, 200 kV BIL, 40kA with a Visible, lockable blades and utility accessible 24/7.

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 04/27/2021).

Any advanced inverter functionality other than that specifically called out on the Customer documentation and/or outlined herein shall be subject to additional study before being enabled.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is 3310, a 34.5 kV unregulated, three-phase, 3 wire, wye, ungrounded, radial, sub-transmission circuit that originates out of the Company's Kent County Substation, in West Greenwich, RI (the "Interconnecting Circuit"). This circuit is located overhead on Division Street, approximately 3.92 miles from the proposed Facility. This Line Extension will include the following work:

- Install ~410 feet of 3-1/c-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry.
    - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
- Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work:
    - Install ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Weaver Hill Road to the first 3-way MH on Weaver Hill Road.

- Install ~4100 circuit feet 3-500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
- Install ~200 circuit feet 3-500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
- Install ~1,400 circuit feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

- Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2, Appendix B):
  - Install MH and duct system (~14,900 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road
    - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
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  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road
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  - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.

An underground line extension originating from the overhead line on Hopkins Hill Rd will be required to reach the proposed Facilities. There is one river that will need to be crossed with overhead conductors alongside the bridge. The Big River Bridge was not constructed to allow for installation of concrete encased ducts.

Civil work from the proposed riser pole on Hopkins Hill Road to the 3-way Manhole at the intersection of Nooseneck Hill Road and Weaver Hill Road to be performed by

others. National Grid to perform civil work from the 3-way Manhole at the intersection of Nooseneck Hill Road and Weaver Hill Road, to the proposed riser pole on Customer property.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL (kW)*
3309	165	0	0	*165*
3310	434	24,248	10,000	*34,682*
3311	30,284	23,795	0	*54,079*
3312	2,735	4,049	0	*6,784*
TOTAL	*33,618*	*52,092*	*10,000*	**95,710**

Table 1: Generation at the Substation and Interconnecting Circuit

- There is one (1) existing recloser on the circuit, none of which are in between the substation and the facility, summarized in Table 2. Refer to Section 5 for further discussion on any required modifications.

Location	Status	Mid-line recloser, or existing DG project PCC recloser	In between Facility and Substation
Pole #18-1, Hopkins Hill Road, West Greenwich	In Service	Mid-line	No

Table 2: Recloser Locations

- There are no existing capacitor banks installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

- There are no existing regulators installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

2.3 Interconnection

Refer to the interconnection diagram in Appendix B for approximate PCC location.

Should the Customer elect to move forward with the Project, the Company's Design Personnel will specify the exact location of the Company's facilities and installation details. The Customer shall be responsible for obtaining all easements and permits required for any line extension not on public way in accordance with the Company's requirements.

The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

For this Project, the PCC is defined as the point where the Customer owned conductors terminate to the Company revenue meter, which is located at Pole #10-6, 189 Weaver Hill Road, West Greenwich, RI. The Customer must install their facilities up to the Company revenue meter. The Customer must provide sufficient conductor to allow the Company to make final connections at the meter pole. The Company will provide final connection of the Customer conductors to the Company meter.

If 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 Geographical Information System ("GIS"). A field review of the feeder was performed on 09/25/2019.

The analysis considered cases at peak load (16,284 kVA @ 100% PF) and net minimum load (5,017 kVA @ 99.52% Lagging PF) at time of maximum expected generation (9:00AM – 6:00PM) on the circuit.

Circuit peak and minimum load values have been taken from the Company's historical load data that has been compiled over 12 months, from 1/1/2019 to 1/1/2020.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Analysis shows that the maximum potential generation exceeds the observed minimum load on the Kent County 34.5 kV bus. However, the substation is currently equipped with bi-directional metering which was previously installed for reasons unrelated to DG work. No additional work is required on the substation bulk power metering.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in steady state voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output, the voltage range at the PCC was within acceptable limits.

Customer provided manufacturer's test reports have been reviewed for 1.4PU pickup values with 1ms or less total clearing time. The proposed design has been found to meet the necessary requirements.

3.4 Flicker Analysis

The IEEE 1547 standard and IEEE 1453 flicker assessments were used to estimate whether or not this site would be likely to cause unacceptable voltage flicker on the interconnecting feeder. This method evaluates for both short term and long-term voltage flicker against IEEE1547-2018 Table 25 - DER Flicker Emission Limits.

Analysis shows that P_{st} and P_{lt} are within acceptable limits and no mitigation for voltage flicker is recommended.

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2015 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long-Term Dynamics module of CYME[1]. A long-term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6-hour period. Other significant DG existing or in process ahead of this Project were modeled at full output and modeled with the appropriate voltage fluctuation curve to simulate reasonable voltage fluctuations.

The generation profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate realistic power output from the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict voltage flicker under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether or not there is a readily apparent concern related to voltage flicker.

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

Analysis shows that the predicted flicker and voltage fluctuations are expected to be acceptable, provided that the following conditions are met:

- The system modifications identified elsewhere in this study are implemented.
- The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS.

[1] CYME Power Engineering Software, Version 8.1, Revision 01, Build 115, Copyright © 1986-2017, Cooper Industries, Ltd.

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 100kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
442	All Projects <100kW CERTIFIED
0	All Projects <100kW Non-CERTIFIED
740	CERTIFIED
3,500	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered a likely event. As a result, a PCC recloser with reclose blocking will be required. Additionally, live-line reclose blocking must be implemented at the following line reclosers summarized in Table 4.

Location	Status (Existing or New)
Pole #25-1, Hopkins Hill Road, Coventry, RI	New

Table 4: Recloser Locations

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C 2180 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation.

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

Addition of generation sources to sub-transmission feeders can result in the back-feeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. Due to the Kent County T1, T2 and T7 supply transformer configurations, there is a path for zero sequence ground fault current to single line to ground faults on the transmission line. Therefore, the Facility does not pose a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Substation modifications related to $3V_0$ are not required**.**

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account existing system conditions, but not the impact of the Customer's new Facility.

Pre-Project

System Impedance at PCC

Z1 = 0.05 + j0.26 p.u.

Z0 = 0.65 + j1.38 p.u.

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

5.3 Fault Current Contributions

Table 5 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings. Mitigation strategies are required to accommodate the proposed Facility, as described in Sections 5.4 and 5.5.

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

PRE PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)
3-phase (LLL)	21581	3999
Phase-Ground (LG)	24066	2346

POST PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)	DELTA I_{fault} @ SUB BUS	DELTA I_{fault} @PCC
3-phase (LLL)	21779	4199	1%	5%
Phase-Ground (LG)	24322	2478	1%	6%

Table 5: Fault Duty

5.4 Substation Protective Device Modifications

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study:

- Add load encroachment settings to the Kent County Transformer #7, 34.5 kV directional overcurrent relay (67)

5.5 Area EPS Protective Device Coordination

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

The existing device settings and associated time-current curves were evaluated for protective devices on the Interconnecting Circuit.

The protection coordination review of the area EPS revealed that the following modifications to the existing EPS protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study. Refer to Appendix B for system modification drawings:

- Install a recloser at the tap for the proposed line extension to the facility at Pole #25-1, Hopkins Hill Rd, Coventry, RI. (Appendix B-3)

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the 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.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states the interconnecting transformer is four (4) Customer owned 2,660 kVA, 34.5 kV delta primary, 600 V wye-ungrounded secondary

padmounted interface transformer with an impedance of Z =6% along with X/R ratio of 7.5.

The proposed transformer satisfies the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Facility is proposing to connect to a non-effectively grounded 34.5 kV circuit, and therefore does not require a means of effective grounding.

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

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

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

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

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable inverter relay settings in accordance with the aforementioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8. This requirement is met.

6.6 Secondary Protection

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

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a circuit breaker for site protection.

The Customer provided documents indicate an interrupting device on the high side (Customer 34.5 kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

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

The Customer provided documents show a phase overcurrent (51) relay element and associated settings.

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

51 – Phase

Customer Proposed: 300A primary amps pickup, 2 second time delay, U4 curve.

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relays make/model is included on the Customer single line.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D. The Customer provided documents show neutral overvoltage (59N) that are unacceptable.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756C Section 7.6.11 and 7.8. This requirement is met.

The Customer provided one-line diagram shows acceptable settings for neutral overvoltage 59N protection.

59N – Neutral Overvoltage

Customer Proposed: $3V_0$ = 12.45 kV primary pickup (46.7 V), 0.8 second time delay.

6.6.6 Current Transformers ("CT") (ESB 756D Section 7.6.4.1)

The Customer provided documents show current transformer with ratings listed, which satisfies this Section of ESB 756D.

6.6.7 Voltage Transformers ("VT") and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show wye-grounded/wye-grounded VT's and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer provided documents indicate a power supply for the redundant relay that satisfies the requirements of this section of ESB 756D.

The Customer has proposed a DC power supply. The Customer shall demonstrate in the witness test that the relay will trip if the DC voltage goes out of the normal operating range.

It is recommended that the power DC power supply be connected to the utility (source) side of the interrupting device in order to ensure power availability to close the interrupting device after an extended outage. This is a recommendation, for consideration by the Customer. It is not a requirement by the Company.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7 & 756C Section 7.8.3)

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting a minimum 5 minutes of healthy utility voltage and frequency. "Healthy Utility Voltage and Frequency" is defined by ESB 756D Table 7.8.3-1. The five-minute time interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five-minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer provided settings and timing device information is acceptable as shown.

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer's one line diagram shows devices and settings to satisfy this requirement.

6.7 Synchronizing Devices (ESB 756D Section 7.6.9 and 7.6.11.2)

Project is inverter based; therefore, synchronizing devices are not required.

6.8 Customer Cabling

The Company is not responsible for the protection of the Customer cable and primary protection for the Customer cable must be provided at the change of ownership.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

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

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the

functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment.
- Inverter manufacturer cut sheet including method of island detection and UL certification.
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project.
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study.
- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme.
- The proposed testing procedure
- The proposed energization plan.
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft MA state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above identified time frames due to errors in the relay settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, is shown below in Table 6:

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 - Civil Work	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Distribution Civil work, 3310 circuit See Note #2 (Cost Sharing may be applicable)	$19,960,065	$19,960,065	$0	$0	$2,211,575	$22,171,640
SUBTOTAL	**$19,960,065**	**$19,960,065**	**$0**	**$0**	**$2,211,575**	**$22,171,640**

NECO - Line Work, Customer Property	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Equipment at Point of Common Coupling, 3310 Circuit. See Note #3	$310,038	$310,038	$0	$0	$34,352	$344,390
SUBTOTAL	**$310,038**	**$310,038**	**$0**	**$0**	**$34,352**	**$344,390**

NECO - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Distribution Line work, 3310 Circuit. See Note #4 (Cost Sharing may be applicable)	$5,621,801	$5,612,059	$5,272	$4,470	$621,816	$6,243,617
SUBTOTAL	**$5,621,801**	**$5,612,059**	**$5,272**	**$4,470**	**$621,816**	**$6,243,617**

NECO - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
Add Load Encroachment to the Kent County T7 Directional Overcurrent Relay. (Cost Sharing may be applicable)	$16,000	$15,000	$1,000	$0	$1,485	$17,485
SUBTOTAL	**$16,000**	**$15,000**	**$1,000**	**$0**	**$1,485**	**$17,485**

Witness Testing & EMS	Pre-Tax Total	Capital	O&M	Removal	NA	Total
Witness Testing. See Note #5	$2,500	NA	$2,500	NA	NA	$2,500
EMS integration. See Note #6	$5,000	NA	$5,000	NA	NA	$5,000
SUBTOTAL	**$7,500**	**$0**	**$7,500**	**$0**	**$0**	**$7,500**

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	$25,915,404	$25,897,162	$13,772	$4,470	$2,869,229	$28,784,633

Notes

1. Definition of abbreviation: NECO-Narangansett Electric Co.; NEPCO-New England Power Co.
2. Installation of (6) - 3-way manholes, (26) - 2-way manholes, (400 feet) - 2 way, 6" PVC - DB concrete encased duct bank, (18,300 feet) 4 way, 6" PVC - DB concrete encased duct bank, (600 feet) 9 way, 6" PVC - DB concrete encased duct bank and associated equipment. For estimating purposes, permanent restoration for civil work is assumed to be twelve (12) feet in width. Note: Should additional permanent restoration (i.e., Curb to curb or centerline to curb) be required, the cost of civil construction could increase.
3. Installation of pole-mounted equipment at the POI-PCC, including approximately 250 feet of 3-477 Al Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers, one (1) primary meter, and associated equipment.
4. Extend the Kent County 3310, 34.5 KV circuit underground from proposed Pole #25-1, Hopkins Hill Road, West Greenwich, RI to the 3310 PCC-POI located at 189 Weaver Hill Road, West Greenwich, RI. (approximately 4.4 Miles). Estimate included in table above assumes installation of 3-1/c-500 kcmil CU EPR 35 KV cable, and associated equipment. Costs include one (1) bridge crossing with risers to 477 Al bare conductor, Installation of new tap recloser located at Pole #25-1, Hopkins Hill Road, West Greenwich, RI, and associated equipment.
5. Witness Testing including review of witness test documentation and manpower for attending witness test.
6. Integration of DG and EPS modifications into Company's Energy Management System (EMS)

Table 6: Cost Estimates

The planning grade estimate provided herein is based on information provided by the Interconnecting Customer for the study and is prepared using historical cost data from similar projects. The associated tax effect liability included is the result of an IRS rule, which states that all costs for construction collected by the Company, as well as the value of donated property, are considered taxable income.[3] This estimate is valid for ninety (90) calendar days from the issuance of this report, after which time it becomes void. If the Interconnection Customer elects to proceed with this project after the ninety (90) calendar days, a revised estimate may be required.

This interconnection application may result in costs charged to The Narragansett Electric Company (the Company) by an Affected System Operator (ASO). Please note that in addition to the payment obligation for your share of the cost of any transmission upgrades identified in an ASO Study or identified during the Distribution System Impact Study of your application, when your facility is energized you also will be assessed for the on-going carrying charges for the transmission upgrades (plus cost security before your facility is energized), as specified in your Interconnection Service Agreement. The on-going carrying charges include O&M, property taxes, and other carrying costs associated with transmission upgrades. The transmission upgrades and on-going carrying charges are calculated and charged to the Company by the ASO, in most instances the Company's transmission provider, New England Power Company (NEP), in accordance with the ASO's tariff (for NEP, Schedule 21-NEP, Attachment DAF, to the ISO-NE Open Access Transmission Tariff ("DAF Charges") and data from the FERC Form 1). You will be charged initially on an estimated basis for the transmission upgrade costs, which will be reconciled to actual costs. On-going carrying charges are calculated by multiplying the capital portion of the

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

transmission upgrade costs by the transmission carrying charge rate in effect at the time. For NEP, the on-going carrying charge rate is subject to adjustment annually as estimated transmission upgrade costs are reconciled to actual costs. The current on-going carrying charge rate for NEP is 5.21%.

The estimated duration for the Company to complete construction of the System Modifications will be identified in the final Interconnection Service Agreement.

The project schedule may be impacted by the ability to have planned outages to allow work to take place on the distribution system. Outages will be contingent on the ability to support the load normally supplied by affected circuits. The schedule can also be impacted by unknown factors over which the Company has no control. The interconnection schedule is contingent on the Interconnecting Customer's successful compliance with the requirements outlined in this report and timely completion of its obligations as defined in *ESB756D, Exhibit 2: Company Requirements for Projects Not Eligible for the Simplified Process*. The schedule for the Company's work shall be addressed during the development, or after the execution, of the Interconnection Agreement.

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the final ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the final ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C. No. 2180, Section 3.4 Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	05/11/2021	Issue to Customer

Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION

If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

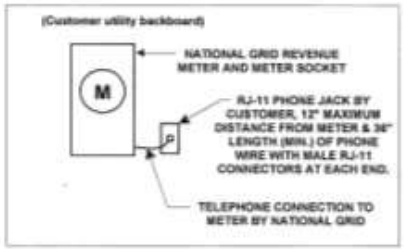

Figure 1A – Indoor Meter Installation
not to scale

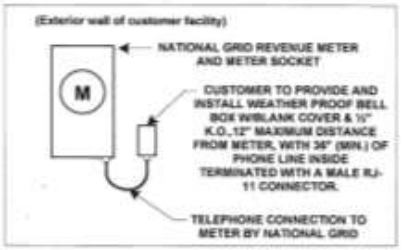

Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION

If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

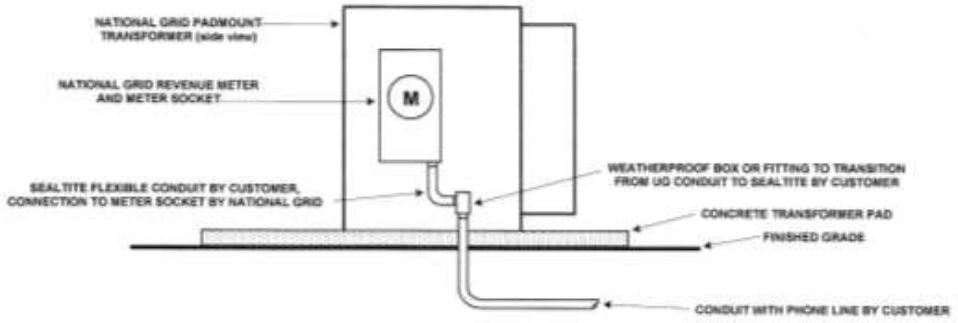

Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

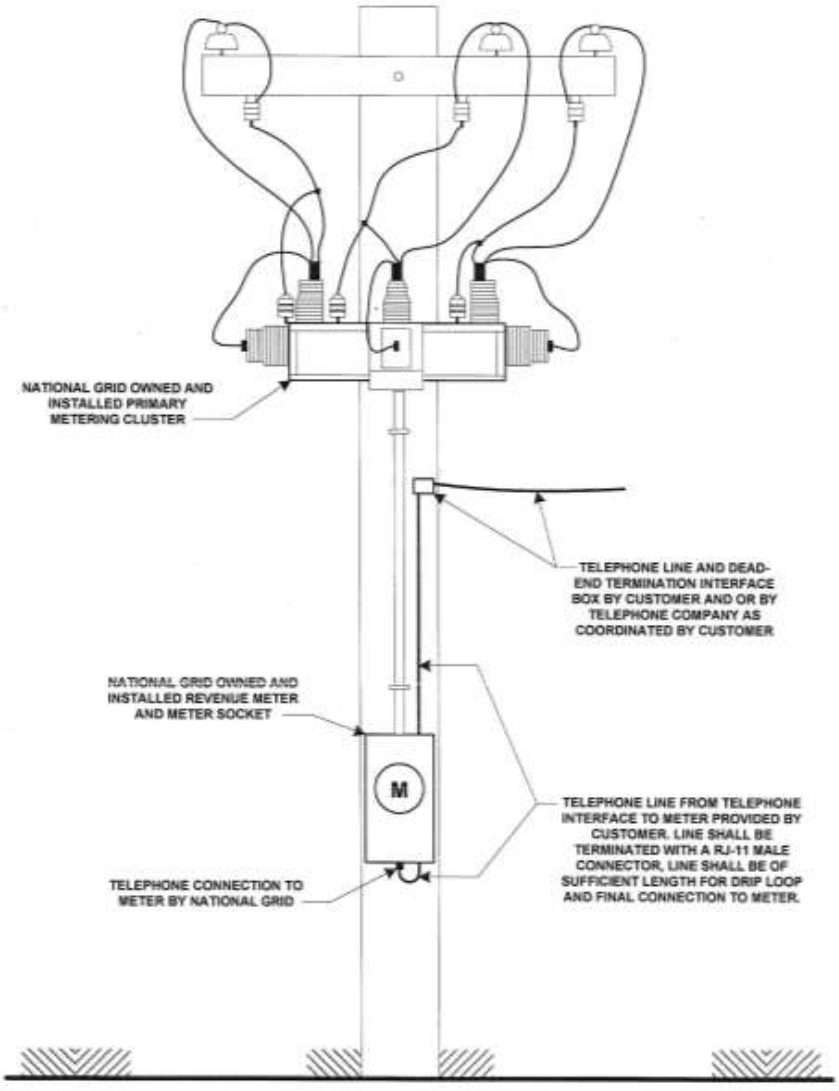

Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

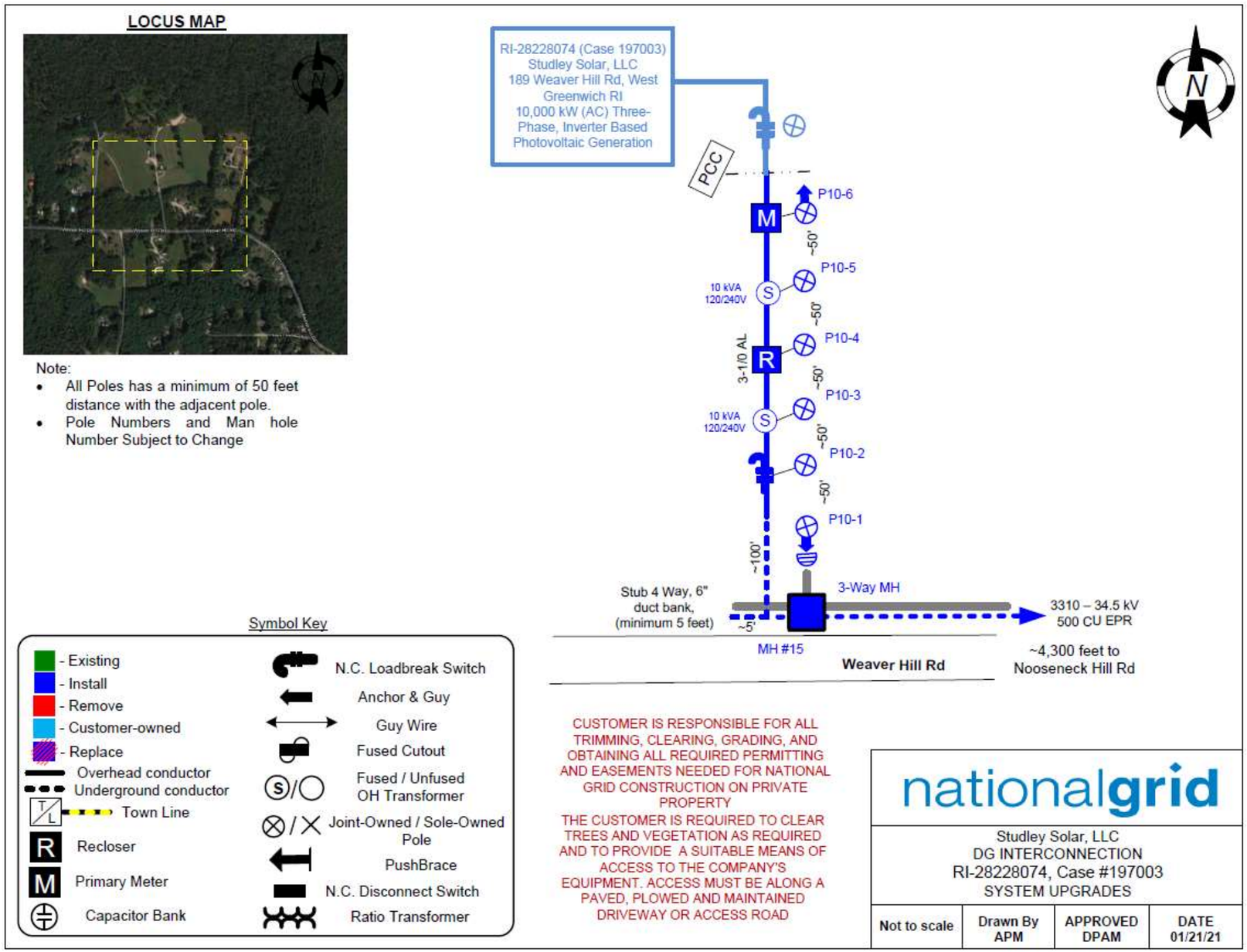

Figure B- 1: PCC Configuration

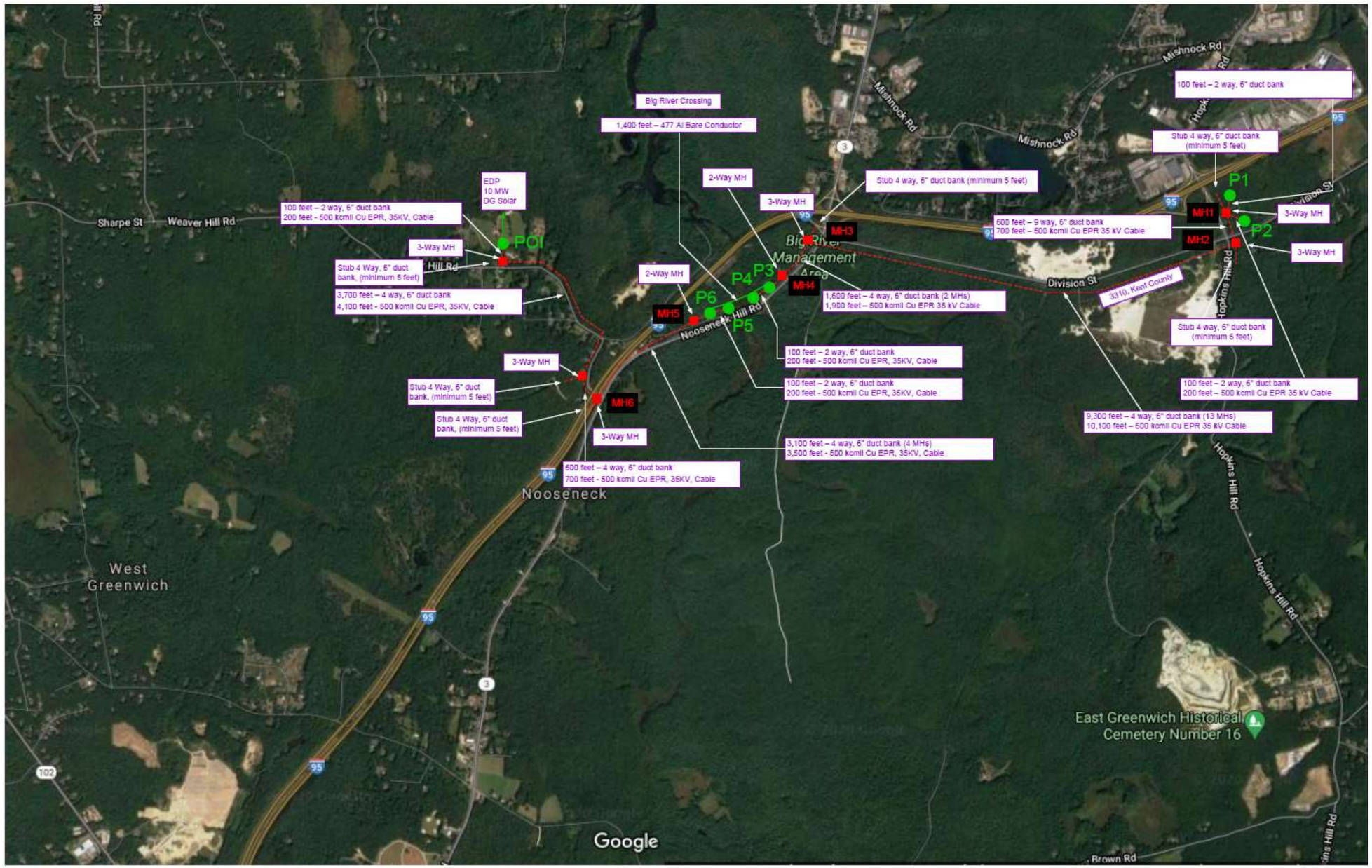

Figure B- 2: System Modification

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File: SP. RI-28228074 App File: 01-RI-28228074_Case-197003_West-Greenwich_Final_5.11.2021	Originating Department: Distribution Planning & Asset Management – NE	Sponsor: Customer Energy Integration-NE

CUSTOMER IS RESPONSIBLE FOR ALL TRIMMING, CLEARING, GRADING, AND OBTAINING ALL REQUIRED PERMITTING AND EASEMENTS NEEDED FOR NATIONAL GRID CONSTRUCTION ON PRIVATE PROPERTY
THE CUSTOMER IS REQUIRED TO CLEAR TREES AND VEGETATION AS REQUIRED AND TO PROVIDE A SUITABLE MEANS OF ACCESS TO THE COMPANY'S EQUIPMENT. ACCESS MUST BE ALONG A PAVED, PLOWED AND MAINTAINED DRIVEWAY OR ACCESS ROAD

LOCUS MAP

Symbol Key

- Existing
- Install
- Remove
- Customer-owned
- Replace
- Overhead conductor
- Underground conductor
- Town Line
- Recloser
- Primary Meter
- Capacitor Bank
- N.C. Loadbreak Switch
- Anchor & Guy
- Guy Wire
- Fused Cutout
- Fused / Unfused OH Transformer
- Joint-Owned / Sole-Owned Pole
- PushBrace
- N.C. Disconnect Switch
- Ratio Transformer

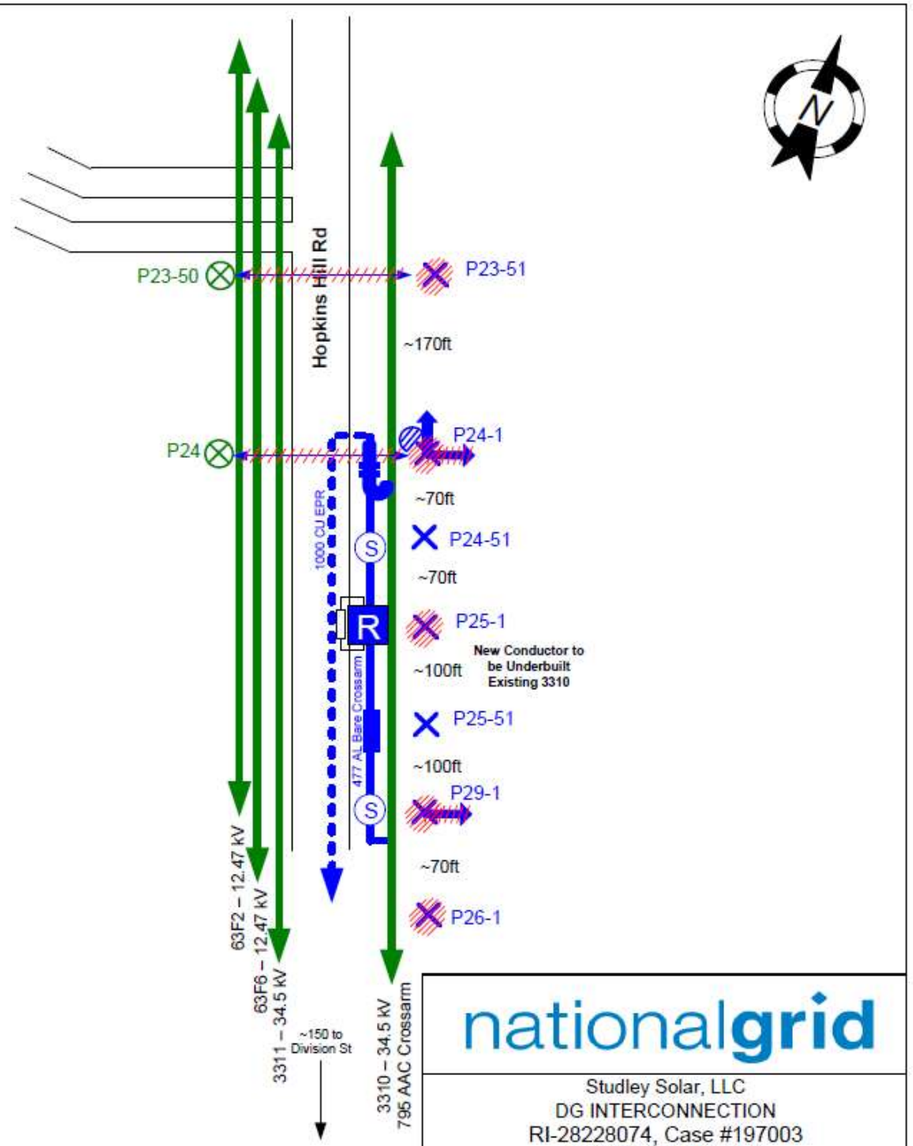


Figure B- 3: System Modification

Appendix C Customer Site and Single Line Diagram

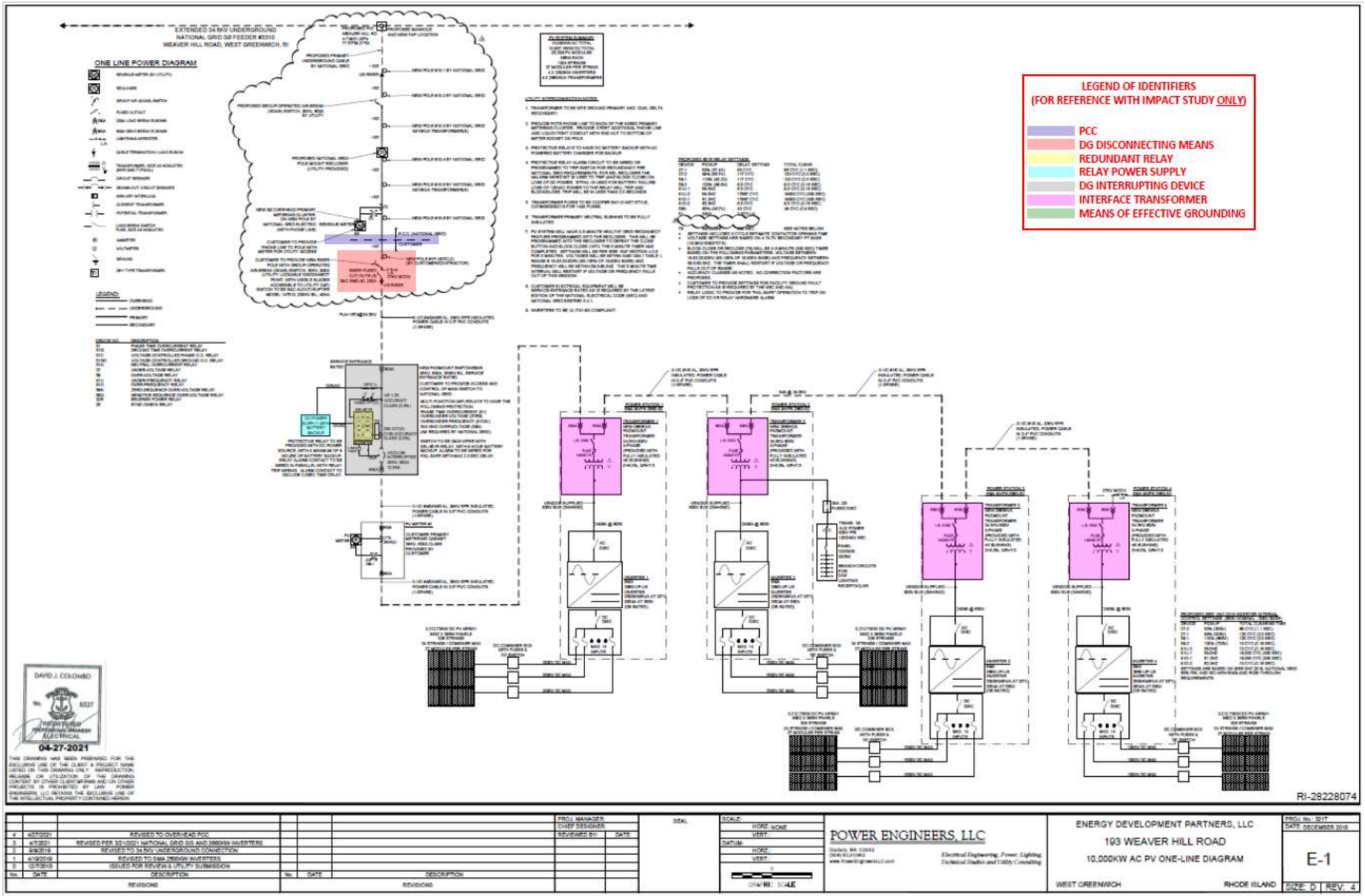


Figure C- 1: Project One-Line
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

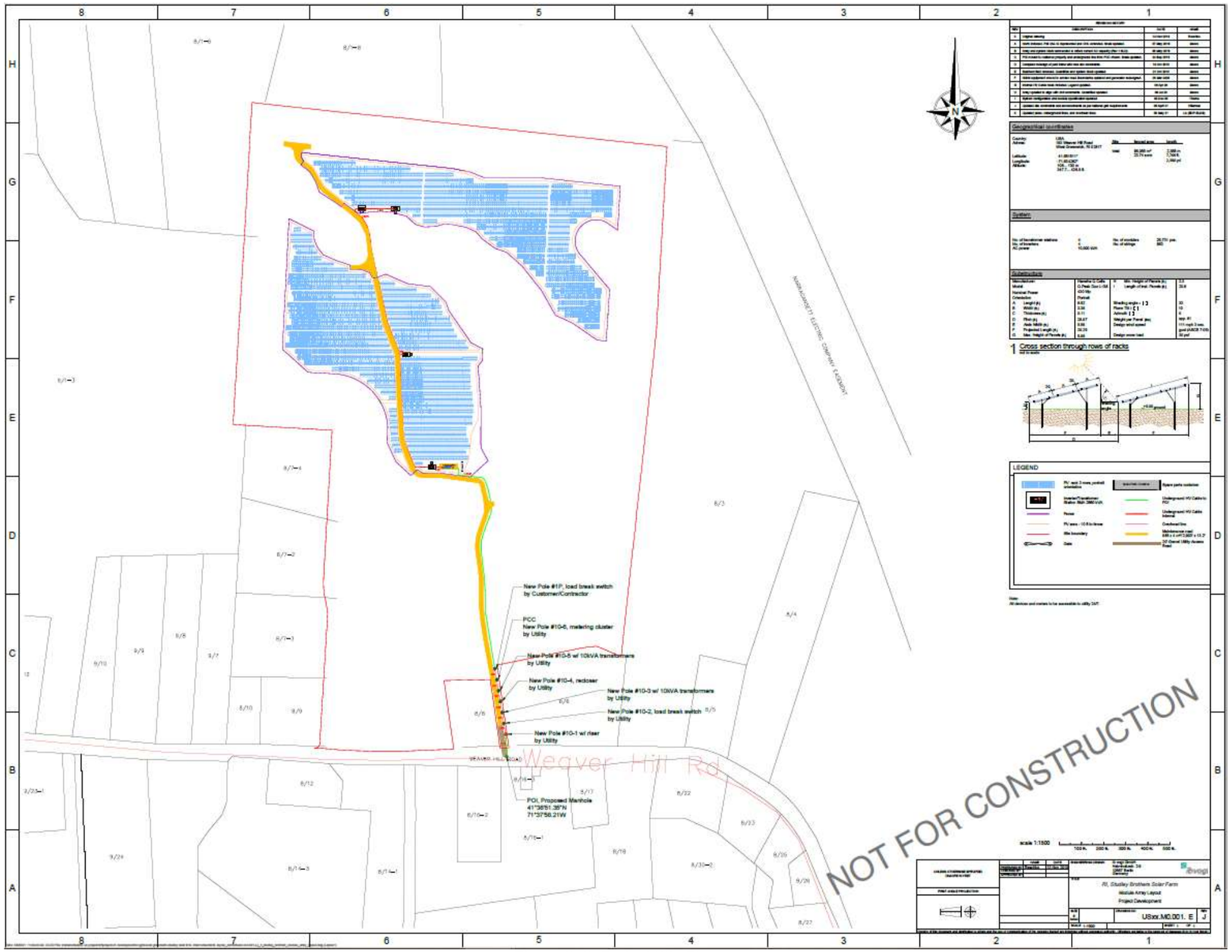


Figure C- 2: Project Site Plan

Revised System Impact Study for Distributed Generation Interconnection to National Grid's 34.5 kV System

DG WR:	RI-28228074
DG Case#:	00197003
Applicant:	Energy Development Partners
Address:	189 Weaver Hill Road
City:	West Greenwich, RI, 02817
DG kW/kVA:	10,000 kW / kVA
DG Type:	Inverter Based Photovoltaic
Feeder:	3310, Kent County Substation

Table of Contents

Section **Page**

List of Tables

Table **Page**

Definitions

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

BESS – Battery Energy Storage System

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DER – Distributed Energy Resources

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

MH - Manhole

NPCC – Northeast Power Coordinating Council

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

PF – Power Factor

P_{lt} – Long term flicker emission limit

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

P_{st} – Short Term flicker emission limit

P.U – Per Unit

PV - Photovoltaic

RTU – Remote Terminal Unit

Executive Summary

The Company has completed the System Impact Study, for the interconnection of Energy Development Partners, ("Customer") a 10,000 kW / kVA Inverter based photovoltaic, ("the Facility"), to its 34.5 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

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

System Modifications

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

1. Approximately 23,650 circuit-foot line extension from Hopkins Hill Road West Greenwich to the Facility, which includes the following distribution line work: (Section 2.2, Appendix B)
    - Install ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser Pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet of 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the 3-way MH on Weaver Hill Road.
    - Install ~100 circuit feet of 3-500 kcmil CU EPR 35 kV cable from the 3-way MH on Weaver Hill Road to the proposed riser Pole #3-25 on Weaver Hill Road.
    - Install ~1,400 circuit feet of overhead 3-477 AL bare conductor and associated equipment on Nooseneck Hill Road.
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Replace approximately 31 Poles and all existing equipment from Pole #2 to the POI Pole #31 on Weaver Hill Road.
        - Additional poles may be required to maintain adequate span lengths, and extensive tree trimming will be required in order to replace all equipment from Pole #2 to Pole #31 Weaver Hill Road.

- Install one (1) 35 kV load break switch, two (2) 25 kVA single phase transformers, one (1) 35 kV recloser, and one (1) riser from proposed Pole #3-25 to proposed Pole #3-28 on Weaver Hill Road.

- Reconductor ~2,000 circuit feet of the 63F6,12.47 kV circuit with 3-477 AL SPCR from Pole #2 to Pole #16 Weaver Hill Road.

- Install ~4,200 circuit feet of 35 kV 3-477 AL SPCR on the 3310, 34.5 kV circuit from riser Pole #3-25 on Weaver Hill Road to the POI Pole #31 for EDP 10 MW located at 189 Weaver Hill Road. Overbuild the 63F6, 12.47 kV circuit along Weaver Hill Road.

2. Approximately 23,650 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2, Appendix B):
   - Install MH and duct system (~15,000feet) from proposed riser pole on Hopkins Hill Road to 3-way MHat intersection of Nooseneck Hill Road/Weaver Hill Road.
     - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
     - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
   - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to 3-way MH on Weaver Hill Road.
   - Install MH and duct system (~100 feet) from 3-way MH on Weaver Hill Road to the proposed riser Pole #3-25 on Weaver Hill Road.
3. Add Load encroachment settings to the Kent County T7 Directional Overcurrent Relay (Section 5.4)
4. Install ~410 circuit feet of 3-477 AAC, two (2) single-phase transformers, one (1) 35 kV recloser, one (1) 35 kV disconnect switch, one (1) 35 kV loadbreak switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Rd, West Greenwich, RI. (Section 2.2 & 5.5, Appendix B)
   - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
5. Install ~350 circuit feet of 3-1/0 AL conductor, one (1) 35 kV loadbreak switch, two (2) single-phase transformers, one (1) 35 kV recloser, and one (1) 35 kV primary meter at the PCC. (Appendix B)

Customer Document Revisions

The Customer is requested to provide the following additional and/or revised documentation as required. All revised drawings shall be stamped and signed by an Electrical Professional Engineer licensed in the

same state as the Project location. The following list is intended as a convenient summary of documents for re-submission, however the Customer is required to comply with all items listed and discussed in this document. Omission of an item from the following summary list that is referenced elsewhere in this document does not release the Customer from providing the necessary documents:

1. Customers One-Line to be revised showing an overhead interconnection from the Companies proposed overhead extension. See Appendix B-1 for more details on the POI-PCC interconnection details.
2. Customer to show nearest GRID pole to PCC. i.e. Pole #31 Weaver Hill Rd on both one-line and site-plan.

Special Operating Requirements

The Customer is required to comply with the following special operating requirements in order to interconnect to the Company EPS:

1. The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS. (Section 3.4)

1.0 Introduction

The Customer has requested a revised interconnection of their 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

The Customer proposes to install the following:

- Four (4) Customer owned SMA 2660-UP-US, 2,667 kW / kVA derated to 2,500 kW / kVA, three phase inverters for a total of 10,000 kW / kVA of inverter-based PV.
- Four (4) Customer owned 2,660 kVA, 34.5 kV delta primary, 600 V wye-ungrounded secondary padmounted interface transformer with an impedance of Z =6% along with X/R ratio of 7.5.
- One (1) Customer owned padmounted switchgear 35kV, 600A, 200 kV BIL G&W Viper recloser with SEL-651R relay assembly with 8-hour battery backup.
- One (1) Customer owned GOAB switch, S&C Model #147513, 200 kV BIL, 40kA with a Visible, lockable blades and utility accessible 24/7.

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 04/27/2021).

Any advanced inverter functionality other than that specifically called out on the Customer documentation and/or outlined herein shall be subject to additional study before being enabled.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is 3310, a 34.5 kV unregulated, three-phase, 3 wire, wye, ungrounded, radial, sub-transmission circuit that originates out of the Company's Kent County Substation, in West Greenwich, RI (the "Interconnecting Circuit"). This circuit is located overhead on Division Street, approximately 3.92 miles from the proposed Facility. This Line Extension will include the following work:

1. Approximately 23,650 circuit-foot line extension from Hopkins Hill Road, West Greenwich to the Facility, which includes the following distribution line work: (Section 2.2, Appendix B)
    - Install ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser Pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet of 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the 3-way MH on Weaver Hill Road.
    - Install ~100 circuit feet of 3-500 kcmil CU EPR 35 kV cable from the 3-way MHon Weaver Hill Road to the proposed riser Pole #3-25 on Weaver Hill Road.
    - Install ~1,400 circuit feet of overhead 3-477 AL bare conductor and associated equipment on Nooseneck Hill Road.
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Replace approximately 31 Poles and all existing equipment from Pole #2 to the POI Pole #31 on Weaver Hill Road.

- Additional poles may be required to maintain adequate span lengths, and extensive tree trimming will be required in order to replace all equipment from Pole #2 to Pole #31 Weaver Hill Road.

- Install one (1) 35 kV loadbreak switch, two (2) 25 kVA single-phase transformers, one (1) 35 kV recloser, and one (1) riser from proposed Pole #3-25 to proposed Pole #3-28 on Weaver Hill Road.

- Reconductor ~2,000 circuit feet of the 63F6, 12.47 kV circuit with 3-477 AL SPCR from Pole #2 to Pole #16 Weaver Hill Road.

- Install ~4,200 circuit feet of 35 kV 3-477 AL SPCR on the 3310 circuit from riser Pole #3-25 on Weaver Hill Road to the POI Pole #31 for EDP 10 MW located at 189 Weaver Hill Road. Overbuild the 63F6, 12.47 kV circuit along Weaver Hill Road.

2. Approximately 23,650 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2, Appendix B):
   - Install MH and duct system (~15,000feet) from proposed riser pole on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road.
     - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
     - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
   - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to 3-way MH on Weaver Hill Road.
   - Install MH and duct system (~100 feet) from 3-way MH on Weaver Hill Road to the proposed riser Pole #3-25 on Weaver Hill Road.
3. Install ~410 ft of 3-477 Al bare conductor, two (2) single-phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV loadbreak switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, West Greenwich,
   - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

     An underground line extension originating from the overhead line on Hopkins Hill Rd will be required to reach the proposed Facilities. There is one river that will need to be crossed with overhead conductors alongside the bridge. The Big River Bridge was not constructed to allow for installation of concrete encased ducts.

     Civil work from the proposed riser pole on Hopkins Hill Road to the 3-way Manhole at the intersection of Nooseneck Hill Road and Weaver Hill Road to be performed by

others. National Grid to perform civil work from the 3-way Manhole at the intersection of Nooseneck Hill Road and Weaver Hill Road, to the proposed riser pole on Weaver Hill Road.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting, circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL (kW)*
3309	165	0	0	*165*
3310	434	24,248	10,000	*34,682*
3311	30,284	23,795	0	*54,079*
3312	2,735	4,049	0	*6,784*
TOTAL	*33,618*	*52,092*	*10,000*	**95,710**

Table 1: Generation at the Substation and Interconnecting Circuit

- There is one (1) existing recloser on the circuit, none of which are in between the substation and the facility, summarized in Table 2. Refer to Section 5 for further discussion on any required modifications.

Location	Status	Mid-line recloser, or existing DG project PCC recloser	In between Facility and Substation
Pole #18-1, Hopkins Hill Road, West Greenwich	In Service	Mid-line	No

Table 2: Recloser Locations

- There are no existing capacitor banks installed on this circuit.
- There are no existing regulators installed on this 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 Pole #31-6, 189 Weaver Hill Road, West Greenwich, RI. The Customer must install their facilities up to the Company revenue meter. The Customer must provide sufficient conductor to allow the Company to make final connections at the meter pole. The Company will provide final connection of the Customer conductors to the Company meter.

If 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 Geographical Information System ("GIS"). A field review of the feeder was performed on 11/16/2021.

The analysis considered cases at peak load (16,284 kVA @ 100% PF) and net minimum load (6,030 kVA @ 93.71% Lagging PF) at time of maximum expected generation (9:00AM – 6:00PM) on the circuit.

Circuit peak and minimum load values have been taken from the Company's historical load data that has been compiled over 12 months, from 1/1/2020 to 1/1/2021.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Analysis shows that the maximum potential generation exceeds the observed minimum load on the Kent County 34.5 kV bus. However, the substation is currently equipped with bi-directional metering which was previously installed for reasons unrelated to DG work. No additional work is required on the substation bulk power metering.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in steady state voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output, the voltage range at the PCC was within acceptable limits.

Customer provided manufacturer's test reports have been reviewed for 1.4PU pickup values with 1ms or less total clearing time. The proposed design has been found to meet the necessary requirements.

3.4 Flicker Analysis

The IEEE 1547 standard and IEEE 1453 flicker assessments were used to estimate whether or not this site would be likely to cause unacceptable voltage flicker on the interconnecting feeder. This method evaluates for both short term and long-term voltage flicker against IEEE1547-2018 Table 25 - DER Flicker Emission Limits.

Analysis shows that P_{st} and P_{lt} are within acceptable limits and no mitigation for voltage flicker is recommended.

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2015 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long-Term Dynamics module of CYME[1]. A long-term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6-hour period. Other significant DG existing or in process ahead of this Project were modeled at full output and modeled with the appropriate voltage fluctuation curve to simulate reasonable voltage fluctuations.

The generation profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate realistic power output from the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict voltage flicker under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether or not there is a readily apparent concern related to voltage flicker.

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

Analysis shows that the predicted flicker and voltage fluctuations are expected to be acceptable, provided that the following conditions are met:

- The system modifications identified elsewhere in this study are implemented.
- The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS.

[1] CYME Power Engineering Software, Version 8.1, Revision 01, Build 115, Copyright © 1986-2017, Cooper Industries, Ltd.

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 100kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
442	All Projects <100kW CERTIFIED
0	All Projects <100kW Non-CERTIFIED
740	CERTIFIED
3,500	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered a likely event. As a result, a PCC recloser with reclose blocking will be required. Additionally, live-line reclose blocking must be implemented at the following line reclosers summarized in Table 4.

Location	Status (Existing or New)
Pole #3-27, Weaver Hill Road, West Greenwich, RI	New

Table 4: Recloser Locations

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C 2180 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation.

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

Addition of generation sources to sub-transmission feeders can result in the back-feeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. Due to the Kent County T1, T2 and T7 supply transformer configurations, there is a path for zero sequence ground fault current to single line to ground faults on the transmission line. Therefore, the Facility does not pose a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Substation modifications related to $3V_0$ are not required**.**

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account existing system conditions, but not the impact of the Customer's new Facility.

Pre-Project

System Impedance at PCC

Z1 = 0.05 + j0.26 p.u.

Z0 = 0.66 + j1.51 p.u.

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

5.3 Fault Current Contributions

Table 5 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings. Mitigation strategies are required to accommodate the proposed Facility, as described in Sections 5.4 and 5.5.

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

PRE PROJECT	Sub Bus (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)
3-phase (LLL)	22,190	3,967
Phase-Ground (LG)	24,853	2,262

POST PROJECT	Sub Bus (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)	DELTA I_{fault} @ SUB BUS 34.5 kV BUS	DELTA I_{fault} @ PCC
3-phase (LLL)	22,397	4,180	0.93%	5.37%
Phase-Ground (LG)	25,124	2,397	1.09%	5.97%

Table 5: Fault Duty

5.4 Substation Protective Device Modifications

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study:

- Add load encroachment settings to the Kent County Transformer #7, 34.5 kV directional overcurrent relay (67)

5.5 Area EPS Protective Device Coordination

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

The existing device settings and associated time-current curves were evaluated for protective devices on the Interconnecting Circuit.

The protection coordination review of the area EPS revealed that the following modifications to the existing EPS protective devices will be required. Associated costs

are identified in Section 9.0 of this Impact Study. Refer to Appendix B for system modification drawings:

- Install a recloser at the tap for the proposed line extension to the facility at Pole #3-27, Weaver Hill Road, West Greenwich, RI. (Appendix B-3)

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the 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.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states the interconnecting transformer is four (4) Customer owned 2,660 kVA, 34.5 kV delta primary, 600 V wye-ungrounded secondary padmounted interface transformer with an impedance of Z =6% along with X/R ratio of 7.5.

The proposed transformer satisfies the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Facility is proposing to connect to a non-effectively grounded 34.5 kV circuit, and therefore does not require a means of effective grounding.

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

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

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

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

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable inverter relay settings in accordance with the aforementioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8. This requirement is met.

6.6 Secondary Protection

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

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a circuit breaker for site protection.

The Customer provided documents indicate an interrupting device on the high side (Customer 34.5 kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

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

The Customer provided documents show a phase overcurrent (51) relay element and associated settings.

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

51 – Phase

Customer Proposed: 300A primary amps pickup, 2 second time delay, U4 curve.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relays make/model is included on the Customer single line.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D. The Customer provided documents show neutral overvoltage (59N) that are unacceptable.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756C Section 7.6.11 and 7.8. This requirement is met.

The Customer provided one-line diagram shows acceptable settings for neutral overvoltage 59N protection.

59N – Neutral Overvoltage

Customer Proposed: $3V_0$ = 12.45 kV primary pickup (46.7 V), 0.8 second time delay.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.6 Current Transformers ("CT") (ESB 756D Section 7.6.4.1)

The Customer provided documents show current transformer with ratings listed, which satisfies this Section of ESB 756D.

6.6.7 Voltage Transformers ("VT") and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show wye-grounded/wye-grounded VT's and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer provided documents indicate a power supply for the redundant relay that satisfies the requirements of this section of ESB 756D.

The Customer has proposed a DC power supply. The Customer shall demonstrate in the witness test that the relay will trip if the DC voltage goes out of the normal operating range.

It is recommended that the power DC power supply be connected to the utility (source) side of the interrupting device in order to ensure power availability to close the interrupting device after an extended outage. This is a recommendation, for consideration by the Customer. It is not a requirement by the Company.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7 & 756C Section 7.8.3)

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting a minimum 5 minutes of healthy utility voltage and frequency. "Healthy Utility Voltage and Frequency" is defined by ESB 756D Table 7.8.3-1. The five-minute time

interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five-minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer provided settings and timing device information is acceptable as shown.

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer's one line diagram shows devices and settings to satisfy this requirement.

6.7 Customer Cabling

The Company is not responsible for the protection of the Customer cable and primary protection for the Customer cable must be provided at the change of ownership.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

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

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment.
- Inverter manufacturer cut sheet including method of island detection and UL certification.
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project.
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study.
- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme.
- The proposed testing procedure
- The proposed energization plan.
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft MA state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above identified time frames due to errors in the relay

settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, will be provided in the final version of this document.

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the final ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the final ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C. No. 2180, Section 3.4 Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	05/11/2021	Underground Extension
2.0	01/31/2022	Overhead Extension

nationalgrid	**DISTRIBUTION PLANNING DOCUMENT** **Interconnection Study**	Doc. RI-28228074 Case #00197003
		Page 27 of 37
	Complex Generating Facility - R.I.P.U.C. 2180	Version 2.0 1/31/2022
	Energy Development Partners **10,000 kW / kVA rating, Inverter Based Photovoltaic** **189 Weaver Hill Road, West Greenwich, RI, 02817**	**DRAFT**

Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION
If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

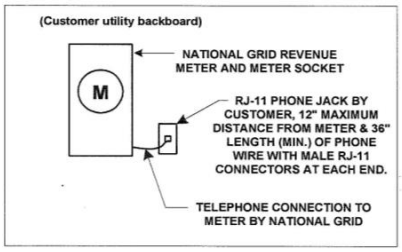


Figure 1A – Indoor Meter Installation
not to scale

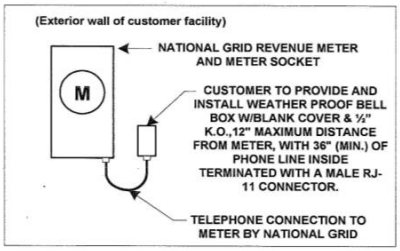


Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION
If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

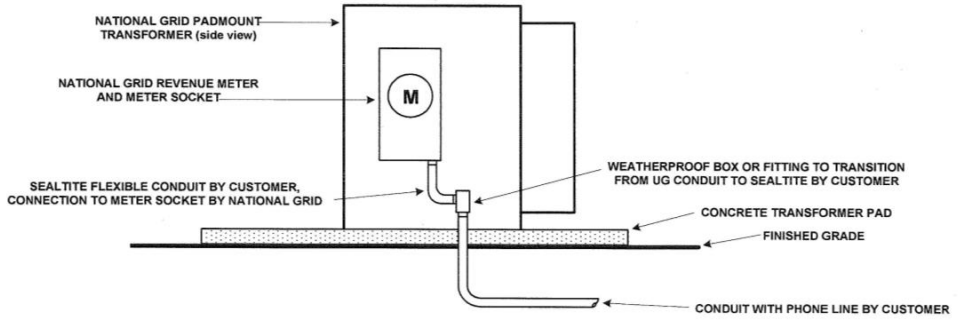


Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

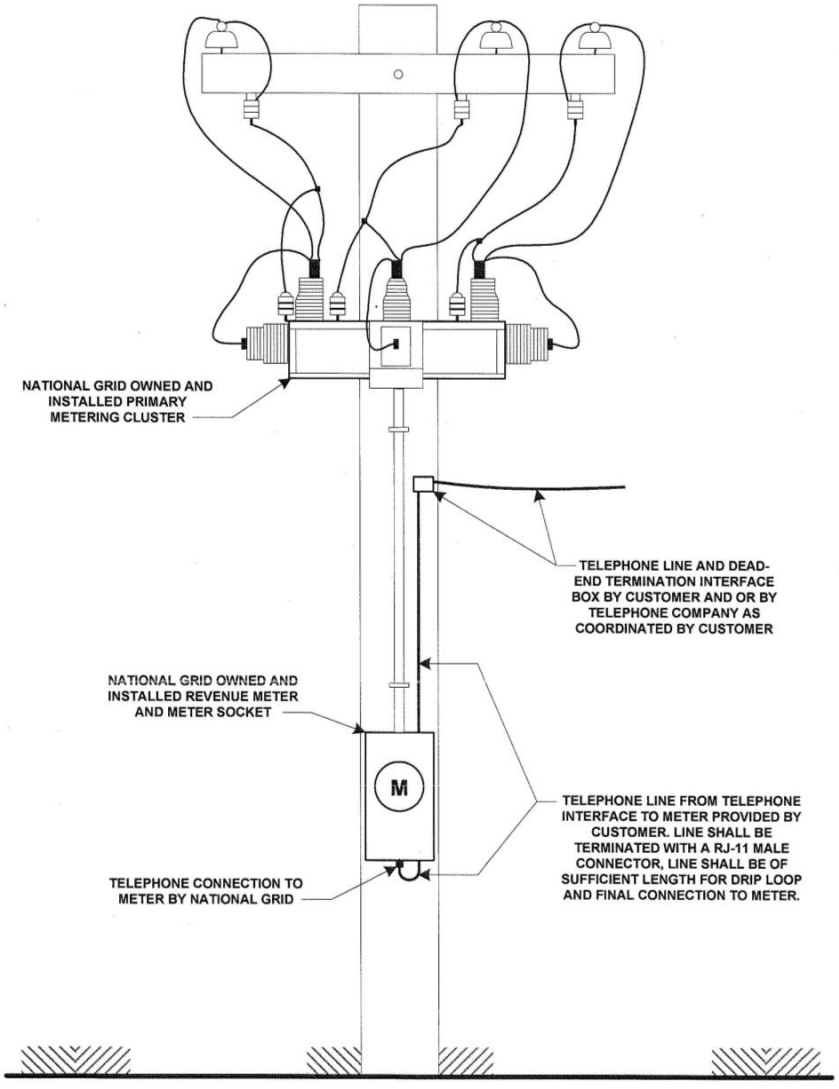


Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

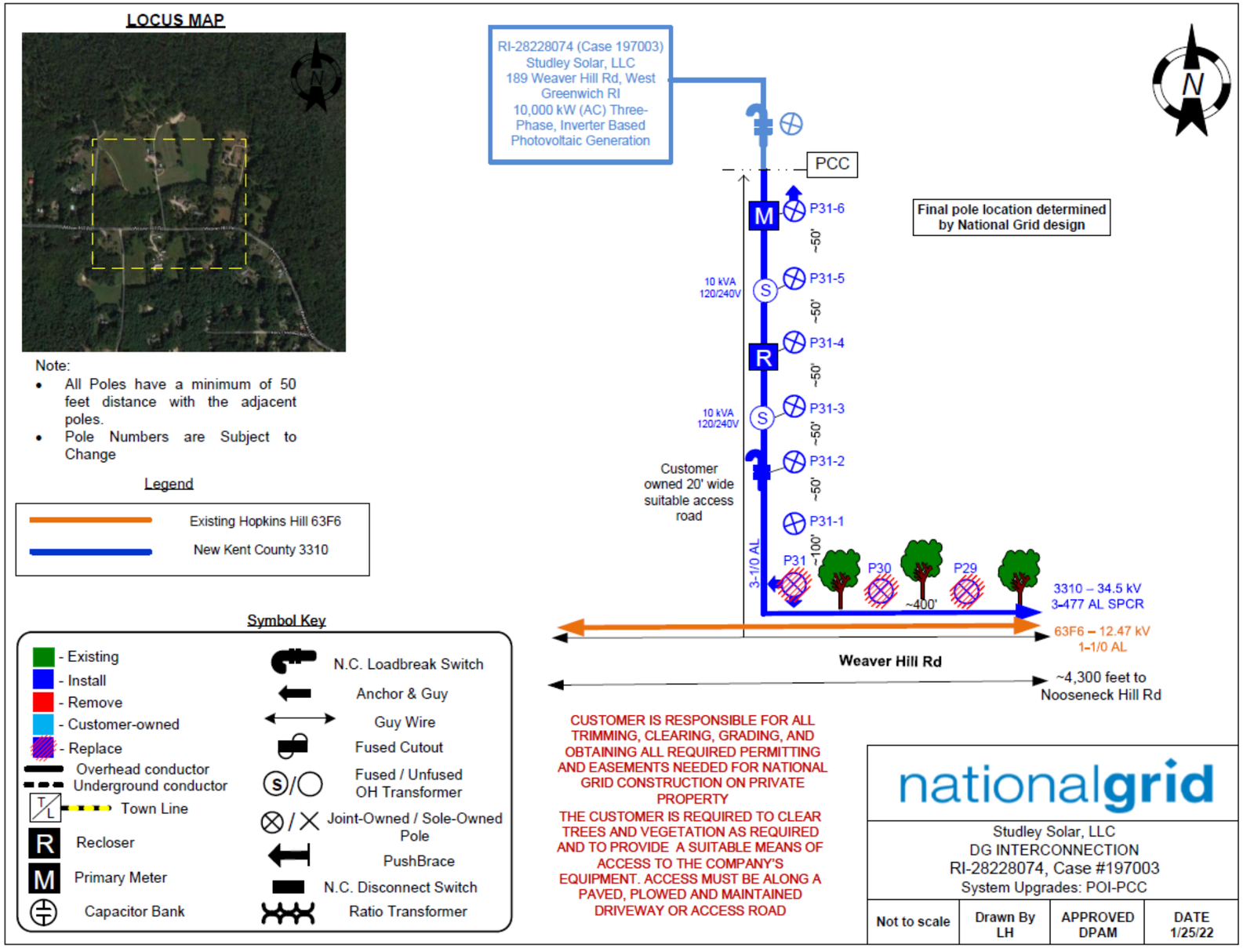


Figure B- 1: PCC Configuration

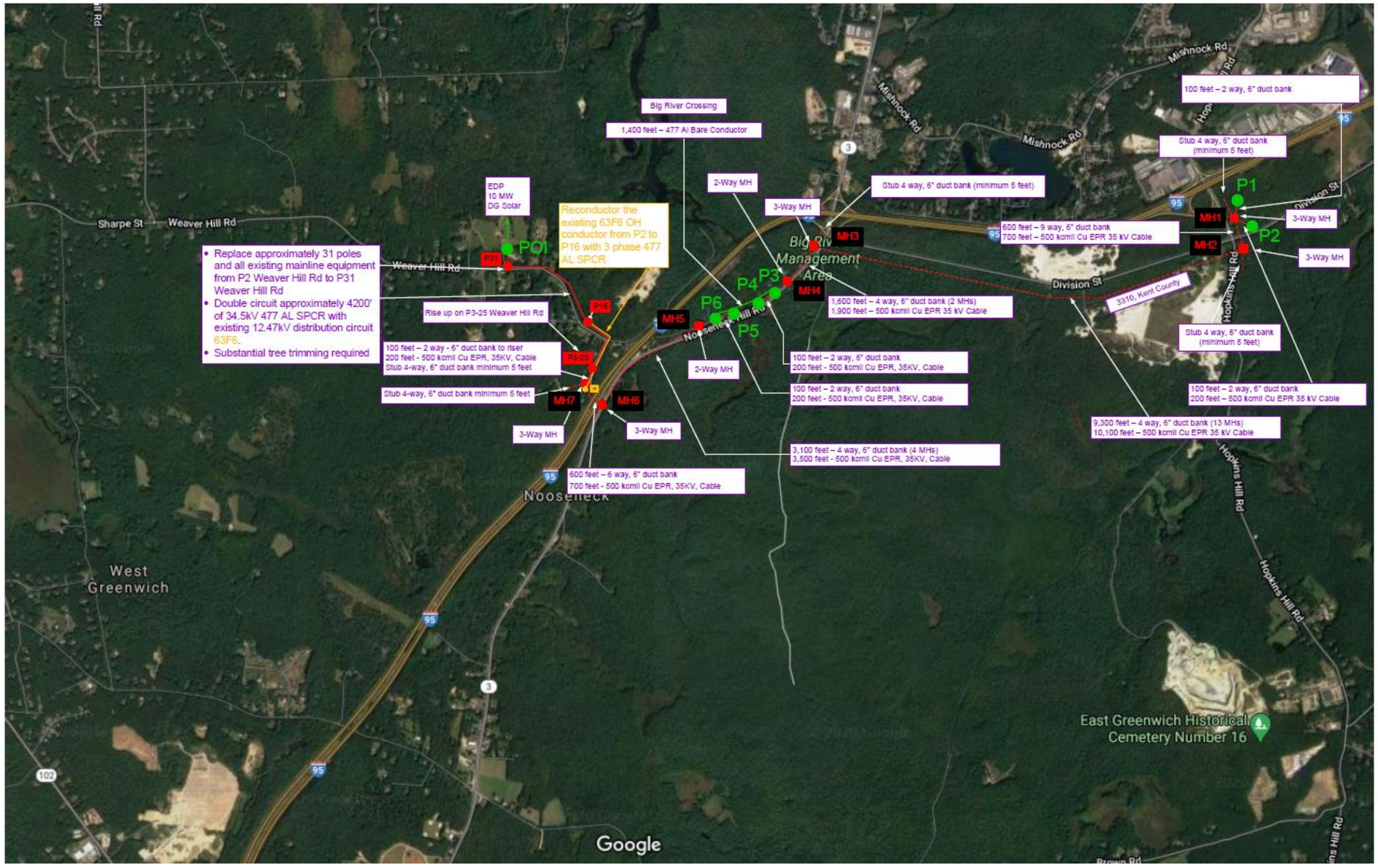


Figure B- 2: System Modification

LOCUS MAP

NOTE:
Not all existing equipment is shown in this drawing. ALL existing equipment associated with the reconductor must be replaced. This includes but is not limited to existing:

- Poles, transformer(s), mid-line equipment, and associated guying

Legend

- New Hopkins Hill 63F6
- New Kent County 3310
- New Kent County 3310 Being Constructed for another DG application

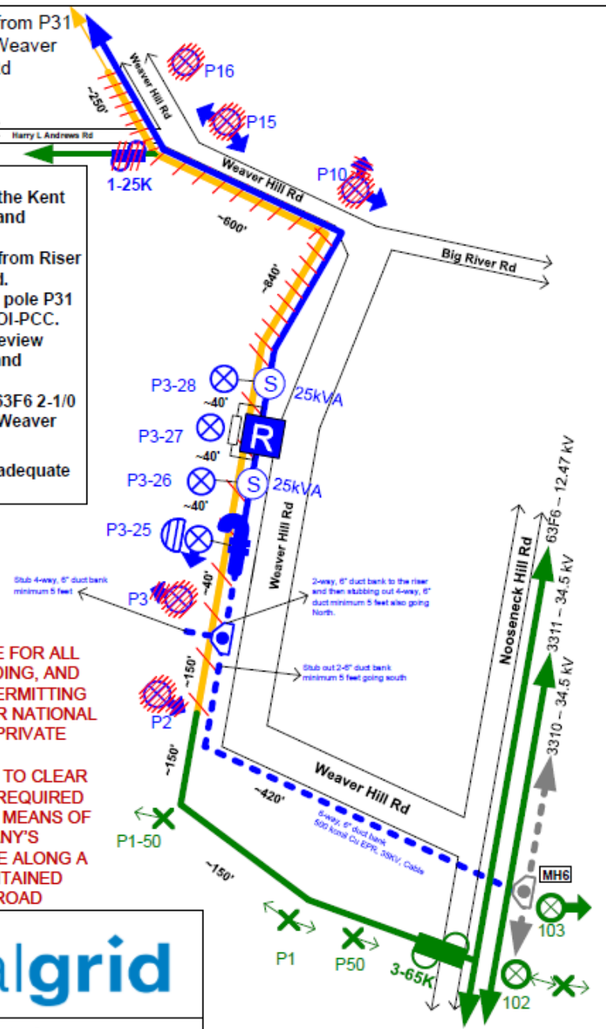
Symbol Key

- Existing
- Install
- Remove
- Customer-owned
- Replace
- Replace
- Overhead conductor
- Underground conductor
- Town Line
- Recloser
- Primary Meter
- Capacitor Bank
- N.C. Loadbreak Switch
- Anchor & Guy
- Guy Wire
- Fused Cutout
- Fused / Unfused OH Transformer
- Joint-Owned / Sole-Owned Pole
- PushBrace
- N.C. Disconnect Switch
- Ratio Transformer

Construction Notes:

- Install new underground circuit extension for the Kent County 3310 circuit with associated manhole and underground design.
- Install approximately 4200' of 3-477 AL SPCR from Riser Pole 3-25 to PCC Pole P31-6 on Weaver Hill Rd.
- Replace all existing equipment from P3 to POI pole P31 Weaver Hill Rd shown in System Upgrades: POI-PCC.
- Extensive tree trimming required. Upon field review results, NGRID will assess all areas required and associated costs.
- Reconductor approximately 2000' of existing 63F6 2-1/0 AAAC XRM to 3-477 AL SPCR from P2 to P16 Weaver Hill Rd.
- Additional poles may be required to maintain adequate span lengths

CUSTOMER IS RESPONSIBLE FOR ALL TRIMMING, CLEARING, GRADING, AND OBTAINING ALL REQUIRED PERMITTING AND EASEMENTS NEEDED FOR NATIONAL GRID CONSTRUCTION ON PRIVATE PROPERTY
THE CUSTOMER IS REQUIRED TO CLEAR TREES AND VEGETATION AS REQUIRED AND TO PROVIDE A SUITABLE MEANS OF ACCESS TO THE COMPANY'S EQUIPMENT. ACCESS MUST BE ALONG A PAVED, PLOWED AND MAINTAINED DRIVEWAY OR ACCESS ROAD



nationalgrid

Studley Solar, LLC
DG INTERCONNECTION
RI-28228074, Case #197003
System Upgrades: Reconductor + Recloser

Not to scale	Drawn By LH	APPROVED DPAM	DATE 12/02/21

Figure B- 3: System Modification

CUSTOMER IS RESPONSIBLE FOR ALL TRIMMING, CLEARING, GRADING, AND OBTAINING ALL REQUIRED PERMITTING AND EASEMENTS NEEDED FOR NATIONAL GRID CONSTRUCTION ON PRIVATE PROPERTY
THE CUSTOMER IS REQUIRED TO CLEAR TREES AND VEGETATION AS REQUIRED AND TO PROVIDE A SUITABLE MEANS OF ACCESS TO THE COMPANY'S EQUIPMENT. ACCESS MUST BE ALONG A PAVED, PLOWED AND MAINTAINED DRIVEWAY OR ACCESS ROAD

LOCUS MAP

Symbol Key

- Existing
- Install
- Remove
- Customer-owned
- Replace
- Overhead conductor
- Underground conductor
- Town Line
- Recloser
- Primary Meter
- Capacitor Bank
- N.C. Loadbreak Switch
- Anchor & Guy
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- Fused / Unfused OH Transformer
- Joint-Owned / Sole-Owned Pole
- PushBrace
- N.C. Disconnect Switch
- Ratio Transformer

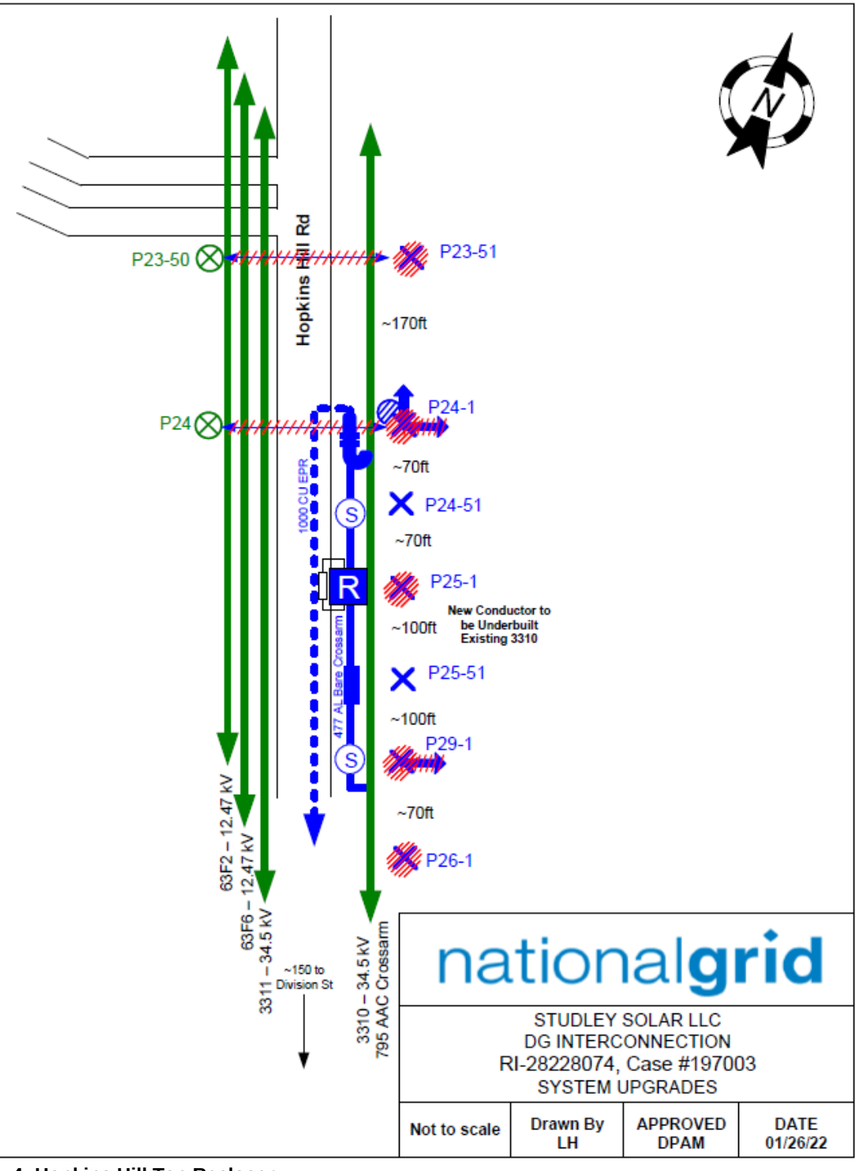


Figure B- 4: Hopkins Hill Tap Recloser

Appendix C Customer Site and Single Line Diagram

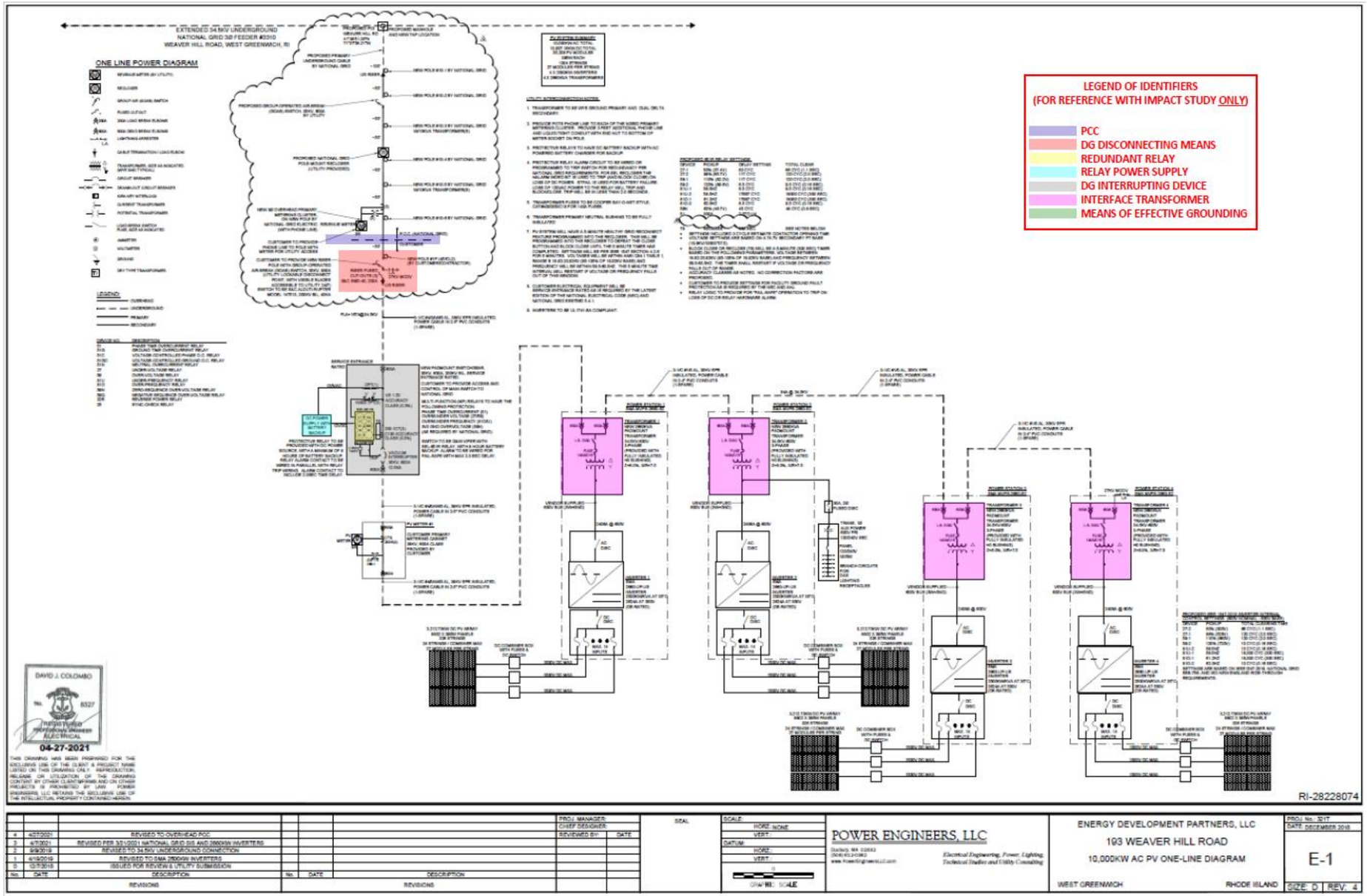


Figure C- 1: Project One-Line
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

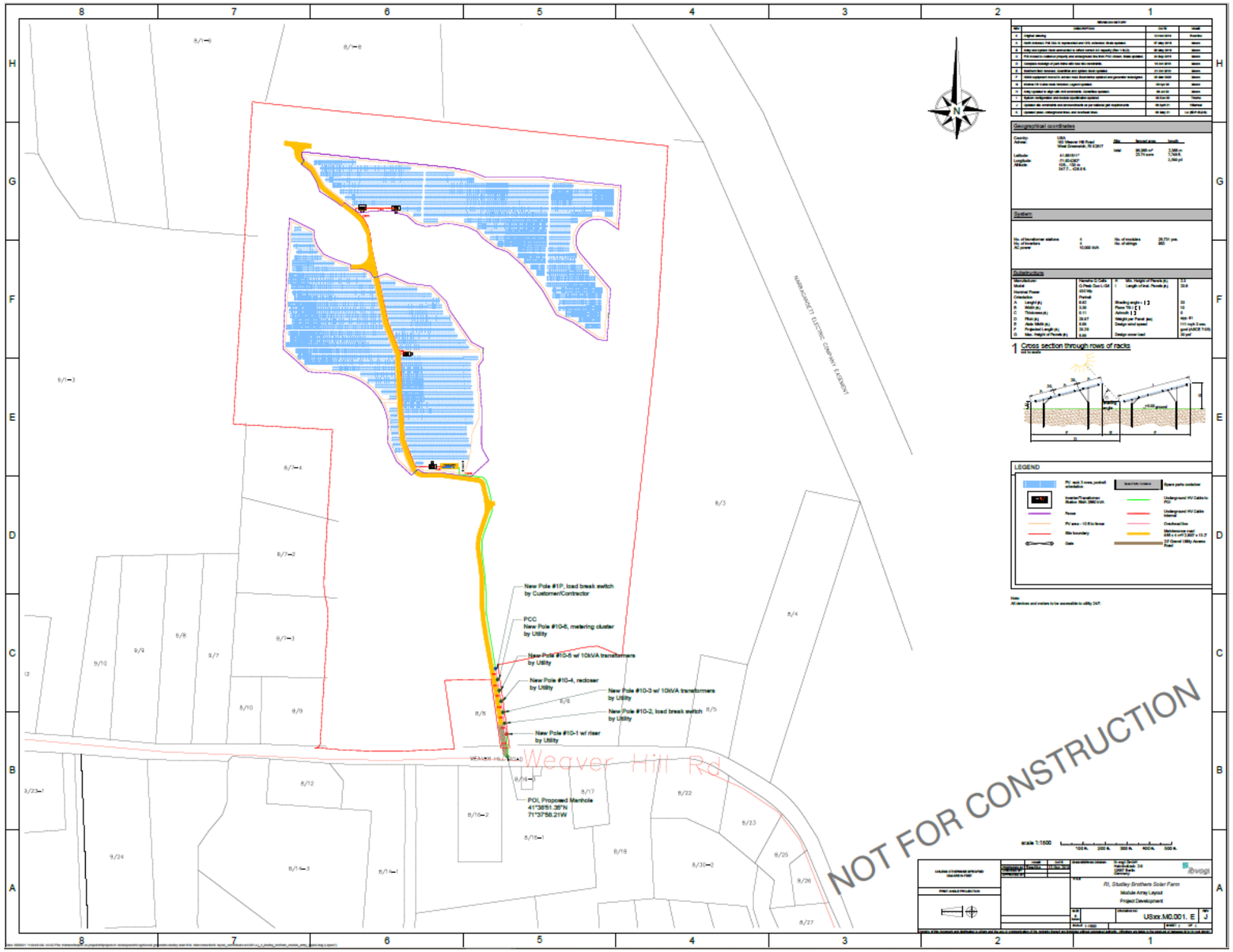


Figure C- 2: Project Site Plan

PRINTED OR DOWNLOADED COPIES ARE NOT DOCUMENT CONTROLLED.		
File: SP. RI-28228074 App File: 02-RI-28228074_Case-197003_West-Greenwich_50BDDRAFT_1.31.2022.docx	Originating Department: Distribution Planning & Asset Management – NE	Sponsor: Customer Energy Integration-NE

Rhode Island Energy™ a PPL company	**DISTRIBUTION PLANNING DOCUMENT** **Interconnection Study**	Doc. RI-28228074 Case #00197003
		Page 1 of 39
	Complex Generating Facility - R.I.P.U.C. 2180	Version 3.0 9/20/2022
	Energy Development Partners **9,200 kW / kVA rating, Inverter Based Photovoltaic** **189 Weaver Hill Road, West Greenwich, RI**	**FINAL**

Revised System Impact Study for Distributed Generation Interconnection to Rhode Island Energy's 34.5 kV System

DG WR:	RI-28228074
DG Case#:	00197003
Applicant:	Energy Development Partners
Address:	189 Weaver Hill Road
City:	West Greenwich, RI
DG kW/kVA:	9,200 kW / kVA
DG Type:	Inverter Based Photovoltaic
Feeder:	3310, Kent County Substation

Rhode Island Energy™ a PPL company	**DISTRIBUTION PLANNING DOCUMENT** **Interconnection Study**	Doc. RI-28228074 Case #00197003 Page 2 of 39
	Complex Generating Facility - R.I.P.U.C. 2180	Version 3.0 9/20/2022
	Energy Development Partners **9,200 kW / kVA rating, Inverter Based Photovoltaic** **189 Weaver Hill Road, West Greenwich, RI**	**FINAL**

Table of Contents

Section **Page**

List of Tables

Table **Page**

Definitions

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

BESS – Battery Energy Storage System

Company – Rhode Island Energy

Customer – The interconnecting customer of this project

DG – Distributed Generation

DER – Distributed Energy Resources

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESB – Rhode Island Energy's Electrical Service Bulletin

Facility – The distributed generating facility for this project, including all related appurtenances and equipment.

IA – Interconnection Application

Interconnecting Circuit – Circuit to which the Facility will connect.

ISA – Interconnection Service Agreement

ISO-NE – Independent System Operator of New England

MH - Manhole

NPCC – Northeast Power Coordinating Council

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

PF – Power Factor

P_{lt} – Long term flicker emission limit

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

P_{st} – Short Term flicker emission limit

P.U – Per Unit

PV - Photovoltaic

RTU – Remote Terminal Unit

Executive Summary

The Company has completed the Revised Impact Study, for the interconnection of Energy Development Partners, ("Customer") a 9,200 kW / kVA Inverter based photovoltaic, ("the Facility"), to its 34.5 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

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

System Modifications

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

1. Distribution line work (Section 2.2, Appendix B):
    - Install ~16,100 feet of 3-1/c 1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
        - Prior analysis has shown that this project requires the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable in this section. The costs provided in this study are for the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable. Another Customer has paid for the installation of 3-1/c 1000 kcmil Cu EPR 35 kV cable.
    - Install ~700 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road to the first 3-way MH on Weaver Hill Road.
    - Install ~4100 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
    - Install ~200 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
    - Install ~1,400 feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

2. Distribution Civil Work (Section 2.2, Appendix B):
    - Install MH and duct system (~14,300 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
        - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
    - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road.
        - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.
    - Install MH and duct system (~3700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road (to be self-built by Customer).
    - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property (to be self-built by Customer).
3. Add Load encroachment settings to the Kent county T7 Directional Overcurrent Relay (Section 5.4)
4. Install ~410 circuit feet of 3-477 AL Bare Conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) 35 kV disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry, RI. (Section 2.2 & 5.5, Appendix B)
    - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
5. Install ~250 feet of 3-477 AL Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers and one (1) primary meter at the PCC. (Appendix B)

Cost Estimate

Refer to the Cost Estimate table in Section 9.0 for a listing of major modifications and associated costs. The total estimated planning grade cost of the work associated with the interconnection of the Facility, is $24,545,166 +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the final Interconnection Service Agreement.

Special Operating Requirements

The Customer is required to comply with the following special operating requirements in order to interconnect to the Company EPS:

1. The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS. (Section 3.4)

1.0 Introduction

The Customer has requested interconnection of a Facility to the Company's existing infrastructure.

The analysis utilized Customer provided documentation to examine the effects on the Company system when the new Facility is connected. The results identify required modifications to the Customer one line diagram(s) and Company infrastructure in order to accommodate the interconnection. As such, the interconnection of the Facility has been evaluated under specific conditions. Should the Customer make any changes to the design, other than those identified in this study, it may require additional time for review, and possibly additional cost.

In accordance with the R.I.P.U.C. 2180 tariff and the Company's ESB series, the Company has completed an Impact Study to determine the scope of the required modifications to its EPS and/or the Facility for providing the requested interconnection service.

Analysis will be performed in accordance with applicable reliability standards and study practices, and in compliance with the applicable codes, standards, and guidelines listed in the Company's *Electric System Bulletin No. 756 Appendix D: Distributed Generation Connected to Rhode Island Energy Distribution Facilities Per The Rhode Island Standards for Interconnecting Distributed Generation ("ESB756D")* to determine the incremental impact and any potential adverse impacts associated with the interconnection of the Facility to the EPS.

2.0 Project Description

2.1 Customer Facility

The Customer proposes to install the following:

- Two (2) Customer owned SMA 4600-UP-US, three phase inverters for an assumed total of 9,200 kW / kVA of inverter-based PV.
- Two (2) Customer owned 4,600 kVA, 34.5 kV wye-ground, 600 V delta secondary padmounted interface transformer with an impedance of Z =5.75% along with X/R ratio of 11.
- One (1) Customer owned padmounted switchgear 35kV, 600A, 200 kV BIL G&W Viper recloser with SEL-651R relay assembly with 8-hour battery backup.
- One (1) Customer owned GOAB switch, S&C Model #147513, 200 kV BIL, 40kA with a Visible, lockable blades and utility accessible 24/7.

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 09/28/2021).

Any advanced inverter functionality other than that specifically called out on the Customer documentation and/or outlined herein shall be subject to additional study before being enabled.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is 3310, a 34.5 kV unregulated, three-phase, 3 wire, wye, ungrounded, radial, sub-transmission circuit that originates out of the Company's Kent County Substation, in West Greenwich, RI (the "Interconnecting Circuit"). This circuit is located overhead on Division Street, approximately 3.9 miles from the proposed Facility. This Line Extension will include the following work:

- Distribution Line Work (Section 2.2, Appendix B):
    - Install ~16,100 feet of 3-1/c 1000 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
        - Prior analysis has shown that this project requires the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable in this section. The costs provided in this study are for the installation of 3-1/c 500 kcmil Cu EPR 35 kV cable. Another Customer has paid for the installation of 3-1/c 1000 kcmil Cu EPR 35 kV cable.
    - Install ~700 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Weaver Hill Road to the first 3-way MH on Weaver Hill Road.
    - Install ~4100 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.

- Install ~200 feet of 3-1/c 500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.

- Install ~1,400 feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

- Install ~410 feet of 3-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

- Distribution Civil Work (Section 2.2, Appendix B):
  - Install MH and duct system (~14,300 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road
    - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are expected.
  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road
    - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are expected.
  - Install MH and duct system (~3,700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road (to be self-built by Customer).
  - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property (to be self-built by Customer).

An underground line extension originating from the overhead line on Hopkins Hill Rd will be required to reach the proposed Facilities. There is one river that will need to be crossed with overhead conductors alongside the bridge. The Big River Bridge was not constructed to allow for installation of concrete encased ducts.

The Customer shall perform civil work from the first 3-way Manhole on Weaver Hill Road to the proposed riser pole on Customer property. Civil work scope performed by the Customer will require Company review and approval of the proposed plans, as well as Company review and approval of the ductbank prior to covering.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL (kW)*
3309	165	0	0	*165*
3310	434	24,248	9,200	*33,882*
3311	30,284	23,795	0	*54,079*
3312	2,735	4,049	0	*6,784*
TOTAL	*33,618*	*52,092*	*9,200*	**94,910**

Table 1: Generation at the Substation and Interconnecting Circuit

- There is one (1) existing recloser on the circuit, none of which are in between the substation and the facility, summarized in Table 2. Refer to Section 5 for further discussion on any required modifications.

Location	Status	Mid-line recloser, or existing DG project PCC recloser	In between Facility and Substation
Pole #18-1, Hopkins Hill Road, West Greenwich	In Service	Mid-line	No

Table 2: Recloser Locations

- There are no existing capacitor banks installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

- There are no existing regulators installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

2.3 Interconnection

Refer to the interconnection diagram in Appendix B for approximate PCC location.

Should the Customer elect to move forward with the Project, the Company's Design Personnel will specify the exact location of the Company's facilities and installation details. The Customer shall be responsible for obtaining all easements and permits required for any line extension not on public way in accordance with the Company's requirements.

The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

For this Project, the PCC is defined as the point where the Customer owned conductors terminate to the Company revenue meter, which is located at Pole #10-6, 189 Weaver Hill Road, West Greenwich, RI. The Customer must install their facilities up to the Company revenue meter. The Customer must provide sufficient conductor to allow the Company to make final connections at the meter pole. The Company will provide final connection of the Customer conductors to the Company meter.

If a Rhode Island Energy right of way (R.O.W) is involved, then the Customer shall provide detailed drawings of any planned construction within any Rhode Island Energy R.O.W., for the Company's review and subsequent approval, showing elevation grades of all phases of construction within the R. O. W. before any construction may begin. Plans and drawings must be submitted that meet all the Company's requirements before the interconnection process can move forward. These plans shall be submitted to Rhode Island Energy's R.O.W./Real-Estate group and the Transmission R.O.W. Engineering and construction group for review and comment before any construction can be allowed to move forward. There may be additional costs and subsequent delays involved with the review, and, or oversight of any construction in, or adjacent to, the Company's R.O.W., and if any Company owned facilities need modification as a result of the Customer's proposed construction. These costs will be in addition to, and outside of the scope of, this SIS. Failure of the Customer to reimburse the Company for these costs may delay or negate the interconnection process.

3.0 Power Flow Analysis

The power flow analysis was substantially performed using electrical system modeling software. A model of the Interconnecting Circuit, as described in Section 2.2, was developed based on data extracted from the Company's Geographical Information System ("GIS"). A field review of the feeder was performed on 09/25/2019.

The analysis considered cases at peak load (16,284 kVA @ 100% PF) and net minimum load (5,017 kVA @ 99.52% Lagging PF) at time of maximum expected generation (9:00AM – 6:00PM) on the circuit.

Circuit peak and minimum load values have been taken from the Company's historical load data that has been compiled over 12 months, from 1/1/2019 to 1/1/2020.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Analysis shows that the maximum potential generation exceeds the observed minimum load on the Kent County 34.5 kV bus. However, the substation is currently equipped with bi-directional metering which was previously installed for reasons unrelated to DG work. No additional work is required on the substation bulk power metering.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in steady state voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output, the voltage range at the PCC was within acceptable limits.

Customer provided manufacturer's test reports have been reviewed for 1.4PU pickup values with 1ms or less total clearing time. The proposed design has been found to meet the necessary requirements.

3.4 Flicker Analysis

The IEEE 1547 standard and IEEE 1453 flicker assessments were used to estimate whether or not this site would be likely to cause unacceptable voltage flicker on the interconnecting feeder. This method evaluates for both short term and long-term voltage flicker against IEEE1547-2018 Table 25 - DER Flicker Emission Limits.

Analysis shows that P_{st} and P_{lt} are within acceptable limits and no mitigation for voltage flicker is recommended.

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2015 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long-Term Dynamics module of CYME[1]. A long-term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6-hour period. Other significant DG existing or in process ahead of this Project were modeled at full output and modeled with the appropriate voltage fluctuation curve to simulate reasonable voltage fluctuations.

The generation profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate realistic power output from the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict voltage flicker under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether or not there is a readily apparent concern related to voltage flicker.

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

[1] CYME Power Engineering Software, Version 8.1, Revision 01, Build 115, Copyright © 1986-2017, Cooper Industries, Ltd.

Analysis shows that the predicted flicker and voltage fluctuations are expected to be acceptable, provided that the following conditions are met:

- The system modifications identified elsewhere in this study are implemented.
- The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS.

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 100kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
442	All Projects <100kW CERTIFIED
0	All Projects <100kW Non-CERTIFIED
740	CERTIFIED
3,500	CERTIFIED
9,200	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered a likely event. As a result, a PCC recloser with reclose blocking will be required. Additionally, live-line reclose blocking must be implemented at the following line reclosers summarized in Table 4.

Location	Status (Existing or New)
Pole #25-3, Hopkins Hill Road, Coventry, RI	New

Table 4: Recloser Locations

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C 2180 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation.

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

Addition of generation sources to sub-transmission feeders can result in the back-feeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. Due to the Kent County T1, T2 and T7 supply transformer configurations, there is a path for zero sequence ground fault current to single line to ground faults on the transmission line. Therefore, the Facility does not pose a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Substation modifications related to $3V_0$ are not required**.**

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account existing system conditions, but not the impact of the Customer's new Facility.

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

Pre-Project

System Impedance at PCC

Z1 = 0.05 + j0.26 p.u.

Z0 = 0.65 + j1.38 p.u.

5.3 Fault Current Contributions

Table 5 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings. Mitigation strategies are required to accommodate the proposed Facility, as described in Sections 5.4 and 5.5.

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

PRE PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)
3-phase (LLL)	21581	3999
Phase-Ground (LG)	24066	2346

POST PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)	DELTA I_{fault} @ SUB BUS	DELTA I_{fault} @PCC
3-phase (LLL)	21779	4199	1%	5%
Phase-Ground (LG)	24322	2478	1%	6%

Table 5: Fault Duty

5.4 Substation Protective Device Modifications

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study:

- Add load encroachment settings to the Kent County Transformer #7, 34.5 kV directional overcurrent relay (67)

5.5 Area EPS Protective Device Coordination

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

The existing device settings and associated time-current curves were evaluated for protective devices on the Interconnecting Circuit.

The protection coordination review of the area EPS revealed that the following modifications to the existing EPS protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study. Refer to Appendix B for system modification drawings:

- Install a recloser at the tap for the proposed line extension to the facility at Pole #25-3, Hopkins Hill Rd, Coventry, RI. (Appendix B-3)

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the Rhode Island Energy revenue meter. This may be accomplished with an analog/POTS (Plain Old Telephone Service) phone line (capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc.), or, in locations with suitable wireless service, a wireless meter.

Feasibility of wireless service must be demonstrated by Interconnecting Customer, to the satisfaction of Rhode Island Energy. If approved, a wireless-enabled meter will be installed, at the customer's expense. If and when Rhode Island Energy's retail tariff provides a mechanism for monthly billing for this service, the customer agrees to the addition of this charge to their monthly electric bill. Interconnecting Customer shall have the option to have this charge removed, if and when a POTS phone line to Rhode Island Energy's revenue meter is provided.

Refer to *Appendix A Figures A-1 and A-2 - Revenue Meter Phone Line Installation Guide).*

The Customer is advised to contact Generation and Load Administration (NewGenCoord@iso-ne.com) at ISO New England regarding all metering, communications circuits, remote access gateway (rig), financial assurance, paperwork, database updates, etc. that may be required for this Facility.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states the interconnecting transformer are two (2) Customer owned 4,600 kVA, 34.5 kV delta, 690 V delta secondary padmounted interface transformer with an impedance of Z =5.75% along with X/R ratio of 11.0.

The proposed transformer satisfies the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Facility is proposing to connect to a non-effectively grounded 34.5 kV circuit, and therefore does not require a means of effective grounding.

As a result, the customers proposed configuration satisfies the requirements of the ESB.

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

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

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

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

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable inverter relay settings in accordance with the aforementioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8. This requirement is met.

6.6 Secondary Protection

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

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a circuit breaker for site protection.

The Customer provided documents indicate an interrupting device on the high side (Customer 34.5 kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

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

The Customer provided documents show a phase overcurrent (51) relay element and associated settings.

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

51 – Phase

Customer Proposed: 300A primary amps pickup, 2 second time delay, U4 curve.

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relays make/model is included on the Customer single line.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D. The Customer provided documents show neutral overvoltage (59N) that are unacceptable.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756C Section 7.6.11 and 7.8. This requirement is met.

The Customer provided one-line diagram shows acceptable settings for neutral overvoltage 59N protection.

59N – Neutral Overvoltage

Customer Proposed: $3V_0$ = 12.45 kV primary pickup (46.7 V), 0.8 second time delay.

6.6.6 Current Transformers ("CT") (ESB 756D Section 7.6.4.1)

The Customer provided documents show current transformer with ratings listed, which satisfies this Section of ESB 756D.

6.6.7 Voltage Transformers ("VT") and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show wye-grounded/wye-grounded VT's and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer provided documents indicate a power supply for the redundant relay that satisfies the requirements of this section of ESB 756D.

The Customer has proposed a DC power supply. The Customer shall demonstrate in the witness test that the relay will trip if the DC voltage goes out of the normal operating range.

It is recommended that the power DC power supply be connected to the utility (source) side of the interrupting device in order to ensure power availability to close the interrupting device after an extended outage. This is a recommendation, for consideration by the Customer. It is not a requirement by the Company.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7 & 756C Section 7.8.3)

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting a minimum 5 minutes of healthy utility voltage and frequency. "Healthy Utility Voltage and Frequency" is defined by ESB 756D Table 7.8.3-1. The five-minute time

interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five-minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer provided settings and timing device information is acceptable as shown.

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer's one line diagram shows devices and settings to satisfy this requirement.

6.7 Synchronizing Devices (ESB 756D Section 7.6.9 and 7.6.11.2)

Project is inverter based; therefore, synchronizing devices are not required.

6.8 Customer Cabling

The Company is not responsible for the protection of the Customer cable and primary protection for the Customer cable must be provided at the change of ownership.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

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

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment.
- Inverter manufacturer cut sheet including method of island detection and UL certification.
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project.
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study.
- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme.
- The proposed testing procedure
- The proposed energization plan.
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft MA state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above identified time frames due to errors in the relay settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, is shown below in Table 6:

Rhode Island Energy System Modification	Conceptual Cost +/-25% Planning Grade Cost Estimate not including Tax Liability				Associated Tax Liability Applied to Capital	Total Customer Costs includes Tax Liability on Capital Portion
RIE - Civil Work	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Approximate donated property tax. See Note #1.	$0	$0	$0	$0	$82,718	$82,718
RIE Supervision and Design Support for Customer Underground Civil Construction. See Note #2	$165,000	$165,000	$0	$0	$18,282	$183,282
Distribution Civil work, 3310 circuit See Note #3 (Cost Sharing may be applicable)	$15,904,009	$15,904,009	$0	$0	$1,762,164	$17,666,173
SUBTOTAL	**$16,069,009**	**$16,069,009**	**$0**	**$0**	**$1,863,164**	**$17,932,173**

RIE - Line Work, Customer Property	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Equipment at Point of Common Coupling, 3310 Circuit. See Note #4	$310,038	$310,038	$0	$0	$34,352	$344,390
SUBTOTAL	**$310,038**	**$310,038**	**$0**	**$0**	**$34,352**	**$344,390**

RIE - Line Work, Mainline	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Distribution Line work, 3310 Circuit. See Note #5 (Cost Sharing may be applicable)	$5,621,801	$5,612,059	$5,272	$4,470	$621,816	$6,243,617
SUBTOTAL	**$5,621,801**	**$5,612,059**	**$5,272**	**$4,470**	**$621,816**	**$6,243,617**

RIE - Substation Work (Distribution Level)	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**9.90%**	**Total**
Add Load Encroachment to the Kent County T7 Directional Overcurrent Relay. (Cost Sharing may be applicable)	$16,000	$15,000	$1,000	$0	$1,485	$17,485
SUBTOTAL	**$16,000**	**$15,000**	**$1,000**	**$0**	**$1,485**	**$17,485**

Witness Testing & EMS	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**NA**	**Total**
Witness Testing. See Note #6	$2,500	NA	$2,500	NA	NA	$2,500

EMS integration. See Note #7	$5,000	NA	$5,000	NA	NA	$5,000
SUBTOTAL	**$7,500**	**$0**	**$7,500**	**$0**	**$0**	**$7,500**

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	**$22,024,348**	**$22,006,106**	**$13,772**	**$4,470**	**$2,520,818**	**$24,545,166**

Notes

1 Approximate donated property tax for the Customer installation of (1) - 3-way manhole, (5) - 2-way manholes, (100 feet) 2-way, 6" PVC - DB concrete encased ductbank, (3700 feet) - 4-way, 6" PVC - DB concrete encased ductbank and associated equipment. Customer is responsible for performing, any and all, temporary and permanent restoration.

2 RIE supervision and design support for underground civil construction performed by the Customer. The cost includes preparation of design package (Scope, Construction specifications, Construction standards/drawings, Vendor information, etc.…), review and approval of civil design drawings, and review and approval of civil construction by full-time RIE inspector.

3 Installation of (4) - 3 way manholes, (21) - 2 way manholes, (300 feet) - 2 way, 6" PVC - DB concrete encased duct bank, (14,000 feet) 4 way, 6" PVC - DB concrete encased duct bank, (600 feet) 6 way, 6" PVC - DB concrete encased duct bank and associated equipment. For estimating purposes, permanent restoration for civil work is assumed to be twelve (12) feet in width. Note: Should additional permanent restoration (i.e. Curb to curb or centerline to curb) be required, the cost of civil construction could increase.

4 Installation of pole-mounted equipment at the POI-PCC, including approxiamtely 250 feet of 3-477 Al Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers, one (1) primary meter, and associated equipment.

5 Extend the Kent County 3310, 34.5 kV circuit underground from proposed Pole #26-2, Hopkins Hill Road, West Greenwich, RI to the proposed DG facility located at 189 Weaver Hill Road, West Greewich, RI. (approximately 3.9 Miles). Estimate included in table above assumes installation of 3-1/c-500 kcmil CU EPR 35 kV cable, and associated equipment. Costs include one (1) bridge crossing with risers to 477 Al bare conductor, Installation of new tap recloser located on Hopkins Hill Road, West Greenwich, RI, and associated equipment.

6 Witness Testing including review of witness test documentation and manpower for attending witness test.

7 Integration of DG and EPS modifications into Company's Energy Management System (EMS)

Table 6: Cost Estimates

The planning grade estimate provided herein is based on information provided by the Interconnecting Customer for the study and is prepared using historical cost data from similar projects. The associated tax effect liability included is the result of an IRS rule, which states that all costs for construction collected by the Company, as well as the value of donated property, are considered taxable income.[3] This estimate is valid for ninety (90) calendar days from the issuance of this report, after which time it becomes void. If the Interconnection Customer elects to proceed with this project after the ninety (90) calendar days, a revised estimate may be required.

This interconnection application may result in costs charged to The Narragansett Electric Company (the Company) by an Affected System Operator (ASO). Please note that in addition to the payment obligation for your share of the cost of any transmission upgrades identified in an ASO Study or identified during the Distribution System Impact Study of your application, when

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

your facility is energized you also will be assessed for the on-going carrying charges for the transmission upgrades (plus cost security before your facility is energized), as specified in your Interconnection Service Agreement. The on-going carrying charges include O&M, property taxes, and other carrying costs associated with transmission upgrades. The transmission upgrades and on-going carrying charges are calculated and charged to the Company by the ASO, in most instances the Company's transmission provider, New England Power Company (NEP), in accordance with the ASO's tariff (for NEP, Schedule 21-NEP, Attachment DAF, to the ISO-NE Open Access Transmission Tariff ("DAF Charges") and data from the FERC Form 1). You will be charged initially on an estimated basis for the transmission upgrade costs, which will be reconciled to actual costs. On-going carrying charges are calculated by multiplying the capital portion of the transmission upgrade costs by the transmission carrying charge rate in effect at the time. For NEP, the on-going carrying charge rate is subject to adjustment annually as estimated transmission upgrade costs are reconciled to actual costs. The current on-going carrying charge rate for NEP is 5.21%.

The estimated duration for the Company to complete construction of the System Modifications will be identified in the final Interconnection Service Agreement.

The project schedule may be impacted by the ability to have planned outages to allow work to take place on the distribution system. Outages will be contingent on the ability to support the load normally supplied by affected circuits. The schedule can also be impacted by unknown factors over which the Company has no control. The interconnection schedule is contingent on the Interconnecting Customer's successful compliance with the requirements outlined in this report and timely completion of its obligations as defined in *ESB756D, Exhibit 2: Company Requirements for Projects Not Eligible for the Simplified Process*. The schedule for the Company's work shall be addressed during the development, or after the execution, of the Interconnection Agreement.

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the final ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the final ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C. No. 2180, Section 3.4 Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half

the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	05/11/2021	Original Underground Study
2.0	01/31/2022	Over-head Restudy
3.0	09/20/2021	Fully Underground Design Restudy

Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION

If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

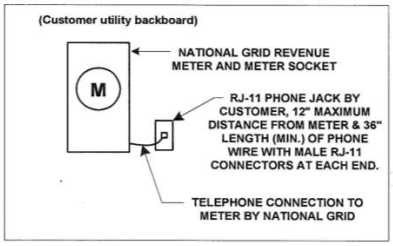


Figure 1A – Indoor Meter Installation
not to scale

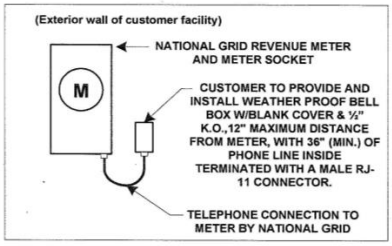


Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION

If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

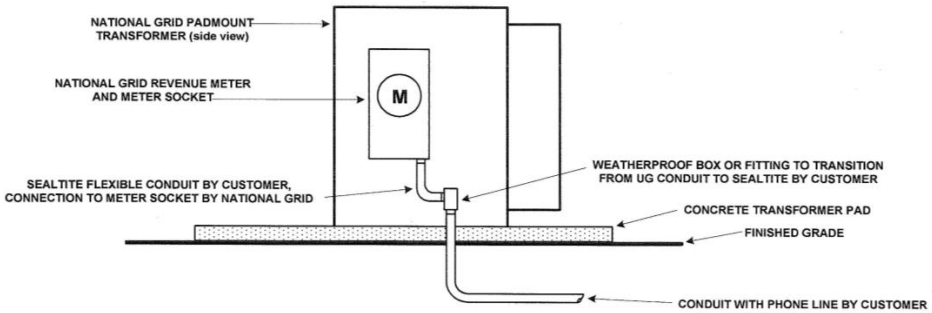


Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

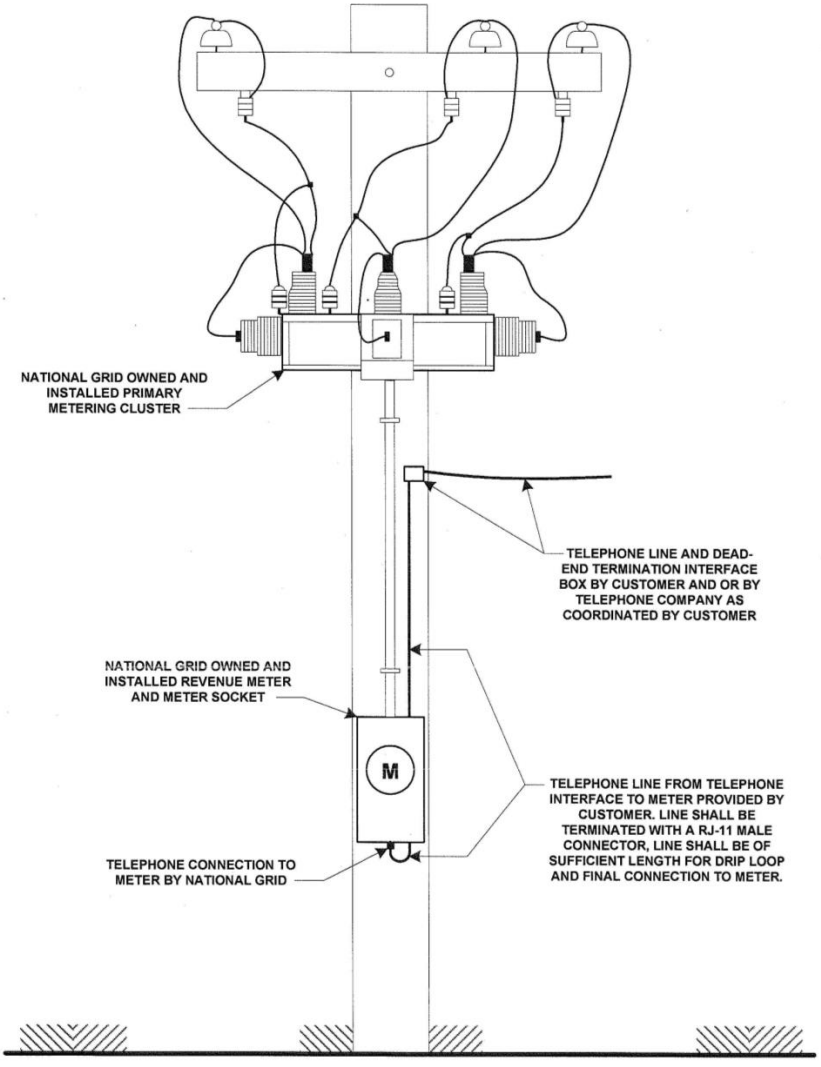


Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

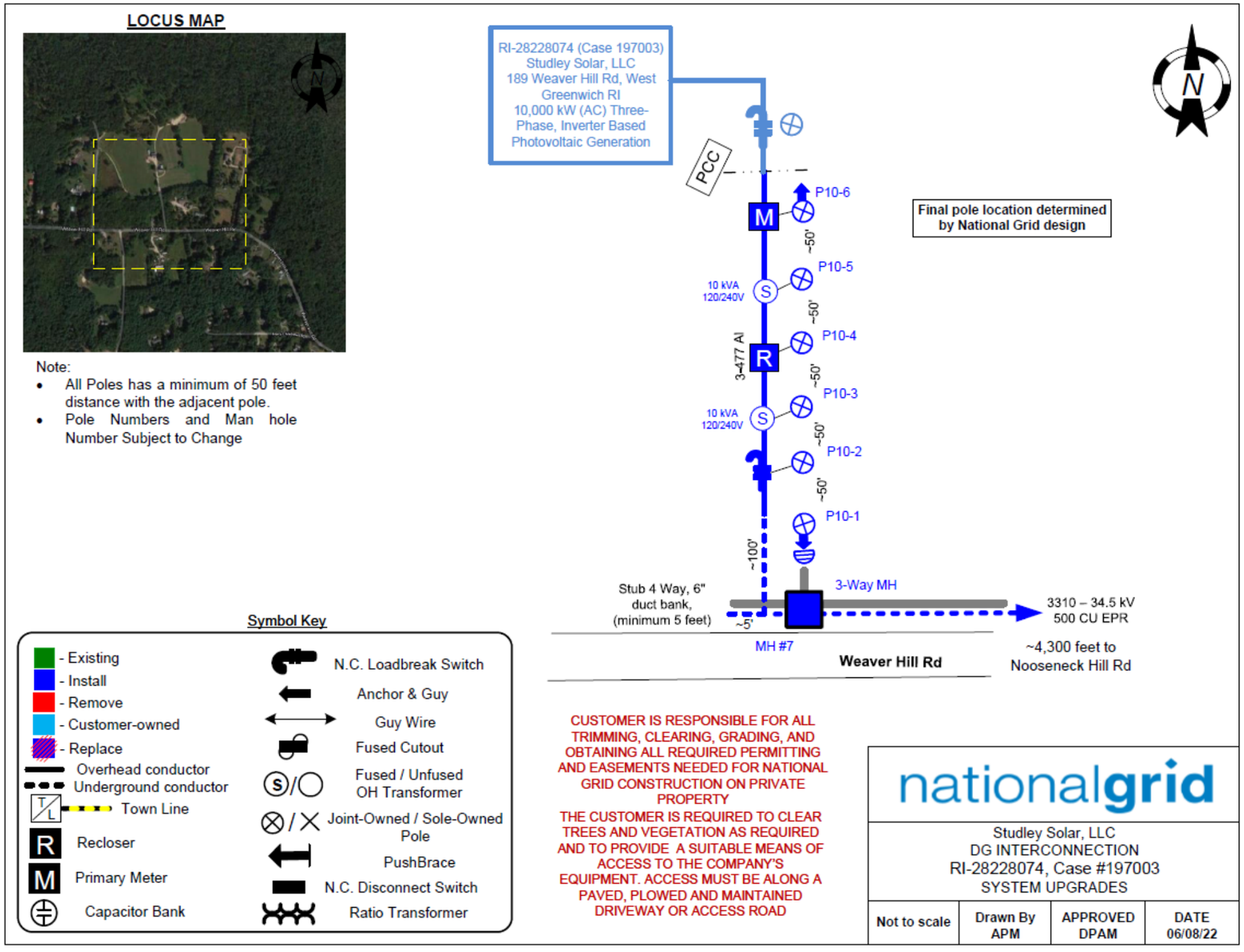


Figure B- 1: PCC Configuration

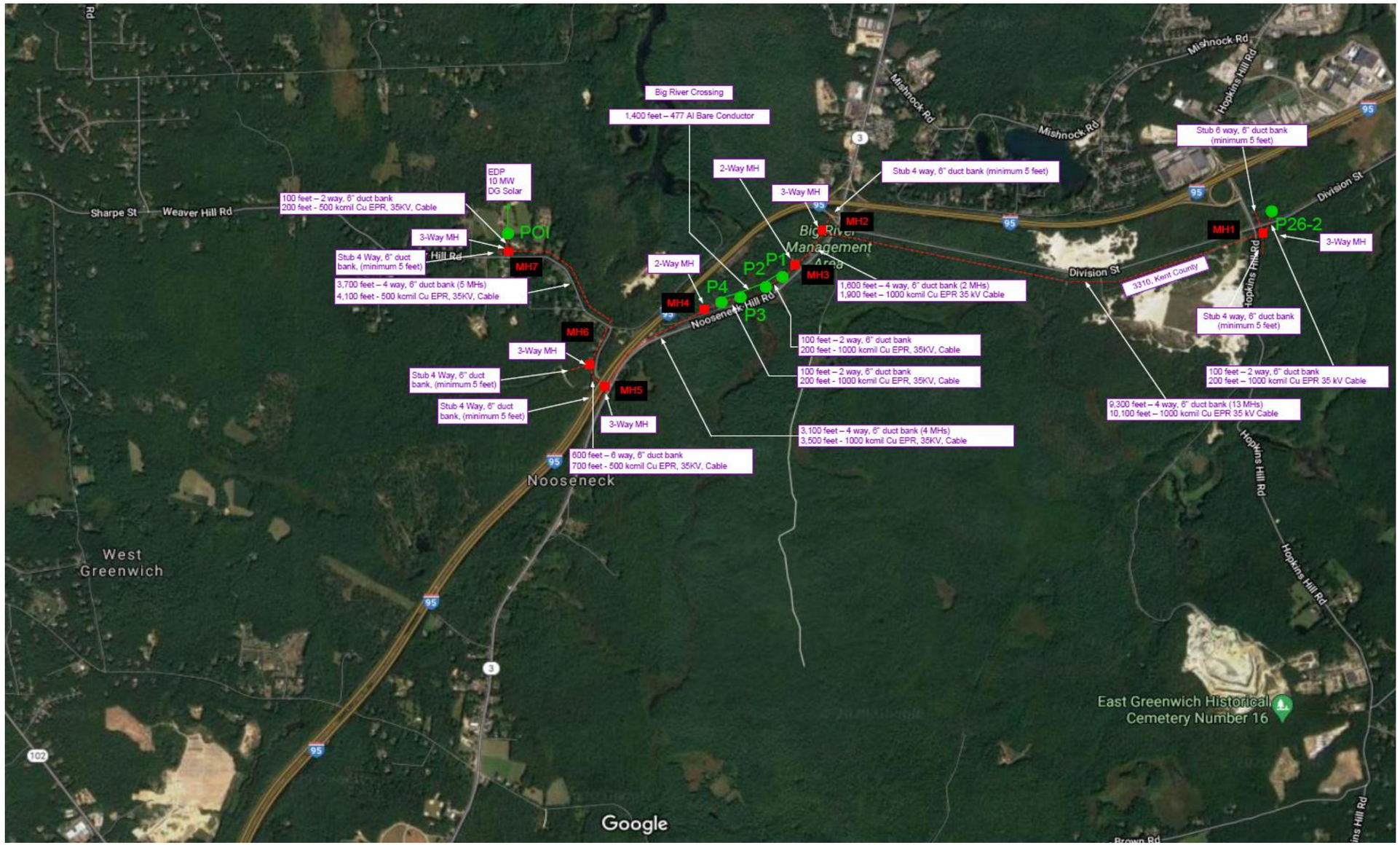


Figure B- 2: System Modification

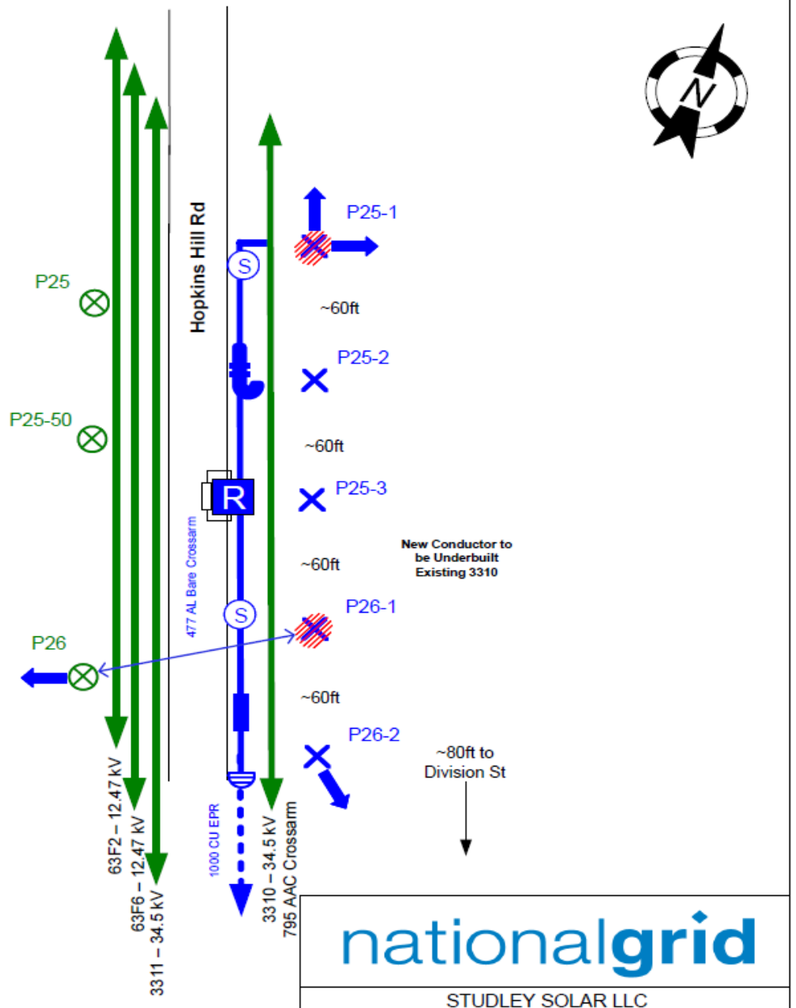
PRINTED OR DOWNLOADED COPIES ARE NOT DOCUMENT CONTROLLED.		
File: SP. RI-28228074 App File: 03-RI-28228074_Case-197003_West-Greenwich_FINAL_9.20.2022	Originating Department: Distribution Planning & Asset Management – NE	Sponsor: Customer Energy Integration-NE

CUSTOMER IS RESPONSIBLE FOR ALL TRIMMING, CLEARING, GRADING, AND OBTAINING ALL REQUIRED PERMITTING AND EASEMENTS NEEDED FOR NATIONAL GRID CONSTRUCTION ON PRIVATE PROPERTY
THE CUSTOMER IS REQUIRED TO CLEAR TREES AND VEGETATION AS REQUIRED AND TO PROVIDE A SUITABLE MEANS OF ACCESS TO THE COMPANY'S EQUIPMENT. ACCESS MUST BE ALONG A PAVED, PLOWED AND MAINTAINED DRIVEWAY OR ACCESS ROAD

LOCUS MAP

Symbol Key

- Existing
- Install
- Remove
- Customer-owned
- Replace
- Overhead conductor
- Underground conductor
- Town Line
- Recloser
- Primary Meter
- Capacitor Bank
- N.C. Loadbreak Switch
- Anchor & Guy
- Guy Wire
- Fused Cutout
- Fused / Unfused OH Transformer
- Joint-Owned / Sole-Owned Pole
- PushBrace
- N.C. Disconnect Switch
- Ratio Transformer



nationalgrid

STUDLEY SOLAR LLC
DG INTERCONNECTION
RI - 28228074
SYSTEM UPGRADES

Not to scale	Drawn By EM	APPROVED DPAM	DATE 06/08/22

Figure B- 3: System Modification

Appendix C Customer Site and Single Line Diagram

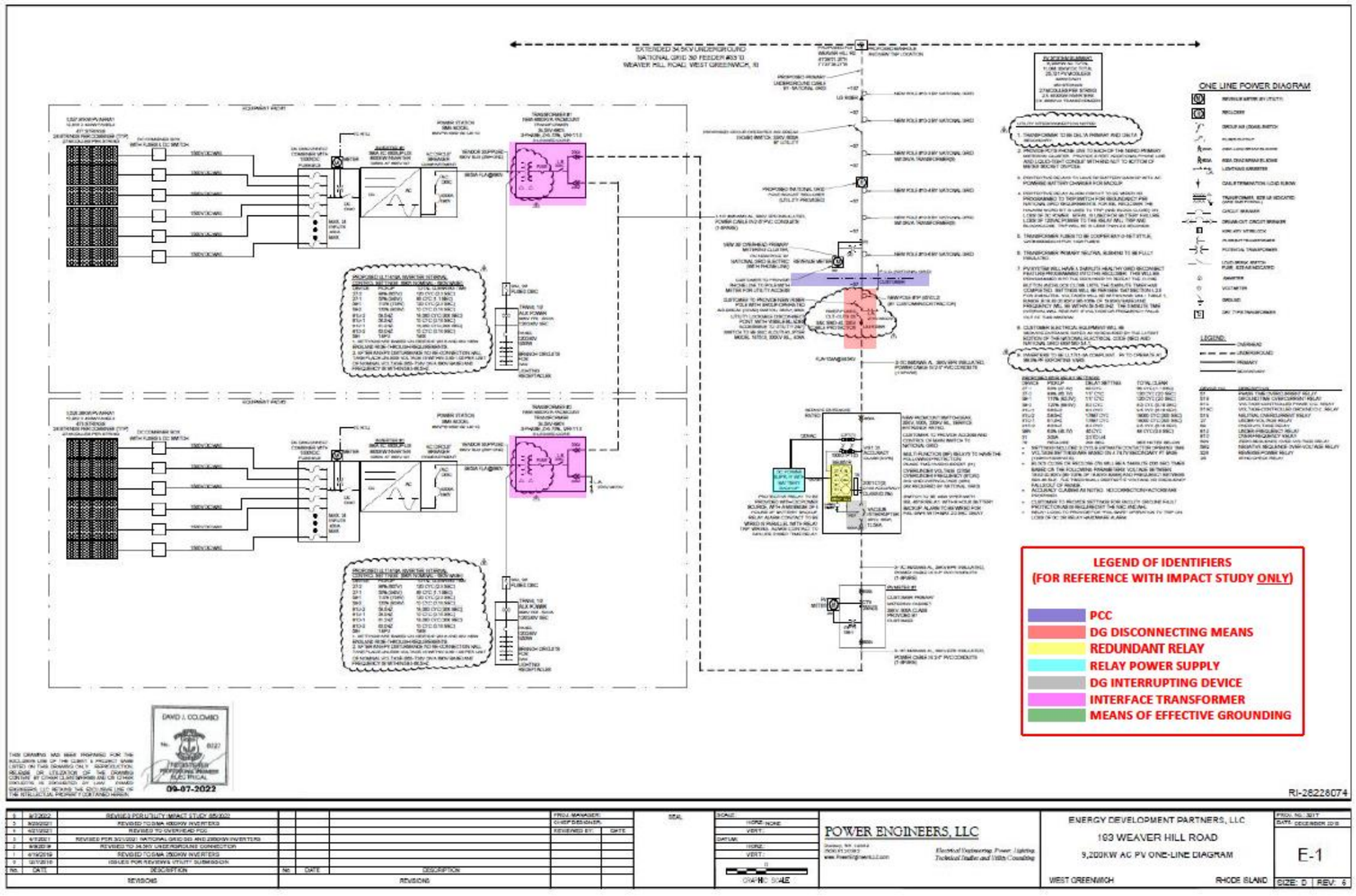


Figure C- 1: Project One-Line
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

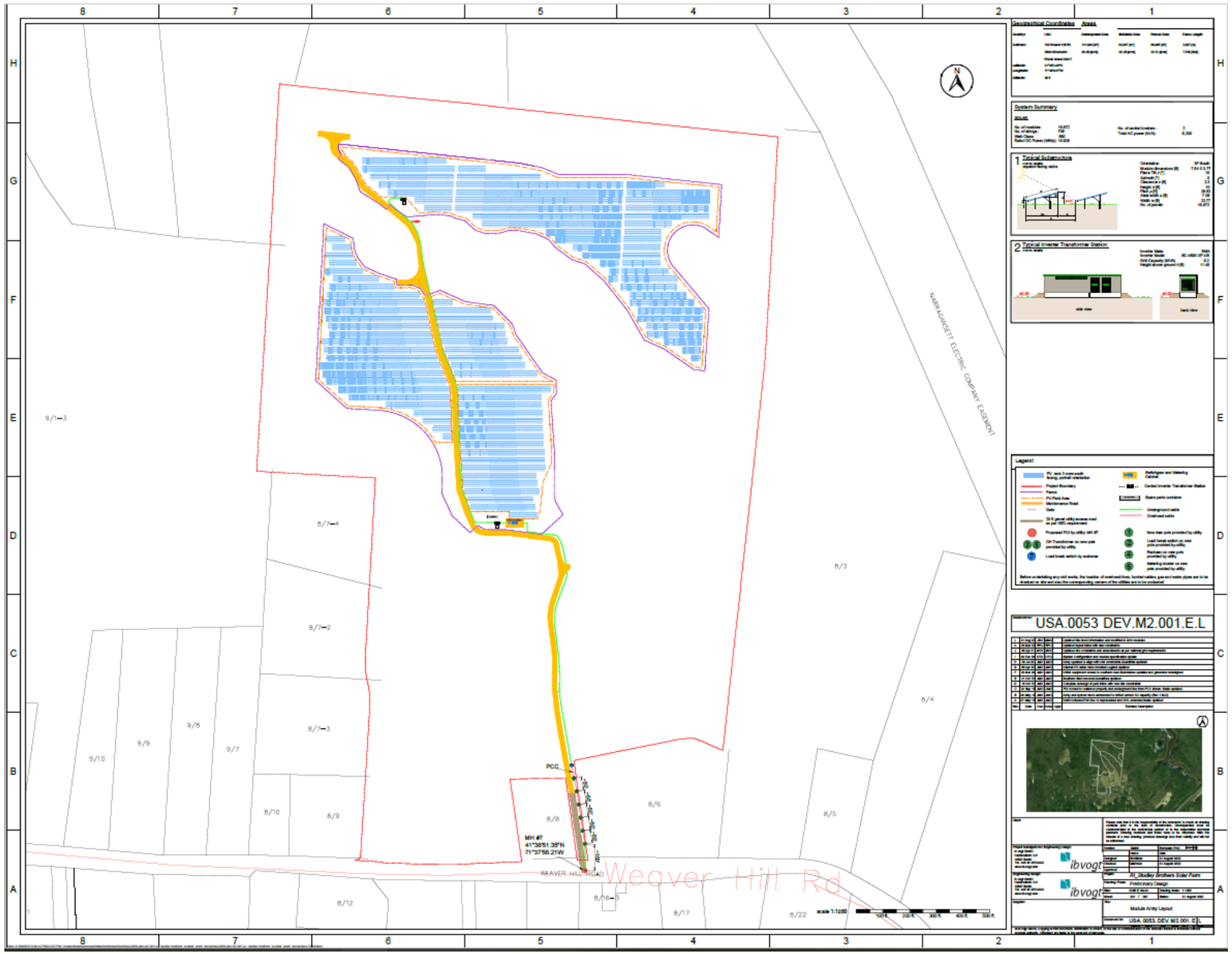


Figure C- 2: Project Site Plan

Division 4-2

Request:

Regarding Energy Development Partners System Impact Study Version 2.0 (Petition, page 166), what was the purpose of the over-head restudy? Explain which portion of the project was subject to the study (system modifications, system improvements, or both)?

Response:

The over-head restudy was to explore a different option per discussions with town representatives who indicated the road had just been repaved. However, when explored, the overhead option had additional complications such that town representatives required the work to be underground.

For this system impact study, all the investments were considered system modifications.

Division 4-3

Request:

Provide a copy of the original Central RI West Area Study that was completed prior to Revision 1 – September 2022 (Petition, page 453). When did the original study commence and when was it completed? When did Revision 1 commence and what prompted a revised study? Please highlight and explain the differences between the original and revised studies.

Response:

There were no substantive changes or revisions to study recommendations between Revisions 0 and 1. Revision 1, was only editing and formatting to finalize the study report. This was done to preserve the initial handoff date to the Division of the study recommendations and models which was third quarter of 2021.

Additionally, the Distributed Generation developers were finalizing their designs, which also coincided with the finalization of the System Impact Study pertaining to their interconnections, which had a direct impact to the Area Study cost estimates and final cost tables.

Division 4-4

Request:

When did each DG customer first propose performing civil work? What prompted the decisions? When did the Company formally confirm each DG customers' decision to perform civil work? Provide supporting information.

Response:

Green Development proposed performing civil work for the Nooseneck project in January 2020. Green requested to self-perform the proposed civil scope prior to execution of the Interconnection Services Agreement ("ISA"). The Company consulted with the customer, and the customer confirmed that the decision to request self-performance relates back to many of the issues discussed during the working sessions for Docket Nos. 5205 and 5206. Benefits of self-performance for the Interconnection Customer include real-time visibility over costs, which potentially could lead to lower costs, as well as the ability to potentially complete the work on a shorter timescale. After review and consideration, the Company approved the request prior to the execution of the ISA.

Revity proposed performing civil and electrical work for the Robin Hollow project around July 2022. Revity requested to self-perform the proposed electrical and civil scope after execution of the ISA. The Company consulted with the customer, and the customer confirmed that the decision to request self-performance relates to their prior experience with a successful self-performance and the ability to continue with Company and customer collaboration; ultimately achieving project milestones and efficiently managing the project installation and procurement budget. After review and consideration, the Company approved the request at this time in the summer of 2022.

EDP proposed performing civil work for the Studley Solar project in February 2022. EDP requested to self-perform the proposed civil scope prior to execution of the ISA. The Company consulted with the customer, and the customer confirmed that the decision to request self-performance related to cost, specifically the ability to complete the work at a lower cost. After review and consideration, the Company approved the request prior to the execution of the ISA.

Division 4-5

Request:

What is the electrical portion to be built by Revity (page 22)? Did RIE suggest, or did Revity propose that the DG customer build the electrical portion? When was this first proposed and when was the decision confirmed? What prompted the decision?

Response:

Bates 351 of Distributed Generation ("DG") Petition for Weaver Hill identifies the electrical scope of work for the customer to self-perform. It is identified in the six other Interconnection Service Agreement ("ISA") amendments for the remaining sites as well on Bates 363, 375, 387, 399, 411, and 423.

In summary, Revity could only perform work on de-energized equipment that was also not in proximity to other energized cables or conductors. Revity was responsible for all seven Point of Common Couplings ("PCC's") at 18 Weaver Hill Road, the DG interconnection of the underground installation on the 3309 and 3310 cable, the PCC for the 3310 feeder and the DG interconnection for Revity installed riser poles. RIE was responsible for the overhead portion of the 3309 on Hopkins Hill Road, cable pulling for the 3310 from Nooseneck to the Revity site on Weaver Hill Road, and the 3309 & 3310 overhead point of interconnection primary meter and recloser.

Please refer to the Company's response to Division 4-4 for further context regarding the customer's proposal for self-performance.

Division 4-6

Request:

Did the Company offer, or did any DG customer request or otherwise receive any cost estimates from the Company for civil work assuming the Company performed the work? If so, provide the estimate, date provided to the DG customer, and associated correspondence. If a cost estimate was not provided to a DG customer, how did that DG customer determine that self-performed civil work would be at or below what it would cost the Company to perform, thereby reducing the DG customer's interconnection costs?

Response:

The Green Development Nooseneck Impact Study 1.0 draft from February 2020 included a cost estimate for the civil work. Please refer to Attachment DIV 4-6-1.

The Revity Robin Hollow project did not have a cost estimate for their portion of civil work.

The EDP Studley Solar Impact Study 1.0 final from May 2021 included a cost estimate for the civil work. Please refer to Attachment DIV 4-6-2.

In discussing with the customers, they were likely able to determine they could perform the civil work at or below the Company's estimate based on prior experience, market based estimates, and quotes from vendors.

System Impact Study
for Distributed Generation Interconnection to
National Grid's 34.5 kV System

DG WR:	RI-27825278	RI-27888883
DG Case#:	00206311	00206313
Applicant:	Green Development, LLC	Green Development, LLC
Address:	899 Nooseneck Hill Rd (Southern Array)	899 Nooseneck Hill Rd (Northern Array)
City:	West Greenwich, RI	West Greenwich, RI
DG kW/kVA:	10,000 kW / kVA	10,000 kW / kVA
DG Type:	Inverter-Based Photovoltaic	Inverter-Based Photovoltaic
Feeder:	Kent Count 3310	Kent County 3310

Table of Contents

Section **Page**

List of Tables

Definitions

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

ESS – Energy Storage System

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DER – Distributed Energy Resources

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)

PF – Power Factor

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") two (2) 10,176 kW / kVA inverter based photovoltaic sites for a total of 20,352 kW / kVA, ("the Facility"), to its 34.5 kV Sub-transmission system, ("the Project"), and presents the conclusions of the study herein.

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

System Modifications

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

1. Approximately 33,100 circuit foot line extension from Hopkins Hill Road to the Facilities, which includes: (Section 2.2)
    - ~30,700 circuit feet of 3-1/C 1000 kcmil SCU EPR Cable (The Customer will only be responsible for costs associated with installing 3-1/C 500 kcmil SCU EPR)
    - All Company owned underground facilities are to be installed in a concrete-encased duct & manhole system built to Company Construction Standards and approved by the Company prior to covering.
    - ~2,400 circuit feet of overhead 3-477 AL Crossarm
2. Overcurrent Setting change at the Kent County 3310 Breaker (Section 5.4)
3. Add Load encroachment settings to the Kent county T7 Directional Overcurrent Relay (Section 5.4)
4. Install new tap recloser at the start of the Line Extension from Hopkins Hill Road (Section 2.2 & 5.5)
5. Install ~500 circuit feet of 1000CU, a pad mounted load break switch, a pad-mounted recloser, an advanced switchgear VFI and two pad mounted primary meters at the PCC. (Appendix B-1)

Customer Document Revisions

The Customer is requested to provide the following additional and/or revised documentation as required. All revised drawings shall be stamped and signed by an Electrical Professional Engineer licensed in the same state as the Project location. The following list is intended as a convenient summary of documents for re-submission, however the Customer is required to comply with all items listed and discussed in this document. Omission of an item from the following summary list that is referenced elsewhere in this document does not release the Customer from providing the necessary documents:

1. Customer site plan is not acceptable as shown (Section 2.3)
2. Customer must provide an LROV letter (Section 3.3)

3. Customer must operate their inverters between 99% PF leading (Importing VARs) and Unity PF (Section 3.4)
4. Customer can opt to use fuses in lieu of a relay (Section 6.6.1)
5. Customer's proposed overcurrent relay elements are not acceptable as shown (Section 6.6.2)
6. Customer's proposed voltage relay elements are not acceptable as shown (Section 6.6.5)
7. Customer's proposed current transformers are not acceptable as shown (Section 6.6.6).
8. Customer's proposed Utility Restoration detection settings are not acceptable as shown (Section 6.6.10).
9. Customer needs to provide derating letter from the manufacturer limiting each site size to no more than 10,000 kW and kVA

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 $19,596,225 +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the final 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

The Customer proposes to install the following:

Case 206311 (Southern Array)

- Three (3) sets of four (4) paralleled Customer owned TMEIC Solarware Ninja PVU-L0880GR 880 kW / 880 kVA Inverters each de-rated to 833.33 kW / kVA for a total of 10,000 kW/kVA of inverter-based DG
- Three (3) Customer owned 3,392 kVA 34.5 kV Delta Primary and 660V Grounded-wye secondary interface transformers with impedances of Z=7.25% and an X/R ratio of 10
- One (1) Customer owned recloser controlled by an SEL-651R relay assembly
- One (1) Customer owned 1200 A 1984X-45F Vector load break switch, accessible to the Utility 24/7

Case 206313 (Northern Array)

- Three (3) sets of four (4) paralleled Customer owned Solarware Ninja PVU-L0880GR 880 kW / 880 kVA Inverters each de-rated to 848 kW / kVA for a total of 10,716 kW/kVA of inverter based DG
- Three (3) Customer owned 3,392 kVA 34.5 kV Delta Primary and 660V Grounded-wye secondary interface transformers with impedances of Z=7.25% and an X/R ratio of 10
- One (1) Customer owned recloser controlled by an SEL-651R relay assembly
- One (1) Customer owned 1200 A 1984X-45F Vector load break switch, accessible to the Utility 24/7

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 1/10/2020).

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 may be required:

1. Case 206311 is the Southern Array and is represented in the one line with file name: "400638-SK-10"
2. Case 206313 is the Northern Array and is represented in the one line with file name: "400638-SK-11"

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is the 3310, a 34.5 kV unregulated, three-phase, 3 wire, wye, non-effectively-grounded, radial sub transmission circuit that originates out of the Company's Kent County Substation, in Warwick, RI (the "Interconnecting Circuit"). This circuit is located overhead on Division Street, approximately 33,100 circuit feet from the proposed Facility. This Line Extension will include the following work:

- Installation of a new tap recloser on proposed Pole #23-26 Hopkins Hill Road with Live line reclose blocking capabilities
- Installation of ~30,700 circuit feet of 3-1/C 1000 kcmil SCU EPR underground cable in manhole and duct system
    - All Company owned underground facilities are to be installed in a manhole and duct system built to Company Construction Standards and approved by the Company prior to covering.
- Installation of ~2400 circuit feet of overhead 3-477 Bare AL Crossarm at the bridge crossings
    - ~1,400 circuit feet over the Big River Crossing
    - ~1,000 circuit feet at Nooseneck River Crossing

An underground line extension originating from the overhead line on Hopkins Hill Rd will be required to reach the proposed Facilities. There are two rivers that will need to be crossed with overhead conductors alongside the bridges.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL* (kW)
3309	0	0	0	*0*
3310	0	0	20,352	*20,352*
3311	0	41,140	0	*41,140*
3312	0	0	0	*0*
TOTAL	*0*	*41,140*	*20,352*	**61,492**

Table 1: Generation at the Substation and Interconnecting Circuit

- There is one (1) existing recloser on the circuit, none of which are in between the substation and the facility, which is summarized in Table 2. Refer to Section 5 for further discussion on any required modifications.

Location	Status	Mid-line recloser, or existing DG project PCC recloser	In between Facility and Substation
Pole #18-1, Hopkins Hill Rd	In Service	Mid-line	No

Table 2: Recloser Locations

- There is a total of 0 kVAR in existing capacitor banks installed on this circuit. Refer to Section 3 for further discussion on any required modifications.
- There are no existing regulators installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

2.3 Interconnection

Refer to the interconnection diagram in Appendix B for approximate PCC location.

Should the Customer elect to move forward with the Project, the Company's Design Personnel will specify the exact location of the Company's facilities and installation details. The Customer shall be responsible for obtaining all easements and permits required for any line extension not on public way in accordance with the Company's requirements.

The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

For this Project, the PCC for these two facilities are defined as the point where the Customer owned conductors terminate to the Company revenue meter. For the Southern Array (Case 206311), the PCC will be located at the secondary terminals of the Company owned pad mounted meter on the southern side of the Customer Access Road. For the Northern Array (Case 206313), the PCC will be located at the secondary terminals of the Company owned pad mounted meter on the Northern side of the Customer Access Road. The access road is located on Nooseneck Hill Road, approximately 450 feet north of Wills Swamp Road. 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 location. 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.

The Customer site plan requires the following revisions in accordance with ESB 756D 5.1.1.3. Drawings shall be stamped by a registered electrical professional engineer, licensed in the project's state. Drawings shall include accurate plot lines, drawn to scale, and site features including, but not limited to, the following:

1. Point of Common Coupling (PCC)
2. Existing and proposed Access road(s) including, at a minimum, dimensions to confirm Company personnel and equipment access requirements are met.

3.0 Power Flow Analysis

The power flow analysis was substantially performed using electrical system modeling software. A model of the Interconnecting Circuit, as described in Section 2.2, was developed based on data extracted from the Company's Geographical Information System ("GIS"). A field review of the feeder was performed on 9/25/2019.

The analysis considered cases at peak load (16,214 kVA @ 98.8 Leading PF) and net minimum load (4,955 kVA @ 99.57% Lagging PF) at time of maximum expected generation (9:00AM – 6:00PM) on the circuit.

Circuit peak and minimum load values have been taken from the Company's historical load data that has been compiled over the past 12 months, from 1/1/2019 to 1/1/2020.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Analysis shows that the maximum potential generation exceeds the observed minimum load on the Kent County 34.5 kV bus. However, the substation is currently equipped with bi-directional metering which was previously installed for reasons unrelated to DG work. No additional work is required on the substation bulk power metering.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS, with proposed line extensions to the Facilities, was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in steady state voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output, the voltage range at the PCC was within acceptable limits.

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. Refer to ESB 756D Section 10.3 for acceptable forms for documentation.

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 Figure 1

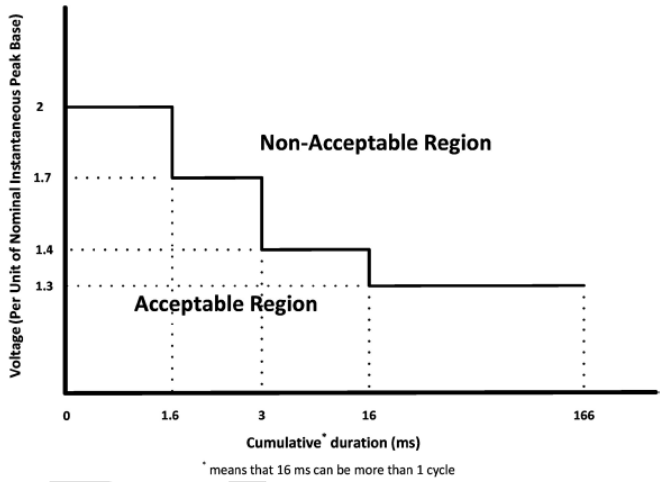


Figure 1: Transient/Temporary Overvoltage Tolerance Curve

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 this site would be likely to cause unacceptable voltage flicker on the interconnecting feeder. This method evaluates for both short term and long term voltage flicker against IEEE1547-2018 Table 25 - DER Flicker Emission Limits.

Analysis shows that P_{st} and P_{lt} are within acceptable limits and no mitigation for voltage flicker is recommended.

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2015 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long Term Dynamics module of CYME[1]. A long term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6 hour period. Other significant DG existing or in process ahead of this Project were modeled at full output and modeled with the appropriate voltage fluctuation curve to simulate reasonable voltage fluctuations.

The generation profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate realistic power output from the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict voltage flicker under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether 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 between -99 % Power Factor (Importing VARs) and unity power factor

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 25kW are listed individually. All other projects below 25kW are listed as a single line item.

[1] CYME Power Engineering Software, Version 8.1, Revision 01, Build 115, Copyright © 1986-2017, Cooper Industries, Ltd.

Project Size (kW)	Certified / Non-Certified
0	All Projects <25kW Certified
0	All Projects <25kW Non-Certified
20,352	CERTIFIED

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered likely event. As a result, PCC recloser with reclose blocking will be required. Additionally, reclose blocking must be implemented at the following line reclosers summarized in Table 4.

Location	Status (Existing or New)
Pole #23-26, Hopkins Hill Rd	New

Table 4: Recloser Locations

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C 2180 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation. Refer to Section 2.1.1 for any assumptions made in the model.

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

Addition of generation sources to sub-transmission feeders can result in the back-feeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. Due to the Kent County T1, T2 and T7 supply transformer configurations, there is a path for zero sequence ground fault current to single line to ground faults on the transmission line. Therefore, the Facility does not pose a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Substation modifications related to $3V_0$ are not required.

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

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account existing system conditions, but not the impact of the Customer's new Facility.

Pre-Project

System Impedances at PCC for Case 206311 & Case 206313

Z1 = 0.12 + j0.50 p.u.

Z0 = 0.79 + j1.46 p.u.

5.3 Fault Current Contributions

Table 5 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings and will not upset existing device coordination on the feeder. Mitigation strategies are required to accommodate the proposed Facility, as described in Sections 5.4 and 5.5.

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

PCC values are for both for Case 206311 & Case 206313. Any assumptions made in calculating the fault current shown in Table 5 are identified in Section 2.1.1.

PRE PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)
3-phase (LLL)	21175	3300
Phase-Ground (LG)	23542	1917

POST PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)	DELTA I_{fault} @ SUB BUS	DELTA I_{fault} @PCC
3-phase (LLL)	21581	3706	1.92%	12.30%
Phase-Ground (LG)	24065	2187	2.22%	14.08%

Table 5: Fault Duty

5.4 Substation Protective Device Modifications

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study:

- Add load encroachment settings to the Kent County Transformer #7, 34.5 kV directional overcurrent relay (67)
- Adjust the instantaneous ground overcurrent setting at the 3310 breaker

5.5 Area EPS Protective Device Coordination

The Project will require a Company owned recloser at the PCC. As this is a non-IPP Project, the recloser will require dead-line check to ensure that the recloser cannot close if the DG is generating.

The existing device settings and associated time-current curves were evaluated for protective devices on the Interconnecting Circuit.

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study. Refer to Appendix B for system modification drawings:

- Install a recloser at the tap for the proposed line extension to the facility on Hopkins Hill Rd

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

The Customer has submitted identical drawings for both Cases 206311 & 206313, the following comments address both projects.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the 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.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states the interconnecting transformers are 3,392 kVA, 34.5 kV Delta primary and 660 V wye-grounded secondary, with and impedance of Z=7.25% and an X/R ratio of 10. The proposed transformers satisfy the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Facility is proposing to connect to a non-effectively grounded 34.5 kV circuit, and therefore does not require a means of effective grounding.

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

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

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

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

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

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

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable internal relay settings in accordance with the afore-mentioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8. This requirement is met.

6.6 Secondary Protection

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

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a recloser for site protection.

The Customer provided documents indicate an interrupting device on the high side (Customer 34.5 kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

The Customer can choose to use fuses in lieu of a relay controlled interrupting device, If the Customer wishes to do this, the comments in the rest of the subsections of Section 6.6 do not apply and the Customer is to provide revised documentation to show adequately sized fuses.

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

The Customer provided documents show a ground overcurrent (51G) relay element and associated settings.

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

Since the Facilities are proposing to interconnect on a non-effectively grounded circuit, the proposed setting is not required.

51G – Ground

Customer Proposed: 25A primary amps pickup, 3 second time delay, U4 curve

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relay make/model is included on the Customer single line.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show relay settings in accordance with the afore-mentioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

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 not met

The Customer provided documents do not satisfy this Section of ESB 756D. Customer to provide revised documentation to show secondary pickup values based off the nominal voltage seen in the relay based off the voltage sensing ratios. However, as stated in Section 6.6.1, if the Customer uses fuses in lieu of a relay the Customer is not required to have these relay elements.

6.6.6 Current Transformers (“CT”) (ESB 756D Section 7.6.4.1)

The Customer provided documents do not satisfy this Section of ESB 756D. Customer to provide revised documentation to show burden and accuracy class However, as stated in Section 6.6.1, if the Customer uses fuses in lieu of a relay the Customer is not required to have CT’s.

6.6.7 Voltage Transformers (“VT”) and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show LEA Voltage sensors and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer provided documents indicate a power supply for the redundant relay that satisfies the requirements of this section of ESB 756D.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7 & 756C Section 7.8.3)

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting a minimum 5 minutes of healthy utility voltage and frequency. “Healthy Utility Voltage and Frequency” is defined by ESB 756D Table 7.8.3-1. The five minute time interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer shall provide settings and timing device information for review by the Company. However, as stated in Section 6.6.1, if the Customer uses fuses in lieu of a relay the Customer is not required to have Utility Restoration Detection settings.

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer’s one line diagram shows devices and settings to satisfy this requirement.

6.7 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.

6.8 Additional Requirements

The Customer must provide a letter from the manufacturer derating all inverters to no more than 833.33 kW and kVA.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

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

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment
- Inverter manufacturer cut sheet including method of island detection and UL certification
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study

- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme
- The proposed testing procedure
- The proposed energization plan
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft MA state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above identified time frames due to errors in the relay settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, is shown below in Table 6:

National Grid System Modification	Feasibility Study Grade Cost Estimate (-50 % to +200 %) not including Tax Liability)				Associated Tax Liability Applied to Capital	Total Customer Costs includes Tax Liability on Capital Portion
Narragansett Electric Company Civil Work	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Installation of Manholes and 6-Inch, PVC-DB, Concrete Encased Duct Banks (Various Sizes). [1] (Cost Sharing may be applicable).	$13,246,283.00	$13,246,283.00	$0.00	$0.00	$1,467,688.16	$14,713,971.16
SUBTOTAL	**$13,246,283.00**	**$13,246,283.00**	**$0.00**	**$0.00**	**$1,467,688.16**	**$14,713,971.16**
Narragansett Electric Company Line Work, Customer Property	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Equipment at Point of Common Coupling, 3310 Circuit [2]	$525,126.00	$525,126.00	$0.00	$0.00	$58,183.96	$583,309.96
SUBTOTAL	**$525,126.00**	**$525,126.00**	**$0.00**	**$0.00**	**$58,183.96**	**$583,309.96**
National Electric Company Line Work, Mainline	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Distribution Line Work, 3310 Circuit [3] (Cost Sharing may be applicable).	$3,843,123.00	$3,827,412.00	$10,548.00	$5,163.00	$424,077.25	$4,267,200.25
SUBTOTAL	**$3,843,123.00**	**$3,827,412.00**	**$10,548.00**	**$5,163.00**	**$424,077.25**	**$4,267,200.25**
NECO - Substation Work (Distribution Level)	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**9.90%**	**Total**
Overcurrent Setting Change at the Kent County 3310 Station Breaker	$1,600.00	$1,600.00	$0.00	$0.00	$158.40	$1,758.40
Add Load Encroachment to the Kent County T7 Directional Overcurrent Relay (Cost Sharing may be applicable)	$16,000.00	$15,000.00	$1,000.00	$0.00	$1,485.00	$17,485.00
SUBTOTAL	**$17,600.00**	**$16,600.00**	**$1,000.00**	**$0.00**	**$1,643.40**	**$19,243.40**
Witness Testing & EMS	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**NA**	**Total**
Witness Testing. [4]	$2,500.00	$0.00	$2,500.00	$0.00	$0.00	$2,500.00
EMS integration. [5]	$10,000.00	$0.00	$10,000.00	$0.00	$0.00	$10,000.00
SUBTOTAL	**$12,500.00**	**$0.00**	**$12,500.00**	**$0.00**	**$0.00**	**$12,500.00**
	Pre-Tax Total	**Capital**	**O&M**	**Removal**	**Tax**	**Total**
Totals	**$17,644,632.00**	**$17,615,421.00**	**$24,048.00**	**$5,163.00**	**$1,951,592.77**	**$19,596,224.77**

Notes

1. Installation of (5) - 3 way manholes, (42) - 2 way manholes, (5) extra-large switchgear manholes, (500 feet) - 2 way, 6" PVC-DB concrete encased duct bank, (12,700 feet) - 4 way, 6" PVC-DB concrete encased duct bank, and (14,500 feet) - 6-way, 6" PVC-DB concrete encased duct bank. Permanent restoration performed to one (1) foot on either side of trench excavation. Construction performed by National Grid civil contractor. Note: Should additional permanent restoration (i.e. curb to curb, centerline to curb, etc...) be required by the town of West Greenwich, the cost of civil construction would increase.
2. Installation of pad-mounted equipment including (1) - 38 kV, 600 A pad-mounted vacuum switch, (1) - 38 kV, 600 A pad-mounted recloser, (1) - 38 kV, PME-9 VFI pad-mounted switchgear, (2) - 38 kV, 600 A pad-mounted primary metering assemblies, (33) - 38 kV, 600 A dead break elbows, (3) - 38 kV, 600 A dead break elbow arresters, approximately (500 feet) - 3-1/c-500 kcmil Cu EPR conductor, and associated equipment.
3. Extend the Kent County 3310, 34.5 kV circuit underground from proposed pole 23-26 Hopkins Hill Road, West Greenwich, RI to the 3310 PCC-POI located at 899 Nooseneck Hill Road, West Greenwich, RI (approximately 5.3 miles). Estimate included in table above assumes installation of 3-1/c-500 kcmil Cu EPR 35 kV cable. Costs include two (2) bridge crossings with risers to 477 Al Bare conductor. Cost sharing, if applicable, would be based on the cost to install 3-1/c-1000 kcmil Cu EPR 35 kV cable.
4. Witness Testing including review of witness test documentation and manpower for attending witness test.
5. Integration of DG and EPS modifications into Company's Energy Management System (EMS).

Table 6: Cost Estimates

The planning grade estimate provided herein is based on information provided by the Interconnecting Customer for the study, and is prepared using historical cost data from similar projects. The associated tax effect liability included is the result of an IRS rule, which states that all costs for construction collected by the Company, as well as the value of donated property, are considered taxable income.[3] This estimate is valid for ninety (90) calendar days from the issuance of this report, after which time it becomes void. If the Interconnection Customer elects to proceed with this project after the ninety (90) calendar days, a revised estimate may be required.

The estimated duration for the Company to complete construction of the System Modifications will be identified in the final Interconnection Service Agreement.

The project schedule may be impacted by the ability to have planned outages to allow work to take place on the distribution system. Outages will be contingent on the ability to support the load normally supplied by affected circuits. The schedule can also be impacted by unknown factors over which the Company has no control. The interconnection schedule is contingent on the Interconnecting Customer's successful compliance with the requirements outlined in this report and timely completion of its obligations as defined in *ESB756D, Exhibit 2: Company Requirements for Projects Not Eligible for the Simplified Process*. The schedule for the Company's work shall be addressed during the development, or after the execution, of the Interconnection Agreement

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the final ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the final ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C. No. 2180, Section 3.4 Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

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

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	2/13/2020	Draft

Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION
If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

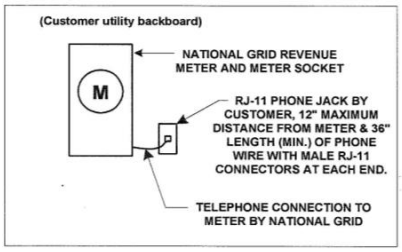


Figure 1A – Indoor Meter Installation
not to scale

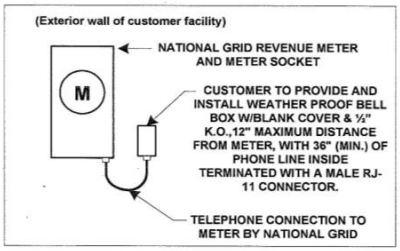


Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION
If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

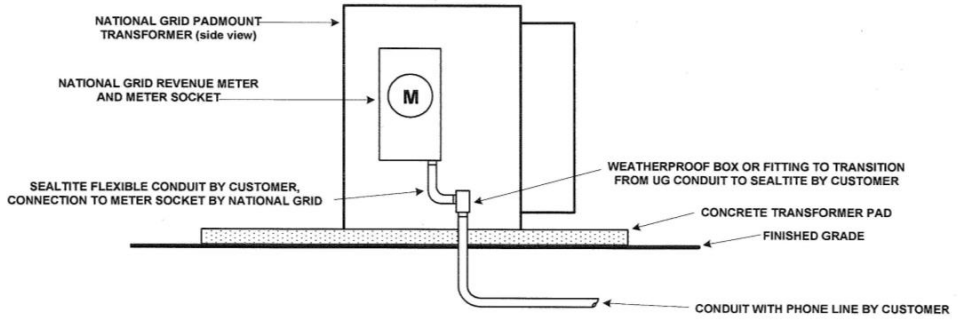


Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

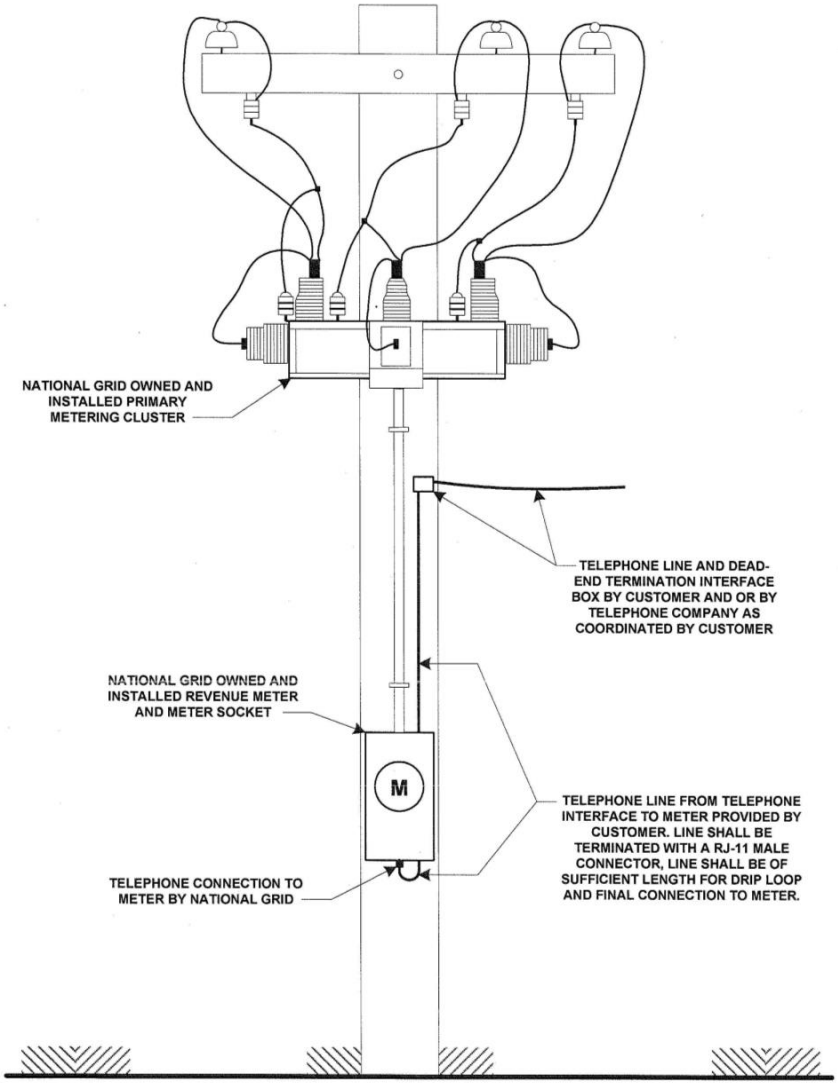


Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

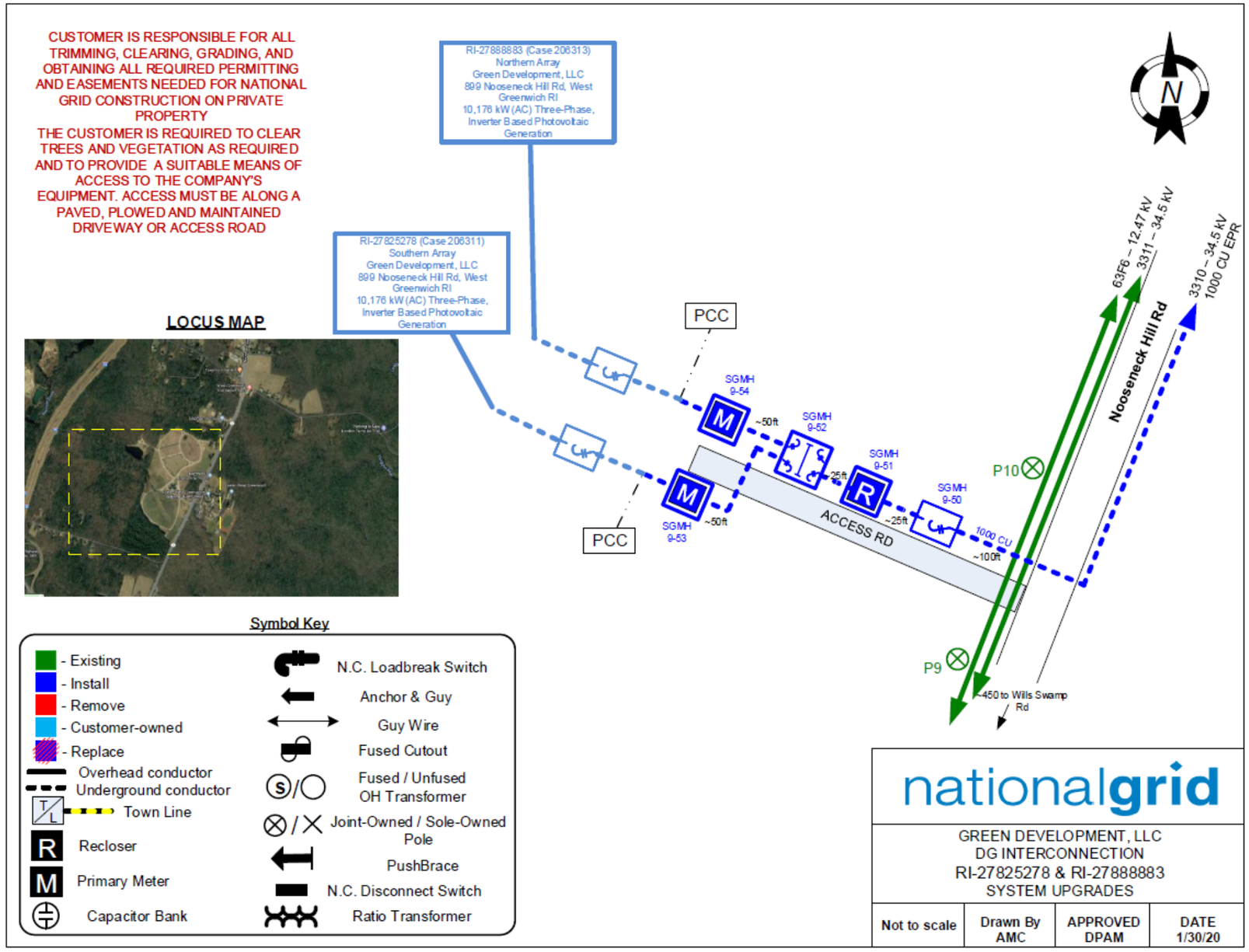


Figure B- 1: PCC Configuration

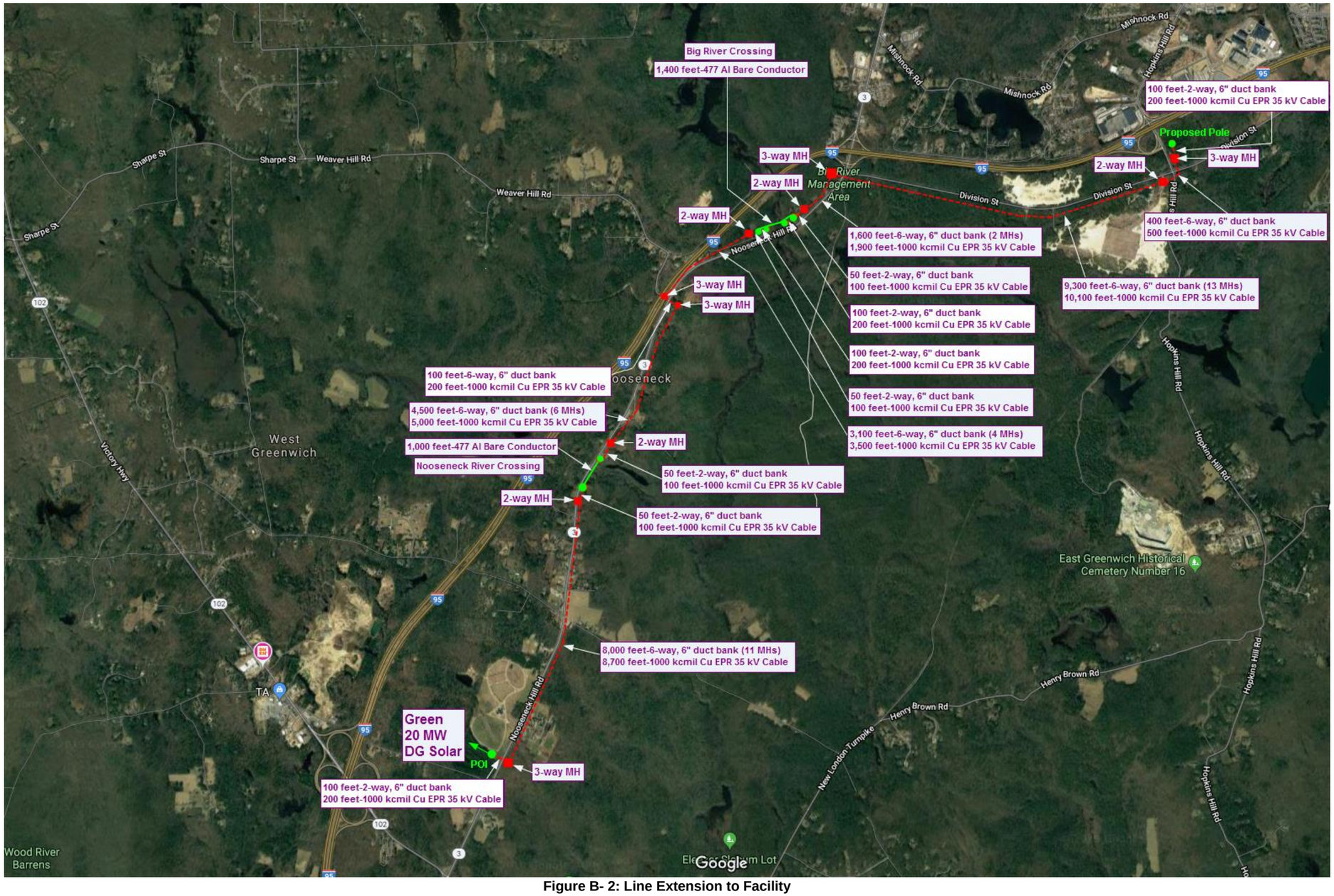


Figure B- 2: Line Extension to Facility

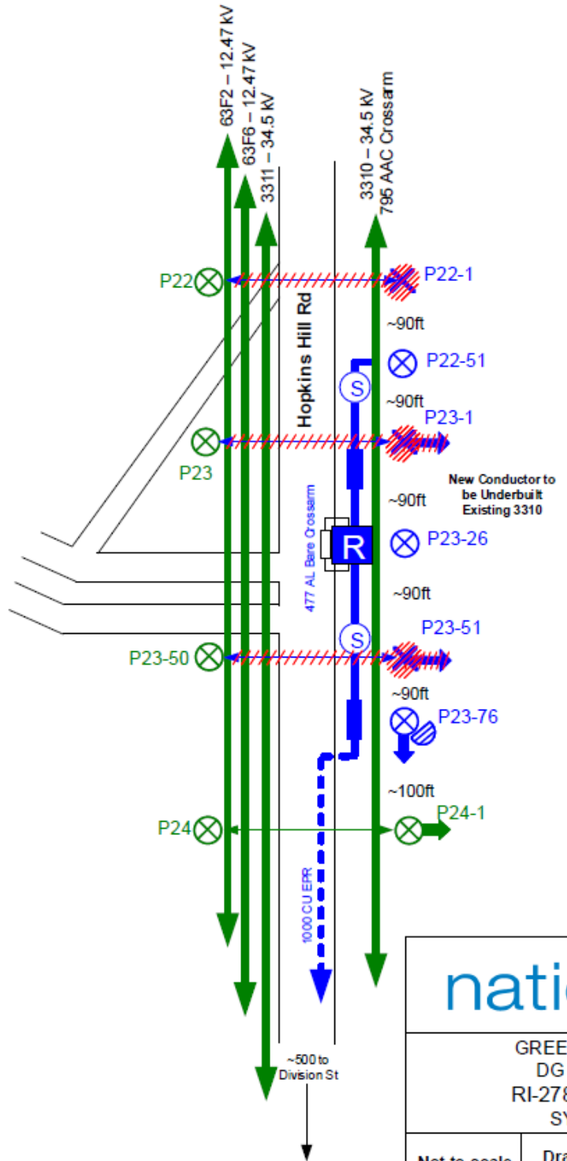
CUSTOMER IS RESPONSIBLE FOR ALL TRIMMING, CLEARING, GRADING, AND OBTAINING ALL REQUIRED PERMITTING AND EASEMENTS NEEDED FOR NATIONAL GRID CONSTRUCTION ON PRIVATE PROPERTY

THE CUSTOMER IS REQUIRED TO CLEAR TREES AND VEGETATION AS REQUIRED AND TO PROVIDE A SUITABLE MEANS OF ACCESS TO THE COMPANY'S EQUIPMENT. ACCESS MUST BE ALONG A PAVED, PLOWED AND MAINTAINED DRIVEWAY OR ACCESS ROAD

LOCUS MAP

Symbol Key

- Existing
- Install
- Remove
- Customer-owned
- Replace
- Overhead conductor
- Underground conductor
- Town Line
- Recloser
- Primary Meter
- Capacitor Bank
- N.C. Loadbreak Switch
- Anchor & Guy
- Guy Wire
- Fused Cutout
- Fused / Unfused OH Transformer
- Joint-Owned / Sole-Owned Pole
- PushBrace
- N.C. Disconnect Switch
- Ratio Transformer



nationalgrid

GREEN DEVELOPMENT, LLC
DG INTERCONNECTION
RI-27825278 & RI-27888883
SYSTEM UPGRADES

Not to scale	Drawn By AMC	APPROVED DPAM	DATE 1/30/20

Figure B- 3: Installation of Tap Recloser on Hopkins Hill Road

Appendix C Customer Site and Single Line Diagram

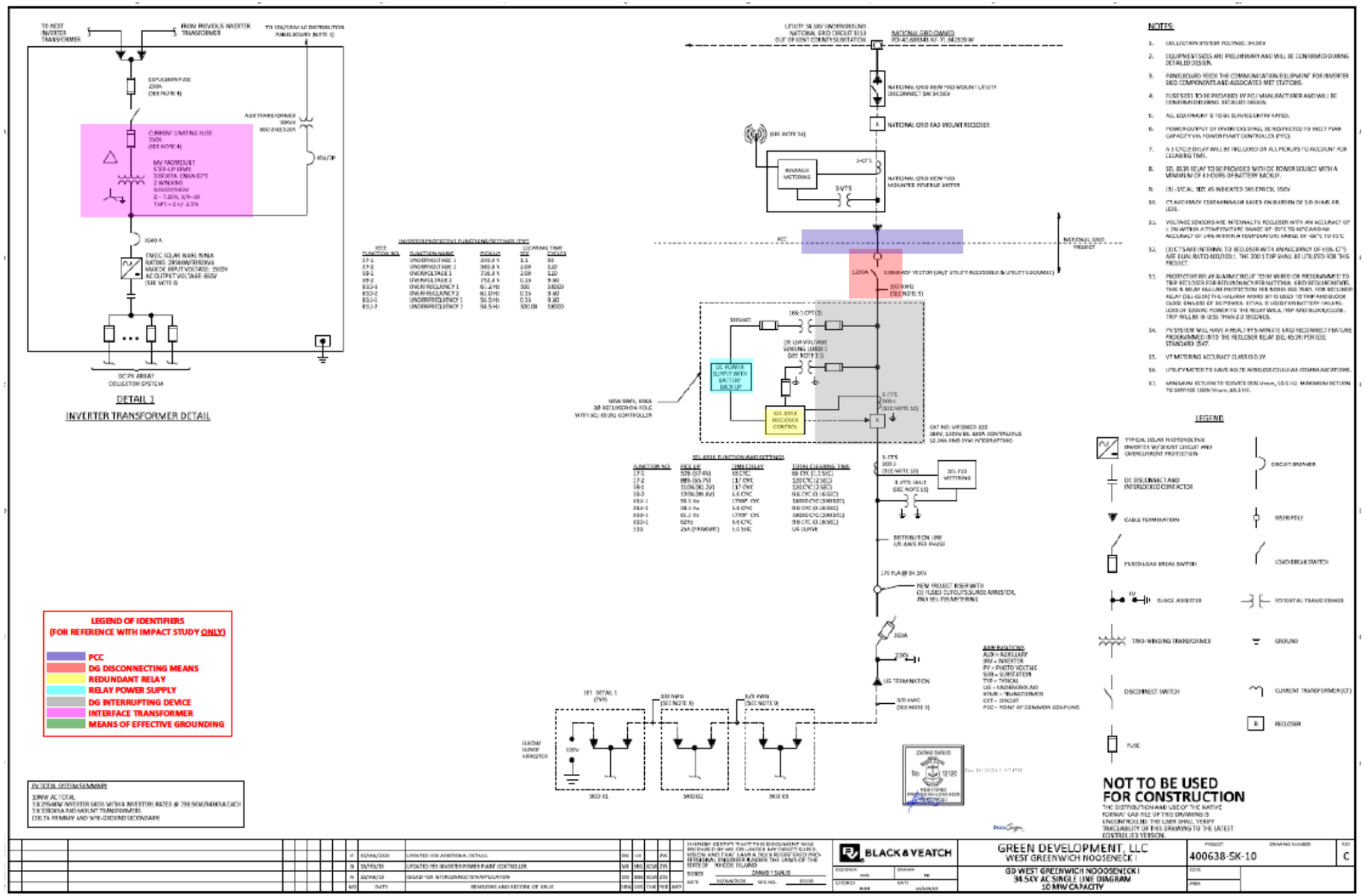


Figure C- 1: Project One-Line (Case 206311)
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

PRINTED OR DOWNLOADED COPIES ARE NOT DOCUMENT CONTROLLED.		
File: SP. RI-27825278 App File: 01-RI-27825278 and RI-27888883 Case 206311 206313_West Greenwich_DRAFT_02-14-2020	Originating Department: Distribution Planning & Asset Management – NE	Sponsor: Customer Energy Integration-NE

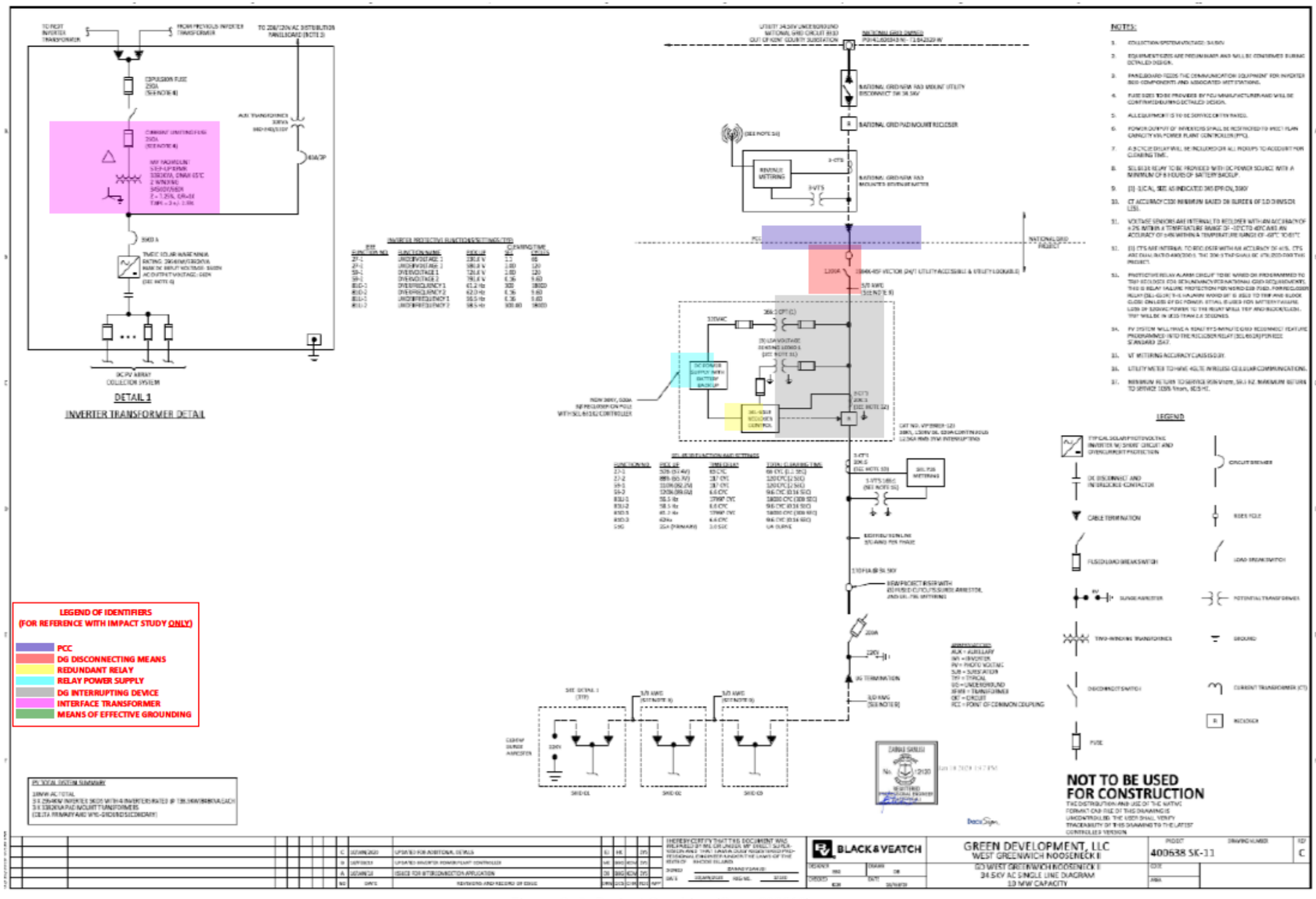


Figure C- 2: Project One-Line (Case 206313)
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

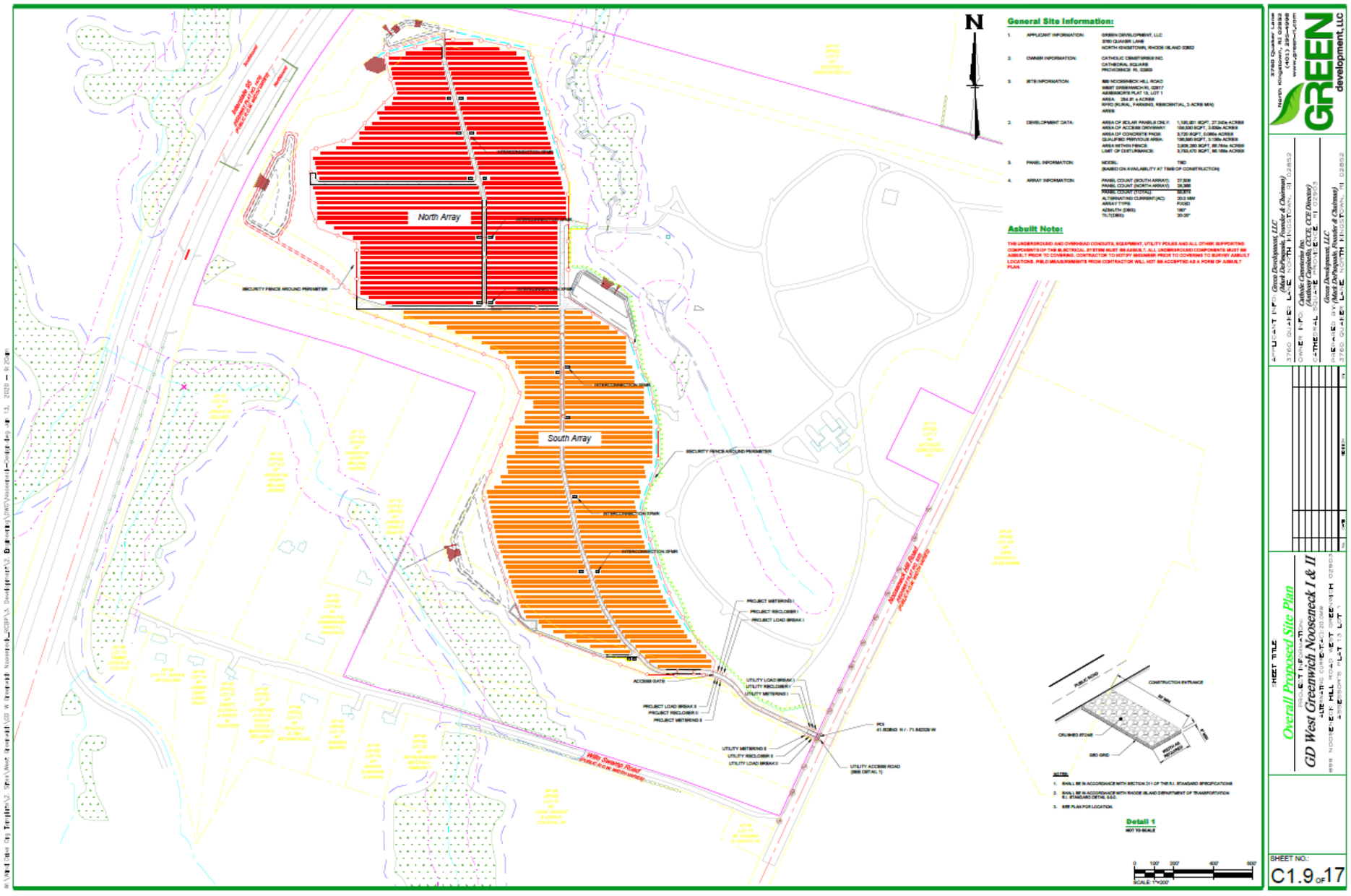


Figure C- 3: Project Site Plan

System Impact Study
for Distributed Generation Interconnection to
National Grid's 34.5 kV System

DG WR:	RI-28228074
DG Case#:	00197003
Applicant:	Energy Development Partners
Address:	189 Weaver Hill Road
City:	West Greenwich, RI
DG kW/kVA:	10,000 kW / kVA
DG Type:	Inverter Based Photovoltaic
Feeder:	3310, Kent County Substation

nationalgrid	**DISTRIBUTION PLANNING DOCUMENT** **Interconnection Study**	Doc. RI-28228074 Case #00197003 Page 2 of 37
	Complex Generating Facility - R.I.P.U.C. 2180	Version 1.0 05/11/2021
	Energy Development Partners **10,000 kW / kVA rating, Inverter Based Photovoltaic** **189 Weaver Hill Road, West Greenwich, RI**	**FINAL**

Table of Contents

Section **Page**

List of Tables

Definitions

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

BESS – Battery Energy Storage System

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DER – Distributed Energy Resources

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

MH - Manhole

NPCC – Northeast Power Coordinating Council

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

PF – Power Factor

P_{lt} – Long term flicker emission limit

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

P_{st} – Short Term flicker emission limit

P.U – Per Unit

PV - Photovoltaic

RTU – Remote Terminal Unit

Executive Summary

The Company has completed the Impact Study, for the interconnection of Energy Development Partners, ("Customer") a 10,000 kW / kVA Inverter based photovoltaic, ("the Facility"), to its 34.5 kV distribution system, ("the Project"), and presents the conclusions of the study herein.

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

System Modifications

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

1. Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work: (Section 2.2, Appendix B)
    - Install ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road.
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Weaver Hill Road to the first 3-way MH on Weaver Hill Road.
    - Install ~4100 circuit feet 3-500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
    - Install ~200 circuit feet 3-500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
    - Install ~1,400 circuit feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
        - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

2. Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2, Appendix B):
    - Install MH and duct system (~14,900 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road.

- Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
- Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are anticipated.

  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road.
  - Install MH and duct system (~3700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
  - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.

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

Special Operating Requirements

The Customer is required to comply with the following special operating requirements in order to interconnect to the Company EPS:

1. The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS. (Section 3.4)

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 $ 28,784,633 +/-25% and includes Company EPS modifications, Customer interconnection, and taxes. An estimated construction schedule will be provided in the final 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

The Customer proposes to install the following:

- Four (4) Customer owned SMA 2660-UP-US, 2,667 kW / kVA derated to 2,500 kW / kVA, three phase inverters for a total of 10,000 kW / kVA of inverter-based PV.
- Four (4) Customer owned 2,660 kVA, 34.5 kV delta primary, 600 V wye-ungrounded secondary padmounted interface transformer with an impedance of Z =6% along with X/R ratio of 7.5.
- One (1) Customer owned padmounted switchgear 35kV, 600A, 200 kV BIL G&W Viper recloser with SEL-651R relay assembly with 8-hour battery backup.
- One (1) Customer owned GOAB switch, S&C Model #147513, 200 kV BIL, 40kA with a Visible, lockable blades and utility accessible 24/7.

A copy of the Customer one lines are provided in Appendix C, illustrating the Customer's proposed design and proposed interconnection to the area EPS. The Customer documents are not binding and shall require modifications and/or clarification as identified herein.

The following parameters were assessed as part of the Project evaluation:

1. The voltage and frequency trip settings as shown on the one line (dated 04/27/2021).

Any advanced inverter functionality other than that specifically called out on the Customer documentation and/or outlined herein shall be subject to additional study before being enabled.

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is 3310, a 34.5 kV unregulated, three-phase, 3 wire, wye, ungrounded, radial, sub-transmission circuit that originates out of the Company's Kent County Substation, in West Greenwich, RI (the "Interconnecting Circuit"). This circuit is located overhead on Division Street, approximately 3.92 miles from the proposed Facility. This Line Extension will include the following work:

- Install ~410 feet of 3-1/c-477 AL Bare conductor, two (2) single phase transformers, one (1) 35 kV recloser, one (1) disconnect switch, one (1) 35 kV load break switch, and one (1) riser at the tap for the proposed line extension to the facility on Hopkins Hill Road, Coventry.
    - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.
- Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following distribution line work:
    - Install ~16,800 circuit feet of 3-500 kcmil CU EPR 35 kV cable from proposed riser pole on Hopkins Hill Road to 3-way MH at the intersection of Nooseneck Hill Road/Weaver Hill Road
        - Subject to cost sharing with previous projects. If cable work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Install ~700 circuit feet 3-500 kcmil CU EPR 35 kV cable from 3-way MH at the intersection of Weaver Hill Road to the first 3-way MH on Weaver Hill Road.

- Install ~4100 circuit feet 3-500 kcmil CU EPR 35 kV cable from the first 3-way MH on Weaver Hill Road to the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road.
- Install ~200 circuit feet 3-500 kcmil CU EPR 35 kV cable from the 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.
- Install ~1,400 circuit feet of overhead 3-477 AL Bare conductor and associated equipment on Nooseneck Hill Road.
  - Subject to cost sharing with previous projects. If work is not performed under previous projects, then the Customer will be responsible for the full cost.

- Approximately 23,200 circuit-foot line extension from Hopkins Hill Road to the Facility, which includes the following civil work: (Section 2.2, Appendix B):
  - Install MH and duct system (~14,900 feet) from proposed riser on Hopkins Hill Road to 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road
    - Subject to cost sharing with previous projects. If civil work is not performed under previous projects, then the Customer will be responsible for the full cost.
    - Corresponding MH and duct system is being designed and constructed by a third party. If this MH and duct system does not get completed, significant schedule delays are expected.
  - Install MH and duct system (~600 feet) from 3-way MH at intersection of Nooseneck Hill Road/Weaver Hill Road to first 3-way MH on Weaver Hill Road
  - Install MH and duct system (~3700 feet) from first 3-way MH on Weaver Hill Road to 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road
  - Install MH and duct system (~100 feet) from 3-way MH at EDP 10 MW POI located at 189 Weaver Hill Road to proposed riser pole on Customer property.

An underground line extension originating from the overhead line on Hopkins Hill Rd will be required to reach the proposed Facilities. There is one river that will need to be crossed with overhead conductors alongside the bridge. The Big River Bridge was not constructed to allow for installation of concrete encased ducts.

Civil work from the proposed riser pole on Hopkins Hill Road to the 3-way Manhole at the intersection of Nooseneck Hill Road and Weaver Hill Road to be performed by

others. National Grid to perform civil work from the 3-way Manhole at the intersection of Nooseneck Hill Road and Weaver Hill Road, to the proposed riser pole on Customer property.

The ability to generate is contingent on this Facility being served by the Interconnecting Circuit during normal operating conditions. Therefore, if the Interconnecting Circuit is out of service, or if abnormal operating conditions of the area EPS are in effect, the Company reserves the right to direct the Customer to disengage the Facility.

The Interconnecting Circuit has the following characteristics:

- Refer to Section 3.0 for circuit loading characteristics.
- The existing and in-process generation at the substation and on the interconnecting circuit is summarized in Table 1. Values shown are based on full nameplate DG output:

Feeder	Generation installed and operating at time of study (kW)	Generation in process at time of study (kW)	Generation proposed for this Project (kW)	*TOTAL (kW)*
3309	165	0	0	*165*
3310	434	24,248	10,000	*34,682*
3311	30,284	23,795	0	*54,079*
3312	2,735	4,049	0	*6,784*
TOTAL	*33,618*	*52,092*	*10,000*	**95,710**

Table 1: Generation at the Substation and Interconnecting Circuit

- There is one (1) existing recloser on the circuit, none of which are in between the substation and the facility, summarized in Table 2. Refer to Section 5 for further discussion on any required modifications.

Location	Status	Mid-line recloser, or existing DG project PCC recloser	In between Facility and Substation
Pole #18-1, Hopkins Hill Road, West Greenwich	In Service	Mid-line	No

Table 2: Recloser Locations

- There are no existing capacitor banks installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

- There are no existing regulators installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

2.3 Interconnection

Refer to the interconnection diagram in Appendix B for approximate PCC location.

Should the Customer elect to move forward with the Project, the Company's Design Personnel will specify the exact location of the Company's facilities and installation details. The Customer shall be responsible for obtaining all easements and permits required for any line extension not on public way in accordance with the Company's requirements.

The Customer shall provide unencumbered direct access to the Company's facilities along an accessible plowed driveway or road, where the equipment is not behind the Customer's locked gate. In those cases where Company equipment is required to be behind the Customer's locked gate, double locking, with both the Company's and Customer's locks shall be employed.

For this Project, the PCC is defined as the point where the Customer owned conductors terminate to the Company revenue meter, which is located at Pole #10-6, 189 Weaver Hill Road, West Greenwich, RI. The Customer must install their facilities up to the Company revenue meter. The Customer must provide sufficient conductor to allow the Company to make final connections at the meter pole. The Company will provide final connection of the Customer conductors to the Company meter.

If 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 Geographical Information System ("GIS"). A field review of the feeder was performed on 09/25/2019.

The analysis considered cases at peak load (16,284 kVA @ 100% PF) and net minimum load (5,017 kVA @ 99.52% Lagging PF) at time of maximum expected generation (9:00AM – 6:00PM) on the circuit.

Circuit peak and minimum load values have been taken from the Company's historical load data that has been compiled over 12 months, from 1/1/2019 to 1/1/2020.

3.1 Reverse Power Flow at Substation

The possibility of the Facility causing reverse power flow through the Company's substation transformer was reviewed.

Analysis shows that the maximum potential generation exceeds the observed minimum load on the Kent County 34.5 kV bus. However, the substation is currently equipped with bi-directional metering which was previously installed for reasons unrelated to DG work. No additional work is required on the substation bulk power metering.

3.2 Interconnecting Circuit Load Flow Analysis

The area EPS was examined with and without the Facility operating at full output. The analysis demonstrated that the addition of the Facility will not create thermal loading problems on the Interconnecting Circuit, or the associated substation.

Specifically, no conductor, transformer, or voltage regulator overloads occur as a result of this interconnection. All Company owned mainline conductor and distribution facilities are thermally large enough to accommodate the proposed generation.

3.3 Interconnecting Circuit Voltage Analysis

The Company is obligated to hold distribution voltages at customer service points to defined limits in ANSI Standard C84.1- 2006. Range A of the ANSI standard requires the Company to hold voltage within +/- 5% of nominal at the PCC.

Under emergency conditions, voltage on the system could reach 90% of nominal prior to corrective action being taken. The Customer is advised to consider this in planning their system requirements and equipment settings, however, no warranties or guarantees are implied.

Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the system generation at full power. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. Also, the PV interconnection shall not contribute to greater than a 3.0% change in steady state voltage on the EPS under any conditions.

The analysis of this facility determined that when the Facility generation is at full output, the voltage range at the PCC was within acceptable limits.

Customer provided manufacturer's test reports have been reviewed for 1.4PU pickup values with 1ms or less total clearing time. The proposed design has been found to meet the necessary requirements.

3.4 Flicker Analysis

The IEEE 1547 standard and IEEE 1453 flicker assessments were used to estimate whether or not this site would be likely to cause unacceptable voltage flicker on the interconnecting feeder. This method evaluates for both short term and long-term voltage flicker against IEEE1547-2018 Table 25 - DER Flicker Emission Limits.

Analysis shows that P_{st} and P_{lt} are within acceptable limits and no mitigation for voltage flicker is recommended.

The IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems, IEEE Std. 1453-2015 was used as a basis for flicker and voltage fluctuation analysis.

This Facility was modeled using the Long-Term Dynamics module of CYME[1]. A long-term dynamic profile for the Facility was used that simulates the voltage fluctuation of the site over a 6-hour period. Other significant DG existing or in process ahead of this Project were modeled at full output and modeled with the appropriate voltage fluctuation curve to simulate reasonable voltage fluctuations.

The generation profile used is based on live metered data from a PV site that is similar in size to this Project. The data is intended to simulate realistic power output from the site, resulting in a varied output from the PV.

Given the nature of flicker, it is impossible to predict voltage flicker under all conceivable environmental conditions. Therefore, the flicker results are used as a metric to evaluate whether or not there is a readily apparent concern related to voltage flicker.

The Company will not be held liable for any power quality issues that may develop with the Customer or any other customers as result of the interconnection of this generation.

Analysis shows that the predicted flicker and voltage fluctuations are expected to be acceptable, provided that the following conditions are met:

- The system modifications identified elsewhere in this study are implemented.
- The reactive contribution of the PV at the PCC operates at 99.5% PF exporting VARs into EPS.

[1] CYME Power Engineering Software, Version 8.1, Revision 01, Build 115, Copyright © 1986-2017, Cooper Industries, Ltd.

4.0 Risk of Islanding

4.1 Islanding Analysis (ESB 756D Section 7.6.12)

The project was screened for the potential of islanding risk. Per IEEE 1547 *section 4.4.1 Unintentional Islanding*, for an unintentional island in which the DG energizes a portion of the Area EPS through the PCC, the DG interconnection system shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 3 was considered on this feeder. Three-phase projects greater than 100kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
442	All Projects <100kW CERTIFIED
0	All Projects <100kW Non-CERTIFIED
740	CERTIFIED
3,500	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED
10,000	CERTIFIED

Table 3: Generation Considered for Risk of Islanding Analysis

Analysis indicates that the overall ability of this Facility to island more than 2.0 seconds is considered a likely event. As a result, a PCC recloser with reclose blocking will be required. Additionally, live-line reclose blocking must be implemented at the following line reclosers summarized in Table 4.

Location	Status (Existing or New)
Pole #25-1, Hopkins Hill Road, Coventry, RI	New

Table 4: Recloser Locations

5.0 Short Circuit and Protection Analysis Company Facilities

The Company performed a review of the Project relative to the short circuit and protective device impacts on the Interconnecting Circuit. This review identifies EPS enhancements that are necessary to complete the Project and its ability to meet Rhode Island R.I.P.U.C 2180 interconnection tariff and the requirements of the Company's ESB 756D. The Interconnecting Circuit, including all relevant DG was modeled in a software package called ASPEN OneLiner[2]. The model was developed using Company records for feeder characteristics, and Customer provided documentation.

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

Addition of generation sources to sub-transmission feeders can result in the back-feeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. Due to the Kent County T1, T2 and T7 supply transformer configurations, there is a path for zero sequence ground fault current to single line to ground faults on the transmission line. Therefore, the Facility does not pose a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Substation modifications related to $3V_0$ are not required**.**

5.2 PCC Impedance

The Interconnecting Circuit impedance is shown below in per unit at the PCC for the proposed Facility, using a 100 MVA base. The PCC location is shown in Appendix B. These values take into account existing system conditions, but not the impact of the Customer's new Facility.

Pre-Project

System Impedance at PCC

Z1 = 0.05 + j0.26 p.u.

Z0 = 0.65 + j1.38 p.u.

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

5.3 Fault Current Contributions

Table 5 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings. Mitigation strategies are required to accommodate the proposed Facility, as described in Sections 5.4 and 5.5.

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

PRE PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)
3-phase (LLL)	21581	3999
Phase-Ground (LG)	24066	2346

POST PROJECT	SUB BUS (Amps @ 34.5 kV)	PCC (Amps @ 34.5 kV)	DELTA I_{fault} @ SUB BUS	DELTA I_{fault} @PCC
3-phase (LLL)	21779	4199	1%	5%
Phase-Ground (LG)	24322	2478	1%	6%

Table 5: Fault Duty

5.4 Substation Protective Device Modifications

The protection coordination review of the area EPS revealed that the following modifications to the existing substation protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study:

- Add load encroachment settings to the Kent County Transformer #7, 34.5 kV directional overcurrent relay (67)

5.5 Area EPS Protective Device Coordination

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

The existing device settings and associated time-current curves were evaluated for protective devices on the Interconnecting Circuit.

The protection coordination review of the area EPS revealed that the following modifications to the existing EPS protective devices will be required. Associated costs are identified in Section 9.0 of this Impact Study. Refer to Appendix B for system modification drawings:

- Install a recloser at the tap for the proposed line extension to the facility at Pole #25-1, Hopkins Hill Rd, Coventry, RI. (Appendix B-3)

6.0 Customer Equipment Requirements

The following Section discusses requirements for Customer owned equipment, which are further outlined in detail in ESB 756D. References to ESB 756D are provided in each sub-section below. It is the Customer's responsibility to comply with all requirements of ESB 756D. Please note that applicable sections of ESB 756D are referenced for information purposes and may not comprise the entirety of applicable sections.

In general, the Customer Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Standard C62.41.2-2002 or IEEE Standard C37.90.1-2002 as applicable.

6.1 Revenue Metering Requirements (ESB 756D Section 7.2.2 and 7.2.3)

For systems greater than 25kW, Interconnecting Customer shall provide a means of communication to the 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.

6.2 Interconnecting Transformer (ESB 756D Section 7.3)

The documentation provided states the interconnecting transformer is four (4) Customer owned 2,660 kVA, 34.5 kV delta primary, 600 V wye-ungrounded secondary

padmounted interface transformer with an impedance of Z =6% along with X/R ratio of 7.5.

The proposed transformer satisfies the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

The Facility is proposing to connect to a non-effectively grounded 34.5 kV circuit, and therefore does not require a means of effective grounding.

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

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

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

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

6.5.1 Primary Protective Relaying (ESB 756D Section 7.6.1, 7.6.2, 7.6.11, & 7.8)

The Customer provided documents indicate that the generator/inverter will be provided with an internal relay that will trip the generator interrupting device. Proposed settings for the 27, 59, 81O/U functions have been provided for review.

6.5.2 Primary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable inverter relay settings in accordance with the aforementioned requirements.

6.5.3 Primary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.11 and 7.8. This requirement is met.

6.6 Secondary Protection

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

6.6.1 Generator Interrupting Device (ESB 756D Section 7.5)

A Company owned recloser is required at the PCC, which will contain utility facing protective elements (27, 59, 81O/U). A Generator Interrupting Device shall be installed for site protection, with overcurrent functionality. The Customer design shows a circuit breaker for site protection.

The Customer provided documents indicate an interrupting device on the high side (Customer 34.5 kV side) of the interconnecting transformer, which satisfies the requirements of ESB 756D.

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

The Customer provided documents show a phase overcurrent (51) relay element and associated settings.

Customer proposed settings are provided on the Customer drawings, as attached in Appendix C.

51 – Phase

Customer Proposed: 300A primary amps pickup, 2 second time delay, U4 curve.

6.6.3 Secondary Protective Relaying (ESB 756D Section 7.6.3)

The Customer provided documents indicate that a redundant utility grade relay is provided that will trip the generator interrupting device. Relays make/model is included on the Customer single line.

6.6.4 Secondary Frequency Protection (ESB 756D Section 7.6.8, 7.6.11.1, and 7.8)

Frequency elements trip settings for primary relaying are required to comply with ISO-NE ride-through requirements as described in ESB756D Section 7.6.8, 7.6.11, and 7.8.

The R.I.P.U.C. No. 2180, requires that, the DER cease to energize the area EPS within 2 seconds, refer to IEEE1547 and UL1741.

The Customer provided documents show acceptable relay settings in accordance with the aforementioned requirements.

6.6.5 Secondary Voltage Relay Elements (ESB 756D Section 7.6.7, 7.6.11.1, and 7.8)

The Customer provided documents show undervoltage (27) and overvoltage (59) elements that satisfy the requirements of this Section of ESB 756D. The Customer provided documents show neutral overvoltage (59N) that are unacceptable.

Voltage relay elements trip settings are required to comply with ISO-NE ride-through requirements as described in ESB756C Section 7.6.11 and 7.8. This requirement is met.

The Customer provided one-line diagram shows acceptable settings for neutral overvoltage 59N protection.

59N – Neutral Overvoltage

Customer Proposed: $3V_0$ = 12.45 kV primary pickup (46.7 V), 0.8 second time delay.

6.6.6 Current Transformers ("CT") (ESB 756D Section 7.6.4.1)

The Customer provided documents show current transformer with ratings listed, which satisfies this Section of ESB 756D.

6.6.7 Voltage Transformers ("VT") and Connections (ESB 756D Sections 7.6.4.2)

The Customer provided documents show wye-grounded/wye-grounded VT's and show the VT ratio, which satisfies this Section of ESB 756D.

6.6.8 Protective Relay Hard-Wiring (ESB 756D Section 7.6.5)

The Customer provided documents call for hardwiring of the redundant relaying trip circuits, therefore satisfies the requirements of this section of ESB 756D.

6.6.9 Protective Relay Supply (ESB 756D Section 7.6.5 and 7.6.6)

The Customer provided documents indicate a power supply for the redundant relay that satisfies the requirements of this section of ESB 756D.

The Customer has proposed a DC power supply. The Customer shall demonstrate in the witness test that the relay will trip if the DC voltage goes out of the normal operating range.

It is recommended that the power DC power supply be connected to the utility (source) side of the interrupting device in order to ensure power availability to close the interrupting device after an extended outage. This is a recommendation, for consideration by the Customer. It is not a requirement by the Company.

6.6.10 Utility Restoration Detection (ESB 756A Section 4.5.2.7 & 756C Section 7.8.3)

The DER shall not connect or return to service following a trip (including any ground fault current sources) until detecting a minimum 5 minutes of healthy utility voltage and frequency. "Healthy Utility Voltage and Frequency" is defined by ESB 756D Table 7.8.3-1. The five-minute time interval is required to restart if the utility voltage or frequency falls outside of this window.

All the devices associated with five-minute timing must meet IEEE C37.90 standard and be capable of withstanding voltage and current surges.

The Customer provided settings and timing device information is acceptable as shown.

6.6.11 Relay Failure Protection (ESB 756D Section 7.6.3)

For all required tripping functions, either redundant relaying or relay failure protection, where a hardware or power supply failure for the redundant relay automatically trips and blocks close of the associated breaker, is required.

The Customer's one line diagram shows devices and settings to satisfy this requirement.

6.7 Synchronizing Devices (ESB 756D Section 7.6.9 and 7.6.11.2)

Project is inverter based; therefore, synchronizing devices are not required.

6.8 Customer Cabling

The Company is not responsible for the protection of the Customer cable and primary protection for the Customer cable must be provided at the change of ownership.

7.0 Telemetry and Telecommunications

The Customer is advised to communicate with ISO-New England for any telemetry requirement as ISO-NE may require real-time monitoring between ISO-NE EMS and the DG site. The Customer shall refer to the ISO-NE website and ISO-NE customer service help desk for details.

This project is considered an independent power producer (IPP), an RTU for telecommunication will not be required by the Company.

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

8.1 Inspections and Compliance Verification

A municipal electrical inspection approval certificate from the local authority having jurisdiction is required of the Customer's Facilities (i.e. primary service entrance conduit, primary switchgear, wiring, and generation equipment). The Company must receive the Customer's Draft set of Project documentation and test plan for the

functional verification tests at least four (4) weeks before the Company's field audit. Documentation from the customer must include, but not be limited to:

- Equipment cut sheets and shop drawings for all major equipment.
- Inverter manufacturer cut sheet including method of island detection and UL certification.
- Inverter protective relay settings
- Settings for any other Customer relay related to the Project.
- The most recent version of the single line diagram and site plan, reflecting all modifications required in this Impact Study.
- Single line diagram of the Facility
- Site diagram of the Facility
- A 3-line diagram and DC schematic illustrating the protection and control scheme.
- The proposed testing procedure
- The proposed energization plan.
- All provided Customer drawings shall be stamped and signed by an Electrical Professional Engineer that is licenses in the state where the Facility is located.

The DG Customer shall adhere to all other Company related verification and compliance requirements as set forth in the applicable ESB 750 series documents. These and documented acceptance testing requirements of these facilities will be specified during the Draft design review of the Project prior to the Company's field audit and energization.

8.2 Testing and Commissioning

The Customer shall submit initial relay settings to the Company no later than twenty-one (21) calendar days following the Company's acceptance of the Facility's service connection's Draft MA state licensed professional engineer sealed design. If changes/updates are necessary, the Company will notify the Customer three (3) business days after the initial relay settings were received, and the Customer shall submit the revised settings within seven (7) calendar days from such notification. Within three (3) business days of receipt of the proposed Draft relay settings, the Company shall provide comments on and/or acceptance of the settings. If the process must continue beyond the above identified time frames due to errors in the relay settings, the Company retains the right to extend the Testing and Commissioning process, as needed, to ensure the Draft relay settings are correct.

Assuming no major issues occurring with the relay settings, the Customer shall submit a Testing and Commissioning Plan (TCP) to the Company for review and acceptance, no later than forty-five (45) calendar days following the Company's acceptance of the Facilities Draft design. The TCP must be drafted, including Company acceptance, no later than six (6) weeks prior to functional testing. The Company requires a minimum of 5 business days for review of any submitted documentation.

8.3 Energization and Synchronization

The "Generator Disconnect Switch" at the interconnection point shall remain "open" until successful completion of the Company's field audit and witness testing.

Prior to the start of construction, the DG Customer shall designate an Energization Coordinator (EC), and prepare and submit an Energization Plan (EP) to the Company for review and comment. The energization schedule shall be submitted to the Company and communicated with the Company's local Regional Control Center at least two (2) weeks in advance of proposed energization. Further details of the EP and synchronization requirements will be specified during the Draft design review of the Project.

The Customer shall submit as-built design drawings to the Company 90 days following commercial operation of their DG Facility.

9.0 Cost Estimate

The non-binding good faith cost planning grade estimate for the Company's work associated with the interconnection of this Facility to the EPS, as identified in this report, is shown below in Table 6:

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 - Civil Work	**Pre-Tax Total**	**Capital**	**O&M**	**Removal**	**11.08%**	**Total**
Distribution Civil work, 3310 circuit See Note #2 (Cost Sharing may be applicable)	$19,960,065	$19,960,065	$0	$0	$2,211,575	$22,171,640
SUBTOTAL	**$19,960,065**	**$19,960,065**	**$0**	**$0**	**$2,211,575**	**$22,171,640**

NECO - Line Work, Customer Property	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Equipment at Point of Common Coupling, 3310 Circuit. See Note #3	$310,038	$310,038	$0	$0	$34,352	$344,390
SUBTOTAL	**$310,038**	**$310,038**	**$0**	**$0**	**$34,352**	**$344,390**

NECO - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Distribution Line work, 3310 Circuit. See Note #4 (Cost Sharing may be applicable)	$5,621,801	$5,612,059	$5,272	$4,470	$621,816	$6,243,617
SUBTOTAL	**$5,621,801**	**$5,612,059**	**$5,272**	**$4,470**	**$621,816**	**$6,243,617**

NECO - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
Add Load Encroachment to the Kent County T7 Directional Overcurrent Relay. (Cost Sharing may be applicable)	$16,000	$15,000	$1,000	$0	$1,485	$17,485
SUBTOTAL	**$16,000**	**$15,000**	**$1,000**	**$0**	**$1,485**	**$17,485**

Witness Testing & EMS	Pre-Tax Total	Capital	O&M	Removal	NA	Total
Witness Testing. See Note #5	$2,500	NA	$2,500	NA	NA	$2,500
EMS integration. See Note #6	$5,000	NA	$5,000	NA	NA	$5,000
SUBTOTAL	**$7,500**	**$0**	**$7,500**	**$0**	**$0**	**$7,500**

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	$25,915,404	$25,897,162	$13,772	$4,470	$2,869,229	$28,784,633

Notes

1. Definition of abbreviation: NECO-Narangansett Electric Co.; NEPCO-New England Power Co.
2. Installation of (6) - 3-way manholes, (26) - 2-way manholes, (400 feet) - 2 way, 6" PVC - DB concrete encased duct bank, (18,300 feet) 4 way, 6" PVC - DB concrete encased duct bank, (600 feet) 9 way, 6" PVC - DB concrete encased duct bank and associated equipment. For estimating purposes, permanent restoration for civil work is assumed to be twelve (12) feet in width. Note: Should additional permanent restoration (i.e., Curb to curb or centerline to curb) be required, the cost of civil construction could increase.
3. Installation of pole-mounted equipment at the POI-PCC, including approximately 250 feet of 3-477 Al Bare conductor, one (1) 35 kV load break switch, one (1) 35 kV recloser, two (2) single-phase transformers, one (1) primary meter, and associated equipment.
4. Extend the Kent County 3310, 34.5 KV circuit underground from proposed Pole #25-1, Hopkins Hill Road, West Greenwich, RI to the 3310 PCC-POI located at 189 Weaver Hill Road, West Greenwich, RI. (approximately 4.4 Miles). Estimate included in table above assumes installation of 3-1/c-500 kcmil CU EPR 35 KV cable, and associated equipment. Costs include one (1) bridge crossing with risers to 477 Al bare conductor, Installation of new tap recloser located at Pole #25-1, Hopkins Hill Road, West Greenwich, RI, and associated equipment.
5. Witness Testing including review of witness test documentation and manpower for attending witness test.
6. Integration of DG and EPS modifications into Company's Energy Management System (EMS)

Table 6: Cost Estimates

The planning grade estimate provided herein is based on information provided by the Interconnecting Customer for the study and is prepared using historical cost data from similar projects. The associated tax effect liability included is the result of an IRS rule, which states that all costs for construction collected by the Company, as well as the value of donated property, are considered taxable income.[3] This estimate is valid for ninety (90) calendar days from the issuance of this report, after which time it becomes void. If the Interconnection Customer elects to proceed with this project after the ninety (90) calendar days, a revised estimate may be required.

This interconnection application may result in costs charged to The Narragansett Electric Company (the Company) by an Affected System Operator (ASO). Please note that in addition to the payment obligation for your share of the cost of any transmission upgrades identified in an ASO Study or identified during the Distribution System Impact Study of your application, when your facility is energized you also will be assessed for the on-going carrying charges for the transmission upgrades (plus cost security before your facility is energized), as specified in your Interconnection Service Agreement. The on-going carrying charges include O&M, property taxes, and other carrying costs associated with transmission upgrades. The transmission upgrades and on-going carrying charges are calculated and charged to the Company by the ASO, in most instances the Company's transmission provider, New England Power Company (NEP), in accordance with the ASO's tariff (for NEP, Schedule 21-NEP, Attachment DAF, to the ISO-NE Open Access Transmission Tariff ("DAF Charges") and data from the FERC Form 1). You will be charged initially on an estimated basis for the transmission upgrade costs, which will be reconciled to actual costs. On-going carrying charges are calculated by multiplying the capital portion of the

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

transmission upgrade costs by the transmission carrying charge rate in effect at the time. For NEP, the on-going carrying charge rate is subject to adjustment annually as estimated transmission upgrade costs are reconciled to actual costs. The current on-going carrying charge rate for NEP is 5.21%.

The estimated duration for the Company to complete construction of the System Modifications will be identified in the final Interconnection Service Agreement.

The project schedule may be impacted by the ability to have planned outages to allow work to take place on the distribution system. Outages will be contingent on the ability to support the load normally supplied by affected circuits. The schedule can also be impacted by unknown factors over which the Company has no control. The interconnection schedule is contingent on the Interconnecting Customer's successful compliance with the requirements outlined in this report and timely completion of its obligations as defined in *ESB756D, Exhibit 2: Company Requirements for Projects Not Eligible for the Simplified Process*. The schedule for the Company's work shall be addressed during the development, or after the execution, of the Interconnection Agreement.

10.0 Conclusion

The project was found to be feasible. It will be allowed to interconnect with certain system modifications and additions to the local Company EPS. Associated costs are provided in Section 9.0.

The Customer must submit revised documentation as identified herein, to the Company for review and approval before an ISA can move forward.

A milestone schedule shall be included in the final ISA and shall be reflective of the tasks identified in ESB756D, Exhibit 2. Upon execution of the final ISA, and prior to advancing the project, the Customer shall provide a detailed project schedule, inclusive of the Exhibit 2 tasks referenced above. After completion of final design and all associated applications, fees, permitting and easement requirements are satisfied, System Modifications for this Project will be placed in queue for construction.

If a Customer fails to meet the R.I.P.U.C. No. 2180, Section 3.4 Time Frames and does not provide the necessary information required by the Company within the longer of 15 days or half the time allotted to the Company to perform a given step, or as extended by mutual agreement, then the Company may terminate the application and the Customer must re-apply.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and successful completion of the Company approved witness testing. Such authorization shall be provided in writing.

11.0 Revision History

Version	Date	Description of Revision
1.0	05/11/2021	Issue to Customer

Appendix A Revenue Metering Phone Line Requirements

An analog phone line to National Grid's revenue meter shall be provided by the Customer. The analog phone line must be capable of direct inward dial without human intervention or interference from other devices such as fax machines, etc. The phone line can be a phone (extension) off the customers PBX phone system, or it may be a separate dedicated phone line as provided by the Telephone Company. The following is to be used as a guide, please contact the Company if additional information is required. The most common installations are outlined below, Wall mounted Meter Installation, Outdoor Padmount Transformer Meter Installation, and Outdoor Pole Mounted Meter Installation.

1) WALL MOUNTED METER INSTALLATION
If the meter is wall mounted indoor or outdoor the customer shall provide a telephone line within 12" of the meter socket and additional equipment as described and shown below in figures 1A & 1B. National Grid will connect the meter to the customer provided phone line.

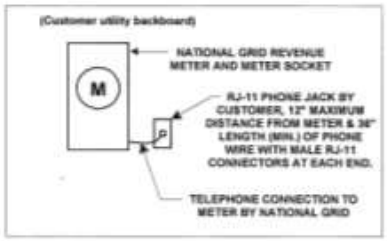


Figure 1A – Indoor Meter Installation
not to scale

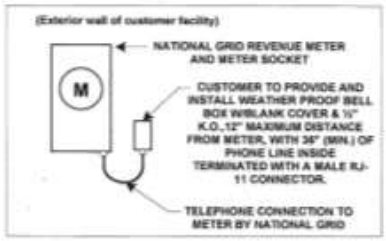


Figure 1B – Outdoor Meter Installation
not to scale

2) OUTDOOR PADMOUNT TRANSFORMER METER INSTALLATION
If the meter is mounted outside on the secondary compartment of the padmount transformer as shown below the conduit shall stub up and roughly line up with the bottom or side knock out of the meter socket and terminate into a weatherproof box or fitting. A liquid tight flexible conduit whip with end bushing and locknut of sufficient length to reach and terminate at the knockout location of the meter socket with three feet of telephone wire coiled (and terminated with a male RJ-11 connector) at its end shall be connected to the weatherproof box or fitting. National Grid will connect the conduit whip to the meter socket and terminate the telephone wire to the meter (see figure 2 below).

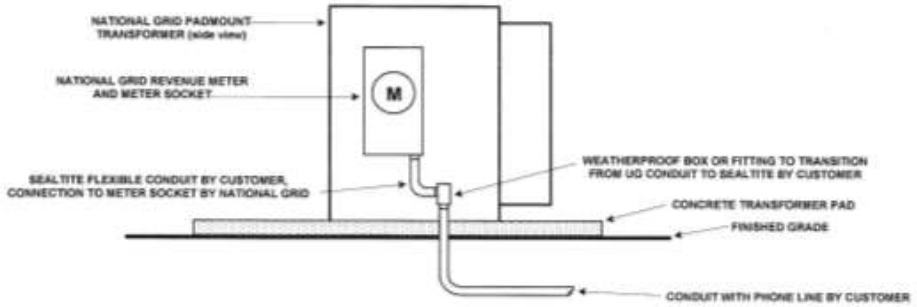


Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

If the meter is located outdoor on a Company owned utility pole as part of a primary metering installation the Customer will install and connect a phone line from the Telephone Company provided termination interface box, the line shall be terminated with a RJ-11 male connector and be of sufficient length to reach the meter socket and create a drip loop, as well as additional line for final connection to the meter. The customer is responsible for the Telephone Company phone line installation. (see figure 3 below).

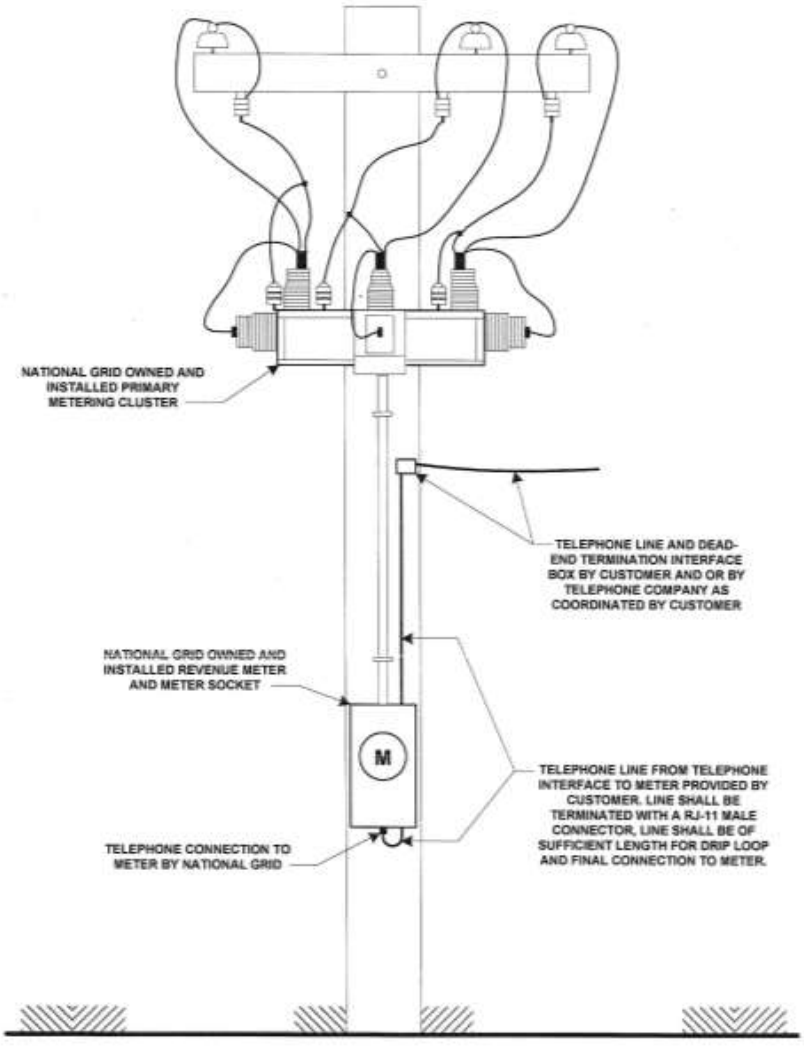


Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

Note: Company EPS modification diagrams provided in this Appendix are intended as a diagrammatic reference of work required to be completed before this Facility may interconnect. The Company will be performing a detailed design following this Impact Study, should the Customer elect to move forward with the interconnection process. At that time, the Company will determine exact locations and requirements for system modification designs. Refer to the body of this Impact Study for further discussion regarding specific EPS modifications that are required for the interconnection of this Facility.

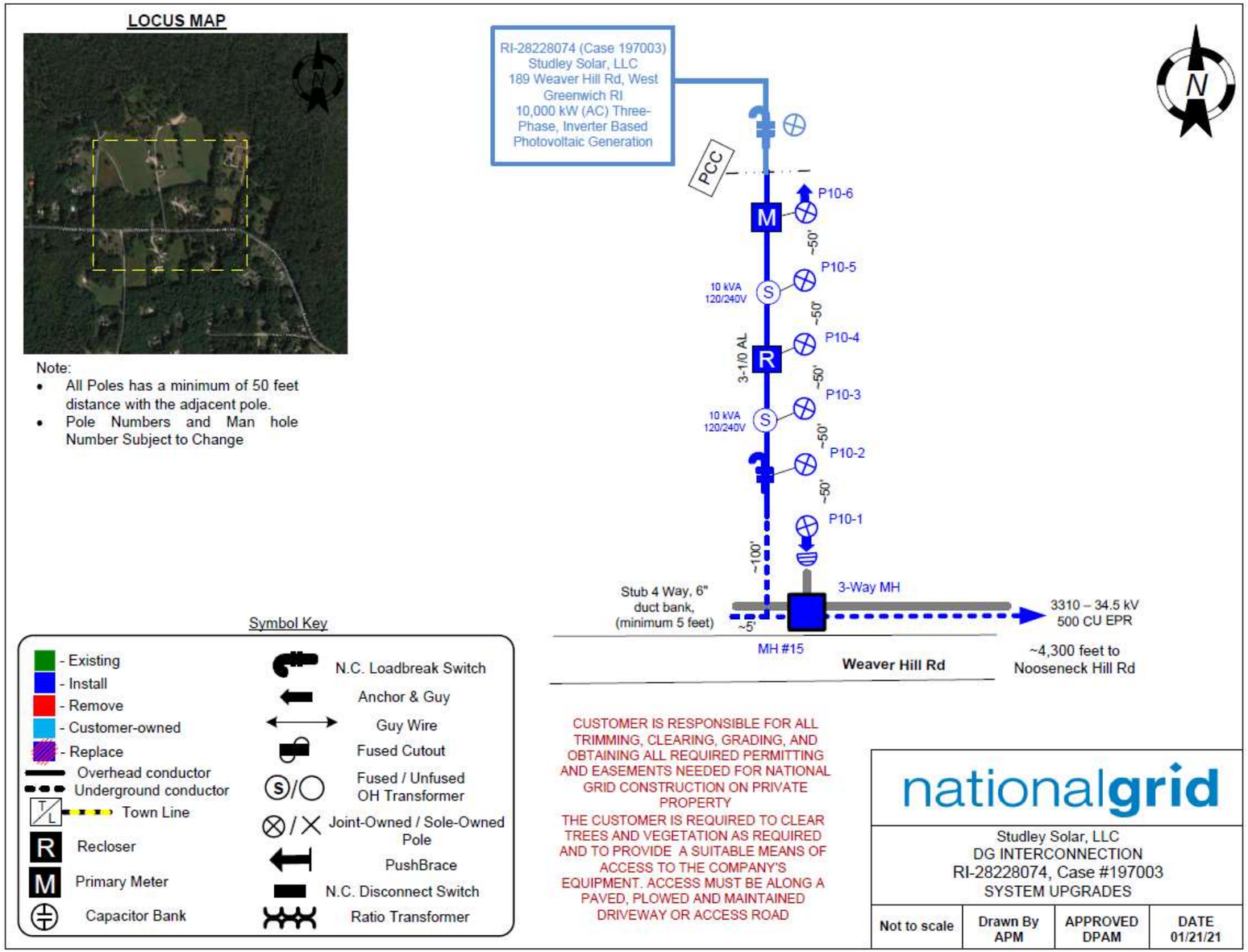


Figure B- 1: PCC Configuration

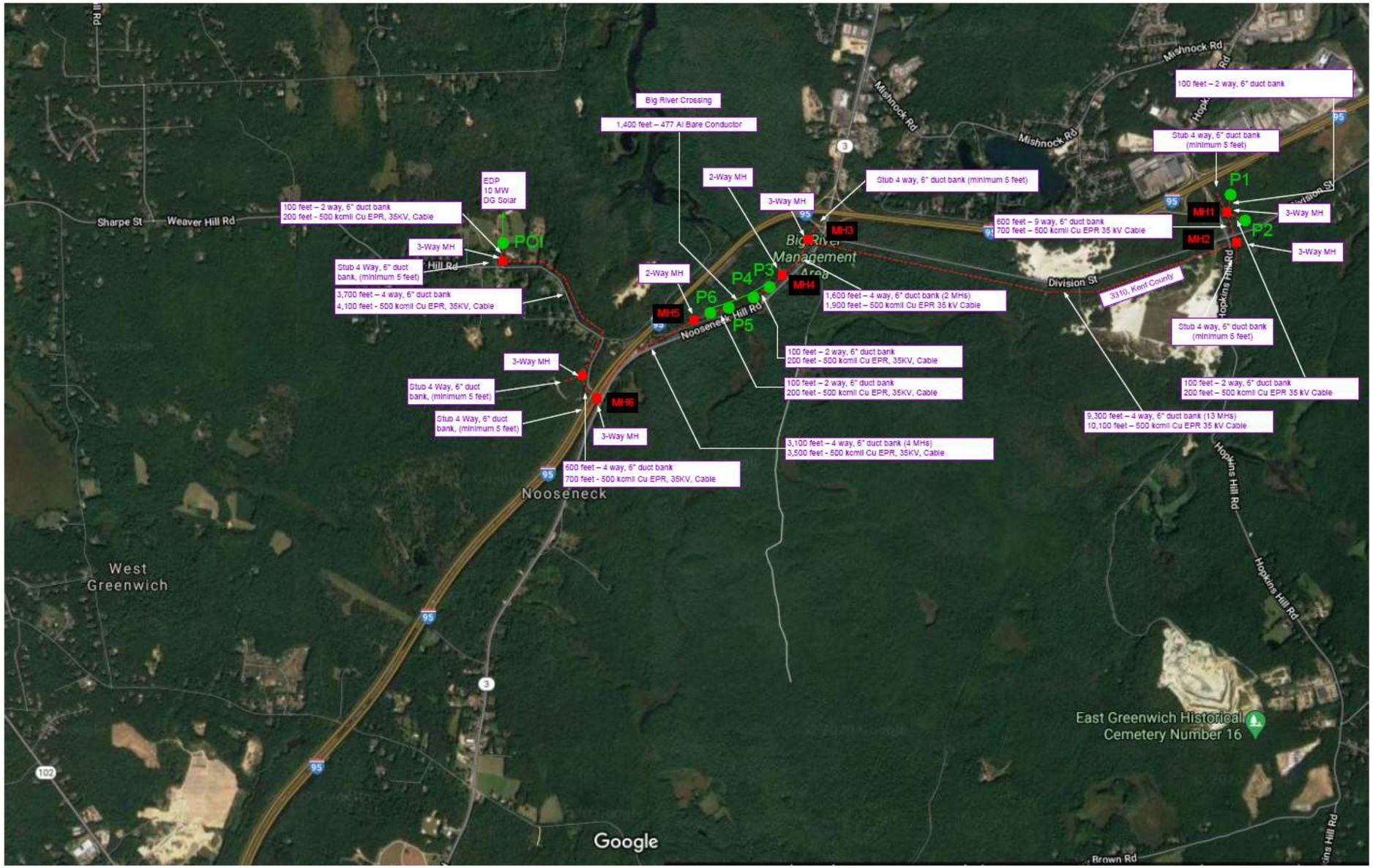


Figure B- 2: System Modification

PRINTED OR DOWNLOADED COPIES ARE NOT DOCUMENT CONTROLLED.		
File: SP. RI-28228074 App File: 01-RI-28228074_Case-197003_West-Greenwich_Final_5.11.2021	Originating Department: Distribution Planning & Asset Management – NE	Sponsor: Customer Energy Integration-NE

CUSTOMER IS RESPONSIBLE FOR ALL TRIMMING, CLEARING, GRADING, AND OBTAINING ALL REQUIRED PERMITTING AND EASEMENTS NEEDED FOR NATIONAL GRID CONSTRUCTION ON PRIVATE PROPERTY
THE CUSTOMER IS REQUIRED TO CLEAR TREES AND VEGETATION AS REQUIRED AND TO PROVIDE A SUITABLE MEANS OF ACCESS TO THE COMPANY'S EQUIPMENT. ACCESS MUST BE ALONG A PAVED, PLOWED AND MAINTAINED DRIVEWAY OR ACCESS ROAD

LOCUS MAP

Symbol Key

- Existing
- Install
- Remove
- Customer-owned
- Replace
- Overhead conductor
- Underground conductor
- Town Line
- Recloser
- Primary Meter
- Capacitor Bank
- N.C. Loadbreak Switch
- Anchor & Guy
- Guy Wire
- Fused Cutout
- Fused / Unfused OH Transformer
- Joint-Owned / Sole-Owned Pole
- PushBrace
- N.C. Disconnect Switch
- Ratio Transformer

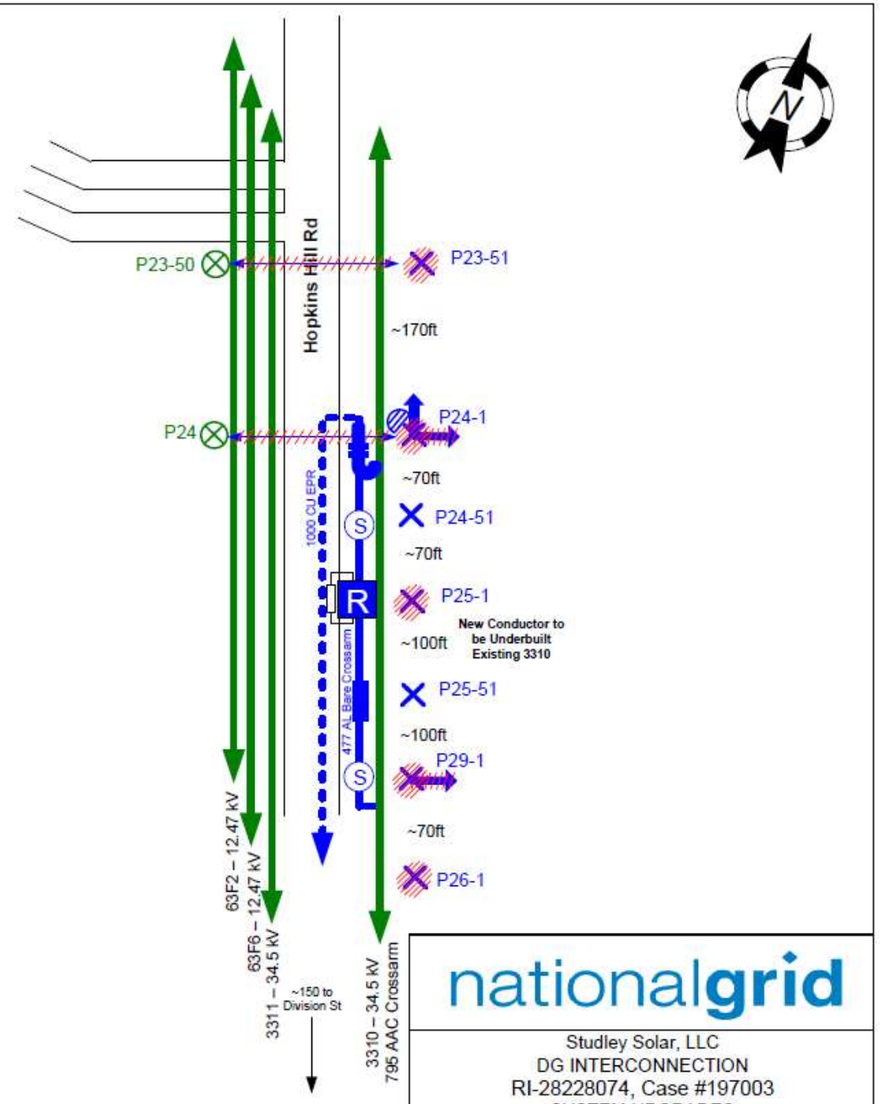


Figure B- 3: System Modification

Appendix C Customer Site and Single Line Diagram

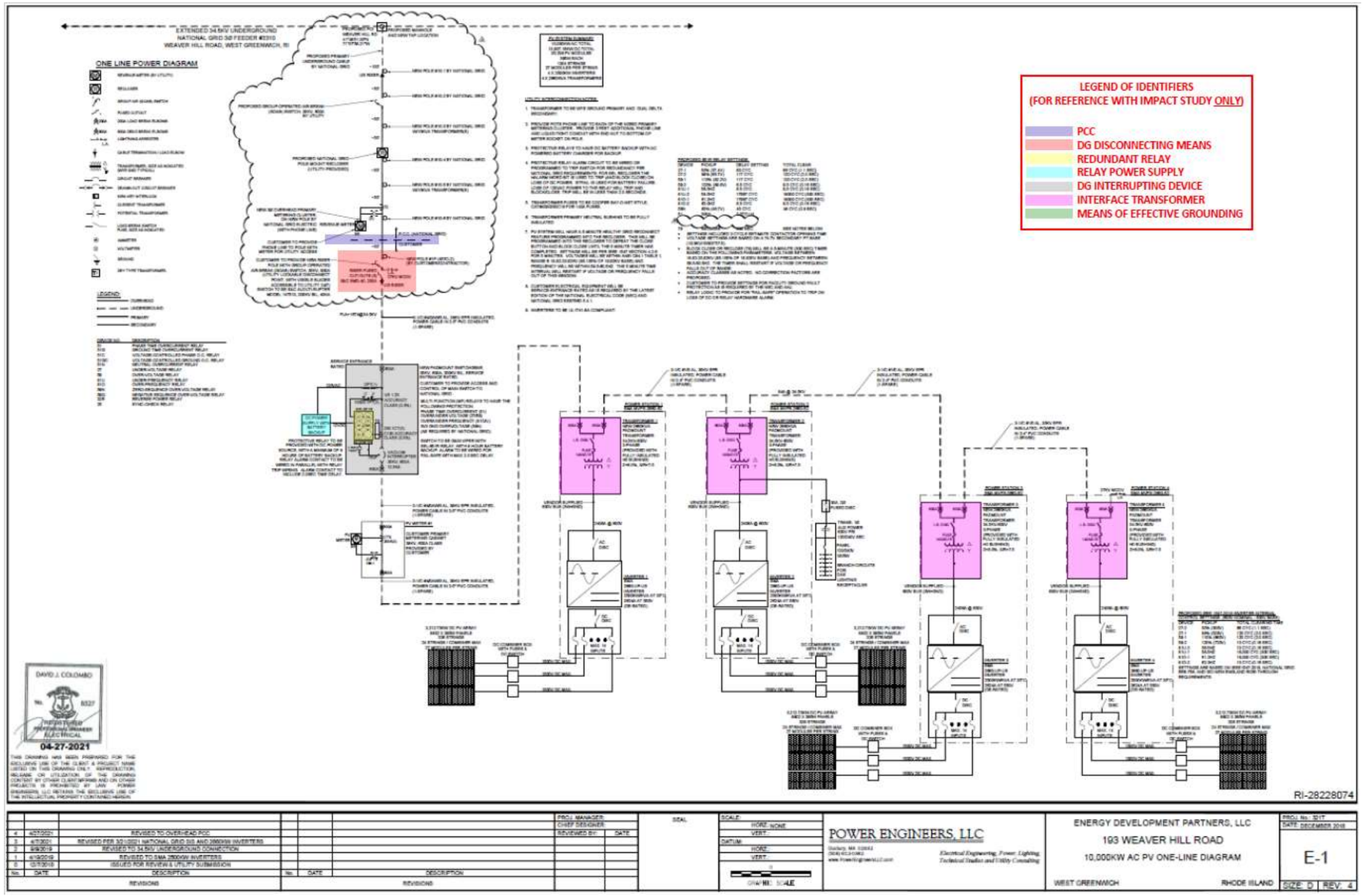


Figure C- 1: Project One-Line
(Refer to body of Impact Study for specific discussion on equipment and requirements. Highlighting of equipment in this Figure does not necessarily denote acceptance)

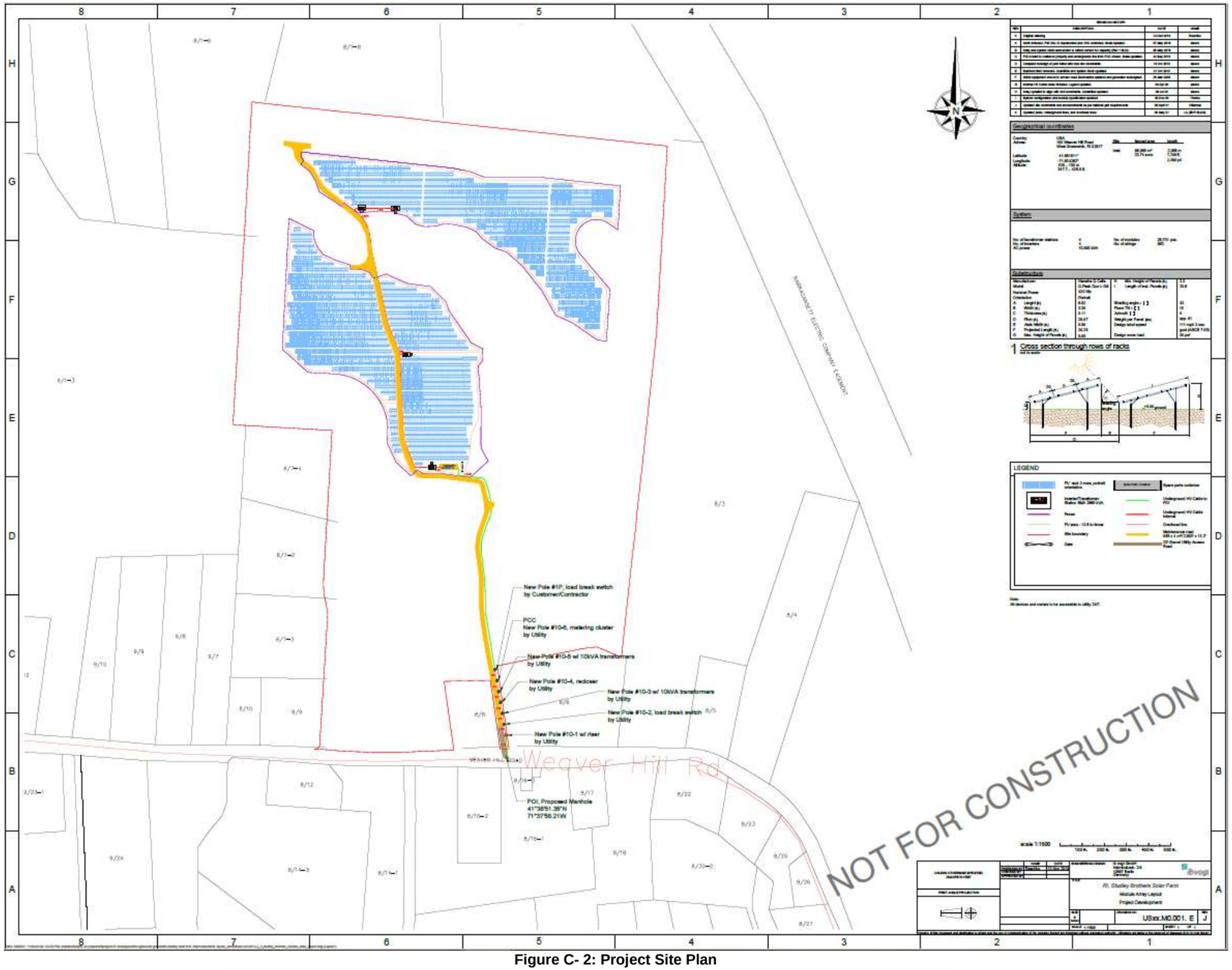


Figure C- 2: Project Site Plan

Division 4-7

Request:

Did the Company request or otherwise receive an upfront cost estimate from the DG customers for the cost of civil work? If so, provide the detailed estimate, date provided to the Company, and associated correspondence. If a cost estimate was not provided, how did the Company determine that civil work would be at or below what it would cost the Company to provide?

Response:

The Company received a cost estimate from Green Development for the Nooseneck ductbank on December 17, 2021. The estimate was $13.5M at the time with an expected accuracy of +/- 10%. Please refer to Attachment DIV 4-7.

The Company received a cost estimate from Revity for the civil and electrical work to be performed at Robin Hollow around late Q1 early Q2 of 2023; prior to initiating the work performed by Revity. The estimate was +/- 25%, based on ductbank vendor negotiated contract installation amount, supplier negotiated purchase orders, and market-based estimates & prior experience for non-major cost items.

The Company did not receive a cost estimate from EDP for the civil work to be performed at Studley Solar. The Company consulted with the customer and confirmed that the customer received a vendor quote. With that information and prior experience with the Company, the customer requested the self-performance due to the ability to complete the work for a lower cost. The Company is proposing to cost share based on actuals following a verification and audit.

Green Development, LLC
2000 Chapel View Blvd
Ste 500 Cranston, RI 02920

12/16/2021

Nooseneck Ductbank

Scope	**Total**
Survey, Engineering Review & General Conditions	$ 477,707.74
Labor & Equipment	$ 5,901,095.90
	$ 6,378,803.64
Subcontractors	
Sawcutting, Electrical, Concrete Forming , Temporary Asphalt Patching & Paving	$ 2,082,788.21
Unforseen Milling & Restoration	$ 1,836,450.00
	$ 3,919,238.21
Materials	
Manholes, risers, brick, concrete, covers, piping, coupling, mule tape, stone, processed gravel, asphalt materials, reinforcing steel	**$ 3,273,804.61**
Total	**$ 13,571,846.46**

Division 4-8

Request:

Is any portion of any DG customer cost to perform civil or electrical work eligible for an investment tax credit or other contributions that would lower the cost? If so, does RIE's reimbursement account for offsets that may have been achieved?

Response:

The Company consulted with the customers and confirmed that no portion of the customer's cost to perform civil work or electrical work was eligible for an investment tax credit.

Division 4-9

Request:

The Central Rhode Island West Area Study provides Option 1 scope and cost estimates associated with DG interconnection totaling $19.69 million (Petition, page 483). The scope for Company work to extend the sub-transmission to the new Weaver Hill substation site is estimated at $10.045 million as shown on page 483, for a total Option 1 cost of $29.735 million.

a. In executable format, provide a detailed breakdown of project components, quantities and unit costs used to develop all estimates.
b. What is the Area Study cost estimate accuracy?
c. Do the cost estimates include all required civil work? Explain.
d. Does the civil work associated with DG interconnection reflect the DG customer work, RIE's work, or both? Was the civil work cost estimate derived by RIE or another source?
e. Compare and reconcile the scope and estimated costs in the Area Study Option 1 to:

    i. each DG Interconnection Study,
    ii. the FY 2023 ISR Plan,
    iii. the FY 2024 ISR Plan,
    iv. the proposed FY 2025 ISR Plan, and
    v. to costs outlined in this Petition.

Response:

a. Please see Attachment DIV 4-9, which contains three tabs and is in an executable format (Excel), for a detailed breakdown of project components, quantities and unit costs used to develop all estimates.
b. These estimates can be considered -50%/+50 estimates; however, the Company acknowledges that recent actual costs for similar type work have exceeded this range.
c. Yes, these estimates include all required civil work.
d. The civil work associated with the Distributed Generation ("DG") interconnection reflects the DG customer's work. The civil work cost estimate was derived from information provided by the DG customers.
e. The Reconciliation tab in Attachment DIV 4-9 shows a capital cost only comparison for each DG Interconnection Study, the FY 2023 Infrastructure, Safety and Reliability ("ISR") Plan, the FY 2024 ISR Plan, the proposed FY 2025 ISR Plan, and the costs outlined in this Petition. The costs outlined in the Petition are also included in the Company's response to PUC 1-1.

Prepared by or under the supervision of: Ryan Constable

Division 4-9, page 2

The Company suggests caution when reviewing this comparison. The values were calculated at different times over a period with varying inflation and equipment costs. Additionally, each ISR Plan includes a cash flow showing 5 years of investments and may not include the full cost of the project. The FY 2023 ISR Plan specifically did not include the full costs of the project and included no costs in FY 2023 directly.

Division 4-10

Request:

Is the DG customer reimbursement for civil work based on a DG customer provided cost estimate, the actual cost for civil work, or the Company's estimated cost for civil work? Explain.

Response:

The DG customer reimbursement is based on the actual cost. After the work is completed, a third party will verify and audit the costs to ensure the total costs incurred are reasonable. The Company is proposing that the verified and audited actual cost be reimbursed.

Division 4-11

Request:

If the DG customer self-performs civil work and actual costs exceed initial estimates by more than 10%, will the DG customer be reimbursed for the excess costs? If the Company performs the same civil work and actual costs exceed the Company's estimate by more than 10%, will the Company be reimbursed for excess costs?

Response:

If the actual costs that exceed the initial estimates are determined to be reasonable costs incurred to perform the work, then yes, the Company is proposing that the Distributed Generation ("DG") customer be reimbursed for the actual costs. When the Company performs the work, if the actual costs exceed the estimate, pursuant to the DG tariff, R.I.P.U.C No. 2258, Standards for Connecting Distributed Generation, the Company can only be reimbursed by the DG customer up to 10% above the estimate if the DG customer is notified of the cost increase. Otherwise, no, the Company is not reimbursed by the DG customer for costs more than 10% above the estimate.

Division 4-12

Request:

If the DG projects were not requesting interconnection, what would be the least cost option to resolve issues identified in the Central RI West Area Study? Assuming the solution includes a new substation at Weaver Hill, would the recommended solution require underground or overhead line extensions and sub-transmission to serve the proposed substation? Provide supporting analysis or assumptions. Similar to RIE's response to PUC 1-4, please provide an aerial map showing circuit routes to serve the proposed Weaver Hill substation assuming that DG projects are not requesting interconnection. Provide a general scope of the project and compare/contrast the solution to proposed construction in the Petition.

Response:

The least cost option would be identical to the current plan. The underground portions of the current plan are a result of routing along roads already double circuited and expected town requirements for underground facilities. The town expectations are a result of similar proposals in the area where underground was required.

The aerial map would be identical to the Company's response to PUC 1-4.

Division 4-13

Request:

What is the cost estimate accuracy in Interconnection Studies?

Response:

The cost estimate accuracy for Interconnection Studies is +/-25% as identified in the DG interconnection tariff RIPUC No. 2258, definition for Impact Study for Renewable DG ("ISRDG").

Division 4-14

Request:

Are the DG customers' civil cost estimates based on final engineering, design and bid results, or some other method? What is the expected accuracy? Provide supporting documentation received by RIE to validate the estimates along with RIE's analysis relied upon to determine that the estimates were reasonable.

Response:

Please refer to the Company's response to Division 4-7 for cost estimate details.

The Company did not conduct an analysis to determine reasonableness since actual construction costs will be audited for reasonableness. Please see Attachment DIV 4-14 for the estimate provided to the Company.

Green Development, LLC
2000 Chapel View Blvd
Ste 500 Cranston, RI 02920

12/16/2021

Nooseneck Ductbank

Scope	**Total**
Survey, Engineering Review & General Conditions	$ 477,707.74
Labor & Equipment	$ 5,901,095.90
	$ 6,378,803.64
Subcontractors	
Sawcutting, Electrical, Concrete Forming , Temporary Asphalt Patching & Paving	$ 2,082,788.21
Unforseen Milling & Restoration	$ 1,836,450.00
	$ 3,919,238.21
Materials	
Manholes, risers, brick, concrete, covers, piping, coupling, mule tape, stone, processed gravel, asphalt materials, reinforcing steel	**$ 3,273,804.61**
Total	**$ 13,571,846.46**

Division 4-15

Request:

The Company states that the installation of a new modular substation at Weaver Hill Road is in the FY2023 Proposal, Docket No. 5209, filed on December 20, 2021 (Petition, page 21). Please cite the exact reference in the FY 2023 ISR plan including when the Company proposed that the project be completed.

Response:

The Company refers to the need for the extension of the 34.5kV system and installation of a new modular substation at Weaver Hill Road in its FY 2023 Proposal, Docket No. 5209 on Bates Page 36. The capital spending for the Weaver Hill Road Substation project is shown on Bates page 81, Attachment 3 – Five-Year Budget with Details. The project is labeled "Weaver Hill Rd." and is included in the System Capacity & Performance spending rationale section.

Division 4-16

Request:

Was the installation of a new modular substation at Weaver Hill Road and associated sub-transmission to serve the substation included in the FY 2023 ISR Plan budget? If so, please reference the project line items and proposed spend by year. Identify the date that the projects would be complete and in service as shown in the budget. Reconcile the proposed spend with the project components provided in response to PUC 1-1. If the Weaver Hill substation and associated sub-T work was not in the FY 2023 ISR Plan budget, provide a reference for the first time this work was proposed in an ISR Plan budget, the completion date as shown in the budget, and reconcile the projects to response PUC 1-1.

Response:

No, the installation of the new modular substation and associated sub-transmission to serve the substation at Weaver Hill Road was not included in the FY 2023 ISR Plan budget. The initial plan from the Area Study was for the work to begin in FY 2024 and be completed in FY 2028. Since the project was not included in the FY 2023 ISR Plan budget, there is no reference to line items. The completion date is per the area study and is FY 2028. Please see the response to DIV 4-9 for a reconciliation of the proposed spending with the project components provided in response to PUC 1-1. The Company refers to the need for substation, distribution line work, and extension of the 3309 and 3310 lines at Weaver Hill Road in FY 2024 ISR Proposal, Docket No. 22-53-EL on Bates Page 105. The cashflows are shown in Attachment 3 – Five-Year Budget with Details, Bates page 117 in the System Capacity and Performance section.

Prepared by or under the supervision of: Kathy Castro

Division 4-17

Request:

If a capital project is mentioned in the Company's ISR Plan filing but not included in the Company's proposed ISR Plan budget that accompanies the Plan, does the Company consider the project "identified in the Company's work plan as a necessary capital investment"? Explain.

Response:

If a capital project is mentioned in the Company's ISR Plan filing but not included in the proposed plan budget, the Company does consider the project "identified in the Company's work plan as a necessary capital investment". The Company includes information in its ISR Plan, such as area study summaries and a five-year plan, to provide visibility to investments that have been identified and needed in future years.

Division 4-18

Request:

Provide Appendix A through Appendix D for Exhibit EJRS-8. Response:

Please see Attachment DIV 4-18 - Appendix A through Appendix D.

MASTER VARIABLES		
Labor rate:	125	$/hr
Equipment rate	50	$/hr

5.1.1

COST SUMMARY	MH	Labor	Materials	Contingency	Engineering	Stores Handling	Permit	AFUDC	OPEX	Total	Removals
	31405	$4,848,000	$4,380,000	$2,307,000	$554,000	$0	$185,000	$887,401	$0	$13,161,000	$0

(rounded to nearest $1k)

CAPEX	OPEX	REMOVALS	TOTAL
#REF!	#REF!	#REF!	#REF!

5.1.1 Nooseneck Utility Connection

Labor rate: *125 $/hr*
Equipment rate *50 $/hr*

Task	Detail	Cat ID	Units	Crew Size	Hours per Unit	Total Man-Hours	Labor & Equipment Cost	Material Cost per Unit	Total Material Cost	Total cost	Units	Crew Size	Hours per Unit	Total Man-Hours	Removal Cost
Civil															
Duct Bank 2x1-6" (A-A)	80 ft		8.575	5	40.00	343	$60,025	$5,460	$46,820	$106,845					
Duct Bank 2x2-6" (B-B)	80 ft		337	5	40.00	13480	$2,359,000	$10,920	$3,680,040	$6,039,040					
Duct Bank 3x3-6" (C-C)	80 ft		9.975	5	80.00	798	$139,650	$23,040	$229,824	$369,474					
Bell ends 6" 2x1	ea		16					$54	$864	$864					
Bell ends 6" 2x2	ea		326					$54	$17,604	$17,604					
Bell ends 6" 3x3	ea		135					$54	$7,290	$7,290					
3/4 in rebar	ft		1272					$4	$5,088	$5,088					
Safety ribbon	1000 ft		30					$172	$5,160	$5,160					
Prefabricated 2 Way MH Foundation and Collar	ea		41	5	120.00	4920	$861,000	$6,750	$276,750	$1,137,750					
Prefabricated 3 Way MH Foundation and Collar	ea		5	5	160.00	800	$140,000	$8,980	$44,900	$184,900					
Drainage culvert	ea.		1	5	120.00	360	$51,000	$1	$9,000	$60,000					
Cable Riser 2x1-6"	ea		14	5	40.00	560	$98,000	$1,200	$16,800	$114,800					
Patch Paving	5 Yd3		260.50	4	16.00	752	$302,400	$75	$261	$19,575					
Final Paving	ton= $100		10,955.00	6	0.25	16433	$2,191,063	$100	$10,955	$1,095,500					
Milling	$2.50/Sq Yard		50,365.00	4	0.05	10073	$1,385,038								
Subtotal						22013	$4,011,075	$56,764	$4,340,401	$8,068,390				0	$0
Construction Support															
Construction Management	1/ 2 day		20	1	4.00	80	$14,000		$0	$14,000					
Construction support	1/2 day		20	1	4.00	80	$14,000	$2,000	$40,000	$54,000					
Traffic Management	day		150	3	12.00	5400	$432,000								
Mobilize/demobilize	ea		6	4	8.00	192	$26,400		$0	$26,400					
Police Protection	day		200	2	8.00	3200	$288,000								
QA/QC	day		10	1	8.00	80	$14,000		$0	$14,000					
Weather	day		9	5	8.00	360	$48,600		$0	$48,600					
Subtotal						9392	$837,000	$2,000	$40,000	$157,000				0	$0
Total						31405	$4,848,075	$58,764	$4,380,401	$9,228,476				0	$0
Contingency 25%										$2,307,119					$0
Engineering 6%										$553,709					$0
OPEX										$0					
Stores handling 12%										$0					
Capital Overheads 18%										$0					
Permitting 2%										$184,570					
AFUDC 7.23%										$887,401	$1,071,971	$13,161,275			
Grand Total										$13,161,275					$0

Project Name	**Nooseneck Duct Bank**				
Funding Project		Work Order	N0000265356	Estimate Type	Conceptual
Company	RIE	Bus. Segment	Distribution	Estimator	Randy Richards
State	RI			Engineer	Andres Molina
Alternative	1	Rev. #	1	Last Updated	11/21/2022
Description	Installation of a 27,000 ft. long duct bank				

	CAPEX	OPEX	COR	TOTAL
Labor	$ 4,848,000	$ -	$ -	$ 4,848,000
Materials	$ 4,380,000	$ -		$ 4,380,000
Engineering	$ 554,000	$ -	$ -	$ 554,000
Contingency	$ 2,307,000	$ -	$ -	$ 2,307,000
Distribution Substation Subtotal Direct Cost				$ 12,089,000
Permitting, Stores Handling, Sales Tax, Transportation, Contingency, AFUDC	$ 1,072,000			$ 1,072,000
Total	$ 1,072,000	$ -	$ -	$ 13,161,000

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 1
DATE: 10/18/2022
ATTACHMENTS: No

TO: Dan Glenning
Rhode Island Energy

Phone: 401-862-2476
Email: dmglenning@rienergy.com

PROJECT NAME:
Nooseneck Audit Procedure

CATEGORY: (check all that apply)

- ☐ Clarification
- ☑ Information not in project documents
- ☐ Engineering conflict
- ☐ Scheduling / coordination conflict
- ☐ Possible cost impact
- ☐ Possible schedule impact
- ☐ This is work that we are not able to proceed with at this time until a response is received.
- ☐ This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please send us the final copy of RIE's Capital Project Audit Procedure on the company's letterhead (if any).

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 2
DATE: 11/22/2022
ATTACHMENTS: No

TO: Gianna Zackarian
Dan Glenning
Rhode Island Energy

Phone: 401-862-2476
Email: dmglenning@rienergy.com

PROJECT NAME:
Nooseneck Audit Procedure

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide a listing of stockroom materials and costs to be used for the estimation efforts as mentioned on the proposal.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 3
DATE: 11/22/2022
ATTACHMENTS: No

TO: Gianna Zackarian
Dan Glenning
Rhode Island Energy

Phone: 401-862-2476
Email: dmglenning@rienergy.com

PROJECT NAME:
Nooseneck Audit Procedure

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide the actual project financials and charges related for the project from Rhode Island Energy.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 2
DATE: 10/18/2022
ATTACHMENTS: No

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Green Development to provide their procedure and / or policy for procurement of subcontractors, materials and any other 3rd party suppliers.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 3
DATE: 11/4/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [x] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Cost Analysis Summary -

Many invoices in the "Nooseneck Invoice & Receipt Backup Folder" are not included in the General Req Tab on the spreadsheet. Please refer to the Questions/Gen Req Notes (highlighted in orange) tabs in the attachment to see the invoices that are not included in the total. Should these invoices be included?

Some amounts that are in the spreadsheet are missing invoices in the backup folder. Please refer to the Questions/Gen Req Notes/Engineering & Design tabs (highlighted in blue) and provide these.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 4
DATE: 11/18/2022
ATTACHMENTS: No

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide the executed contract between National Grid and Green Development for their work on the Nooseneck Duct Bank, including any applicable attachments related to costs.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 5
DATE: 11/18/2022
ATTACHMENTS: No

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide the communicated need date for the completion of work assigned to Green Development at time of award and any changes to such date as applicable.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 6
DATE: 11/18/2022
ATTACHMENTS: No

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide the project financials related to this portion of the project to ensure costs represented by Green were actualized by National Grid.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 7
DATE: 11/18/2022
ATTACHMENTS: No

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide the Daily Reports for 12/17/2021. In the "Daily Reports_09132022" file, under Labor & Equipment, column EF for date 12/17/2021 references (Rows 70 and 72) a Night Crew report I wasnt able to locate. I could only find a Day Crew report.

Please provide clarification for 1/17/2021. Column FK adds up to $31,958.68, but the Daily Report provided for 1/17/2021 is only a total of $23,969.01.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 8
DATE: 11/21/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please provide responses to questions on the Word Document attached. I have also listed the questions below -

EW Electrical – The items highlighted in blue total to $90,864.78, but the notes say “this number reflected items in blue actual 89,929.62” and the number referenced is $89,956.62. However, the amount listed on the spreadsheet is $89,069.58. There are lot quite a few amounts here, please clarify which amount is correct.

Also the amounts that were adjusted, what do they relate to and the reason for them being adjusted (Column F)?

The invoices in the Response Folder that were sent over total to $1,424,141.46 vs $1,424,229.26 listed on the original

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 9
DATE: 11/25/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Williams Scotsman – Green Response Covers invoices from 9/21-4/22.
As I am looking at these invoices the amounts from 9/21 – 4/22 are not aligning with the amount on the spreadsheet. I have listed the invoices below with their respective amounts that totals to $13,582.88. On the spreadsheet it states $13,315.38, please clarify this discrepancy.

$	3,459.19	Sep-21	2021-9011486059	$ 13,582.88
$	1,143.25	Sep-21	2021-9011724423	
$	1,143.25	Oct-21	2021-9012001083	
$	1,143.25	Nov-21	2021-9012278712	

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 10
DATE: 12/5/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Please confirm cost adders below:

Contingency 25%
Engineering 15%
Stores handling 3%
Permitting 2%
AFUDC 5.5%
Capital Overheads 21%

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 11
DATE: 12/5/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

One drainage culvert was charged to the project. Where is it located on the drawing package?

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 12
DATE: 12/5/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Daily reports April 12, 2022 through April 28, 2022 show a crew on a drilling operation training and performing a drilling operation. Please clarify where this work took place?

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 13
DATE: 12/5/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- [x] Clarification
- [x] Information not in project documents
- [ ] Engineering conflict
- [ ] Scheduling / coordination conflict
- [ ] Possible cost impact
- [ ] Possible schedule impact
- [ ] This is work that we are not able to proceed with at this time until a response is received.
- [ ] This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

The summary sheet is missing for duct bank from EM44 to EM45? Please provide this or provide clarification.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 14
DATE: 12/5/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- ☑ Clarification
- ☑ Information not in project documents
- ☐ Engineering conflict
- ☐ Scheduling / coordination conflict
- ☐ Possible cost impact
- ☐ Possible schedule impact
- ☐ This is work that we are not able to proceed with at this time until a response is received.
- ☐ This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

Cost summary sheet lines 106 & 107 shows 2 ducts from EM-44 to UP23 & UP24. Only 1 installed in field? Please clarify.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

ENTRUST SOLUTIONS GROUP

REQUEST FOR INFORMATION

29 Bartlett Street
Marlborough, MA 01752
Ph: 508-481-9801
Fax: 508-481-9805

RFI NO.: 15
DATE: 12/5/2022
ATTACHMENTS: Yes

TO: Green Development
2000 Chapel View Boulevard
Suite 500
Cranston, RI 02920

Phone:
Email:

PROJECT NAME:
Nooseneck Audit

CATEGORY: (check all that apply)

- ☑ Clarification
- ☑ Information not in project documents
- ☐ Engineering conflict
- ☐ Scheduling / coordination conflict
- ☐ Possible cost impact
- ☐ Possible schedule impact
- ☐ This is work that we are not able to proceed with at this time until a response is received.
- ☐ This RFI represents work that if continued may result in re-work or equipment damage if resolution is not provided.

REQUEST:

April 2022 there is drilling equipment and utility Gator vehicles charged for equipment to the duct bank installation. Please explain where is was utilized within the project.

Requested Response Date: ASAP

From: Reshma Bhagat Phone: 978-328-4476 Email: rbhagat@entrustsol.com

RESPONSE:

From: Phone: Email:

Date:

cc: File

Division 4-19

Request:

Will completion of the Weaver Hill substation provide redundant service that otherwise would not have been available to any or all of the DG projects?

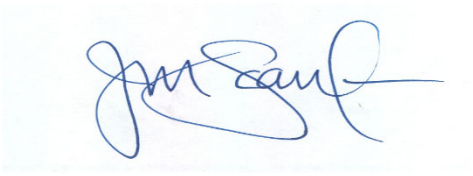
Response:

No, Weaver Hill will not provide redundant service that otherwise would not have been available to any or all of the DG projects. The Weaver Hill substation will have redundant service. The DG projects served from the Weaver Hill substation will be transferred from the Coventry and Hopkins Hill substations, which also have redundant service.

Certificate of Service

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

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



Joanne M. Scanlon

February 15, 2024
Date

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

Parties' Name/Address	E-mail	Phone
The Narragansett Electric Company d/b/a Rhode Island Energy Andrew Marcaccio, Esq. Celia B. O'Brien, Esq. 280 Melrose Street Providence, RI 02907	AMarcaccio@pplweb.com;	401-784-7263
	COBrien@pplweb.com;	
	JScanlon@pplweb.com;	
	SBriggs@pplweb.com;	
	KRCastro@RIEnergy.com;	
	ERussell@RIEnergy.com;	
Division of Public Utilities Margaret L. Hogan, Esq.	Margaret.L.Hogan@dpuc.ri.gov;	
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Revity Energy LLC Nicholas L. Nybo, Esq.	nick@revityenergy.com;	508-269-6433

Revity Energy LLC & Affiliates 117 Metro Center Blvd., Suite 1007 Warwick, RI 02886	Frank@edp-energy.com;	
Green Development Seth Handy, Esq. HANDY LAW, LLC 42 Weybosset Street Providence, RI 02903	seth@handylawllc.com; conor@handylawllc.com; ms@green-ri.com; hm@green-ri.com; mu@green-ri.com;	401-626-4839
File an original & 5 copies w/: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.WilsonFrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107