California North Coast Offshore Wind Studies

Wind Speed Resource and Power Generation Profile Report

This report was prepared by Mark Severy, Christina Ortega, Charles Chamberlin, and Arne Jacobson of the Schatz Energy Research Center. It is part of the *California North Coast Offshore Wind Studies* collection, edited by Mark Severy, Zachary Alva, Gregory Chapman, Maia Cheli, Tanya Garcia, Christina Ortega, Nicole Salas, Amin Younes, James Zoellick, & Arne Jacobson, and published by the Schatz Energy Research Center in September 2020.

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Disclaimer

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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.

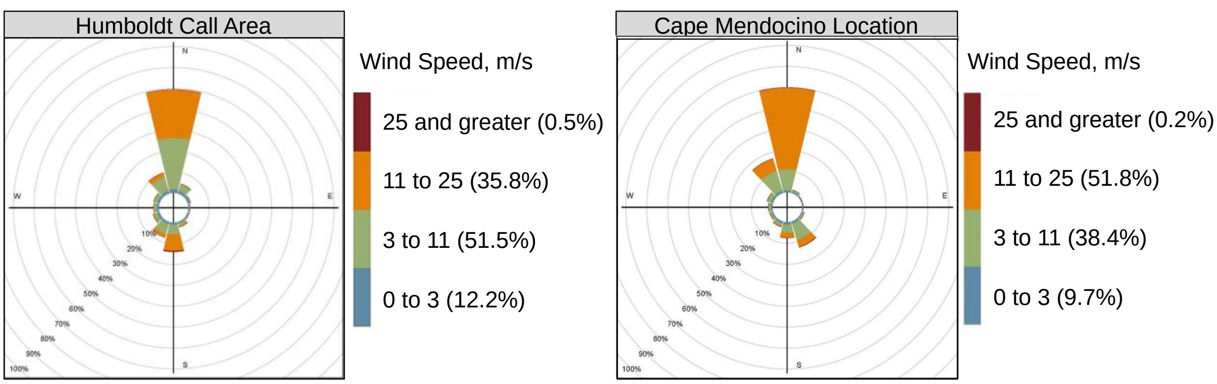

Figure ES.1. Annual average wind rose for Humboldt Call Area and Cape Mendocino locations.

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.

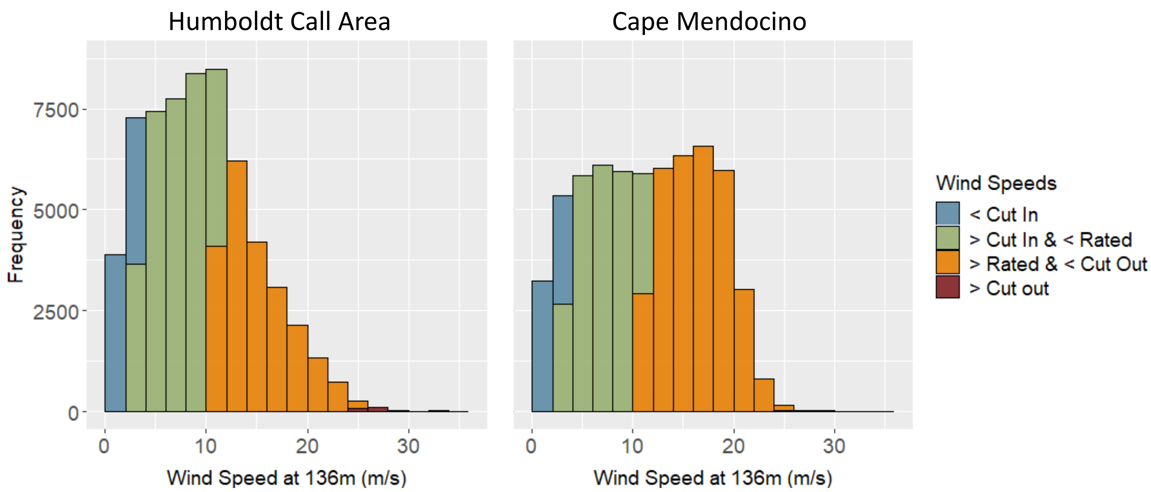

Figure ES.2. Wind speed distribution for Humboldt Call Area and Cape Mendocino location.

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).

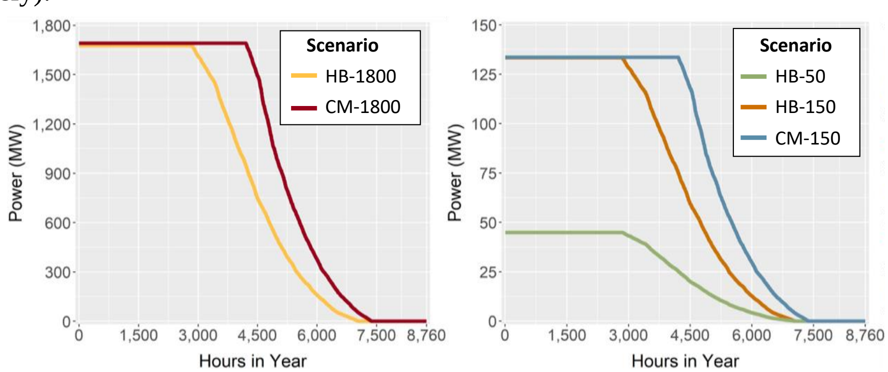

Figure ES.3. Generation duration curves for all wind farm scenarios for a typical year.

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).

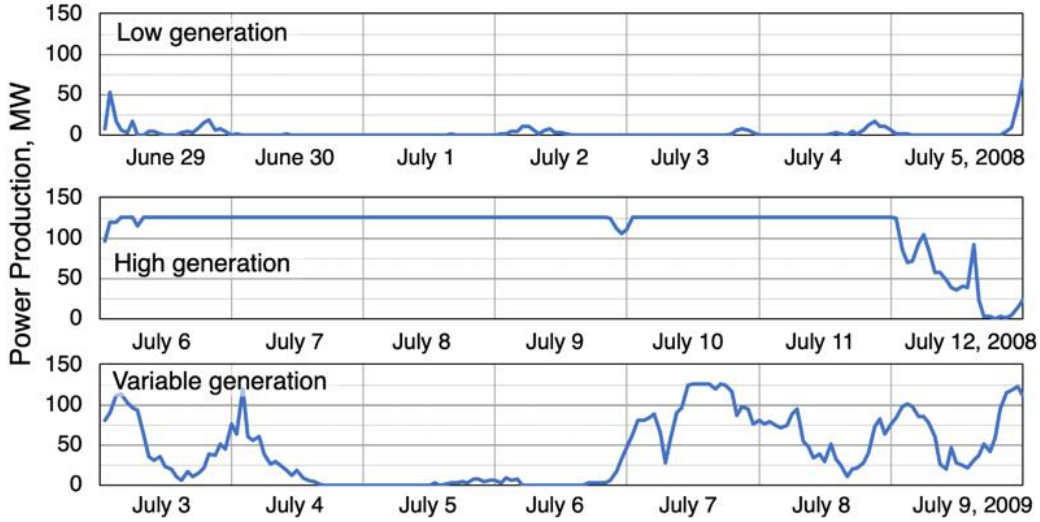

Figure ES.4. Three example week-long period of power output from a 144 MW wind farm located in the Humboldt Call Area.

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.

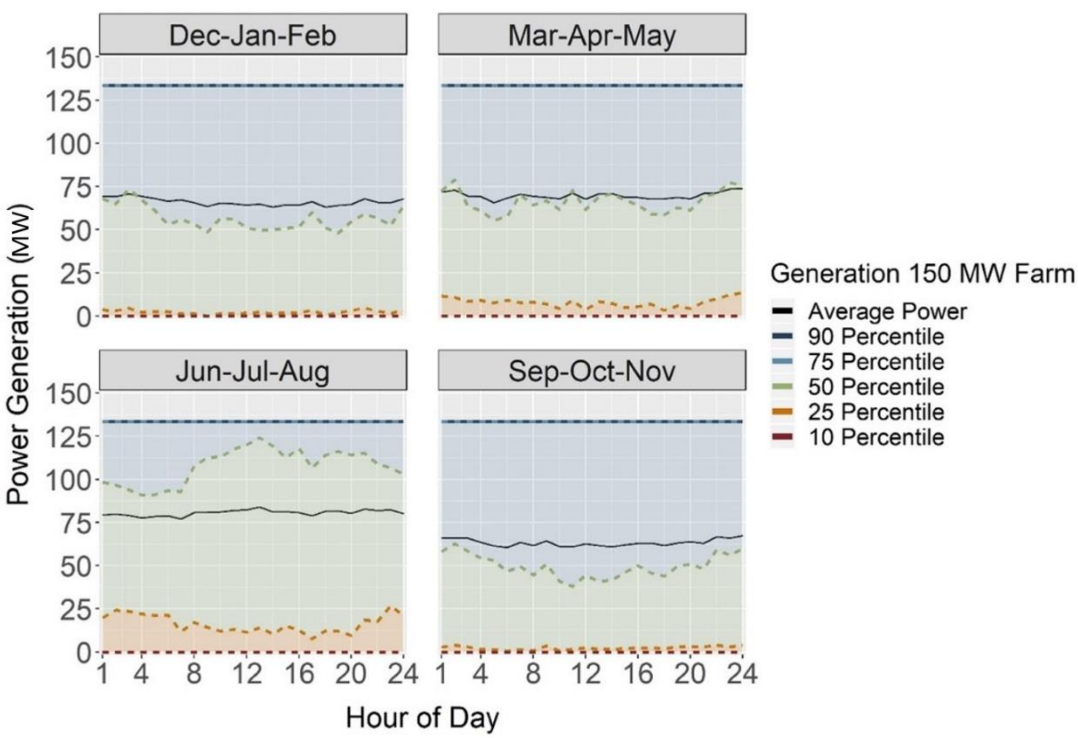

Figure ES.5 Hourly power generation of the 150 MW farm in the Humboldt Call Area by season.

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). 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 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.

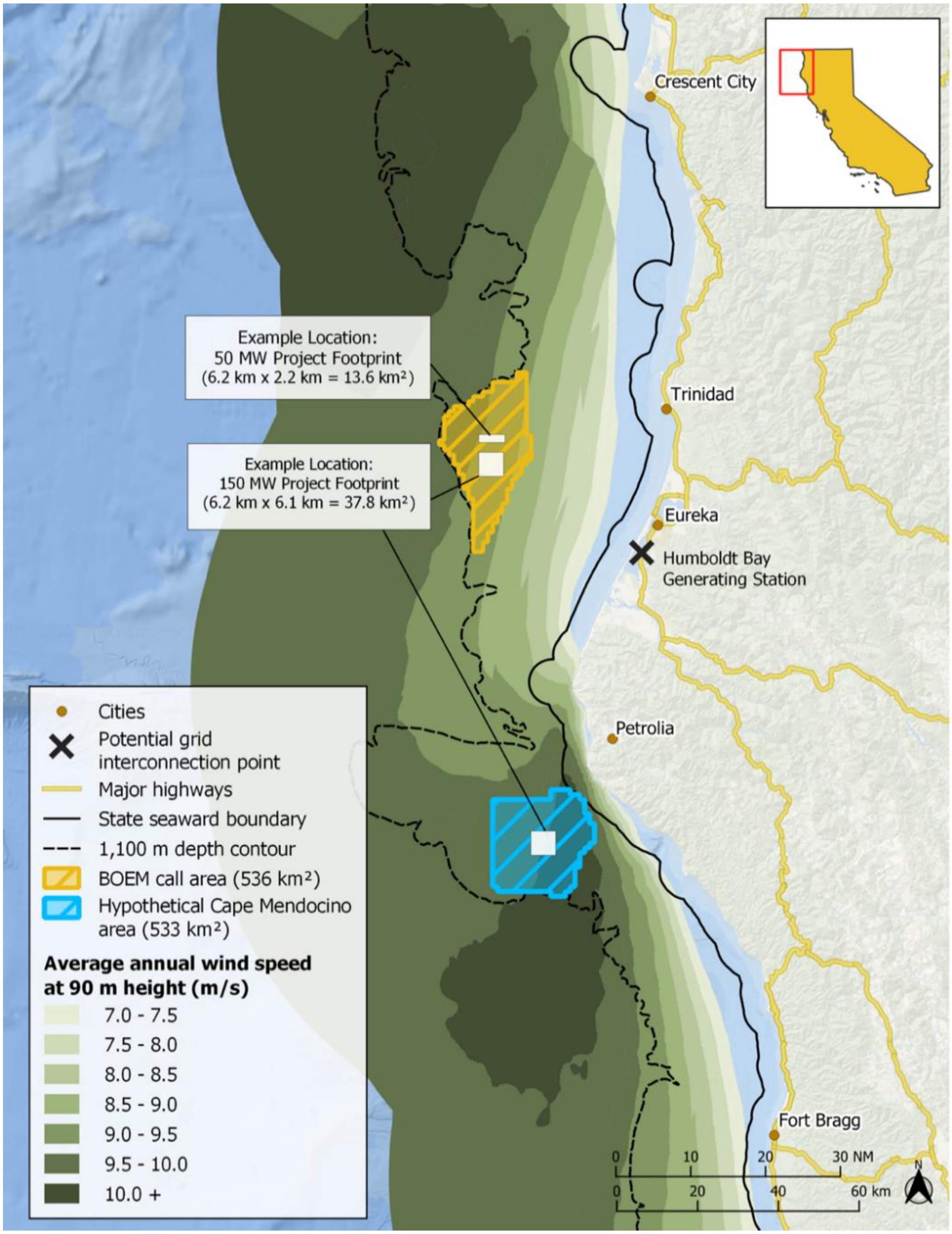

Figure 1. Wind speed and study areas.

Table 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 2 and its power curve is shown in Figure 2.

Table 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 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 3, top view).

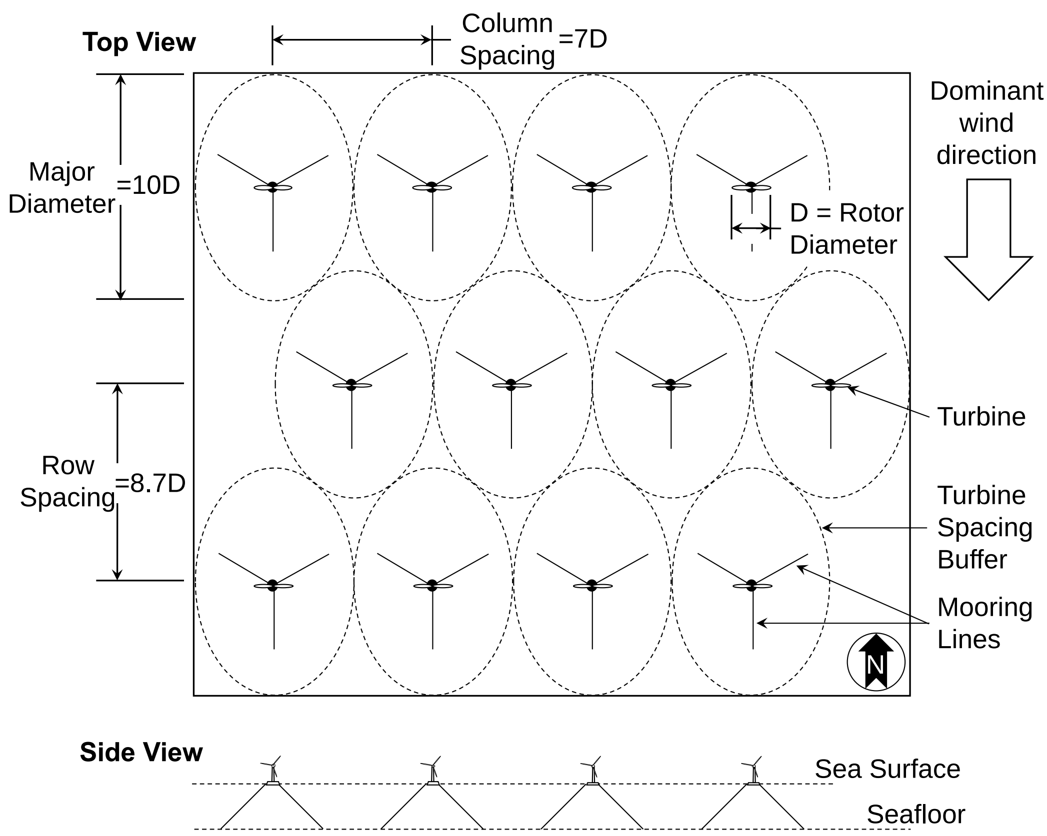

Figure 3. Turbine spacing and layout for an example 144 MW array using 12x 12 MW turbines. The top view of the array shows the horizontal spacing (top) and the side view shows the vertical profile (bottom).

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 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 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 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 3).

Table 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 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 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 4. The Notional Mendocino Area consistently provides higher wind speeds than the Humboldt Call Area. The histograms of wind speed (Figure 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.

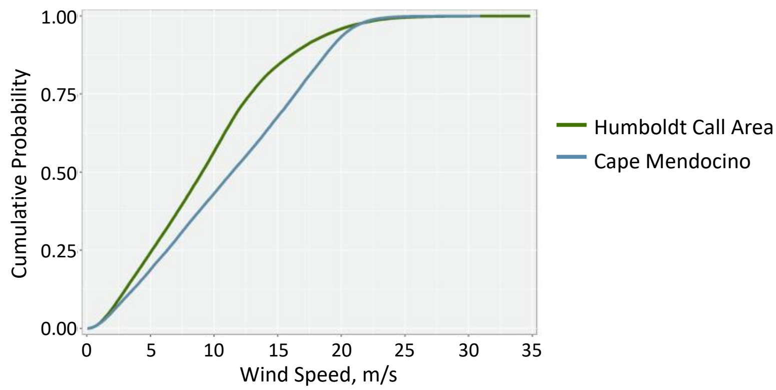

Figure 4: Cumulative probability density function of wind speed in both locations.

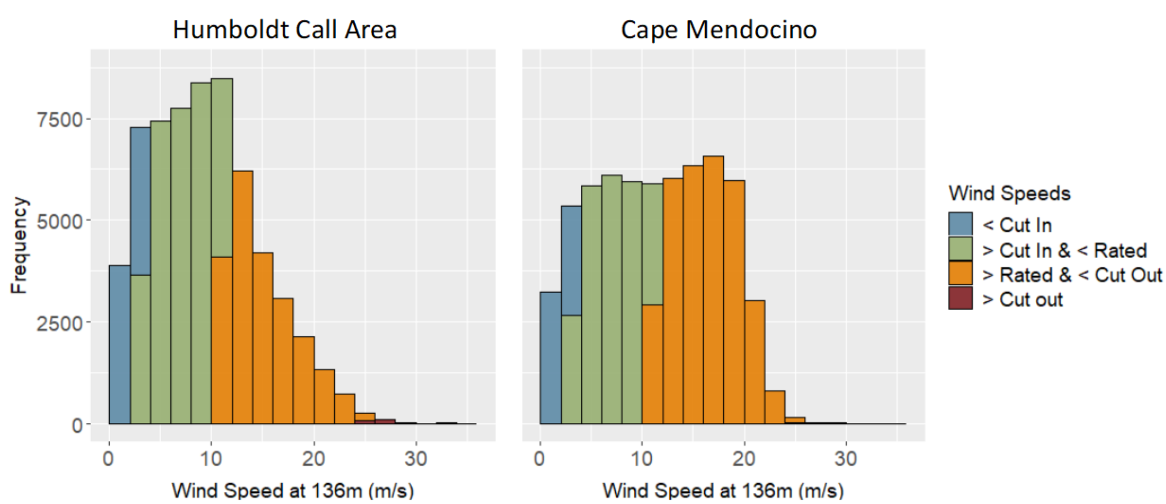

Figure 5. Histograms of wind speed and frequency of occurrence for Humboldt Call Area (left) and Cape Mendocino (right). The y-axis is frequency of occurrence of hours in the seven-year period of record.

The distribution of wind speed varies by month and season (Figure 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.

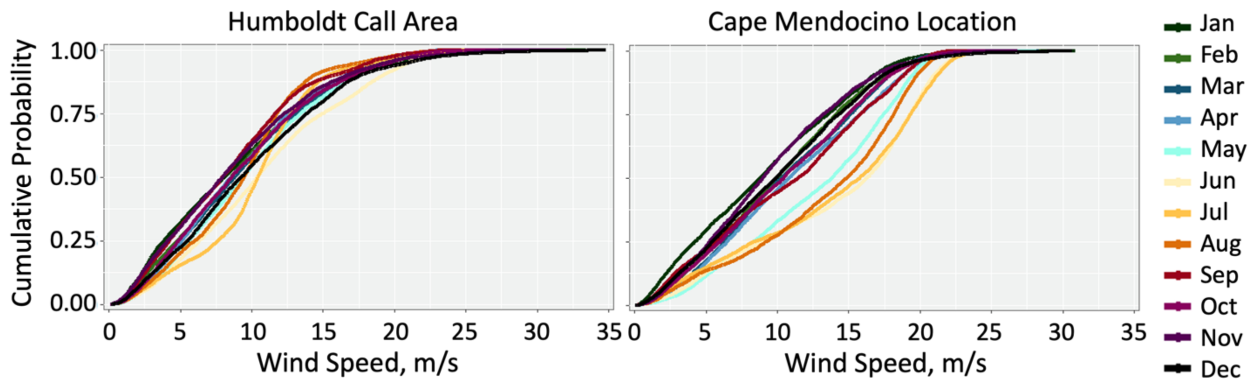

Figure 6. Cumulative distribution function of wind speed by month at both locations.

3.2 Wind Speed Direction and Velocity

Wind roses from the Humboldt Call Area (Figure 7) and Notional Cape Mendocino area (Figure 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.

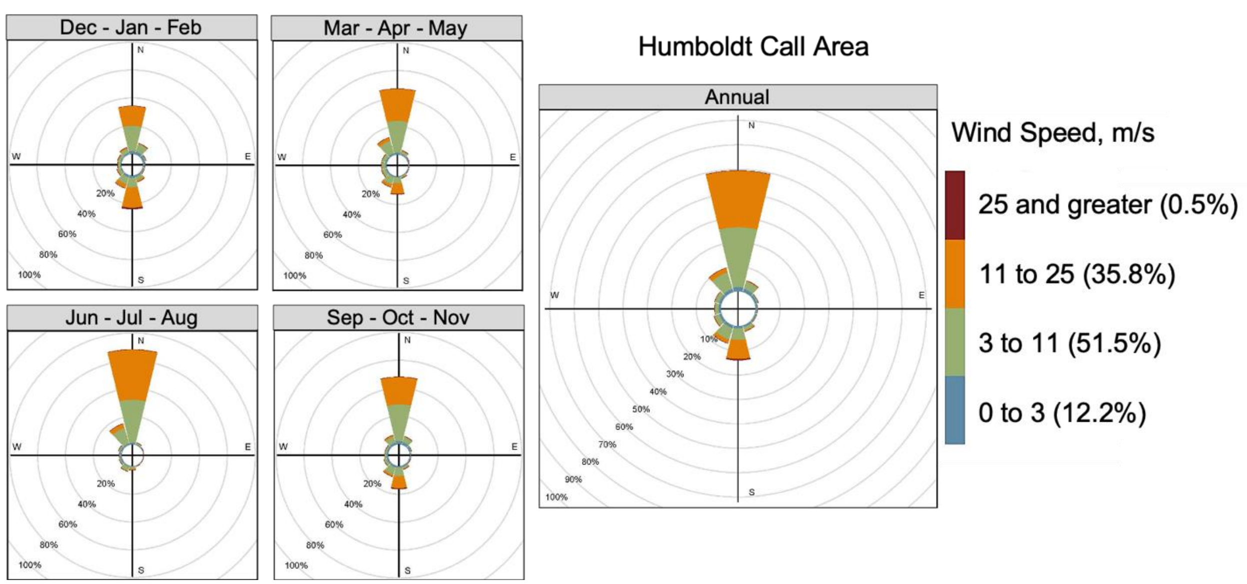

Figure 7. Wind rose for the Humboldt Call Area annually (right) and by season (left). Percentages on the radial axis represent the percent of time the wind speeds occurred.

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.

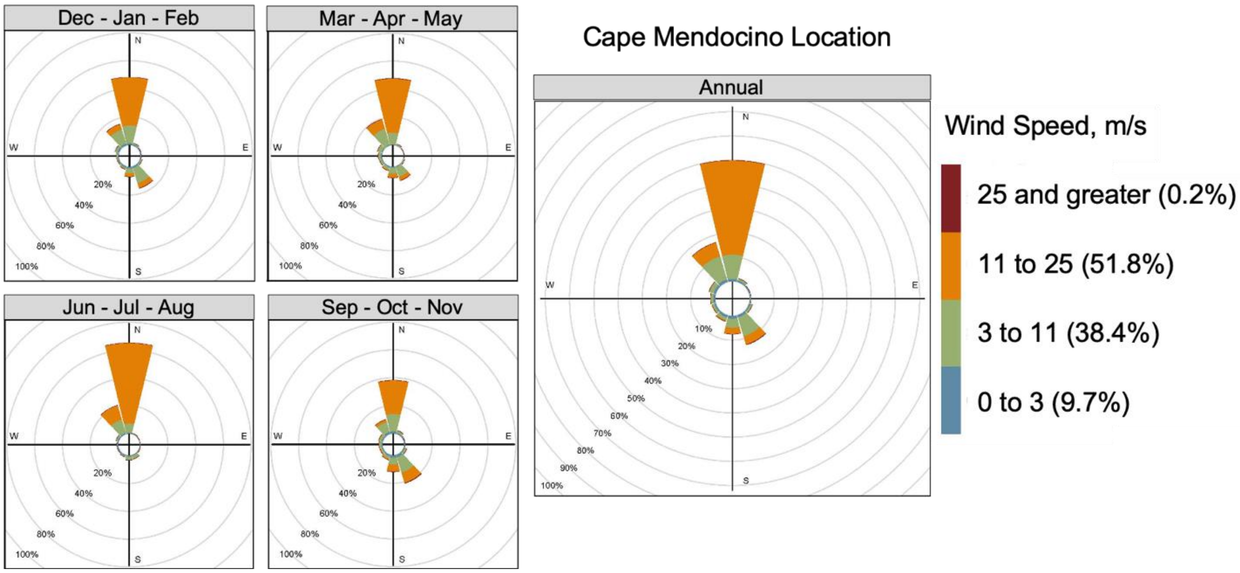

Figure 8: Wind roses for Mendocino area – by season and annual average.

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 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.

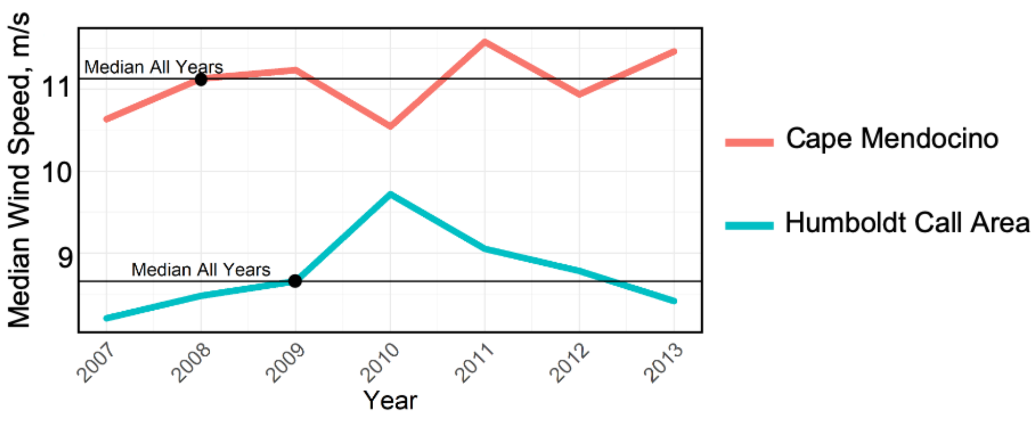

Figure 9. Results of median wind speed year analysis for Humboldt Bay. Note the y-axis does not include 0 m/s.

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 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 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.

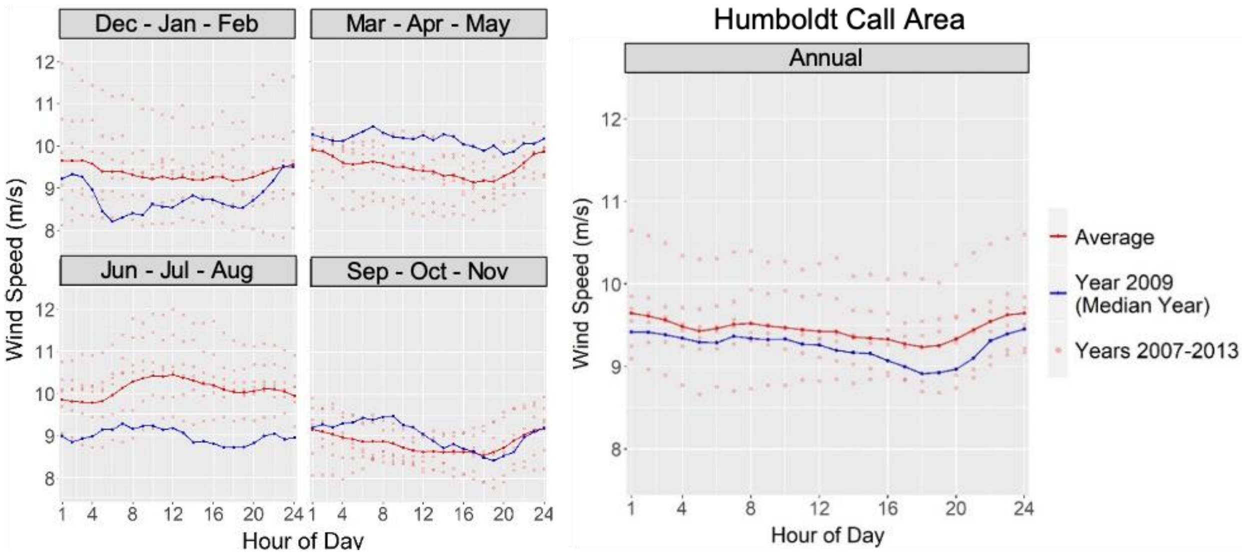

Figure 10. Daily profile of average wind speed for the year (right) and by season (left) for the Humboldt Call Area. The dots represent data averaged for each of the seven years with the average and median years highlighted in red and blue, respectively.

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 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 11, left).

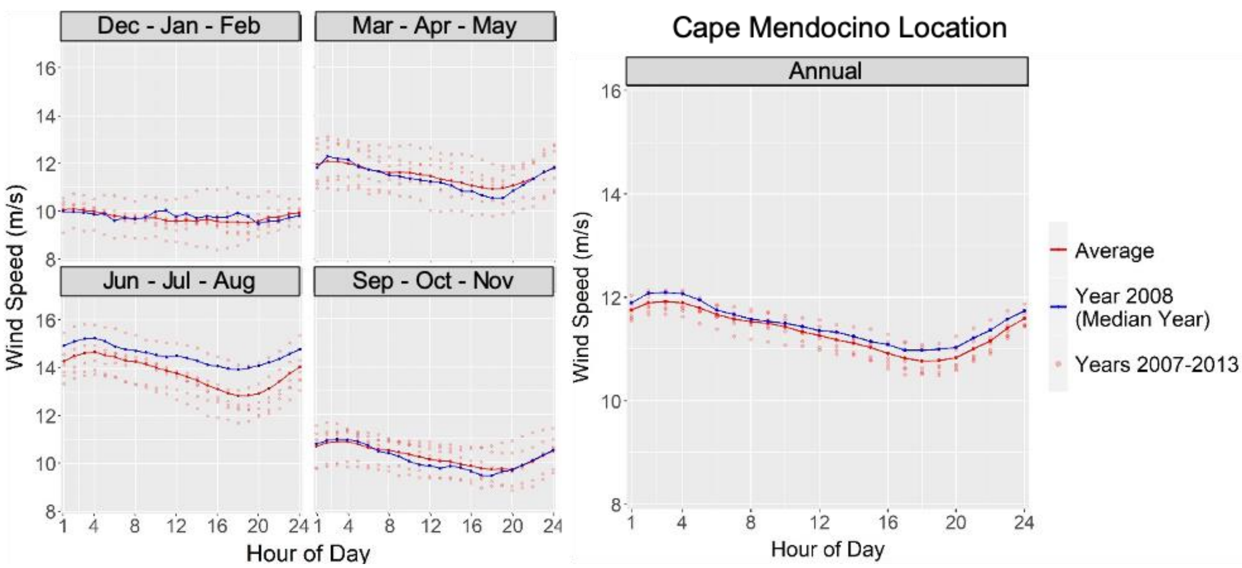

Figure 11: Daily profile of average wind speed for the year (right) and by season (left) for the Cape Mendocino location. The dots represent data averaged for each of the seven years with the average and median years highlighted in red and blue, respectively.

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 24 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 5) leads to capacity factors (Table 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 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 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 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 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.

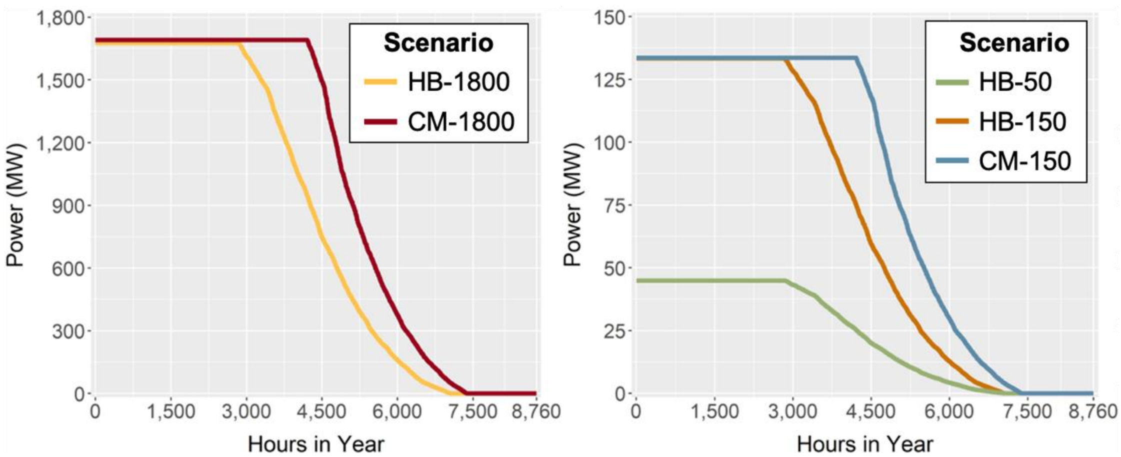

Figure 12. Generation duration curves for all project scenarios. The 1,800 MW scenarios are on the left, and the 150 MW and 50 MW scenarios are shown in the right graphic. Note the difference in power scales between the two graphs.

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 25 and Figure 26, 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 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.

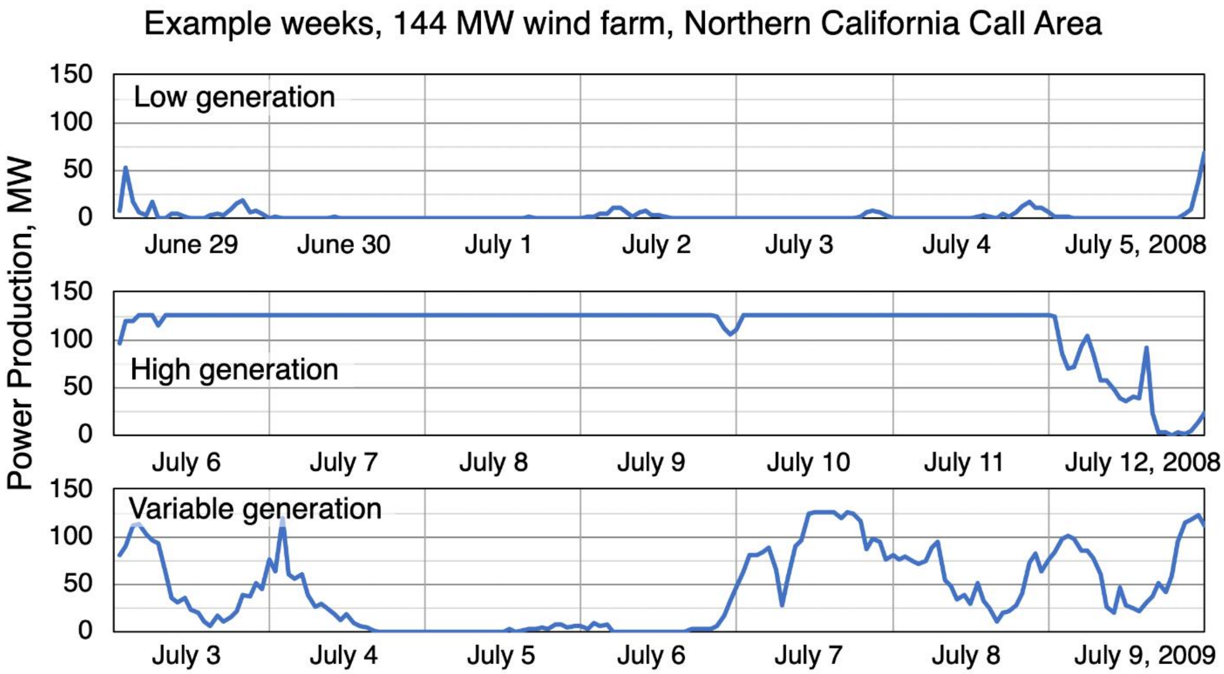

Figure 13: Variability of diurnal patterns of power production for three different weeks.

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 14 and Figure 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 14 and Figure 15 to essentially scale proportionally between them.

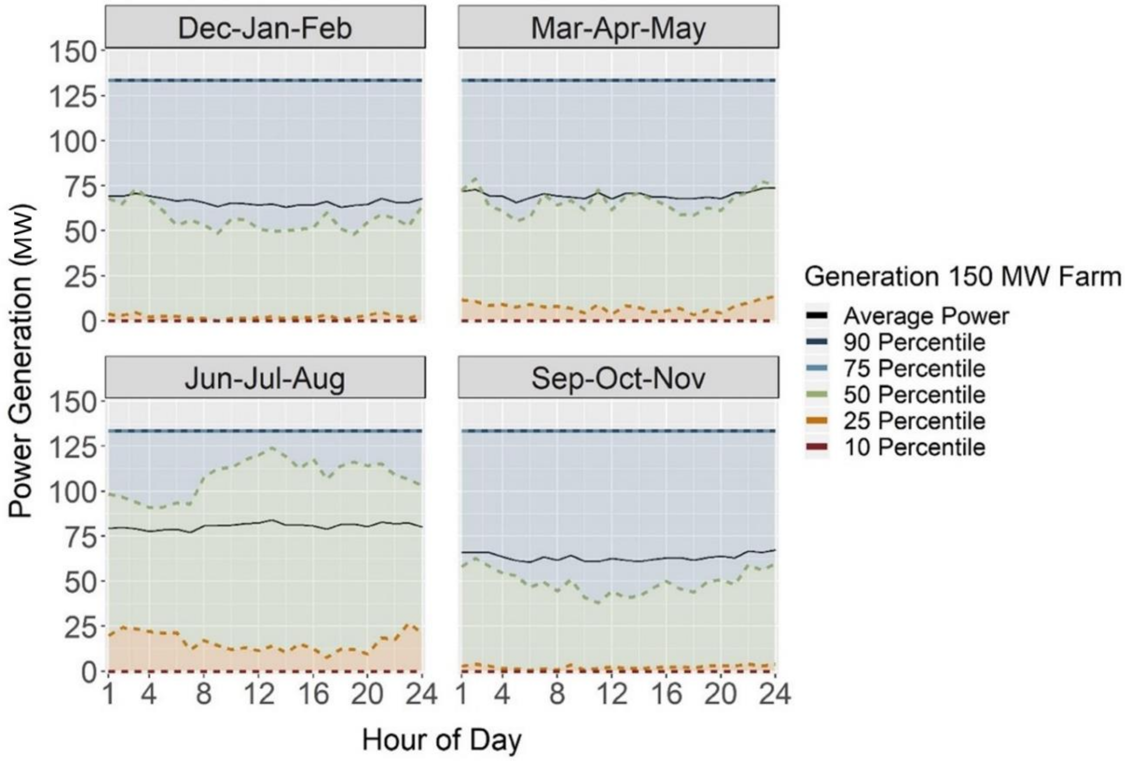

Figure 14: Hourly power generation of the 150 MW farm in the Humboldt call area by season.

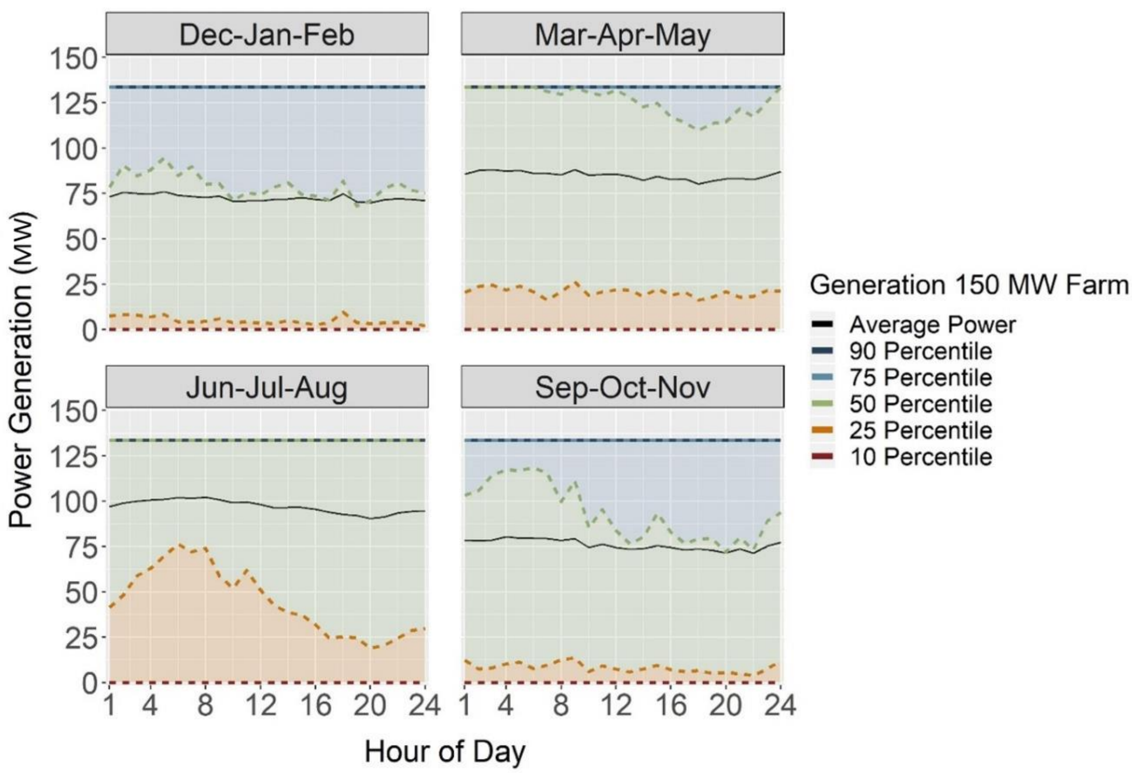

Figure 15: Hourly power generation of the 150 MW farm in the Mendocino area by season.

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 A - STUDY LOCATIONS

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

Table 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)

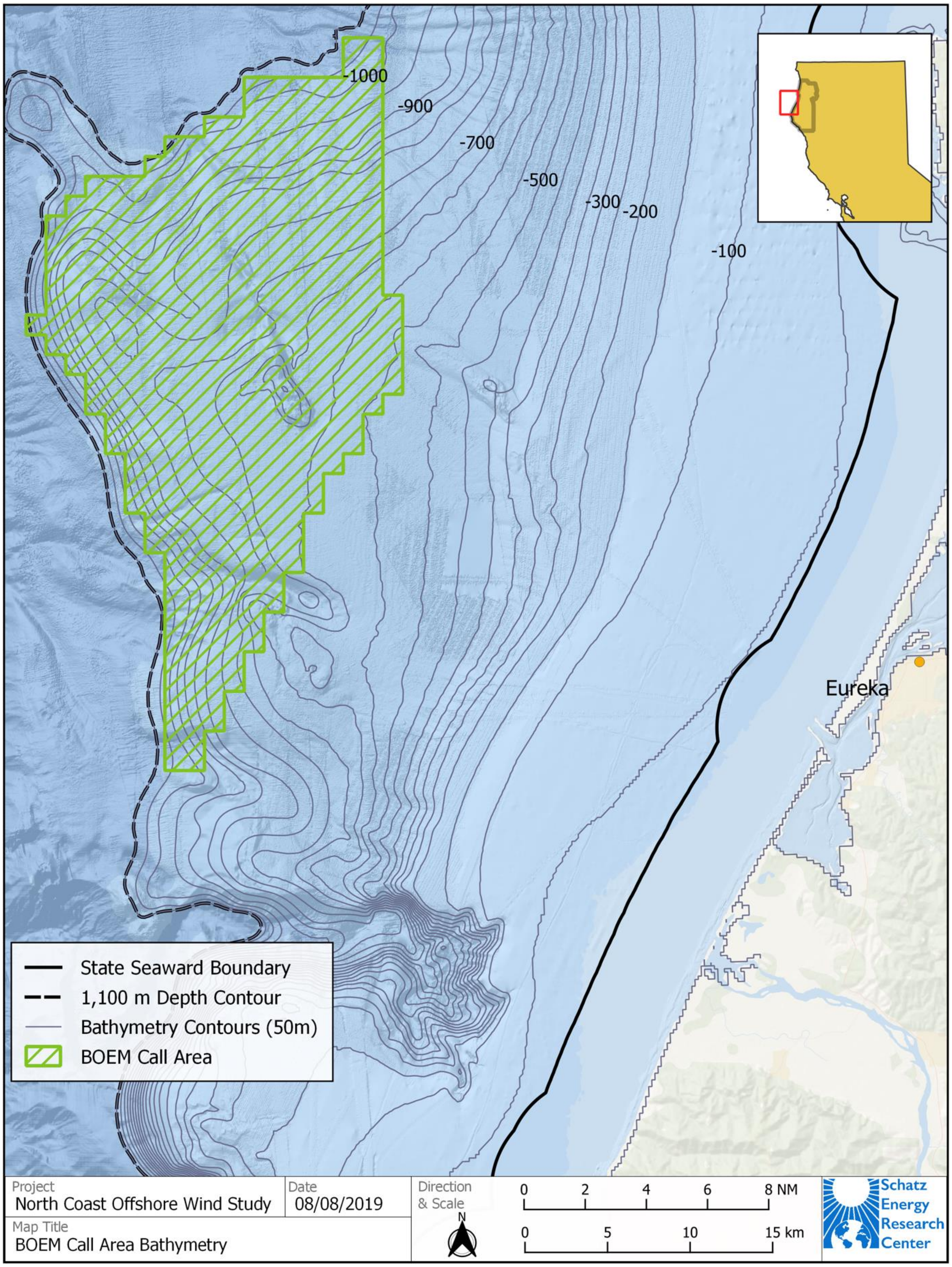

Figure 16. Northern California Call Area with 50 m bathymetric contours.

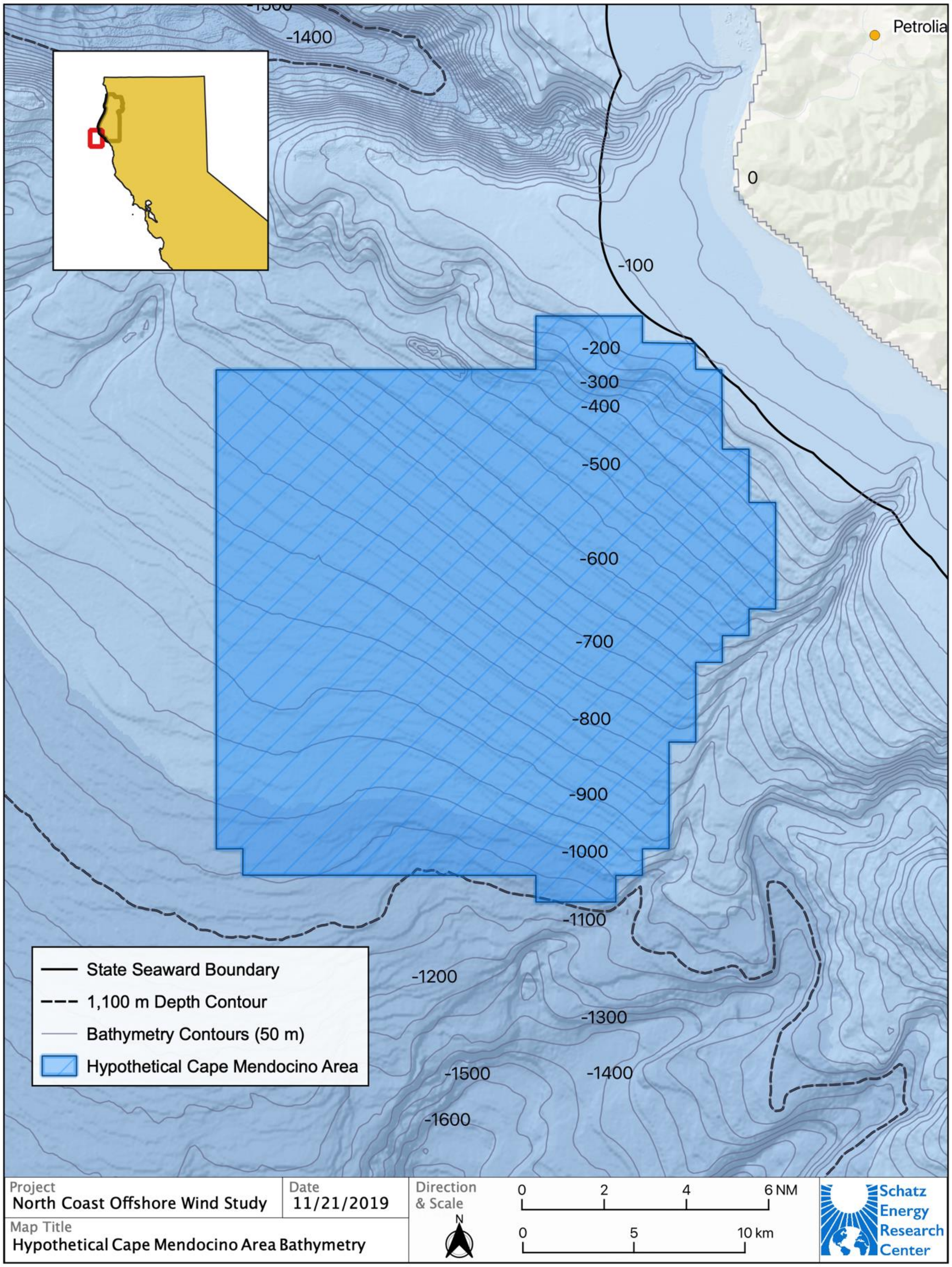

Figure 17. Notional Cape Mendocino area with 50 m bathymetric contours.

APPENDIX B - TURBINE LAYOUTS AND SPACING

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

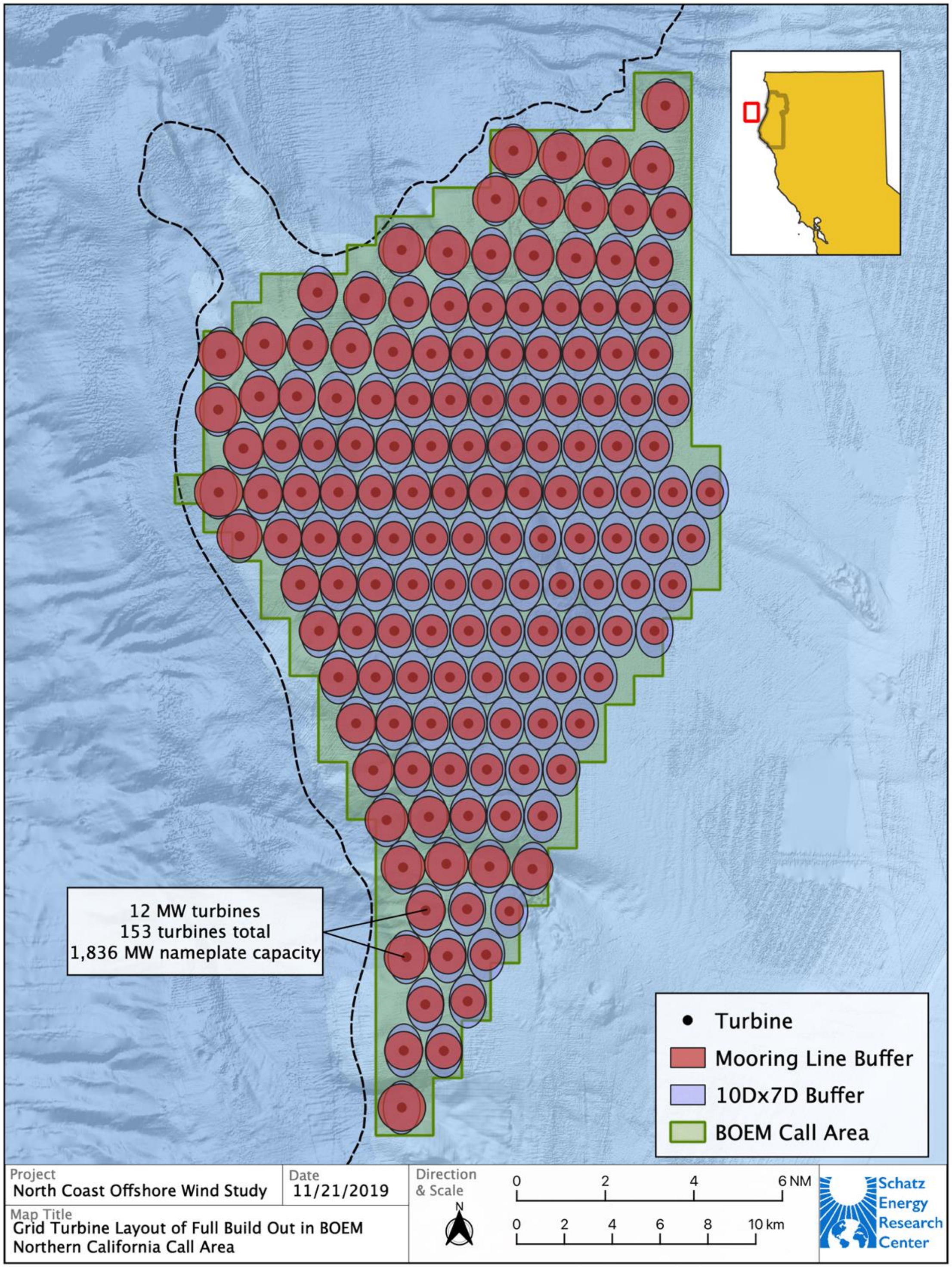

Figure 18. Grid turbine layout of the full-build out scenario in the Humboldt Call Area.

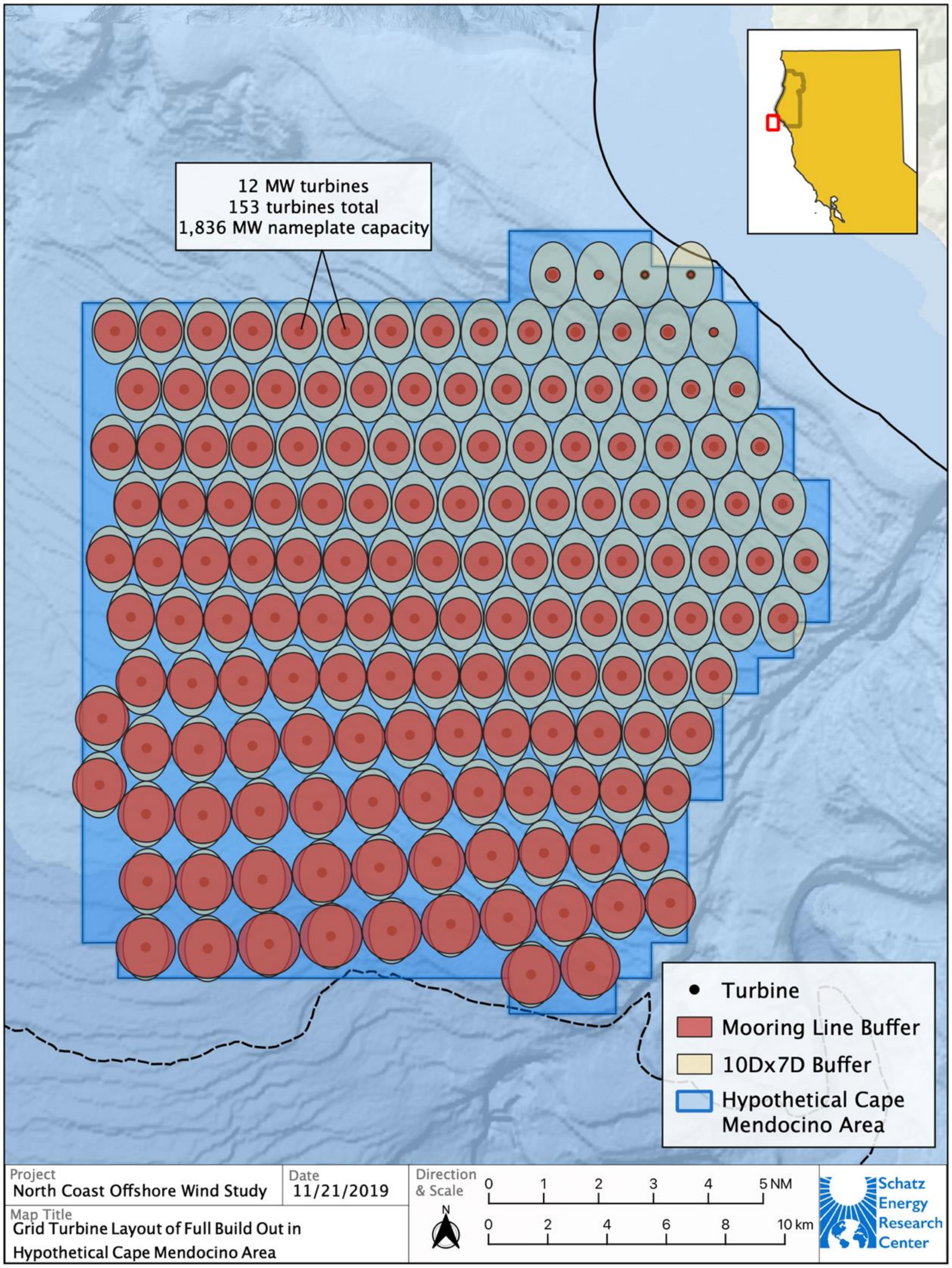

Figure 19. Grid turbine layout of the full build out scenario in the Mendocino Area.

APPENDIX 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):

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

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 20).

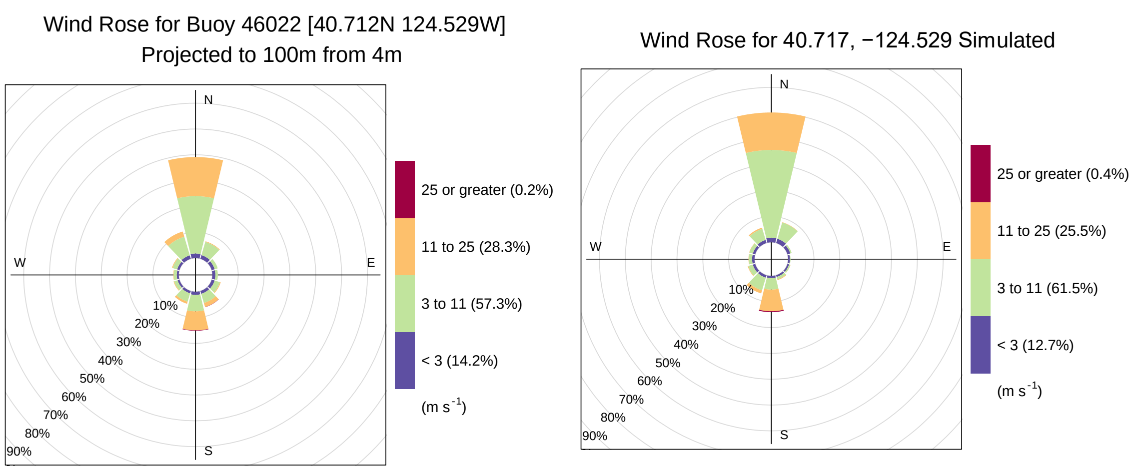

Figure 20. Wind rose based on buoy data for the period of record (2007-2013) (left) and wind rose based on modeled data for the same time period (right)

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):

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

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.

C.1 Cumulative Distribution Function

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

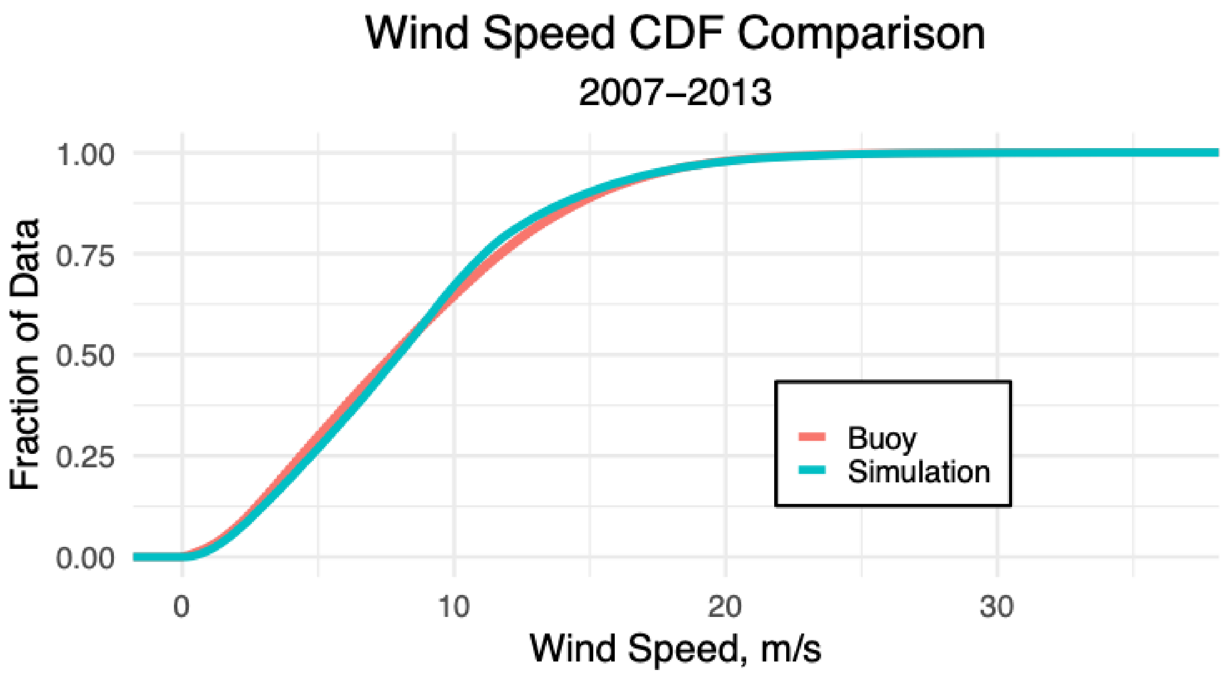

Figure 21. Wind speed cumulative distribution function comparison of the simulated and measured data sets over the period of record. Measured data are scaled according to equation (C-1) using be α = 0.1028945.

Additional descriptive characteristics for comparison are given in Table 8 and Table 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 20), the cumulative distribution functions (Figure 21), and the descriptive statistics in general (Table 8 and Table 9), the simulated data is concluded to be adequately similar to the measured data for use in this analysis.

Table 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 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 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 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 10.

Table 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 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 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.

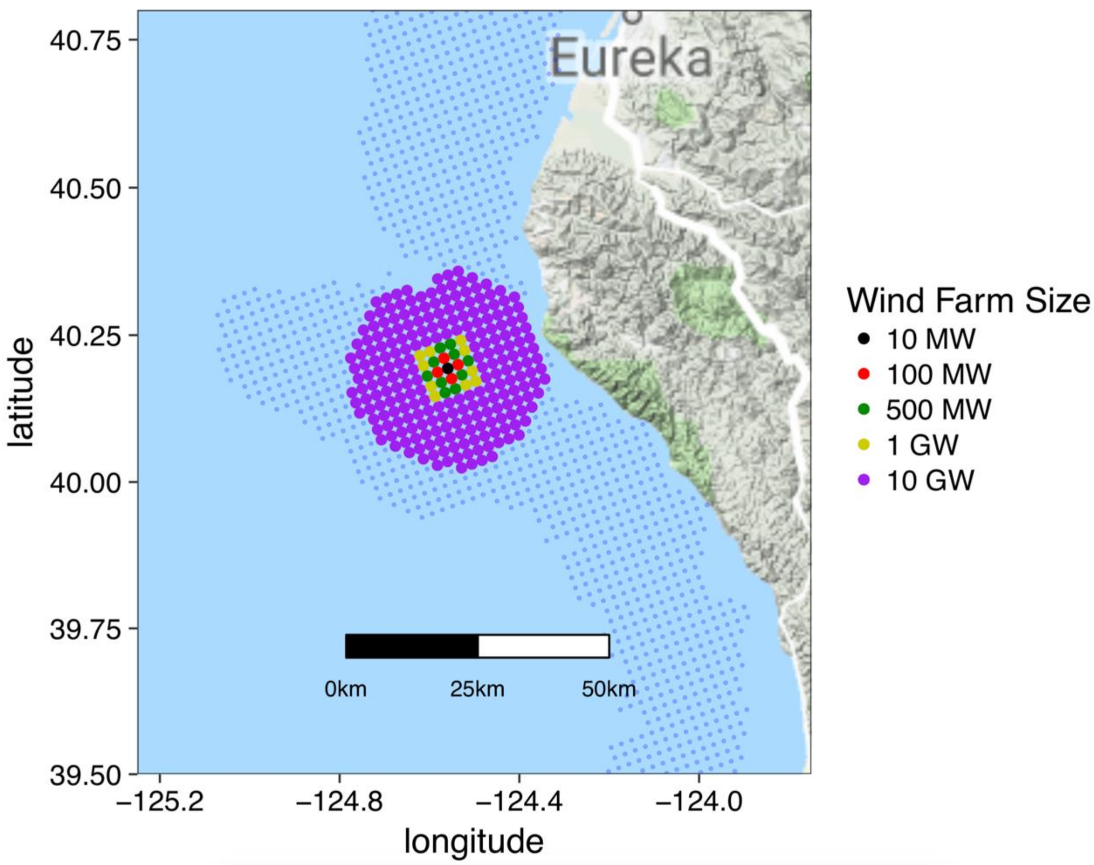

Figure 22: Wind farm sizes in Cape Mendocino ranging from 10 MW to 10 GW. Larger capacities also encompass the points used to display previous capacities in other colors.

Table 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%

Figure 23

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 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 24 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 12).

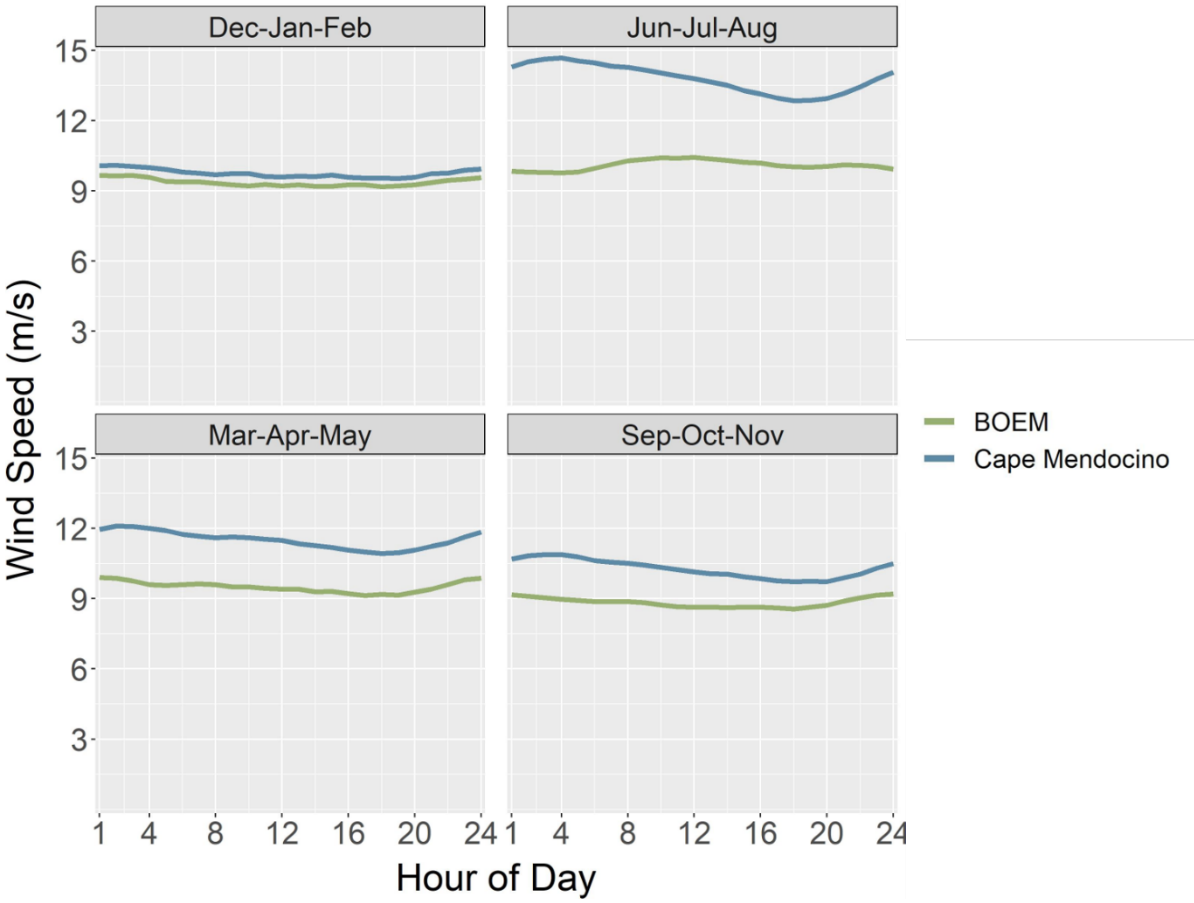

Figure 24. Average hourly wind speed profiles by season for both locations.

Table 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 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 25) and the Notional Cape Mendocino Area (Figure 26). 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.

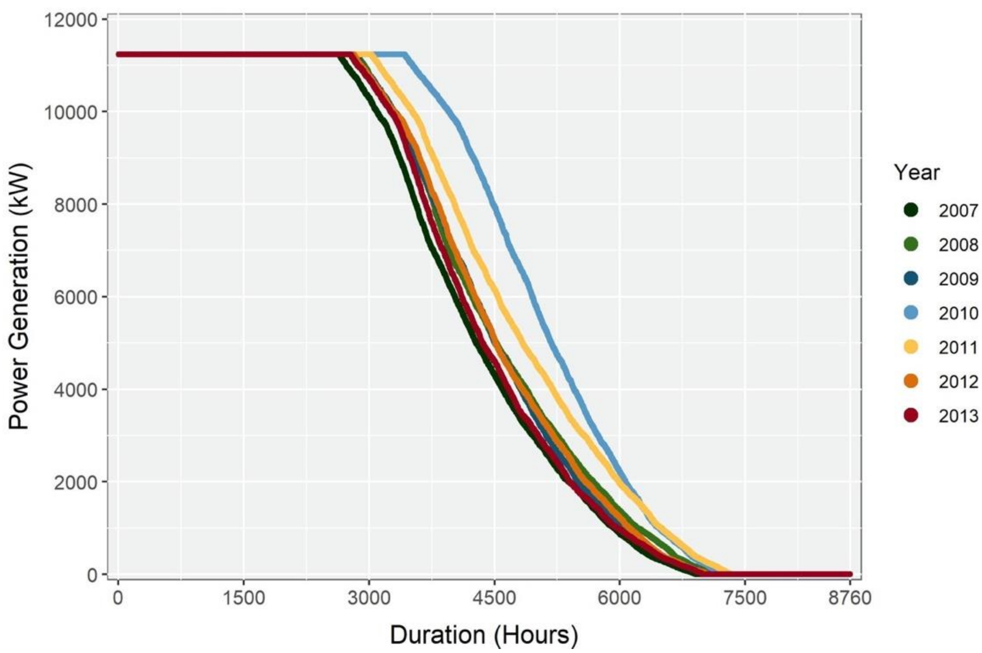

Figure 25. Generation duration curve for the entire period of wind speed records in the Humboldt Call Area.

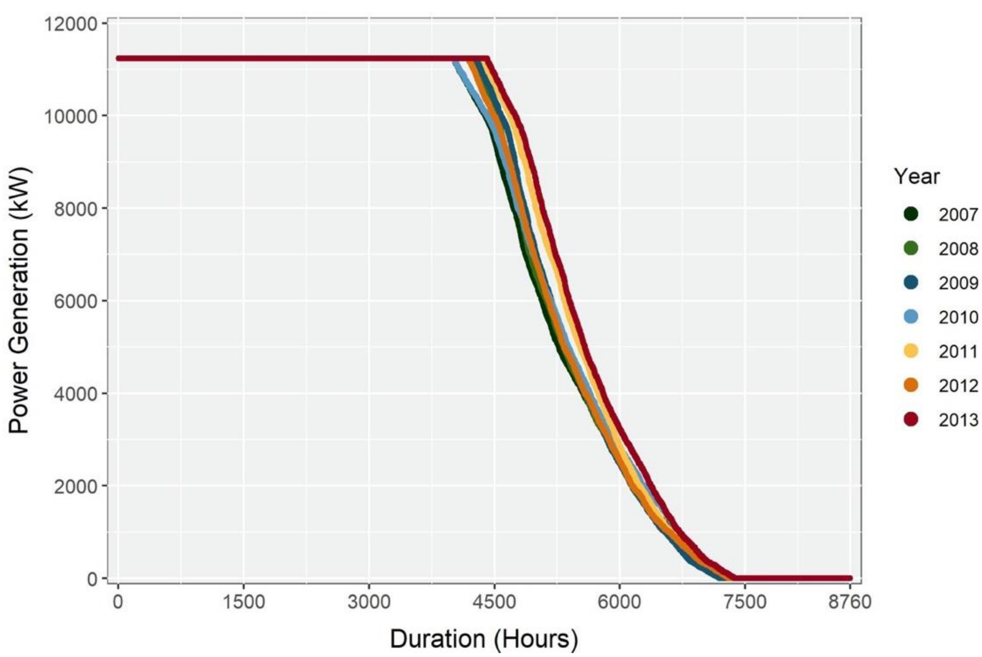

Figure 26. Generation duration curve for the entire period of wind speed records in the Cape Mendocino location.

APPENDIX 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 27 and Figure 28.

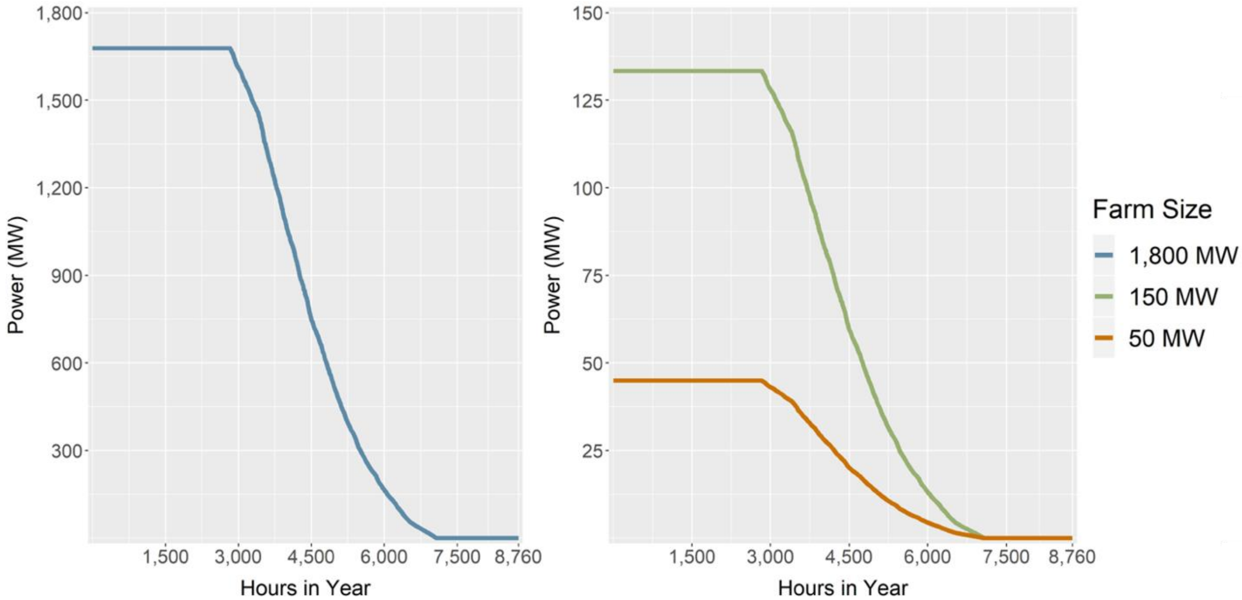

Figure 27. Humboldt Call Area generation duration curves for 1,800 MW scenario (left) and 150 MW and 50 MW scenario (right).

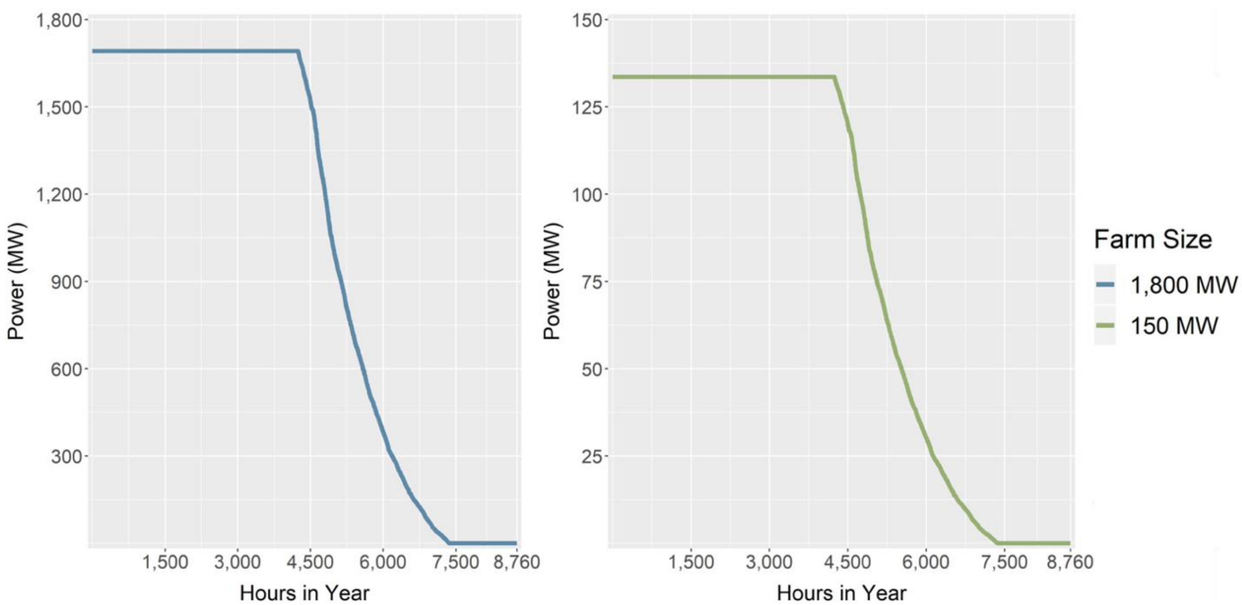

Figure 28. Cape Mendocino generation duration curves for 1,800 MW scenario (left) and 150 MW scenario (right).

APPENDIX 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 29) and the Cape Mendocino location (Figure 30).

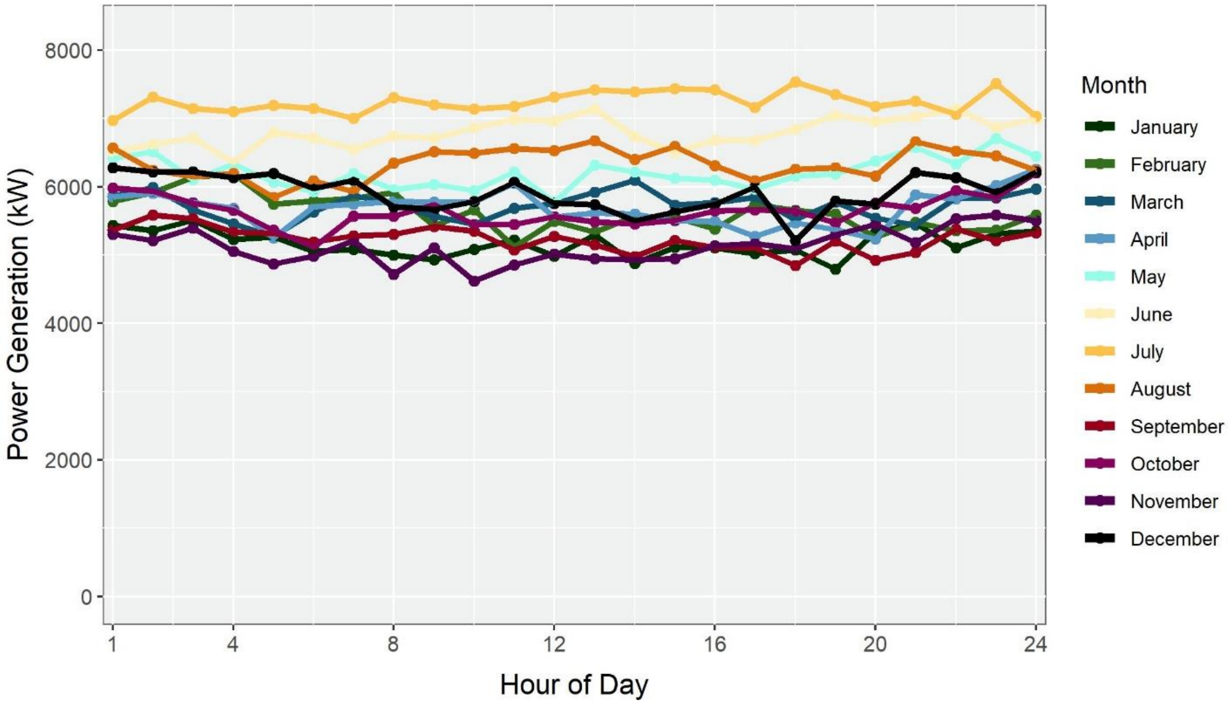

Figure 29. Average hourly power output by month of a 12 MW turbine in the Humboldt Call Area.

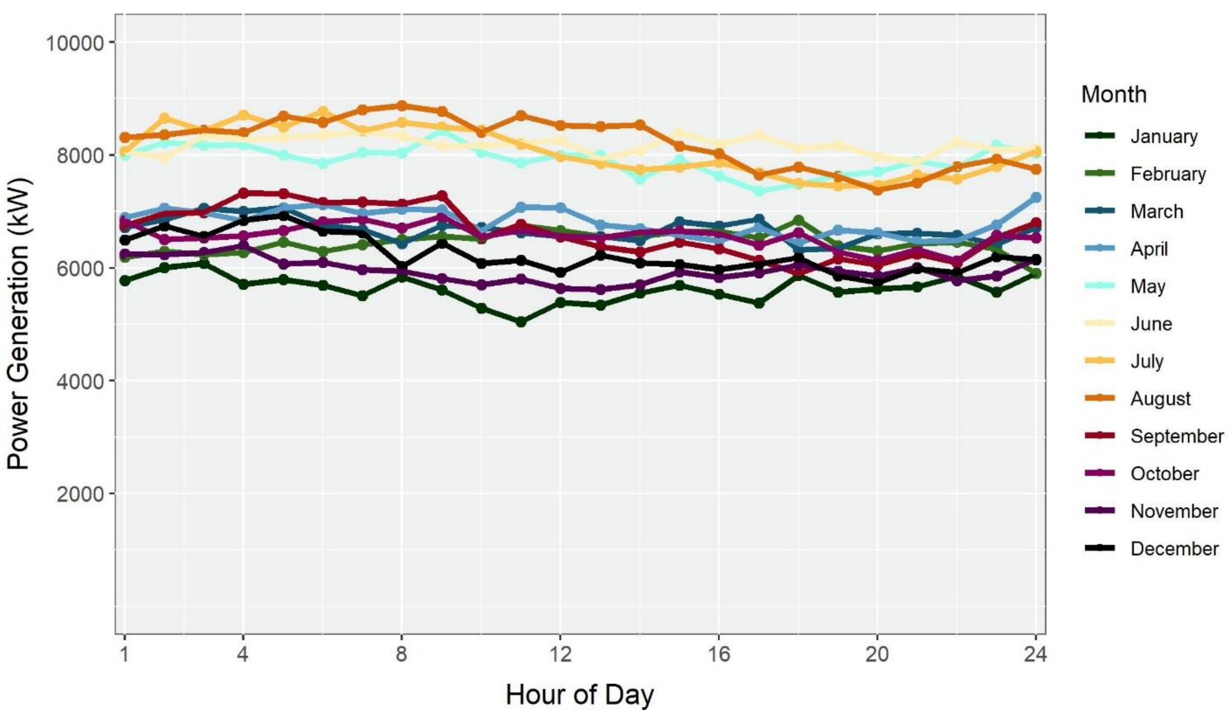

Figure 30. Average hourly power output by month of a 12 MW turbine in the Cape Mendocino location.