NS-TH-4a

VERMONT ELECTRIC CO-OP

Customer Generation System Interconnection Report

MHG Solar, LLC – 44°48’12.6” N 72°26’33.5”W off of Rte. 100 Lowell, VT
4,999 kVA (AC) Photovoltaic Inverter-Based Generator

2/20/2025

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Definitions

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

BESS – Battery Energy Storage System

Company – Vermont Electric Co-operative, Inc.

Constrained – A Facility, or Equipment that is required to operate in a certain criteria to adapt to EPS conditions. This may be in terms of limited export or import and certain hours of each day/season.

Customer – The interconnecting customer of this project

DER – Distributed Energy Resource

DG – Distributed Generation

DTT – Direct Transfer Trip

EPS – Electrical Power System

ESS – Energy Storage System

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

GSU – Generator Step-Up Unit, the interconnecting transformer for the Project.

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)

POI – Point of Interconnection (closest existing primary voltage infrastructure to the Project)

PF – Power Factor

P_{lt} - Long Term Flicker Perceptibility

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

P_{st} - Short Term Flicker Perceptibility

P.U. – Per Unit

PV - Photovoltaic

Unconstrained – A Facility or Equipment that is operating continuously within its full capabilities and specifications.

Executive Summary

ControlPoint Technologies, on behalf of Vermont Electric Cooperative, Inc., "The Company", has completed the Impact Study for the interconnection of the MHG Solar, LLC “The Customer” who is proposing a 4,999 kW / 4,999 kVA (AC) Photovoltaic inverter generating facility, “The Facility”, to its 12.47 kV distribution system proposed at 44°48’12.6”N 72°26’33.5”W off of Rte. 100 Lowell, VT. The technical analysis and requirements specified are exclusive to this project and are based upon the Facility arrangement illustrated in the following Diagrams:

- PV-300 & PV-301_One Line Diagram – Dated 2/27/2024
- Lowell Site Plan_02 28 24

Refer to Appendix A Interconnection Customer Diagrams, Figure 6*,* Figure 7*, &* Figure 8*.*

Any further design changes made by the Interconnection Customer post-Interconnection Application (IA) without the Company’s knowledge, review, and/or approval will render the findings of this report null and void. If changes are anticipated, the Company should be informed immediately so that requirements and recommendations contained within this study may be revised where necessary. This will ensure that the Customer is informed of Company requirements within a timely fashion and should eliminate delays and expenses, which could otherwise be experienced by the Customer.

<u>The purpose of this study was to</u>:

1. Conduct, as applicable, steady-state, stability, short circuit, contingency analyses and perform assessments of reliability performance of the Company’s Distribution System within the area of interconnection, with and without the proposed Facility. The study will determine the incremental impact and any potential adverse impacts associated with the interconnection of the Facility to the Company Electric Power System (EPS) and is in compliance with the applicable codes, standards, and guidelines listed below:

    a. *Vermont Public Utility Commission Rule 5.500*
    b. *Vermont Electric Cooperative’s Distributed Resource Interconnection Guidelines*
    c. *ANSI/IEEE C37.90 - Standard for Relays and Relay Systems Associated with Electric Power Apparatus*
    d. *IEEE Std C62.45TM-2002, IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (480V and Less) AC Power Circuits.*
    e. *NEC – National Electrical Code*
    f. *NESC - National Electrical Safety Code*
    g. *UL 519 - Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*
    h. *IEEE Std. 1453 - Recommended Practice for the Analysis of Fluctuating Installations on Power Systems*

   i. *IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*
   j. *UL 1741 - Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources*
   k. *Inverter Source Requirement Document of ISO New England (ISO-NE SRD), dated February 6, 2018*

2. Provide a report describing the results of the Impact Study including:
   a. Any required System Modifications
   b. Cost estimate of facilities and system modifications required to serve the Interconnection Facility to the EPS
   c. Identify operating restrictions.

<u>System Modifications</u>
The System Impact Study found that the interconnection of the Project should have no adverse impacts on the area EPS protection from a safety and reliability assessment, provided the following recommended System Modifications to the Company's EPS and operating limits for the distributed resource are implemented:

1. Section 3.4 Service Configuration: Located in Lowell, VT:
   a. POI to PCC
      i. From Pole #JYT 4 to the PCC, extend three phase 336 kcmil AL overhead conductors approximately 550 feet.
      ii. Install one (1) Generator Disconnect
      iii. Install one (1) PCC recloser
      iv. Install one (1) Primary Meter
2. Section 4.2 General Thermal Loading Analysis: Between Pole #JYT 3 and Pole #JYT 4 on Route 100 in Lowell, VT, convert approximately 220 circuit feet of overhead conductor from two phase to three phase, and reconductor to 336 kcmil AL.
3. Section 4.2 General Thermal Loading Analysis: From Pole #JYT 1 to #JYT 3 on Route 100 in Lowell, VT, reconductor approximately 170 circuit feet of existing three phase 1/0 AAAC overhead conductor with 336 kcmil AL.
4. Section 4.3 Reverse Power Flow: Enable distributed generation settings at the #5 Lowell Substation bus regulators.
5. Section 4.4 Voltage Analysis: Settings change for the #5 Lowell Substation bus regulators.
6. Section 4.4 Voltage Analysis: Settings change for the midline regulator at Pole 9B 2 on Carter Road.
7. Section 5 Temporary Over-Voltage on Transmission Supply: Install 46 kV Overvoltage Protection Scheme (OVP) scheme for the #5 Lowell Substation transformer.

Special Operating Requirements:

1. The Customer's Facility inverters shall operate at 95% leading power factor with respect to the EPS, exporting VARs, with a combined inverter output of 4,749 kW and 4,999 kVA (Section 4.1).
2. Any advanced inverter functionality shall be subject to additional study before being enabled.
3. Inverter healthy grid reconnect time delays shall be set as follows:
    a. "INV-1" through "INV-10": 360 seconds
    b. "INV-11" through "INV-20": 420 seconds
4. Each inverter shall be programmed with a 2% of nameplate "soft start" ramp rate upon entering service.

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. Section 3.2 – Customer must submit Company-acceptable derating documentation for all the Project inverters.
2. Section 7.1 Interface Transformer: The Customer must provide documentation stating the Z% and X/R ratio of the Interconnection Transformer, see Section 3.2.
3. Section 7.2 Disconnect Switch: The Customer must provide an appropriate disconnect switch.
4. Section 7.8 Additional Requirements: The Customer must provide a kVA rating of the Facility on the one-line.
5. Section 7.8 Additional Requirements: The Customer must provide a revised site plan.
6. Section 8: Relay and Protection Requirements: The Customer must provide protection settings for review prior to connection.

Cost Estimate

Estimated costs for all required System Modifications will be provided by the Company.

1 Introduction

Per the Company Generating Interconnection Application Form dated February 28th, 2024, MHG Solar, LLC, the Customer, has requested a Distributed Generation (DG) interconnection of a 4,999 kW/kVA (AC) inverter-based photovoltaic (PV) generating facility to the Company's 12.47 kV Electric

Power System (EPS). The Facility is located at 44°48’12.6”N 72°26’33.5”W off of Route 100 in Lowell, VT.

1.1 Statement of Limitations

In the preparation of this report, the information provided to ControlPoint by the Company was used by ControlPoint to make certain assumptions with respect to conditions which may exist in the future. While ControlPoint believes the assumptions made are reasonable for the purposes of this report, ControlPoint makes no representation that the conditions assumed will, in fact, occur. In addition, while ControlPoint has no reason to believe that the information provided by the Company, and on which this report is based, is inaccurate in any material respect, ControlPoint has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to ControlPoint, the actual results will vary from those presented.

2 Study Objective

The primary objectives of this System Impact Study are to:

1. Identify System Modifications necessary for the Project to reliably interconnect to the Company’s EPS.
2. Identify deficiencies in the proposed Project.
3. Identify operating restrictions.

3 Project Description

3.1 Facility Description

The Facility consists of the following items as depicted in the Customer’s Project Diagram (Appendix A, Figure 7):

- Twenty (20) Customer owned Chint Power Systems Model SCH250KTL-DO/US-800-24 V2 inverters, each of which has a rating of 250 kW, one (1) of which is to be de-rated to 249 kW, for a total of 4,999 kW of inverter-based generation. Inverters are compliant with UL1741 SA and SB.
- Two (2) Customer owned 2,800 kVA 12.47/7.2 kV grounded-wye - 800/462 V grounded-wye interconnection transformers both with impedance Z = 6.75% and an assumed X/R = 5.85.

The Company will own and maintain all equipment up to the delivery point, which is defined as the Facility side of the Company installed load break switch. The Customer will own and maintain all equipment from the delivery point into and throughout the Facility.

3.2 Assumptions

If the Project information is different from that listed below, then a re-study might be required:

1. This analysis assumed an X/R ratio of 5.85 for both interconnection transformers.
2. This analysis assumed an approximate distance of 550’ from the POI pole #JYT 4 to the proposed PCC location.
3. The Project output as proposed by the Customer is restricted to 4,999 kW / kVA, this is to be confirmed by Company-acceptable de-rating documentation which will state that:
    a. Nineteen (19) of the inverters shall be de-rated to 250 kW / kVA.
    b. One (1) inverter shall be de-rated to 249 kW / kVA.

3.3 Area Electric Power System

The proposed location of the Facility is normally served by the Company’s 12.47/7.2 kV three-phase, 4-wire, multi-grounded wye, effectively grounded radial circuit 1A from the #5 Lowell Distribution Substation.

The #5 Lowell substation and 1A circuit characteristics are as follows:

- The 1A circuit is a 12.47 kV nominal, multi-grounded wye, effectively grounded, voltage regulated via a set of bus regulators at the #5 Lowell Substation distribution. The #5 Lowell substation is a 12.47 kV distribution substation supplied at 46 kV via two sources - the Jay 17, and the GMP Johnson substations. There is one (1) substation 46 kV - 12.47 kV power transformer rated at 5/7.5 MVA. There are two (2) distribution circuits - the 1A and 3A.
    - The circuits are bus regulated via a set of three (3) single phase, 333 kVA (462 Amp) regulators with V_{float} = 123.5 V, R = 0, X = 0, 30 second delay to first tap, and bandwidth = 3 V. The regulator controls have settings that will cause the regulator taps to lock in place when the device senses reverse power.
- Table 1 below, shows the Thermal Loading on the interconnecting substation and its circuits with DER Impact.

Feeder/XFMR	Interconnected (MW)	Prior-in-queue, in-progress (MW)	Project (MW)	Total DER	Light Load (MW)	Peak Load (MW)	Generation / Min Load Ratio
1A	0.172	0.016	4.999	5.187	0.119	0.612	43.592
3A	0.225	0.017	0	0.241	0.193	0.948	1.250
Lowell No. 5 TR	0.397	0.033	4.999	5.429	0.312	1.56	17.399

Table 1: DG on the #5 Lowell Substation

- There are five (5) line protective devices on the 1A circuit, none of which are between the circuit recloser and the Project, summarized in Table 2 below:

Location	Device ID	Manufacturer	Model	Fault Current Rating	Status
Pole #8A 4 Stephenson Road, Lowell	05-1-1D	S&C	TripSaver	4,000	In Service
Pole #9 51 Loop Road, Westfield	05-2-1D3	Cooper	35 V4H	1,400	In Service
Pole #9D 33X, Collins Mill, Westfield	05-2-1D5	Cooper	25 V4H	1,000	In Service
Pole #JYT 78, VT Rte 100, Lowell	05-3-1G	Cooper	25 V4H	1,000	In Service
Pole #9 31 Loop Road, Westfield	05-2-1D1	Cooper	25 V4H	1,000	In Service

Table 2: 1A - Line Protection Devices

- There are two (2) existing capacitor banks on the Lowell 1A circuit with a total capacitance of 150 kVAR, summarized in Table 3.

Location	Size (kVAR)	Type	Control	Status
Pole #JYT 74, VT Rte 100, Lowell	50	Fixed	N/A	In Service
Pole #9B 24 Carter Road, Lowell	100	Fixed	N/A	In Service

Table 3: 1A Capacitors

- There is one (1) existing line regulator on the Lowell 1A circuit at Pole 9B 2 on Carter Road, with V_{float} = 123.5 V, R = 0, X = 0, 30 second delay to first tap, and bandwidth = 3 V. The regulator controls have settings that will cause the regulator taps to lock in place when the device senses reverse power.

3.4 Service Configuration

Per Company requirements, Facilities 150 kW or larger will require SCADA communications. The Company will meet this requirement with a PCC Recloser. A recloser will also require a gang-operated switch on the Company side. The following is required in order to interconnect this Facility. All associated modifications are to be located at or adjacent to 44°48’12.6”N 72°26’33.5”W, Route 100 Lowell, VT (*Refer to Appendix B)*:

  - POI to PCC

- From Pole #JYT 4 to the PCC, extend approximately 550 circuit feet of three phase 336 kcmil AL overhead conductors.
- Install one (1) Generator Disconnect.
- Install one (1) PCC recloser.
- Install one (1) Primary Meter.

The Point of Common Coupling (PCC) will be designated as the Company side bushings of the GSU. The Company’s Design Personnel will determine the exact location of the Company’s facilities. The Interconnecting Customer shall be responsible for obtaining all easements and/or land acquisitions required for the interconnection of this Facility in accordance with the Company’s requirements.

The Customer shall provide direct access to the Company’s load break switches, reclosers, and meters along a plowed, 24/7 accessible 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.

The Facility shall only operate when supplied by the normal service configuration. Under abnormal conditions, including auto-transfer to alternative feeder supplies, the Company reserves the right to disconnect the Facility.

4 Power Load Flow Analysis

The power flow analysis was substantially performed using CYMDIST 9.4 Rev 2. A model of the #5 Lowell 1A circuit was developed based on data from the Company’s Milsoft WindMil power system model. The analysis was performed at the following loads:

- Maximum Load:
  - #5 Lowell Substation – 1,572 kVA @ 99% PF Lagging
  - 1A Circuit - 612 kVA @ 100% PF
- Daytime Minimum Load:
  - #5 Lowell Substation – 323 kVA @ 97% PF Leading
  - 1A Circuit – 150 kVA @ 79% PF Leading

4.1 Sub-Transmission Voltage and VAR impacts

The proposed generation is interconnecting to the Lowell substation which is served by the Company’s 46 kV sub-transmission system. Given the proposed generation’s ability to backfeed to the 46 kV system and affect existing concerns regarding voltage and reactive losses, a high-level review was performed to determine the effects of the proposed generation. The results of this review are summarized below. A Company provided PSSE model of the existing 46 kV system under peak load was used for this review.

- Results indicate that at Unity PF operation, there is an anticipated increase in reactive losses on the 46 kV system. To mitigate the increased VAR flow on the 46 kV sub transmission system, the proposed generation must operate at leading 95% PF with respect to the EPS (exporting VARs to the EPS). See Table 4:

Bus Name	Pre Project			Post Project @ Unity PF			Post Project @ 95% (Exporting VARs)		
	MW	MVAR	MVA	MW	MVAR	MVA	MW	MVAR	MVA
COOP_SWNG	-33.6	-3	33.734	-38.4	-0.8	38.408	-38	-1.1	38.016
JAY_TAP (SC1)	0	-14.5	14.500	0	-15	15.000	0	-14.9	14.900
VEC_LOWELL	1.6	0.2	1.612	-3.8	0.7	3.864	-3.4	-1	3.544
KINGDOM_COL	-64.1	-15.7	65.995	-62	-16.9	64.262	-64.1	-15.5	65.947

Table 4: Reactive Losses on 46 kV Sub Transmission System

- There are no voltage concerns identified due to the project's interconnection and therefore no additional mitigations on 46 kV the sub-transmission system are required.

4.2 Thermal Loading Analysis

A Steady State Analysis of the circuit loading, with and without the PV system operating, was performed on the 1A circuit and the #5 Lowell Substation. The following items were found to be thermally overloaded due to the Project and require the listed upgrades:

1. 1A Circuit:
   a. From Pole #JYT 3 to Pole #JYT 4 on Route 100 in Lowell, VT, convert approximately 220 circuit feet of overhead conductor from two phase to three phase, and reconductor to 336 kcmil AL.
   b. From Pole #JYT 1 to #JYT 3 on Route 100 in Lowell, VT, re-conductor approximately 170 circuit feet of existing three phase 1/0 AAAC conductors to 336 kcmil AL.

4.3 Reverse Power Flow

The possibility of the Facility causing reverse power flow into the #5 Lowell distribution bus and the 1A circuit was reviewed and determined to be likely at both peak and low load levels, under normal circuit configuration. In order to accommodate the Project, reverse power flow capable controls and settings will be required on the #5 Lowell Substation bus regulators.

4.4 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 customer service point. Under normal operating conditions it is expected that the Company will be able to meet its obligations for ANSI C84.1 with the Facility generation at full power and the interconnecting circuit in its normal configuration as long as the full list of system upgrades identified in this report are implemented. The Customer must maintain voltage at the PCC at +/- 5% of nominal under normal conditions. In addition, the Facility shall not contribute to greater than a 3.0% change in voltage on the EPS under any conditions.

The impact of this proposed generation Facility was carefully reviewed. A base case, with the circuit in its existing configuration, was run for maximum and minimum loading at time of maximum expected generation. The base voltage at the PCC was recorded per phase during analysis.

Due to sub-transmission level impacts caused by the interconnection of this Facility, the project must operate at a 95% leading power factor with respect to the EPS, exporting VARs, as stated in Section 4.1. At this power factor, the steady state load flow results for the 1A circuit show the voltage levels do not stay within the ANSI “A” range on the Company’s EPS with the generation Facility interconnected. Additionally, the change in voltage at the PCC exceeded the maximum of 3.0% for both the maximum load and minimum load cases. To satisfy the Company’s criteria, the following mitigations must be implemented:

- Setting change for the #5 Lowell Substation bus regulators.
- Setting change for the midline regulator on Pole 9B 2 Carter Road.

Any additional change in power factor operation shall be reviewed by the Company. The Company will not be held liable for any power quality issues that may develop with any customers as a result of the interconnection of this Facility.

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.

4.5 Flicker Analysis

Flicker may arise due to variable loads and distributed generation resources. The *IEEE Recommended Practice for Measurement and Limits of Voltage Fluctuations and Associated Light Flicker on AC Power Systems*, IEEE Std. 1453-2015 provides guidance on flicker and voltage fluctuations. The flicker planning level should be no more than P_{st} = 0.9 over a 10-minute period, and no more than P_{lt} = 0.7 over a 120-minute period. These flicker levels use a perception-weighted average of voltage fluctuations that may occur at different frequencies, normalized such that 50% of customers would likely complain at a flicker level of 1.0. To ensure the aforementioned P_{st} and P_{lt} levels are maintained on the Area EPS, flicker emission levels from individual sites shall not exceed 0.35 and highest V_{Delta} shall not exceed 3.0%.

Assessing flicker using a conservative instant on and off fluctuation of the Facility during minimum and maximum loads, and including the list of EPS modifications in the Executive Summary, gives the following results:

Case	Worst Pst		Criteria:
	Max Load	Min Load	Pst < 0.35
	0.2375	0.2298	Pass
N-0	Worst Vdelta		Criteria:
	Max Load	Min Load	Vdelta < 3%
	3.05%	2.95%	Fail

Table 5: Flicker (P_{st}) Values

With the EPS modifications stated in the Executive Summary, the worst case V_{Delta} of 3.05% occurred at maximum load during an instant on case with the Facility operating at 95% leading PF with respect to the EPS, which is not acceptable. To address this concern, the following operating requirement shall be implemented for the Facility:

- Inverter healthy grid reconnect time delays shall be set as follows:
  - “INV-1” through “INV-10”: 360 seconds
  - “INV-11” through “INV-20”: 420 seconds

With the aforementioned operating requirement in place, the analysis produced the following results:

Case	Worst Pst		Criteria
	Max Load	Min Load	Pst < 0.35
N-0	0.2352	0.2181	Pass
	Worst Vdelta		Criteria
	Max Load	Min Load	Vdelta < 3%
	3.02%	2.80%	Pass

Table 6: Flicker (P_{st}) Values with Inverter Healthy Grid Connect Time Intervals

With the EPS modifications stated in the Executive Summary and the inverter healthy grid reconnect operating requirement, the worst case V_{Delta} in the above cases of 3.02% occurred at maximum load with the Facility operating at 95% leading PF with respect to the EPS. This value is observed when the site as a whole trips offline and will be considered acceptable. According to IEEE 1547-2018, Rapid Voltage Change (RVC) criteria do not apply to unplanned tripping.

P_{st} was conservatively estimated using IEEE 1453 Equation 14 shown in Figure 1, and values shown in Figure 2 below:

$$P_{ST} = \left(\frac{d}{d_{Pst=1}} \right) \times F \qquad (14)$$

Figure 1: IEEE 1453 Equation 14

$$P_{ST} = 0.1519 = \left(\frac{3.02}{2.568} \right) \times 0.2$$

Table 4—P_{st} = 1 test points for rectangular voltage fluctuations (Walker [B46])

Col.1 Changes per minute	Col.2 Fluctuation Frequency Hz	Col.3 Pst=1 Relative voltage changes for unit flicker severity for 230 V lamps ΔV/V (%)	Col.4 Pst=1 Relative voltage changes for unit flicker severity for 120 V lamps ΔV/V (%)
0.1	0.000833	7.400	8.202
0.2	0.001667	4.580	5.232
0.4	0.003333	3.540	4.062
0.6	0.00500	3.200	3.645
1	0.00833	**2.724**	**3.166**
2	0.01667	**2.211**	**2.568**
3	0.02500	1.95	2.250
5	0.04167	1.64	1.899
7	0.05833	1.459	1.695
10	0.0833	1.29	1.499
22	0.1833	1.02	1.186
39	0.3250	**0.906**	**1.044**
38	0.4000	0.87	1.000
68	0.5667	0.81	0.939
110	0.9167	**0.725**	**0.841**
176	1.4667	0.64	0.739
273	2.2750	0.56	0.650
375	3.1250	0.50	0.594
480	4.0000	0.48	0.559
585	4.8750	0.42	0.501
682	5.6833	0.37	0.445
796	6.6333	0.32	0.393
1020	8.5000	0.28	0.350
1055	8.7917	0.28	0.351
1200	10.000	0.29	0.371
1390	11.583	0.34	0.438
1620	13.500	**0.402**	**0.547**
2400	20.000	0.77	1.051
2875	23.9583	1.04	1.49

Figure 2: Values used in IEEE 1453 Equation 14, for this Project.

Figure 3: IEEE 1453 Table 4

Table 3—Indicative planning levels for rapid voltage changes (IEC 61000-3-7)

Number of changes, N	ΔV/Vr (%)	
	MV	HV-EHV
N ≤ 4 per day	5–6	3–5
N ≤ 2 per hour	4	3
2 < N ≤ 10 per hour	3	2.5

Figure 4: IEEE 1453 Table 3

IEEE Std 1453-2015
IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems

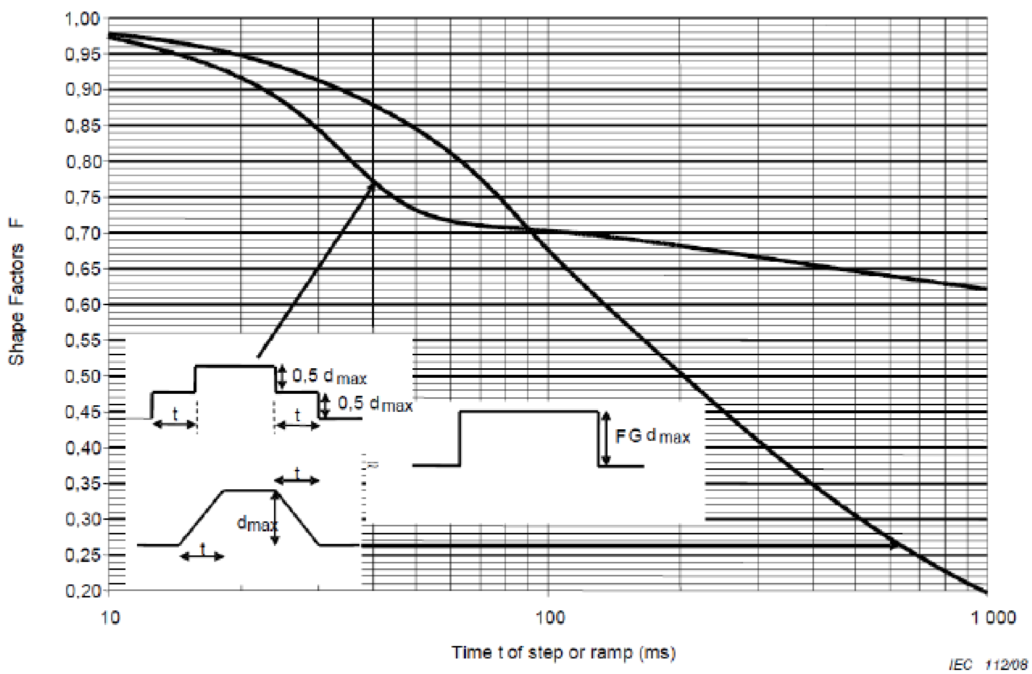


Figure C.2—Shape factor for double step and double ramp changes

Figure 5: IEEE 1453 Figure C.1

Analysis of the 4,999 kVA Facility has determined that the estimated maximum P_{st} at the PCC is 0.2352. Therefore, no additional mitigations are required for flicker when considering the mitigations listed in Section 4.1 and 4.4 above, which require the Facility to operate at a 95% leading PF with respect to the EPS. Refer to IEEE 1453-2015 Table 3, and Figure 5: IEEE 1453 Figure C.1 for additional information on flicker screening.

5 Temporary Over-Voltage on Transmission Supply

Due to the Company’s 46 kV Delta - 12.47 kV grounded–wye supply transformer configuration, overvoltages on unfaulted phases may occur during line to ground faults on the supply system. Detailed analysis was completed to determine whether the interconnection of the Facility may pose significant risk of causing temporary over-voltage conditions to develop on the supply system during line to ground faults on the supply line. The analysis indicates that ground fault over-voltage protection would be required on the Lowell substation transformer prior to the interconnection of the Facility.

6 Protection Analysis

The Company performed a protection review of the proposed interconnection of the 4,999 kVA PV distributed energy resource Facility to its 12.47 kV, multi-grounded wye, effectively grounded circuit. The review focused on the system protection scheme and Facility interface. A separate coordination review will be done by the Company.

6.1 Fault Current Contributions

Short Circuit analyses demonstrated that short circuit duties did not exceed the existing equipment capability. All generating units were assumed to be in-service. A short circuit model of the #5 Lowell Substation and 1A Circuit was developed using ASPEN Oneliner.

Inverters are current limited devices that are characterized to only supply positive sequence fault current which is limited to approximately 120%. A conventional generator was modeled with the following impedances to mimic the characteristics of an inverter:

- Sub transient Positive Sequence Impedance, Z1 = 0.82 + j0.00
- Transient Positive Sequence Impedance, Z1 = 0.82 + j0.00
- Synchronous Positive Sequence Impedance, Z1 = 0.82 + j0.00
- Negative Sequence Impedance, Z2 = 9999 + j0.00
- Zero Sequence Impedance, Z0 = 9999 + j9999

Table 7 summarizes the Project’s effect on fault current levels at the 12.47 kV PCC off of VT Route 100, in Lowell, and at the 12.47 kV substation bus which feeds the 05-1A circuit. These fault currents are within equipment ratings of the existing devices on the circuit. The Customer is responsible for ensuring that their own equipment is rated to withstand the available fault current according to the NEC.

Fault Location	Fault Type	Pre-Project Amps	Post- Project Amps	Δ%
Lowell 05-1A 12.47 kV Bus	Line to Ground	2,840	2,888	1.69%
	Three Phase	2,641	2,699	2.20%
Project PCC Proposed Pole #JYT 4-3 VT Route 100, Lowell, VT	Line to Ground	2,631	2,677	1.75%
	Three Phase	2,531	2,593	2.45%

Table 7: Pre & Post Facility Fault Current

Table 8 summarizes the Pre and Post generation effect on system impedance values at the Facility’s 12.47 kV Interconnection Point.

Fault Location	Positive Sequence Impedance (Ω)	Negative Sequence Impedance (Ω)	Zero Sequence Impedance (Ω)	R0/X1	X0/X1	Max Vpu on unfaulted phase
Project PCC Pre-DG	0.20415 + j1.83879	0.2058 + j1.8403	0.22812 + j1.62174	0.12406	0.88196	1.000
Project PCC Post-DG	0.38917 + j1.76261	0.39102 + j1.76369	0.22812 + j1.62175	0.12942	0.92008	1.018

Table 8: Pre & Post Point of Common Coupling Impedance

6.2 Temporary Over-Voltage on Area EPS

The aggregate generation exceeds the minimum load on the 1A circuit. This condition can cause a temporary overvoltage (TOV) as a result of:

- Ground Fault Over Voltage (“GFOV”) – Should a line-to-ground fault occur on the 1A circuit that causes the circuit breaker or line reclosers to open, the distribution system downstream of these devices loses its reference to the system neutral. The Project itself is considered as ineffectively grounded with three phase inverter sources. Thus, the neutral can shift and the inverter may not detect and operate in sufficient time to prevent damaging overvoltage to the system.
- Load Rejection Over Voltage (“LROV”) - The inverters act as a constant current source which can create a transient overvoltage event when a switch opens and forces all of the inverter current through a fixed load impedance.

The required PCC circuit recloser (Section 7.3) will protect the EPS against both load rejection and ground fault overvoltage risk. Additionally, the Company requires all inverter-based projects to meet the settings requirements of the Default IEEE 1547-2018 Setting Requirements[1], dated December 13, 2022.

6.3 System Coordination Review

Per Company requirements, a separate Protection study will be completed. The study will take into account the device changes listed below:

- At Pole #JYT 4-3 off of VT Route 100, Lowell, install one (1) new pole-mounted PCC recloser.

7 Facility General Requirements

7.1 Interface Transformer

Per Company requirements, the Customer's generation shall interface with the Company system through a transformer or bank of transformers of an adequate kVA rating and proper voltage rating with a grounded wye primary and a grounded wye or delta secondary winding.

The Customer submitted one-line states that the interface transformers will be two (2) 2,800 kVA, 12.47/7.2 kV wye-grounded primary - 800/462 V wye-grounded secondary interface transformers with impedance Z = 6.75%. This analysis assumed the transformers have an X/R = 5.85, see Section 3.2.

The Customer must provide revised documentation showing the X/R ratio of the interface transformer.

7.2 Disconnect Switch

The Customer will furnish and install a gang operated, load break capable, lockable, visible open, disconnect switch to isolate the Facility from the Company's Distribution System.

The Customer must provide revised documentation showing an appropriate Disconnect.

7.3 Communication Equipment

Per Company requirements, The Company may require the installation of additional equipment to ensure the rapid separation of the Customer-generator from the Company system in order to facilitate restoration of service to other customers, to maintain system stability, to mitigate possible fault damage, or for other reasons. A remote terminal unit located in the Customer's plant and compatible with the Company's Supervisory Control and Data Acquisition (SCADA) system will be required. This unit will permit direct trip control of the Customer's interconnecting

[1] https://greenmountainpower.com/wp-content/uploads/2023/01/Default-IEEE1547-2018-Settings-Requirements-2022_12_13_V2.pdf

circuit breaker by Company Operations personnel. SCADA communications equipment is required to be installed at generating facilities with capacity of 150 kW or greater. Such equipment shall be specified or approved by the Company.

7.4 Inverter

The Project is responsible for verifying compliance with Vermont PSB Rule 5.500 section 5.520. The Company requires all inverters connected to the area EPS to be lab tested by a Nationally Recognized Testing Laboratory (NRTL) and certified to conform with all the tests of IEEE 1547.1. UL 1741-SA is the preferred certification for inverters; however, the Company may accept comparable certifications from other NRTLs. The Company may accept field testing by an NRTL; however, if all test conditions specified by IEEE 1547.1 cannot be completed in the field, additional protection requirements may be applied.

7.5 Unintentional Islanding

Per *IEEE 1547 section 8.1.1 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 project was screened for the potential of islanding during abnormal operating conditions. The screening evaluation is per the “Suggested Guidelines for Anti-Islanding Screening” in from the Sandia Labs report for the U.S. Department of Energy. The screening evaluation reviewed the load to generation match (aggregate), amount and type of other DG on the interconnection circuit, and VAR match. The following guidelines are used to determine if Direct Transfer Trip (DTT) is required:

Step 1: Determine whether the proposed DG is greater than 2/3 of minimum load. If it is, then move on to step 2 - 4. If not, a detailed Anti-Islanding study would not be required.

The aggregate proposed DG of 5,187 kW is larger than 2/3 of the minimum load, thus failing Step 1. Proceed to Step 2.

Step 2: If Q_{pv} + Q_{load} is within 1% of Q_{cap} then a study would be prudent.

The Qpv + Qload is not within 1% of Qcap, proceed to Step 3.

Step 3: If there are rotating machines greater than 25% of the total aggregate DG, a study would be required.

The rotating machine generation is less than 25% of the total aggregate DG on the circuit. Proceed to Step 4.

Step 4: If there are multiple inverter manufacturers and no single manufacturer’s product makes up at least 2/3 of the total DG in the potential island; a detailed Anti-Islanding study is required. If the situation is such that more than 2/3 of the total DG is from a single manufacturer, then the risk of unintentional islanding can be considered negligible.

This Project has greater than 2/3 of the inverter manufacturer majority on the circuit, therefore DTT and further islanding study is not required.

It is recommended that any upstream line reclosers from the Project have live-line reclose blocking implemented to prevent closing in on an unintentionally islanded system. There are currently no upstream line reclosers.

7.6 Direct Transfer Tripping

Analysis indicates that the ability of this Facility to island is unlikely; therefore, DTT will not be required.

7.7 Service Quality and Harmonics

The connection of the Facility to the Company system must not reduce the quality of service currently existing on the Company system. Voltage fluctuation flicker and excessive voltage and current harmonic content are among the service quality considerations. Harmonic limitations should conform to the latest IEEE guidelines and/or ANSI standards. Refer to Table 9 below for IEEE 1547-2003 guidelines:

Individual harmonic order h (odd harmonics)[2]	***h < 11***	***11 < h < 17***	***17 < h < 23***	***23 < h < 35***	***35 < h***	***Total demand distortion (TDD)***
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

Table 9: Maximum harmonic current distortion in percent of current (I)

The Company reserves the right to disconnect the Facility if abnormal conditions develop. The Company will not be held liable for any power quality issues that may develop with any customers as a result of the interconnection of this Facility.

[2] Even harmonics are limited to 25% of the odd harmonic limits above.

7.8 Additional Requirements

One-Line:

- Customer must provide Customer cable size, material, and neutral information.
- The Customer must provide a kVA rating of the Facility on the one-line.
- The proposed inverters in the one-line do not match the inverters in the datasheet provided.
- The Customer must provide primary inverter protection settings.

Site Plan:

- Must be PE Stamped
- The output of the Project in kW and kVA to be shown.
- Project name / address to be shown
- Scale is required
- North arrow is required
- Property lines to be shown
- Street names to be shown
- Minimum pole separation in feet to be provided
- Customer Disconnect to be shown
- Inverter location to be shown
- Access for the Company to utility equipment and the Customer Disconnect must be listed as 24/7/365
- Existing single phase service home located immediately north of the Project to be shown.
- PCC to be shown
- VEC interconnection equipment and poles to be shown
- Access Road Detail to be shown:
    - Width
    - A turnaround area for vehicles to exit without backing up
    - Maximum grade to be provided

8 Relay and Protection Requirements

8.1 High (12.47 kV) and Low (800 V) Side Protection

The Facility proposes site protection via 800 V main breakers beyond each interface transformer. Each inverter for the Facility will be protected with a circuit breaker.

8.2 Circuit Breaker & Inverter Protection

Circuit breakers or other interrupting equipment located at the interconnection point must be Certified or “Listed” (as defined in Article 100, the Definitions Section of the National Electrical Code) as suitable for their intended application. This includes being capable of interrupting the maximum available fault current expected at their location.

The Customer’s Generating Facility and Project Interconnection Facilities shall be designed so that the failure of any single device or component shall not potentially compromise the safety and reliability of the Company’s Distribution and Transmission System. The DR Customer’s paralleling-device shall be capable of withstanding 220% of the Project Interconnection Facility rated voltage (IEEE 1547-4.1.8.3). The Project Facility shall have the capability to withstand voltage and current surges in accordance with the environments defined in IEEE Std C62.41.2-2002 or IEEE Std C37.90.1-2002 as applicable and as described in L.3.e (IEEE 1547-4.1.8.2).

This Project shall meet these requirements via the inverter internal protections.

8.3 Voltage Settings

The Customer inverter shall have the following voltage settings per ISO-NE requirements:

Voltage Range (p.u.)	Operating Mode/ Response	Minimum Ride-through Time(s) (design criteria)	Maximum Response Time(s) (design criteria)
V > 1.20	Cease to Energize	N/A	0.16
1.175 < V ≤ 1.20	Permissive Operation	0.2	N/A
1.15 < V ≤ 1.175	Permissive Operation	0.5	N/A
1.10 < V ≤ 1.15	Permissive Operation	1	N/A
0.88 ≤ V ≤ 1.10	Continuous Operation	infinite	N/A
0.65 ≤ V < 0.88	Mandatory Operation	Linear slope of 8.7 s/1 p.u. voltage starting at 3 s @ 0.65 p.u.: $T_{VRT} = 3\text{ s} + \frac{8.7\text{ s}}{1\text{ p.u.}}(V - 0.65\text{ p.u.})$	N/A
0.45 ≤ V < 0.65	Permissive Operation [a,b]	0.32	N/A
0.30 ≤ V < 0.45	Permissive Operation [b]	0.16	N/A
V < 0.30	Cease to Energize	N/A	0.16

The following additional operational requirements shall apply for all inverters:

a. In the Permissive Operation region above 0.5 p.u., inverters shall ride-through in Mandatory Operation mode, and

b. In the Permissive Operation region below 0.5 p.u., inverters shall ride-through in Momentary Cessation mode with a maximum response time of 0.083 seconds.

c. The project must enter Momentary Cessation for over voltage conditions while operating in the Permissive Operation mode. The inverters are to enter Momentary Cessation while operating in the Permissive Operation Mode with a Maximum Response Time of 0.1s. If the proposed inverters are not capable of this Maximum Response Time, a Category III inverter shall be used instead which can comply with this requirement (IEEE 2018 6.4.2 Table 16).

Table 10: ISO-NE Internal Inverter Voltage Protective Settings (Table III)

8.4 Frequency Settings

The Generating Facility shall operate in synchronism with the Company’s Distribution or Transmission System. Whenever the Company’s Distribution or Transmission System frequency at the interconnection point varies from and remains outside normal (nominally 60 Hz), the Facility’s

Protective Functions shall cease to energize the Company's Distribution or Transmission System within the stated maximum trip time. "Maximum Trip time" refers to the time between the onset of the abnormal condition and the Facility ceasing to energize the Company's Distribution or Transmission System. Protective Function sensing equipment and circuits may remain connected to Company's Distribution or Transmission System to allow sensing of electrical conditions for use by the "reconnect" feature. The purpose of the allowed time delay is to allow a Generating Facility to "ride through" short-term disturbances to avoid nuisance tripping. Set points shall not be user adjustable (though they may be field adjustable by qualified personnel). As per the ISO-NE SRD, the required inverter frequency trip settings are as follows:

Shall Trip Function	Required Settings	
	Frequency (Hz)	Clearing Time(s)
OF2	62.0	0.16
OF1	61.2	300.0
UF1	58.5	300.0
UF2	56.5	0.16

Table 11: ISO-NE Internal Inverter Frequency Protective Settings (Table II)

Frequency Range (Hz)	Operating Mode	Minimum Time(s) (design criteria)
f > 62.0	No ride-through requirements apply to this range	
61.2 < f ≤ 61.8	Mandatory Operation	299
58.8 ≤ f ≤ 61.2	Continuous Operation	Infinite
57.0 ≤ f < 58.8	Mandatory Operation	299
f < 57.0	No ride-through requirements apply to this range	

Table 12: ISO-NE Internal Inverter Frequency Protective Settings (Table IV)

8.5 Return to Service

Per IEEE 1547, when entering service, the Facility shall not energize the Area EPS until the applicable voltage and system frequency are within the ranges specified in Table 10 and Table 11 and the permit service setting is set to "Enabled". The Customer shall meet all such requirements as stated in IEEE 1547.

8.6 Protection Scheme Summary

The Customer must submit an updated one-line that meets all the requirements specified within this document before an IA can move forward.

9 Acceptance

Per company requirements, interconnection equipment between the Customer's generator and the point of delivery to the Company must be inspected and accepted by a qualified Company representative before the Customer will be allowed to connect their generating equipment to the Company network.

9.1 Calibration and Testing

- All interconnection relay settings will be reviewed and approved by the Company.
- The Customer is required to have evidence that the relays have been calibrated and must provide accurate documentation of the calibrations.
- All components of the protective relaying scheme must be activated and must function correctly before the Customer will be allowed to connect their generating equipment to the Company network.
- Relaying which serves only to protect the Customer's equipment and is not specifically required by the Company may not require detailed review by the Company.

9.2 Functional Testing

- In addition to relay calibration and testing, a complete functional test of the entire interconnection protection package will be required. The customer shall provide the proposed testing procedure to the Company for review and approval.
- This shall include an operational test of individual relays, a functional test of the subsystems and the total system and as many trips of the generator breaker as necessary to verify the correct operation of the interconnection protective relays and the breaker trip circuits.
- Operational and functional testing may be performed by the Company or by a qualified contractor approved by the Company.
- Test blocks

9.3 As-Built Drawings

- Prior to the initial functional test, the Customer shall supply the Company with as-built relay drawings with sufficient information to safely perform, review and/or interpret the functional test results.

10 Customer Responsibilities

10.1 Company Approval

- No generation, no matter its intent, shall be installed or operated in parallel with the Company EPS without prior notification to and approval by the Company.
- This responsibility applies to an initial facility, as well as to subsequent additions and/or modifications of Generator-owner equipment or change of ownership through sale. The

Generator-owner is responsible for modifying their system to comply with any future mandate of the Regional ISO; NPCC; and NERC or successor organizations including cost incurred.

- If the Generator-owner makes significant changes in the design or scheduling of the project, then any previous information furnished by the Company to the Generator-owner shall be subject to review and possible change. Failure to communicate such changes to the Company may result in a delay of service or termination of service by the Company.
- The Generator-owner is responsible for maintaining Company specified telecommunication equipment and services as required for the installation. See Section 7.3 above for communications requirements.

10.2 Protection of Customer Owned Equipment

- The Customer is responsible for protecting customer-owned equipment in such a manner that faults or other disturbances on the Company's system do not cause damage to the Customer's equipment.
- The Company will not assume responsibility for protection of customer-owned generator(s) or of any other portion of the Customer's electrical equipment.

10.3 Maintenance and Testing

- The Customer is responsible for the maintenance and testing of all interconnection equipment, including power apparatus and the interconnection relay system.
- Periodic tests should be performed according to the manufacturer's recommended test guidelines and, as a minimum, shall be performed in accordance with Section 10, Part 10.3 of this document.
- Specific relay test data shall be made available to the Company upon request to provide evidence that each relay will operate as desired.
- Failure of the Customer to provide proper testing and maintenance will result in the Customer being notified and requested to take prompt corrective action within ten (10) days.
- Should the Customer then fail to provide proper testing and maintenance within the ten days, parallel operation may be required to cease until appropriate corrective action is taken and Company approval is obtained.
- The Customer shall bear the cost of any necessary testing that may be requested by the Company. Such testing may be required as a result of a malfunction of a component of the protective system, accidental damage to parts of the protective system, or the like.

10.4 Minimum Schedules for Inspection, Maintenance and Testing

- The Customer is responsible for inspection, maintenance and testing of the interconnection relay system and associated equipment in accordance with the Company's relay maintenance procedures.

- Copies of maintenance and test records shall be maintained by the Customer and shall be available for review by the Company.

10.5 Compliance and Notification

- The customer-generator must not operate interconnected to the Company’s system if any equipment, relays or protection schemes specified by the Company are not in-service or are not functioning correctly.
- The Company is to be made aware, immediately, of any protective relay that is found to be defective if not replaced immediately by a duplicate, operable device.

10.6 Inspection

- The Company reserves the right to inspect, test, and certify in writing the accuracy of any metering equipment owned by the Customer.
- The Company reserves the right to inspect, test, and certify in writing the Customer’s compliance with the protection standards established herein and approved by the Company.
- The Company reserves the right to inspect and test the electrical interface at any time to certify its proper operation.

10.7 Additional Requirements

- The Company requires all inverter-based projects to meet the settings requirements of the Default IEEE 1547-2018 Setting Requirements[3], dated December 13, 2022.

11 Cost Estimates

Estimated costs for all required System Modifications will be provided by the Company.

[3] https://greenmountainpower.com/wp-content/uploads/2023/01/Default-IEEE1547-2018-Settings-Requirements-2022_12_13_V2.pdf

12 Conclusion

Initial findings indicate system upgrades will be required to mitigate system impacts of the proposed interconnection. Additionally, the Interconnecting Customer must show that the installed Facility will be compliant with requirements of the IC Tariff and will perform according to Company Interconnection Requirements. Estimated costs for all required System Modifications will be provided by the Company.

The Company will require the following System Modifications:

1. Section 3.4 Service Configuration: Located in Lowell, VT:
    a. POI to PCC
        i. From Pole #JYT 4 to the PCC, extend three phase 336 kcmil AL overhead conductors approximately 550 feet.
        ii. Install one (1) Generator Disconnect
        iii. Install one (1) PCC recloser
        iv. Install one (1) Primary Meter
2. Section 4.2 General Thermal Loading Analysis: Between Pole #JYT 3 and Pole #JYT 4 on Route 100 in Lowell, VT, convert approximately 220 circuit feet of overhead conductor from two phase to three phase, and reconductor to 336 kcmil AL.
3. Section 4.2 General Thermal Loading Analysis: From Pole #JYT 1 to #JYT 3 on Route 100 in Lowell, VT, reconductor approximately 170 circuit feet of existing three phase 1/0 AAAC overhead conductor with 336 kcmil AL.
4. Section 4.3 Reverse Power Flow: Enable distributed generation settings at the #5 Lowell Substation bus regulators.
5. Section 4.4 Voltage Analysis: Settings change for the #5 Lowell Substation bus regulators.
6. Section 4.4 Voltage Analysis: Settings change for the midline regulator at Pole 9B 2 on Carter Road.
7. Section 5 Temporary Over-Voltage on Transmission Supply: Install 46 kV Overvoltage Protection Scheme (OVP) scheme for the #5 Lowell Substation transformer.

Before an interconnection application can move forward, the Customer must submit a PE stamped electrical one-line that meets all of the requirements specified within this document to the Company for review and approval.

13 Revision History

Version	Date	Description of Revision
1.0	9/27/2024	Issue Draft to Utility
1.0	11/04/2024	Final Draft Issue to Utility
1.1	2/12/2025	Adjusted verbiage on rating
1.2	2/20/2025	Adjusted verbiage on output

Appendix A Interconnection Customer Diagrams

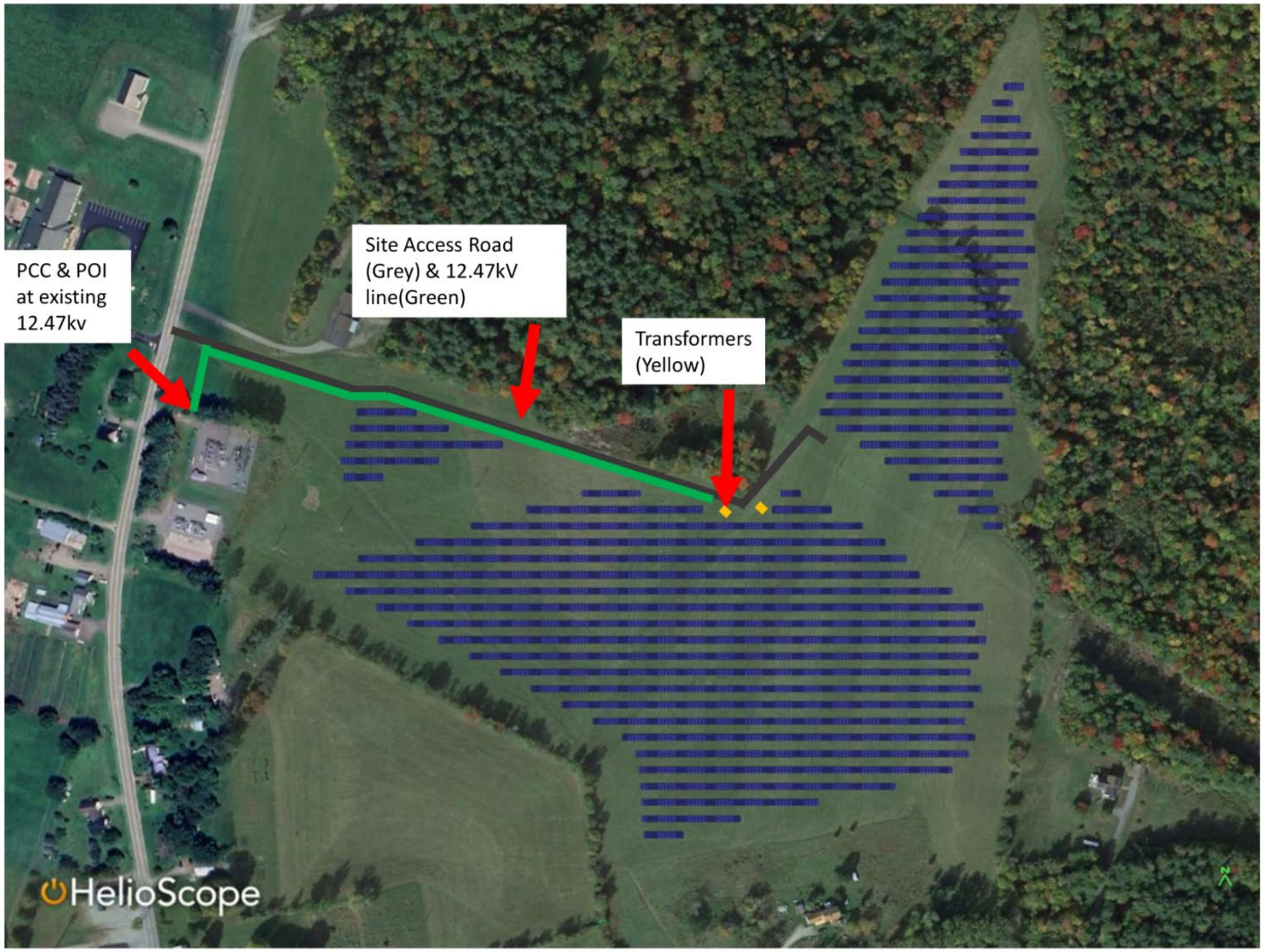
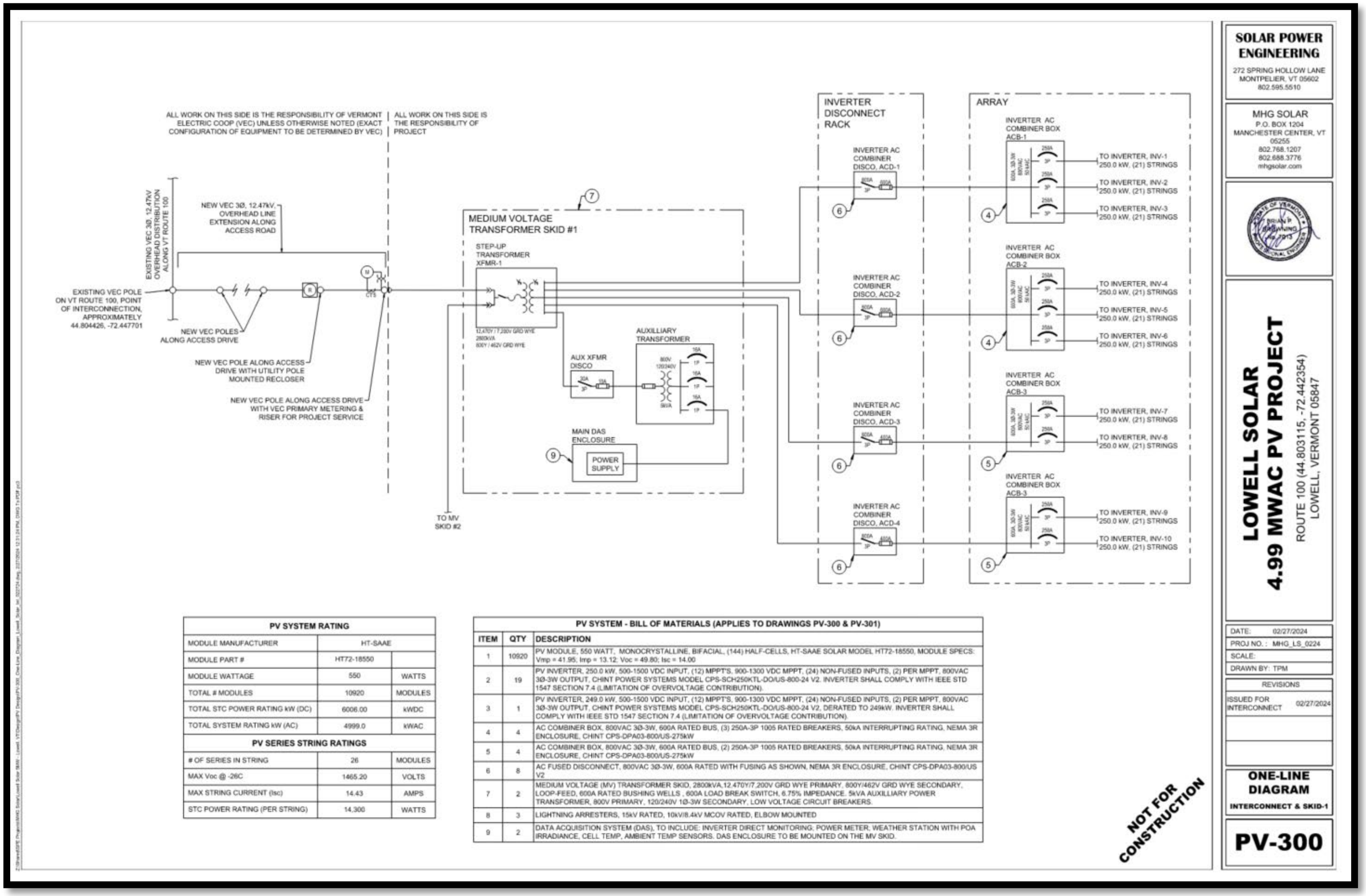


Figure 6: Project Site Plan



PV SYSTEM RATING		
MODULE MANUFACTURER	HT-SAAE	
MODULE PART #	HT72-18550	
MODULE WATTAGE	550	WATTS
TOTAL # MODULES	10920	MODULES
TOTAL STC POWER RATING kW (DC)	6006.00	kWDC
TOTAL SYSTEM RATING kW (AC)	4999.0	kWAC
PV SERIES STRING RATINGS		
# OF SERIES IN STRING	26	MODULES
MAX Voc @ -26C	1465.20	VOLTS
MAX STRING CURRENT (Isc)	14.43	AMPS
STC POWER RATING (PER STRING)	14,300	WATTS

PV SYSTEM - BILL OF MATERIALS (APPLIES TO DRAWINGS PV-300 & PV-301)

ITEM	QTY	DESCRIPTION
1	10920	PV MODULE, 550 WATT, MONOCRYSTALLINE, BIFACIAL, (144) HALF-CELLS, HT-SAAE SOLAR MODEL HT72-18550, MODULE SPECS: Vmp = 41.95; Imp = 13.12; Voc = 49.80; Isc = 14.00
2	19	PV INVERTER, 250.0 kW, 500-1500 VDC INPUT, (12) MPPT'S, 900-1300 VDC MPPT, (24) NON-FUSED INPUTS, (2) PER MPPT, 800VAC 3Ø-3W OUTPUT, CHINT POWER SYSTEMS MODEL CPS-SCH250KTL-DO/US-800-24 V2. INVERTER SHALL COMPLY WITH IEEE STD 1547 SECTION 7.4 (LIMITATION OF OVERVOLTAGE CONTRIBUTION).
3	1	PV INVERTER, 249.0 kW, 500-1500 VDC INPUT, (12) MPPT'S, 900-1300 VDC MPPT, (24) NON-FUSED INPUTS, (2) PER MPPT, 800VAC 3Ø-3W OUTPUT, CHINT POWER SYSTEMS MODEL CPS-SCH250KTL-DO/US-800-24 V2, DERATED TO 249kW. INVERTER SHALL COMPLY WITH IEEE STD 1547 SECTION 7.4 (LIMITATION OF OVERVOLTAGE CONTRIBUTION).
4	4	AC COMBINER BOX, 800VAC 3Ø-3W, 600A RATED BUS, (3) 250A-3P 1005 RATED BREAKERS, 50kA INTERRUPTING RATING, NEMA 3R ENCLOSURE, CHINT CPS-DPA03-800/US-275kW
5	4	AC COMBINER BOX, 800VAC 3Ø-3W, 600A RATED BUS, (2) 250A-3P 1005 RATED BREAKERS, 50kA INTERRUPTING RATING, NEMA 3R ENCLOSURE, CHINT CPS-DPA03-800/US-275kW
6	8	AC FUSED DISCONNECT, 800VAC 3Ø-3W, 600A RATED WITH FUSING AS SHOWN, NEMA 3R ENCLOSURE, CHINT CPS-DPA03-800/US V2
7	2	MEDIUM VOLTAGE (MV) TRANSFORMER SKID, 2800kVA,12.470Y/7.200V GRD WYE PRIMARY, 800Y/462V GRD WYE SECONDARY, LOOP-FEED, 600A RATED BUSHING WELLS , 600A LOAD BREAK SWITCH, 6.75% IMPEDANCE. 5kVA AUXILLIARY POWER TRANSFORMER, 800V PRIMARY, 120/240V 1Ø-3W SECONDARY, LOW VOLTAGE CIRCUIT BREAKERS.
8	3	LIGHTNING ARRESTERS, 15kV RATED, 10kV/8.4kV MCOV RATED, ELBOW MOUNTED
9	2	DATA ACQUISITION SYSTEM (DAS), TO INCLUDE: INVERTER DIRECT MONITORING; POWER METER; WEATHER STATION WITH POA IRRADIANCE, CELL TEMP, AMBIENT TEMP SENSORS. DAS ENCLOSURE TO BE MOUNTED ON THE MV SKID.

Figure 7: Project One-line Page 1

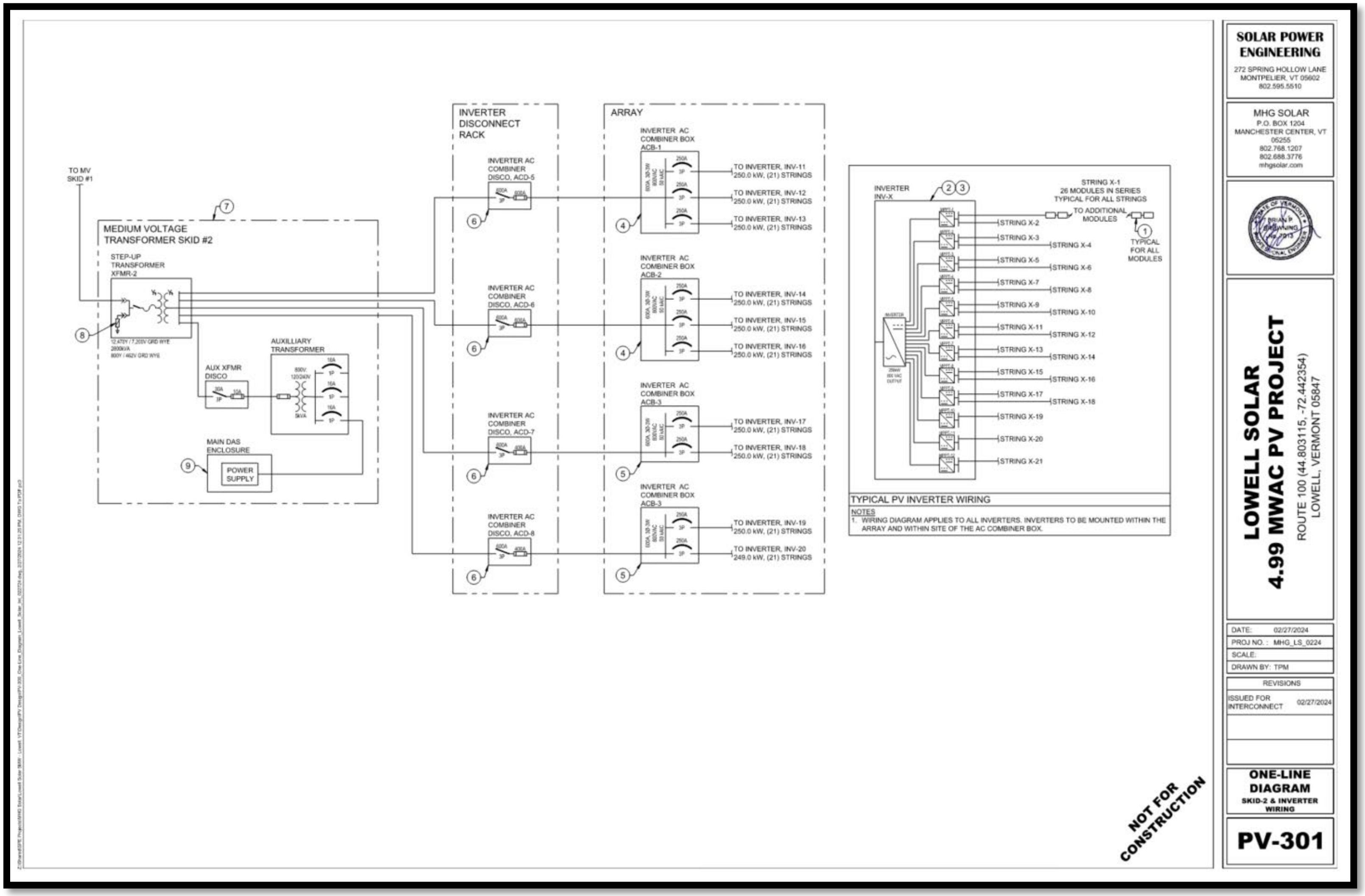


Figure 8: Project One-Line Page 2

Appendix B Electric Power System Modifications

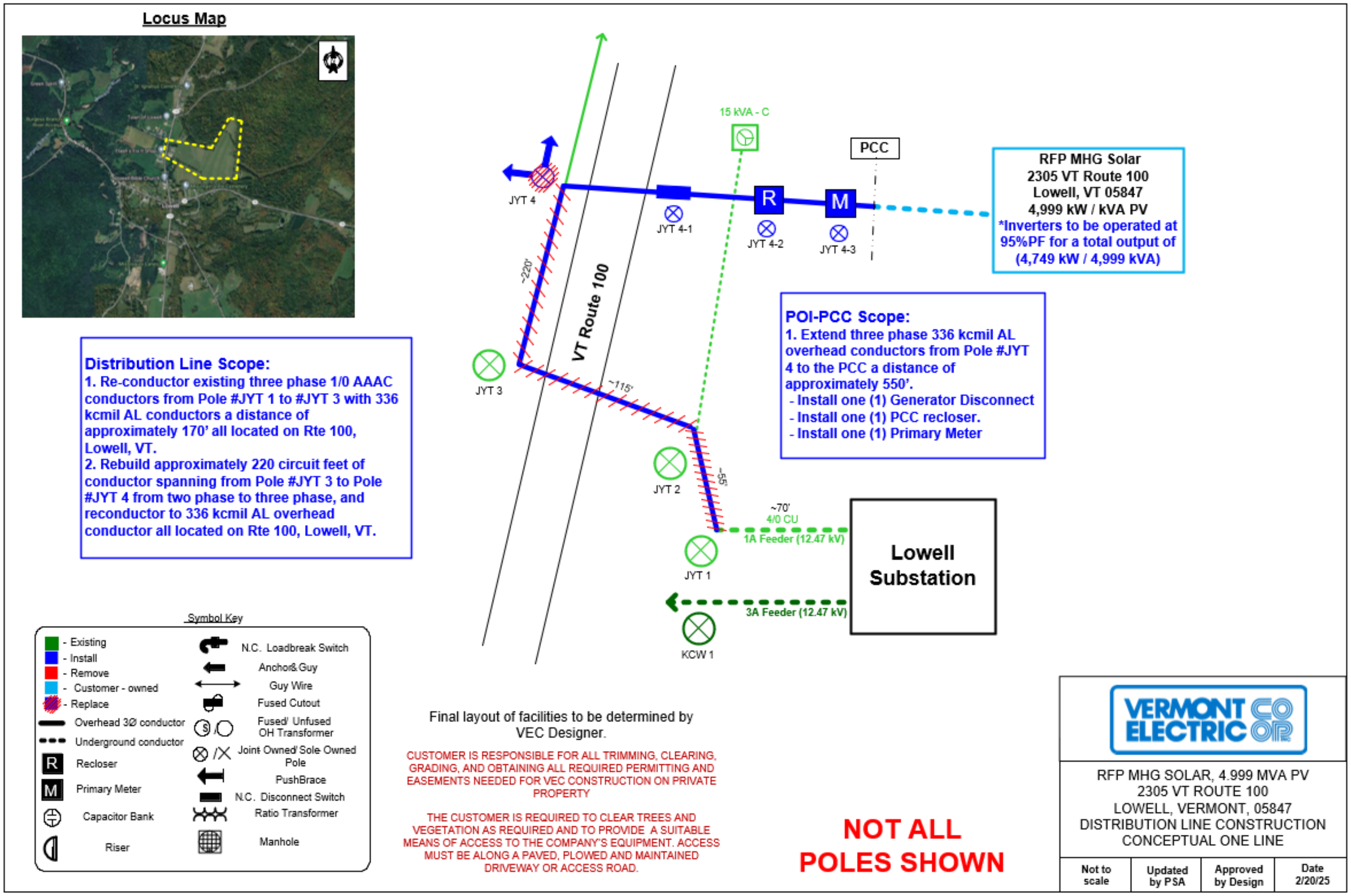


Figure 9: POI-PCC Upgrades