Central Maine Power
An Avangrid company

Shore Power

Sub-Transmission Interconnection Feasibility Study

Final Report: 003

Charles Reed – 2024

Table of Contents

List of Figures

List of Tables

Revision Log

Report Version	Updates
001	• First Report Released
002	• Added Appendix A, which includes a table comparing all potential solutions.
003	• Added additional summary table in the Executive Summary.

1 Executive Summary

1.1 Objective

This report documents feasibility study results for the Shore Power Interconnection project ("the Project"). The report describes the results of the steady state performance of the proposed Project on the Central Maine Power Company ("CMP") Portland Area sub-transmission 34.5 kV network. This study was performed in accordance with ISO-NE Planning Procedure 5-6 "Interconnection Planning Procedure for Generation and Elective Transmission Upgrades", ISO-NE reliability standards as explained in the ISO-NE Transmission Planning Technical Guide, and AVANGRID Technical Manual TM 1.2.00 "Electric Transmission Planning Manual - Criteria & Processes," to demonstrate that the proposed Project will not result in significant adverse impacts on the reliability and operating characteristics of the CMP sub-transmission system.

The Project proposes to interconnect a maximum of three ships to receive power from the sub-transmission network while ported. There will be three separate docking locations off Thames Street in downtown Portland. The maximum load capabilities of the docking locations would be 2 MW, 9 MW, and 14 MW, respectively. If all three docking locations are utilized simultaneously, there would be a load demand of 25 MW on the sub-transmission system, at a power factor of 0.975. The primary areas of concern for this study are the Portland Area 34.5 kV area network, and the limited 115 kV sources to the Portland Area.

Study results pointed toward three potential solutions to serve the full customer load demands. Reference Table 1-1 for a summary of these solutions. Reference Section 5 and Appendix A for additional details on these solutions.

Table 1-1: Summary of Proposed Solutions

Options	Maximum Supported Power	Total Cost	Total Timeline
Option 1 - Using Existing Distribution Capacity	**2 MW** Ocean Gateway Small - 2 MW	$0.2 M	<1 year
Option 2 - Expedite construction of Bayside substation, with a 115 kV Transmission Line from the Cape Substation	**9 MW - 25 MW** Ocean Gateway Small - 2 MW, Portland Terminal - 9 MW, Ocean Gateway Large - 14 MW	**$332 M - $345.55 M**	7+ years
Option 3 - Bayside substation constructed as proposed, with necessary distribution lines to connect the Customer	**9 MW - 25 MW** Ocean Gateway Small - 2 MW, Portland Terminal - 9 MW, Ocean Gateway Large - 14 MW	**$46.58 M - 60.13 M**	10+ years

Note 1: Maximum power for berth sizes in Table 1-1 were provided by the customer.
Note 2: All costs in Table 1-1 are high-level estimates (+200%/-50%) that are provided for order-of-magnitude only and are subject to change.

2 Introduction

2.1 Objective

This report documents feasibility study results for the Shore Power Interconnection project ("the Project"). The report describes the results of the steady state performance of the proposed Project on the Central Maine Power Company ("CMP") Portland Area sub-transmission 34.5 kV network. This study was performed in accordance with ISO-NE Planning Procedure 5-6 "Interconnection Planning Procedure for Generation and Elective Transmission Upgrades", ISO-NE reliability standards as explained in the ISO-NE Transmission Planning Technical Guide, and AVANGRID Technical Manual TM 1.2.00 "Electric Transmission Planning Manual - Criteria & Processes," to demonstrate that the proposed Project will not result in significant adverse impacts on the reliability and operating characteristics of the CMP sub-transmission system.

2.2 Study Area / Project Description

The Project proposes to interconnect a maximum of three ships to receive power from the sub-transmission network while ported. There will be three separate docking locations off Thames Street in downtown Portland. The maximum load capabilities of the docking locations would be 2 MW, 9 MW, and 14 MW, respectively. If all three docking locations are utilized simultaneously, there would be a load demand of 25 MW on the sub-transmission system at a power factor of 0.975. The primary areas of concern for this Study are the Portland Area 34.5 kV area network, and the limited 115 kV sources to the Portland Area.

Figure 2-1 and Figure 2-2 below show the Project's geographical map and one-line diagram respectively.

Figure 2-1: Geographical Overview

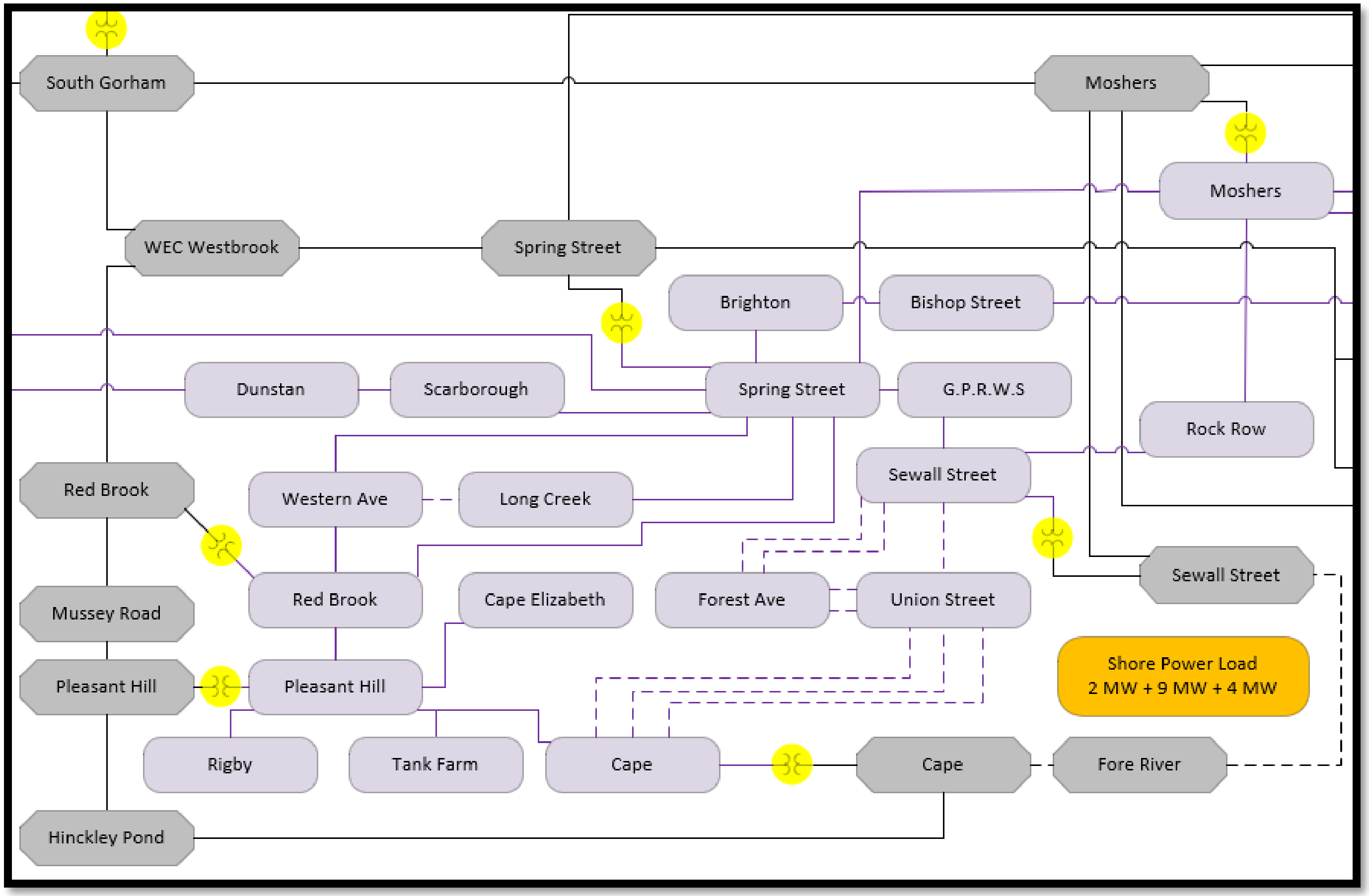

Figure 2-2: Existing Greater Portland Area Topology

3 Steady State Analysis

3.1 Analysis Description

This study includes a comprehensive steady state analysis in accordance with the MPUC Safe Harbor Criteria including the following types of analysis:

- Thermal Analysis – Determined the level of steady-state power flows on transmission circuits under base case conditions and following Planning Events.
- Voltage Analysis – Determined steady-state voltage levels and performance under base case conditions and following Planning Events.
- Loss of Load Screening – Determine whether any contingency events result in consequential loss of load violating Safe Harbor criteria.

Unless otherwise stated, the study assumption and methodologies for the analysis performed were consistent with the ISO-NE Transmission Planning Technical Guide[1].

3.2 Study Assumptions

3.2.1 Source of Cases

The 2021 ISO-NE Library Base Cases were utilized as the source of the Transmission Area Study. This case set included 2022 N+0 cases and 2032 N+10 cases. These cases were modified to include relevant larger generator interconnections or QP projects, spot loads, and distributed generation. This set of modified ISO-NE library cases was reviewed and modified as necessary to support the greater Portland Transmission Area Study.

3.2.2 Load Levels Studied

The load level assumptions made were as follows. Reference Table 3-1 for summary.

- Summer/Winter Peak Load Level Analyses: 100% of the 90/10 peak load level (i.e., 10% probability of being exceeded due to variations in weather). CMP load level brought to 1,700 MW in PSS®E.
- Off-Peak Load Level Analyses (i.e., Scheduled Maintenance Testing): Load at the 90th percentile calculated from last 3 years of historic data, unless no material change in load is observed from last calculation[2]. CMP load level brought to 1,312 MW in PSS®E.
- Light Load Level: Load calculated from the ISO-NE target for non-manufacturing load or 12,180 MW. The intent of the light load scenario was to determine the study area's sensitivity to regional load levels, as well as to identify any possible high voltage violations or thermal overloads

---

[1] *The ISO-NE Technical Planning Guide is updated on a periodic basis. The latest revision, 8.0, can be accessed at transmission_planning_technical_guide_rev_8.pdf (iso-ne.com)*

[2] *Adopted from ISO-NE intermediate load methodology.*

created at the lower load values while area generation is at maximum. CMP Load level was brought to 760 MW in PSS®E.

- Demand Resources: utilization of ISO-NE's regional base cases that incorporate all demand resources that are procured through the Forward Capacity Market and forecasted energy efficiency and distributed generation resources included in the annual Capacity, Energy, Load, and Transmission ("CELT") report forecast.

Table 3-1: Initial CMP Load Levels Per Case Type

Case Name	Case	Initial CMP Load		Net Load (Pct of Initial CMP Load)
		2022 case	2032 case	
EPK1	Summer Evening Peak	1700	2032 CELT	100%
EPK2	Summer Evening Peak	1700	2032 CELT	95%
EPK3	Summer Evening Peak	1700	2032 CELT	92%
MPK1	Mid-Day Peak	1700	2032 CELT	100%
MPK2	Mid-Day Peak	1700	2032 CELT	100%
MPK3	Mid-Day Peak	1700	2032 CELT	100%
MNT	Scheduled Maintenance	1300	1300 MW of 2032 CELT	100%
LL	Light Load	2022 CELT LL	2032 CELT LL	100%
LL2	Light Load	2022 CELT LL	2032 CELT LL	100%

3.2.3 Safe Harbor Load Loss Criteria

For area studies, and consistent with the Safe Harbor criteria, CMP utilizes the following load interruption acceptability criteria.

- Consequential[3] Load Interruption:
  - *N-1 single element contingency:* 25 MW
  - *Scheduled maintenance testing:* 60 MW
- Non-Consequential Load Interruption: not allowed during local transmission planning

[3] Consequential is defined as the resulting loss of load connected to a station directly impacted by the contingency event. Example would include a radial transmission line interrupted during a line contingency causing the radially fed substation to be disconnected from the transmission source unable to support the load connected to it via another transmission source.

3.2.4 Generation Dispatch Assumptions

The following existing generation assumptions were used for the area study.

- Non-Intermittent Resources: one major unit offline in the study area.
- Wind Generation: single availability factor (% of nameplate) calculated every 5 years for all onshore wind generation at all load levels. Median value (percent of nameplate) based on all day. Separate value for summer peak months (June-September) and shoulder months (April, May, October, November). Summer peak value is 10%; shoulder months value is 20%. Shoulder value to be used for maintenance outage modeling.
- Run-of-River Hydro Generation: Separate availability factors (MW) for summer peak and shoulder periods, calculated every 5 years for each hydro generating plant. Median value based on all day for summer peak months (June-September); Median value based on all day for shoulder months (April, May, October, November). Shoulder value to be used for maintenance outage modeling.
- Solar Generation: Solar generation was modeled at different percentages in accordance with the guidance provided by ISO-NE's Transmission Planning Guide. Reference Table for details
- Batteries: Batteries were modelled as one-sixth the nameplate value in summer evening peak cases, and offline in all other cases. In accordance with the guidance provided by ISO-NE's Transmission Planning Guide.

Furthermore, Yarmouth 1 and 2 (approximately 50 MW each) are assumed out of service as both units are not included in the ISO-NE CELT report.

Table 3-2 – Generation Assumptions for Case Types

Case Name	Case	PV	Batteries	ROR & Wind
EPK1	Summer Evening Peak	26%	Nameplate div by 6	Peak Safe Harbor
EPK2	Summer Evening Peak	10%	Nameplate div by 6	Peak Safe Harbor
EPK3	Summer Evening Peak	0%	Nameplate div by 6	Peak Safe Harbor
MPK1	Mid-Day Peak	40%	OOS	Peak Safe Harbor
MPK2	Mid-Day Peak	65%	OOS	Peak Safe Harbor
MPK3	Mid-Day Peak	65%	OOS	Peak Safe Harbor
MNT	Scheduled Maintenance	26%	OOS	LL Safe Harbor
LL	Light Load	90%	OOS	LL Safe Harbor
LL2	Light Load	90%	OOS	LL Safe Harbor

3.2.5 Modelling of Proposed Avangrid Transmission Projects and Queued Interconnections

Projects were reviewed and included on the bases of their in-service date. For example, in the N+0 year case, projects in-service prior to June 30, 2021 were included in the 2021 cases. This date was chosen because they are the conservatively early dates at which the peak load conditions can occur for summer load distributions. ISO-NE limits the base case inclusion of planned projects to those with an in-service date within five years of the current study year. As a result, the 2029 (N+10) cases model only those projects currently projected to be in service up to 2026.

Table 3-3: Spot Load Additions

BUS #	BUS NAME	P, MW	Q, MVAR	Load ID
102258	BRIGHTON AVE	0.58	0.19	L1
100124	FORE RIVER	1.71	0.56	L1
100124	FORE RIVER	1.52	0.50	L2
100124	FORE RIVER	0.55	0.18	L3
102245	LAMBERT ST	0.71	0.23	L1
800111	ROCK ROW	18.20	7.77	RR
100141	PLEASANTHILL	2.09	0.69	L1
100141	PLEASANTHILL	0.52	0.17	L2
100141	PLEASANTHILL	0.47	0.15	L3
100141	PLEASANTHILL	0.54	0.18	L4
102299	RIGBY	1.24	0.41	L1
100127	SPRING ST	1.71	0.56	L1
102296	UNION STREET	0.55	0.18	L1
102296	UNION STREET	0.84	0.27	L2
100457	MUSSEY ROAD	3	0	IX
100457	MUSSEY ROAD	1.2	0	CO
100457	MUSSEY ROAD	4.4	2.156	SD

Table 3-4: QP Project Additions

QP #	Type	Nameplate	State	Nearest Bus
1021	Solar	16.3 MW	Maine	W Buxton / Spring St.
639	HVDC	1200 MW	Maine	Larrabee Rd
889	STATCOM	600 MVAR	Maine	Buxton

3.2.6 Analysis Software

Siemens/PTI's PSS®E Version 34.9.4 was used to modify the individual power-flow basecases, develop the area solutions, and cross-check N-1 results. TARA Version 2301.1 Contingency Analysis ("CA") and Security Constrained Re-Dispatch ("SCRD") were used to perform the N-1 and N-1-1 analysis.

3.3 Study Methodology

When performing contingency analysis, three distinct time frames were studied, each requiring consideration of different factors, limits, and planning criteria.

- All Lines In– This represents the normal system state, with the system pre-postured to respond to contingency events. A similar pre-postured state exists in-between a first and second contingency during N-1-1 testing.
- Pre-Adjustments– In the time immediately following a contingency event, only dynamic devices (generators, STATCOMS, SVCs, etc.) would have had time to respond to the new system conditions. Operator actions or automatic equipment operations that occur after a time delay will not be considered.
- Post-Adjustment The time after automatic equipment operations and certain operator actions have occurred.

3.3.1 Solution Parameters

Table 3-5 outlines the pre-contingency and post-contingency solution parameters used for steady-state analysis. “Phase Angle Regulators” and “Area Interchange Control” settings were disabled for post-contingency operation. This was done to model the immediate effects following a contingency prior to operator actions, but after automatic control (such as LTC actions and automatic switched shunts).

Table 3-5: Steady State Solution Parameters

Scenario	Area Interchange Control	Tap Adjustments	Phase Angle Regulators	SVDs & Switched Shunts	DC Tap Adjustments
All-Lines-In (N-0)	Disabled	Stepping	Enabled	Enabled	Enabled
Post-Contingency Pre-Adjustment (N-1 & N-1-1)	Disabled	Disabled	Disabled	Continuous Only	Enabled
Post-Contingency Post-Adjustment (N-1 & N-1-1)	Disabled	Stepping	Enabled	Enabled	Enabled

3.3.2 Thermal Criteria

AVANGRID utilizes ratings of its facilities in its transmission planning studies to ensure safe operation without excessive loss of equipment life. The ratings used are consistent with those developed in compliance with the NERC FAC-008-3 standard for the bulk electric system ("BES") and approved methods for local transmission facilities. The following three rating categories (also described in Table 3-6) were monitored in the steady state analysis:

- Normal – This rating is the continuous rating of the transmission facility adjusted to seasonal ambient conditions. There are no restrictions on utilization of the full normal rating for any extent of time.
- Long Time Emergency (LTE) – Facilities may be loaded between their Normal and LTE rating for a number of hours after a contingency depending on ambient conditions. The transmission facility must return to a loading level below its normal rating once the time duration of the LTE has expired.
- Short Time Emergency (STE) – This rating is applicable for short term loadings on transmission facilities after a contingency has occurred, assuming the pre-contingent loading is within the facility's normal rating. The maximum length of time that a facility may be within its STE rating is 15 minutes.

For this study, operating transmission element within their "Long-term Emergency" (LTE) rating following a contingency or a scheduled maintenance outage is acceptable.

Table 3-6 – Steady State Thermal Limits

System Condition	Time Interval	Thermal Rating
All Lines-In (N-0)	Continuous	Normal
Post Contingency (N-1 and N-1-1)	More than 15 minutes following contingency	LTE
	Within 15 minutes of contingency	STE

Avangrid considers a thermal significant adverse impact when the post-project flow across a non-BES element exceeds its appropriate thermal rating and the flow across the element increases from the pre-project case by more than 2%.

3.3.3 Voltage Criteria

The voltage limits on all transmission buses in Maine with a nominal voltage of 34.5 kV and above were monitored in this study. Transmission system voltages must remain within the steady state bandwidth of 0.95 – 1.05 per-unit both before and after a contingency. In the post-transient period following a contingency however, before non-dynamic system adjustments can be made, per-unit system voltages of between 0.90 and 1.05 are permitted. This is depicted in Table 3-7 below.

Table 3-7 – Steady-State Voltage Limits

System Condition	Low Voltage Limit	High Voltage Limit
All-Lines-In (N-0)	0.95	1.05
Post-Contingency Pre-Adjustment (N-1 & N-1-1)	0.90	1.05
Post-Contingency Post-Adjustment (N-1 & N-1-1)	0.95	1.05

In addition to these voltage magnitude limits, the AVANGRID Electric Transmission Planning Manual details the Delta-V criterion. The term "Delta-V" refers to the change in voltages seen following routine switching actions that occur less than once per hour (e.g. capacitor bank or shunt reactor switching). This criterion is intended to comply with IEEE Standard 1453 in order to keep voltage flicker within tolerable limits during normal system conditions. In an all-lines-in (N-0) scenario, the Delta-V following any planned switching action should be limited to 3%. With an element out-of-service for routine maintenance (lineout), the Delta-V should be limited to 5%. Voltage change during a fault, generation trip, or the operation of a series transmission element is not considered voltage flicker and will not be tested against the Delta-V criterion.

The proposed solutions to the area needs were developed to comply with the Delta-V criterion as shown in Table 3-8; however, the Delta-V criterion was not used as a basis to identify needs in this study.

Table 3-8 – Delta-V Limits

System Condition	Delta-V Limit (%)
N-0	3
Line-out	5

3.3.4 Loss of Load Criteria

The Maine PUC Safe-Harbor Planning Standards include provisions that define the acceptable loss of load following certain contingency scenarios. For a valid single-element N-1 contingency or a scheduled maintenance outage paired with a subsequent single element contingency occurs, the consequential loss of load served must remain below the prescribed limits. These limits are listed in Table 3-9.

Table 3-9 – Loss of Load

Contingency Event	Loss of Load Limit (MW)
Single Element (N-1)	25
Scheduled Maintenance + Single Element (Sched. Maint. N-1-1)	60

3.4 Contingency Modelling

Contingencies local to the project were studied as part of the analysis. Contingency events studied include the loss of transmission and sub-transmission facilities, loss of a local transformers, loss of local generation, breaker failure contingencies, loss of elements without a fault, and bus outages. Three groups of contingencies were created for this study and arranged into contingency "decks" run during the steady-state analysis:

- N-1 – A deck including contingencies that are acceptable for N-1 analysis.
  - Single-element contingencies (lines, transformers, generators, etc.)
  - Scheduled maintenance outages[4]
  - Multi-element contingencies (bus faults, double circuit towers, breaker failure, etc.) that impact bulk power system (BPS) elements
- Lineout – A deck consisting of contingencies that make up the acceptable first-level events when performing N-1-1 testing.
  - Single-element contingencies (lines, transformers, generators, etc.)
  - Scheduled maintenance outages (Maintenance load only)[5]
- Contingency – A deck consisting of contingencies that make up the acceptable second-level events when performing N-1-1 testing.
  - Single-element contingencies (lines, generators, etc.)
  - Multi-element contingencies (bus faults, double circuit towers, breaker failure, etc.) that impact bulk power system (BPS) elements[6]

[4] *Maine Safe Harbor criteria excludes transformers as a second contingency for N-1-1 scenario.*

[5] *Scheduled maintenance outages are not valid for identifying needs in peak load cases. For informational purposes, the peak load cases were also subjected to maintenance outage testing as a sensitivity screening. These scenarios were not considered when developing solutions.*

[6] https://www.npcc.org/Standards/Directories/Directory%204_TFSP_Rev_20151001_GJD.pdf

4 Results

4.1 Initial Screening Results

An initial screening was conducted to determine the best potential interconnection points for the Project. Four interconnection locations were selected and tested based on proximity to the project site.

1. Connect to existing Distribution System (Served from Union Street Station) nearest to Project location.
2. Run new 34.5 kV line from Union Street Station to the Project.
3. Run new 115 kV line from the Cape 115 kV station to the Project.
4. Serve the Project from a planned future substation location called Bayside.

Using PowerGEM's TARA Transfer limit analysis, load was incrementally added to each interconnection point until a violation occurred. These results were then cross checked manually using a second software program PSSE. The results of this analysis are summarized in Table 4-1. Descriptions of each of these four locations are described further in this section.

Table 4-1: The Maximum Load Level Supported by Each Interconnection Point

Load Level (MW)	Solution Source			
	Existing Distribution	New Line from Union Street 35 kV Station	New Line From Cape 115 Station	New Line from NEW Bayview Station
2	X	X	X	X
9			X	X
11 (2+9)			X	X
14			X	X
16 (14+2)			X	X
25 (14+2+9)			X	X

4.1.1 Existing Distribution

A review of the area distribution system determined that existing Portland 12.47 kV circuits would see overloads if more than 2 MW of additional load were connected.

4.1.2 New Line from Union Street 34.5 kV Substation

The N-1 limiting element for this location was the Sewall Street Transformer. The N-1-1 limiting element(s) for this location are the underground cables between Sewall, Forest, Union, and Cape substations. After 2 MW of load is added to Union Street, these cables begin to see N-1-1 criteria violations. These cables cannot be further upgraded as they are currently the largest size the existing duct banks can support and the existing duct banks are also at their capacity. There are additional N-1-1 criteria violations for the Cape, Spring Street, and Red Brook transformers, as well as the 115 kV source concerns noted in the description of the Cape interconnection location in Section 4.1.3. Reference Figure 4-1 for additional details.

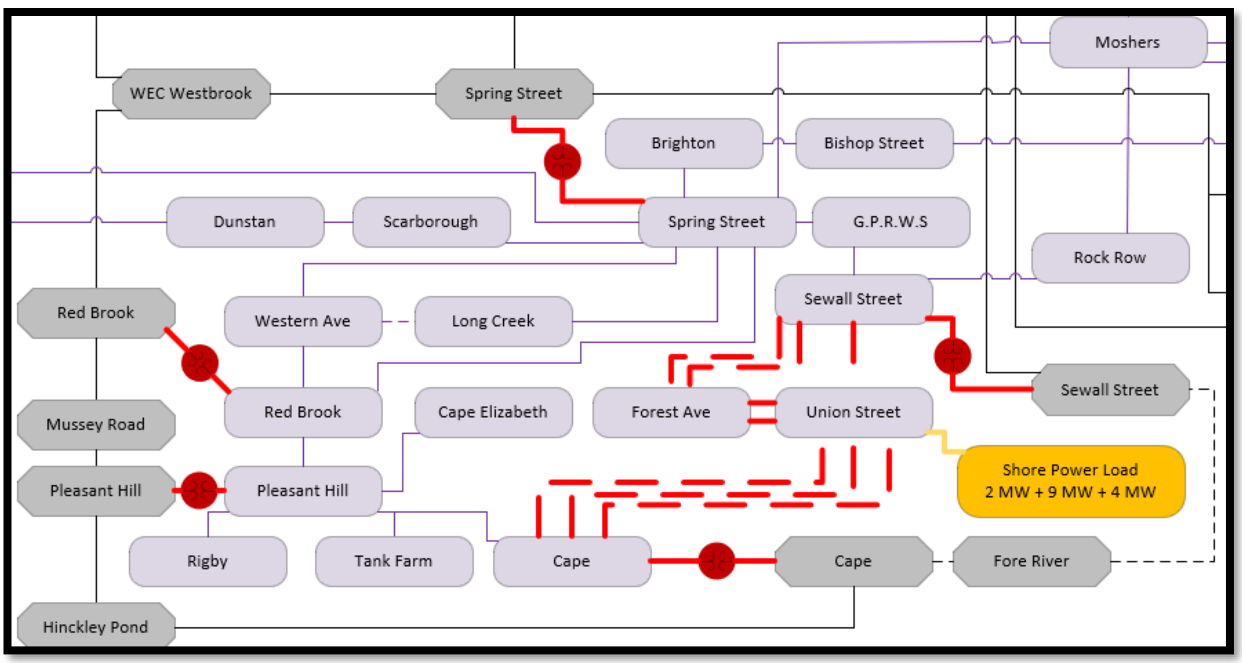

Figure 4-1: Potential Violations (Red) in Screening Cases for the Union Street Solution as Load Levels Exceed 2 MW

4.1.3 New Line from Cape 115 kV Substation

The location screening further indicated that the Cape Substation could handle up to 25 MW of additional load. There are some concerns with the Portland 115 kV loop that contains Cape Substation. There are certain contingency combinations that result in reverse power and/or loss of load violations. Adding load to Cape would result in adverse impact to this loop. But these concerns could be resolved with additional reverse power protections at the Cape and Redbook substations, combined with a new 115 kV source connecting to Pleasant Hill. Reference Figure 4-2 for additional details.

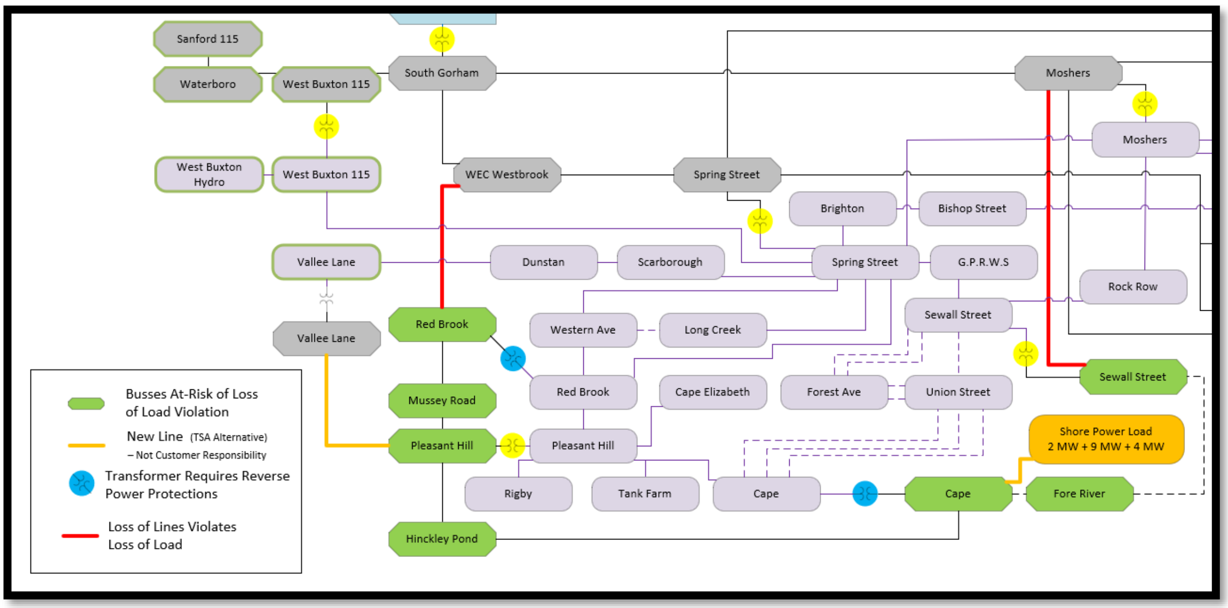

Figure 4-2: Limiting Factors for the Cape Solution

4.1.4 New Line from Future Bayside Substation

The need for a new 115 kV source in Portland has been observed in similar studies for this region. A new 115 kV substation would help prevent adverse impacts and provide support for new projects, initiatives, and area growth. One of the potential options for a new 115 kV source is the Bayside substation, located on the north side of the Greater Portland Peninsula. Reference Figure 4-3. This substation would be a 115/12.47 kV substation that could be able to support 11.6 – 31 MVA of new load for Greater Portland. (Final load values dependent on design constraints, real estate, and size of transformers). This could be a long-term solution to serve the load needs of the project.

CMP is recommending the construction of this substation along with new 115 kV transmission lines connecting this station to at least two other 115 kV substations near the Portland Area. Reference Figure 4-4. The construction of this Bayside substation is dependent on several factors, including review and approval by the Maine Public Utilities commission, and support from the community. Following the construction of the Bayside substation, up to the full 25 MW of shore power load could be supported, all that would be required would be the construction of distribution circuits along the 1.3 miles between the Bayside substation location and the Shore Power location.

Figure 4-3: Location of Bayside substation relative to Shore Power Site.

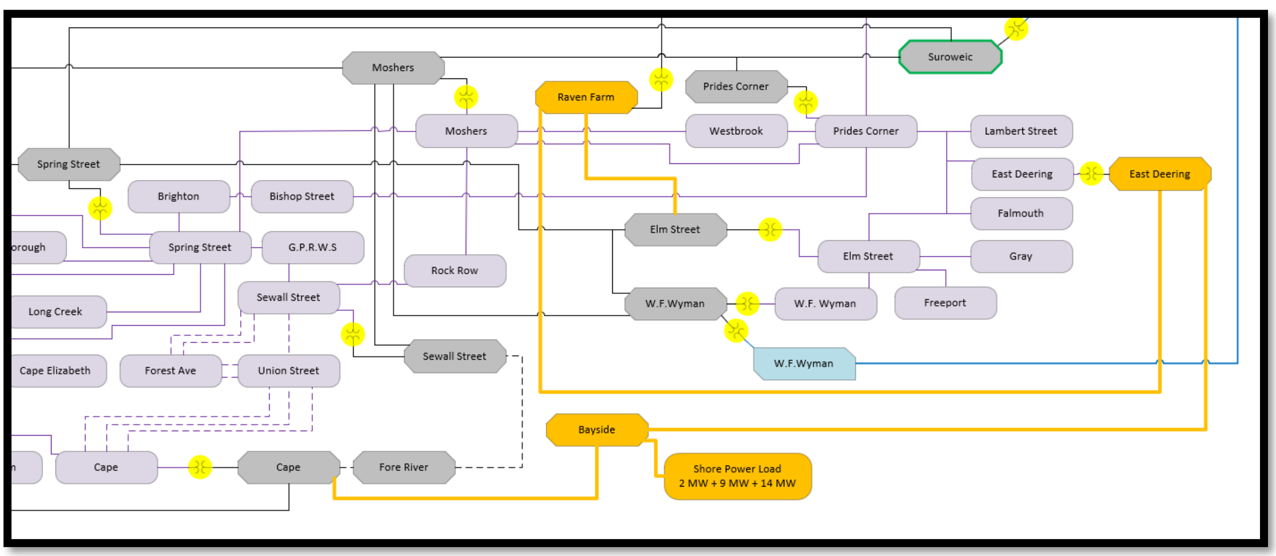

Figure 4-4: Bayside Solution Example

5 Solutions

5.1 Distribution-Only Solution

The nearest 12.47 kV distribution circuit is 645D3 and is fed from the Union Street substation. As of October 2023, this circuit has capacity to feed a load of 2 MW and (assuming summer 2022 peak load conditions) could support the smallest berth of the shore power project with no major upgrades.

The load capacity is limited by an underground cable from Union Street substation (0.6 miles), as well as constraints on the sub-transmission underground network.

This load capacity assumes present day conditions and cannot be guaranteed. Availability would need to be re-evaluated if there are load changes to the area prior to project construction.

With no circuit or substation upgrades required, the typical scope of work to interconnect a 2MW load would be a 4-wire riser pole, radial underground #2AL 15kV distribution cable to a 2MVA padmounted transformer. Typical costs are used because no detailed site plan is available. Scope of work and costs are subject to change with site plan details. CMP costs include only electrical components (pole, cable, transformer, and connections). Excavation and conduit manhole infrastructure will be provided and installed by customer and are not included in cost estimate. Actual costs will come from detailed design in SAP. Estimate for this scope of work, accounting for uncertainty on site details is $200,000.

5.2 Expedited Cape Substation Solution

To serve the additional 9 MW berth and 14 MW berth, a connection to a 115 kV substation would be required, as the 34.5 kV sub-transmission network in the area does not have the available load capacity at this time.

The shore power equipment is designed to connect to a 12.47 kV or 34.5 kV power source and cannot directly connect to a 115 kV substation. A full 115 kV solution would require a substation on the greater Portland peninsula to convert 115 kV power to a distribution voltage level that could support the shore power equipment. Reference Figure 5-1.

Reference Table 5-1 for the estimated cost to construct the Bayside substation (or similarly sized local substation), the cost to construct a 115 kV line to connect it to the nearest 115 kV source, and the cost to construct four underground distribution circuits to connect project site to nearest local substation.

These costs are high-level estimates that are provided for order-of-magnitude only. These costs could vary if a different site were found for a local substation, or if a different route were determined for the 115 kV line. If substation location other than Bayside were preferred, it would be the responsibility of the project to procure a suitable site location.

Table 5-1: High Level Estimated Cost to Construct New Local Substation.

Solution Component	Estimated Cost in Millions
Local 115/12.47 kV substation	$ 116.12 M
Cape SS Modifications	$ 49.41 M
New 115 kV line between Cape and Local substation	$ 119.89 M
Distribution Costs to Connect Project to Local Substation	$ 60.13 M
TOTAL COST	**$ 345.55M**

Figure 5-1: Example of Cape Solution

5.3 Shore to Bayside Solution

Central Maine Power has observed the need for new substations on the Greater Portland peninsula in other regional studies and is recommending the construction of the Bayside substation to support area load growth. This substation would be a 115/12.47 kV substation that could be able to support 11.6 – 31 MVA of new load for Greater Portland. Assuming this longer-term project moves forward, the project would only be responsible for the distribution costs to connect the project site the 1.3-mile distance to the Bayside substation. Reference Figure 5-1.

The construction of this Bayside substation is dependent on several factors. In addition to requiring approval by NERC, FERC and ISO-NE, the project will also require review and approval by the Maine Public Utilities commission, and support from the community. This is a long-term project that may take up to 10 years or longer to complete.

Following the construction of the Bayside substation, the project would only be responsible for the distribution circuit cost necessary to connect the project site to the Bayside site. The (+200/-50%) estimate to construct 4 circuits to support >20MW is $60.13M. Reference Table 5-2 to see how the desired megawatt need of the final solution impacts the number of required circuits and the relative cost.

Table 5-2: Distribution Solution Cost Options

MW	Distribution circuits	Cost
2	1	$ 0.20 M
9	2	$ 46.38 M
14	3	$ 53.25 M
23 (9+14)	4	$ 60.13 M

6 Conclusion

The results of this feasibility study revealed adverse impacts to the current subtransmission and distribution systems if more than 2 MW of additional load is connected to present-day downtown Portland. This could support the smallest berth of the project, but a new 115kV/12.47 kV substation will be required on the greater Portland peninsula to support the additional 9 MW and 14 MW berths. CMP is currently advocating for a new 115kV/12.47 kV substation at the Bayside location to support load growth in the area. The normal process to advocate for new infrastructure involves several parties external to CMP and could take up to 10 years to review and complete. Following the successful construction of this Bayside substation the customer would only be responsible for construction of the required distribution circuits, which is estimated to be about $60M to support both the 9 MW and 14 MW berths. If the customer wanted to expedite this timeline, they would need to find a suitable location for a 115/12.47 kV substation, connect this new substation to the nearest source (Cape 115 kV), and construct the required distribution circuits. The costs to expedite this timeline vary but are estimated to be about $346M.

Appendix A – Summary Table of Potential Solutions

Supported Berths	Transmission Solution	Transmission Cost	Distribution Solution	Distribution Cost	Total Cost	Total Timeline
2 MW	NA	NA	1 Circuit tap off local source 645D3	$0.2M	$0.2 M	<1 year
9 MW	Customer Moves Bayside Project Forward, with Transmission Line from Cape	$285.42 M	2 Circuits from Bayside to Shore	$46.58M	$332 M	7+ years
9 MW	CMP constructs Bayside Substation	NA	2 Circuits from Bayside to Shore	$46.58 M	$46.58 M	10+ years
14 MW (Or 2 + 9)	Customer Moves Bayside Project Forward, with Transmission Line from Cape	$285.42 M	3 Circuits from Bayside to Shore	$53.25 M	$338.67 M	7+ years
14 MW (Or 2 + 9)	CMP constructs Bayside Substation	NA	3 Circuits from Bayside to Shore	$53.25 M	$53.25 M	10+ years
23 MW (9 + 14)	Customer Moves Bayside Project Forward, with Transmission Line from Cape	$285.42 M	4 Circuits from Bayside to Shore	$60.13 M	$345.55 M	7+ years
23 MW (9 + 14)	CMP constructs Bayside Substation	NA	4 Circuits from Bayside to Shore	$60.13 M	$60.13 M	10+ years

Note 1: All costs are high-level estimates (+200%/-50%) that are provided for order-of-magnitude only and are subject to change.

Note 2: The costs listed above represent only the customer-funded portions of the solutions.