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Northern California Offshore Wind Generation and Load Compatibility Assessment with Emphasis on Electricity Grid Constraints, Mitigation Measures and Associated Costs

Final Synthesis Report

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Schatz Energy Research Center

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Bureau of Ocean Energy Management

DISCLAIMER

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INTRODUCTION

Floating offshore wind is in its nascent stages of development on the West Coast of the United States. The Bureau of Ocean Energy Management has identified three call areas off the California coast that they are considering for lease. Two of the call areas are located offshore from central California and one call area is offshore from Humboldt Bay in the far northern region of the state. This study is focused specifically on evaluating the Humboldt Call Area.

Due to the steep continental shelf and deep waters directly offshore of California, offshore wind turbines off the California coast would need to be floating. Floating wind technology allows offshore wind turbines to be placed further from shore, where the wind speeds are generally faster and more consistent. Rather than being fixed to the ocean floor like the offshore wind turbines in the shallower waters off the East Coast of the U.S. or northern continental Europe, floating platforms are tethered to the ocean floor using mooring lines and anchors. While the technology has been demonstrated successfully in pilot projects around the world, a commercial-scale floating offshore wind farm has not been deployed in the United States.

Locating an offshore wind farm in northern California has numerous benefits as well as several challenges. This region was identified as a prospective area for development because the offshore wind speeds are the highest in the state and there is a suitable deep-water port in Humboldt Bay that could be used for assembly and deployment. However, there are various challenges that need to be overcome prior to development, including limited electricity transmission capacity, stakeholder concerns, and possible seismic hazards, to name a few.

The California North Coast Offshore Wind Study evaluates the primary benefits, challenges, and barriers to offshore wind development in northern California. Led by the Schatz Energy Research Center at Humboldt State University, this study analyzes a broad set of issues around offshore wind in northern California. Three agencies separately funded different pieces of the analysis: The Bureau of Ocean Energy Management supported an evaluation of the power generation profile, transmission constraints and options, and economic viability; the California Ocean Protection Council funded an environmental assessment, evaluation of port and coastal infrastructure, a study of stakeholder perspectives, and a policy analysis; and the California Governor’s Office of Planning and Research provided support to study the military mission compatibility, a potential subsea transmission cable, and geologic hazards associated with the wind farm and ancillary components.

This report contains the analyses funded by the Bureau of Ocean Energy Management. The research team on this study included the Schatz Energy Research Center (Chapters 1-3 and 6-11), Pacific Gas and Electric (Chapter 4), and Mott MacDonald (Chapter 5). Each chapter is treated as a stand-alone document, with its own list of references, appendices, and page numbers. The chapters are described below with a summary of the findings. Appendix A at the end of this report includes a description of the assumptions that were used for this study.

<u>Chapter 1 - Wind Speed Resource and Power Generation Profile Report</u>

The wind resource off the coast of Humboldt County, California was analyzed for patterns that could make potential offshore wind electricity generation viable. Wind speeds were typically bidirectional, coming from the North or South, and averaged between 9-10 m/s annually. Three offshore wind scenarios were analyzed: a 48 MW farm, a 144 MW farm, and a 1,836 MW farm producing an estimated 202 GWh, 509 GWh, and 7,540 GWh of energy per year, respectively. The 48 MW scenario had a capacity factor of 48%, while the 144 MW and 1,836 MW scenarios had capacity factors of 47%. The analysis showed the wind farms running at full power for an estimated 2,850 hours, or 33% of the year, and the wind farms producing no power for an estimated 1,670 hours, or 19% of the year. The remainder of the year they produced somewhere between zero and full power.

Chapter 2 - Offshore Wind and Regional Load Compatibility Report

A nodal model of Humboldt County was used to assess compatibility among Humboldt's electrical load, interregional transmission capacity (limited to 70 MW of imports or exports), and offshore wind power production at three scales: 48 MW, 144 MW, and 1,836 MW. Load data were projected by Humboldt's Community Choice Aggregator, while historical generation data were drawn from the California Energy Commission's Quarterly Fuel and Energy Report. Model results show that nearly all the energy from a 48 MW facility could be used locally, energy from a 144 MW would be split close to evenly between local utilization and exports, and, under the assumption of existing transmission constraints, the majority of the energy from a 1,836 MW facility would be curtailed. All scales of wind development come with the added benefit of greenhouse gas reductions.

Chapter 3 - Interconnection Constraints and Pathways

This chapter describes the required transmission upgrades for interconnecting different scales of offshore wind on the North Coast and the different pathways to develop the transmission infrastructure. This chapter's main goal is to discuss the pathways for transmission infrastructure development in California that are relevant to offshore wind. The chapter also includes a summary of the technical requirements and estimated costs for interconnection of offshore wind generation from the Humboldt Call Area. Further details on these technical requirements are described subsequently in Chapter 4.

Chapter 4 - Interconnection Feasibility Study Report

A study was conducted to assess the feasibility of interconnecting three scales of wind farms (48 MW, 144 MW and 1,836 MW) located offshore of Humboldt County. This study was conducted under the assumption that all regional power sources including offshore wind were operating at peak output. For the large-scale scenario, three alternatives were considered. These included: 1) coming onshore in the Humboldt Area and then interconnecting to Vaca-Dixon via Round Mountain, 2) coming onshore in the Humboldt Area and then interconnecting to Vaca-Dixon directly, and 3) routing power via subsea cables to a new substation in the SF Bay Area. Standard, steady-state power flow analyses were performed under various contingencies and the infrastructure required to meet reliability standards was determined along with the associated costs. Study conclusions found that costs were not proportional to installed capacity, as the transmission upgrade cost per MW of installed generation capacity was considerably larger for the smaller wind farm scenarios. For the 48 MW facility, costs ranged from $363M to $726M, for the 144 MW facility the range was $669M to $1.34B, and for the 1,836 MW wind farm costs ranged from $1.4B to $2.8B.

Chapter 5 - Subsea Transmission Cable Conceptual Assessment

A concept-level assessment was conducted to develop two options for routing a high-voltage, direct-current (HVDC) transmission cable as an alternative to overland transmission upgrades for the 1,836 MW wind farm development scenario. This chapter evaluates hazards and constraints for routing a subsea cable from the Humboldt Bay to the San Francisco Bay Area and develops two cable corridors with high-level cost estimations. One cable corridor is nearshore, and the other is further offshore in deep water. Both corridors face a significant set of challenges that would need to be overcome to install and operate an HVDC link, though the challenges may not make construction insurmountable. Some of the primary challenges for the nearshore corridor are environmental permitting and submarine canyon crossing, while the primary challenges for the offshore corridor include specialized cable design for deep water (2,000 m) and telecom cable crossings. Initial cost estimates are between $2.1 and $3.1 billion for the cable and electrical converter stations.

Chapter 6 - Electricity Market Options for Offshore Wind

A review of the electricity markets regulated by the California Independent System Operator (CAISO) identified various products and selling strategies, and how an offshore wind installation could be managed within those markets. This chapter provides an overview of the Day-Ahead and Real-Time energy markets, niche energy products such as Ancillary Services, Congestion Revenue Rights, and Convergence Bidding, as well as the Resource Adequacy and Hybrid Resource regulatory tools. Offshore wind can participate in the key Day-Ahead and Real-Time markets without need of a broader strategy, and new technologies enable selling of Ancillary Services. Congestion Revenue Rights, Convergence Bidding, Resource Adequacy, and Hybrid Resources could play a role in the economic strategy of an offshore wind facility, but specific transmission, plant, and as-yet undetermined CAISO regulation data would be needed before this role would be clear.

Chapter 7 - Market Revenue Study

This study describes and quantifies the potential benefits of three markets available to offshore wind developers: The resource adequacy (RA) market, the ancillary services market (AS), and the energy market. Offshore wind was compared to California solar, and land-based wind in California, New Mexico, and Wyoming. Energy and AS prices are based on historical 2019 data, while RA revenues are based on a combination of 2020 effective load carrying capacity and projected 2022 resource adequacy payments. The expected revenue available per MW of offshore wind is significantly higher than land-based wind or solar. This is due to the higher overall energy generated (expressed as a higher capacity factor). Each megawatt of installed offshore wind generates more megawatt-hours. However, the value per MWh of offshore wind is approximately the same. Based on our analysis, approximately 4% of the annual revenue is through RA capacity payments, 1% through participation in ancillary services markets, and 95% through generation of energy and participation in energy markets.

Chapter 8 - Economic Viability of Offshore Wind in Northern California

This chapter assesses the potential economic viability of several offshore wind (OSW) farm scenarios sited offshore of northwestern California and served by the Port of Humboldt Bay, California. A bottom-up cost model was developed to determine the costs of an offshore wind farm installed in the Humboldt region. The costs were used to evaluate levelized cost of electricity and power purchase agreement price for three scales of offshore wind farms. This analysis determined that only the largest of the OSW farm scenarios (1,836 MW beginning commercial operations in 2028) using a single owner financing scheme achieved real levelized PPA prices that fell below $100/MWh, a notional threshold for OSW projects having potential to be economically viable.

Chapter 9 - Subsea Transmission Cable Stakeholder Identification

A potential subsea transmission cable will have effects on the environment and also on different stakeholder groups. This chapter identified stakeholders and interested parties that may see a benefit or impact from development of a subsea cable. Sixteen stakeholder groups are identified and their potential perspectives are discussed based on review of existing literature (this preliminary assessment did not include primary data collection or interviews). Potential perspectives were grouped into seven themes. Two benefits were identified: renewable energy development and economic development; and five concerns were identified: environmental considerations, economic loss, existing ocean uses, telecom and military operations, and cultural resources. The different groups and their potential perspectives are presented and discussed in this chapter.

Appendix A - Offshore Wind Study Assumptions

To assess the potential for offshore wind energy generation along the northern coast of California twelve different scenarios were defined that vary by wind array scale, location, and electrical transmission route. Appendix A provides a description of the wind farm scenarios in the North Coast Offshore Wind Study. The assumptions listed in this Appendix apply to the work documented in all chapters of this report, as well as to the work documented in the companion reports funded by the California Ocean Protection Council and the California Governor's Office of Planning and Research.

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Chapter 1: Wind Speed Resource and Power Generation Profile Report

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EXECUTIVE SUMMARY

The strong wind speeds off the northern California coast provide a promising opportunity to generate renewable electricity using floating offshore wind turbines. This report summarizes the variability and magnitude of the wind resource off the coast of Humboldt County and evaluates the power generation profile of wind turbines located in this region. The wind resource is evaluated in two locations: offshore Humboldt Bay and offshore Cape Mendocino. The Humboldt Bay location was selected because the Bureau of Ocean Energy Management (BOEM) submitted a Call for Information and Nominations in this area in 2018. The Cape Mendocino location was studied as a second site for comparison because it has the highest annual average wind speeds in the region and was evaluated by the National Renewable Energy Laboratory as a potential location for offshore wind (Musial, 2016a). The Cape Mendocino site is not being considered by BOEM for a lease and is used in this analysis solely for comparative purposes.

The electricity production capacity is calculated for three wind farm scales: 50 MW (4x 12 MW turbines), 150 MW (12x 12 MW turbines), and 1,800 MW (153x 12 MW turbines). This report is the first piece of a study to investigate the generation potential for offshore wind, the compatibility with electric load, transmission constraints, and associated costs. This report will become part of a wider analysis considering the transmission costs and economics of offshore wind development in northern California.

Wind Speed Patterns

The wind speed in both locations is bi-directional, with the majority of wind coming from the north throughout the entire year (Figure ES.1) while south and southeastern winds tend to occur during the winter months.

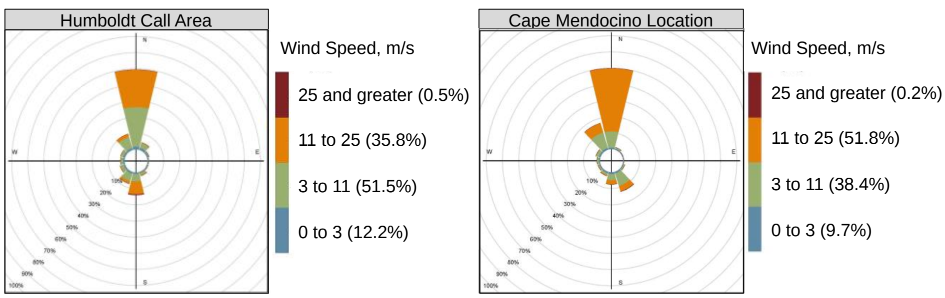

Figure ES.1. Annual average wind rose for Humboldt Call Area and Cape Mendocino locations.

Using seven years of modeled data, the wind speed distribution shown in the histograms in Figure ES.2 are categorized into different zones of a typical 12 MW offshore wind turbine power curve, where the blue and red regions produce no power, the orange region produces the rated power output of 12 MW per turbine, and the green bins produce power between 0 and 12 MW. Wind speeds adjusted to a 136 meter hub height in the Humboldt Call Area occur primarily between 3 and 11 m/s, while the majority of wind in the Cape Mendocino location is in the turbine’s rated power zone between 11 and 25 m/s.

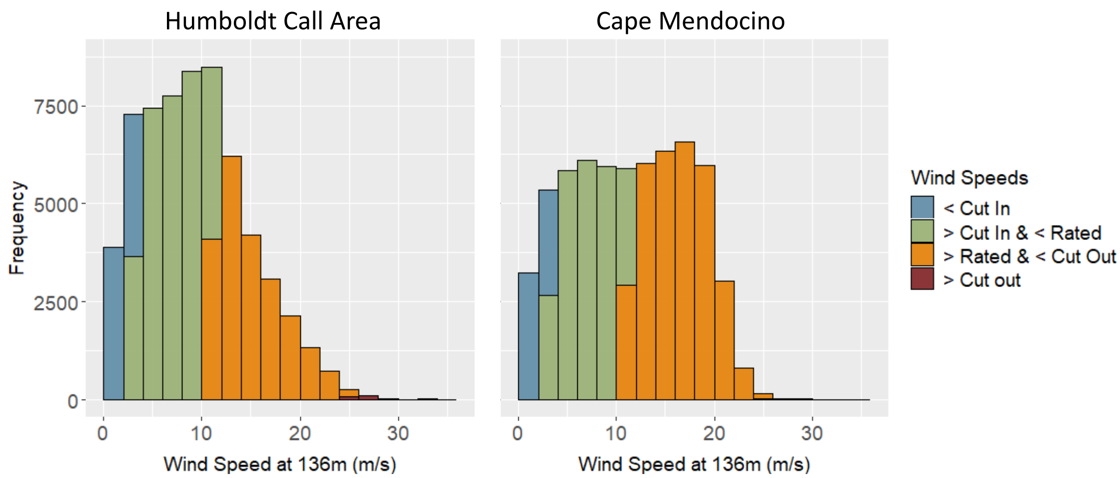

Figure ES.2. Wind speed distribution for Humboldt Call Area and Cape Mendocino location.

Power Production Variability

These wind speed profiles lead to the typical annual electricity production and capacity factor for wind farms around 47-48% in the Humboldt Call Area and 56-57% in the Cape Mendocino location after accounting for expected power losses (Table ES.1). The capacity factor of larger wind farms is slightly lower due to increased wake effects from the turbine array.

Table ES.1. Summary of electricity production from different scale wind farms for a typical year.

Location	*Scenario Name*	*Wind Farm Size*	*Annual Energy Production*	*Capacity Factor*
Humboldt Call Area	HB-50	48 MW	202 GWh/yr	48%
	HB-150	144 MW	599 GWh/yr	47%
	HB-1800	1,836 MW	7,540 GWh/yr	47%
Cape Mendocino Location	CM-150	144 MW	717 GWh/yr	57%
	CM-1800	1,836 MW	9,074 GWh/yr	56%

Power output from the wind farms is distributed between two extremes: the wind farms most commonly produce at their rated power output or at zero output when the wind is either too fast or too slow or the turbines are shut down because of maintenance, environmental factors, or curtailment. The generation duration curves shown in Figure ES.3 highlights this trend, showing large fractions of time at the maximum power or minimum power (the horizontal portion of the graphic on the left and right of each chart, respectively).

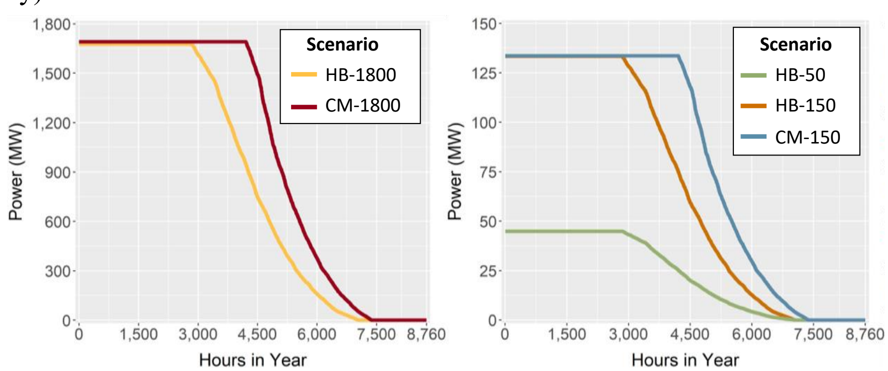

Figure ES.3. Generation duration curves for all wind farm scenarios for a typical year.

Offshore wind power production can be extremely variable in nature. For example, three week-long periods in early July are compared to show weeks where power production can be near zero, at the rated capacity, or varying between these levels (Figure ES.4).

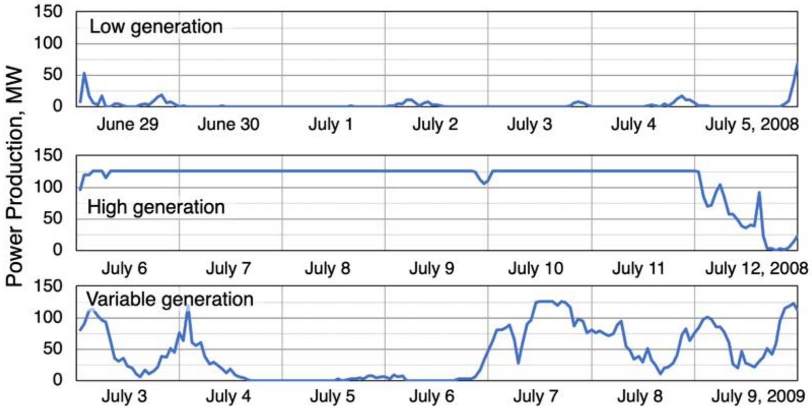

Figure ES.4. Three example week-long period of power output from a 144 MW wind farm located in the Humboldt Call Area.

This trend is best visualized by looking at the percentile distribution of power production for different seasons throughout the year. Figure ES.5 shows the fraction of time that power production exceeds different levels for a 144 MW wind turbine array in the Humboldt Call Area. The graphs show that the 75th percentile always exists at the maximum output and the 10th percentile always exists at 0 MW.

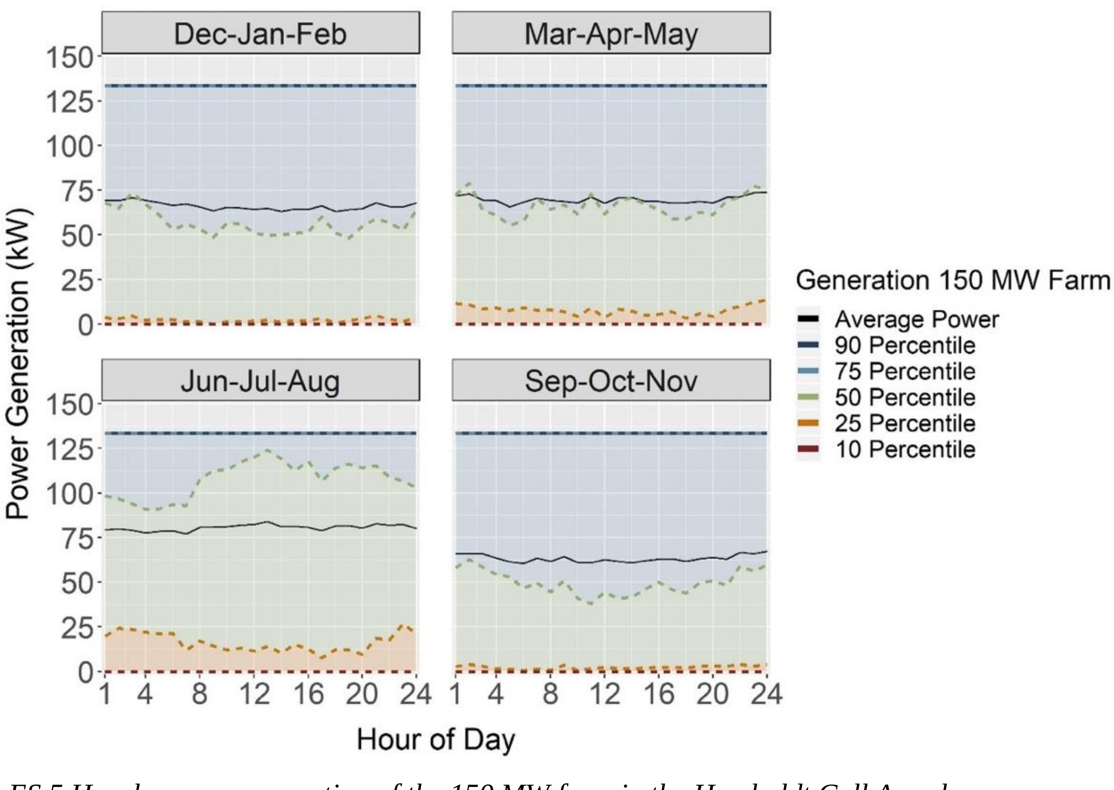

Figure ES.5 Hourly power generation of the 150 MW farm in the Humboldt Call Area by season.

Summary

Analysis of the wind speed and power production profile indicate that the northern California coast could be host to productive wind farms with capacity factors near or exceeding 50%. The wind speed resource in the Cape Mendocino location is more favorable from a power generation standpoint than the Humboldt

Call Area because the wind speed distribution better matches the power curve of offshore wind turbines. However, this location is only analyzed for illustrative purposes, and there are economic disadvantages to this area because the distance from port and the distance to an interconnection point will increase the costs for installation, maintenance, and electric cable costs for transmission back to shore. Furthermore, this location has not been screened by any ocean user community and is not representative of a BOEM call area. BOEM has not indicated any interest in this representative area for wind development. A forthcoming economic analysis will evaluate the tradeoffs between power production and distance to port and interconnection.

Analysis of the wind speed patterns in northern California show that wind farms will frequently produce power at their rated capacity but also have a large fraction of time when there is no power production. This generation profile may have implications for how offshore wind can be integrated into wider California electricity markets depending on the predictability and time of generation. Forthcoming analyses will include an assessment of how offshore wind is compatible with Humboldt County and state-wide electric demand. These analyses will also assess the cost and extent of transmission upgrades that would be required to support this generation.

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1. INTRODUCTION

Offshore wind energy can make significant contributions to a clean, affordable, and secure national energy mix. According to the U.S. Department of Energy, the technical potential for offshore wind development in the United States Outer Continental Shelf is two times as large as our national electrical load (DOE, 2016). This abundant resource provides significant opportunities to develop clean and reliable electricity generation to meet growing demand and replace scheduled power plant retirements in coastal states. With capital costs of offshore wind rapidly decreasing (NREL, 2015) and advances in the floating platforms suitable for the deep waters along the Pacific Coast, offshore wind developers have become interested in installing one or more offshore wind farms along the Humboldt County coast in northern California (Principal Power, 2018; BOEM, 2018a). However, development of offshore wind in this region requires a comprehensive, integrated assessment of the wind generation potential, electric load profile, and transmission capabilities to ensure that new generation is compatible with existing loads and has access to sufficient transmission capacity.

This report provides an assessment of offshore wind energy generation potential for several different scales of potential development. The analysis includes a wind speed resource assessment and an evaluation of the energy generation profile on the north coast of California. The assessment studies two locations: offshore Humboldt Bay and offshore Cape Mendocino. The Humboldt Bay location was selected because it the Bureau of Ocean Energy Management (BOEM) submitted a Call for Information and Nominations in this area in 2018. The Cape Mendocino location was studied as a second site for comparison because it has the highest annual average wind speeds in the region and was evaluated by the National Renewable Energy Laboratory as a potential location for offshore wind (Musial, 2016a). The Cape Mendocino site is not being considered by BOEM for a lease and is used in this analysis solely for comparative purposes.

1.1 Study Scenarios

The potential for offshore wind energy generation is investigated along the California's north coast (Figure 1-1). This study provides an analysis of wind speed at two locations and the electricity generation potential from three scales of wind turbine arrays. The different study scenarios are described below:

- Location
  - Humboldt Bay - The Humboldt Call Area as defined by BOEM's Call for Information and Nominations (2018a, b). Eleven commercial developers have expressed interest in this area.
  - Cape Mendocino - A notional study area offshore Cape Mendocino, which has the highest average annual wind speeds in California.
    - *Note:* This area is being studied for illustrative and modeling purposes only. This area has not been screened by any ocean user community and is not representative of a BOEM call area. BOEM has not indicated any interest in this representative area for wind development.
- Wind Array Scale
  - Pilot Scale - nominal 50 MW using 4x 12 MW turbines (48 MW actual nameplate capacity). This scale was selected because it is expected to fit within the current generation portfolio of existing generators in Humboldt County without major transmission upgrades.
  - Small Commercial - nominal 150 MW using 12x 12 MW turbines (144 MW actual nameplate capacity). This scale was selected because it is the approximate scale of a wind array that could be installed without major upgrades to the transmission system and is the approximate scale of an unsolicited lease request to BOEM from the Redwood Coast Energy Authority (2018).
  - Large Commercial - nominal 1,800 MW using 153x 12 MW turbines (1,836 MW actual nameplate capacity). This scale was selected because it represents a full build out of the Humboldt Call Area using standard assumptions about turbine and mooring line spacing, as

described in Section 1.2.3. The boundary of the notional Cape Mendocino area was sized to accommodate the same number of turbines as the Northern California Call Area using the same build-out assumptions.

The five study scenarios are listed in Table 1-1 include all combinations of location and scale, except for a 50 MW wind array in the Cape Mendocino area. Different scenarios and their naming convention are summarized in Table 1-1.

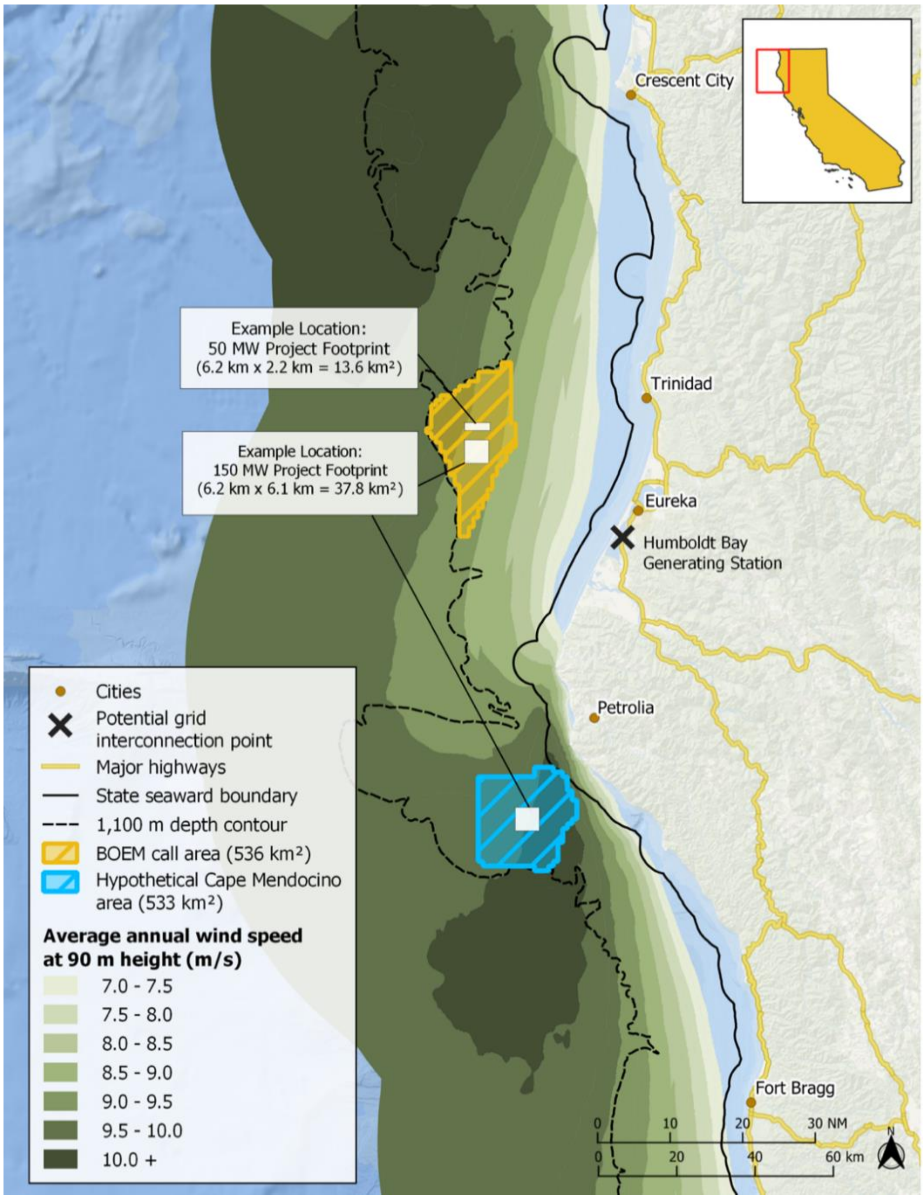

Figure 1-1. Wind speed and study areas.

Table 1-1. Study scenarios for offshore wind.

Scenario Name	*Location*	*Number of Turbines*	*Nominal Array Size*	*Nameplate Capacity*
HB-50	Humboldt Call Area	4	50 MW	48 MW
HB-150		12	150 MW	144 MW
HB-1800		153	1,800 MW	1,836 MW
CM-150	Cape Mendocino Notional Study Area	12	150 MW	144 MW
CM-1800		153	1,800 MW	1,836 MW

1.2 Wind Farm Specifications

Wind farms specifications and design assumptions that are relevant to this analysis are described below. Geographical specifications and detailed maps of the study locations are provided in Appendix A.

1.2.1 Locations

Two locations are being considered, as described below.

1.2.1.1 Humboldt Bay Area

The Northern California Call Area identified by the Bureau of Ocean Energy Management (BOEM, 2018a) located west of Humboldt Bay approximately 20 to 30 nautical miles offshore.

1.2.1.2 Cape Mendocino Notional Area

A second wind array location is considered for illustrative purposes. A hypothetical wind array area offshore Cape Mendocino was outlined by the Schatz Energy Research Center. This area has not been screened by any ocean user community and is not representative of a BOEM call area. BOEM has not indicated any interest in this representative area for wind development.

The Cape Mendocino notional area was chosen in federal waters offshore Cape Mendocino. This general area was identified by Musial et al. (2016a) as a promising offshore wind area due to its high wind speeds. The area to be studied in this project was defined by three simple assumptions: 1) including the highest average wind speeds in the region, 2) creating a boundary that will accommodate the same number of turbines as the Call Area for the full build out scenario, and 3) excluding any deep-water canyons.

1.2.2 Turbine

All wind farms are assumed to use a 12 MW turbine. This turbine size was selected based on interviews with developers who indicated they would deploy turbines rated at 12 MW or larger in the Northern California Call Area. The specifications for this turbine are derived from the standard reference turbine developed by NREL (Musial et al., 2019). The turbine specifications are outlined in Table 1-2 and its power curve is shown in Figure 1-2.

Table 1-2.Turbine specifications.

Rated Power	*Hub Height*	*Rotor Diameter*	*Blade Length*
12 MW	136 m	222 m	107 m[a]

Source: Musial et al. 2019

[a] Blade length based on GE Haliade-X 12 MW turbine (GE, 2019)

Figure 1-2. Power curve for 12 MW turbine, adapted from Musial et al. (2019).

1.2.3 Turbine Layout

Turbines are assumed to be spaced at least seven rotor-diameters (7D) apart, following Musial et al. (2016a). Based on conversations with developers, the spacing was increased to 10D in the direction of predominant winds to minimize wake effects and conflicts. Turbine rows are offset to increase the packing density while maintaining the 7Dx10D spacing (Figure 1-3, top view).

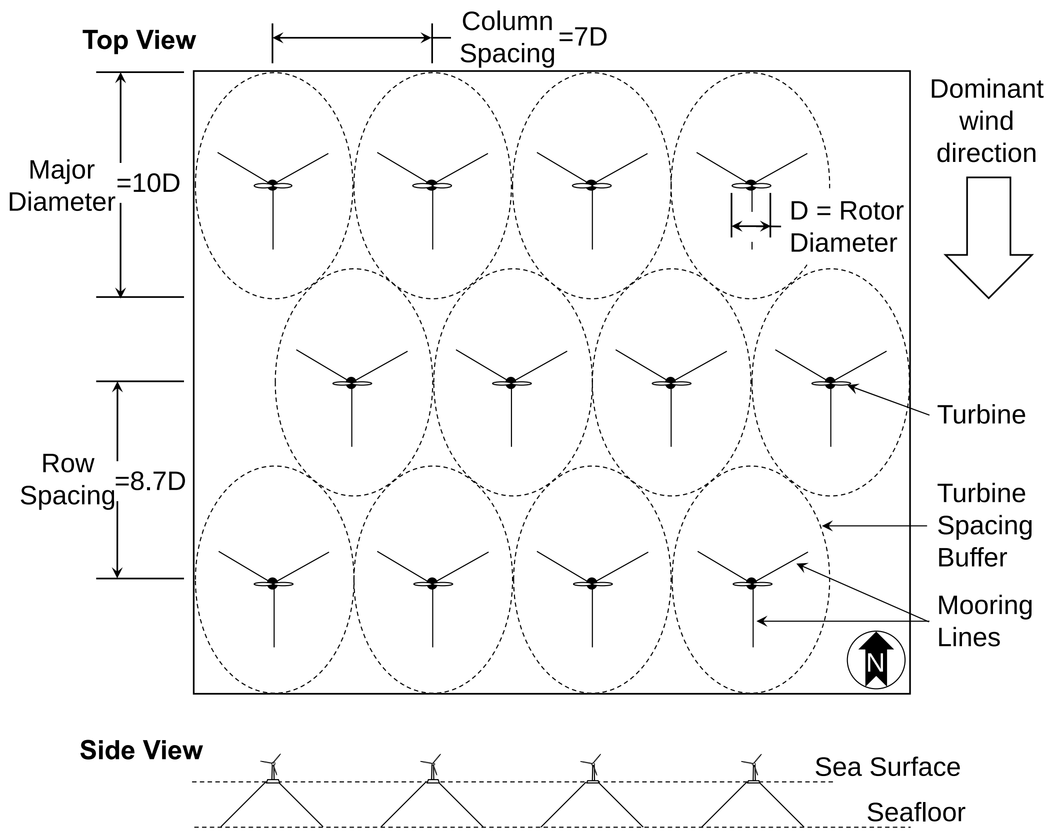

Figure 1-3. Turbine spacing and layout for an example 144 MW array using 12x 12 MW turbines. The top view of the array shows the horizontal spacing (top) and the side view shows the vertical profile (bottom).

The 1,800 MW, full build out scenario involves placing floating turbines in deep water. Mooring lines, which connect the floating substructure to the seafloor, spread out horizontally from the substructure and attach to the seafloor with anchors (Figure 1-3, side view). Turbines should be spaced such that mooring lines from adjacent turbines do not overlap to avoid damage during installation or operation. Deeper water requires longer mooring lines that extend further away from the floating platform and could extend beyond the 7Dx10D turbine spacing. Following Copping and Grear (2018, page C.2), we assuming a 45-degree mooring line angle relative to the sea surface; this leads to the radius of the mooring system being equal to the ocean depth. This assumption applies to both semi-taut and catenary mooring systems, although a catenary mooring line will extend further on the seafloor further making initial contact after 45 degrees. Using the spread from this assumed mooring system, mooring lines from adjacent turbines would start overlapping at an ocean depth of 918 m. To avoid overlapping morring lines, the spacing of turbines is increased in waters deeper than 918 m (see the turbine layouts in Appendix B). Lastly, the turbines are spaced around the perimeter of the wind farm such that the mooring lines do not extend beyond the boundary of the area.

2. METHODS

The analytical methods and data sources for the resource assessment and transmission compatibility are provided in this section.

2.1 Data sources

Data sources and citations are provided in the subsections below.

2.1.1 Bathymetry

Bathymetric raster data near the Humboldt Call Area originated from the General Bathymetric Chart for the Oceans global ocean terrain model (GEBCO, 2019). The data resolution is in 15 arc-second intervals.

2.1.2 Modeled Wind Speed

The wind speed and direction data used for this analysis originated from the National Renewable Energy Laboratory's (NREL) Wind Integration National Dataset (WIND) Toolkit (Draxl et al., 2015). Data are available at 100 meters above mean sea level at hourly resolution for a seven-year period of record. The dataset has a spatial resolution of 2 km by 2 km grid cells. Within the dataset, 122 points fall within the Humboldt Call Area and 129 coordinates fall within the Cape Mendocino Area. The WIND Toolkit data is the largest wind integration dataset publicly available and has been validated with observational data from all over the United States (Draxl et al. 2015). Wang et al. (2019) compared and validated several offshore wind speed datasets and found that the WIND Toolkit was the best available data for California.

2.1.3 Measured Wind Speed

Measured wind data were available for buoy station 46022 operated by the National Data Buoy Center (NOAA, 2018), at coordinates (40.712 °N, 124.529 °W) and a height of 4 meters above sea level. This data was used for comparison and validation of the WIND Toolkit estimates simulated for coordinates (40.716747 °N, 124.529144 °W) at a height of 100 m above sea level. WIND Toolkit estimates were created for the entire period of record from 2007-2013, which match a period available for the buoy. Buoy data were missing 7.2% of individual records, with significant variance in missing records year to year, between 0.6% in 2007 and 53% in 2010. Buoy data were used to validate the accuracy of the modeled wind speed data (see Appendix C).

2.2 Analysis Methods

The techniques and assumptions used to analyze the data are presented in this section.

2.2.1 Spatial Averaging

Instead of averaging wind speed values for every coordinate of data inside the area, WIND Toolkit data for the coordinate closest to the centroid (40.960258 °N, -124.6492 °W for the BOEM Call Area and 40.095638°N, -124.485748°W for Cape Mendocino area) of the area was used for the analysis (see Appendix D for validation). Time series wind speed data for 100 m elevation above mean sea level for this coordinate was sorted by year, month, day, hour, and wind speed and direction.

2.2.2 Median Annual Wind Speed Profile

Offshore wind speed data are available from 2007 to 2013. Rather than model the average values between each year, a median wind speed year was selected to model power generation. This allows the analysis to take into account the actual variability of the resource compared to using the average values from all seven years, which would smooth out any fluctuations. A median wind speed was calculated for each year separately and compared with the median wind speed for the entire seven-year span.

2.2.3 Adjusting Height of Wind Speed Data

Wind speed data need to be adjusted to the hub height of the turbine (136 m) to evaluate the performance of the wind turbine. The modeled wind speeds data at 100 meters were corrected to the hub height using the wind shear equation (Equation 1) and a wind shear exponent (α) of 0.1, which is typical for open waters (Masters, 2013).

$$U = U_0\left(\frac{h}{h_0}\right)^{\alpha} \qquad \textit{(Equation 1)}$$

where:

U = wind speed at height h = 136 m
U_0 = wind speed at height h_0 = 100 m
α = wind shear exponent = 0.1

2.2.4 Power Output Calculation

The turbine's power curve was used to calculate the nominal (i.e., zero losses) power output based on the modeled wind speed at 136 m. The power curve presented by NREL (Musial et al., 2019) provided the power output for each integer wind speed. Linear interpolation between each integer was used to calculate the power for the exact wind speed at every hour of available data.

2.2.5 Power Losses

All wind turbines are subject to performance losses, as a result of environment, energy management, and system design. The total turbine efficiency is determined as the sequential product of one minus each of these individual loss factors, as shown in (Equation 2):

$$Total\ Efficiency = \prod_{i=1}^{n}(1 - Loss\ Factor_i) \qquad \textit{(Equation 2)}$$

There are two types of losses applied to the power estimates: proportional losses and down-time (shut-off) losses. Proportional losses affect the entire system and reduce the power output proportionally due to causes such as wake effects, electrical efficiencies, and turbine performance. Down-time losses cause turbines to individually shut-off and cause the power output to be zero, due to factors such as curtailment, high wind control hysteresis, and site access limitations.

Most of the loss factor values were taken either from industry values obtained from AWS Truepower (2014) or Musial et al. (2016a, b). Wake effect losses were modeled using the Eddy-Viscosity method (as recommended in Churchfield, 2013) and calculated using NREL's System Advisor Model (SAM), Beta Version 2019.12.2.

Wake loss factors are shown in Table 1-3. The total percent of proportional losses and shut-off losses disregarding wake effects was 6.4% and 7.3%, respectively (see list of all loss factors in Table 1-4). To model the shut-off losses, 7.3% of the time, the power output data was set to zero at randomly selected times throughout the year. The random application of these losses should best represent the unexpected nature of failures and grid outages. After shut-off losses were applied, the remaining 6.4% of proportional losses (such as efficiency losses) are removed from the power output along with the site-specific wake loss factors (Table 1-3).

Table 1-3. Loss factors due to wake losses. Wake losses change based on location and wind farm scale.

Scenario	*Power Loss due to Wake*
HB-50	0.03%
HB-150	1.07%
HB-1800	2.41%
CM-150	0.89%
CM-1800	1.61%

Table 1-4. Power loss factors

Loss Category	*Loss Origin*	*Loss Factor*	*Depends On*	*Effect on Model*
Wake Effect	Internal Wake Effect of the Project [a]	Varies	Wind farm scale and density, see Table 1-3	Even reduction
	Wake Effect of Existing or Planned Projects [a]	0.0%		Even reduction
Availability	Contractual Turbine Availability [a]	3.0%	O&M plan; Proven reliability/ newness of turbine	Turn to 0 MW
	Non-contractual Turbine Availability [a]	1.3%		
	Availability Correlation with High Wind Events [a]	1.3%	Frequency of high wind events	Turn to 0 MW
	Availability of Collection & Substation [a]	0.2%	Timing of substation downtime	Turn to 0 MW
	Availability of Utility Grid [a]	0.3%	Timing of grid blackouts	Turn to 0 MW
	Plant Re-start after Grid outages [a]	0.2%	Timing of grid blackouts	Turn to 0 MW
	First-Year Plant Availability [a]	0.0%		
Electrical	Electrical Efficiency [a]	2.0%	Distance between turbines and substation	Even reduction
	Power Consumption of Weather Package [a]	0.1%		Even reduction
Turbine Performance	Sub-optimal operation [a]	1.0%		Even reduction
	Power Curve Adjustment [a]	2.4%		Even reduction
	High Wind Control Hysteresis	1.0%	Wind regime at site; turbine model	Turn to 0 MW
	Inclined Flow [a]	0.0%		Even reduction
Environmental	Icing [a]	0.0%*	Temperature	Turn to 0 MW
	Blade Degradation [a]	1.0%		Even reduction
	Low/High Temperature Shutdown [b]	0.0%*	Temperature, turbine limits	Turn to 0 MW
	Site Access [a]	0.1%	O&M plan, availability of parts, staff, vessels	Turn to 0 MW
	Lightning [b]	0.1%		Turn to 0 MW
Curtailments	Directional Curtailment [a]	0.0%	Layout and spacing	Turn to 0 MW
	Environmental Curtailment [a]	0.0%	Local environmental regulation	Turn to 0 MW
	PPA Curtailment [a]	0.0%	Wind farm scale and density	Turn to 0 MW
	Pre-Wake Total	**13.2%**		

[a] AWS Truepower (2014)
[b] Musial et al. (2016a, b)
* Adjusted to 0 to account for mild northern California temperatures

3. RESULTS

The results from the resource assessment are presented below and include analyses of wind speed and power generation patterns.

3.1 Wind Speed Distribution

The cumulative distribution function of wind speeds for both sites are shown in Figure 1-4. The Notional Mendocino Area consistently provides higher wind speeds than the Humboldt Call Area. The histograms of wind speed (Figure 1-5) show the frequency of occurrence of each wind speed. The Humboldt Call Area has a noticeable Weibull distribution, which is common for wind regimes, with the most frequent wind speeds at 11 m/s and a long tail of high wind speeds at low probability. The Cape Mendocino location wind speed profile has fairly consistent probability of occurrence between 3 m/s and 20 m/s with a sharp decline above 20 m/s.

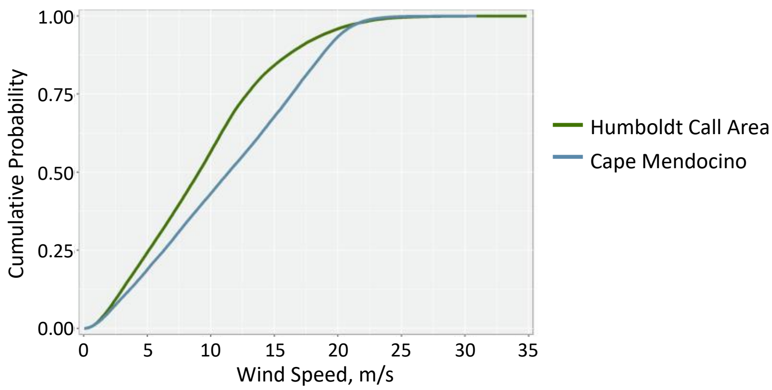

Figure 1-4: Cumulative probability density function of wind speed in both locations.

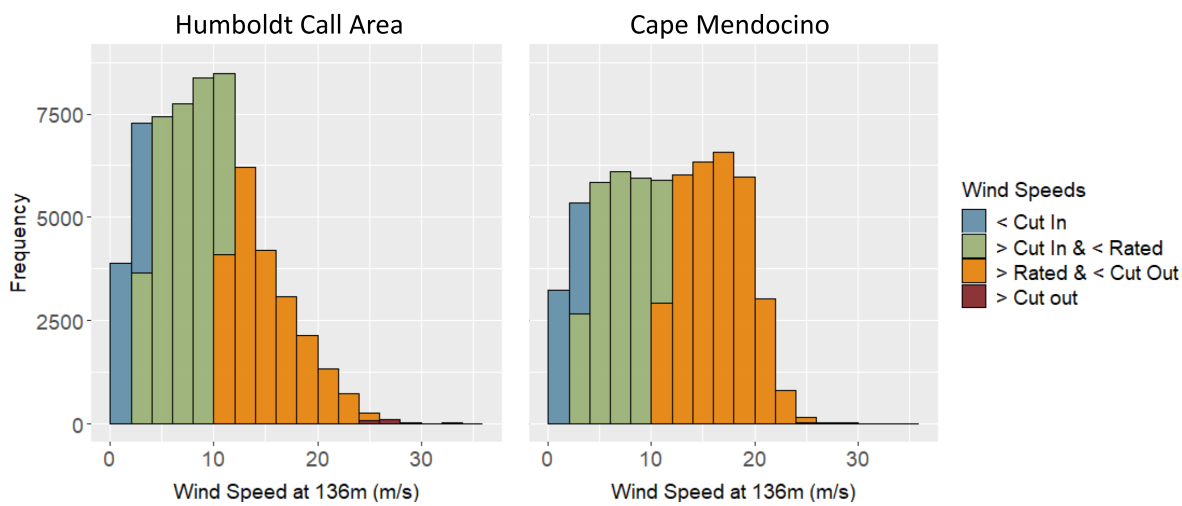

Figure 1-5. Histograms of wind speed and frequency of occurrence for Humboldt Call Area (left) and Cape Mendocino (right). The y-axis is frequency of occurrence of hours in the seven-year period of record.

The distribution of wind speed varies by month and season (Figure 1-6). The Humboldt Call Area has a fairly consistent distribution of wind speeds for each month of the year with more wind speeds between 10 and 15 m/s in the summer months (May, June, July, and August). The Cape Mendocino area has greater variation between months, with a greater fraction of high wind speeds occurring in the summer months compared to the other months which have a consistent distribution of wind speed between 0 and 17 m/s.

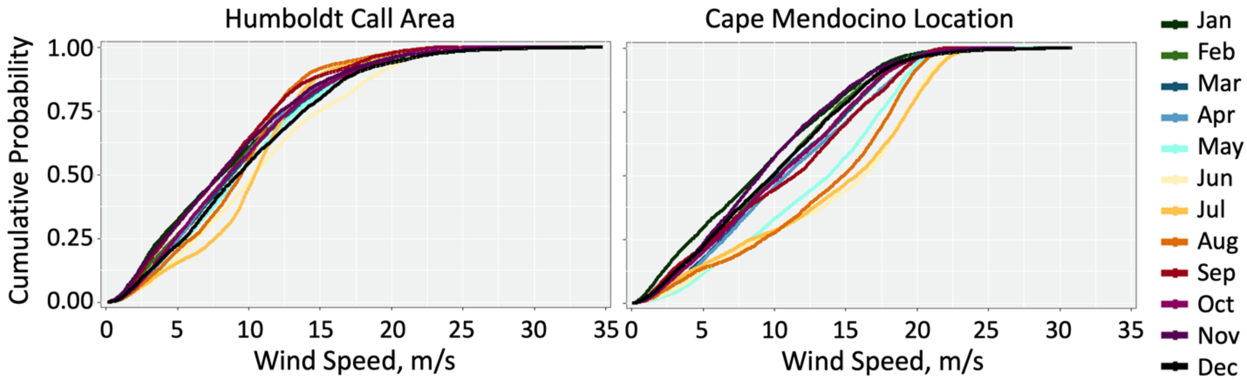

Figure 1-6. Cumulative distribution function of wind speed by month at both locations.

3.2 Wind Speed Direction and Velocity

Wind roses from the Humboldt Call Area (Figure 1-7) and Notional Cape Mendocino area (Figure 1-8) show a bi-directional wind pattern with predominant winds from the North. Both areas experience the highest wind speeds in the winter from the south and south-south-east, respectively. The wind roses below separate the wind speeds into four categories, based on the power curve of the turbine:

- Below cut in speed: 0 to 3 m/s; No power output because wind turbine is not spinning
- Increasing power output: 3 to 11 m/s; power output increases with wind speed
- Rated wind speed: 11 to 25 m/s: Power production is constant at rated power output
- Above cut out speed: 25 + m/s; No power output because wind speed is too high

Wind speeds in the Humboldt Call Area are between 3 to 11 m/s for the majority of the time (51.5%). The rated power output will be produced 35.8% of the time, and no power will be produced 12.9% of the time due to low wind speed (12.2%) and high wind speeds (0.5%). Wind is predominately from the north all year round, especially in the spring and summer. During the fall and winter, southern winds are also common. Winds from the west and east are rare.

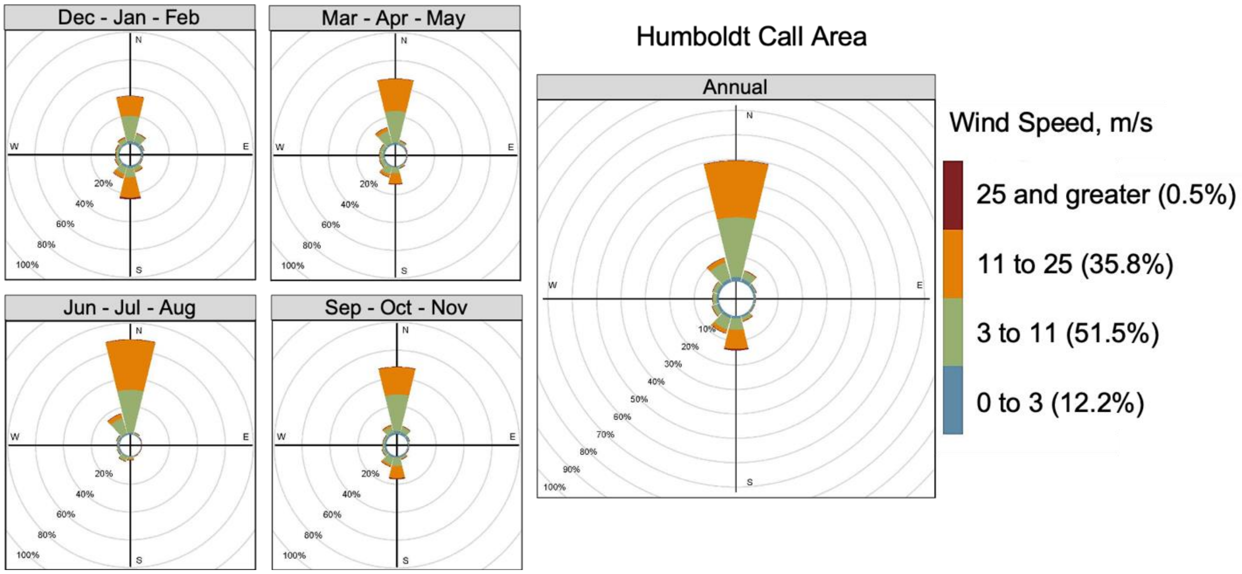

Figure 1-7. Wind rose for the Humboldt Call Area annually (right) and by season (left). Percentages on the radial axis represent the percent of time the wind speeds occurred.

Wind speeds in the Notional Cape Mendocino Area are in the rated wind speed area for the majority of the year (51.8%) from 11 to 25 m/s. No power will be produced 9.9% of the time due to low wind speed (9.7%) and high wind speeds (0.2%). Wind is predominately from the north all year round, especially in the spring and summer. During the fall and winter, high winds coming from the south-south-east are common. Wind from the west and east are rare.

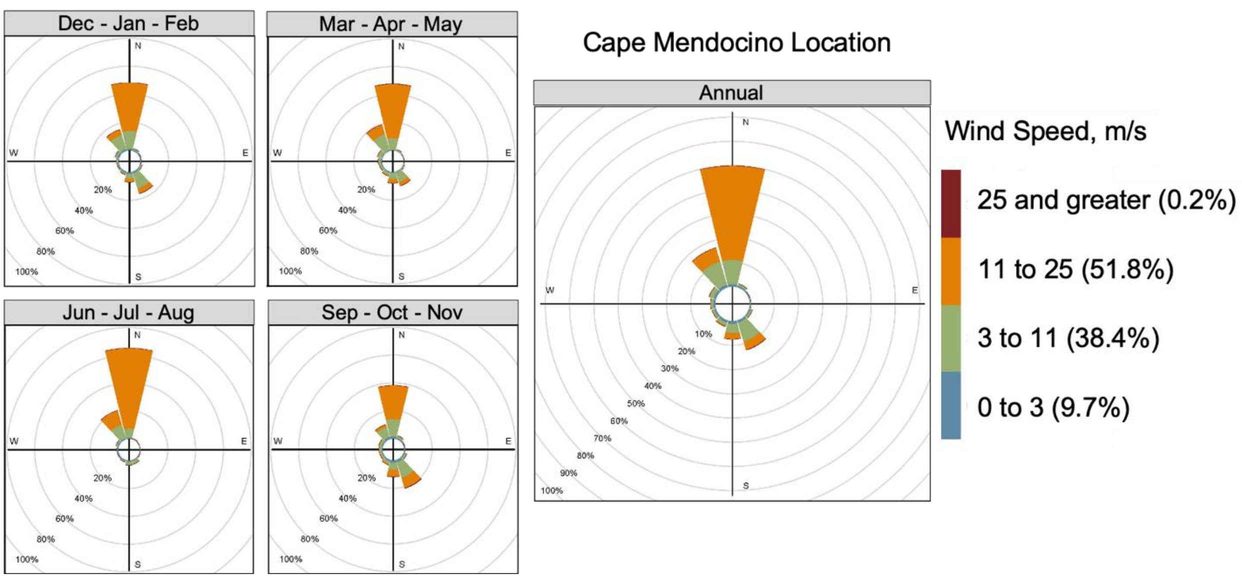

Figure 1-8: Wind roses for Mendocino area – by season and annual average.

3.3 Wind Speed Variability

This section looks at the variability of wind speed from between years, seasons, and hour of day. From the seven-year period of modeled data, the annual median wind speed can vary between years by 1 m/s in Cape Mendocino and 1.5 m/s in the Humboldt Call Area (Figure 1-9). The median wind years were identified as 2008 and 2009 for Cape Mendocino and the Humboldt Call Area, respectfully. The wind speed profile from the median year will be used as the typical representative annual profile for the energy analysis below.

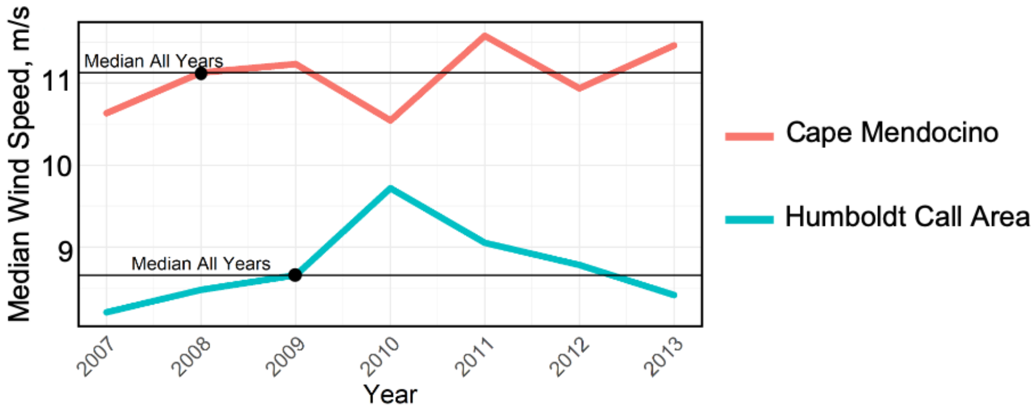

Figure 1-9. Results of median wind speed year analysis for Humboldt Bay. Note the y-axis does not include 0 m/s.

Daily profiles of wind speed change with seasonal weather patterns. On average throughout the year, the Humboldt Call Area receives the lowest wind speed between 5 and 8 p.m. and rises to its maximum at midnight (Figure 1-10, right). Seasonal minimums and maximums follow this trend for winter, spring, and fall, but during the summer winds are the strongest between 8 a.m. and 12 p.m. and fall to the minimum overnight (Figure 1-10, left). The wind speed profiles from the seven-year period of record show variation in magnitude up to 1.5 m/s average annual hourly wind speed, but each year displays a similar daily pattern during each season.

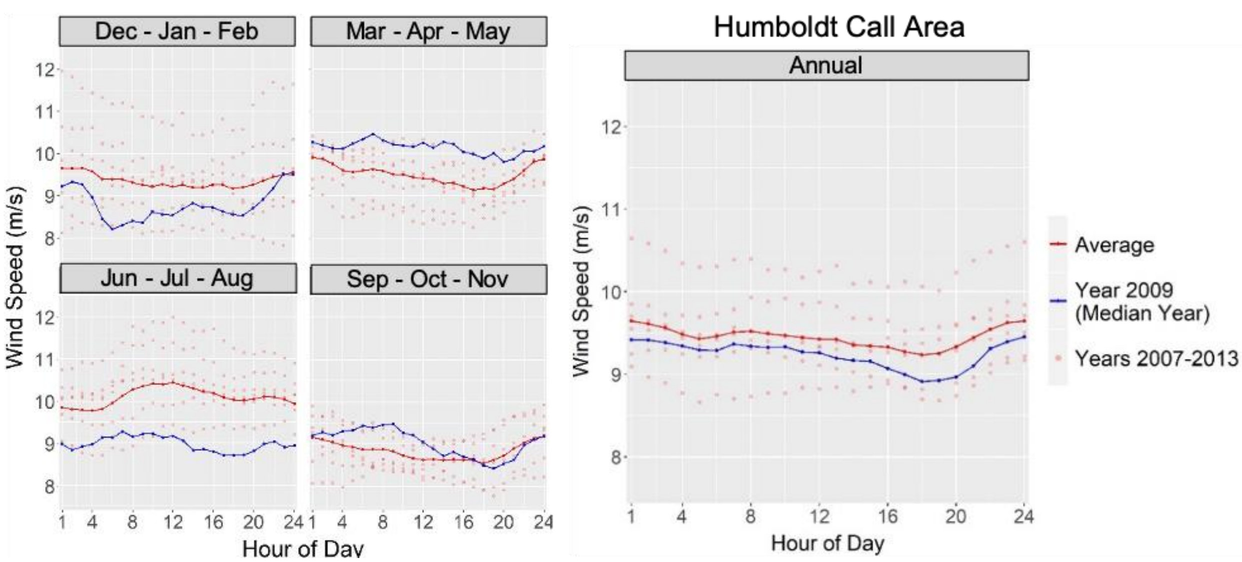

Figure 1-10. Daily profile of average wind speed for the year (right) and by season (left) for the Humboldt Call Area. The dots represent data averaged for each of the seven years with the average and median years highlighted in red and blue, respectively.

At the Notional Cape Mendocino location, seasonal changes are more significant, but there is less year-to-year variation in wind speed. Similar to the Humboldt Call Area, the minimum daily wind speed occurs in the evening between 5 and 8 p.m. (Figure 1-11, right). The maximum daily wind speed typically occurs just after midnight, between 2 and 4 a.m. Each season displays a similar daily profile, with greater peaks and valleys in the summer and a flatter profile in the winter months (Figure 1-11, left).

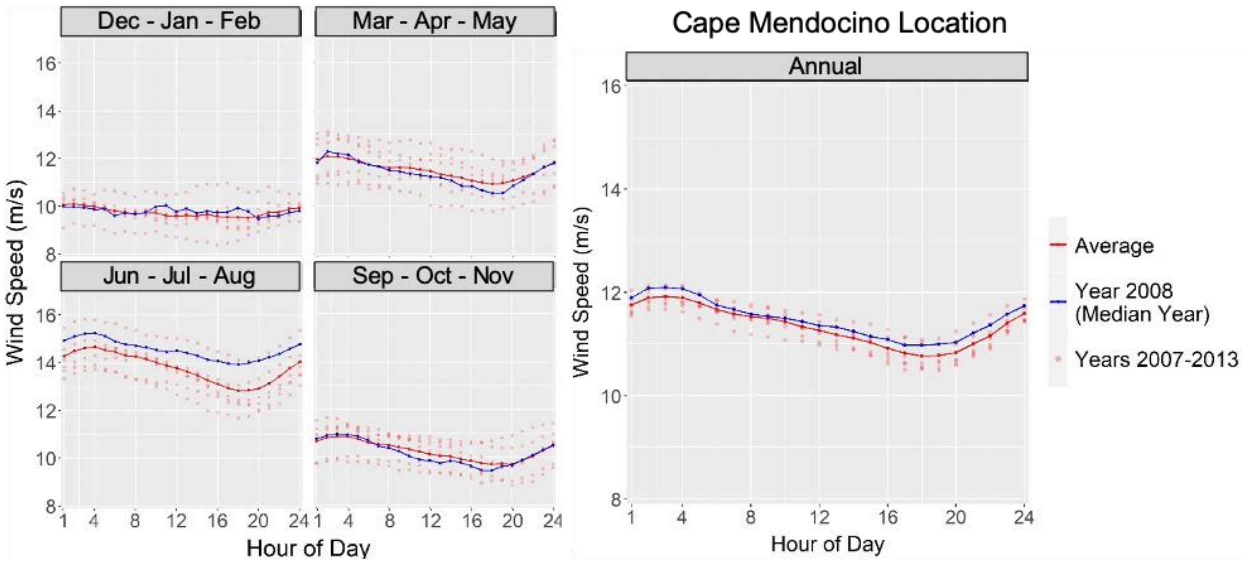

Figure 1-11: Daily profile of average wind speed for the year (right) and by season (left) for the Cape Mendocino location. The dots represent data averaged for each of the seven years with the average and median years highlighted in red and blue, respectively.

The average hourly wind speeds by season for both the Humboldt Call Area and the Cape Mendocino location are showed together on one graph in Appendix E, Figure 1-23 for comparison.

3.4 Power Generation

Power generation profiles for the different wind farm scenarios are calculated after taking into account all loss factors. The annual energy production (Table 1-5) leads to capacity factors (Table 1-6) for all five scenarios that range from 47% to 48% for the Humboldt Call Area to 56% to 57% for the Cape Mendocino Area for the typical year. Interannual variation of power production is greater in the Humboldt Call Area than the Cape Mendocino Area (6% compared to 2% coefficient of variation). The capacity factors of larger wind farms are slightly lower than small wind farms due to increased wake effects within larger turbine arrays.

Table 1-5. Annual energy production (AEP) for five wind farm scenarios. Bold values indicate the median wind speed year.

	Annual Energy Production, GWh/yr				
Year	*HB-50*	*HB-150*	*HB-1800*	*CM-150*	CM-1800
2007	192	571	7,180	713	9,020
2008	203	602	7,574	**717**	**9,074**
2009	**202**	**599**	**7,540**	720	9,119
2010	228	678	8,522	720	9,115
2011	216	642	8,078	740	9,361
2012	204	605	7,601	716	9,062
2013	199	590	7,426	743	9,410
Standard Deviation	12	36	450	12	154
Coefficient of Variation	5.8%	5.8%	5.8%	1.7%	1.7%

Table 1-6. Capacity factor (CF) for five wind farm scenarios. Bold values indicate the median wind speed year.

	Capacity Factor				
Year	*HB-50*	*HB-150*	*HB-1800*	*CM-150*	*CM-1800*
2007	46%	45%	45%	57%	56%
2008	48%	48%	47%	**57%**	**56%**
2009	**48%**	**47%**	**47%**	57%	57%
2010	54%	54%	53%	57%	57%
2011	51%	51%	50%	59%	58%
2012	49%	48%	47%	57%	56%
2013	47%	47%	46%	59%	59%

The annual energy production and capacity factor provide a description of how the wind turbine arrays will perform when summed across the whole year. A generation duration curve is used to investigate how the level of power production varies throughout the year. The generation duration curves for the Humboldt Call Area and the Notional Cape Mendocino Area show the power output on the vertical axis and the cumulative number of hours per year when the wind farm is operating at that power output or above on the horizontal axis (Figure 1-12). For all scenarios, the wind farms operate are often operating at their maximum capacity or at zero power output, as shown in the horizontal portions of the lines on the left and right of the plots, respectively. The amount of time operating at the maximum power output corresponds to the amount of time that the wind speed is in the turbine's rated wind speed range from 11 to 25 m/s. The amount of time that the wind farm is at zero power output corresponds to times when the wind speed is less than 3 m/s or the turbines are at 0 MW output based on the loss factors described in Table 1-4.

The wind farms in the Humboldt Call Area will run at full power for an estimated 2,850 hours or 33% of the year and will produce no power for an estimated 1,670 hours or 19% of the year. Hypothetical wind farms in the Cape Mendocino Area would product full power more frequently and zero power less frequently due to a more favorable wind speed distribution. The farms in Cape Mendocino would operate at maximum power for 4,220 hours or 48% of the year and will produce no power for an estimated 1,370 hours or 16% of the year. For all scenarios, the most striking feature of the generation duration curves is that they produce either full power or no power for over 50% of the year; during the remaining time, power output for each turbine is between 0 and 12 MW.

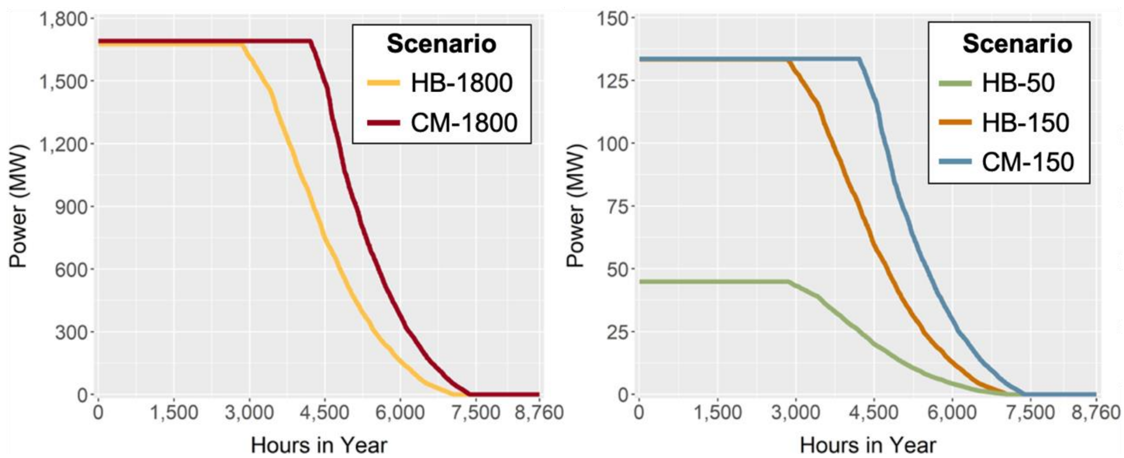

Figure 1-12. Generation duration curves for all project scenarios. The 1,800 MW scenarios are on the left, and the 150 MW and 50 MW scenarios are shown in the right graphic. Note the difference in power scales between the two graphs.

The generation duration curve varies slightly between years but maintains the same shape as the typical year. Annual variation in power production is greater at the Humboldt Call Area than the Cape Mendocino location (see Appendix F, Figure 1-24 and Figure 1-25, respectively). Generation duration curves for individual scenarios are provided in Appendix G.

To illustrate what this power portfolio looks like during normal operation, the power production time series for three example weeks is shown in Figure 1-13. The graphic shows period of low generation, high generation, and variable generation for the HB-150 scenario during example weeks in early July of 2008 and 2009. During the low generation period, the wind speed is consistently below the cut in speed and the array produces little to no power for a week. In the following high generation period, the wind farm is typically operating at the rated wind speed and produces near maximum power for the whole week. Lastly, the variable scenario shows a time series where the wind fluctuates between the cut in and rated wind speeds.

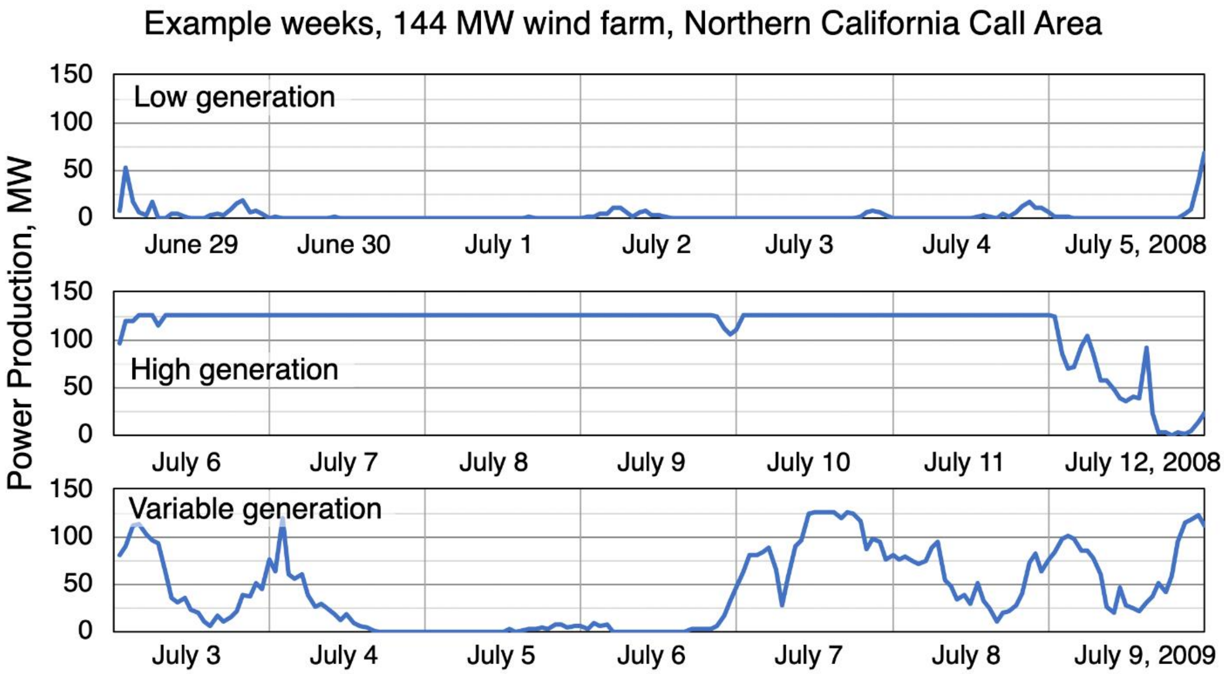

Figure 1-13: Variability of diurnal patterns of power production for three different weeks.

The power generation time series are useful to help understand how the wind farm can interact with the transmission grid. Wind generation can vary greatly from day-to-day and week-to-week. The low and high generation days are typical for the spring and summer. However, during the late fall and winter power generation can fluctuate quickly between maximum power output and zero power output when the wind speeds exceed the cut out speed of the turbine. Although the wind speeds only exceed the cut out velocity 0.5% of the time in the Humboldt Call Area and 0.2% of the time in the Cape Mendocino location, this can have a significant impact on grid operators when the spikes above 25 m/s and the entire wind farm must shut down for several hours until it is safe to restart.

The hourly distribution of the power output from wind farms changes by season. Figure 1-14 and Figure 1-15 show the frequency of different power output levels for the 150 MW scenarios. Each line represents a different percent likelihood of occurrence, specifically 10%, 25%, 50% (the median), 75%, and 90%. The green dashed line, at the interface between the blue and green range, shows the median power output or 50th percentile and the solid line represents the average. Half of the time power output will be above this level and half of the time it will be below this level. The power generation that corresponds to the area between the 25% and 75% lines would also occur 50% of the time.

Most notable, the hourly distribution plots show the extreme spread between the maximum and minimum power output. In all season, the 75th percentile extends to the maximum output, indicating that 25% of the time the wind array is at maximum capacity. Even further, the 50th percentile reaches the maximum output for the entire day during the summer in Cape Mendocino. On the bottom of each chart, the 10th percentile always rests at 0 MW output, and in many hours, the 25th percentile is also at 0 MW. One main takeaway from these charts is that power is bipolarly distributed between the maximum and minimum at all hours of the day.

Given that the capacity factors for the 150 MW and 1,800 MW alternatives are nearly the same, we would expect the hourly power generation profile plots shown in Figure 1-14 and Figure 1-15 to essentially scale proportionally between them.

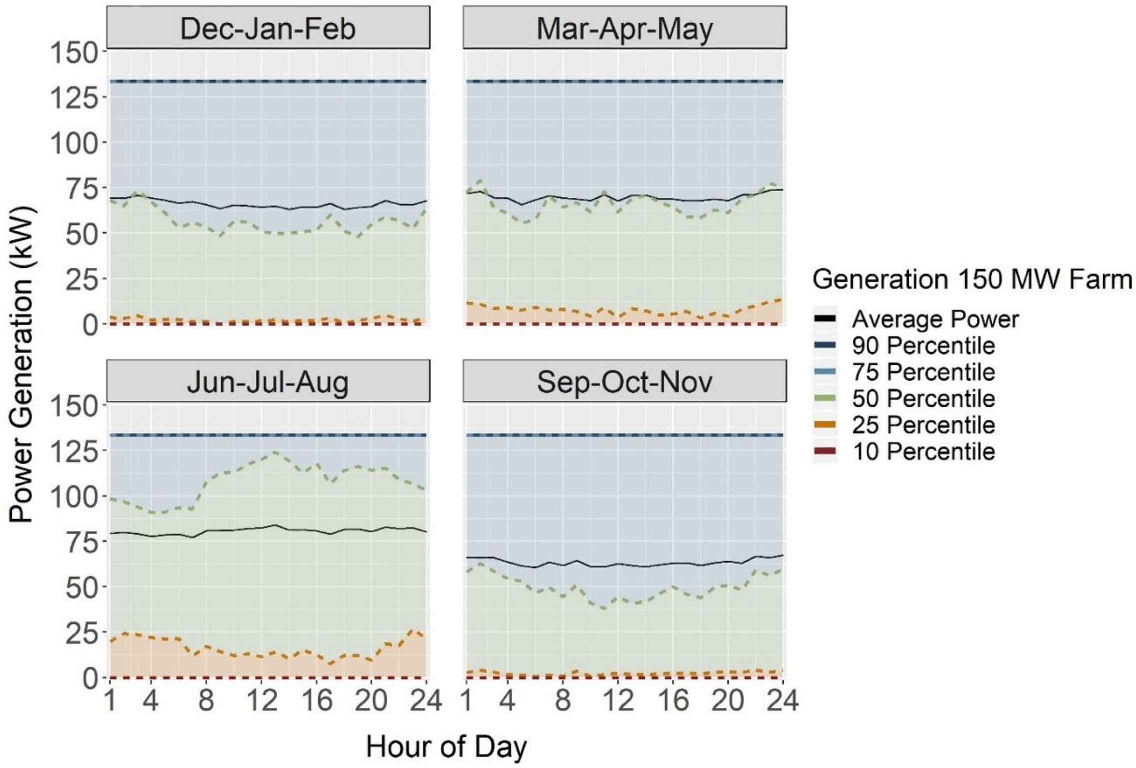

Figure 1-14: Hourly power generation of the 150 MW farm in the Humboldt call area by season.

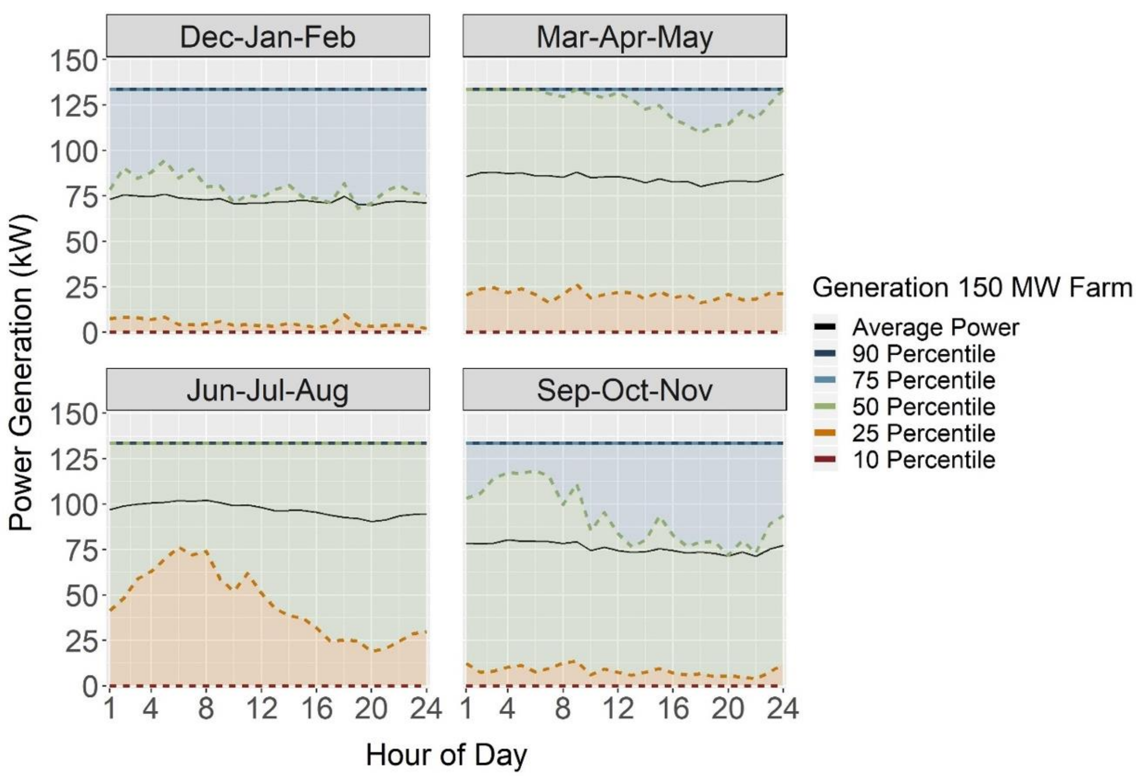

Figure 1-15: Hourly power generation of the 150 MW farm in the Mendocino area by season.

4. DISCUSSION

Analysis of the wind speed and power production profile indicate that the northern California coast could be host to productive wind farms with capacity factors near or exceeding 50%. The wind speed resource in the Cape Mendocino location is more favorable from a power generation standpoint than the Humboldt Call Area because the wind speed distribution better matches the power curve of offshore wind turbines. However, this location is only analyzed for comparative purposes only and there are economic disadvantages because the distance from port and the distance to an interconnection point will increase the costs for installation, maintenance, and electric cable costs for transmission back to shore. Furthermore, this location has not been screened by any ocean user community and is not representative of a BOEM call area. BOEM has not indicated any interest in this representative area for wind development. A forthcoming economic analysis will evaluate the tradeoffs between power production and distance to port and interconnection.

Analysis of the wind speed patterns in northern California show that wind farms will frequently produce power at their rated capacity but also have a large fraction of time when there is no power production. This generation profile may have implications for how offshore wind can be integrated into wider California electricity markets depending on the predictability and time of generation. Forthcoming analyses will include an assessment of how offshore wind is compatible with Humboldt County and state-wide electric demand and the cost and extent of transmission upgrades that would be required to support this generation.

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APPENDIX 1.A - STUDY LOCATIONS

This section provides additional geographical specifications about the Humboldt Call Area and the Cape Mendocino notional area (Table 1-7). The bathymetric profiles of both locations are shown in Figure 1-16 and Figure 1-17.

Table 1-7. Geographic specifications of study locations.

		BOEM Northern California Call Area	*Hypothetical Cape Mendocino Area*
General area		Offshore Humboldt Bay	Offshore Cape Mendocino
West-East width		12 NM (22 km)	14 NM (25 km)
North-South width		25 NM (46 km)	15 NM (29 km)
Total area		207 mi^2 (537 km^2)	155.25 NM^2 (532.5 km^2)
Perimeter		81 NM (150 km)	55.6 NM (103 km)
Centroid location	Lat.	-124.662°	-124.496°
	Lon.	40.965°	40.090°
Distance to shore	Min.	17.4 NM (32.2 km)	3.1 NM (5.70 km)
	Max.	30.4 NM (56.3 km)	20.0 NM (37.0 km)
Average annual wind speed at 90 m height	Min.	8.875 m/s	9.625 m/s
	Mean	9.35 m/s	9.875 m/s
	Max.	9.875 m/s	10.125 m/s
Ocean depth	Min.	1,640 ft (500 m)	328 ft (100 m)
	Mean	2,673 ft (815 m)	2,140 ft (652 m)
	Max.	3,610 ft (1,100 m)	3,610 ft (1,100 m)
Construction and maintenance port	Name	Redwood Marine Terminal 1	
	Lat.	40.817°	
	Lon.	-124.182°	
Centroid to port distance, approximate ship route		27 NM (50 km)	55.5 NM (103 km)
Interconnection point	Name	Humboldt Bay Generating Station	
	Lat.	40.742°	
	Lon.	-124.211°	
Centroid to interconnection point distance, approximate cable route		25 NM (46 km)	45 NM (83 km)

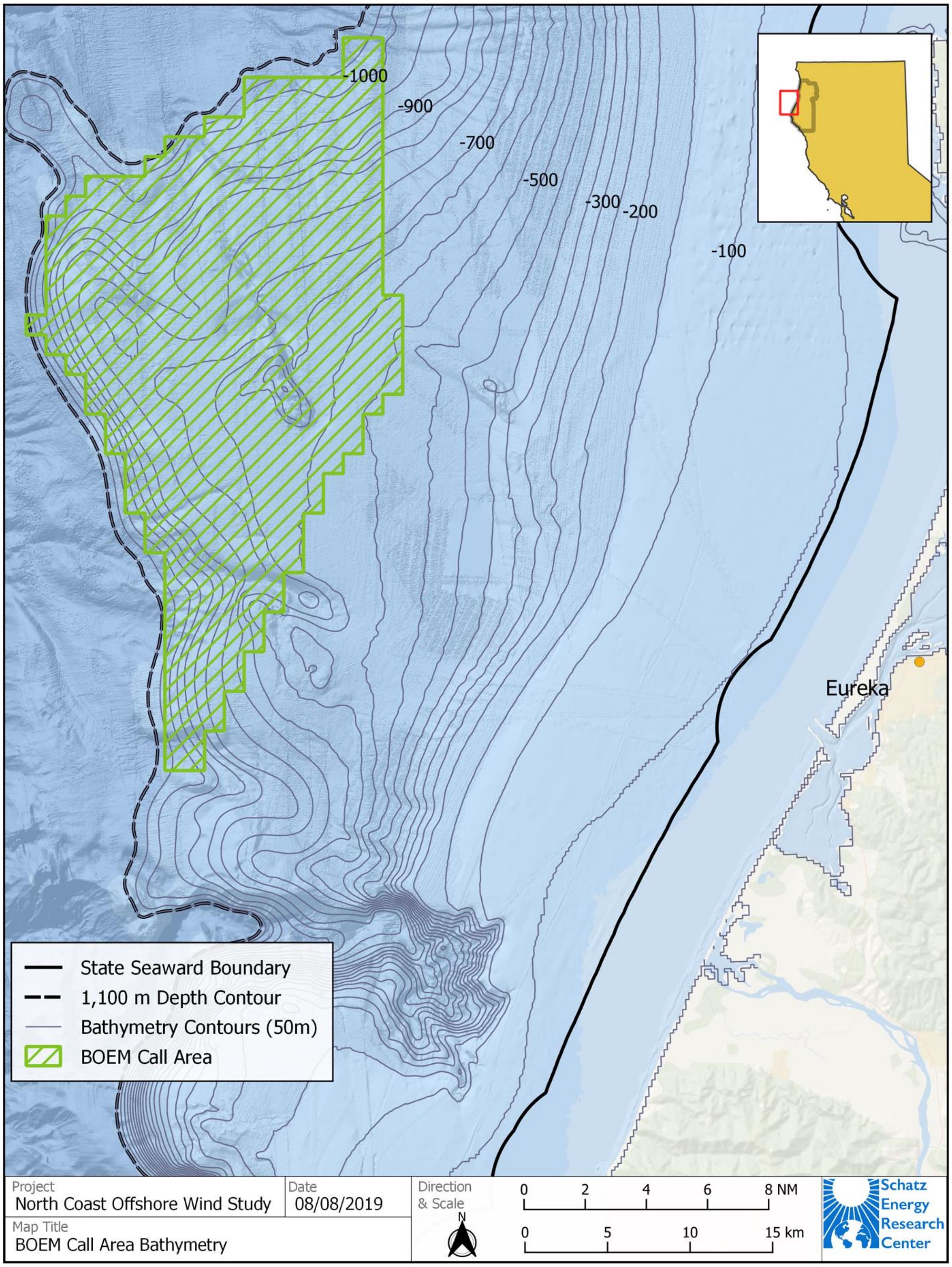

Figure 1-16. Northern California Call Area with 50 m bathymetric contours.

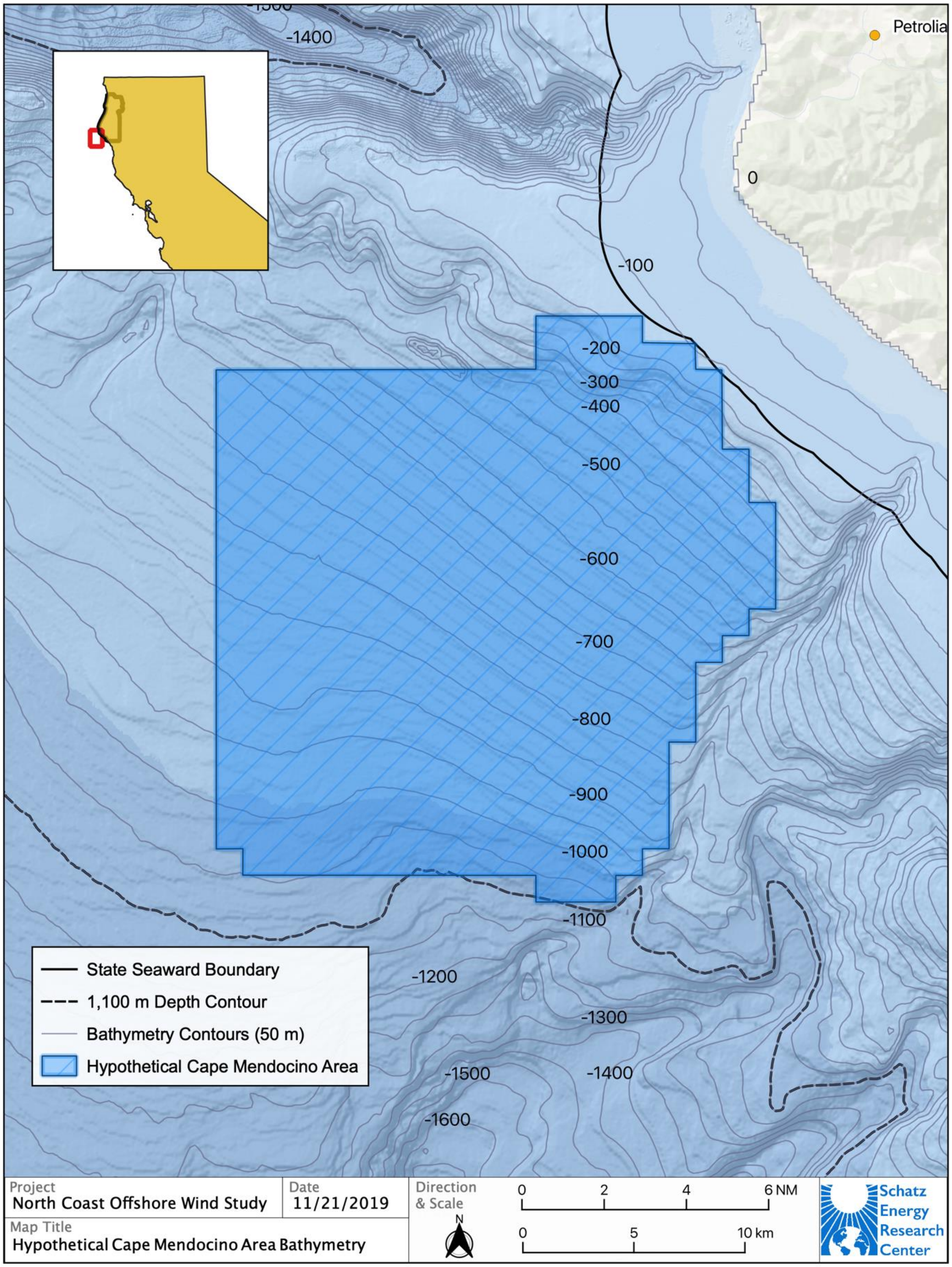

Figure 1-17. Notional Cape Mendocino area with 50 m bathymetric contours.

APPENDIX 1.B - TURBINE LAYOUTS AND SPACING

Turbine placement, spacing, and mooring line footprint for the nominal 1,800 MW scenarios are shown in Figure 1-18 for the Humboldt Call Area and Figure 1-19 for the notional Cape Mendocino location.

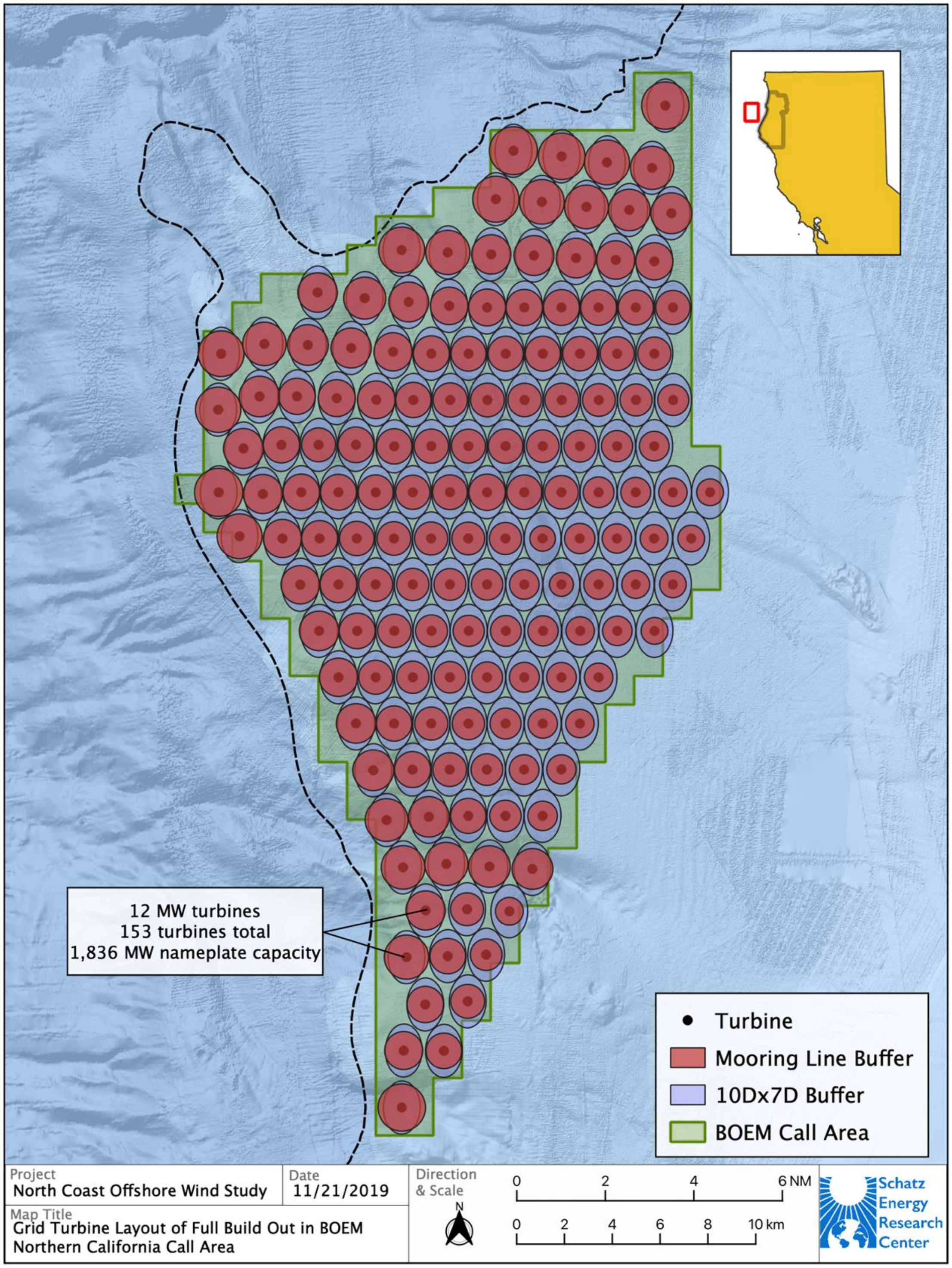

Figure 1-18. Grid turbine layout of the full-build out scenario in the Humboldt Call Area.

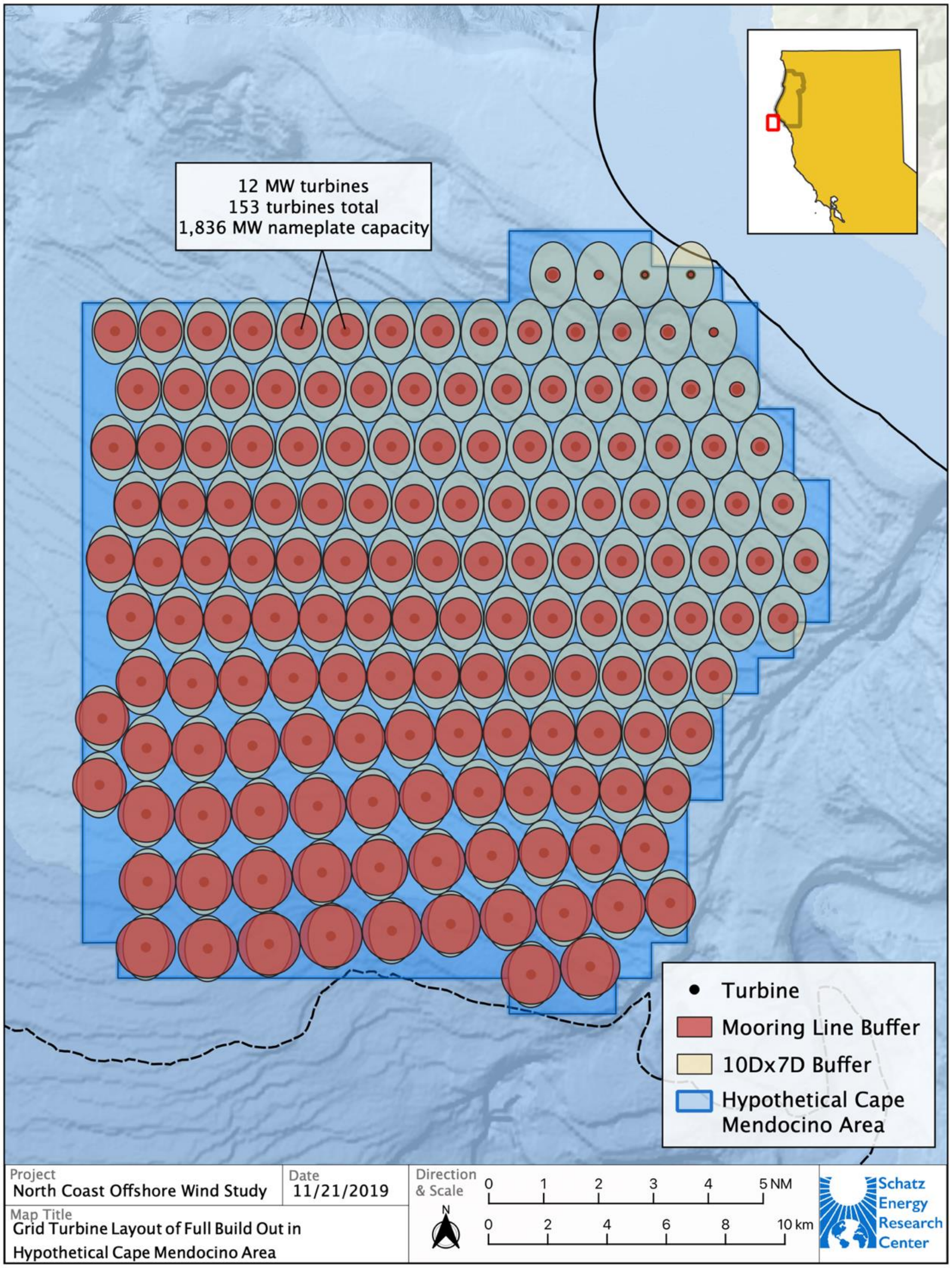

Figure 1-19. Grid turbine layout of the full build out scenario in the Mendocino Area.

APPENDIX 1.C - MODELED WIND SPEED VALIDATION FROM SURFACE BUOYS

The objective of this study was to validate the accuracy of the modeled wind speeds by using measured data from a surface buoy. Measured wind data were available for buoy station 46022 operated by the National Data Buoy Center (NOAA, 2018), at coordinates (40.712 °N, 124.529 °W) and a height of 4 meters above sea level. Modeled wind data originated from the National Renewable Energy Laboratory's (NREL) Wind Integration National Dataset (WIND) Toolkit at a height of 100 meters above mean sea level and coordinates (40.716747 °N, 124.529144 °W) (Draxl et al., 2015).

In order to compare two wind speed datasets, they first need to be adjusted to the same height. The modeled WINDToolkit data are available at 100 m height above the sea surface, so the measured buoy data were adjusted to that height. Buoy wind speed data, which are available from surface measurements at 4 meter above the sea surface, were extrapolated to a height of 100 m according to wind shear power law equation (C-1):

$$\text{Buoy 100m wind speed} = \text{Buoy 4m wind speed} \cdot \left[\frac{100m}{4m}\right]^{\alpha} \qquad \text{(C-1)}$$

using a wind shear coefficient (α) of 0.1, which is typical for a vertical wind profile over open waters (Masters, 2013)

Wind roses were then created which show similarity in terms of wind speed and directional distribution (Figure 1-20).

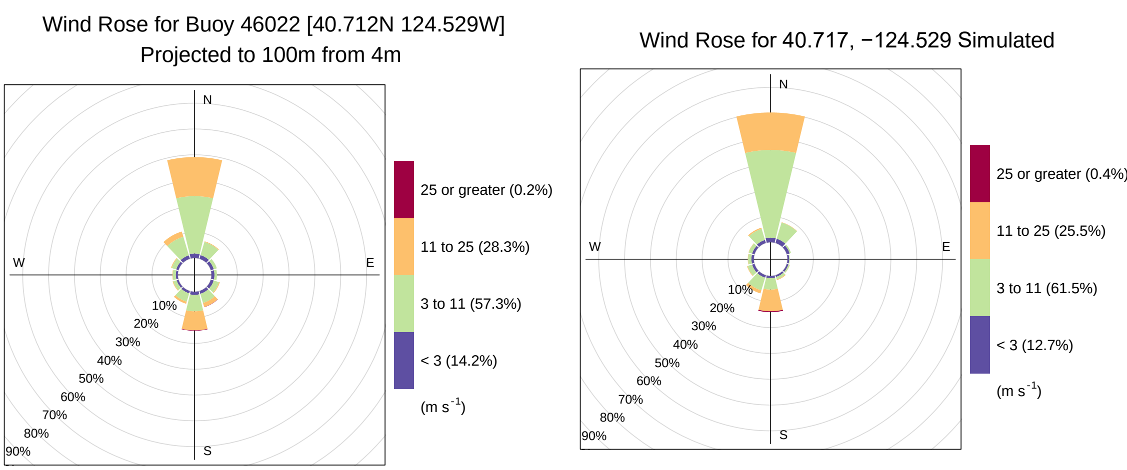

Figure 1-20. Wind rose based on buoy data for the period of record (2007-2013) (left) and wind rose based on modeled data for the same time period (right)

Shear Coefficient

In order to compare the datasets in a more quantitative way, the following process was employed:

First a new shear coefficient, α was calculated from these data according to the following equation (C-2):

$$\alpha = \frac{ln\left[\frac{mean(simulated100mwindspeed)}{mean(buoy4mwindspeed)}\right]}{ln\left[\frac{100m}{4m}\right]} \qquad \text{(C-2)}$$

This value was found to be $\alpha = 0.1028945$, less than 3% different from the standard shear coefficient of 0.1 used for calculations over open water. An extrapolated buoy wind speed at 100 m was then calculated according to equation (1) with the updated α value. This calculated wind speed was used to compare to the buoy data for all future analyses.

1.C.1 Cumulative Distribution Function

A cumulative distribution function of the two datasets is shown below in Figure 1-21. Based on this result, wind speed distribution was concluded to be similar for the simulated and measured data.

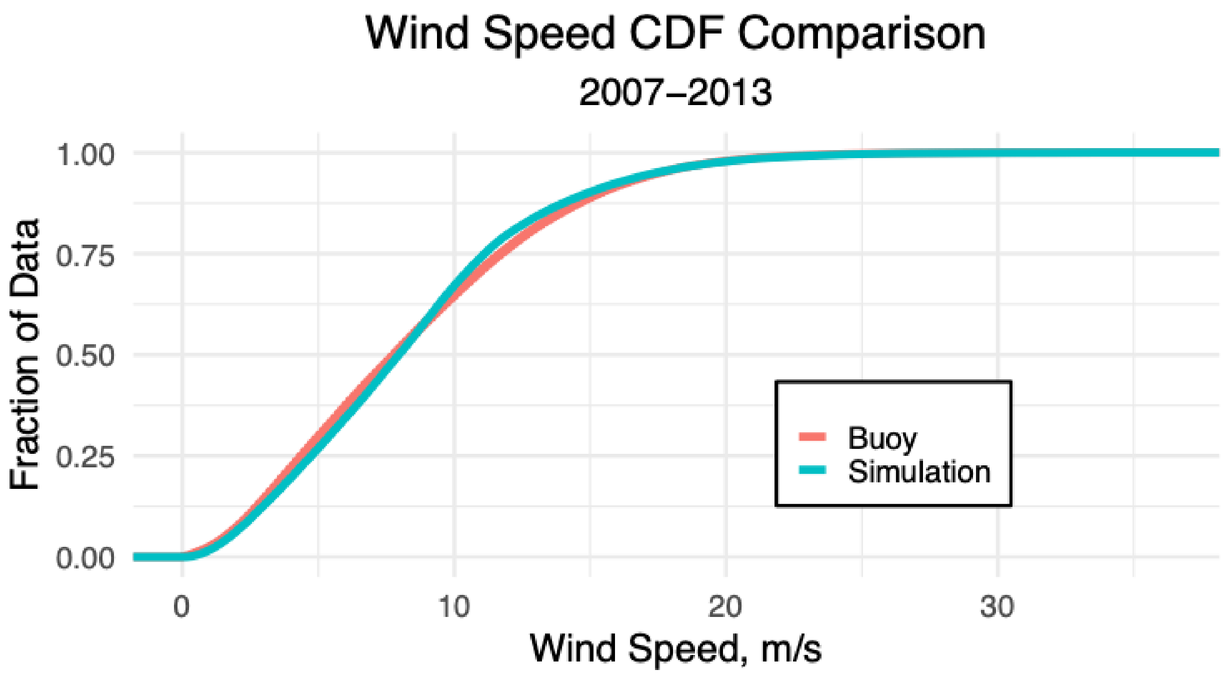

Figure 1-21. Wind speed cumulative distribution function comparison of the simulated and measured data sets over the period of record. Measured data are scaled according to equation (C-1) using be α = 0.1028945.

Additional descriptive characteristics for comparison are given in Table 1-8 and Table 1-9. KS values are calculated from a two variable two sample KS test, with the two variables being wind speed and wind direction (Peacock, 1983).

Based on the typical value of the shear coefficient, α correlating the two data sets as well as the similarities of the wind rose (Figure 1-20), the cumulative distribution functions (Figure 1-21), and the descriptive statistics in general (Table 1-8 and Table 1-9), the simulated data is concluded to be adequately similar to the measured data for use in this analysis.

Table 1-8. Descriptive statistics by year and for entire period of record.

s	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*Period of Record*
n, Buoy	52,224	48,720	47,796	24,900	33,402	41,798	43,998	292,838
n, Simulation	8760	8784	8760	8760	8760	8784	8760	61368
$\bar{x}$, Buoy (m/s)	7.995	8.38	8.01	9.405	9.007	8.833	8.014	8.419
$\bar{x}$, Simulation (m/s)	7.96	8.21	8.193	9.332	8.536	8.581	8.122	8.419
median, Buoy (m/s)	7.381	7.799	7.242	8.634	8.774	8.217	7.242	7.799
median, Simulation (m/s)	7.556	7.697	7.761	8.798	8.142	7.978	7.756	7.962
S_x, Buoy (m/s)	4.915	5.013	4.971	5.635	4.705	5.258	4.662	5.019
S_x, Simulation (m/s)	4.662	4.719	4.768	5.177	4.651	5.169	4.463	4.827
< 3 m/s, Buoy	17%	15%	17%	12%	10%	12%	14%	14%
< 3 m/s, Simulation	14%	13%	14%	11%	11%	13%	13%	13%
3-11 m/s, Buoy	56%	57%	56%	52%	57%	57%	58%	56%
3-11 m/s, Simulation	63%	64%	60%	56%	65%	62%	60%	62%
11-25 m/s, Buoy	27%	28%	28%	36%	33%	30%	27%	29%
11-25 m/s, Simulation	22%	23%	25%	33%	24%	24%	26%	26%
> 25 m/s, Buoy	0%	0%	0%	1%	0%	1%	0%	0%
> 25 m/s, Simulation	1%	0%	0%	0%	0%	1%	0%	0%
KS Statistic D	0.133	0.106	0.096	0.175	0.218	0.158	0.185	-
n1 for KS test	8760	8784	8760	8760	8760	8784	8760	-
n2 for KS test	8704	8120	7966	4150	5567	6966	7333	-
$P(>Z_\infty)$	1.2E-61	8.3E-37	2.0E-29	1.2E-69	7.3E-134	2.0E-78	4.3E-112	-

Table 1-9. Descriptive statistics by month.

Statistic	*January*	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*
n, Buoy	29,600	26,628	25,812	20,964	22,092	21,282	26,016	25,980	25,692	26,406	20,856	21,510
n, Simulation	5208	4752	5208	5040	5208	5040	5208	5208	5040	5208	5040	5208
$\bar{x}$, Buoy (m/s)	8.887	9.534	9.283	8.708	8.731	8.37	7.897	6.704	6.432	7.732	8.611	10.538
$\bar{x}$, Simulation (m/s)	8.223	8.642	9.051	8.557	8.683	8.998	8.223	7.713	7.128	8.377	8.14	9.287
median, Buoy (m/s)	8.077	9.052	8.913	8.495	8.495	7.938	7.66	6.128	5.71	6.545	7.799	9.888
median, Simulation (m/s)	7.102	7.982	8.316	7.942	8.394	8.878	8.715	7.843	6.824	7.459	7.073	8.325
Sx, Buoy (m/s)	5.684	5.164	5.017	4.764	4.735	4.407	4.188	3.881	4.1	5.005	5.434	5.949
Sx, Simulation (m/s)	5.771	5.214	5.332	4.662	4.304	4.267	3.258	3.374	3.876	5.062	5.556	5.91
< 3 m/s, Buoy	15%	10%	11%	13%	13%	12%	14%	18%	22%	18%	15%	9%
< 3 m/s, Simulation	21%	15%	12%	11%	8%	8%	8%	9%	15%	12%	19%	14%
3-11 m/s, Buoy	51%	53%	54%	55%	55%	58%	62%	66%	62%	58%	55%	48%
3-11 m/s, Simulation	50%	54%	57%	60%	65%	63%	74%	79%	70%	61%	54%	50%
11-25 m/s, Buoy	34%	37%	36%	33%	32%	30%	25%	16%	15%	25%	30%	42%
11-25 m/s, Simulation	28%	31%	31%	29%	27%	29%	18%	13%	14%	26%	26%	35%
> 25 m/s, Buoy	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%
> 25 m/s, Simulation	1%	0%	1%	0%	0%	0%	0%	0%	0%	0%	1%	1%
KS Statistic D	0.157	0.15	0.12	0.089	0.089	0.134	0.174	0.213	0.195	0.185	0.161	0.211
n1 for KS test	5208	4752	5208	5040	5208	5040	5208	5208	5040	5208	5040	5208
n2 for KS test	4933	4438	4302	3494	3682	3547	4336	4330	4282	4401	3476	3585
$P(>Z_\infty)$	1.2E-49	1.2E-40	6.1E-26	9.2E-12	2.4E-12	7.6E-29	1.9E-57	9.7E-88	2.3E-71	6.7E-66	3.9E-42	5.3E-77

APPENDIX 1.D - SPATIAL AVERAGING: USING THE CENTROID TO REPRESENT AN AREA

The objective of this study is to confirm the assumption made throughout this report that a single site containing wind speed data can be used to represent larger wind farm installations.

Throughout the analysis, we place a single 10 MW wind turbine at select data points on the 2 km grid and scale that 10 MW capacity to meet certain proportions of electric load. This assumes the upscaled capacity will occupy that single data point and the wind resource for that capacity will be the same as at the point. In reality, gigawatt scale power cannot occupy that small of an area. Therefore, we will confirm that using a single point may act as an adequate indicator for a wind farm that would spread into surrounding area

We examined five different wind farm sizes: 10 MW, 100 MW, 500 MW, 1 GW, and 10 GW at the Cape Mendocino Area (Figure 1-22). The wind resource at this site is very good and there are enough data points to place any of these size farms. However, since the data points are on a 2 km by 2 km grid, it was assumed that turbines could be placed between data points and the in-between wind resource would not vary significantly from nearby points. For the wind installations of interest, the number of data points used are given in Table 1-10.

Table 1-10. Number of data points used to represent various wind farm capacities.

Wind Farm Capacity	*Number of Data Points*
10 MW	1
100 MW	5
500 MW	15
1,000 MW	25
10,000 MW	255

We examined wind farms near Cape Mendocino, since that is the location of the highest average annual wind speed on the northern California coast (Figure 1-22). Seven-year averages of the capacity factor and availability (proportion of time the turbine is producing power) were examined to determine if an expanded wind farm area differs from the capacity at the centroid of the area (Table 1-11). Between 10 MW to 1,000 MW there was a calculated absolute difference of 0.1% in the capacity factor, which is a negligible difference. Scaling even further to a 10,000 MW wind farm estimated from the wind resource at a single point showed a 0.78% absolute difference in capacity factor. The availability was not noticeably affected by the wind farm size between 10 MW and 10,000 MW.

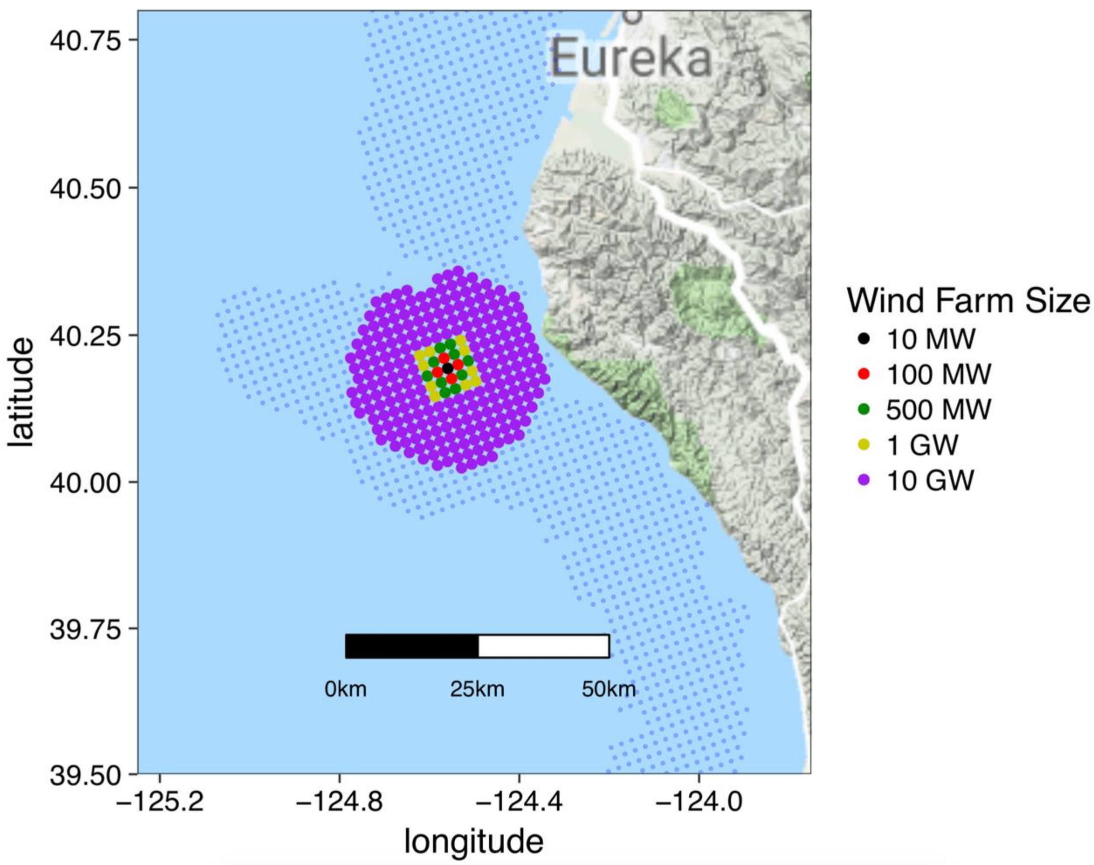

Figure 1-22: Wind farm sizes in Cape Mendocino ranging from 10 MW to 10 GW. Larger capacities also encompass the points used to display previous capacities in other colors.

Table 1-11: Wind farms at Cape Mendocino ranging from 10 MW to 10 GW. The metrics do not significantly differ between farm capacities.

Wind Farm Capacity	*Capacity Factor*	*Availability*
10 MW	66.4%	90.5%
100 MW	66.4%	90.5%
500 MW	66.4%	90.5%
1,000 MW	66.3%	90.5%
10,000 MW	65.8%	90.4%

In conclusion, the capacity factors calculated when using wind speed data from the centroid of a 10 MW wind farm through a 10,000 MW wind farm showed a difference of 0.78% in the capacity factor. The maximum range of interest in this study is 1,836 MW, where there will be even less difference from the extrapolation of the wind speed data area

APPENDIX 1.E - SEASONAL AVERAGE WIND SPEED PROFILES

The average hourly wind speeds by season for both the Humboldt Call Area and the Cape Mendocino location are showed in Figure 1-23 for comparison. The average wind speed in Cape Mendocino is higher at all hours of each season, with the biggest difference in the summer (Table 1-12).

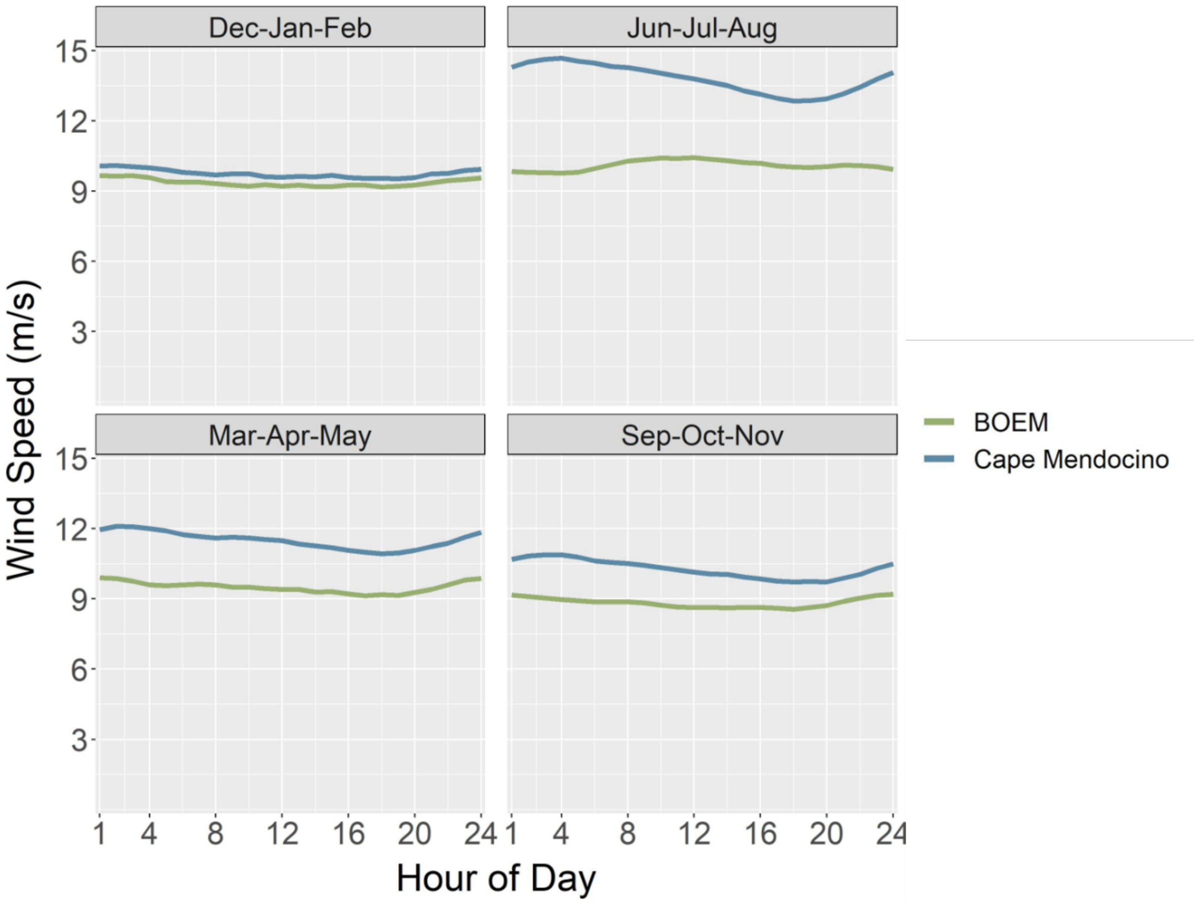

Figure 1-23. Average hourly wind speed profiles by season for both locations.

Table 1-12. Percent difference between seasonal average wind speeds in two locations.

		Average Wind Speed		
Season	*Months*	*Humboldt Call Area*	*Cape Mendocino*	*Percent Difference*
Winter	Dec, Jan, Feb	9.4	9.8	4%
Spring	Mar, Apr, May	9.5	11.5	19%
Summer	Jun, Jul, Aug	10.1	13.8	31%
Fall	Sep, Oct, Nov	8.8	10.3	16%

APPENDIX 1.F - GENERATION DURATION CURVE FOR ALL YEARS OF RECORD

Generation duration curves are presented here for the nominal 150 MW wind farms located in the Humboldt Call Area (Figure 1-24) and the Notional Cape Mendocino Area (Figure 1-25). The generation duration curve between years varies slightly, but maintains the same shape for each year. Annual variation in power production is greater at the Humboldt Call Area than the Cape Mendocino location.

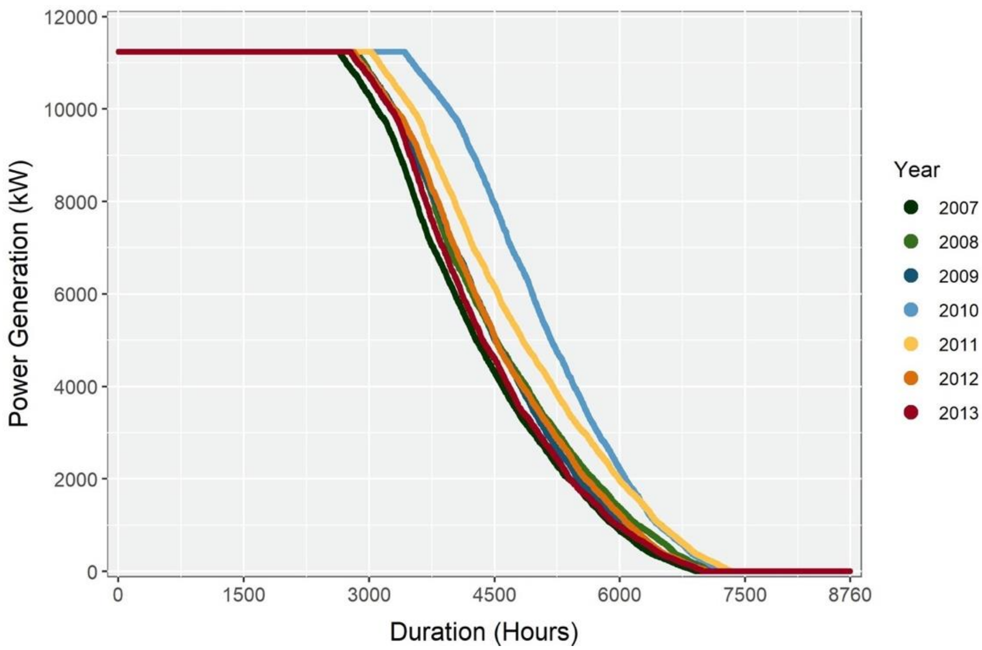

Figure 1-24. Generation duration curve for the entire period of wind speed records in the Humboldt Call Area.

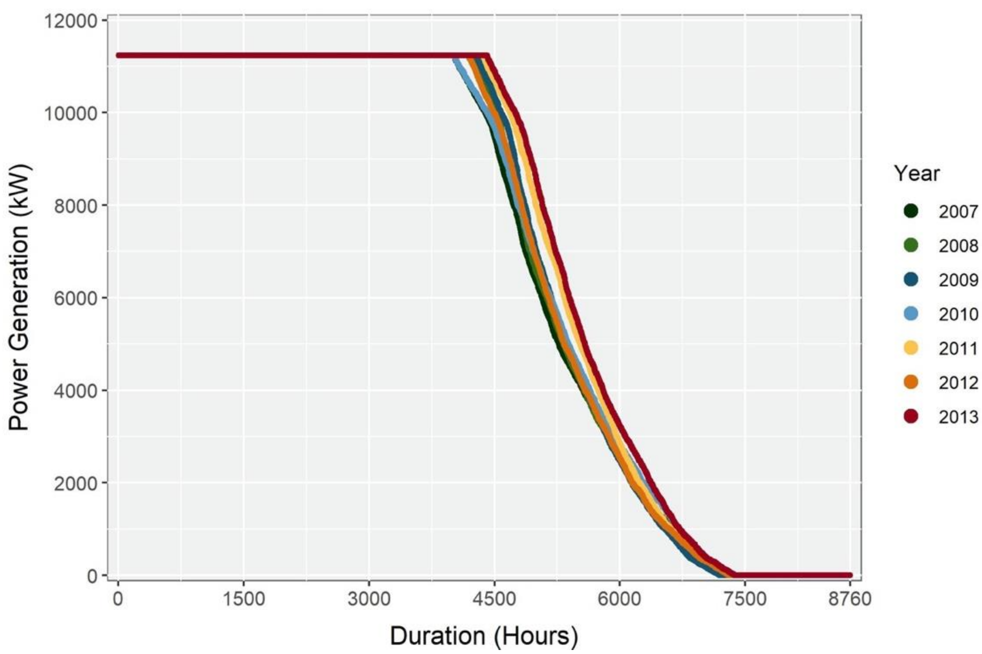

Figure 1-25. Generation duration curve for the entire period of wind speed records in the Cape Mendocino location.

APPENDIX 1.G - GENERATION DURATION CURVES FOR INDIVIDUAL SCENARIOS

The generation duration curves for the Humboldt Call Area scenarios are provided in . The generation duration curves for the Cape Mendocino location are provided in Figure 1-26 and Figure 1-27.

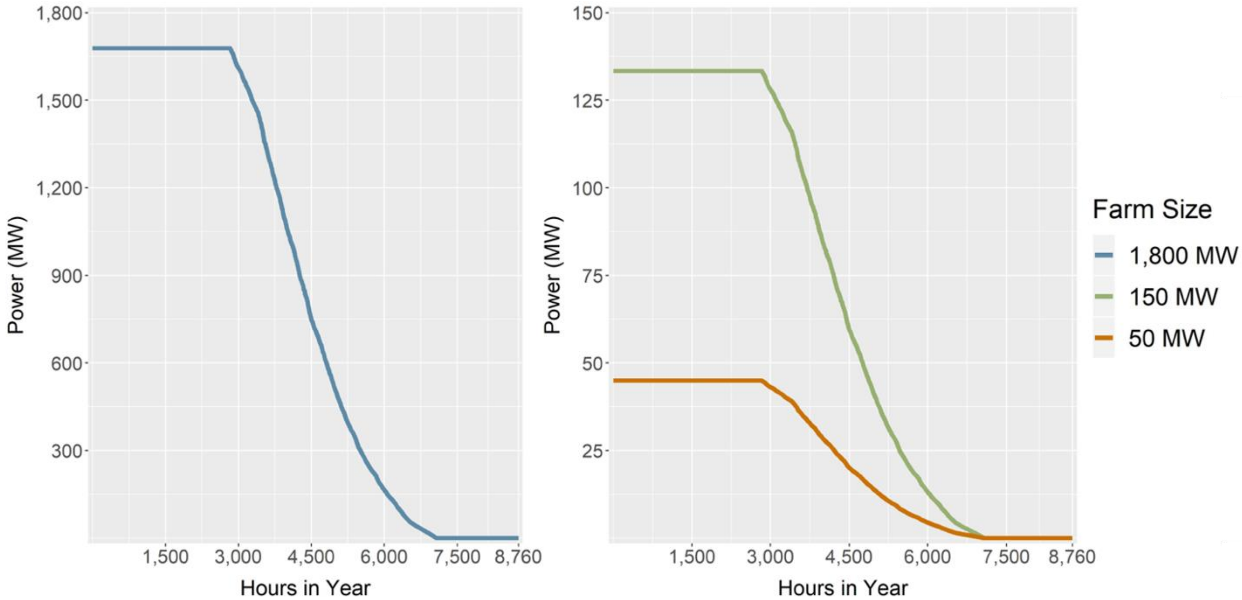

Figure 1-26. Humboldt Call Area generation duration curves for 1,800 MW scenario (left) and 150 MW and 50 MW scenario (right).

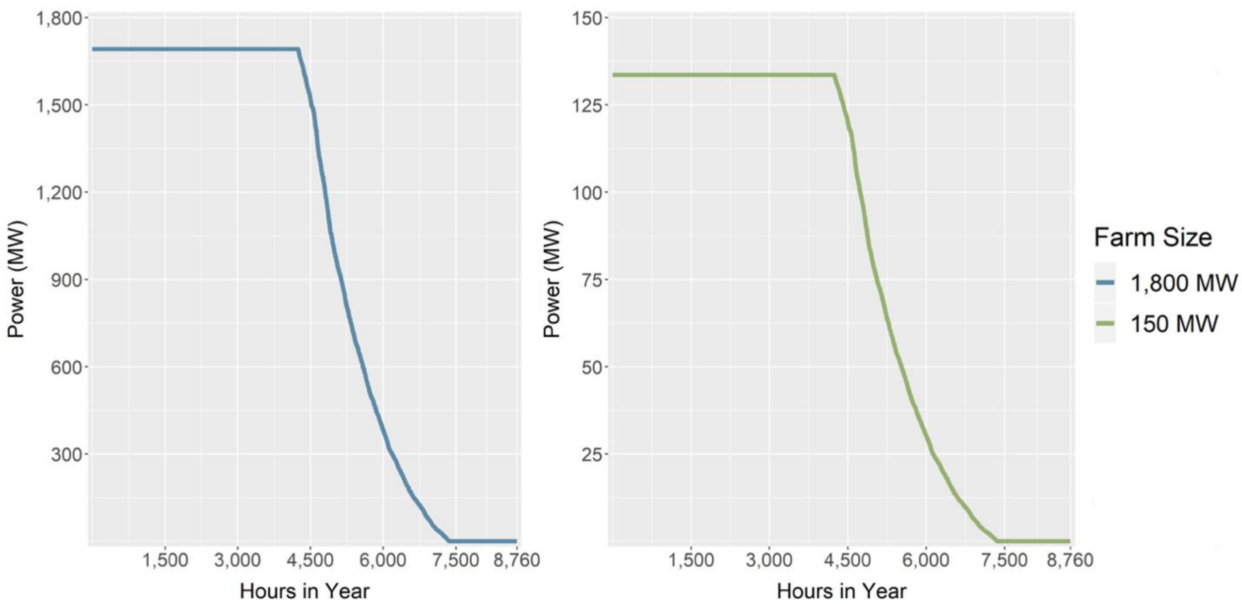

Figure 1-27. Cape Mendocino generation duration curves for 1,800 MW scenario (left) and 150 MW scenario (right).

APPENDIX 1.H - AVERAGE HOURLY POWER OUTPUT

The average hourly power output from a single 12 MW turbine during different months is shown for the Humboldt Call Area (Figure 1-28) and the Cape Mendocino location (Figure 1-29).

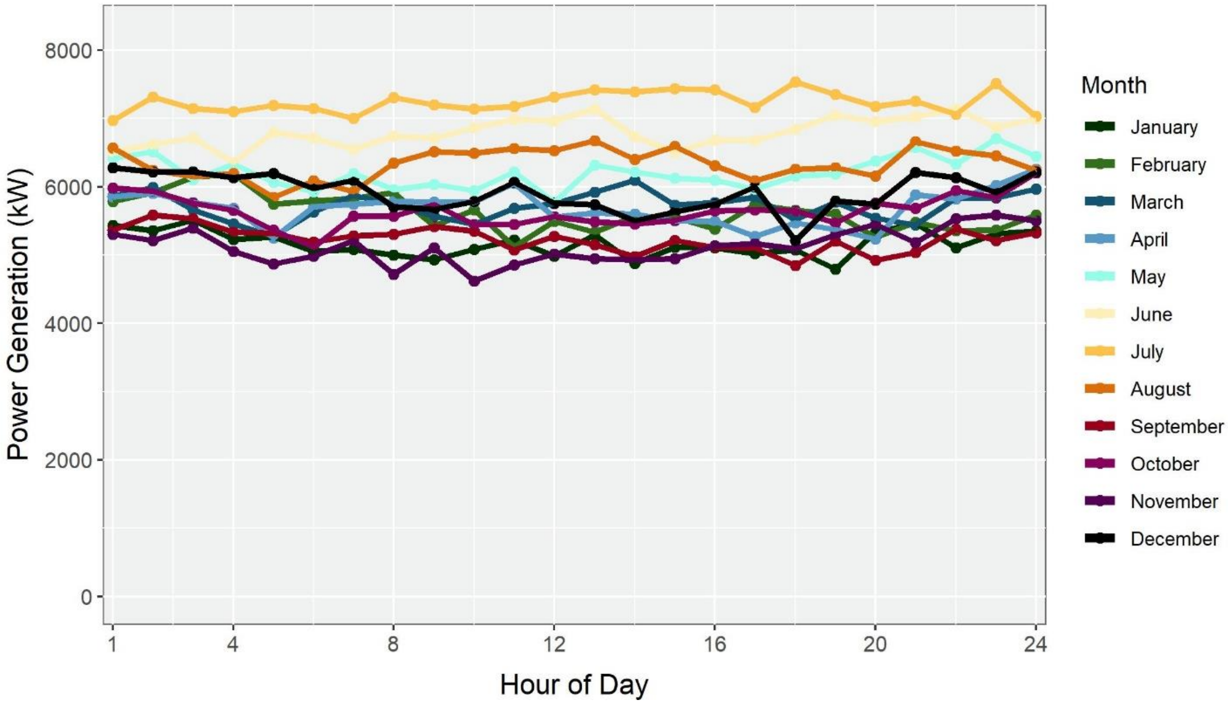

Figure 1-28. Average hourly power output by month of a 12 MW turbine in the Humboldt Call Area.

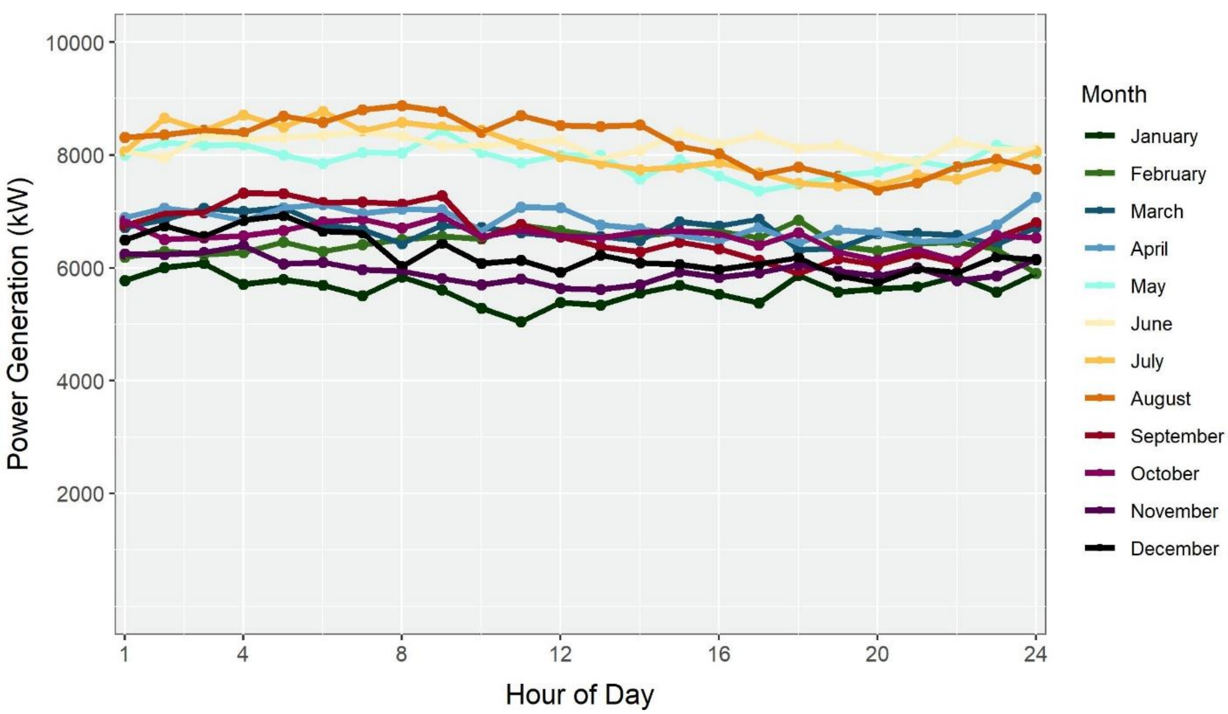

Figure 1-29. Average hourly power output by month of a 12 MW turbine in the Cape Mendocino location.

Chapter 2: Offshore Wind and Regional Load Compatibility Report

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Table of Contents

1. INTRODUCTION

Humboldt County is an access point to the enormous offshore wind resource located on the north coast of California, but there is limited regional load and transmission capacity to absorb this electricity or transfer it to other load centers in the state. Offshore wind farms off the coast of Humboldt County would either need to be 1) small scale to fit within the existing load and transmission constraints, 2) a modest scale development using a combination of strategies to minimize grid impacts such as storage, load development, and curtailment, or 3) a large-scale development requiring major transmission infrastructure improvements to connect the wind farm to other locations in the state. The Humboldt Call Area, located 20 - 30 miles offshore Humboldt Bay, which is being considered for a lease auction (BOEM, 2018), could accommodate up to a 1.8 GW-scale wind farm, but smaller wind farms could also be deployed. The analysis presented below evaluates the compatibility between offshore wind farms and the existing generation sources and loads in Humboldt County, assuming the existing transmission infrastructure has a maximum export capacity of 70 MW of power out of the county (Zoellick, et al., 2011).

The Humboldt County transmission system is partially isolated from the rest of California's network. There are two transmission corridors that connect the county from the east and one transmission corridor heading south (Figure 2-1).

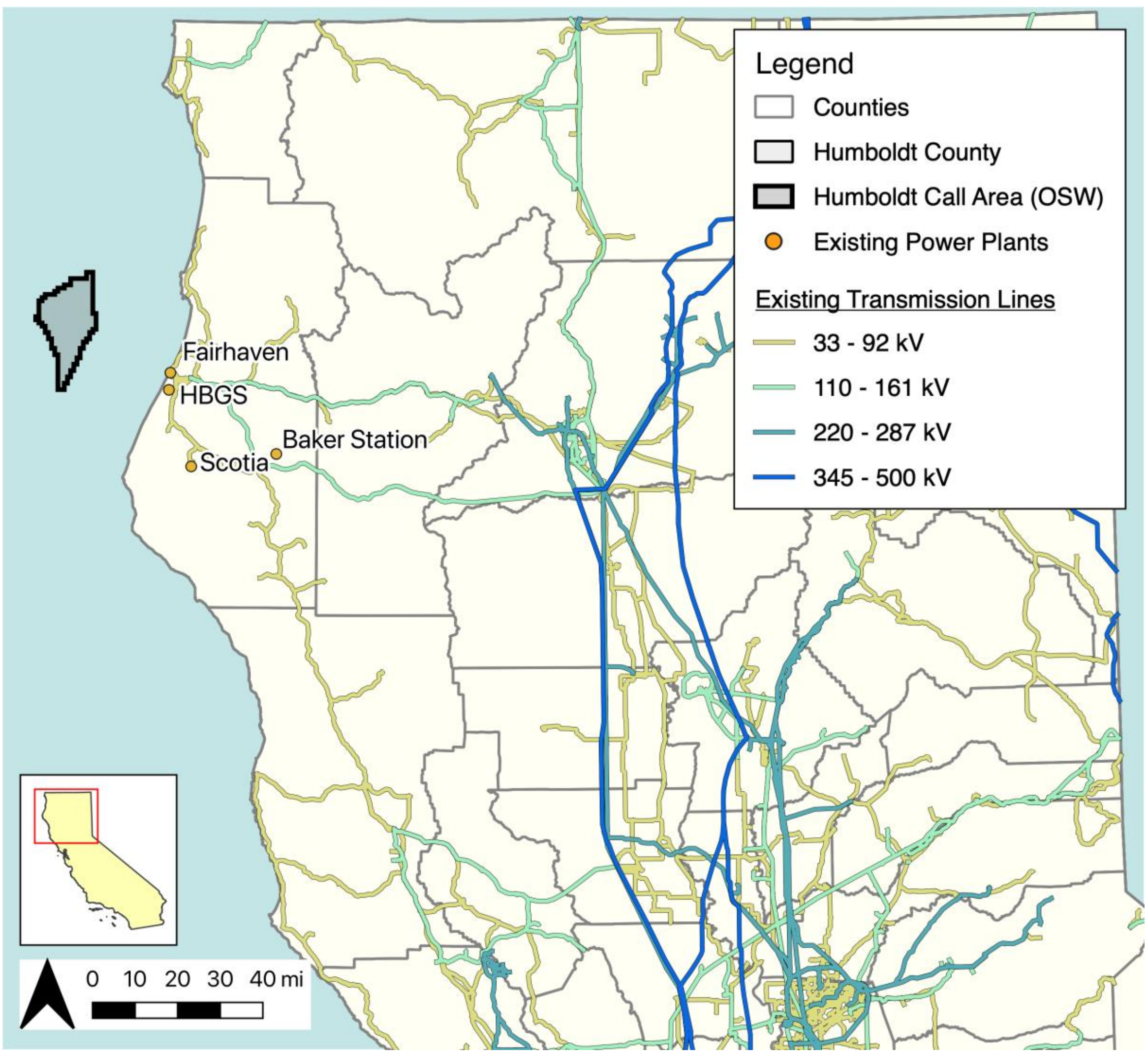

Figure 2-1. Existing transmission lines in northern California.

Humboldt County's electrical demand is intended to be served primarily by four regional power plants, relying on limited electricity transmission into or out of this region. The 60-kV transmission line heading south into Mendocino County serves small communities along its path, but it is not meant to transfer large amounts of power because of its size and voltage. The two parallel, 115-kV transmission lines heading east are redundant lines used to import power to Humboldt County as needed and serve the communities along the way. Lastly, a 60-kV transmission line connects to the east in the same right of way as the northern 115-kV circuit.

1.1 Purpose

To understand the potential for offshore wind development using existing infrastructure, this report describes the regional electricity load and generation sources and then adds different scales of offshore wind development to see how they impact the electricity grid. The analysis evaluates the compatibility between electricity demand, existing generation sources, and potential offshore wind development in Humboldt County, California. The purpose of the study is to determine what scale of wind farms could fit within the current transmission constraints and to understand the impact of offshore wind generation on the regional grid.

**Note:* This study is not a technical assessment of the capacity of existing transmission infrastructure or the requirements of new transmission to accommodate offshore wind. In order to evaluate the transmission capacity and required upgrades, the electric grid operator, Pacific Gas and Electric Company (PG&E), conducted an informational transmission planning study (see Chapter 4:). The analysis described below is used to understand the interaction between future offshore wind generation and existing generators in Humboldt County. PG&E's analysis shows that transmission upgrades could be required at small scales of development based on energy flows and line capacity, even if the simplified load compatibility analysis below does not identify them. A discussion of the different modeling approaches is provided below.

2. METHODS

Existing and historical data for regional electricity demand and generation sources were compiled and projected to the year 2030 to create a future baseline condition. Offshore wind generators at scales of approximately 50 MW, 150 MW, and 1,800 MW are added to the future conditions to determine how these generators could be used to meet electricity demand with existing infrastructure. These wind farm scales were selected to be representative of a pilot-scale project (50 MW), a small commercial-scale project (150 MW, which matches an unsolicited lease request for this area (RCEA, 2018)), and a full build out of the Humboldt Call Area (1,800 MW). The impact of offshore wind generation is quantified in terms of 1) reduction in the energy output of Humboldt Bay Generating Station (HBGS) that was displaced by offshore wind, 2) reduction in energy imports necessary to meet county demand, 3) increase in energy exports from the county, and 4) curtailment of offshore wind energy output. This analysis uses an export limitation of 70 MW for the Humboldt County transmission system (Zoellick, et al., 2011), assuming that no significant upgrades to the transmission system are made to accommodate offshore wind. Instead of upgrading infrastructure, offshore wind power is curtailed in this model so that it does not exceed the transmission capacity.

The analysis was conducted by creating an input/output model of generation plus electricity imports (input) and local load plus electricity exports (output) in the statistical computing language R. The central node in this model is the Humboldt County electrical system (Figure 2-2). The electricity generators include all four existing local generators plus three potential scales of future offshore wind development. These generation sources are used to meet local load in the region. Energy cannot be stored in the Humboldt node, so the sum of inputs must equal the sum of outputs at each time interval (of one hour). If local load cannot fully meet this demand, electricity is imported into the area; if there is a surplus of generation, electricity is exported outside of this region. The transmission line into and out of the area is limited to a maximum capacity of 70 MW (Zoellick, et al., 2011). If generation exceeds the 70 MW export capacity, offshore wind (OSW) energy is curtailed to meet this criterion. Other capacity limitations and energy losses on electricity transmission between each node are not considered in this analysis.

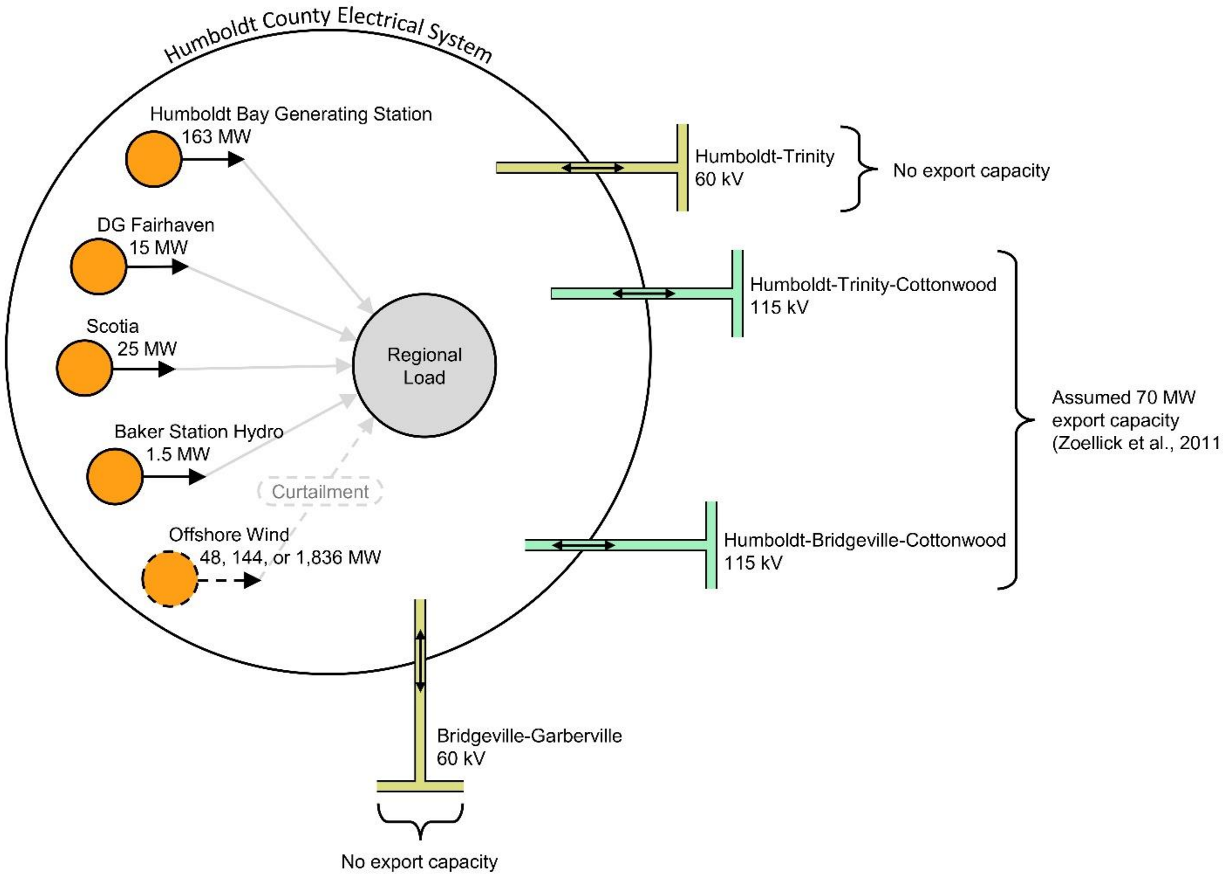

Figure 2-2. Humboldt County electrical system and model inputs and outputs.

2.1 Data Sources

This analysis required data sources for regional electricity demand, generation profile of existing power plants, and simulated generation profile from offshore wind. The data sources are described in the following sections.

2.1.1 Electricity Load

Future electricity load in 2030 was used for this analysis to better align with the timeframe when offshore wind generators could be in operation. Historic electricity load in Humboldt County has been decreasing according to data provided by PG&E for the period from 2008 to 2018 (PG&E, 2019), but future projections expect electricity demand to be higher (Figure 2-3). The California Energy Commission (CEC) publishes projected electricity demand through 2030 for PG&E's service territory (CEC, 2020a), but these projections may not be representative of Humboldt County's future load for three reasons. First, Humboldt County is a winter peaking region, meaning that it has the maximum demand in the winter months unlike the majority of PG&E's service territory. Second, Humboldt County's load has been changing at a different rate than PG&E service territory as a whole (Figure 2-3). While the CEC estimates that electricity demand in PG&E service territory may increase by 6%, 13%, or 21% from 2018 to 2030 based on the low, mid, or high demand scenarios, respectively, the demand in Humboldt County is likely to change at a different rate. Third, Humboldt County comprises less than 1% of PG&E's combined load, and their projections may not be representative of this smaller region.

Instead of using PG&E's 2030 projected load and scaling it down for Humboldt County, a local demand forecast was determined to be more suitable. The future county load for 2030 was obtained from the community choice aggregator in Humboldt County, the Redwood Coast Energy Authority (RCEA). The 2030 County Load in the Business as Usual scenario (RCEA, 2020), which provides an hourly load profile for a typical day for each month, was used in the following analysis. The projected load anticipates the annual average electrical load rising to 102 MW by 2030, an increase of 6% relative to the 96.4 MW figure reported in the most recent year of historical data from November, 2017 to October, 2018 (Figure 2-3). This load growth aligns with the low demand future scenario for PG&E service territory (CEC, 2020a), but matches the hourly and monthly load profiles that are specific to Humboldt County.

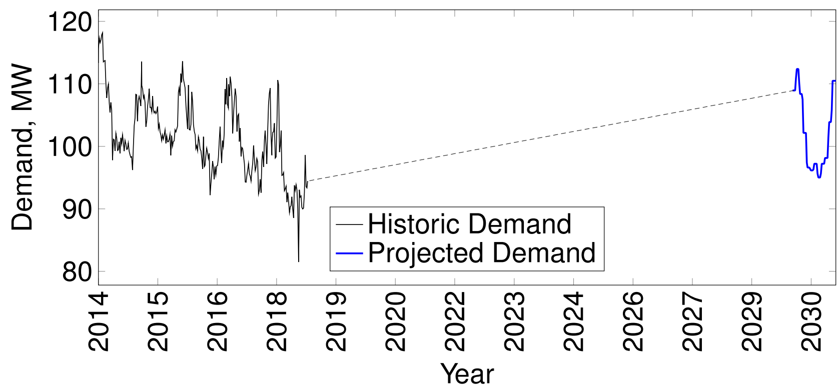

Figure 2-3. Historical and projected Humboldt County load used in this model.

2.1.2 Existing Power Plants

The operation schedule of existing power plants is considered in this model to evaluate if and when offshore wind can contribute to meeting the regional load. There are four active power plants located within Humboldt County: a small hydroelectric facility, two biomass power plants, and a reciprocating engine natural gas power plant (Table 2-1). Historical electricity generation data in Humboldt County were obtained from the California Energy Commission's Quarterly Fuel and Energy Report (QFER) (CEC, 2020b), which reports production data from all California power plants larger than 1 MW. Recent production levels were used to project the future output in 2030. Detailed methods for estimating future generation are provided in Appendix A.

Table 2-1. Humboldt County generation resources.

Plant Name	*Nameplate Capacity*	*Plant Type*	*Annual Energy Production*[1]	*Notes*
Baker Station Hydro	1.5 MW	Small Hydro	4,340 MWh	Annual production reported in QFER. Assumed equal output every hour.
DG Fairhaven Power Plant	15 MW	Biomass[2]	116,000 MWh	Monthly generation reported in QFER. Hourly profile is flat by month.
Scotia	25 MW[3]	Biomass[2]	118,000 MWh	Monthly generation reported in QFER. Hourly profile is flat by month.
Humboldt Bay Generating Station	163 MW[4]	Natural Gas	422,000 MWh	Operated in the model as a load following plant to meet demand. Air permits restrict operating level.[5]

[1] Based upon historic averages. See Appendix A.
[2] Wood/Wood waste solids (CEC, 2020c).
[3] The QFER lists three generators for Scotia: Gen A, Gen B, and #3. Gen A and Gen B are 12.5 MW each, while #3 is 7.5 MW. #3 is not included in this total because it has not produced power since 2014.
[4] The QFER lists HBGS's capacity as 167 MW, but other sources report it as 163 MW (CEC, 2020c).
[5] Minimum output restricted to12 MW (Royall & Holm, 2018).

2.1.3 Offshore Wind Generation

Electricity generation from offshore wind in the Humboldt Call Area is modeled using the simulated power output from Chapter 1: that provides energy generation profiles for wind farms at different scales. Three different scales of wind farms were evaluated for compatibility with existing load:

- Pilot scale: 48 MW total using 4x 12 MW turbines.
- Small commercial scale: 144 MW total using 12x 12 MW turbines.
- Large commercial scale: 1,836 MW total using 153x 12 MW turbines, which is a full build out of the Humboldt Call Area identified by the Bureau of Ocean Energy Management (2018).

2.2 Power Plant Dispatch Model

Power plants are dispatched to meet the electricity demand at every hour of each day. The model selects which power plants to dispatch and where to deliver the energy based on the flow diagram shown in Figure 2-4. In the model, the output from all generators except HBGS is determined based on historical output. The generators' outputs plus offshore wind are added together to meet Humboldt County load. If the production exceeds the demand, offshore wind is exported. If production is below demand, HBGS is ramped up to meet the local load without causing exports. HBGS's air quality permit does not allow the plant to continuously run below 12 MW of output (Royall & Holm, 2018), so in order to maintain ramping capability a lower limit of 12 MW was applied to HBGS.

The transmission interconnection between Humboldt County and the rest of the state was assumed to have a maximum capacity of 70 MW (Zoellick, et al., 2011). When there is more than 70 MW of excess offshore wind energy, the offshore wind farm is curtailed to stay below the capacity restriction.

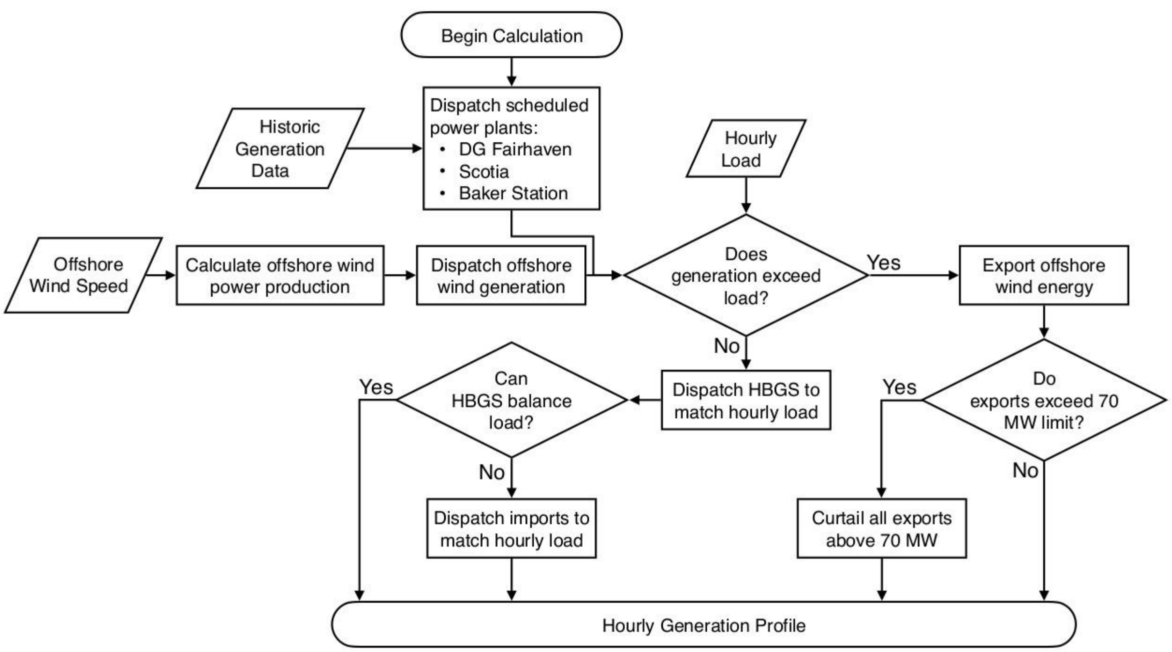

Figure 2-4. Decision process for calculating hourly load and generation profile.

2.3 Differences between PG&E Transmission Planning Study

Importantly, the methodology used in this analysis differs from how PG&E evaluated what transmission upgrades are required to interconnect an offshore wind farm. While this analysis allows generators to ramp up or down to meet regional load, the interconnection feasibility study (PG&E, 2020) evaluates the electrical conditions during peak load scenarios with all power plants producing their nameplate capacity.

Electrical transmission infrastructure is designed and built to safely withstand peak conditions and needs to evaluate the most extreme scenarios to make sure the system can handle this capacity. Results from the informational interconnection study (PG&E, 2020) yield different results that show transmission infrastructure is needed to accommodate offshore wind developments 48 MW and greater. PG&E's study is answering the question of what infrastructure is needed to support all generation in a peak scenario, while this report studies the compatibility of offshore wind and existing generation in meeting the regional load throughout the entire annual operating cycle.

The results from the analysis presented below do not indicate whether or not transmission upgrades are required. Instead, the results illustrate how offshore wind farms could be integrated into the regional electricity grid given the existing load, generation resources, and assumed transmission capacity.

3. RESULTS

Four offshore wind development scenarios were analyzed, consisting of a baseline with no offshore wind development and three sizes of offshore wind development: 48 MW, 144 MW, and 1,836 MW.

3.1 Baseline Generation in Humboldt

The dispatchable natural gas-fired Humboldt Bay Generating Station is the primary electricity generating source for the Humboldt Area. In this model, we assume HBGS is ramped up and down to meet the regional demand. Two biomass-fuel power plants are operated consistently throughout the year as baseload power. Excess electricity demand is met with energy imported on transmission lines that connect elsewhere in the state. Note that Baker Station, a small hydroelectric facility, provides a small amount of energy relative to the other generators.

Figure 2-5 shows the monthly electricity demand and the generation portfolio that is used to meet that energy demand for current 2018 load (left) and 2030 projected load (center and right). The current profile uses reported generation data and adds imports to meet the demand (Figure 2-5 (a), left). Using the same historic generation data, imports can be increased to meet the expected load in 2030 (Figure 2-5 (b), center) without overloading the 70 MW transmission capacity.

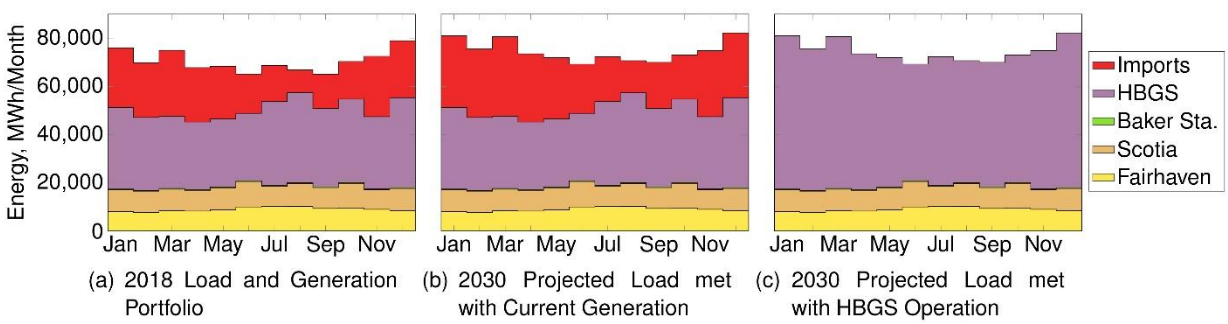

Figure 2-5 Historic generation in Humboldt County coupled with imports required to meet 2030 projected load. The height of each monthly bar exactly matches the regional load in 2018 (a) and 2030 (b) and (c).

Instead of relying on imports, the 2030 electricity demand could also be met by increasing the capacity factor of HBGS to match the hourly demand. Figure 2-5 (c) shows HBGS ramping up to meet the future load. This method of modeling the future generation portfolio provides a preference for power from HBGS over imported electricity. Future generation scenarios that include offshore wind also dispatch HBGS before selecting imports, similar to the algorithm depicted in Figure 2-5 (c).

3.2 Daily Generation Profile

Adding offshore wind generation to Humboldt County changes the sources of electricity used in the region. Figure 2-6 shows how the energy generation portfolio changes for different scale wind farms and different daily wind patterns. The chart includes the generation profile for a low, variable, and high wind speed regime with 48 MW, 144 MW, and 1,836 MW of installed offshore wind capacity.

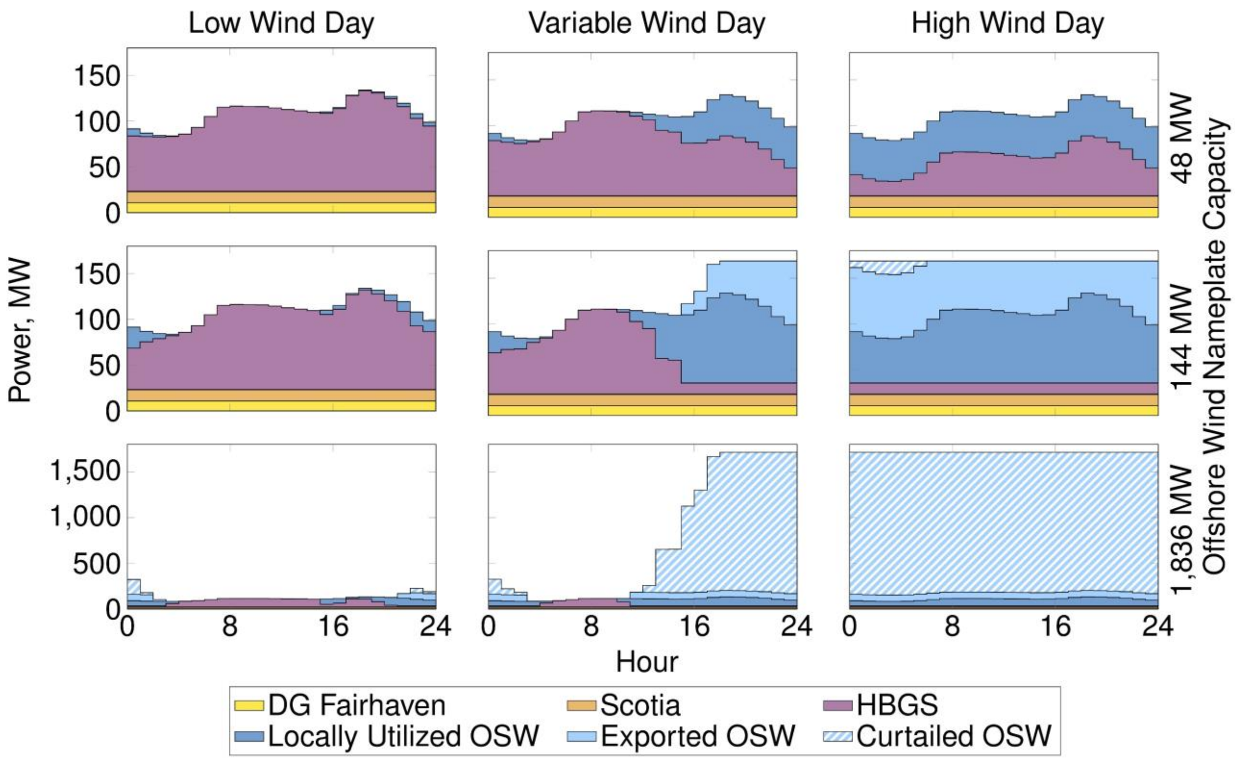

Figure 2-6. Hourly generation and load during three different wind speed regimes in February (vertical columns). The generation mix is shown for each day when adding 48 MW, 144 MW, and 1,836 MW wind farms (horizontal rows). Note that the y-axis scale for the 1,836-MW cases covers a much wider range of values than the y-axis scales for the 48 and 144-MW cases.

The example days in Figure 2-6 provide an overview of how different scale generators affect the portfolio of regional generation.

- Pilot Scale - A 48-MW wind farm (top row) operates in tandem with HBGS to meet electricity demand. Even during high wind speed days, offshore wind generation does not exceed regional load, and there is no offshore wind energy exported out of the region.
- Small Commercial Scale - During high wind speeds days, the 144-MW wind farm exceeds local demand. Power output from the wind farm is consistent under high winds (notice the flat upper bound in the high wind speed day) and the electricity is distributed between local load first, then to export, and lastly it is curtailed if the 70 MW export capacity limit is reached. During high wind, HBGS operates at its minimum power output; during low or variable winds, HBGS follows the local load.
- Large Commercial Scale - Production from an 1,836-MW wind farm far exceeds the energy demand in the region. During periods of moderate to high wind speed, offshore wind energy is exported at maximum capacity, but the majority of the production is curtailed due to transmission limitations. Importantly, even with a large offshore wind installed capacity, HBGS still needs to operate on low and variable wind speed days to meet the regional energy demand when the wind farm is not producing.

3.3 Annual Generation Summary

Adding offshore wind generation changes the annual energy generation portfolio in the area. The annual generation portfolio is shown in Figure 2-7 for historic, baseline, and three different wind farm scales. The historic generation portfolio includes electricity imported to meet current electrical load. The baseline portfolio represents the modeled generation portfolio in 2030 before adding offshore wind. Note that the baseline is slightly higher than historic, indicating the increase in load between 2018 and 2030. The baseline condition does not include any imports because HBGS is dispatched to meet load in this model before relying on imports. In the actual energy market, an economic decision would be made whether to dispatch HBGS or rely on imports based on market prices

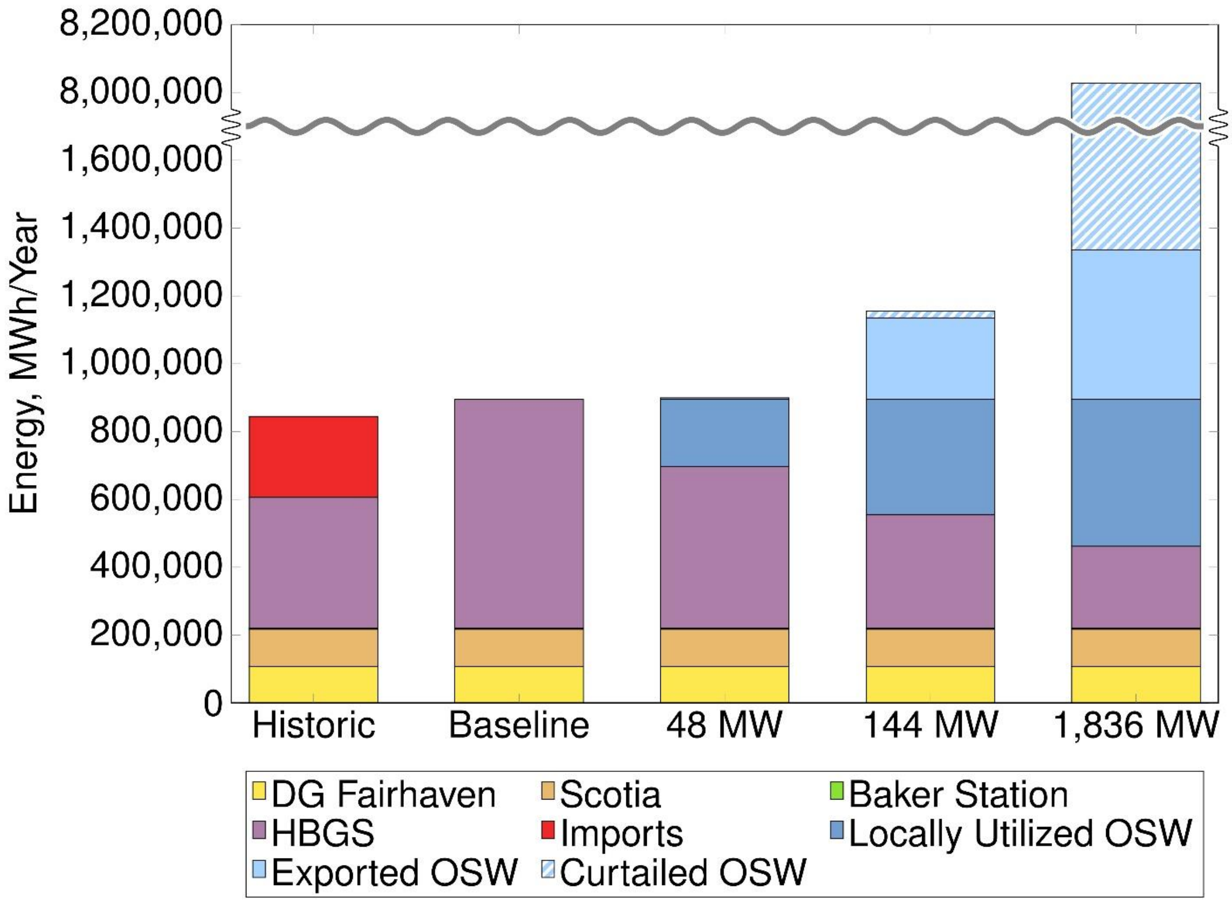

Figure 2-7. Annual energy generation by source for different levels of offshore wind development. Note the discontinuity in the vertical axis.

Increasingly large wind developments reduce the need for HBGS generation. Furthermore, while curtailment is absent entirely for the 48 MW scenario and is clearly a very small fraction of potential wind output for the 144 MW scenario, for the 1,836 MW scenario nearly all of the output is curtailed, with roughly equal portions utilized locally and exported. Little more usable electricity is extracted from the 1,836-MW scenario compared to the 144-MW scenario given the assumed grid constraints discussed previously.

Offshore wind development reduces HBGS output by 29% at 48 MW, by 51% at 144 MW, and by 64% at 1,836 MW (Table 2-2). In contrast, exports and curtailment increase steadily with increased nameplate capacity of offshore wind. For a 48-MW development, nearly all output could be consumed locally, with less than 2% exported and none curtailed. In the 144-MW scenario, exports increase to 40% of output with 3% curtailment, and in an 1,836-MW development with no transmission upgrades, exports represent 6% of the total offshore wind output with 88% curtailment.

Table 2-2. Annual offshore wind electricity generation, end use, and HBGS operating characteristics.

Scenario	*Offshore Wind Capacity Factor*[1]	*Total Offshore Wind, MWh*	*Curtailment, MWh*	*Exports, MWh*	*HBGS Output, MWh*	*HBGS Reduction*
Baseline	no offshore wind	0	0	0	674,000	-
48 MW	48%	203,000	0	4,330	476,000	29%
144 MW	47%	602,00	21,024	241,000	334,000	51%
1,836 MW	47%	7,570,000	7,189,514	440,000	241,000	64%

[1] Capacity factor determined from the Humboldt Call Area in Chapter 1: .

3.4 Monthly Generation Summary

The historic and baseline cases have previously been shown at monthly resolution (Figure 2-5), while the monthly outputs with the addition of offshore wind generation are depicted in Figure 2-8 to Figure *2-10*.

In a 48-MW wind development scenario, offshore wind provides 22% of regional load (Figure 2-8). HBGS remains the dominant electricity source throughout the year. HBGS output rises in the winter months to meet the increased local demand. Generation exceeds total demand in the months of May through October, leading to a small amount of export, but no curtailment.

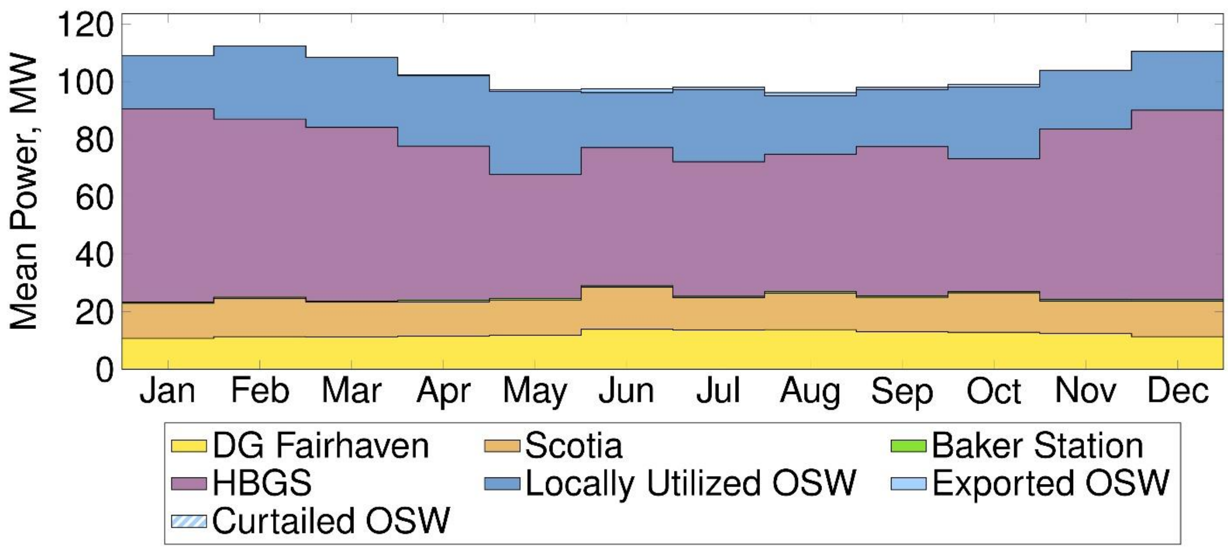

Figure 2-8. Monthly electricity generation by source to meet Humboldt County's projected 2030 load profile with addition of a 48 MW offshore wind farm.

With a larger, 144-MW offshore wind project, exports increase to significant levels, and small amounts of curtailment - caused by local generation exceeding local demand by more than 70 MW - are required (Figure 2-9). Some HBGS output is displaced by offshore wind, and offshore wind grows to become the largest source of local electricity.

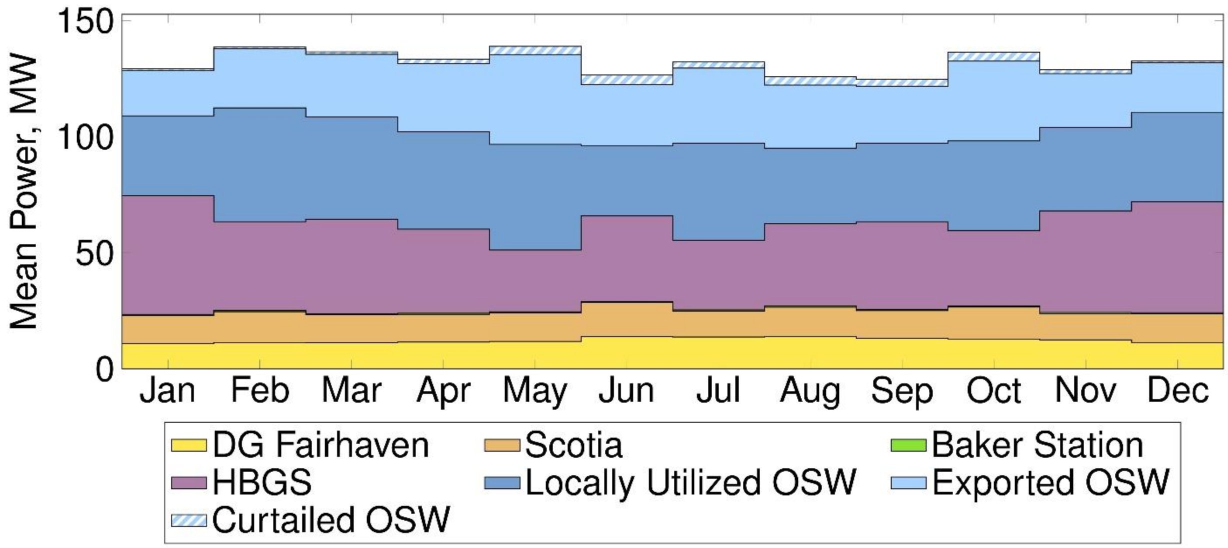

Figure 2-9. Monthly electricity generation by source to meet Humboldt County's projected 2030 load profile with addition of a 144 MW offshore wind farm.

The result of an 1,836 MW offshore wind development is much more dramatic (*Figure 2-10*). Electricity from wind energy is greater than all other factors by more than an order of magnitude, leading to generation far exceeding demand in all months, and tremendous exports and – without changes to transmission infrastructure – massive curtailment.

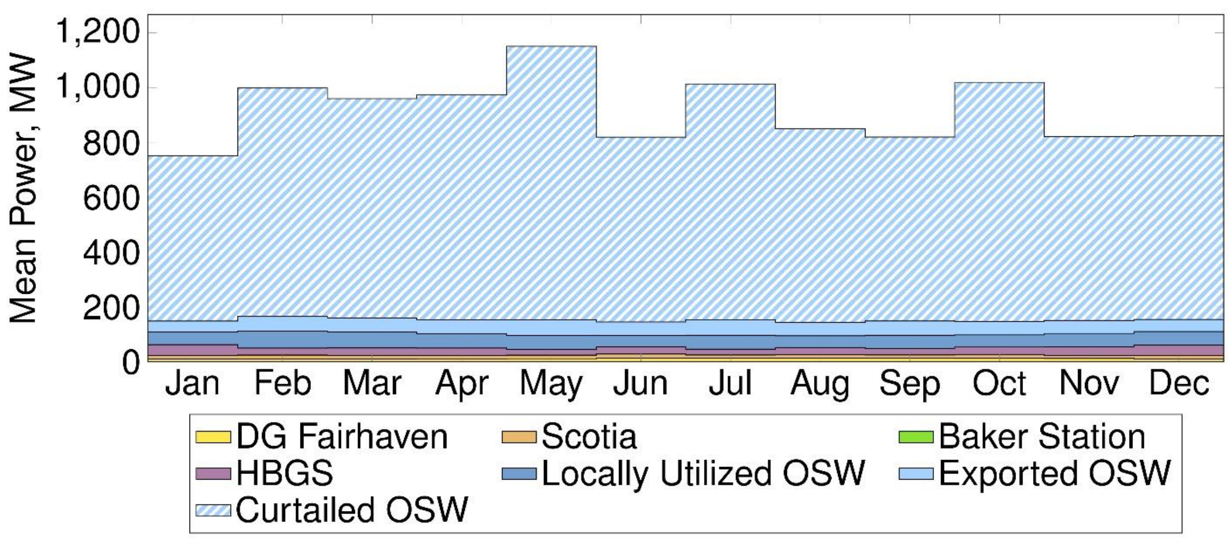

Figure 2-10. Monthly electricity generation by source to meet Humboldt County's projected 2030 load profile with addition of an 1,836-MW offshore wind farm.

4. DISCUSSION

Humboldt County's historic yearly consumption of 923 GWh has been met by a mix of 72% local generation (including 26% renewable, local generation) and 28% imports. With the projected increase in load and in the absence of offshore wind development, consumption increases to 977 GWh, met by an increasing quantity of imports equaling 32% of demand. Local generation falls to 67%, with only 24% of demand met by local renewables. In the baseline scenario in this report, the local natural gas plant, HBGS, is ramped up to eliminate imports (see Figure 2-5 (c)). This model allows HBGS to ramp up to meet regional load, while in practice, remaining regional load could be met through either HBGS or imported electricity. The decision whether to dispatch HBGS or imports would be an economic decision that is outside the scope of this analysis.

Under the 48-MW offshore wind development scenario, HBGS's yearly generation can be reduced by 29% compared to the baseline scenario, now serving 54% of local load instead of 76%. Offshore wind meets 22% of local consumption, raising the share of local renewables to 46%. In this scenario, 2% of offshore wind generation is exported and none is curtailed.

Under the assumptions of a 144-MW offshore wind development, local wind can meet 38% of local demand, increasing the share of local renewables to 64% and reducing HBGS's role to 38% of local demand. Under this scenario, 44% of electricity generation from offshore wind is exported, and 3.5% is curtailed. Curtailments would be reduced to zero with an additional 36 MW of export capacity (106 MW total).

With an 1,836-MW development, local renewables meet 73% of local demand, as offshore wind increases to provide 48% of local demand. Note that increasing the size of the wind farm by a factor of 13 only increases the local share from 38% to 48%, a modest increase by comparison. HBGS, in this scenario, delivers only 36% the energy of the original scenario, 27% of local load. In this scenario, 94% of offshore wind generation cannot be used within Humboldt County, and transmission infrastructure upgrades would be required to avoid the tremendous level of curtailment resulting from current transmission limitations. This model shows peak curtailment of 1,580 MW, elimination of which would require expansion of the existing transmission capacity from 70 MW to 1,650 MW.

The assumptions built into this model result in offshore wind displacing some output from the natural gas-fired Humboldt Bay Generating Station, which reducing greenhouse gas emissions from the regional electricity generating sources. Based on HBGS's 2018 production and emissions (CEC, 2020b; CARB, 2019), this plant has an emissions intensity of 0.465 metric tons of CO_2 equivalent per MWh, or 1,030 lb/MWh (see Appendix C). As shown in Table 2-2, above, the addition of 48, 144, and 1,836 MW of offshore wind would result in HBGS's energy output reducing by 29%, 51%, and 64%, respectively. This leads to a reduction of 92,000, 158,000, and 202,000 metric tons of CO_2 per year, respectively.

5. REFERENCES

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APPENDIX 2.A - CALCULATION OF HOURLY GENERATION

The methods used to calculate hourly generation for each power plant are described below.

2.A.1 DG Fairhaven Power Plant E0037

Monthly generation records between January 2001 and December 2018 were available through QFER. These records showed significant variability, short periods of shutdown, and a long period of shutdown during 2016/2017. All records in which the power plant operated were averaged by month, and then divided by the number of hours in the month to create a flat generation profile (i.e., a constant power output) for each month.

2.A.2 Scotia E0063

Monthly generation records between January 2001 and December 2018 were available through QFER. These records showed significant variability, short periods of shutdown, and a long period of shutdown at the end of 2015. Note that there was also a third generator running prior to 2014, which has not since been operated. Since the data before and after 2016 look distinctly different, only data starting from 2016 were used. All records since 2016 were averaged by month, and then divided by the number of hours in the month to create a flat generation profile for each month.

2.A.3 Baker Station Hydro H0547

Only yearly generation for the years 2017 and 2018 were available for this plant through QFER. The average was taken and assumed to be distributed evenly across the year for every hour.

2.A.4 Offshore Wind

As mentioned previously, offshore wind generation by hour had previously been projected. It was not altered in any way for this analysis.

2.A.5 Humboldt Bay Generating Station G0268

Total monthly generation for HBGS between January 2001 and December 2018 were available by engine through QFER. This plant was retrofitted in 2010 with the replacement hardware (i.e., 10x 16.3 MW Diesel cycle engines) brought online during 2011.

Because HBGS is a load following power plant (CEC, 2020d), its output was analytically shaped to match county demand. This method resulted in a monthly output 75% higher than historical (QFER) data would suggest. Nevertheless, because it was carried through all analyses, the assumed behavior allows for a consistent comparison.

According to the air quality permits for HBGS, the facility is not allowed to operate any engine for more than 80 hours per year at less than 12 MW (75% output) (Royall & Holm, 2018). To avoid complicating the implementation, the HBGS output was therefore restrained from going below 12 MW. Therefore, we assumed that HBGS was able to produce anywhere from 12 MW to 163 MW (its nameplate capacity) at any hour such that imports and exports are minimized.

APPENDIX 2.B - HUMBOLDT BAY GENERATING STATION OPERATIONAL CHARACTERISTICS

Formerly Humboldt Bay Power Plant (HBPP), the Humboldt Bay Generating Station (HBGS) was repowered and renamed in 2010. It is located at 1000 King Salmon Avenue, in Eureka, California and owned by Pacific Gas and Electric Company (Kessler, 2007). Previously, HBPP was powered by two fossil fuel steam plants of 53 and 54 MW, installed in the late 1950s, and two 15 MW mobile emergency power plants (MEPPs), which were brought online in 1976 (CEC, 2020b; Herbert & Root, 2012). The repowered HBGS hosts ten Wärtsilä 18V50DF (dual fuel) reciprocating engines. The primary fuel for these engines is natural gas, but they can be operated with diesel during times of natural gas curtailment. Each engine at HBGS has a nameplate capacity of 16.3 MW, for a total power plant nameplate capacity of 163 MW (Kessler, 2007; Wärtsilä, 2020). Since repowering in 2010, annual output from HBGS has ranged between 360,000 MWh/year and 470,000 MWh/year (Table 2-3) with power output varying by month (Figure 2-11). Since repowering to HBGS, the capacity factor has ranged from 25 to 32% each year.

Table 2-3. Annual output from HBPP (2001-2009) and HBGS (2010-2019) reported by the California Energy Commission (2020c).

Year	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Output, MWh/year	673,401	375,715	225,065	372,161	438,432	441,313	482,871	521,879	552,072	452,810
Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Output, MWh/year	467,071	429,408	373,054	362,095	392,783	367,748	431,524	384,787	405,143	

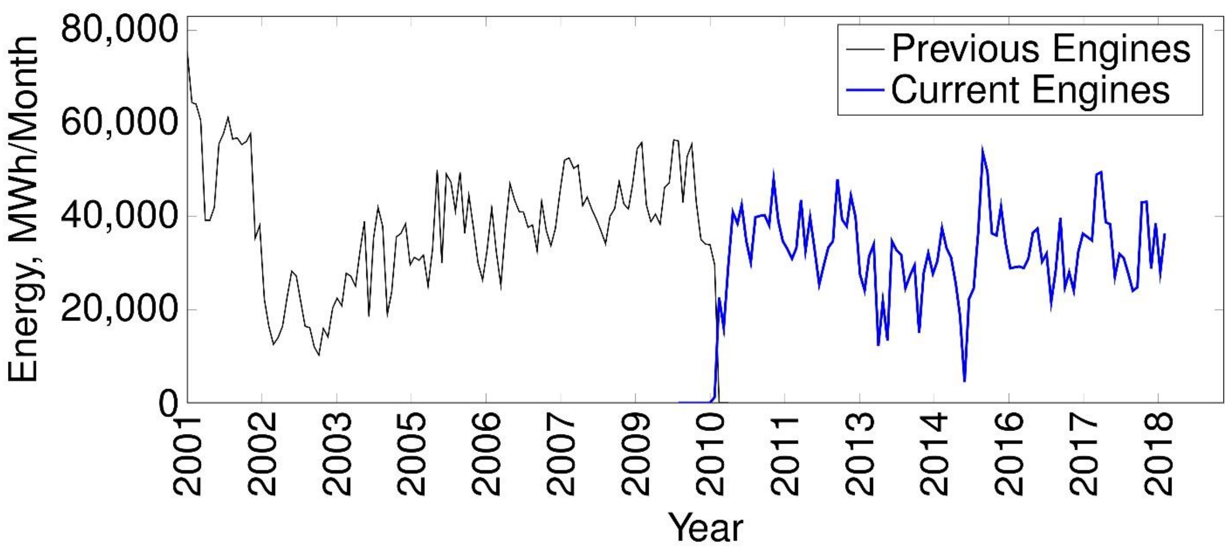

Figure 2-11. Monthly HBGS energy generation before and after repowering.

2.B.1 Operating Characteristics

Due to the limited transmission into and out of Humboldt County, power plants within the county must meet a large fraction of local electric demand, supplying both real power and reactive power. As the largest power plant in Humboldt County, HBGS may provide base load power during extended periods of high demand and operate as a load following plant to meet varying energy demand. The power plant is dispatched following signals from the California Independent System Operator (CAISO) based on economic market conditions, demand, and local grid stability. The air district operating permit states, “As a commercial power plant, market circumstances and demand … dictate the exact operation of permitted equipment" (Royall & Holm, 2018).

In its Application for Certification for the Humboldt Bay Repowering Project, the HBGS is described as being designed to operate in two modes: load following, in which the plant operates at output levels between 11.4 MW and 163 MW; and daily cycling, in which the plant can cycle up to its maximum output and be shut down on nights or weekends (CEC, 2008). The HBGS air quality permit, which expires on March 16, 2023, similarly allows for two operational modes, labeled as load following and base load (Royall & Holm, 2018). In addition to meeting local real power demand, synchronous generators, such as HBGS, can supply reactive power by adjusting the generator's field current to maintain a constant voltage at the generator bus (von Meier, 2006, p. 184-185, 202-203); this is sometimes termed "voltage support". Additionally, HBGS is capable of filling in gaps due to generation by intermittent renewables. In 2008, air quality certifications were changed "to integrate the operation of the HBGS with intermittent renewable energy resources (e.g. wind and solar)" (Winstead, 2018; Goldthrite, 2018).

The modes of operation for HBGS are summarized below.

- Daily cycling (Base Load per Royall & Holm (2018))
  In a base load mode of operation, "HBGS may be operated at maximum continuous output for as many hours per year as scheduled by load dispatch, and limited by operational constraints of the permit to operate (approximately 75% annual capacity factor)" (Royall & Holm, 2018). The engines may operate for a sum total of up to 80 engine-hours per calendar day at output levels between 50% and 75% (8-12 MW) (Royall & Holm, 2018, p. 33). Engines are not permitted to operate below 50% capacity (Royall & Holm, 2018).

- Load following
  As a load-following plant (CEC, 2008; CEC, 2020d; Royall & Holm, 2018), the engines can be operated at any level from "a single unit operating at 70 percent load to all 10 units operating at full load" to meet variable demand (CEC, 2008).

- During Regional Power Outages
  PG&E has submitted a variance petition to allow HBGS to "operate in an island mode, or as a black start unit, or to serve area load, during times of regional power outages" (Bitner, 2020). This petition waives the requirements that engines not run more than 80 engine-hours per calendar day at loads less than 75%, and that engines not run below 50% load. The variance is intended to be in place while PG&E's operating permit is amended.

- Integration with renewables
  The ramping capabilities of Wärtsilä internal combustion engines could allow HBGS to integrate operation with intermittent sources of renewable energy resources (see Winstead, 2018; Goldthrite, 2018). This mode of operation has not been employed by HBGS and would require approval and may have implications to engine lifetime or maintenance costs.

The HBGS is dispatched like any other power plant participating in the CAISO market. The Scheduling Coordinator for the plant submits bids into the market. The bids submitted can be crafted to meet the objectives of the operating modes described above. CAISO then awards bids and dispatches plants in an optimal fashion in order to meet system requirements for power quantity, power quality, and reliability, all while minimizing the cost of service. If the output from the plant does not meet its dispatch instructions, the deviation can be resolved through the energy imbalance market and/or uninstructed deviation penalties may be incurred.

As a fossil fuel-fired plant, the HBGS has a marginal operating cost that is greater than that of fuel-free renewable generators, such as an offshore wind plant. Intermittent renewables like wind and solar are typically offered into the CAISO market as "price takers." This means that they offer their power at a price of zero dollars per MWh. This essentially ensures that they will be awarded their bid. They are then compensated at the market clearing price.

If a large wind farm were interconnected within the Humboldt Area and it were offered into the CAISO market as a price taker, then it would typically be dispatched ahead of the HBGS plant. The HBGS plant would then be dispatched to meet the remaining net load for the area in a fashion that met power requirements and minimized cost. Available power that could be imported via the transmission lines serving the Humboldt Area would also be considered when optimizing the dispatched power mix.

2.B.2 Application in Load Compatibility Model

In the load compatibility model described in the main body of this report, Humboldt County power plants were dispatched on an hourly basis starting with the production from existing biomass and hydroelectric resources, then adding the modeled offshore wind power, and finally HBGS's minimum output in load following mode: 12 MW (CEC, 2008, rounded up to the nearest MW). Then, if total generation was less than demand, HBGS output was increased to meet county demand, up to its maximum output of 163 MW. If additional power was needed, it was met with imports. Surplus local generation up to 70 MW was exported, and surplus generation above 70 MW was curtailed.

This method resulted in a monthly HBGS output 75% higher than historical production data reported by the California Energy Commission (2020c). The increased HBGS output in this model is a result of the model prioritizing HBGS over imported electricity, while in actual operation imports are used more frequently in the area based on price. Nevertheless, because it was carried through all analyses, the assumed behavior allows for a consistent comparison. Otherwise, economic assumptions would have to be included in the model to make a dispatch decision between imports and HBGS to balance regional load.

APPENDIX 2.C - HUMBOLDT BAY GENERATING STATION EMISSIONS INTENSITY CALCULATION

The EPA's Emissions & Generation Resource Integrated Database lists Humboldt Bay Generating Station (HBGS) 2018 emissions as 179,007 metric tons of CO_2 equivalent, and annual net generation as 383,862 MWh (EPA, 2020). This leads to an emissions factor of 0.466 metric tons CO_2 equivalent per MWh, or 1030 lb per MWh.

QFER annual data record for 2018 lists HBGS production as 384,787 MWh, matching the QFER monthly data exactly, and quite close to the EPA's data (CEC, 2020b). The California Air Resources Board lists HBGS 2018 emissions as 179,025 metric tons of CO_2 equivalent (CARB, 2019). These data lead to a slightly lower emissions factor of 0.465 metric tons CO_2 equivalent per MWh, or 1025 lb per MWh.

These factors are within 0.3% of each other, and the emissions factor of 0.465 metric tons CO_2 equivalent is used because it is more conservative for the purposes of calculating CO_2 reduction.

Chapter 3: Interconnection Constraints and Pathways

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Table of Contents

1. INTRODUCTION

The northern California coast has access to an enormous offshore wind resource that could be used for renewable energy production, but there is limited regional load and transmission capacity to either use this electricity locally or transfer it to other load centers in the state. The Bureau of Ocean Energy Management (BOEM) has identified an area of the coast of Humboldt Bay that is being considered for a competitive lease auction to offshore wind developers (BOEM, 2018a). The Humboldt Call Area, located west of Humboldt Bay (BOEM, 2018b), is large enough to accommodate an estimated 1.8 gigawatts (1.8×10^9 watts) of installed offshore wind capacity that could interconnect to the electrical grid in Humboldt County. While the offshore wind speed profile is well suited to energy generation, there are several challenges associated with development including the construction of new transmission infrastructure.

The electric transmission system in the Humboldt Planning Area is connected to California's bulk transmission system through four circuits at 60 kV and 115 kV (Figure 2-2). Electric load in the region is met through four local generators and electricity imported on the transmission network. The transmission is built to serve local load and not designed to be a large exporter of electricity. Interconnecting an offshore wind farm within the Humboldt Planning Area will require upgrades to the transmission system.

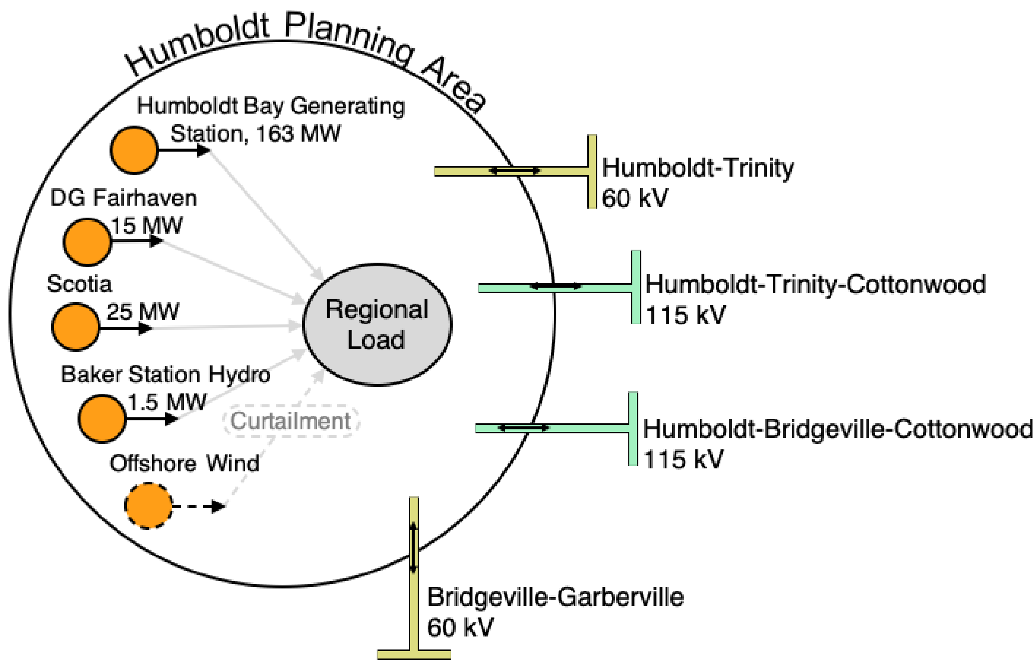


Figure 3-1. Humboldt County electrical system and model inputs and outputs.

This report describes the required transmission upgrades for interconnecting offshore wind on the north coast and the different pathways to develop the transmission infrastructure. The report presents:

- Permitting pathways for developing new transmission infrastructure in California (Section 2),
- Technical requirements for interconnection of offshore wind generation from the Humboldt Call Area (Section 3),
- Estimated costs of the transmission upgrades (Section 4)

2. PATHWAYS FOR TRANSMISSION DEVELOPMENT

The electric transmission system provides a link between different generation facilities and distribution networks to move energy from the generation source to the end use. The transmission system is designed to meet the capacity requirements of regional electricity load and electricity generating facilities.

Transmission lines are built and expanded to ensure reliable and safe transfer of power. When new generation sources are proposed, such as offshore wind in the north coast, the existing transmission network must be evaluated to determine if the new generation source will exceed the capacity constraints of the system. Transmission improvements are then proposed as needed to allow safe and reliable interconnection of a new generation source. Transmission improvements can include upgrades or new construction of transmission cables or the substations that serve as connection points along the transmission path.

There are two pathways to build transmission in California to support new generation. One pathway is for the interconnection customer to propose a new generation facility then work with the regional transmission owner and the independent system operator to build transmission upgrades to accommodate the new generation source. In this approach, the cost of the upgrades is carried by the interconnection customer. Another pathway is for State policy to drive the support of new transmission to meet mandates for reliability, renewable generation, or safety. Under this state-led approach, the cost of the upgrades is ultimately carried by ratepayers, although some investments must be made by the interconnection customer. Both pathways are described in the subsections below.

2.1 Interconnection Customer

When a new generator proposes interconnection to the independent systems operator (ISO) controlled transmission system, the ISO must analyze the ability of the existing transmission infrastructure to absorb the proposed electricity generation without creating reliability or safety impacts to the grid. If the existing infrastructure cannot accommodate the proposed capacity, the ISO will require improvements to address the capacity constraints.

There are three processing tracks for interconnection customers wishing to interconnect to the ISO controlled transmission system; the cluster study process, the independent study process, and the fast track process. The default process for ISO interconnection requests is the cluster study process, and the independent study process is applicable only in special circumstances. The fast track process is only available to projects no larger than 5 MW and will therefore not relevant to offshore wind.

The independent study process can happen at any time of the year, but must demonstrate that the cluster study process will not accommodate the desired commercial operation date of the project, and must pass a flow impact test or short circuit duty test to show that it is electrically independent of projects in the cluster queue. The independent study process only takes approximately 240 calendar days if applying for energy only status, but will require additional work for full capacity. Additionally, if a project is requesting resource adequacy deliverability, they will have to join the cluster study process in the next available window.

For the cluster study process, the interconnection request window is open once per year from April 1st-April 30th. A cluster study considers interconnection requests from a group of interconnection customers at once in order to understand the overall impact on the grid. Within the cluster study, both group studies which look at all projects, and individual studies may be performed for each project at the discretion of the ISO. The interconnection studies begin in late July and take approximately two years to complete.

Interconnection studies in a cluster track are completed in two phases. The first phase is preliminary and includes all projects in the cluster study to identify the needed upgrades to existing infrastructure. Phase one consists of a short circuit analysis, a stability analysis, a power flow analysis, and deliverability assessments. At this stage every project is given a maximum cost responsibility for transmission system upgrades. The second phase is an update to account for changes in interconnection requests such as withdrawn applications. At this stage the final upgrades are determined and the ISO will assign financial responsibility to the various interconnection customers.

The cost responsibility for transmission upgrades will fall on the interconnection customer - or wind farm developer - through this pathway.

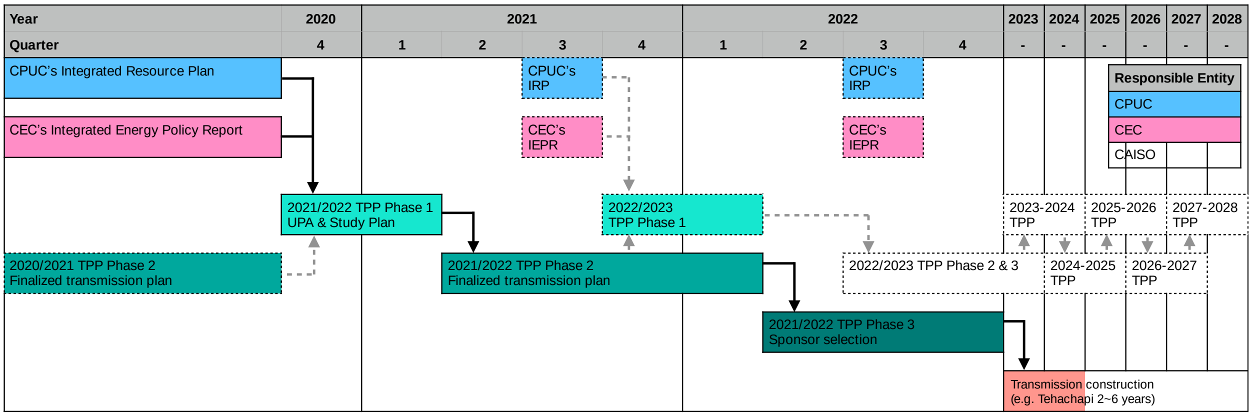
2.2 Public Policy Pathway

State policy guides the development of large-scale transmission in the state as needed in order to connect generation resources to electricity loads. As California policy has set a goal to achieve 100% clean energy by 2045 through Senate Bill (SB) 100, state agencies including the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) will help create practical pathways to meet these targets. These state planning processes can help garner public policy support for offshore wind development if they determine that offshore wind can help meet the overall mandates set by the State. The California Independent System Operator (CAISO)'s transmission planning process (TPP) evaluates the need for new transmission lines to maintain reliability while meeting the projected future load and new generation sources. The TPP draws from the outcomes from the CEC and CPUC planning documents, described below.

Through the Integrated Energy Policy Report (IEPR), the CEC evaluates California's progress towards meeting the state's policy and renewable energy goals. The IEPR provides a forecast of future energy demand in California and is a cornerstone of infrastructure planning to support future demand.

The CPUC's Integrated Resource Plan is developed to ensure that California has a safe, reliable, and economic electricity supply that is consistent with environmental priorities and goals. Their analysis evaluates the need to new generation sources. Offshore wind was included as a candidate resource for the first time in the 2019-2020 IRP planning cycle Proposed Reference System Plan. However, offshore wind is only included in one sensitivity scenario, and is not considered an available resource until 2030. Sensitivity scenarios are used by CAISO to ensure energy projects are feasible from a transmission standpoint without prematurely indicating that a project is imminent (D. Hou, personal communication, April 21, 2020).

Projects that are included in the IEPR or IRP, are then incorporated into the following year's TPP (see Figure 3-2). CAISO's TPP is intended to serve as a unified transmission infrastructure plan for the entire CAISO balancing area (Billington, 2019, P.13). The TPP is the keystone of transmission planning and precursor to construction of any *ratepayer-funded* transmission infrastructure (since FERC's approval of the Generator Interconnection and Deliverability Allocation Procedures (GIDAP) in 2012). This funding is provided through transmission access charges to reach a rate of return approved by the Federal Energy Regulatory Commission. Charges are bundled together and paid for by utility and distribution companies, and ultimately charged to ratepayers (CAISO, 2017, P.4-5). Generators may still procure transmission outside of the TPP process, but without reimbursement from ratepayers (CAISO, 2019, P.45-46). According to D. Hou of CAISO, however, the upgrades *could* be refunded after completion (D. Hou, personal communication, April 21, 2020). The three-phase TPP begins every year but takes two years to complete.



Notes:
*   High Level Needs (HLN) / Long Term Procurement Process (LTPP) only occurs for planning cycles beginning in odd years.
** UPA = Unified Planning Assumptions.

Figure 3-2. Graphical timeline of Transmission Planning Process (TPP).

Phase One

Phase one begins in December of the prior year, and runs through the end of the first quarter of the first year.

> The objective of this process is to establish the goals of the current year TPP, agree on data assumptions and inputs for the creation of base cases…and allow transmission planning participants to review and comment on the scope of the upcoming technical studies. The intended outcome of this effort is to aggregate and incorporate into the study plan, as appropriate, all relevant information and data necessary for the CAISO to develop and finalize the unified planning assumptions and study plan prior to the commencement of the technical assessments performed during phase 2.
>
> Following the draft study plan publication, the CAISO will open a comment window to receive stakeholder comments regarding the study plan and for interested parties to submit economic planning study requests. After the comment window is closed, the CAISO will review stakeholder comments, evaluate economic planning study requests, select the high priority studies and publish the final study plan. (Billington, 2019, P.22)

This phase draws information primarily from three sources: the CEC's IEPR, CPUC's IRP, and the previous TPP (CAISO, 2019, P.12; Hou, 2017). The IEPR is a long-term forecast of energy demand, while the IRP is an energy efficiency, demand response, and generation resource procurement plan which "ensure[s] California has a safe, reliable, and cost-effective electricity supply" compliant with California's RPS (CPUC, 2020). The IRP has replaced the LTPP in this process (CAISO, 2019, P.12).

CAISO would only initiate transmission upgrades to address reliability issues. Said another way, in order to be included in this phase, offshore wind would have to be included in the policy-driven plans (e.g. the IRP or IEPR), of a state-level entity (e.g. CPUC or CEC) (D. Hou, personal communication, April 21, 2020). Preliminary feasibility studies of offshore wind could provide the confidence to CPUC to include offshore wind in the IRP, paving the way for inclusion in CAISO's TPP.

Phase Two

Once the UPA and study plan have been finalized, phase two of the process begins. Phase two runs from the second quarter of the first year through the first quarter of the second year. During phase two, the phase one study plan is executed and a finalized transmission plan is created. This phase also includes several opportunities for stakeholders to provide input before culminating in approval of the transmission plan by the CAISO Board of Governors (Billinton, 2019, P.23,32).

Phase Three

Phase three of the TPP starts in the second quarter of the second year, and runs through the end of the year. (Billinton, 2019, P.62) During this phase, project sponsors bid on transmission projects that were identified in Phase 2 for "[p]roposals to finance, construct, own, operate and maintain regional transmission facilities "(Billinton, 2019, P.63). At the end of Phase 3, approved project sponsors are reported.

Permitting and Construction

Once included in a board approved TPP, projects return to the CPUC and other agencies for the siting and permitting process (D. Hou, personal communication, April 21, 2020). Based on the timeline of the Tehachapi Renewable Transmission Project, the construction process can be completed in as little as two years, or as many as six years (SCE, 2019). It is worth noting that this projection is based on only two data points within a single project, and actual completion times could vary more significantly. For more information on CAISO's TPP, see Appendix A.

In order to understand the potential costs of the transmission upgrades needed to utilize offshore wind energy, studies were performed across the three scales of offshore wind development. For the pilot and small commercial scale, only a single option was evaluated, while in the large commercial case four possible transmission pathways were evaluated.

3. TRANSMISSION UPGRADE ALTERNATIVES

PG&E conducted an informational interconnection study for offshore wind in order to estimate the transmission upgrades required for offshore wind. The transmission study identified system impacts caused solely from the addition of an offshore wind farm then added system components to mitigate any thermal or voltage violations. The assumptions built into the study are:

- Evaluate three different scale wind farms independently, 48 MW, 144 MW, and 1,836 MW, all using 12 MW wind turbines (see Chapter 1)
- Power output for different wind farms modeled for Humboldt Call Area (see Chapter 1:)
- Provide full deliverability of offshore wind power and other existing generation sources (i.e. no curtailment)
- Use load forecast for year 2029
- One-in-five year adverse weather conditions based on ambient temperature
- Model system under summer peak and spring off-peak scenarios
- Include all existing generators in the region but not new generators from the CAISO queue
- Mitigate overload under normal conditions (N-0 conditions, no contingency) and single contingencies (N-1 conditions, loss of one system element)
- Evaluate results against NERC TPL-001-4 standard to determine if the transmission system is acceptable based on Category P0, P1, P6, and P7 standards.

The assumptions, methods, and results from the informational interconnection study are described completely in PG&E (2020). Transmission upgrades identified in this study are summarized in the subsections below for each scale wind farm.

3.1 Pilot Scale (48 MW)

At the smallest scale of offshore wind development considered in this study, 48 MW, PG&E recommends upgrades to the transmission system to mitigate thermal overload and avoid blackouts caused by failure of one system component (i.e. N-1 contingencies). After interconnecting a 48 MW offshore wind generator at the Humboldt Bay Substation, two sections of transmission line exceeded their thermal loading capacity during summer peak conditions (PG&E, 2020 pg. 20). Furthermore, the addition of a 48 MW offshore wind generator would make the Humboldt transmission region susceptible to blackouts caused by failure of either 115-kV transmission line or the 115/60-kV transformer at the Bridgeville Substation (PG&E, 2020 pg. 21). To mitigate these issues, PG&E recommends construction of a parallel 115-kV transmission line connecting the Humboldt Bay, Humboldt, Trinity, and Cottonwood Substations, plus construction of a 115- kV transmission line connecting the Bridgeville and Garberville Substations (Figure 3-3).

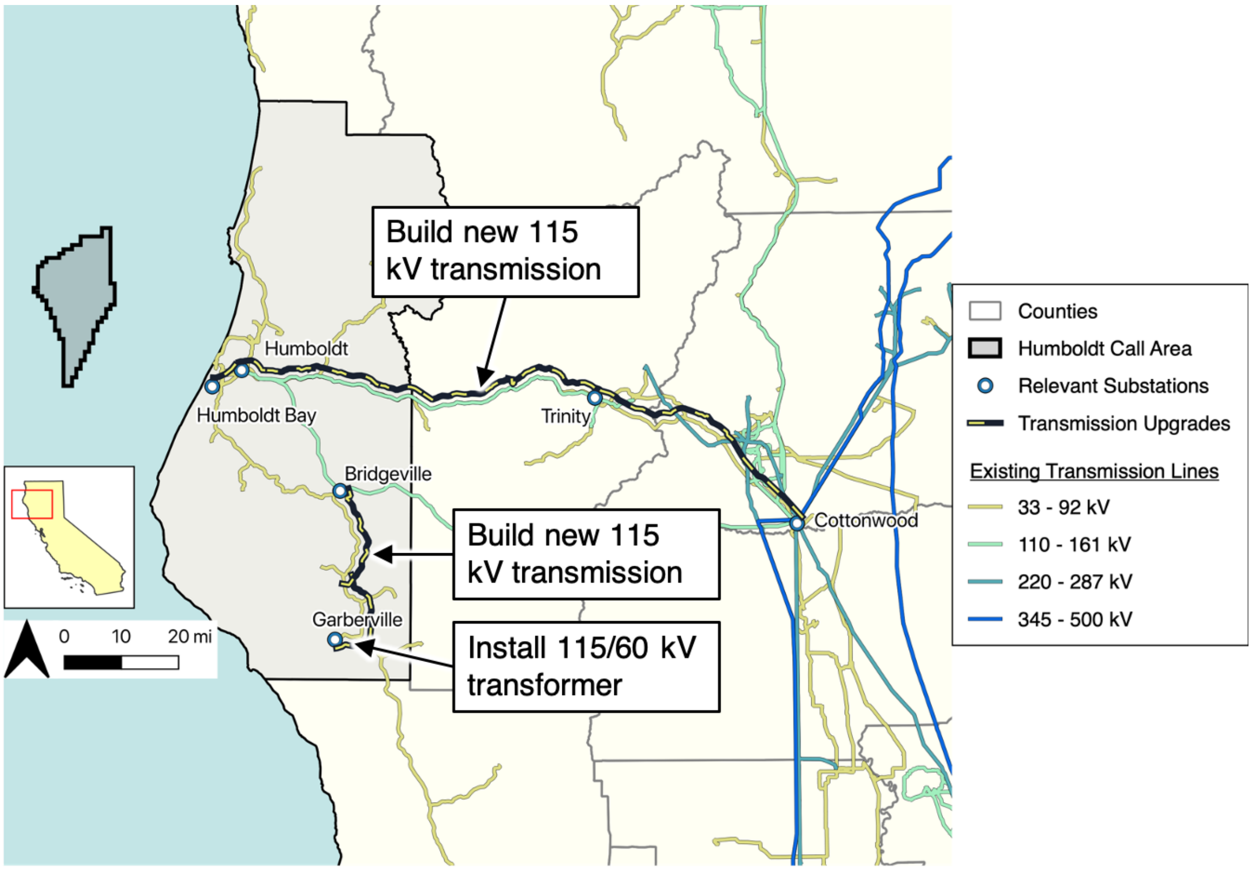


Figure 3-3. Transmission improvements for 48 MW wind farm scenario.

3.2 Small Commercial Scale (144 MW)

Interconnecting a 144 MW offshore wind generator creates the same overload issues identified in the 48 MW interconnection but to a greater extent (PG&E, 2020 pg. 31). To mitigate these issues and provide reliable service without voltage or thermal overload, PG&E recommends the same new transmission lines identified for the 48 MW scenario plus additional reconductoring of the existing 115-V transmission line going east to the Trinity Substation and reconductoring the existing 115-kV and 60-kV transmission lines going south to the Willits Substation (Figure 3-4).

The transmission upgrades described above for a 48 MW or 144 MW generator allow those wind farms to interconnect to the grid, but do not build a pathway for larger deployment of offshore wind in the region. Larger offshore wind farms will require higher voltage transmission and wider rights-of-way that connect with major load centers in the state. Transmission upgrades at these smaller scales do not contribute to the transmission needs of gigawatt-scale development. In other words, investments made for smaller, initial projects become sunk costs that do not contribute directly to the build out of larger, future wind farms.

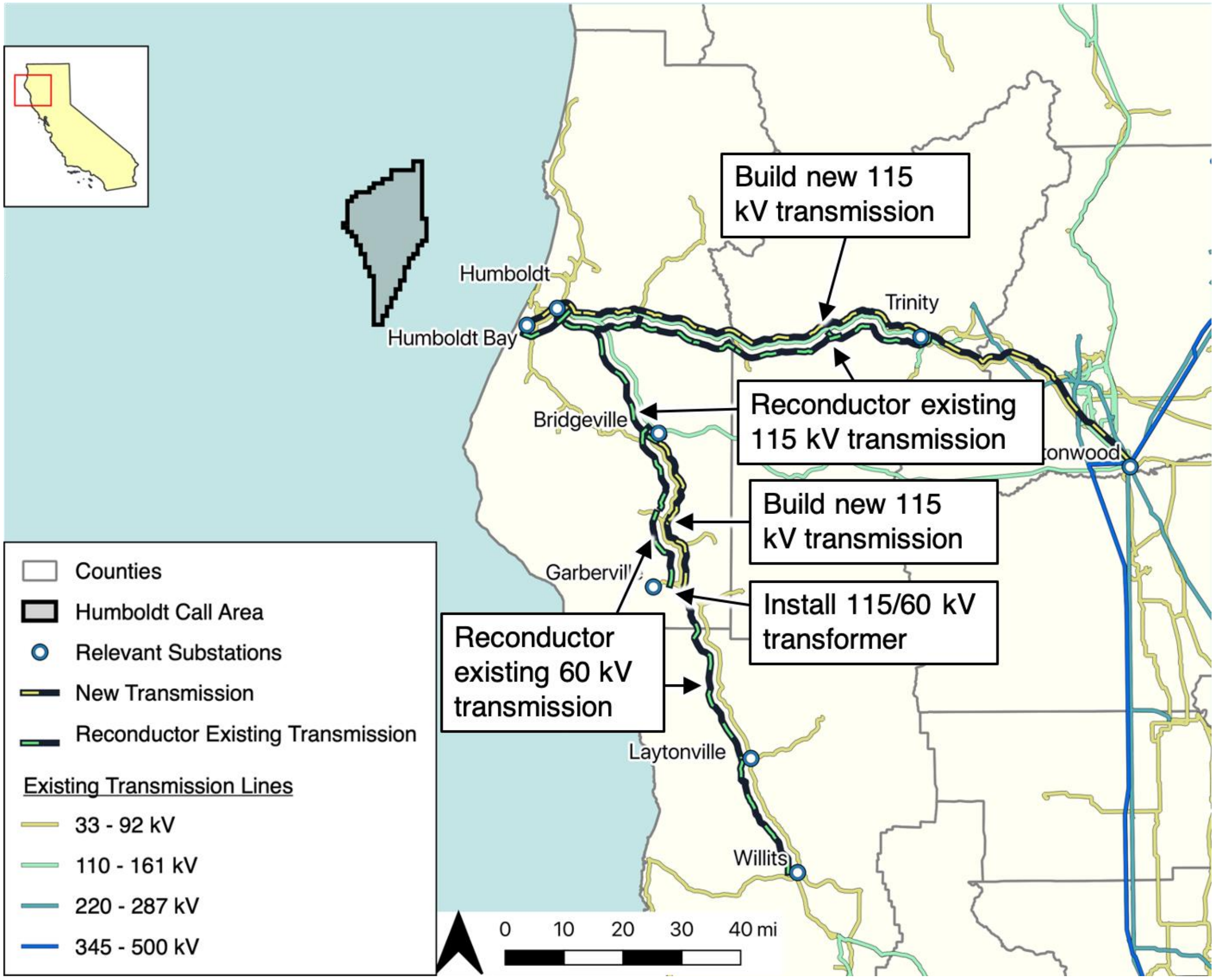


Figure 3-4. Transmission improvements for 144 MW wind farm scenario.

3.3 Large Commercial Scale (1,836 MW)

Interconnection of a larger offshore wind development on the order of 1,836 MW far exceeds the capacity of the Humboldt transmission system and regional electricity demand. For this large-scale scenario, transmission options were considered that connect the wind farm into major north-south transmission lines or larger load centers in the state. Three alternatives were identified by PG&E for the 1,836 MW scenario, including two over-land options and one subsea option (Figure 3-5). The subsea transmission alternative is separated into nearshore and far-from-shore cable corridors, both of which include the same onshore transmission infrastructure.

The alternatives presented below were developed as part of a conceptual planning study and would need much more evaluation to determine the feasibility. There would be challenges associated with developing any of the alternatives. Constructing new, long-distance overland transmission would face several barriers, including widening existing or acquiring new utility rights-of-way; environmental permitting across a diverse set of ecological conditions; engineering, access, and construction of transmission in mountainous, forested terrain with limited road access; social concerns from stakeholders or adjacent communities; and wildfire and safety concerns associated with substations and overhead transmission lines. A conceptual subsea cable was evaluated as a separate option for long-distance transmission to connect large-scale wind generators offshore from the northern California coast to major load centers in the state. A subsea power cable would face some of the same barriers and also several different challenges. The analysis presented below does not provide a comparison between the alternatives, but instead only identifies the conceptual alternatives based on a power flow analysis.

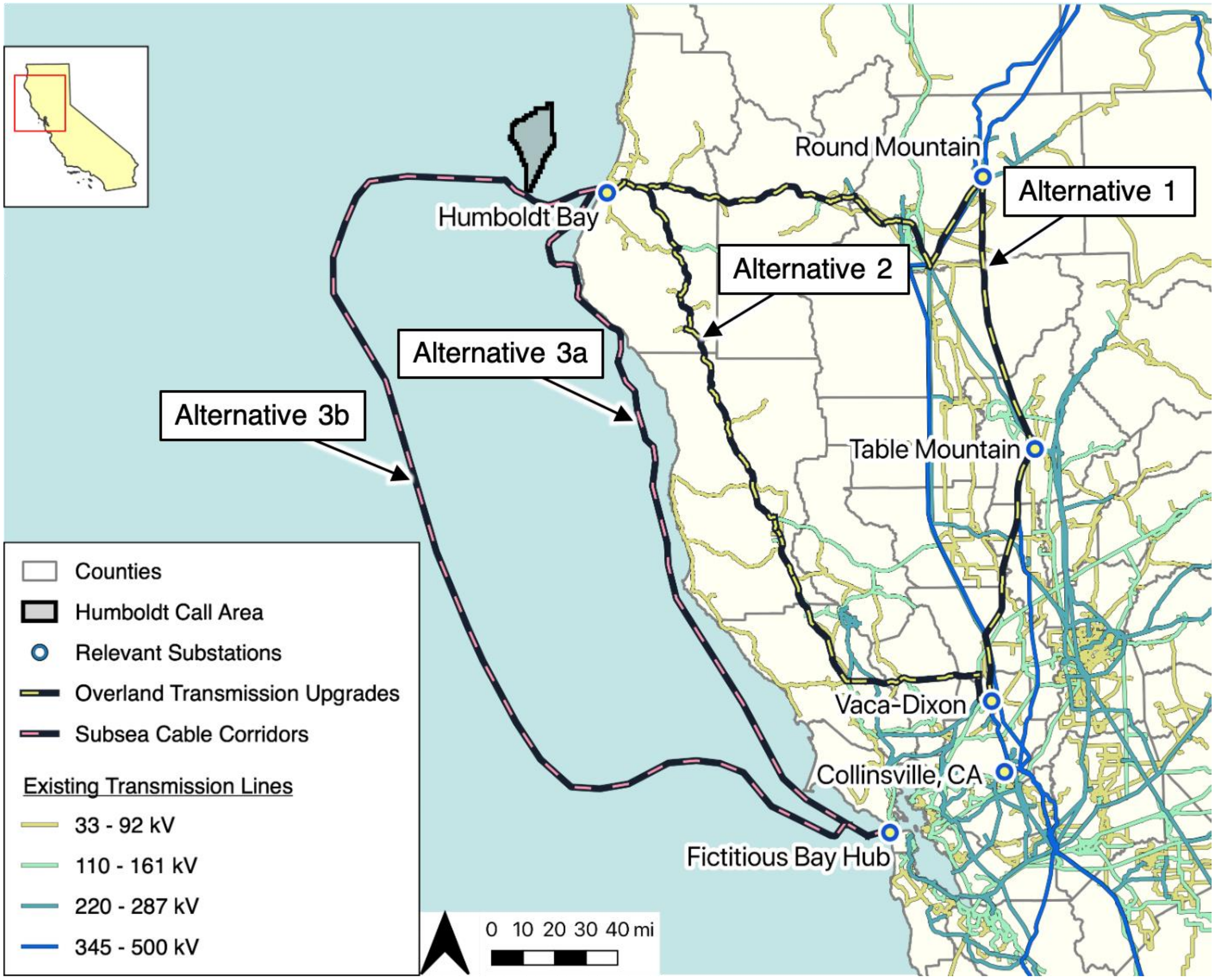


Figure 3-5. Transmission alternatives for 1,836 MW wind farm scenario.

3.3.1 Overland Transmission

Two overland transmission alternatives were investigated for interconnecting offshore wind. Both alternatives involve building new transmission to connect to the 500-kV transmission system running north-south in California's Central Valley.

The California-Oregon Intertie (COI) is a system of three parallel 500-kV transmission lines connecting southern Oregon (near Klamath Falls) to northern California (near Redding) with a capacity of 4,800 MW (north to south) (PG&E, 2020, pg 43-44). Alternative 1 was developed in an attempt to connect offshore wind into COI at the Round Mountain Substation. During the analysis of this alternative, two key capacity challenges were identified: 1) interconnection at Round Mountain would cause thermal overload during summer peak conditions on the 500-kV transmission lines from Round Mountain to Table Mountain and Vaca-Dixon, and 2) there is not enough available capacity allocated on COI to sustain this connection due to existing contractual obligations and reserved capacity (PG&E, 2020 pg 47). Therefore, new transmission capacity would need to be constructed beyond the connection to Round Mountain to accommodate 1,836 MW of offshore wind. In addition to building a 500-kV transmission line connecting

Humboldt to Round Mountain, new 500-kV transmission would need to be constructed from the Round Mountain to the Table Mountain and then Vaca-Dixon Substations in parallel with existing lines.

Alternative 2 uses a different pathway to move energy directly to densely populated regions of the state with greater power demand. Instead of connecting through two other large substations in Round Mountain and Table Mountain, Alternative 2 creates a path directly to the Vaca-Dixon Substation. New transmission infrastructure is added between Vaca-Dixon and the East Bay Area to deliver power to the substations that serve larger loads, including the Pittsburg Power Plant and Tesla Substations and construction of a new 230/500 kV substation in Collinsville, CA (PG&E, 2020 pg 61-63).

3.3.2 Subsea Cable

A conceptual high-voltage, direct-current (HVDC) subsea cable was evaluated as a separate option for long-distance transmission to connect large-scale wind generators offshore from the northern California coast to major load centers in the state. PG&E identified the Greater San Francisco Bay Area (SF Bay Area) to be the target location for interconnection because of the significant load, limited generation facilities, and potential reliability issues within different transmission planning divisions in the region. Two conceptual subsea cable corridors were identified that could connect the Humboldt Bay and SF Bay Areas: one near-shore corridor and one deep-water corridor located further from shore (Chapter 3).[1] Either subsea cable corridor will require the same on-land infrastructure including HVDC converter stations at the northern and southern terminal.

A subsea transmission cable to the SF Bay Area would connect at a central location and distribute power to three separate transmission sub-regions because no single region in the SF Bay Area can absorb an additional 1,836 MW of capacity (PG&E, 2020 pg. 71). From a generic central node (location not identified), power would spread to the SF Peninsula (Potrero Substation), the South Bay (Los Esteros Substation), and the East Bay (East Short Substation). Connecting the central node to three sub-regions would results in power flows that exceed the capacity of existing transmission lines if alternating current power is allowed to flow uncontrolled (PG&E, 2020 pg 71). To control the power flow to each sub-region, PG&E recommends installing phase shifters or using DC-transmission lines between the central converter station to the sub-regional substations (PG&E, 2020 pg 71).

4. TRANSMISSION COSTS

PG&E estimated the transmission upgrade costs for each alternative using the unit cost guide provided by CAISO (2020). The cost estimate included a 100% contingency factor to provide an upper bound that would account for difficult terrain, limited road access, and permitting challenges (see the range in Figure 3-6). Within the range, the Schatz Energy Research Center identified an adjusted cost estimate (black line in Figure 3-6) by adding specific cost multipliers for terrain and estimates land acquisition and excavation. The adjusted cost estimates were $540 million for the 48 MW scale, $970 million for the 144 MW scale, and between $1.7 and $3.0 billion for the 1,836 MW scale.

[1] Each subsea cable corridor would face a variety of design and permitting challenges. More information about the conceptual engineering design, technology, and corridors is provided in the report from Porter and Phillips (2020).

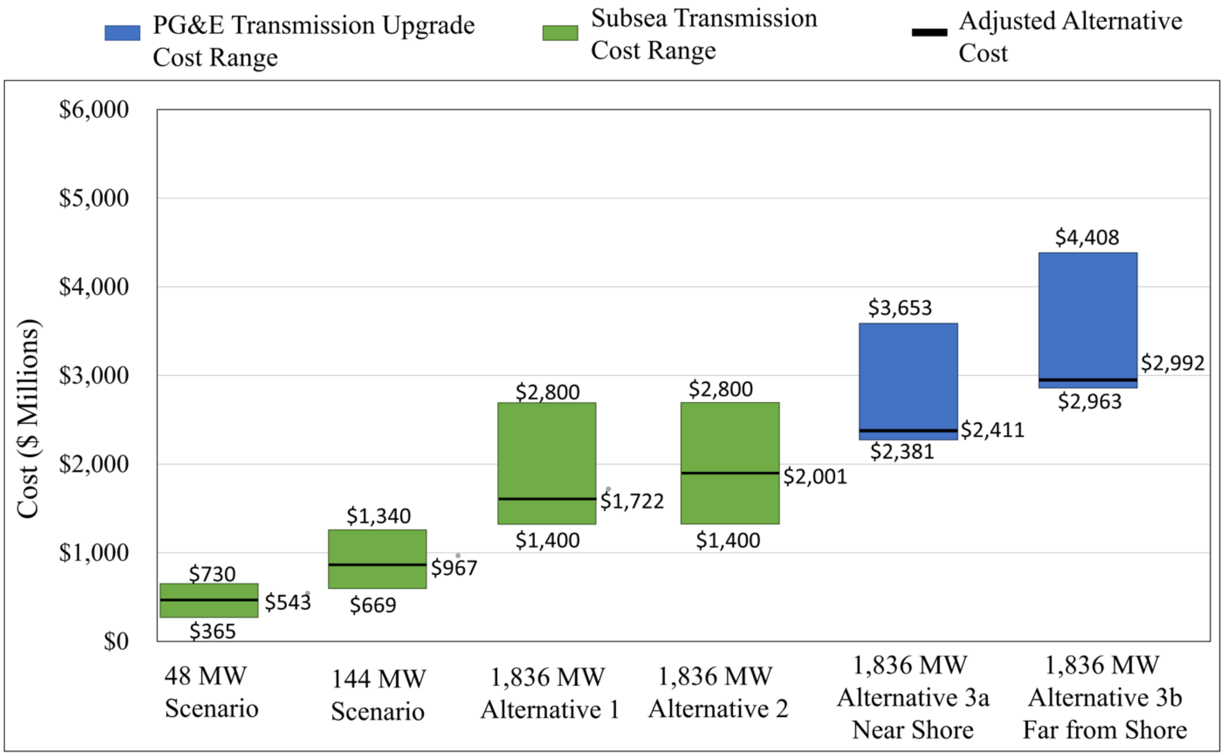


Figure 3-6. Transmission upgrade costs for different offshore wind scenarios showing the range of costs from PG&E study (colored bar), with adjusted value estimated (line).

As expected, the transmission upgrades are more expensive for larger capacity wind farms. But since the large-scale transmission costs are spread across more generation capacity, they have a lower cost per unit of installed wind farm capacity (Figure 3-7).

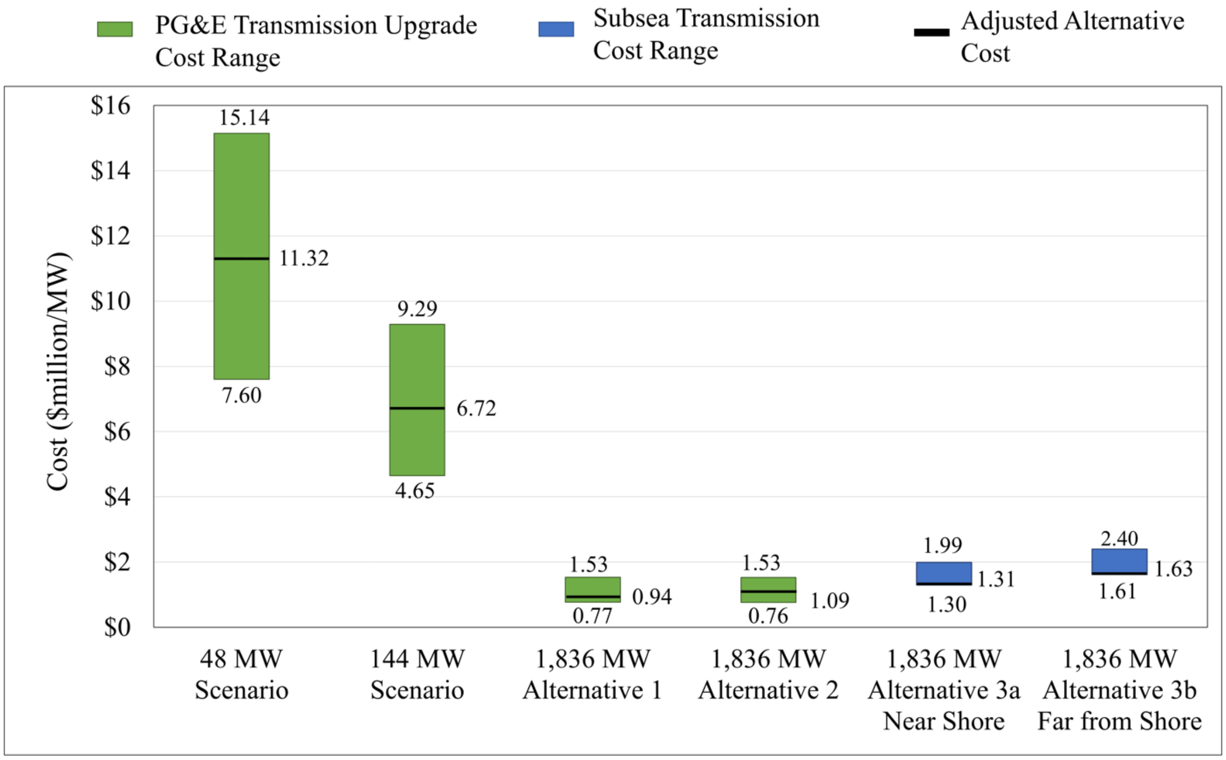


Figure 3-7. Transmission cost upgrades per unit of installed offshore wind capacity showing the range of costs from PG&E study (colored bar), with adjusted value estimated (line).

To compare against recent large-scale transmission development projects in California, the upgrade costs were normalized by the transmission line length (Figure 3-8). Recent costs for transmission developments over 2 GW capacity are roughly $10 million per mile. The cost estimates for the 1,836 MW wind farm transmission line alternatives fall within the expected range of costs. The smaller scale wind farm transmission costs fall outside the capacity range of previous case studies, as they have lower estimated costs per mile values. This may be due to their lower transmission line voltages.

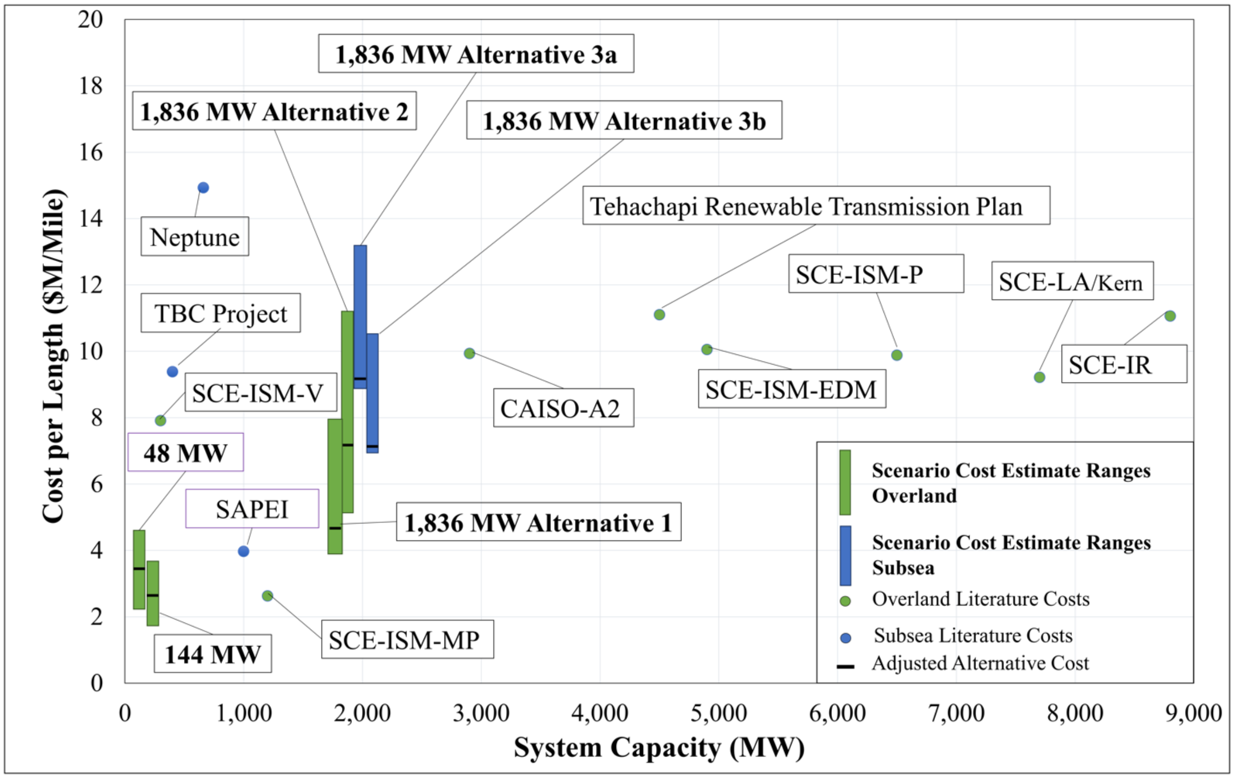


Figure 3-8. Cost per mile of the wind farm alternatives compared to recent project costs in California. Description and source for recent California transmission projects are provided in Appendix A.

5. ACRONYMS

Acronym	Name
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEC	California Energy Commission
CPUC	California Public Utilities Commission
FERC	Federal Energy Regulatory Commission
GIDAP	Generator Interconnection and Deliverability Allocation Procedures
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Plan
LTPP	Long-term Procurement Process
RPS	Renewables Portfolio Standard
TPP	Transmission Planning Process

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APPENDIX 3.A - TRANSMISSION UPGRADE CASE STUDIES

Transmission cost, capacity, and line distance data were collected from a Lawrence Berkeley National Laboratory report on transmission for wind energy (Mills et al., 2009) and online transmission reviews (Dombek, 2012; TransmissionHub, 2018). They are summarized in

Table 3-1 Summary of cost and capacity of completed transmission projects in California.

Project Abbreviation	*Location*	*Project capacity (MW)*	*Cost (Millions $)*	*Source*
CAISO-A2	Mira Loma, CA	2,900	$1,500	(Mills et al., 2009)
SCE-LA/Kern	Los Angeles and Kern Counties	7,700	$2,610	
SCE-ISM-P	Inyo, San Bernardino, and Mono Counties, Pisgah	6,500	$1,550	
SCE-ISM-EDM	Inyo, San Bernardino, and Mono Counties, El Dorado/Mohave	4,900	$1,900	
SCE-ISM-MP	Inyo, San Bernardino, and Mono Counties, Mountain Pass	1,200	$110	
SCE-ISM-V	Inyo, San Bernardino, and Mono Counties, Victorville	300	$70	
SCE-IR	Imperial and Riverside Counties	8,800	$2,670	
Tehachapi Renewable Transmission Plan	Kern, Los Angeles, and San Bernardino Counties	4,500	$2,500	(TransmissionHub, 2018)
Trans Bay Cable Project	San Francisco Bay	400	$400	(CAISO, 2007)
Neptune	Lower Bay (New Jersey to Long Island)	660	$744	(Ardelean, M., Minnebo, Philip, 2015) (Hocker, C., Martin, L. 2020)
SAPEI	Tyrrhenian Sea (Italy to Sardinia)	1,000	$1,035	(Ardelean, M., Minnebo, Philip, 2015) (Dotti, 2017)

Chapter 4: Interconnection Feasibility Study Report

Prepared by:
Pacific Gas and Electric Company

Pacific Gas and Electric Company

Interconnection Feasibility Study Report (Informational Only)

Capacity and Reliability

Schatz Energy Research Center

Humboldt County Offshore Wind Feasibility Analysis

Final

April 17, 2020

WE DELIVER ENERGY.

Pacific Gas and Electric Company

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Tables:

Executive Summary

Pacific Gas and Electric Company (PG&E) is pleased to support Schatz Energy Research Center (Schatz Center) to conduct an informational feasibility study for interconnecting offshore wind generation near Humboldt Bay. Performing this informational feasibility study is in response to the Bureau of Ocean Energy Management's request to better understand the feasibility of interconnecting potential offshore wind generation, and the potential electric grid impacts. The study is funded under a cooperative agreement with the Bureau of Ocean Energy Management (BOEM).

The Schatz Energy Research Center of Humboldt State University requested PG&E to perform a study to evaluate impacts of interconnecting three scales of wind farms to the PG&E electric transmission system.

Below are the wind farm scales that will be studied in years 2029. The wind farms are to be assessed individually:

- Option 1 – 48 MW, consisting of four 12 MW turbines
- Option 2 – 144 MW, consisting of twelve 12 MW turbines

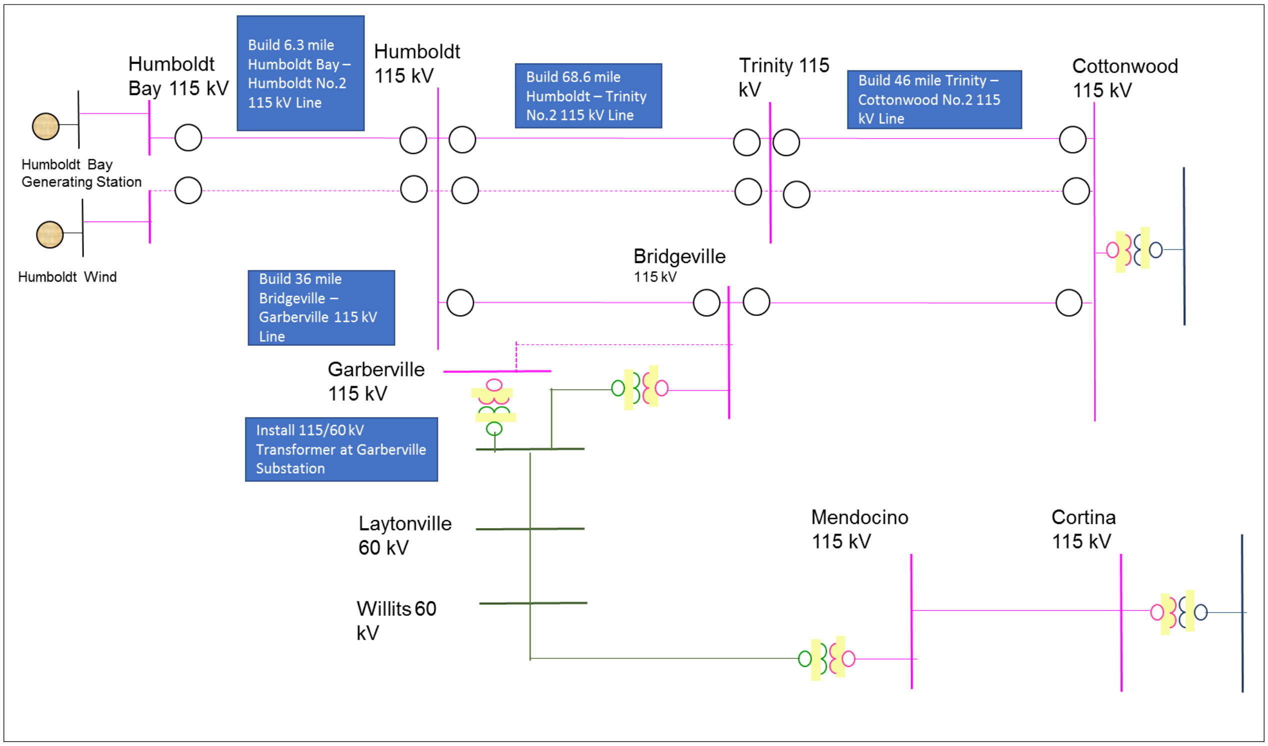
The above wind farm projects will assume interconnection at Humboldt Bay 115 kV Substation.

- Option 3 – 1,836 MW, consisting of one hundred fifty-three 12 MW turbines

The entire 1,836 MW is to be interconnected at new 500 kV Substation by Humboldt Bay.

Considering the Humboldt area has a relatively less densely populated load center with an adequate amount of internal generation, the system is currently designed for small margin to import and export electric power. The import and export capability in this area is very weak, therefore, to interconnect a large amount of generation in this area would require robust alternatives. Various alternatives will be considered to address exports to large load areas off the coast of California as well as alternatives leading to strong 500 kV and 230 kV Transmission pathways. All alternatives will lead power to the CAISO controlled transmission grid and eventually flow to large load centers that will benefit from the diverse mix of generating resources.

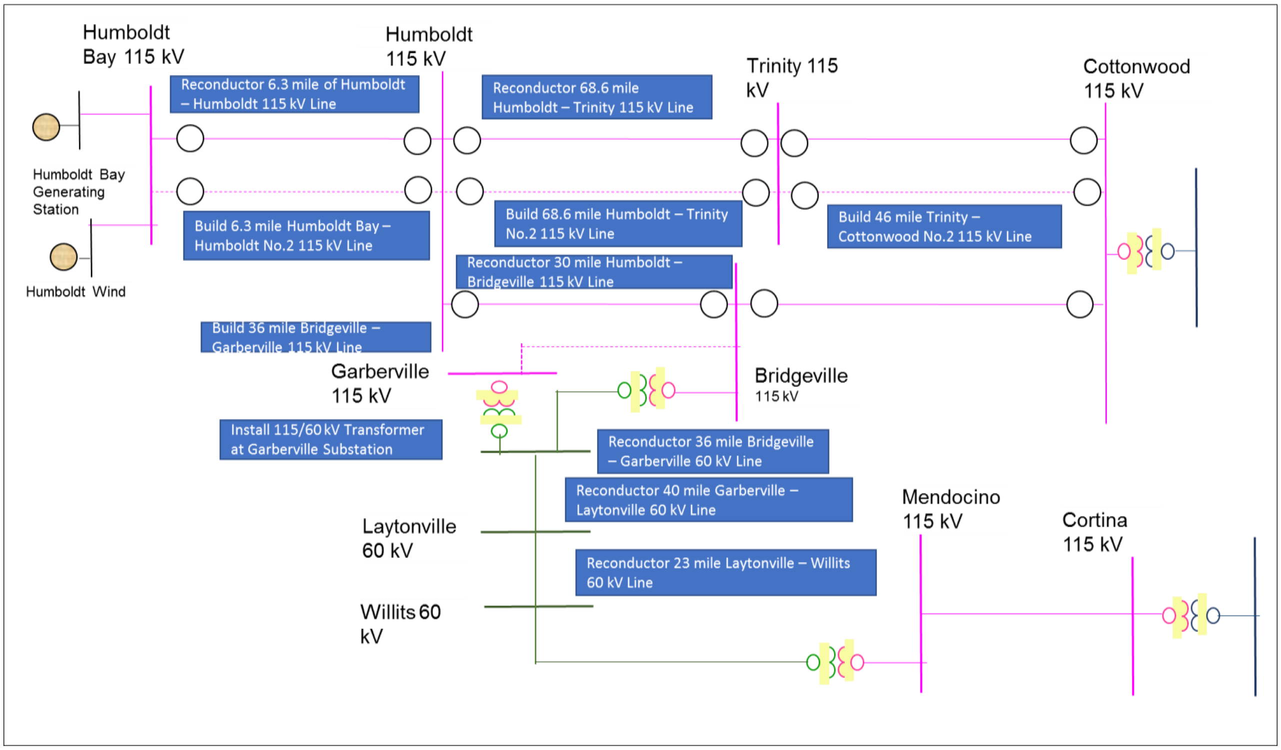
Option 1 – 48 MW, consisting of four 12 MW turbines
This option considered 48 MW's connected at Humboldt Bay 115 kV Substation. Based on the contingency analysis, study results show normal system overloads and overloads caused by single contingencies. Analysis performed show that when a loss of a 115 kV transmission line occurred the remainder 115 kV lines overload due to the excess power flow. The current system configuration and capacity would not be able to support 48 MW's connected to the Humboldt system in a heavy summer scenario with Humboldt Generating Station operating at close to or full output. It is recommended to build 115 kV lines to alleviate congestion on the Humboldt 115 kV Transmission grid. Potential upgrades may cost between $365M to $730M.



OPTION 1 to interconnect 48 MW's in Humboldt Area		
Alternative	**Facility**	**Cost Estimate**
Alt 1: Status Quo		$0
Alt 2: Build New 115 kV Transmission Lines	Build new 6.3 mile Humboldt Bay - Humboldt No. 2 115 kV Line	$14M
	Build new 68.58 mile Humboldt - Trinity No. 2 115 kV Line	$154M
	Build new 46.28 mile Trinity - Cottonwood No. 2 115 kV Line	$104M
	Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation	$12M
	Build a new 36 mile Bridgeville - Garberville No. 2 115 kV Line	$81M
	Total	**$365M - $730M**

Option 2 – 144 MW, consisting of twelve 12 MW turbines

This option considered 144 MW's connected at Humboldt Bay 115 kV Substation. Based on the contingency analysis study, results show normal system overloads and overloads caused by single contingencies. Analysis performed showed that when a 115 kV transmission line loss occurred the remaining 115 kV lines overload due to the excess power flow. The current system configuration and capacity would not be able to support 144 MW's connected to the Humboldt system in a heavy summer scenario with Humboldt Generating Station operating at close to or full output. It is recommended to build 115 kV lines to alleviate congestion on the Humboldt 115 kV Transmission grid. It is also recommended to interconnect to Humboldt 115 kV Substation to offload costs and avoid reconductoring and building a new line to Humboldt Bay 115 kV Substation. Potential upgrades may cost between $669M to $1.34B.



OPTION 2 to interconnect 144 MW's in Humboldt Area		
Alternative	**Facility**	**Cost Estimate**
Alt 1: Status Quo		$0
Alt: 2 Reconductor and build new 115 kV and 60 kV Lines	Reconductor 6.3 miles of Humboldt Bay - Humboldt 115 kV Line	$14M
	Reconductor 30.3 miles of Humboldt - Bridgeville 115 kV Line	$68M
	Reconductor 68.58 mile of Humboldt - Trinity 115 kV Line	$50M
	Reconductor 36 mile of Bridgeville - Garberville 60 kV Line	$30M
	Reconductor 40 miles of Garberville - Laytonville 60 kV Line	$90M
	Reconductor 23 miles of Laytonville - Willits 60 kV Line	$52M
	Build new 6.3 mile Humboldt Bay - Humboldt No. 2 115 kV Line	$14M
	Build new 68.58 mile Humboldt - Trinity No. 2 115 kV Line	$154.2M
	Build new 46.28 mile Trinity - Cottonwood No. 2 115 kV Line	$104.25M
	Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation	$12M
	Build a new 36 mile Bridgeville - Garberville No. 2 115 kV Line	$81M
	Total	**$669M - $1.34B**

Option 3 – 1,836 MW, consisting of one hundred fifty-three 12 MW turbines
As explained above, considering that the Humboldt transmission system has no 500 kV facilities and has limited importing and exporting capabilities to allow interconnection of such large amount of new generation, three distinct alternatives to connect to the existing 500 kV system were evaluated under this option. The alternatives considered to interconnect the entire 1,836 MW are:

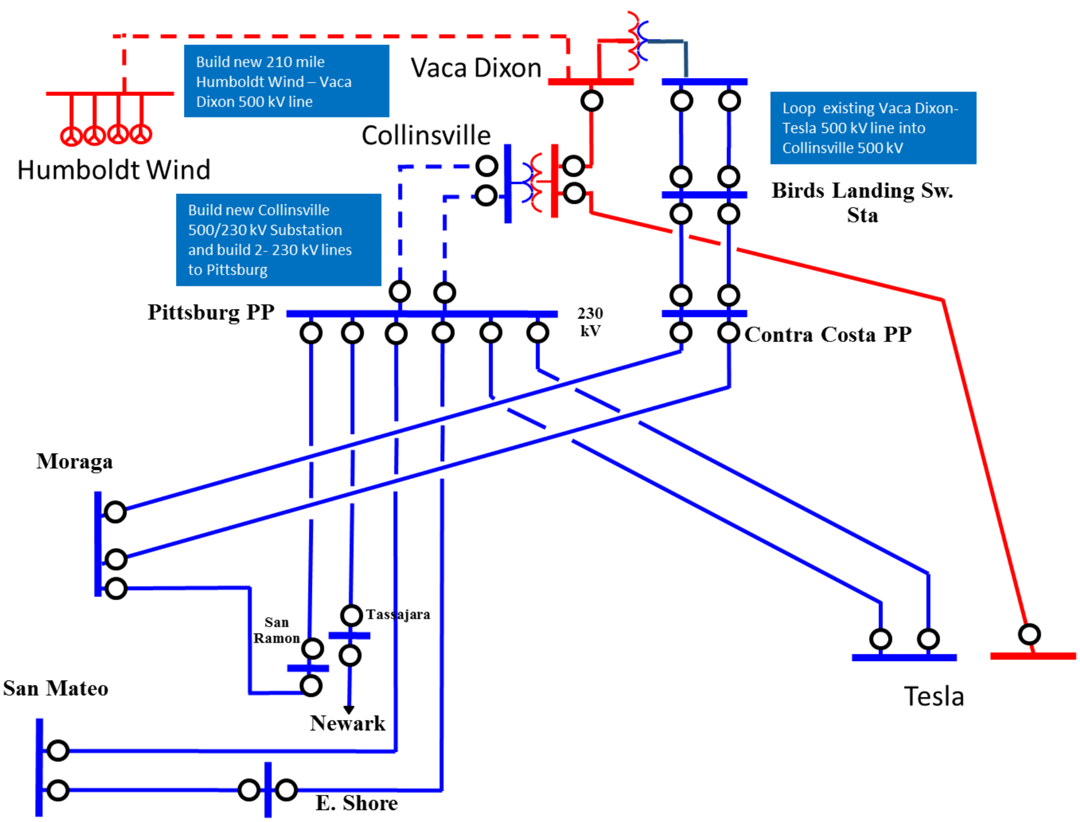
Alternative 1
This alternative consists of an interconnection of 1,836 MW's from the Humboldt shore to Round Mountain 500 kV Substation. The Round Mountain 500 kV Substation is part of a WECC

path 66 connection. In depth studies will need to be performed and coordinated between the CAISO, WECC and Affected Parties. The studies performed indicated with COI fully scheduled there is not enough capacity to interconnect 1,836 MW's. It is recommended to build new 500 kV lines from Round Mountain 500 kV Substation down to the major PG&E load center. The load center is served from Vaca Dixon and Tesla 500 kV substations. Contingency analysis was performed for governor power flow and no substantial issues were identified for the additional 500 kV path. It is also recommended that many more robust studies occur to capture voltage and transient stability if it is decided this alternative is viable. Potential upgrades may cost between $1.4B to $2.8B.

OPTION 3 to interconnect 1836 MW's in Humboldt Area		
Alternative	**Facility**	**Cost Estimate**
Alt: 1 Build 500 kV Line from Humboldt area to Round Mountain 500 kV Substation	Build new 120 mile Humboldt Wind - Round Mountain 500 KV Line	$480M
	Build new 89 mile Round Mountain - Table Mountain 500 KV Line	$360M
	Build new 83 mile Table Mountain - Vaca Dixon 500 kV Line	$336M
	Build new 57 mile Vaca Dixon - Tesla 500 kV Line	$228M
	Reconductor 3 miles of USWP-JRW - Cayetano 230 kV Line	$5M
	Total	**$1.4B - $2.8B**

Alternative 2

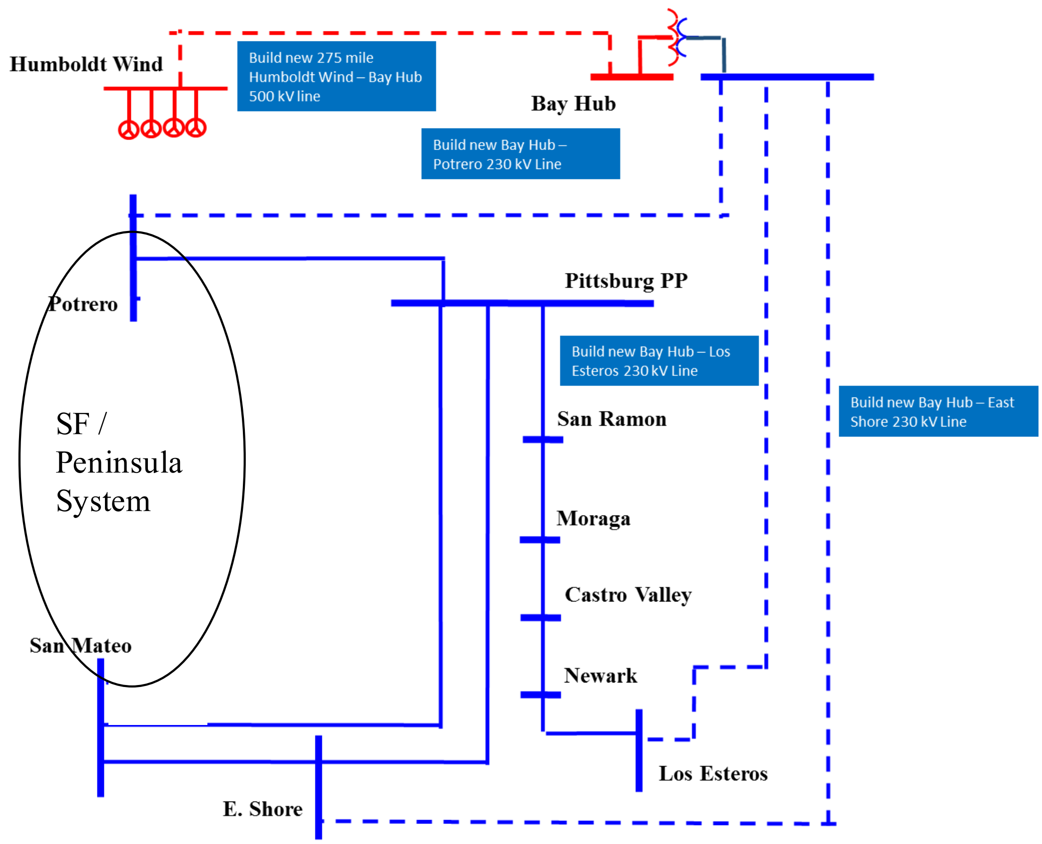
This alternative connects the Humboldt offshore wind to the Vaca Dixon 500 kV Substation. By going directly to the Vaca Dixon substation and a direct path into the Bay Area with the Collinsville Project, the effects on COI are limited and no substantial issues were identified in governor power flow analysis. The additional scope of work to implement the Collinsville Project would bring in another 500 kV source into the bay area and serve bay area demand. The Collinsville connection terminates at Pittsburg Substation which has many robust outlets. Transmission lines connect to Potrero (via TBC) and serves the SF area. A connection to San Mateo is also available and serves the Peninsula. The Tri Valley, Fremont and San Jose area also connected to Pittsburg. The Oakland area is also served by Pittsburg. Lastly a major connection to Tesla is also available to import or export any excess power to be distributed throughout PG&E greater transmission system. Potential upgrades may cost between $1.4B to $2.8B.



OPTION 3 to interconnect 1836 MW's in Humboldt Area		
Alternative	**Facility**	**Cost Estimate**
Alt 2: Build 500 kV Line from Humboldt area to Vaca Dixon	Build new 210 mile Humboldt Wind - Vaca Dixon 500 kV Line	$840M
	Build new Collinsville 500 kV Substation	$500M
	Loop Vaca Dixon-Tesla 500 kV line into new Collinsville Substation	
	Reconductor 25 miles of Vaca Dixon-Collinsville 500 kV Line	
	Install 500/230 kV transformer at new station	
	Construct two, 5.3-mile underground 230 kV lines over to Pittsburg P.P. Substation	
	Install voltage support as required at various locations with the Bay Area	
	Reconductor 12.5 miles of E. Shore - San Mateo 230 kV Line	$20M
	Reconductor 3 miles of USWP-JRW - Cayetano 230 kV Line	$5M
	Reconductor 3 miles of Cayetano - North Dublin 230 kV Line	$5M

	Reconductor 9 miles of Newark D - NRS 400 115 kV Line	$20M
	Reconductor 8.5 miles of Pittsburg - Clayton 115 kV Line	$13M
	Total	$1.4B - $2.8B

Alternative 3
This alternative involves building a 500 kV substation within the Bay Area. This 500 kV substation would have three 230 kV lines that export power to Potrero, Los Esteros, and East Shore 230 kV substations. This alternative does not interconnect to the 500 kV Bulk System. All generation is in turn subscribed within the Bay Area. Depending on the allocation of MW's per designated substation the alternatives could include many local upgrades to none at all. In the capacity section of the report more details are provided. It is recommended that the 230 kV lines coming out of the BayHub Substation be DC controllable. Potential upgrades may cost between $3.5B to $5.8B.



OPTION 3 to interconnect 1836 MW's in Humboldt Area		
Alternative	**Facility**	**Cost Estimate**
Alt 3: Build 500 kV Line from Humboldt area to Bay Area	Build new 275 mile Humboldt Wind - BayHub 500 kV Line	$2.75B
	Build new Bay Hub 500/230 kV Substation	$700M
	Build 3-230 kV HVDC subsea cables	
	1) Bay Hub - Potrero No. 1 230 kV Line	
	2) Bay Hub - E. Shore No. 1 230 kV Line	
	3) Bay Hub - Los Esteros No. 1 230 kV Line	
	Reconductor 12.5 miles of E. Shore - San Mateo 230 kV Line	$20M
	Total	$3.5B - $5.8B

Introduction

The Humboldt County Offshore Wind Feasibility Analysis is comprised of three different options and generations sizes being studied. All options will be studied in year 2029.

The first option includes an interconnection of wind generation plant with a total rated output of 48 MW to Pacific Gas and Electric's (PG&E's) Humboldt Bay 115 kV Substation which is located in Humboldt County, CA. The project was modelled with a total installed capacity of 55.57 MVA to meet FERC Order 827 which FERC addresses Reactive Power Requirements for Non-Synchronous Generators and FERC Order 842 which addresses interconnected generators to provide frequency response.

The second option includes an interconnection of wind generation plant with a total rated output of 144 MW to Pacific Gas and Electric's (PG&E's) Humboldt Bay 115 kV Substation which is located in Humboldt County, CA. The project was modelled with a total installed capacity of 165.71 MVA to meet FERC Order 827 and FERC Order 842.

The third option includes an interconnection of wind generation plant with a total rated output of 1836 MW to Pacific Gas and Electric's (PG&E's) electric grid. Per the Schatz Research Energy team various routes were assessed to export power to the bulk transmission system. The three alternatives considered include 1) a route to the east 2) a route to the southeast 3) a route directly to the bay area load centers. The project was modelled with a total installed capacity of 2105.18 MVA to meet FERC Order 827 and FERC Order 842.

For the above high level scope projects to be interconnected high level transmission upgrades will be necessary. Alternatives above consider contingency analysis and scope of alternatives have been increased to mitigate potential normal system (N-0) and single contingency (N-1) outages. All alternatives studied are to be used for informational purposes. Within this Informational Feasibility Study, PG&E may propose variations, additions, or other alternatives and Point of Interconnections (POIs) that may be better suited for interconnecting Project Options in the recommendations section of the report.

The study will assess the units at full capacity deliverable status with a current snapshot of the system for heavy summer and spring off peak scenarios. The basecases utilized are used for reliability studies and developed through the CAISO Transmission Planning Process (TPP). Generation dispatch is again based on TPP assumptions and does not reflect the optimal dispatch based on economics, as price per MW by unit is not available for this study. Also within this study no curtailments are assumed for a status quo basecase which includes generation options modelled and no contingency performed. Curtailments were also not addressed for any single contingency. Solutions or mitigations are suggested for potential violations. Congestion management however is observed for P6 contingencies which includes a single contingency to occur, with time in between for the system to adjust, and then another contingency occurs.

Please also note the various generator options are not modelled at collector station and collector branch levels as transient stability is not in the scope of this study. The generation total amount is modeled at the assumed POI bus.

The Informational Study will identify:

- Transmission system impacts caused solely by the addition of the Project
- System reinforcements necessary to mitigate any adverse impacts of the project under various system conditions; and
- Facilities required for system reinforcements with a non-binding good faith estimate of cost of responsibility.

Study Assumptions

Load Assumptions

PG&E has prepared a System Bulk basecase that focusses primarily on the Extra High Voltage (EHV) System. The System base cases model the WECC full-loop (interconnected) system with a load forecast that assumes a 1-in-5-year high ambient temperature adverse weather condition for the collective PG&E system.

Historically, PG&E has been a “summer peaking” system. There are pockets within PG&E that can experience higher demand loading in periods other than the summer months (for example, Humboldt and the coastal areas of the North Coast, North Bay, San Francisco, Peninsula and Central Coast often peak during the winter months). In this study since we are observing the overall effects to the entire PG&E system a summer peak scenario was chosen to study. This scenario includes heavy North to South flows on COI a 500 kV path that interconnects Oregon and California. In addition to Summer Peak conditions, other potentially limiting system conditions studied include Spring Off-Peak[1] conditions, with much lower system load than in the corresponding Summer Peak case. The table below reflects the time of year captured in the studies:

Table 1 Scenario Time Summary

Seasons	Load Periods
Summer (Jun 1 – Aug 31)	Peak (5pm to 7pm, weekdays)

For Year 10 (2029) basecases, Reactive Load forecasts are based on a general power factor assumption (0.97 lagging for summer peak cases and 0.99 leading power factor for off-peak cases) based on historical and expected power factor performance.

Load forecasts for the system cases are based on a 1-in-5-year adverse weather assumption based on ambient temperature; the resulting yearly forecasts for each Planning Area are shown in the table below. Each of the columns of represents a single Summer Peak case and each row represents the division Load in MW or Alternative Achievable Energy Efficiency (AAEE) Mid value associated with that case, which are totaled in the last row.

Table 2 System Load Summer Peak Forecast Summary (1 in 5 year, with AAEE Mid included)

Division Name	2029
HUMBOLDT	121
N. COAST	800
N.VALLEY	935
SACRAMENTO	1206
SIERRA	1319
NORTHBAY	689
EAST BAY	878
DIABLO	1662
S.F.	945
PENNSULA	954
STOCKTON	1646
STANISLAUS	315
YOSEMITE	998
FRESNO	2584
KERN	2034
MISSION	1392
DE ANZA	1060
SAN JOSE	1918
CENCOAST	638
LOSPADRS	530
AREA TOTALS	22,624
AAEE (Mid)	-1451

Generation Dispatch

For the summer peak scenario, heavy imports are modelled coming into California from the northwest. In addition to the heavy imports the NorCal Hydro is dispatched at 80%. Leaving no capacity on many 500 kV lines in the northern part of PG&E's system. Since peak load was identified as 7pm in the CAISO Transmission Planning Process solar is not dispatched. Wind is however dispatched quite high. Thermal units are to be modelled to meet net qualifying capacity submitted to the CAISO by the generator owner the same holds for QF generating units.

For the spring off peak scenario heavy exports are modelled from California to the Northwest. With loads modelled quite low the generation assumptions for the non-peak scenarios were developed utilizing historical data. Solar is dispatched high since load is identified as 1 pm and Wind is dispatched at 55%. Thermal units may be modelled off-line or dispatched very low. Peakers are modelled off-line.

Renewable Generation Dispatch

Table 3 Renewable Generation Dispatch

PTO	Scenario	Day/Time (PST)	BTM-PV			Transmission Connected PV			Transmission Connected Wind			% of managed peak load		
		2029	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE	PGE	SCE	SDGE
CAISO	Summer Peak	9/4 HE 19	0%	0%	0%	0%	0%	0%	93%	54%	22%	93%	100%	97%
CAISO	Spring Off Peak	4/7 HE 13	80%	81%	79%	100%	98%	98%	55%	54%	22%	21%	26%	17%

Steady State Power Flow Analysis

Basecase Assumptions

PG&E uses a WECC base case to model the external WECC system merged with a PG&E seed case to model PG&E's system. The seed case is used for all other steady-state analyses. The topology of the seed case is consistent with data that is submitted for WECC base cases. This basecase is then approved by the CAISO through the Transmission Planning Process to complete reliability studies.

Power flow analyses were performed using PG&E's 2019 Series Summer Peak Bulk System base cases for 2029. Category P1 contingencies (L-1, T-1, G-1), P6 and P7 were simulated for each of the proposed alternatives for all base case scenarios. The analysis of these contingencies helps identifying low or high voltages also diverged cases could indicate either voltage instability or a possibly voltage collapse requiring further investigation. Contingencies also help identify any potential thermal overloads due to reduced reliability on the electric transmission grid.

Projects modelled in the studied basecases include projects approved through the CAISO Transmission Planning Process to be implemented in the next 10 years.

Two (2) power flow base cases will be used to evaluate the transmission system impacts of the Project. While it is impossible to study all combinations of system load and generation levels during all seasons and at all times of the day, these base cases represent extreme loading and generation conditions for the study area.

- 2029 Summer Peak Full Loop Base Case:

Summer peak power flow base cases will be used to evaluate the transmission system impacts of the interconnection of the Project on the PG&E system. Power flow analysis will be performed using the most recent PG&E 2029 Summer Peak Base Case (in General Electric Power Flow format). This base case will model a 1-in-5 year adverse weather load level for the impacted areas in the system. The base case will also be modified to represent extreme loading and generation conditions for the study area.

- 2029 Spring Off-Peak Full Loop Base Case:

Power flow analysis will also be performed using PG&E's 2029 Spring Off-Peak Base Case (in General Electric Power Flow format) in order to evaluate potential congestion on transmission facilities during the Off-Peak system conditions. The loads in this base case will be about 20-30% of the summer peak loads.

Contingencies

The contingencies evaluated for steady state studies are a standard contingency set used by PG&E's Transmission Planning Department, the list is created annually. The base cases will be used to simulate the impact of the interconnection during normal operating conditions and with all single (Category "P1 and P7") and multiple (Category "P6") contingencies in PG&E's impacted areas and Bulk Transmission System to be assessed.

System Planning simulations were performed to identify any possible thermal, or voltage violations resulting from the interconnection of additional generation connected to PG&E's Transmission System with all facilities in service. Results of the analysis were evaluated against NERC TPL-001-4 standard.

The following criteria were used to determine acceptable performance with the Standards:

Category P0: For normal operating conditions, no facilities shall exceed their applicable facility ratings or exceed the desired voltage range.

Category P1: For single contingency scenarios, no facilities shall exceed their applicable facility ratings nor shall they exceed the desired voltage.

Category P6: (Multiple Contingency) For a single contingency followed by system adjustment and then overlapped with another single contingency, no facilities shall exceed their applicable facility ratings nor shall they exceed the desired voltage.

Category P7: (Multiple Contingency) For the loss of any two adjacent circuits on common structures, no facilities shall exceed their applicable facility ratings nor shall they exceed the desired voltage.

Reliability Standards, Study Criteria, and Methodology

Power flow analyses will be performed to ensure that PG&E's transmission system remains in full compliance with NERC, WECC, and CAISO planning standards. The results of these power flow analyses will serve as <u>informational only</u> that an evaluation of the reliability impact of this new facility and its connection to interconnected transmission systems has been performed. Since the study is used for informational purposes only PG&E's obligations with NERC as the registered Transmission Owner for the PG&E transmission system will not need to communicate the results for this interconnection to the CAISO, or other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities will be solicited to ensure coordination of transmission systems, and such solicitation if the project moves forward and is submitted into the CAISO interconnection process.

The criteria used in evaluating the performance of the Transmission System are the current North American Electric Reliability Corporation (NERC) Reliability Standards, and WECC regional criterion, including the following:

- TPL-001-WECC-CRT-3 – Transmission System Planning Performance
- TPL-001-4 – Transmission System Planning Performance Requirements

Cost Methodology

Costs provided are non-binding and not based on any Transmission Owner preliminary engineering and design. Costs were based on the 2020 PG&E Proposed Generator

Interconnection Unit Cost Guide[1] submitted to the CAISO for 3rd party interconnections to use for high level cost estimates. More detailed estimates are available once the project has been submitted through the CAISO Interconnection Study Process. Therefore costs provided are subject to modification. Costs also do not include environmental and permitting requirements. These sorts of costs can not be provided accurately until the project scope has been further developed to address the exact location and route of the project.

The Unit Cost Guide provides per unit cost per equipment. Notes are also provided within the document to establish multipliers for various conditions. These multipliers may have been utilized to obtain more accurate costs.

For the range of costs, the AACE Level 5 costs adders were utilized. The AACE level 5 guidance was applied to accurately reflect the early stage of the project. The AACE level 5 multiplier of +100% was included. For greater details on AACE guidance please refer to http://www.aacei.org/toc/toc_17r-97.pdf

Costs provided are in 2020 dollars. If parties are interested in cost estimating done in constant dollars and then escalated over the years during which the project will be constructed and then in turn arriving at project costs in nominal dollars. Please refer to the table below. Costs provided in this report were not escalated.

Current PTO Escalation Rates:

	2020	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Escalation Rates	2.50%	1.70%	1.70%	2.10%	2.30%	2.30%	2.30%	2.40%	2.40%	2.10%	2.30%
2019 Escalation Factors	1.000	1.017	1.034	1.056	1.080	1.105	1.131	1.158	1.185	1.210	1.238

Mathematical formula = Cost in Nominal Dollars = Cost in Constant Dollars x Escalation Factor

Other Cost Assumption	**Explanation**
All labor is straight time and based on a 5 day work week schedule. Overtime may be required due to clearances and work hour restrictions to meet project schedules.	
Contingency factor for New Transmission Line: 35%, Contingency for Reconductoring Transmission Line (assuming 25% tower modification and no foundation issue): 50%. Contingency factor for Substation Equipment and Installation: 0% (zero %)	Accuracy of the cost estimate for budgeting pupose is based on level of detail engineering completed.
Owner's Representative Fee for EPC construction: 10% of the total project cost	Additional cost for PTO to manage,monitor and provide

[1] http://www.caiso.com/informed/Pages/StakeholderProcesses/ParticipatingTransmissionOwnerPerUnitCosts.aspx.

	technical oversight of the project
Unit costs include costs to procure materials, installation, engineering, project management costs, home office costs, and contingency	
Unit costs exclude allocated corporate overhead and AFUDC (will be added to total cost estimates)	
Unit costs exclude generator's responsibility for Income Tax Component of Contribution (ITCC), (will be added to total cost estimates, if required)	
Unit costs exclude environmental monitoring and mitigations	
Transmission line cost per mile assumes conventional construction	
Cost per mile of T\L requiring helicopter construction (or deconstruction) will have higher than published per-unit cost, the labor component of helicopter construction is incrementally higher, which is not included in the per-unit cost	
The unit costs assume that operational clearances are available as required.	
Installations at 500kV are rare for generation interconnection projects in PG&E's service area and good cost data is not available. PG&E will have to develop 500 kV cost on a case-by-case basis.	
The estimated costs here do not include any applicable ITCC tax.	
Cost estimates assume that the project site has regular soil conditions and is not located in an extra high seismic zone as identified in PG&E DCM 073102 nor in a locations consisting of the following conditions: liquefiable soils, expansive soils, unstable soils, susceptible to rupture, high ground water table (less than approximately 15 feet below finish grade), FEMA flood zone(s), excessive ground settlement due to subsidence or other geological factors, and hilly and/or rocky terrain requiring substantial grading effort.	
Costs also assume that the site can be drained via customary storm water drainage infrastructure (i.e., without pump or lift stations) and not require on-site percolation basins. Costs assume including implementing Storm Water Pollution and Prevention (SWPP) and SPCC oil containment system(s).	
Cost does not include any remedial work for impact on neighboring properties.	
Costs assume that the on-site existing soil is adequate for engineered fill and can be reused on-site to achieve a balanced cut-fill earthwork volume. Costs do not assume removal of hazardous material or site remediation.	
Costs assume that the site has nearby easy access to public roads and does not include any costs for access roads outside the substation.	
Costs do not assume extensive permitting effort.	
For installing Fiber Optic on existing poles the listed cost is only for the Fiber. It does not include splicing, stringing, relocation or replacement of poles, engineering or installation cost. Installation will be performed by Transmission line Groups and they will estimate the cost on project basis.	
For installing Fiber Optic on new poles the listed cost is only for the Fiber. It does not include splicing, stringing, banding equipment, specialized Fiber, additional staging efforts, material costs, engineering or installation costs. Installation will be performed by Transmission line Groups and they will estimate the cost on project basis.	

Option 1 and 2

Background

The Humboldt Planning Area ("Humboldt") covers approximately 3,000 square miles and is located in the northwestern corner of PG&E's service territory. Some of the larger cities that PG&E serves in this area are Eureka, Arcata, Garberville and Fortuna.

Humboldt's electric transmission system is comprised of 60 kV and 115 kV transmission facilities. Generators at Humboldt Bay Power Plant (HBPP) and local Qualifying Facilities (QF) provide most electric supply to the Humboldt area. Electricity supply is supplemented by transmission from the North Valley and North Coast areas.

Humboldt Division is connected to the PG&E bulk transmission system via four transmission circuits, each about 80 to 100 miles in length. These consist of two 115 kV lines and one 60 kV line from Cottonwood Substation in the east and one 60 kV line from Mendocino Substation in the south.

The power import capability of the Humboldt transmission system is a function of the load within Humboldt and the amount of internal generation. The existing system's import capability can adequately serve the projected load growth up to 10 years and beyond as long as the existing (or equivalent replacement) generation facilities remain in service.

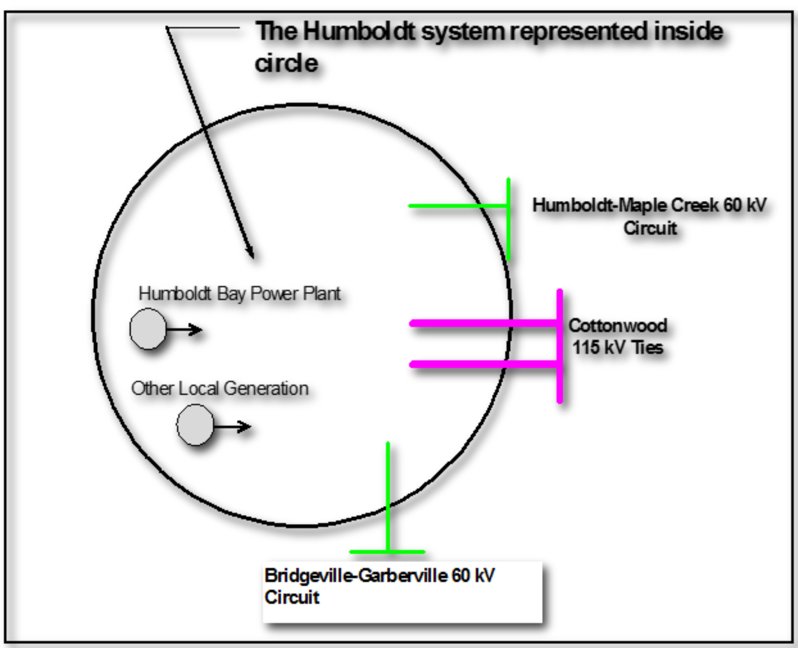


Figure 1 Humboldt Electric Transmission System connections

In the Humboldt area a dispatch of 207 MW's is modelled for local area generation, which included both QFs and the Humboldt Bay Power Plant (HBPP). The Humboldt Bay Power

Plant, operational as of August 2010, is composed of ten 16.8 MW internal combustion engine-driven generating units.

Transmission capacity concerns in the Humboldt area are mainly due to long transmission lines and the dispatch of local Humboldt generation. There are three lines that export power from the new Humboldt Bay Power Plant. When two lines are out of service, a thermal overload on the remaining line is expected during summer and winter peak loading conditions. These overloads are exacerbated when electric demand is lower in the local Humboldt and Eureka 60 kV load pocket. This overload may also be reduced by decreasing the Humboldt Bay Power Plant generation output connected to the 60 kV system.

Option 1

Two alternatives were considered in the evaluation of this option. This section provides a description and evalu alternatives investigated.

Alternative 0: Status Quo

This alternative will be assessed to better represent the issues identified in PG&E's system when the individual project interconnections are modelled without any upgrades to the system. This alternative would not be recommended as a mitigation as this alternative does not address the potential issues identified.

Alternative 1: Build new transmission lines from:

- Humboldt Bay – Humboldt No. 2 115 kV Line
- Humboldt – Trinity No. 2 115 kV Line
- Trinity – Cottonwood No.2 115 kV Line
- Bridgeville – Garberville No. 2 115 kV Line

Associated Substation reconfigurations and upgrades at substations not to be assumed in this study. Acquiring land and permitting will also not be included in this study

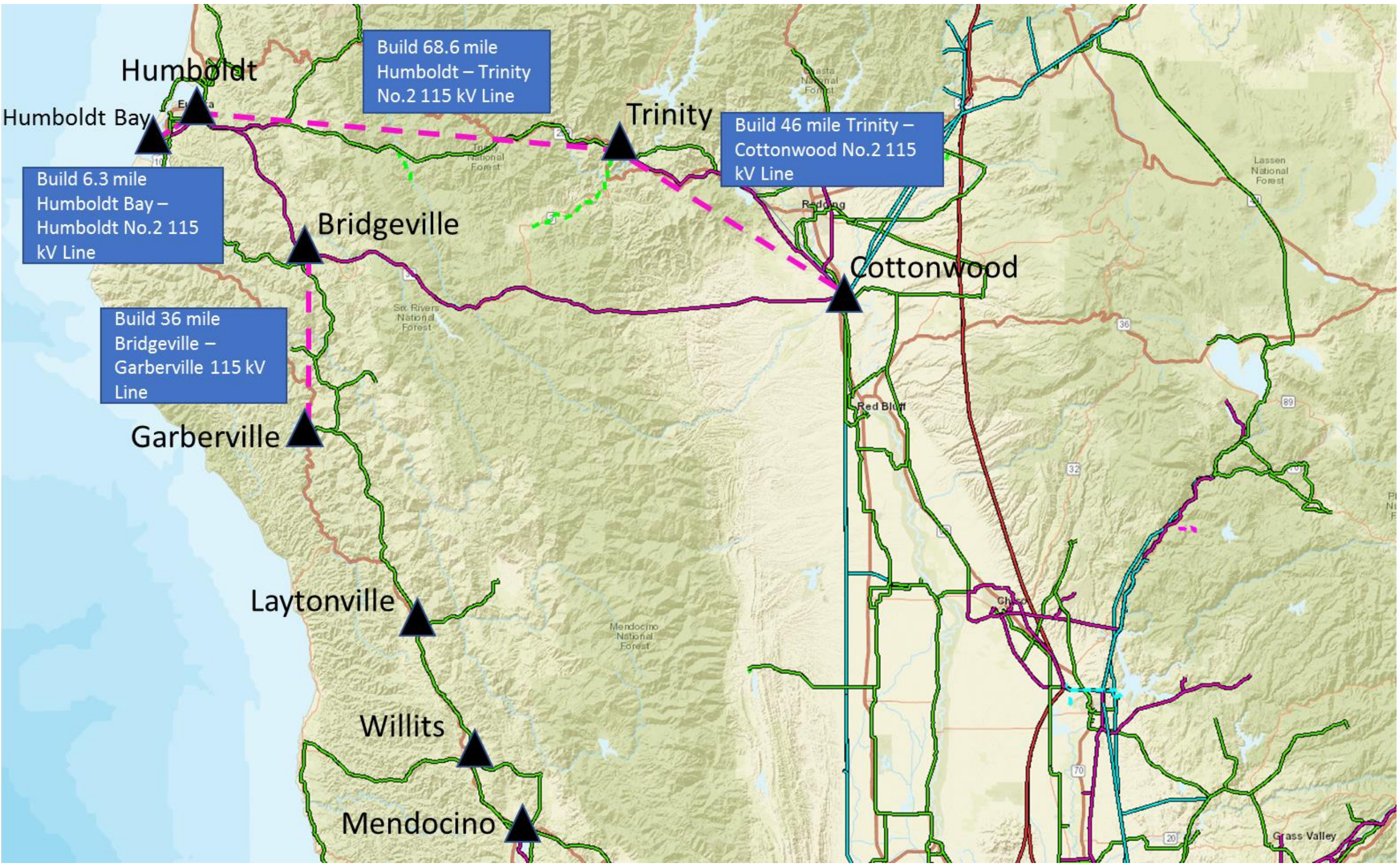


Figure 2 Option 1 Alternative 2 GIS Map

Capacity and Reliability Review

Planning assessment has identified potential thermal overloads in 2029 under peak loading conditions for normal conditions. During a normal condition the Humboldt Bay – Humboldt No. 2 115 kV line could potentially load up to 141% of its normal summer conductor ratings. Likewise, upon normal conditions the Bridgeville – Garberville 60 kV line could potentially load up to 118% of its normal summer conductor ratings. The table below shows a summary of the thermal loading with respect to the worse contingencies.

Table 4 Option 1 Alternative 1 Line Loading Summary

Transmission Line	Pre-Project Loading (normal rating)	Post-Project Loading (normal rating)
Humboldt Bay – Humboldt No. 2 115 kV Line	70%	141%
Bridgeville – Garberville 60 kV Line	103%	118%

With the current configuration, additional generation connected to the Humboldt Bay PP 115 kV bus the capacity allocated is not enough to sustain a connection as large as 48 MW's. The Bridgeville – Garberville 60 kV Line may expect marginal overloads depending on the loads and generation dispatch in pre-project scenarios. Since this overload is observed in a 10 year case and not observed in earlier study horizons no project has been approved for execution. With a system changing aggressively due to mandatory state initiatives, the loads adjusted with solar panels and battery installations, and energy efficiency programs, a 10 year definite forecast is unknown. If electrification is considered then the load forecast will vary even more. The same is true for generation dispatch as renewables are integrated in the North Coast system, support may not be needed from the Humboldt area and the overload on this particular line may be alleviated. However with the addition of generation in the Humboldt area this line will expect overloads. With so many unknowns for the long term horizon this project has not been executed and will be monitored in future studies to identify when the need is necessary.

Study Objective and Description of Alternatives

The objective of this study is to identify a long-term solution to interconnect 48 MW's to Humboldt Bay 115 kV Substation and to address the capacity and reliability issues incurred. The alternatives should alleviate the thermal and voltage violations and adequately and reliably serve the local system.

Two alternatives were considered with one being interconnecting the generator without any upgrades; and the second to build new 115 kV lines to enhance reliability. The following section provides a general description of the alternatives proposed and associated rough costs.

Alternative (1): Status Quo

This alternative is not recommended because it does not address the potential thermal overloads that could occur for normal status of the Humboldt system or for various NERC P1 (N-1) contingencies such as any 115 kV line out of service in the Humboldt area or the Bridgeville 115/60 kV Transformer out of service.

Alternative (2): Build new 115 kV transmission lines

- Build new 6.3 mile Humboldt Bay - Humboldt No. 2 115 kV Line
- Build new 68.6 mile Humboldt - Trinity No. 2 115 kV Line
- Build new 46.3 mile Trinity - Cottonwood No. 2 115 kV Line
- Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation
- Build a new 36 mile Bridgeville - Garberville No. 2 115 kV Line

The estimated rough cost for this alternative is about $365 million to $730 million.

Rough Cost Breakdown

The following table shows a unit cost breakdown for the different alternatives.

Table 5 Cost Breakdown for Option 1

OPTION 1 to interconnect 48 MW's in Humboldt Area		
Alternative	Facility	Cost Estimate
Alt 1: Status Quo		$0
Alt 2: Build New 115 kV Transmission Lines	Build new 6.3 mile Humboldt Bay - Humboldt No. 2 115 kV Line	$14M
	Build new 68.58 mile Humboldt - Trinity No. 2 115 kV Line	$154M
	Build new 46.28 mile Trinity - Cottonwood No. 2 115 kV Line	$104M
	Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation	$12M
	Build a new 36 mile Bridgeville - Garberville No. 2 115 kV Line	$81M
	Total	$365M - $730M

Evaluation of Alternatives

A power flow contingency analysis was performed using the 2029 base cases against all the Category P1 (L-1, T-1, G-1), P7 and selected P6 contingencies within the study area. The results were then screened for any thermal overloads or voltage violations along with any non converging cases or excessive voltage mismatches. For this power flow analysis all base cases converged.

The table below shows the power flow analysis results.

Table 6 Power Flow Results for Option 1

NERC Category	Facility Name	Base KV	Contingency Name	Rating (N/E)	2029HS _48MW	2029SP OP_48 MW	Corrective Action Plan
P0	31020 HMBOBAYPPB 115 31000 HUMBOLDT 115 1 1	115	P0: Base Case	487 Amps (N)	141.1%	95.8%	Option 1/Alternative 2
P0	Bridgeville - Garberville 60 kV Line	60	P0: Base Case	303 Amps (N)	113%	>90%	Option 1/Alternative 2
P0	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P0: Base Case	303 Amps (N)	117.8%	>90%	Option 1/Alternative 2
P0	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P0: Base Case	303 Amps (N)	112%	>90%	Option 1/Alternative 2
P1-2	Humboldt - Bridgeville 115 kV Line	115	P1-2: HUMBOLDT BAY-RIO DELL JCT 60kV [7100] MOAS OPENED on EEL RIVR_NEWBURG	400 Amps (E)	111.2%	>90%	Option 1/Alternative 2
P1-2	Humboldt Bay -Rio Dell 60 kV Line (HMBLT BY - EEL RIVR)	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	499 Amps (E)	122.4%	>90%	Option 1/Alternative 2
P1-2	Rio Dell Jct - Bridgeville 60 kV Line	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	113.4%	>90%	Option 1/Alternative 2
P1-2	Rio Dell - Bridgeville 60 kV Line (Carlotta - Swains Flat)	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	110.3%	>90%	Option 1/Alternative 2
P1-2	Humboldt Bay - Rio Dell Jct 60 kV Line	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	120.6%	>90%	Option 1/Alternative 2
P1-2	Rio Dell - Bridgeville 60 kV Line (Swains Flat - Bridgeville)	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	109.9%	>90%	Option 1/Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P1-2: BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	119.1%	v>90%	Option 1/Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P1-2: BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	124.7%	>90%	Option 1/Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line	60	P1-2: BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	120.1%	>90%	Option 1/Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	110.5%	>90%	Option 1/Alternative 2

NERC Category	Facility Name	Base KV	Contingency Name	Rating (N/E)	2029HS_48MW	2029SPOP_48MW	Corrective Action Plan
P1-2	Humboldt - Bridgeville 115 kV Line	115	P1-2: HUMBOLDT-TRINITY 115kV [1820]	400 Amps (E)	114%	>90%	Option 1/Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	116%	>90%	Option 1/Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	111.5%	>90%	Option 1/Alternative 2
P1-2	Humboldt - Bridgeville 115 kV Line	115	P1-2: HUMBOLDT BAY-RIO DELL JCT 60kV [7100] MOAS OPENED on NEWBURG_RIODLLTP	400 Amps (E)	97.6%	>90%	Option 1/Alternative 2
P1-3	Humboldt Bay -Rio Dell 60 kV Line (HMBLT BY - EEL RIVR)	60	P1-3: BRDGVLLE 115/60kV TB 1	499 Amps (E)	100.6%	>90%	Option 1/Alternative 2
P1-3	Humboldt Bay - Rio Dell Jct 60 kV Line	60	P1-3: BRDGVLLE 115/60kV TB 1	372 Amps (E)	90.9%	>90%	Option 1/Alternative 2
P6	31080 HUMBOLDT 60.0 31092 MPLE CRK 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	350 Amps (E)	NConv (DC 137.2%)	>90%	Option 1/Alternative 2
P6	Bridgeville - Garberville 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 177.8%)	>90%	Option 1/Alternative 2
P6	Bridgeville - Garberville 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	100.4%	>90%	Option 1/Alternative 2
P6	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 197.0%)	>90%	Option 1/Alternative 2
P6	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 172.7%)	>90%	Option 1/Alternative 2
P6	Garberville - Laytonville 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 142.5%)	>90%	Option 1/Alternative 2
P6	Garberville - Laytonville 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 144.2%)	>90%	Option 1/Alternative 2
P6	Humboldt - Bridgeville 115 kV Line	115	P6: HUMBOLDT-TRINITY 115kV [1820] & HUMBOLDT BAY-HUMBOLDT #1 60kV [7080]	400 Amps (E)	112.6%	>90%	Option 1/Alternative 2
P6	Humboldt - Trinity 115 kV Line	115	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	87.4%	>90%	Option 1/Alternative 2
P6	Humboldt Bay - Rio Dell Jct 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	234.2%	>90%	Option 1/Alternative 2
P6	Humboldt Bay -Rio Dell 60 kV Line (HMBLT BY - EEL RIVR)	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	499 Amps (E)	214%	>90%	Option 1/Alternative 2
P6	Rio Dell - Bridgeville 60 kV Line (Carlotta - Swains Flat)	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	220.9%	>90%	Option 1/Alternative 2
P6	Rio Dell - Bridgeville 60 kV Line (Swains Flat - Bridgeville)	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	220.7%	>90%	Option 1/Alternative 2
P6	Rio Dell Jct - Bridgeville 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	225%	>90%	Option 1/Alternative 2
P6	Rio Dell Tap 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV	499 Amps	195.1%	>90%	Option 1/Alternative

NERC Category	Facility Name	Base KV	Contingency Name	Rating (N/E)	2029HS _48MW	2029SP OP_48 MW	Corrective Action Plan
			[1810] & HUMBOLDT-TRINITY 115kV [1820]	(E)			2
P6	Trinity - Maple Creek 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 112.0%)	>90%	Option 1/Alternative 2
P7-1	Humboldt - Humboldt Bay #1 60 kV Line	60	P7-1: HUMBOLDT BAY & HUMBOLDT BAY LINES	350 Amps (E)	106.4%	>90%	Option 1/Alternative 2
P6	31556 TRINITY 60.0 31564 FRNCHGLH 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	326 Amps (E)	NConv (DC 110.4%)	>90%	Option 1/Alternative 2
P6	31564 FRNCHGLH 60.0 31566 KESWICK 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	326 Amps (E)	NConv (DC 105.8%)	>90%	Option 1/Alternative 2
P6	31566 KESWICK 60.0 31582 STLLWATR 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	281 Amps (E)	NConv (DC 110.7%)	>90%	Option 1/Alternative 2
P6	Laytonville - Willits 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	363 Amps (E)	NConv (DC 111.0%)	>90%	Option 1/Alternative 2

Status Quo – Existing 115kV System

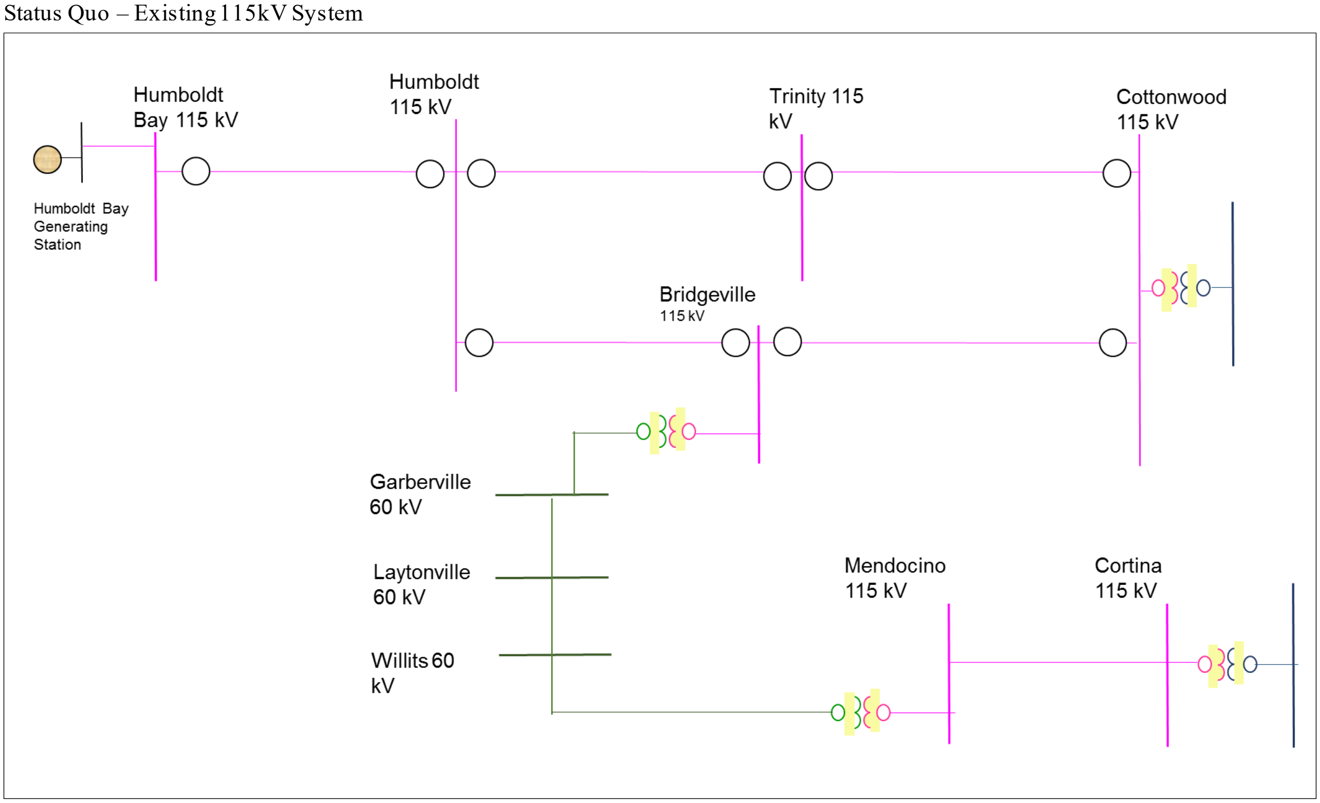


Figure 3 Existing Humboldt 115 kV System Single Line Diagram

Alternative 2 - Build new 115 kV lines

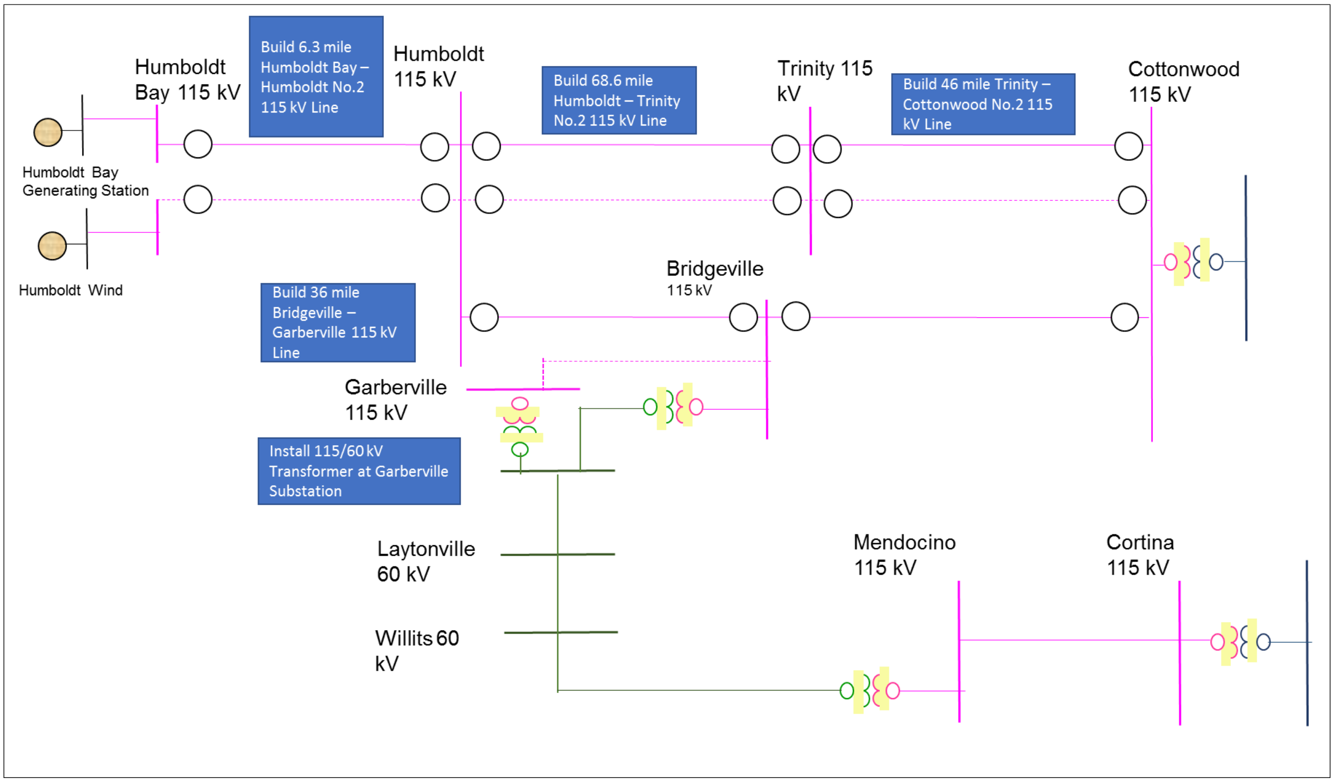


Figure 4 Alternative to Build new Humboldt 115 kV Lines Single Line Diagram

Status Quo

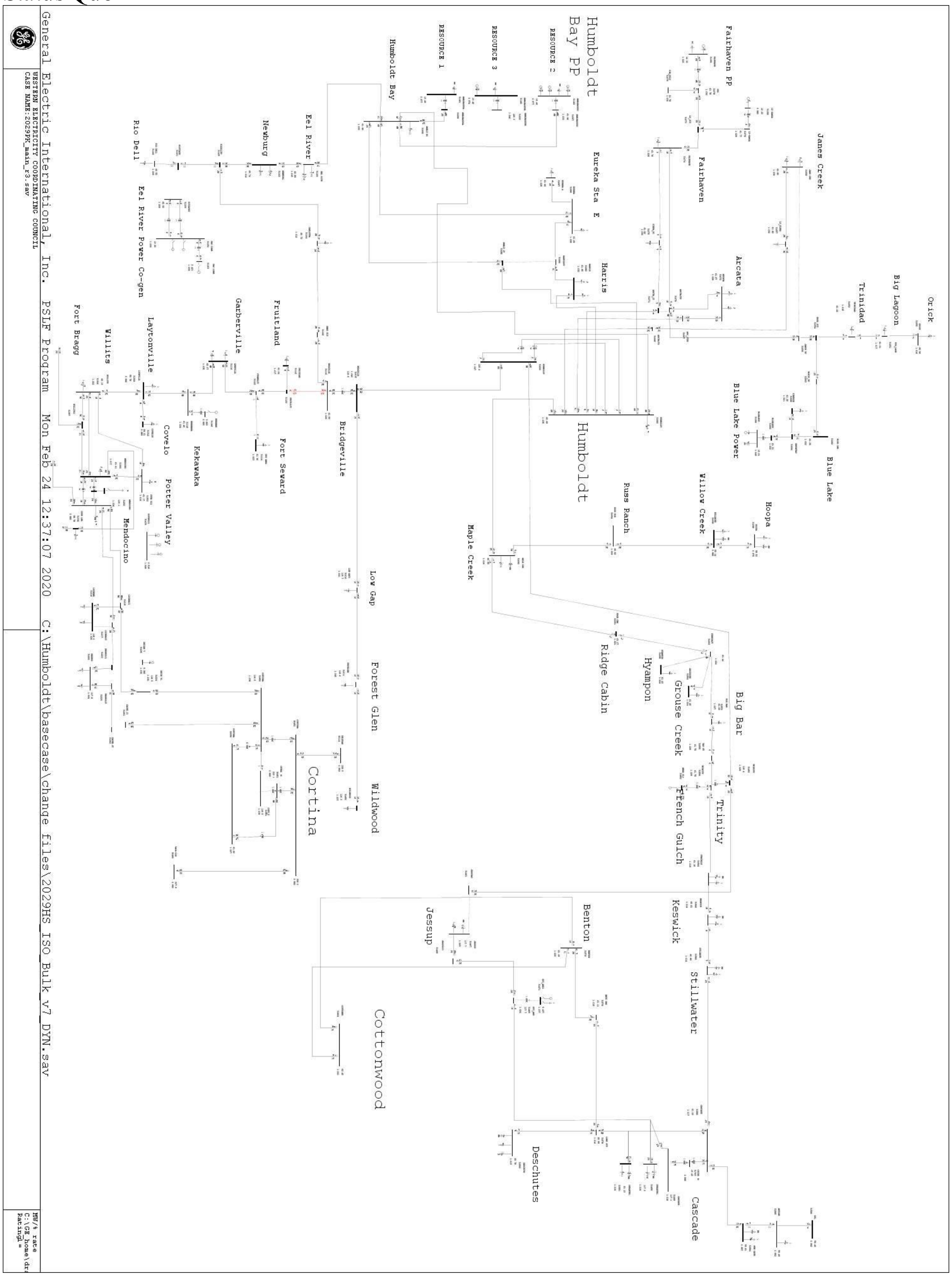


Figure 5 Status Quo 2029 Heavy Summer PSLF Power Flow (N-0)

48 MW generator Interconnected

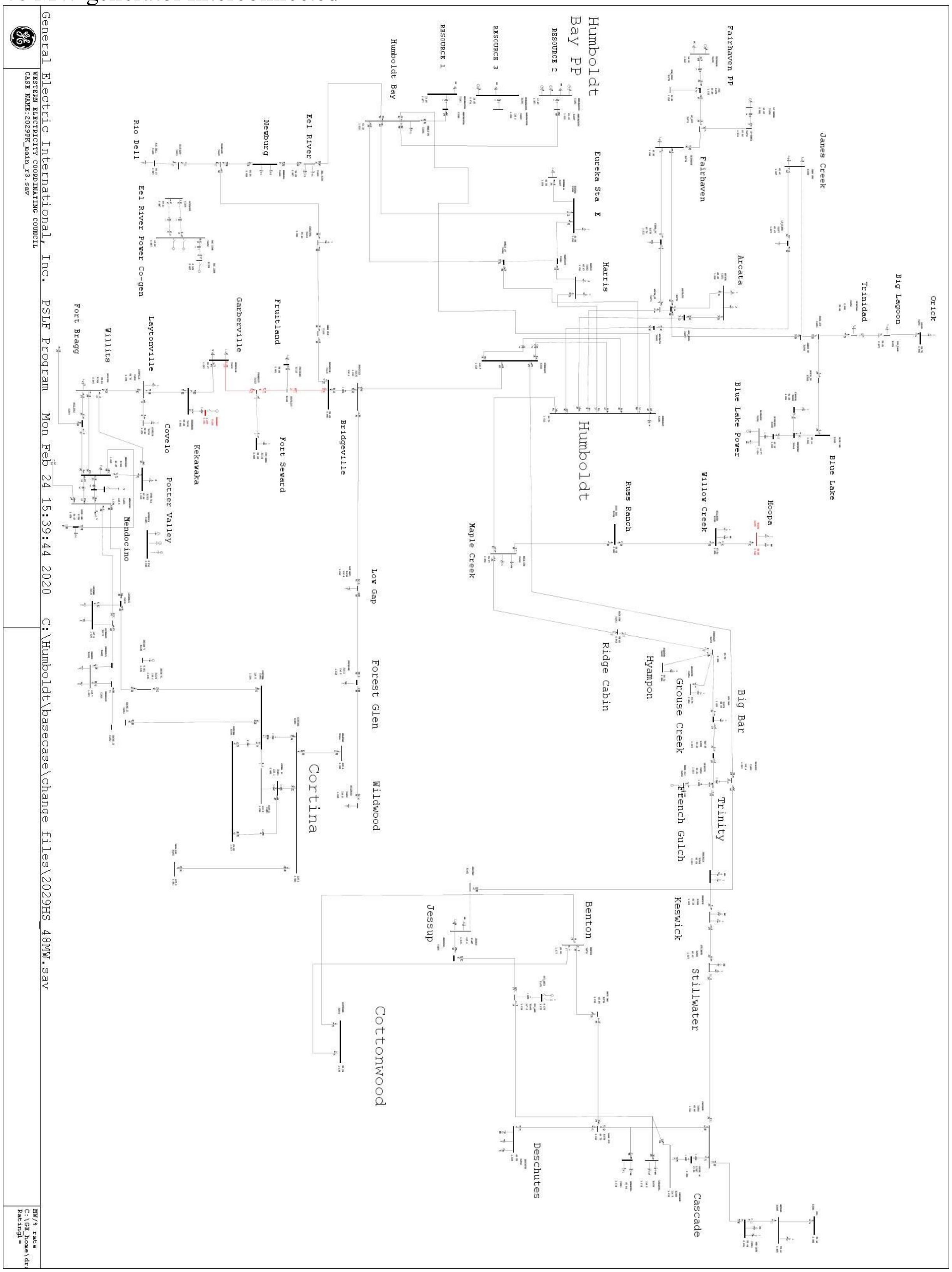


Figure 6 Option 1 2029 Heavy Summer PSLF Power Flow (N-0)

Status Quo – Power Flow

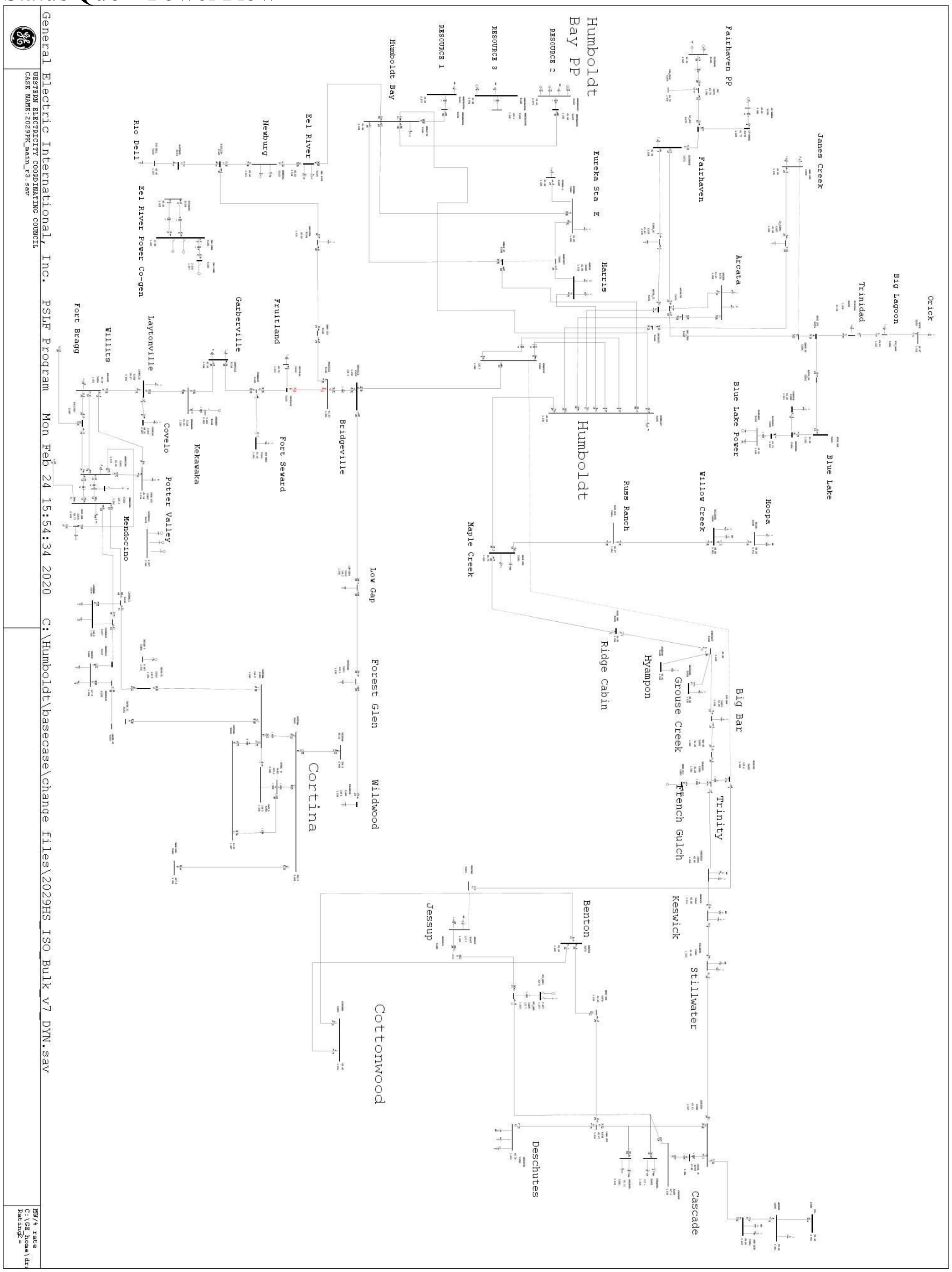


Figure 7 Status Quo 2029 Heavy Summer (N-1) Humboldt – Trinity 115 kV line Out of Service

48 MW generator Interconnected

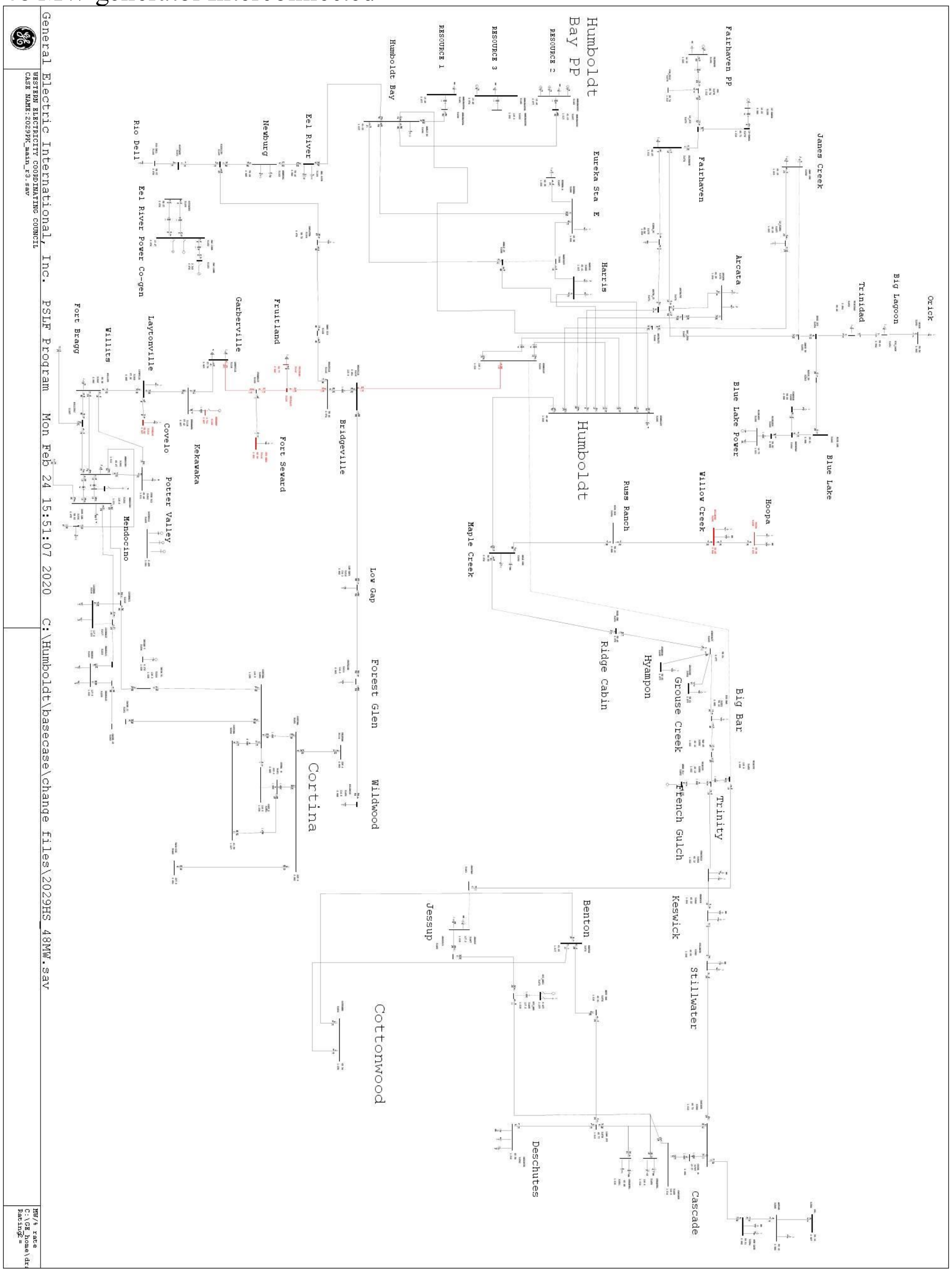


Figure 8 Option 1 2029 Heavy Summer (N-1) Humboldt – Trinity 115 kV Line Out of Service

Option 2

Two alternatives were considered in the evaluation of this option. This section provides a description and evaluation of the alternatives investigated.

<u>Alternative 0: Status Quo</u>

This alternative will be assessed to better represent the issues identified in PG&E's system when the individual project interconnections are modelled without any upgrades to the system. This alternative would not be recommended as a mitigation as this alternative does not address the potential issues identified.

Alternative 1: Reconductor existing transmission lines from:

- Humboldt – Humboldt Bay 115 kV
- Humboldt – Trinity 115 kV
- Humboldt – Bridgeville 115 kV
- Bridgeville – Garberville 60 kV Line
- Garberville – Laytonville 60 kV
- Laytonville – Willits 60 kV Lines

Build new line(s):

- Humboldt Bay – Humboldt No. 2 115 kV Line
- Humboldt – Trinity No. 2 115 kV Line
- Trinity – Cottonwood No.2 115 kV Line
- Bridgeville – Garberville No. 2 115 kV Line
- Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation

Associated Substation reconfigurations and upgrades at substations not to be assumed in this study. Acquiring land and permitting will also not be included in this study

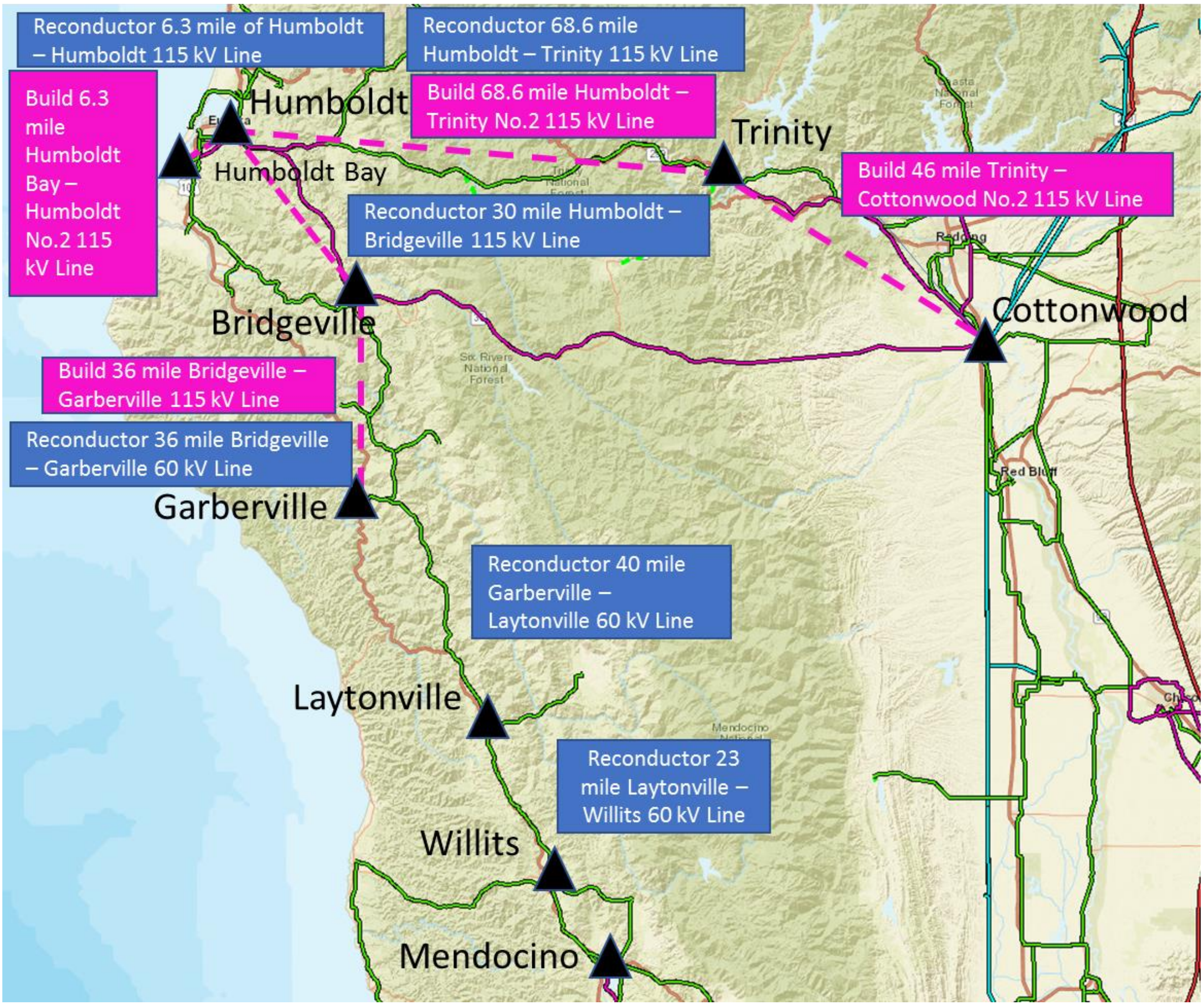


Figure 9 Option 2 Alternative 2 GIS Map

Capacity and Reliability Review

The planning assessment has identified potential thermal overloads in 2029 under peak loading conditions for normal conditions. During a normal condition the Humboldt Bay – Humboldt No. 2 115 kV line could potentially load up to 227% of its normal summer conductor ratings. Likewise, upon normal conditions the Bridgeville – Garberville 60 kV line could potentially load up to 138% of its normal summer conductor ratings. The table below shows a summary of the thermal loading with respect to the worse contingencies.

Table 7 Option2 alternative 1 Line Loadings

Transmission Line	Pre-Project Loading (normal rating)	Post-Project Loading (normal rating)
Humboldt Bay – Humboldt No. 2 115 kV Line	70%	227%
Bridgeville – Garberville 60 kV Line	103%	138%

With the current configuration, additional generation connected to the Humboldt Bay PP 115 kV bus the capacity allocated is not enough to sustain a connection as large as 144 MW's. The Bridgeville – Garberville 60 kV Line may expect marginal overloads depending on the loads and generation dispatch in pre-project scenarios. Since this overload is observed in a 10 year case and not observed in earlier study horizons no project has been approved for execution. With a system changing aggressively due to mandatory state initiatives, the loads adjusted with solar panels and battery installations, and energy efficiency programs, a 10 year definite forecast is unknown. If electrification is considered then the load forecast will vary even more. The same is true for generation dispatch as renewables are integrated in the North Coast system, support may not be needed from the Humboldt area and the overload on this particular line may be alleviated. However with the addition of generation in the Humboldt area this line will expect overloads. With so many unknowns for the long term horizon this project has not been executed and will be monitored in future studies to identify when the need is necessary.

Study Objective and Description of Alternatives

The objective of this study is to identify a long-term solution to interconnect 144 MW's to Humboldt Bay 115 kV Substation and to address the capacity and reliability issues incurred. The alternatives should alleviate the thermal and voltage violations and adequately and reliably serve the local system.

Two alternatives were considered with one being interconnecting the generator without any upgrades; and the second to build new 115 kV lines and reconductoring existing transmission lines to enhance reliability. The following section provides a general description of the alternatives proposed and associated rough costs.

Alternative (1): Status Quo

This alternative is not recommended because it does not address the potential thermal overloads that could occur for normal status of the Humboldt system or for various NERC P1 (N-1) contingencies such as any 115 kV line out of service in the Humboldt area or the Bridgeville 115/60 kV Transformer out of service.

Alternative (2): Reconductor existing transmission lines from:

- Humboldt – Humboldt Bay 115 kV
- Humboldt – Trinity 115 kV
- Humboldt – Bridgeville 115 kV
- Bridgeville – Garberville 60 kV Line
- Garberville – Laytonville 60 kV

- Laytonville – Willits 60 kV Lines

Build new line(s):

- Humboldt Bay – Humboldt No. 2 115 kV Line
- Humboldt – Trinity No. 2 115 kV Line
- Trinity – Cottonwood No.2 115 kV Line
- Bridgeville – Garberville No. 2 115 kV Line
- Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation

The estimated rough cost for this alternative is about $669 million to $1.34 billion.

Rough Cost Breakdown

The following table shows a unit cost breakdown for the different alternatives.

Table 8 Cost Breakdown for Option2

Alternative	OPTION 2 to interconnect 144 MW's in Humboldt Area Facility	Cost Estimate
Alt 1: Status Quo		$0
Alt: 2 Reconductor and build new 115 kV and 60 kV Lines	Reconductor 6.3 miles of Humboldt Bay - Humboldt 115 kV Line	$14M
	Reconductor 30.3 miles of Humboldt - Bridgeville 115 kV Line	$68M
	Reconductor 68.58 mile of Humboldt - Trinity 115 kV Line	$50M
	Reconductor 36 mile of Bridgeville - Garberville 60 kV Line	$30M
	Reconductor 40 miles of Garberville - Laytonville 60 kV Line	$90M
	Reconductor 23 miles of Laytonville - Willits 60 kV Line	$52M
	Build new 6.3 mile Humboldt Bay - Humboldt No. 2 115 kV Line	$14M
	Build new 68.58 mile Humboldt - Trinity No. 2 115 kV Line	$154.2M
	Build new 46.28 mile Trinity - Cottonwood No. 2 115 kV Line	$104.25M
	Build a new 115 kV bus and install a 115/60 kV Transformer at Garberville Substation	$12M
	Build a new 36 mile Bridgeville - Garberville No. 2 115 kV Line	$81M
	Total	$669M - $1.34B

Evaluation of Alternatives

A power flow contingency analysis was performed using the 2029 base cases against all the Category P1 (L-1, T-1, G-1), P7 and selected P6 contingencies within the study area. The results were then screened for any thermal overloads or voltage violations along with any non converging cases or excessive voltage mismatches. For this power flow analysis all base cases converged.

The table below shows the power flow analysis results.

Table 9 Power Flow results for Option 2

NERC	Facility Name	BaseKV	Contingency Name	Rating (N/E)	2029HS_144MW	2029SPOP_144MW	Corrective Action Plan
P0	31020 HMBOBAYPPB 115 31000 HUMBOLDT 115 1 1	115	P0: Base Case	487 Amps (N)	227%	178.3	Option2/ Alternative 2
P0	Bridgeville - Garberville 60	60	P0: Base Case	303	133.1%	>95%.	Option2/

NERC	Facility Name	BaseKV	Contingency Name	Rating (N/E)	2029HS_144MW	2029SPOP_144MW	Corrective Action Plan
	kV Line			Amps (N)			Alternative 2
P0	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P0: Base Case	303 Amps (N)	138.3%	>95%.	Option2/ Alternative 2
P0	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P0: Base Case	303 Amps (N)	132%	>95%.	Option2/ Alternative 2
P0	Humboldt - Bridgeville 115 kV Line	115	P0: Base Case	400 Amps (N)	131.9%	>95%.	Option2/ Alternative 2
P0	Humboldt - Trinity 115 kV Line	115	P0: Base Case	303 Amps (N)	124.2%	>95%.	Option2/ Alternative 2
P1-2	Humboldt - Bridgeville 115 kV Line	115	P1-2: HUMBOLDT BAY-RIO DELL JCT 60kV [7100] MOAS OPENED on EEL RIVR_NEWBURG	400 Amps (E)	139%	>95%.	Option2/ Alternative 2
P1-2	Humboldt Bay -Rio Dell 60 kV Line (HMBLT BY - EEL RIVR)	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	499 Amps (E)	138.5%	>95%.	Option2/ Alternative 2
P1-2	Rio Dell Jct - Bridgeville 60 kV Line	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	133.6%	>95%.	Option2/ Alternative 2
P1-2	Rio Dell - Bridgeville 60 kV Line (Carlotta - Swains Flat)	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	130.3%	>95%.	Option2/ Alternative 2
P1-2	Rio Dell Tap 60 kV Line	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	499 Amps (E)	122.1%	>95%.	Option2/ Alternative 2
P1-2	Humboldt Bay - Rio Dell Jct 60 kV Line	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	141.1%	>95%.	Option2/ Alternative 2
P1-2	Rio Dell - Bridgeville 60 kV Line (Swains Flat - Bridgeville)	60	P1-2: HUMBOLDT-BRIDGEVILLE 115kV [1810]	372 Amps (E)	130%	>95%.	Option2/ Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P1-2: BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	131.3%	>95%.	Option2/ Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P1-2: BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	137.2%	>95%.	Option2/ Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line	60	P1-2: BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	132.3%	>95%.	Option2/ Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	138.8%	>95%.	Option2/ Alternative 2
P1-2	31080 HUMBOLDT 60.0 31092 MPLE CRK 60.0 1 1	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	350 Amps (E)	103.9%	>95%.	Option2/ Alternative 2
P1-2	Humboldt - Bridgeville 115 kV Line	115	P1-2: HUMBOLDT-TRINITY 115kV [1820]	400 Amps (E)	200%	97.5	Option2/ Alternative 2
P1-2	31010 LOW GAP1 115 31015 BRDGVLLE 115 1 1	115	P1-2: HUMBOLDT-TRINITY 115kV [1820]	562 Amps (E)	121.5%	>95%.	Option2/ Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	145%	>95%.	Option2/ Alternative 2
P1-2	Bridgeville - Garberville 60 kV Line	60	P1-2: HUMBOLDT-TRINITY 115kV [1820]	339 Amps (E)	139.8%	>95%.	Option2/ Alternative 2

NERC	Facility Name	BaseKV	Contingency Name	Rating (N/E)	2029HS_144MW	2029SPOP_144MW	Corrective Action Plan
P1-2	31011 FRSTGLEN 115 31010 LOW GAP1 115 1 1	115	P1-2: HUMBOLDT-TRINITY 115kV [1820]	562 Amps (E)	120.7%	>95%.	Option2/ Alternative 2
P1-2	Humboldt - Bridgeville 115 kV Line	115	P1-2: HUMBOLDT BAY-RIO DELL JCT 60kV [7100] MOAS OPENED on NEWBURG_RIODLLTP	400 Amps (E)	135.1%	>95%.	Option2/ Alternative 2
P1-3	Humboldt Bay -Rio Dell 60 kV Line (HMBLT BY - EEL RIVR)	60	P1-3: BRDGVLLE 115/60kV TB 1	499 Amps (E)	110.5%	>95%.	Option2/ Alternative 2
P1-3	Humboldt Bay - Rio Dell Jct 60 kV Line	60	P1-3: BRDGVLLE 115/60kV TB 1	372 Amps (E)	102.4%	>95%.	Option2/ Alternative 2
P6	31080 HUMBOLDT 60.0 31092 MPLE CRK 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	350 Amps (E)	NConv (DC 246.6%)	NConv (DC 52.0%)	Option2/ Alternative 2
P6	HMBLT BY-HARRIS 60kV Line	60	P6: HUMBOLDT BAY-HUMBOLDT #1 60kV [7080] & HUMBOLDT BAY-HUMBOLDT #2 60kV [7090]	350 Amps (E)	137.6%	>95%.	Option2/ Alternative 2
P6	31110 BRDGVLLE 60.0 31015 BRDGVLLE 115 1 1	60/115	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	99 MVA (E)	NConv (DC 100.3%)	>95%.	Option2/ Alternative 2
P6	Bridgeville - Garberville 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 266.6%)	NConv (DC 208.6%)	Option2/ Alternative 2
P6	Bridgeville - Garberville 60 kV Line (Bridgeville - Fruitland Jct)	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 293.5%)	NConv (DC 214.5%)	Option2/ Alternative 2
P6	Bridgeville - Garberville 60 kV Line (Fort Seward Jct - Garberville)	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 259.1%)	NConv (DC 207.7%)	Option2/ Alternative 2
P6	Garberville - Laytonville 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 224.8%)	NConv (DC 202.3%)	Option2/ Alternative 2
P6	Garberville - Laytonville 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 228.6%)	NConv (DC 191.2%)	Option2/ Alternative 2
P6	Humboldt - Bridgeville 115 kV Line	115	P6: HUMBOLDT-TRINITY 115kV [1820] & HUMBOLDT BAY-EUREKA 60kV [7070] MOAS OPENED on HUMBOLDT_HARRIS	400 Amps (E)	168.6%	98.6%	Option2/ Alternative 2
P6	Humboldt - Bridgeville 115 kV Line	115	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	400 Amps (E)	NConv (DC 133.0%)	>95%.	Option2/ Alternative 2
P6	Humboldt - Bridgeville 115 kV Line	115	P6: HUMBOLDT-TRINITY 115kV [1820] & HUMBOLDT BAY-HUMBOLDT #1 60kV [7080]	400 Amps (E)	167%	>95%.	Option2/ Alternative 2
P6	Humboldt - Trinity 115 kV Line	115	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	131.2%	99.7%	Option2/ Alternative 2
P6	Humboldt - Trinity 115 kV Line	115	P6: BRIDGEVILLE-COTTONWOOD 115kV [1110] & HUMBOLDT 115/60kV TB 2	339 Amps (E)	154.1%	>95%.	Option2/ Alternative 2
P6	Humboldt Bay - Rio Dell Jct 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	NConv (DC 256.5%	175.9%	Option2/ Alternative 2

NERC	Facility Name	BaseKV	Contingency Name	Rating (N/E)	2029HS_144MW	2029SPOP_144MW	Corrective Action Plan
					)		
P6	Humboldt Bay -Rio Dell 60 kV Line (HMBLT BY - EEL RIVR)	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	499 Amps (E)	NConv (DC 235.6%)	156.3%	Option2/ Alternative 2
P6	Rio Dell - Bridgeville 60 kV Line (Carlotta - Swains Flat)	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	NConv (DC 239.8%)	167.3%	Option2/ Alternative 2
P6	Rio Dell - Bridgeville 60 kV Line (Swains Flat - Bridgeville)	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	NConv (DC 225.7%)	167%	Option2/ Alternative 2
P6	Rio Dell Jct - Bridgeville 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	372 Amps (E)	NConv (DC 243.3%)	169.7%	Option2/ Alternative 2
P6	Rio Dell Tap 60 kV Line	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	499 Amps (E)	NConv (DC 211.0%)	143.2%	Option2/ Alternative 2
P6	Trinity - Maple Creek 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	339 Amps (E)	NConv (DC 219.1%)	NConv (DC 33.2%)	Option2/ Alternative 2
P7-1	Humboldt - Humboldt Bay #1 60 kV Line	60	P7-1: HUMBOLDT BAY & HUMBOLDT BAY LINES	350 Amps (E)	106.4%	>95%.	Option2/ Alternative 2
P6	31450 WILDWOOD 115 31524 COTWD_2E 115 1 1	115	P6: HUMBOLDT-TRINITY 115kV [1820] & HUMBOLDT 115/60kV TB 2	483 Amps (E)	111.5%	>95%.	Option2/ Alternative 2
P6	31452 TRINITY 115 31461 JESSTAP 115 1 1	115	P6: BRIDGEVILLE-COTTONWOOD 115kV [1110] & HUMBOLDT 115/60kV TB 2	455 Amps (E)	110.3%	>95%.	Option2/ Alternative 2
P6	31461 JESSTAP 115 31521 COTWD_1D 115 1 1	115	P6: BRIDGEVILLE-COTTONWOOD 115kV [1110] & HUMBOLDT 115/60kV TB 2	455 Amps (E)	108.1%	>95%.	Option2/ Alternative 2
P6	31556 TRINITY 60.0 31564 FRNCHGLH 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	326 Amps (E)	NConv (DC 204.0%)	NConv (DC 32.1%)	Option2/ Alternative 2
P6	31564 FRNCHGLH 60.0 31566 KESWICK 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	326 Amps (E)	NConv (DC 194.6%)	NConv (DC 30.2%)	Option2/ Alternative 2
P6	31566 KESWICK 60.0 31582 STLLWATR 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	281 Amps (E)	NConv (DC 209.2%)	NConv (DC 33.0%)	Option2/ Alternative 2
P6	31580 CASCADE 60.0 31582 STLLWATR 60.0 1 1	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	326 Amps (E)	NConv (DC 155.9%)	NConv (DC 32.6%)	Option2/ Alternative 2
P6	31580 CASCADE 60.0 31582 STLLWATR 60.0 1 1	60	P6: HUMBOLDT-BRIDGEVILLE 115kV [1810] & HUMBOLDT-TRINITY 115kV [1820]	326 Amps (E)	NConv (DC 109.4%)	>95%.	Option2/ Alternative 2
P6	Laytonville - Willits 60 kV Line	60	P6: HUMBOLDT-TRINITY 115kV [1820] & BRIDGEVILLE-COTTONWOOD 115kV [1110]	363 Amps (E)	NConv (DC 181.1%)	NConv (DC 180.3%)	Option2/ Alternative 2
P1-2	31450 WILDWOOD 115	115	P1-2: HUMBOLDT-TRINITY 115kV [1820]	483	139.3%	>95%.	Option2/

NERC	Facility Name	BaseKV	Contingency Name	Rating (N/E)	2029HS_144MW	2029SPOP_144MW	Corrective Action Plan
	31524 COTWD_2E 115 1 1			Amps (E)			Alternative 2
P1-2	31450 WILDWOOD 115 31011 FRSTGLEN 115 1 1	115	P1-2: HUMBOLDT-TRINITY 115kV [1820]	562 Amps (E)	120.5%	>95%.	Option2/ Alternative 2

Status Quo – Existing 115kV System

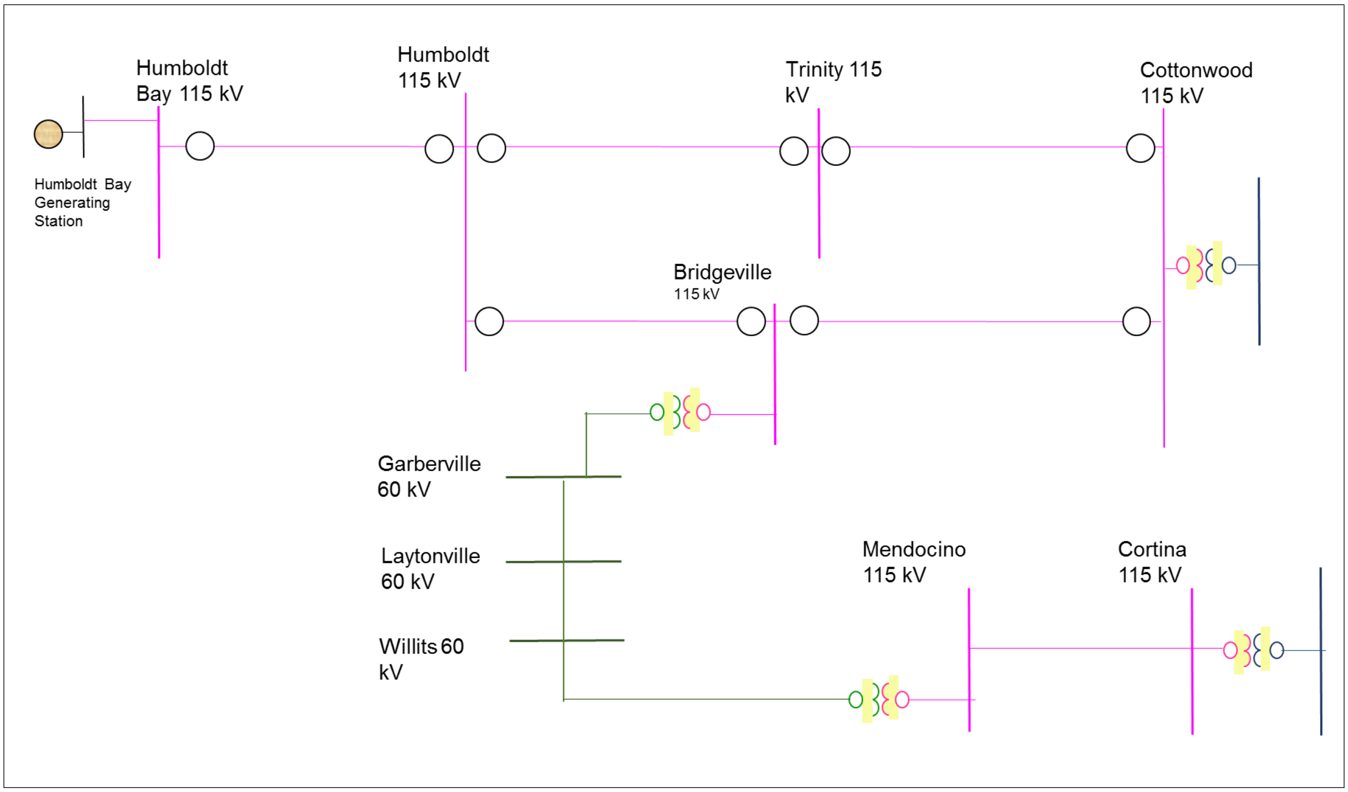


Figure 10 Existing Humboldt 115 kV System Single Line Diagram

Alternative 1

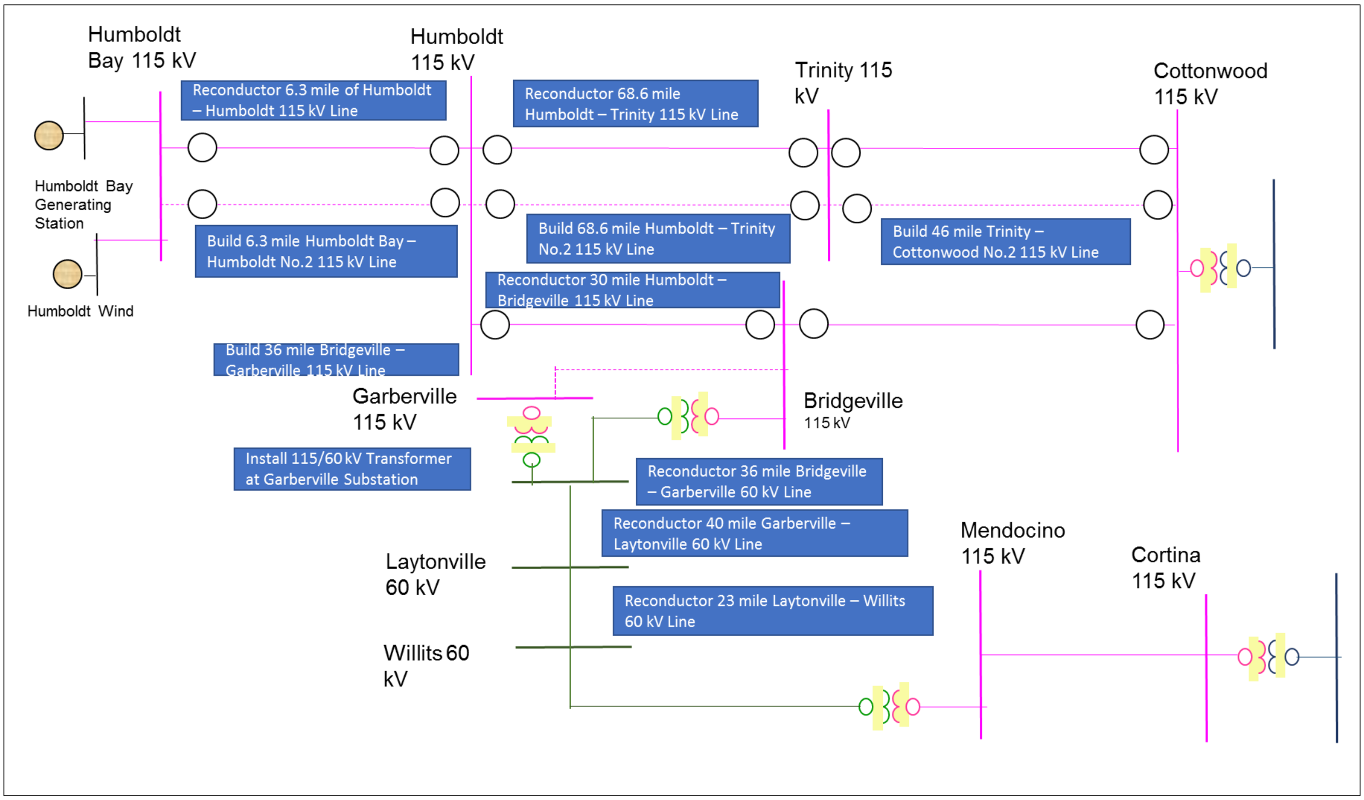


Figure 11 Option 2 Alternative 1 to Build new Humboldt 115 kV Lines and Reconductor Single Line Diagram

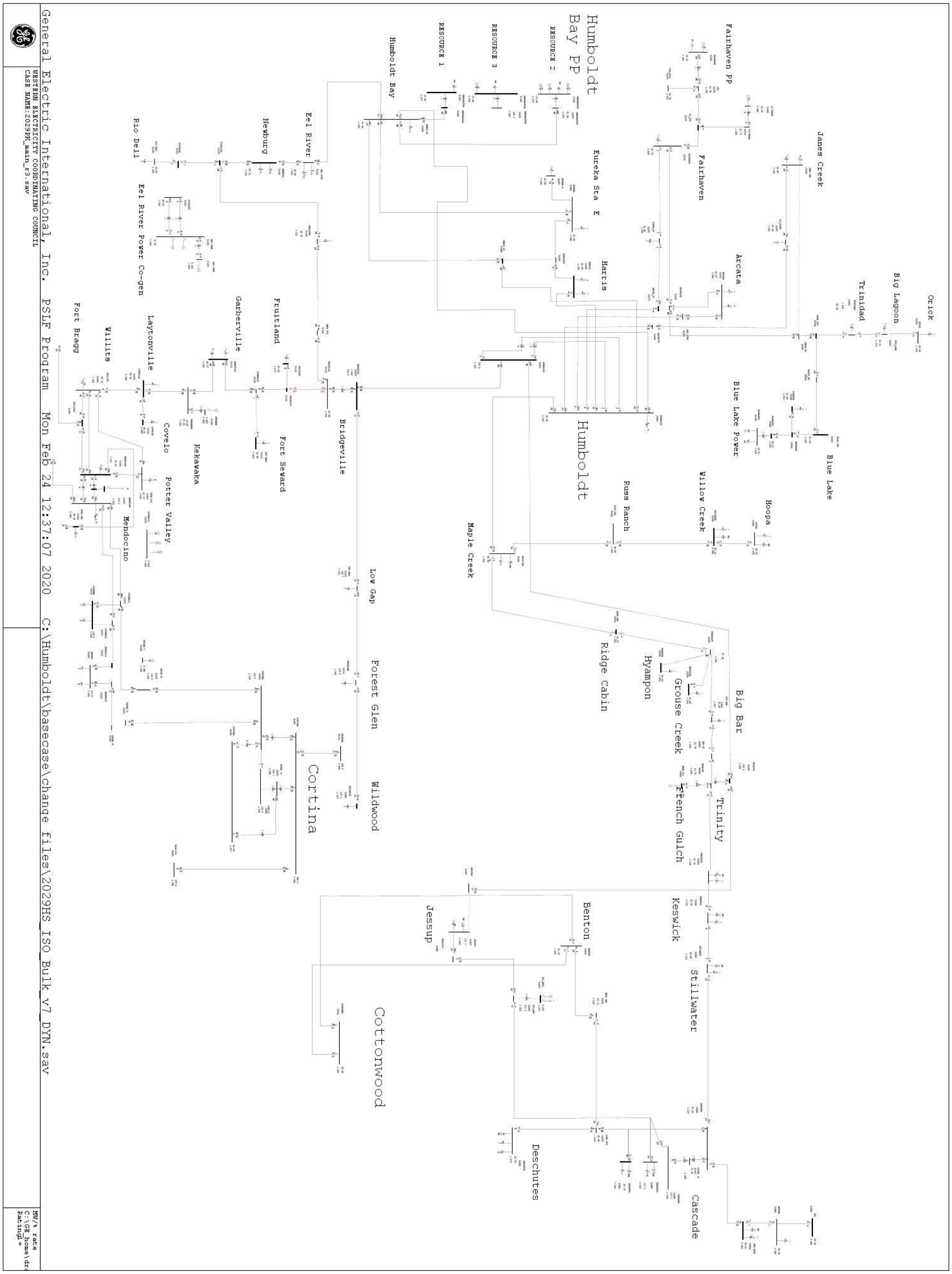


Figure 12 Status Quo 2029 Heavy Summer PSLF Power Flow (N-0)

144 MW Generator Interconnected

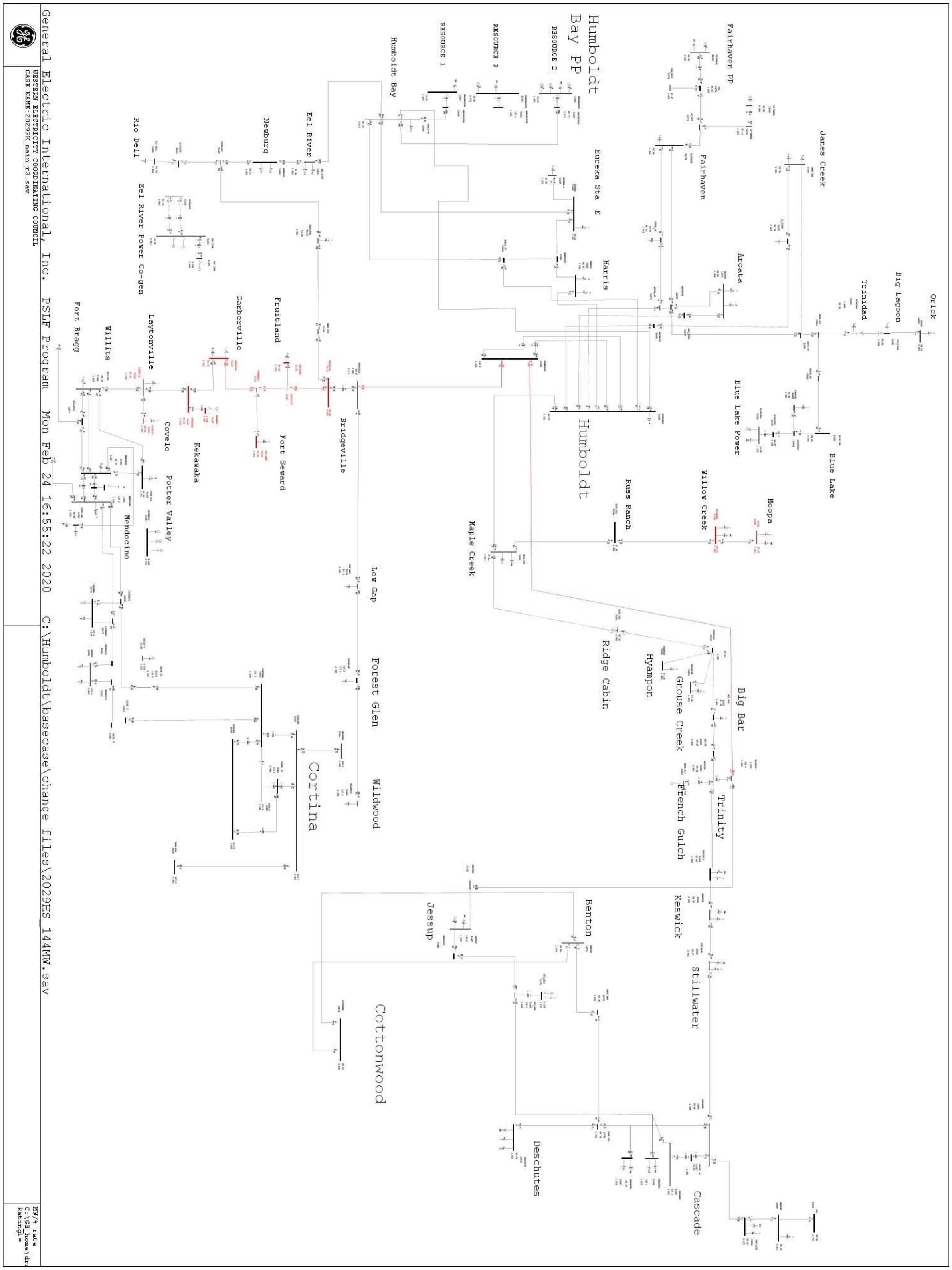


Figure 13 Option 2 Alternative 1 2029 Heavy Summer PSLF Power Flow (N-0) normal conditions

Status Quo

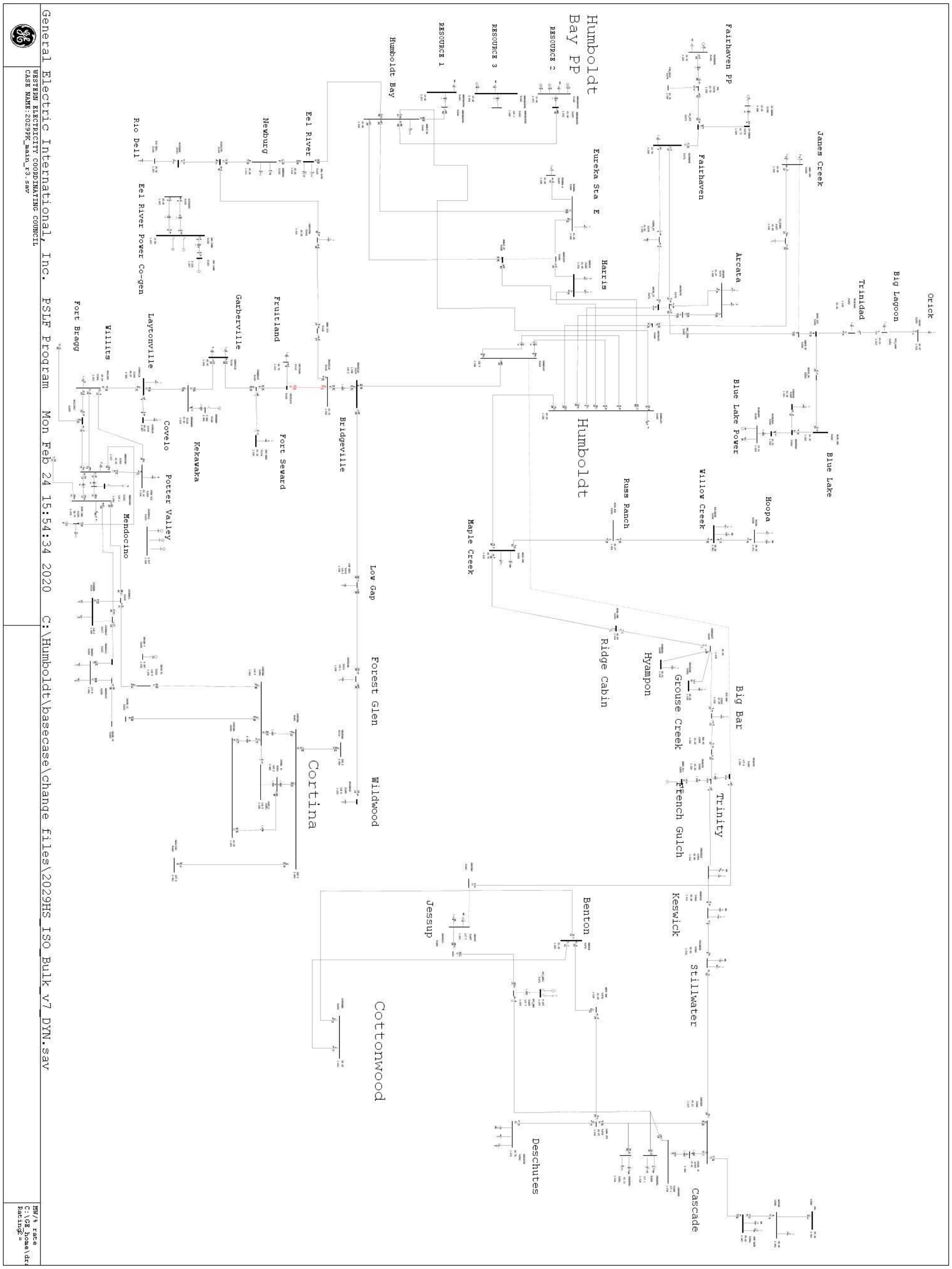


Figure 14 Status Quo 2029 Heavy Summer (N-1) Humboldt – Trinity 115 kV Line Out of Service

144 MW Generator Interconnected

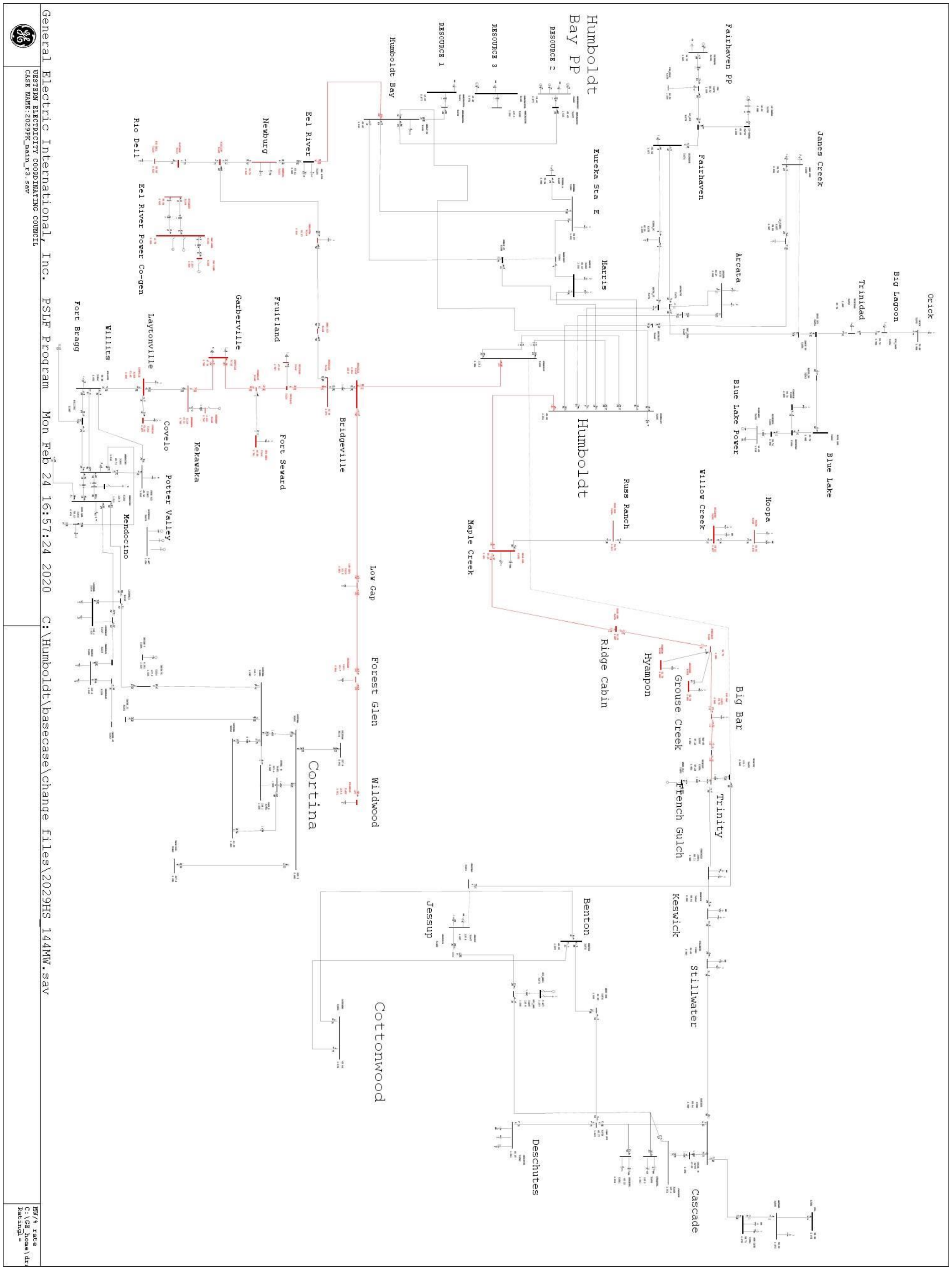


Figure 15 Option 2 2029 Heavy Summer (N-1) Humboldt – Trinity 115 kV Line Out of Service

Option 3

Three alternatives were considered in the evaluation of this option. This section provides a description and evaluation of the alternatives investigated.

Alternative 1 Background

The PG&E service territory covers approximately 70,000 square miles and is located in northern and central California. PG&E shares external electrical interconnections with BPA in the north, Southern California Edison in the south, and NV Energy in the east, in addition to numerous internal electrical interconnections within California.

Per Schatz Energy Research Center a route east is to be considered for Alternative 1. As such, a 500 kV line from the Humboldt area to Round Mountain 500 kV substation was assessed. Round Mountain 500 kV Substation is directly connected to the California – Oregon – Intertie referred to as COI.

The COI consists of three jointly owned 500 kV AC lines from Oregon to northern California, which together are recognized as a Western Electric Coordinating Council (WECC) regional transmission path, identified as Path 66. This path is shown below. Two lines of the COI are known as the Pacific AC Intertie (PACI), the third is the California Oregon Transmission Project (COTP).

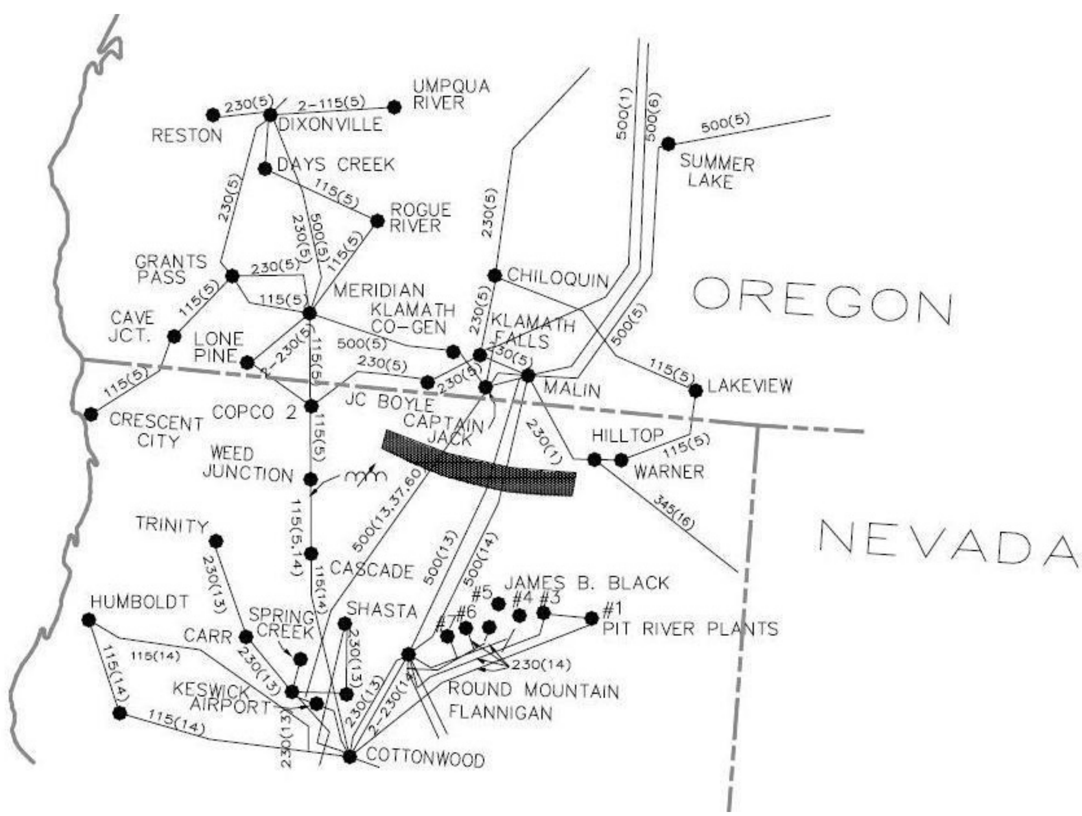


Figure 16 WECC Map of Path 66 (COI)

The nominal COI rating is 4,800 MW from north-to-south, and 3,675 MW from south to north. However, in addition to limitations due to outages, nomograms have been developed to identify simultaneous operating constraints between this path and other paths including:

The Pacific DC Intertie (Path 65),
The North of John Day (Path 73),
Hemingway-Summer Lake (Path 75), and
Borah West (Path 17).

Other factors that affect operating conditions are:
Northern California hydro generation,
Other northern California generation,
Northern California load,
Northwest hydro and thermal generation dispatch,
Northwest load levels, and
Reno-Alturas (Path 76 or NW-Sierra) flow.

The 4800 MW rating is highly dependent on interactions with other WECC Paths, Northern California Hydro (NCH) output, Northern California load, and also relies on a multifaceted Remedial Action Scheme (RAS) to support reliable power transfers.

Therefore if this alternative were to be chosen as a viable option a coordination study with all path owners and affected parties would have to be coordinated through the WECC process by performing a Path Rating Study.

Also in this informational study only power flow analysis was performed. COI is limited by voltage stability. If this option becomes viable it will be necessary to perform voltage stability studies as COI is variable. Note in such study it would also be suggested that transient stability studies also be performed.

The Round Mountain 500 kV Substation is located in the North Valley Division in the northeastern corner of PG&E's service territory. North Valley's electric transmission is comprised of 60, 115, 230, and 500 kV transmission facilities. The 230 kV facilities, which complement the Pacific Intertie, also run north to south with connections to hydroelectric generation facilities referred to as NorCal Hydro. Northern California Hydro (NCH) is 4100 MW of generation comprised of the USBR Central Valley Project, PG&E's Pit and Feather River systems, CDWR's Hyatt Thermalito units, and the units on the South Fork of the Feather River, and the North Yuba river systems. The 115 and 60 kV facilities are utilized to serve local electric demand.

In addition to the PI and COI, there is one other external interconnection to PacifiCorp. The internal transmission connections to the Humboldt and Sierra areas are via Cottonwood, Table Mountain, Palermo, and Rio Oso substations.

The major transmission paths are shown below:

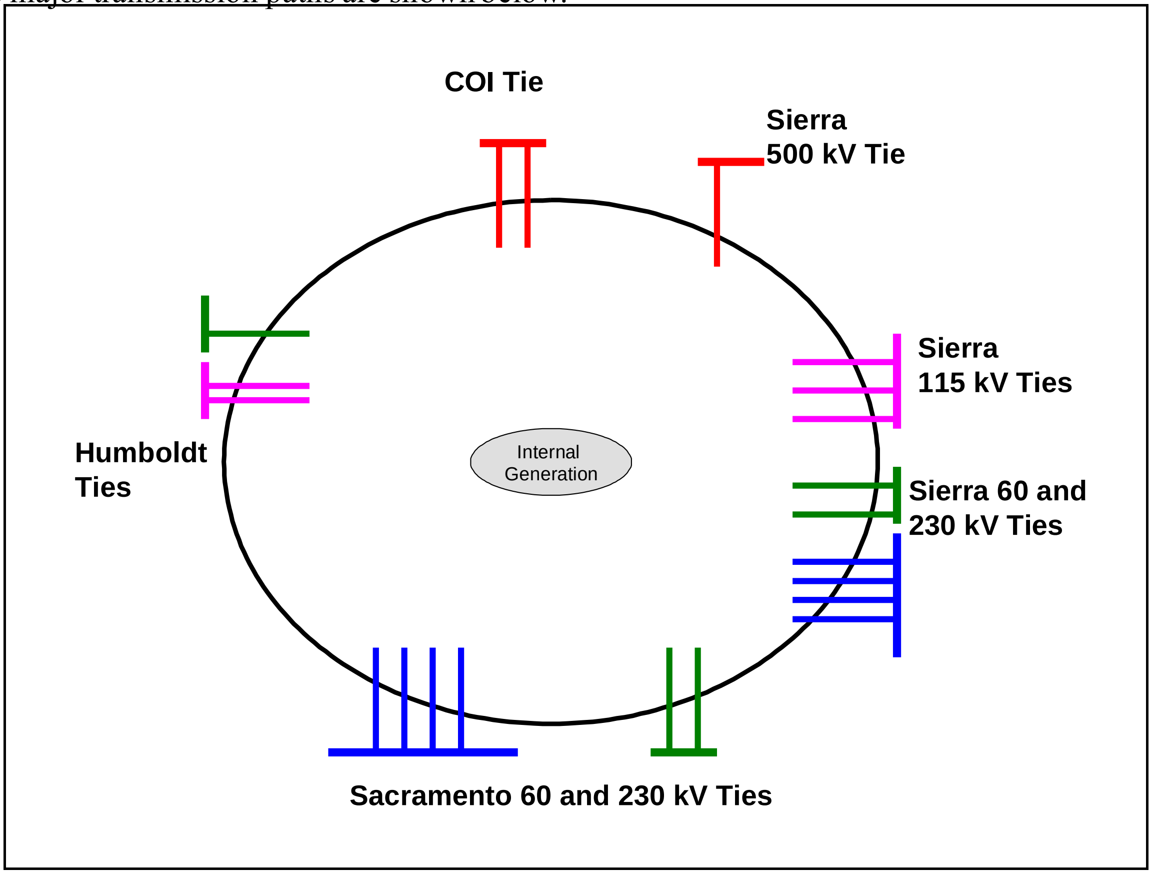


Figure 17 North Valley System Transmission connections

The EHV 500 kV Bulk system and portions of the underlying 230 kV system were assessed for overall system performance in accordance with the NERC TPL-001-4 Reliability Standard.

Alternative 1: Build new 500 KV Substation and route transmission east

- Build new 120 mile Humboldt Wind - Round Mountain 500 KV Line
- Build new 89 mile Round Mountain - Table Mountain 500 KV Line
- Build new 83 mile Table Mountain - Vaca Dixon 500 kV Line
- Build new 57 mile Vaca Dixon - Tesla 500 kV Line
- Reconductor 3 miles of USWP-JRW - Cayetano 230 kV Line

Associated Substation reconfigurations and upgrades at substations not to be assumed in this study. Acquiring land and permitting will also not be included in this study

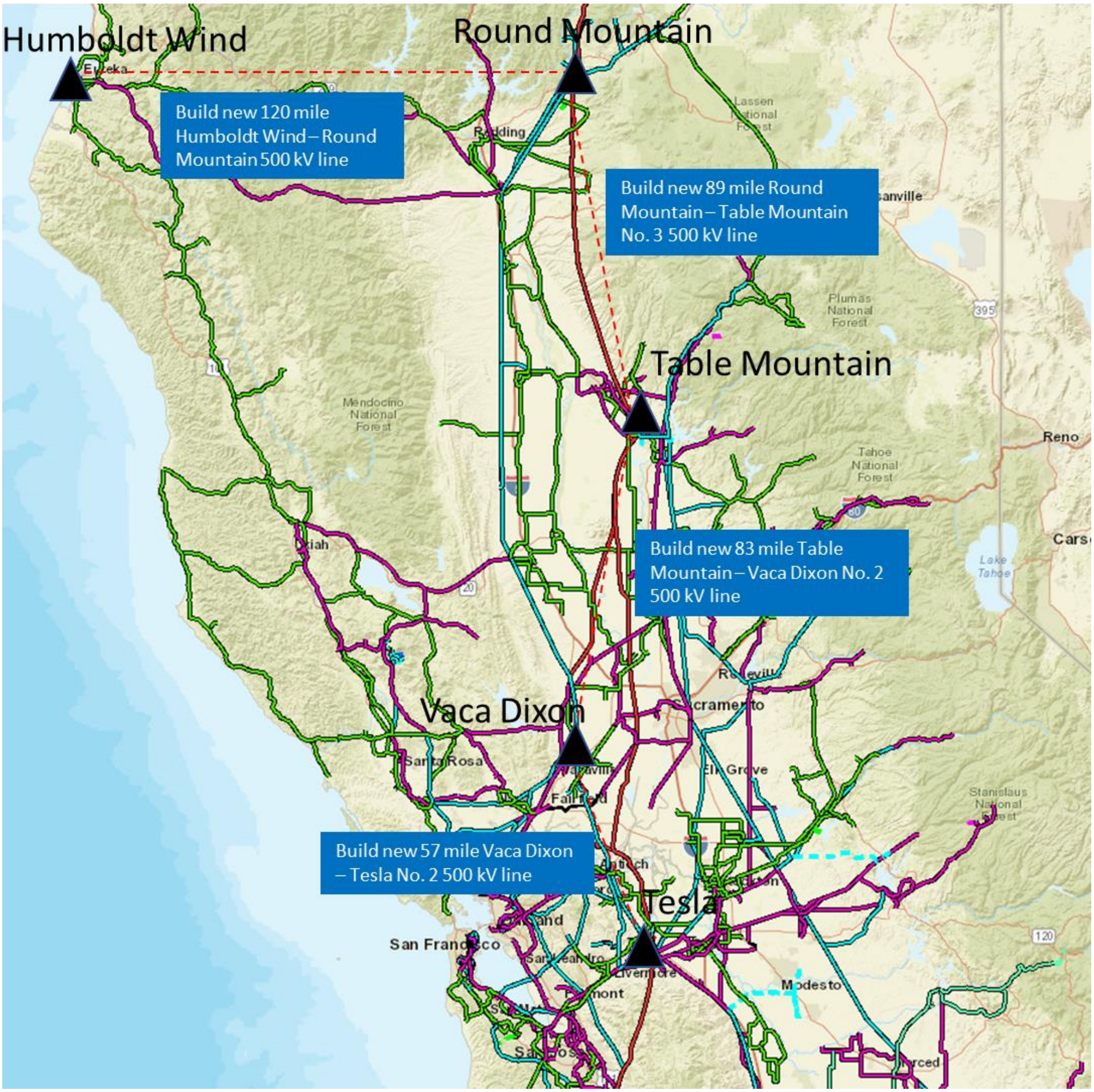


Figure 18 Option 3 Alternative 1 GIS Map

Capacity and Reliability Review

Planning assessment has identified a potential thermal overload in 2029 under peak loading conditions for normal conditions. During normal conditions the Round Mountain – Table Mountain No.1 500 kV line could potentially load up to 116%, the No. 2 line could potentially load up to 117% of its normal summer conductor ratings. Likewise, upon normal conditions the Table Mountain – Vaca Dixon 500 kV line could potentially load up to 113% of its normal summer conductor ratings. Lastly the Cayetano – USWP – JRW 230 kV line could potentially load up to 101.5% of its normal summer conductor rating. The table below shows a summary of the thermal loading with respect to the worse contingencies.

Table 10 Option 3 Alternative 1 Line Loading Summary

Transmission Line	Pre - Project Loading (normal rating)	Post - Project Loading (normal rating)	Post - Project Loading with additional 500 kV lines built (normal rating)
Round Mountain - Table Mountain No.1 500 KV Line	85%	116%	85%
Round Mountain - Table Mountain No.2 500 KV Line	86%	117%	85%
Table Mountain - Vaca Dixon 500 kV Line	84%	112%	80%
Vaca Dixon - Tesla 500 kV Line	66%	92%	120%
USWP-JRW - Cayetano 230 kV Line	98%	102%	70%

With the current configuration, additional generation connected to the Round Mountain 500 kV Substation is not feasible as status quo. With contractual obligations and reserved capacity on COI there is not enough available capacity allocated on Path 66 to sustain a connection as large as 1836 MW's. The 500 kV lines south of Round Mountain will overload due to excess power flow. Running power flow with additional 500 kV lines built in parallel with the original lines overloaded as identified in the Post – Project loading column causes the increase in powerflow on the Vaca Dixon – Tesla 500 kV line up to 120% of its normal summer conductor rating. The Vaca Dixon – Tesla No. 2 500 kV line addition was then included in the larger scope and tested to verify no other through flow issues occurred.

Evaluation of Alternative

A power flow contingency analysis was performed using the 2029 base cases against all the Category P1 (L-1, T-1, G-1), P7 and selected P6 contingencies within the study area. The results were then screened for any thermal overloads or voltage violations along with any non converging cases or excessive voltage mismatches. For this power flow analysis all base cases converged.

The table below shows the power flow analysis results.

Table 11 Power Flow Results for Option 3 Alternative 1

NERC	Facility Name	Basek V	Contingency Name	Rating	2029HS OP1	2029S POPo p1	Corrective Action Plan
P0	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230.0	System Normal	885.9A	101.4%	>95%	Alternative 1
P0	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	System Normal	2199.9A	116.1%	>95%	Alternative 1
P0	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	System Normal	2199.9A	115.9%	>95%	Alternative 1
P0	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	System Normal	2199.9A	117.1%	>95%	Alternative 1
P0	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	System Normal	2199.9A	116.9%	>95%	Alternative 1
P0	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	System Normal	2199.9A	116.1%	>95%	Alternative 1
P0	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	System Normal	2199.9A	117.1%	>95%	Alternative 1
P0	TABLE MT 500kV-TM_VD_11 500kV ckt=1	500	System Normal	2477.9A	112.6%	>95%	Alternative 1
P0	TM_VD_12 500kV-TM_VD_11 500kV ckt=1	500	System Normal	2477.9A	112.6%	>95%	Alternative 1
P0	TM_VD_12 500kV-VACA-DIX 500kV ckt=1	500	System Normal	2477.9A	111.7%	>95%	Alternative 1
P1-2	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TESLA-METCALF #1 500kV Line	1005.1A	100.2%	>95%	Alternative 1
P1-2	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Table Mountain - Vaca Dixon No.1 500 kV Line	745.0A	108.8%	>95%	Alternative 1
P1-2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Olinda - Maxwell No.1 500 kV Line	953.9A	109.5%	>95%	Alternative 1
P1-2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Tesla No.1 500 kV Line	953.9A	100.8%	>95%	Alternative 1
P1-2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Vaca Dixon No.1 500 kV Line	953.9A	110.6%	>95%	Alternative 1
P1-2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Captain Jack - Olinda No.1 500 kV Line	3279.9A	102.3%	>95%	Alternative 1
P1-2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell No.1 500 kV Line	3279.9A	105.7%	>95%	Alternative 1
P1-2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain No.2 500 kV Line	3279.9A	141.4%	>95%	Alternative 1
P1-2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Captain Jack - Olinda No.1 500 kV Line	3279.9A	101.9%	>95%	Alternative 1
P1-2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Olinda - Maxwell No.1 500 kV Line	3279.9A	105.5%	>95%	Alternative 1
P1-2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Round Mountain - Table Mountain No.2 500 kV Line	3279.9A	140.9%	>95%	Alternative 1
P1-2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Captain Jack - Olinda No.1 500 kV Line	3279.9A	103.2%	>95%	Alternative 1
P1-2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell No.1 500 kV Line	3279.9A	106.6%	>95%	Alternative 1
P1-2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain No.1 500 kV Line	3279.9A	141.6%	>95%	Alternative 1
P1-2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Captain Jack - Olinda No.1 500 kV Line	3279.9A	102.7%	>95%	Alternative 1
P1-2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Olinda - Maxwell No.1 500 kV Line	3279.9A	106.4%	>95%	Alternative 1
P1-2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Round Mountain - Table Mountain No.1 500 kV Line	3279.9A	141.1%	>95%	Alternative 1
P1-2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Captain Jack - Olinda No.1 500 kV Line	3279.9A	102.3%	>95%	Alternative 1
P1-2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell No.1 500 kV Line	3279.9A	105.7%	>95%	Alternative 1
P1-2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain No.2 500 kV Line	3279.9A	141.4%	>95%	Alternative 1
P1-2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Captain Jack - Olinda No.1 500 kV Line	3279.9A	103.2%	>95%	Alternative 1
P1-2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell No.1 500 kV Line	3279.9A	106.6%	>95%	Alternative 1
P1-2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain No.1 500 kV Line	3279.9A	141.6%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-NDUBLIN 230kV ckt=1	230	Table Mountain - Tesla #1 500kV Line & TESLA-METCALF #1 500kV Line	1004.1A	100.7%	>95%	Alternative 1
P6-1-	CAYETANO 230kV-	230	TESLA-METCALF #1 500kV Line & METCALF-MOSSLAND	1004.1A	106.0%	>95%	Alternative 1

NERC	Facility Name	Basek V	Contingency Name	Rating	2029HS OP1	2029S POPo p1	Corrective Action Plan
1	NDUBLIN 230kV ckt=1		#1 500kV Line				
P6-1-1	CAYETANO 230kV-NDUBLIN 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	1004.1A	110.4%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-NDUBLIN 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & TESLA-LOSBANOS #1 500kV Line	1004.1A	102.8%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-NDUBLIN 230kV ckt=1	230	Vaca Dixon - Tesla #1 500kV Line & TESLA-METCALF #1 500kV Line	1004.1A	107.4%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-NDUBLIN 230kV ckt=1	230	Vaca Dixon - Tesla #1 500kV Line & TRACY-TESLA #1 500kV Line	1004.1A	100.2%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & METCALF-MOSSLAND #1 500kV Line	1005.1A	106.9%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	1005.1A	111.2%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & TESLA-LOSBANOS #1 500kV Line	1005.1A	103.8%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TRACY-TESLA #1 500kV Line & TESLA-METCALF #1 500kV Line	1005.1A	100.4%	>95%	Alternative 1
P6-1-1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	Vaca Dixon - Tesla #1 500kV Line & TESLA-METCALF #1 500kV Line	1005.1A	108.3%	>95%	Alternative 1
P6-1-1	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Tesla #1 500kV Line	745.0A	101.1%	>95%	Alternative 1
P6-1-1	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Vaca Dixon #1 500kV Line	745.0A	116.9%	>95%	Alternative 1
P6-1-1	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Tesla #1 500kV Line	745.0A	101.3%	>95%	Alternative 1
P6-1-1	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Vaca Dixon #1 500kV Line	745.0A	117.0%	>95%	Alternative 1
P6-1-1	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Table Mountain - Vaca Dixon #1 500kV Line & Vaca Dixon - Tesla #1 500kV Line	745.0A	110.4%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	953.9A	100.3%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	953.9A	109.6%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	953.9A	110.2%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Tesla #1 500kV Line	953.9A	104.3%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Vaca Dixon #1 500kV Line	953.9A	114.1%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Tesla #1 500kV Line	953.9A	104.4%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Vaca Dixon #1 500kV Line	953.9A	114.2%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Tesla #1 500kV Line & TESLA-LOSBANOS #1 500kV Line	953.9A	100.9%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Tesla #1 500kV Line & TESLA-METCALF #1 500kV Line	953.9A	102.7%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Tesla #1 500kV Line & TRACY-TESLA #1 500kV Line	953.9A	106.1%	>95%	Alternative 1
P6-1-1	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Vaca Dixon #1 500kV Line & Vaca Dixon - Tesla #1 500kV Line	953.9A	113.2%	>95%	Alternative 1
P6-1-1	LS PSTAS 230kV-NEWARK D 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & METCALF-MOSSLAND #1 500kV Line	850.0A	103.1%	>95%	Alternative 1
P6-1-1	LS PSTAS 230kV-NEWARK D 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	850.0A	109.1%	>95%	Alternative 1
P6-1-1	LS PSTAS 230kV-NEWARK D 230kV ckt=1	230	Vaca Dixon - Tesla #1 500kV Line & TESLA-METCALF #1 500kV Line	850.0A	105.4%	>95%	Alternative 1
P6-1-1	NDUBLIN 230kV-VINEYARD 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	1004.1A	100.3%	>95%	Alternative 1
P6-1-1	NEWARK E 230kV-NWK DIST 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	2339.5A	103.2%	>95%	Alternative 1
P6-1-1	NEWARK F 115kV-NEWARK E 230kV ckt=11	115/230	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	462.0MVA	100.1%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3279.9A	109.8%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3279.9A	105.4%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3279.9A	105.3%	>95%	Alternative 1

NERC	Facility Name	Basek V	Contingency Name	Rating	2029HS OP1	2029S POPo p1	Corrective Action Plan
P6-1-1	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Malin - Round Mountain #1 500kV Line	3279.9A	126.8%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Tesla #1 500kV Line	3279.9A	110.1%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3279.9A	109.6%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3279.9A	105.2%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3279.9A	105.2%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Malin - Round Mountain #1 500kV Line	3279.9A	126.2%	>95%	Alternative 1
P6-1-1	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Tesla #1 500kV Line	3279.9A	110.1%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3279.9A	110.8%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3279.9A	106.3%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3279.9A	106.2%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #1 500kV Line	3279.9A	127.0%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #2 500kV Line	3279.9A	134.1%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Tesla #1 500kV Line	3279.9A	110.3%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3279.9A	110.5%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3279.9A	106.1%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3279.9A	106.1%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #1 500kV Line	3279.9A	126.3%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #2 500kV Line	3279.9A	133.6%	>95%	Alternative 1
P6-1-1	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Tesla #1 500kV Line	3279.9A	110.3%	>95%	Alternative 1
P6-1-1	ROUND MT 230kV-COTWD_E2 230kV ckt=2	230.0	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Vaca Dixon #1 500kV Line	850.0A	106.4%	>95%	Alternative 1
P6-1-1	ROUND MT 230kV-COTWD_E2 230kV ckt=2	230.0	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Vaca Dixon #1 500kV Line	850.0A	106.5%	>95%	Alternative 1
P6-1-1	ROUND MT 230kV-COTWD_E2 230kV ckt=2	230.0	Table Mountain - Vaca Dixon #1 500kV Line & Vaca Dixon - Tesla #1 500kV Line	850.0A	100.6%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3279.9A	109.8%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3279.9A	105.4%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3279.9A	105.3%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Malin - Round Mountain #1 500kV Line	3279.9A	126.8%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Table Mountain - Tesla #1 500kV Line	3279.9A	110.0%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3279.9A	110.8%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3279.9A	106.3%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3279.9A	106.2%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #1 500kV Line	3279.9A	127.0%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #2 500kV Line	3279.9A	134.1%	>95%	Alternative 1
P6-1-1	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Table Mountain - Tesla #1 500kV Line	3279.9A	110.2%	>95%	Alternative 1
P6-1_2	CAYETANO 230kV-NDUBLIN 230kV ckt=1	500	TESLA-METCALF #1 500kV Line & TESLA E 230/500kV Bank #2	1004.1A	105.1%	>95%	Alternative 1
P6-1_2	CAYETANO 230kV-NDUBLIN 230kV ckt=1	500	Vaca Dixon - Tesla #1 500kV Line & TESLA E 230/500kV Bank #2	1004.1A	100.6%	>95%	Alternative 1

NERC	Facility Name	Basek V	Contingency Name	Rating	2029HS OP1	2029S POPo p1	Corrective Action Plan
P6-1_2	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & METCALF 230/500kV Bank #11	1005.1A	100.6%	>95%	Alternative 1
P6-1_2	CAYETANO 230kV-USWP-JRW 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & TESLA E 230/500kV Bank #2	1005.1A	106.0%	>95%	Alternative 1
P6-1_2	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Table Mountain - Telsa #1 500kV Line & Table Mountain 230/500kV Bank #1	745.0A	100.6%	>95%	Alternative 1
P6-1_2	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Table Mountain - Vaca Dixon #1 500kV Line & Table Mountain 230/500kV Bank #1	745.0A	120.1%	>95%	Alternative 1
P6-1_2	COTWD_E 230kV-ROUND MT 230kV ckt=3	230	Table Mountain - Vaca Dixon #1 500kV Line & VACA-DIX 230/500kV Bank #11	745.0A	109.1%	>95%	Alternative 1
P6-1_2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	953.9A	109.5%	>95%	Alternative 1
P6-1_2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Telsa #1 500kV Line & Table Mountain 230/500kV Bank #1	953.9A	103.0%	>95%	Alternative 1
P6-1_2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Telsa #1 500kV Line & TESLA E 230/500kV Bank #2	953.9A	100.9%	>95%	Alternative 1
P6-1_2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Vaca Dixon #1 500kV Line & Table Mountain 230/500kV Bank #1	953.9A	114.6%	>95%	Alternative 1
P6-1_2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	Table Mountain - Vaca Dixon #1 500kV Line & VACA-DIX 230/500kV Bank #11	953.9A	111.0%	>95%	Alternative 1
P6-1_2	LS PSTAS 230kV-NEWARK D 230kV ckt=1	230	TESLA-METCALF #1 500kV Line & TESLA E 230/500kV Bank #2	850.0A	102.2%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Captain Jack - Olinda No.1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.7%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.0%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	3279.9A	105.6%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & ROUND MT 230/500kV Bank #1	3279.9A	140.2%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Table Mountain 230/500kV Bank #1	3279.9A	140.2%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Captain Jack - Olinda No.1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.3%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	108.8%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	3279.9A	105.4%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & ROUND MT 230/500kV Bank #1	3279.9A	139.8%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500	Round Mountain - Table Mountain #2 500kV Line & Table Mountain 230/500kV Bank #1	3279.9A	139.7%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Captain Jack - Olinda No.1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	110.6%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Malin - Round Mountain No.1 500kV Line & ROUND MT 230/500kV Bank #1 & Round Mountain - Table Mountain No.1 500kV Line	3279.9A	122.1%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.9%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	3279.9A	106.5%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500 kV Line & ROUND MT 230/500kV Bank #1 & Malin - Round Mountain #2 500kV Line	3279.9A	131.1%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Table Mountain 230/500kV Bank #1	3279.9A	140.5%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Captain Jack - Olinda No.1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	110.2%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Malin - Round Mountain No.1 500kV Line & ROUND MT 230/500kV Bank #1 & Round Mountain - Table Mountain No.1 500kV Line	3279.9A	121.5%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.8%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	3279.9A	106.3%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Round Mountain - Table Mountain #1 500 kV Line & ROUND MT 230/500kV Bank #1 & Malin - Round Mountain #2 500kV Line	3279.9A	130.6%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500	Round Mountain - Table Mountain #1 500kV Line & Table Mountain 230/500kV Bank #1	3279.9A	140.0%	>95%	Alternative 1

NERC	Facility Name	Basek V	Contingency Name	Rating	2029HS OP1	2029S POPo p1	Corrective Action Plan
P6-1_2	ROUND MT 230kV-COTWD_E2 230kV ckt=2	230.0	Table Mountain - Vaca Dixon #1 500kV Line & Table Mountain 230/500kV Bank #1	850.0A	109.3%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Captain Jack - Olinda No.1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.7%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.0%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	3279.9A	105.6%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Round Mountain - Table Mountain #2 500kV Line & ROUND MT 230/500kV Bank #1	3279.9A	140.2%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Round Mountain - Table Mountain #2 500kV Line & Table Mountain 230/500kV Bank #1	3279.9A	140.2%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Captain Jack - Olinda No.1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	110.6%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Malin - Round Mountain No.1 500kV Line & ROUND MT 230/500kV Bank #1 & Round Mountain - Table Mountain No.1 500kV Line	3279.9A	122.1%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & OLINDA 500/230kV Bank #1	3279.9A	109.9%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500/230kV Bank #1	3279.9A	106.5%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Round Mountain - Table Mountain #1 500 kV Line & ROUND MT 230/500kV Bank #1 & Malin - Round Mountain #2 500kV Line	3279.9A	131.1%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Round Mountain - Table Mountain #1 500kV Line & Table Mountain 230/500kV Bank #1	3279.9A	140.5%	>95%	Alternative 1
P6-1_2	DELEVAN 230kV-CORTINA 230kV ckt=1	230	TRACY-LOSBANOS #1 500kV Line & TRACY 500kV Bus Shunt	953.9A	100.8%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500kV Bus Shunt	3279.9A	141.4%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500.0	Round Mountain - Table Mountain #1 500kV Line& TABLE MT 500kV Bus Shunt	3279.9A	142.2%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-RM_TM_11 500kV ckt=1	500.0	Round Mountain - Table Mountain #2 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	142.2%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500kV Bus Shunt	3279.9A	140.9%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500.0	Round Mountain - Table Mountain #1 500kV Line& TABLE MT 500kV Bus Shunt	3279.9A	141.7%	>95%	Alternative 1
P6-1_2	RM_TM_12 500kV-TABLE MT 500kV ckt=1	500.0	Round Mountain - Table Mountain #2 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	141.7%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500.0	Table Mountain - Telsa #1 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	142.4%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500.0	Table Mountain - Vaca Dixon #1 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	142.4%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-RM_TM_21 500kV ckt=2	500.0	TRACY-TESLA #1 500kV Line & TRACY 500kV Bus Shunt	3279.9A	141.6%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500.0	Table Mountain - Telsa #1 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	141.9%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500.0	Table Mountain - Vaca Dixon #1 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	141.9%	>95%	Alternative 1
P6-1_2	RM_TM_22 500kV-TABLE MT 500kV ckt=2	500.0	TRACY-TESLA #1 500kV Line & TRACY 500kV Bus Shunt	3279.9A	141.1%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY 500kV Bus Shunt	3279.9A	141.4%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Round Mountain - Table Mountain #1 500kV Line& TABLE MT 500kV Bus Shunt	3279.9A	142.2%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_11 500kV ckt=1	500.0	Round Mountain - Table Mountain #2 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	142.2%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Table Mountain - Telsa #1 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	142.4%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	Table Mountain - Vaca Dixon #1 500kV Line & TABLE MT 500kV Bus Shunt	3279.9A	142.4%	>95%	Alternative 1
P6-1_2	ROUND MT 500kV-RM_TM_21 500kV ckt=2	500.0	TRACY-TESLA #1 500kV Line & TRACY 500kV Bus Shunt	3279.9A	141.6%	>95%	Alternative 1

Alternative 1

Build New 500 kV Lines

Figure 19 REDACTED

Normal Condition (N-0)

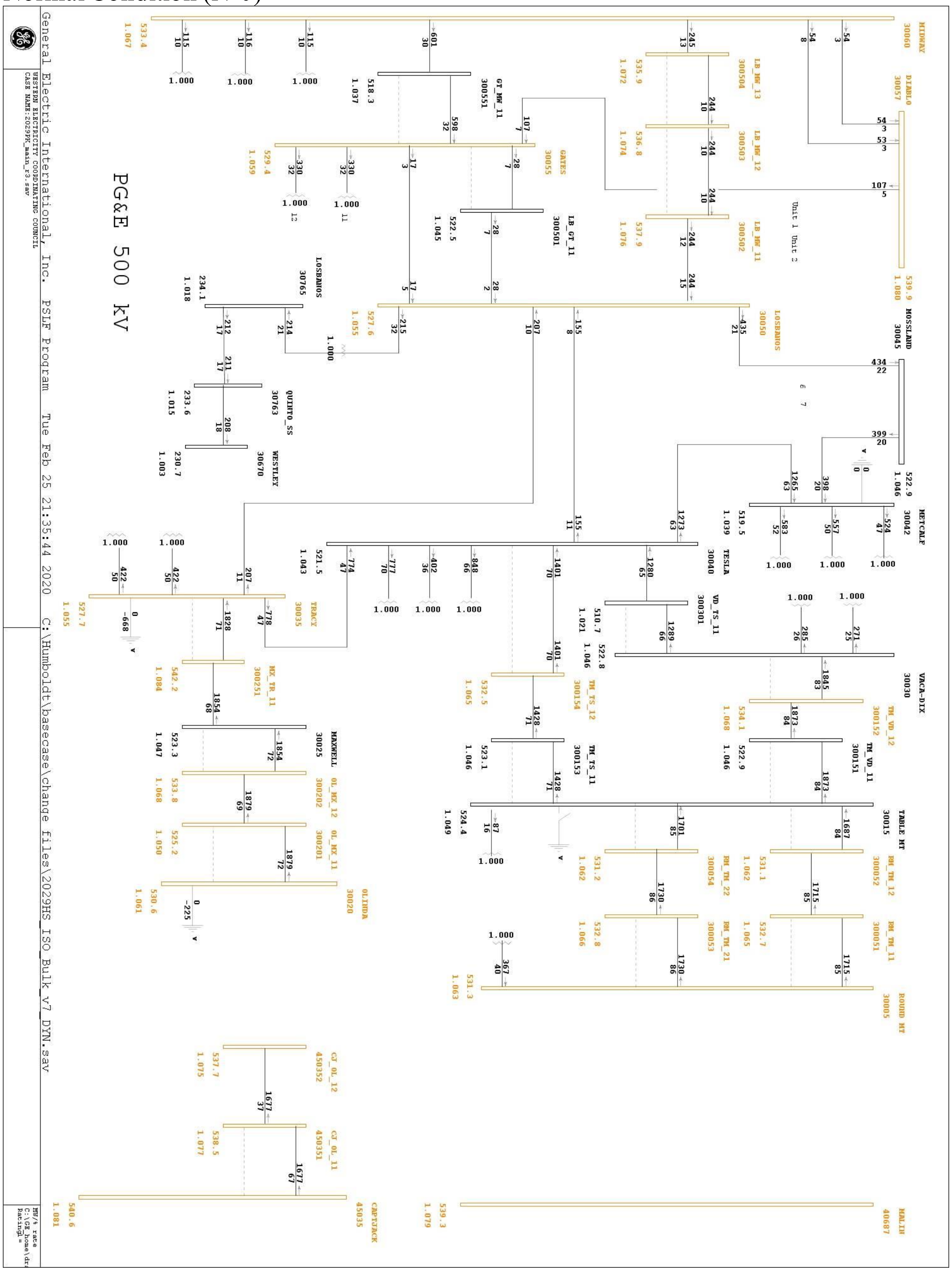


Figure 20 Status Quo 2029 Heavy Summer PSLF Power Flow (N-0)

Generator modelled with connection to Round Mountain (not complete alternative)

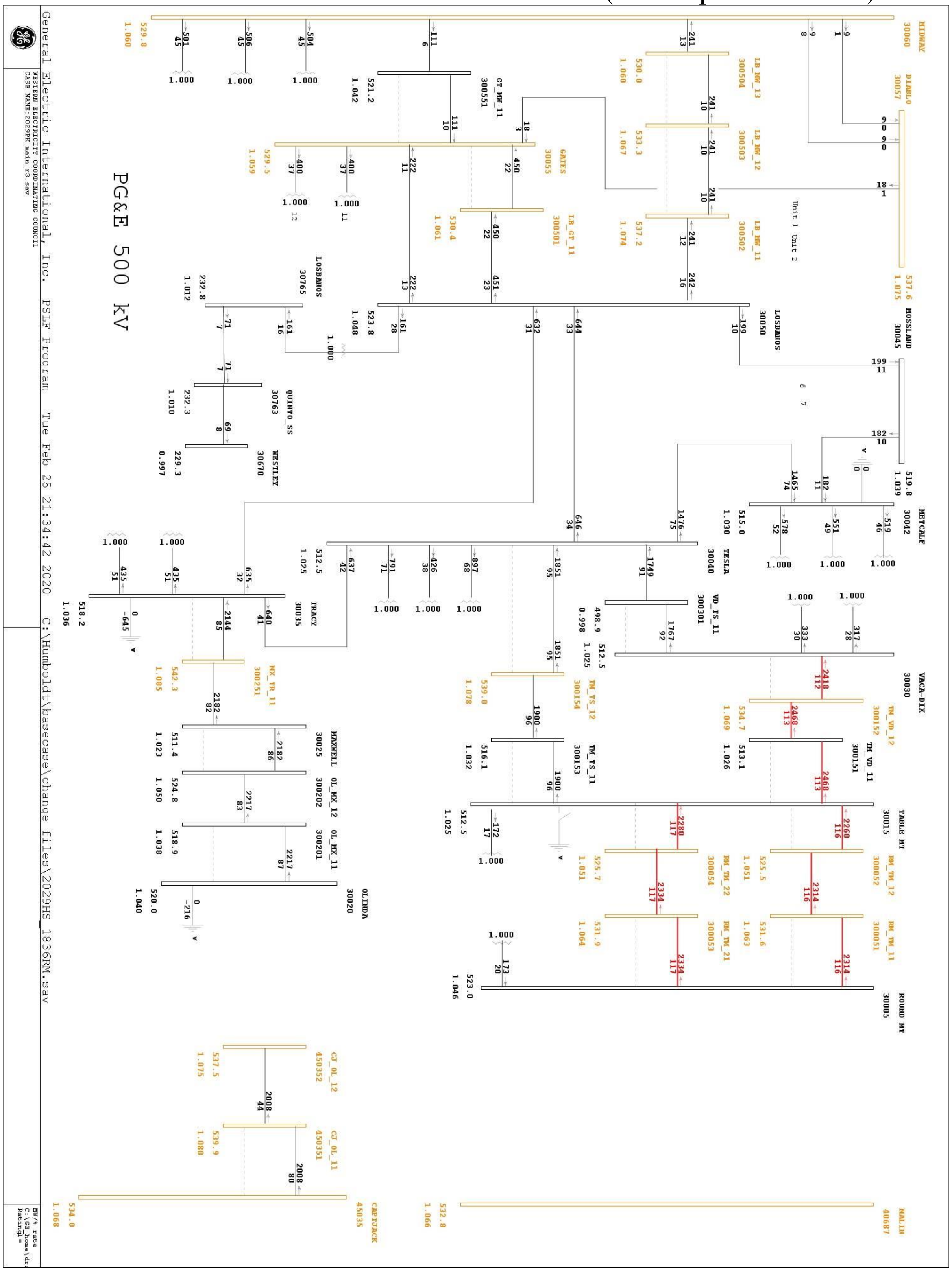


Figure 21 Option 3 connected to Round Mountain 500 kV with no associated upgrades, 2029 Heavy Summer (N-0)

Option 3 Alternative 1

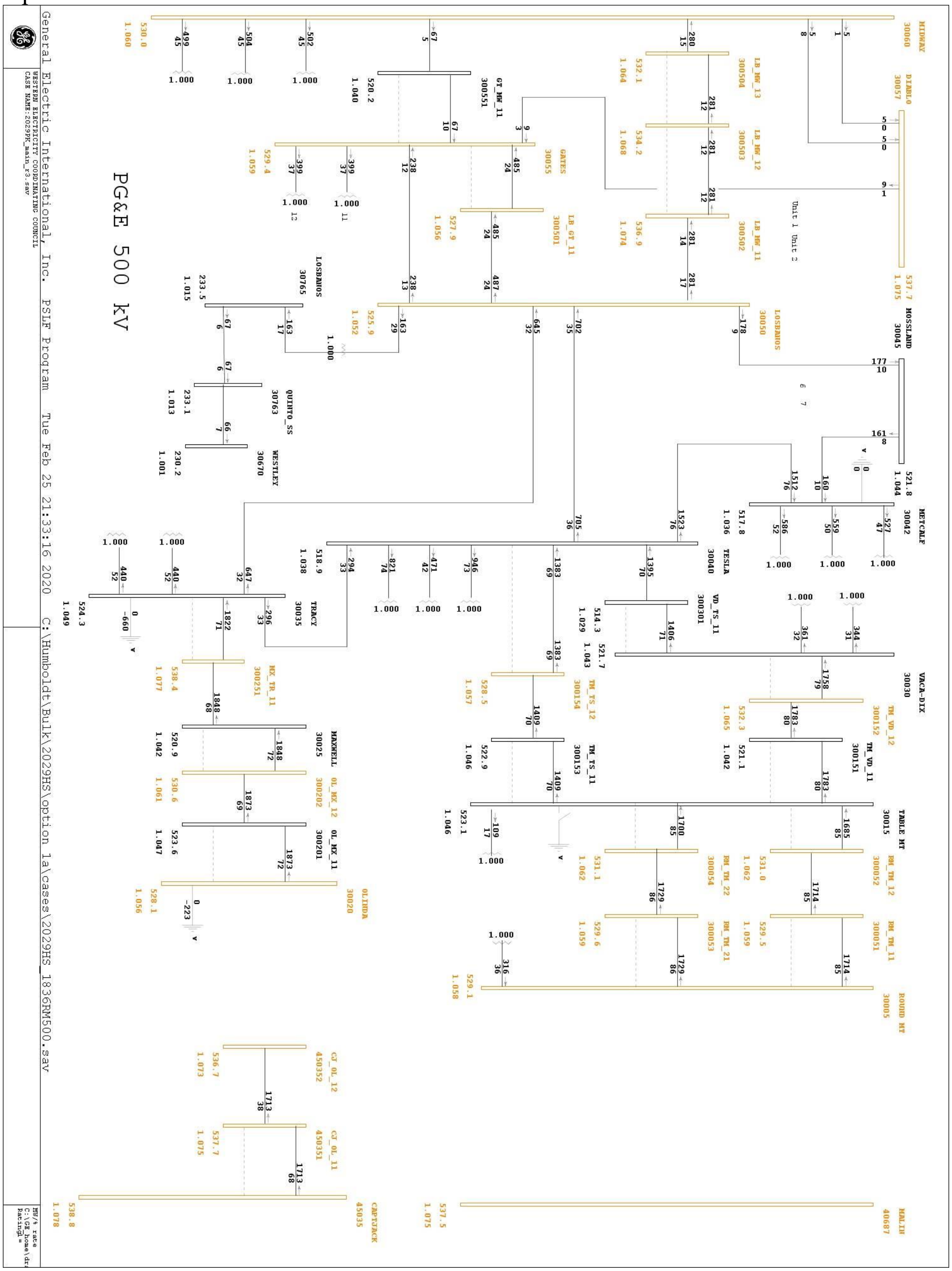


Figure 22 Option 3 Alternative 1 2029 Heavy Summer PSLF Power Flow (N-0)

Generator Modelled with no upgrades modelled: (N-1) Round Mountain – Table Mountain 500 kV Line Out

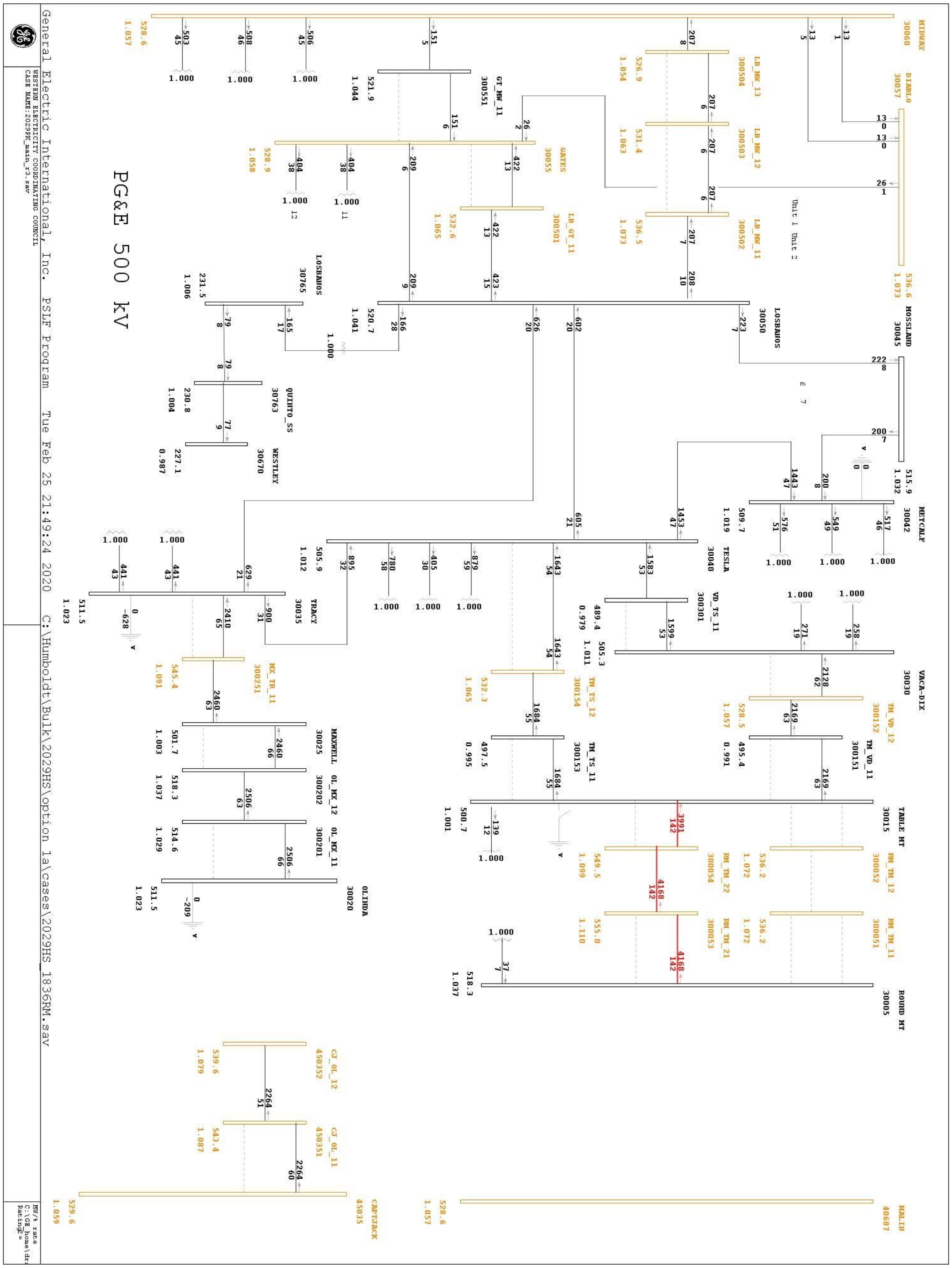


Figure 23 Option 3 connected to Round Mountain 500 kV with no associated upgrades, 2029 Heavy Summer (N-1) Round Mountain – Table Mountain 500 kV line out

Option 3 Alternative 1

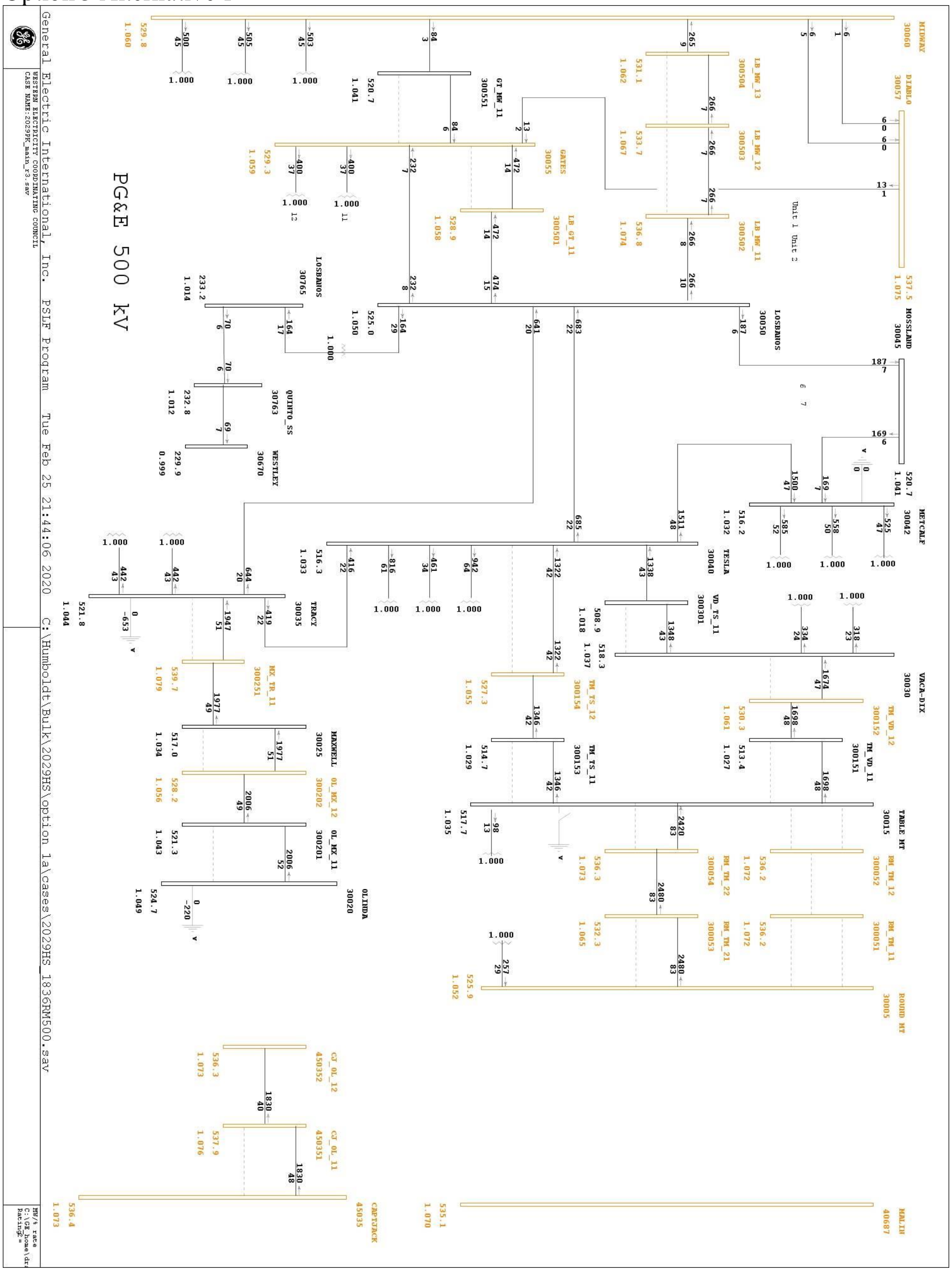


Figure 24 Option 3 Alternative 1 2029 Heavy Summer (N-1) Round Mountain – Table Mountain 500 kV line out

Alternative 2 Background

Alternative 2 consists of interconnecting offshore wind from the Humboldt Coast to Vaca Dixon 500 kV Substation.

The Vaca-Dixon system consists of 230, 115, and 60 kV Lines. Its primary sources include two 500/230 kV Transformers at Vaca-Dixon, four 230 kV lines providing hydro generation via Delevan Substation, two 230 kV lines providing wind generation via Bird's Landing Substation, and local generation. Locally, these sources feed the 115 and 60 kV systems through three Vaca-Dixon 230/115 kV Transformers. This area can be broken up into two major sub-systems: the Vacaville 115 kV pocket and the 60 kV pocket.

The Vacaville 115 kV pocket serves several substations including Vacaville, Suisun, and Jameson, through four 115 kV lines. The 60 kV pocket consists of two Vaca-Dixon 115/60 kV transformers feeding two 60 kV lines.

The southern portion of Solano County has 1,036 MW of wind generation capacity, which is primarily exported to the Greater Bay Area transmission system via two 230 kV lines. The major transmission paths below.

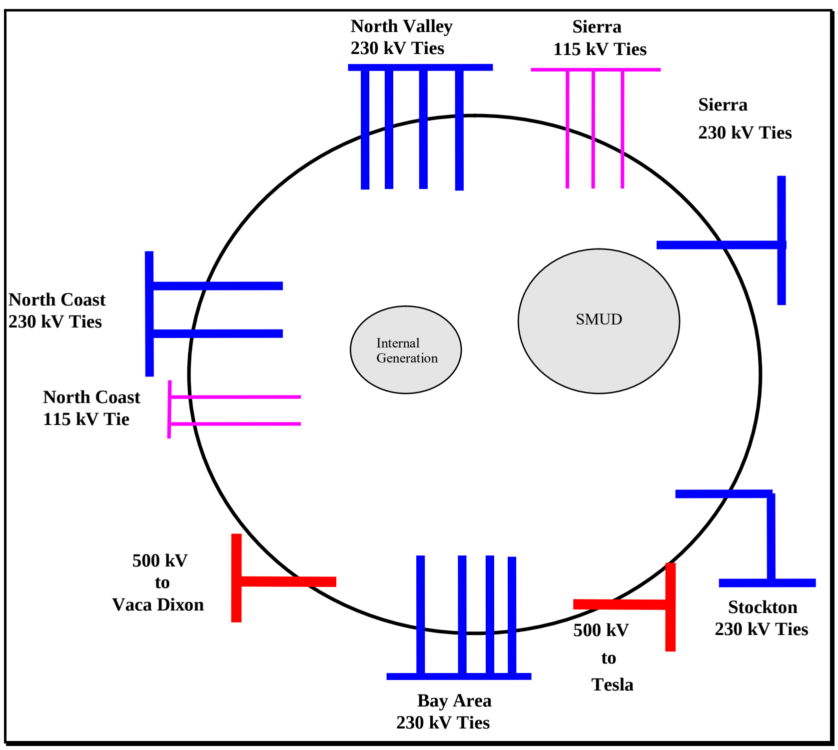


Figure 25 Vaca Dixon Transmission System Connections

As observed above Vaca Dixon sub-transmission system primarily serves the Yolo and Solano Counties. These load centers are currently not as densely populated as the bay area. If an interconnection is terminated at Vaca Dixon 500 kV Substation a route to deliver this power the Bay Area would be recommended.

An option considered is to build a new 500 kV and 230 kV substation to be located in Solano County which would connect to the Vaca Dixon – Tesla 500 kV line. This option would then include building two new 230 kV lines from the new substation to Pittsburg 230 kV Substation which is approximately 5.3 miles in distance. The new 230 kV lines will likely need to cross under the Sacramento River to the East Bay. The new substation connecting to the Vaca Dixon – Tesla 500 kV line along with the 230 kV lines would add a new and diverse source into the area. Resources can be utilized from the northern or southern part of the system giving more flexibility for renewable power to serve Bay Area load.

The Pittsburg area is designed with many 230 kV transmission lines to serve loads in other load pockets in the Bay Area. This particular area is considered the East Bay Planning Division. The East Bay Planning Division, a sub-area of the Greater Bay Area encompasses the East Bay, Diablo, and Mission divisions. This area primarily relies on internal generation to serve electric customers.

Some of the major substations within the East Bay Planning Division are Sobrante, Moraga, Newark, East Shore, San Ramon, Pittsburg, and Contra Costa Substations. The major load centers include the cities along the San Francisco Bay in Alameda and Contra Costa Counties as well as cities in the East Bay hills and Tri-Valley area. The East Bay Planning Division relies on generation and import lines to serve the local demand and exports power to both the SF-Peninsula and South Bay Planning Divisions. Key substations that import power into the East Bay Planning Division are Tesla, Vaca-Dixon, and Metcalf substations, all of which have 500 kV sources. In addition, there are 230 kV transmission facilities from Lakeville and Ignacio Substations that are used to import power from the Geysers geothermal generation in the north and to import from Vaca-Dixon. Generation facilities in the East Bay Planning Division include PG&E's Gateway Generating Station, the Russell City Energy Center (RCEC), and the Marsh Landing Generating Station. Excess internal generation in the East Bay Planning Division is exported to its neighboring areas. The East Bay Planning Division also directly exports approximately 400 MW into San Francisco via the Trans Bay Cable (TBC) under normal operating conditions. The major transmission paths are shown below.

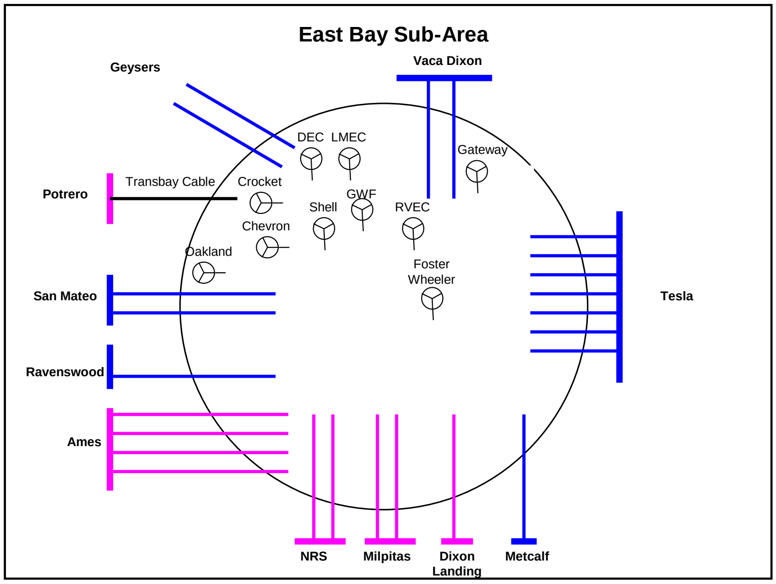


Figure 26 East Bay Transmission System Connection

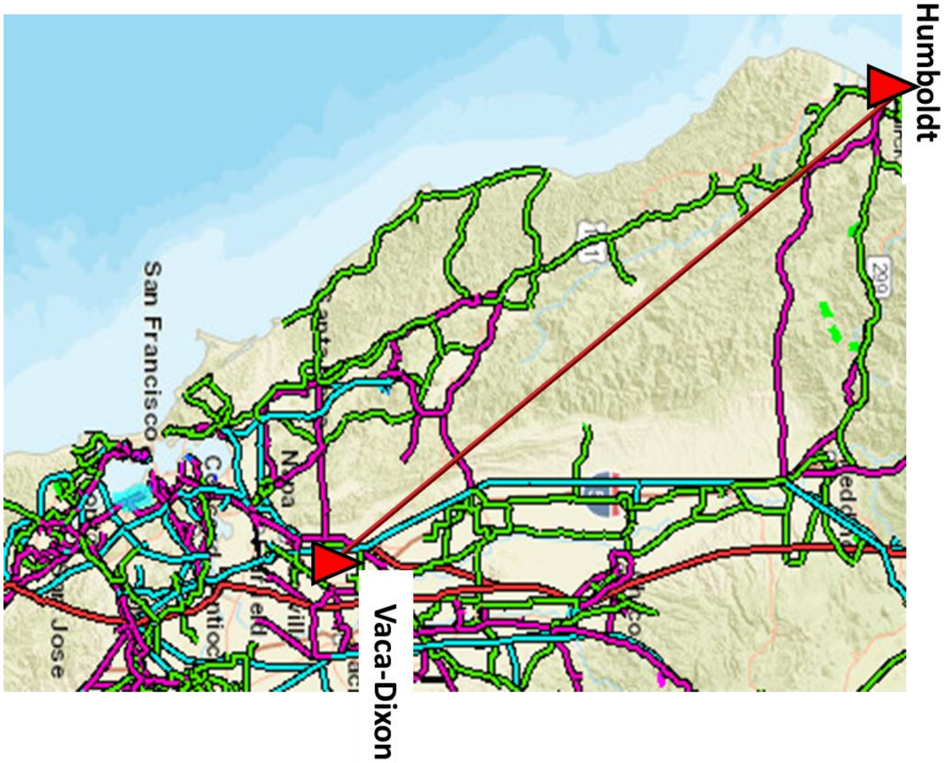
In the East Bay area dispatch of approximately 4,000 MW is modelled for local area generation.

Alternative 2 Scope

Alternative 2: Build 500 kV Substation and route transmission southeast

- Build 500 kV Transmission Line from 500 kV Substation (to be assumed next to Humboldt Bay 115 kV Substation) to Vaca Dixon 500 kV Substation
- Build new Collinsville 500 kV Substation
- Loop Vaca Dixon-Tesla 500 kV line into new station
- Reconductor 25 miles of the Vaca Dixon-Collinsville 500 kV Line
- Install 500/230 kV transformer at new station
- Construct two, 5.3-mile subsea 230 kV cables to Pittsburg P.P. Substation
- Install voltage support as required at various locations with the Bay Area

Associated Substation reconfigurations and upgrades at substations not to be assumed in this study. Acquiring land and permitting will also not be included in this study



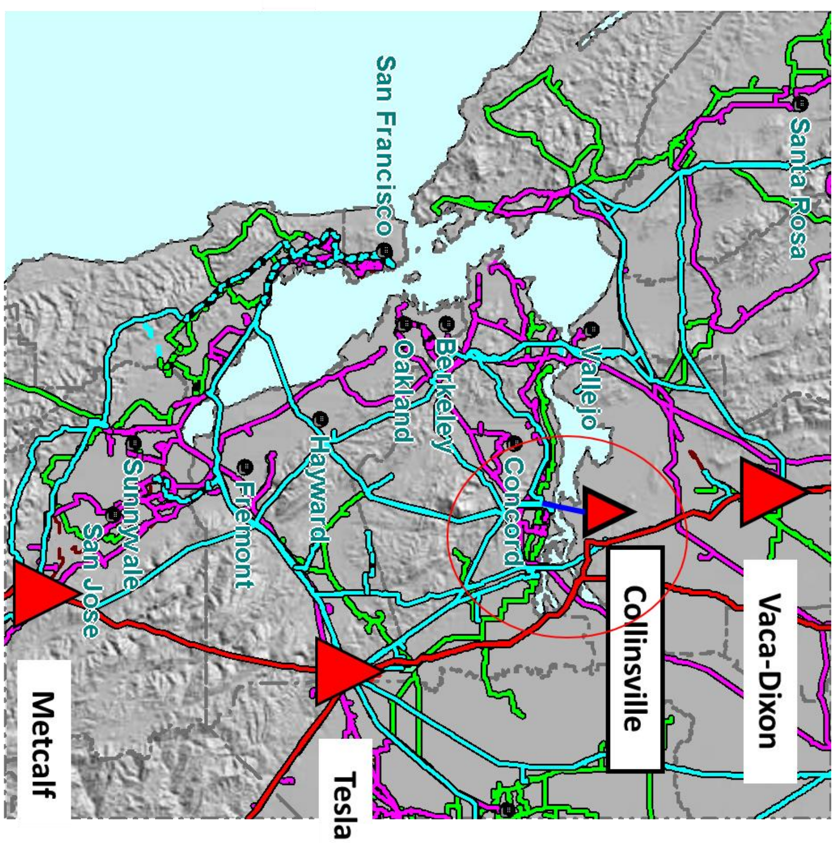


Figure 27 Humboldt to Vaca Dixon GIS map and Collinsville GIS map

Capacity and Reliability Review

Planning assessment has identified a potential thermal overload in 2029 under peak loading conditions for normal conditions. During normal conditions the Vaca Dixon - Collinsville 500 kV line could potentially load up to 131% of its normal summer conductor ratings. The table below shows a summary of the thermal loading with respect to the worse contingencies.

Table 12 Option 3 Alternative 2 Line Loading Summary

Transmission Line	Pre - Project Loading (normal rating)	Post - Project Loading (normal rating)
Vaca Dixon - Collinsville 500 kV Line	66% (VD - Tesla)	131%

With the current configuration, additional generation connected to the Vaca Dixon 500 kV/Collinsville 500 kV Substations is not feasible as status quo. The additional generation injected into the substations causes overloads on the Vaca Dixon – Collinsville 500 kV Line. This Vaca Dixon – Tesla 500 kV Line is looped into Collinsville. The portion of line between Vaca Dixon and Collinsville overload due to the added generation at the Vaca Dixon bus. Reconductoring of this portion of the line would be recommended to withstand normal operating conditions.

Evaluation of Alternative

A power flow contingency analysis was performed using the 2029 base cases against all the Category P1 (L-1, T-1, G-1), P7 and selected P6 contingencies within the study area. The results were then screened for any thermal overloads or voltage violations along with any non converging cases or excessive voltage mismatches. For this power flow analysis all base cases converged.

The table below shows the power flow analysis results.

Table 13 Power Flow Results for Option 3 Alternative 2

NERC	Facility Name	BasekV	Contingency Name	Rating	2029H SOP2	2029SP OPop2	Corrective Action Plan
P0	VACA-DIX 500kV-VD_CV_11 500kV ckt=1	500.0	System Normal	2230.0A	130.8%	>95%	reconductor
P0	VD_CV_11 500kV-COLLNSVL 500kV ckt=1	500	System Normal	2230.0A	131.0%	>95%	reconductor
P1-2	ROUND MT 230kV-ROUND MT 500kV ckt=1	230/500	Captain Jack - Olinda #1 500kV Line	1122.0MVA	>95%	105.2%	existing issue
P1-2	VACA-DIX 500kV-VD_CV_11 500kV ckt=1	500.0	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line	3555.9A	102.7%	>95%	reconductor
P1-2	VD_CV_11 500kV-COLLNSVL 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line	3555.9A	102.7%	>95%	reconductor
P1-3	BRIGHTON 230kV-LOCKJ1 230kV ckt=1	230.0	Table Mountain 230/500kV Bank #1	850.0A	>95%	111.8%	existing issue
P1-3	EIGHT MI 230kV-TESLA E 230kV ckt=1	230	Table Mountain 230/500kV Bank #1	928.0A	>95%	127.9%	existing issue
P1-3	GOLDHILL 230kV-EIGHT MI 230kV ckt=1	230.0	Table Mountain 230/500kV Bank #1	975.0A	>95%	104.2%	existing issue

NERC	Facility Name	BasekV	Contingency Name	Rating	2029H SOP2	2029SP OPop2	Corrective Action Plan
P1-3	GOLDHILL 230kV-LODI 230kV ckt=1	230	Table Mountain 230/500kV Bank #1	964.9A	>95%	104.7%	existing issue
P1-3	OLINDA 500kV-OLINDAW 230kV ckt=1	500/230	ROUND MT 230/500kV Bank #1	1041.0MVA	>95%	107.7%	existing issue
P1-3	OLINDAW 230kV-KE_SOUTH 230kV ckt=1	230.0	ROUND MT 230/500kV Bank #1	810.8A	>95%	100.9%	existing issue
P1-3	RIO OSO 230kV-LOCKFORD 230kV ckt=1	230.0	Table Mountain 230/500kV Bank #1	800.0A	>95%	103.1%	existing issue
P1-3	ROUND MT 230kV-ROUND MT 500kV ckt=1	230/500	OLINDA 500/230kV Bank #1	1122.0MVA	>95%	103.9%	existing issue
P6-1_1	CAYETANO 230kV-NDUBLIN 230kV ckt=1	227.0	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	1004.1A	102.1%	>95%	reduce generation
P6-1_1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	228.0	TESLA-METCALF #1 500kV Line & METCALF-MOSSLAND #1 500kV Line	1005.1A	100.4%	>95%	reduce generation
P6-1_1	CAYETANO 230kV-USWP-JRW 230kV ckt=1	229.0	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	1005.1A	103.0%	>95%	reduce generation
P6-1_1	NEWARK E 230kV-NWK DIST 230kV ckt=1	230.0	TESLA-METCALF #1 500kV Line & MOSSLAND-LOSBANOS #1 500kV Line	2339.5A	102.6%	>95%	reduce generation
P6-1_1	OLINDA 500kV-OLINDAW 230kV ckt=1	500/230	Malin - Round Mountain #1 500kV Line & Malin - Round Mountain #2 500kV Line & Round Mountain - Table Mountain #2 500kV Line	1041.0MVA	>95%	128.9%	reduce generation
P6-1_1	OLINDAW 230kV-KE_SOUTH 230kV ckt=1	230.0	Malin - Round Mountain #1 500kV Line & Malin - Round Mountain #2 500kV Line & Round Mountain - Table Mountain #2 500kV Line	810.8A	>95%	115.5%	reduce generation
P6-1_1	ROUND MT 230kV-ROUND MT 500kV ckt=1	230/500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	1122.0MVA	>95%	113.8%	reduce generation
P6-1_1	ROUND MT 230kV-ROUND MT 500kV ckt=1	230/500	Round Mountain - Table Mountain #2 500kV Line & Malin - Round Mountain #2 500kV Line & Round Mountain - Table Mountain #1 500kV Line	1122.0MVA	>95%	110.8%	reduce generation
P6-1_1	ROUND MT 230kV-ROUND MT 500kV ckt=1	230/500	Round Mountain - Table Mountain #2 500kV Line & Round Mountain - Table Mountain #1 500kV Line & Malin - Round Mountain #1 500kV Line	1122.0MVA	>95%	111.5%	reduce generation
P6-1_1	VACA-DIX 500kV-VD_CV_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3555.9A	103.0%	>95%	reconductor
P6-1_1	VACA-DIX 500kV-VD_CV_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3555.9A	102.4%	>95%	reconductor
P6-1_1	VACA-DIX 500kV-VD_CV_11 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3555.9A	102.0%	>95%	reconductor
P6-1_1	VACA-DIX 500kV-VD_CV_11 500kV ckt=1	500	Table Mountain - Tesla #1 500kV Line & TRACY-TESLA #1 500kV Line	3555.9A	106.1%	>95%	reconductor
P6-1_1	VD_CV_11 500kV-COLLNSVL 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & Captain Jack - Olinda #1 500kV Line	3555.9A	103.1%	>95%	reconductor
P6-1_1	VD_CV_11 500kV-COLLNSVL 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-LOSBANOS #1 500kV Line	3555.9A	102.5%	>95%	reconductor
P6-1_1	VD_CV_11 500kV-COLLNSVL 500kV ckt=1	500	Olinda - Maxwell #1 500kV Line & Maxwell - Tracy #1 500kV Line & TRACY-TESLA #1 500kV Line	3555.9A	102.1%	>95%	reconductor
P6-1_1	VD_CV_11 500kV-COLLNSVL 500kV ckt=1	500	Table Mountain - Tesla #1 500kV Line & TRACY-TESLA #1 500kV Line	3555.9A	106.2%	>95%	reconductor

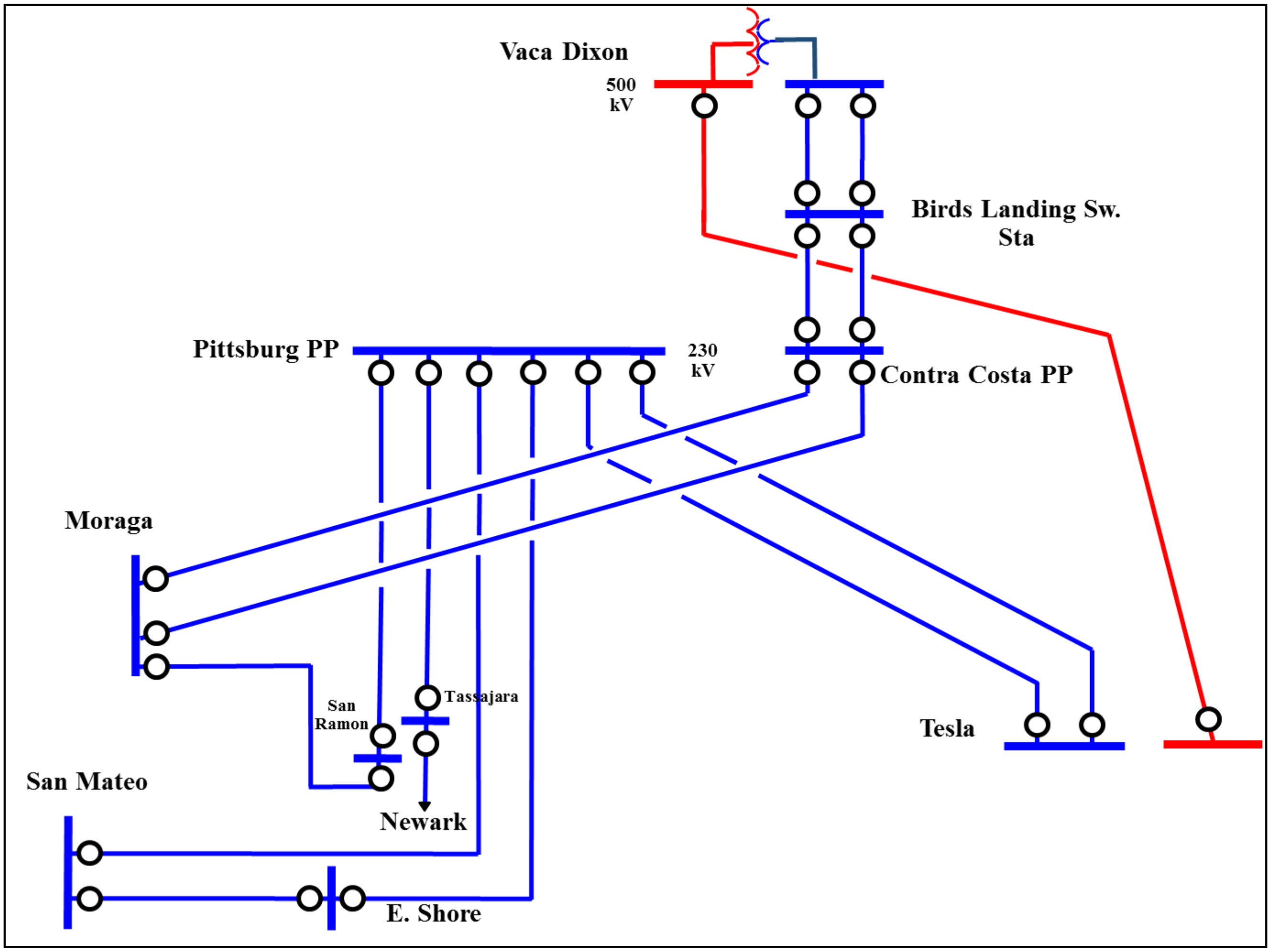


Figure 28 Status Quo East Bay 230 kV Single Line Diagram

Build new Collinsville Substation

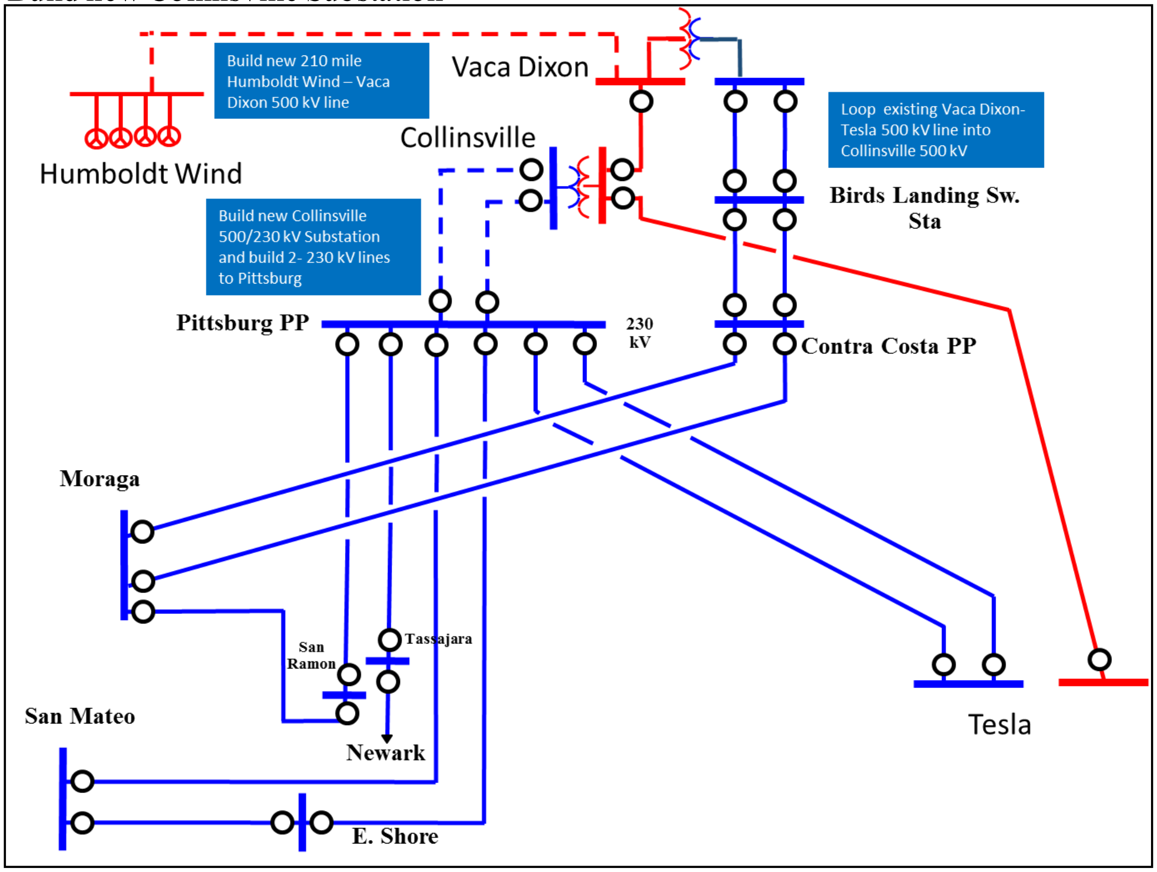


Figure 29 Option 3 Alternative 2 Single Line Diagram

Normal Condition (N-0)

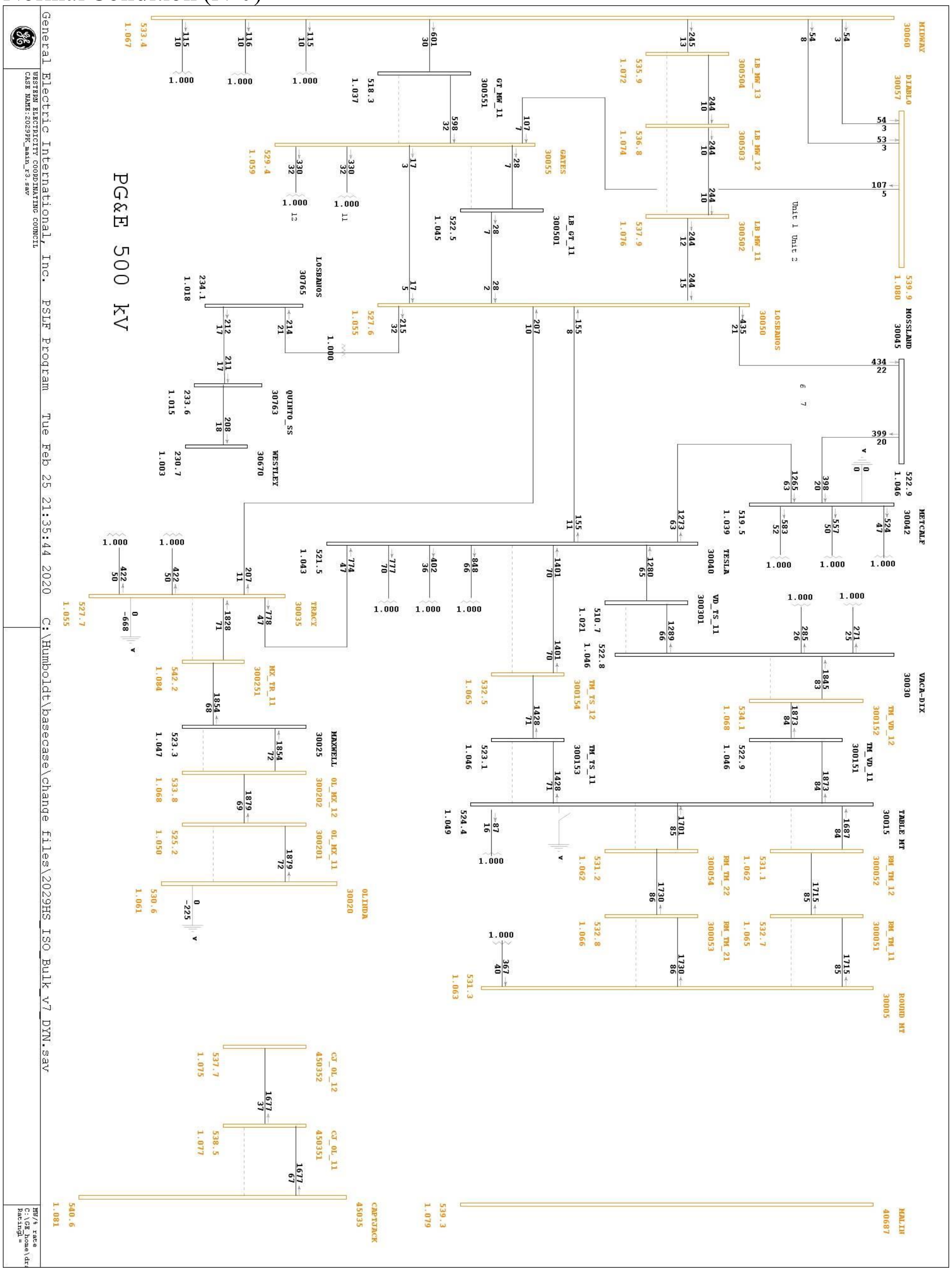


Figure 30 Status Quo 2029 Heavy Summer PSLF Power Flow (N-0)

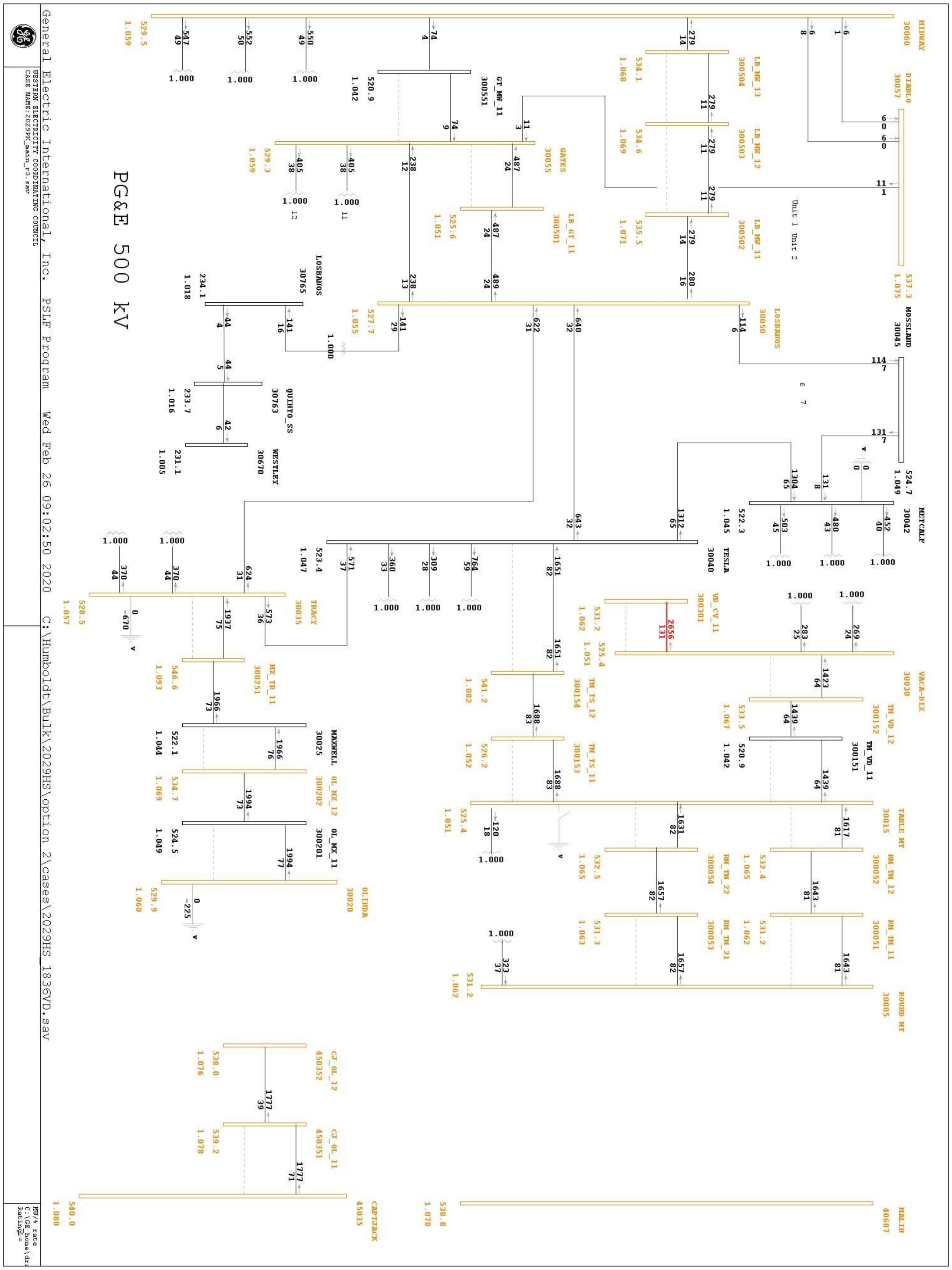


Figure 31 Option 2 connected to Vaca Dixon with new Collinsville connection (no other associated upgrades modelled) (N-0)

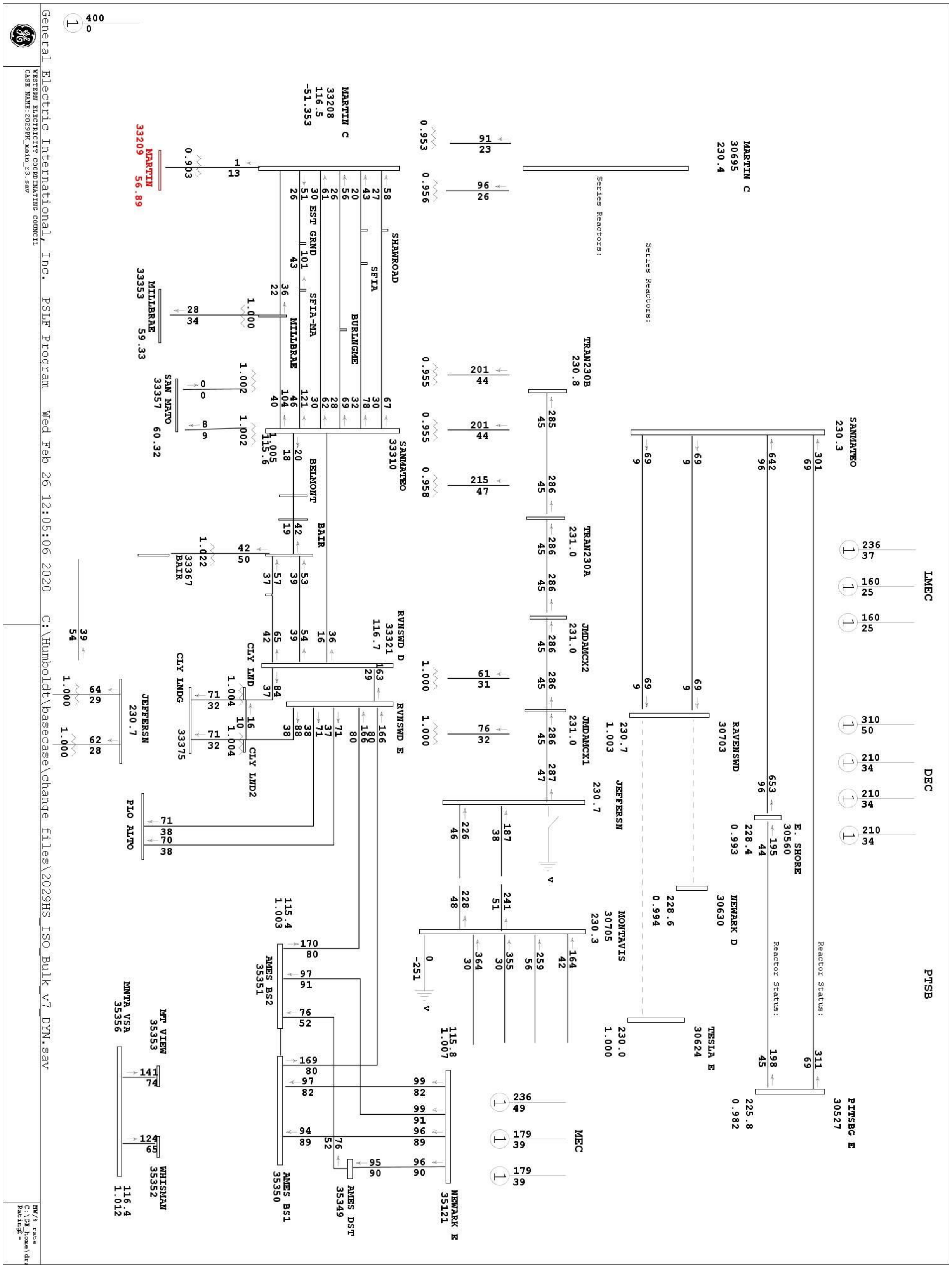


Figure 32 Status Quo 2029 Heavy Summer PSLF Power Flow (N-2) Newark – Ravenswood and Tesla – Ravenswood 230 kV Line Out

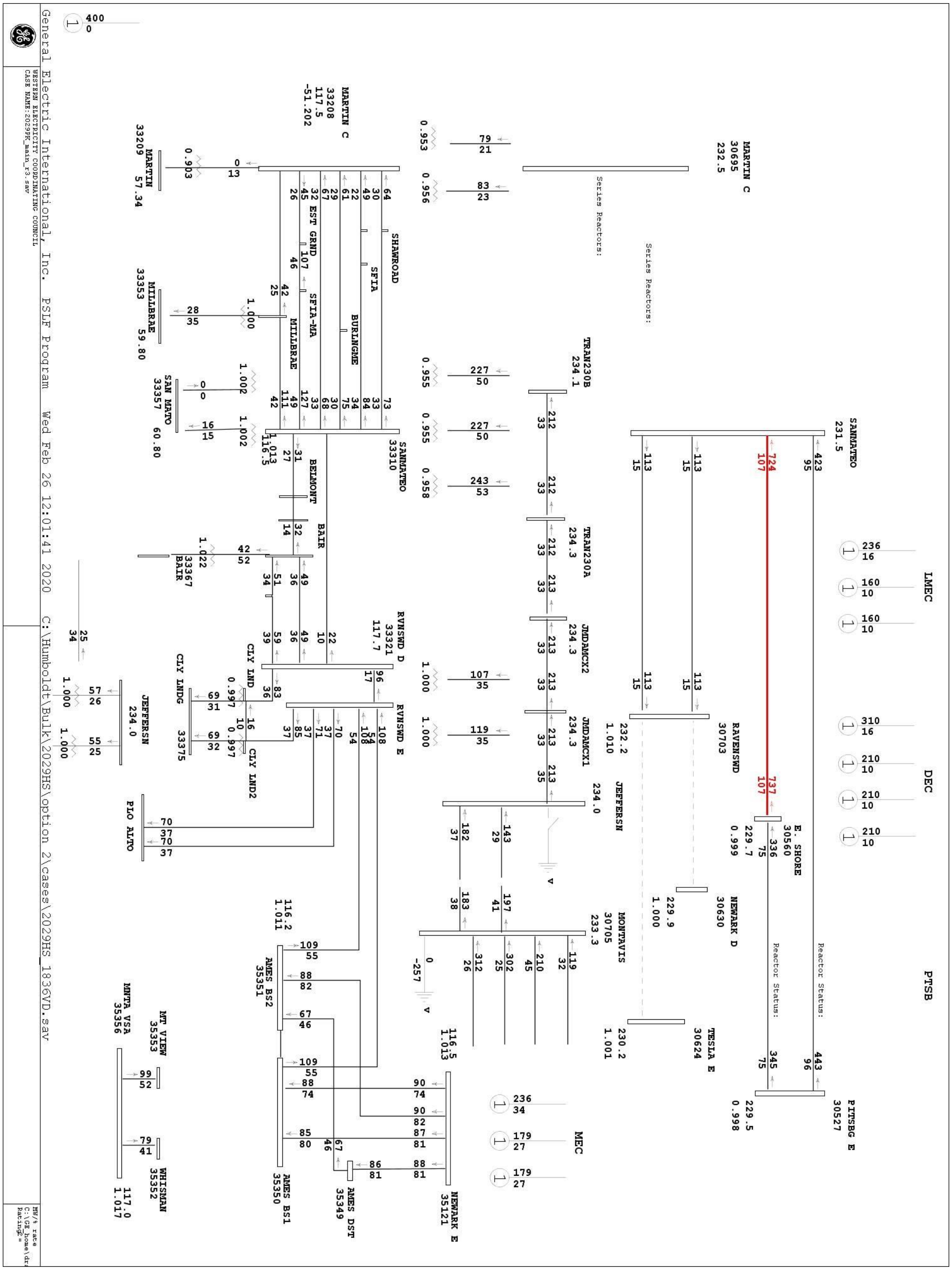


Figure 33 Option 2 connected to Vaca Dixon with new Collinsville connection and no other associated upgrades with DCTL Newark – Ravenswood and Tesla – Ravenswood 230 kV lines out

Alternative 3 Background

PG&E studied the interconnection of 1,836 MW of offshore wind connected from the Humboldt Coast to the Bay Area. There is no single sub-transmission substation that could withstand an injection of 1,836 MW's. Therefore, power was distributed to three points of connection 1) Potrero located in the SF Peninsula 2) Los Esteros located in the South Bay and 3) East Shore located in the East Bay. The San Francisco-Peninsula Planning Division ("SF-Peninsula"), is composed of cities in San Francisco and San Mateo Counties. The major cities in SF-Peninsula are San Francisco, San Bruno, San Mateo, Redwood City, and Palo Alto. While the SF-Peninsula has some small generation facilities, the area relies almost exclusively on transmission line imports to serve its electric demand. Power is imported into SF-Peninsula from Pittsburg, East Shore, Tesla, Newark, Monte Vista, and Ames substations located in the Greater Bay Area's East Bay and South Bay Planning Divisions. The amount and location of transmission import is dependent on electric demand and generation dispatched within the Greater Bay Area. The major SF-Peninsula transmission paths below.

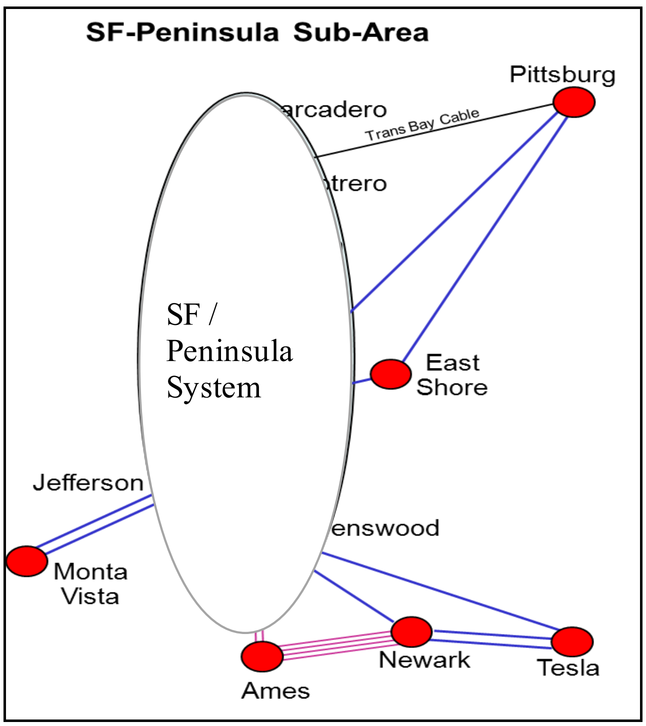


Figure 34 San Francisco Peninsula Transmission System connection

SF-Peninsula relies heavily on import lines to serve local demand because no large-scale generation is located within the area. The San Francisco System includes 230 kV and 115 kV transmission facilities with all transmission lines installed underground and utilizes gas-insulated switchgear at these facilities in much higher concentration than other PG&E areas. The system receives power through eight lines into Martin Substation and the Trans Bay Cable (TBC) into Potrero Substation. The San Francisco-Peninsula Planning Division modeled a generation dispatch of around 12 MW.

The South Bay Planning Division ("South Bay"), a sub-area of the Greater Bay Area, encompasses the De Anza and San Jose divisions and the City of Santa Clara (Silicon Valley Power, or SVP). Some of the key substations that deliver power into or in South Bay are Metcalf, Newark, Monta Vista, and Los Esteros Substations. Major cities in the area include San Jose, Santa Clara, Mountain View, Morgan Hill, and Gilroy. Major internal generation in the South Bay includes Calpine's Metcalf Energy Center, Los Esteros Critical Energy Facility, and Gilroy Units; and SVP's Donald Von Raesfeld Power Plant. South Bay is home to many large load customers such as Google, Facebook, Apple, Salesforce, Cisco Systems and Agilent Technologies to name a few.

The major transmission paths are illustrated below.

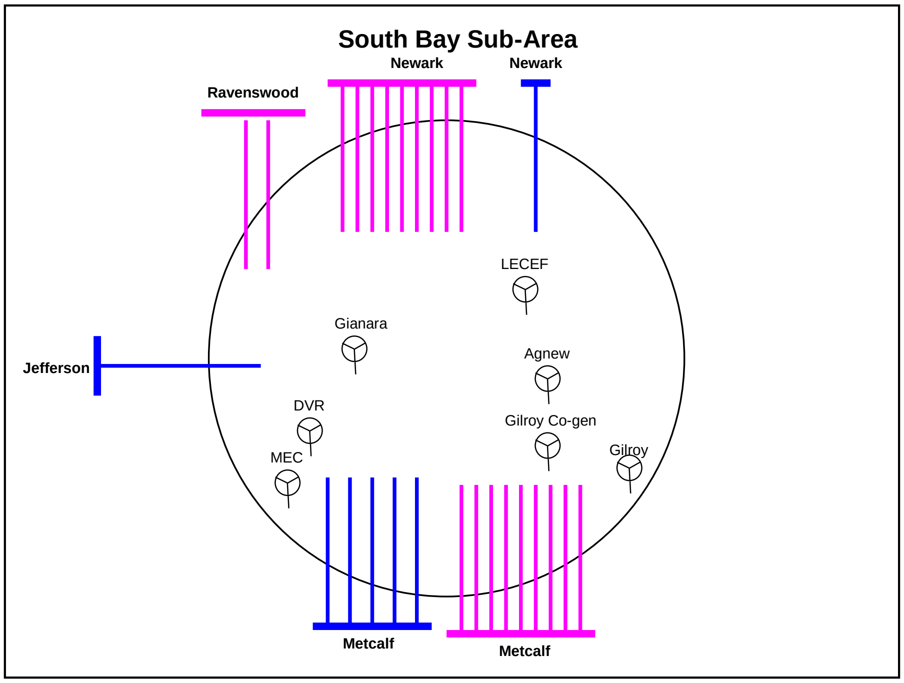


Figure 35 South Bay Transmission System connections

The East Bay Planning Division, a sub-area of the Greater Bay Area that encompasses the East Bay, Diablo, and Mission divisions, is composed of cities in Alameda and Contra Costa Counties. Major cities in the East Bay Planning Division include Oakland, Berkeley, Hayward, Fremont, San Ramon, Dublin, Pleasanton, Concord, Pittsburg, and Antioch. This area primarily relies on internal generation to serve electric customers. Some of the major substations within the East Bay Planning Division are Sobrante, Moraga, Newark, East Shore, San Ramon, Pittsburg, and Contra Costa Substations. The major load centers include the cities along the San Francisco Bay in Alameda and Contra Costa Counties as well as cities in the East Bay hills and Tri-Valley area. The East Bay Planning Division relies on generation and import lines to serve the local demand and exports power to both the SF-Peninsula and South Bay Planning Divisions. Key substations that import power into the East Bay Planning Division are Tesla, Vaca-Dixon, and Metcalf substations, all of which have 500 kV sources. In addition, there are 230 kV transmission facilities from Lakeville and Ignacio Substations that are used to import power from the Geysers geothermal generation in the north and to import from Vaca-Dixon. Generation facilities in the East Bay Planning Division include PG&E's Gateway Generating Station, the Russell City Energy Center (RCEC), and the Marsh Landing Generating Station. Excess internal generation in the East Bay Planning Division is exported to its neighboring areas primarily the South Bay and Peninsula. In addition to generation in the East Bay Planning Division, there are transmission interconnections to Tesla Substation, Vaca-Dixon Substation and the wind resources to the south of Vaca-Dixon, and geothermal generation from the Geysers generation units to the north. The East Bay Planning Division also directly exports approximately 400 MW into San Francisco via the Trans Bay Cable (TBC) under normal operating conditions. The major transmission paths are illustrated below.

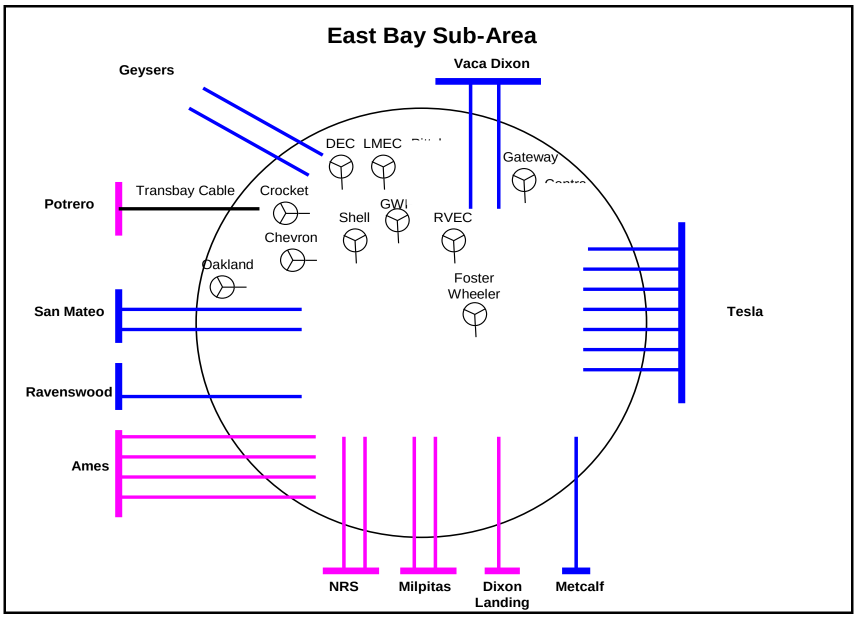


Figure 36 East Bay Electric Transmission connections

The East Bay Planning Division assessment modeled a dispatch of approximately 4,000 MW for local area generation. The East Shore Substation is located in the City of Hayward (Mission division) and serves as a 230kV source for the local 115 kV system, including Grant, Mt. Eden, and Dumbarton Substations. At the same time, East Shore is connected with Pittsburg, San Mateo and Russell City Energy Center (RCEC) so that it can deliver power to the Peninsula area via the East Shore-San Mateo 230 kV line and serve local load via transformer banks #1 and #2. In addition to East Shores ties to the Peninsula. The South Oakland sub-system includes 115 kV transmission facilities extending from Moraga and East Shore Substations. Three 115 kV lines serve San Leandro Substation and two lines serve Oakland J Substation. The East Shore-Oakland J 115 kV Reconductoring Project, scheduled to be operational in 2022, will reconductor a normally open path from the south, providing a third and a diverse source into Oakland J. With this project, capacity constraints on PG&E's system are alleviated, eliminating the need to drop load at Oakland Station J for an N-1 contingency. With the East Shore-Oakland J 115 kV Reconductoring Project, East Shore Substation becomes a strong source for the Oakland area.

Alternative 3: Build 500 kV transmission line from Humboldt area to Bay Area

- Build new 275 mile Humboldt Wind - BayHub 500 kV Line
- Build new Bay Hub 500/230 kV Substation
- Build 3-230 kV HVDC subsea cables
  1) Bay Hub - Potrero No. 1 230 kV Line
  2) Bay Hub - E. Shore No. 1 230 kV Line
  3) Bay Hub - Los Esteros No. 1 230 kV Line
- Reconductor 12.5 miles of E. Shore - San Mateo 230 kV Line

Associated Substation reconfigurations and upgrades at substations not to be assumed in this study. Acquiring land and permitting will also not be included in this study

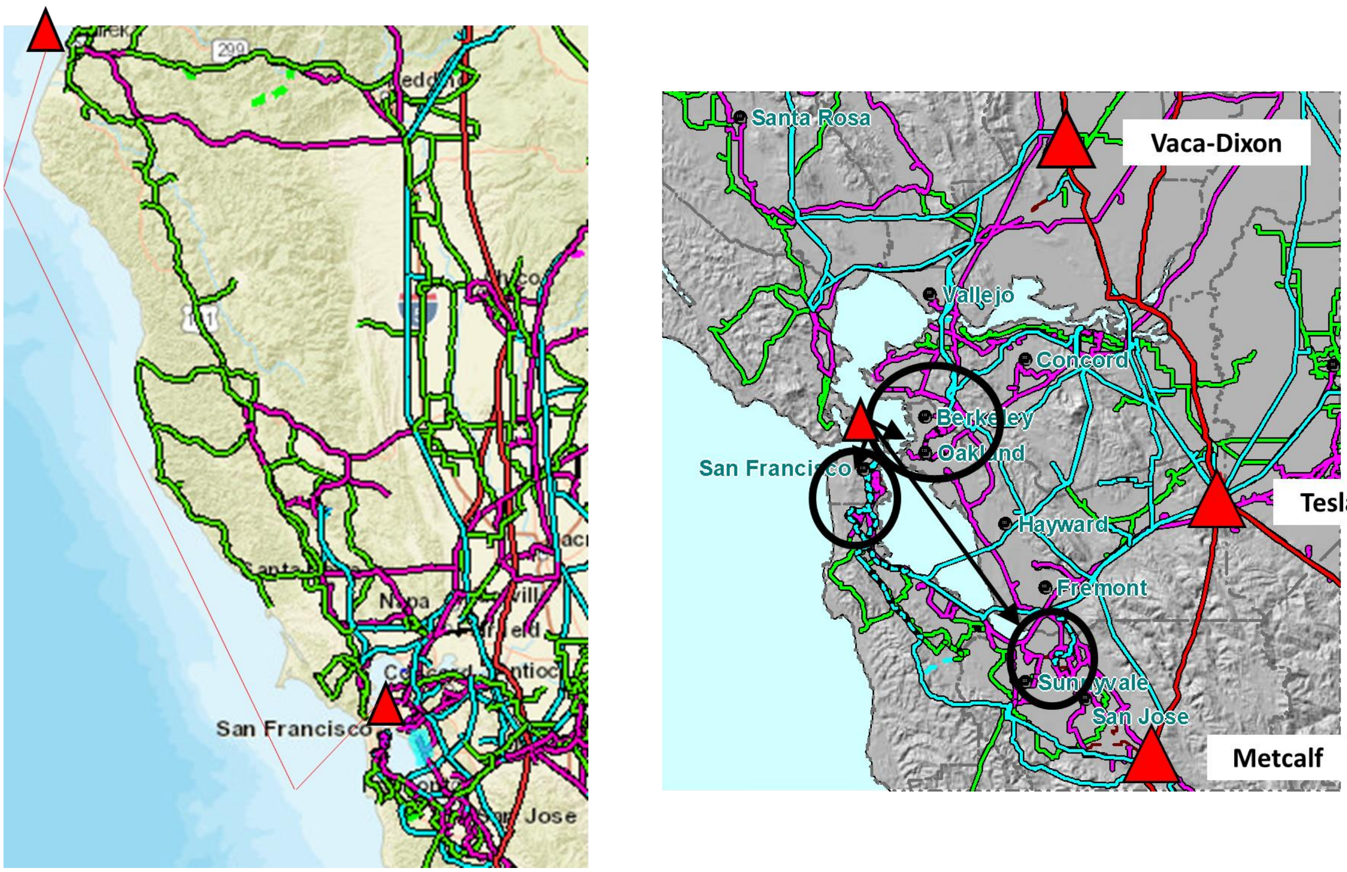


Figure 37 Humboldt to Bay Area GIS map and Bay Area GIS map

Capacity and Reliability Review

Planning assessment has identified a potential thermal overload in 2029 under peak loading conditions for emergency conditions. During various P1 and P7 contingency conditions the various transmission lines located within the SF Peninsula overload. The lines could potentially load up to 170% of its emergency summer conductor ratings. The table below shows a summary of the thermal loading with respect to the worse contingencies.

Table 14 Option 3 Alternative 3 Line Loading Summary

Transmission Line	Pre - Project Loading (emergency rating)	Post - Project Loading (emergency rating)
POTRERO-PTR_SHUNT-EMBARCADERO 230 kV	24%	131%
POTRERO – MISSON 115 kV	64%	120%
EMBARCADERO-MARTIN 230 kV	71%	170%
POTRERO 230/115 kV transformer	32%	174%
SANMATEO to BELMONT 115 kV	88%	106%
PITSBURG to CLAYTON 115 kV	98%	100%

With the current configuration, additional generation connected to the Bay Area Substations is not feasible as status quo. The additional generation injected into the substations causes overloads for many transmission lines. This is observed when the power flow from Bay Hub 230 kV to the load serving substations is not controlled. It is recommended to either install phase shifters or allocate DC transmission lines to control power flow. If power flow is not distributed in a controlled manner the distribution of generation will favor Potrero Substation. In the study it was observed from the 1836 MW's installed the Potrero Substation injected 1182 MW's, Los Esteros injected 369 MW and East Shore injected 197 MW's. With the large imports into the Potrero Substation the excess power then overloaded many of the lines interconnected within the SF Peninsula. If total MW of injection is reduced to around 1300MW's and distributed optimally this study shows that there will be no P1 or P7 violations.

Evaluation of Alternative

A power flow contingency analysis was performed using the 2029 base cases against all the Category P1 (L-1, T-1, G-1), P7 and selected P6 contingencies within the study area. The results were then screened for any thermal overloads or voltage violations along with any non converging cases or excessive voltage mismatches. For this power flow analysis all base cases converged.

The table below shows the power flow analysis results.

Table 15 Power Flow Results for Option 3 Alternative 3

NERC	Facility Name	BaseKV	Contingency	Rating (N/E)	2029HS	2029HS BAY	2029SP OPBAY	Corrective Action Plan
P1-2	33204 POTRERO 115 30698 POTRERO 230 1 1	115/230	P1-2:A9:1:_EMBRCDRD-POTRERO 230kV [0]	462 MVA (E)	>95%	173.9%	125.9%	allocate power flow via DC controllable injection
P1-2	30689 MARTN S5 230 30685 EMBRCDRD 230 2	230	P1-2:A9:2:_EMBRCDRD-EGBERT 230kV [0]	1050 Amps (E)	>95%	170.1%	123.2%	allocate power flow via DC controllable injection

NERC	Facility Name	BaseKV	Contingency	Rating (N/E)	2029HS	2029HS BAY	2029SP OPBAY	Corrective Action Plan
	1							
P1-2	30689 MARTN S5 230 30695 MARTIN C 230 1 1	230	P1-2:A9:2:_EMBRCDRD-EGBERT 230kV [0]	1050 Amps (E)	>95%	161.4%	124.2%	allocate power flow via DC controllable injection
P1-2	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P1-2:A9:6:_EGBERT-MARTIN C 230kV [0]	1050 Amps (E)	>95%	138.8%	95.9%	allocate power flow via DC controllable injection
P1-2	30689 MARTN S5 230 30695 MARTIN C 230 1 1	230	P1-2:A9:6:_EGBERT-MARTIN C 230kV [0]	1050 Amps (E)	>95%	130.4%	96.9%	allocate power flow via DC controllable injection
P1-2	30694 MARTN S4 230 30695 MARTIN C 230 1 1	230	P1-2:A9:5:_EMBRCDRD-MARTIN C 230kV [0]	1050 Amps (E)	>95%	124.6%	90.4%	allocate power flow via DC controllable injection
P1-3	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P1-3:A9:3:_POTRERO 230/115kV TB 1	1050 Amps (E)	>95%	124.1%	85.1%	allocate power flow via DC controllable injection
P1-2	33203 MISSON 115 33204 POTRERO 115 1 1	115	P1-2:A9:1:_EMBRCDRD-POTRERO 230kV [0]	788 Amps (E)	>95%	120%	96%	allocate power flow via DC controllable injection
P1-3	30689 MARTN S5 230 30695 MARTIN C 230 1 1	230	P1-3:A9:3:_POTRERO 230/115kV TB 1	1050 Amps (E)	>95%	117.8%	85.5%	allocate power flow via DC controllable injection
P7-1	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P7-1:A10:1_Eastshore-San Mateo 230 kV and Pittsburg-San Mateo 230 kV lines	1050 Amps (E)	>95%	114.3%	70.2%	allocate power flow via DC controllable injection
P1-2	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P1-2:A16:10:_EASTSHORE-SAN MATEO 230kV [4650]	1050 Amps (E)	>95%	111.1%	71.4%	allocate power flow via DC controllable injection
P1-2	33203 MISSON 115 33204 POTRERO 115 1 1	115	P1-2:A9:12:_A-P #1 115kV [9932]	788 Amps (E)	76.5%	108%	84.3%	allocate power flow via DC controllable injection
P7-1	33310 SANMATEO 115 33312 BELMONT 115 1 1	115	P7-1:A10:19_Ravenswood-Bair Nos. 1 & 2 115 kV lines	556 Amps (E)	88.2%	105.8%	>95%	allocate power flow via DC controllable injection
P7-1	30689 MARTN S5 230 30695 MARTIN C 230 1 1	230	P7-1:A10:1_Eastshore-San Mateo 230 kV and Pittsburg-San Mateo 230 kV lines	1050 Amps (E)	>95%	105.7%	71.3%	allocate power flow via DC controllable injection
P1-1	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P1-1:A21:5:_TBC_POT2180.50kV & TBC_PTB2180.50kV Gen Units	1050 Amps (E)	>95%	103.2%	74.8%	allocate power flow via DC controllable injection
P1-2	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P1-2:A9:13:_POTRERO-TBC_POT1 #1 115kV [0]	1050 Amps (E)	>95%	102.6%	74.3%	allocate power flow via DC controllable injection
P1-2	30689 MARTN S5 230 30695 MARTIN C 230 1 1	230	P1-2:A16:10:_EASTSHORE-SAN MATEO 230kV [4650]	1050 Amps (E)	>95%	102.6%	72.4%	allocate power flow via DC controllable injection
P7-1	30689 MARTN S5 230 30685 EMBRCDRD 230 2 1	230	P7-1:A10:2_Newark-Ravenswood 230 kV and Tesla-Ravenswood 230 kV lines	1050 Amps (E)	>95%	102.2%	70.1%	allocate power flow via DC controllable injection
P7-1	32950 PITSBURG 115 32970 CLAYTN 115 1 1	115	P7-1:A8:23_Pittsburg-Clayton Nos. 3 & 4 115 kV lines	1762 Amps (E)	98.8%	100%	>95%	allocate power flow via DC controllable injection

If we control the amount of flow injected into the substations we can eliminate the issues identified above and limit the flow to 1231 MW there will be no overload identified.

Table 16 Optimal simultaneous power flow injection

Injection Location	Potrero 230 kV	Los Esteros 230 kV	East Shore 230 kV
Maximum achievable injection (MW)	460.3	380.3	391.7
Limiting element	E. SHORE to SANMATEO 230 kV		
Limiting contingency	P7-1: Newark-Ravenswood 230 kV and Tesla-Ravenswood 230 kV lines		

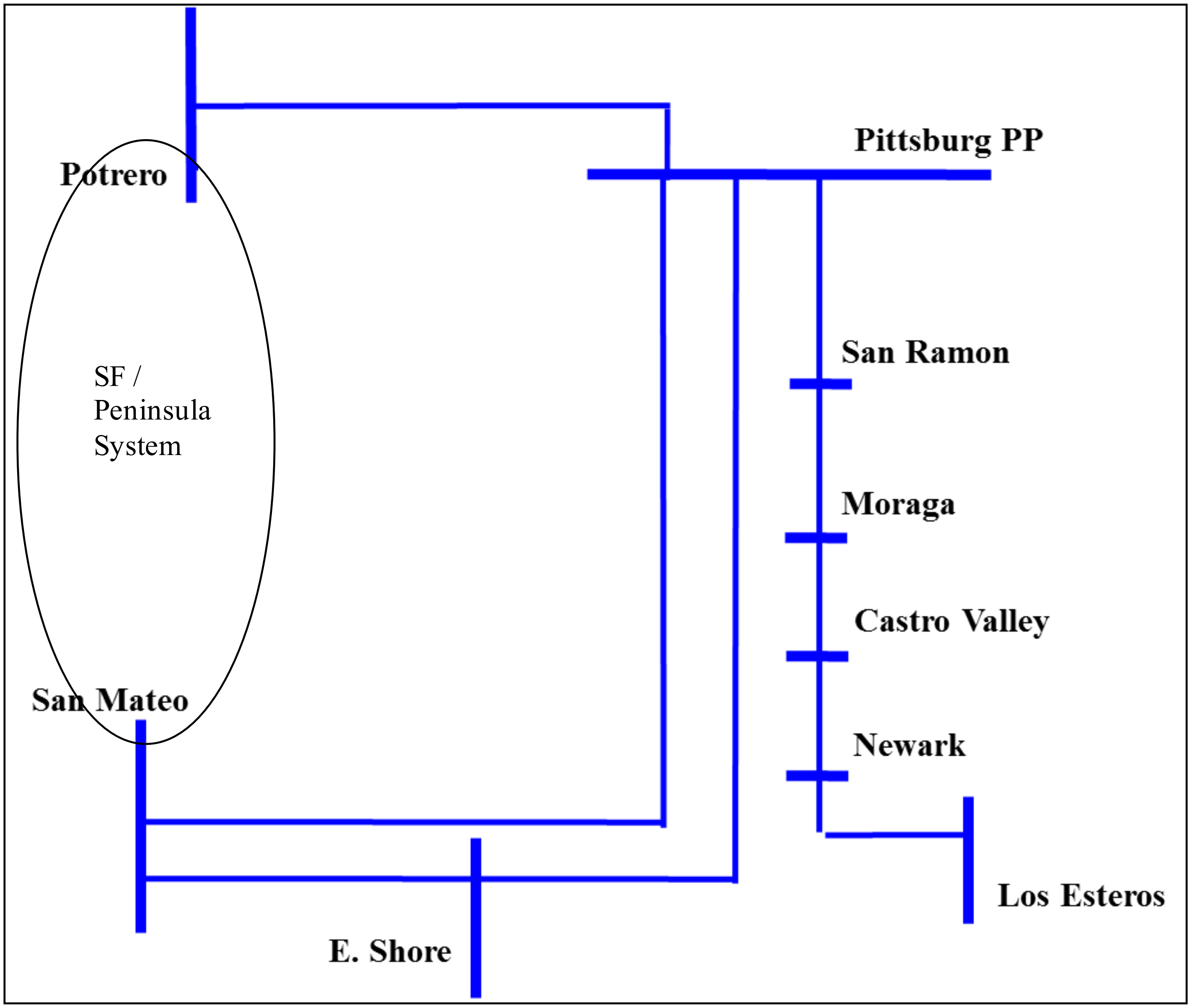


Figure 38 Status Quo Bay Area 230 kV Single Line Diagram

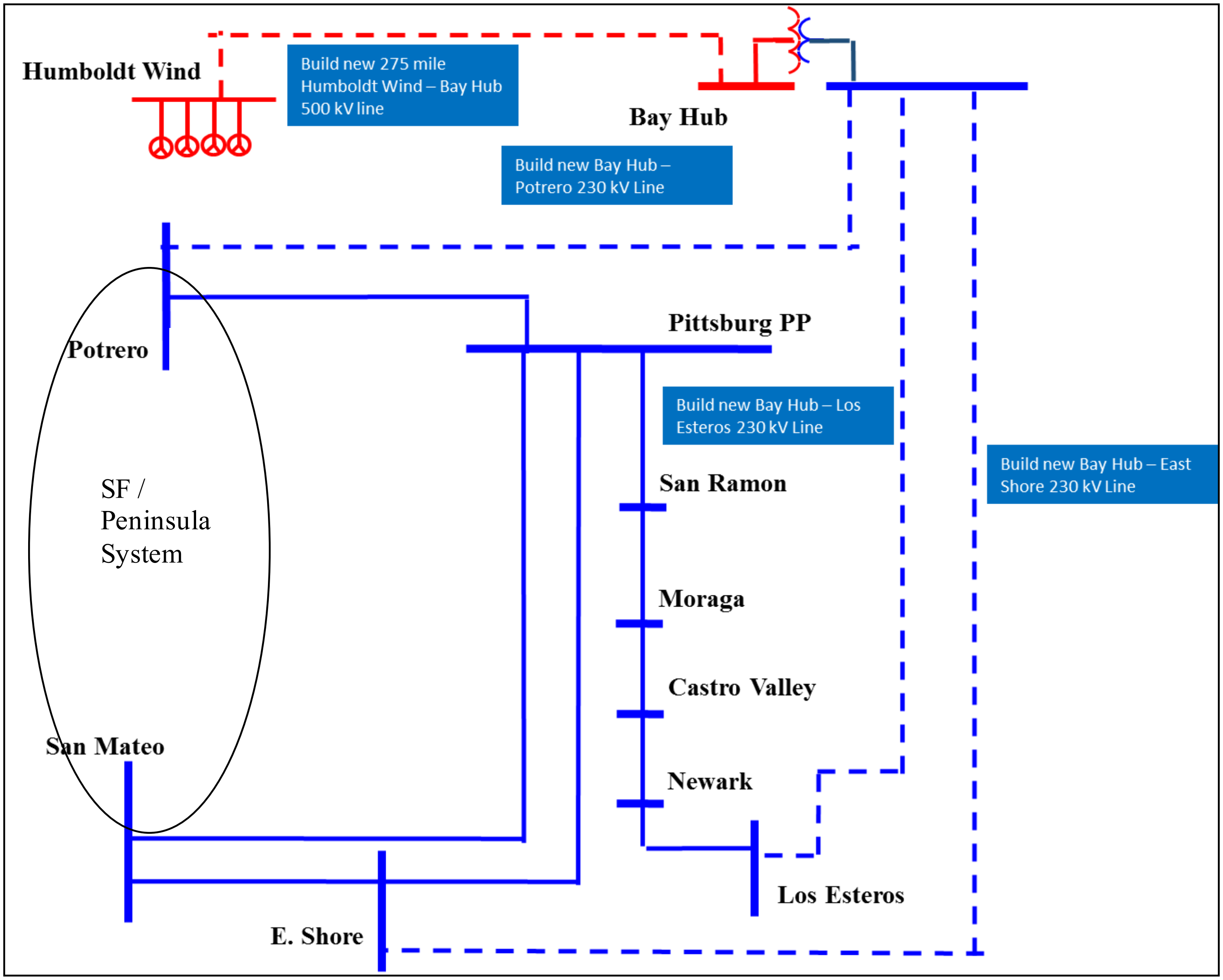


Figure 39 Option 3 Alternative 3 Single Line Diagram

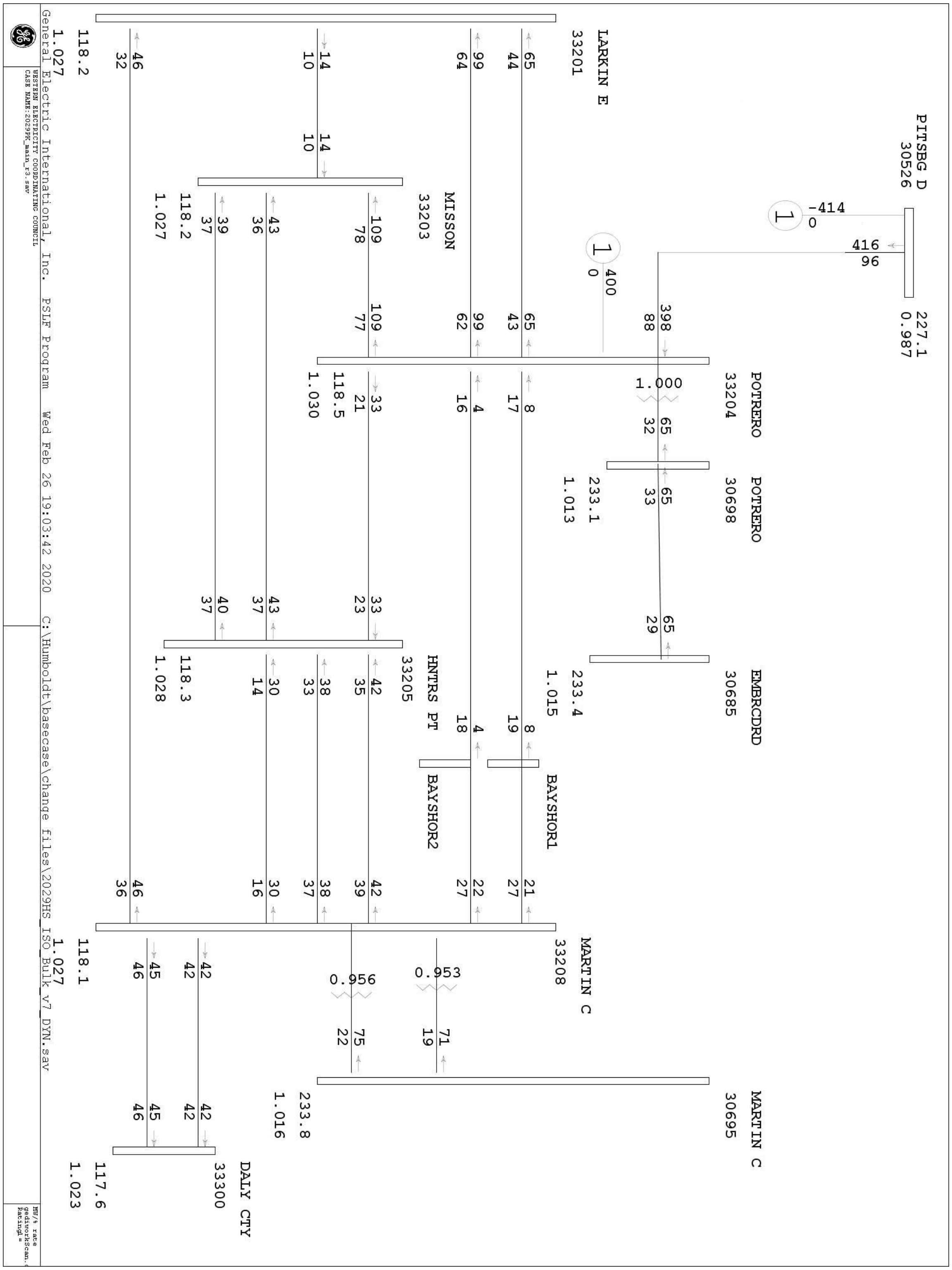


Figure 40 Status Quo 2029 Heavy Summer PSLF Power Flow (N-0)

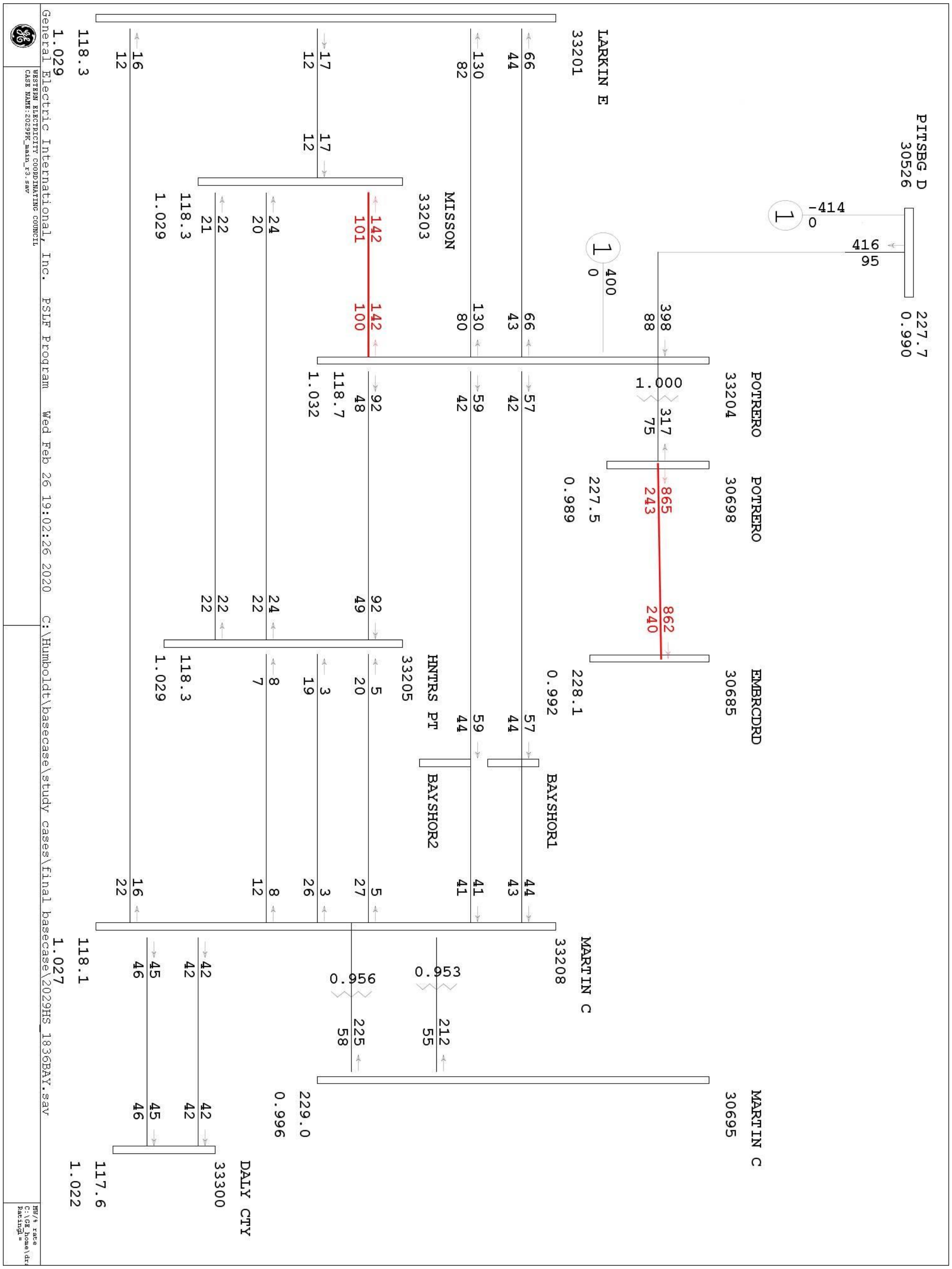


Figure 41 Option 3 Alternative 3 without power flow control on new Bay Hub 230 kV Lines (N-0)

Study Objective and Description of Option 3 Alternatives

The objective of this study is to identify a long-term transmission plan for the interconnection of various generator sizes in the Humboldt area. The 500 kV, 230 kV and 115 kV system were observed to address the capacity and reliability issues that may occur. The alternatives should not alleviate the thermal and voltage violations.

Three alternatives were considered with one being a connection to the east; and the second connects to the southeast. The third alternative is to connect directly to the Bay Area. All alternatives require new substations and substantial new line builds to integrate the new generation interconnection plans requested. The following section provides a general description of the alternatives proposed and associated rough costs. Please note all costs are based on PG&E 2019 unit cost. Costs also do not include any land permitting and right of way costs. Costs also do not include an acquisition of additional land.

Alternative (1): Build new 500 KV Substation and route transmission east

- Build new 120 mile Humboldt Wind - Round Mountain 500 KV Line
- Build new 89 mile Round Mountain - Table Mountain 500 KV Line
- Build new 83 mile Table Mountain - Vaca Dixon 500 kV Line
- Build new 57 mile Vaca Dixon - Tesla 500 kV Line
- Reconductor 3 miles of USWP-JRW - Cayetano 230 kV Line

The estimated rough cost for this alternative is about $1.4B-$2.8B.

Alternative (2): Build 500 kV Substation and route transmission southeast

- Build 500 kV Transmission Line from fictitious 500 kV Substation (to be assumed next to Humboldt Bay 115 kV Substation) to Vaca Dixon 500 kV Substation
- Build new Collinsville 500 kV Substation
- Loop Vaca Dixon-Tesla 500 kV line into new station
- Reconductor 25 miles of Vaca Dixon-Collinsville 500 kV Line
- Install 500/230 kV transformer at new station
- Construct two, 5.3-mile subsea 230 kV cables to Pittsburg P.P. Substation
- Install voltage support as required at various locations with the Bay Area

The estimated rough cost for this alternative is about $1.4B-$2.8B.

Alternative (3): Build 500 kV transmission line from Humboldt area to Bay Area

- Build new 275 mile Humboldt Wind - BayHub 500 kV Line
- Build new Bay Hub 500/230 kV Substation
- Build 3-230 kV HVDC subsea cables
  4) Bay Hub - Potrero No. 1 230 kV Line

5) Bay Hub - E. Shore No. 1 230 kV Line
6) Bay Hub - Los Esteros No. 1 230 kV Line

- Reconductor 12.5 miles of E. Shore - San Mateo 230 kV Line

The estimated rough cost for this alternative is about $3.5B - $5.8B.

Rough Cost Breakdown

The following table shows a unit cost breakdown for the different alternatives.

Table 17 Cost Breakdown for each Alternative for Option 3

	OPTION 3 to interconnect 1836 MW's in Humboldt Area	
Alternative	**Facility**	**Cost Estimate**
Alt: 1 Build 500 kV Line from Humboldt area to Round Mountain 500 kV Substation	Build new 120 mile Humboldt Wind - Round Mountain 500 KV Line	$480M
	Build new 89 mile Round Mountain - Table Mountain 500 KV Line	$360M
	Build new 83 mile Table Mountain - Vaca Dixon 500 kV Line	$336M
	Build new 57 mile Vaca Dixon - Tesla 500 kV Line	$228M
	Reconductor 3 miles of USWP-JRW - Cayetano 230 kV Line	$5M
	Total	**$1.4B - $2.8B**
Alt 2: Build 500 kV Line from Humboldt area to Vaca Dixon	Build new 210 mile Humboldt Wind - Vaca Dixon 500 kV Line	$840M
	Build new Collinsville 500 kV Substation	$500M
	Loop Vaca Dixon-Tesla 500 kV line into new Collinsville Substation	
	Reconductor 25 miles of Vaca Dixon-Collinsville 500 kV Line	
	Install 500/230 kV transformer at new station	
	Construct two, 5.3-mile underground 230 kV lines over to Pittsburg P.P. Substation	
	Install voltage support as required at various locations with the Bay Area	
	Reconductor 12.5 miles of E. Shore - San Mateo 230 kV Line	$20M
	Reconductor 3 miles of USWP-JRW - Cayetano 230 kV Line	$5M
	Reconductor 3 miles of Cayetano - North Dublin 230 kV Line	$5M
	Reconductor 9 miles of Newark D - NRS 400 115 kV Line	$20M
	Reconductor 8.5 miles of Pittsburg - Clayton 115 kV Line	$13M
	Total	**$1.4B - $2.8B**
Alt 3: Build 500 kV Line from Humboldt area to Bay Area	Build new 275 mile Humboldt Wind - BayHub 500 kV Line	$2.75B*
	Build new Bay Hub 500/230 kV Substation	$800M
	Build 3-230 kV HVDC subsea cables	
	1) Bay Hub - Potrero No. 1 230 kV Line	
	2) Bay Hub - E. Shore No. 1 230 kV Line	
	3) Bay Hub - Los Esteros No. 1 230 kV Line	
	Reconductor 12.5 miles of E. Shore - San Mateo 230 kV Line	$20M
	Total	**$3.5B - $5.8B**

* 50% contingency applied to upper end cost. For all others the AACE Level 5 costs adders were utilized.

Table 18: Cost Breakdown for each Alternative

Conclusion & Recommendation

Option 1
This option considered 48 MW's connected at Humboldt Bay 115 kV Substation. Based on the contingency analysis study results show normal system overloads and overloads caused by single contingencies occur. Analysis performed showed when a loss of a 115 kV transmission line occurred the remainder 115 kV lines overload due to the excess power flow. The current system configuration and capacity would not be able to support 48 MW's connected to the Humboldt system in a heavy summer scenario with Humboldt Generating Station operating at close to or full output. It is recommended to build 115 kV lines to alleviate congestion on the Humboldt 115 kV Transmission grid. Potential upgrades may cost between $365M to $730M.

Option 2
This option considered 144 MW's connected at Humboldt Bay 115 kV Substation. Based on the contingency analysis study results show normal system overloads and overloads caused by single contingencies. Analysis performed showed when a loss of a 115 kV transmission line occurred the remainder 115 kV lines overload due to the excess power flow. The current system configuration and capacity would not be able to support 144 MW's connected to the Humboldt system in a heavy summer scenario with Humboldt Generating Station operating at close to or full output. It is recommended to build 115 kV lines to alleviate congestion on the Humboldt 115 kV Transmission grid. It is also recommended to interconnect to Humboldt 115 kV Substation to offload costs and avoid reconductoring and building a new line to Humboldt Bay 115 kV Substation. Potential upgrades may cost between $669M to $1.34B.

Option 3

Alternative 1
This alternative consists of an interconnection of 1836 MW's from the Humboldt shore to Round Mountain 500 kV Substation. The Round Mountain 500 kV Substation is part of a WECC path 66 connection. In depth studies will need to be performed and coordinated between the CAISO, WECC and Affected Parties. The studies performed indicated with COI fully scheduled there is not enough capacity to interconnect 1836 MW's. It is recommended to build new 500 kV lines from Round Mountain 500 kV Substation down to the major PG&E load center. The load center is served from Vaca Dixon and Tesla 500 kV substations. Contingency analysis was performed for governor power flow and no substantial issues were identified for the additional 500 kV path. It is also recommended that many more robust studies occur to capture voltage and transient stability if it is decided this alternative is viable. Potential upgrades may cost between $1.4B to $2.8B.

Alternative 2
This alternative connects the Humboldt offshore wind to the Vaca Dixon 500 kV Substation. By going directly to the Vaca Dixon substation and a direct path into the bay area with the Collinsville Project, the effects on COI are limited and no substantial issues were identified in governor power flow analysis. The additional scope of work to implement the Collinsville

Project would bring in another 500 kV source into the bay area and serve bay area demand. The Collinsville connection terminates at Pittsburg Substation which has many robust outlets. Transmission lines connect to Potrero (via TBC) and serves the SF area. A connection to San Mateo is also available and serves the Peninsula. The Tri Valley, Fremont and San Jose area also connected to Pittsburg. The Oakland area is also served by Pittsburg. Lastly a major connection to Tesla is also available to import or export any excess power to be distributed throughout PG&E Greater Bay Area transmission system. Potential upgrades may cost between $1.4B to $2.8B.

Alternative 3
This alternative involves building a 500 kV substation within the Bay Area. This 500 kV substation would have three 230 kV lines that export power to Potrero, Los Esteros, and East Shore 230 kV substations. This alternative bypass any connection to the 500 kV Bulk System and all generation is in turn subscribed within the Bay Area. Depending on the allocation of MW's per designated substation the alternatives could include many local upgrades to none at all. In the capacity section of the report more details are provided. It is recommended that the 230 kV lines coming out of the BayHub Substation be DC controllable. Potential upgrades may cost between $3.5B to $5.8B.

The three options evaluated as part of this informational feasibility study, along with the various alternatives to enable exporting the varying levels of offshore wind power generation from the Humboldt coastal region to the electric transmission system backbone, were found to require significant investments in electric transmission infrastructure development. A potential option that could be investigated is the use of storage systems to integrate with the existing infrastructure, particularly during off-peak conditions when generation is not fully utilized giving the grid substantial capacity to transport electricity. For Option 1 and 2, storage systems along with generation management may provide an opportunity to avoid some of the identified local upgrades. However, Option 3 still requires substantial upgrades and new infrastructure to transport such large amount of generation from the coastal region to the middle of the state where the electric system backbone is located and ultimately to the load centers for costumer consumption. It is recommended to revisit these interconnections, particularly the lower level options, with full deliverability not necessarily being the focus but rather studying and understanding when and how much generation could be utilized throughout a period in time. If there are ways to integrate offshore wind generation with the rest of the renewable generation technologies at a reasonable cost, it could benefit grid operators by having more diverse generation to serve customers reliably, especially as California's clean energy goals continue to evolve.

Chapter 5: Subsea Transmission Cable Conceptual Assessment

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Technical Memorandum
Transmission Cable

Project:	Humboldt Offshore Wind		
Our reference:	507100657	**Subject:**	Humboldt-SF Bay Subsea Transmission Cable
Prepared by:	Aaron Porter, PE	**Date:**	8/28/20
Approved by:	Shane Phillips, PE	**Checked by:**	Michelle Gostic

Executive Summary

A concept-level assessment was conducted to develop options and document hazards and constraints for routing a high voltage direct current (HVDC) cable from the Humboldt Bay area to the San Francisco Bay (SF Bay) area. The transmission cable would be intended to deliver power generated from an offshore wind farm(s) in the Humboldt area to load centers in the SF Bay area. The subsea transmission cable was assessed in parallel to upland grid upgrade options. The subsea distance between SF Bay and Humboldt Bay (~250 miles) necessitates the use of an HVDC electrical system to minimize electrical losses. The HVDC cable system would consist of the cable system itself and an HVDC converter station at each end of the transmission cable (Humboldt Area and SF Bay Area) to convert the power to/from the standard alternating current (AC) grid system.

The subsea study area between Humboldt Bay and SF Bay includes both natural and anthropogenic constraints and hazards with variable levels of risk. These hazards and constraints will require a combination of avoidance and mitigation measures to install a transmission cable between the two areas. In summary, the project risks due to hazards and constraints are the following:

- Hazards
  - Deep subsea canyons extending from the nearshore area to depths below the continental shelf, where subsea landslides strong enough to rupture cables are common.
  - Seismic fault line surface displacements which may be too large to mitigate for. Cable repairs may be required with a major seismic event.
  - Some of the largest subsea sandwaves in the world are present outside the Golden Gate, which may preclude subsea transmission cable routing through the Golden Gate.
- Constraints
  - Areas of exposed bedrock and other hard substrate are located within marine habitat areas where cable protection methods may be either expensive or not permitted by agencies.
  - Potential interferences with or damage from fishing activities if the cable is not able to be buried or otherwise protected
  - No power cables have been installed to the depths required to route offshore of the subsea canyons (over 9,000 feet deep), and proven cable technology has not yet been developed for installation at these depths.
  - The offshore route will likely require crossing telecommunication cables in very deep water (5,000 feet or greater), which will require permissions from the existing operators. Though telecommunication cables

crossings at these depths are common, power/telecommunication cable crossings at this depth do not appear to have previously been attempted.

Based on the location and mitigation possibilities for the hazards and constraints, two potential cable corridors have been developed: a “Nearshore” corridor, an “Offshore” corridor. Both corridors have significant challenges that would need to be overcome to install and operate an HVDC link, though the challenges may not be insurmountable. Further analysis may be conducted to refine the severity of these risks and to develop possible mitigation strategies.

The construction cost of the system is estimated to be approximately $2.1 – 3.1 billion, depending on whether one or two cables are installed. It is likely that a single pole pair (one cable bundle) would be able to meet the rating requirements of 1,800 megawatts (MW). Installing two cables along different routes would provide redundancy for the transmission system in the case one cable incurs a fault or is damaged but would come at an additional cost of approximately $1 billion. Should multiple transmission cables be required to support transmission of multiple offshore windfarms (greater than 1800 megawatts), separation of cable routes should be considered to reduce risk of cable damage due to the hazards identified.

1 Introduction and Criteria

A pre-feasibility level assessment was conducted to evaluate hazards and constraints, potential cable design parameters (route and type), and costs of a potential subsea power link between the Humboldt Bay area and the San Francisco Bay area. The subsea transmission cable was assessed in parallel to upland grid upgrade options to transmit excess power generated in the region to the load centers in the San Francisco Bay area.

The distance between Humboldt and San Francisco Bay (SF Bay) is approximately 250 miles, and this length necessities the use of a high-voltage direct current (HVDC) electrical system to minimize electrical losses. A HVDC cable system would consists of the cable itself, and an HVDC converter station at each end of the cable (Humboldt Area and SF Bay Area) required to convert power to/from the standard alternating current (AC) grid system. There are not technical limits to the length of an HVDC system, but at present levels of technology, HVDC cables can only be deployed as links, rather than a network of HVDC cables. HVDC link systems have been deployed world-wide for long-distance transmission requirements for solar energy, subsea cables, and transmitting hydropower energy, with examples on the US West Coast. On the US West Coast the Pacific Direct Current Intertie was initially constructed by Bonneville Power Administration over a length of 846 miles to provide lower-cost hydropower energy to the Southern CA region.

The subsea routing assessment was conducted by compiling publicly available data to map potential hazards and constraints to cable installation and operation in the subsea study area. Within this document, hazards are defined as an event, process or phenomena which results in a risk of damage to the cable system (such as fault line displacement). Constraints are defined as established mapped conditions or environmental conditions, such as marine habitat areas, which need to be addressed as part of the routing assessment. The mapped hazards and constraints are the basis for the routing assessment. Associated requirements for upland infrastructure (converter stations) were developed and assessed at a pre-conceptual level.

The project team included experienced submarine cable installers, coastal engineers, and power export cable design engineers. This memorandum provides study criteria, existing conditions, cable design considerations, converter station considerations, installation considerations, mapping of mitigation levels required, and two potential cable route options with a summary of risks and benefits of each.

1.1 Study Criteria

Level of Assessment

This assessment is intended to be conceptual in nature and is based only on review of publicly available data. No electrical modeling or system studies have been conducted as part of this work. Work conducted was based on desktop level review only. Findings are intended to be used at a planning-level only and are not intended to be used for design or other engineering purposes without additional analysis. High-risk areas have been identified, but detailed investigation of the potential high-risk areas was not conducted.

Electrical Rating requirement

It is assumed that the HVDC link aims to have a rating of approximately 1800MW, but the final rating may be less, if required based upon results of the assessment.

Routing Assessment Approach

Hazards and constraints should be considered in determination of potential submarine cable routing corridors. Hazards are not necessarily an obstacle to feasibility, as hazards (such as anchor strike) impose different ranges of risk, and those hazards can be mitigated to result in a lower risk level, which may be acceptable in some cases. Similarly, a constraint is not necessarily an obstacle to feasibility, but different constraints (such as existing telecommunication cables), require different levels of mitigation. This assessment estimated the likelihood of feasible mitigation measures for the different hazards and constraints. The following classifications will be utilized to categorize the different hazards and constraints as they relate to mapping:

- **No-go area**; mitigation of high-risk elements likely not possible.
- **Major mitigation**; cable installation possible with major mitigation. Major mitigation is intended to include solutions that require further analysis to develop, necessitate additional coordination and permissions, are associated with a very high cost, or technology needed is not yet proven.
- **Minor mitigation**; cable installation possible with minor mitigation. Minor mitigation is intended to include proven technologies and engineered mitigation measures that are widely applied in industry.
- **No mitigation required**

Cable routing hazards and constraints in the study region between Humboldt Bay and SF Bay are summarized in Section 2 and assessed in Section 3.

2 Existing Conditions

Existing conditions were evaluated to develop the hazards and constraints which may affect concept level routing[1], assessment of installation risks, and design of the cable transmission system. Information was collected from the public domain, and hazard information was also provided by Humboldt State University (HSU). The potential hazards and constraints are listed in Tables 1 and 2.

These hazards and constraints were mapped to provide a guide to determine which could be avoided or may require mitigation solutions. To provide a basis for development of concept routes, the applicable hazards and constraints were mapped in a graphical information system (GIS), as shown in Figure 1. Details, risks and potential mitigation levels required for the hazards and constraints are addressed in Section 3.3.

Table 1 – Subsea Study Area Hazards

Hazard	Details
BOEM Offshore Wind Call Areas	Offshore wind farm areas are assumed to contain subsea cables and anchors which likely have embedment requirements.
Seismic Surface Fault Rupture and Deformation	Three high risk fault lines within the project area were identified in coordination with HSU: San Andreas Fault, the Cascadia Megathrust, and the Mendocino Fault line. Further investigation is needed to quantify the probability of an extreme seismic event and to estimate the amount of displacement at these fault lines. Displacement may be on the order of 10m vertical and 50m horizontal with probabilities ranging from 1/700-1/300 years (HSU, 2019)
Seismic Shaking	There is a high concentration of historical earthquakes offshore of Cape Mendocino (historically, 1M6 event or greater per decade). The shaking could include long duration of large accelerations and strong motion effects (HSU, 2019). Seismic activity appears to be reduced near the existing telecommunication cables, off further offshore.
Submarine Canyons	Several submarine canyons fed by high-discharge rivers are found off California's coast at the outer edge of the continental shelf. Many of these canyons are characterized by high sediment transport rates, submarine landslides, and rapid turbidity currents. The canyons shown in Figure 1 span a depth range upwards of 3280ft (1000m) and are incised at least 328ft (100m) into the continental slope (Harris, 2014).
Sand Waves	Sand waves up to 33ft (10m) in height and 700ft (220m) in length propagate in water depths between 100-300ft seawards of the Golden Gate Bridge.
Shipping Vessel Traffic	Cargo and tanker ships navigate throughout the project area and in emergencies may need to drop anchor. Vessel tracking data suggests that ships sailing north-south parallel to the west coast are concentrated within a corridor located 50 miles offshore. The water depth in which vessels operate is likely beyond the depth at which vessels drop anchor.
Bottom Trawl Fishing	Trawling fishing activity occurs throughout the project area; it is primarily concentrated within 30 miles of the shoreline. Bottom trawl fishing is prohibited in waters between the Essential Fish Habitat Conservation Area between the1280m and 3500m depth contours.
Tsunami	Tsunami impact to the seabed is minimal in deep water. Tsunami inundation may results in erosion and strong currents near shore (HSU, 2019)
Gas Hydrates	Gas hydrates are one of contributing factors to landslides on the continental margin offshore of Cape Mendocino. Gas hydrates have been documented offshore of Eureka between the state/federal boundary and the Humboldt Call Area (HSU, 2019).
Ocean Disposal Sites	Offshore dredged material disposal dumping may interfere with the cable.

[1] Shipwrecks and other smaller nearshore obstructions and intereferences are not assessed at this scale but will need investigation in a later phase.

Table 2 - Subsea Study Area Constraints

Constraint	Details
BOEM Offshore Wind Call Areas	Wind farm call areas may require site permissions.
Existing Submarine Telecommunications cables	Four subsea transmission cables make landfall at Manchester, CA (approx. 125mi south of Humboldt). Additionally, a series of subsea cables are routed parallel to the shoreline, approx. 100 miles offshore, and were installed between 1997-2002. Parallel cables should be installed horizontally apart by at least 2x water depth to conduct repairs without affecting nearby features (such as existing cables), but 3-4x water depth is the preferred spacing in industry.
Steep Slopes	Very steep slopes (exceeding 30º) are found within the submarine canyons and along the submerged Mendocino Ridge, which is a feature extending seawards from Cape Mendocino. Further south, steep slopes are observed are 10-30 miles offshore.
Hard Substrate	Hard substrate is documented along Mendocino Ridge, in isolated nearshore areas between Eureka and Manchester, and along the coastline north of San Francisco Bay. Burial in hard substrate is typically more challenging, and if not possible can require post-lay protection mats.
Ocean Disposal Sites	There are several federal ocean disposal sites offshore of Humboldt Bay and San Francisco Bay which may require permissions.
Installation Depth	Water offshore of the continental shelf is very deep. The deepest water which power cables have previously been installed in is approximately 6560 ft (2,000m). Depth in the study area exceeds 9,840 ft (3,000m).
Sea-State	Large wave heights and long wave period swell along the California coastline
Cable Installation Vessel Operational Limitations and Capacity	Because the cable installation would be primarily parallel to shoreline, the vessels will be in a beam sea condition, which decreases the sea state in which the vessels can operate. At present the approximate vessel cable length capacity is ~62 miles/vessel (100km/vessel) due to current tonnage capacity. Because multiple vessel campaigns are needed to install the cable, joints are likely required. Cable recovery and operation & maintenance activity is limited by sea state, and it is possible that such activities will not be able to occur for significant wave heights exceeding 10 feet
Marine Habitat Areas	Marine Habitat Areas are defined as those areas mapped by NOAA in the Marine Protected Area Inventory (2017). These areas cover nearshore area (within ~40 miles of shoreline) between Manchester and San Francisco Bay; Mendocino Ridge; Eel Canyon area further north.

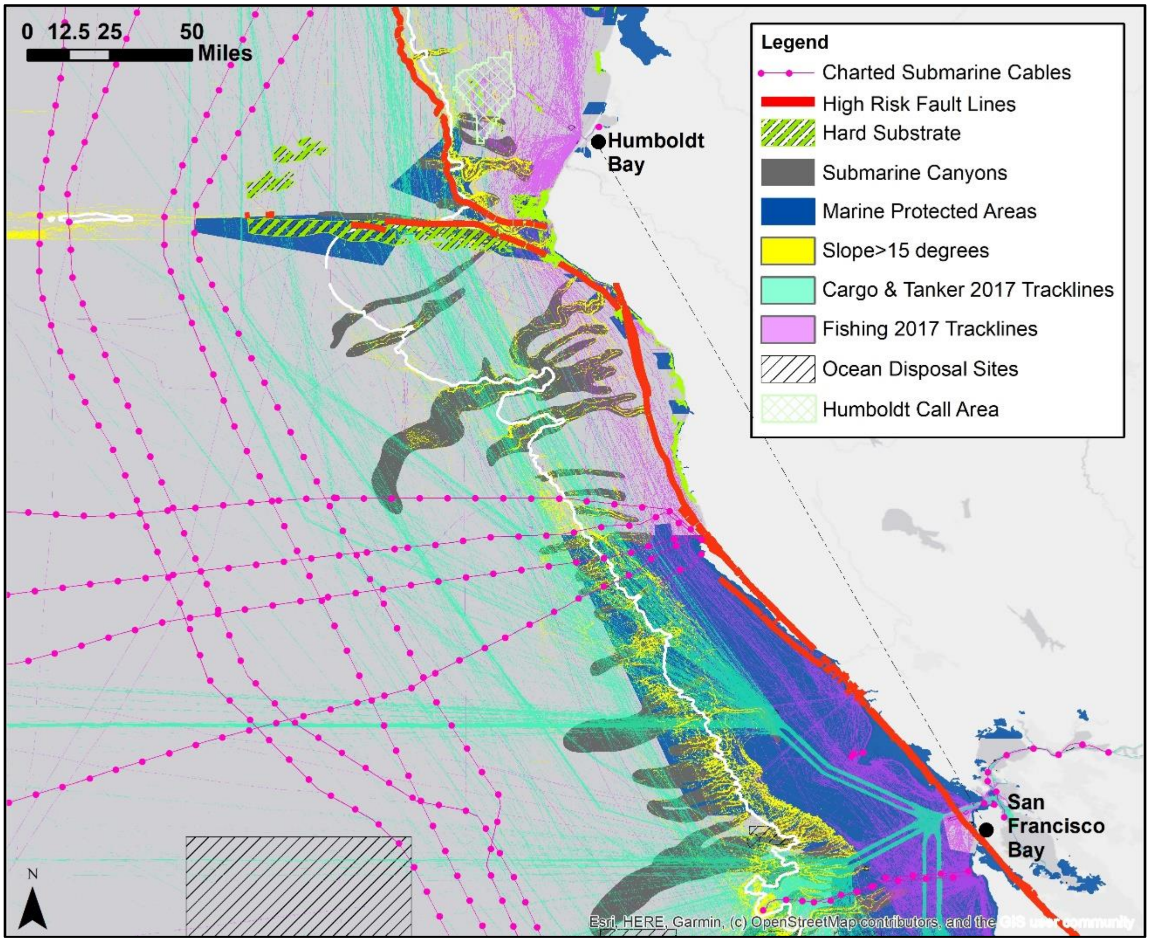

Figure 1 - Existing Subsea Conditions Between Humboldt and San Francisco Bays. White line shows the 6,560ft (2,000m) contour

3 Assessment

An assessment has been conducted to identify potential transmission cable system requirements and to document the constraints and hazards relative to potential cable routes. This section first includes an assessment of the cable and converter station components (Section 3.1), key constraints (Section 3.2), and key hazards (Section 3.3). Based on these inputs a routing risk assessment was conducted (Section 3.4) for potential nearshore and offshore cable corridors. Potential landfall in the SF Bay area is described in Section 3.4, and an overview of a probable construction cost for the system is provided in Section 3.5.

3.1 Electrical Technical Assessment

3.1.1 Cable Design

Cable design includes consideration of the rating requirements, types, and number of cables/

3.1.1.1 Cable Rating

- Assessment
  - Assume 500kV cable. The industry is moving towards this option for multiple cable types and should be considered within the project timeframe.

3.1.1.2 Cable Types:

The type of cable affects how many cables are required for the potential cable rating.

- MIND
  - The highest capacity type of cable is mass-impregnated non-draining (MIND) with Polypropylene Paper Laminate (PPL) insulation (to +/- 800kV), though the highest present service rating of this type of cable is +/- 600 kv. With a 4000A converter station, it would be able to be rated up to ~2.4GW for a single pole pair (cable bundle). The cost of MIND cable is about $800,000 per km of cable supplied
- XLPE
  - Extruded cross-linked polyethylene (XPLE) cables are designed for use up to +/- 320kV, though service experience has shown them up to 400 kV (cable rating of approximately 1.3-1.6 GW per cable). For this project it is assumed that the cable may be up to 500 kV given the project timeline, which would likely be able to meet the project rating requirements, depending on landfall details. The cost of XLPE cable is about $650,000 per km of cable supplied.
- Assessment
  - The cable may be XPLE or MIND, but for both cable types there is not a proven technology at 9,840ft+ (3,000m+) water depth.

3.1.1.3 Number of cables

- The number of cables is dependent on water temperature & landfall details.
- Based on a 500kV cable technology being available, 1 pole pair may be possible to meet the rating requirements but requires further analysis.
- If multiple cable routes are required offshore, further assessment of spacing requirements relative to the proposed cable alignments and existing constraints needs to be investigated further. Industry standard offset distance for repair and maintenance is approximately 2-4x water depth, which is needed to safely

bring the cable to the surface, repair the cable, and lay back down on the seabed in accordance with industry practice. Horizontal offset distances need further investigation at pinch points (such as between existing subsea cables) to evaluate if two cables can feasibly be installed.
  - Details at the SF Bay area interconnection could result in a need to have two 1GW solutions, rather than a single 1.8GW solution.
- Assessment
  - A single pole pair (single installation) is likely possible, as shown in Figure 2 for an example XPLE pole pair. A two-cable bundle solution (splitting transmission into two cable routes) would provide additional resiliency but would result in significantly higher cost, and further analysis is needed to confirm spacing availability and offshore route feasibility.

3.1.1.4 Cable Design Summary

A single pole pair is likely possible (single installation). XPLE or MIND cable is likely possible to meet rating requirements, but there is not presently a solution for safe installation at 3,000m water depth. Technology developments would be required to allow installations at 3,000m and are not yet proven to be feasible.

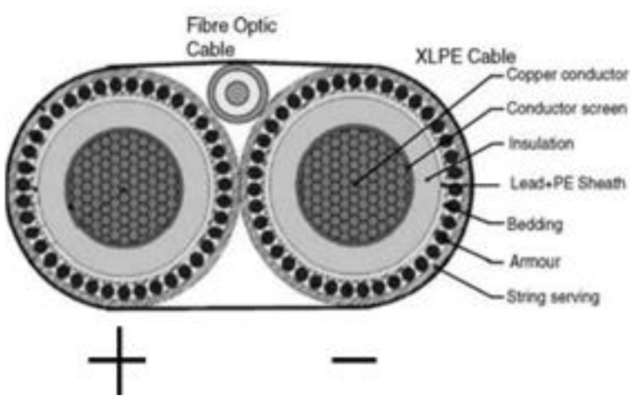

Figure 2 - Cable Cross-Section Concepts - Bundled XPLE Pole Pair example

3.1.2 Converter Stations

3.1.2.1 Background and Type

  - Converter stations are needed to convert AC current to DC, and vice-versa. An HVDC transmission system requires converter stations at both terminals of the DC link. Converter stations include specialty electrical equipment such as valves, converter transformers, and filters.
  - There are two types of technology available for converter station: Line Commutated Converters (LCC) and Voltage Sourced Converters (VSC). Both converter station types require multiple acres of land, but there are some key differences between converter types that are considered for this study, as described in Table 3.
- Assessment:
  - VSC is more likely for this project due to likely space requirements in the SF Bay Area and potential AC strength issues with any rolling blackouts/brownouts in CA region for LCC converter stations.

Table 3 – Converter Station Type Summary

LCC	VSC
• Compatible with only one type of cable (MIND) • If AC strength is too low; could lead to instability in the system. Cannot do a “black-start” requires external power. • Likely requires space equivalent on the order of 10-20 acres. • Mature technology	• Compatible with either MIND, or cheaper XPLE cable. • More expensive, but smaller footprint likely on the order of 5-12 acres • Does not require external power support • Newer technology, emerging in the 1980s and 1990s • At the time of this study there are no active VSC converter stations operating at the design rating of approximately 1800MW (though there are others in planning stage).

Figure 3 - Example LCC Converter Station (Western Link, 2200MW)

3.1.2.2 Location

This section provides commentary on siting of an HVDC converter station, whether offshore or onshore.

Onshore

- The converter stations should be designed for seismic considerations and should be sited with regard to tsunami inundation risk.

- Assessment:
  - If in the inundation zone, the converter station may need to include mitigative measures such as a flood wall or construction on fill.

Offshore

- In general, offshore converter stations are more expensive and complex than converter stations on land.
- At the time of this study there are no existing floating HVDC converter stations, the only offshore converter stations are affixed to the seabed. However, floating HVDC converter stations may be

developed in the future. The Carbon Trust (2018) undertook a concept assessment for floating offshore substations, which included California, and found that floating substations in this wave climate are likely feasible when considering likely floating structure accelerations. However, HVDC converter stations were not specifically addressed.

  - If developed, a floating HVDC converter station will need to accommodate potentially large motions at Humboldt due to the energetic wave climate.
  - If a fixed offshore platform HVDC converter option were installed it would need to be close to the coast in water depth less than approximately 150 feet, which may not be preferred by stakeholders or permitting agencies. Two platforms may be required, which would require two cables
  - Similar to floating offshore wind, the floating structures would necessitate dynamic cables, designed to be able to move within the water. At present, there is no HVDC solution for dynamic cables. The cost for dynamic HVDC cables is likely to be higher as they will likely require copper sheathing.
- Assessment:
  - For this study it has been assumed the HVDC converter stations are on land since floating offshore HVDC converter stations and the associated dynamic HVDC cables have not yet been proven technology. Secondly, there are limited locations for a shallow-water fixed foundation HVDC converter station offshore.

3.1.2.3 Converter Station Summary

VSC is more likely for this project due to space requirements and potential issues with blackouts/brownouts in the CA region for LCC converter stations. A floating HVDC converter station may potentially be developed in the future, but no existing technology currently exists for the converter station, or the required dynamic HVDC cables required for interconnection. On-shore converter stations of this magnitude are currently in the planning stage elsewhere in the world.

3.1.3 Potential Spurs to Coastal Towns

At the request of HSU, the possibility of developing spurs to coastal towns from an offshore HVDC backbone has been considered. A brief summary of the challenges and opportunities are described below.

- Converter Stations.
  - A converter station is required to tap off power to smaller communities along route; ongoing maintenance of offshore converter station required (expensive), unless routed to shore.
- Cables
  - More joints offshore means higher risk for potential damage
- Routing
  - If cables are routed onshore, this might provide opportunity for upland routing to avoid canyons/faults.
- Assessment:
  - A spur off the main subsea HVDC link would be very expensive solution to deliver a relatively small amount of power to these communities. This alternative is unlikely to be pursued with existing technology but may potentially be pursued if the DC link is routed upland for a portion of the route.

3.2 Hazard and Constraints Assessment

An assessment of the hazards and constraints affecting the cable system has been developed relative to the mitigation and risk criteria listed in Section 1. Results of this assessment are provided in Tables 4 and 5 for hazards and constraints, respectively. Details for key constraints and hazards affecting the cable routing are provided in Appendix 5.B.

Table 4 - Hazard Assessment Summary

Potential Hazard	Potential Risk to Transmission Cable System	Potential Mitigation	Assessment
BOEM Offshore Wind Call Areas	Cable may conflict with anchoring and mooring plans.	Coordination with developer or avoidance	Major Mitigation Required
Surface Fault Rupture and Deformation	Displacement of transmission line within upper plate of Cascadia subduction zone.	Align cable along fault lines; Provide excess slack in the cable; Cable armoring with improved tensile strengths and deformation capabilities; Install additional cable for redundancy. Mitigation techniques are applicable for small events; for significant earthquakes cable damage can be inevitable.	Major Mitigation Required. Repairs may need to be planed for. Cable should cross faults in area where repairs are feasible.
Seismic Shaking	Strong motion effects to transmission line	Cable armoring with improved tensile strengths and deformation capabilities; Converter station design considerations.	Major Mitigation Required. Area limits not specified.
Submarine Canyons	Displacement of transmission cables from possible lateral motion during landslide event (HSU, 2019). Steep slopes of canyon walls create spanning and vibration issues.	Complex remedial leveling work would be needed to mitigate for cable spanning. No known mitigation for landslide/turbidity currents.	No-go Area. High risk of damage likely not possible with mitigation. Cable repairs within submarine canyons may not be possible. Submarine canyon details may be assessed further to identify favorable areas.
Shipping Vessel Traffic	Anchors dropped from shipping vessels penetrate and are dragged along seabed, potentially damaging cable.	A cable burial risk assessment (CBRA) utilizing automatic information system (AIS) vessel tracking data should be conducted to aid in acceptable burial depth recommendations.	Minor Mitigation Required
Bottom Trawl Fishing	Bottom Trawl fishing gear is dragged along the seabed. If not buried to sufficient depth, fishing gear can damage cable.	A cable burial risk assessment (CBRA) should be conducted to determine the acceptable burial depth based on acceptable risk.	Minor Mitigation Required
Tsunami	Erosion and strong currents near shore could cause displacement of transmission cable. Inundation and damage to converter station	Sufficient cable burial depth to protect against scour during tsunami event; Seabed in deeper water will be less impacted by a tsunami wave; Placement of converter stations outside design tsunami inundation area.	Minor Mitigation Required
Sand waves	Height and geometry of sand waves can prevent plow from achieving uniform burial depth.	Mitigation typically limited to sand waves of 2-3m. Dredge away sand waves to create flat surface prior to burial; Provide additional burial depth to prevent cable exposure; Stabilize with rock.	Major Mitigation Required. See Section 3.4
Gas Hydrates	Destabilization of subsurface sediment resulting in displacement of transmission cable.	Alternative engineering solutions may be possible, but not within the scope of this assessment. Avoidance if possible.	Minor Mitigation Required.

Table 5 - Constraint Assessment

Potential Constraint	Potential Risk to Transmission Cable System	Potential Mitigation	Assessment
BOEM Offshore Wind Call Areas	Site use permissions may not be possible.	Coordination with developer or avoidance	Major Mitigation Required
Existing submarine cables in deep water	Agreements likely need to be obtained. In many cases, protection must be installed at vertical crossing of existing submarine telecommunication cables. May be challenging to install cable protection infrastructure at these depths. Cable protection more common in shallower water.	Shallow water (<6,560ft or <2,000m). Cable protection measures may need to be installed, such as concrete mattresses. Typical crossing between 65-90 degrees Deep water (>6,560ft or >2,000m): installation of mitigative measures in very deep water are rare or do not exist.	Shallow water (<6,560ft or <2,000m). Minor Mitigation Required Deep water (>6,560ft or >2,000m): Major Mitigation Required
Steep Slopes	Risk of runaway of the plough or ROV and consequential damage to the cable. Fiber optic cables appear to be laid on California shelf on slopes up to 30 degrees.	Avoidance if possible. Specification or development of appropriate cable installation and/or cable burial equipment.	Minor Mitigation Required
Hard Substrate	Required depth of burial may not be achieved in areas with hard substrate.	Alternative cable protection measures such as concrete mattress or rock cutting.	Major Mitigation Required
Ocean Disposal Sites	Site use permissions may not be possible.	Coordination with United State Army Corps of Engineers, provide adequate cable burial or protection or avoidance.	Major Mitigation Required
Installation Depth	HVDC transmission cables at 9,840ft (3,000m) water depth are not yet proven to be feasible	Technology developments would be required to allow installations.	Major Mitigation Required
Sea State	Installation and maintenance activity downtime due to sea state may increase costs.	Further analysis required.	Minor Mitigation Required
Cable Installation Vessel Operational Limitations and Capacity	Multiple joints may result in higher risk of cable fault. Multiple installation campaigns may result in a multi-season or multi-year installation process. .	Industry may develop vessels with larger capacities to meet global demand; may be able to install with 1 or 2 campaigns by 2030s.	Minor Mitigation Required
Marine Habitat Areas	Cable installation can impact/disturb the seabed and it is possible may not be permitted. Prototype review indicates these could be major issue, but mitigation may be possible. Each MPA in California has different regulations. E.g. some restrict fishing, type of vessel traffic, etc., Further refinement needed as part of next steps.	Coordination, avoidance or other mitigation techniques/requirements TBD.	Major Mitigation Required

3.3 Routing Assessment

Results of the hazard and constraint assessment have been applied to the available data layers for each hazard and constraint. The hazards and constraints which geographic data was available for are summarized in Table 6[2]. Based on the assessment in Section 3.2 a suitability map was generated by assigning the classifications for the compiled GIS data layers (Figure 4). Converter stations were not assessed as part of the routing assessment since they are assumed to be located on land. As part of this study, Mott MacDonald was scoped with developing offshore and onshore corridors for assessment. Potential cable corridors were developed based on hazard and constraints mapping, and in coordination with technical experts during a multi-disciplinary team workshop (shown in Figure 4). Two potential cable corridors were developed based on concept-level avoidance of the mapped constraints and are summarized in Table 7.

Table 6 - Potential subsea cable hazards and criteria for constraint mapping

Potential Hazard/ Constraint	Mapping Classification	Mapped Data
Submarine Canyons	No-Go	Large submarine canyons, extending over a depth range of at least 3,280ft (1,000m) and being incised at least 320ft (100m) into the slope at some point along the thalweg (Harris, 2014).
Existing submarine cables in deep water	Major Mitigation Required	NOAA charted submarine cables on the ocean floor at depths greater than 6,560ft (2,000m) contour.
BOEM Offshore Wind Call Areas	Major Mitigation Required	BOEM offshore wind call area data layer (Marine Cadastre).
Surface Fault Rupture and Deformation	Major Mitigation Required	Three highest-risk fault lines (as coordinated with HSU: San Andreas Fault, Mendocino Fault, and Cascadia Megathrust. Mapped according to USGS QFaults layer.
Existing submarine cables (depth<6560ft (2000m)	Major Mitigation Required	NOAA charted submarine cables on the ocean floor at depths shallower than the 6,560ft (2,000m) contour.
Marine Habitat Areas	Major Mitigation Required	MPA's (excluding the 700fm – 1094fm Essential Fish Habitat Conservation Area).
Hard Substrate	Major Mitigation Required	Hard substrate layer provided by HSU.
Ocean Disposal Sites	Major Mitigation Required	Ocean disposal sites layer (Marine Cadastre)
Shipping Vessel Traffic	Minor Mitigation Required	Combined cargo and tanker vessel transit counts for 2017 were mapped based on AIS data from Marine Cadastre.
Fishing	Minor Mitigation Required	Fishing vessel transit counts for 2017 were mapped based on AIS data from Marine Cadastre.
Steep Slopes	Minor Mitigation Required	Areas steeper than 15^{o} degrees were categorized as minor constraints.

[2] Not all hazards and constraints are mapped due either to the nature of the hazard/constraint, or the available data.

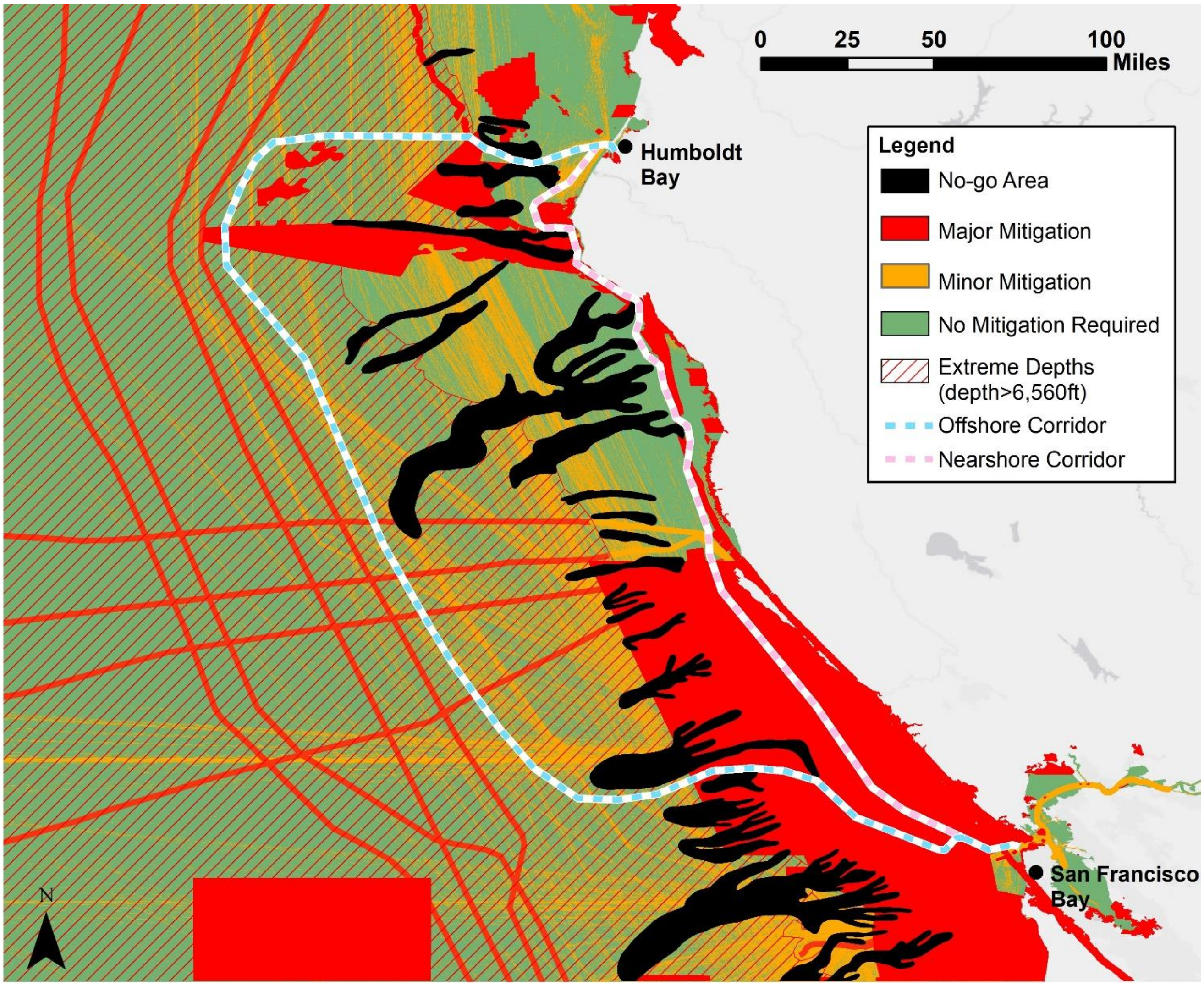

Figure 4. Suitability Map for the Study Area relative to the Offshore and Nearshore Corridors.

Table 7 - Cable Corridor Summary

Cable Corridor	Nearshore	Offshore
Approximate Length	~260 miles	~410 miles
Maximum Distance From Shore	~25 miles	~100 miles
Maximum Depth	~600 feet	~13,000 feet
Primary Constraints	Submarine canyons, hard substrate, marine habitat areas, metocean conditions	Water depth, proximity to, and crossings of telecommunication cable crossings in deep water, continental shelf, metocean conditions
Primary Hazards	Submarine landslides, seismic shaking and displacement, fishing vessels	Seismic shaking and displacement

3.4 Landfall

Potential landfall at the Humboldt Bay and SF Bay termini of the HVDC cable were assessed at a pre-conceptual level, and results of the assessment are provided below.

3.4.1 Humboldt Bay

Landfall at Humboldt is anticipated to be similar to the landfall methodologies outlined in the Humboldt Cable Landfall Memorandum (MM, 2020), with the cable making landfall on a sandy beach.

- Assessment: The likely methodology for landfall is horizontal directional drill (HDD) on the South or North Spit, with a secondary HDD to cross the bay and be routed to the selected converter station site, depending on landfall location. HDD feasibility is dependent on geotechnical investigations, and size of the cable bundle, and requires further analysis.

3.4.2 San Francisco Bay

HSU requested MM to investigate the possibility of routing the HVDC cable to a location within SF Bay. Landfall and nearshore routing in this area are more complex than landfall in the Humboldt Area. No cables presently are routed through the Golden Gate. A number of different challenges were identified:

- Presence of large sandwaves in the Golden Gate (e.g., Figure 5)
- A majority of the shoreline north and south of the Golden Gate consists of steep bluffs and cliffs
- Marine Sanctuary
- High volume of vessel traffic
- Multiple cable crossings appear to be required.

A number of the complexities may be able to be mitigated with appropriate engineering operational permissions, but there are a number of complexities which may preclude routing through the Golden Gate. The presence of sandwaves is typically mitigated by dredging and flattening the area in which the cable will be buried to the same level of the trough of the sandwave. However, CSA Ocean Sciences Inc. (2019) reports this may not be an economical solution for sandwaves with a height of 7-22 feet (2-3 meters). The sandwave height in the Golden Gate are some of the largest in the world (Barnard et al, 2006), reported to be on the order of 30ft (9m). Additionally, in order to conduct repairs in this area, dredging would be required to retrieve the cable for repair, or a new cable would be required.

- Assessment: Further analysis required to assess feasibility of routing subsea cable through the Golden Gate, whether around or through the sandwave areas, but at this level of assessment the option appears unfavorable.

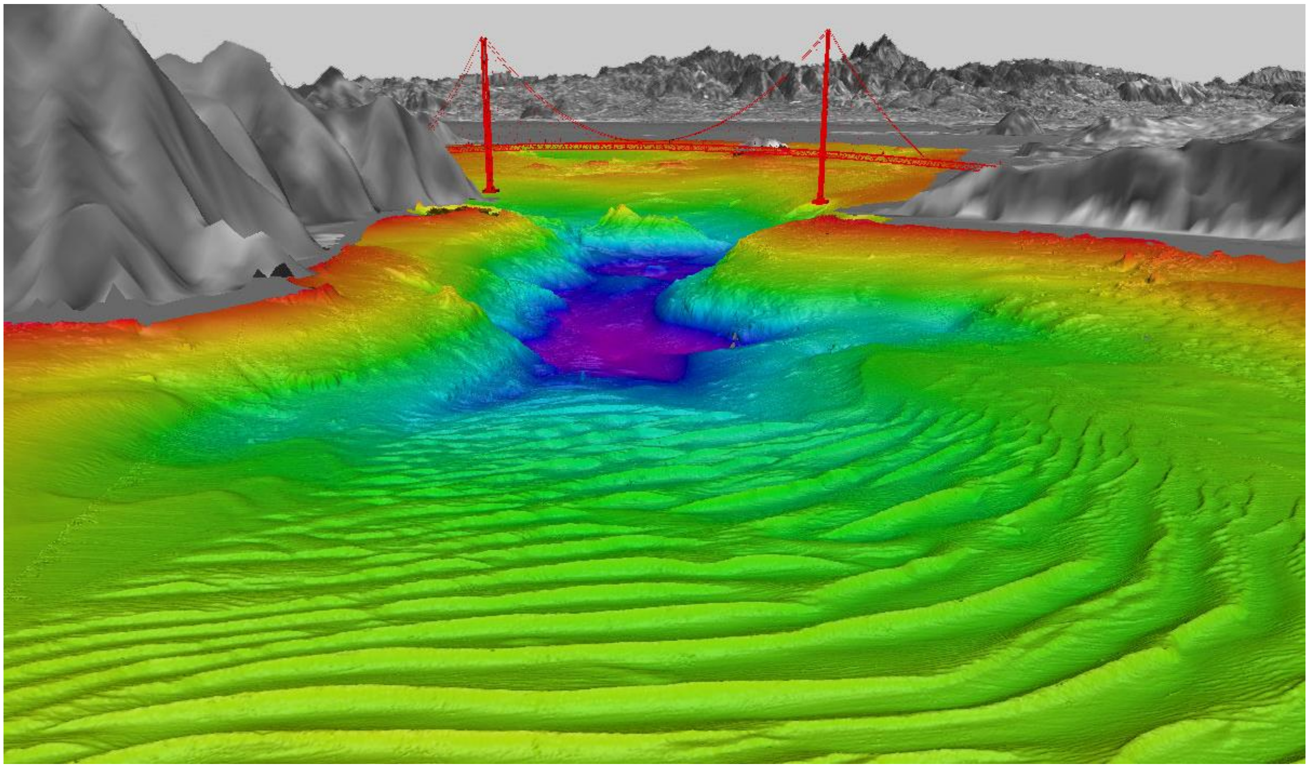

Figure 5 - Golden Gate Sandwaves (note 3x vertical exaggeration) (USGS, 2006)

3.5 Cost

A conceptual-level assessment of potential construction cost was developed to aid in infrastructure planning. Construction costs were based on prior project experience only, and no engineering was conducted. It is important to note that in the subsea cable industry, construction cost is heavily dependent on market at time of bidding. Considering this, a high-level cost estimate was developed. Costs developed do not include land acquisition, re-grading, permitting, engineering, or taxes. Converter station cost is assumed to be for an on-shore station.

- ~$300m per converter station → $600million (supply only). Additional cost for land, earthworks, upland routing (depending on location of converter station) should be incorporated into planning, but were not scoped for Mott MacDonald
- ~$2.5m per km of HVDC link for supply and install (400km) → $1 billion.
- 30% contingency for market fluctuations and complexity of install.
- Planning-level cost estimate: $2.1 billion (for 1 cable bundle), $3.1 billion if two cables required.

4 Summary

A concept-level assessment was conducted to develop options and documents risks and challenges for a high voltage direct current (HVDC) cable from the Humboldt Bay area to the San Francisco Bay (SF Bay) area for the 1,836 MW scenario. The HVDC cable system would consist of the cable system itself and an HVDC converter station at each end of the cable (Humboldt Area and SF Bay Area).

The construction cost of the system is estimated to be approximately $2.1 – 3.1 billion (based on the nearshore route length), depending on whether one or two cables are installed. It is likely that a single pole pair would be able to meet the rating requirements of 1800 megawatts (MW). Installing two cables along different routes would provide redundancy for the system in case one cable incurs a fault, but would come at an additional cost of approximately $1 billion.

The subsea study area between Humboldt Bay and San Francisco Bay includes both natural and anthropogenic constraints and hazards with variable levels of risk. These hazards and constraints will require a combination of avoidance and mitigation measures in order to install a transmission cable between the two areas. The primary risks include:

- Hazards
  - Deep subsea canyons extending from the nearshore area to depths below the continental shelf, where subsea landslides strong enough to rupture cables are common.
  - Seismic fault line surface displacements which may be too large to mitigate for. Cable repairs may need to be expected to be conducted with a major seismic event.
  - Some of the largest subsea sandwaves in the world are present outside the Golden Gate, which may preclude subsea transmission cable routing through the Golden Gate.
- Constraints
  - Areas of exposed bedrock and other hard substrate are located within marine habitat areas where cable protection methods may be either expensive or not permitted by agencies.
  - Potential interferences with fishing activities if the cable is not able to be buried or otherwise protected
  - No power cables have been installed to the depths required to route offshore of the subsea canyons (over 9,000 feet deep), and proven cable technology has not yet been developed for installation at these depths.
  - The offshore route will likely require crossing telecommunication cables in very deep water (5,000 feet or greater), which will require permissions from the existing operators. Though telecommunication cables crossings at these depths are common, power/telecommunication cable crossings at this depth do not appear to have previously been attempted.

Due to the location and severity of the constraints and hazards, two potential cable corridors have been developed, a “Nearshore” corridor, an “Offshore” corridor (Figure 6). Both corridors have significant challenges that would need to be overcome to install and operate an HVDC link, though the challenges may not be infeasible. A risk/benefit table has been developed for these corridors based on the results of the hazards and constraints assessment in Table 8.

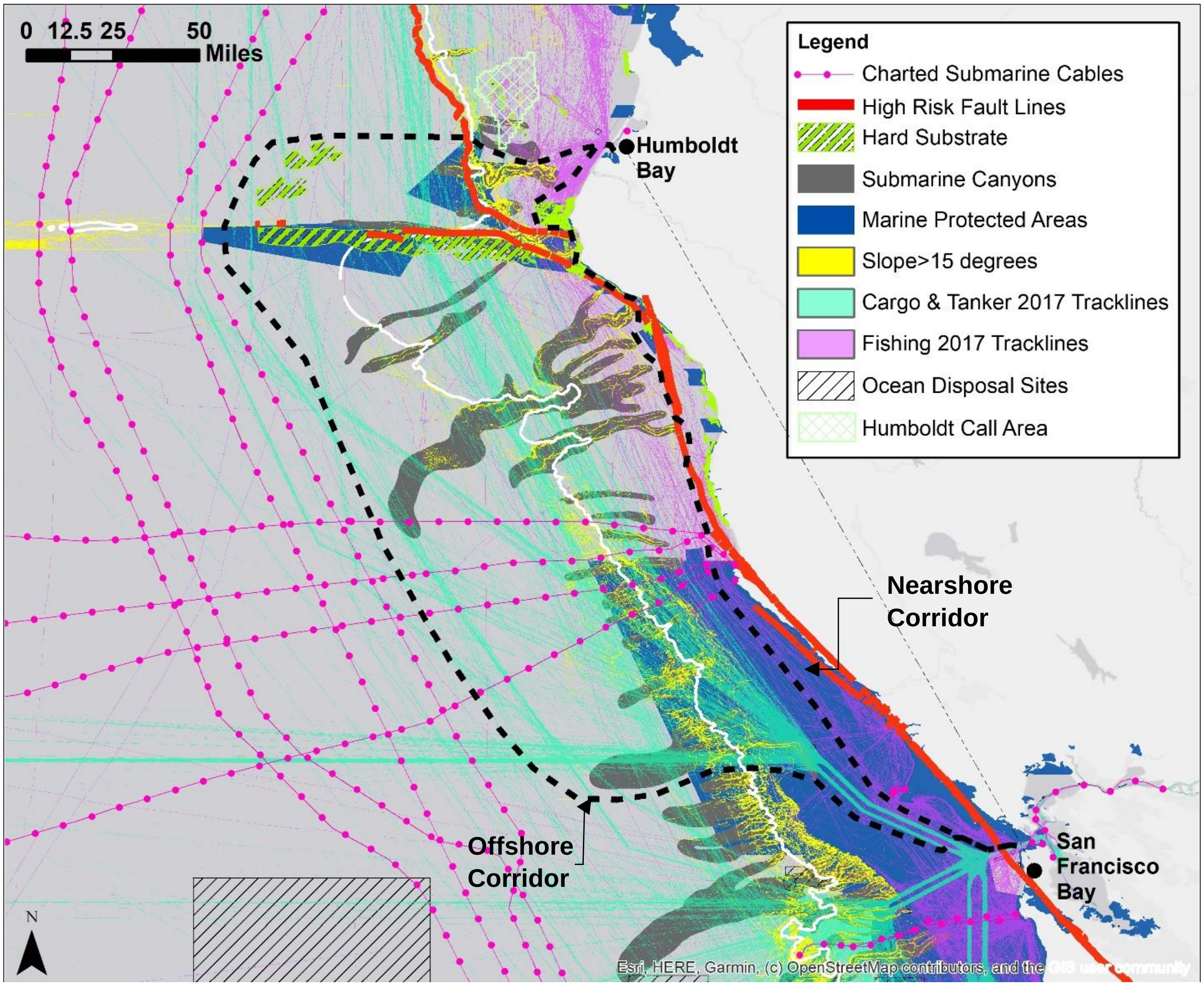

Figure 6 - Offshore and Nearshore Corridors relative to hazard and constraint map.

Further analysis may be conducted to refine the severity of the risks, develop mitigation strategies, and further assess feasibility of the nearshore and offshore routes. The next steps may include:

- Broader data compilation effort and more detailed assessment of trenchability along the seabed
- Outreach to manufacturers to determine likelihood of cable armoring design that can accommodate 9,840+ feet (3,000+ meters) of water depth.
- Conducting a cable burial risk assessment for the nearshore route. This would include detailed assessment of the pinch-points near the heads of Eel and Delgada Canyon, and the Golden Gate.
- Assessment of a combination of subsea and overland routing along the coastline to avoid canyons and potentially avoid the Golden Gate.
- Siting analysis for the required converter stations
- Landfall conceptual engineering to confirm two cables are not required.
- Overland routing engineering analysis in combination with refinement of the subsea and landfall assessments. Overland, subsea, and landfall constraints should be considered together.

Table 8 - Risks/Benefits

	Nearshore	Offshore
Benefits	• **Shallower water:** Potentially fewer constraints on cable design and ability to bury and protect cable. • **Vessel Anchor Strike:** Fewer vessel traffic zone crossings • **Cost:** Shorter distance → less material, shorter schedule. • **Steep slopes:** Does not require crossing the shelf, but does require crossing Mendocino Ridge	• **Submarine Canyons**: Does not cross submarine canyons or turbidites. • **Fishing:** Fewer interferences with fishing vessels or trawling if cable is not buried. • **Marine Habitat Areas:** Minimizes installation length in marine habitat areas. • **Shipping Vessels:** Requires crossing high vessel traffic zone but is at water depth where anchor use is very unlikely.
Risks	• **Submarine Canyons:** Approaches multiple submarine canyons – high risk of either damage to cable during installation or during operation. • **Hard Substrate:** Nearshore bedrock may preclude burial, require expensive burial of the cable, or require other protection methods such as concrete mattresses. • **Seismic:** Crossing of multiple large faults, crossing Mendocino Ridge in seismically active zone. • **Fishing**: Interferences with fishing vessels or trawling if cable is not buried. • **Marine Habitat Areas:** May require installation for significant length of Marine Habitat Areas. • **Alignment:** May require a higher number of turns to avoid nearshore interferences and to cross fault lines at oblique angles.. • **Downtime**: May result in additional construction downtime	• **Cost**: Approximately 30% longer distance → more material, longer installation schedule. • **Continental Shelf:** Requires crossing the shelf • **Seismic:** Crossing of Megathrust large faults (Cascadia Subduction), crossing Mendocino Ridge in less seismically active zone. • **Depth:** may exceed 9,480ft (3,000m), and is much deeper than any existing installed transmission cable. Will likely require special considerations during design of cable, considering strain from installation at this depth. • **Cable Crossings:** Power/Telecommunication cable crossings appear to have never been previously attempted at this depth. Risk is that permission to cross cable is not received. Limited area between North/South Cables and the "toe" of the submarine canyons, which should be avoided if possible due to sediment flows.

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Appendix 5.A

Geographic layers utilized for the mapping assessment

Dataset	Source
NOAA Central California DEM	NOAA
NOAA Northern California DEM	NOAA
NOAA Central Pacific Coastal Relief Model	NOAA
NOAA California Ocean Uses	CA Offshore Wind Energy Gateway
Vessel Tracklines (2017)	Marine Cadastre
Marine Protected Area Inventory (2017)	Marine Cadastre Original Source: NOAA Marine Protected Areas Center
Lithological Seafloor	Humboldt State University (HSU)
Fault Lines (QFault)	USGS
California State Waters Map Series Data Catalog	USGS
Geology side-scan sonar	Marine Cadastre
Wrecks + Obstructions	Marine Cadastre
Ocean Disposal Sites	Marine Cadastre
NOAA Charted Submarine Cables	Marine Cadastre
Mean Ocean Surface Current	Marine Cadastre
Mean Tidal Current	Marine Cadastre
2017 Vessel Transit Counts (Fishing, Cargo, Tanker)	Marine Cadastre
Geomorphology of the oceans “canyons” layer	Harris et al, 2014

Appendix 5.B – Hazard and Constraints Assessment Details

Hazard Assessment

Submarine Canyons

- The most common faults in deep water are submarine landslides and associated turbidity currents. Where possible, cable route planners avoid zones of active landslides and turbidity currents such as submarine canyons and channels, but this is not always possible (Source: International Cable Protection Committee)
- CSA Ocean Sciences Inc . (2019) has mapped subsea canyons in the study area. Of the major canyons, Eel Canyon and Delgada Canyon are both mapped within 1-3km of the shoreline. Harris (2014) has mapped additional canyons, which have been included in this analysis.
- Puig et al (2004) has identified periodic storm-induced sediment gravity flows at head of Eel Canyon.
- The continental margin off Cape Mendocino contains more submarine landslides than any other region along west coast of US. One of more prominent slides is Humboldt slide zone, west of Eureka 250-500m water depths. (Field, 1990).
- Submarine Cables and Pipelines (2017) has identified landslides and turbidity currents caused by seismic activity in Taiwan. The events identified travelled over 300 kilometers and caused 19 breaks in 7 different cable systems. The cable repairs works required 11 different vessels which disrupted internet connections for China, Japan, The Philippines, Singapore, and Vietnam.
- CSA Ocean Sciences Inc. (2019) notes the following with regards to the Taiwan event: “Each of submarine cable failures to date: less robust telecom failures, not buried, in deep water, or had been laid in mudslide area down slope of continental shelf”.
- Carter et al (2014) summaries the following w/regards to submarine canyons
  - 2006 Taiwan earthquake triggered instantaneous breakage of cables due to sediment density flows
  - Key lesson: avoid, where possible, submarine canyons, especially those fed by high discharge rivers.
  - Frequency of sediment density flows is a consideration – crossing a system with a probability of 1x/century may be acceptable.

Seismic Activity

- The HVDC cable will need to cross multiple fault lines, with varying risk of a seismic event and surface displacement. For this study, the focus was on the major fault lines.
- Seismic risk is a significant consideration for cable maintenance risk. For example half of all trans-pacific cables were damaged due to 2011 Japan Earthquake.
- BOEM recommends to avoid direct fault areas where large displacements occur.
- Some mitigation techniques exist, but its unlikely that all risk from seismic activity can be mitigated.
- Both CSA Ocean Sciences Inc. (CSA Ocean Sciences Inc., 2019) and the California Public Utility Commission (CPUS, 2014) have issued reports recommending that additional cable slack be incorporated in fault areas where displacements could occur. Additionally, crossing the fault line at an oblique angle and improved cable tensile strength may provide some resilience. However, there is likely no reasonable mitigations available, and some level of repairs should be expected due to displacement.
- The need for planning for seismic risk will likely be a function of the likelihood of occurrence relative to the design life of the cable.

- Fault lines will need to be crossed, and depending on the severity of the vent, no mitigation may be able to preclude damage. Therefore, the cable should be routed through areas where maintenance activities can be safely carried out. Additionally, avoiding the downslope area of a subsea canyon may reduce risk. Fault crossings and cable route requires further geologic investigation to quantify risk. A secondary cable, crossing different fault lines, could provide resilience against a major seismic event.

Constraints Assessment

Installation Depth

- Given the current status of existing HVDC cable technology, it is installation of the HVDC cable in water deeper than 1600m would likely incur significant risk due to the levels of lay strain and water pressures at such depths.
- High-risk to plan for HVDC cable installation in very deep (1600m+ water depth), but should not be precluded from possibility.

Installation Vessels

- At present the approximate vessel cable length capacity is ~100km/vessel (current tonnage capacity). Therefore, multiple vessel campaigns would likely be required with the existing vessel fleet.
- Industry may develop vessels with larger capacities to meet global demand; may be able to install with 1 or 2 campaigns by 2030s.
- To reduce installation timeline, it may be possible to have multiple vessels installing in parallel.

Open Ocean Operations and Wave Climate

- Because joints are likely required between the multiple vessel campaigns needed to install the cable, further assessment needed to assess downtime during this process.
- The jointing process is similar in deep/shallow water, but additional time and complexity is present in deep-water locations to bring up the cable from large depths.
- During jointing operations the vessel needs to be stable (e.g. requiring calm seas) for long period of time (3-5 days), which may be difficult in the Pacific.
- Because the cable installation would be primarily parallel to shoreline, the vessels will be dealing with beam seas, which decreases the sea state in which the vessels can operate (more downtime).
- Barge installations in shallower water are typically more weather dependent due to the type of equipment used.
- There is likely to be downtime for cable installation vessels/barges in the study area more so for near-shore areas. Additional assessment may be required to confirm weather window availability for jointing operations.

Maintenance

- According to the International Cable Protection Committee:
  - Worldwide there are approximately 150-200 subsea cable faults per year, due to a number of different causes.
  - 60-70% of faults are due to fishing and shipping occurring in shallow (<600 feet) water.
  - Less than 10% of faults are caused by natural hazards, but do occur in deep water.

- Cable recovery and operation & maintenance activity is limited by sea state. It is possible that such activities will not be able to occur for significant wave heights exceeding 10 feet (3m). During these operations the vessel needs to be stable for long period of time (3-5 days), which may be difficult in this area of the Pacific in winter conditions. Repairs may be limited to summer seasons.
- Requires cable installation spacing of typically at least 2x water depth to conduct repairs without affecting nearby features (such as existing cables). 3-4x water depth is preferred spacing.
- Maintenance takes longer offshore than in nearshore due to deeper water and complexity of operations.
- Certified, trained jointers need to be available to maintain the cable warranty.
- Maintenance planning should be conducted. There may be significant downtime should a cable fault occur, between the time of the fault, and repairs being conducted. Appropriate vessels will need to be mobilized with trained crew, and repairs to power cables have never before been conducted for the depths along portions of the study area.

Telecommunication Cable Crossings

- Permissions will likely be needed to cross existing telecommunications cables. In shallow-water applications the risks of export cables crossing telecommunication cables are mitigated by engineering appropriate protection measures, such as a concrete marine mattress or other. Telecommunication cables also cross one another in deep water, but the permission risk for a high-voltage cable crossing an existing telecommunications cable may be more challenging.
- Concrete mattress protection may be deployed from vessels or remote operated vessels (ROVs) to protect cables which are crossed (CSA Ocean Sciences Inc., 2019), as shown in . However, installation of this technology at extreme depths where a number of the telecommunication cables are present, is likely to be very be challenging. Installation of concrete mattresses at extreme depths (3,000m+) is not known to have occurred globally (note that a detailed investigation was not conducted, and examples may exist).
- Feasibility of cable crossing in very deep water requires additional investigation.

Figure 7 - Cable Crossing Protection Example Applications

Chapter 6: Electricity Market Options for Offshore Wind

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Table of Contents

1. OVERVIEW

The purpose of this document is to describe electricity markets operated by the California Independent System Operator (CAISO)[2] and the opportunity for offshore wind to participate. Offshore wind power plant operators may or may not participate directly in these markets, depending on the individual plant attributes and business plan (e.g., they may have a power purchase agreement with a third party). An overview of the different CAISO concepts covered in this report are given in Table 6-1, along with their relevance to offshore wind power. Details of the CAISO concepts in this document came from CAISO's Business Practice Manual (Delparte, 2020a,b), which provides an excellent reference for further details.

[2] The California Independent System Operator (CAISO) is an independent Balancing Authority responsible for operating a portion of the Western US electric power system. CAISO manages 26,000 circuit miles of transmission lines and coordinates generation resources through competitive electricity markets. CAISO's jurisdiction covers most of California, as well as small areas of Nevada.

Table 6-1. Overview of CAISO electricity market concepts and relevance to offshore wind.

CAISO Concept	*Description*	*Relevance to Offshore Wind*
Day Ahead Market	Market where energy is bought and sold to address demand for the next day after market closure, guided by load and generation forecasts	The day-ahead market accounts for most of the energy transactions, and offshore wind will likely participate and influence prices in this market.
Real Time Market	Market to address the shortfall between the energy bought/sold on the day-ahead market and the real-time energy demand	Though smaller than the day-ahead market, the real-time market is still a key area for participation.
Ancillary Services	Frequency regulation and operating reserves procurement providing grid stability and supporting reliability	New technology can allow offshore wind to provide ancillary services.
Resource Adequacy	Capacity product designed to ensure enough peak power supply is available at all times	Offshore wind's qualification for capacity payments will depend on the probability of generation at system peak times, and will require analysis since it is a new resource.
Congestion Revenue Rights	The tradable rights to costs and revenues generated by grid congestion	While offshore wind is not required to obtain Congestion Revenue Rights, given the local grid constraints additional study is recommended.
Convergence Bidding	A system similar to commodity options markets designed to minimize the price difference between day-ahead and real-time energy prices, allowing virtual bids to be placed without requiring physical capabilities to generate.	Virtual bidding traders will incorporate the influence of offshore wind in their bidding strategies. Offshore wind plant operators may also participate, though there will be less utility in doing so than a non-intermittent resource.
Hybrid Resources	Resources combining multiple forms of generation, which are subject to special constraints	Offshore wind may qualify if combined with other generation and/or energy storage, but many policy details have yet to be finalized.

2. CAISO ENERGY MARKET

The main tool used by the CAISO to manage energy generation resources is the integrated energy market. The market operates in two phases: the day-ahead market, used to serve the expected energy demand, and the real-time market to serve more immediate demand fluctuations. These markets include serving energy demand and also ancillary services; for the sake of simplicity the day-ahead and real time markets are discussed in terms of energy in this section.

2.1 Day Ahead

The Day Ahead Market (DAM) is a process for organizing generation resources to meet hourly demand for the next day after market bidding closes. Despite the name, the day-ahead market for any given day opens seven days prior, and closes at 1 p.m. the afternoon before the day in question. The CAISO then processes all bids, balancing active generation and load throughout their authority area to determine which bids are successful and result in the least cost option for reliably serving load, given the constraints on the system.

There are two pathways to participate in this area of the CAISO market: self-scheduling, and competitive bidding. Under self-scheduling, a scheduling coordinator can submit a schedule to the CAISO describing the amount of energy that a resource will generate during each trading hour regardless of participation in the competitive bidding process. Resources which participate in self-scheduling are known as "price takers," as they will accept the final energy price (determined by a combination of market forces and possible adjustments by the CAISO), which can in some cases be negative.[3]

In contrast, resources in the competitive market offer energy at a specified price interval, constructing a "bid stack" with prices based upon given market circumstances and plant operating characteristics.[4] In its simplest form, a bid will offer increasing operating capacity for increasing prices. A simple example of a competitive market bid is shown in Table 6-2; actual bid stacks contain up to 10 increments describing a resource's willingness to participate in the various CAISO market products.

Table 6-2. Simplified example market bid.

Operating Capacity	Energy Price
50 MW (min capacity)	\$15/MWh
75 MW	\$20/MWh
100 MW	\$25/MWh
150 MW (max capacity)	\$40/MWh

The competitive market often generates higher profits since bids can be designed in a way to prevent producing during times when the market clearing price is lower than the marginal cost of operation for a resource. There is some risk of a poorly constructed bid stack failing – if the lowest energy price falls above the closing market energy price, the bid will not be awarded.

In tandem with those selling energy supply into the DAM, scheduling coordinators representing load serving entities (such as utilities or community choice aggregators) are placing bids to purchase the energy being provided. The demand bidding process is very similar to the supply bidding structure: bids can either be self-scheduled, or entered competitively. Competitive demand bids mirror their supply counterparts, with the maximum purchase quantity at the lowest cost, and the lowest purchase quantity at the highest cost. At a certain price/supply point, the day-ahead supply meets the day-ahead demand, and the market energy price (and the price offered to self-schedulers) is set to that value. This energy price is not uniform throughout the entire Balancing Authority Area, but will vary from locality to locality based upon available demand, load, and transmission constraints. The day-ahead market awards generally account for approximately 90% of the energy demand that will be required the next day.

2.1.1 Relevance to Offshore Wind

Offshore wind can participate in the DAM similar to existing land-based wind facilities. Self-scheduling presents far less risk for wind plants over conventional plants: whereas conventional plants have significant marginal costs (reflected in the increasing price tiers of a competitive bid stack), wind plants have essentially zero marginal cost (a wind turbine will produce minimum power at the cut-in wind speed for the same cost as its rated power at higher wind speeds). As long as the market clearing price is positive, a self-scheduling wind plant can make money without needing a more complex bidding strategy. While there is the long-term risk that market clearing price will be insufficient to reimburse initial investment in a wind farm, there is no market bidding mechanism to address that concern.

[3] If the market experiences an energy glut, it is possible that the market price would be negative - forcing self-schedulers to pay money to generate electricity. Alternately, power plants utilizing energy storage may purchase energy to charge energy storage.

[4] Characteristics such as start-up time and cost to run would be entered into the bid; there is often a desire to select plants already running, or with lower operating costs, if energy bid prices are equal.

2.2 Real Time Market

As mentioned earlier, approximately 90% of demand is covered in the DAM. The Real Time Market (RTM) is designed to procure any products needed to correct for the difference between the demand forecasted in the DAM and the actual need on the grid during each interval in the RTM. There are two markets time intervals within the RTM: the fifteen-minute market and the five-minute market (also known as the real time dispatch).

Similar to the day-ahead market, scheduling coordinators can either self-schedule or competitively bid into the real-time market. A self-scheduling resource will still simply provide their scheduled product to the CAISO, and receive the final price determined at the end of the real time dispatch. A resource can also submit a competitive bid stack into the real-time market, which provides the most control of the final product price, but is more complex and riskier than competitive bids in the day-ahead market.

A resource can also competitively bid into the DAM, but abstain from doing so in the RTM. Bids which have been awarded in the DAM are automatically passed into the RTM, however these awards are still subject to real-time mitigation and fluctuations. Without a competitive real-time bid, a resource will have no impact on how the mitigation and fluctuation will impact their final award. This is not the same as price-taking, rather there are adjustments made to the day ahead award following the RTM closely.

2.2.1 Relevance to Offshore Wind

Nothing would prevent an offshore wind installation from actively bidding into the RTM, although it can be riskier given the variable nature of the resource. However, a variable energy resource (such as a wind installation) has protections built into the market to mitigate some of these risks. For example, the CAISO requires all resources participating as a variable energy resource to provide (or purchase from the CAISO) a meteorological forecast specific to the likely output capability of the resource. The CAISO takes this forecast into account when reviewing bids, and will mitigate any bid promising a product which cannot be provided according to the forecast and resource characteristics. This reduces the risk of penalties for a resource failing to honor their award - penalties which can be significant, and also result in a resource being removed from market participation.

Even with the protections available, a very cautious bid strategy would need to be developed to limit the risk of unfulfillable awards. As with the day-ahead market opportunities, self-scheduling and competitive markets offer a trade-off between stability and potential profits. There is likely considerable value in a prototype offshore wind project exploring these issues as a blueprint for future projects. One option is to integrate energy storage as discussed in Section 3.5 about Hybrid Resources further below.

3. OTHER ASPECTS OF CAISO OPERATIONS

There are several other aspects of operations beyond simply matching energy demand with generation, as discussed in the day-ahead and real-time markets above. The more advanced products, discussed below, provide grid stability and resiliency over just meeting demand.

3.1 Ancillary Services (AS)

Ancillary Services are a market mechanism that values the different ways a generator can support a reliable grid through frequency and voltage support or dispatchable reserve power. These services provide a way for generators to generate revenue while providing the CAISO assurance that the stable grid operation can be maintained during unexpected demand or supply issues. There are two components of ancillary services: Regulation Up/Down and Spinning/Non-Spinning Reserves, which are described below.

3.1.1 Regulation Up/Down

Regulation Up/Down are methods of frequency control, where generators can increase (Regulation Up) or decrease (Regulation Down) the power output to adjust power supply to control grid frequency and stabilize any fluctuations. Depending on the resource type, regulation services must be dispatched nearly instantaneously so any plant providing this service must be connected to the CAISO Automatic Generation Control (AGC), which sends dispatch instructions every four seconds.

There are two ways to participate in the Regulation service within the CAISO market: bidding into the DAM and RTM as discussed above, or participating in the Regulation Energy Management market. In the Regulation Energy Management market, the CAISO is given full control of dispatching the resource, and the resource becomes unauthorized to participate in bidding.

3.1.2 Spinning/Non-Spinning Reserves

Similar to Regulation, Spinning and Non-Spinning Reserves provide dispatchable power to compensate when demand suddenly outpaces supply, for example if an operating plant goes offline. Spinning Reserves refer to capacity that can be sent to the grid from currently-operational (“spinning”) generators, whereas Non-Spinning Reserves refer to capacity that can be brought online in various time frames.

3.1.3 Relevance to Offshore Wind

The most reliable way for any wind installation to participate in the Ancillary Services market is with integrated, dispatchable energy storage. Without energy storage, the variable nature of wind resources brings added risks, but new technology and system management strategies enable wind power plants to provide AS.

Land-based wind systems have been able to provide Regulation Up frequency modulation using energy stored in rotor momentum, although this can only provide short-term regulation before the rotors lose enough energy to seriously curtail energy production (Morren, Pierik and de Haan 2006). A more versatile strategy to quickly dispatch energy is to deliberately shift normal turbine operations from maximum power point tracking (MPPT) to a less productive level, leaving unused capacity. When Ancillary Services are required, turbine operations can shift closer to the MPPT and dispatch additional energy. The unused capacity level can be set to a constant, or with sufficient forecasting and planning, a variable capacity. Recent tests at Tule Wind Farm demonstrated this concept. With advanced power plant controllers and slight curtailment, the wind farm was able to respond to the 4-second AGC signals, and provide regulation services (Loutan et al., 2020).

3.2 Resource Adequacy (RA)

Resource Adequacy is an organizational tool mandated by the California Public Utilities Commission (CPUC) to ensure an adequate level of energy resource is available at all times to meet expected peak demand. Load serving entities are required to provide a certain amount of RA, determined by rules developed by the CPUC and through agreements with the CAISO. Qualified energy providers may then contract to provide RA; if successful, they will be assigned a period of time and a set quantity of capacity they must be able to provide, regardless of other commitments. For example, a plant could be required to have 10 MW of available capacity from 12 p.m. - 4 p.m. on October 4th. An RA contractor may not necessarily end up providing this resource, but they must offer it into the CAISO market through a bid called a Must Offer Obligation.

If enough capacity is available and provides a better value, then the contractor will not need to provide the RA capacity they were assigned. RA can be thought of as a kind of insurance: RA resources provide a stable power supply for load-serving entities when normal operations cannot, and regardless of whether the extra capacity is actually needed, the RA provider will still be paid for reserving resources. However, if these obligations are not met when called on, payments can be revoked – even for times when they were not called.

3.2.1 Relevance to Offshore Wind

As a variable energy resource, offshore wind would have the RA capacity determined by the Effective Load Carrying Capacity method. Currently this method looks at historical production of a variable energy resource and sets the RA Qualifying Capacity at 70% of its historical output. As newly developed variable energy resources have no historical output, they often must wait to provide RA for at least one year. Offshore wind may fall into this category, and clarification should be sought before attempting to provide Resource Adequacy.

3.3 Congestion Revenue Rights

Congestion occurs when transmission lines are not rated to meet the load demand in a given local area. This can cause local fluctuations in energy prices, as generators that were otherwise not competitive are utilized to meet their local demand. These additional energy costs, referred to as Congestion Revenues, can be paid out through a variety of mechanisms. Which entities are responsible for these costs and which are entitled to these revenues are determined through Congestion Revenue Rights.

Congestion Revenue Rights can be purchased at a specific percentage of the congestion costs over specific time intervals, and they can be purchased between two nodes only, or between multiple nodes in specific arrangements. Purchasing these rights provide a way for a resource to hedge against profit losses due to congestion in the grid, but it is also another avenue to simply bring in revenues. Participants in the Congestion Revenue Rights market do not have to be a scheduling coordinator, and they do not have to be a resource in the CAISO energy or AS markets.

3.3.1 Relevance to Offshore Wind

An offshore wind installation could participate in Congestion Revenue Rights trading, and it may be particularly valuable in a transmission constrained area like Humboldt County. Recognizing that the implementation of a new resource would almost certainly impact congestion, it would be highly advantageous to develop a strategy to trading Congestion Revenue Rights in such a way as to make a profit.

3.4 Convergence Bidding

Convergence Bidding, also known as Virtual Bidding, is a market for participants to take a financial position by placing day-ahead market bids to be liquidated in the real time market – energy demand is bought at day-ahead prices and sold at real-time prices, and energy supply is sold at day-ahead prices and "purchased back" at real-time prices. But while virtual bids compete in the market alongside traditional supply and demand bids, they do not involve the buying or selling of actual energy, and do not affect any physical generation or load. Neither scheduling coordinators nor load serving entities are required to participate, and importantly, virtual bidding is not involved in grid reliability.

Given that Convergence Bidding is not linked with the production or consumption of energy, it is natural to wonder why it exists. While the simplest reason is legal (convergence bidding is required by the Federal Energy Regulatory Commission), Convergence Bidding also closes the gap between day-ahead and real-time prices, which prevents scheduling coordinators and load serving entities from withholding participation in one market to pursue better prices in the other. This balancing is competition based: virtual demand makes money if the energy price increases between the day-ahead and real-time market, while virtual supply makes money if the energy price decreases between day-ahead and real-time, so competition between these two positions will shrink the price gap. Convergence Bidding also provides a means for market actors to hedge risk based on the knowledge of their own operations.

3.4.1 Relevance to Offshore Wind

Assuming participation in the CAISO markets, any offshore wind development would be able to participate in convergence bidding. The relevance to wind generators would largely be the same for any other resource, to reduce risk, increase profit, and influence physical supply commitment in its favor.

3.5 Hybrid Resources

Hybrid Resources, broadly, are any combination of multiple generation technologies controlled by the same owner/operator, behind a single point of interconnection, and operating in the CAISO markets under a single resource ID. A common hybrid resource is a combination generation and battery storage resource. CAISO is in the process of completing the Hybrid Resource Initiative, which will implement the regulatory framework to allow hybrid resource projects to fairly participate in the markets. As this policy development is ongoing, the exact requirements of a hybrid resource are not yet finalized.

While the market products and instruments noted above do not change for hybrid resources, Hybrid Resources participate in different ways – for example, protections for variable energy resources may no longer apply. How Hybrid Resources can be profitable and what barriers they present will depend on the Hybrid Resource Initiative, set to be fully implemented by the fall of 2021.

3.5.1 Relevance to Offshore Wind

The most likely way for an offshore wind installation to become a hybrid resource would be to include integrated battery storage. Newer technology may enable other means of becoming a Hybrid Resource, such as floating platforms hosting both wave energy converters and wind turbines. Currently 40% of projects in the CAISO queue are Hybrid Resources, (CAISO, 2019) and it would be worthwhile for offshore wind developers to follow the Hybrid Resource Initiative.

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Chapter 7: Market Revenue Study

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Table of Contents

1. INTRODUCTION

This report provides an analysis of revenue generated from offshore wind farms for selling electricity through markets regulated by the California Independent System Operator (CAISO).

1.1 Purpose

If offshore wind power is developed in California, the projects will have access to several market revenue opportunities, including the resource adequacy market (RA), the energy market, and the ancillary services (AS) market. Chapter 6: describes the organization of these markets.

The purpose of this report is to make initial estimates of the revenue available given our assumptions about the generation profiles of California-based offshore wind and recent historical prices. This will help shed light on which of these markets could be financially viable for offshore wind to participate in, and to develop a quantitative understanding of the revenue streams and their magnitudes.

In order to provide context, market revenues are compared to four alternative renewable resource types: California solar, California land-based wind, New Mexico land-based wind, and Wyoming land-based wind. New Mexico and Wyoming were chosen because they are candidates for imports of wind energy into California.

1.2 Background

The background section describes how three relevant energy markets function in California: resource adequacy, energy, and ancillary services.

Resource adequacy (RA) is the mechanism in California to ensure adequate generation capacity is available to match peak loads and ramping needs on the system. Load serving entities are responsible for procuring RA in advance through bilateral contracts with qualifying generators. In order to qualify, the generators are required to offer bids in the energy market and to be available for generation. In the context of variable renewable energy like offshore wind, there is a “typical” coincident peak capacity factor for each resource type to define their estimated contribution to meeting these peak conditions on the power system, based on the characteristics of the project. This is called the effective load carrying capacity (ELCC) of that resource.

Energy and AS are dispatched in two integrated markets that are organized by the CAISO: the Day Ahead Market (DAM), and the Real-Time Market (RTM), both of which are available to offshore wind generators (Hundiwali, et al., 2019, P. 12). Energy markets pay generators based on the timing and location of energy generation, with markets that clear up to a day in advance (DAM) and as fast as 5 minutes ahead (RTM).

Participation in regulation up and regulation down AS markets requires the ability to respond to automatic generator control signals on a four second time step, which has been recently proven for land-based wind farms (Delparte, 2020a; Loutan and Gevorgian, 2020).

Bids into the energy and AS markets must be coordinated. Variable energy resources, such as offshore wind, are only able to bid a sum of AS and energy equal to the maximum available power of the generator (Delparte, 2020b, section 4.3). For example, a 2 MW wind farm with a forecast output of 1 MW for one hour could bid 1 MW into the energy market and 100 kW into the AS market, but CAISO would only award a sum total of up to 1 MW in regulation up and energy. For comparison, a conventional (dispatchable) 2 MW generator making the same bid could sell 1 MW into the energy market *and* 100 kW into the regulation up market. For offshore wind, as with any resource in general, participation in the AS market would mean forgoing the opportunity of potential energy revenue for regulation revenue. AS provides two types of revenue: payment is made to generators for holding capacity in reserve, and additional “mileage” payments are made based on a combination of CAISO’s dispatch signal and the generator’s capability to follow it (Sadeghi-Mobarakeh & Mohsenian-Rad, 201; Departe, 2020a section

4.3.1; Delparte, 2020c). For the purposes of this analysis, mileage payments are ignored, because historical CAISO data have shown their value to be small and actual mileage dispatches are unknown.

This report does not consider certain other revenue opportunities and mechanisms that are in principle available to offshore wind projects. These include financial participation in transactions for Congestion Revenue Rights and Convergence Bidding. Both of which could be entered into independently from offshore wind development. Our analysis also does not consider how offshore wind power could be paired with energy storage to improve the value of the resource (e.g., participation as a hybrid resource).

2. METHODS

In this section we first describe our method for estimating the annual generation profile of offshore wind and other resources. Then we describe how we used these to estimate a value for the available revenue through each mechanism under consideration.

2.1 Annual Generation Profiles

We estimate the typical annual hourly generation of six different resource types with a variety of associated methods. The profiles were created for hypothetical generators with 1 MW nameplate capacity.

For each resource, we develop an 8,760-hour annual load profile and estimate capacity factors using the formula below:

$$\text{Capacity Factor} = \frac{\text{Generation [MWh]}}{\text{Capacity [MW]}} \cdot \frac{1\text{ year}}{8760\text{ hours}}$$

2.1.1 Offshore Wind

The electricity generation profile for a 48 MW development in the BOEM call area was extracted from Chapter 1: An 8,760-hour annual profile for a possible 48 MW project was divided by 48 to create a profile normalized per 1 MW of nameplate capacity, and the capacity factor was extracted from this.

2.1.2 California Solar and Land-based Wind

We estimate the profile for in-state renewables by combining historical data on total energy generated and the timing of generation. We start with the historical quantities of in-state energy generation by fuel type and installed in-state electric generation capacity by fuel type (CEC, 2020) to estimate a typical annual capacity factor for both solar and wind across the entire state. Then, historical hourly profiles of generation and curtailment (CAISO, 2020c) from 2019, the most recent year on record, were scaled to match the estimated annual energy of a 1 MW project, based on the typical capacity factors calculated above.

2.1.3 California, New Mexico, and Wyoming Land-based Wind (Method 2)

A different method was used to generate profiles for New Mexico and Wyoming-based wind farms because rich datasets of historic wind generation were not available. This method was applied to California land-based wind as well, providing a more direct comparison to these results as well as a sensitivity analysis on California land-based wind. These results are referred to as “Method 2” to distinguish the results for California land-based wind.

Again, the first step was to calculate capacity factors by location. These relied on the EIA (2020a)’s data of net generation by state and energy source and existing nameplate by state and energy source and followed the method above.

We then use an hourly estimated wind power dataset (“80-Meter Hub Height (Current Technology)” (NREL, 2020)) which is scaled by the capacity factor to create generation profiles. The locations used for these data are shown in Table 7-1.

Table 7-1 Locations of representative wind farms.

State	*Nearby Project[1]*	*Project Hub Height[1]*	*Latitude*	*Longitude*
CA	Alta Wind Energy Center	80m	35.06	-118.40
NM	New Mexico Wind Energy Center	80m	34.73	-104.04
WY	Top of the World Wind Project	80m	43.07	-105.82

[1]Source: USGS (2020)

All of the calculated capacity factors are shown in Table 7-2. It is notable that offshore wind has a significantly higher capacity factor than other resources. In the context of renewable energy development on the north coast of California, where offshore wind could be developed first, the capacity factor for the offshore wind resource is much higher than solar development along the coast. The typical solar capacity factor in Humboldt County is approximately 15%, while statewide the solar generators have nearly double the capacity factor, reflecting higher irradiance in other regions of California (EIA, 2020b).

Table 7-2 Calculated capacity factors by development type and location along with their seasonal variation, as measured by the coefficient of variance across the seasonal average capacity factors.

Development	*Calculated Capacity Factor*	*COV of Seasonal Average Capacity factor*
Humboldt Call Area Offshore Wind	48.2%	9.3%
CA Solar	26.5%	32.7%
CA Land-based Wind	26.1%	35.2%
CA Land-based Wind (Method 2)	26.3%	27.3%
NM Land-based Wind (Method 2)	38.3%	24.1%
WY Land-based Wind (Method 2)	31.1%	24.3%

Seasonal average generation profiles for the modeled resources are illustrated in Figure 7-1. This report consistently follows meteorological season definitions in which winter is all of December, January, and February, spring includes all of March, April, and May, and so forth. Offshore wind clearly has the flattest output across the typical day, with land-based wind resources generally displaying a midday dip and solar with an expected diurnal pattern following day and night. The seasonal variation seen in Figure 7-1 is also summarized at a high level in Table 7-2 through an estimate of the coefficient of variance (COV, the standard deviation of seasonal capacity factor divided by the annual capacity factor). Offshore wind has by far the least seasonal variation, with a COV of 9%. Other resources have seasonal variability 2.6 to 3.8 times as high, with significant differences in California's land-based wind across the two methods of computation.

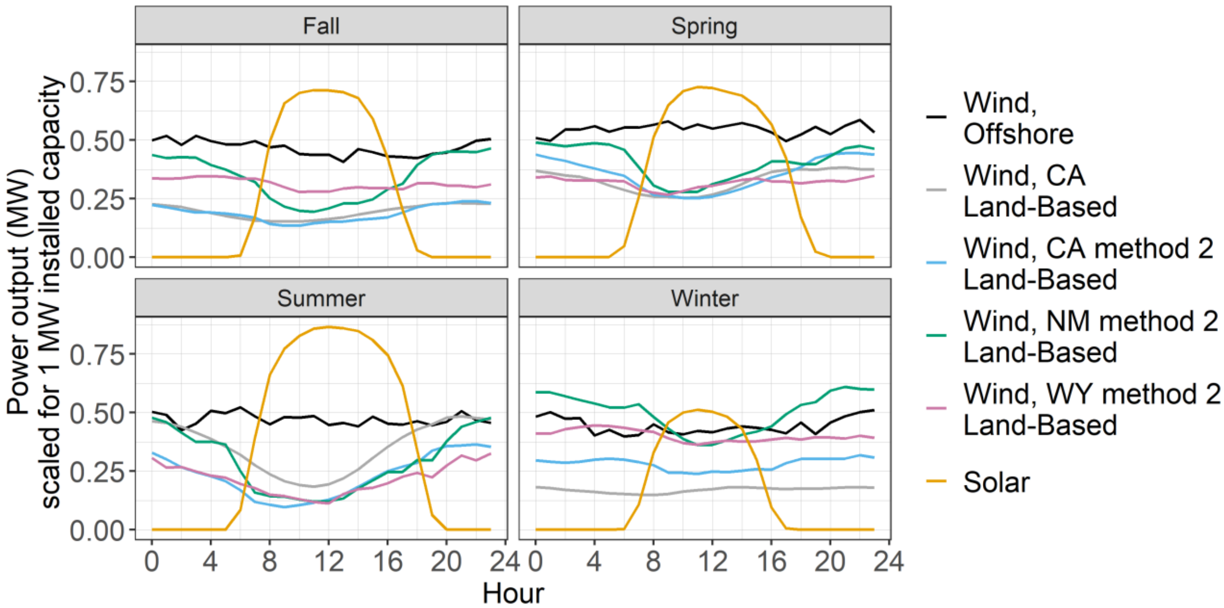

Figure 7-1 Seasonal average hourly output from a modeled 1 MW facility.

2.2 Revenue Generation Model

We use these capacity factors and generation profiles to estimate revenue across a range of opportunities. First, the Resource Adequacy market is considered, which, as will be explained below, is analyzed entirely independently of the other markets. Second, the methods used to develop hourly annual value of energy and AS in each market are discussed. Third and finally, the generation and value profiles are synthesized into annual revenue and average electricity values.

2.2.1 Resource Adequacy Market

Renewable resources such as solar and wind can sell a fraction of their nameplate capacity in the RA market each month. This fraction is based on the *expected* electricity generation or capacity factor of the resource during peak demand times, determined through CPUC's effective load carrying capability (ELCC) modeling. ELCC values have historically been updated annually. The fraction varies by month and resource type (CPUC 2019), split only into solar and wind, with no discrimination between onshore and offshore wind. The latest available values were found in CPUC (2020) "2020 NQC List for CPUC RA Compliance May 22, 2020 Version." CPUC (2019) includes weighted average price per kWh, projected as far as 2022. As this is the date closest to likely wind farm deployment, 2022 was used. Annual revenue is the product of the monthly RA fraction, the RA price, and the wind farm size, summed across the year. Results in this report are given on a per MW (of development) basis.

2.2.2 Hourly Energy and AS Value Profiles

In order to determine the value of energy in the DAM and RTM and the value of AS in the DAM and RTM, market clearing prices at a number of pricing nodes were extracted from the CAISO OASIS database (CAISO, 2020a; 2020b). In the DAM, both AS and energy are sold on an hourly basis, and thus have a price determined for each hour of the year. In the AS RTM, services are sold every 15 minutes, while in the energy RTM bids clear every five minutes. In order to align with generation profiles, values were averaged across each hour.

Based on the study by PG&E (2020), there are multiple regions through which electricity could flow or be sold, including Humboldt, the main corridor in the central valley, Vacaville, and the San Francisco Bay Area. To understand variation across space, prices were analyzed at eight nodes across northern California, enumerated in Table 7-3. Locations are shown on the map in Figure 7-2.

Table 7-3. Nodes at which energy prices were analyzed.

Location	*Pricing Node*
Humboldt	HMBUNIT2_7_GN010
San Francisco	BAYSHOR2_1_N001
South SF Bay	OLS-AGNE_7_N001
East SF Bay	RICHMOND_1_N004
Cottonwood	ANDERSON_6_N001
Round Mountain	CEDRCRK_6_N101
Table Mountain	OROVILLE_6_N102
Vacaville	VACAVIL_1_N102

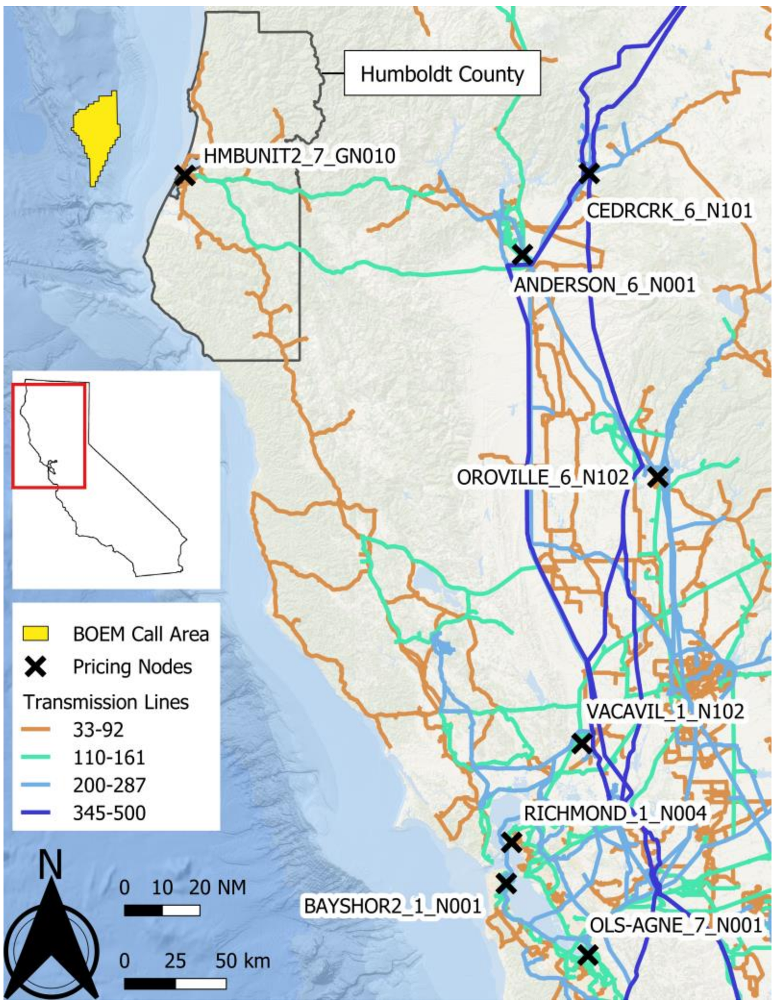

Figure 7-2. A map of pricing node locations analyzed in this report. Also shown are existing transmission lines in northern California.

Seasonal average hourly energy market clearing prices at four nodes are shown in Figure 7-3 for the DAM and RTM. Prices in both markets generally fall between $25 and $50 per MWh, but there is significant variation across the hours and seasons. Midday price troughs caused by the significant deployment of solar PV so far in California suggest that additional electricity generated from solar (without storage) will generally be less valuable than electricity generated from wind, particularly land-based wind which tends to have a midday generation trough.

No clear trend is visible between the RTM and the DAM, aside from random variability between them, and trends across nodes are small.

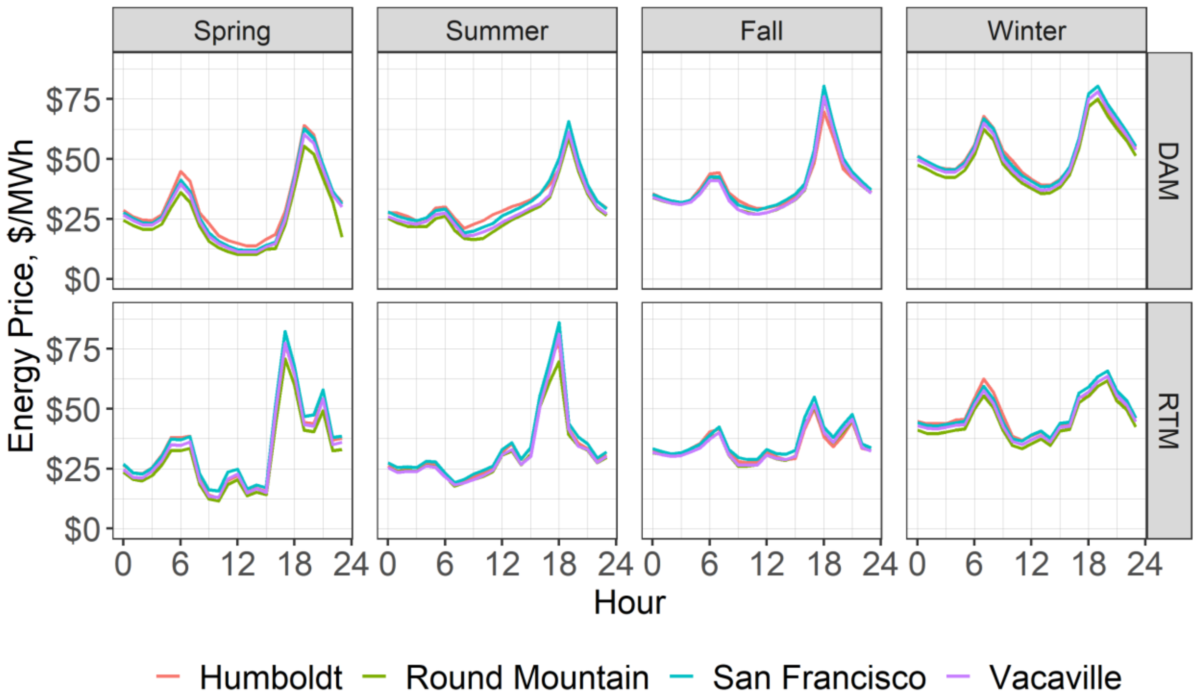

Figure 7-3 Seasonal average electricity price in the DAM and RTM in 2019 across a representative sample of nodes.

2.2.3 Hourly Ancillary Services Value Profiles

Ancillary Services are not transacted at specific nodes like energy, but in two regions and eight sub-regions (CAISO, 2019, section 8.3.3). AS regional prices are built up from larger to smaller regions: the price in a particular sub-region is equal to sum of the shadow price in that subregion, plus the shadow price in the system region, plus the shadow price in the expanded system region. Per Delparte (2020b) “the Ancillary Service Marginal Price of a reserve in a sub-region will always be higher than or equal to the price of the same reserve in the outer sub-region or Expanded System Region.”

The AS prices for our analysis of offshore wind are estimated using the sum of the Expanded System Region, the System Region, and the NP26 subregion which includes NP15 and ZP26 in Figure 7-4. Seasonal average hourly ancillary services market clearing prices in the DAM and RTM are shown in Figure 7-5. As mentioned above, the “total” price is the sum of three nested regions. AS prices are highest in spring and the hours 16:00 to 20:00 but are generally quite low, below $10/MWh. This leads to the hypothesis that the AS market will not be a lucrative market for offshore wind, which will be explored further in the Results section.

Figure 7-4 CAISO sub-regions. NP26 includes NP15 and ZP26. Source: http://oasis.caiso.com/mrioasis/logon.do

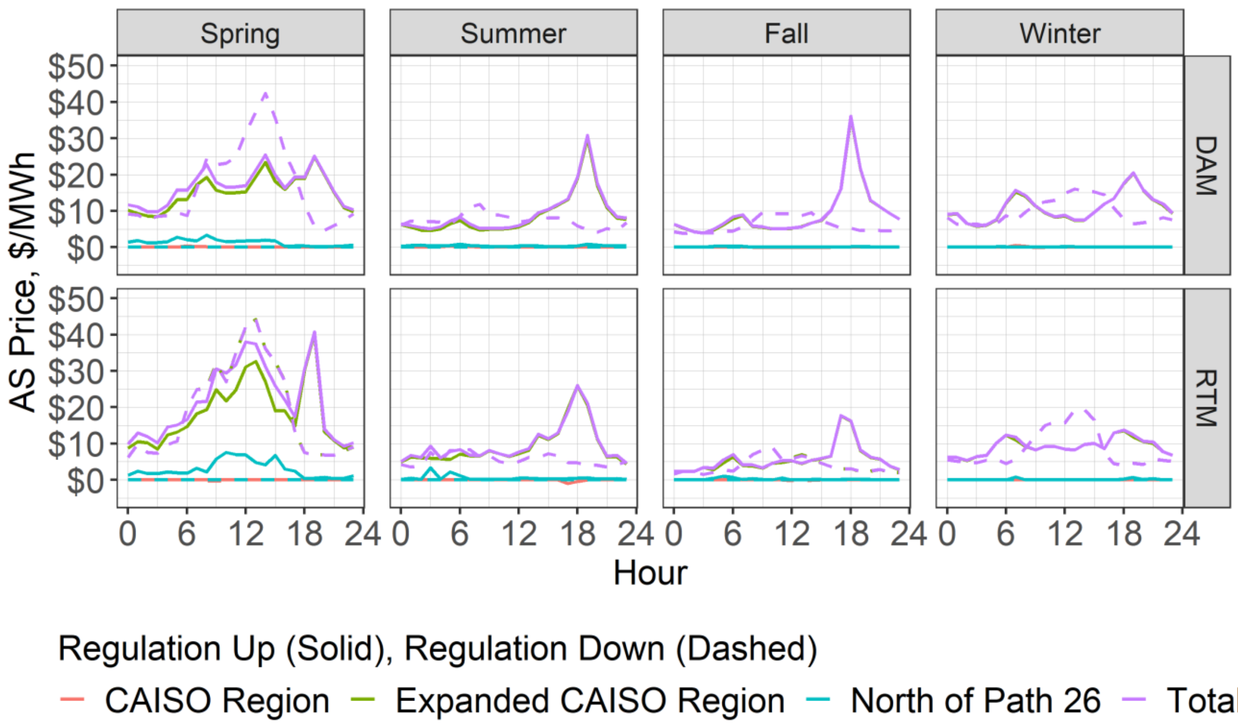

Figure 7-5 Seasonal average price of ancillary services in 2019 in the RTM and DAM.

2.2.4 Average Electricity Value and Annual Revenue Calculation

Generating energy and AS market revenue requires placing a bid into the market that is at or below the market clearing price, then operating the power plant as dispatched. For zero-marginal-cost energy sources such as wind and solar, which do not incur fuel costs, it is typical to bid $0.00 (i.e., be a "price taker"), since all bidders are awarded the market clearing price, not their bid prices. This allows for a near-maximization of revenue. Renewable energy producers with a production tax credit (PTC) will typically bid the negative of their PTC, as it is profitable to pay up to the PTC value, which depends on the details of projects and the available tax credits when they were developed. For example, a wind project with a PTC of $15/MWh from the federal government, may be willing to pay up to $15/MWh to generate electricity (Huntowski, et al., 2012). Developments which begin construction before December 31, 2020 are currently eligible for a PTC of $15/MWh, but this tax credit has not been extended beyond the end of 2020 (DOE, 2020). Therefore, for this analysis, the influence of production tax credits was not included, and thus all renewable energy producers are assumed to bid $0.00 at every time interval.

The revenue at each node was then calculated as the product of energy produced and price at each hour where the clearing price met or exceeded the bid ($0.00), summed up over the year. The average value of electricity produced was calculated as the revenue divided by the total energy produced by the farm (regardless of whether it was sold in the market).

Revenue and average value of sold electricity have an independent outcome for each of the six possible developments in Table 7-2 at each of eight nodes in Table 7-3, 48 in total.

3. RESULTS

Summarizing our overall results, Table 7-4 illustrates the potential yearly revenue for three hypothetical 1 MW renewable energy facilities. More details on the various revenue pathways are summarized in subsequent sections below.

The estimated total revenue for each project type in Table 5 includes contributions from energy market participation, deploying up to 10% of generation capacity into the AS market with perfect market information, and selling capacity credit with typical values of RA for California. The total revenue per installed MW for offshore wind is approximately a factor of two higher than land-based wind or solar. This is due to its high capacity factor and greater overall energy generation for each installed MW. However, the unit value per kWh of the electricity generated is approximately the same across each resource type.

All of our results are presented with a significant caveat: They depend on historic data for prices and market conditions, which may change significantly in the future. Examples of factors driving change in future outcomes are transmission changes, load shape changes due to electrification, and increased penetration of distributed energy resources like solar, storage, and electric vehicles.

Table 7-4 Annual revenues and generation, and effective value of electricity generated by offshore wind and two illustrative alternatives, with energy sold at the Humboldt node. Revenues are reflective of a 1-MW facility.

	Development		
	Offshore Wind	*CA Land-Based Wind*	*CA Average Solar*
Energy Revenue ($/yr)	$153,000	$79,000	$71,600
Additional AS Revenue[1] ($/yr)	$1,400	$908	$1,570
RA Revenue ($/yr)	$6,780	$6,780	$5,060
Total Revenue[1] ($/MW•yr)	$161,000	$86,700	$78,200
Electricity Generated (MWh)	4220	2290	2320
Effective Value ($/MWh)	$38.20	$37.90	$33.70

[1]Up to 10% of hourly output is sold into the AS market, following Loutan and Gevorgian (2020).

3.1 Resource Adequacy Revenues

Table 7-5 shows the fraction of nameplate capacity that can be sold in the RA market, its projected price in 2022, and the resulting revenue. These are based on onshore wind resources since there is no standard assumption available currently for the RA fraction from offshore wind. RA revenue for a California land-based wind farm is 34% greater than revenue for a solar development of equal nameplate capacity. If offshore wind is installed and operated, a higher RA fraction will likely be appropriate based on the actual characteristics of generation and will likely be higher than what is shown in Table 4, given the significantly higher capacity factors for the offshore resource. Thus, our results for offshore wind are indicative of a lower-bound estimate, benchmarked to land-based wind.

Table 7-5 Resource adequacy revenues for a 1 MW resource. No differentiation is made between onshore and offshore wind (CPOC, 2020).

	RA Fraction		*RA Price, $/MW*	*Period Revenue, $/MW*	
Month	*Wind*	*Solar*	*Both*	*Wind*	*Solar*
Jan	0.14	0.04	$2,960	$414	$118
Feb	0.12	0.03	$2,960	$355	$89
Mar	0.28	0.18	$2,960	$829	$533
Apr	0.25	0.15	$2,960	$740	$444
May	0.25	0.16	$2,960	$740	$474
Jun	0.33	0.31	$2,960	$977	$918
Jul	0.23	0.39	$2,960	$681	$1,154
Aug	0.21	0.27	$2,960	$622	$799
Sep	0.15	0.14	$2,960	$444	$414
Oct	0.08	0.02	$2,960	$237	$59
Nov	0.12	0.02	$2,960	$355	$59
Dec	0.13	0.00	$2,960	$385	$0
Annual	-	-	-	$6,778	$5,062

3.2 Energy Market Revenue and Values

The total revenue from energy market participation is summarized in Figure 7-6 Projected monthly average energy market revenue from simulated 1 MW facilities, based on 2019 CAISO market clearing prices at the Humboldt node.Figure 7-6 - Figure 7-10, showing the seasonality and annual total revenue expected from the various resources we analyzed.

Revenue in the RTM and the DAM across the year for various developments are shown in Figure 7-6, showing similarity in the average prices between the markets for each resource. High market prices in winter combine with a consistent offshore wind resource to boost its value during that season, while all the resources are similar in terms of revenue per MW in the summer.

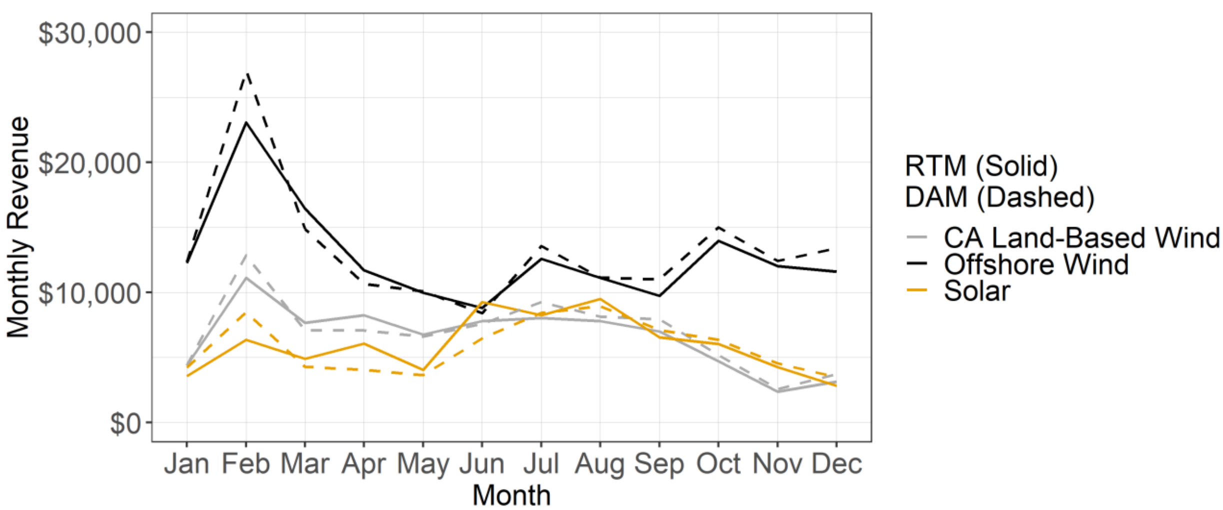

Figure 7-6 Projected monthly average energy market revenue from simulated 1 MW facilities, based on 2019 CAISO market clearing prices at the Humboldt node.

Figure 7-7 depicts the annual revenues of the various renewable energy types we considered across the studied nodes for a hypothetical 1 MW project. This figure assumes that all produced electricity is offered into the depicted market (DAM or RTM energy markets) at a bid of $0.00, with no production tax credit. They also assume perfect fidelity in output prediction (this is, naturally, a larger assumption for the DAM). There is some, though not a great divergence, between the DAM and RTM market prices across this period. For a given nameplate capacity, offshore wind would generate the most revenue, by a significant margin. This result is independent of where the energy is sold.

For all development types and market, interconnection at the Humboldt and the San Francisco Bay pricing nodes generate the most revenue, while those in the main corridor in the Central Valley, Table Mountain, Round Mountain, Cottonwood, and Vacaville tend to generate slightly less.

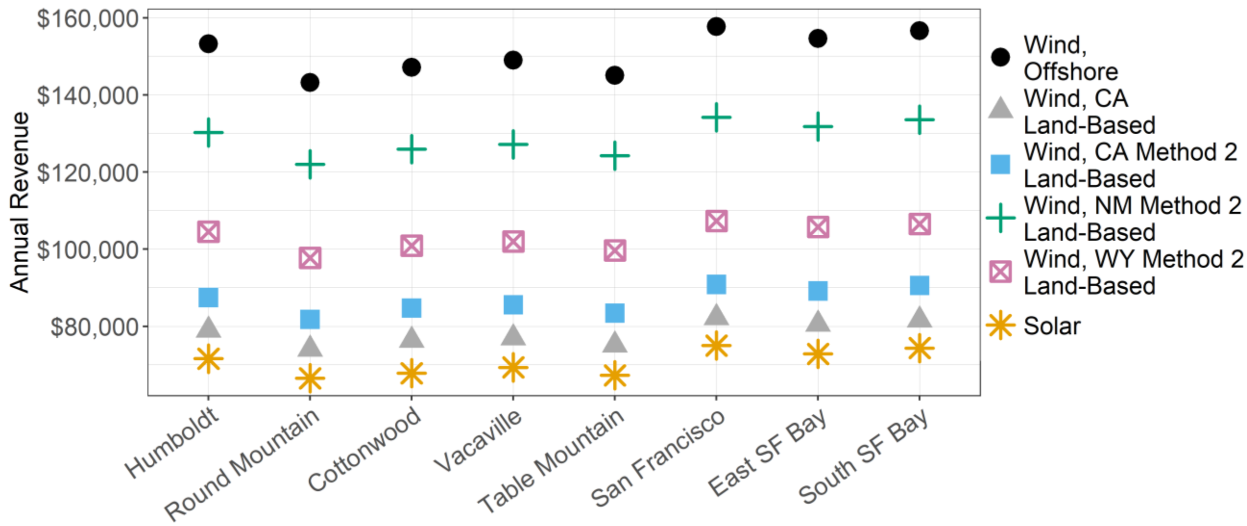

Figure 7-7 Projected revenues from simulated 1 MW facilities at all considered nodes, based on 2019 CAISO RTM market clearing prices. See Appendix 0 for raw data.

Looking at the unit value of electricity produced (per MWh), shown in Figure 7-8, land-based wind with profiles generated from method 2 produce the most valuable electricity, while solar produces the least valuable electricity. Offshore wind and California land-based wind calculated via method 1 produce electricity with similar values.

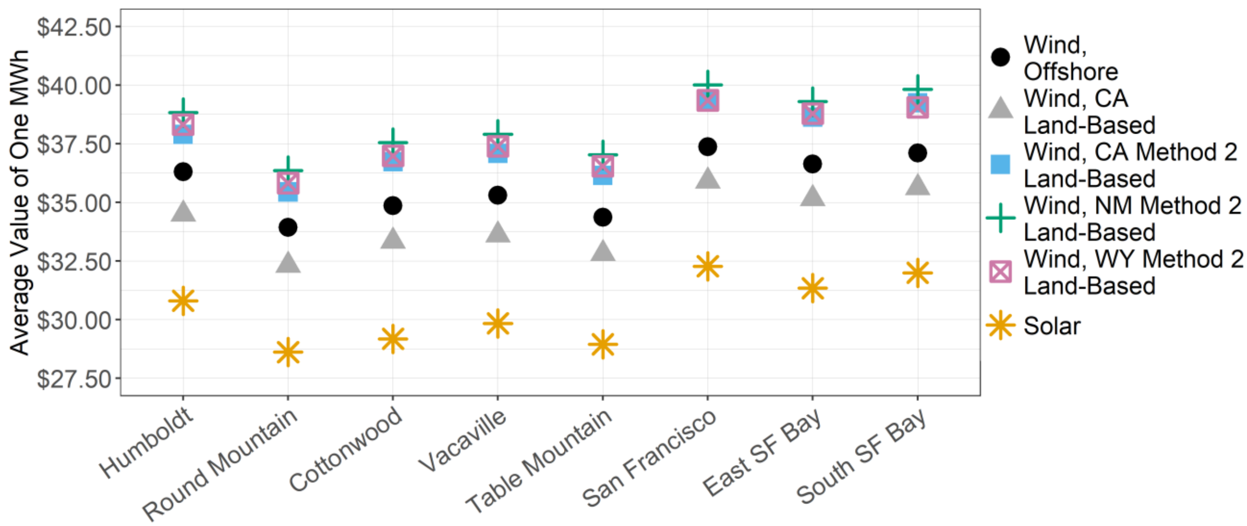

Figure 7-8 Average electricity selling price from simulated 1 MW facilities at all considered nodes based on 2019 CAISO RTM market clearing prices. See Appendix 0 for raw data. Note that zero is not included in the y-axis to enable emphasis on the differences between various resources and between nodes.

Figure 7-9 and Figure 7-10 show the price trend over time in the RTM and DAM, respectively. These show a subset of previously studied technologies to allow for a clear visualization of the broad trend in energy prices. For all nodes except San Francisco, prices have trended slightly downwards for the past three years from around $40/MWh to $30/MWh (Figure 7-9). Prices at the San Francisco node have increased over this period, driven by a price spike relative to other nodes in early 2019, and relatively high prices during the second half of 2019. Prices at the San Francisco node have returned to normal relative to the other nodes during the first half of 2020.

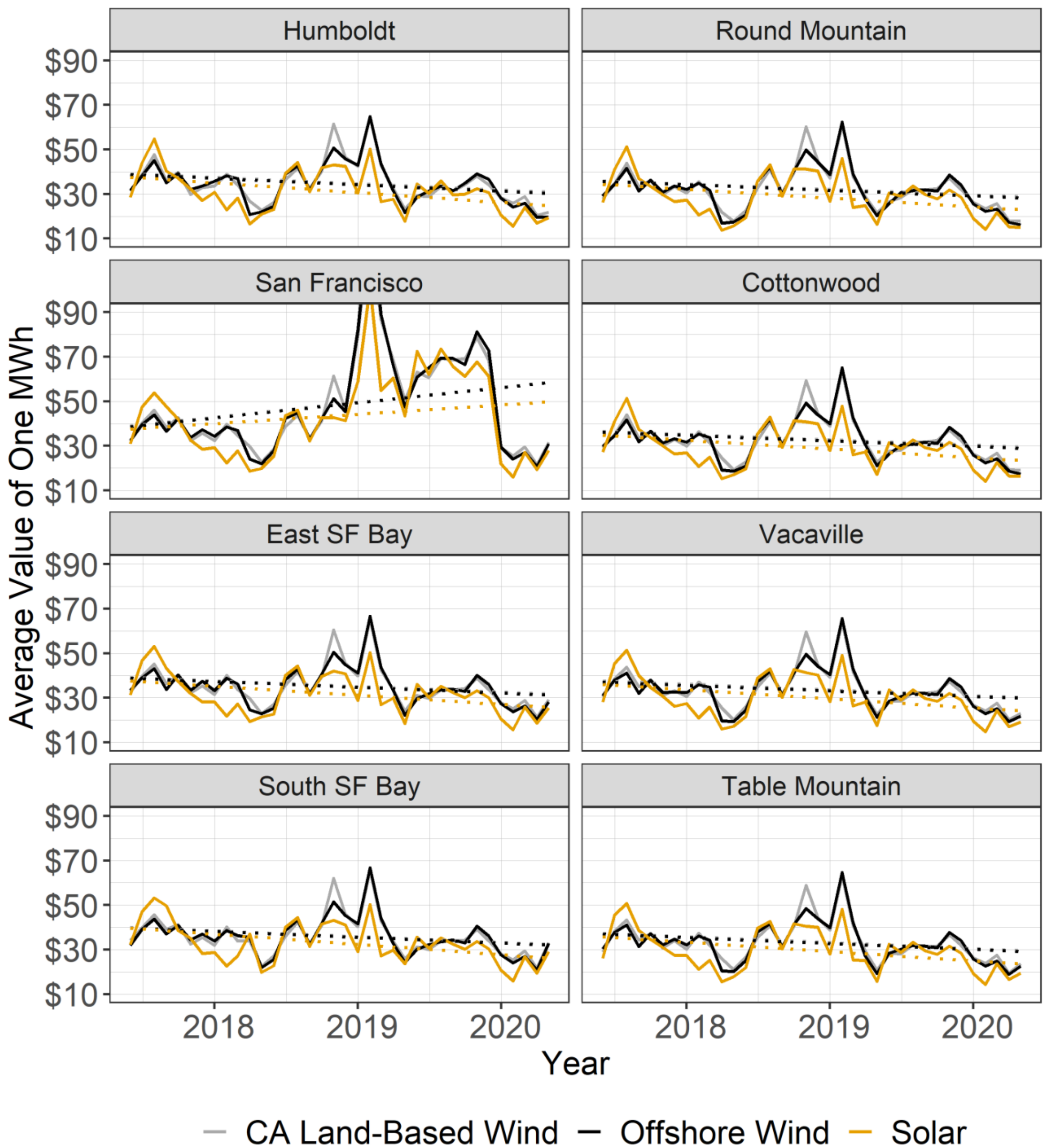

Figure 7-9 Average monthly value of electricity for various renewable energy developments across studied CAISO nodes (see Table 7-3) from July 2017 to July 2020 in the Real-Time Market. A simple linear trend for each is shown with a dashed line. Note that the land-based and offshore wind trend lines are nearly coincident. The year tick marks the beginning of the associated year. In February 2019, values in San Francisco exceed the chart range, at $131.4, $134.6, and $101.5 per MWh of land-based wind, offshore wind, and solar, respectively.

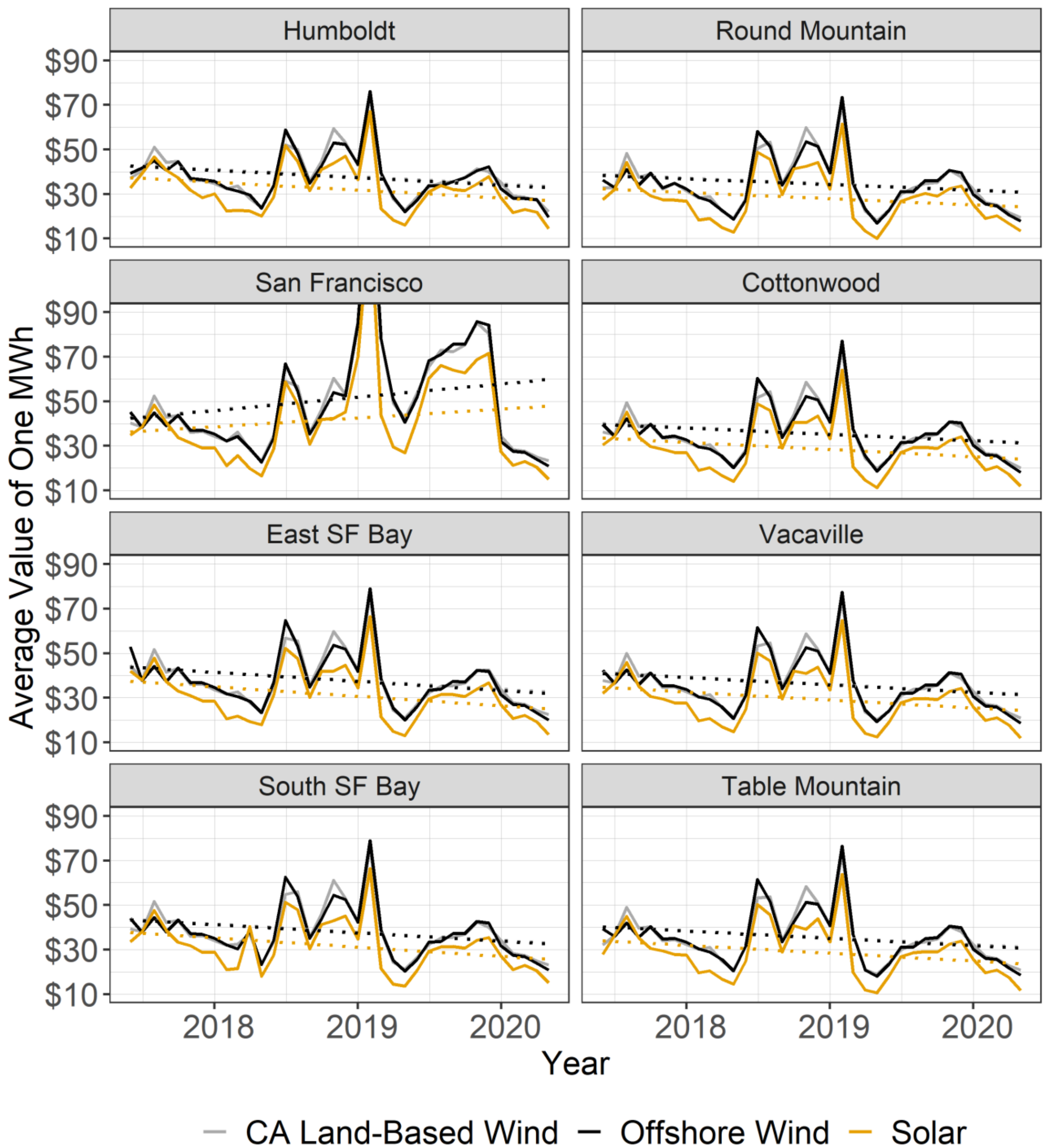

Figure 7-10 Average monthly value of electricity for various renewable energy developments across the studied CAISO nodes (see Table 7-3) from July 2017 to July 2020 in the Day-Ahead Market. A simple linear trend for each is shown with a dashed line. Note that the land-based and offshore wind trend lines are nearly coincident. The year tick marks the beginning of the associated year. In February 2019, values in San Francisco exceed the chart range, at $153.2, $158.9, and $133.9 per MWh of land-based wind, offshore wind, and solar, respectively.

3.3 Integrated AS-Energy Market Revenues

In order to develop a best-case assessment of the value which the AS market provides to offshore wind, hourly AS prices were combined with hourly energy prices. Figure 7-11 compares the monthly revenue in the energy market only (in teal) with the revenue if the generator had perfectly bid the entirety of its capacity into the market (among energy, regulation up, and regulation down) which ended up clearing at the highest price in that hour (in red). This comparison was performed at the Humboldt pricing node (HMBUNIT2_7_GN010) using 2019 data. It should also be noted that the proof of concept tests showing that wind farms can provide frequency regulation services occurred with the turbines operating with 10% headroom, meaning that they could only sell 10% of their hourly production potential on the AS market (Loutan and Gevorgian, 2020). Thus, the potential increases in value shown in Figure 7-11 would only be available to 10% of the energy produced by the facility.

Revenues for several months (March, April, and May) are noticeably higher with integrated market participation, reflecting a number of hours in these months in which AS were more valuable than the equivalent energy. However, fully capturing these differences would require an unrealistic level of accuracy in predicting market prices, since bids must be made before clearing prices can be established. In this omniscient case, annual revenue is 8% higher, at $171,000 compared to $158,000 with participation only in the energy market. Thus, AS market participation has the potential to provide additional revenue for offshore wind development but would require a sophisticated bidding strategy.

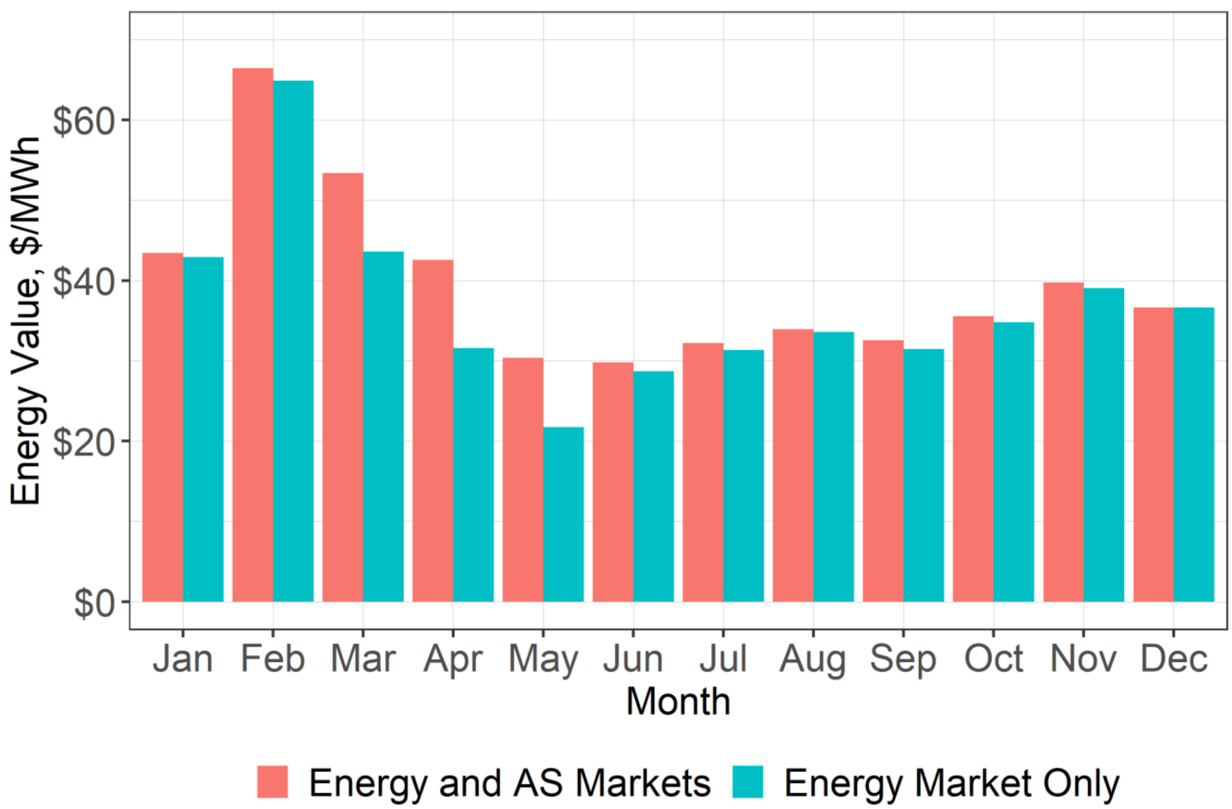

Figure 7-11 Monthly revenues derived from 2019 CAISO data from the RTM at the Humboldt node, showing energy market only compared to a prescient bidding strategy combining AS and energy markets.

4. DISCUSSION AND CONCLUSION

Overall, the expected revenue available per MW of offshore wind is significantly higher than land-based wind or solar. This is due to the higher overall energy generated (expressed as a higher capacity factor). Each megawatt of installed offshore wind generates more megawatt-hours. However, the value per MWh of offshore wind is approximately the same. Based on our analysis, approximately 4% of the annual revenue is through RA capacity payments, 1% through participation in ancillary services markets, and 95% through generation of energy and participation in energy markets.

Significantly higher winter month resource adequacy (RA) and energy payments for offshore wind compared to solar and persistently high revenue through other seasons lead to far higher revenues on a per MW basis. Offshore wind energy is 20% more valuable than solar on average, due to solar's low generation in the evening and during winter months, the most expensive time of day and season, respectively.

When compared to out-of-state, land-based wind resources, offshore wind loses some of its edge. RA payments are equal for the two resources[5], and the value of Humboldt's offshore wind energy is on par with California land-based wind and lower than the studied sites in California, New Mexico, and Wyoming. New Mexico and Wyoming wind are more valuable because their generation is higher in the winter and evening hours – when electricity is most expensive – compared to the relatively flat offshore wind generation. Where Humboldt Bay's offshore wind has an advantage is in its capacity factor of 48% compared to 26-38% for the studied land-based resources. This higher capacity factor drives significantly higher annual revenues for the same scale generator. Cape Mendocino offshore wind (following from the analysis in Chapter 1:) has a higher capacity factor, 57%, which would drive 20% to 21% higher energy revenue across the eight studied nodes.

Differences in nodal energy prices are relatively significant based on historical trends. Prices in Humboldt and the San Francisco Bay are 10% higher than those in the Central Valley, creating up to 10% more energy revenue in these regions for offshore wind. This implies that the choice of transmission infrastructure – whether subsea cables connecting the wind directly to the San Francisco Bay, or a line through the Central Valley – may influence the value to the energy in the market.

Energy prices and attendant market revenues have fallen over the past three years in both the day-ahead and the real-time markets, except in the San Francisco region. The DAM and RTM are approximately the same across technologies, except that the implied value for solar generation has seen greater declines in the RTM over this period. However, it is important to note that there is significant variability and the trend is not monotonically decreasing. There was a significant increase in price during late 2018 and early 2019 compared to other years, and there is a seasonal cycle of prices that is larger than the year to year trend of the decline.

Participation in regulation up and regulation down ancillary services could drive additional revenue to an offshore wind development, but accurately estimating the possible revenue for a real-world project would require modeling that is beyond the scope of this analysis. If perfect foresight were possible, the potential revenues are 9% higher for a resource that perfectly bids into AS vs. energy in each time step. Current evaluations have shown that wind can sell 10% of its output capability in the RA market, shrinking this potential opportunity to a 0.9% increase in revenue.

These estimates for revenues potential from offshore wind are intended to be a starting point for identifying pathways to value for projects and identifying where additional work is needed to better understand the opportunity. Since the majority of revenue is from the energy market, understanding possible trends in future energy prices could be important, particularly given the trend towards lower

[5] RA payments are independent of a specific development's capacity factor and are defined based on typical performance of a resource. In our analysis we used established values for land-based wind to estimate the RA value of offshore wind, which could be higher in practice.

prices over time. The capability of land-based wind to provide AS has been demonstrated, but the overall potential value is likely ~1% of energy market revenue, indicating a niche role. For RA value, our analysis used existing land-based wind as a benchmark and likely lower bound for the capacity value around 5% of the revenue in the energy market. Additional work to establish the typical expected contribution to peak capacity by offshore wind could result in higher real value. If the RA value factor were approximately scaled with capacity value, the RA value of offshore wind could be about double what we assumed.

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APPENDIX 7.A - REAL-TIME MARKET REVENUES AND ENERGY VALUES

This appendix summarizes the annual revenues and average energy market value per MWh of electricity for each studied resource type at each assessed location.

7.A.1 RTM Revenue Table

Table 7-6 shows the annual revenue in the real-time market for each of the development types discussed in this report.

Table 7-6 Real-Time Market annual revenues for modeled resource types at a scale of 1 MW

Location	*Offshore Wind*	*Solar*	*CA Land-based Wind*	*CA Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*
Cottonwood	$147,158	$67,823	$76,361	$84,743	$125,985	$100,902
San Francisco	$157,772	$75,011	$82,232	$90,850	$134,238	$107,341
Round Mountain	$143,269	$66,508	$74,018	$81,785	$121,994	$97,723
Humboldt	$153,250	$71,595	$79,017	$87,451	$130,296	$104,510
South SF Bay	$156,646	$74,362	$81,584	$90,545	$133,624	$106,523
Table Mountain	$145,059	$67,283	$75,148	$83,400	$124,263	$99,666
East SF Bay	$154,661	$72,850	$80,505	$89,150	$131,849	$105,806
Vacaville	$149,056	$69,353	$76,971	$85,568	$127,200	$101,987

7.A.2 RTM Energy Value Table

Table 7-7 shows the mean value of electricity produced and sold in the real-time market for each of the development types discussed in this report. Total revenue is divided by total generation, not by the quantity of energy that is sold into the market (i.e. unsold energy decreases the average value).

Table 7-7 Real-Time Market average value of one MWh of electricity for modeled resource types.

Location	*Offshore Wind*	*Solar*	*CA Land-based Wind*	*CA Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*	*NM Land-based Wind, Method 2*
Cottonwood	$34.86	$29.18	$33.34	$36.73	$37.55	$36.99
San Francisco	$37.38	$32.28	$35.90	$39.37	$40.01	$39.35
Round Mountain	$33.94	$28.62	$32.32	$35.44	$36.36	$35.82
Humboldt	$36.30	$30.81	$34.50	$37.90	$38.83	$38.31
South SF Bay	$37.11	$32.00	$35.62	$39.24	$39.82	$39.05
Table Mountain	$34.36	$28.95	$32.81	$36.14	$37.03	$36.54
East SF Bay	$36.64	$31.35	$35.15	$38.64	$39.29	$38.79
Vacaville	$35.31	$29.84	$33.61	$37.08	$37.91	$37.39

Chapter 8: Economic Viability of Offshore Wind in Northern California

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EXECUTIVE SUMMARY

The objective of this report is to model the potential economic viability of several offshore wind (OSW) farm scenarios sited offshore of northwestern California and served by the Port of Humboldt Bay, California. Broadly speaking, economic viability refers to the prospects for a wind farm project to successfully attract private-sector investment for wind farm buildout and commercial operation. The scenarios include two sites, both of which occur in federal waters – one the BOEM call area offshore from Humboldt Bay, California, and the second a notional alternative site offshore from Cape Mendocino, California. Scenarios also include three farm sizes ranging from 44 to 1,836 megawatts (MWs). As large-scale transmission infrastructure upgrades are usually paid for in California using rate-based funding such as Transmission Access Charges (TACs), rather than power purchase agreement (PPA) prices, transmission upgrade costs were not included in the economic viability analysis, but total transmission improvement costs are reported and discussed. In particular, the total capital cost for necessary transmission improvements scales directly with OSW farm size, with the largest farm size (1,836 MW) scenarios requiring an estimated $1.40 – 4.47 billion in transmission investment. The higher end of the range represents a subsea cable option for moving energy from generation to load centers in the San Francisco Bay Area.

Economic viability is modeled using the most current available version (2019.12.2 Beta) of the System Advisor Model (SAM) developed and distributed by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). The analysis makes use of default parameters built into SAM and customized parameters and elements from the OSW cost model developed by the Schatz Center project team. Key customized parameters from that cost model include capital expenditures ("CapEx") and operating expenditures ("OpEx"). These OSW cost model elements (all in constant 2019 dollars and adjusted for scenario construction start dates) were estimated by the project team using both bottom-up modeling as well as cost factors drawn from the literature. Other customized elements include a weather data file for wind resource at the sites under study, and specifications for a 12-MW turbine system.

Two financing structures were studied – a PPA single-owner project and a PPA sale-leaseback arrangement. In the assumed absence of federal production or investment tax credits (PTC, ITC) for new OSW projects in the mid-2020s, no tax equity "flip" structures were considered. As PPA prices are not readily available, instead the project team set an internal rate of return (IRR) target of 11% by year 20 of the project, and had SAM estimate a real levelized PPA price necessary for the project to deliver the target return. Analysis of SAM outputs indicate that only the largest farm size (1,836 MW) scenarios under study, using a single-owner financing arrangement, have economic viability potential, meaning that the estimated real levelized PPA price is roughly within range of market potential. Factors such as resuming the availability of federal tax credits, sharply increasing demand for renewable energy, or reduced project costs (such as from technology experience linked to expanded installed capacity) would improve the economic viability of offshore wind farms in northern California. Floating-platform OSW project cost reductions lag fixed-bottom OSW project costs by 5-7 years and are expected to converge in the early 2030s (Musial, 2020).

Table of Contents

1. INTRODUCTION

The objective of this report is to model the potential economic viability of several offshore wind farm development scenarios sited offshore of northwestern California and served by the Port of Humboldt Bay, California. Broadly speaking, economic viability refers to the prospects for a project to successfully attract private-sector investment for wind farm buildout and commercial operation. Economic viability is modelled using the most current available version (2019.12.2 Beta) of the System Advisor Model (SAM) developed and distributed by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL). SAM is a techno-economic computer model that calculates performance and financial metrics of renewable energy projects, including offshore wind farms (Blair et al., 2018).

We begin the chapter with a discussion of the methods and approaches used in the analysis, including a summary of how the SAM model works, the customized scenario inputs we developed, and the financial and other types of analysis we employed. We then summarize the results of the analysis and provide concluding comments.

2. METHODS AND APPROACHES

In the analysis that follows we draw upon project scenarios for various configurations of a commercial offshore wind (OSW) farm sited offshore of northwestern California and served by the Port of Humboldt Bay, California. The OSW farm is assumed to sell energy to load-serving entities by way of a power purchase agreement (PPA). This introductory description closely follows Blair, et al. (2018). Generally speaking, renewable energy projects sell electricity at a fixed price with optional annual escalation and time-of-delivery (TOD) factors. For such projects, SAM derives a number of financial metrics, including:

- Levelized cost of energy
- PPA price or internal rate of return (IRR)
- Debt fraction or debt service coverage ratio

SAM can either calculate the IRR based on a power price one specifies or calculate the PPA price based on a target IRR that one specifies. As PPA price data are proprietary and not available for this analysis, we took the approach of specifying an IRR (the 11% SAM default value) and having SAM estimate the implied required PPA price schedule.

SAM calculates the levelized cost of energy (LCOE) from after-tax cash flows, so that the LCOE represents the cost of generating electricity over the project life. As Blair, et al. (2018) note, project annual cash flows relevant to a commercial OSW farm selling energy through a PPA include:

- Revenues from PPA-mediated electricity sales
- Wind farm capital costs and operating, maintenance, and replacement/repair costs
- Loan principal and interest payments
- Tax benefits and liabilities (accounting for any available tax credits for which the project is eligible)
- Investor's IRR requirements

The SAM financial model can account for a wide range of incentive payments and tax credits.

SAM requires input data to describe the performance characteristics of physical equipment in the system, as well as project costs and financial assumptions. SAM is available from the NREL website and operates as a desktop computer application. As noted, it comes with default input values, and tools for downloading some inputs from online NREL databases. SAM also requires a weather data file as input to describe the renewable energy resource and weather conditions at a project location.

2.1 Project Assumptions and Parameters

A total of 5 scenarios were developed by the Schatz Center project team for SAM analysis of the economic viability of OSW farms based near Humboldt Bay, California. These scenarios include the following variables:

- Location: The BOEM call area in federal waters offshore from Humboldt Bay, California (HB) and a notional alternative offshore site for comparison purposes located in federal waters offshore from Cape Mendocino, California (CM). Both location scenarios are assumed to use the Port of Humboldt Bay for construction, and for maintenance, repair, and component replacement support during OSW farm operations.
- Scale: 48, 144, and 1836 MW (HB); 144 and 1836 MW (CM).

The resulting scenarios for the economic viability analysis have the following abbreviated names (Table 8-1):

Table 8-1. Naming convention for offshore wind scenarios.

Abbreviated Name	*Wind Farm Capacity*	*Location*
HB-48	48 MW	Humboldt Bay
HB-144	144 MW	
HB-1826	1,836 MW	
CM-144	144 MW	Cape Mendocino
CM-1836	1,836 MW	

SAM provides parameter default values as well as a library of weather files, turbine systems specifications, and other relevant elements of analysis. SAM allows users to develop customized weather data, system component files, and parameters for their projects as well. Accordingly, the project team used the following customized inputs:

- Weather data for the wind resource, specifically created for the two scenario locations, were extracted from the National Renewable Energy Laboratory's WINDToolkit (Draxl et al., 2015).
- 12-MW turbine specifications, including hub height, rotor diameter, and turbine power, are defined from standard turbine parameters published by NREL (Musial et al., 2019a) and from General Electric (GE) turbine specifications (GE, 2020). This turbine specification was added to the SAM turbine library.
- Balance of system elements, including a floating semi-submersible platform, OSW farm electrical system (including array cables, export cable, substation, and grid connection), mooring system, and other ancillary elements based on developer input and assumptions in Musial, et al. (2019a).
- Capital cost (“CapEx”) and O&M cost (“OpEx”) factors originating from a custom project cost model developed by the Schatz Center project team for each scenario under analysis. The cost model features component-level bottom-up elements as well as cost factors, and was developed from published scholarly works and technical reports, expert input, and feedback from OSW developers. All costs are in constant 2019 dollars and adjusted for each scenario’s assumed (approximately 2024) construction date. Where possible, cost model outputs were benchmarked using parameters closely matching the 600-MW Site 5 study scenario (south Oregon OSW site offshore of Port Orford, Oregon) modeled by Musial, et al. (2019a).
- The spacing between each turbine is 7 times the rotor diameter in the East-West direction and 10 rotor diameters in the North-South direction. The turbines are arranged in rows that are offset perpendicularly to the prevailing winds (turbine layouts for each scenario are described in more detail in Appendix A, Section 4.3.4).

Note that OSW farm operations modeled here will require substantial transmission infrastructure investments to move energy to load centers. The cost of such transmission infrastructure projects in California is usually paid for using rate-based funding such as transmission access charges (TACs) -- volumetric fees assessed on energy consumption for using the transmission grid controlled by the California Independent System Operator (CAISO). Under the ISO tariff definition, the TAC point of measurement is currently assessed at end-use customer meters on gross load as measured by MWh's of metered customer usage (CAISO, 2017). Substantial new transmission projects in California are approved by the CAISO, which also approves a transmission project sponsor to finance, construct, own, operate and maintain new transmission paid for by TAC assessments.

In cases where multiple generators develop renewable energy facilities in locations underserved by transmission, and the renewable energy is required to meet California's Renewable Portfolio Standard (RPS) requirement, CAISO developed the location constrained resource interconnection (LCRI) policy. Under the LCRI, generators that interconnect to the grid are responsible for paying a pro rata share of the going-forward costs of the line (through TACs) until the line is fully subscribed and the transmission owner is "re-paid" for its initial investment (Fink et al., 2011).

As transmission is usually paid for by a TAC revenue stream rather than from PPA prices, and transmission typically has a much longer service lifetime than generation, transmission is not included in CapEx and OpEx used in the SAM project economic feasibility analysis. The assumption is that CAISO and other entities will approve required transmission infrastructure investment that will have its costs recovered by a TAC assessment. That said, we do report total capital-cost estimates (from PG&E and Mott Macdonald (subsea cable)) for transmission upgrade estimates, as financing these transmission investments is a necessary condition for OSW farm development in waters offshore from northern California.

SAM default values were used for all other required simulation assumptions and parameters. Among the more prominent of these are a 25-year project life; 2.5% inflation rate; 6.5% real discount rate; 9.06% nominal discount rate; 1% PPA escalation rate; 11% IRR target by project year 20; and a debt service coverage ratio (DSCR) of 1.3, used to determine the debt component of single-owner project financing (note that DSCR is the ratio of net operating income to required debt service, a prominent benchmark for an entity's capacity to support debt (and lease) payments).

SAM allows users to select from a number of different assumed financing and ownership structures for simulation analysis. In this study, we considered two alternatives:

- A PPA single-owner project with financing deriving from a mix of debt and equity determined by the SAM default DSCR of 1.3.
- A PPA sale-leaseback project. In this structure, the owner sells the wind farm to a tax equity investor that then leases it back to the previous owner. The tax equity investor is then acting as the lessor, with the previous owner being the lessee. The lessor receives cash rent and the tax benefits, and the lessee receives the wind farm's operating profit. A sale-leaseback arrangement enables a corporation to access more capital than traditional financing methods. When the property is sold to an outside investor, the corporation receives 100% of the value of the property, whereas traditional loan financing is limited to a loan-to-value ratio or debt-coverage-ratio.

With projected commercial operation dates (CODs) of 2026 or 2028 (1,836 MW scenarios), and uncertainty regarding possible renewal of investment or production tax credits, the economic analysis here assumes no applicable federal tax credits such as the ITC or PTC. Modified accelerated cost recovery system (MACRS) depreciation and bonus depreciation is assumed for all scenarios. As a result, the tax benefits received by the lessor in a sale-leaseback structure is limited to depreciation.

As specific PPA price schedules for market-viable projects prevailing in the wholesale electricity market in California are proprietary and unavailable to the project team, instead of specifying a PPA price schedule and solving for IRR, we employed SAM's default 11% IRR target and used SAM to solve for the implied PPA price schedule.

2.2 Notional viability threshold

Economic viability is assumed to reflect a reasonable likelihood that a project can successfully attract private investment capital for development and operation. Recall we use SAM to solve for the minimum required PPA price schedule to deliver a specified IRR. The analysis is deterministic, and thus does not reflect the usual elements of investment risk. Inherently riskier projects must pay a higher expected return to attract investors who have an opportunity cost of capital based on other project investment opportunities available in the market. Thus, viability is a fuzzy target at this level of model abstraction.

In the present modeling exercise, PPA price is the sole source of revenue for an OSW project. Aligned with that, SAM derives a minimum PPA price schedule necessary for a project to generate an 11% IRR. Accordingly, the question of economic viability in this analysis is determined by whether the required PPA price schedule generated by SAM reflects prevailing PPA contract prices for other renewable energy projects competing to contract with a load-serving entity. We briefly offer several recent analyses of prevailing PPA contract prices below.

Wiser and Bolinger (2018) provide information on PPA prices (in constant 2018 dollars) for wind energy in the US. Wiser and Bolinger report steadily declining levelized real PPA prices in the US since approximately 2009 - 2010. No PPA executed since 2013 in the western US had a levelized real price above $80/MWh, and no PPA executed since approximately 2015 in the western US had a levelized real price above $60/MWh. Note that the PPA prices in their sample were reduced by the receipt of state and federal incentives, and Wiser and Bolinger report that the levelized PPA in their report would be at least $15/MWh higher without the federal tax credits or treasury grant. Thus, to provide comparability with the present study, an un-subsidized real levelized PPA price of approximately $80/MWh appears to be an upper bound. The California Independent System Operator (CAISO) reports the average wholesale electricity price in California in 2018 was $50/MWh (CAISO, 2019).

Bolinger, et al. (2019) provide information about real levelized PPA prices (in constant 2018 dollars) for utility-scale solar PV energy (bundled with renewable energy credits (RECs) where relevant) in the US. The goal of Bolinger and colleagues' report is to estimate how much post-incentive revenue a utility-scale solar project requires to be viable. While the present study is of course an OSW project assumed not to benefit from federal tax credits, to the extent that California utilities procure renewable energy to meet state RPS requirements, land-based wind and solar PV serve as substitutes, and as such, there should be a degree of comparability in PPA prices. The Bolinger, et al. report shows real levelized utility-scale solar PV PPA prices in California trending between approximately 25 to $50/MWh since 2016. While not a primary focus of the present study, Bolinger and colleagues also note that an increasing number of solar PV projects are bundled with battery storage, paid for either through a bundled PPA price or by way of capacity payments. Note that as with Wiser and Bolinger (2018), these PPA prices are reduced by federal incentives, and it is unlikely that an un-subsidized price would be any higher than that reported above for wind energy in California.

Beiter, et al. (2019) provide an analysis of PPAs for energy and RECs between the planned Vineyard Wind LLC wind farm and electric distribution companies in Massachusetts. Importantly, Beiter, et al. also identify additional external revenue streams and project benefits that lead to a levelized revenue factor (described below) that exceeds the PPA price and helps support OSW project success. The Vineyard Wind LLC project (in progress; delayed) has potential to be the first utility-scale OSW farm in the United States. Beiter, et al. report a first-year PPA of $74/MWh ($2022, facility 1) and $65/MWh ($2023, facility 2), both with 400 MW capacity.

As noted above, Beiter, et al. (2019) also considered ITC benefits and anticipated external revenue stream sources beyond the PPA, such as from the ISO-NE forward capacity market. This bundle of PPA and REC revenue, tax credit benefits, and anticipated revenue from the sale of capacity were used to derive a levelized revenue of energy (LROE). Beiter et al.'s total calculated LROE for the Vineyard Wind LLC wind farm is estimated to be $98/MWh ($2018). Beiter, et al. note that this LROE estimate appears to be within the range of the LROE estimated for offshore wind projects recently tendered in northern Europe with a start of commercial operation by the early 2020s. Note that in the present analysis, no other revenue streams or federal tax credits apply. Therefore, the LROE from Beiter, et al. serves more as a rough benchmark for a required levelized real PPA price in the current SAM economic viability analysis.

Based on the recent past benchmark levelized PPA prices and LROE described above, it is likely that a California public utility seeking to contract for renewable energy would have more attractive, lower-priced renewable energy available if offshore wind energy were to require a levelized real PPA price above approximately $100/MWh in constant 2019 dollars (including the value of bundled RECs). That is not to say a project will be viable at any levelized price below $100/MW. Rather, the appropriate interpretation of this notional threshold is as follows:

- Levelized real PPA price from SAM > $100/MWh: Project is unlikely to be viable under current market assumptions
- Levelized real PPA price from SAM ≤ $100/MWh: Project may be viable under current market assumptions

This situation could certainly change if either the supply side or the demand side of the renewable energy market in California or the region were to change. This will be discussed in greater detail in the conclusion of this report. Further, many utility-scale solar projects are bundling some degree of battery storage, which reduces intermittency and meets resource adequacy requirements. As solar with energy storage becomes more common, it can provide a better economic comparison point because it can produce a similar generation profile to offshore wind.

3. RESULTS

We begin with cost model results by scenario, broken out by major component elements. Next, we consider key financial metrics for the single owner financing alternative, followed by the sales-leaseback financing alternative. We report Year-1 PPA price, real levelized PPA price, and real LCOE. We also provide information on the mix of debt and equity in the optimized SAM solution for each scenario.

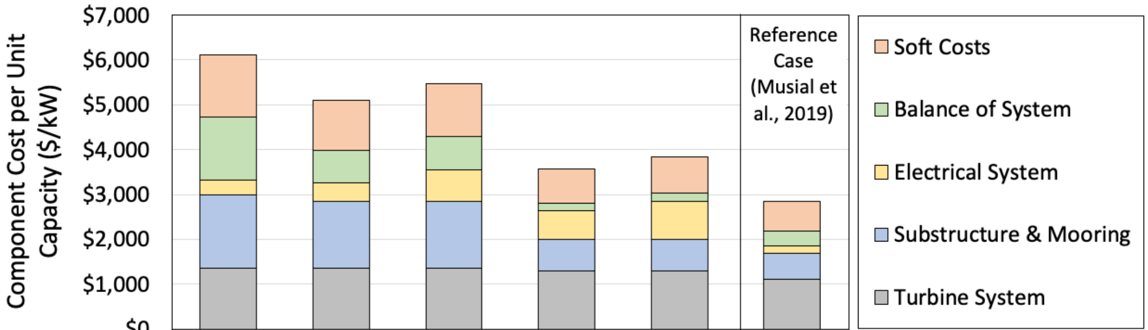
3.1 Wind farm estimates by major component elements

As previously noted, in the development of the cost model, we made use of a number of component cost assumptions from Musial et al. (2019a), though much of our cost model derives from original bottom-up modeling. When we performed benchmarking runs of our cost model using the 600 MW scenario parameters drawn from Musial et al.'s Study Site 5 scenario (south Oregon OSW site offshore of Port Orford), and adjusted for their 2032 COD date, our model's CapEx cost factor estimate was less than 1% below the CapEx value they reported. On a less comparable scenario-to-scenario basis, comparing Musial et al's Study Site 5 scenario for a 2027 COD date (which assumes 12 MW turbines and a 600 MW farm) with our CM 1836 scenario with a roughly comparable 2028 COD date, 12 MW turbines, but a farm size more than 3 times as large, our model's CapEx cost factor estimate was 1.6% higher than the value they reported.

O&M costs are somewhat more difficult to compare, as different projects have different distances to O&M ports, different port-area labor market conditions, different port tariffs, and different access to support vessels, leading to naturally different O&M costs. When we performed a benchmarking comparison as described above (again, assuming a later 2032 COD date), our OpEx cost factor estimate was $44.23/kW, compared to their estimate of $54/kW. Consequently, our OpEx estimate was about 18%

below that of Musial et al. (2019a). Comparing Musial et al's Study Site 5 scenario for a 2027 COD date (which assumes 12 MW turbines and a 600 MW farm) with our CM 1836 scenario with a roughly comparable 2028 COD date, 12 MW turbines, but a farm size more than 3 times as large, our model's OpEx cost factor estimate was 22% lower than the value they reported.

In Figure 8-1 we show the major components of CapEx by scenario. One can see that turbine cost factors show very modest economies of scale, whereas electrical array system cost factors (inclusive of costs for floating substation and export cable to landfall) display diseconomies of scale linked to the higher capacity array cables, export cables, and floating substation required when a larger number of turbines are interconnected. Also note that the notional Cape Mendocino site is farther from the port of Humboldt Bay and the landfall site for energy being moved from the wind farms, resulting in more export cable expenditure being required than for the HB scenarios.



	HB-48	HB-144	CM-144	HB-1836	CM-1836	Ref-600
Soft Costs	$1,387	$1,117	$1,186	$761	$807	$678
Balance of System	$1,392	$723	$735	$173	$181	$319
Electrical System	$332	$406	$705	$632	$837	$171
Substructure & Mooring	$1,630	$1,479	$1,479	$709	$709	$577
Turbine System	$1,366	$1,366	$1,366	$1,294	$1,294	$1,110

All values in $/kW

Figure 8-1. Major component costs of the CapEx per kilowatt ($/kW) for all offshore wind scenarios and a 600 MW reference case from Musial et al. (2019a) Oregon feasibility study.

In Table 8-2 we show estimated OpEx costs by scenario. As the notional Cape Mendocino site is farther from the port of Humboldt Bay than the BOEM call area, operations and maintenance (O&M) costs are slightly higher for the CM scenarios than for HB scenarios of equivalent capacity. One can also see very modest economies of scale for O&M costs.

Table 8-2. Estimated OpEx costs for each scenario in dollars per kilowatt per year for all offshore wind scenarios and a 600 MW reference case from Musial et al. (2019a) Oregon feasibility study.

OpEx Costs by Scenario	*HB-48*	*HB-144*	*CM-144*	*HB-1836*	*CM-1836*	*Ref-600*
Operations, *$/kW-year*	$30.48	$30.52	$31.07	$28.88	$29.40	$23.77
Maintenance, *$/kW-year*	$32.48	$32.35	$33.66	$30.27	$31.44	$21.46
OpEx Total, *$/kW-year*	$62.96	$62.87	$64.73	$59.15	$60.84	$44.23

3.2 Single owner

Key financial metrics improve as OSW farm size increases (Figure 8-2). Only the two largest scenarios – 1,836 MW farms in the BOEM call area or the notional Cape Mendocino alternative site – feature real levelized PPA prices that fall below the notional $100/MWh threshold for projects with the potential for being economically viable. Our SAM results are roughly comparable to the 600-MW Site 4 and 5 study scenarios modeled by Musial, et al. (2019a) for a 2027 COD date and comparable 12 MW turbines. In particular, Musial et al. report a real LCOE ($2018) for a 2027 COD date of $74/MWh for their lowest-cost Site 5 scenario offshore of Port Orford, Oregon, which features a 53% net capacity factor, while our lowest-cost CM-1836-SO scenario's real LCOE ($2019) is $78.90, at a 56.7% capacity factor. Musial et al. report a real LCOE of $87/MWh for their Site 4 scenario offshore of Coos Bay, Oregon with a 2027 COD date and a 46% capacity factor, which roughly matches up with our HB-1836-SO scenario's real LCOE ($2019) of $88.90/MWh and 47.5% capacity factor.

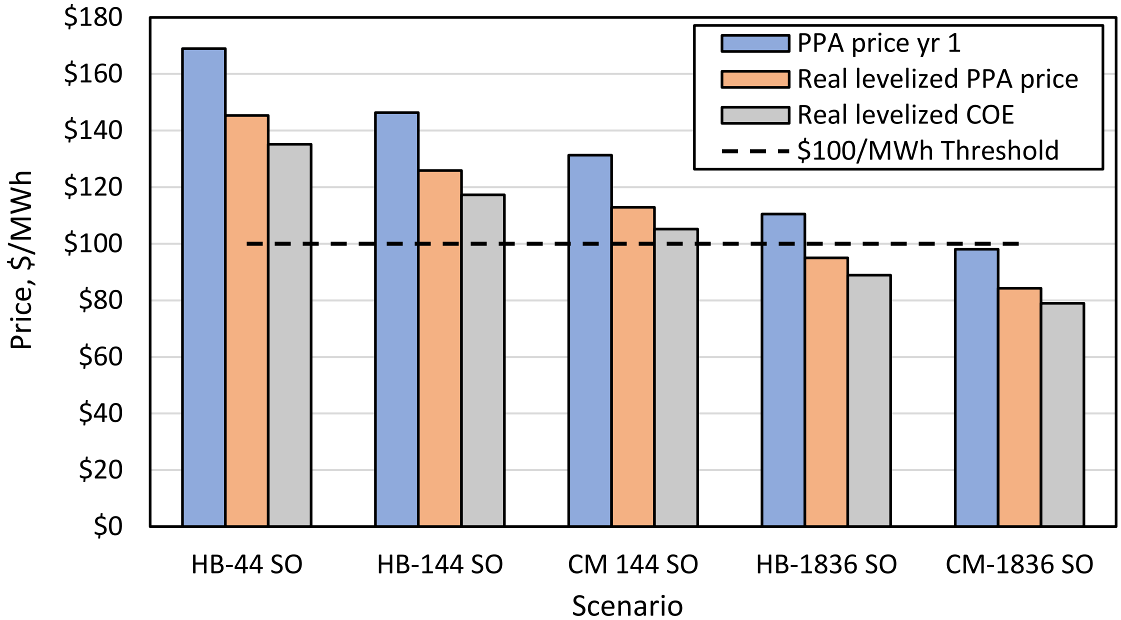


Figure 8-2. Financial performance metrics for five wind farm scenarios using single owner project financing.

From Table 8-3 one can draw inference as to why the notional Cape Mendocino site out-performs the BOEM call area. In particular, while the Cape Mendocino site requires roughly an additional half-billion dollars in net capital cost for the 1,836-MW scenario, the substantially higher capacity factor associated with its superior wind resource leads to the stronger financial performance of the notional Cape Mendocino site.

Table 8-3. Descriptive project financing measures for single owner financing.

Measure	*HB-44*	*HB-144*	*CM-144*	*HB-1836*	*CM-1836*
Capacity Factor	48.6%	48.1%	57.2%	47.5%	56.7%
IRR, End of Project	13.3%	13.3%	13.3%	13.3%	13.3%
Net Capital Cost ($ million)	$319	$798	$858	$7,150	$7,670
Equity ($ million)	$ 85	$212	$228	$1,880	$2,020
Debt ($ million)	$234	$586	$629	$5,268	$5,644

3.3 Sale-leaseback

As with the single owner financing alternative, key financial metrics improve as OSW farm size increases in the sale-leaseback financing option (Figure 8-3). Unlike the single owner financing option, none of the sale-leaseback financing scenarios fall below the notional $100/MWh threshold for projects with the potential for being economically viable.

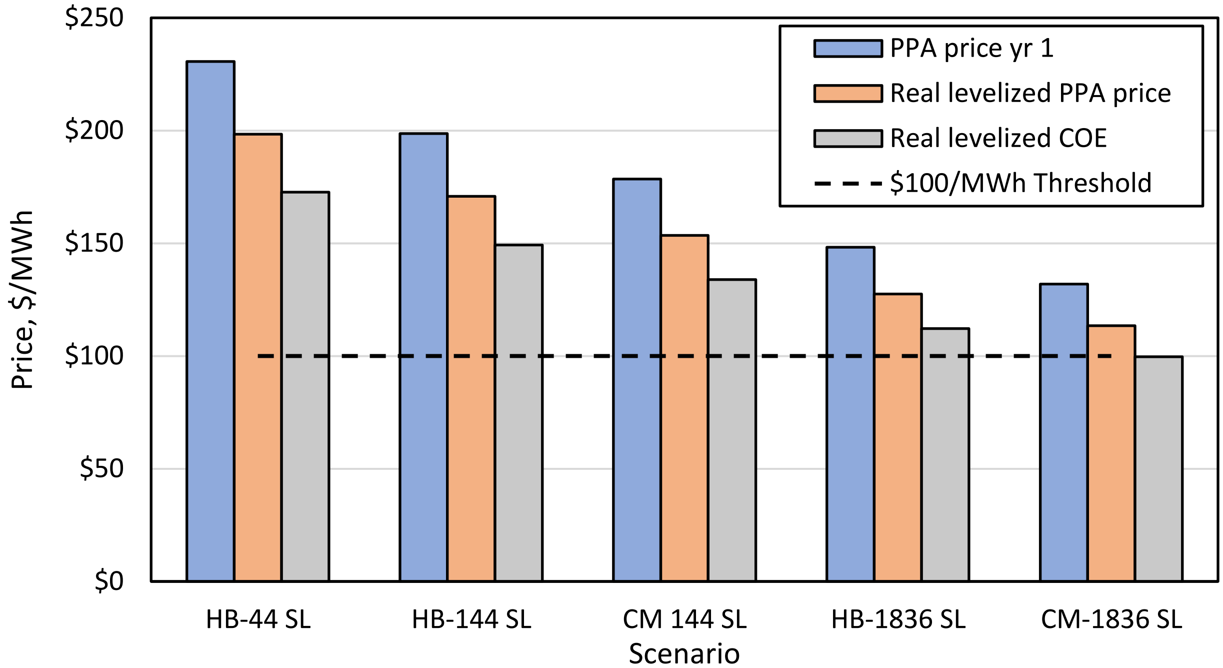


Figure 8-3. Financial performance metrics for five wind farm scenarios using sale-leaseback project financing

Note that in the sale-leaseback financing alternative in SAM, the program requires an investor IRR target and solves for PPA prices and other metrics. The default investor IRR target is 11% by Year 20 of the project. As a result, while investors with an 11% IRR target by Year 20 are assured their target is met (with a sufficiently high PPA price schedule), the developer IRR is solved for from the assumed investor IRR target. As a result, one can see in Table 8-4 that solution values for developer IRR by scenario are much weaker than for the investor.

Table 8-4. Descriptive project financing measures for sale-leaseback financing ($ million)

Measure	HB-44	HB-144	CM-144	HB-1836	CM-1836
Capacity Factor	48.6%	48.1%	57.2%	47.5%	56.7%
Investor IRR, end of project	11.8%	11.8%	11.8%	11.8%	11.8%
Developer IRR, end of project	5.5%	6.0%	5.8%	7.0%	6.8%
Sale of Property, $ million	$308	$770	$827	$6,881	$7,380

3.4 Transmission Infrastructure Upgrade Costs

As noted, transmission infrastructure upgrade costs, particularly involving substantial new transmission lines and substation development, are generally paid for by energy consumers by way of transmission access charges (TACs). Nonetheless, these upgrades are necessary for OSW farms to operate successfully in the waters offshore from northern California. Below we report estimated capital costs for these essential upgrades by scenario, rounded to the nearest million dollars. It should be noted that the upper end of the range of estimated capital cost is roughly estimated as twice the value of the lower range for the 48 MW, 144 MW, and 1,836 MW “East” and “South” alternatives. All terrestrial transmission pathway estimates were provided by PG&E; the subsea cable pathway estimate was provided by Mott Macdonald. The cost estimates were then adjusted, taking into consideration terrain, length of line, and the acquisition of land, which is represented by the black bar in *Figure 8-4*.

Note that the "East" pathway routes energy from Humboldt Bay to the transmission junction at the Round Mountain Substation, whereas the "South" pathway routes energy from Humboldt Bay to the Vaca-Dixon Substation junction. Also note that the cost of transmission improvements is assumed to be the same for OSW farms located in either the Humboldt Call Area or the notional Cape Mendocino area. This is because the cost of delivering energy from the wind farm sites to a shore-side Humboldt Bay Substation with the OSW export cable is already built into the cost for the OSW farms.

As one can see from *Figure 8-4*, the estimated adjusted costs of transmission improvements necessary to move energy from the OSW farms under study to load centers generally increases with assumed wind farm scale, as expected. The more energy that needs to be transmitted to load centers, the greater the capacity of transmission infrastructure that must be built and the greater the cost. One can also see that the adjusted cost of a subsea cable near shore is estimated to be approximately a billion dollars more than either the south or the east terrestrial transmission pathway. Additionally, the adjusted cost of a subsea cable far from shore is estimated to be almost a billion dollars more than a near shore subsea transmission pathway.

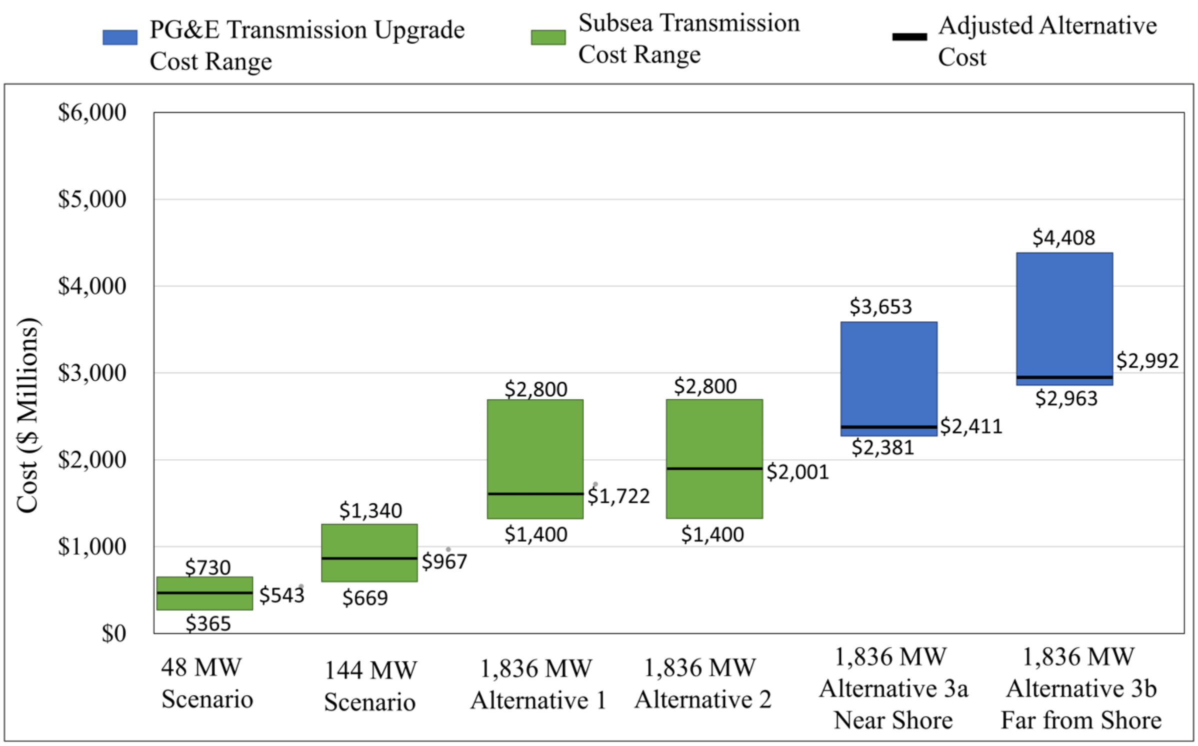


Figure 8-4. The adjusted values of transmission upgrade capital cost estimates from PG&E.

4. CONCLUSIONS

Only the largest of the OSW farm scenarios – CM-1836 and HB-1836 – using a single owner financing scheme, have real levelized PPA prices that fall below the $100/MWh notional threshold for OSW projects having potential to be economically viable ($78.90 and $88.90, respectively). In both cases these real levelized PPA prices are comparable to the LROE estimate from Beiter et al. (2019), but lie far above the approximately $40-60 per MWh values for western-region wind energy project real levelized PPA prices documented by Wiser and Bolinger (2018) for roughly 2015 - 2017 (and which are inclusive of revenue from REC credits, any relevant capacity payments, and federal tax credits). Note that roughly similar to lower-cost results can be obtained for utility-scale solar, a substitute for load-serving entities subject to RPS requirements (Bolinger et al., 2019). Wiser and Bolinger note that these reported real levelized PPA prices would be at least $15/MWh higher in the absence of federal tax credits. Thus, to make them roughly comparable to the current analysis in which these tax credits have expired, the range of observed wind farm PPA prices would be approximately $55-75 per MWh. One can see that even the very largest OSW farm scenarios investigated here require real levelized PPA prices well above these observed “market” PPA prices for 2015-17 in the western U.S. Moreover, the ability of a single owner to assemble the more than $7 billion in required project debt and equity financing to cover net capital cost may be optimistic.

Overall, one must conclude that even under the most favorable large-scale OSW farm scenarios, the market-based economic case for these projects is tenuous. This situation could certainly change if wind farm project costs were to decline; if additional revenue sources, tax credits or grants became available; or if underlying market demand for renewable energy were to change. As Beiter, et al. (2019) note, a market-rate PPA price (likely well below $100/MWh) bundled with one or more outside revenue streams such as capacity or REC payments, along with federal or state credits, could result in a levelized revenue of electricity (LROE, conceptually similar to the bundled real levelized PPA price in Wiser and Bolinger (2018) that is inclusive of all relevant external revenue streams and tax credits) sufficient to make a project competitive. Currently those outside revenue and benefit sources cannot safely be assumed to be available for the OSW project scenarios under study, but were they to be, then the resulting LROE (or bundled PPA price) would be the appropriate instrument for gauging viability. On the demand side, increasingly stringent RPS requirements placed on load-serving entities would likely increase market-viable PPA contract prices due to all the lowest-cost or most resource-rich renewable energy project opportunities having already been exploited. Moreover, smaller demonstration-scale OSW projects with grant or other government funding may be feasible in a non-market context. Floating-platform OSW project cost reductions lag fixed-bottom OSW project costs by 5-7 years, and are expected to eventually converge (Musial, 2020).

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APPENDIX 8.A - COST ESTIMATION METHODOLOGY

The following appendix presents the methods used to develop the offshore cost model in support of the North Coast Offshore Wind Study carried out at the Schatz Energy Research Center. This cost model is customized to reflect specific project assumptions, scenarios, and locations. The project is assumed to occur in the waters off of Humboldt County, California, using 12 MW turbines for floating offshore wind farms ranging in size from 50 to over 1,800 MW nameplate capacity.

The purpose of the cost model is to provide insight into several economic performance metrics, broadly categorized as economic impacts to the State of California, and the economic viability of various scenarios. Economic impacts are the total number of new jobs in California and indirect economic output (in dollars) resulting from offshore wind farm development. Economic viability metrics include levelized cost of energy and power purchase agreement prices necessary to yield a target internal rate of return for wind farm investors and developers.

The cost model was developed as a sum of component costs under two broad categories, one-time capital costs and recurring operations, maintenance, and repair costs. The major components of the initial capital expenditures (Capex) are the turbine system; the substructure and mooring system; the electrical system; the installation costs; and the soft costs, which include development, construction financing, insurance, contingencies, leasing, commissioning, decommissioning, and a lease. The operational expenditures (Opex), include operations, maintenance, and repair costs. Each cost component is modeled in one of several ways, including bottom-up models, industry-standard factors, and expert estimates (Table 8-5).

Table 8-5: Overview of costs and methods

Category	*Method*	*Value*	*Note*
Component costs			
Turbine	Literature average	$1,480/kW	Adjusted for learning effects based on construction date
Substructure & Mooring System	Piecewise function from literature	Between $1,236 - $577/MW (2032 $)	Value changes based on wind farm scale
Port and Staging	Estimate from literature	$ 44/kW	
Electrical interarray cables	Optimized string and voltage layout to minimize cost	between $66-$79/kW	66 kV interarray cables
Electrical export cables	Optimized number of cables and voltage	between $611-$693/kW	66 kV for 48 MW farm; 132 kV for 144 MW farm; 275 kV for 1,836 MW farm
Ancillary electrical components	Required infrastructure based on design	Between $9.42 - $18.05/kW	Includes substation and substructure (as needed)
Development costs			
Engineering & management	Factor from literature	4% of total component cost	
Permitting & site characterization	Flat estimate from literature	$13,110,000	Same cost for all scales
Assembly and Installation	Based on assembly and installation time, vessel rate, vessel travel time, personnel wages, weather, and wind	Varies, $/kW	Includes 30% downtime due to metocean conditions; Assembly time based on operation videos
Transmission costs			
Transmission Upgrades	Project specific estimate from PG&E	varies	See Chapter 4: , above, for documentation
Soft costs			

Category	*Method*	*Value*	*Note*
Commissioning	Factor	1% of component costs	
Construction Insurance	Factor	1% of component costs	
Decommissioning Bond	Factor	15% of component costs	
Procurement contingency	Factor	5% of component costs	
Installation contingency	Factor	30% of installation cost	
Construction Financing	Estimate from literature	$ 118/kW	
Lease Price	Average of previous leases	$237/acre	
Operations costs			
Insurance	Estimate from literature	$ 31/kW	
Management & admin	Estimate from literature	$ 5.80/kW	
Lease fees	Calculated	$3.80-$4.60	Based on BOEM offshore wind documentation
Overhead	Factor	37.60% of wages	
Maintenance costs			
Corrective maintenance	Calculated based on failure rate, material costs, repair duration, # technicians required, vessel rate and travel, and personnel	$35.82-$36.74/kW	Range changes based on COD and location
Condition-based maintenance	Assumption	20% of corrective maintenance	
Calendar-based maintenance	calculated based on failure rate, material costs, repair duration, # technicians required, vessel rate and travel, and personnel	$3.21-$3.89	Assumed approximately 2 major replacements every 5 year and 2 minor repairs every year
* All values in 2019 US Dollars unless otherwise noted.			

Industry learning effects are estimated to adjust for future construction dates learning effects are estimated in terms of cost reduction percentages between 2019 and 2032 (Table 8-6). The estimates are based on the calculations from Musial et al. (2019a), which are drawn from an in depth cost-reductions pathways study done by InnoEnergy and BVG.

Table 8-6: Learning curve reductions as a percentage of project costs (adapted from Musial et al. 2019a)

COD	**2019**	**2022**	**2027**	**2032**
Development	0.00%	3.79%	6.68%	11.75%
Rotor Nacelle Assembly	0.00%	0.61%	9.45%	25.00%
Substructure	0.00%	0.77%	11.92%	31.52%
Foundation	0.00%	0.61%	9.47%	25.06%
Array Cable System	0.00%	14.12%	25.97%	46.81%
Export Cable System	0.00%	14.83%	27.34%	49.36%
Turbine Installation	0.00%	0.05%	8.02%	21.20%
Substructure & Foundation Installation	0.00%	0.09%	14.11%	37.33%
Operations	0.00%	22.32%	28.27%	41.93%
Maintenance	0.00%	24.76%	31.41%	46.69%
Gross AEP	0.00%	1.63%	2.19%	5.03%
Total Losses	0.00%	0.09%	1.19%	2.74%
CapEx	0.00%	6.76%	16.17%	32.67%
OpEx	0.00%	9.16%	14.84%	27.89%
AEP	0.00%	1.75%	2.40%	5.72%

Scale effects are modeled directly in the bottom-up models, which allows the scale effects to be reflected in the factor-based costs as well. In this project, scale effects refer to both the turbine scale and the total farm scale. For example, larger turbines (in terms of capacity) means that there are fewer turbines to install per unit capacity and thus installation vessel costs are lower. Larger farms mean that the power export cables can be more efficiently sized and thus electrical system costs are lower. Supply chain effects are outside the scope of this project.

The cost model is responsive to a variety of input parameters. Input parameters include farm scale (MW), turbine size (MW), capacity factor (%), farm area (acres), distance to port (km), distance to landfall (km), average water depth (m), commercial operation date (COD) (year), and substructure construction method (local or imported). Transmission upgrade costs are estimated by project partners (PG&E and Mott MacDonald) and included as a separate line item in the cost model. For the purpose of this project, a number of scenarios were assessed, with the input parameters summarized in *Table 8-7 and Table 8-8.*

Table 8-7: Input parameters for BOEM call area scenarios

Parameter	*units*	*B50e*	*B150e*	*B1800e*	*B1800s*	*B1800sub*
Wind Farm Capacity	MW	48	144	1836	1836	1836
Turbine Power Rating	MW	12	12	12	12	12
Capacity Factor	%	55	55	55	55	55
Wind Farm Area	acres	2,323	8,154	132,448	132,448	132,448
Distance to port	km	53	53	53	53	53
Distance to land	km	44	44	44	44	44
Average depth	m	800	800	800	800	800
COD	year	2026	2026	2028	2028	2028
Structure construction	-	import	import	local	local	local
Transmission route	-	east	east	east	south	submarine

Table 8-8: Input parameters for hypothetical Cape Mendocino area scenarios

Parameter	*units*	*M150e*	*M1800e*	*M1800s*	*M1800sub*
Wind Farm Capacity	MW	144	1836	1836	1836
Turbine Power Rating	MW	12	12	12	12
Capacity Factor	%	65	65	65	65
Wind Farm Area	acres	8154	123,553	123,553	123,553
Distance to port	km	95	95	95	95
Distance to land	km	88	88	88	88
Average depth	m	800	800	800	800
COD	year	2026	2028	2028	2028
Structure construction	-	import	local	local	local
Transmission route	-	east	east	south	submarine

8.A.1 Turbine

In this cost model, the turbine component includes the tower, rotor, nacelle, and all the internal electronics. The turbine cost is calculated as the average of recent literature estimates then adjusted to account for learning effects that would reduce costs (summarized in Table 8-6). To calculate turbine costs in $/kW, recent literature sources were gathered and converted to present dollars (2019 $) (Table 8-9). The average value from these sources was then projected into the future using the learning effects described in Table 8-6. The turbine cost estimate was calculated to be $1,480/kW of nameplate capacity.

Table 8-9: Turbine cost data

Source	*Cost, $/kW*	*Cost, 2019 $/kW*	*Turbine Size, MW*	*Dollar Vintage*
Stehly (2018)	$ 1,521.00	$ 1,576.52	5.64	2017
BVG (2019)	$ 1,333.33	$ 1,179.25	10	2018
Shafiee (2016)	$ 1,329.00	$ 1,430.14	5	2014
Myhr (2016)	$ 1,909.32	$ 2,087.08	5	2013
Musial (2016)	$ 1,583.00	$ 1,704.89	6	2015
JEDI default (n.d.)	$ 1,000.00	$ 1,110.50	n/a	2012
Stehly (2018)	$ 1,094.00	$ 1,133.93	2.32	2017
Stehly (2018)	$ 1,521.00	$ 1,576.52	5.64	2017
Valpy (2017)	$ 1,030.95	$ 1,068.58	6	2017
Costas (2015)	$ 1,532.34	$ 1,648.95	5.08	2014
Beiter (2016)	$ 1,583.00	$ 1,681.94	6	2016
Stehly (2018)	$ 1,521.00	$ 1,576.52	5.64	2017
Noonan (2018)	$ 1,408.45	$ 1,459.86	unknown	2017
Average	$ 1,412.80	$ 1,479.49	5.65	2015
Adjusted to COD 2026	$ 1,365.93		Learning effect is 8%	
Adjusted to COD 2028	$ 1,293.75		Learning effect is 13%	

The turbine model makes a number of assumptions. First, it assumes that cost (in $/kW) does not change with turbine size. This assumption is based on data analysis and Musial et al.'s note that "a higher turbine rating may not result in an increase in per-unit turbine capital expenditures (CapEx) ($/kilowatt [kW]) at all" (Musial et al., 2019b). Second, it is assumed that the market for fixed-bottom turbines and floating turbines is the same. This assumption is based on the small floating market during the study period and the lack of any indication from any manufacturers of movement toward a customized floating turbine. Recent press-releases from major manufacturers discuss improvements in turbine size, but no other significant deviation from the standard machine (GE, n.d.)(*Siemens Gamesa Launches 10 MW Offshore Wind Turbine; Annual Energy Production (AEP) Increase of 30% vs. Predecessor*, n.d.). Third, it is assumed that east Asian manufacturing does not have a large effect on the prices of the world market due to the large East Asian pipeline.

There are a number of limitations with this method. First, it is only based on publicly available academic literature, with limited sources. Second, the industry has been changing rapidly, and turbine sizes have been rapidly increasing, so academic cost models written as few as 5 years ago were estimating costs for turbines that were less than half of the size of the turbines expected in the '20s. Therefore, the older academic literature is now outdated and cannot be the best estimate for turbines built 5-10 years in the future. Third, turbine costs are determined with project-specific contracts that depend largely on the complex supply chain.

8.A.2 Substructure and Mooring System

The cost model for the substructure and mooring system is based on industry expert cost estimates. Two recent cost estimates from Musial et al. (2019a) for a 24 MW and 600 MW wind farm were used to establish a piecewise function to estimate costs at any scale (Figure 8-5). Costs are assumed to decreased linearly with farm scale for farms between 24 MW (the lower point) and 600 MW (the upper point), and that the majority of the scale effects have been realized by the time a farm is 600 MW (40 x 15 MW turbines), and that cost remained relatively constant as farms grew beyond 600 MW, see Figure 8-5. Musial et al. (2019) reported the costs with a 2032 COD. In order to apply their costs to this model, the learning effects from Table 8-6 were used to adjust the values to the appropriate COD for the project scenario.

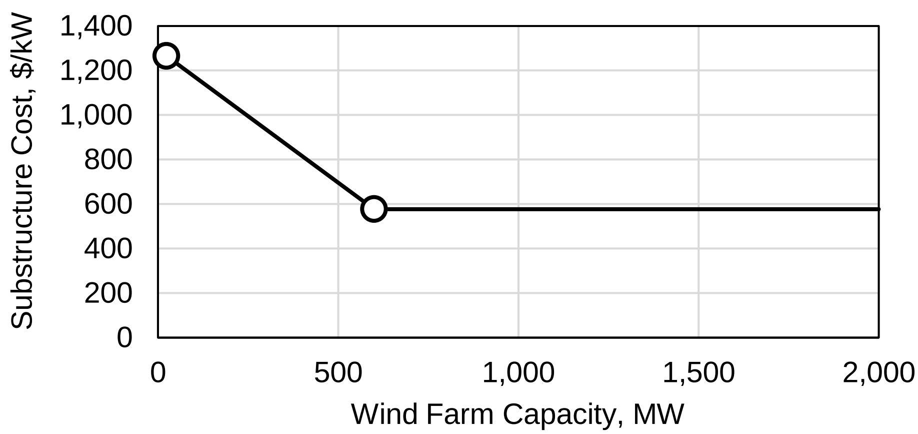

Figure 8-5: Substructure and mooring system cost as a function of farm scale

There are three primary assumptions built into this cost model. First, it is assumed that cost scales linearly with farm size. Cost effects based on turbine size and prevailing metocean conditions (severe or mild, hurricane risk, etc) are not included here. Second, it is assumed that all scale-based cost reductions have been achieved at scales over 600 MW. There may be further cost reductions beyond this scale, but without supporting data, a flat $/kW was used for wind farms above 600 MW. Finally, it is assumed that different substructure types (for example, concrete or steel, barge or lattice, etc) have the same cost.

The input data are based on a 2019 NREL report on offshore wind in Oregon (Musial et al., 2019a). This report included an analysis of the effect of scale on a farm off the coast of Oregon, and reported the cost of the substructure and mooring system. The weather regime in Oregon is similar to Northern California (classified as severe in terms of parameters that effect offshore wind)(Dewan & Stehly, 2016), and the site is only slightly shallower, so this is assumed to be the most relevant cost estimates for substructures. The COD for these estimates is 2032, which was addressed based on learning effects cost reduction estimates in Musial et al. (2019a). The substructure cost estimates from Musial et al. (2019a) are for 15 MW turbines, instead of 12 MW turbines like the present analysis. However, since the costs are provided on a $/kW basis, and the substructure will be similar, the cost are not adjusted by turbine size.

8.A.3 Electrical System

The electrical system component cost is estimated as the sum of each subcomponent cost including: interarray power cables (within the wind farm); export power cables (connecting wind farm to shore); offshore converter substations (connecting interarray and export cables); and ancillary components. The lowest cost electrical system design was selected for each project scenario, based on the calculation of capacity requirements for wires and components, then estimating total farm costs for a variety of designs, and finally selecting the lowest cost factor ($/kW) for each overall scenario. Cost reductions due to learning effects are applied to the estimated cost to adjust for the appropriate commercial operation date.

Cable costs are calculated using historical submarine cable cost literature relating ampacity and price (see Figure 8-6) projected onto available cable sizes, plus a price premium. Cable capacity is based on a recent manufacturer catalog relating cable size, in cross sectional area (mm2), to ampacity. Power capacity is calculated based on Equation 1, where $\cos\emptyset$ is the power factor, which is assumed to be 0.95 based on the minimum acceptable power capacity for a wind farm connected to the grid (Brownell et al., 2005). The price premium depends on the size and type of cable: the price premium for array cables is 15% and the price premium for a dynamic export cable is 100% (Robert Weeks, personal communication, October 2019; Bill Wall, personal communication, October 2019).

Equation 1: $$P = IV\sqrt{3} * \cos\emptyset$$

8.A.3.1 Interarray Cables

Array cable costs are calculated based on a variety of layouts for each farm that vary the number of turbines per string, assuming the turbines are daisy-chained together. In each layout, the minimum cable size between each turbine is determined based on the power through each cable. The arrays are limited to two cable sizes, and the total farm cost is calculated for each option, based on the number of sections of each cable size, and the unit cost of the cable.

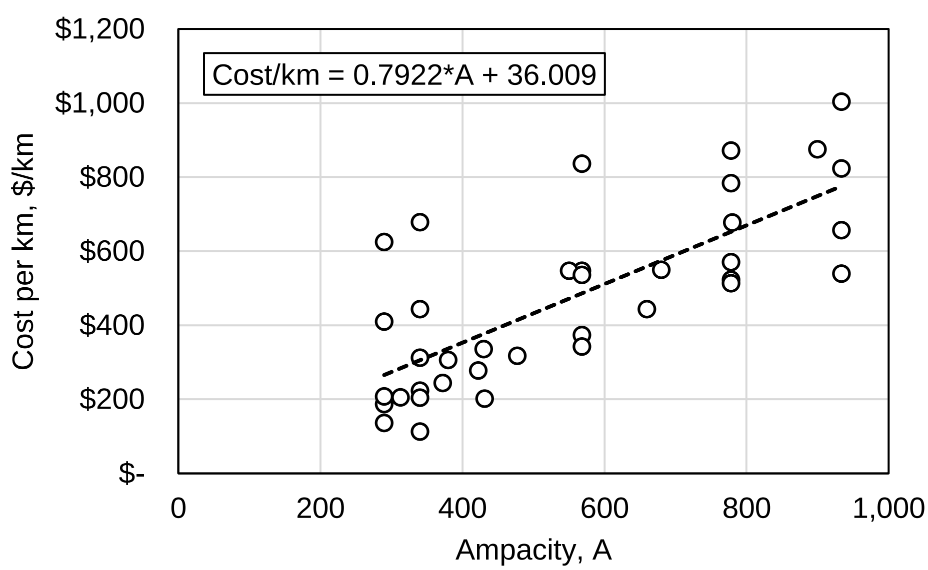

Figure 8-6: Array cable cost as a function of ampacity

For example, in the 48 MW farm, there are four turbines. You could have one string of four turbines, two strings of two turbines, or four strings of one turbine (attaching to an offshore substation). If you have four strings of one turbine, you would need four lengths of 95 mm^2 cable. If you have two strings of two turbines, the maximum power through the string is still within the capacity of the 95 mm^2 cable, so you would also have four lengths of 95 mm^2 cable. However, if you have one string of four turbines, you would need to size up some of the cable to 240 mm^2. You would end up with two lengths of 240 mm^2 cable and two lengths of 95 mm^2 cable. If each length is 2,582 m, the cost of the 95 mm^2 cable is $266/m and the 240 mm^2 cable is $305/m, then your cost for four strings of one or two strings of two turbines is $3,154,952, while your cost for one string of four turbines is $3,777,725. This is not an insignificant difference, but the model also considers the possibility of exporting the power from the string of four without an offshore substation, while the four strings of one turbine would require some type of combiner box or bus bar or substation in order to avoid running four cables to shore.

8.A.3.2 Export Cables

The export cable costs are much simpler than the array cable costs. Similar to the array cables, the relationship between size and cost is established based on academic literature (dependent on the rated voltage of the cable). It is assumed that 1 km of the export cable is a dynamic cable, with a 100% price premium. The power capacity of the cables are calculated based on Equation 1 (see above). The cost of the minimum export cable size is multiplied by the distance to landfall to calculate the total farm cost. If no cable is big enough to carry the whole load of the farm, then multiple cables will be used.

8.A.3.3 Offshore Substation

Offshore substations are used to connect the interarray cables with the export cable back to shore. This is not a replacement for onshore substations that connect to the electrical grid infrastructure. The number of offshore substations is assumed to be the same as the number of export cables. Each substation is assumed to be floating on a platform of a similar cost to the substructure and mooring system that support the wind turbines. The cost of the substation is based on the substation rating and its location, with a relatively small premium for offshore substations.

8.A.3.4 Total Electrical Infrastructure

The sum total cost of the array cables, the export cabling, the substations, and the platforms and moorings are compared to determine the lowest cost design. The lowest cost design is selected for the model, disregarding considerations of power loss or redundancy.

There are a large number of assumptions made in this component model. The first significant assumption is that cost is the main driver for design selection (costs for the 144 MW farm range from approximately $700/kW to $900/kW, so the cost can vary significantly if there is a different priority). Second, it is assumed that all the cables are 3-core cables. Third, it is assumed that the price premium for dynamic cables is 15% for cables used in the array, and 100% for export cables (the difference is due to the size of the cable and the impact on the engineering and structural integrity of the cable). Fourth, it is assumed that the array cables are either 33 or 66 kV and that for medium voltage submarine cables under 99kV, costs ($/m) are independent of voltage. Fifth, it is assumed that the turbine cables are laid out in a grid, and that they are daisy-chained together. The length of the array cable between each turbine is 9.3 times the diameter of the turbine rotor, plus the length needed to float the cable between 100-150 meters below the sea surface (adding approximately 500 meters). Finally, it is assumed that gas-insulated substations (substations that are enclosed and insulated with hexaflouride gas, allowing for a smaller footprint and for more protection from the elements) are used (*GIS | High-Voltage Gas Insulated Switchgear Substations*, n.d.).

This cost model is limited due to the following factors. First, the cost data used to determine the costs of the submarine cables is relatively old. Second, the model does not account for losses. Losses are calculated in the power production model, but cables might be sized due to losses instead of purchase price, which is not accounted for in this model. Third, there might be system accessories that are necessary but not included in the model.

The data used in this cost model includes academic literature, manufacturer publications and personal communications with experts. Dicorato, Gonzalez-Rodriguez, and Ioannou have reported their cable cost assumptions (Dicorato et al., 2011; Gonzalez-Rodriguez, 2016; Ioannou et al., 2018). ABB's catalog is used to estimate the ampacity of different cable sizes (*ABB*, n.d.).

8.A.4 Transmission Upgrades

The electric grid is very complex, as are transmission limits and upgrades, and therefore the associated costs. The local electric utility, Pacific Gas and Electric (PG&E), determined transmission constraints and transmission system upgrade costs for potential offshore wind farms. PG&E provided cost estimates for the upgrades required for different wind farm sizes and potential transmission pathways. Transmission scenarios recommended by PG&E are described in Table 8-10. A full description of the transmission upgrades are described in Chapter 4: . The submarine pathway total cost estimate includes both the PG&E upgrade estimates and the submarine cable cost estimate provided by Mott MacDonald.

Table 8-10: Transmission upgrade costs

Scenario	*Cost estimate range*	*Midpoint*	*Scenario Estimate ($/kW) (corrected for COD)*	*Source*
48 MW	$363.45M - $726M	$545M	$ 11,984.05	PG&E (see Chapter 4:)
144 MW	$669M - $1,340M	$1,005M	$ 7,366.40	PG&E (see Chapter 4:)
1836 MW eastern path	$1,290M - $2,590M	$1,940M	$ 1,115.83	PG&E (see Chapter 4:)
1836 MW southern path	$1,300M - $2,600M	$1,950M	$ 1,121.58	PG&E (see Chapter 4:)
1836 MW submarine path, grid upgrades	$820M - $1,640M	$1,230M	$ 2,488.92	PG&E (see Chapter 4:)
1836 MW submarine path, cable only	$2,500M – $3,500M	$3,00M	$ 11,984.05	Mott MacDonald (see Chapter 5:)

The midpoints of the provided cost range are used as the transmission upgrade cost in the cost model. The costs are provided in 2019 dollars, so they are escalated to the appropriate year for transmission construction following escalation factors provided by PG&E, based on IHS Global Insight's Q3 2019 Power, summarized in Table 8-11.

Table 8-11: Escalation values adapted from PG&E project report (see Chapter 4:)

	2020	*2021*	*2022*	*2023*	*2024*	*2025*	*2026*	*2027*	*2028*	*2029*	*2030*
Escalation Rates (%)	2.50	1.70	1.70	2.1	2.3	2.3	2.3	2.4	2.4	2.1	2.3
2019 Escalation Factors	1.000	1.017	1.034	1.056	1.080	1.105	1.131	1.158	1.185	1.210	1.238

8.A.5 Port Fees and Costs

The Port of Humboldt Bay is currently not able to support either assembly activities or operational and maintenance activities for an offshore wind farm, but is in the process of soliciting proposals for a terminal operator that would make the necessary port infrastructure upgrades development and upgrades

(*Lease of Marine Terminal I*, 2019). It is expected that the terminal operator would charge various fees for use of terminal facilities by wind farm developers and operators, allowing the operator to recoup the port development costs. Costs will be different for different stakeholders. For this reason, costs are calculated differently for different parts of the economic analysis.

The costs borne directly by the wind farm developer effect economic viability of the wind farm, and are estimated based on a recent published estimate. These costs include the various fees that a terminal operator would charge for use of the terminal facilities. The estimate for port fees and costs derives from Musial et al. (2019a), as it is the most geographically comparable study in the literature, and is the most recent available published authoritative source.

Total port upgrade and development costs have been estimated by a project partner, Mott MacDonald, and depend on wind farm scale (see Porter and Phillips, 2020). The upgrades required by a small wind farm would cost between 130-200 million dollars (midpoint at 165 million dollars, 2019 vintage) while the upgrades required for a large farm would be between 400-700 million dollars (midpoint at 575 million dollars). Similar to the transmission cost estimates, the midpoint is taken as the cost estimate for the model. The economic impact assessment utilizes these costs to determine the impact of the development of a wind farm on the local economy.

8.A.6 Installation

The installation and assembly cost model is a bottom-up model, validated against expert estimates, and includes cost reductions attributed to learning effects. The major part of the cost model is based on installation and assembly actions, the expected time for each action (adjusted for the operational weather window (OWW)), the personnel and vessels required for each action, and wages and vessel day rates, see equations 2, 3, and 4:

Equation 2: Total cost (for activity A) = Personnel cost + Vessel cost

Equation 3: Personnel cost = Time (hours, adjusted for OWW) * Number of personnel * Wage ($/hr)

Equation 4: Vessel cost = Time (days, adjusted for OWW, rounded up) * Vessel day rate ($/day)

Actions are based on the required actions for the installation and assembly for each part of the farm, see Table 8-12. The OWW is assumed to be 30% for every activity that includes vessels at sea. Wages have an overhead of 37.6% added to the personnel costs.

Table 8-12: Installation action assumptions

Action	*Time*	*Units*
Port to site and return (export cable lay)	4	hours (total)
Export cable pre-lay & post lay	3	hours (total)
Export cable lay and trench	44	hours (total)
Array cable import		
Port to site and return (array cable lay)	7	hours/trip (1 trip per 5,000 tonnes, approx. 70 km of cable)
Array cable lay	6	hours/turbine
HDD drill & pull cable	7	months
Port to site and return (mooring system lay)	4	hours/ 6 anchors
Mooring system drop & buoy off	6	hours/anchor
Turbine component imports	n/a	see total cost
Turbine assembly	1	days/turbine
Turbine pre-commissioning	4	hours/turbine
Turbine tow out	10	hours/turbine
Turbine ballast	12	hours/turbine

Turbine attach	10	hours/turbine
Turbine commissioning	18	hours/turbine
Return to port (turbine tow out)	2	hours/turbine
Substructure import	20	days/3 turbines
Substructure offloading	12	hours/turbine
Substructure pre-testing	6	hours/turbine

There are a number of assumptions that go into this model. The first, most important set of assumptions are regarding the timing of different actions. Action timing (in hours and days) was estimated based on a combination of academic literature, developer videos, and personal communications. In addition, 30% of the time was added to every action at sea to account for the possibility of waiting for better weather. It is assumed that installation activities are scheduled for the summer, which is generally calmer weather in northern California, but it is still likely that there will be some conditions that are not appropriate for installation activities. Secondly, it is assumed that vessel day rates include crew, and that the crew is capable of performing vessel-specific actions (for example, the crew of the anchor handling tug supply vessel are assumed to be responsible for dropping the anchors and setting up the mooring systems in-situ). Third, it is assumed that substructure assembly costs are included in the line-item for the cost of the substructure, so the installation line item for the cost of the substructure does not increase if the substructure is assembled locally.

This cost model accounts for all installation processes and builds the cost from the bottom up. There are a few improvements that could be made to improve the accuracy, but which were outside the scope of this work. First, the timing of the different activities is not well validated. Second, the model does not consider scheduling - it is assumed that every action can happen when it needs to without interfering with other installation activities. Third, the operational weather window (OWW) is an industry standard method, but it is simplified to 30% of time for every activity and does not account for northern California specific conditions or vessel specific limits.

The data that is utilized in this model includes academic literature, industry reports, and video evidence. Data regarding the timing of different actions is drawn from videos and from the NREL cost model documentation (Maness et al., 2017; Beiter et al., 2016). Wage data is drawn from literature regarding the offshore wind industry in northern California (Collins & Daoud, 2019). Vessel data, including day rates, speeds, and vessel capacity, is drawn from maritime industry reports and from academic literature regarding offshore wind vessels.

8.A.7 Development

Development costs were estimated based on simple estimates for a number of sub-components. Development costs include engineering and management, permitting, and site characterization. These costs are calculated for 2019, then reduced to account for the learning effect. Engineering & management is estimated to be 4% of balance of systems and turbine costs (Beiter et al., 2016). Permitting and site characterization costs are estimated to be a flat value (approximately 13 million dollars and 4 million dollars respectively) due to lack of information regarding potential scale effects on permitting costs (Maness et al., 2017).

Assumptions for this model are costs reported from the NREL balance of system (BOS) model in 2016 (Maness et al., 2017). The assumption that permitting and site characterizations costs are flat is an assumption that likely over-estimates cost for smaller farms and under-estimates costs for larger farms.

8.A.8 Soft Costs

In this cost model, soft costs include construction financing, construction insurance, commissioning, a decommissioning bond, procurement contingencies, installation contingencies, and the initial lease costs. Most of these costs are estimated using cost factors, see Table 8-13. Construction financing costs were estimated using an industry expert estimate (Musial et al., 2019a). The lease cost was estimated as a simple average of previous BOEM lease costs due to the deep uncertainty of auction-based costs and the nascent stage of the floating technology.

Table 8-13: Cost factors for estimating soft costs

Component	*Value*	*Applied to*	*Source*
Construction Insurance	1%	Turbine and BOS	Beiter (2016)
Insurance (general)	1%	Turbine and BOS	Beiter (2016)
Decommissioning Bond	15%	Turbine and BOS	Beiter (2016)
Procurement Contingency	5%	Hardware	Beiter (2016)
Installation Contingency	30%	Installation	Beiter (2016)
Commissioning	1%	Turbine and BOS	Beiter (2016)

8.A.9 Operations

Operational costs are calculated as the sum of the costs of sub-components. Operations costs include the BOEM lease fee, insurance, administration and management, port costs and fees, and grid costs and fees. The BOEM operating fee is calculated based on BOEM documentation, see equation 5. Insurance costs are estimated based on Castro-Santos et al. (2016). Administration and management costs are based on a previous version of an NREL cost model, in the back end of the Jobs and Economic Development Impact model and both port and grid costs and fees are assumed to be nearly zero (National Renewable Energy Laboratory, 2019).

Equation 5: Operating fee = (Op fee rate, %)*(nameplate, MW)*(cap factor, %)*(hrs per year)*(average LMP)

where,
Op fee rate = 2%
hours per year = 8760
Average LMP is assumed to be $40/MWh

There are a number of simplifying assumptions that are included in this cost estimate. It is assumed that operational insurance as well as management and administration costs are simple costs in $/kW that do not change with farm scale due to lack of granularity in industry estimates. In addition, port fees and costs are neglected due to high levels of uncertainty and the lack of local infrastructure - the development of the O&M port will define the port costs and fees. Ongoing grid connection fees do not seem to be significant for generators' operations, although there are relatively small fees for the initial connection (CAISO, 2013).

Sources of data for the estimation of operational costs are based on government documentation and academic literature. BOEM has documented the fees associated with leasing (Bureau of Ocean Energy Management, 2018).The academic literature is used to estimate insurance and administration costs and management costs (Castro-Santos et al., 2016; Maness et al., 2017; Beiter et al., 2016).

8.A.10 Maintenance

The cost model for maintenance costs are based on a bottom-up model. Maintenance costs are separated into three types of maintenance: calendar maintenance, condition-based maintenance, and corrective maintenance (Ioannou et al., 2018). Corrective maintenance costs are calculated for three types of turbine failures: minor repairs, major repairs, and major replacements, and cable repairs, see equation 6. Note that the model does not include any maintenance costs for hardware once the power has reached the state-wide grid.

Equation 6: Maintenance cost (for failure A)=(failure rate)*[material costs + (vessel rate)*(repair time+travel time+mobilization time)+ (wages)*(number of technicians)*(repair time+travel time)]

Condition based maintenance is calculated as 20% of corrective maintenance. Calendar based maintenance is estimated similarly to the corrective maintenance (see equation 6) for an in-situ annual maintenance and a larger, quayside maintenance occurring every five years. Material costs are assumed to be double the average minor or major repair cost for annual and five-year maintenance, respectively. Repair duration is assumed to be 12 or 36 hours for annual and five-year maintenance, respectively.

The assumptions built into the maintenance cost estimate are as follows: First, it assumes that failure rates are constant for the life of the project and do not vary with the severity of the weather regime or the frequency of proactive maintenance activities. Second, scheduling issues are not included in the calculations - it is assumed that technicians and vessels are available when needed. Third, it is assumed that the failure rate for the mooring lines is zero. Fourth, it is assumed that the time required to wait for an operable weather window (OWW) is 30%.

In addition to the assumptions, there are a number of limitations for this simplified cost model. First, the effect of the local weather regime might be underestimated. Dewan et al. (2016) notes that weather in Northern California is more extreme than in the North Sea, so failure rates might be higher than the majority of global installed capacity. Second, the relationship between failure rate and turbine size is not included because it is unknown. In addition, the material cost estimates to complete the repairs are for smaller turbines, but the relationship between cost and turbine size is unknown.

Input data for the model comes primarily from the academic literature. The method is drawn from Ioannou (2018) and NREL adjustments to the Research Institute of the Netherlands O&M tool (Beiter et al., 2016). Failure rates, material costs, and number of technicians come from a summary table published by Ioannou (2018). Wage data is drawn from literature regarding the offshore wind industry in Northern California (Collins & Daoud, 2019). Vessel data (including day rates, speeds, and vessel capacity) is drawn from maritime industry reports and from academic literature regarding offshore wind vessels (Dalgic et al., n.d.; "Anchor Handling Tug (AHT) Orcus," n.d.; Paterson et al., 2017; Burgess, 2016; Lacal-Arantegui et al., 2018). Cable failure rates are drawn from construction development reports for HVDC submarine cable projects (European Regional Development Fund, n.d.).

Chapter 9: Subsea Transmission Cable Stakeholder Identification

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1. INTRODUCTION

Humboldt County is an access point to the enormous offshore wind resource located on the north coast of California, but there is limited regional load and transmission capacity to absorb this electricity or transfer it to other load centers in the state. A subsea cable is one transmission alternative that could bring power from the north coast to areas with higher demand in the San Francisco Bay Area. As part of the North Coast Offshore Wind Study, two preliminary subsea cable corridors were developed that could connect between Humboldt Bay and the San Francisco Bay. The purpose of this memorandum is to describe different stakeholder groups and interested parties that may see benefits or concerns resulting from the subsea cable. The analysis includes an identification of stakeholder groups and interested parties and a viewpoint analysis to describe their potential perspective. Interviews and outreach to stakeholder groups and interested parties were not conducted as part of this study; information presented here is based on knowledge gained throughout the project and literature review of existing resources.

This document includes:

Section 2 - A brief description of the subsea cable corridors and components
Section 3 - A description of the scope of the analysis and the methods used for the study
Section 4 - A summary of stakeholder groups and interested parties' main benefits and concerns
Section 5 - A table listing all identified different stakeholder groups and interested parties with their potential perspectives

2. ABBREVIATED DESCRIPTION OF SUBSEA CABLE

The preliminary subsea cable corridors and technical components studied in this analysis are described in more detail in the Draft Subsea Transmission Cable Technical Memorandum by Mott MacDonald (Porter & Phillips, forthcoming).

Two potential subsea cable corridors were identified: near shore and offshore (Figure 9-1). The cable would connect between an existing converter station near Humboldt Bay Substation (King Salmon, CA) and a fictional converter station located within the San Francisco Bay Area, called the "Bay Hub". The Bay Hub would be connected to three transmission systems in the Bay Area with the following substations: East Shore (Oakland), Potrero (San Francisco), and Los Esteros (San Jose).

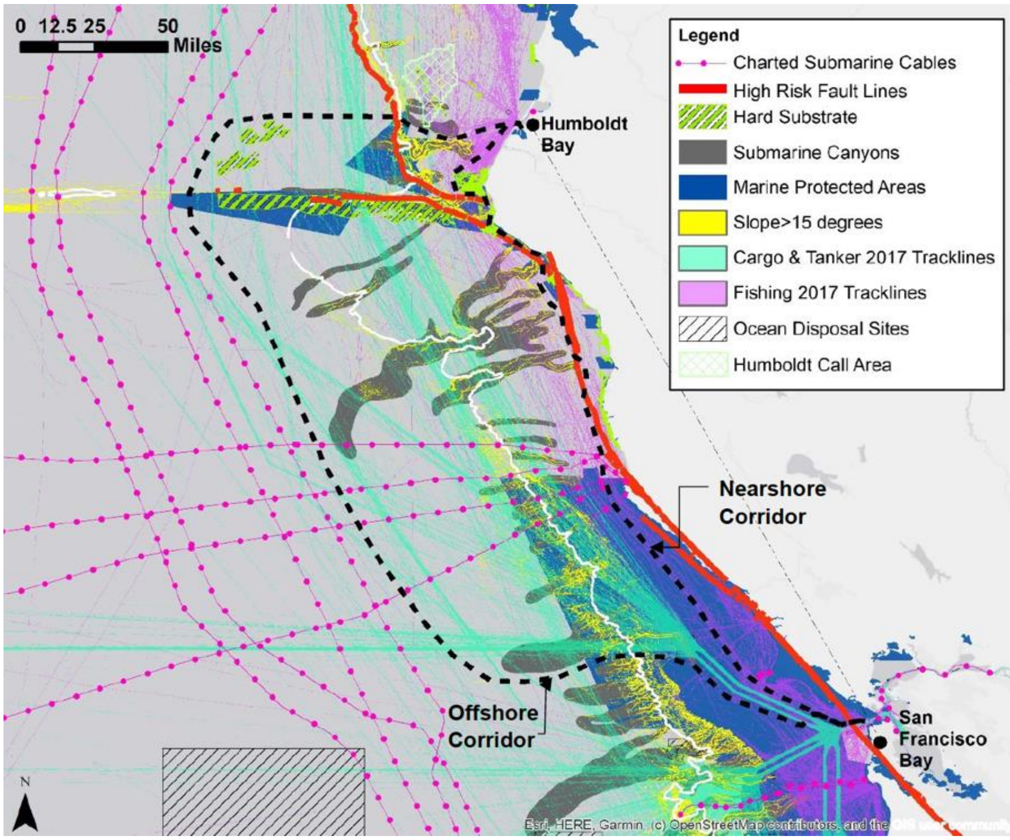

Figure 9-1. Map of subsea cable corridors and potential hazards; source: Draft Subsea Transmission Cable Technical, (Porter & Phillips, forthcoming)

The location of the Bay Hub is not determined in this study. Bringing a subsea cable through the Golden Gate would be extremely challenging from a geophysical and environmental permitting perspective. For the purposes of this study, the Bay Hub is located in some generic fictional onshore location in or around the San Francisco Bay Area, without specifying a particular siting location.

3. METHODS AND SCOPE OF ANALYSIS

Potential perspectives were identified for stakeholder groups[6] and other parties that have expressed interest in or may be impacted by offshore wind development. Potential perspectives were identified using a literature review of existing resources and by gathering insights from previous offshore wind analyses on the north coast conducted by Emery et al. (2020). Interviews and other methods of primary data collected were not used in this analysis due to the limited scope of work and the very early conceptual stage of the subsea transmission cable.

4. SUMMARY OF GROUPS/PARTIES AND PERSPECTIVES

The construction of a subsea corridor will impact groups in a variety of ways. Through a literature review, the following stakeholders and interested parties were identified and their potential perspectives are listed

[6] This research uses the term ‘stakeholder’ to describe immediate participants who are likely to interact with the process either during permitting, public meetings, through lawsuits, or during project development and implementation (Mitchell et al., 2003). These stakeholder groups are not intended as an exhaustive listing of community members or entities that might be engaged in or impacted by a potential offshore wind energy project, but instead provide a limited snapshot into local groups/communities that could be expected to play a significant role in the development process.

in Table 9-1. Summary of identified stakeholder and interested party perspectives., including: federal, state and local agencies, environmental groups, fishermen, labor, local business, county residents, Native American tribes, and the energy industry.

Table 9-1. Summary of identified stakeholder and interested party perspectives.

Theme	*Group(s)*	*Perspectives*
Potential Benefits		
Renewable Energy Development	Advocacy Organizations, State Agencies, Ratepayers, Environmental Groups, Energy Industry, and Tribes	The installation of a subsea cable could help expand the development of renewable electricity generated from offshore wind farms and help contribute to California's clean energy targets.
Economic Development	Labor Unions, Harbor District, Local Business Organizations, Local agencies, and Tribes	The installation and operation of a subsea transmission cable may create local jobs (including high wage jobs with benefits), professional development opportunities, and potential community benefit packages.
Potential Concerns		
Environmental Considerations	Environmental Organizations, Fishermen, State and Federal Agencies, Tribes, Local coastal residents/communities, and SF Bay Area Residents	The installation of a subsea cable could have negative effects to the local ecosystems because of wildlife displacement, the introduction of stormwater runoff on land, potential impacts to water quality and navigable waters from dredge/fill material, etc.
		An energized subsea cable may interfere with certain electro-or magneto-sensitive species that could affect marine fauna behavior (feeding and migration).
Economic Loss	Trawling Fishermen and Ratepayers	A subsea corridor may cause negative financial impacts due to loss of some historic fishing grounds, impacts on transit zones, and other concerns.
		A subsea corridor may cause the cost of energy to become more expensive than existing costs.
Existing Ocean Uses	Fishermen	A subsea cable may interfere with the fishing sector and result in a loss of historic fishing grounds to trawlers in particular, fishermen could incur impacts from increased vessel traffic on transit zones during installation or repair, potential for the loss of fishing gear due to entanglement, and other concerns.
Existing Ocean Uses	Shipping and Vessel Traffic	A subsea cable could interfere with established shipping routes during installation or repair, or pose a risk to damaging cable during anchoring.
Telecom and Military Operations	Military and Telecom Cable Operators	A subsea corridor may interfere with communications instruments and military operations, such as ability to access and repair telecom or other subsea cables.
Cultural Resources	State agencies, Tribes	The installation of a subsea cable may have potential impacts such as risking damage to submerged cultural resources (known and unknown).

5. DESCRIPTION OF GROUPS AND POTENTIAL PERSPECTIVES

Stakeholder groups and interested parties that may see benefits or concerns associated with a subsea transmission cable are described in Table 9-2 along with their potential viewpoint and perspectives.

Table 9-2. Potential perspectives for the identified stakeholder groups and interested parties.

Stakeholder Group/ Interested Party	*Location of Interest*	*Potential Perspectives*	*References*
Marine Protected Areas (MPA) management agencies	Subsea cable corridor and Bay Hub	Environmental concerns around subsea cable corridor which may encounter MPAs regarding effects to hard substrate fish habitat (i.e., Essential Fish Habitat (EFH), potential effects to electro-and magneto-sensitive species).	CDFW (2020).
Renewable Energy Advocacy Organizations	Subsea cable	The cable aids in developing more renewable energy that will reduce greenhouse gas (GHG) emissions.	Emery et al. (2020).
Environmental Groups	Installation of subsea cable	Environmental groups could have concerns related to: • Conservation of species and habitats, • Disturbance of marine fauna behavior (spawning, mating, feeding, communications, migration) with special concern for endangered, threatened or charismatic species, and • Air pollution and greenhouse gas (GHG) emissions from construction activities.	BSEE (2014), see Section 4.3 Stakeholder Interfaces, pages 19-21.
California State Agencies	Subsea cable, converter landfall location, and nearshore subsea cable in State waters	State agencies could have the following perspectives: • Concern for disturbance of cultural resources (known and unknown), • Preservation of the environment and resources with consideration of species and activities of local prominence (i.e., interests of commercial and recreational fishermen), and • Support for the development of renewable energy to meet state renewable energy targets.	OPC (2020), Objective 4.4. De León (2018), SB 100.

Stakeholder Group/ Interested Party	*Location of Interest*	*Potential Perspectives*	*References*
Fishermen	Nearshore subsea cable corridor and portions of offshore cable corridor	Fishermen could have the following concerns: • Loss of historic fishing grounds: around cable site, redistribution of fish, negative impacts to fishing operations from the potential entanglement of gear resulting in negative monetary impacts, • Potential impacts on trawling operations (disruption of established/historic fishing grounds), • Cable entanglement with fishing gear (resulting in loss of gear, potential fines, and subsequent gear retrieval), and • A decrease in work for the fishing sector (potentially). If a subsea cable allows for development in the region, several side effects due to the development include: • The inability to access fishing grounds into and out of the Humboldt Bay channel, due to increased vessel traffic during limited safe bar crossing intervals, • Competition for storage and access/space at the dock for fishermen's gear and the cable installation and maintenance, • Potential port infrastructure improvements including dredging & marine debris removal, • Opportunities for social justice regarding climate change responses that disproportionately affects fisherman with negative impacts, • Increased disenfranchisement among fishermen, • The challenge of obtaining a unified voice and position among fishermen, • Fishing sector contribution to the social & cultural fabric of the region which can negatively affect tourism if it is lost, and • Fishermen may express concern that electromagnetic fields (EMF) could affect marine life behavior.[7]	Emery et al. (2019), pages 8-9. Emery et al. (2020), pages 16-17; H.T. Harvey, (2020) page 87. Rodmell and Johnson (2020), page 78, and 86. H.T. Harvey, (2020) page 94-95.

[7] *Note that when evaluating this concern against scientific evidence, it is important to understand its validity. There is not much evidence that low levels of EMF would repel fish from their original habitat, but there is evidence for effects on feeding efficiency and migration. It is also possible that EMF could provide a benefit to fishermen by making some fish species more available.*

Stakeholder Group/ Interested Party	*Location of Interest*	*Potential Perspectives*	*References*
Fishermen *(continued)*	Nearshore subsea cable corridor and portions of offshore cable corridor	• Reduction of recreational fishing grounds can potentially create heavier reliance on remaining open fishing areas in areas where the cable encounters the most nearshore waters accessible by recreational fishers, however the areas where this could potentially affect recreational fishers are minimal as the majority of the subsea cable lays considerably offshore.	
Shipping and Vessel Traffic	Offshore cable corridor	Shipping companies could have the following perspectives: • Increased vessel traffic during installation could impede normal shipping vessel routes, • Existing shipping routes/lanes have been established by US Coast Guard based on safety criteria and subsea cable installation could cause a temporary detour at Humboldt Bay and San Francisco Bay entrances which may impede vessels from safety, and • Potential anchoring vessels could cause damage to subsea cable.	Berge (2019), public comment to BOEM Call Areas from Pacific Merchant Shipping Association.
Fiber Optic Cable Owners	Subsea cable corridors	Fiber optic cable companies could have the following perspectives: • A subsea power cable installation would need to include mitigation when crossing a submarine telecom cable (power cable could have potential impacts or damage existing fiber optic cables during installation), • Without proper installation, the HVDC transmission signal could interfere with the fiber optic signal, and • Installation is a particular challenge for the deep-water subsea cable corridor as no transmission cable has been installed at these depths.	

Stakeholder Group/ Interested Party	*Location of Interest*	*Potential Perspectives*	*References*
Labor Unions	Subsea cable installation and maintenance	Members of labor unions may have one of the following perspectives: • A variety of construction jobs may increase, including good paying positions (local and imported), • Positions with benefits may become available, • An increase in membership for the Unions and work hours for community members, and • Could be in support, dependent on whether unionized labor is negotiated successfully.	Emery, et al. (2019), page 5. Emery, et al. (2020), page 9.
Local Business Organizations or Economic Development Chapters	Subsea cable corridors and hub construction, deployment, installation, and maintenance	Perspectives surrounding economic development include: • Potential job creation in Humboldt Bay or San Francisco Bay Area during construction and ongoing maintenance,[8] • Indirect economic benefit (e.g. local spending of earnings) and indirect job creation (e.g. service industry jobs that support additional spending from labor), • Local professional development (specialized training, cable and power transmission hub maintenance), and • A potential community benefits package.	Emery et al. (2019). Emery et al. (2020).
Harbor District or Port Authorities	Port facilities	Development of a subsea cable may increase port traffic, which would provide economic benefit to the port and harbor district where vessels dock and load equipment.	Emery et al. (2020), page 9
U.S. Navy or Department of Defense (DOD)	Offshore	Perspectives may include: • Concern that the cable might interfere with military operations or submarine equipment, • No opposition for the near-shore transmission line if it stays within the no restriction zone, and • Opposition for the offshore transmission line because of intersection with a restricted zone according to the 2018 map.	Ianconagelo (2020). Chung (2018), page 26. Nikolewski (2018).

[8] *Note that some of the equipment and vessels used for subsea cable installation are highly specialized and may not develop a local workforce. However, on-land electrical and interconnection infrastructure, could be served by a local workforce.*

Stakeholder Group/ Interested Party	*Location of Interest*	*Potential Perspectives*	*References*
US Army Corps of Engineers (USACE) and US Environmental Protection Agency (EPA)	Nearshore & Offshore- Subsea cable installation and maintenance	These federal agencies could have the following perspectives: • Concern for the impacts from the potential subsea cable routes, length of the subsea cable, and how the subsea cable will be installed (i.e., will the subsea cable be buried thus leading to potential effects from trenching the ocean floor such as impacts to water quality standards and to navigable waters).[9]	BSEE (2014), Refer to page 18, USACE role with subsea cable installation.
Federal Agencies (Bureau of Ocean Energy Management, US Fish and Wildlife Service, National Marine Fisheries Service, National Oceanic and Atmospheric Administration (including Office of National Marine Sanctuaries), US Coast Guard)	Nearshore & Offshore- Subsea cable installation and maintenance	These federal agencies could have the following perspectives: • Potential impacts (such as loss of habitat or taking of a listed species) from cable installation to federal or state listed endangered species within area, • Conservation of species and habitats, avoidance of disturbance of marine fauna behavior (spawning, mating, feeding, migration, EFH), and • If the cable encounters a National Marine Sanctuary (NMS) (such as Cordell Banks or Greater Farallones NMS), additional review and approval required.	NOAA (2020). Areas of NOAA Office of National Marine Sanctuaries, Cordell Bank National Marine Sanctuary Boundary, and Greater Farallones National Marine Sanctuary Boundary.
Electric Utility Ratepayers	Subsea cable, both corridors	Ratepayers could have one of the following perspectives: • Concern about increases in electricity prices, and • Some may be more than willing to pay more for renewable energy.	Emery et al. (2019).

[9] *Note that these concerns would be addressed and mitigated as needed through standard permitting processes from the USACE and EPA.*

Stakeholder Group/ Interested Party	*Location of Interest*	*Potential Perspectives*	*References*
Tribes	Subsea cable installation: all phases, Converter landfall location	The Tribes could have the following perspectives: • Based on geography or other reason, Cultural Resources: known (sensitive info) & unknown (discovery), risking damage to submerged cultural resources, • Concerns about offshore wind developments impacts to future tribal generations, • Concerns for marine life and habitats. Many Native Americans regard the ocean and horizon viewsheds with great importance, and there may be concerns with project siting and fishing rights, • Support for economic development potential (workforce development for its members especially if regional economic and social benefits could be developed), and • Interest in renewable energy development to work against climate change.	BOEM (2018), Section 4.1, page 20. Emery et al. (2020) pages ii, 8, and 9.
SF Bay Area Residents	Converter Landfall location	Any redevelopment within the county must occur in a manner that is: • Sensitive to the historic aspect, • Sensitive to the environment (scenic beauty), and • Compatible with what already exists within the area. Local residents may have one or more of the following concerns regarding stormwater runoff: • May cause flooding and property damage, • Negatively impact local ecosystem and waterways, • Aesthetically displeasing, and • May require new or renovated infrastructure to transport water, which takes up space and money.	Port of SF (2004). Department of Energy & Environment (n.d.).

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Appendix A. Offshore Wind Study Assumptions

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Table of Contents

1. INTRODUCTION

The potential for offshore wind energy generation is being investigated along the northern coast of California for twelve different scenarios that vary by wind array scale, location, and electrical transmission route. This document provides a description of the wind farms scenarios in the North Coast Offshore Wind Study. This document begins with an overview of the different wind farms, including maps of the region, then presents the technical details that form the basis of analysis. The assumptions presented in this document were developed using publicly available reports and communication with developers.

2. OVERVIEW OF CHARACTERISTICS

The different options comprising a scenario are summarized in the list below. Each scenario contains a distinct combination of options as defined in Table A-1 and shown in the maps in Figure A-1 and Figure A-2. Each option is described in greater depth in the Technical Descriptions in Section 4.

- **Location**
  - Offshore Humboldt Bay (HB) – outlined by the Bureau of Ocean Energy Management (BOEM) Humboldt Call Area (BOEM, 2018). The HB area is roughly 40 - 55 km (20 – 30 nautical miles) offshore with an area of 540 km^2 (210 mi^2) and ocean depths between 500 to 1,100 meters (1,600 to 3,600 ft).
  - Offshore Cape Mendocino (CM) - notional study area with high wind speeds. The CM area is roughly 6 - 40 km (3 - 20 nautical miles) offshore with an area of 532 km^2 (190 mi^2) and ocean depths between 100 to 1,100 meters (330 to 3,600 ft).
    Note: This area is being studied for comparative and modeling purposes only. This area has not been screened by any ocean user community and is not representative of a BOEM call area. BOEM has not indicated any interest in this representative area for wind development. Justification for the study of this area is provided in the Location section below.
- **Wind Array Scale**
  - Pilot Scale - approximately 50 MW using 4 - 12 MW turbines (actually 48 MW)
  - Small Commercial – approximately 150 MW using 12 - 12 MW turbines (actually 144 MW)
  - Large Commercial – Full build out of study areas for a capacity of approximately 1,800 MW using 153 -12 MW turbines (actually 1,836 MW)
- **Cable Landfall**
  - The wind farm export will be horizontally directionally drilled (HDD) under the South Spit and Humboldt Bay with a vault for connecting two HDDs on the South Spit.
- **Interconnection Location**
  - Overland Transmission - interconnection at Humboldt Bay Substation near the Humboldt Bay Generating Station (HBGS).
  - Subsea Transmission – conversion to high-voltage, direct-current (HVDC) near HBGS.[10] then transmitted to interconnection point with electrical grid within the San Francisco Bay.
- **Transmission Route**
  - Overland East - using existing utility right of way heading east
  - Overland South - using existing utility right of way heading south
  - Subsea - hypothetical subsea cable corridor heading south to the San Francisco Bay
- **Development Timeline**
  - Operation Date
    - 50 MW and 150 MW projects are assumed to be operational in 2026
    - 1,800 MW project assumed to be operation in 2028

[10] This adds cable length to send the export cable north from the the Cape Mendocino area HVDC conversion. This choice simplifies the analysis rather than identifying another suitable location further south on the coast.

- System Lifetime - assumed to be 20 years

3. DESCRIPTION OF SCENARIOS

Twelve total scenarios are being evaluated, including seven in the Humboldt Call Area and five in the Cape Mendocino area (Table A-1). For the Call Area, the project will study all three wind array scales with both overland transmission routes. In the Cape Mendocino area, the 150 MW and full build out scenario will be studied for overland transmission. The 50 MW scenario is deemed too small to warrant the longer transmission route from the Cape Mendocino. For both locations, the subsea transmission route will be studied only for the 1,800 MW scale scenario.

Table A-1. Description of basic characteristics defining each scenario.

Scenario Name[a]	*Geographic Location*	*Wind Array Nameplate*	*Turbine Size*	*Transmission Route*	*Cable Landfall*	*Electrical Interconnection Location*
HB-50-East	Offshore Humboldt Bay (HB)	48 MW	12 MW12 MW	Overland, east	Landfall at South Spit of Humboldt Bay (HB)	Interconnection near Humboldt Bay Generating Station (HBGS)
HB-50-South				Overland, south		
HB-150-East		144 MW		Overland, east		
HB-150-South				Overland, south		
HB 1800-East		1,836 MW[b]		Overland, east		
HB-1800-South				Overland, south		
HB-1800-Subsea				Subsea, south	Two locations: 1) Landfall at South Spit for conversion to HVDC near HBGS 2) Landfall at subsea cable southern terminus (location tbd in Mendocino/Sonoma/SF Bay Area)	Subsea cable interconnection location tbd (Mendocino/Sonoma/SF Bay Area)
CM-150-East	Offshore Cape Mendocino (CM)	144 MW	12 MW	Overland, east	Landfall at South Spit of Humboldt Bay (HB)	Interconnection near Humboldt Bay Generating Station (HBGS)
CM-150-South				Overland, south		
CM-1800-East		1,836 MW[b]		Overland, east		
CM-1800-South				Overland, south		
CM-1800-Subsea				Subsea, south	Two locations: 1) Landfall at South Spit for conversion to HVDC near HBGS 2) Landfall at subsea cable southern terminus (location tbd in SF Bay Area)	Subsea cable interconnection location tbd in SF Bay Area

[a] Scenarios are label with naming convention *AA-##-Bbb*, where '*AA*' indicates the wind array location, '*##*' indicates the approximate wind array scale, and '*Bbb*' indicates the transmission route.

[b] A cost analysis will also be conducted for a 3,000 MW wind array using a south subsea transmission route.

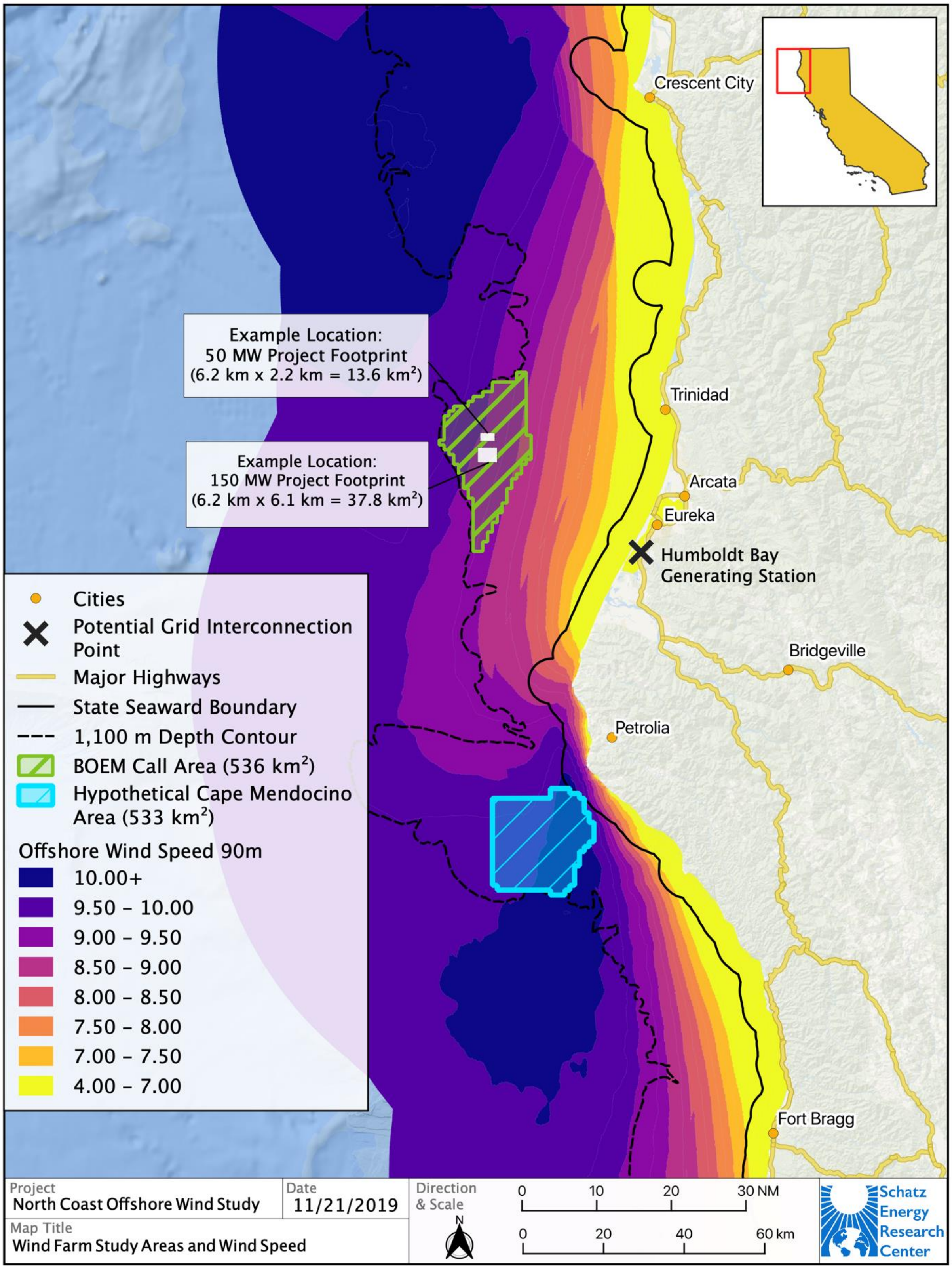

Figure A-1. Map containing ocean wind speeds and potential wind array locations and sizes.

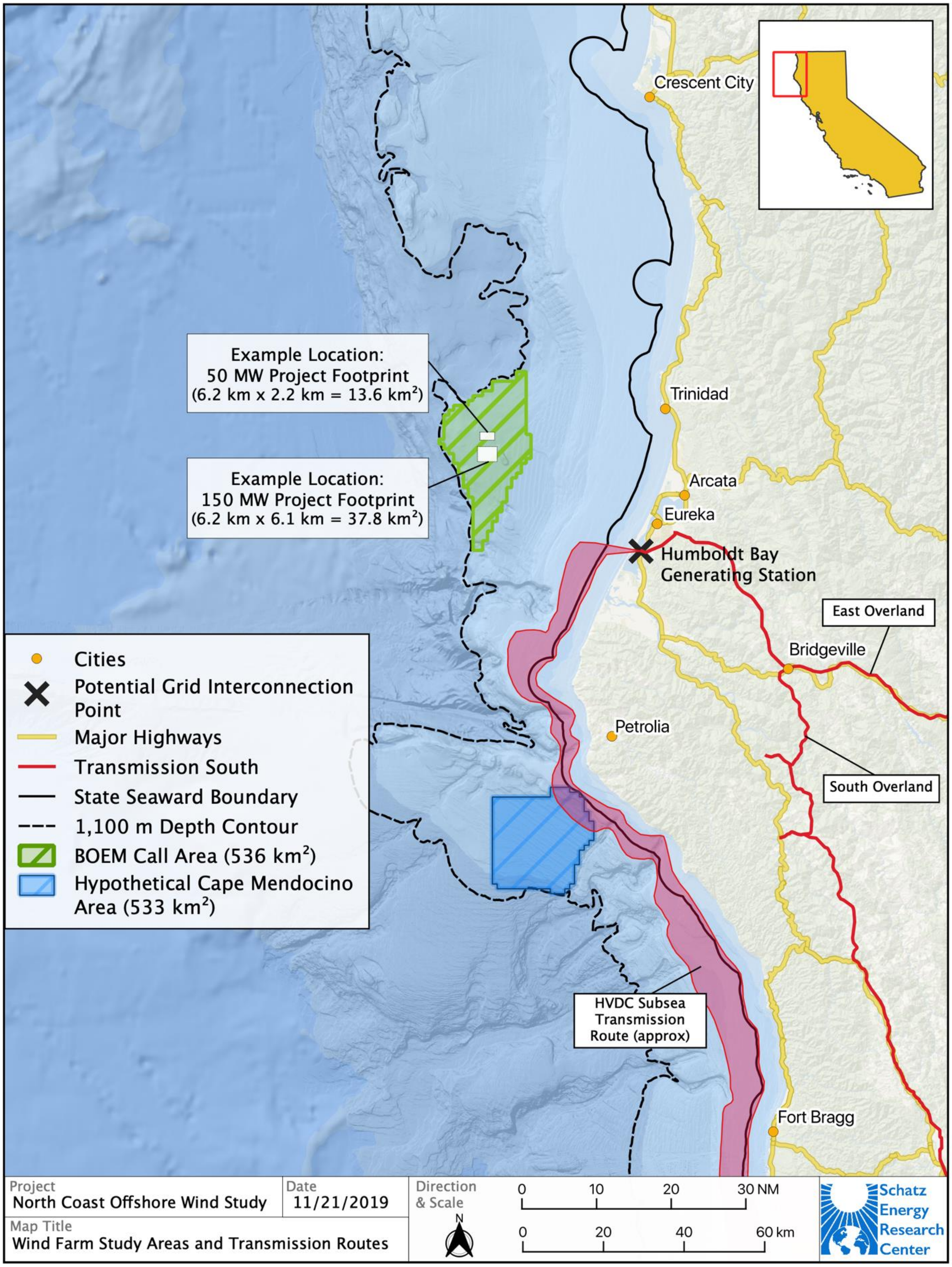

Figure A-2. Map of the overland and subsea transmission line options for the two potential wind array areas.

4. TECHNICAL DESCRIPTION

The remainder of this document provides more details about the options that outline a scenario.

The characteristics that define each scenario are described in detail below.

4.1 Timeline

Offshore wind development is in the early stages of planning in California. The assumed timeline for development (Figure A-3) will depend on the actual speed of leasing, permitting, development, and construction.

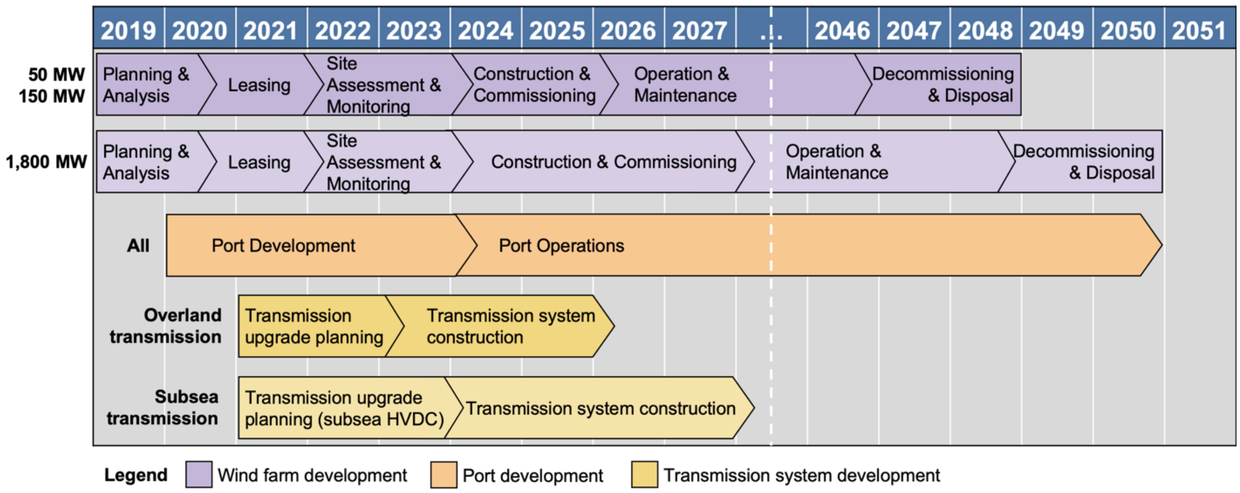

Figure A-3. Assumed timeline of development.

BOEM (2019a) describes an approximately seven-year regulatory process of offshore wind development (see Table A-2). The process in California is currently in the Planning and Analysis phase. The assumptions for the timeline are listed below:

- All scenarios, irrespective of location, capacity, and transmission route, have the same leasing and permitting timeline. The 1,800 MW wind array has longer construction phase to account for significantly more turbine installations.
- Wind array commissioning: 2026 (50 & 150 MW) or 2028 (1,800 MW)
- Wind array lifetime: 20 years
- Wind array start of decommissioning: 2046 (50 & 150 MW) or 2048 (1,800 MW)

Table A-2. Timeline for development of offshore wind facility.

Phase	*Description*	*Duration*	*Assumed Timeline*
Planning & Analysis [a]	• Intergovernmental Task Force • Call for Information and Nominations • Area identification • Environmental reviews	~ 2 years	until 2020

Phase	*Description*	*Duration*	*Assumed Timeline*
Leasing [a]	• Publish leasing notice • Hold competitive auction • Issue lease	~ 1-2 years	2020 - 2022
Site Assessment [a]	• Site Characterization • Site Assessment Plan	up to 5 years (assumed 2 years)	2022 - 2024
Construction & Commissioning [c]	• Construction and Operations Plan • NEPA and CEQA environmental review • Facility Design Report • Fabrication and Installation Report • Procurement • Assembly • Construction of wind farm • Commissioning of wind farm	~ 2 years (50 & 150 MW) ~ 4 years (1,800 MW)	2024 – 2026 2024 – 2028
Operation & Maintenance [c]	• Ongoing operations • Ongoing maintenance	20 years[d]	2026 – 2046 (50 & 150 MW) 2028 – 2048 (1,800 MW)
Decommissioning & Disposal [c]	• Decommissioning • Disposal	2 years	2046 – 2048 (50 & 150 MW) 2048 – 2050 (1,800 MW)
Port Development [b]	• Port development planning • Permitting process for port development • Port construction	4 years	2020 - 2024
Port Maintenance & Operations [b]	• Ongoing maintenance and operations of the port and harbor facilities	23 years	2024 - 2050
Transmission Upgrade Planning[b]	• Permitting • Planning • Engineering	2 years (overland) 3 years (subsea HVDC)	2021 – 2022 2021 – 2023
Transmission System Construction [b]	• Construction of transmission system	3 years (overland) 4 years (subsea HVDC)	2023 – 2026 2024 – 2028

[a] BOEM (2019a)

[b] Port and transmission system development is not a part of BOEM's regulatory process, but the timeline needs to be outlined for this study.

[c] BOEM (2019a) combines these phases into a single "Construction & Operation" phase. For the purposes of this study, we split this into three groups

[d] 25 years is the typical lease term (starting at the date of lease issuance). The lease tern could be longer than 25 years or extended for repowering purposes.

4.2 Location

Two locations will be investigated: the Humboldt Call Area located west of Humboldt Bay and another location offshore Cape Mendocino. Descriptions and maps are provided below and summarized in Table A-3. The footprint occupied by the wind array is assumed to be an economic exclusive zone where other commercial users are legally excluded from fishing or transiting through the site.

4.2.1 Offshore Humboldt Bay (HB)

The Humboldt Call Area identified by the Bureau of Ocean Energy Management (BOEM, 2018) located west of Humboldt Bay approximately 20 to 30 nautical miles offshore (Figure A-4).

4.2.2 Offshore Cape Mendocino (CM)

A second wind array location is considered for comparative purposes. A hypothetical wind array area offshore Cape Mendocino was outlined by the Schatz Energy Research Center to study the differences between this site and a wind array within BOEM's Humboldt Call Area (2018). This area has not been screened by any ocean user community and is not representative of a call area. BOEM has not indicated any interest in this representative area for wind development.

A notional wind array area was outlined in federal waters offshore Cape Mendocino (Figure A-5). This general area was identified by Musial et al. (2016a) as a promising offshore wind area and we are studying this region for comparative purposes. The area to be studied in this project was defined by three simple assumptions: 1) including the highest average wind speeds in the region, 2) creating a boundary that will accommodate the same number of turbines as the Call Area for the full build out scenario, and 3) excluding any deep-water canyons. The area is defined in Figure A-5 and characterized below.

Table A-3. Geographic specifications of study locations.

Site name		*Humboldt Call Area*	*Hypothetical Cape Mendocino Area*
General area		Offshore Humboldt Bay	Offshore Cape Mendocino
West-East width		12 NM (22 km)	14 NM (25 km)
North-South width		25 NM (46 km)	15 NM (29 km)
Total area		207 mi^2 (537 km^2)	155.25 NM^2 (532.5 km^2)
Perimeter		81 NM (150 km)	55.6 NM (103 km)
Centroid location	Lat.	-124.662°	-124.496°
	Lon.	40.965°	40.090°
Distance to shore	Min.	17.4 NM (32.2 km)	3.1 NM (5.70 km)
	Max.	30.4 NM (56.3 km)	20.0 NM (37.0 km)
Average annual wind speed at 90 m height	Min.	8.875 m/s	9.625 m/s
	Mean	9.35 m/s	9.875 m/s
	Max.	9.875 m/s	10.125 m/s
Ocean depth	Min.	1,640 ft (500 m)	328 ft (100 m)
	Mean	2,673 ft (815 m)	2,140 ft (652 m)
	Max.	3,610 ft (1,100 m)	3,610 ft (1,100 m)
Construction and maintenance port	Name	Redwood Marine Terminal 1	
	Lat.	40.817°	
	Lon.	-124.182°	
Centroid to port distance, approximate ship route		27 NM (50 km)	55.5 NM (103 km)
Interconnection point	Name	Humboldt Bay Generating Station	
	Lat.	40.742°	
	Lon.	-124.211°	
Centroid to interconnection point distance, approximate cable route		25 NM (46 km)	45 NM (83 km)

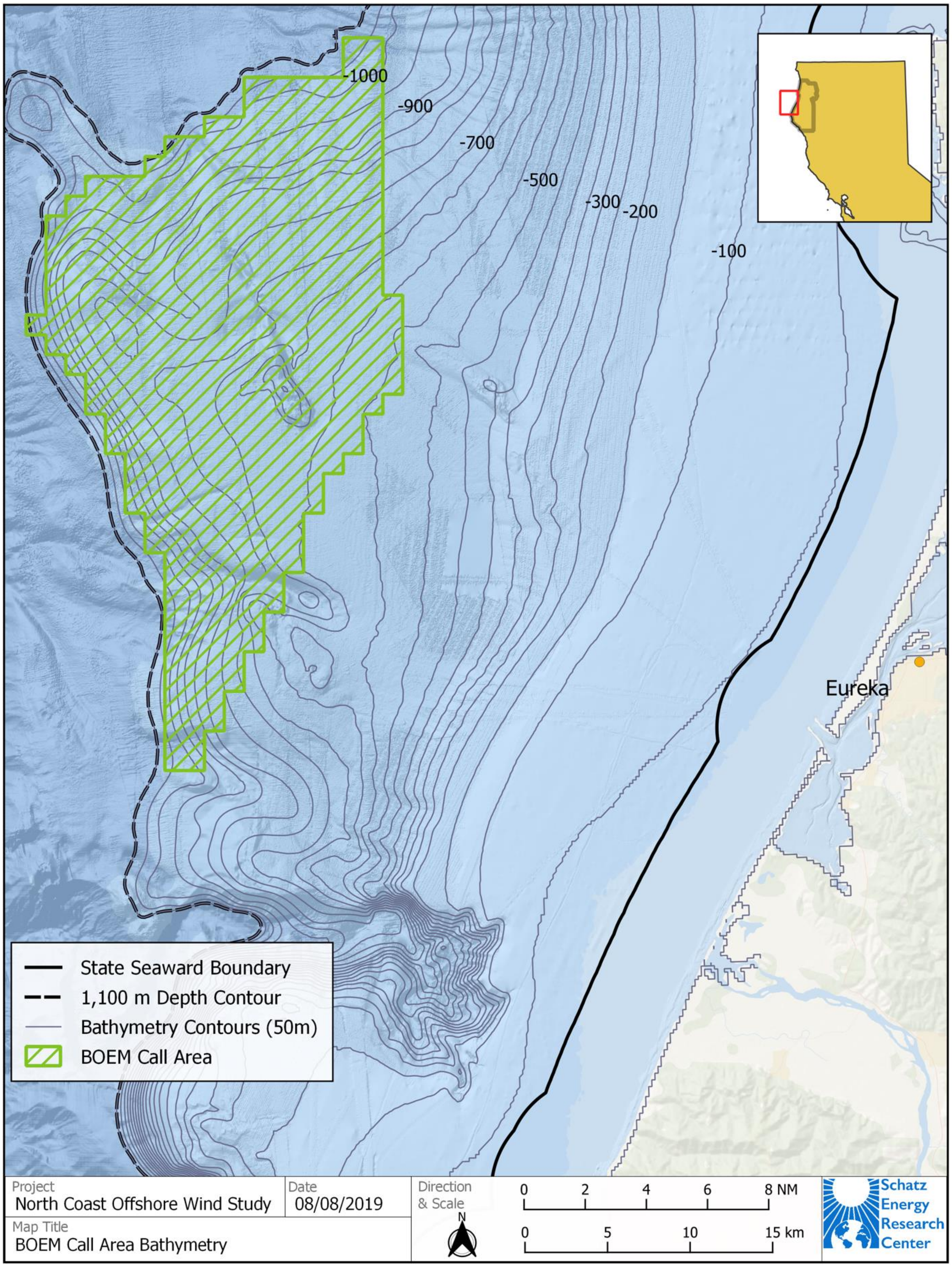

Figure A-4. Humboldt Call Area with 50 m bathymetric contours.

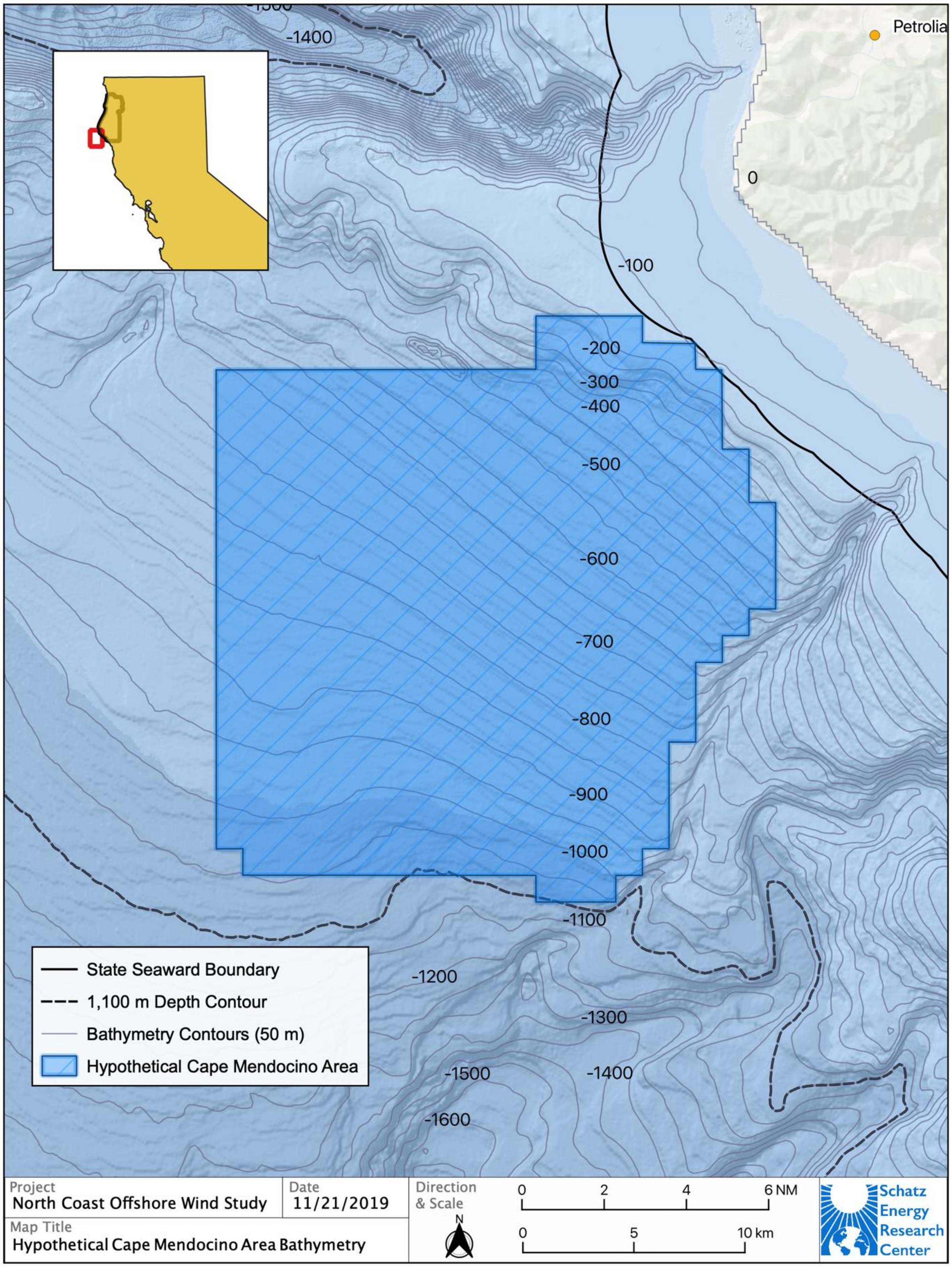

Figure A-5. Notional Cape Mendocino area with 50 m bathymetric contours

4.3 Equipment Description

This section provides technical details for the equipment assumed in this study. This section describes the turbines, floating substructure, mooring lines, and wind farm layout.

4.3.1 Wind Turbines

All wind farms are assumed to use a 12 MW turbine. The specifications for this turbine are derived from the standard reference turbine developed by the National Renewable Energy Laboratory (NREL). The dimensions of the turbine are pictured in Figure A-6 with the specifications outlined in Table A-4. The power curve is shown in *Figure A-7*.

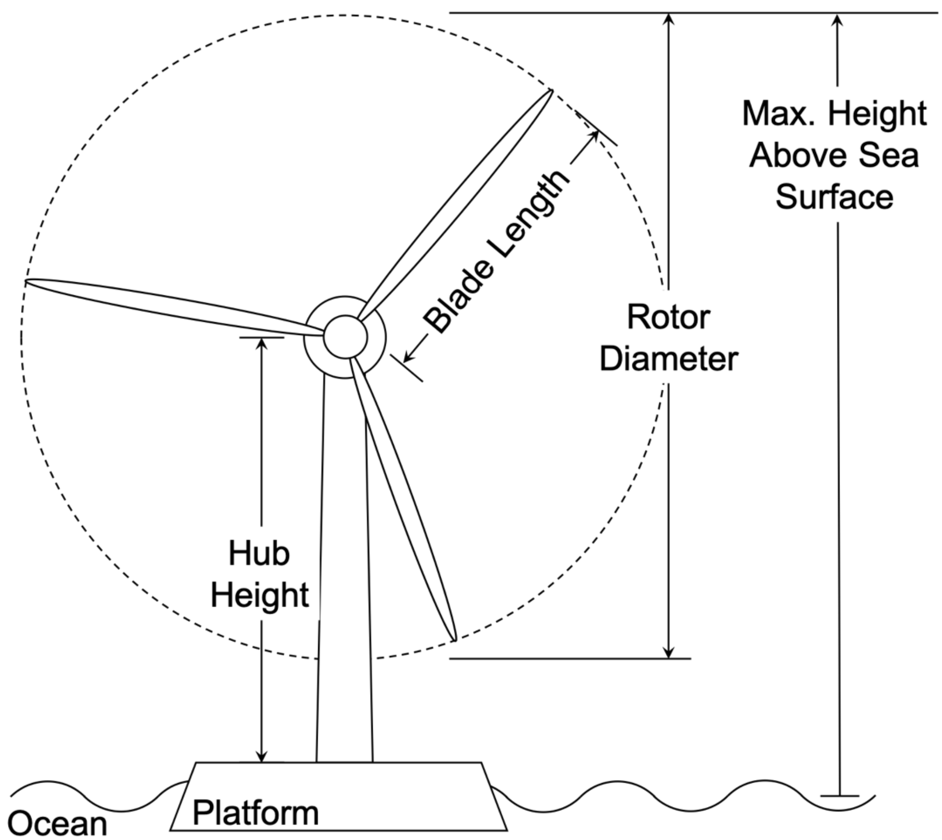

Figure A-6. Dimensions of a wind turbine.

Table A-4. Specifications of wind turbines in this study. Specifications are subject to change based on developer outreach.

Wind Array Capacity	*Turbine Rated Power*	*Hub Height*	*Rotor Diameter*	*Blade Length*	*Max. Height Above Sea Surface*	*Source*
50 MW	12 MW	136 m	222 m	107 m[a]	264 m	Musial et al., 2019
150 MW						
Full Build						

[a] Blade length based on GE Haliade-X 12 MW turbine (GE, 2019b).

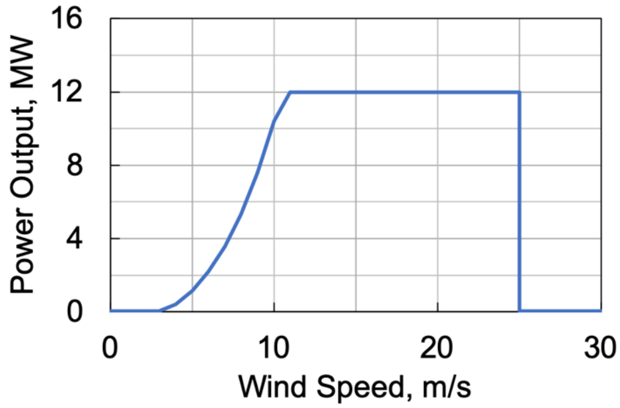

Figure A-7. Power curves for 12 MW NREL reference turbines from Musial et al. (2019).

4.3.2 Floating Substructure Description

A semi-submersible floating substructure will be used for this analysis following Musial et al. (2016a and 2019). The basic substructure design comprises three semisubmersible columns connected in a triangular formation with the turbine mounted in the center (Figure A-8). Platform dimensions (Table A-5) are determined using expert advice from developers and a basic design described in Robertson et al. (2014). Two substructure sizes are identified, one large (Type A) and one small (Type B), that cover the range of potential substructure dimensions. The material of the substructure is either steel or concrete, but not specified for the purposes of this study.[11]

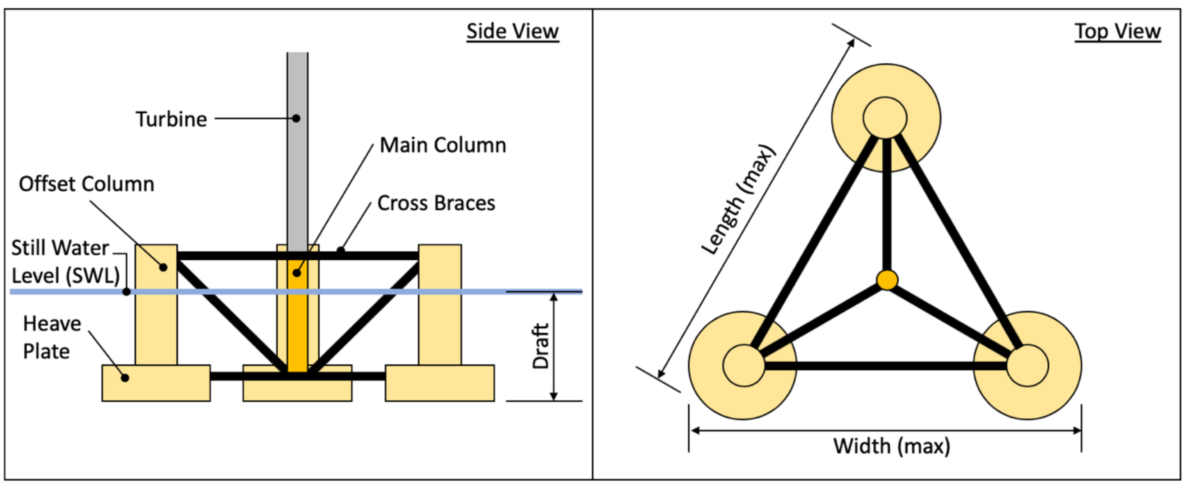

Figure A-8. Dimensions of a floating platform. Generic design based on Robertson et al. (2014).

[11] Our goal is to be technology agnostic. Both steel and concrete platforms could be used.

Table A-5. Description of floating substructure.

Parameter	*Type A*	*Type B*
Length (max)	91 m (300 ft)	61 m (200 ft)
Width (max)	91 m (300 ft)	61 m (200 ft)
Draft (unloaded)	7.6 m (25 ft)	5.5 m (18 ft)
Draft (in transit)	11 m (36 ft)	7.6 m (25 ft)
Draft (in operation)	18 m (60 ft)	18 m (60 ft)

4.3.3 Mooring Line and Anchor Description

Mooring and anchor systems will change based on ocean depth, bottom type, and other factors. For this study we cannot carry out a detailed mooring and anchor design, so a simple system was identified that would be suitable for water deeper than 600 m and would have a limited footprint on the ocean floor.

A three-line, taut-leg mooring system will connect to the bottom of the substructure with equal spacing from one another (Figure A-9). The mooring line will be composed of high-modulus polyethylene (HMPE) starting at the connection point on the substructure and then transition to a steel chain close to the anchor (Copping & Greg, 2018). Anchor piles will be used to connect the mooring line to the seafloor.

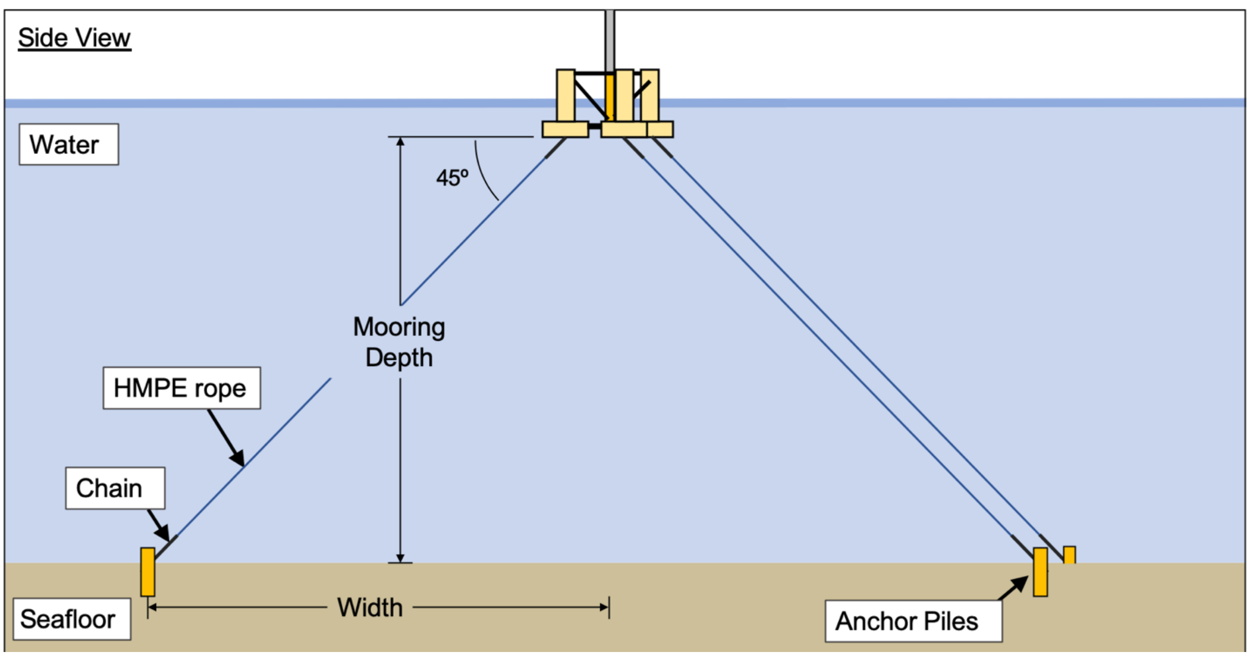

Figure A-9. Side view of platforms with taut-leg mooring and anchor piles. Drawing not to scale.

The mooring lines extend radially away from the floating substructure and attach to the seafloor. The mooring line angle is 45 degrees to the surface. Thus, the footprint of the mooring on the seafloor is a circle with a radius equal to the mooring line length (i.e. the ocean depth minus the platform draft). See Figure A-10 for an example layout. Mooring line and anchor specifications are presented in Table A-6.

The mooring system will have a larger footprint in deeper water. Using the offset 7D x 10D turbine spacing outlined in Section 4.3.4, below, mooring lines from neighboring turbines will begin to overlap at an ocean depth of 918 meters. To avoid overlap, the spacing turbine spacing will increase in waters deeper than 918 m.

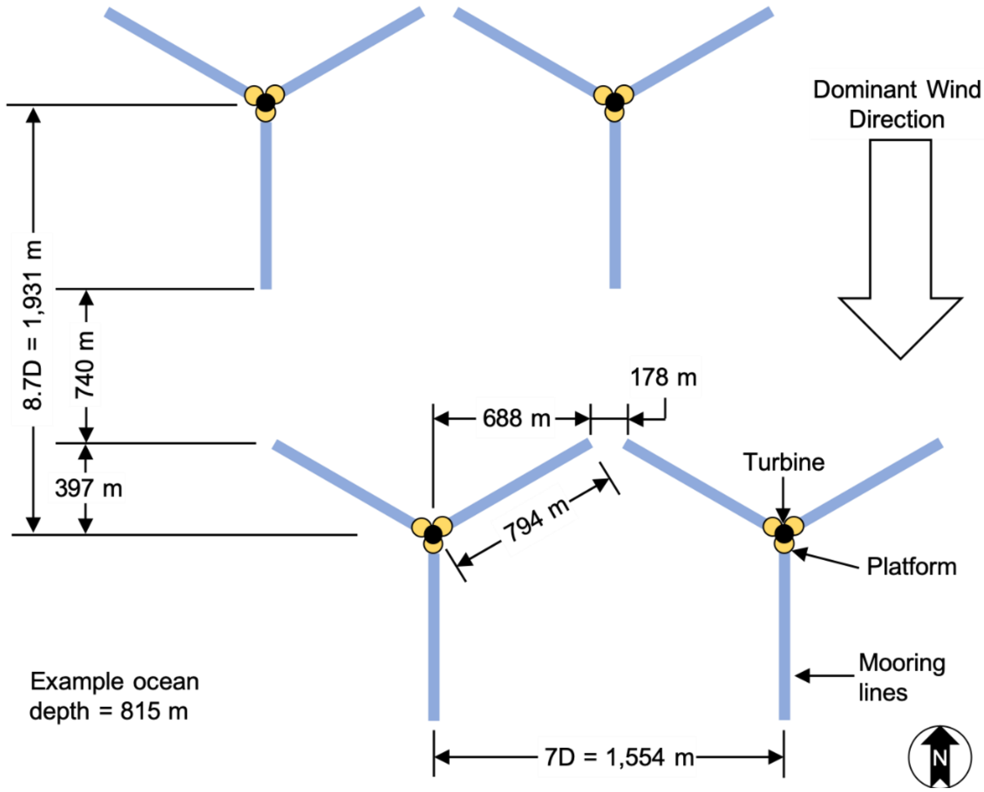

Figure A-10. Top view of mooring lines with 12 MW turbine array. Footprint of mooring lines in this illustration is based on an 815 meter ocean depth, the average depth of the Humboldt Call Area.

Table A-6. Mooring line and anchor specifications. Subject to change based on developer outreach.

Parameter	*Value*	*Justification*	*Source*
Mooring type	Taut-leg mooring lines	Most suitable technology for deep waters between 600 and 1,000 m	Developer input
Connection points	On platform sides, 18 m below sea surface, three connection spaced equidistant from each other	Copied verbatim, with depth changed from 18 to accommodate substructure draft	Copping & Grear, 2018
Mooring line configuration	120° between each line with respect to the seafloor	Based on unsolicited lease requests and proven technology	Copping & Grear, 2018
Mooring line material	HMPE rope, transitioning to a chain near the anchor	HMPE is light and flexible. The chain will withstand more along the seabed.	Copping & Grear, 2018; Eriksson & Kullander, 2013
Mooring line diameter	112 mm	Based on unsolicited lease requests/copied verbatim. Unscaled from 5 MW turbine.	Copping & Grear, 2018

Parameter	*Value*	*Justification*	*Source*
Mooring line mass	8.2 kg/m	Based on unsolicited lease requests/copied verbatim. Unscaled from 5 MW turbine.	Copping & Grear, 2018
Anchor type	Piled Anchors	Suitable for deep water. In-depth geologic study required to determine actual anchor type.	Developer input

4.3.4 Wind Farm Array

Three wind array scales will be studied: 50, 150, and 1,800 MW, as described below. A 12 MW turbine will be used in all wind arrays.

- Pilot Scale - approximately 50 MW wind array comprised of four 12 MW turbines (48 MW total)
- Small Commercial - approximately 150 MW wind array comprised of twelve 12 MW turbines (144 MW total)
- Large Commercial – Installation of turbines in the entire Humboldt Call Area, which can accommodate 153 turbines at 12 MW each for a 1,800 MW nameplate capacity (1,836 MW total)

The wind turbines are arranged within the array using four criteria:

1. <u>10D x 7D Spacing:</u> Wind turbines have 10 rotor diameters (10D) of space in the North-South direction and 7D of space in the East-West direction. Spacing is increased in the North-South direction to minimize wake effects in the direction of the dominant winds. The spacing is determined by establishing an elliptical area around each turbine. The major diameter, 10D, of the ellipse is in the direction of the prevailing wind, and minor diameter, 7D, perpendicular to it. The spacing was established following Musial et al. (2016b) and using input from developers. The number of rows and columns of turbines depends on the total power capacity of the wind array. The critical dimensions of the turbines and wind array are described in Table A-7.
2. <u>Offset Rows:</u> Rows in the wind array are offset perpendicular to the prevailing winds to minimize wind shading from the upstream row. Spacing dimensions are provided in Figure A-11 and Table A-7.
3. <u>Mooring Line Overlap:</u> Mooring lines from adjacent turbines cannot overlap. In deeper waters, mooring systems require a larger footprint on the ocean floor. This study assumes that the horizontal footprint of the mooring system is equal to the depth of the mooring lines (see Section 4.3.3). As the ocean becomes deeper and the mooring system footprint extends, the turbine spacing will increase to avoid overlapping mooring lines (see Figure A-12 and Figure A-13, for example.
4. <u>Mooring Line Boundary:</u> Mooring lines must be kept within the perimeter of the call area.

For the full build out scenario, turbines are placed with the spacing in Figure A-11 unless deep water requires increased spacing to eliminate mooring line overlap. This layout allows for 153 of the 12 MW turbines to fit within the Humboldt Call Area (Figure A-12), with a total capacity of 1,800 MW. The boundary of the Cape Mendocino study area was created to accommodate the same number of 12 MW turbines for full build out (Figure A-13).

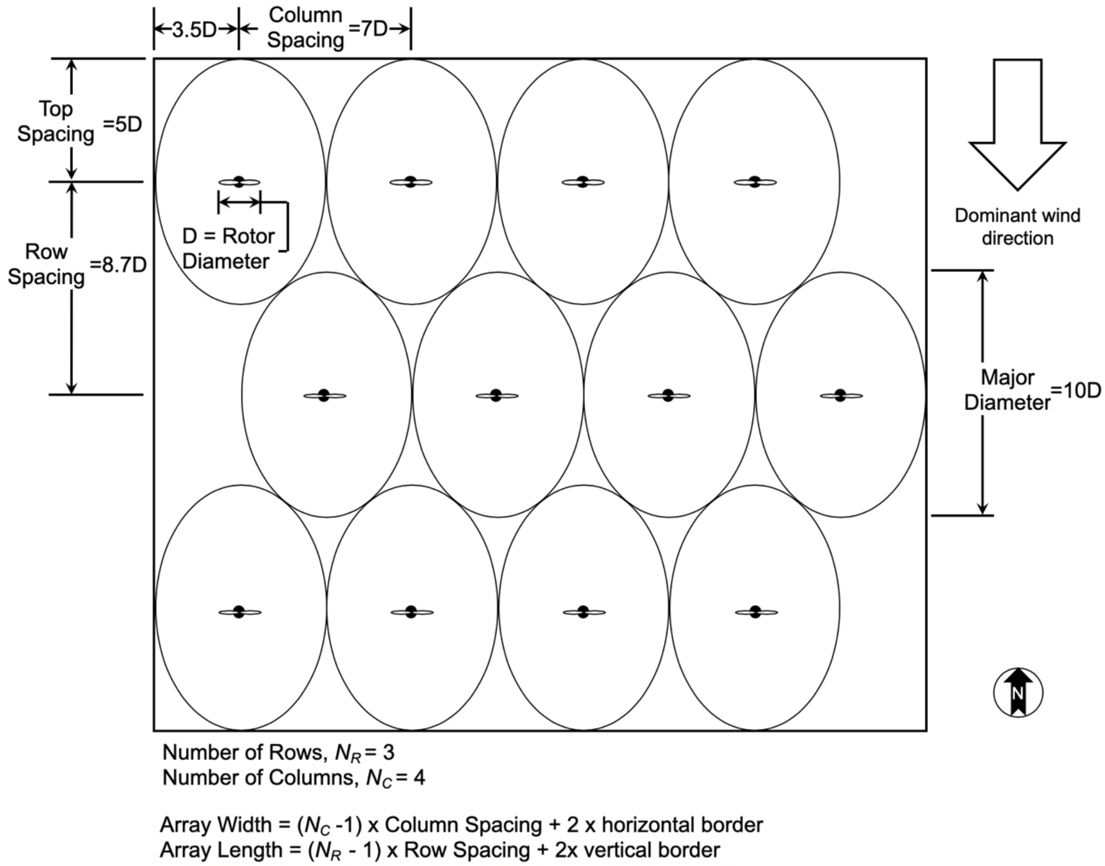

Figure A-11. Dimensions of a wind array layout.

Table A-7. Specifications for the turbines and dimensions for the wind array grid layout.

Wind Array Capacity	*Number of Turbines*	N_{Column}	N_{Row}	*Array Width*	*Array Length*	*Array Area*	*Calculated Specific Power, MW/km*^{2}
48 MW	4	4	1	6.2 km	2.2 km	13.6 km^2	3.5 MW/km^2
144 MW	12	4	3	6.2 km	6.1 km	37.8 km^2	3.8 MW/km^2
1,800 MW	153	See maps below for full build out arrangement					~4.0 MW/km^2 [a]

[a] The specific power is slightly different between both study areas because the areas are slightly different.

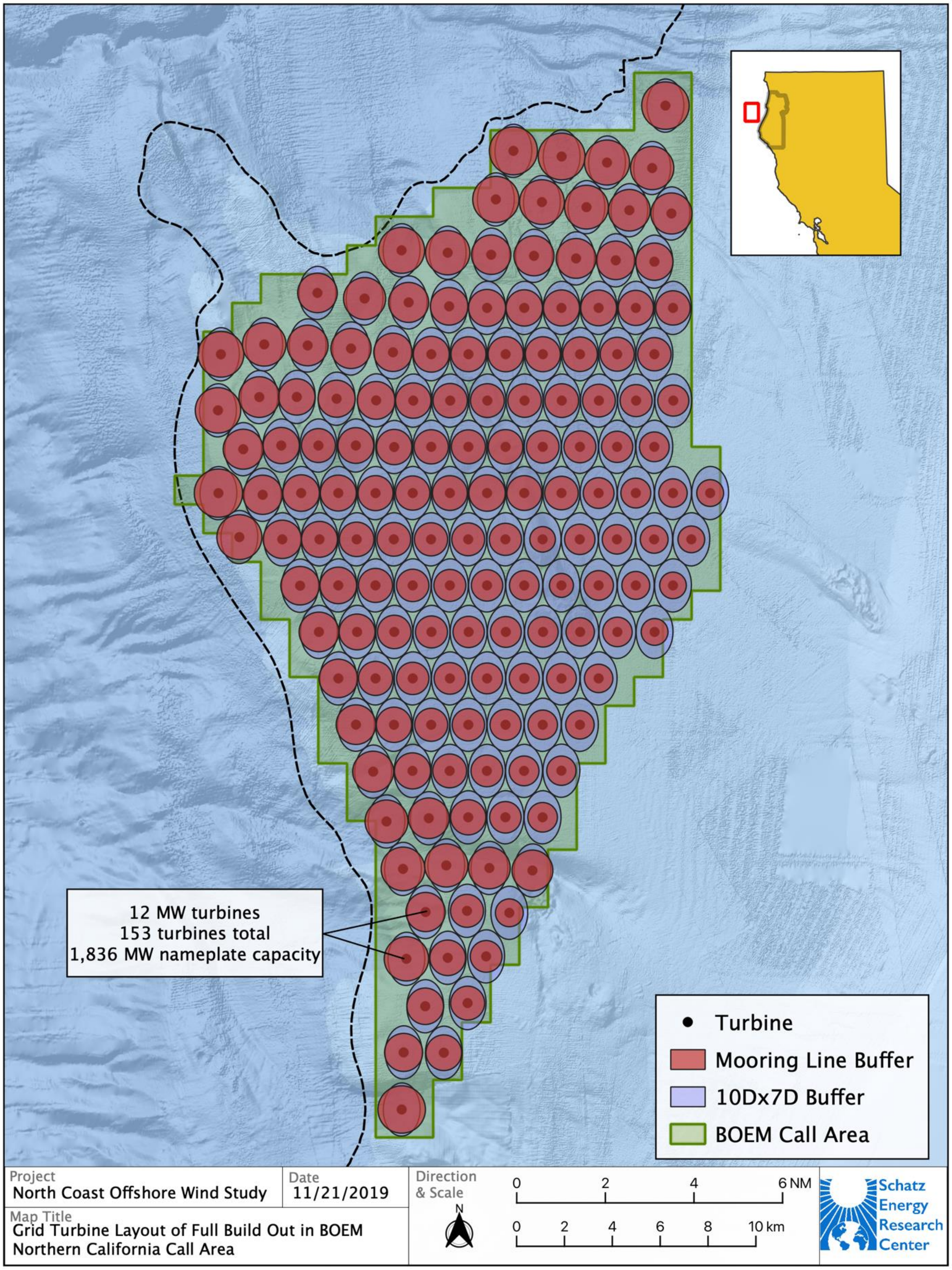

Figure A-12. Turbine layout of full-build out scenario in Humboldt Call Area.

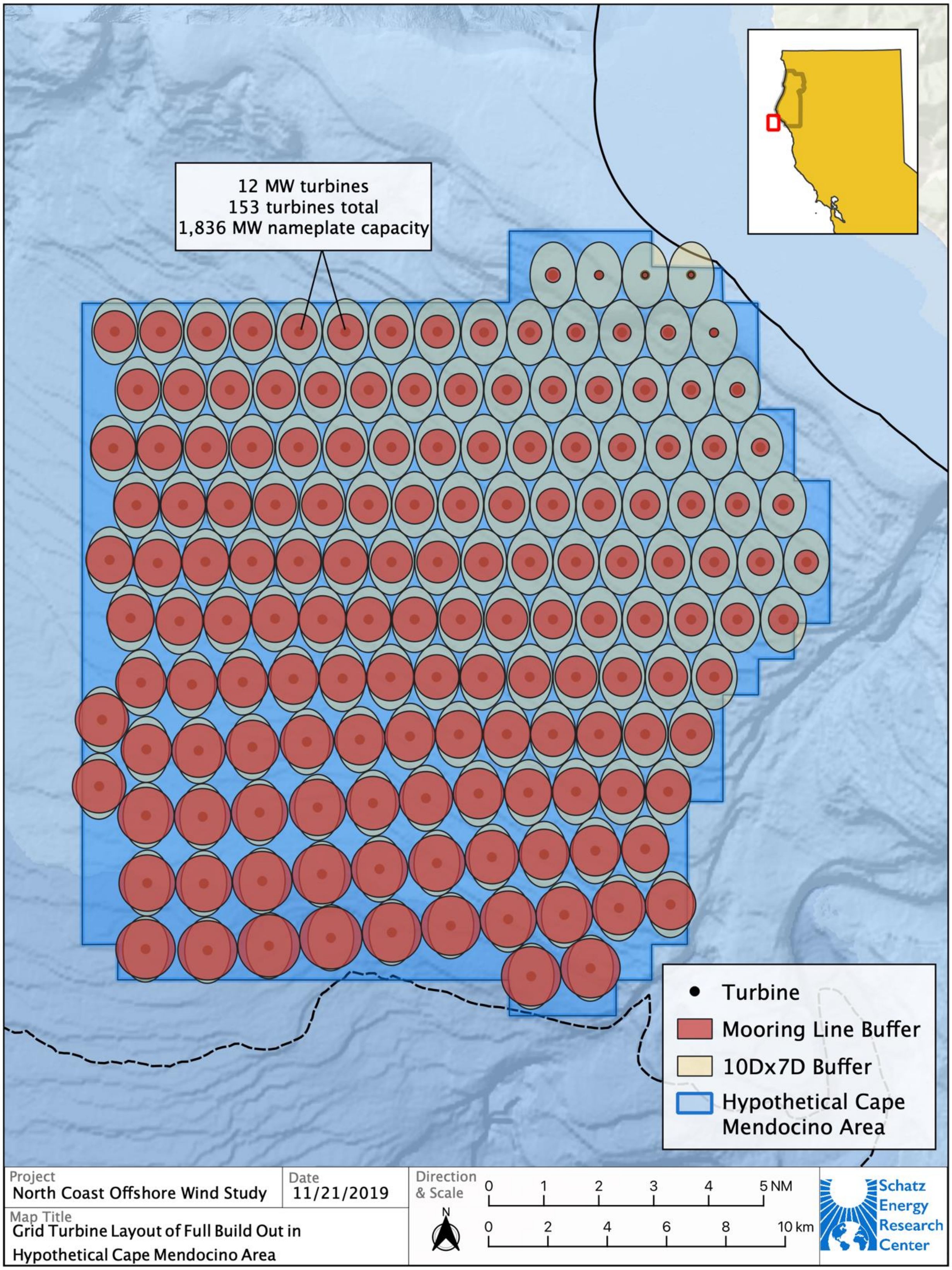

Figure A-13. Turbine layout of full build out scenario in notional Cape Mendocino area.

4.3.5 Lighting and Markings

Lighting and markings on the turbines and structures must meet the requirements of the Federal Aviation Administration (FAA) per 14 CFR 77.7 and 14 CFR 77.9 and US Coast Guard (USCG) Aids to Navigation Manual Chapter 4 Section G. For this study, we are assuming the lighting and markings follow the guidelines outlined in BOEM's (2019b) draft proposed recommendations. The specifications are repeated below (BOEM, 2019b):

- Aviation Obstruction Lighting
    - Each turbine outfitted with one light at the highest point on the nacelle and one light mounted mid-mast. The light specifications are:
        - Red LEDs (wavelength between 675 to 900 nm).
        - Photometric values of a FAA Type L-864 medium intensity obstruction light. Lighting most conspicuous to aviators. Lighting spread below the horizontal plane is minimal but still within photometric values of FAA Type L-864.
        - Flashing simultaneously at 30 flashes per minute.
        - Visible in all directions in the horizontal plane.
        - Lighting is most conspicuous to aviators. Lighting spread below the horizontal plane should be minimal but meet the photometric values of a FAA Type L-864.
        - Using a photosensor, automatically reduce light intensity when it is safe based on meteorological visibility. Reduce lighting intensity to 30% when visitiblity is 3.1 mi (5 km) or greater and to 10% when visibility is 6.2 mi (10 km) or greater.
- Paint and Markings
    - Turbine and tower paint should be no lighter than RAL 9010 Pure White and no darker that RAL 7035 Light Grey.
    - Foundation base should be painted yellow.
    - Ladders at foundation base should be painted in a contrasting color from yellow to be easily distinguishable.
    - Each turbine has a distinct identifier painted on the unit.

Aircraft detection lighting systems and dimming technologies are not included in the assumed installation.

4.4 Electrical Infrastructure

This section provides details about the electrical infrastructure including interarray cables, export cables, offshore substation, cable landfall location, interconnection point, and transmission route options. Figure A-14 provides a visual representation of the various electrical equipment of an offshore wind farm delivering power via an overland transmission route.

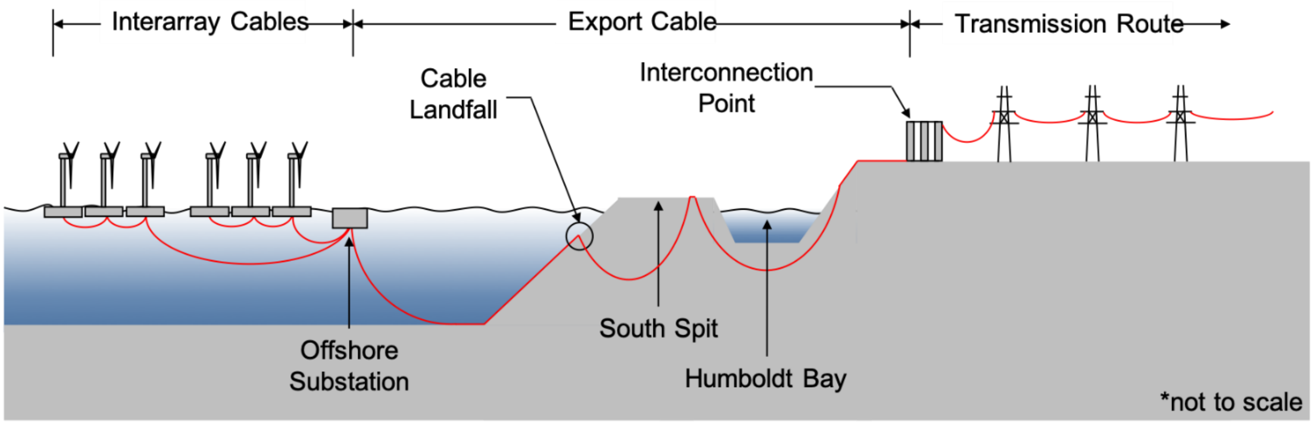

Figure A-14. Generalized representation of electrical system locations for overland transmission routes.

4.4.1 Interarray Cables, Offshore Substation, and Export Cable

The wind farm electrical system configuration is a radial string design with cross-linked polyethylene (XLPE), interarray cables rated for 66 kV. The turbines will be connected in a daisy-chain. A buoyancy cable floating system will be used to route the interarray cable through the water column at depths from 100-150 meters from the bottom of each turbine platform and then to a floating substation.

The offshore floating substation is the electrical connection point for the array cables and will house the necessary electrical equipment such as a collector bus, protective switchgear, a step-up transformer, and power quality equipment (e.g. shunt reactors). The AC transformer will step-up the voltage for the export cable back to shore and a shunt trip reactor may be needed to adjust for voltage variations and compensate for reactive power within the export cable.

High voltage, alternating current (HVAC), cross-linked polyethylene (XLPE) cables will be used to export power from the offshore substation to the interconnection point at the Humboldt Bay Generating Station (Table A-8). The subsea cables will be buried 1.5 meters under the ocean floor while traversing back to shore until the water reaches 9 meters depth, where cable landfall will begin.

Table A-8. Export cable specifications based on cables from ABB (2019).

Wind farm capacity	*No. of cables/cores*	*Nominal cable voltage*	*Cross sectional area of conductor*	*Outer Diameter of Cable*
50 MW	1 cable x 3 core	66 kV	300 mm^2	134 mm
150 MW	1 cable x 3 core	132 kV	800 mm^2	194 mm
1,800 MW	6 cable x 3 core	275 kV	1,600 mm^2	265 mm

4.4.2 Cable Landfall and Interconnection Locations

The export cable landfall will be in the northern section of the South Spit of Humboldt Bay (highlighted area on the left in Figure A-15). The landfall and interconnection approach being studied is described below.

Horizontal directional drilling (HDD) to bring the export cable onshore will begin at an ocean depth of 9 meter on the Pacific coastline. The HDD will connect to a cable vault located within this area. A second HDD is then used to route the cable from this vault under the floor of Humboldt Bay to another vault located on Buhne Point (highlighted area on the right in Figure A-15), located adjacent to HBGS. The necessary electrical switchgear and equipment including a transformer will be located at HBGS where power conditioning and synchronization will occur before exporting power to the electrical utility grid.

Figure A-15. General areas for cable landfall.

4.4.3 Subsea HVDC Transmission Cable

For the preliminary subsea transmission concept, landfall and the wind farm export cable routing under the spit and bay to the HBGS are the same. However, for the subsea transmission scenarios, the HVAC export cables will connect to a HVDC conversion station at or near the HBGS. Once converted, the HVDC submarine transmission cable will be routed back under the bay and spit for subsea transmission to the south. The southern terminus landfall location is unknown at this time, but will be in the San Francisco Bay Area.

The subsea transmission concept will also look at HVDC conversion near the HBGS, but this preliminary decision was made to simplify the analysis and look at one interconnection point rather than trying to identify another suitable HVDC conversion location further south on the coast.

4.4.4 Transmission Routes

The Humboldt region electricity system has a modest 100 MW average load and a transmission system that has limited capacity to export power into the broader California grid. Installing a gigawatt-scale generator in the region will far exceed any local demand and will require construction of a new high-voltage transmission line to export power from the offshore wind farm to the rest of California. New transmission will need to connect with California's 500 kV transmission lines (solid blue lines in Figure A-16). Pacific Gas and Electric Company (PG&E), who owns the transmission lines, determined four potential transmission options, including two overland and two subsea (Figure A-16). Based on power flow modeling of the transmission system, summaries of the upgrade options are provided below.[12]

[12] Details about the technical specifications of the upgrades and associated costs are provided in the Transmission Power Planning Study report (forthcoming).

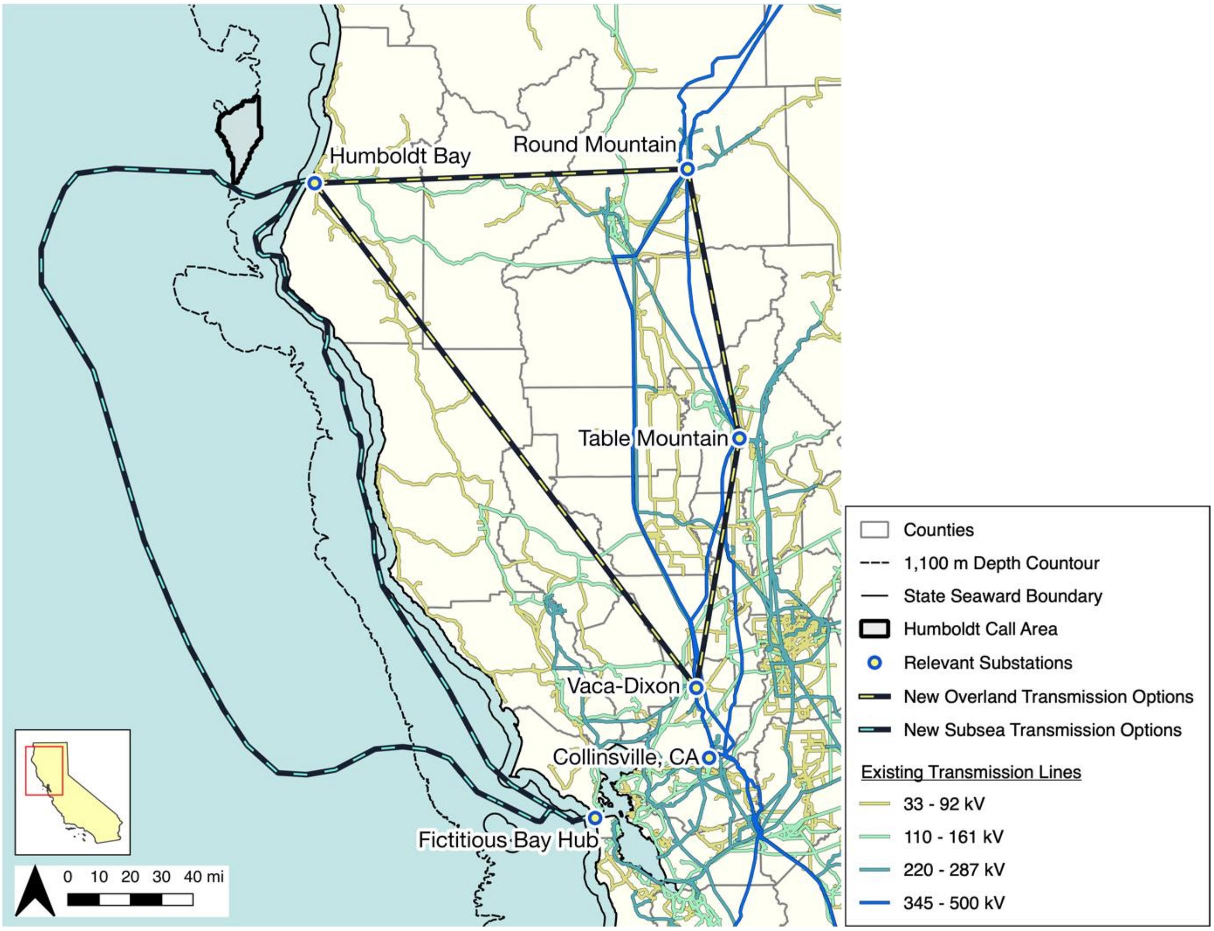

Figure A-16. Transmission upgrade alternatives for 1.8 GW of offshore wind from the Humboldt Call Area.

Overland East

A new 500 kV HVAC transmission line would connect between Humboldt Bay Substation and Round Mountain Substation. The transmission pathway follows a utility right of way for an existing 115 kV transmission line alongside California Highway 36. This alternative would require:

- Construct new 500 kV substation near Humboldt Bay Substation
- Build new 500 kV transmission line from Humboldt Bay to Round Mountain; Round Mountain to Table Mountain; and Table Mountain to Vaca-Dixon
- Reconductor some auxiliary transmission lines and make upgrades to impacted substations

Overland Southeast

A new 500 kV HVAC transmission line would connect between Humboldt Bay Substation and the Vaca-Dixon Substation. The transmission pathway follows a utility right of way for an existing 60 kV transmission line that runs alongside the Eel River and California Highway 101 into Lake County then heading east towards Vacaville. This alternative would require:

- Construct new 500 kV substation near Humboldt Bay Substation
- Build new 500 kV transmission line from Humboldt Bay to Vaca-Dixon
- Construct new 500 kV substation near Collinsville, CA
- Reconductor some auxiliary transmission lines and make upgrades to impacted substations

Subsea Transmission Cable

A high-voltage, direct-current (HVDC) subsea cable will connect between Humboldt Bay and the San Francisco Bay Area. Power from the wind farm will be converted into HVDC at a converter station near the Humboldt Bay Substation. Once converted, the subsea transmission cable will be routed back to sea and toward the San Francisco Bay Area. There are two possible cable corridors, one nearshore and one further from shore. The southern terminal of the cable is at a generic point in the San Francisco Bay Area, “Fictitious Bay Hub”. The Bay Hub will connect into several transmission networks because no single network in the Bay Area can accept this much additional capacity. This alternative would require:

- Construct new AC to DC converter station near Humboldt Bay Substation
- Build new HVDC subsea cable between Humboldt Bay the San Francisco Bay Area.
    - Two possible subsea cable corridors have been identified.
- Construct new 230/500 kV DC Bay Hub Substation at an undetermined location in the Bay Area
- Construct six new 230 kV cables that would connect the Bay Hub to different transmission networks in the Bay Area

  Reconductor some auxiliary transmission lines

4.5 Construction and Maintenance

Construction, maintenance, and operation occur as part of three phases described below: assembly and installation; operations and maintenance; and decommissioning.

4.5.1 Assembly and Installation

As part of this project, a port infrastructure assessment will be performed for Humboldt Bay to determine where the construction activities may take place. This feasibility-level evaluation will identify port-side and navigation infrastructure needs, inventory existing port facilities, and determine the necessary upgrades to support the development of an offshore wind farm. Based on a previous pre-screen analysis, Humboldt Bay can be classified as a quick reaction port and an assembly port, and further analysis of the supply chain will be required to determine if Humboldt is a suitable port for fabrication and construction activities (Porter and Phillips, 2016).

For this preliminary description of construction and installation activities, it is assumed that fabrication and construction of the components will occur at another port or facility outside of Humboldt County and components will be shipped to Humboldt Bay for assembly. However, specific local fabrication activities may be investigated based on the results of industry outreach. Assuming components are fabricated outside Humboldt Bay, the components will be stored in a lot upon arrival in Humboldt Bay. Among other factors, the size capacity of the upland storage and staging areas will influence the scheduling of assembly (e.g. whether all components are delivered first or the assembly process will take place in parallel to deliveries to ensure space is available for future components). The port-side assembly process is complex and requires specific infrastructure, equipment and vessels, which will be determined during the course of this project. The preliminary assumption is that assembly will take place quayside and equipment testing will take place in protected waters to identify any faulty components before towing the substructure and turbine unit to the site.

The Humboldt Bay Harbor Recreation and Conservation District has expressed interest in an offshore renewable energy port to be located at Redwood Marine Terminal I in Samoa, California (HBHRCD, 2019). Improvements to this port terminal will be necessary in order to support the storage, assembly, and operation and maintenance of components for an 1,800 MW offshore wind development. Potential specifications of the port include three vessel berths, an ultra-high capacity wharf for the tower and nacelle, and access piers to move equipment between the upland storage and fabrication areas onto the wharves (Figure A-17).

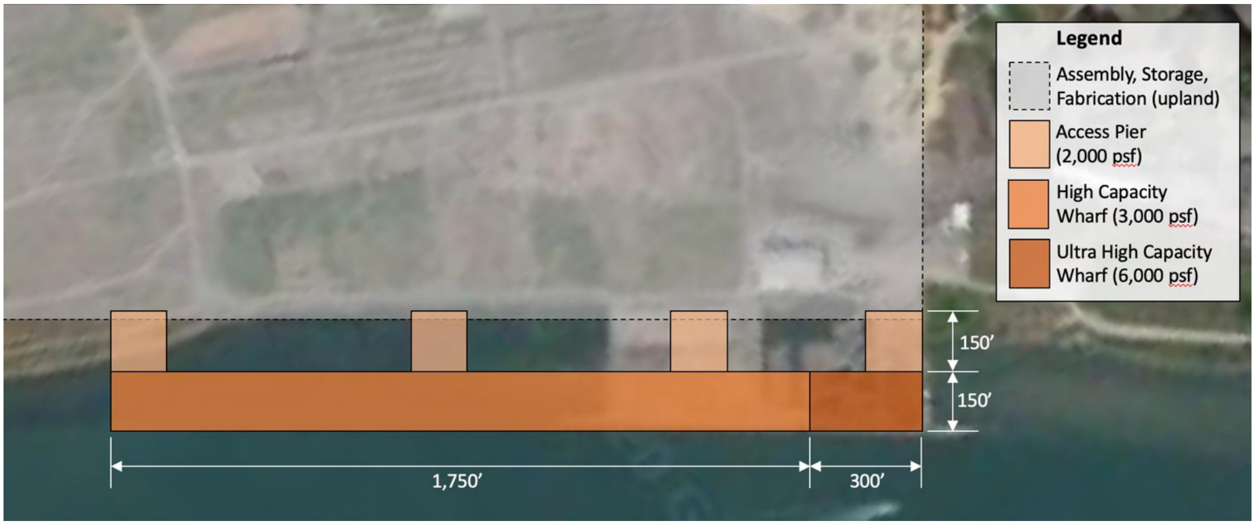

Figure A-17. Example port facility for offshore wind development.

A preliminary list of equipment that is likely required for assembly and construction is provided in Table A-9. This list will be revised based on input from experts and developers during this study.

Table A-9. Assembly and construction equipment preliminary assumptions – will be revised during analysis.

Parameter	*Value*	*Justification*	*Source*
Farm site equipment	Anchor Handling Tug Supply vessel (AHTS), Remote Operated Underwater Vehicle (ROV), Cable laying vessel (CLV)	Based on installation process assumptions	Beiter et al (2016)
Port equipment	2 Crawler cranes *(capacity of at least one >500 tonnes)*, assembly area, storage area	Installation process assumptions	Beiter et al (2016)
Transport equipment	AHTS, 2 smaller tugs for assistance	Installation process	Beiter et al (2016)
Cable landfall equipment	Horizontal drill rig (onshore), jack-up barge	Based on expected coastal regulations	

4.5.2 Operations and Maintenance

The operation and maintenance (O&M) plan will be developed in more detail as this study progresses. The O&M plan will be developed by Mott MacDonald as part of the port infrastructure assessment. The list of O&M tasks will be used to evaluate the port infrastructure requirements, economic costs, and environmental impacts of the maintenance activities.

The preliminary assumption is that O&M is based out of the Humboldt Bay and that semi-submersible platforms can be towed to and from port for major maintenance activities. Potential vessels for use in O&M activities are: a crew transfer vessel (CTV), a large anchor handling tug supply vessel (AHTS), smaller assist tugs, and a remote operated underwater vehicle (ROV) or a dive-support vessel that can be commissioned when necessary (Table A-10). Other equipment such as a larger "mother ship" for support or a helicopter may be considered as part of the O&M plan depending on the results from developer outreach.

Table A-10. Operations and maintenance preliminary vessel assumptions

O&M plan	*Vessels*	*Justification*	*Source*
Port-based	AHTS, CTV, assist tugs	Described O&M plan based on ECN's O&M tool	Beiter et al (2016)

Until more information is collected, repairs are assumed to occur using the schedule and failure rates outlined by Ioannou (2018, p. 413), which includes assumed failure rates, average repair time, and material costs for repair and replacement of major components. The impact of local metocean conditions on the O&M procedures are currently unknown for the study areas and will be incorporated into this study if and when this information becomes available.

4.5.3 Decommissioning

During the Construction and Operations phase of the project, a Construction and Operations Plan (COP) is submitted to BOEM that must describe all activities related to the project including decommissioning and site clearance procedures. A detailed project-specific description and explanation of the general concept and proposed decommissioning procedures for all installed components and facilities must be provided (BOEM 2016).

The major steps for decommissioning an offshore wind farm include:

- turbine/foundation assembly removal,
- mooring line and anchors removal,
- electrical cable removal,
- scour protection to prevent damage to the seafloor, and
- salvage or disposal of all materials.
-

These activities are required to be completed within 2 years following termination of the lease. Prior to decommissioning, the developer is required to submit a decommissioning application and receive approval from BOEM. Additional regulations can be found in Part 585 Subpart I of Volume 30 of the Code of Federal Regulations (C.F.R.) - Renewable energy and Alternate Uses of Existing Facilities on the Outer Continental Shelf (2011).

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