

Transmission Alternatives for California North Coast Offshore Wind

Volume 2: Description and Preliminary Analysis of Transmission Alternatives



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The report is also available on the Schatz Energy Research Center website at: [schatzcenter.org/publications](https://www.schatzcenter.org/publications)

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The Schatz Energy Research Center at Cal Poly Humboldt advances clean and renewable energy. Our projects aim to reduce climate change and pollution while increasing energy access and resilience.

Our work is collaborative and multidisciplinary, and we are grateful to the many partners who together make our efforts possible.

Learn more about our work at [schatzcenter.org](https://www.schatzcenter.org)

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1 INTRODUCTION AND PURPOSE

This transmission analysis report is part of a collaborative effort to assess the impact that transmission alternatives can have on the economic viability of modest scale (less than 500 MW) offshore wind development in the Humboldt Wind Energy Area located off the coast of Humboldt County, California. These transmission alternatives have been evaluated at several scales of offshore wind development between 30 to 480 MW to determine the potential for offshore wind development given existing transmission infrastructure and the investments that would be needed for wind projects that exceed the existing transmission capacity. In addition, impacts to revenue potential have been assessed since economic viability is a function of both costs and revenues.

This work is supported by funding from the Bureau of Ocean Energy Management (BOEM) and is being led by the Schatz Energy Research Center (Schatz Center) at Cal Poly Humboldt. Project partners include the National Renewable Energy Laboratory and Quanta Technology, LLC. The research is comprised of four tasks, each of which features a standalone report. Descriptions of the four tasks and the responsible parties are shown in Table 1.

Table 1: List of tasks for California North Coast Offshore Wind Transmission Alternatives Study

Task Description	Responsible Party
Task 1. Wind Resource Assessment	Schatz Energy Research Center
Task 2.1 Description of Transmission Alternatives	Schatz Energy Research Center
Task 2.2 Transmission Analysis	Quanta Technology, LLC
Task 2.3 Cost-Benefit Analysis	National Renewable Energy Laboratory

This report, which is associated with Task 2.1, provides background information compiled for this study of transmission alternatives, describes the transmission alternatives examined, discusses preliminary analyses of the alternatives, and identifies alternatives and scenarios that were further assessed in Task 2.2 and Task 2.3. The transmission alternatives studied include:

- curtailment of wind turbines during periods of transmission congestion,
- installation of battery storage to manage the timing of energy delivery,
- development of regional electricity load to absorb more offshore wind energy locally, and
- development of local hydrogen production to absorb more offshore wind energy.

2 BACKGROUND INFORMATION

Information required for this study included data about the transmission system serving the Humboldt Area, the electrical load and electrical generation sources in the Humboldt Area, and the offshore wind generation potential for the Humboldt Wind Energy Area. This background information is discussed below. In consultation with BOEM, the study year chosen for this analysis was 2030.

2.1 Transmission System

The Humboldt Area transmission system consists of 60 kV and 115 kV transmission facilities and multiple generation sources that include natural gas, biomass, solar, and hydroelectric power plants (Figure 1). The Humboldt Bay Generating Station and the other local plants serve the regional load of 90 to 110 MW with supplemental power coming from the bulk Pacific Gas & Electric transmission system. Transmission infrastructure into and out of the area is limited to four, 80 to 100 miles long transmission circuits. Two 115 kV circuits and one 60 kV circuit run along an east-west corridor from the Cottonwood Substation and one 60 kV circuit runs north-south from the Mendocino Substation.

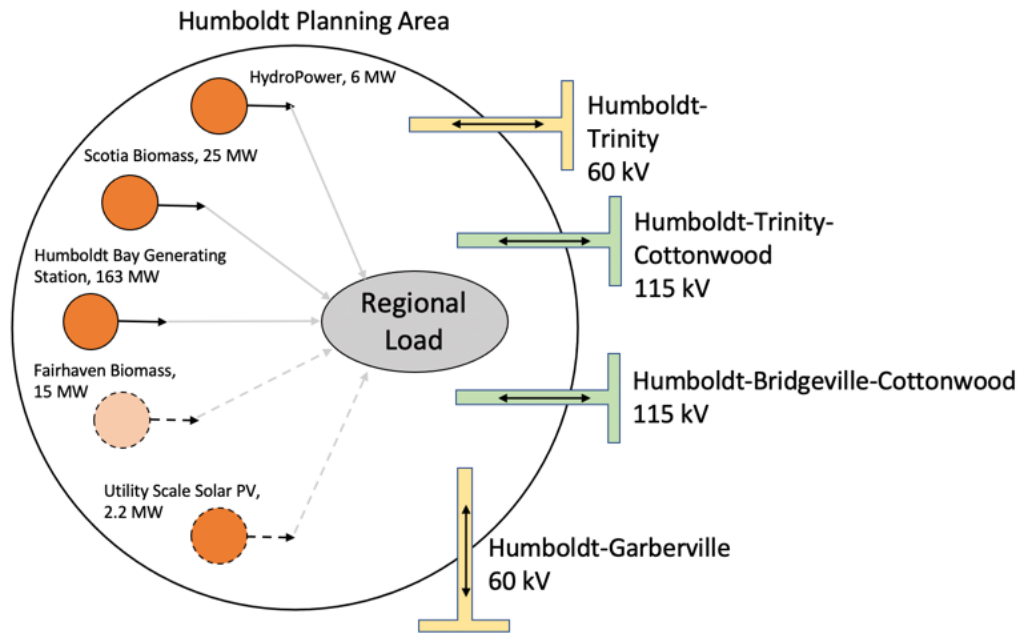


Figure 1: Simplified schematic of Humboldt's generation sources and transmission circuits

Figure 2 shows the location of the Humboldt Wind Energy Area and Humboldt County's transmission system relative to the major transmission corridor that runs north and south in California. The Humboldt Area transmission system is constrained and the lines serving the area are not sized to accommodate a large import or export of power. Development of large-scale offshore wind that generates significantly more energy than can be used locally will require upgrades to the interconnecting transmission lines to export power to the State's major transmission system.

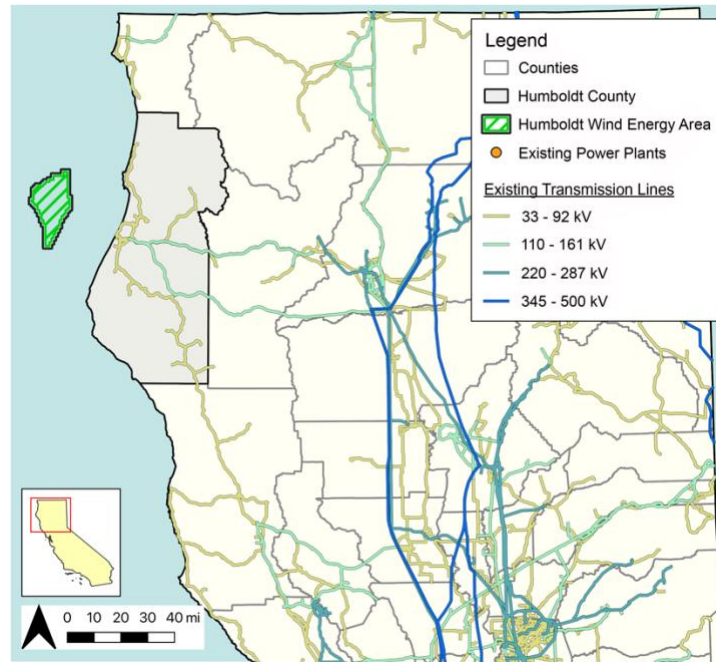


Figure 2: Map showing the electrical transmission system in Humboldt County and the northern part of California with respect to the offshore Humboldt Wind Energy Area

2.2 Humboldt Area Load

Assumptions for the 2030 Humboldt Area load were based on the Redwood Coast Energy Authority's (RCEA) RePower Humboldt report (RCEA 2019). RCEA is the Community Choice Aggregator for Humboldt County that currently supplies generation resources for over 90% of Humboldt County electricity customers. RCEA prepared the RePower Humboldt report as a regional plan for meeting Humboldt County's energy needs. The RePower Humboldt plan identifies energy supply and demand strategies with a goal of achieving net-zero greenhouse gas emissions and the county becoming a net-exporter of renewable energy by 2030. The action plan estimates the projected demand for 2030 for various cases and looks at existing and new power resources that can meet the future demand and achieve the stated goals.

Error! Reference source not found. shows RCEA's projected 2030 load profiles for a base case and an augmented growth case that were developed through the energy planning work. The base case is a business-as-usual profile and was calculated using a 2025 load forecast by The Energy Authority (TEA) and an assumed 1% load growth per year from 2025 to 2030. The augmented load growth consists of additional electrified transportation and building heating loads to the base case while taking into account the projected solar generation from future customer NEM photovoltaic systems. An additional profile (not shown in the figure) was also developed that is based on the augmented profile plus a continuous 20 MW load. The additional 20 MW load is intended to represent the addition of a new industrial fish farming facility that is being planned for installation in the Humboldt Bay area (GHD 2021). See Appendix A for more details about the assumptions regarding Humboldt Area load.

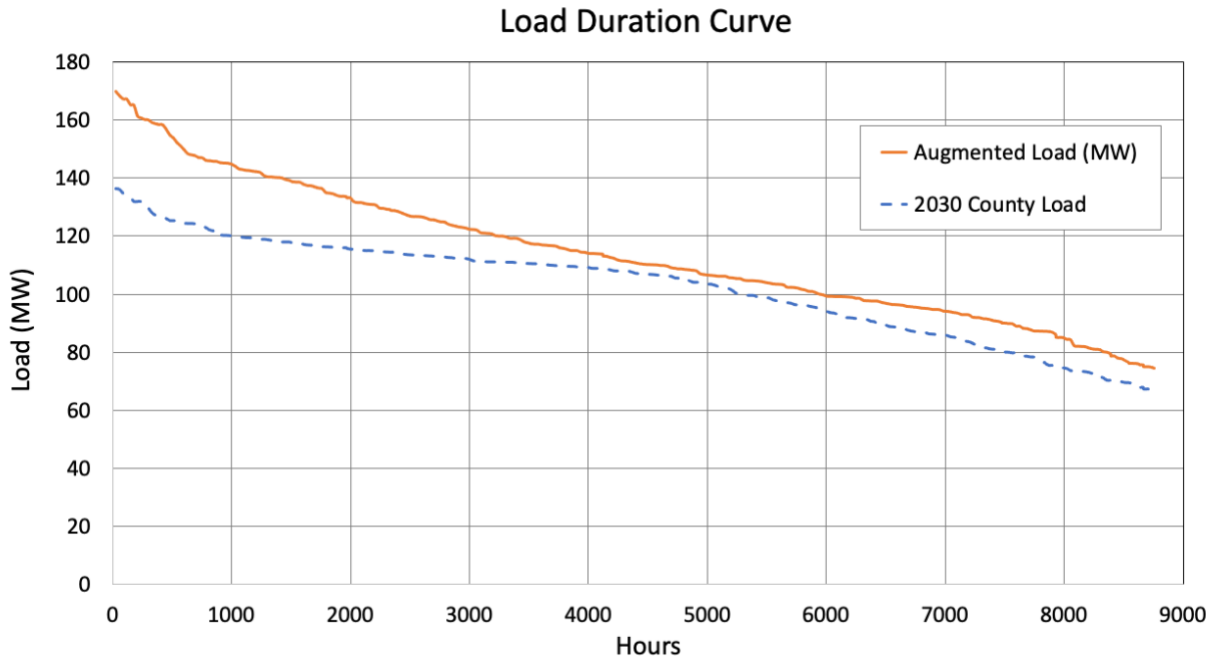


Figure 3: Projected load profiles for Humboldt County

The annual energy demand and peak demand for the three load profiles provided to Quanta for evaluation are:

- RCEA base case - annual demand of 894 GWh per year with a peak demand of 136 MW
- RCEA augmented growth - annual load of 999 GWh per year with a peak demand of 169 MW
- RCEA augmented plus a continuous 20 MW load - annual demand of 1174 GWh per year with a peak demand of 189 MW

2.3 Humboldt Area Generation

The large majority of the load in the Humboldt Area is currently met using local generation assets, and this approach is expected to continue into the future. The assumptions in this study regarding which generators will serve the Humboldt Area in 2030 were developed based on the status of generators that currently exist in the area and the assumptions used in the California Independent System Operator's (CAISO's) long-term planning models¹. In addition, we incorporated information from the RCEA RePower Humboldt report (RCEA 2019). Specifically, four planned² distributed solar photovoltaic installations were included, and assumptions about the operation of local biomass power plants were incorporated. The DG Fairhaven biomass power plant, which is currently not operational, the potential onshore wind power project, and the small hydropower projects shown in the RePower Humboldt study were not included in the

¹ Quanta Technologies, as part of the Task 2.2 study, obtained CAISO long-term planning model information.

² The RCAM Solar photovoltaic installation was installed in 2021.

local generation mix. Table 2 shows the generators considered for the 2030 simulations. See Appendix A for more details about the assumptions regarding Humboldt Area generation.

Table 2: High-level overview of expected generation in the Humboldt area in 2030 (Daneshpooy and Anilkumar 2022)

Unit Name	Unit Type	Fuel Type	Maximum Cap (MW)
Carlotta	Hourly Resource	Solar Photovoltaic	4.2
Hatchery Road Solar	Hourly Resource	Solar Photovoltaic	4.2
Hoopa Solar	Hourly Resource	Solar Photovoltaic	4.2
Humboldt OSW	Hourly Resource	WT-Offshore	Scenario Dependent
HumboldtBayIC01	Thermal	ICE-NatGas	16.3
HumboldtBayIC02	Thermal	ICE-NatGas	16.3
HumboldtBayIC03	Thermal	ICE-NatGas	16.3
HumboldtBayIC04	Thermal	ICE-NatGas	16.3
HumboldtBayIC05	Thermal	ICE-NatGas	16.3
HumboldtBayIC06	Thermal	ICE-NatGas	16.3
HumboldtBayIC07	Thermal	ICE-NatGas	16.3
HumboldtBayIC08	Thermal	ICE-NatGas	16.3
HumboldtBayIC09	Thermal	ICE-NatGas	16.3
HumboldtBayIC10	Thermal	ICE-NatGas	16.3
Kekawaka	Hydro	HydroRPS	6
PacificLumber1	Thermal	Bio-ST	12.5
PacificLumber2	Thermal	Bio-ST	12.5
PacificLumber3	Thermal	Bio-ST	7.5
RCAM Solar	Hourly Resource	Solar Photovoltaic	2.2

2.4 Wind Farm Production

An assessment of the power generation potential for offshore wind within the Humboldt Wind Energy Area for different wind farm scales was performed and results were presented in the Task 1 report: California North Coast Offshore Wind Study - Wind Speed Resource and Power Generation Profile Augmentation Report (Younes et al. 2022).

The Humboldt Wind Energy Area, as identified by the Bureau of Ocean Energy Management (2018a, 2018b), is a 536 km² area located west of Humboldt Bay, approximately 20 to 30

naautical miles (37 to 56 km) offshore that has average annual wind speeds at 90 m above sea level ranging from 8.5 to 9.0 meters per second (Figure 4).

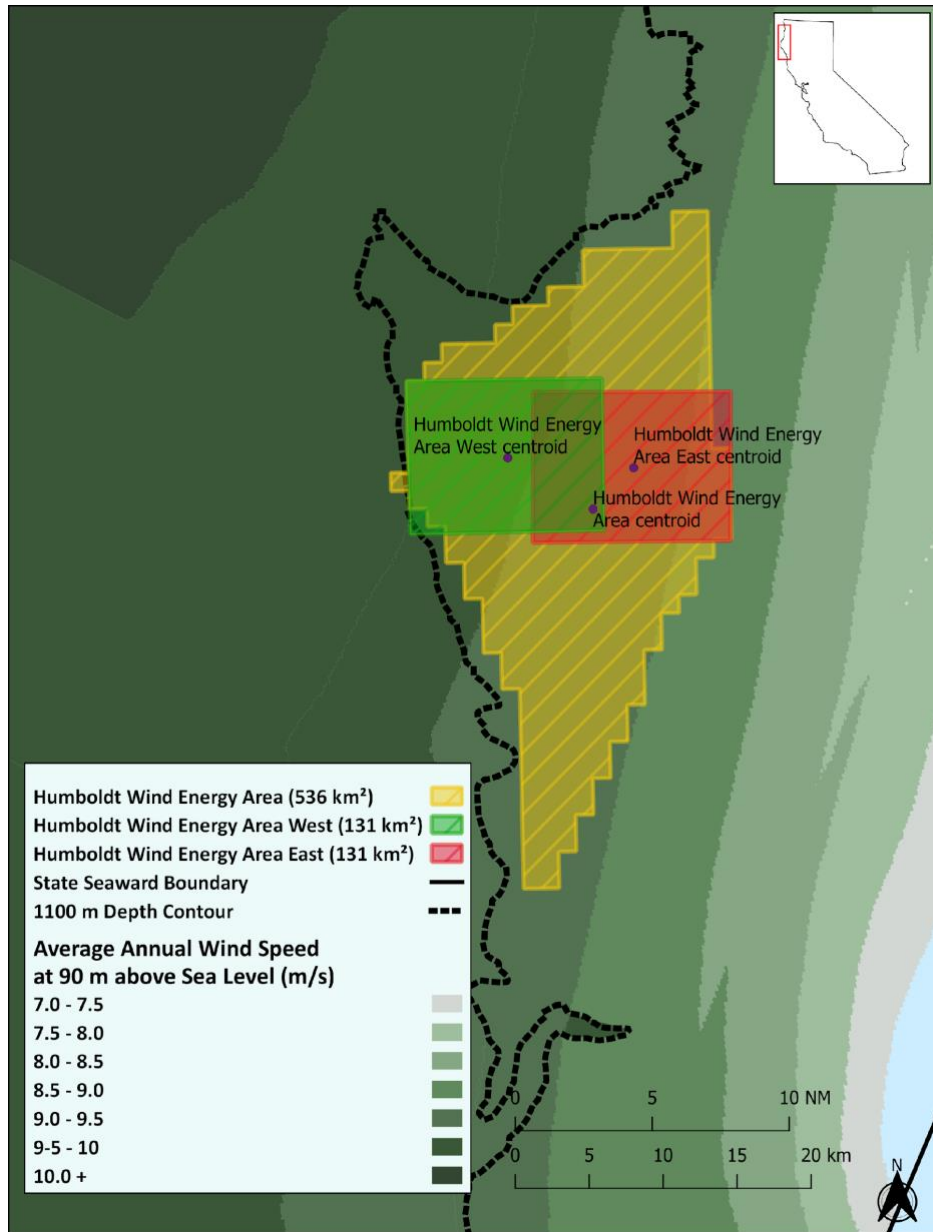


Figure 4: Map of Humboldt Wind Energy Area

This study assessed the generation potential for wind farm sizes of 144 MW, 168 MW, 288 MW, and 480 MW. All wind farms were assumed to use a 12 MW nameplate capacity turbine. For information about the array layout, turbine quantity and turbine spacing see the Task 1 report (Younes et al. 2022).

Power generation profiles for the various size wind farms were calculated for the Humboldt Wind Energy Area West centroid, and the estimated annual energy production based on a 95% confidence interval for population mean for each size are summarized in Table 3.

Table 3: Estimated annual generation for wind farm sizes in study

Offshore Wind Farm (MW)	Total Generation (GWh per yr)
144	662
168	770
288	1,320
480	2,190

3 DESCRIPTION OF ALTERNATIVES TO REDUCE OR AVOID TRANSMISSION SYSTEM UPGRADES

Transmission infrastructure upgrades are expected to be very costly for any wind farm development over a certain threshold (Severy et. al. 2020). In order to reduce the cost of transmission upgrades, methods to fit the generation of the studied windfarms within the constraints of the current transmission system were investigated. These included curtailment, battery energy storage systems (BESSs), load growth, and hydrogen electrolysis. Each of these methods could be used by a wind farm operator to reduce power exports along constrained transmission lines at key times to maximize wind farm output without overloading transmission infrastructure. The reduction in power exports could come from simply curtailing the wind farm (directly reducing generation). A second option could include using a BESS to store excess wind energy that would otherwise need to be curtailed, and dispatching the wind energy at a later time when it is needed. Finally, if Humboldt County's local load were to increase as a result of factors such as vehicle and building electrification; or, if another load such as a hydrogen production facility were developed near the point of wind farm interconnection, a larger wind farm could be developed to meet the local load. The following section goes into further detail on each of these alternatives to transmission system upgrades.

3.1 Curtailment

Curtailment of wind power is simply a reduction in wind energy production. Curtailment is often involuntary, and can result from transmission congestion, greater energy generation than is needed to fill local load and exports, as well as voltage and interconnection issues and market based protocols (Bird et al. 2014). Curtailment is a common operational strategy in the onshore wind industry. In 2020, the wind curtailment rate across most of the major power markets in the United States ranged from less than 1% to about 5% (Wiser & Bolinger, 2021).

In the wholesale electricity market, the signal to curtail is given by a price signal below the marginal cost of production. For this study, the signal that triggered curtailment was a price of negative \$25 per MWh. The marginal cost of production for a wind farm is \$0 per MWh. However, this study assumed there would be a production tax credit of \$25 per MWh available to the developer. This meant that a market price as low as negative \$25 per MWh could be accommodated before the wind farm owner would lose money associated with production.

The technical ability of wind turbines to curtail output is well established, and there are a variety of curtailment techniques employed depending on the level of need for curtailment. In cases where large amounts of the wind farm's production need to be curtailed, individual turbines or the entire wind farm could be shut down. The main method to shut down the production of an

individual turbine is to feather the blades, which involves rotating the blades 90 degrees so that they are parallel to the direction of wind flow instead of perpendicular. Blades can be locked in addition to feathering when required (i.e. for maintenance). Another technique to curtail individual turbines is to increase their cut in speed so that it is higher than the rated cut in speed, thereby decreasing overall generation (Whitby et al. 2021).

The advantage of curtailment is that it can, to some degree, obviate the need for grid upgrades by reducing power when that power would overload the electrical transmission network. Curtailment comes at no operational cost; however, there are opportunity costs due to lost revenues associated with undelivered power.

The way that curtailment is enabled is via the choice of interconnection pathway for the generation resource. During the interconnection process a decision must be made prior to the execution of system impact studies. At this time the interconnection customer must choose whether they want to interconnect with Full Deliverability or Energy Only deliverability status. This choice can have a significant impact on the transmission infrastructure requirements associated with development of the project and the associated costs if upgrades are needed. The interconnection approach can also can impact the project's net qualifying capacity, and hence its revenue potential.

As discussed in Severy, et al., (2020), there are two pathways for triggering the upgrade of transmission infrastructure. One approach is driven by state policy and planning processes, while the other involves identification of the need for transmission system network upgrades when a project developer is proposing to interconnect new generation. Regardless of the approach, the cost of transmission upgrades is generally covered by ratepayers. However, if the need for network upgrades is determined during the interconnection process, the interconnection customer will typically need to finance the cost. Then, once commercial operation of the new generation is reached, the interconnection customer will be reimbursed in full over a five year period (CAISO 2021).

3.1.1 Energy Only Deliverability

Per the CAISO Tariff (CAISO 2021), under Energy Only deliverability status, the project may trigger the need to carry out transmission system reliability network upgrades, but it would not trigger deliverability network upgrades. In addition, the interconnection customer's generator will be assigned a net qualifying capacity of zero, which means they will not qualify for resource adequacy and will therefore forego the revenue potential associated with capacity payments. When conducting system impact studies to determine the need for transmission upgrades, generators with Energy Only deliverability status will be curtailed as needed to mitigate transmission constraints.

3.1.2 Full Capacity Deliverability

Under Full Capacity Deliverability interconnection status, the project may trigger both reliability network upgrades and deliverability network upgrades, and the interconnection customer's generator will be assigned a net qualifying capacity based on the CAISO's Deliverability Allocation Procedures (CAISO 2021). The assigned net qualifying capacity will impact resource adequacy opportunities and associated revenue opportunities. When conducting system impact studies to determine the need for transmission upgrades, generators with Full Capacity deliverability status will not be curtailed for the purpose of congestion management.

3.2 Battery Energy Storage Systems

Battery energy storage systems (BESSs) are the most popular scalable means of storing electrical energy. Since they can store energy during times of abundant generation and dispatch it later, they can enable reduced curtailment from offshore wind and other non-dispatchable resources (i.e., solar) and increase revenues from any resource. Revenues are increased via price arbitrage, which in this context means using wind or solar electricity to charge battery storage when wholesale prices are low, selling power at a times during when electricity is more expensive, which is currently during the evening hours.

In California Independent System Operator (CAISO) territory, batteries can participate in the energy market, — generally performing energy arbitrage — the resource adequacy (RA) market, and the ancillary services (AS) market.

Fribush (2016) found that energy arbitrage was not profitable with an average round trip energy storage efficiency of 75% given the diurnal price differentials that were experienced. The storage systems were tested with bids into CAISO's day ahead (DA) market based on proprietary algorithms developed internally by PG&E. Fribush notes a significant complexity when bidding simultaneously into energy and AS markets. Fulfilment of AS bids can lead to either charging or discharging of the battery, making it difficult or impossible to determine how much charging/discharging is available for the next energy bids into the DA, since the bids happen simultaneously.

Storage systems were able to achieve ancillary services revenues of up to \$7,000 per MW per month, though \$2,000 per MW per month appears to have been more typical. This was from participation in the frequency response market, which was the most lucrative in their experience. They note that for this application a shorter-duration storage may provide the same service at a lower investment cost. This is comparable to the BESS ancillary service revenues that were estimated in the Quanta Technologies Task 2.2 analysis, where in the 144 MW case paired with battery storage the ancillary services revenues totaled about \$3,300 per MW per month.

Regardless of the present market value, it is clear that BESSs will be a valuable — and cost effective — grid resource. Frazier et al. (2021) used a least-cost optimization model of the U.S. electricity sector from 2020 to 2050 to determine that diurnal storage (i.e., mostly 4 to 6 hour BESSs) are “extremely cost competitive.” The value provided by storage is “driven primarily by the combination of capacity value and energy arbitrage (or time-shifting) value” (Frazier et al., 2021, p. vii), and thus this report would lead us to believe that energy arbitrage is, or will become, an important source of revenue for storage. As storage penetration increases, activities like peak shaving will become less important, and storage will need to be built with increasing durations to effectively shift load over increasing time periods.

Frazier et al. (2021) go on to cite sources that further describe the value of energy storage and how that value is likely to change as storage penetration increases and the value of time-shifting decreases.

Energy time-shifting value comes from storage charging when prices are low and discharging when prices are high, so the duration of storage and shape of the energy price profile determine the possible value of this service. Price profiles can vary widely across spatial regions and change with investments in new generation, transmission, and storage resources. Low-cost generation from PV and wind drive prices down during periods of high generation. Transmission investments can reduce

congestion, which can reduce the frequency and magnitude of price spikes (Wang et al., 2017). Energy time-shifting from storage can raise off-peak prices and lower peak prices, and this leads to declining energy time-shifting value with increased storage penetration and an eventual techno-economic limit where the volatility of price profiles is not large enough to overcome losses from storage (Brijs et al., 2019). (Frazier et al., 2021, p. 2)

As Frazier et al. explain, variable resources can increase price instability, as can transmission congestion. Both of these factors would tend to make energy storage paired with offshore wind in Humboldt County more economical assuming transmission constraints remain. As Frazier et al. also note, increasing penetration of storage decreases the value of storage, creating a limit to how much storage can be economically deployed in a given region.

Given the potential value afforded by storage systems, two scenarios investigated in Task 2.2 included BESSs. These scenarios added a 4 hour, 15 MW BESS capable of providing ancillary services and energy arbitrage to the base case load scenarios for 144 MW and 168 MW wind farms. These simulations focused on revenue potential rather than grid reliability; additional discussion of these scenarios and how they were developed is provided in Section 4.3.

3.3 Load Growth

Load growth includes categories such as vehicle and building electrification, as well as the building of industrial projects, such as the planned Nordic Aquafarm fish farming facility. Increased growth of any kind of load is expected to reduce the need for curtailment at no cost to the wind farm developer, thereby improving project economics.

We used load growth assumptions from RCEA's RePower Humboldt study (RCEA 2019) to develop the *RCEA augmented load* scenario. This included electrification of heating loads that would account for a 20% reduction in the county's natural gas and propane use, as well as adoption of 22,000 electric vehicles. Together these additional electric loads added 164 GWh a year of electricity consumption, or 18% of the base load. We also considered the *decreased* customer load due to the installation of 40 MW of new customer-sited rooftop solar producing 59 GWh per year. Together these additional loads and behind-the-meter generators would increase the demand for grid electricity by 11.7% over the 2030 baseline consumption of 894 GWh.

The Nordic Aquafarm fish farming facility (GHD 2021) was estimated to draw a continuous 20 MW of electrical power. This additional 20 MW load was added to the RCEA augmented load scenario in order to create the *RCEA augmented load + 20 MW* scenario.

These two load growth scenarios were evaluated and compared with the base case load scenario to assess how the level of wind energy curtailment was affected and what sort of impact it would have on revenues and project economics.

3.4 Hydrogen Production - Electrolysis

Utilizing excess wind power generation for large-scale hydrogen production provides a tremendous opportunity to generate and store significant amounts of renewable energy that can be used across many sectors of the economy. Electrolysis is the process of splitting water to generate hydrogen gas and when the electricity used comes from a renewable energy source, such as wind or solar, the product is termed green hydrogen. As a zero-emission energy carrier

and storage medium, green hydrogen has economic, environmental, and health benefits. Of the many applications, the most promising uses for renewable hydrogen along the north coast of California are:

- transportation - provide renewable transportation fuel for light-duty fuel cell electrical vehicles and fuel cell electric buses
- power generation and grid balancing - provide centralized power production using fuel cells and gas blending for power plant gas engines
- grid support services - operate an electrolyzer plant as a controllable load
- blending of hydrogen into the natural gas system

Large capacity hydrogen production that exceeds local demand would require intensive capital investments, including liquefaction facilities to transport and store hydrogen as a liquified gas throughout the region. While outside the scope of this study, large-scale hydrogen production from offshore wind provides a tremendous opportunity to transition to renewable transportation fuels, and should be investigated further in a follow up study.

The near-term use for green hydrogen on the North Coast is as a renewable transportation fuel for local and regional fuel-cell electric buses (FCEBs) and light-duty, fuel-cell electric vehicles (FCEVs). The county's transit agency - Humboldt Transit Authority (HTA) - is in the planning stages to transition away from fossil-fuel buses and replace their entire fleet with zero-emission buses. The fleet would have an estimated demand of 600 kg per day (kg per day) of hydrogen. Similar planning efforts are also underway in surrounding counties along the coast and inland to Redding.

In the *2020 Annual Evaluation of Fuel Cell Electric Vehicle Development & Hydrogen Fuel Station Network Development* report, the California Air Resources Board projects between 1 to 250 FCEVs will be on the road in the North Coast Region (Humboldt, Mendocino, and Del Norte counties) by 2026 and will require up to a combined fueling capacity of 1,100 kilograms per day (FCHEA 2020). This fueling capacity is based on a highly ambitious adoption of up to 250 FCEV fuel demand projection. For the purposes of this analysis, we assume 50% of the number of vehicles will be in service with an estimated fuel demand of 600 kg per day, resulting in a near term combined demand of 1200 kg per day.

Longer-term, the largest and most flexible application possibility is gas blending of hydrogen into the natural gas pipeline that supplies the Humboldt Bay Generation Station (HBGS). The HBGS hosts ten Wartsila 18V50DF (dual fuel - natural gas and diesel) 16.3MW reciprocating engines for a combined plant capacity of 163MW. The manufacturer has been testing and developing their engines to run on a mix of natural gas/hydrogen and on pure hydrogen. It is unknown whether the existing engines can operate on blended gas, but replacement of a portion or all of the existing engines at end of life with hydrogen compatible units should be investigated (Wartsila 2020). Direct injection of hydrogen from low pressure buffer tanks at the production facility into the low-pressure natural gas pipeline feeding the power plant and the flexibility in the range of mixing blends avoids the high capital and operating costs for high pressure compression and storage that is required for other applications.

Hydrogen could also be blended into the bulk natural gas system in percentages ranging from about 5% up to as much as 15% by volume and utilized for general consumption. This has been

shown to be feasible and is an easy way to utilize renewable hydrogen and reduce the carbon emissions associated with consumption of natural gas (Melania et al. 2013).

Using wind power to generate renewable hydrogen is gaining momentum worldwide with several wind-to-hydrogen projects planned for the North Sea. By the end of 2021, Danish energy company Orsted is scheduled to be producing 1000 kg per day of green hydrogen from their 2-MW H2RES demonstration renewable energy project in Denmark. Nine other projects including the large industrial scale “Green Fuels for Denmark” project are being evaluated (Orsted 2021). In the Port of Ostend, Belgium, the 4-GW HYPOR Oostende wind farm project is under construction and will include a 50MW electrolysis plant to produce green hydrogen for electricity generation, transportation, heat, and industrial purposes (DEME 2021). Many other wind-to-hydrogen projects are planned in the Netherlands, Germany, the United Kingdom, Spain, and Saudi Arabia. In the United States, fuel cell technology firm Plug Power has partnered with Apex Clean Energy in a 345-MW wind power purchase agreement to develop an electrolysis plant in Texas that could produce up to 30 metric tons per day of green hydrogen (Plug Power 2021).

4 PRELIMINARY ANALYSES AND PLANNING FOR TASK 2.2

This section discusses the preliminary analyses and planning work that was conducted in preparation for the more sophisticated transmission analysis work performed by Quanta Technologies as documented in the Task 2.2 report, CA North Coast OSW Study Transmission Analysis. The Schatz Center team collected the necessary background information needed for the subsequent analyses, and also developed a simplified single node model of the Humboldt Area transmission system. This single node model was used to conduct preliminary analyses and examine the ability to use curtailment, energy storage and load growth as means to reduce the transmission upgrades needed to accommodate offshore wind energy production on the North Coast. The results from these preliminary analyses informed the wind farm scenarios and transmission alternatives that were later examined by the Quanta Technology team in Task 2.2 of this study.

4.1 Tax Credits

In recent years, wind power facilities have been able to take advantage of one of two tax credit options – the *production tax credit* (PTC) or the *investment tax credit* (ITC). Production tax credits are rewarded per kilowatt hour generated by a qualifying facility, and tax credit value has traditionally decreased annually to encourage rapid construction. In 2021, the final year for which PTCs are currently available, the PTC for a wind power facility was \$18 per MWh, 60% of the original credit value (Bowers 2021). Alternately, developers could instead opt to take investment tax credits, a one-time credit to offset some of the capital costs of developing a plant. For offshore wind installations in particular, legislation is in place to offer an ITC equal to 30% of the tax basis for qualifying properties within the navigable waters or coastal waters of the US for constructions starting before 2026 (Griskonis and Rodgers 2021).

Unfortunately, these credits are currently set to expire: PTCs will end for any plants constructed after 2021, and ITCs will end for any plant constructed after 2025. There is language in the proposed Build Back Better Act to extend these credits – a \$25 per MWh PTC or 30% ITC for projects beginning construction before 2027, with an additional 10% credit on either if sufficient building materials are sourced in the US. These credits would also only be available if prevailing

wage and apprenticeship requirements are met (H.R. 5376 2021, Alexander et al. 2021). However, these expanded credits are contingent upon the Build Back Better Act becoming law as currently written, which is far from certain.

We note that the PTC was modeled in the Task 2.2 work by Quanta Technologies at a value of \$25 per MWh, as this value is currently consistent with CAISO models. Similarly, NREL considered a PTC of \$25 per MWh or an ITC of 30% in their economic analyses. As can be seen from the results of these studies the tax credits are very significant and therefore their availability could have a large impact on the economic viability of a proposed project.

4.2 Curtailment

We assessed the curtailment in all study scenarios with a single node Humboldt transmission model which we developed. Model inputs included regional load, generation, and locational marginal pricing (LMP) profiles from the Cottonwood node. For each hour of the simulated year, the model determined whether or not wind energy was curtailed, both through transmission constraints and as a result of economics. Additionally, the model was used to simulate the pairing BESSs with the wind farm in order to determine how the BESS affects the required wind farm curtailment. A description of the single node transmission model can be found in Appendix A.

The single node model assessed two types of curtailment. Transmission constrained curtailment occurred at any hour where the excess wind generated by the wind farm exceeded the transmission constraints for exports out of Humboldt County. For this analysis, the export limit was assumed to be 75 MW. This export limit is based on transmission information obtained from PG&E for past energy planning studies for the Humboldt area (Zoellick 2013 and Zoellick 2005), and on analysis conducted by Quanta as part of Task 2.2. In addition to transmission constrained curtailment, economic curtailment occurred at each hour where the value of the Cottonwood Locational Marginal Price³ was less than the negative value of the production tax credit, or -\$25 per MWh. The assumption here is that the wind farm developer will continue to dispatch wind electricity as long as they are not losing money. For this analysis, the PTC was assumed to be \$25 per MWh. Total curtailment was the sum of the transmission constrained curtailment and the economic curtailment.

As shown in Figure 5, preliminary findings from the single node model demonstrated that with no BESS, curtailment began to rise steeply for wind farm capacities greater than about 150 MW. A similar behavior was seen in the Task 2.2 results prepared by Quanta Technologies, though the steep rise appeared to begin at a slightly larger wind farm size. Based on these results we had Quanta Technologies assess the impacts of curtailment for 144 MW, 168 MW and 288 MW wind farm capacities. The impact to curtailment when pairing a BESS with a wind farm, as exhibited in Figure 5, is discussed in the Section 4.3.

³ The Cottonwood Locational Marginal Price (LMP) is the hourly wholesale price of energy at a particular node on the CAISO controlled transmission system. The Cottonwood node is the location where the main 115 kV transmission lines serving the Humboldt Area connect to the bulk California grid. The price at this node was thought to be generally reflective of prices in Humboldt that are not impacted by local congestion in the Humboldt Area.

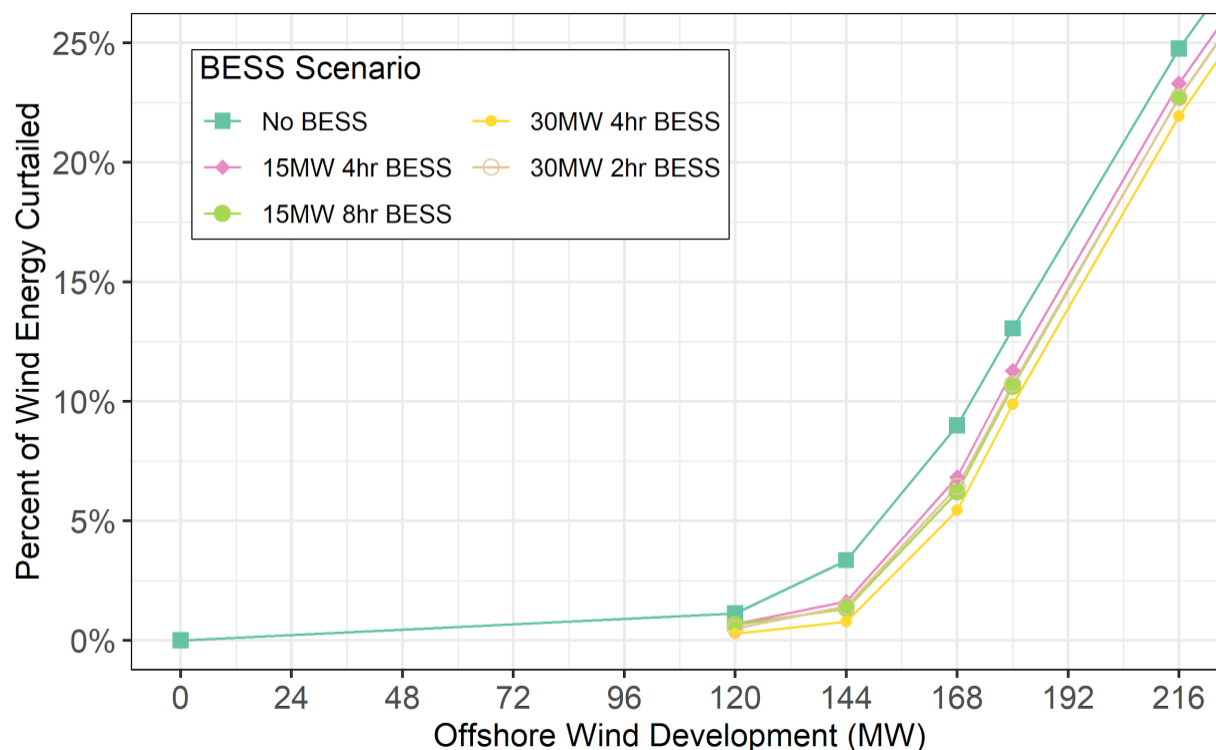


Figure 5: Single node model curtailment results with different offshore wind farm and BESS combinations

4.2.1 Curtailment Due to Humboldt Bay Generating Station Islanded Operation

As discussed in Section 2.3 of this report, most of the load in the Humboldt Area is served by local generation. One key generating asset is the Humboldt Bay Generating Station (HBGS), owned and operated by Pacific Gas and Electric. The purpose of this generator is to serve the Humboldt Area, and it is capable of meeting the entire regional load. In June of 2020, it was announced by PG&E that HBGS had been reconfigured and was now capable of serving the main population centers in the Humboldt Area⁴ while the area was disconnected from the larger California grid, referred to as islanding (PG&E 2020a). This was an important improvement for reliability for the Humboldt Area because of the Public Safety Power Shutoffs (PSPS) that began occurring in 2019 as a response to the increased threat of wildfires. When PSPS events occur in areas surrounding the Humboldt Area, it is not uncommon for the 115 kV transmission lines serving the area to be disconnected. With the new islanding capability of the HBGS, it is now capable of serving the area when this happens.

One consequence of this islanding capability is that PG&E requires that all other wholesale generators greater than 1 MW in capacity that are connected to the islanded Humboldt grid must

⁴ The areas that can be powered by HBGS when in island mode include multiple cities and towns, including Eureka, Arcata, McKinleyville and Fortuna.

curtail operation during islanding events. This has occurred multiple times since June of 2020. For example, in August and September of 2021 the Humboldt Sawmill Company's biomass cogeneration power plant⁵ was shut down for a cumulative 28 days due to HBGS islanding events (Gwynn 2021). At this time, it is anticipated that an offshore wind plant interconnected in the Humboldt Area would also be forced to curtail during HBGS islanding events. It is hoped that in the future accommodations can be made that would allow local renewable generators greater than 1 MW in capacity to remain online during HBGS islanding events, but this outcome is far from certain.

This study of transmission alternatives for offshore wind development on the California North Coast did not assess the impact of curtailment due to HBGS islanding events.

4.3 Battery Energy Storage Systems

The single node model was used to simulate pairing BESSs with a wind farm in order to determine how the BESS affects the required wind farm curtailment. Internal BESS analysis was performed with the objective of determining which BESS configuration would mitigate curtailment of a slightly larger wind farm than would otherwise be optimal, and then pass those results on to Quanta to confirm the effects on curtailment and see the effects on revenue. The results generated from single node model runs are shown in Figure 5. A noted decrease in curtailment can be seen for a given wind farm size with battery storage, and curtailment decreases for larger capacity BESSs. For example, for a 144 MW wind farm, it can be seen that curtailment decreases markedly when adding a BESS with a 15 MW, 4 hour capacity. However, increasing the BESS size beyond this capacity seems to have diminishing impact. Based on these results, it was decided that we would have Quanta simulate a 15 MW, 4 hour BESS for both the 144 MW and 168 MW wind farms. A 15 MW, 4 hour BESS was chosen as it is a reasonable size and duration for this application, and the results of the single node model showed that larger systems did not result in significant reductions of curtailment compared to system costs.

BESS costs were estimated using NREL's 2021 Annual Technology Baseline (ATB) (Augustine and Blair 2021; NREL 2021). The ATB provides capital expenditures (CapEx) and fixed operations and maintenance (FOM) estimates for 4 hour storage systems, and extrapolates these results to include 2, 6, 8, and 10 hour systems. Cost projections are out to the year 2050, and include an advanced, moderate, and conservative cost projection for each year. For example, the advanced projections assume the greatest improvement in cost effectiveness of future BESS's, and so reflect the lowest price per unit power, whereas the conservative estimates assume the least improvement in BESS technology, and so result in the highest cost per unit power. For this analysis, the moderate assumptions were used so as to land in the median of NREL's projections. Assumptions for BESS operating parameters were gathered from Cole and Frazier (2020), and are listed in Table 4. Cole and Frazier (2020) determined literature values of the round trip efficiency (RTE) to be between 0.7 to 0.95, and settled on 0.85 as a representative value. It is important to note that the FOM estimated by NREL is not the same value as the variable operations and maintenance (O&M) used by Quanta to estimate revenue in the subsequent report. In the ATB analysis, variable O&M costs were assumed to be zero as a result of the assumed single charge/discharge cycle of the BESS over its estimated lifetime. Because of this,

⁵ Humboldt Sawmill Company was formed in 2018 and owns the sawmill, cogeneration plant and other manufacturing facilities in Scotia, CA. These assets were formerly owned by Pacific Lumber Company. The generator Unit Names in Table 2 reflect the former ownership by Pacific Lumber Company.

O&M costs were considered to always be ‘fixed’, and all O&M costs were therefore lumped into the FOM costs. FOM costs were assumed to be 2.5% of the O&M costs (Cole and Frazier 2020).

Table 4: Simulated BESS parameters

Parameter	Value for 4 hour BESS
RTE	0.85
Capacity (hours)	4
Charge/Discharge cycles per day	1
Capacity Factor	16.7%
Lifetime (years)	15
Chemistry	Li-Ion

Figure 6 compares the moderate CapEx cost projections between various BESS capacities in cost per unit power. Learning curve projections show costs dropping over time as the technology and markets mature. For each BESS capacity the cost projection drops considerably by 2030, which is the year of interest for this analysis. The 2030 CapEx and FOM costs utilized for the 4 hour battery were a CapEx of \$784 per kW and an FOM of \$20 per kW-yr.

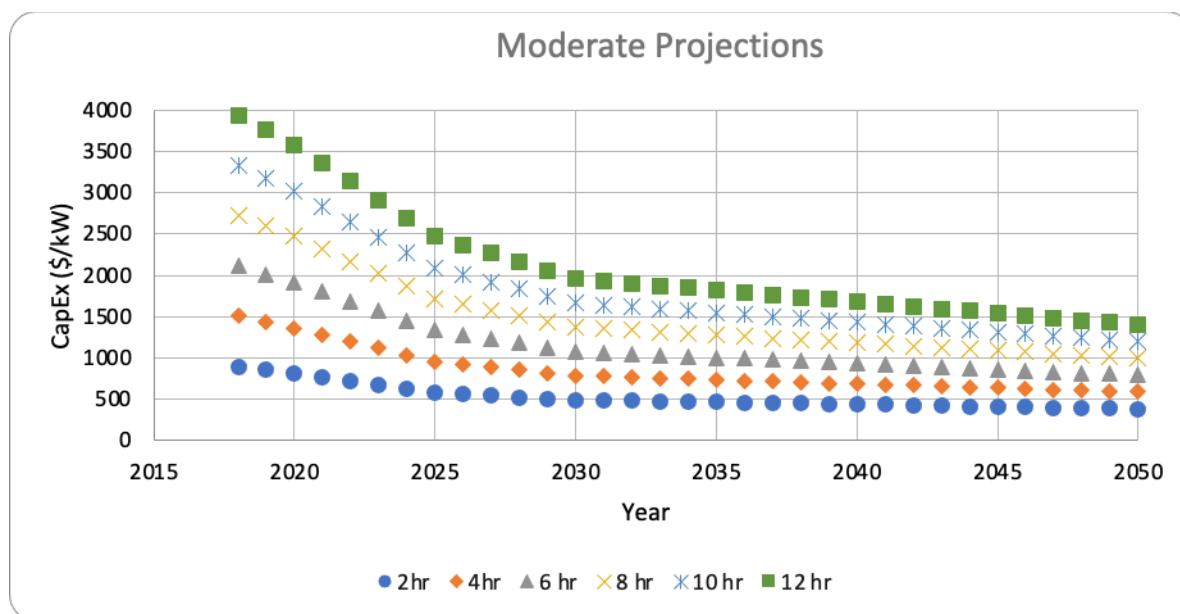


Figure 6: Utility scale BESS CapEx projections for the years 2018 to 2050

4.4 Load Growth

The single node model was used to analyze three different load scenarios to get a preliminary sense of the effects of load growth on wind farm energy curtailment. Figure 7 shows the results

from this analysis, which were then used to inform decisions regarding analyses of interest for Quanta Technologies to perform in more detail.

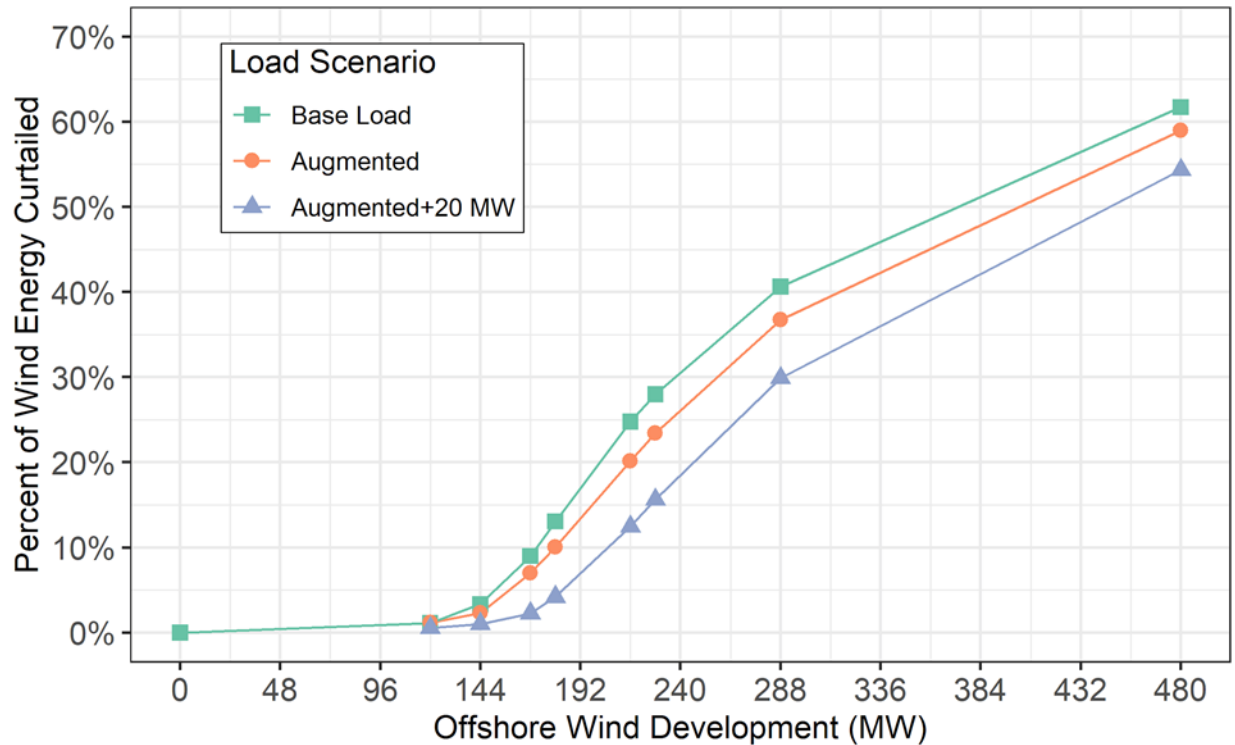


Figure 7: Percentage of annually generated wind energy curtailed with each load scenario studied

Wind farm developments ranged from a 120 MW development to a 480 MW development. The load profiles used were the RCEA base case load, the RCEA augmented load, and a third load profile that added a constant 20 MW load to the augmented load profile, simulating a large facility operating 24/7 (for further details regarding the load profiles, see Appendix A). As expected, increasing load from the base case resulted in decreased curtailment for all wind farm sizes. Additionally, since increasing local load meant that more of the wind farms generation was being utilized within Humboldt County, increasing the load meant that larger wind farms could be developed without triggering the need for export transmission infrastructure system upgrades. From this analysis, it was determined that a useful result to obtain from Quanta Technologies would be the largest wind farm development that could be built without triggering significant transmission infrastructure upgrades for each load scenario.

5 HYDROGEN PRODUCTION - ELECTROLYSIS

5.1 Methods to Examine Hydrogen Generation

As noted in Section 3.4, for this study we evaluated the possibility of producing green hydrogen from excess and low-value wind energy for use as a renewable transportation fuel on the North Coast. For the purposes of this analysis, we estimated the hydrogen demand to be 1200 kg per day. We then conducted a high-level analysis to investigate the opportunity to use surplus and

low-cost, dispatch-constrained electricity, due to either export or economic limits, to produce renewable hydrogen. The approach used in this analysis was:

1. Identify from cited case studies the projected 2030 specifications and costs for a hydrogen production plant and vehicle refueling station with capacities that best fit the local demand,
2. Determine the amount of curtailed, non-curtailed, and imported energy needed to meet the annual energy demand and use these amounts and their associated costs to estimate the total cost of delivered hydrogen,
3. Estimate the revenues from the sale of hydrogen as a transportation fuel using the estimated total dispensed cost and a forecasted 2030 pump price,
4. Estimate the revenue from the sale of Low Carbon Fuel Standard (LCFS) environmental credits accrued from the production and sale of renewable hydrogen,
5. Calculate the opportunity cost associated with using non-curtailed windfarm energy to produce hydrogen.

The assessment of costs relied heavily on the work presented in *The Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California* report prepared by the University of California Advanced Power and Energy Program (Reed et al. 2020). Building on previous published cases and studies, as well as as-built costs, this report offers the most comprehensive and current information available on the projected performance and costs for renewable hydrogen production from polymer electrolyte membrane (PEM) electrolysis.

Production costs of hydrogen were based on CapEx, FOM costs, and cost of electricity over the life of the project, with the cost of electricity being the main driver. In their roadmap, Reed et al. (2020) used projected performance and costs to inform Department of Energy's Hydrogen Production Analysis (H2A) v3.2018 tool developed by National Renewable Energy Laboratory. A total capital cost (electrolyzer stacks, power electronics, balance of system, engineering, permitting, and site acquisition) of \$800 per kW, total system electricity use of 50.2 kWh per kg, stack life/replacement at 85,000 hours at 15% of total CapEx, and an O&M expense pro-rated with CapEx with a 9-year stack life were the input parameters to the model for 2,000 and 20,000 kg per day production plants (Reed, et al., 2020).

H2A results using these inputs forecast a projected 2030 nonfeedstock (no electricity cost included) production cost of \$0.90 per kg and \$0.81 per kg for the 2,000 kg per day and 20,000 kg per day PEM electrolysis systems, respectively. The small difference in price is due to the capital cost scale factor of 0.95 for PEM electrolyzer plants. The nonfeedstock production costs and the 50.2 kWh per kg electrical use conversion value were used to calculate production costs for the small-scale and large-scale PEM plants using a \$0.03 per kWh cost for electricity. The production cost projections (in 2020 \$) for these cases are shown in Table 5.

In a similar study, *Hydrogen Production Cost from PEM Electrolysis - 2019*, Peterson et al. (2020) evaluated four case studies also using the H2A tool. The cases were based on current (2019) and future (2035) technology years at both distributed (1,500 kg per day) and central (50,000 kg per day) hydrogen production rates with all cases using a \$0.03 per kWh electricity

cost. These costs are also shown in Table 5 and are comparable with the projected costs in the Reed study.

Table 5: Hydrogen production cost projections for various sized plants with an electricity cost of \$0.03 per kWh

Case - Projected Year	Capacity (kg per day)	Production Cost \$ per kg
Small-scale Plant – 2030 ^a	2,000	\$2.41
Large-scale Plant – 2030 ^a	20,000	\$2.32
Distributed Current – 2019 ^b	1,500	\$2.74
Distributed Future – 2035 ^b	1,500	\$2.07
Central Current – 2019 ^b	50,000	\$2.49
Central Future – 2035 ^b	50,000	\$2.01

References: a - Reed, et al. (2020). b - Peterson et al. (2020), note that costs were given in 2016 \$ dollars and have been adjusted to 2020 \$ based on the U.S. Consumer Price Index (U.S. Bureau of Labor Statistics 2021).

Once generated, the gas must be processed for storage and delivery. There are two types of delivery: compressed gas and liquid. For compressed gas, the generated hydrogen is compressed into tube trucks and delivered to the fueling station where it is stored in high pressure tanks. Alternately, hydrogen is cooled to a liquid state before being transported to the fueling station, where it is stored in cryogenic tanks.

The type of processing depends on the fueling station land availability, station size, and delivery distance. Given the projected local demand is estimated at 1,200 kg per day and the relatively short delivery distance, liquid processing is unnecessary, so gas compression processing and delivery costs were used. A large-scale plant would generate more gas than is needed locally, and the more cost-effective, high density liquid method for long distance deliveries would be the preferred method of transport. The HDSAM (Hydrogen Delivery Scenario Analysis Model), developed by Argonne National Laboratory, was used to project the 2030 “plant-gate-to-dispenser” cost for a 1,200 kg per day station and an 80% utilization factor. The projected cost for gaseous delivery is \$4.25 per kg.

Estimates for the cost of dispensed hydrogen for a 1,200 kg per day station were calculated as the sum of the operating cost (cost of electricity multiplied by system energy use conversion value), the nonfeedstock production cost, and the gas processing and delivery chain costs (Table 6).

Table 6: Examples of the Dispensed Cost of Hydrogen for Various Costs of Electricity

Cost of Electricity (\$ per kWh)	Operating Cost (\$ per kg)	Nonfeedstock Production Cost (\$ per kg)	Gas Processing and Delivery Cost (\$ per kg)	Dispensed Cost (\$ per kg)
0	\$0.00	\$0.90	\$4.25	\$5.15
0.03	\$1.51	\$0.90	\$4.25	\$6.66
0.055	\$2.76	\$0.90	\$4.25	\$7.91

5.2 Hydrogen Alternative Results

We think the most likely near-term North Coast application for electrolytic hydrogen will be to provide fuel for the local zero emission vehicle transportation sector. We estimate the near-term annual hydrogen supply needed for this purpose to be 438,000 kg per yr, and we estimate the electricity needed to generate this hydrogen electrolytically to be 22,000 MWh per yr, which represents about 3% of the total electricity that could be generated by a 168-MW offshore wind farm in the Humboldt Wind Energy Area. Table 7 provides some of the assumptions used in the hydrogen analysis.

Table 7: Hydrogen production and refueling station model input values

Simulation Input	Value
Hydrogen Demand	1200 kg per day
Plant Energy Consumption	50.2 kWh per kg H ₂
Daily Energy Demand	60.2 MWh
Curtailment LMP	-\$25 per MWh
Plant Production Capacity	2000 kg per day

Given that the cost of electricity is the main driver for the cost of producing electrolytic hydrogen, the use of curtailed (or surplus) and low-cost energy is critical to making hydrogen cost competitive. In this section we look at the opportunity to use no-cost (curtailed) and low-cost wind energy to produce low-cost hydrogen, and we calculate the cost to produce, process, and deliver the generated hydrogen.

We evaluated a 168 MW wind farm for the hydrogen alternative because it was the largest wind farm that could be interconnected in the Humboldt Area without requiring significant transmission upgrades (Daneshpooy and Anilkumar 2022), and it was likely to offer enough curtailed wind energy to allow the hydrogen alternative to provide economic benefit. In addition, as shown in Table 8, 168 MW wind farm is large enough to generate the majority of hydrogen needed. Our team performed simulations to assess the percentage of days in a year in which there was sufficient curtailed energy available to meet the daily demand for various wind farm sizes. The simulation results indicate that the curtailed energy from the 168 MW wind farm can meet the daily demand on 60% of the days annually. This amount of energy equates to 12,980 MWh of free or surplus energy each year.

Table 8: Simulation results - percentage of days annually with sufficient hydrogen resource for various wind farm sizes

120 MW	144 MW	168 MW	180 MW	216 MW	228 MW	288 MW	480 MW
10%	33%	60%	67%	75%	76%	79%	87%

The annual hydrogen demand was considered to be supplied from the following three sources:

Transmission Alternatives for California North Coast Offshore Wind

- curtailed energy - surplus energy that would otherwise have been lost (not generated) due to economic and export constraints.
- non-curtailed windfarm energy - energy produced by the windfarm that is not exported to the grid, but instead is used onsite to generate hydrogen. This energy has an opportunity cost that will be addressed when evaluating project revenues.
- imported energy - energy purchased from the grid at retail prices to address days when wind generation shortfalls occur.

The first source evaluated was the curtailed energy. As noted above, the curtailed energy from a 168 MW wind farm was found to be 12,980 MWh per yr. Next, we identified the wind generation shortfall days for the 168 MW wind farm. Shortfall days were defined as the days in which the wind farm generation output was below the daily energy demand of 60.2 MWh. This threshold assumes that the developer will prioritize power from the wind farm for hydrogen production before exporting to the grid. The energy deficit for each of these days was totaled and resulted in a combined total of 823 MWh each year, or approximately 4% of the annual energy demand for hydrogen generation. An alternative solution to purchasing grid power on these shortfall days is to install additional gas storage tanks that can provide a day-to-day buffer capacity to store hydrogen on excess days in order to get through shortfall conditions.⁶ This approach may be preferable; however, a more detailed, hourly analysis is needed to compare these options. Finally, we determined the required non-curtailed wind farm energy to be 8,197 MWh per yr.

The total dispensed cost of hydrogen (including production, processing and delivery, and dispensing chain costs) is based on the fraction of energy and associated cost from each energy source consumed in the hydrogen production plant and fueling station. Table 9 presents the fractional cost associated with each source of energy. The energy cost for electricity from the windfarm is zero, however, the non-curtailed portion has an opportunity cost that will be assessed in the revenue section below. The energy cost for the purchased energy is the average bundled retail rate for electricity purchased at primary voltage under PG&E's Electric Schedule E-20 (PG&E 2021). The sum of the fractional costs results in a total dispensed cost of \$5.28 per kilogram of hydrogen. As a comparison, this total dispensed cost is below the 2030 dispensed cost of hydrogen (\$6.50 to \$11.25 per kg) as forecasted by Reed and et. al (2020). This is an expected result as their assessment was based on a \$30 per MWh energy cost.

⁶ A tank capable of storing multiple days' supply of hydrogen would be required to eliminate the need for imported energy.

Table 9: Component costs of the estimated 2030 total dispensed hydrogen cost (\$5.28 per kg) for a 168 MW wind farm

Source of Energy	Amount of Energy (MWh)	Energy Cost (\$ per MWh)	Production, Processing & Delivery Costs (\$ per kg)	Dispensed Cost (\$ per kg)	Percent of Energy	Fractional Costs
Curtailed Energy	12,980	\$0	\$5.15	\$5.15	60%	\$3.09
Non-curtailed Energy	8,197	\$0	\$5.15	\$5.15	36%	\$1.85
Purchased Retail Energy	823	\$177	\$5.15	\$8.89	4%	\$0.33

To assess the economic viability of the hydrogen alternative, we also needed to assess the revenue potential and account for any lost revenue. This required the development of estimates for two revenue streams: 1) the sale of transportation fuel using an estimated hydrogen delivery cost and forecasted pump price in 2030, and 2) the sale of Low Carbon Fuel Standard (LCFS) environmental credits from the production and dispensing of renewable, electrolytically-produced, compressed gas hydrogen. In addition, we needed to assess the lost revenue potential from the use of non-curtailed wind farm energy for hydrogen generation.

Reed et al. (2020) have reported a 2030 forecasted dispensed cost of hydrogen, without LCFS credits, ranging between \$5.50 and \$9.00 for a variety of hydrogen production technologies. We use this as a proxy for future retail pump prices. This range assumes the increased adoption of fuel cell vehicles and robust market competition in the hydrogen industry. Given the remoteness of Humboldt County and its distance from the limited number of industrial gas suppliers in the Sacramento area, the high delivery costs for these suppliers would most likely keep local pump prices near the upper end of the price range.

The estimated net revenue at the pump from the sale of 438,800 kg per yr of transportation fuel with a dispensed hydrogen cost of \$5.28 per kg and a forecasted pump price ranging from \$5.50 to \$9.00 per kg is \$98,000 to \$1,631,000 per year, respectively. Additional revenue potential is available from the LCFS credits. The value of the LCFS credits is a function of the carbon intensity of the production pathway for the hydrogen. The CARB lookup pathway for the production and processing of gaseous hydrogen using 100% renewable energy is specified as “Compressed H₂ produced in California from electrolysis using solar- or wind-generated electricity (HYER)” (CARB 2018). The LCFS program is currently only authorized through 2030, with the credit price capped at \$200. Assuming the program is extended to 2050, it is projected that the credit per kilogram at a \$150 LCFS credit value would be \$3.50 per kg in 2030 and decrease to \$1.00 per kg by 2050 (Reed). The estimated annual LCFS credit of \$2.25 per kg over a 20-year period results in an LCFS income for the dispensing of 1,200 kg per day of \$985,000.

Table 10 presents the estimated range of total net revenues from renewable hydrogen sales for the North Coast zero emission vehicle transportation sector, including revenues from both hydrogen fuel sales and LCFS credits. The total net revenues range from approximately \$1.1 M to \$2.6 M, depending on the forecasted sales price of hydrogen. Projecting this price is complex and relies on many factors, including the demand for hydrogen through the increased adoption of local fuel-cell vehicles and the future cost of available hydrogen from regional suppliers.

Table 10: Estimated revenue from hydrogen sales and environmental credits - 168MW wind farm

Revenue Stream	Dispensed Cost (\$ per kg)	Sales Price (\$ per kg)	Net Revenue per kg (\$ per kg)	Estimated Annual Revenue (\$)
Transportation Fuel – Low Sales Price	\$5.28	\$5.50	\$0.22	\$ 97,000
LCFS Credit	N/A	N/A	\$2.25	\$ 985,000
Total – Low Sales Price	N/A	N/A	N/A	\$ 1,106,000
Transportation Fuel – High Sales Price	\$5.28	\$9.00	\$3.72	\$ 1,631,000
LCFS Credit	N/A	N/A	\$2.25	\$ 985,000
Total – High Sales Price	N/A	N/A	N/A	\$ 2,639,000

The revenue projections for hydrogen sales must also consider the opportunity costs of hydrogen production. While the capital investments required for hydrogen production represent opportunity costs of their own, these costs are best explored in further research when more is known of the potential supply logistics, market demand, and station design. However, since meeting local hydrogen demand requires more energy than can be obtained from the curtailment of wind energy, the required non-curtailed energy imposes an opportunity cost. Hydrogen production using the 168 MW wind farm would require 8,197 MWh per year that could otherwise be sold into the grid. Using the average annual LMP at the Humboldt node of \$32 per MWh, the opportunity cost for the non-curtailed wind energy used to produce hydrogen is \$262,000 per year. This would effectively decrease the total estimated net revenues shown in Table 10 by 10% to 24%, respectively, and would need to be considered when assessing the economic viability of the hydrogen alternative. Overall, the hydrogen alternative appears to be a viable economic option based on this very preliminary, high level analysis. However, before investment decisions are made, a much more detailed, bankable analysis using specific project information would need to be conducted.

6 DISCUSSION OF TASK 2.1 RESULTS AND INTEGRATION WITH TASK 2.2 AND TASK 2.3

The Task 2.1 analyses resulted in the following accomplishments:

- Data inputs required for the Task 2.2 transmission analysis and the Task 2.3 economic analysis were developed and/or compiled. This included:
 - Humboldt Area load and load growth
 - Humboldt Area generation sources
 - Wind farm site characteristics and generation profile
 - Tax credit information
 - Battery cost and performance data
- The offshore wind project alternatives to be evaluated in Task 2.2 and Task 2.3 were conceptualized and defined. The analysis to complete this conceptualization included preliminary analyses of curtailment using a single node model of the Humboldt Area transmission system to determine which scenarios and alternatives should be prioritized for evaluation.
- A preliminary analysis of the potential for hydrogen production was completed.

In Task 2.2, Quanta Technologies examined the cost of required transmission upgrades and the revenue generation potential for various wind farm sizes and choices of non-transmission alternatives (i.e., curtailment, load growth and battery energy storage). In Task 2.3, NREL determined the levelized cost of energy, the levelized cost of transmission, and the net electricity value based on revenue projections and levelized costs for selected scenarios. The key purposes of the Task 2.1 research were to gather the necessary input data for the Task 2.2 and Task 2.3 analyses and to inform the decisions that needed to be made regarding which sizes of offshore wind development and which transmission scenarios would be evaluated. Below we briefly discuss the scenarios that were selected for evaluation in Task 2.2 and Task 2.3.

We begin with a discussion of the analyses that Quanta Technologies performed and their intended purposes. Power flow studies, also known as system impact studies, that were conducted by Quanta Technologies are shown in Table 11. Power flow studies were used to determine transmission upgrade costs for various wind farm sizes, or the size of offshore wind development compatible without transmission upgrades.

Table 11: Power flow studies conducted by Quanta Technologies

Scenario	Interconnection	Load	Wind Farm Size
A-1	Energy Only	Base case	144 MW
A-2	Energy Only (alternate onshore landing) ⁷	Base case	144 MW
A-3	Energy Only	Base case	168 MW
A-4	Energy Only	Base case	288 MW
A-5	Energy Only	Base case	480 MW
A-6 ⁸	Energy Only	Base case, Augmented, Augmented + 20 MW	174 MW, 225 MW, 231 MW
B-1	Full Deliverability	Baseline	144 MW
B-2	Full Deliverability	Baseline	288 MW
B-3	Full Deliverability	Baseline	480 MW

Transmission upgrade costs were found to be significant in the initial California North Coast Offshore Wind Studies Interconnection Feasibility Study Report (PG&E 2020b). However, our single node transmission system model showed curtailment to be relatively modest for wind farm sizes of about 168 MW and below. This indicated that it may be beneficial to install wind farms under an Energy Only scenario, where transmission upgrade costs could be minimized by allowing the wind plant to be curtailed as a means of mitigating transmission constraints. The Energy Only studies, A-1 through A-6, were intended to determine which sized wind farms, installed as Energy Only interconnections, could be installed without transmission upgrades.

The three Full Deliverability studies (B-1 through B-3) were aimed at understanding the range of transmission costs that might be incurred with interconnection at Full Deliverability, as was studied previously (PG&E 2020b).

As a follow up to the power flow studies discussed above, Quanta Technologies then conducted production cost studies. These studies examined the Energy Only interconnection option for various wind farm sizes and assessed the amount of curtailment that would be required to mitigate transmission constraints. In addition, the revenue potential for each of these scenarios was assessed, and the revenue impacts associated with curtailment were determined. Table 12 lists the production costs studies that were performed by Quanta Technologies as part of Task 2.2.

⁷ Scenario A-2 investigated the cost impacts of bringing the wind power onshore on the north spit of Humboldt Bay and tying into a new Fairhaven substation. All other scenarios assumed an onshore landing at the Humboldt Bay Generating Station.

⁸ Scenario A-6 was an assessment of the largest wind farm that could be installed without transmission upgrades under three different load assumptions.

Table 12. Production cost studies conducted by Quanta Technologies

Scenario	Interconnection	Load	Storage	Wind Farm Size
C-1	Energy Only	Base case	None	144 MW
C-2	Energy Only	Base case	None	168 MW
C-3	Energy Only	Base case	None	288 MW
C-4	Energy Only	Base case	15-MW, 4-hr	144 MW
C-5	Energy Only	Augmented	None	168 MW
C-6	Energy Only	Base case	15-MW, 4-hr	168 MW

Scenario C-2, 168-MW without storage, was evaluated to determine revenue and curtailment for a wind farm that is near the largest size which could interconnect – assuming base case load – with minimal transmission upgrades.

Scenario C-3, 288 MW, was assessed to estimate the curtailment associated with a wind farm that exceeded the capacity of existing transmission infrastructure by a significant margin. This assessment confirmed our internal finding that there is a tremendous degree of curtailment – over 30% -- at this scale.

Scenarios C-4 and C-6, with 15-MW, 4-hour BESSs were evaluated to provide a first cut analysis of the role that battery energy storage might play. The relatively small storage size was chosen so that the BESS might connect with full deliverability, and thus be eligible for resource adequacy (RA) revenue, and so that it would not cannibalize its own revenue, as the larger wind farms do by suppressing local wholesale marginal prices. The two runs with the same storage capacity allowed us to examine how varying sizes of wind farms impact the value of storage. In particular, when selecting these trials, we knew that revenue steeply declined between 144 MW and 168 MW, and we sought to understand whether the value storage could play would steeply *increase* when going from a 144 MW to 168 MW wind farm.

Finally, Scenario C-5 was intended to learn about the effect of load growth on revenue generation. We already knew that increasing load could push up the maximum allowable size of project with no transmission upgrades from 168 MW to 225 MW, but we were interested in a comparison of revenue and curtailment between two load growth scenarios at the same wind farm size.

As part of Task 2.1, we also conducted a preliminary economic assessment of the hydrogen production alternative for a 168 MW wind farm. The total projected annual net revenues associated with the hydrogen production facility compared to the 168 MW wind farm by itself ranged from an additional \$0.84 M per yr to \$2.38 M per yr. While this analysis indicates the hydrogen alternative may be a viable economic option, this is a very preliminary, high-level analysis. Before an investment decision was made, a much more detailed, bankable analysis using specific project information would need to be conducted.

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Appendix A NODE MODEL METHODS

The Schatz Center single node model approximates the energy curtailment for every hour in a typical year, after accounting for local load, local generation, and transmission limitations on energy exports. The purpose of this appendix is to provide sufficient background information to the reader such that they can understand the basic workings of the single node model operated by SERC in parallel to Quanta's analyses.

A.1. Analytical Model

The Schatz Center single node model inputs are constructed as discrete scenarios, with each scenario consisting of a load profile, offshore wind generation profile, non-offshore wind generation profile, and (when battery storage is included) energy storage power and duration characteristics (described later). The model is designed such that any number of scenarios can be added.

A.1.1. Critical Assumptions for Battery Storage

- The minimum charge level of storage is 0%, which aligns with NREL's cost model: (Cole and Frazier 2020)
- Storage has an 85% roundtrip efficiency, which is modeled as a discharge efficiency of 100% and a charging efficiency of 85%, again aligning with NREL's cost model (Cole and Frazier 2020).

A.1.2. Model Outputs

For each simulation run, the model exports an 8760-hour profile of inputs and outputs, including raw wind generation, exports, and curtailment, plus summary files depending on analysis. The first summary file tabulates the annual generation from offshore wind, curtailments, exports, losses (due to battery charging inefficiency) and annual revenue. The second summary file provides monthly total curtailment values for each scenario programmed into the model. The third summary file provides daily total curtailment values. After exporting the summary files, the model data is saved and exported to a separate R program for plotting the data of interest.

A.1.3. Model Algorithm

Figure A-1 is a general flow chart for the model algorithm for non-BESS alternatives. Each step of the flow chart is detailed below, with the addition of the BESS algorithm.

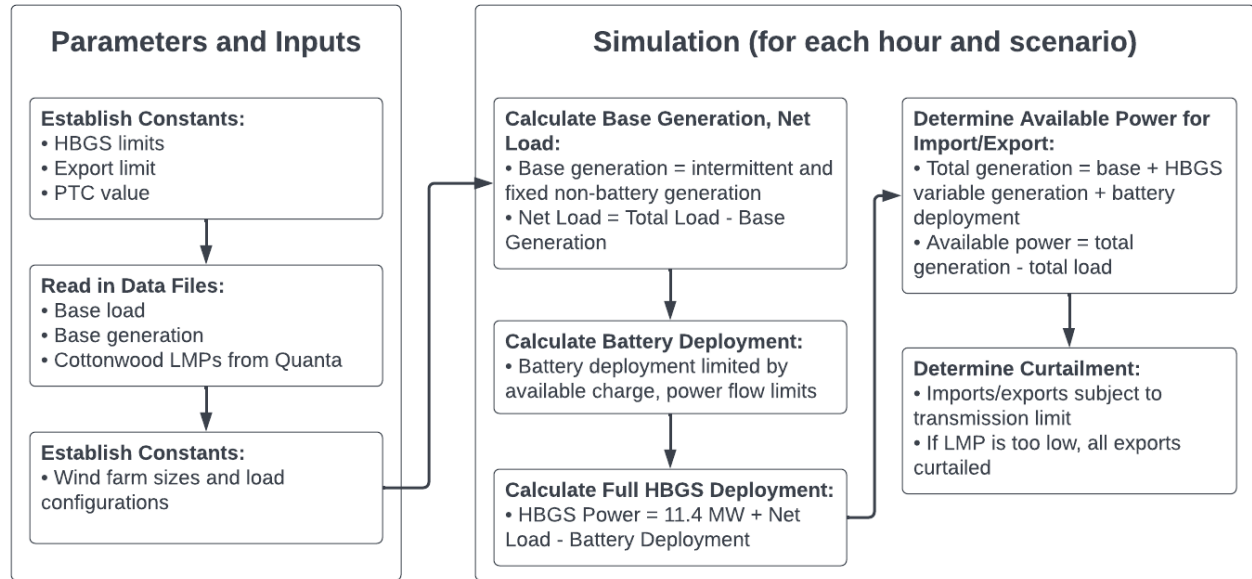


Figure A-1: Flow chart for the Schatz Center single node model

Establish Constants

Three key values remain static over the typical year-long simulation:

1. *Operational limits of the HBGS:* The HBGS can operate anywhere between 11.4-MW and 163-MW at each hour. It is modeled as a 11.4-MW must-run resource + a perfectly flexible 151.6-MW plant.
2. *Energy export limits:* Humboldt County has a constant export capacity of 75 MW.
3. *Production Tax Credit (PTC) value:* The production tax credit used to estimate economic curtailment was assumed to be \$25 per MWh per communications with Quanta Technologies (Quanta Technologies 2021). Economic curtailment was assumed to occur wherever the Cottonwood LMP was less than $-1 \times \text{PTC}$, or -25 \$ per MWh.

Read in Data Files

Input data files provide load, generation, and energy price data to the simulation model. Load and generation data were provided by RCEA, and pricing data was provided by Quanta. Wind data, and by extension offshore wind generation estimates, were developed as part of Task 1. Additional information about the input data is given below.

As part of their strategic plan analysis, RCEA developed load and generation forecasts for 2030. We received hourly data for a typical day for each month of 2030, 288 observations in total. We applied the typical day to every day in its respective month to create an “8760-hour” file. RCEA’s dataset includes utility-scale generation from local biomass, utility-scale and customer solar, and small hydro, and provides updates to their earlier 2019 RePower report (RCEA 2019). These generation sources were assumed to be “must-run” sources.

RCEA provided two sets of load data: a baseline load and an augmented load. The augmented load incorporated three additional changes: growth of EV charging, increases in building electrification demand, and growth in behind-the-meter customer solar. The analysis team also

created an additional profile, adding a constant 20 MW load on top of RCEA's augmented load to account for the planned Nordic Aquafarms fish farm along the Samoa peninsula.

The offshore wind data used to determine power generation were modeled at the centroid of the Humboldt Wind Energy Area, and incorporated a full set of down-time loss factors (i.e. including Availability of Utility Grid and Plant Re-start after Grid Outages set to zero). We note that this was distinct from the dataset shared with Quanta Technology where these outages were not included because Quanta's model addressed them.

LMP values were taken from the Cottonwood node instead of the Humboldt node, as the node model has no way of incorporating variable pricing in the market resulting from the introduction of additional wind power. This is an important distinction between the Schatz Center single node model analysis and the analysis performed by Quanta Technologies, which used Humboldt node prices.

Development of Scenarios

Developing analysis scenarios for this study is discussed in detail in Section 6. Owing to its use as a preliminary analysis tool, the Schatz single node model operates with simpler scenarios than the Quanta and NREL models used for Task 2.2 and Task 2.3. While the single node model requires the wind farm size, energy load, and storage characteristics, the interconnection option (energy only or full deliverability) is ignored.

Simulation Loop

For each hour, i , we begin by calculating the base (i.e., fixed) generation:

$$G_i = 11.4\text{MW} + BM_i + H_i + W_i$$

Where:

- G_i = Base generation (MW) at hour i
- BM_i = Biomass generation (MW) at hour i
- H_i = Hydroelectric generation (MW) at hour i
- W_i = Offshore wind generation (MW) at hour i

Next, we calculate the net load:

$$L_{net,i} = L_i - G_i$$

Where:

- $L_{net,i}$ = Net load (MW) at hour i
- L_i = Total load (MW) at hour i
- G_i = Base generation (MW) at hour i

Once the net load has been established, determine battery deployment. Calculate the value which would lead to zero curtailment, or the sum of the hourly net load and the constant export limit:

$$BP_i = L_{net,i} + E$$

Where:

$$\begin{aligned} BP_i &= \text{Desired battery power (MW) at hour } i \\ L_{net,i} &= \text{Net load (MW) at hour } i \\ E &= \text{Export limit (MW)} \end{aligned}$$

For example, with a 10-MW net load and 70-MW export limit, the desired battery output would be 80-MW. With a -20-MW net load (i.e., 20-MW of exports before considering the battery), the desired battery output would be 50-MW. Alternately, if exports are being economically curtailed in this hour, then the desired battery power will be equal to the net load.

Now that the desired battery output is known for a given hour i , the model can calculate the actual battery output. To start, calculate the upper limit on battery output based on its power and capacity:

$$B_{max,out,i} = \min([SOC_i - SOC_m] \cdot \eta_d, P_m)$$

Where:

$$\begin{aligned} B_{max,out,i} &= \text{Maximum battery output power for hour } i \text{ (MW)} \\ SOC_i &= \text{State of charge (in MWh) at hour } i \\ SOC_m &= \text{Minimum state of charge (in MWh) allowed} \\ \eta_d &= \text{Battery discharge efficiency} \\ P_m &= \text{Rated power of battery (MW)} \end{aligned}$$

Next, the model determines the upper limit on energy input into the battery based on power and capacity:

$$B_{max,in,i} = \max([SOC_i - SOC_{max}] \cdot \eta_c, -P_m)$$

Where:

$$\begin{aligned} B_{max,in,i} &= \text{Maximum energy input into battery in hour } i \text{ (MW)} \\ SOC_{max} &= \text{State of charge (in MWh) at hour } i \\ C &= \text{Battery energy capacity (MWh)} \\ \eta_c &= \text{Battery charging efficiency} \\ P_m &= \text{Rated power of battery} \end{aligned}$$

The model can then calculate the true battery deployment using by comparing the desired deployment, maximum energy input, and maximum energy output:

$$B_i = \max(\min(BP_i, B_{max,out,i}), B_{max,in,i})$$

Where:

$$\begin{aligned} B_i &= \text{Actual battery power deployment (MW) at hour } i \\ BP_i &= \text{Desired battery power deployment (MW) at hour } i \\ B_{max,out,i} &= \text{Maximum battery output power for hour } i \text{ (MW)} \\ B_{max,in,i} &= \text{Maximum energy input into battery in hour } i \text{ (MW)} \end{aligned}$$

If needed, the HBGS can dispatch additional energy beyond the 11.4 MW contributed to the base load in order to meet the local load:

$$HBGS_i = 11.4\text{MW} + L_{net,i} - B_i$$

Where:

$$\begin{aligned} HBGS_i &= \text{Humboldt Bay Generating Station power deployment (in MW) at hour } i \\ &\quad \text{(not including the 11.4 MW included in the base generation)} \\ L_{net,i} &= \text{Net load (MW) at hour } i \\ B_i &= \text{Actual battery power deployment (MW) at hour } i \end{aligned}$$

With all energy sources accounted for, the model can calculate the total generation, power imports/exports, and determine if production curtailment is necessary:

$$G_{T,i} = G_i + B_i + HBGS_i$$

Where:

$$\begin{aligned} G_{T,i} &= \text{Total generation (MW) at hour } i \\ G_i &= \text{Base generation (MW) at hour } i \\ B_i &= \text{Actual battery power deployment (in MW) at hour } i \\ HBGS_i &= \text{Humboldt Bay Generating Station power deployment (in MW) at hour } i \text{ (not} \\ &\quad \text{including the 11.4 MW included in the base generation)} \end{aligned}$$

$$Q_i = G_{T,i} - L_i$$

Where:

$$\begin{aligned} Q_i &= \text{Power available (MW) for import (if negative) or export (if positive) at hour } i \\ G_{T,i} &= \text{Total generation (MW) at hour } i \\ L_i &= \text{Total load (MW) at hour } i \end{aligned}$$

$$C_i = \max(Q_i - E, 0)$$

Where:

$$\begin{aligned} C_i &= \text{Curtailed power generation (MW)} \\ Q_i &= \text{Power available (MW) for export if positive at hour } i \\ E &= \text{Export limit (MW)} \end{aligned}$$

In cases where economic curtailment is necessary (when the energy price would lead to negative profit), any exported power would be curtailed. When prices are low and local generation is high, it is possible for both economic curtailment (energy that would be exported) and transmission limit curtailment (when available power is greater than the export limit) to occur simultaneously.

Finally, hourly revenue is calculated based on the 2020 hourly LMP energy price at Cottonwood (LMP):

$$R_i = LMP \cdot (W_i + B_i - C_i)$$

Where:

$$\begin{aligned} R_i &= \text{Revenue at hour } i \text{ (\$)} \\ LMP &= \text{Locational marginal price (\$ per MW) at the Cottonwood node} \end{aligned}$$

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- W_i = Offshore wind generation (MW) at hour i
- B_i = Actual battery power deployment (MW) at hour i
- C_i = Curtailed power generation (MW)

Since the Schatz Center node model has no way to compensate for node price suppression that occurs as wind farm size increases, model revenue estimates were strictly used for preliminary analysis.