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	EXETER RENEWABLES 1 LLC 10,000kW AC, SOLAR 89 TEN-ROD RD EXETER, RI	Final

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

DG WR:	RI-26012283
Applicant:	EXETER RENEWABLES 1 LLC
Address:	89 TEN-ROD RD
City:	EXETER
DG kW/kVA:	10,000 kW ***and*** 10,000 kVA
DG Type:	SOLAR
Feeder:	TBD

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Definitions

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

Company – National Grid

Customer – The interconnecting customer of this project

DG – Distributed Generation

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESB – National Grid's Electrical Service Bulletin

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

IA – Interconnection Application

Interconnecting Circuit – Circuit to which the Facility will connect

ISA – Interconnection Service Agreement

ISO-NE – Independent System Operator of New England

NPCC – Northeast Power Coordinating Council

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

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

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Executive Summary

The Company has completed the Impact Study, for the interconnection of Energy Development Partners ("Customer") 10 MW, Photovoltaic, 1 site, ("the Facility"), to its 34.5kV 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.

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

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. Install 7,200 circuit feet of two (2) sets of underground 3-1/C 1000 SCU EPR cable from P9121 in the right-of-way outside Lafayette Substation to existing Pole #5 South County Trail. Customer responsible for installation of Man hole and Duct civil work. (Section 2.2).
2. Install 2,000 circuit feet of one (1) set of underground 3-1/C 1000 SCU EPR cable from manhole located at the intersection of Ten Rod rd and South County trail to riser pole 11-6. Customer responsible for installation of Man hole and Duct civil work. (Section 2).
3. Install a recloser on proposed Pole #11-7 (Figure B-1).
4. Install a three-phase disconnect switch on proposed Pole #11-8(Figure B-1).
5. Install a primary meter on proposed Pole #11-9 (Figure 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:

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 **$24,393,907** +/-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 2500-EV-US 2,500kW/kVA inverters for a total of 10,000 kW/kVA inverter based photovoltaic DG.
- Two (2) Customer owned Pad-mounted 5000kVA, 34.5kV wye ground primary/ 550V delta interface transformer with an Zh-X impedance of 6% and a X/R ratio of 7.5, Zh-y of impedance of 6% and a X/R ratio of 7.5, and Zx-y of impedance of 12% and a X/R ratio of 12.
- Two (2) 38kV neutral grounding reactors at 22 ohms.
- One (1) Customer owned 35kV Padmount G&W switchgear and SEL-651R relay assembly.
- One (1) Customer owned 35kV S&C Omni-Rupter 147513 Air-Break (GOAB) Switch

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 March 2018).

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:

2.2 Company Area EPS

The area EPS was evaluated, and it was determined that the most viable interconnecting circuit is 30T1, a 34.5kV regulated, three-phase, 4 wire, wye, effectively-grounded, radial distribution circuit that originates out of the Company's Wickford Junction Substation, in North Kingstown, RI (the "Interconnecting Circuit"). The feeder is regulated by way of a load tap changer at the substation. This circuit is located immediately adjacent to the Facility underground on Ten-Rod RD.

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)
30T1	-	40,000	10,000	*50,000*
30T2	-	58,080	-	*58,030*
TOTAL	-	*98,080*	*10,000*	**108,030**

Table 1: Generation at the Substation and Interconnecting Circuit

- There are **zero** existing reclosers on the circuit. 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 P13-52#, Dry Bridge RD North Kingstown	Proposed	DG Projects RI-24926794, RI-24926796, RI-24926805, RI-24926798 PCC	No

Table 2: Recloser Locations

- There is a total of **zero** in existing capacitor banks installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

Table 3: Capacitor Locations

- There are **zero** existing regulators installed on this circuit. Refer to Section 3 for further discussion on any required modifications.

Table 4: Regulator Locations

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 #11-6, 89 Ten-Rod RD, RI, USA. 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.

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. Company pole number nearest the proposed PCC
2. Company line extension to site and from nearest Point of Interconnection
3. Existing and proposed Access road(s) including, at a minimum, road material, surface loading criteria, and 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").

The analysis was completed with the assumption of no loading on the feeder. This project will be served from a feeder that was designed for the two projects requested by the customer.

3.1 Power Flow Pre-Existing Conditions

The proposed Facility had no observable impact on the aforementioned area.

3.2 Reverse Power Flow at Substation

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

Reverse Power Flow was not found to be a concern on the distribution level, however the Transmission study may require additional upgrades should these projects create problems.

3.3 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.

3.4 Interconnecting Circuit Voltage Analysis

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

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

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

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

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

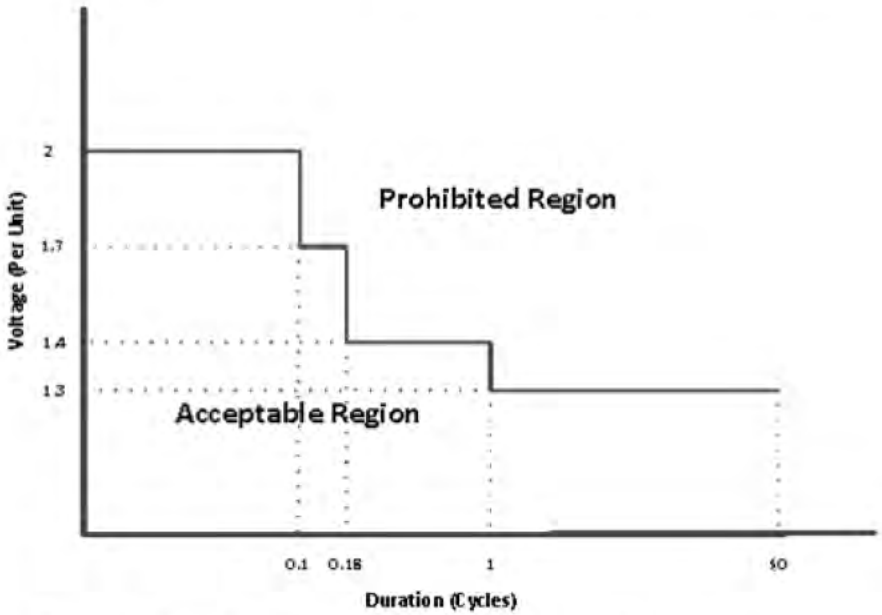

Figure 1: IEEE Transient Over Voltage Tolerance Curve

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

3.5 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.

Flicker Analysis was not conducted with the assumption that no load would be served on this interconnecting circuit.

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.

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.

The Customer shall provide documentation from the inverter manufacturer for the islanding detection method to be used by the inverter(s). The documentation shall be sufficient to determine whether the islanding detection method is active (perturbing the utility system and looking for a response), or passive (monitoring grid parameters without perturbing the system), and describe how the islanding detection method functions, including what parameters (i.e. phase, frequency, VARs,) are perturbed and monitored. Additionally, the Customer shall confirm the firmware version enabled in the inverters.

Based on known in-service and in-progress projects at the time of study, the generation shown in Table 5 was considered on this feeder. Three-phase projects greater than 25kW are listed individually. All other projects below 25kW are listed as a single line item.

Project Size (kW)	Certified / Non-Certified
40,000	Certified

Table 5: 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 highly unlikely event and no mitigation measures are required.

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.

4.2 Direct Transfer Tripping (DTT)

A DTT system is not required by the Company for this interconnection provided the Customer can provide a stamped one-line and documentation that certifies the inverters are UL 1741-2005/IEEE 1547 compliant and have an acceptable means of active islanding detection, refer to Section 0.

Although DTT is not required for the Distribution system, DTT may be required on a Transmission level and will be evaluated in the Transmission Study.

The Customer is responsible for all initial and recurring costs associated with the communication line for the DTT circuit. The Customer is responsible for communication with Local Telecommunications Provider to secure the line, and to coordinate scheduling with Local Telecommunications Provider for installation of the line prior to interconnection of the DG. The Company has no control over the Local Telecommunications Provider's process or schedule. The Customer is advised to contact Local Telecommunications Provider as soon as possible to assure that the communication circuit is in place before the interconnection due date.

4.2.1 Direct Transfer Trip Requirements

The specifications given in this section are for copper based, leased line communication. Should the Customer prefer to use fiber-based

communication, the Company's specifications will be provided upon request. For Customers using direct fiber-based DTT, the Customer is responsible for all installation and maintenance costs and coordination, including having the installing entity follow the Company's third party attachments policy where attaching fiber to Company structures. The Customer is additionally responsible for all initial and recurring costs associated with third party attachments.

Copper based, leased line DTT requirements are as follows:

- The Company's Standard RFL is model S00763PF which uses the Guard Before Trip feature for DTT applications.
- The breakers being controlled must be tripped for relay/breaker Loss of Potential (LOP), Relay failure, loss of Guard signal, and receipt of the trip signal. Relay failure, LOP and loss of guard signal shall have a 30 second delay to trip the breaker. This is to avoid nuisance tripping due to the system transients.
- Since the Company does not specify the relay type, any timer that is equivalent to an ABB RXKL1 is acceptable.
- When the order actually takes place, both the transmitter and receiver must be ordered from RFL as a package.
- Even if there are different orders for the transmitter and the receiver (i.e. the receiver order from the Customer and the transmitter order from the Company), RFL must be informed of this to insure that the two devices are compatible. RFL will test them together before shipping.
- The Company will also specify all trip and guard frequencies. The Company uses default settings of the groups 3 and 5 to set the guard and trip frequencies.
    - Group 3:
      Tone 1 Tx: 1540Hz (trip) 1690Hz (Guard)
      Tone 1 Rx: 2030Hz (Trip) 1880Hz (Guard)
    - Group 5:
      Tone 2 Tx: 2220 Hz (Trip) 2370 Hz (Guard)
      Tone 2 Rx: 2710Hz (Trip) 2560 Hz (Guard)

The Customer is responsible for all initial and recurring costs associated with the leased communication line for DTT circuit. The Customer is advised to establish communication with The Local Telecommunications Provider to

place order for the leased-line for DTT to make sure that the communication circuit is in place in-time before the interconnection.

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[1]. 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 Short Circuit and Protective Device Pre-Existing Conditions

The proposed Facility had no observable impact on the aforementioned issue.

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

Addition of generation sources to distribution feeders can result in the backfeeding of the substation transformers, effectively turning a station designed for load into a generation step-up transformer. The Company's typical 115kV-35kV class substation transformer has a delta connection on the transmission side and wye-grounded connection on the distribution side. Due to the transformer's configuration, it cannot contribute zero sequence ground fault current to single line to ground faults on a transmission line, and the voltage on the unfaulted phases rises significantly and rapidly. These overvoltages have potential to exceed insulation levels of the station and transmission line equipment, and maximum continuous operating voltage of surge arresters. Zero sequence voltage protection (commonly referred to as "$3V_0$") on the primary side of the transformer is required in order to detect these overvoltage conditions. This $3V_0$ protection will disconnect the generation from the substation transformer, and stop the generation and transformer from contributing to the transmission-side overvoltage condition.

Detailed analysis was completed to determine whether the interconnection of the Facility, in conjunction with existing connected facilities, may pose significant risk of causing temporary over-voltage conditions to develop on the system during line to

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

ground faults on the high side of the substation transformer. The load to generation match at the substation has been evaluated assuming minimum load, maximum generation, and one feeder out of service in order to determine if substation modifications are required.

For this Project, results indicate that the Facility poses a significant risk of causing temporary overvoltage to develop on the primary side of the substation transformer. Consequently, $3V_0$ will be required at the substation's T1, 115kV Grd-Y – 34.5kV Grd-Y, supply transformer.

5.3 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 = 0.01749 + j0.13095 p.u.

Z0 = 0.01636 + j0.18385 p.u

5.4 Fault Current Contributions

Table 6 summarizes the Facility's effect on fault current levels at the PCC. These fault currents are within existing equipment ratings and will not upset existing device coordination on the feeder.

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

Any assumptions made in calculating the fault current shown in Table 6 are identified in Section 2.1.1.

PRE PROJECT	SUB BUS (Amps @[VOLTAGE])	PCC (Amps @[VOLTAGE])
3-phase (LLL)	7622	7052

Phase-Ground (LG)	9014	8123

POST PROJECT	SUB BUS (Amps @[VOLTAGE])	PCC (Amps @[VOLTAGE])	DELTA I_{fault} @ SUB BUS	DELTA I_{fault} @PCC
3-phase (LLL)	7639	7052	< 2%	<0%
Phase-Ground (LG)	9029	8974	<1%	<10%

Table 6: Fault Duty

5.5 Substation Protective Device Modifications

The existing device settings and associated time-current curves were evaluated for protective devices at the substation. The analysis shows that modifications will not be required at the substation.

5.6 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 analysis shows that modifications will not be required.

If modifications are required to mid-line components, reference the component on the drawings provided in appendix b. it can be as simple as pointing to the device on the line and referencing that it must be modified.

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 transformers are two (2) Customer owned Pad-mounted 5000kVA, 34.5kV wye ground primary/ 550V delta interface transformer with an Zh-X impedance of 6% and a X/R ratio of 7.5, Zh-y of impedance of 6% and a X/R ratio of 7.5, and Zx-y of impedance of 12% and a X/R ratio of 12. The proposed transformer satisfies the requirements of the ESB.

6.3 Effective Grounding (ESB 756D Section 7.3.2.1)

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

The Customer must provide an interlock such that the Facility cannot be connected to the EPS when the grounding transformer is offline.

The proposed configuration will satisfy the effective grounding requirements for the system. The model was run with a grounding reactor of impedance of 22 ohms, which yielded satisfactory effective grounding results.

The referenced alternate grounding transformer was evaluated with a particular set of characteristics to check for effective grounding and coordination with protective devices on the utility system. It is the responsibility of the Customer to verify that the equipment ratings on their system are adequate and that the use of the grounding bank is acceptable to the design in general.

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.

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), overvoltage (59) and neutral overvoltage (59N) 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 (Utility 34.5kV 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)

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

The Customer's provided relay settings do not provide sufficient coordination with other devices on the EPS. The following are minimum

values that would be acceptable for coordination. Values are provided here for informational purposes only. The Customer must provide revised settings for review by the Company:

51 – Phase

Customer Proposed: 280A primary amps pickup, 2.0 Time Dial, U4 curve

Customer 51-Phase relay elements trip settings are required to comply with ISO-NE ride-through requirements. This requirement is met

51G – Ground

Customer Proposed: 50A primary amps pickup, 1 Time Dial, U1 curve

The above is provided for informational purposes only. It is the Customer's responsibility to provide revised settings that will be sufficient to trip the Customer's interrupting device for faults on the Company system as well as for faults within the Facility. The Company will evaluate for coordination with EPS protective devices.

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.

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

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 internal relay setting as well as primary and backup 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), overvoltage (59) and neutral overvoltage (59N) 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

6.6.6 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 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)

Following a trip of the protective relay, a Utility Restoration Detection function shall prevent manual and automatic reclosing of the Customer's DG intertie device until the Customer's relay has detected that the Utility EPS has been within the voltage and frequency windows identified by IEEE 1547 section 4.2.6 for a minimum of five minutes. The five minute time interval is required to restart if the utility voltage or frequency falls outside of this window.

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

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

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 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.

6.9 Additional Requirements

The Facility may be required to use high-speed protection if time-delayed protection would result in degradation in the existing sensitivity or speed of the protection systems on the Company's EPS.

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.

In accordance with ESB 756D, National Grid requires a Remote Terminal Unit (RTU) be installed at the customer site for real time monitoring and reporting of generation data for this project. This requirement is per the recommendations of IEEE 1547.3 IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.

The Interconnection Customer (IC) is responsible for making provisions on its end for standard data points to be sent to National Grid's Energy Management System (EMS) at its Regional Control Center in Northborough, MA.

The Customer is also 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.

7.1 EMS-RTU:

The Customer's RTU system shall be capable of updating EMS as follows:

- Status - every 2 seconds
- Analogs - every 4 seconds
- Full scan of all points - every 3 minutes

Scaling of analog points will be in engineering units; scaling is done during the commissioning process with The Company's EMS.

The required analog and status points are listed in the Telemetry Requirements (see below).

Unless the Customer's breaker status can be read over a dedicated RS485 serial connection to local protective relays, the individual breaker status will be required to be hard wired to an IO module.

RTU power is to be supplied by a battery and battery charger system capable of keeping the system on line for a minimum of eight (8) hours in the event main power is lost.

The IC will own, operate and maintain the RTU system and any related equipment.

The RTU systems listed below are generally acceptable to National Grid. This list is intended as a reference when selecting the RTU. National Grid takes no responsibility adequacy of these products. Recommended RTU's include, but are not limited to, the following:

- GE IBOX http://www.gedigitalenergy.com/multilin/energy/catalog/ibox.htm
- Cooper-SMP-4 http://www.cooperindustries.com/content/public/en/power_systems/products/automation_and_control/smp_products/smp_4_dp_gateway.html ;With wall mount IO http://www.cooperindustries.com/content/public/en/power_systems/products/automation_and_control/smp_products/smp_i_o.html
- Televent Sage http://www.telvent.com/en/business_areas/smart_grid/solutions_overview/smart_grid/smart_networks/sage-rtu.cfm
- Schneider Electric Ion http://products.schneider-electric.us/products-services/products/power-energy-monitoring-system/network-communications/remote-terminal-units/ion7550-rtu/
- Novatech Orion LX Renewable http://www.novatechweb.com/utility/orionlx/

7.2 Telemetry:

The RTU will be required to provide for/report the following:

- Status of main generator breaker (or multiple generator breakers for the case where there is no main generator breaker)
- Control of main generator breaker for trip (the trip signal should also block close the generator breaker) & Permit close functionality (or multiple generator breakers for the case where there is no main generator breaker)
- Total amps (A-phase, B-phase, and C-phase) at the Point of Common Coupling (PCC) with The Company.
- Three phase line-to-line voltages (A-B, B-C & C-A) at the PCC with The Company.

- Total MW (+ delivered by generator, - received by generator) at the PCC with the Company
- Total MVAR (+ delivered by generator, - received by generator) at the PCC with the Company
- Total MVA (+ delivered by generator, -received by generator) at the PCC with the Company

7.3 Telecommunication:

Communication between the IC's owned RTU and The Company's EMS will be in DNP protocol over a Multiprotocol Label Switching (MPLS) circuit connected to the Company's network. MPLS circuit allows EMS to funnel data to both primary and back-up systems simultaneously. The Company will assign the RTU a DNP slave id.

The IC is responsible to secure a Multiprotocol Label Switching (MPLS) connected to The Company's new network through the Customer's Verizon representative. The Company will supply a default MPLS default serial configuration to the Customer's RTU. The IC is responsible to configure its RTU communications.

The MPLS circuit will require the Customer to purchase a GarrettCom Magnum DX940 Industrial Router with the following specifications:

- DX940-4RJ-H, base unit with four RJ45 10/100 Ethernet ports (Slot B), 90-250Vdc/ac power supply. (-L for 24-48Vdc/ac power supply).
- DXC-DDS, DDS WAN port (Slot C)
- DXC-2GSFP, Gb Module, two SFP pluggable (Slot A)
- (1) SFP-SX, Fiber Optic SFP transceiver, 1Gb SX (Slot A)
- DXC-4SERIAL, four RS232/RS485/RS422 software selectable serial ports (Slot D)
- ACC-DX-00-RRM, reverse rack mount brackets
- MNS-DX-SECURE, licensed software
- MNS-DX-ADVAR, advanced routing software

Notes:

- Serial ports are not typically used but are available if serial connections to RTUs are required.
- If DIN rail mounting brackets are required, the part number is ACC-DX-00-DM.
- At least one SFP-SX transceiver should be ordered even if Port is not used; if fiber pairs are looped then two shall be ordered.

The IC shall notify the Company with 10 days in advance of telecommunications circuit installation to coordinate programming of the Company's EMS with the Customer's RTU.

The IC is responsible for all initial and recurring costs associated with the MPLS communication line.

The Interconnecting Customer shall provide a telecommunication line to the Company's revenue meter in accordance with ESB 756D, Section 5.4.2. The conduit for the phone line shall line up with the bottom or side knock out of the meter socket and have three feet of telephone wire coiled at its end. The Company will connect the conduit to the meter socket, terminate the telephone wire, and connect it to the modem in the meter. The Company will specify, test, install, and own the voltage and current transformers necessary to meet the metering requirements for this project. (See Appendix A- Meter Installations).

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 7:

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 - Line Work, Customer Property	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Equipment at Point of Common Coupling - See Note #1	$124,873	$124,873	$0	$0	$13,836	$138,709
SUBTOTAL	$124,873	$124,873	$0	$0	$13,836	$138,709
NECO - Line Work, Mainline	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
New 34.5kV Circuit #2. UG From Lafayette - Customer POI. See Note #2	$2,107,203	$2,107,203	$0	$0	$233,478	$2,340,682
SUBTOTAL	$2,107,203	$2,107,203	$0	$0	$233,478	$2,340,682
NECO -Line Work - Transmission Level	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
New 115 kV Transmission Line Tap, See Note #3	$1,819,463	$1,777,063	$8,623	$33,777	$172,197	$1,991,661
SUBTOTAL	$1,819,463	$1,777,063	$8,623	$33,777	$172,197	$1,991,661
NECO - Substation Work (Distribution Level)	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
New 115 kV/34.5 kV Distribution Substation, See Note #4	$3,611,479	$3,611,479	$0	$0	$400,152	$4,011,631
SUBTOTAL	$3,611,479	$3,611,479	$0	$0	$400,152	$4,011,631
NECO - Substation Work Non - PTF (Transmission Level)	Pre-Tax Total	Capital	O&M	Removal	9.69%	Total
New 115 kV/34.5 kV Transmission Substation, See Note #5	$10,523,563	$10,523,563	$0	$0	$1,019,733	$11,543,297
SUBTOTAL	$10,523,563	$10,523,563	$0	$0	$1,019,733	$11,543,297

NECO - Substation Work PTF (Transmission Level)	Pre-Tax Total	Capital	O&M	Removal	9.90%	Total
New 115 kV/34.5 kV Transmission Substation, See Note #6	$3,697,468	$3,697,468	$0	$0	$366,049	$4,063,518
SUBTOTAL	$3,697,468	$3,697,468	$0	$0	$366,049	$4,063,518

Donated Property Tax	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Donated Property Tax	$0	$0	$0	$0	$293,177	$293,177
SUBTOTAL	$0	$0	$0	$0	$293,177	$293,177

Interconnecting Customer Interconnection Facilities ("ICIF")	Pre-Tax Total	Capital	O&M	Removal	11.08%	Total
Witness Testing	$7,500	$0	$7,500	$0	$0	$7,500
SUBTOTAL	$7,500	$0	$7,500	$0	$0	$7,500

	Pre-Tax Total	Capital	O&M	Removal	Tax	Total
Totals	$21,884,049	$21,841,649	$8,623	$33,777	$2,209,178	$24,393,907

Notes

1. Installation of pole mounted equipment including (1) primary meter, ( ) Loadbreak, (1) recloser, and (1) disconnect.
2. Install ~8,000 circuit feet of two (2) sets of 3-1/c 1000 SCU cable, from Lafayette Substation to man hole located at intersection of Ten Rod Road and South County Trail. Install ~2500 circuit feet of one ( ) set of 3-1/c 1000 SCU cable from man hole located at the intersection of Ten Rod Road and South County Trail to the customer's POI
3. Installation of 115kV loop tap off the L-190 to new Wickford Substation, consisting of breaking the L-190 line at structure # 143 and installing two new spans of wire between the existing transmission line and the substation busses. New steel three pole structures on concrete caisson foundation will be required. Structure # 123 on the adjacent 34.5kV, 3311 line will need to be replaced to support the L-190 construction.
4. Install two (2) 34.5kV feeder positions with protection and control, including but not limited to site work, grounding, conduits, fencing and driveway from the street.
5. Install 115kV ring bus including breaker, disconnect switches, bus, bus insulators and wave trap; and associated site-work, grounding, foundations, structures, and associated protection and control.
6. Install 115kv 4-Breaker Ring Bus with protection and control,including but not limited to site work, grounding and conduits.
7. Costs do not include distribution line modifications on South County Trail and at the PCC of the Dry Bridge projects (24926794, 24926796, 24926798, 24926805).

Table 7: 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.[2] 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.

Note: Authorization for parallel operation will not be issued without a fully executed Interconnection Agreement, receipt of the necessary insurance documentation, and

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

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	7/15/2020	Issue to Customer

nationalgrid	DISTRIBUTION PLANNING DOCUMENT Interconnection Study	Doc. RI-26012283 Page 34 of 41
	Complex Generating Facility – RIPUC 2180	Version 1.0 7/15/20
	EXETER RENEWABLES 1 LLC 10,000kW AC, SOLAR 89 TEN-ROD RD EXETER, RI	Final

Appendix A Revenue Metering Phone Line Requirements

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

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

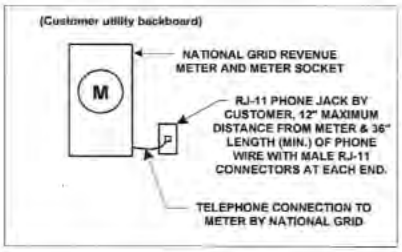

Figure 1A – Indoor Meter Installation
not to scale

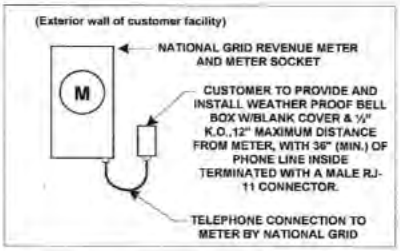

Figure 1B – Outdoor Meter Installation
not to scale

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

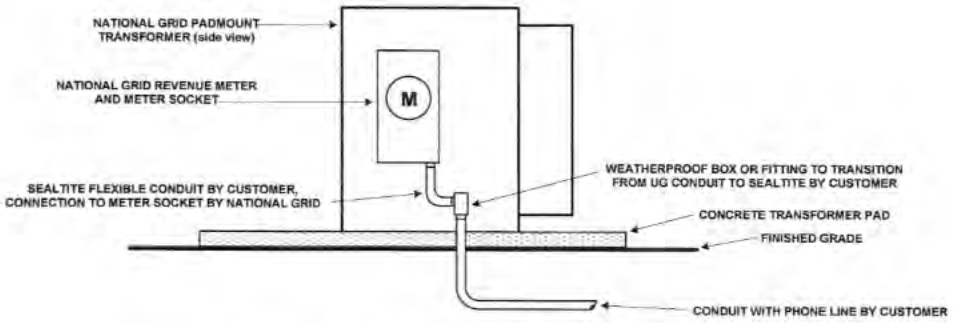

Figure A- 1: Revenue Meter Phone Line Installation Guide

3) OUTDOOR POLE MOUNTED METER INSTALLATION

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

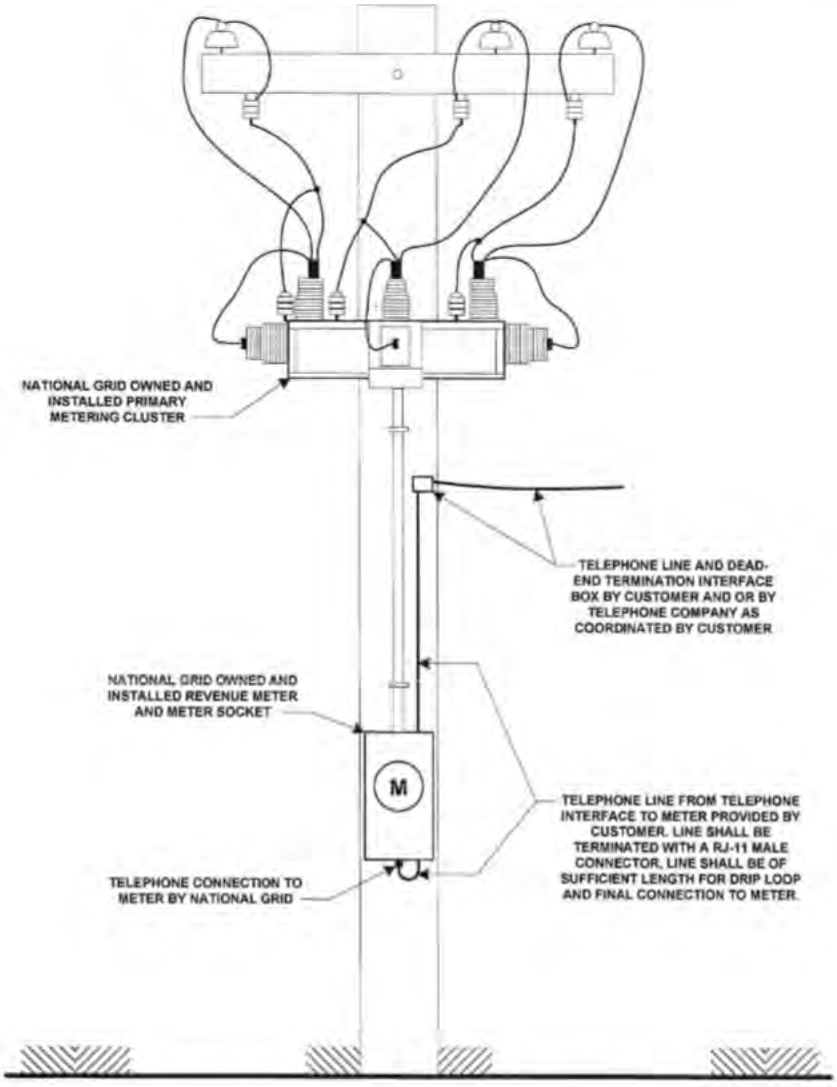

Figure A- 2: Revenue Meter Phone Line Installation Guide

Appendix B System Modification Diagrams

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

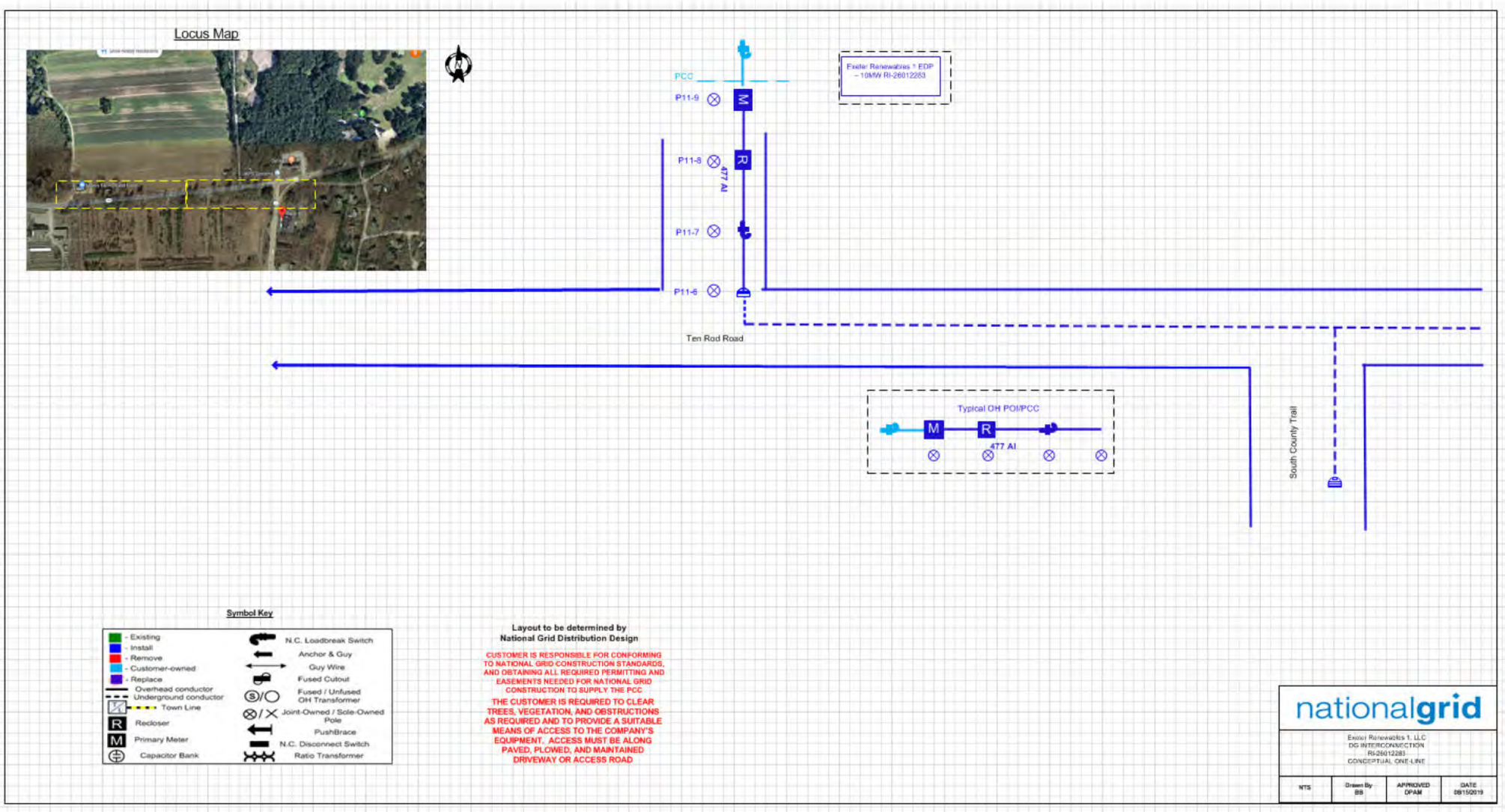

Figure B- 1: PCC Configuration

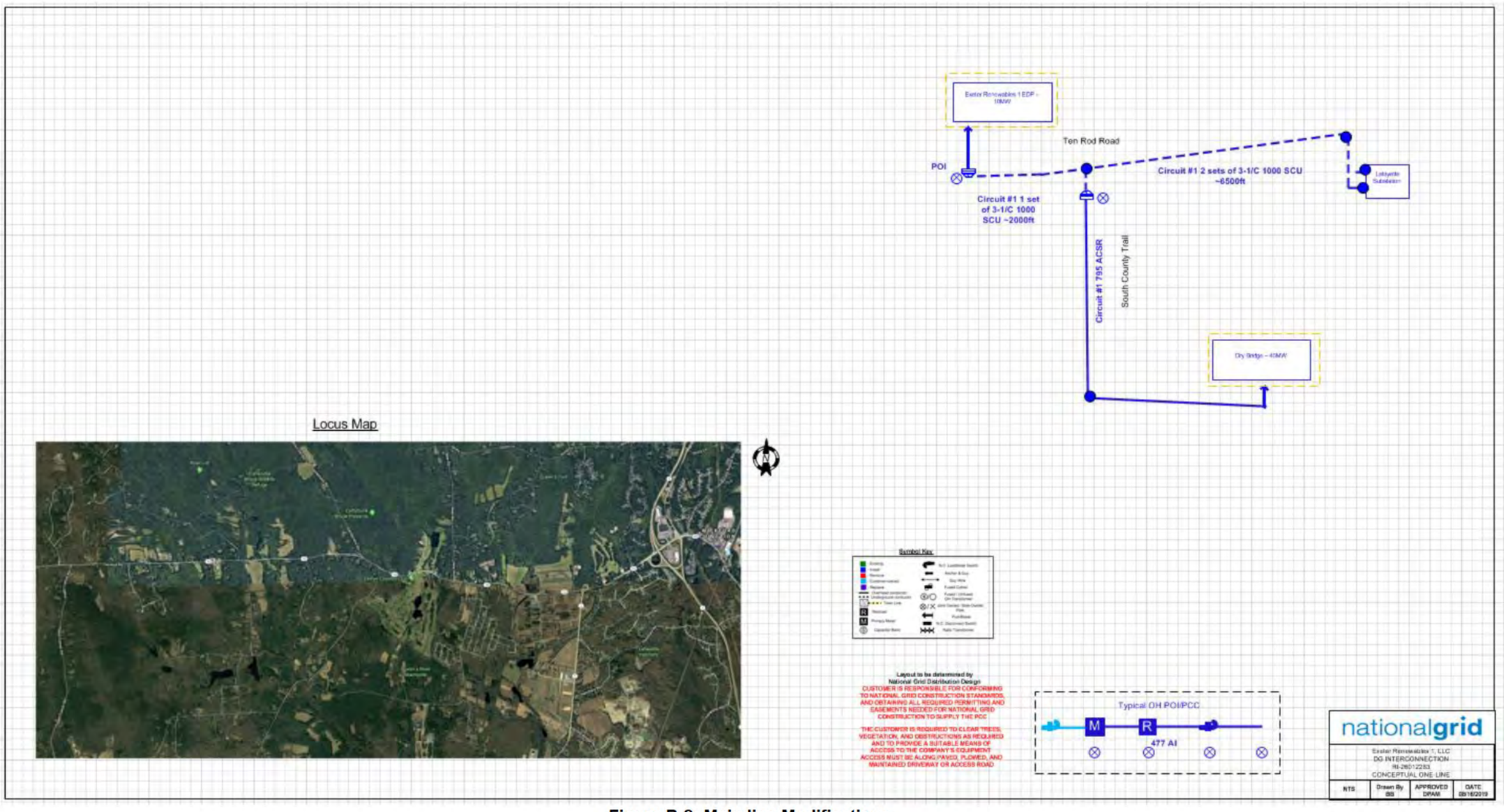

Figure B-2: Main line Modifications

REDACTED

Appendix C Customer Site and Single Line Diagram

[redacted]

[redacted]