Level 4 Interconnection Agreement

This Agreement is made and entered into this 14th day of April 2023 by and between Maine State Prison, ("Interconnection Customer") located at 475 Cushing Rd. (Friendship Rd.), Warren, Maine, and Central Maine Power Company, a Maine corporation having its office and principal place of business in Augusta, Kennebec County, Maine, existing under the laws of the State of Maine, (" T & D Utility "). Interconnection Customer and T & D Utility each may be referred to as a "Party," or collectively as the "Parties."

Recitals:

Whereas, Interconnection Customer is proposing to develop a Small Generator Facility, consistent with the Interconnection Request completed by Interconnection Customer on January 13, 2021; and

Whereas, Interconnection Customer desires to interconnect the Small Generator Facility with T & D Utility 's Electric Distribution System.

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 This Agreement shall be used for all approved Level 2, Level 3, and Level 4 Interconnection Requests according to the procedures set forth in the Standard Small Generator Interconnection Rule.

1.2 This Agreement governs the terms and conditions under which the Small Generator Facility will interconnect to, and operate in Parallel with, T & D Utility 's Electric Distribution System.

1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power.

1.4 Nothing in this Agreement is intended to affect any other agreement between T & D Utility and the Interconnection Customer. However, in the event that the provisions of this agreement are in conflict with the provisions of the T & D Utility tariff, the T & D Utility tariff shall control.

1.5 Responsibilities of the Parties

1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, and Operating Requirements.

1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generator Facility, and construct, operate, and maintain its Interconnection Equipment in accordance with the applicable manufacturer's recommended maintenance schedule, in accordance with this Agreement.

1.5.3 T & D Utility shall construct, own, operate, and maintain its Electric Distribution System and Interconnection Facilities in accordance with this

Agreement.

1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed the National Electrical Code, the American National Standards Institute, IEEE, Underwriters Laboratories, and any other Operating Requirements.

1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Exhibits to this Agreement and shall do so in a manner as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the other party

1.5.6 Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Common Coupling.

1.6 Parallel Operation Obligations Once the Small Generator Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all written rules and procedures developed by the T & D Utility which pertain to the parallel operation of the Small Generator Facility, copies of which are provided as an Exhibits 1, 2, and 3 to this Agreement.

1.7 Reactive Power
The Interconnection Customer shall design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Common Coupling at a power factor within the range of 0.95 leading to 0.95 lagging.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection
The Interconnection Customer shall test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection, and in accordance with IEEE 1547 Standards.

2.2 Certificate of Completion
Prior to commencing parallel operation, the Interconnection Customer shall provide T & D Utility with a Certificate of Completion in the form of Attachment 6 of the Interconnection Forms and Agreements. The Certificate of Completion must either be signed by an electrical inspector with the authority to approve the interconnection or be accompanied by the electrical inspector's own form authorizing interconnection of the Small Generation Facility.

2.3 Parallel Operation Obligations
The Interconnection Customer shall abide by all permissible written rules and procedures developed by the T & D Utility which pertain to the parallel operation of the Small Generation Facility. In the event of conflicting provisions, the Interconnection Procedures shall take precedence over the T & D Utility's rule or procedure. Copies of the Utilities rules and procedures for parallel operation are either provided as an Exhibit to this Agreement or an Exhibit that provides a reference to a website where copies of the rule or procedure is maintained.

2.4 Right of Access
At reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, Company shall have access to Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its Customers.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date
This Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement
This Agreement shall become effective on the Effective Date and shall remain in effect perpetually, unless terminated earlier in accordance with Article 3.3 of this Agreement.

3.3 Termination
No termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving T & D Utility 20 Business Days written notice.

3.32 Either Party may terminate this Agreement after Default pursuant to Article 6.6.

3.33 Upon termination of this Agreement, the Small Generator Facility will be disconnected from T & D Utility's Electric Distribution System. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection
The T & D Utility may temporarily disconnect the Small Generator Facility from its Electric Distribution System for so long as reasonably necessary in the event one or more of the following conditions or events occurs:

3.4.1 Emergency Conditions
"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of T & D Utility, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Electric Distribution System, T & D Utility 's Interconnection Facilities or (3) that, in the case of the Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Small Generator Facility or the Interconnection Equipment. Under Emergency Conditions, T & D Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Small Generator Facility. T & D Utility shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small Generator Facility. The

Interconnection Customer shall notify T & D Utility promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect T & D Utility's Electric Distribution System. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair
T & D Utility may interrupt interconnection service or curtail the output of the Small Generator Facility and temporarily disconnect the Small Generator Facility from T & D Utility's Electric Distribution System when necessary for routine maintenance, construction, and repairs on T & D Utility's Electric Distribution System. T & D Utility shall provide the Interconnection Customer with five Business Days notice prior to such interruption. T & D Utility shall use reasonable efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

3.4.3 Forced Outages
During any forced outage, T & D Utility may suspend interconnection service to effect immediate repairs on T & D Utility's Electric Distribution System. T & D Utility shall use reasonable efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, T & D Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 Adverse Operating Effects
T & D Utility shall provide the Interconnection Customer with a written notice of its intention to disconnect the Small Generator Facility if, based on Good Utility Practice, the T & D Utility determines that operation of the Small Generator Facility will likely cause disruption or deterioration of service to other Customers served from the same electric system, or if operating the Small Generator Facility could cause damage to T & D Utility's Electric Distribution System. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. T & D Utility may disconnect the Small Generator Facility if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five Business Days from the date the Interconnection Customer receives the T & D Utility's written notice supporting the decision to disconnect, unless Emergency Conditions exist in which case the provisions of Article 3.4.1 apply.

3.4.5 Modification of the Small Generator Facility
The Interconnection Customer must receive written authorization from T & D Utility before making any change to the Small Generator Facility that may have a material impact on the safety or reliability of the Electric Distribution System. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without T & D Utility's prior written authorization, the latter shall have the right to temporarily disconnect the Small Generator Facility.

3.4.6 Reconnection
The Parties shall cooperate with each other to restore the Small Generator

Facility, Interconnection Facilities, and T & D Utility 's Electric Distribution System to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in the Exhibits to this Agreement. If a Facilities Study was performed, T & D Utility shall identify its Interconnection Facilities necessary to safely interconnect the Small Generator Facility with T & D Utility's Electric Distribution System, the cost of those facilities, and the time required to build and install those facilities.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its Interconnection Equipment, and (2) operating, maintaining, repairing, and replacing T & D Utility's Interconnection Facilities as set forth in the Exhibits to this Agreement.

4.2 Distribution Upgrades
T & D Utility shall design, procure, construct, install, and own any Distribution Upgrades. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Billing, Payment, Milestones, and Financial Security

5.1 Billing and Payment Procedures and Final Accounting

5.1.1 T & D Utility shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of T & D Utility provided Interconnection Facilities and Distribution Upgrades contemplated by this Agreement as set forth in the Exhibits to this Agreement, on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within thirty (30) calendar days of receipt, or as otherwise agreed to by the Parties.

5.1.2 Within ninety (90) calendar days of completing the construction and installation of T & D Utility 's Interconnection Facilities and Distribution Upgrades described in the Exhibits to this Agreement, T & D Utility shall provide the Interconnection Customer with a final accounting report of any difference between (1) the actual cost incurred to complete the construction and installation and the budget estimate provided to the Interconnection Customer and a written explanation for any significant variation. (2) the Interconnection Customer's previous deposit and aggregate payments to T & D Utility for such Interconnection Facilities and Distribution Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous deposit and aggregate payments, T & D Utility shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to T & D Utility within thirty (30) calendar days. If the Interconnection Customer's previous deposit and aggregate payments exceed its cost responsibility under this Agreement, T & D Utility shall refund to the Interconnection Customer an amount equal to the difference within thirty (30) calendar days of the final accounting report.

5.2 Interconnection Customer Deposit
At least twenty (20) Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of T & D Utility 's Interconnection Facilities and Distribution Upgrades, the Interconnection Customer shall provide T & D Utility with a deposit equal to 50 percent of the cost estimated for its Interconnection Facilities prior to its beginning design of such facilities.

Article 6. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

6.1 Assignment
This Agreement may be assigned by either Party upon fifteen (15) Business Days prior written notice, and with the opportunity to object by the other Party. When required, consent to assignment shall not be unreasonably withheld; provided that:

6.1.1 Either Party may assign this Agreement without the consent of the other Party to any affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement;

6.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of T & D Utility, for collateral security purposes to aid in providing financing for the Small Generator Facility;

6.1.3 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the Interconnection Customer.

6.2 Limitation of Liability
Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees to the extent permissible by applicable law, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

6.3 Indemnity

6.3.1 This provision protects each Party from liability incurred to third Parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Article 6.2.

6.3.2 To the extent permissible by applicable law, each party shall indemnify and hold the other party harmless from and against any and all claims, actions, lawsuits, judgments and costs, including reasonable attorney's fees, that the indemnified party may become liable to pay or defend due to bodily injury or property damage caused by the negligent acts or omissions of the indemnifying party or its employees, arising out of or in connection with the indemnifying party's performance of its obligations pursuant to this Agreement. The indemnification obligation of the Customer shall not apply to any claim for which Customer would not be liable under the Maine Tort

Claims Act (14 M.R.S. § 8101, et seq.) if such claim were made directly against the Customer and Customer shall continue to enjoy all rights, claims, immunities and defenses available to it under law.

6.3.3 If an indemnified person is entitled to indemnification under this Article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

6.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this Article, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

6.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

6.4 Consequential Damages

Neither Party shall be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

6.5 Force Majeure

6.5.1 As used in this Article, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

6.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible.

6.6 Default

6.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party. Upon a Default, the non-defaulting Party shall give written notice of such Default to the defaulting Party. Except as provided in Article 6.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

6.6.2 If a Default is not cured as provided for in this Article, or if a Default is not capable of being cured within the period provided for herein, the non-defaulting Party shall have the right to terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the defaulting Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this Article will survive termination of this Agreement.

Article 7. Insurance

The Interconnection Customer may be required by the T & D Utility to carry liability insurance for its interconnection subject to the restrictions and limitations found in Maine Public Utility Commission Rule Ch. 324 §12(F). To the extent T & D Utility requires liability insurance, its requirements for the Interconnecting Customer and any required documentation of coverage shall be included herewith under Exhibit 4.

Article 8. Dispute Resolution (see provisions in the Maine Public Utility Commission's Standard Small Generator Interconnection Rules)

Article 9. Miscellaneous

9.1 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the State of Maine, without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

9.2 Amendment
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

9.3 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for

the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

9.4 Waiver

9.4.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

9.4.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from T & D Utility. Any waiver of this Agreement shall, if requested, be provided in writing.

9.5 Entire Agreement
This Agreement, including all Exhibits, constitutes the entire Agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

9.6 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original, but all constitute one and the same instrument.

9.7 No Partnership
This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

9.8 Severability
If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

9.9 Environmental Releases
Each Party shall notify the other Party, first orally and then in writing, of the release any hazardous substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Small Generator Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish

to the other Party copies of any publicly available reports filed with any governmental authorities addressing such events.

9.10 Subcontractors
Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

9.10.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall T & D Utility be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

9.10.2 The obligations under this Article will not be limited in any way by any limitation of subcontractor's insurance.

Article 10. Notices

10.1 General
Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national currier service, or sent by first class mail, postage prepaid, to the person specified below:

If to Interconnection Customer:

Maine State Prison
Attn: Gary LaPlante
111 state House Station
Augusta, ME, 04333-0111
Telephone: (207) 287-2711

If to T & D Utility:

Central Maine Power Company
Attention: Nathan Pelletier, Project Manager
83 Edison Drive
Augusta, ME 04336
Phone: 207-629-2356
Fax: 207-629-0696

With Copy to:
Legal Department
Central Maine Power Company

83 Edison Drive
Augusta, ME 04336
Phone: 207-621-6546
Fax: 207-621-6538

10.2.1 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

If to Interconnection Customer:

Maine State Prison
Attn: Gary LaPlante
111 state House Station
Augusta, ME, 04333-0111
Telephone: (207) 287-2711

If to T & D Utility:

Central Maine Power Company
Attention: Nathan Pelletier, Project Manager
83 Edison Drive
Augusta, ME 04336
Phone: 207-629-2356
Fax: 207-629-0696

10.3 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

If to Interconnection Customer:

Maine State Prison
Attn: Gary LaPlante
111 state House Station
Augusta, ME, 04333-0111
Telephone: (207) 287-2711

If to T & D Utility:

Central Maine Power Company
Attention: Nathan Pelletier, Project Manager
83 Edison Drive
Augusta, ME 04336
Phone: 207-629-2356
Fax: 207-629-0696

Article 11. Signatures

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective duly authorized representatives.

For the Transmission Provider: Central Maine Power Company

DocuSigned by:

Name: andrea VanLuling Date: 4/19/2023

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Andrea VanLuling

Title: Vice President- Treasurer & Controller

DocuSigned by:

Name: Keith Radonis Date: 4/19/2023

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Keith Radonis

Title: Director – Interconnection Services

For the Interconnection Customer: Maine State Prison

Name: ____________________ Date: 04/19/2023

Gary LaPlante

Title: Director of Operation - Maine Department of Corrections

Exhibits:

1. **Transmission & Distribution Interconnection Requirements for Generation**
2. **Metering O&M Charge for Metering Equipment (Schedule D)**
3. **Interconnection Facilities Support Charges (Schedule L)**
4. **Insurance Requirements**
5. **Biennial relay calibration and operational testing**
6. **Costs**
7. **ISO-NE i.3.9 and Reliability Committee approval**
8. **Payment Plan**
9. **Max Net Power Injection at the POI (MW)**
10. **Representations and Indemnification**

EXHIBIT 1

Transmission & Distribution Interconnection Requirements for Generation: The customer is required to be interconnected per CMP's Transmission & Distribution Interconnection Requirements for Generation (also known as the "Blue Book") which is updated annually and can be found on CMP's website.

EXHIBIT 2

Metering O&M Charge for Metering Equipment (Schedule D):

This EXHIBIT 2 is based on estimates from the Impact Study. The parties agree that this exhibit will be amended once actual costs have been determined.

1/27/2022
SJD

Schedule D - MONTHLY METERING O&M COST ESTIMATE

12 kV Distribution Pole Mounted Tariff Rate Primary Metering Equipment

Monthly O&M Cost Estimate for Metering Equipment

Item	Type	Meter Serial Numbers	Qty	Equipment Cost	Installation Cost	Customer Maintenance
MV90 METER KWH IN/OUT	EMR		1	$ 5,000.00	$ 1,200.00	$ 6,200.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
	Sub-Total Installed Equipment Cost					$ 17,900.00
	General Expense @ 6%					1,074.00
	Total Installed Cost					$ 18,974.00
	Monthly Maintenance Charge @ 1.43% of Total Installed Cost					$ 271.33
	Monthly Translation					$ 25.00
	Total Monthly Meter Charges					$ 296.33

Note: The Interconnection Customer is responsible for providing a phone line for the metering equipment and is responsible for all associated costs for this phone line.

EXHIBIT 3

Interconnection Facilities Support Charges (Schedule L):

This EXHIBIT 3 is based on estimates from the Impact Study. The parties agree that this exhibit will be amended once actual costs have been determined.

	Total Interconnection Facilities		
1	Install (1) new pole for primary metering equipment and connect the overhead line to Pole #124, 475 Cushing Rd. (Friendship Rd.), Warren, ME, Install a GOAB switch, Install (1) new pole for GOAB switch, Extend 3 phase line from POI to GOAB switch Pole.	$ 85,000	
2	Established Maine Public Utility Rate Per Section 55 - Interconnection Facilities (Annual)	10.08%	(.84 x 12 Months)
3	Annual Cost	$ 8,568	(Line 1 x Line2)
4	Months in a year	12	
5	Monthly Amount Due	$ 714.00	(Line 3 / Line 4)
	Total Distribution Upgrades		
6	Three phase 300A solid blade, replace with a new three phase line recloser and controller, Pole #92 (Warren Rd.), Update settings of three (3) existing Single Phase line regulators, rated 219A, at Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd, SCADA implementation.	$ 116,273	
7	Established Maine Public Utility Rate Per Section 55 - Distribution Upgrade (Annual)	1.20%	(.10 x 12 Months)
8	Annual Cost	$ 1,395	(Line 1 x Line2)
9	Months in a year	12	
10	Monthly Amount Due	$ 116.27	(Line 3 / Line 4)
	Payment Schedule		
11	Monthly Amount Due	$ 830.27	(Equals Line 5)

Note: The applicable rates for monthly Operation and Maintenance (herin "O&M") charges for Distribution Upgrades and Interconnection Facilities installed by the T&D Utility pursuant to the Interconnection Agreement and those set forth in Section 55 of T&D Utility's Terms and Conditions, filed with and approved by the Maine Public Utilities Commission, as revised from time to time.

EXHIBIT 4

Insurance Requirement: The customer is responsible for having insurance for their interconnection. Please see below requirements of insurance and provide an updated insurance certificate annually. The customer may self-insure to meet its insurance obligations.

i. For non-inverter-based Generating Facilities:

Generating Capacity greater than 5 MW: $3,000,000

Generating Capacity greater than 2 MW up to and including 5 MW: $2,000,000

Generating Capacity greater than 500 kW up to and including 2 MW: $1,000,000

Generating Capacity greater than 50 kW up to and including 500 kW: $500,000

Generating Capacity less than or equal to 50 kW: no insurance required

ii. For inverter-based Generating Facilities:

Generating Capacity greater than 5 MW: $2,000,000

Generating Capacity greater than 2 MW up to and including 5 MW: $1,000,000

Generating Capacity less than or equal to1 MW: no insurance required

EXHIBIT 5

Biennial relay calibration and operational testing of your facility's protection system is required per in the Transmission and Distribution Interconnection Requirements for Generations.

EXHIBIT 6

Cost: A total cost estimate of $220,247 was identified within PRJ 628 System Impact Study Addendum dated March 27, 2023. Per the Chapter 324 of the MPUC rules, the Feasibility/Impact Final Report is intended to produce an estimate of system modification costs (within ± twenty-five percent (25%)). The Company and Customer have mutually agreed to not conduct a facilities study, which would have provided the detailed costs of the electric system modifications necessary to interconnect the Customer's proposed generator. Therefore, the Customer shall be responsible for all costs of such electric system modifications, even if they are in excess of $220,247, plus twenty-five percent. In executing this Interconnection Agreement, the Customer is agreeing to proceed forward financially as well as within the parameters defined within the PRJ 628 Final Report dated April 25th, 2022, PRJ 628 System Impact Study Addendum dated March 27, 2023.

EXHIBIT 7

Additional Utility Study, ISO-NE i.3.9, and Reliability Committee Approval:

Both Parties agree that this Interconnection Agreement is not valid and permission to operate will not be granted by the T&D Utility until the Interconnection Customer has:

1) Completed any T&D Utility required transmission study, including but not limited to non-comprehensive, cluster, or regional studies, and agreed to any resulting upgrades required to interconnect;
2) Completed the ISO-NE i.3.9 process and agreed to any resulting upgrades required to interconnect;
3) Upon completion of the i.3.9 process, received approval at the most immediately available Reliability Committee meeting;

The Interconnection Customer may delay payment for upgrades called for in Chapter 324 until the Interconnection Customer's Small Generator Facility has been approved by the NEPOOL Reliability Committee. Upon Reliability Committee approval, payment shall be made in accordance with Chapter 324 and this Interconnection Agreement. Should the Interconnection Customer elect to delay payment pursuant to the previous sentence, the payment terms and timelines outlined in Exhibit 8 remain valid, except that the first payment will be due 30 days after Reliability Committee approval and subsequent payments will be in accordance with the time period between payments as established in Exhibit 8.

EXHIBIT 8

In accordance with the September 30, 2020, Maine Public Utilities Commission ("MPUC") Order Granting Waiver in Docket No. 2020-00211, the Payment of System Modifications required under Section 12(T) of Chapter 324 shall be based on the Section I.3.9 approval date by ISO-NE rather than the execution date of the Interconnection Agreement.

Under this approved waiver, the Project shall have 90 Business Days from the date of ISO-NE Section I.3.9 approval to make the initial payment (25% of the quoted costs or first installment of a payment plan, as applicable under MPUC Chapter 324) for any required Distribution Upgrades and Interconnection Facilities.

Additionally, and pursuant to the same Order Granting Waiver, the good faith estimate of construction timelines required under Section 12(S) of Chapter 324 of the MPUC rules will be provided upon project receipt of Section I.3.9 approval by ISO-NE. CMP will provide this good faith estimate of construction timelines within 10 Business Days of the project's electronic submittal of the Section I.3.9 approval letter from ISO-NE to CMP.

Payment Plan: The Parties agree that this Interconnection Agreement shall be governed by Chapter 324 of the rules of the Maine Public Utilities Commission ("MPUC"), as adopted by the MPUC though Order Amending Rule dated March 6, 2020, which rule became effective on March 15, 2020 ("Chapter 324"). In the event of any conflict between the provisions set forth in this Interconnection Agreement and those set forth in Chapter 324, the provisions of Chapter 324 shall govern.

Both Parties agree to a payment plan by which the initial payment of 25% of the costs of required Distribution Upgrades and Interconnection Facilities shall be due 90 Business Days after execution of the Interconnection Agreement and the final 75% payment shall be due 90 Business Days after the 25% payment is made. This payment schedule shall supersede the payment schedule set forth in Article 5 of this Interconnection Agreement. Any such payments will be adjusted and refunded to the Interconnection Customer in accordance with § 12(G) Cost Sharing, § 13(I) (Cancellation of Interconnection Agreement), and 13(J) Cost Reconciliation of Chapter 324.

EXHIBIT 9

Max Net Power Injection at the POI (MW): In executing this Interconnection Agreement, the Customer is agreeing to operate within the parameters defined within PRJ 628 Final Report dated April 25th, 2022, PRJ 628 System Impact Study Addendum dated March 27, 2023.

- Application size of 4.980 MW of photovoltaic (PV) generation

EXHIBIT 10

Representations and Indemnification

Representation and Covenant

IRS Notice 2016-36 provides a safe harbor for transfers of property from either an electricity generation, cogeneration facility or an energy storage facility to a regulated public utility, used to facilitate the transmission of electricity over the utility's distribution system, to be treated as a contribution to the capital of a corporation under Internal Revenue Code § 118(a), and not a contribution in aid of construction (CIAC) under Internal Revenue Code § 118(b). This notice requires five safe harbor conditions to be met for transfers of property from an Interconnection customer to a regulated public utility for treatment as a non-taxable event.

One such condition in Notice 2016-36 is that the Interconnection Customer represents and covenants that for income tax purposes, the amount of any payments and the cost of any property transferred to the T&D Utility for the Interconnecting Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years.
With this representation and covenant, the T&D Utility shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges the Interconnection Customer under this agreement.

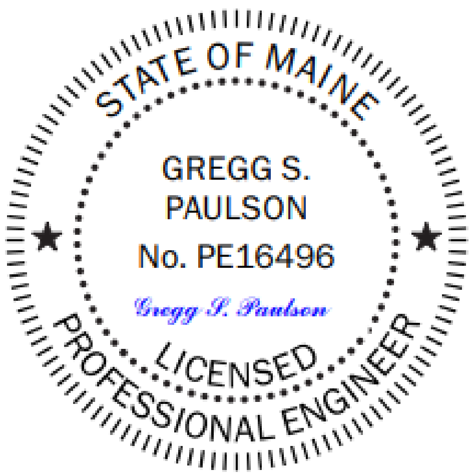
Indemnification

Notwithstanding Article 6.3, Interconnection Customer to the extent permissible by applicable law shall protect, indemnify and hold harmless Central Maine Power Company from the cost consequences of any current tax liability imposed against Central Maine Power Company as the result of payments or property transfers made by Interconnection Customer to Central Maine Power Company under this Level 4 Interconnection Agreement, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Central Maine Power.

PRJ 628
Maine State Prison
(Warren)
Final Report

Distribution Interconnection Impact Study

-- POI: Pole #124, 475 Cushing Rd. (Friendship Rd.), Warren, ME--



April 25th, 2022

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Distribution Planning Department
Central Maine Power Company

Report Revision History

Revision Number	**Revision Date**	**Nature of Revision**

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1. Executive Summary

This distribution system impact study evaluates the effects of the proposed Distributed Generation (DG) interconnection, located at 475 Cushing Rd., Warren, on the operation and performance of the electric distribution system. A system model was developed to simulate the DG interconnection under various operating conditions.

The simulation results have shown that the proposed DG interconnection of **4.980 MW** of photovoltaic (PV) generation would not result in any irremediable adverse impacts to the Electric Distribution Company (EDC) distribution system, nor to customers supplied from the same distribution feeder to which this DG will be interconnected.

Total Cost: $322,283

Results Summary:

- Load-Flow
  - Equipment Loading - Substation: **Pass**
  - Equipment Loading – Between Substation and POI: **Pass**
- Voltage Impact
  - Steady State Voltage Analysis: **Pass**
    - Mitigation applied
  - Voltage Change Analysis: **Pass**
  - Contingency Circuit Analysis
    - See section results for details
- Short-Circuit Analysis: **Pass**
    - See (Ground) Coordination Study Results, see appendix J
- Circuit Protection
  - Transformer Inrush: **Pass**
    - Circuit Protection Coordination: **Pass**
    - Circuit Coordination Study, see Appendix J
  - Site Protection Review (Intertie Relay): **Pass**
- Effective Grounding: **Pass**
- Harmonics Evaluation: **Pass**
- Unintentional Islanding (ROI):
  - Risk of unintentional islanding is low with this project
- TGFOV
  - PRJ 628 passes SANDIA screening and does not require additional costs
- Interconnection Cost Metering/Charges

2. Introduction

The purpose of this study is to identify any potential adverse impacts to the Distribution System that would result from the interconnection of **4.980 MW** of photovoltaic (PV) generation, limited to **4.980 MW** of total export, applied by **Maine State Prison** to Circuit **246D3** (12.47 kV) out of the **Thomaston Creek Substation**. The proposed Point of Interconnection (POI) will be at **Pole #124** on 475 Cushing Rd. (Friendship Rd.), Warren, ME.

The study was conducted in accordance with Central Maine Power Company (CMP) reliability and design standards, study guidelines, procedures and practices and Chapter 324 Rules governing distributed generation interconnection as approved by the Maine Public Utilities Commission (MPUC).

It is assumed that the customer (**Maine State Prison**) will conduct further studies of their facilities as they deem necessary, to ensure adequacy of any customer-owned equipment in conjunction with the proposed generation equipment.

The following studies were performed to evaluate the impact to distribution equipment and performance of the circuit and the substation:

- Load-Flow
- Voltage Impact
  - Steady State Voltage Analysis
  - Voltage Change Analysis
- Short-Circuit Analysis
- Circuit Protection
  - Transformer Inrush
  - Circuit Protection Coordination
  - Site Protection Review (Intertie Relay)
- Effective Grounding
- Harmonics Evaluation
- Unintentional Islanding (ROI)

In addition, the study will provide a brief description and non-binding cost estimate of upgrades required to interconnect the project to the distribution system.

3. Project Description

The **4.980 MW** of photovoltaic (PV) generation, will be connected to the existing overhead distribution lines at Pole #124 on 475 Cushing Rd. (Friendship Rd.), Warren, ME as shown in Figure 3-1. The connection will be made to the primary voltage of 12.47 kV via Circuit **246D3** which is served from the **Thomaston Creek Substation**.

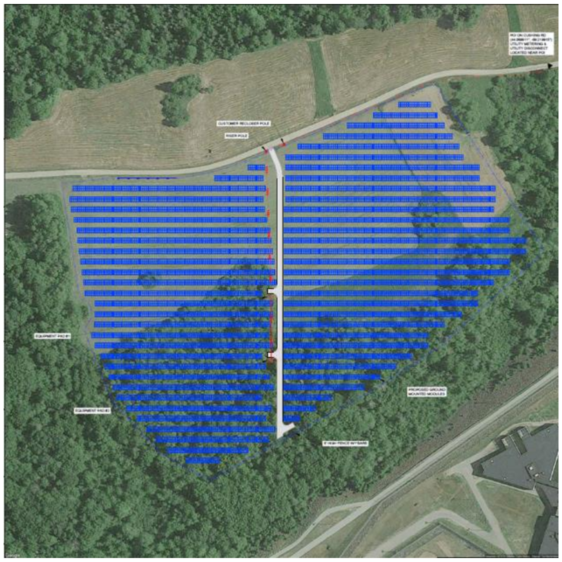

Figure 3-1: Site plan proposed by the project

Note: Cable number on drawing does not match the AC Wire and Cable Schedule table. Study follows the table. An updated SLD needs to be provided and verified prior to project interconnection

Note: GSU transformer configuration needs to be grounded-wye/ grounded-wye. An updated SLD needs to be provided and verified prior to project interconnection.

The distance from the POI to the nearest three phase line is **0** miles, and approximately **3.941 miles** to the substation.

The total project **AC kW** output capacity is limited to 4,980 kW with thirty (30) 166 kW inverters, [SOLECTRIA, XGI 1500-166]. Two (2) 2,500 kVA grounded-wye / wye GSU transformers, along with one (1) 75 kVA dry type grounding transformer is proposed as part of the customer one-line configuration for the project to connect to CMP's 12.47 kV grounded-wye distribution system. Appendix H summarizes useful data from the customer application report.

Customer Information:

Maine State Prison (Maine Department of Corrections Atten Gary LaPlante)
111 state House Station
Augusta, ME, 04333-0111
Telephone: (207) 287-2711

4. Study Method

Both off-peak and peak loads recorded from the past 24 months were reviewed to determine the necessary base case(s). The PV generation project was studied to analyze its operation in conjunction with, without negatively affecting, the distribution system. The study used worst case scenarios and aids to determine possible mitigation techniques for observed adverse impacts. Various studies were done on the base case to identify existing issues, and any that were found, prior to interconnection, were considered pre-existing conditions. For study purposes, these conditions were addressed by modification of the base case as appropriate to preclude their impact on the generation studies.

5. Study Assumptions

The **Thomaston Creek Substation** Transformer Bank No.1 (7.5 / 10.5 MVA), with Load Tap Changer (LTC) rated, regulate the 12.47 kV circuit voltage. To maintain satisfactory service and normal load flow to customers connected to Circuit **246D3**, and provide for operational flexibility, the circuit voltage must be maintained within the normal Company Planning criteria of 123 volts minimum and a maximum of 126 volts at the substation, on a 120-volt basis.

The base voltage and LTC settings are:
Base Voltage: 124.0 V
Bandwidth: 3.0 V
Time Delay: 30 s

To the extent permissible, the project generation is assumed to operate in unity power factor mode by the Customer. It is also assumed that ISO New England will review the proposed project separately and may require the generator to operate in voltage control mode. In that case, their requirements may determine the operating mode and power factor.

Customer equipment and facilities were modeled to the extent necessary to evaluate the impact of Company facilities equipment ratings, service voltage, circuit reliability, protection, and system operation. It is the customer's responsibility to ensure that their facilities are adequate for the proposed project.

It is assumed that the Customer may, at their discretion, utilize transformer taps, if available, on each GSU to adjust the secondary voltage to levels they deem acceptable for their inverters, and other equipment. This should have no direct impact on the utility side voltage of the GSU transformers.

The CMP **Thomaston Creek Substation** Transformer Bank No.1 is rated for 7.5 / 10.5 MVA, and it serves two (2) 12.47 kV circuits**, 246D2** and **246D3**. There are no pre-existing projects on the circuits.

Also, the circuit **246D2** will be contingency circuit for circuit **246D3.**

Since the proposed project will off-set normal circuit loading, the worst-case scenario to be analyzed, for steady state study purposes, is minimum load and maximum project output.

SCADA Requirement - All facilities that have a generating capacity of 1,000 kW or greater must be equipped with SCADA equipment (as described in Chapter V, "Supervisory Control and Data Acquisition" of CMP's Transmission and Distribution Interconnection requirements for Generation). The required communications protocol for SCADA is DNP3. The preferred method of delivery is via a TCP/IP circuit; however, a serial data circuit is also acceptable. The Company may also direct that encryption of SCADA data is required.

6. Historical Loads

Historical load from the past 24 months for circuits **246D3** and **246D2** (contingency circuit) was used as the basis for the load modeling in the base and generation cases. The following Tables, 6-1 & 6-2, give an overview of the historical load for peak and off-peak conditions on circuits **246D2** and **246D3**. Refer to Appendix F for the Thomaston Creek Substation one-line diagram.

Table 6-1— Peak Load on Circuits 246D2 and 246D3

Device	MVA	Amps Phase A	Amps Phase B	Amps Phase C	PF (%)
246D2	2.596	155	120	74	99.4
246D3	3.645	190	173	129	90.3

Table 6-2 Off-Peak Load on Circuits 246D2 and 246D3

Device	MVA	Amps Phase A	Amps Phase B	Amps Phase C	PF (%)
246D2	0.979	44	50	38	99.1
246D3	1.856	92	91	64	88.9

7. Load Flow Analysis

7.1. Equipment Loading – Substation

Several Load Flow studies were conducted to determine the project's impact on the distribution equipment thermal loading. Considering peak and off-peak loading conditions with maximum generation, Circuit **246D3** was analyzed to identify overloads and equipment incompatibility with reverse power flow, if present. Figures 7-1 and 7-2 show the load flow under peak and off-peak conditions, without and with the proposed project interconnection.

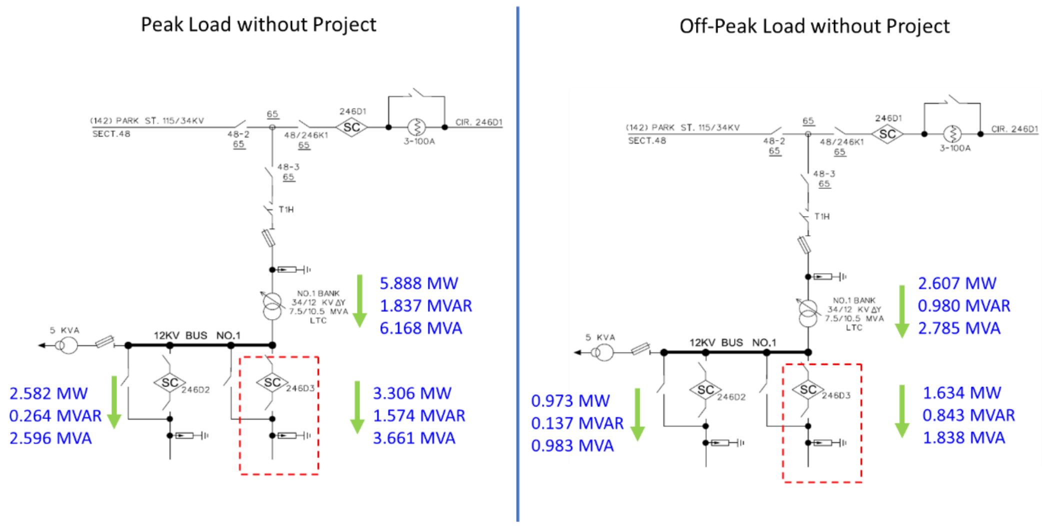

Figure 7-1: Substation Bank Loading under peak and off-peak conditions without proposed project.

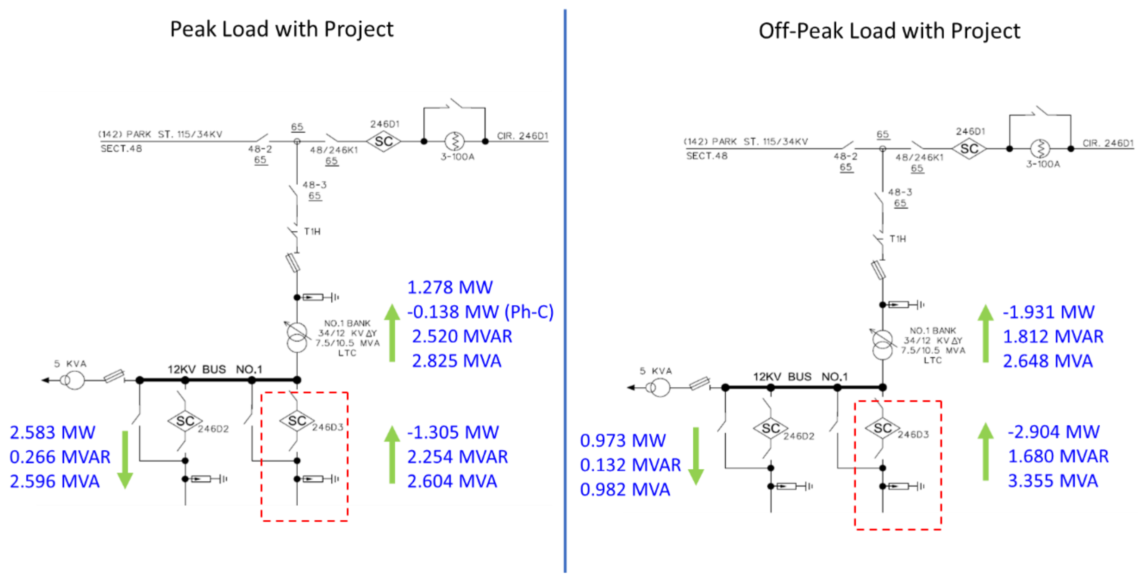

Figure 7-2: Substation Bank Loading under peak and off-peak conditions with proposed project

The worst-case scenario, maximum project output under off-peak load conditions, does not cause the substation transformer rating to be exceeded. Reverse power flow through the project circuit and transformer is observed during both peak and off-peak load condition upon the interconnection of the proposed project.

7.2. Equipment Loading – Between Substation and POI

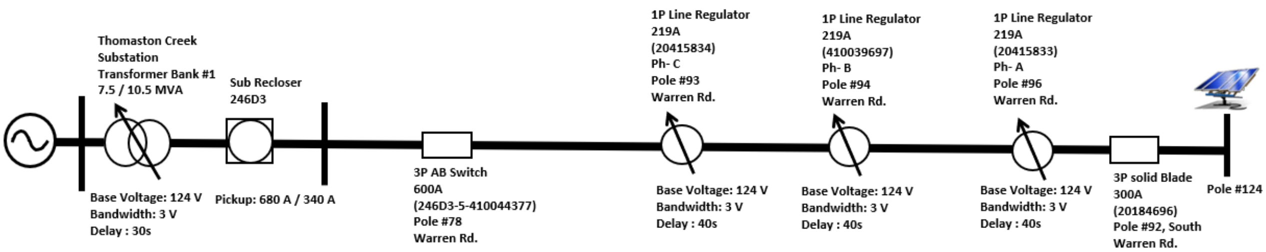

Figure 7-3: Protection Review - POI to Substation.

No overloaded equipment found due to the interconnection of the proposed project.

8. Voltage Impact

8.1. Steady State Voltage Analysis

A Steady State Voltage Analysis was conducted to determine the project's impact on the distribution circuit voltage. To ensure adequate service voltage to customers, 114 to 126 volts, the circuit voltage must remain within the range of 117 to 126 volts (120-volt base) during normal operation. In general, the circuit voltage at the substation must remain in the range of 123 to 126 volts to maintain an adequate voltage on **Circuit 246D3** under all anticipated load conditions, regardless of project operation. Table 8-1 shows the simulation results for voltage impact on **246D3**.

Table 8-1: Simulation Results for Voltage Impact on Circuit 246D3 under Peak and Off-peak loads due to proposed project interconnection.

Circuit 246D3 Load	4.980 MW PV (ON/OFF)	Substation Voltage (V)	POI Voltage (V)	V-max (V)	V-min (V)	Threshold (V)
Peak (1.033 pu)	OFF	123.26	123.81	125.86	116.94	117 - 126
Peak (1.033 pu)	ON	123.69	124.61	**127.07**	118.39	
Off-peak (1.045 pu)	OFF	122.97	122.57	123.90	119.70	
Off-peak (1.045 pu)	ON	122.71	123.46	124.55	120.56	

Overvoltage is observed upon interconnection of the project. Mitigation methods include:

- Update settings of Three (3) Single-Phase line regulators, rated 219A, Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd.
  - Operate in Co-gen mode, with settings:
  - Forward: 124 V, R = 0, X = 0
  - Reverse: 124 V, R = 1, X = 0
  - BW = 3 V & TD = 40 s

Table 8-2 shows values considering mitigation methods applied.

Table 8-2: Simulation Results for Voltage Impact on Circuit 246D3 under Peak and Off-peak loads due to proposed project interconnection. After Mitigation.

Circuit 246D3 Load	4.980 MW PV (ON/OFF)	Substation Voltage (V)	POI Voltage (V)	V-max (V)	V-min (V)	Threshold (V)
Peak (1.033 pu)	OFF	123.26	123.81	125.86	116.94	117 - 126
Peak (1.033 pu)	ON	123.67	124.07	125.53	118.37	
Off-peak (1.045 pu)	OFF	122.97	122.57	123.90	119.70	
Off-peak (1.045 pu)	ON	122.70	122.92	123.76	120.54	

8.2. Voltage Change Analysis

A Voltage Change Analysis was performed to determine the instantaneous change in voltage (voltage change/flicker) that would occur in the distribution system upon sudden loss of the **4.980 MW** project. The voltage flicker at the POI given a 100% loss of the project must be "< / = 3%". Similarly, the voltage change at the line regulators and substation LTC must be less than or equal to half their bandwidths "< / = 1.5 V" and "< / = 1.5 V", respectively. Results consider mitigation applied in *Section 8.1*.

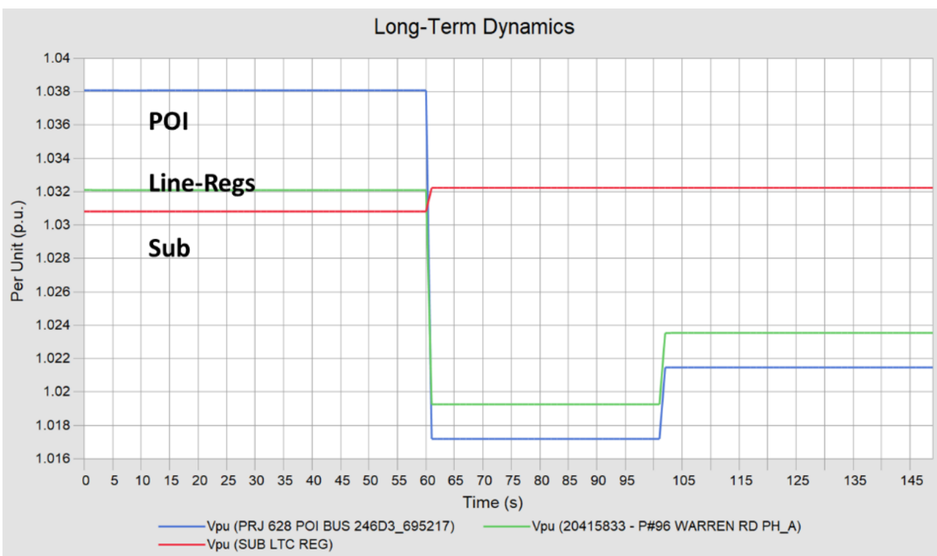

Figure 8-1: Circuit 246D3 POI and Substation Voltage Change at peak Loads Due to Sudden 100% Loss of the 4.980 MW Project.

Peak Load with 100% sudden loss of the proposed project, results:

$$\Delta V = 1.0381 - 1.0172 = 0.0209\, p.u. \Rightarrow 2.09\,\% < 3\% \quad @\text{ POI}$$
$$\Delta V = 1.0321 - 1.0193 = 0.0128\, p.u. \Rightarrow \mathbf{1.536\, V} > 1.5\, V\ @\text{ Line Regulators}$$
$$\Delta V = 1.0322 - 1.0308 = 0.0014\, p.u. \Rightarrow 0.168\, V < 1.5\, V\ @\text{ Substation LTC}$$

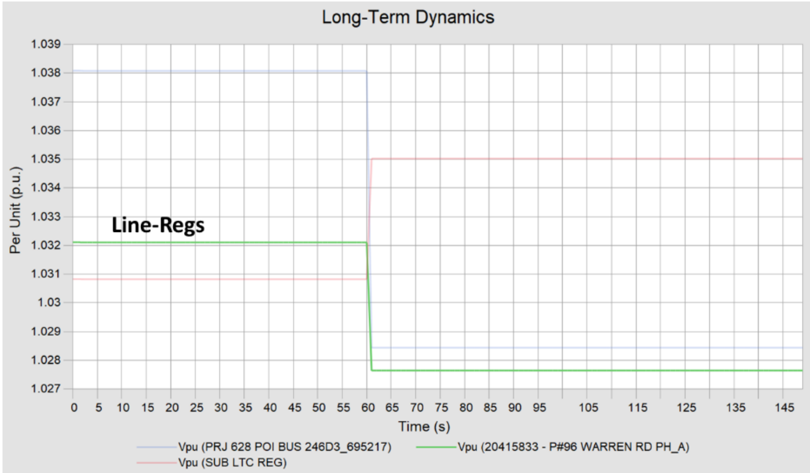

Figure 8-2: Circuit 246D3 POI and Substation Voltage Change at peak Loads Due to Sudden 75% Loss of the 4.980 MW Project.

Peak Load with 75% sudden loss of the proposed project, result:

$$\Delta V = 1.0321 - 1.0276 = 0.0045\, p.u. \;\; \Rightarrow \;\; 0.54\, V \; < 1.5\, V \text{ @ Line Regulators}$$

The voltage flicker is below the allowable 3% limit at the POI and at the substation voltage regulator the voltage change is less than half its bandwidth. Therefore, the project passes this section of study.

8.3. Contingency Circuit Analysis

Circuit **246D2,** served from the same substation as the primary circuit (Thomaston Creek Substation, 12 KV), is the contingency circuit for Circuit **246D3**. Results consider mitigation applied in *Section 8.1*.

Simulation results for Circuit **246D2** as the contingency circuit show overvoltage violation, Vmax 126.28 V, and max flicker of 2.09%, during both Peak and Off-Peak load scenarios.

Therefore, the proposed project cannot operate during the contingency conditions when Circuit **246D2** picks up the load from Circuit **246D3**.

9. Short Circuit Analysis

A short circuit analysis was performed to determine the fault duty at various points and to identify any distribution protection equipment that exceeds its interrupting capability as a result of the project interconnection.

Below is a summary of the maximum fault levels on the 12.47 kV Distribution System Circuit **246D3**. The difference in percentage before and after the interconnection at the substation is shown in Table 4 and the point-of-interconnection (POI) in Table 5.

Table 9-1: Summary of Short Circuit Analysis at Substation.

DER Status	**LLL (A)**	**LLG (3IO) (A)**	**LLG (A)**	**LL (A)**	**LG (A)**
OFF	3121	4364	3534	2703	3641
ON	3341	4630	3724	2796	3752
Difference	7%	6%	5%	3%	3%

Table 9-2: Summary of Short Circuit Analysis at POI.

DER Status	**LLL (A)**	**LLG (3IO) (A)**	**LLG (A)**	**LL (A)**	**LG (A)**
OFF	1411	966	1316	1222	1147
ON	1647	1167	1466	1316	1264
Difference	**17%**	**21%**	**11%**	8%	10%

The proposed project does not cause any protective devices on Circuit **246D3** to exceed 87.5% of their short circuit interrupting capabilities. However, the contributions at POI for ground related faults with the proposed project interconnected are significant, this will be addressed in ground coordination study. See Circuit (Ground) Coordination Study results in Appendix J for additional information and upgrades.

10. Circuit Protection Review

The project is located at approximately **3.941 miles** from Thomaston Creek Substation. The distance from POI to the nearest three phase line is **0 mile**.

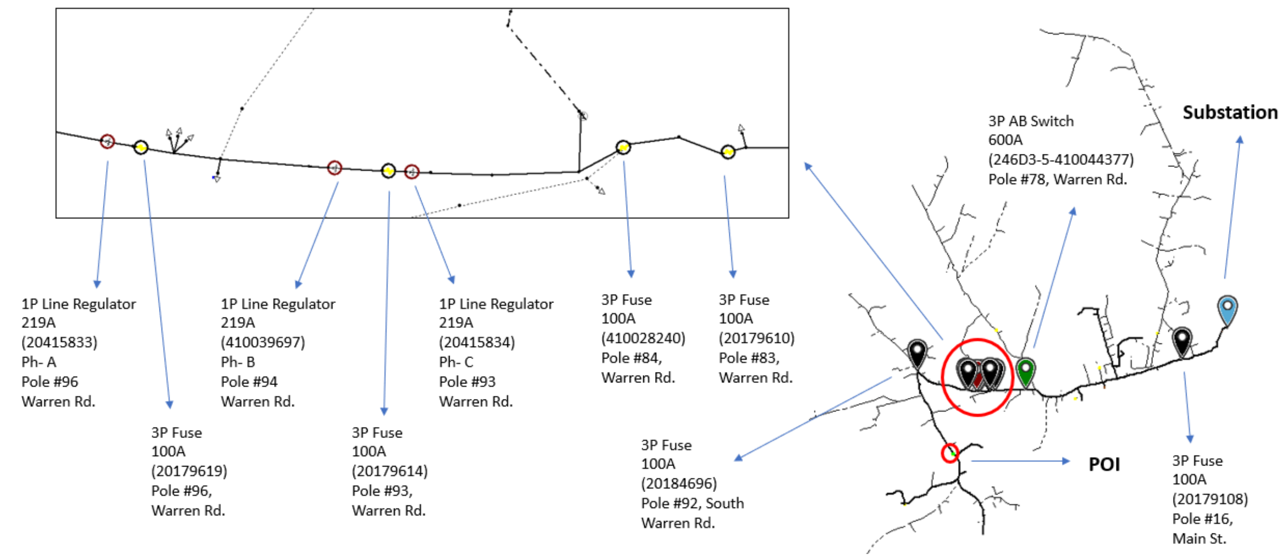

Figure 10-1: Distribution Circuit 246D3.

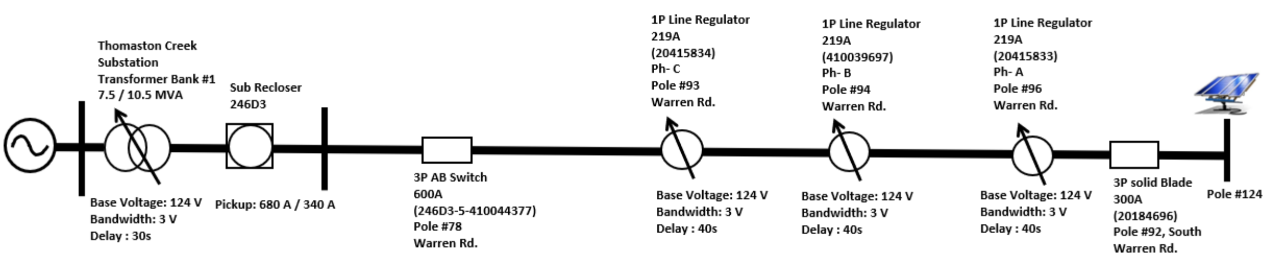

Figure 10-2: Protection Equipment between POI and Substation.

10.1. Transformer Inrush (GSUs)

The transformer inrush current is highly non-linear, it peaks at 1/2 cycle (0.008 sec) after the transformer is energized. The current then drops to normal after about 6 cycles (0.1 sec). The magnitude of the inrush current depends on the following:

- Time that you throw the switch.
- Length and size of the conductors feeding the transformer.
- Stiffness (available fault current) of the system feeding the transformer.
- The size of the transformer.
- The type of transformer.

The worst case for transformer inrush current is when the two (2) 2,500 kVA generating step-up (GSU) transformers are energized. The inrush current is determined as:

$$10 \times \text{Rated} = 10 \times 231.5 \text{ A} = 2{,}315 \text{ A}$$

Review of reclosers in the circuit, between POI and substation, is performed in the following section.

10.2. Circuit Protection Coordination

Review of the TCC curve for substation recloser **246D3** with SEL-351R control shows that the inrush current, considering the project GSU transformers, will not trip its settings within 6 cycles. Additionally, the reverse power flow may be as high as 161.60 A at recloser **246D3** with the project online.

Review of the TCC curve for the new line recloser with SEL-651R control shows that the inrush current, considering the project GSU transformers, will trip its settings within 6 cycles, approximately at 0.028s. Additionally, the recloser will trip its settings within 6 cycles, approximately at 0.06s. Also, the reverse power flow may be as high as 208.84 A at the new line recloser with the project online.

The new line recloser need to be updated as indicated in the table below. See Appendix J, coordination study report, for additional information. See TCC curve located in Appendix D, for details.

Table 10-1: Recloser(s) Upgrade/Update Summary.

Recloser	Upgrade	2nd Order Harmonic Blocking – Needed?	Directional Control – Needed?	Settings Update?
SS. **246D3**	No	No	No	No
New Line Recloser: Pole #92 Warren Rd.	New install	Yes	Yes	No

10.3. Site Protection Review (Intertie Relay)

Maine State Prison (475 Cushing Rd. (Friendship Rd)) has proposed to use a recloser as shown below with a G&W Electric SEL-651R as the intertie relay. The SEL-651R overcurrent protection (site recloser) for Maine State Prison (475 Cushing Rd. (Friendship Rd)) will need to coordinate with protection reclosers upstream of the project's POI and coordinate reconnection timing with other project reclosers in the circuit (if any).

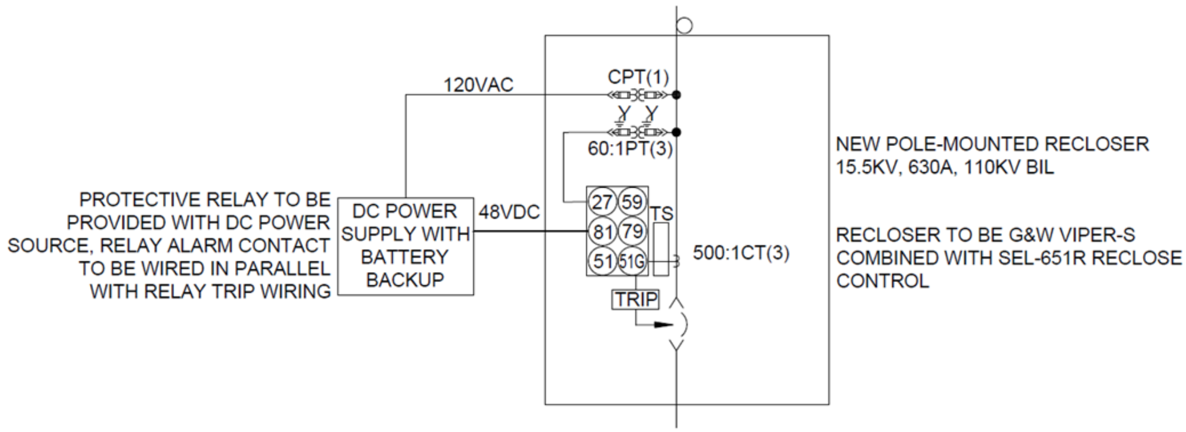

Figure 10-1: New Pole-mount recloser provided by the customer.

Table 10-2:Relay Settings

PROPOSED PROTECTION RELAY SETTINGS							
DEVICE	PICKUP			Time Delay		Total Clearing Time	
	Primary		Secondary				
27-1	50%	(3599.8 V)	(60 V)	63 CYC	1.05 SEC	66 CYC	1.1 SEC
27-2	88%	(6335.6 V)	(105.6 V)	117 CYC	1.95 SEC	120 CYC	2 SEC
59-1	110%	(7919.5 V)	(132 V)	117 CYC	1.95 SEC	120 CYC	2 SEC
59-2	120%	(8639.5 V)	(144 V)	6.6 CYC	0.11 SEC	9.6 CYC	0.16 SEC
81U-1	58.5 HZ			17997 CYC	299.95 SEC	18000 CYC	300 SEC
81U-2	56.5 HZ			6.6 CYC	0.11 SEC	9.6 CYC	0.16 SEC
81O-1	61.2 HZ			17997 CYC	299.95 SEC	18000 CYC	300 SEC
81O-2	62 HZ			6.6 CYC	0.11 SEC	9.6 CYC	0.16 SEC
51		288 A	0.58 A	SET PER UTILITY STANDARDS			
51G		96 A	0.19 A	SET PER UTILITY STANDARDS			
79	0.95 PU - 1.05 PU			17997 CYC	299.95 SEC	18000 CYC	300 SEC
	59 HZ - 60.5 HZ						

SETTINGS ASSUME 3 CYCLE ESTIMATED DEVICE TRIP OPENING TIME
SETTINGS ARE BASED ISO-NE Source Requirement Document Table 1 (VOLT) AND Table 2 (FREQ).
SETTINGS ARE BASED ON A 120V SECONDARY PT BASE.

10.4. Single Phasing

The behavior of three-phase transformers, when one of the phases is lost, is commonly called "single phasing." Upon a single phasing condition voltages and currents, on both the HV side and LV side, depend greatly on the transformer winding connection (delta, wye, wye-grounded, etc.) as well as the transformer's core construction. A single phasing condition is very difficult to detect by relays where the CTs are monitoring current on the LV side of the transformer.

On the customer side, with the presence of long underground cables (high capacitance); the occurrence of the Ferranti effect is highly possible. The effect is more pronounced in cables than in lines and can induce several limitations. Also, with increased capacitance, the charging current drawn is also increased. Underground cables have 20 to 75 times the line charging current compared to overhead lines. Due to these two conditions, it is suggested that the recloser have the ability of monitoring zero-sequence voltage to eliminate the single-phasing concerns.

11. Effective Grounding

Utilities in the Northeastern part of the United States currently use the conventional effective grounding concept prescribed in IEEE 142. The standard says, “The grounding scheme of the DR interconnection shall not cause overvoltage that exceeds the rating of the equipment connected to the Area EPS and shall not disrupt the coordination of the ground fault protection on the Area EPS.” The grounding impedance (X_0) is calculated based on the positive sequence impedance (X_1) provided by the inverter manufacturer and X_0 /X_1 <3, R_0/X_1<1 are generally used. Refer to Appendix I for the modified customer proposed one-line diagram of the project.

Table 11-1: Effective Grounding Values at POI.

Status	**R_0/X_1**	**X_0/X_1**	**Threshold**
w/o project	0.519	1.694	**R_0/X_1 < 1** **X_0/X_1 < 3**
w/ project	0.530	1.727	

The proposed two (2) 2,500 kVA Wye-grounded to Wye need to be updated as mentioned in *Section 3*. The results consider the GSU transformers as Wye-grounded to Wye-grounded, along with one (1) 75 kVA dry type Grounded-Wye / Delta grounding transformer and they are effectively grounded. The proposed equipment will not worsen the grounding conditions, hence, not creating adverse impacts to distribution Circuit **246D3**.

12. Harmonics Evaluation

According to the small generating facility characteristic data provided for the inverter, the **harmonics characteristics are (THD) <3 %**. In IEEE 519, the accepted THD is 5%. Therefore, the project passes this section of the study.

13. Unintentional Islanding (ROI)

The generator must adhere to IEEE Standard 1547 that mandates a DG must detect an unintentional islanding condition and cease to energize the Electric Power System (EPS) within two seconds of the occurrence. An islanding condition results whenever the DG continues to power a location even though electrical grid power from the local EPS is no longer present. This would occur if the feeder breaker is opened for any reason other than for a fault on the feeder, or if any other manual switching device in the feeder main line to the DG is opened. It should be noted that there may be interaction with other generators on the feeder. As stated on CMP's Transmission & Distribution Interconnection Requirements for Generation, this operation can create hazards to personnel, other customers, and the public, and may cause equipment damage. Because of the hazards involved, islanding must be avoided.

The Sandia National Laboratories Guidelines Report[1] Suggested Guidelines for Assessment of DG Unintentional Islanding Risk analyses are used to perform preliminary screens and determine the risk of islanding.

The preliminary Sandia Risk of Islanding (ROI) screening results indicate that the risk of an unintentional islanding is low, and no additional mitigation or study are needed, see Appendix E below.

[1] *SANDIA Report: Suggested Guidelines for Assessment of DG Unintentional Islanding Risk, Revised November 2012 March 2013 – Added clarifying footnote (p10) and editorial correction (p12).* https://energy.sandia.gov/wp-content/gallery/uploads/SAND2012-1365-v2.pdf

14. Transmission Ground Fault Overvoltage (T-GFOV)

Ground Fault Overvoltage (T-GFOV) occurs when the voltage rises on un-faulted phases during a single line to ground fault. A DER cannot identify a ground fault on the transmission or sub-transmission side of a delta transformer winding due to an islanded condition thus the DER may continue to operate and create an overvoltage condition. This condition can cause serious damage to customer and electric utility equipment due to voltages rising up to 173% of nominal if not addressed.

In order to determine the substations in the CMP territory that could be susceptible to Transmission or sub-transmission Ground Fault Overvoltage (T-GFOV), the Company performed a topology review which consisted of an assessment of distribution substations with two or less transmission lines to the substation with a delta or ungrounded-wye connected high side transformer. Based on this topology assessment and review, it was determined that **Substation Thomaston creek is susceptible to T-GFOV.**

Based on the ROI screen steps performed as described above, Project 628 passes the ROI screen and does not require additional costs or study related to T-GFOV.

15. Conclusions

1. Line Upgrade
    - There are no 1P/2P to 3P line upgrades required.

2. Load Flow Analysis
    - Reverse power observed upon the interconnection of the proposed project.

3. Equipment Loading
    - No overloaded equipment found due to interconnection of the project

4. Voltage Impact
    - Overvoltage is observed upon interconnection of the project. Mitigation methods include:
        - Update settings of Three (3) Single-Phase line regulators, rated 219A, at Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd.
            - Operate in Co-gen mode, with settings:
            - Forward: 124 V, R = 0, X = 0
            - Reverse: 124 V, R = 1, X = 0
            - BW = 3 V & TD = 40 s
    - The voltage change at the POI and the substation are within the allowable limit during a 100% loss of the proposed project.

5. Contingency Circuit Analysis
    - The proposed project cannot operate during the contingency conditions when Circuit **246D2** picks up the load from Circuit **246D3**.

6. Short circuit Analysis
    - Protective devices can interrupt the available short circuit with project interconnection.
    - See Coordination Study Results in Appendix J for additional information (upgrades if needed).

7. Circuit Protection Coordination
    - Three-phase solid blade, rated at 300A, needs to be replaced with a new three-phase recloser, Pole #92 (Warren Rd.). See *Section 10.2* for features and settings.

8. Effective grounding
    - No adverse impacts were found in the effective grounding study due to the interconnection of the project.

9. Harmonics
    - No adverse impacts observed.

10. Unintentional Islanding (ROI)
    - ROI is low, no additional mitigation or study are needed.
11. Transmission Ground Fault Overvoltage (TGFOV)
    - PRJ 628 passes SANDIA screening and does not require additional costs.

The project will be able to interconnect if required upgrades, updates and mitigation methods applied or listed (if any), including project modifications, throughout the report are performed, reviewed, and approved, in order to maintain the distribution system's integrity and reliability. Contingency Circuit Analysis section pertains only to the ability of the project to operate during contingencies - *Contingency operation subject to change at CMP's discretion.*

16. Suggested Solutions and Cost Estimation

Total Cost $322,283

Note:

- This estimate is in accordance with the guidance provided under the Maine Public Utilities Commission Chapter 324 Rule. Under §12.N, the rule states the Utility "should endeavor to estimate within +/- 25%." While the intent of this estimate is to refine costs to upgrade to a figure within that tolerance, the total amount to upgrade is an estimate of costs and may not reflect all known costs at the time of the estimate. Should a project desire more refinement or a detailed breakdown of an estimate, please refer to the last paragraph of Section N where it states, "The detailed system modifications and more accurate costs of the modifications necessary to interconnect the ICGF shall be identified in the Facilities Study." If the project desires a Facilities Study, please advise the Interconnection Services Group.

- Estimate is based on Distribution Planning Estimating Guide Version 1.4 Appendix A.

- Estimate assumes a 20% overall contingency.

- Estimate Includes Project Engineering, Project Manager, Administrative Support, Miscellaneous Overheads, and Allocations.

- TBD costs are not included in the total dollar amount and are a separate cost "high level" associated with the project interconnection.

System Upgrade/Revisions

- Three phase 300A solid blade, replace with a new three phase line recloser and controller, Pole #92 (Warren Rd.).
    - Features and settings: second order harmonic blocking, directional sensing capabilities
- Update settings of three (3) existing Single Phase line regulators, rated 219A, at Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd.
    - Operate in Co-gen mode, with settings:
    - Forward: 124 V, R = 0, X = 0
    - Reverse: 124 V, R = 1, X = 0
    - BW = 3 V & TD = 40 s
- SCADA implementation, cost **$1,000.**

Ground Coordination Study Results

- No additional costs.

Transmission Ground Fault Overvoltage (T-GFOV)

- Cost responsibility for this project, none.

Transient Overvoltage Compliance (TOV)

- Cost **$16,500**
- See Appendix E.

Interconnection Cost

- The project will require a **bi-directional pole mounted primary metering package** located off the existing 12.47 kV overhead CMP distribution circuit. The facility includes one solid state meter, three 12.47 kV CT and three 12.47 kV VT, the detailed price is listed in Appendix B, cost **$18,974 (total installed cost)/$296.33 (per month maintenance and translation)**
- Install (1) new pole for primary metering equipment and connect the overhead line to Pole #124, 475 Cushing Rd. (Friendship Rd.), Warren, ME.
- Install a GOAB switch.
- Install (1) new pole for GOAB switch.
- Extend 3 phase line from POI to GOAB switch Pole.

Customer Responsibilities

- Everything on the load side or customer side of the Gang Operated Air-Break Switch (GOAB) representing the Point of Common Coupling (PCC) will be the responsibility of the customer or developer. This includes any protective reclosers, breakers, the telephone line to the Revenue Meter and all associated equipment.
- All facilities that have a generating capacity of 1,000 kW or greater must be equipped with SCADA equipment.
- Updated SLD required, any variation of the values assumed in this study will need to be verified prior to project interconnection:
  - Cable number on drawing does not match the AC Wire and Cable Schedule table. Study followed the table.
  - Update the GSUs configuration to Yg-Yg.

Please Note: This report contains estimates regarding the scope of the required modifications to CMP's transmission and/or distribution system and/or to the project to accommodate the requested interconnection. These estimates may be dependent on upgrades from projects that have previously submitted interconnection requests. All costs and upgrades are those required based on each preceding project progressing as anticipated. Should a previous project upon which your project is dependent withdraw from the interconnection queue before their upgrades are completed, all dependent projects will be restudied to determine any impact to their interconnection. This may result in changes to the cost estimates necessary to interconnect your ICGF. Any additional time or resources needed to complete a restudy will be invoiced to your project. Any specific upgrades covered under the Cost Sharing provisions of Section 12(G) of Chapter 324 of the MPUC Rules would remain subject to those provisions.

17. Appendix

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A. Planning Cost Estimate

Table 17-1: Planning Cost Estimate

Project Name:	Main state Prison	Project #:	PRJ 628
Location:	475 Cushin Road, Warren, ME	Org Date:	21-Apr-22
Section		Rev Date:	
By:	Distribution Planning Department	Rev by:	

Item	Quantity to:			Revised Unit Cost			Estimated SubTotal Cost			Contingency	Estimated Total Cost		
									Contingency value =	20%			
	Install	Remove	Shift	CAP	COR	O&M	CAP	COR	O&M		CAP	COR	O&M
Poles - Electric Owned and Maintained													
35kV - Reinsulate Single Phase	0	0	0	$ -	$ 113	$ 225	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Reinsulate Three Phase	0	0	0	$ -	$ 113	$ 675	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - New Single Phase	0	0	0	$ 3,375	$ -	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - New Three Phase	2	0	0	$ 7,875	$ -	$ -	$ 15,750	$ -	$ -	20%	$ 18,900.00	$ -	$ -
35kV - Replace Single Phase	0	0	0	$ 4,500	$ 900	$ 450	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Replace Three Phase	1	1	0	$ 6,600	$ 1,440	$ 720	$ 6,600	$ 1,440	$ -	20%	$ 7,920.00	$ 1,728.00	$ -
35kV - Dress for aerial cable	0	0	0	$ 1,500	$ -	$ 150	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Pole Set Assist	0	0	0	$ 2,250	$ -	$ 225	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - H-Frame, Two Pole Structure	0	0	0	$ 29,250	$ 8,775	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
OH Conductor (per section - 150ft)													
35kV - Single Phase	0	0	0	$ 788	$ 158	$ 79	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Three Phase Tap	0	0	0	$ 2,700	$ 540	$ 270	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Three Phase Mainline	2	0	0	$ 3,600	$ 720	$ 360	$ 7,200	$ -	$ -	20%	$ 8,640.00	$ -	$ -
35kV - Three Phase Mainline - Spacer	0	0	0	$ 4,500	$ 900	$ 450	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Replace Secondary/Service Conductor	0	0	0	$ 1,800	$ 225	$ 270	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Aerial Cable - Express	0	0	0	$ 8,700	$ 1,710	$ 855	$ -	$ -	$ -	20%	$ -	$ -	$ -
UPZ Vegatation Management	0	0	2	$ 3,000	$ 600	$ 300	$ -	$ -	$ 600	20%	$ -	$ -	$ 720.00
Major OH Equipment													
35kV - Cutout - Single	0	0	0	$ 450	$ 90	$ 45	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Cutout - Three	0	1	0	$ 1,350	$ 270	$ 135	$ -	$ 270	$ -	20%	$ -	$ 324.00	$ -
35kV - Bells - 1ø	0	0	0	$ 300	$ 60	$ 30	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Bells - 3ø	0	0	0	$ 900	$ 180	$ 90	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Disc Switch - InLine	0	0	0	$ 2,250	$ 450	$ 225	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Disc Switch - UnderArm	0	0	0	$ 3,375	$ 675	$ 338	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Load Break Switch	1	0	0	$ 13,500	$ 2,700	$ 1,350	$ 13,500	$ -	$ -	20%	$ 16,200.00	$ -	$ -
35kV - OH Recloser	0	0	0	$ 56,250	$ 11,250	$ 5,625	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - OH Cap Bank	0	0	0	$ 38,250	$ 6,750	$ 3,375	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - OH Arrestors	0	0	0	$ 1,125	$ 225	$ 113	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - SCADA Controlled Recloser - 3Ø	1	0	0	$ 60,450	$ 12,090	$ 3,750	$ 60,450	$ -	$ -	20%	$ 72,540.00	$ -	$ -
35kV - SCADA Switch - 3Ø	0	0	0	$ 50,700	$ 9,300	$ 3,750	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - SCADA Single Phase Reclosers	0	0	0	$ 40,950	$ 8,190	$ 3,000	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - TripSavers - 1Ø	0	0	0	$ 7,500	$ 1,275	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - FuseSavers - 1Ø	0	0	0	$ 4,500	$ 675	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
Misc Labor not accounted for in listed Activities													
Overhead Department Labor in Hours	40	0	0	$ 210	$ 210	$ 210	$ 8,400	$ -	$ -	20%	$ 10,080	$ -	$ -
Underground Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Trans/Station Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Test Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Subtotal							$ 111,900	$ 1,710	$ 600		$ 134,280	$ 2,052	$ 720
Project Management	Evaluation, Design and Support						$ 17,280	$ -	$ -		$ 20,736	$ -	$ -
Construction Manager	Support during project construction						$ 16,800	$ -	$ -		$ 20,160	$ -	$ -
Field Engineering/Planners	Responsible for Design						$ 10,800	$ -	$ -		$ 12,960	$ -	$ -
Allocations	Allocations assigned to the project						$ 13,500	$ -	$ -		$ 16,200	$ -	$ -
						subtotal	$ 170,280	$ 1,710	$ 600		$ 204,336	$ 2,052	$ 720
Misc Overheads	Overheads during all phases of the project						$ 64,706	$ 650	$ 228	38%	$ 77,648	$ 780	$ 274
Total							**$ 234,986**	**$ 2,360**	**$ 828**		**$ 281,984**	**$ 2,832**	**$ 994**
							CAP	**COR**	**O&M**		**CAP**	**COR**	**O&M**

Total							**$ 234,986**	**$ 2,360**	**$ 828**		**$ 281,984**	**$ 2,832**	**$ 994**
							CAP	**COR**	**O&M**		**CAP**	**COR**	**O&M**

B. Metering Equipment Cost Estimates

Table 17-2: Metering Cost Table

						1/27/2022
	Schedule D - MONTHLY METERING O&M COST ESTIMATE					SJD
	12 kV Distribution Pole Mounted Tariff Rate Primary Metering Equipment					
	Monthly O&M Cost Estimate for Metering Equipment					
		Meter		Equipment	Installation	Customer
Item	Type	Serial Numbers	Qty	Cost	Cost	Maintenance
MV90 METER KWH IN/OUT	EMR		1	$ 5,000.00	$ 1,200.00	$ 6,200.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
	Sub-Total Installed Equipment Cost					$ 17,900.00
	General Expense @ 6%					1,074.00
	Total Installed Cost					$ 18,974.00
	Monthly Maintenance Charge @ 1.43% of Total Installed Cost					$ 271.33
	Monthly Translation					$ 25.00
	Total Monthly Meter Charges					$ 296.33

Note: The Interconnection Customer is responsible for providing a phone line for the metering equipment and is responsible for all associated costs for this phone line.

C. Circuits Map

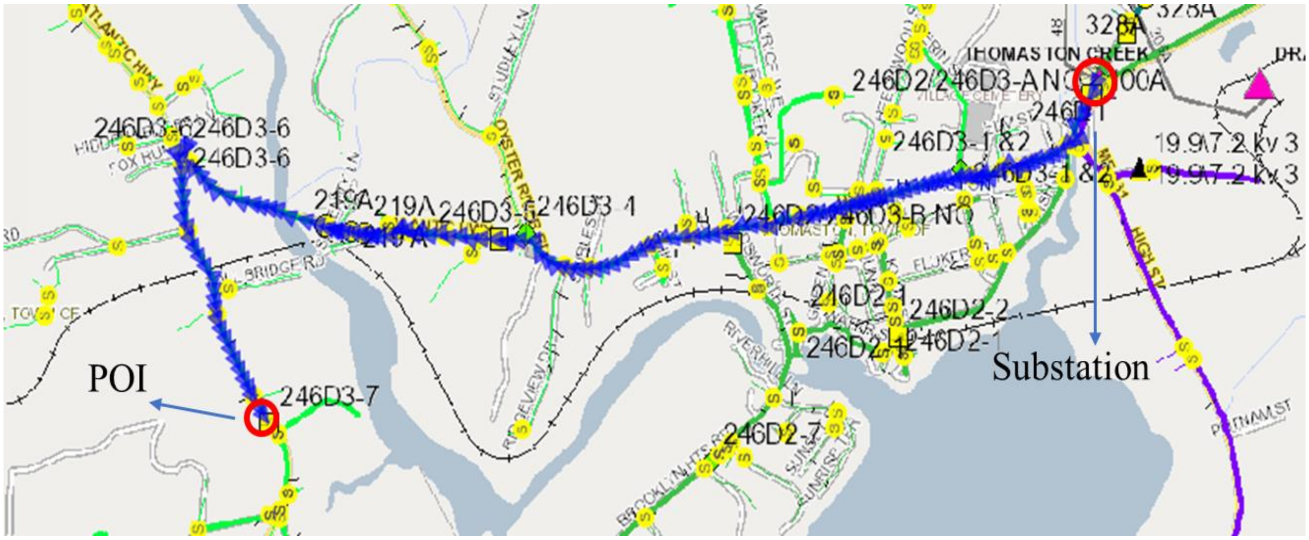

Figure 17-1: Circuit 246D3 in Smart-Map

D. TCC Settings

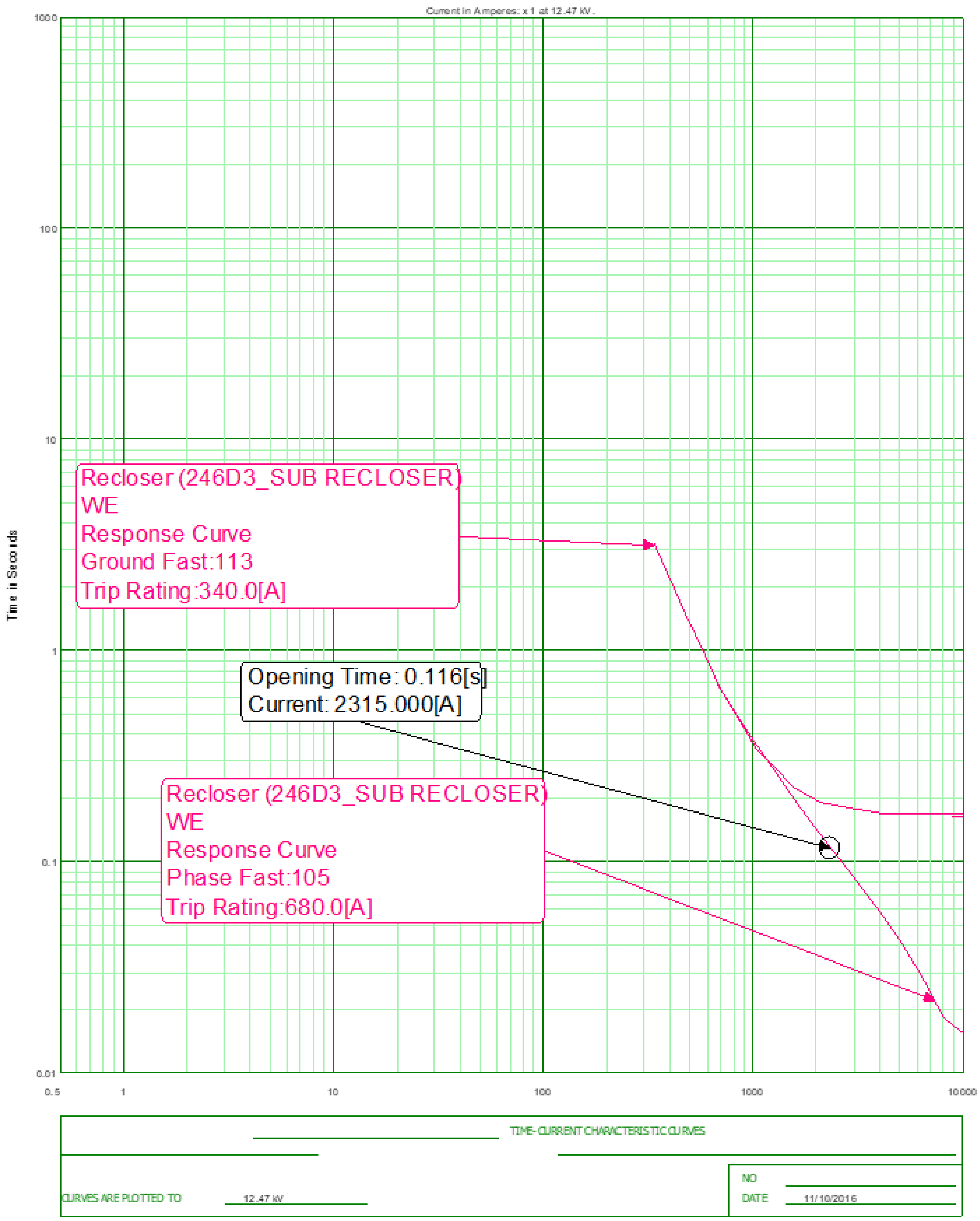

Figure 17-2: TCC for Substation Recloser.

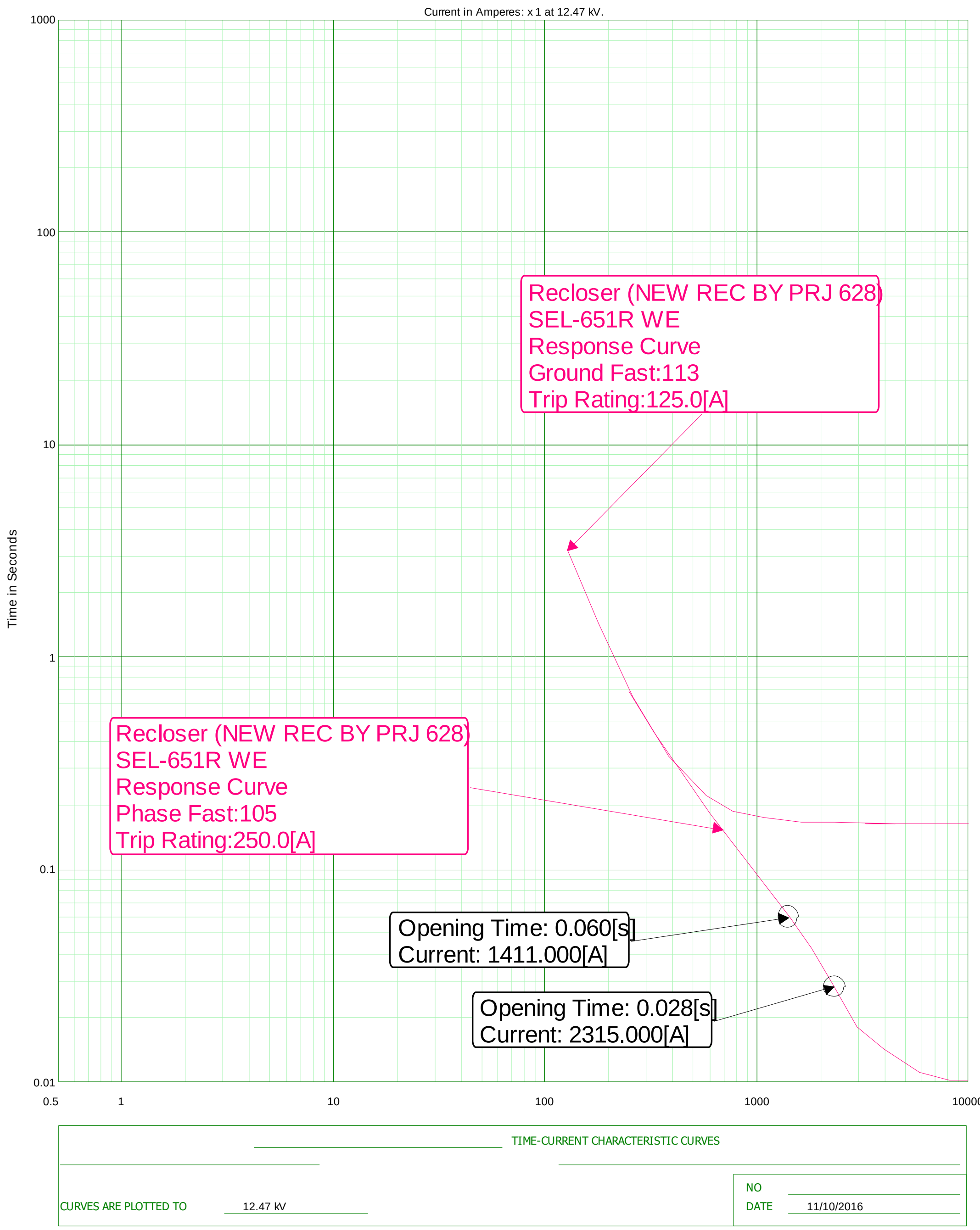

Figure 17-3: TCC for New Line Recloser.

E. LROV, ROI and Transient OV Screenings

Table 17-3: Screenings Results Table

Analysis	Results	Corrective Action	Cost
Load Rejection Overvoltage LROV IEEE 1547-2018 Section 7.4.2	LROV < 10	Surge arrestors needed, HECO document not available.	$16,500 (12 kV)
Risk of Islanding (ROI) At Substation Level	The risk of an unintentional islanding is low.	No additional mitigation or study are needed at this time.	None.
Transient Overvoltage (HECO) Compliance, IEEE 1547-2018 Section 7.4.2	Documents not provided.	HECO document is required by all projects.	See LROV row above.

F. Thomaston Creek Substation One-Line Diagram

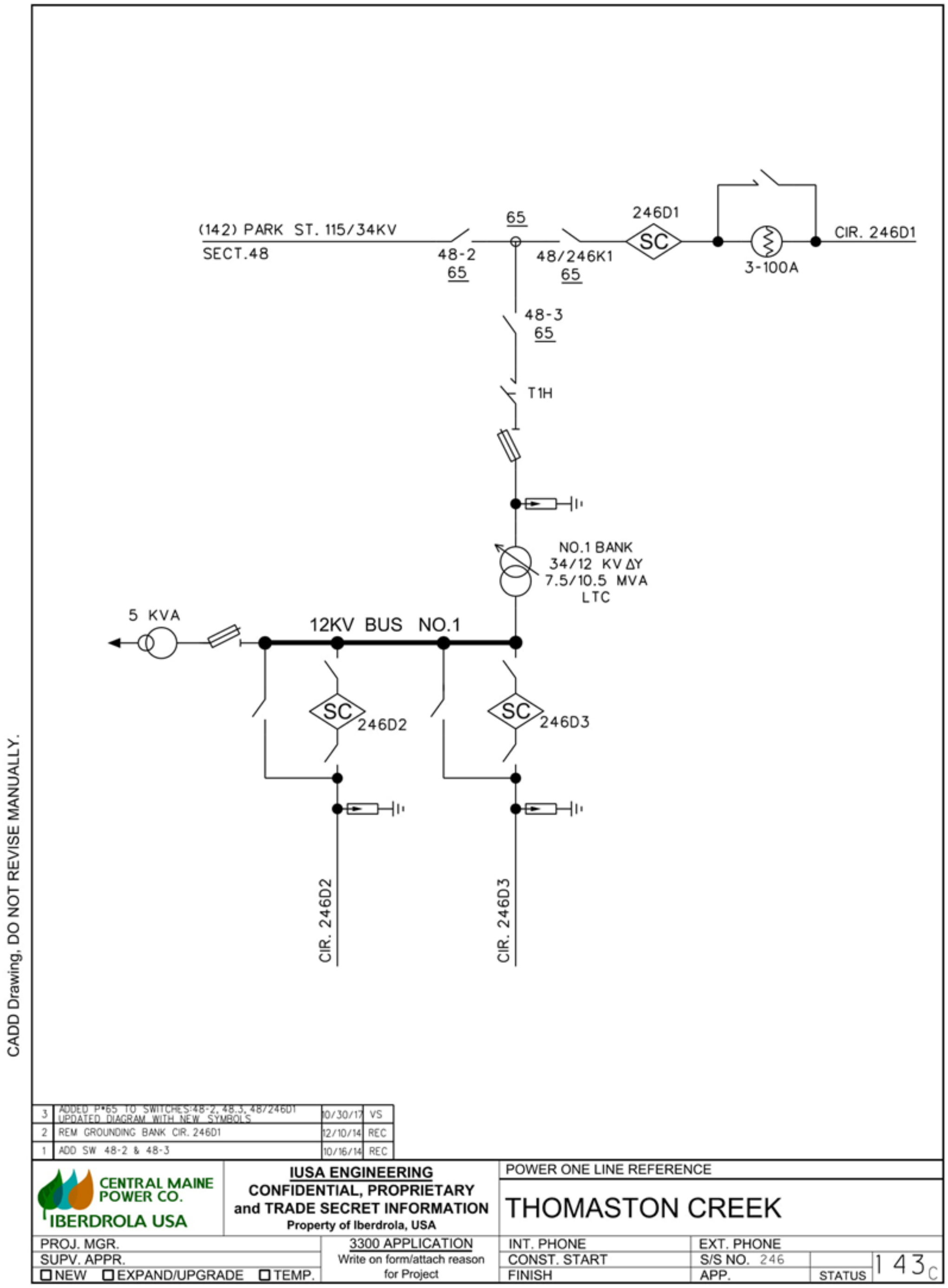

Figure 17-3: One Line Diagram of Thomaston Creek Substation

G. Field Planner Summary

PRJ 628
Maine State Prison (Warren)
POI: Pole #124, 475 Cushing Road (Friendship Rd.), Warren, ME

Notification #:
CMP Acct # 30012953730

April 21, 2022

Project Description
The 4.980 MW of photovoltaic (PV) generation (the project), limited to 4.980 MW will be connected to the existing overhead distribution lines at Pole #124, 475 Cushing Road (Friendship Rd.), Warren, ME. The project will be connected to the primary voltage of 12.47 kV through Circuit 246D3, which is served from the Thomaston Creek Substation Transformer Bank No.1 (project max amperage – 230.57 amps/phase @ 12.47 kV).

System Upgrade

Substation: (Stations & System Protection)
- SCADA Implementation, **(See IS report)**

Distribution: (Distribution Work Order #1)
- Three phase 300A solid blade, replace with a new three phase line recloser and controller, Pole #92 (Warren Rd.).
  - Features: second order harmonic blocking, directional sensing capabilities
  - Settings: Phase; 250 A 2(105) 2(117), Ground; 125 A 2(113) 2(131)
  - **CU: U3HDR3GW15CTRL630A, MID: 30048737**
- Update settings of three (3) existing Single Phase line regulators, rated 219A, at Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd.
  - Operate in Co-gen mode, with settings:
  - Forward: 124 V, R = 0, X = 0
  - Reverse: 124 V, R = 1, X = 0
  - Bandwidth = 3 V & Time Delay = 40 s
  - **CU: C6IDDBHMPR, MID: D873200**
- Extend 3 Phase line from POI to GOAB switch Pole.

Interconnection (Distribution Work Order #2)
- Install a new pole #124.1 for primary metering.
- Install a new pole #124.2 Air-Break switch.

Distribution Engineer

Figure 17-4: Field Planner Summary (Document Attached).

PRJ 628
Maine State Prison (Warren)
POI: Pole #124, 475 Cushing Road (Friendship Rd.), Warren, ME

Notification #:
CMP Acct # 30012953730

April 21, 2022

Other

Maine State Prison (Warren) has proposed to use a recloser with SEL-651R as the intertie relay. The site intertie relay will need to be able to detect ground bank transformer faults and remove the project generation from service for all project system current, frequency, or voltage abnormalities. The SEL-651R overcurrent protection for Maine State Prison (Warren) will need to coordinate with protection reclosers upstream of the project's POI and coordinate reconnection timing with other project reclosers in the circuit (if any).

- The proposed project cannot operate during the contingency conditions when Circuit **246D2** picks up the load from Circuit **246D3**.

Note: Updates due to modification requests happening post the "Final Results Meeting", and other ongoing CMP upgrades, may alter the listed in this document. It is highly recommended that the pertaining team communicates with interconnections for latest reports and addendums.

Distribution Engineer

Figure 17-5: Field Planner Summary (Document Attached). Continued.

H. Application

PUC Chapter 324 – Forms and Agreements

Forms and Agreements 4: Level 2, Level 3 and Level 4 Interconnection Application

A Customer-Generator applicant ("Applicant") hereby makes application to CMP Co (Utility or T & D Utility) to install and operate a generating facility interconnected with the CMP Co utility system. This application will be considered as an application for interconnection of generators under Expedited interconnection review provided the generator is not greater than 2 MW but shall serve as an Application for Standard interconnection review if greater than 2 MW or if Expedited review does not qualify the generator for interconnection.

Written applications should be submitted by mail, e-mail or fax to [[*insert utility name*]], as follows:

[*Utility*]: Central Maine Power Company (CMP Co)
[*Utility's address*]: 83 Edison Drive, Augusta, ME 04336
Fax Number:
E-Mail Address: nathan.pelletier@cmpco.com
[*Utility*] Contact Name: C/O Nathan Pelletier
[*Utility*] Contact Title:

An application is a Complete Application when it provides all applicable information required below. (Additional information to evaluate a request for interconnection may be required and will be so requested from the Interconnection Applicant by Utility after the application is deemed complete).

Section 1. Applicant Information

Legal Name of Interconnecting Applicant (or, if an Individual, Individual's Name)
Name: Maine Department of Corrections Atten Gary Laplante
Mailing Address: 111 State House Station
City: Augusta State: ME Zip Code: 04333-0111

Facility Location (if different from above):
475 Cushing Rd Warren Maine 04864 (entrance) Site 44.068447, -69.233098
Telephone (Daytime): 207-287-2711
Telephone (Evening):
Fax Number: 207.287.4370
E-Mail Address: Gary.LaPlante@maine.gov

30012953730

CMP
(Utility)

~~3501-3985-862~~
(Existing Account Number, if generator to be interconnected on the Customer side of a utility revenue meter)

1

Figure 17-6: Project Application

Type of Interconnect Service Applied for ________ Network Resource, __________
(choose one)

Energy Only, X_____ Load Response (no export) ________ Net metering

Section 2. Generator Qualifications

Data apply only to the Small Generating Facility, not the Interconnection Facilities.
Energy Source: X__ Solar ___ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River):_____

Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type)________________

Prime Mover: Fuel Cell ___ Recip. Engine ___ Gas Turb. ___ Steam Turb. ___
Microturbine ___ PV X__ Other ______________________________

Type of Generator: Synchronous ____Induction ____ Inverter X___

Generator Nameplate Rating: 166______kW (Typical)
Generator Nameplate kVA: 166_____

Interconnection Customer or Customer-Site Load: none______________kW (if none, so state)

Typical Reactive Load (if known): none___________
Maximum Physical Export Capability Requested: 4980__________ kW

List components of the Small Generating Facility Equipment Package that are currently certified:

	Equipment Type	Certifying Entity
1.	Solectria XGI166	
2.	LG Electronics LG440S2W-U6 (440W)	UL 1703
3.		
4.		
5.		

Is the prime mover compatible with the certified protective relay package?
Yes X___No ____

Generator (or solar collector):

Manufacturer, Model Name & Number: Solectria XGI 1500-166________________

Figure 17-7: Project Application - Continued.

I. Project Proposed One-Line Diagram

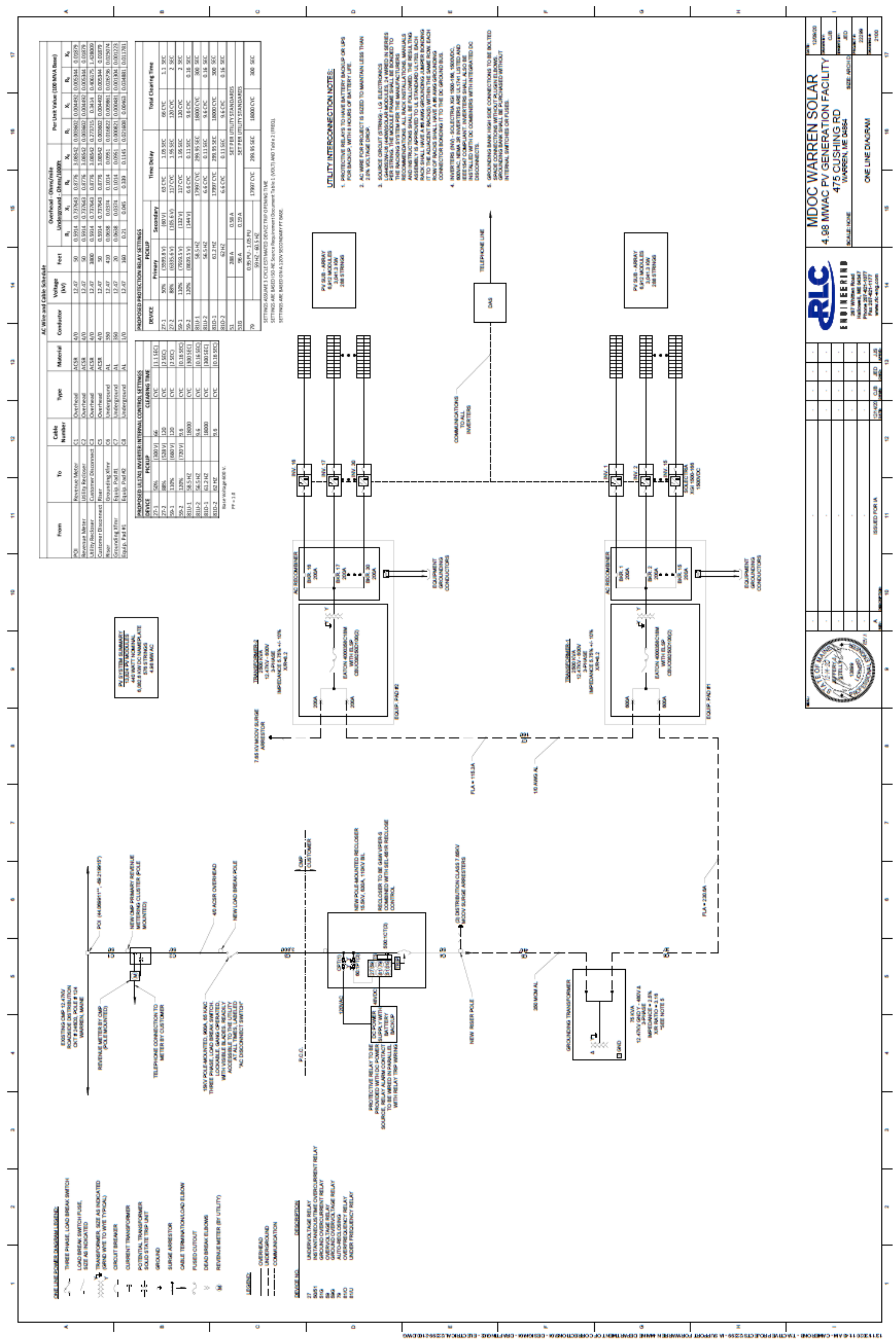

Figure 17-8: Proposed project One Line Diagram.

J. Circuit (Ground) Coordination Study

I.Conclusion

PRJ 628
The short circuit current contribution due to PRJ 628, with proposed two (2) 2,500 kVA Yg-Yg GSUs along with one (1) 75 kVA Grounded-Wye / Delta grounding transformer, is above the 10% limit. However, the short current values are below 87.5% of the protection devices interrupting ability. The related impacts and required upgrades are as follow.

Coordination results: for a fault at the POI for PRJ 628, the substation circuit recloser 246D3 will trip before the POI recloser clears the fault. Therefore, coordination is not possible. The required mitigations are:

- **PRJ 628 POI recloser required settings/functions (developer's responsibility):**
  - 51P Settings:
    - Pickup rating = 110% of FLA = 250 A
    - Curve = 104
  - 51G settings:
    - Pickup rating = 120 A
    - Curve = 112
  - Recloser Relay needs 50P function instantaneous elements (POI fault duty).
  - Recloser Relay needs 67P function directional elements. The ride through feature needs to be disabled for forward faults (Fault at DER site).
  - Note that the new line recloser will need to operate twice for the downstream PRJ 628 faults.
  - *Note: If the site recloser is not able to attain the listed settings above, developer must notify CMP for proper course of action.*

- **Substation recloser 246D3:**
  - No upgrade due to PRJ 628.

- **New line recloser:**
  - Replace one (1) three-phase solid blade on Pole #92, South Warren Rd. with a new 3ph electronic recloser with SEL-651R controller, with updated features and settings as follows:
    - Second harmonic blocking and directional sensing capabilities.
    - Phase: 250 A 2(105) 2(117)
    - Ground: 120 A 2(113) 2(131)
    - Block tripping in the reverse direction.
    - Expect one operation for the faults on the customer side of the PRJ 628 POI recloser.

II. Cost Estimation

PRJ 628 Total Cost from Coordination Study $0

- New line recloser on Pole #92, South Warren Rd.
    - Settings update, see conclusions above
    - Cost covered in SIS

III. Introduction

PRJ 628:
The **4.980 MW** of photovoltaic (PV) generation (the project), will be connected to the existing overhead distribution lines at pole #124 with physical location near **475 Cushing Road (Friendship Rd.), Warren, ME**. The primary voltage is 12.47 KV and the connection will be made via Circuit **246D3,** which is served from the **Thomaston Creek Substation**.

The total project generation AC kW capacity is limited to 4,980 kW with thirty (30) 166 kW inverters. Two (2) 2,500 kVA Grounded-Wye / Grounded-Wye, pad-mounted transformers and one (1) 75 kVA Grounded-Wye / Delta grounding transformer are proposed as part of the customer one-line configuration for the project to connect CMP's 12.47 kV Grounded-Wye distribution system.

- **Related Protection Upgrades from the System Impact Study are:**
    - **New Line recloser:**
        - Replace one (1) three-phase solid blade on Pole #92, South Warren Rd. with a new 3ph electronic recloser with SEL-651R controller, with updated features and settings as follows:
            - Second harmonic blocking and directional sensing capabilities.
            - Phase: 250 A 2(105) 2(117)
            - Ground: 125 A 2(113) 2(131)
            - Block tripping in the reverse direction.

IV. Scope of Study & Assumption

The addition of PV increases the fault current levels at all points on the system; In addition, direct-current offsets that occur when the X/R ratio of the Thevenin impedance is high should also be considered. However, as more PV is added, the aggregate effect must be considered. If the PV interconnection transformer provides a ground source, its contribution to ground faults will be higher than the PV inverter contribution to faults, and that should also be considered. Fault current studies should be run with all PV "on" to determine the aggregate effect on fault current.

The following study results provide a detailed analysis of the protection coordination performed on the substation and its distribution circuits.

This report considers all existing DER projects with an issued SIS final report interconnecting at this substation. The results are considering all proposed system upgrades and modifications proposed in the SIS final reports as being implemented.

All the inverter-based generations are assumed to have 125% of nameplate fault contribution as the worst scenario.

The following studies are evaluated in the following section:

- Fault contributions at POI & Sub with the most updated project one-line.
- Propose settings for new protection devices or modification on existing protection devices.
- Fault Sensing Analysis
- CTI Screen
- Line Protection Device Directionality Analysis
- Substation Protection Device Reverse Flow and Reverse Faults Analysis
- POI Recloser Coordination

The following requirements are implemented in the following section:

1. Coordination time intervals (CTI) between electronic recloser slow curves or fuses were evaluated assuming a minimum CTIs requirement from IEEE Std 242-2001 as the acceptable limit.

Table IV-1: Table 15-3 from IEEE std 242-2001

OVERCURRENT COORDINATION — IEEE Std 242-2001

Table 15-3—Minimum CTIs[a]

Downstream	Upstream			
	Fuse	Low-voltage breaker	Electro-mechanical relay	Static relay
Fuse	CS[b,c]	CS	0.22 s	0.12 s
Low-voltage circuit breaker	CS[c]	CS	0.22 s	0.12 s
Electromechanical relay (5 cycles)	0.20 s	0.20 s	0.30 s	0.20 s
Static relay (5 cycles)	0.20 s	0.20 s	0.30 s	0.20 s

[a]Relay settings assumed to be field-tested and -calibrated.
[b]CS = Clear space between curves with upstream minimum-melting curve adjusted for pre-load.
[c]Some manufacturers may also recommend a safety factor. Consult manufacturers' time-current curves.

2. The max short current value shall be within the 87.5% of the protection device interrupting ability.
3. The total reverse power flow to the substation shall be smaller than half of the substation recloser phase pick up current.
4. The maximum phase and ground reverse fault contributions shall be less than the respective phase and ground overcurrent pickup settings.
5. All protective devices shall operate for 50% of the lowest fault current in their zone or operate for the 100% lowest fault current with 25 ohms grounding impedance.
6. Fuse Saving protection scheme: the recloser will operate before the fuse starts to melt; The cable damage curve shall be to the right and above the fuse curve.

V.Existing Protective Devices

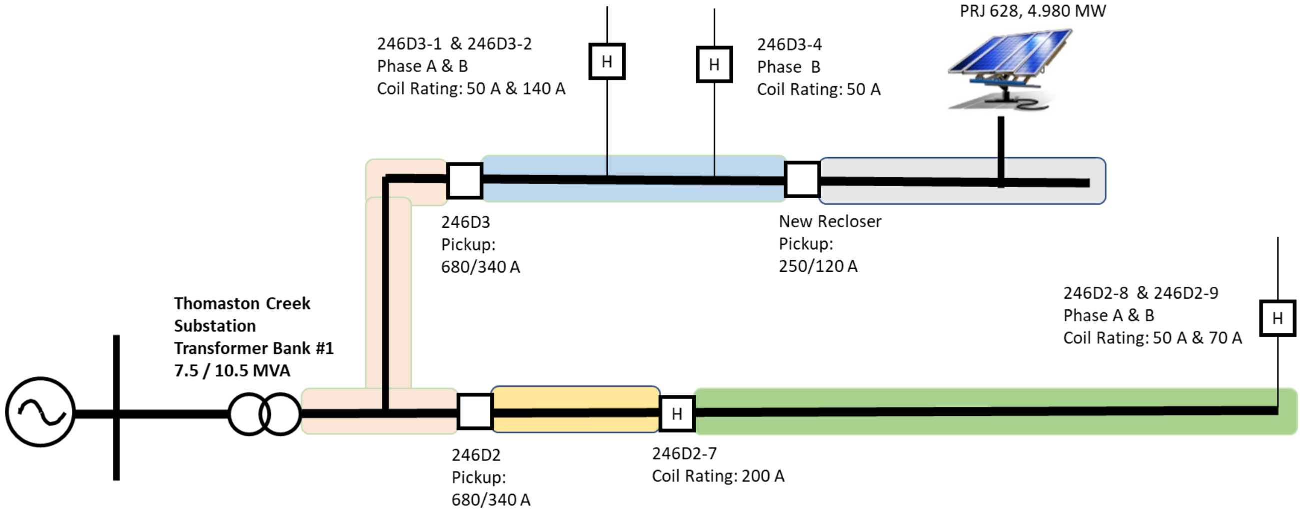

Figure V-1: Protection Scheme

Table V-1. System Reclosers Settings

Device	Pick Up Current (Phase/Ground) A	Coil Rating (A)	Phase Fast	Phase Slow	Ground Fast	Ground Slow
246D3, SEL351R, WE	680/340	N/A	105	117	113	131
New 3P SEL 651R line recloser *	250/120	N/A	105	117	113	131
246D3-1, 1P Hydraulic, L	N/A	50 (PhA)	A	B	N/A	N/A
246D3-2, 1P Hydraulic, L	N/A	140 (PhB)	A	D	N/A	N/A
246D3-4, 1P Hydraulic, V4H	N/A	50	A	C	N/A	N/A

*These are the assumed new settings for the upgraded reclosers.

VI.Coordination Analysis

Fault Current and Interrupting Rating

The addition of PV generators increases the fault current levels at all points on the system; therefore, it is important to verify that the maximum fault current through each protective device does not exceed its interrupting rating.

Table VI-1: Fault Current at POI & Sub with/without the PRJ 628

		LLL (A)	LLG(3I0)	LLG (Phase)	LL(A)	LG(A)
POI_PRJ 628	OFF	1411	966	1316	1222	1147
	ON	1647	1167	1466	1316	1264
		17%	21%	11%	8%	10%
Sub (**246D3**)	OFF	3121	4364	3534	2703	3641
	ON	3341	4630	3724	2796	3752
		7%	6%	5%	3%	3%

The short circuit current contribution due to the **PRJ 628** is higher than the 10% limit.
The post-project short current values are still below 87.5% of the protection devices interrupting ability considering the project on Circuit 246D3.
The following section will provide the analysis for the coordination aspects.

Fault Sensing

The circuit should be checked to verify that all the protective devices can sense faults within their respective protective zones. Phase and ground pickup sensitivity to faults at the next downstream device(s) were evaluated assuming a 2/1 fault duty to pickup ratio as a minimum acceptable sensitivity ratio.

Note: cyme_id246D3_311300 is the end of the 246D3 sub recloser protection zone.

- Substation Recloser **246D3**

  - *Table VI-2.1: Sensitivity of 246D3 pickup for fault at 246D3_311300 with PRJ 628 OFF [pre-existing condition]*

	LLL (A)	LLG (A)* (3I0)	LLG (A) (Phase)	LL (A)	LG (A)
Total Fault Duty at end of zone	1557	1121	1463	1348	1304
Fault Flow Through 246D3	1557	1121	1463	1348	1304
Sensitivity Index (680/340)	2.29	3.30	2.15	1.98	3.84

Table VI-2.2: Sensitivity of 246D3 pickup for fault at 246D3_311300 with PRJ 628 ON

	LLL (A)	LLG (A)* (3I0)	LLG (A) (Phase)	LL (A)	LG (A)
Total Fault Duty at end of zone	1778	1310	1605	1438	1411
Fault Flow Through 246D3	1552	1183	1453	1358	1306
Sensitivity Index (680/340)	2.28	3.48	2.14	1.99	3.84

Conclusion:
From the fault data above, the substation recloser **246D3** does not have adequate fault sensitivity prior to the project connection to detect LL faults, but the sensitivity is adequate for all other faults. After

interconnection, the proposed project has slightly improved the sensitivity to detect and clear all phase and ground faults within the zone of protection, although LL fault sensitivity is still inadequate.

- New Line Recloser [**Pole #92, South Warren Rd.**]

Table VI-3: Sensitivity of new line recloser pickup for faults at end of Zone (Cyme ID: 246D3_779408)

	LLL (A)	LLG (A)* (3I0)	LLG (A) (Phase)	LL (A)	LG (A)
Total Fault Duty at end of zone	1415	949	1263	1143	1062
Fault Flow Through new line recloser	1212	837	1128	1072	969
Sensitivity Index (250/120 A Pickup)	4.85	6.98	4.51	4.29	8.08

<u>Conclusion:</u>
The proposed new line recloser, from the fault data above, the line recloser has adequate fault sensitivity post-project interconnection. This line recloser is adequately set to detect and clear all phase and ground faults within the zone of protection.

Proposed Protection Relay Settings from Developers

<u>PRJ 628</u>
PRJ 628 has proposed a G & W Viper SEL-651R recloser, the setting is shown below:

PROPOSED PROTECTION RELAY SETTINGS							
DEVICE	PICKUP			Time Delay		Total Clearing Time	
	Primary		Secondary				
27-1	50%	(3599.8 V)	(60 V)	63 CYC	1.05 SEC	66 CYC	1.1 SEC
27-2	88%	(6335.6 V)	(105.6 V)	117 CYC	1.95 SEC	120 CYC	2 SEC
59-1	110%	(7919.5 V)	(132 V)	117 CYC	1.95 SEC	120 CYC	2 SEC
59-2	120%	(8639.5 V)	(144 V)	6.6 CYC	0.11 SEC	9.6 CYC	0.16 SEC
81U-1	58.5 HZ			17997 CYC	299.95 SEC	18000 CYC	300 SEC
81U-2	56.5 HZ			6.6 CYC	0.11 SEC	9.6 CYC	0.16 SEC
81O-1	61.2 HZ			17997 CYC	299.95 SEC	18000 CYC	300 SEC
81O-2	62 HZ			6.6 CYC	0.11 SEC	9.6 CYC	0.16 SEC
51		288 A	0.58 A	SET PER UTILITY STANDARDS			
51G		96 A	0.19 A	SET PER UTILITY STANDARDS			
79	0.95 PU - 1.05 PU 59 HZ - 60.5 HZ			17997 CYC	299.95 SEC	18000 CYC	300 SEC

SETTINGS ASSUME 3 CYCLE ESTIMATED DEVICE TRIP OPENING TIME
SETTINGS ARE BASED ISO-NE Source Requirement Document Table 1 (VOLT) AND Table 2 (FREQ).
SETTINGS ARE BASED ON A 120V SECONDARY PT BASE.

Figure VI-1. POI recloser setting proposed by developer.

The POI recloser settings provided are 51P as 288A and 51G as 96A with TD and Curve assumed to be 1.0TD U4.

Coordination Time Interval Screening

The utility-owned protective device should not operate for faults beyond the next protective device within the PV zone except when required for backup operation.

Table below shows the CTI for protection pairs on 246D3 with PRJ 628 ON.

Table VI-4: Fault current at each location and the related CTI with its upstream devices

Fault Location	Branch Current measured location	Branch Current (A) (LLL/LLG/LL/LG)	CTI between phase slow curve
New Line Recloser	246D3	**1597**/1499/1395/1347	0.930 s
246D3-4 (1P)	246D3	NA/NA/NA/**1743**	0.812 s
246D3-1 (1P)	246D3	NA/2707/2295/**2747**	0.358 s
246D3-2 (1P)	246D3	NA/2707/2295/**2747**	0.273 s

The CTIs values, post project interconnections, are not worsened by PRJ 628, therefore, no mitigation is proposed.

Table VI-5.1: Fault at POIs and the phase related CTIs with its upstream devices

Fault Location	Branch Current measured location	Branch Current (A) (LLL/LLG/LL/LG)	POI relay/recloser Phase fast response time	Upstream Recloser Response time for the phase Fast/Slow Curve	CTI: POI recloser/relay (phase fast response) and upstream protection device (phase fast response).	CTI: POI recloser/relay (phase fast response) and upstream recloser (phase slow response).
PRJ 628 (POI) (51P, 280A, U4, TD 1)	246D3	1411/1311/1235/1154	0.256 s	0.226 s / 1.416 s	N/A	1.16 s
PRJ 628 (POI) (51P, 250A, 104 curve)	246D3	1411/1311/1235/1154	0.017 s	0.226 s / 1.416 s	0.209 s	1.399 s
PRJ 628 (POI) (51P, 250A, 104 curve)	Proposed New Line recloser	1411/1311/1235/1154	0.017 s	0.060 s / 0.213 s	0.043 s	0.196 s

Table VI-5.2: Fault at POIs and the ground related CTIs with its upstream devices

Fault Location	Branch Current measured location	Branch Current (A) (LG)	POI relay/recloser Ground fast response time	Upstream Recloser Ground Response time for the Fast/Slow Curve	CTI: POI recloser/relay (ground fast response) and upstream protection device (ground fast response).	CTI: POI recloser/relay (ground fast response) and upstream recloser (ground slow response).
PRJ 628 (POI) (51G, 112 curve, Td=1s Pickup: 120 A)	246D3	1154	0.052 s	0.301 s / 5.929 s	0.249 s	5.877 s
PRJ 628 (POI) (51G, 112 curve, Td=1s Pickup: 120 A)	Proposed New Line recloser	1154	0.052 s	0.172 s / 5.437 s	0.120 s	5.385 s

Substation recloser **246D3** will operate on its fast and slow phase curves for downstream **PRJ 628 POI faults** at 0.226 and 1.416 seconds respectively.
New line recloser proposed by PRJ 628 will operate on its fast and slow phase curves for downstream **PRJ 628 POI faults** at 0.060 and 0.213 seconds respectively. Coordination with POI recloser elements is not possible.
Required settings for POI recloser (PRJ 628):

- 51P Settings:
  - Pickup rating = 110% of FLA = 250 A
  - Curve = 104
- 51G settings:
  - Pickup rating = 120 A
  - Curve = 112
- Recloser Relay needs 50P function instantaneous elements (POI fault duty).
- Recloser Relay needs 67P function directional elements. The ride through feature needs to be disabled for forward faults (Fault at DER site).
- *Note: If the site recloser is not able to attain the listed settings above, developer must notify CMP for proper course of action.*

Note that the new line recloser will need to operate twice for faults at PRJ 628 POI.

Line Protection Device Directionality Analysis

There will be reverse power flow from the DER project, it is necessary to check the protection device between the POI and the substation of the bi-directional sensing ability.

➢ New Line Recloser [Pole #92, South Warren Rd.]

Table VI-6: Branch current values at POIs when applying a fault at the New Line Recloser

Branch current	LLL (A)	LLG(3I0)	LLG (A) (Phase)	LL (A)	LG (A)
PRJ 628 ON					
PRJ 628 contribution	237	131	173	110	109

Table VI-7: Reverse power flow at new line recloser ('- 'is reverse direction)

	FLA [A]	Aggregated Reverse Current at New Line Recloser [A]
PRJ 628 ON	230.57	-208.84

Conclusion:
The new line recloser, the reverse power flow due to PRJ 628 is higher than half of the proposed phase pickup. Therefore, the proposed new line recloser on Pole #92, South Warren Rd, will need to have directionality control.

Substation Recloser: Reverse faults sensitivity and Reverse power flow

The fault contributions from the DG needs to be less than the phase/ground pickups, and the reverse power flow needs to be below one half of the phase pickup

Table VI-8: Branch current values when applying a fault at substation bus. (PRJ 628 ON)

	LLL (A)	LLG(3I0)	LLG (A) (Phase)	LL (A)	LG (A)
Branch current at first segment of 246D3	221	84	180	107	105

Table VI-9: Reverse power flow at substation ('- 'is reverse direction)

	FLA [A]	Aggregated Reverse Current at 246D3 [A]
PRJ 628 ON	230.57	-161.60

Conclusion:
Substation recloser **246D3**, from the above tables, the fault contribution, for a fault at the **12.47 kV** bus, as well as reverse power flow due to **PRJ 628** are below the thresholds. Therefore, the substation recloser does not require directional control.

Transformer Inrush

The trip time for protection reclosers phase fast must be greater than 0.1 s.

Table VI-20: Trip time for substation and new line recloser, phase fast curve.

Reclosers	Trip time for recloser phase fast curve		Second harmonic blocking
	10*rated current	Fault duty	
246D3	[2315 A] 0.116 s	-	Not required
New line recloser	[2315 A] 0.028 s	[1411 A] 0.060 s	Required

Substation recloser 246D3 (with SEL 351R control), review of the TCC settings shows that the inrush current from the PRJ 628 GSU transformers will not trip its settings within 6 cycles, measured approximately at 0.116 second. Therefore, the substation recloser does not require second harmonic blocking due to PRJ 628.

New proposed line recloser (with SEL 651R control), review of the TCC settings shows that the inrush current from the PRJ 628 GSU transformers will trip its settings within 6 cycles, measured approximately at 0.028 second. Also, considering the LLL fault duty at POI_PRJ 628 (1411 A, from Table VI-1), the new line recloser will be tripped within 6 cycles, measured approximately at 0.060 seconds. Therefore, the new line recloser should be installed with SEL-651R control having second harmonic blocking.

Substation P&C Summary for PRJ 628

Conclusion from P&C: P&C analyzed the data presented in the Distribution Engineering coordination study above.

With the addition of PRJ 628 on the downstream circuit of feeder 246D3, there are several coordination and operational areas that need to be reviewed from the substation P&C perspective. P&C has made the following conclusions:

Fault Sensitivity: The feeder fault sensitivity was below the acceptable ratio prior to the project being connected. The infeed from this project further reduces the sensitivity to phase faults. It is assumed that the downstream coordination has been reviewed and found acceptable to clear most phase and ground faults within the zone of protection.

Reverse Power Flow: The aggregated reverse power flow current through the feeder is less than the threshold requiring directional control.

Faults in the Reverse Direction: Fault contributions from the DG is less than the substation recloser phase and ground pickups, therefore directional control is not required on the substation recloser settings.

Feeder coordination with proposed adjustments to project settings: For faults on the project side of the POI recloser, the POI recloser will interrupt and clear the fault prior to the substation feeder operating. Coordination is achieved and no settings changes at the substation are recommended.

Transformer Inrush: Considering the source strength of the utility for faults at the POI, the station recloser is unlikely to trip due to transformer inrush current, therefore no inrush mitigation upgrades are recommended.

T-GFOV: Thomaston Creek is susceptible to transmission ground fault overvoltage risk and requires additional protection-based mitigation should the risk of islanding screen fail.

VII.Appendix

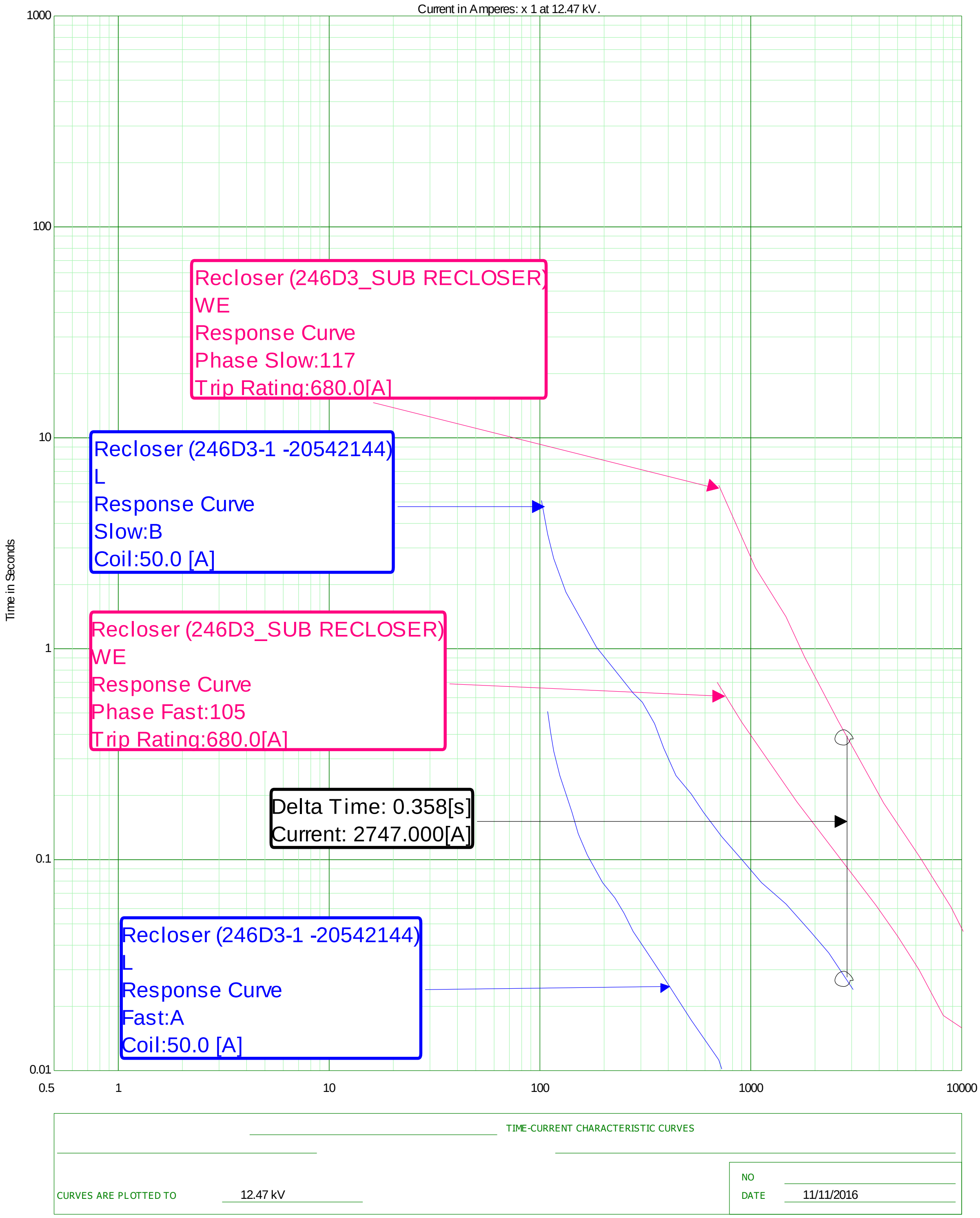

Figure VII-1: Substation Recloser (246D3) and Line Reclosers 246D3-1 Coordination

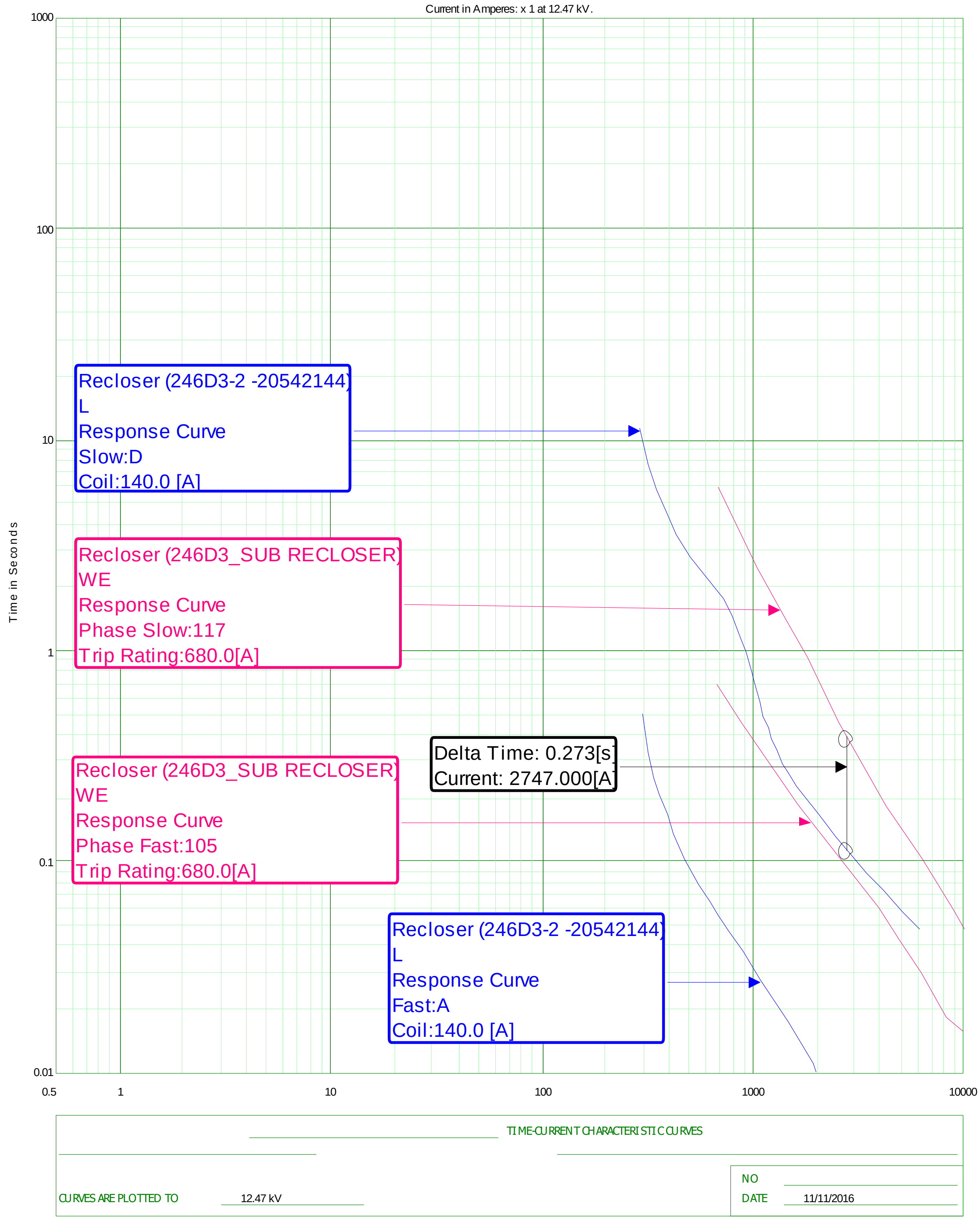

Figure VII-2: Substation Recloser (246D3) and Line Reclosers 246D3-2 Coordination

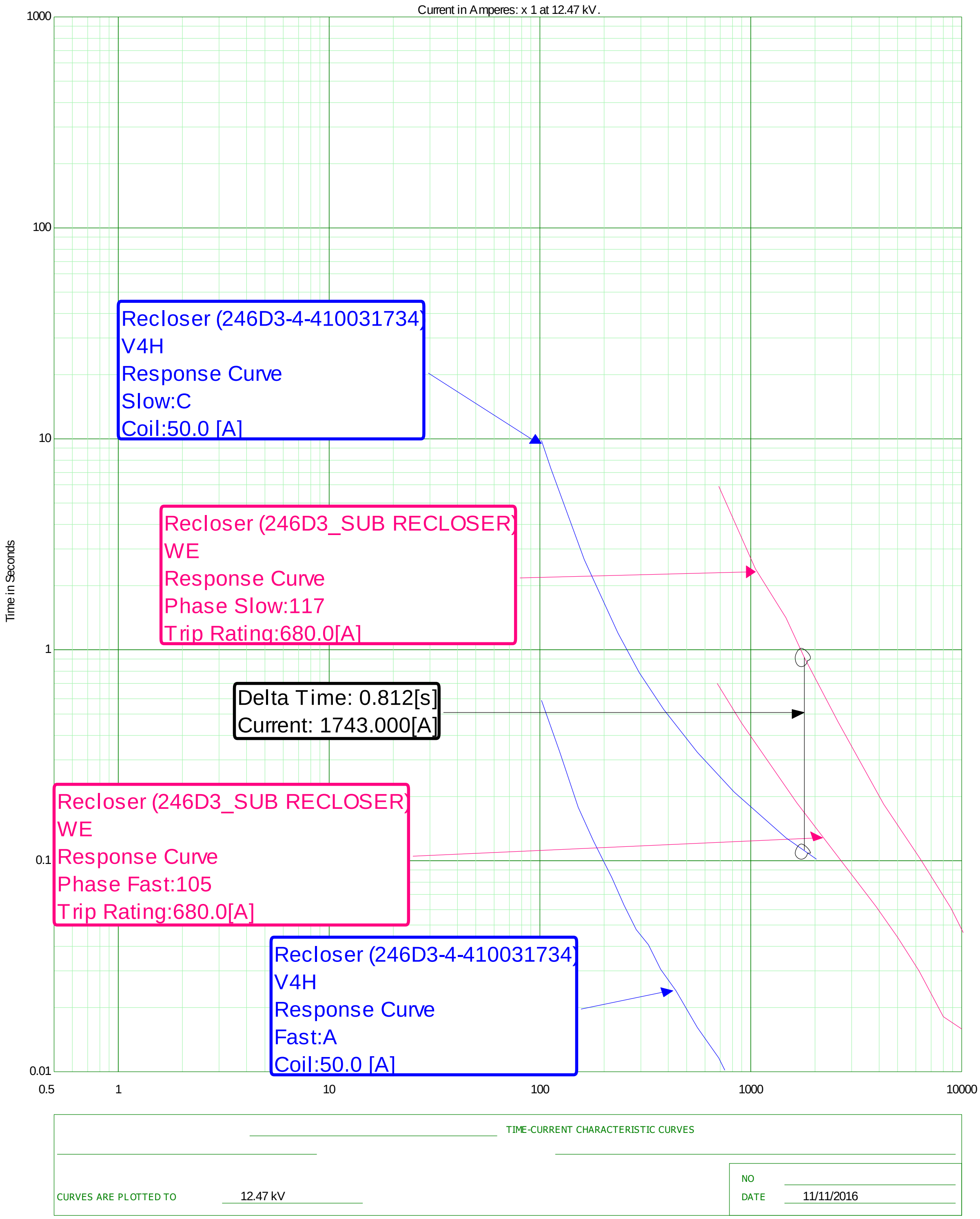

Figure VII-3: Substation Recloser (246D3) and Line Reclosers 246D3-4 Coordination

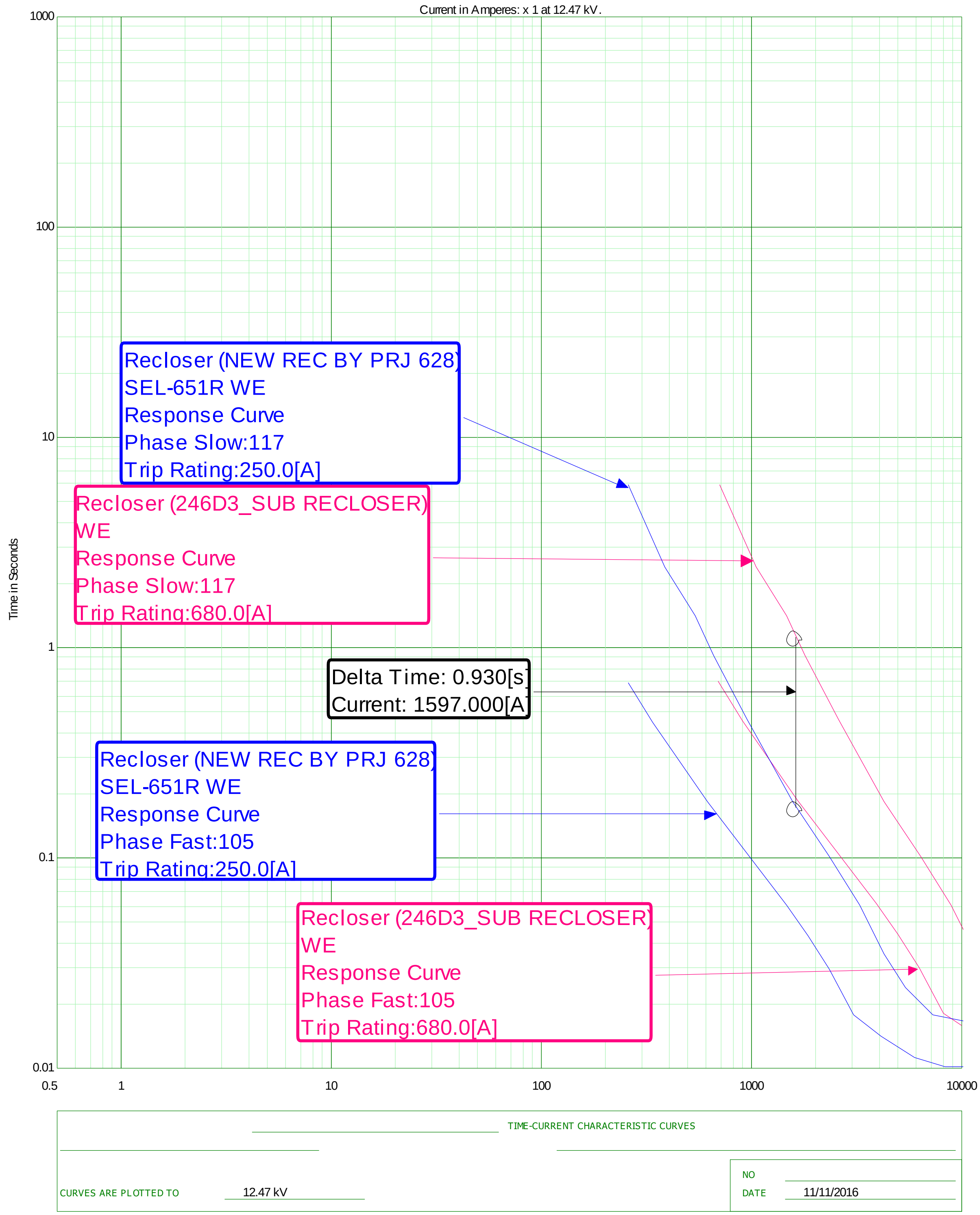

Figure VII-4: New line Recloser and Substation Recloser 246D3 Coordination

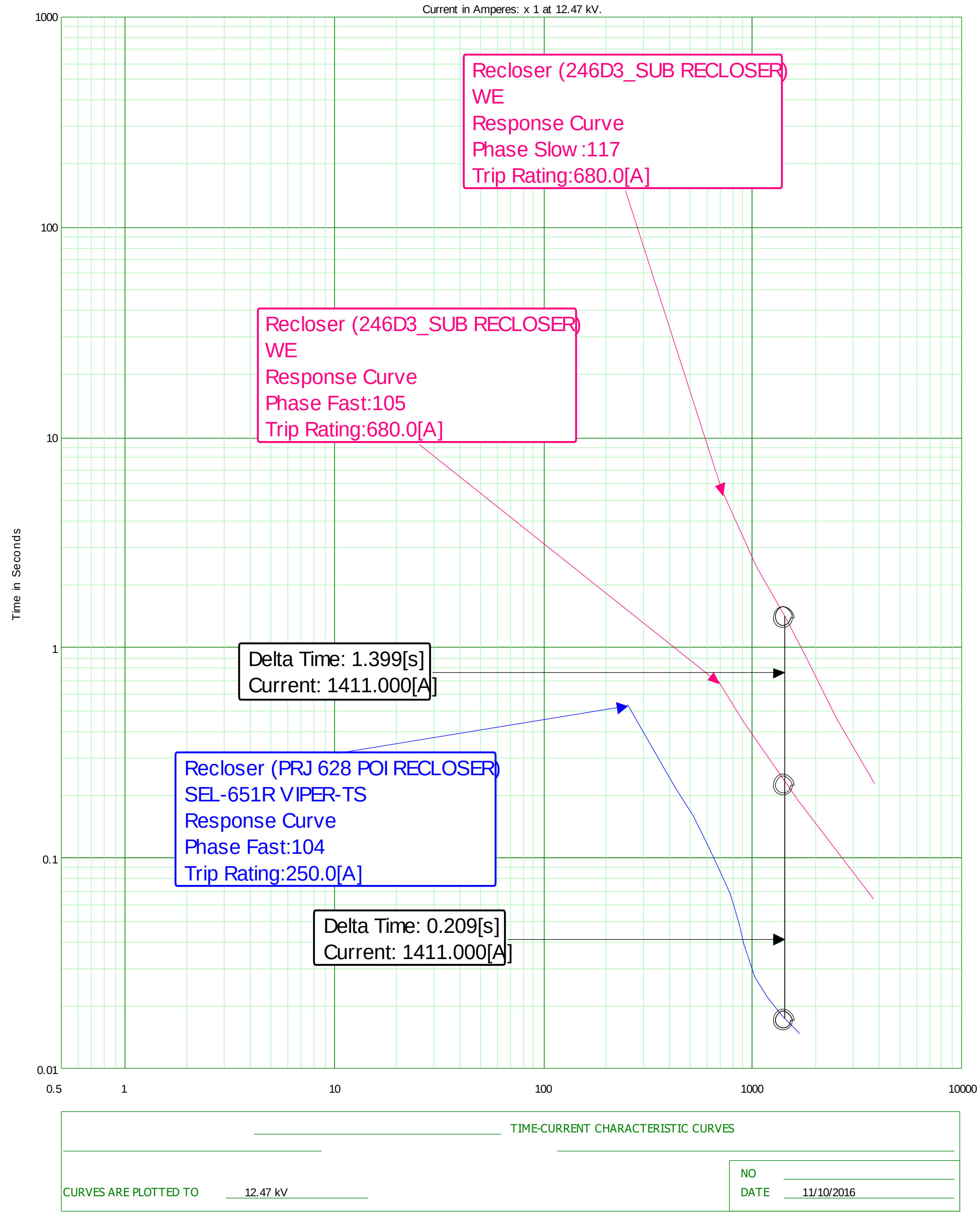

Figure VII-5: Substation Recloser 246D3 and PRJ 628 POI Recloser Phase Coordination (Required settings per study).

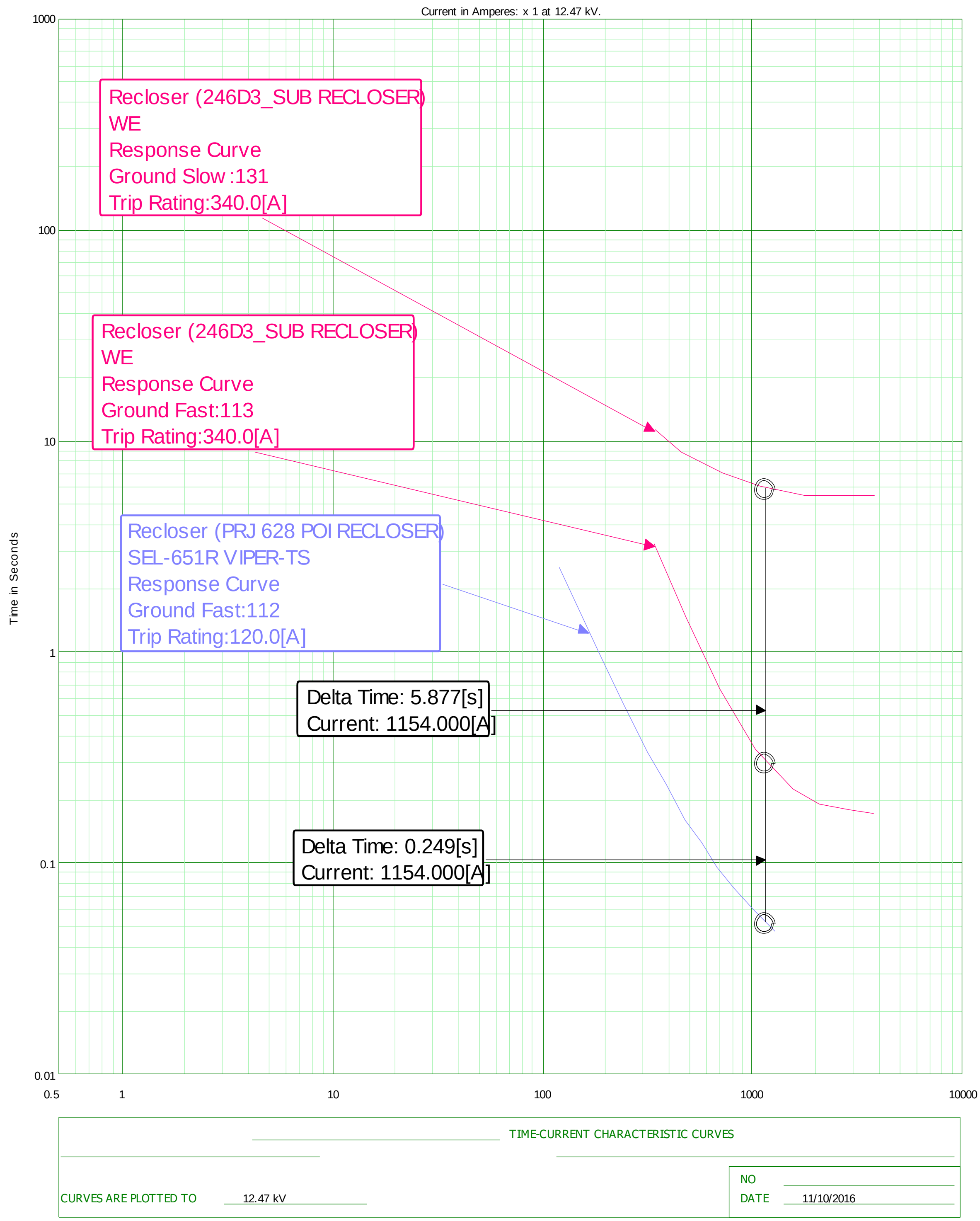

Figure VII-6: Substation Recloser 246D3 and PRJ 628 POI Recloser Ground Coordination (Required settings per study).

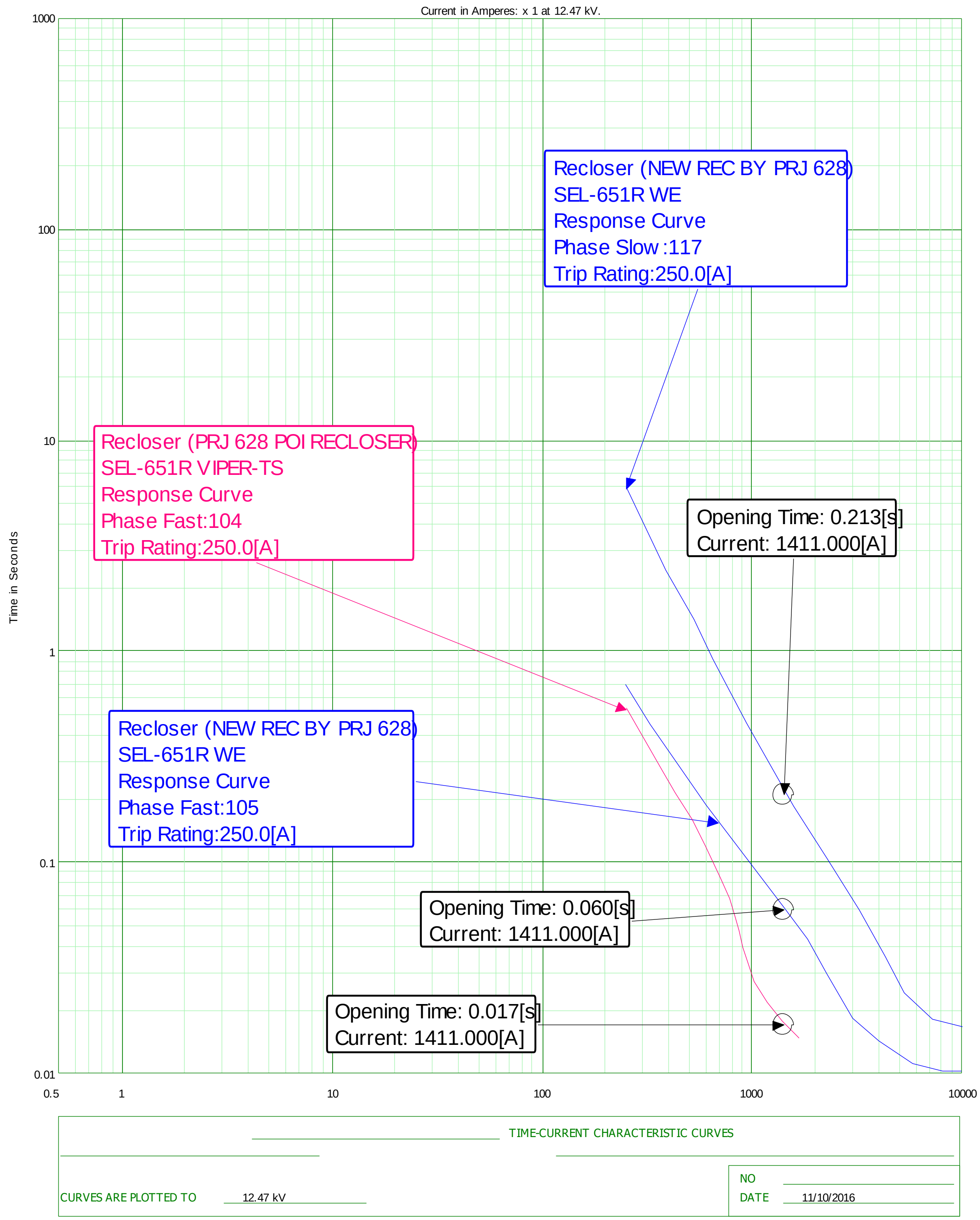

Figure VII-7: New Line Recloser and PRJ 628 POI Recloser Phase Coordination (Required settings per study).

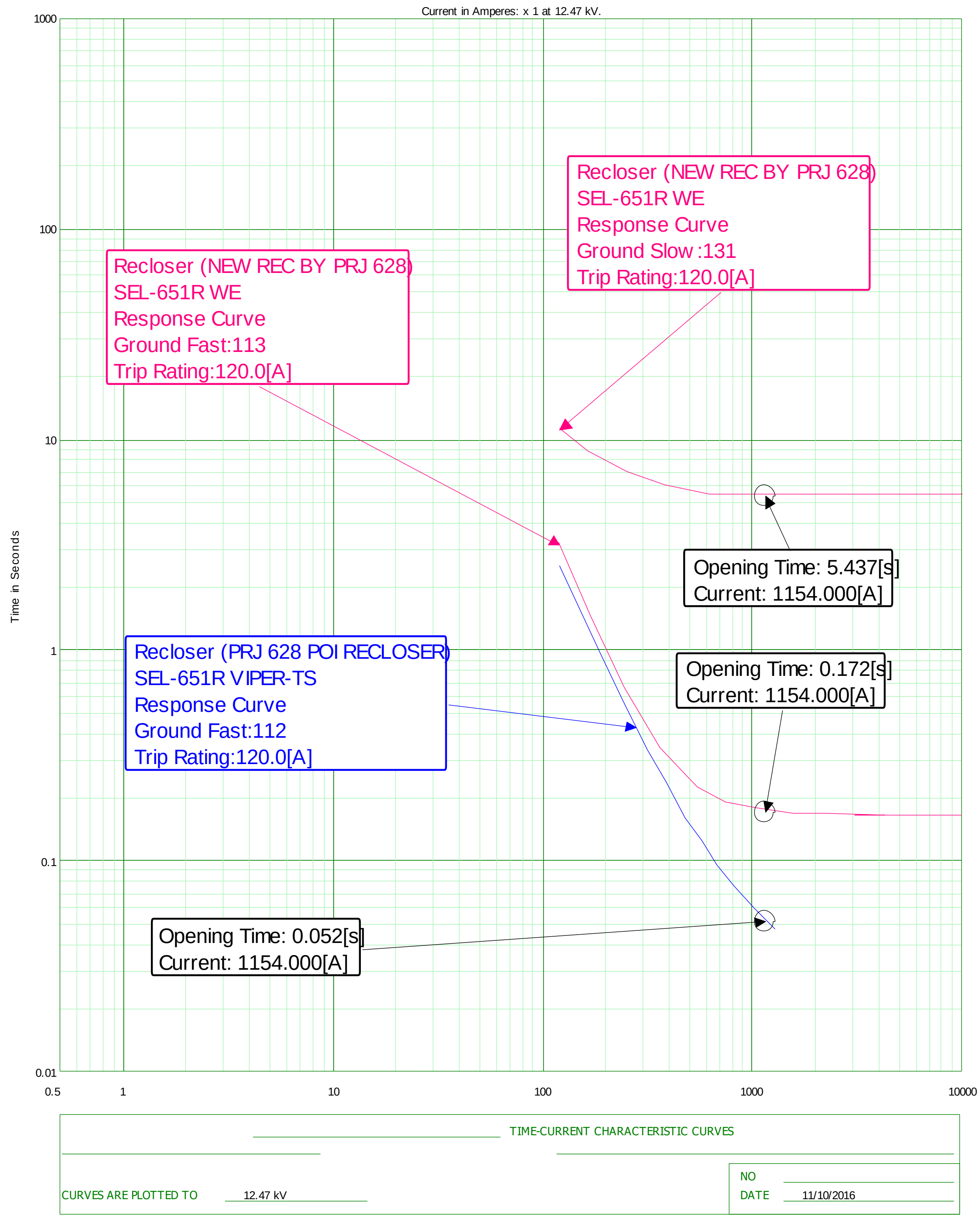

Figure VII-8: New Line Recloser and PRJ 628 POI Recloser Ground Coordination (Required settings per study).

PRJ 628

Maine State Prison

(Warren)

Final Report

System Impact Study

Addendum

March 27, 2023

Distribution Planning Department

Central Maine Power Company

1. Description

This addendum provides an updated System Impact Study (SIS) cost estimate to the project based on recently updated cost projections. There are no impacts to the technical findings in the SIS. Only the SIS cost estimate has been updated.

2. Previous Cost Estimate **($305,783)**

System Upgrade/Revisions

- Three phase 300A solid blade, replace with a new three phase line recloser and controller, Pole #92 (Warren Rd.). **(Cost in Table 17-1)**
  - Features and settings: second order harmonic blocking, directional sensing capabilities
- Update settings of three (3) existing Single Phase line regulators, rated 219A, at Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd. **(Cost in Table 17-1)**
  - Operate in Co-gen mode, with settings:
  - Forward: 124 V, R = 0, X = 0
  - Reverse: 124 V, R = 1, X = 0
  - BW = 3 V & TD = 40 s
- SCADA implementation, **cost $1,000.**

Line Upgrade/Revision

- N/A

Circuit (Ground) Coordination Study Results

- Cost **none.**

Transmission Ground Fault Overvoltage (T-GFOV)

- Cost responsibility for this project, **none.**

Transient Overvoltage Compliance (TOV)

- Cost **none.**

Interconnection Cost

- The project will require a bi-directional pole mounted primary metering package located off the existing 12.47 kV overhead CMP distribution circuit. The facility includes one solid state meter, three 12.47 kV CT and three 12.47 kV VT, cost **$18,974 (total installed cost**)/**$296.33 (per month** maintenance and translation) **(Cost in Table 17-2)**
- Install (1) new pole for primary metering equipment and connect the overhead line to Pole #124, 475 Cushing Rd. (Friendship Rd.), Warren, ME. **(Cost in Table 17-1)**
- Install a GOAB switch. **(Cost in Table 17-1)**
- Install (1) new pole for GOAB switch. **(Cost in Table 17-1)**

- Extend 3 phase line from POI to GOAB switch Pole. **(Cost in Table 17-1)**

Customer Responsibilities

- Everything on the load side or customer side of the Gang Operated Air-Break Switch (GOAB) representing the Point of Common Coupling (PCC) will be the responsibility of the customer or developer. This includes any protective reclosers, breakers, the telephone line to the Revenue Meter and all associated equipment.
- All facilities that have a generating capacity of 1,000 kW or greater must be equipped with SCADA equipment.
- Updated SLD required, any variation of the values assumed in this study will need to be verified prior to project interconnection:
    - Cable number on drawing does not match the AC Wire and Cable Schedule table. Study followed the table.
    - Update the GSUs configuration to Yg-Yg.

Please Note: This report contains estimates regarding the scope of the required modifications to CMP's transmission and/or distribution system and/or to the project to accommodate the requested interconnection. These estimates may be dependent on upgrades from projects that have previously submitted interconnection requests. All costs and upgrades are those required based on each preceding project progressing as anticipated. Should a previous project upon which your project is dependent withdraw from the interconnection queue before their upgrades are completed, all dependent projects will be restudied to determine any impact to their interconnection. This may result in changes to the cost estimates necessary to interconnect your ICGF. Any additional time or resources needed to complete a restudy will be invoiced to your project. Any specific upgrades covered under the Cost Sharing provisions of Section 12(G) of Chapter 324 of the MPUC Rules would remain subject to those provisions.

Table 17-1: Planning Cost Estimate

Project Name:	Main state Prison	Project #:	PRJ 628
Location:	475 Cushin Road, Warren, ME	Org Date:	21-Apr-22
Section		Rev Date:	
By:	Distribution Planning Department	Rev by:	

Item	Quantity to:			Revised Unit Cost			Estimated SubTotal Cost			Contingency	Estimated Total Cost		
									Contingency value =	20%			
	Install	Remove	Shift	CAP	COR	O&M	CAP	COR	O&M		CAP	COR	O&M
Poles - Electric Owned and Maintained													
35kV - Reinsulate Single Phase	0	0	0	$ -	$ 113	$ 225	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Reinsulate Three Phase	0	0	0	$ -	$ 113	$ 675	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - New Single Phase	0	0	0	$ 3,375	$ -	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - New Three Phase	2	0	0	$ 7,875	$ -	$ -	$ 15,750	$ -	$ -	20%	$ 18,900.00	$ -	$ -
35kV - Replace Single Phase	0	0	0	$ 4,500	$ 900	$ 450	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Replace Three Phase	1	1	0	$ 6,600	$ 1,440	$ 720	$ 6,600	$ 1,440	$ -	20%	$ 7,920.00	$ 1,728.00	$ -
35kV - Dress for aerial cable	0	0	0	$ 1,500	$ -	$ 150	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Pole Set Assist	0	0	0	$ 2,250	$ -	$ 225	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - H-Frame, Two Pole Structure	0	0	0	$ 29,250	$ 8,775	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
OH Conductor (per section - 150ft)													
35kV - Single Phase	0	0	0	$ 788	$ 158	$ 79	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Three Phase Tap	0	0	0	$ 2,700	$ 540	$ 270	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Three Phase Mainline	2	0	0	$ 3,600	$ 720	$ 360	$ 7,200	$ -	$ -	20%	$ 8,640.00	$ -	$ -
35kV - Three Phase Mainline - Spacer	0	0	0	$ 4,500	$ 900	$ 450	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Replace Secondary/Service Conductor	0	0	0	$ 1,800	$ 225	$ 270	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Aerial Cable - Express	0	0	0	$ 8,700	$ 1,710	$ 855	$ -	$ -	$ -	20%	$ -	$ -	$ -
UPZ Vegatation Management	0	0	2	$ 3,000	$ 600	$ 300	$ -	$ -	$ 600	20%	$ -	$ -	$ 720.00
Major OH Equipment													
35kV - Cutout - Single	0	0	0	$ 450	$ 90	$ 45	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Cutout - Three	0	1	0	$ 1,350	$ 270	$ 135	$ -	$ 270	$ -	20%	$ -	$ 324.00	$ -
35kV - Bells - 1ø	0	0	0	$ 300	$ 60	$ 30	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Bells - 3ø	0	0	0	$ 900	$ 180	$ 90	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Disc Switch - InLine	0	0	0	$ 2,250	$ 450	$ 225	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Disc Switch - UnderArm	0	0	0	$ 3,375	$ 675	$ 338	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - Load Break Switch	1	0	0	$ 13,500	$ 2,700	$ 1,350	$ 13,500	$ -	$ -	20%	$ 16,200.00	$ -	$ -
35kV - OH Recloser	0	0	0	$ 56,250	$ 11,250	$ 5,625	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - OH Cap Bank	0	0	0	$ 38,250	$ 6,750	$ 3,375	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - OH Arrestors	0	0	0	$ 1,125	$ 225	$ 113	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - SCADA Controlled Recloser - 3Ø	1	0	0	$ 60,450	$ 12,090	$ 3,750	$ 60,450	$ -	$ -	20%	$ 72,540.00	$ -	$ -
35kV - SCADA Switch - 3Ø	0	0	0	$ 50,700	$ 9,300	$ 3,750	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - SCADA Single Phase Reclosers	0	0	0	$ 40,950	$ 8,190	$ 3,000	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - TripSavers - 1Ø	0	0	0	$ 7,500	$ 1,275	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
35kV - FuseSavers - 1Ø	0	0	0	$ 4,500	$ 675	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
Misc Labor not accounted for in listed Activities													
Overhead Department Labor in Hours	40	0	0	$ 210	$ 210	$ 210	$ 8,400	$ -	$ -	20%	$ 10,080	$ -	$ -
Underground Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Trans/Station Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Test Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Subtotal							$ 111,900	$ 1,710	$ 600		$ 134,280	$ 2,052	$ 720
Project Management	Evaluation, Design and Support						$ 17,280	$ -	$ -		$ 20,736	$ -	$ -
Construction Manager	Support during project construction						$ 16,800	$ -	$ -		$ 20,160	$ -	$ -
Field Engineering/Planners	Responsible for Design						$ 10,800	$ -	$ -		$ 12,960	$ -	$ -
Allocations	Allocations assigned to the project						$ 13,500	$ -	$ -		$ 16,200	$ -	$ -
						subtotal	$ 170,280	$ 1,710	$ 600		$ 204,336	$ 2,052	$ 720
Misc Overheads	Overheads during all phases of the project						$ 64,706	$ 650	$ 228	38%	$ 77,648	$ 780	$ 274
Total							$ 234,986	$ 2,360	$ 828		$ 281,984	$ 2,832	$ 994
							CAP	COR	O&M		CAP	COR	O&M

Table 17-2: Metering Cost Table

1/27/2022

SJD

Schedule D - MONTHLY METERING O&M COST ESTIMATE

12 kV Distribution Pole Mounted Tariff Rate Primary Metering Equipment

Monthly O&M Cost Estimate for Metering Equipment

Item	Type	Meter Serial Numbers	Qty	Equipment Cost	Installation Cost	Customer Maintenance
MV90 METER KWH IN/OUT	EMR		1	$ 5,000.00	$ 1,200.00	$ 6,200.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
	Sub-Total Installed Equipment Cost					$ 17,900.00
	General Expense @ 6%					1,074.00
	Total Installed Cost					$ 18,974.00
	Monthly Maintenance Charge @ 1.43% of Total Installed Cost					$ 271.33
	Monthly Translation					$ 25.00
	Total Monthly Meter Charges					$ 296.33

Note: The Interconnection Customer is responsible for providing a phone line for the metering equipment and is responsible for all associated costs for this phone line.

3. <u>New/Updated Cost Estimate **($220,247)**</u>

- Three phase 300A solid blade, replace with a new three phase line recloser and controller, Pole #92 (Warren Rd.). **(Cost in Table A-1)**
    - Features and settings: second order harmonic blocking, directional sensing capabilities
- Update settings of three (3) existing Single Phase line regulators, rated 219A, at Pole #96 (Ph A), Pole #94 (Ph B), and Pole #93 (Ph C), Warren Rd, **cost $22,500.**
    - Operate in Co-gen mode, with settings:
    - Forward: 124 V, R = 0, X = 0
    - Reverse: 124 V, R = 1, X = 0
    - BW = 3 V & TD = 40 s
- SCADA implementation, **cost $1,000.**

Line Upgrade/Revision

- N/A

Circuit (Ground) Coordination Study Results

- Cost **none.**

Transmission Ground Fault Overvoltage (T-GFOV)

- Cost responsibility for this project, **none.**

Transient Overvoltage Compliance (TOV)

- Cost **none.**

Interconnection Cost

- The project will require a bi-directional pole mounted primary metering package located off the existing 12.47 kV overhead CMP distribution circuit. The facility includes one solid state meter, three 12.47 kV CT and three 12.47 kV VT, cost **$18,974 (total installed cost**)/**$296.33 (per month** maintenance and translation) **(Cost in Table A-2)**
- Install (1) new pole for primary metering equipment and connect the overhead line to Pole #124, 475 Cushing Rd. (Friendship Rd.), Warren, ME. **(Cost in Table A-1)**
- Install a GOAB switch. **(Cost in Table A-1)**
- Install (1) new pole for GOAB switch. **(Cost in Table A-1)**
- Extend 3 phase line from POI to GOAB switch Pole. **(Cost in Table A-1)**

Customer Responsibilities

- Everything on the load side or customer side of the Gang Operated Air-Break Switch (GOAB) representing the Point of Common Coupling (PCC) will be the responsibility of the customer or developer. This includes any protective reclosers, breakers, the telephone line to the Revenue Meter and all associated equipment.

- All facilities that have a generating capacity of 1,000 kW or greater must be equipped with SCADA equipment.
- Updated SLD required, any variation of the values assumed in this study will need to be verified prior to project interconnection:
    - Cable number on drawing does not match the AC Wire and Cable Schedule table. Study followed the table.
    - Update the GSUs configuration to Yg-Yg.

Please Note: This report contains estimates regarding the scope of the required modifications to CMP's transmission and/or distribution system and/or to the project to accommodate the requested interconnection. These estimates may be dependent on upgrades from projects that have previously submitted interconnection requests. All costs and upgrades are those required based on each preceding project progressing as anticipated. Should a previous project upon which your project is dependent withdraw from the interconnection queue before their upgrades are completed, all dependent projects will be restudied to determine any impact to their interconnection. This may result in changes to the cost estimates necessary to interconnect your ICGF. Any additional time or resources needed to complete a restudy will be invoiced to your project. Any specific upgrades covered under the Cost Sharing provisions of Section 12(G) of Chapter 324 of the MPUC Rules would remain subject to those provisions.

Table A-1: Updated Planning Cost Estimate

Project Name:	Maine State Prison	Project #:	PRJ 628
Location:	475 Cushin Road, Warren, ME	Org Date:	21-Apr-22
Section		Rev Date:	27-Mar-23
By:	Distribution Planning Department	Rev by:	Distribution Planning Department
Project Stage:	Concept		

Item	Quantity to:			Revised Unit Cost			Estimated SubTotal Cost			Contingency	Estimated Total Cost		
								Contingency value =		20%			
	Install	Remove	Shift	CAP	COR	O&M	CAP	COR	O&M		CAP	COR	O&M
Poles - Electric Owned and Maintained													
15kV - Reinsulate Single Phase	0	0	0	$ -	$ 75	$ 150	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Reinsulate Three Phase	0	0	0	$ -	$ 75	$ 450	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - New Single Phase	0	0	0	$ 2,250	$ -	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - New Three Phase	2	0	0	$ 4,500	$ -	$ -	$ 9,000	$ -	$ -	20%	$ 10,800	$ -	$ -
15kV - Replace Single Phase	0	0	0	$ 3,000	$ 600	$ 300	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Replace Three Phase	1	1	0	$ 4,500	$ 900	$ 450	$ 4,500	$ 900	$ -	20%	$ 5,400	$ 1,080	$ -
15kV - Dress for aerial cable	0	0	0	$ 1,050	$ -	$ 105	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Pole Set Assist	0	0	0	$ 1,500	$ -	$ 150	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - H-Frame, Two Pole Structure	0	0	0	$ 22,500	$ 6,750	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
Poles - Telco Owned and maintained													
15kV - New Single Phase	0	0	0	$ 750	$ -	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - New Three Phase	0	0	0	$ 3,750	$ -	$ -	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Replace Single Phase	0	0	0	$ 1,500	$ 300	$ 150	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Replace Three Phase	0	0	0	$ 3,750	$ 750	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
OH Conductor (per section - 150ft)													
15kV - Single Phase	0	0	0	$ 188	$ 38	$ 19	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Three Phase Tap	0	0	0	$ 375	$ 75	$ 38	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Three Phase Mainline	2	0	0	$ 675	$ 135	$ 68	$ 1,350	$ -	$ -	20%	$ 1,620	$ -	$ -
15kV - Three Phase Mainline - Spacer	0	0	0	$ 1,200	$ 240	$ 120	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Replace Secondary/Service Conductor	0	0	0	$ 225	$ 45	$ 23	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Aerial Cable - Express	0	0	0	$ 6,000	$ 1,200	$ 600	$ -	$ -	$ -	20%	$ -	$ -	$ -
UPZ Vegatation Management	0	0	2	$ 3,000	$ 600	$ 300	$ -	$ -	$ 600	20%	$ -	$ -	$ 720
Major OH Equipment													
15kV - Cutout - Single	0	0	0	$ 300	$ 60	$ 30	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Cutout - Three	0	1	0	$ 900	$ 180	$ 90	$ -	$ 180	$ -	20%	$ -	$ 216	$ -
15kV - Bells - 1ø	0	0	0	$ 225	$ 45	$ 23	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Bells - 3ø	0	0	0	$ 600	$ 120	$ 60	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Disc Switch - InLine	0	0	0	$ 1,500	$ 300	$ 150	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Disc Switch - UnderArm	0	0	0	$ 2,700	$ 540	$ 270	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - Load Break Switch	1	0	0	$ 7,500	$ 1,500	$ 750	$ 7,500	$ -	$ -	20%	$ 9,000	$ -	$ -
15kV - OH Recloser	0	0	0	$ 45,000	$ 9,000	$ 4,500	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - OH Cap Bank	0	0	0	$ 25,500	$ 5,100	$ 2,550	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - OH Arrestors	0	0	0	$ 750	$ 150	$ 75	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - SCADA Controlled Recloser - 3Ø	1	0	0	$ 46,500	$ 9,300	$ 3,750	$ 46,500	$ -	$ -	20%	$ 55,800	$ -	$ -
15kV - SCADA Switch - 3Ø	0	0	0	$ 39,000	$ 9,300	$ 3,750	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - SCADA Single Phase Reclosers	0	0	0	$ 31,500	$ 6,300	$ 3,000	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - TripSavers - 1Ø	0	0	0	$ 6,750	$ 1,275	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
15kV - FuseSavers - 1Ø	0	0	0	$ 3,750	$ 675	$ 375	$ -	$ -	$ -	20%	$ -	$ -	$ -
Misc Labor not accounted for in listed Activities													
Overhead Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Underground Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Trans/Station Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Test Department Labor in Hours	0	0	0	$ 210	$ 210	$ 210	$ -	$ -	$ -	20%	$ -	$ -	$ -
Subtotal							$ 68,850	$ 1,080	$ 600		$ 82,620	$ 1,296	$ 720
Project Management	Evaluation, Design and Support						$ 14,400				$ 17,280	$ -	$ -
Construction Manager	Support during project construction						$ 14,000				$ 16,800	$ -	$ -
Field Engineering/Planners	Responsible for Design						$ 9,000				$ 10,800	$ -	$ -
Allocations	Allocations assigned to the project						$ 13,500				$ 16,200	$ -	$ -
						subtotal	$ 119,750	$ 1,080	$ 600		$ 143,700	$ 1,296	$ 720
Misc Overheads	Overheads during all phases of the project						$ 26,345	$ 238	$ 132	22%	$ 31,614	$ 285	$ 158
Total							**$ 146,095**	**$ 1,318**	**$ 732**		**$ 175,314**	**$ 1,581**	**$ 878**
							CAP	COR	O&M		CAP	COR	O&M

Table A-2: Updated Metering Cost Table

						1/27/2022
	Schedule D - MONTHLY METERING O&M COST ESTIMATE					SJD
	12 kV Distribution Pole Mounted Tariff Rate Primary Metering Equipment					
	Monthly O&M Cost Estimate for Metering Equipment					
Item	Type	Meter Serial Numbers	Qty	Equipment Cost	Installation Cost	Customer Maintenance
MV90 METER KWH IN/OUT	EMR		1	$ 5,000.00	$ 1,200.00	$ 6,200.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Current Transformer	CT		1	500.00	1,200.00	1,700.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
12 kV Voltage Transformer	VT		1	1,000.00	1,200.00	2,200.00
	Sub-Total Installed Equipment Cost					$ 17,900.00
	General Expense @ 6%					1,074.00
	Total Installed Cost					$ 18,974.00
	Monthly Maintenance Charge @ 1.43% of Total Installed Cost					$ 271.33
	Monthly Translation					$ 25.00
	Total Monthly Meter Charges					$ 296.33

Note: The Interconnection Customer is responsible for providing a phone line for the metering equipment and is responsible for all associated costs for this phone line.