California North Coast Offshore Wind Studies

Transmission Upgrades Report and Policy Analysis

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1. INTRODUCTION

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

The electric transmission system in the Humboldt Planning Area is connected to California's bulk transmission system through four circuits at 60 kV and 115 kV (Figure 1). Electric load in the region is met through four local generators and electricity imported on the transmission network. The transmission is built to serve local load and not designed to be a large exporter of electricity. Interconnecting an offshore wind farm within the Humboldt Planning Area will require upgrades to the transmission system.

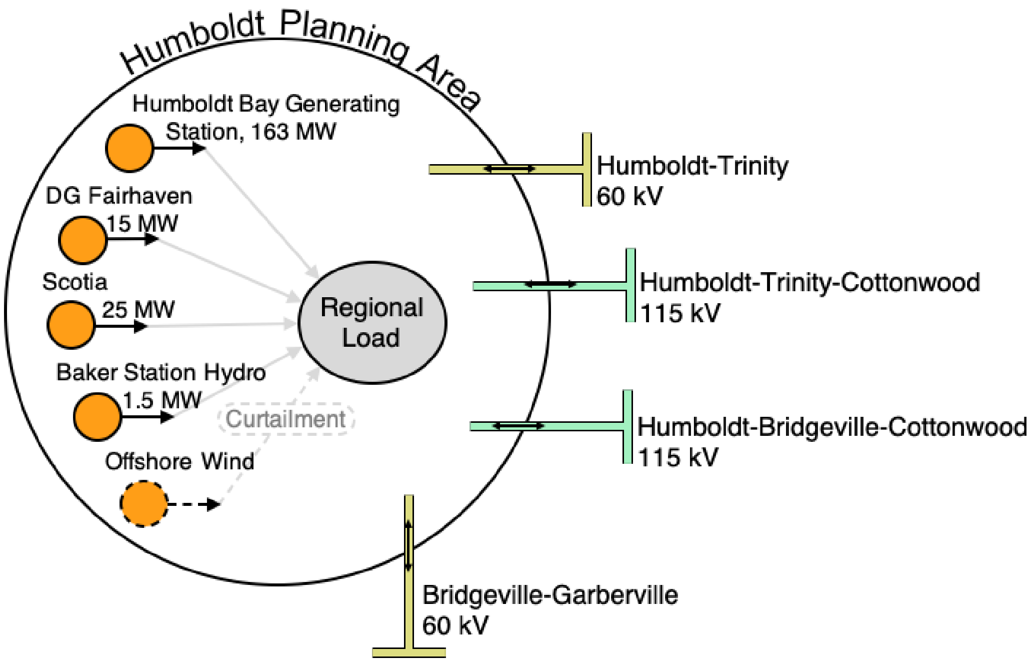


Figure 1. Humboldt County electrical system and model inputs and outputs.

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

- Permitting and reimbursement pathways for developing new transmission infrastructure in California (Section 2.),
- Technical requirements for interconnection of offshore wind generation from the Humboldt Call Area (Section 3.),
- Estimated costs of the transmission upgrades (Section 4.),
- Policy analysis and discussion of different alternatives, scales, and pathways for interconnecting offshore wind (Section 5.).

2. PATHWAYS FOR TRANSMISSION DEVELOPMENT

The electric transmission system provides a link between different generation facilities and distribution networks to connect generators with end uses. The transmission system is designed to meet the deliverability requirements of regional electricity load and electricity generating facilities. Transmission lines are built and expanded to ensure reliable and safe transfer of power. When new generation sources are proposed, for example offshore wind on the north coast, the existing transmission network must be evaluated to determine if the new generation source will exceed the capacity constraints of the system. Transmission improvements are then proposed as needed to allow safe and reliable interconnection of a new generation source at full capacity. If the transmission capacity is exceeded, and the new generator is unable to upgrade the transmission infrastructure, the project can still interconnect but its output will be limited by the capacity of the transmission system. Transmission improvements can include upgrades or new construction of transmission cables or the substations that serve as connection points along the transmission path.

There are two pathways to build transmission infrastructure in California to support new generation. The associated cost responsibility and reimbursements can vary depending both on which approach is taken, and what type of infrastructure is constructed. One pathway is for an interconnection customer to propose a new generation facility and then work with the regional transmission owner and the California Independent System Operator (CAISO; this will also be abbreviated as ISO in some places) to build transmission upgrades to accommodate the new generation source (Billinton, 2019). Another pathway is for state policy to drive the support of new transmission to meet mandates for reliability, renewable generation, or safety. Under this approach, CAISO will release a competitive solicitation to construct and maintain new projects as described in Section 2.2. While the selected project sponsor is required to develop the necessary transmission upgrades, they generally are not required to go through the interconnection process (Billinton, 2019).

In nearly any approach for transmission development, much of the upgrade cost is ultimately carried by ratepayers, although some upfront investments must be made by the developer prior to reimbursement. Implementation and reimbursement details are described below in Section 2.3.

2.1 Interconnection Customer Pathway

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

There are three processing tracks for interconnection customers wishing to interconnect to the ISO-controlled transmission system: the cluster study process, the independent study process, and the fast track process (Rutty, 2020, p.23). The default process for ISO interconnection requests is the cluster study process, and the independent study process is applicable only in special circumstances (Rutty, 2020, p.62). The fast track process is only available to projects no larger than 5 MW (Rutty, 2020, p.127) and is therefore not relevant to offshore wind, which will have generators much larger than this threshold.

The independent study process can happen at any time of the year but must demonstrate that the cluster-study process will not accommodate the desired commercial operation date of the project (Rutty, 2020, p.24). Additionally, the proposed project must pass a flow impact test or short circuit duty test to show that it is electrically independent of projects in the cluster queue (Rutty, 2020, p.118). The timeline for an independent study depends on how the proposed generator will be operated. The independent study process takes approximately 240 calendar days if the generator will only provide energy when the grid conditions allow and will not participate in resource adequacy markets (Energy Only Deliverability

Status) (CAISO, 2019, February 27). The independent study process requires additional time if the application is for Full Capacity Deliverability Status, where the generator's full power output can be provided to the grid under peak load conditions and the generator is eligible to provide resource adequacy capacity (CAISO, 2019, February 27). Additionally, if a project is requesting resource adequacy deliverability, it will have to join the cluster study process in the next available window (LeVine, 2014, p.51).

For the cluster study process, the interconnection request window is open once per year from April 1st-April 30th (LeVine, 2020, p.102). A cluster study considers interconnection requests from a group of interconnection customers at once in order to understand the overall impact on the grid. Within the cluster study, both group studies, which consider all projects, and individual studies may be performed for each project at the discretion of CAISO (Rutty, 2020, p.64). The interconnection studies begin in late July and take approximately two years to complete (CAISO, 2018, March 06).

Interconnection studies in a cluster track are completed in two phases. The first phase is preliminary and includes all projects in the cluster study to identify the needed upgrades to existing infrastructure. Phase One consists of a short circuit analysis, a stability analysis, a power flow analysis, and deliverability assessments. At this stage every project is given a maximum cost responsibility for transmission system upgrades (LeVine, 2020, p.37). The second phase is an update to account for changes in interconnection requests such as withdrawn applications. At this stage the final upgrades are determined and CAISO will assign financial responsibility and deliverability status to the various interconnection customers (Rutty, 2020, p.73).

2.2 Public Policy Pathway

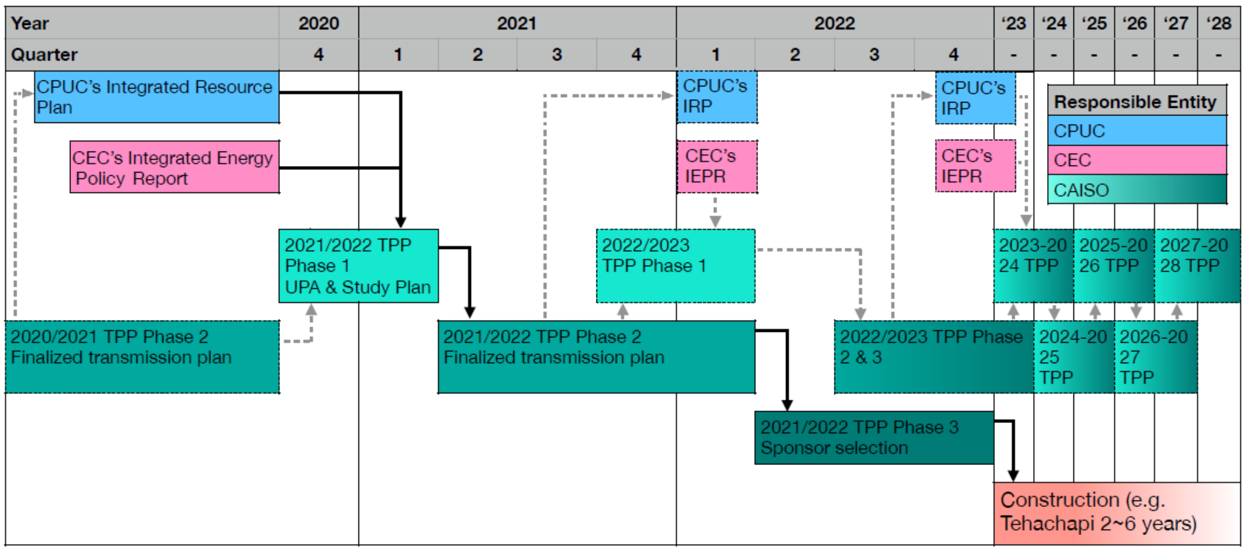
The state of California has set aggressive legislative goals for renewable energy, with the most recent target set at achieving 100% clean energy by 2045 through Senate Bill (SB) 100. In practical terms, these goals are translated into regulatory action through the work of multiple state agencies, including the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and CAISO. Each of these institutions hosts an important cyclical planning process within a defined jurisdiction to help plan investments in generation, efficiency, demand response, transmission, and other electricity system infrastructure and programs. The planning processes are linked, with outputs of one supporting inputs to the next. These state planning processes are the core public policy pathway for offshore wind development and are used to determine if offshore wind can help meet the goals set by the State.

The CEC hosts the Integrated Energy Policy Report (IEPR), which evaluates California's progress towards meeting the state's policy and renewable energy goals. The IEPR also provides a forecast of future energy demand in California and is a cornerstone of infrastructure planning to support future demand. These demand forecasts are used by the other agency processes to inform planning for investments. The CPUC hosts the Integrated Resource Planning (IRP) process, which identifies preferred portfolios of investment for the investor-owned utilities that are subject to CPUC regulation (Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas and Electric Company). Through a stakeholder-informed analysis and modeling process, the IRP aims to identify the least-cost portfolio of investments in generation, storage, efficiency, demand response, and other resources that are consistent with a safe, reliable, and economic electricity supply and meeting environmental priorities and goals. Finally, the CAISO hosts the transmission planning process (TPP), which evaluates the need for new transmission lines to maintain reliability while meeting the projected future load and in the context of expected new generation and other resources from the IRP. The TPP also considers generation and load proposed through interconnection requests as described in Section 2.1 (Billinton, 2019, p.21).

Below, we describe the way offshore wind has recently been incorporated into these planning processes and the current status, with a focus on the TPP since it is the jurisdictional planning forum for transmission upgrades.

At the core of IRP is an analysis evaluating the need for new generation sources. Offshore wind was included for the first time as a possible resource in the 2019-2020 IRP Reference System Portfolio sensitivity analysis, meaning that the potential was analyzed with preliminary data but there was not sufficient information to support fully incorporating in the IRP. Sensitivity scenarios are used by CAISO to ensure energy projects are feasible from a transmission standpoint without prematurely indicating that a project is imminent (D. Hou, personal communication, April 21, 2020), and the CAISO has subsequently proposed to include offshore wind in the 2021-22 TPP[1]. With additional stakeholder feedback and improved analysis, the offshore wind resource may be included as a default candidate resource in future IRP cycles.

Planned generation or potential transmission projects that are included in the preferred portfolio of the IRP are then incorporated into the following year's TPP (see Figure 2). CAISO's TPP is intended to serve as a unified transmission infrastructure plan for the entire CAISO balancing area (Billinton, 2019, p.13). The three-phase TPP begins every year but takes two years to complete. The TPP is the keystone of transmission planning and a precursor to construction of most transmission infrastructure.



Notes:
<u>* UPA = Unified Planning Assumptions.</u>

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

<u>Phase One of the TPP</u>

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

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

[1] http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=359001183

> study requests. After the comment window is closed, the CAISO will review stakeholder comments, evaluate economic planning study requests, select the high priority studies and publish the final study plan (Billinton, 2019, P.22).

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

Phase Two

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

Phase Three

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

Permitting and Construction

Once included in a board approved TPP, transmission projects return to the CPUC and other agencies for the siting and permitting process (D. Hou, personal communication, April 21, 2020). Based on the timeline of the Tehachapi Renewable Transmission Project, the construction process can be completed in as little as two years, or as many as six years or more (SCE, 2019). Actual completion times for transmission projects are highly variable, and there is limited recent experience in California with large, multi-gigawatt transmission projects.

2.3 Reimbursement Pathways

There are two types of transmission upgrade reimbursement pathways used in California: deliverability upgrades and reliability upgrades. Deliverability upgrades are implemented to relieve transmission system operating limits, which would constrain the ability of generators to provide energy to the aggregate load on the CAISO-controlled grid (Mannheim, 2017, p.19). Reliability upgrades are made to ensure that grid stability and safety are not impacted when new generation comes online (Mannheim, 2017, p.108).

Deliverability upgrade costs are socialized to rate-payers if the upgrades were built following transmission deliverability allocation from the CAISO, which is done during both the interconnection customer pathway (Section 2.1) and the public policy pathway (Section 2.2) (LeVine, 2020, p.73). The reimbursement is funded through a transmission access charge (TAC), which is collected as a "postage stamp" addition on the rate-payers bill (CAISO, 2019, p.46).

Reliability upgrades can be reimbursed by the rate-payer up to a certain point, again through a TAC (LeVine, 2020, p.161). The amount of reimbursement is determined either in the interconnection studies or the TPP, and is done on a cost per installed capacity ($/MW) basis (LeVine, 2020, p.98). In situations where the reimbursement does not cover the full cost of reliability upgrades, developers are eligible for, though not guaranteed, compensation based on revenues from congestion revenue rights (CRRs) (Kelley, 2019. p.95).

Another important factor influencing reimbursement is the voltage rating of the transmission infrastructure. CAISO has defined local transmission as rated up to 200 kV, and area transmission as rated greater than 200 kV (Billinton, 2019, p.78). While the cost responsibility and reimbursement amounts remain the same for the developer in either situation, the classification as local or area transmission influences which ratepayers cover the reimbursement through the TAC. For area upgrades, the cost of all area transmission development in the state is divided evenly between all ratepayers in California (CAISO, 2017). This area TAC is paid to the transmission owner who then distributes the reimbursement to the developer. For local upgrades, the cost of transmission development is divided evenly between the ratepayers that are part of the regional transmission owner's distribution system. The implication for small scale wind development on the north coast that involve transmission lines below 200 kV is that the cost burden of transmission upgrades would likely fall to ratepayers of the local utility (Pacific Gas and Electric) rather than the ratepayers for the entire state. One exception for reimbursements of local upgrades occurs when the transmission owner does not have a distribution system. In this situation the cost of local upgrades are considered in the area TAC, and reimbursed by the rate-payers of the entire state (CAISO, 2017, p.5).

Finally, there are reimbursement options for projects that complete upgrades prior to deliverability allocation, but this comes with significant risk as they will not be entitled to TAC reimbursement if they are not allocated deliverability. In this situation the project would still be eligible to recover costs through congestion revenue rights (Kelley, 2019. p.95). Similarly, in the early stages of a project a developer can choose to build a merchant transmission facility where they entirely opt out of TAC reimbursement. This type of project is guaranteed congestion revenue rights as reimbursement and assumes the risk of market fluctuations which could diminish the value of the CRRs.

3. TRANSMISSION UPGRADE ALTERNATIVES

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

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

- Evaluate three different scale wind farms independently, 48 MW, 144 MW, and 1,836 MW, all using 12 MW wind turbines (see Severy and Garcia, 2020)
- Power output for different wind farms modeled for Humboldt Call Area (see Younes et al., 2020)
- Provide full deliverability of offshore wind power and other existing generation sources (i.e. no curtailment)
- Use load forecast for Year 2029
- Consider one-in-five year adverse weather conditions based on ambient temperature
- Model system under summer peak and spring off-peak scenarios
- Include all existing generators in the region, but not new generators from the CAISO queue
- Mitigate overload under normal conditions (N-0 conditions, no contingency) and single contingencies (N-1 conditions, loss of one system element)
- Evaluate results against the NERC TPL-001-4 standard to determine if the transmission system is acceptable based on Category P0, P1, P6, and P7 standards.

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

3.1 Pilot Scale (48 MW)

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

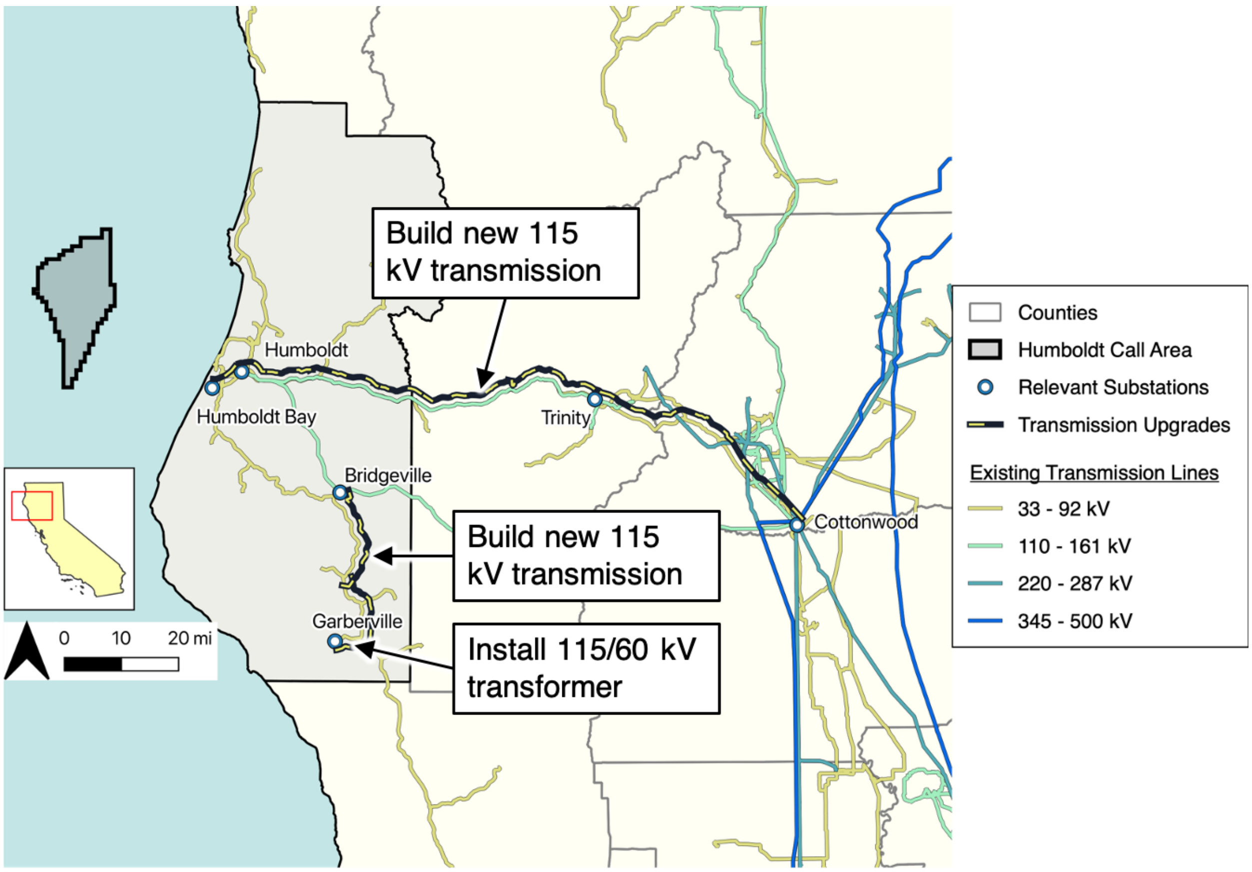


Figure 3. Transmission improvements for 48-MW wind farm scenario.

3.2 Small Commercial Scale (144 MW)

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

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

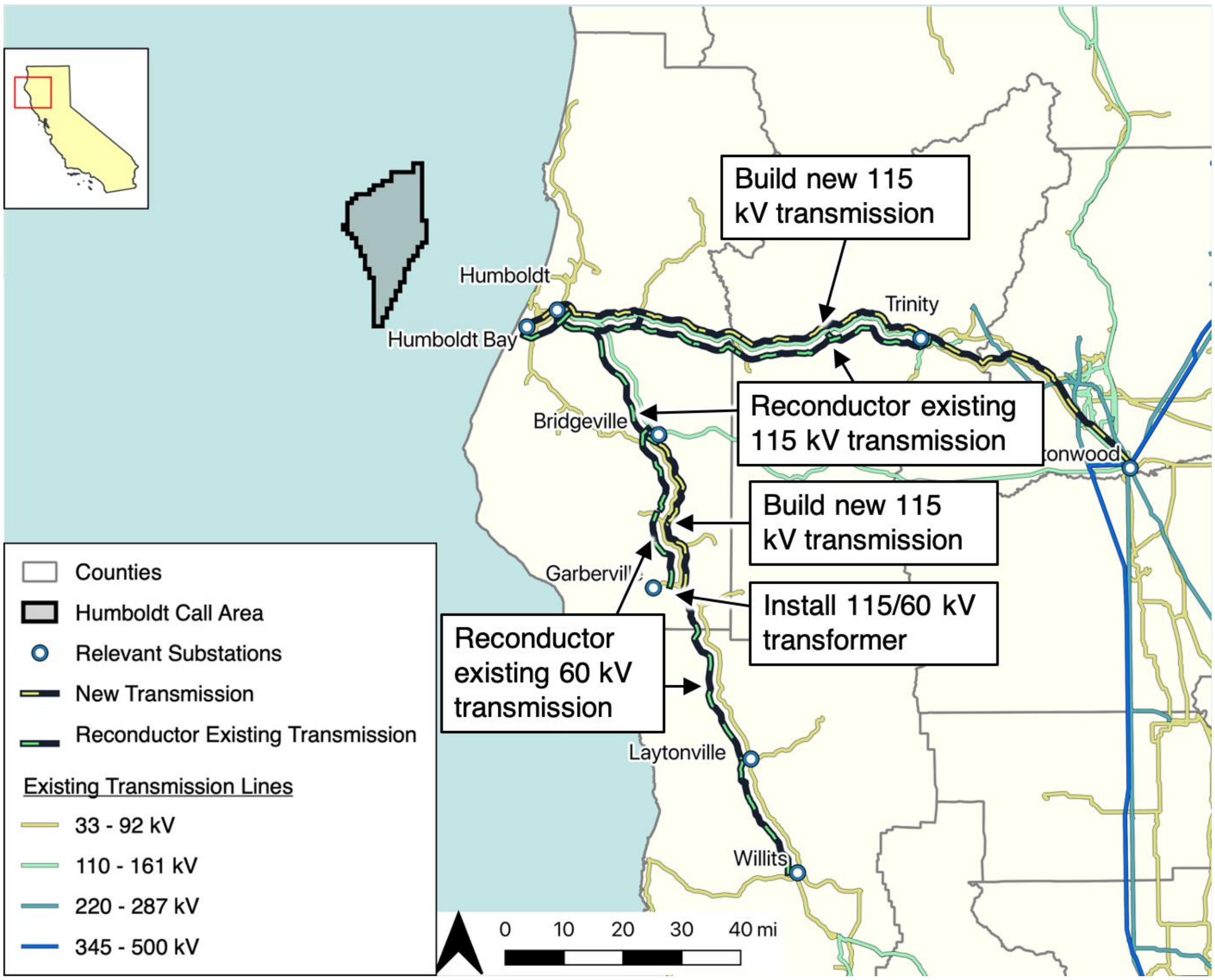


Figure 4. Transmission improvements for 144-MW wind farm scenario.

3.3 Large Commercial Scale (1,836 MW)

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

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

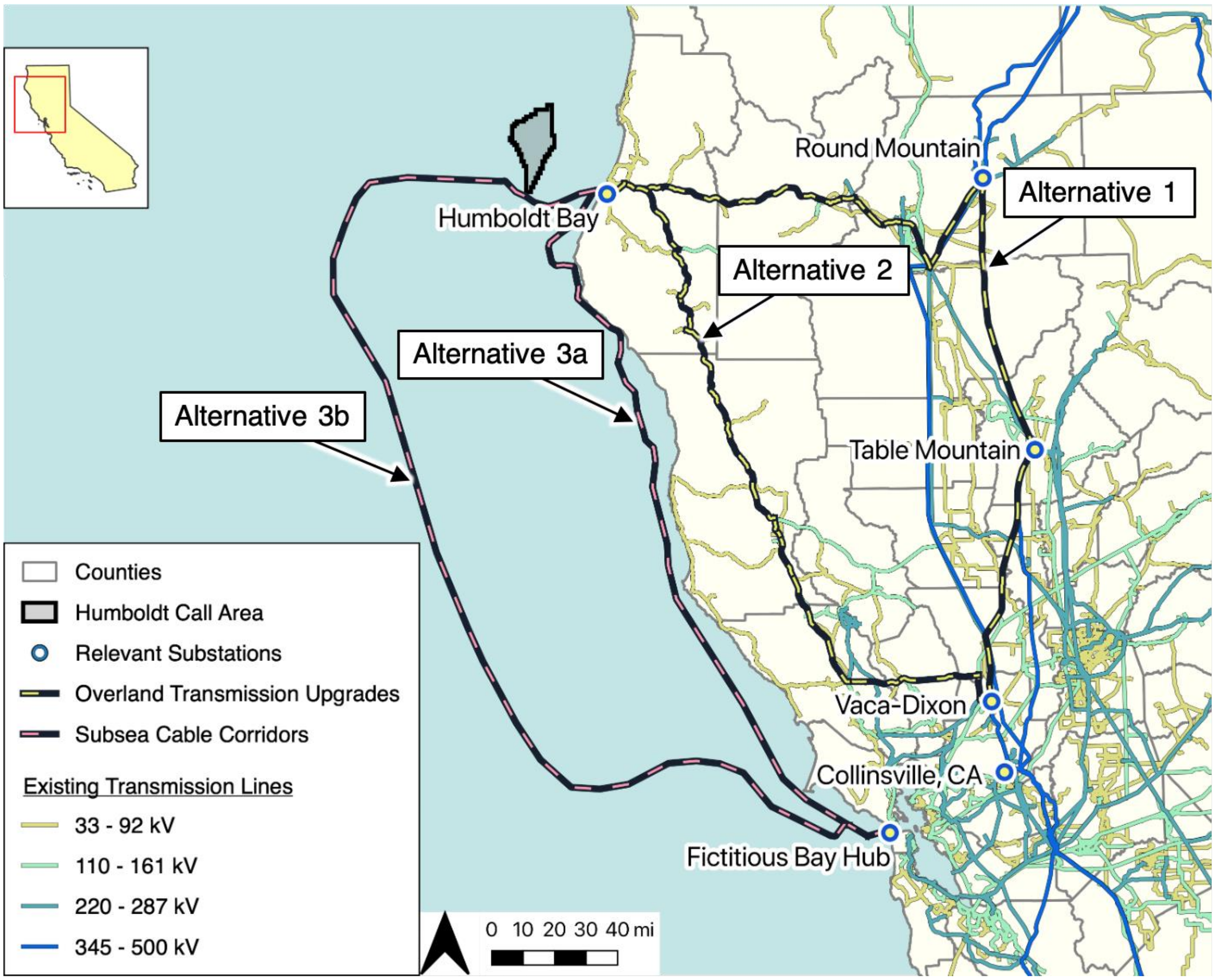


Figure 5. Transmission alternatives for 1,836-MW wind farm scenario.

3.3.1 Overland Transmission

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

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

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

3.3.2 Subsea Cable

A conceptual high-voltage, direct-current (HVDC) subsea cable was evaluated as a separate option for long-distance transmission to connect large-scale wind generators offshore from the northern California coast to major load centers in the state. PG&E identified the Greater San Francisco Bay Area (SF Bay Area) to be the target location for interconnection because of the significant load, limited generation facilities, and potential reliability issues within different transmission planning divisions in the region. Two conceptual subsea cable corridors were identified that could connect the Humboldt Bay and SF Bay Areas: one near-shore corridor and one deep-water corridor located further from shore (Porter & Philips, 2020).[2] Either subsea-cable corridor will require the same on-land infrastructure including HVDC converter stations at the northern and southern terminal.

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

4. TRANSMISSION COSTS

PG&E estimated the transmission upgrade costs for each alternative using the unit-cost guide provided by CAISO (2020). The cost estimate included a 100% contingency factor to provide an upper bound that would account for difficult terrain, limited road access, and permitting challenges (see the range in Figure 6). Within the range, the Schatz Energy Research Center identified an adjusted cost estimate (black lines

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

in Figure 6) by adding specific cost multipliers for terrain and estimates land acquisition and excavation. The adjusted cost estimates were $540 million for the 48-MW scale, $970 million for the 144-MW scale, and between $1.7 and $3.0 billion for the 1,836-MW scale.

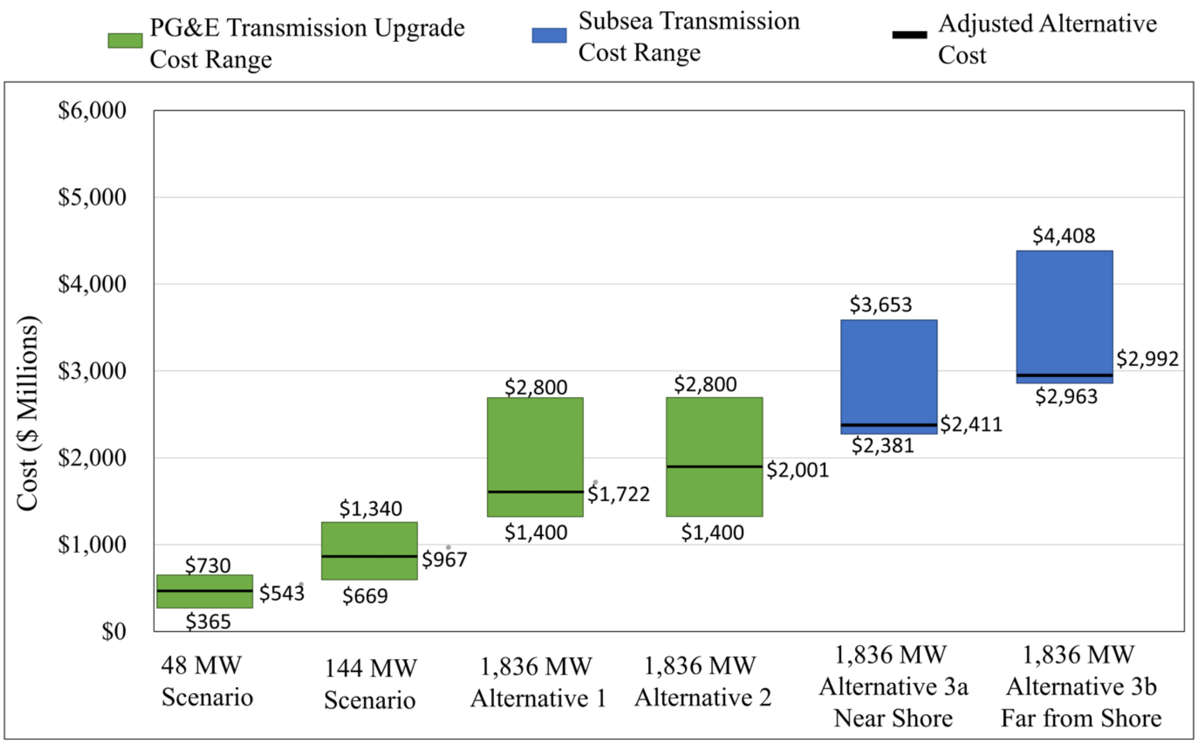


Figure 6. Transmission upgrade costs for different offshore wind scenarios showing the range of costs from PG&E study (colored bar), with adjusted value estimated (line).

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

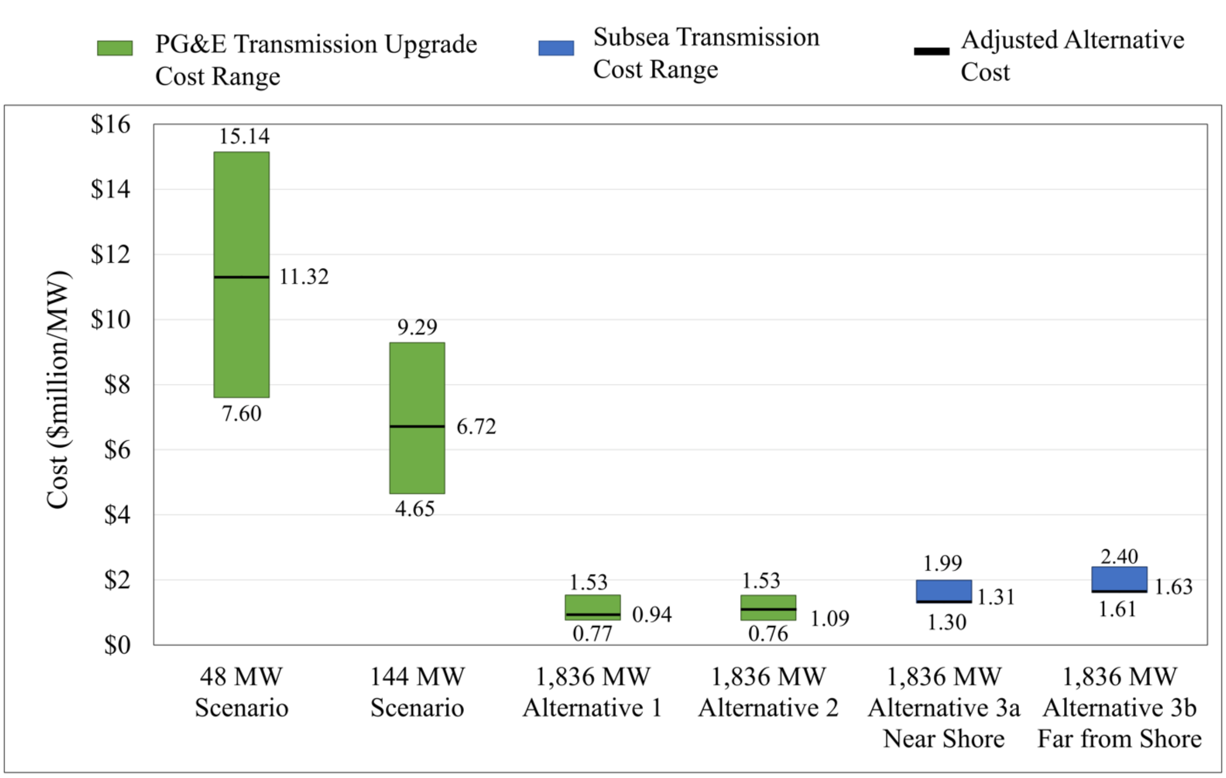


Figure 7. Transmission cost upgrades per unit of installed offshore wind capacity showing the range of costs from PG&E study (colored bar), with adjusted value estimated (line).

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

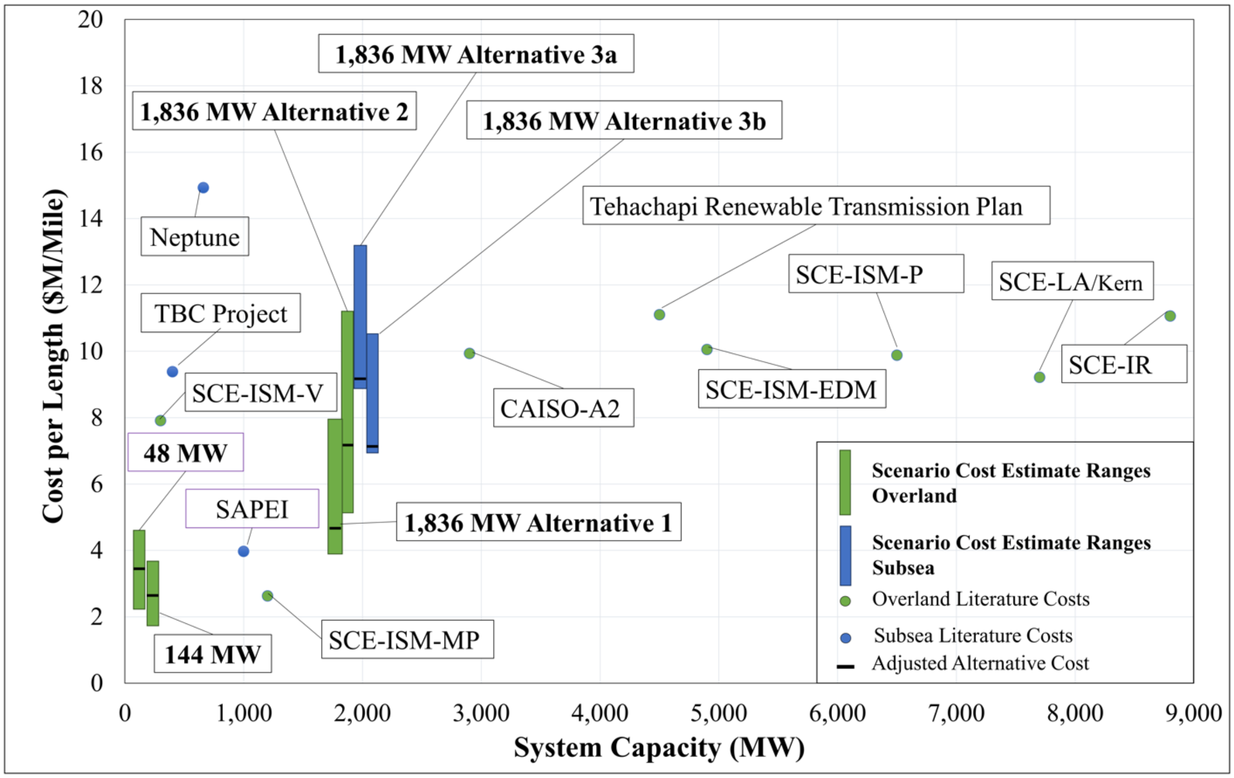


Figure 8. Cost per mile of the wind farm alternatives compared to recent project costs in California. Descriptions and sources for recent California transmission projects are provided in Appendix A.

5. DISCUSSION

Based on this analysis, significant upfront transmission investment would be required for either small- or large-scale offshore wind projects on the north coast.

While investments need to be made to develop transmission for a small to medium-scale project, this capacity would be largely irrelevant to development of a large-scale wind farm. That is, development of transmission capacity at the small scale does not provide a foundation for further capacity development for the large scale. As a result, in the absence of low-cost transmission alternatives at the smaller scale, substantial investment is needed just to get started, and then even more investment is needed to move to large-scale development. This highlights the importance of identifying lower-cost alternatives for small-scale development of the technology. Moreover, economies of scale mean that a small wind farm will have a high cost per MWh. Finally, large-scale transmission line development will require billions of dollars in investment and may take a decade or more to permit and install. If offshore wind must wait for large-scale transmission to get started on the north coast, it will take a long time before there is anything in the water.

Based on the results from this initial transmission assessment, there are four main questions that are discussed in the subsections below:

- What are the implications for developing the first offshore wind project on California's north coast?
- Are there approaches that could reduce the required transmission investment?
- What are the steps for offshore wind transmission to gain long-term public policy support?
- How accurate are the cost estimates resulting from this methodology?

5.1 Initial Development

Economies of scale are important for offshore wind farms to be competitive in electricity markets. However, the scale of the first project(s) in northern California will be limited by technical, jurisdictional, political, and social aspects in addition to the economic principles. The size of the first project will be limited by:

- Techno-Economic Factors – The scale and cost of offshore wind technology (turbines, platforms, export cables) available at the construction date will influence possibilities for development.
- Jurisdiction - The footprint of available offshore wind energy areas as identified by BOEM may limit project size. The 2018 Humboldt Call Area is the maximum possible size of a subsequent wind energy area within that region. The Humboldt Call Area may be further divided into multiple wind energy areas that become open to a competitive lease auction.
- Social - Local stakeholder approval and public support has been historically demonstrated as an important criterion for regional industrial development of new technology in Humboldt County.

Although the smaller projects will not achieve the same economies of scale benefit as a larger development, the offshore wind industry could seek to use the first project as a stepping stone to demonstrate the technology and gain experience in California. Estimates of transmission upgrade costs are \$11 million and \$6.7 million per MW for the 48-MW and 144-MW scales, respectively, while transmission costs for a 1,836-MW project range from \$0.9 million to \$1.7 million per MW (Figure 7). The upfront transmission costs for smaller projects are significantly higher, and the transmission investment for the smaller projects is not a building block for larger development. The analysis described in Section 3. identifies 115-kV transmission lines for the smaller projects and 500-kV transmission lines for the larger buildout, which require different size rights-of-way, towers, and substations. Thus, transmission investments made for a preliminary project will not lessen the cost of future development.

The tradeoffs between small- and large-scale development creates a dilemma for the initial pathway to development. On one hand, a small project may be more likely due to technical limitations, and jurisdictional boundaries, and a small-scale initial project will build applied experience and a supply chain to operate this industry in California. While gaining this knowledge could contribute to larger wind farm development, the transmission upgrades constructed at a small-scale will not be applicable to meeting the transmission needs for future construction. Based on our team's economic analysis (Hackett and Anderson, 2020), small-scale offshore wind development will not achieve cost parity with average wholesale electricity in California, but developers likely see smaller projects as a stepping stone towards building larger offshore wind farms that have significantly lower costs of production. On the other hand, a large-scale project will achieve significant overall cost reductions due to the economies of scale for offshore wind farm components and installation, but developers may be hesitant to make such large investments without practical experience of wind projects on the north coast.

Overall, if offshore wind is to be developed in California, the greatest benefit will come from large-scale deployment, both to the state in terms of installing large-scale renewable energy generation to meet Senate Bill 100 (SB 100) targets, and to the wind developer to achieve lower costs through economies of scale. In order to reach that final goal, policy makers need to either open a pathway to support transmission for a large-scale initial project, or, more likely, support measures to address some of the cost hurdles for initial, small-scale projects that will be used as a launching point for a bigger industry.

5.2 Low-Cost Alternatives

One option that could facilitate more cost-effective near-term development is to identify low-cost alternatives for transmission interconnection. While transmission interconnection costs are largely reimbursed, the upfront costs for small-scale projects are significant. The upfront transmission upgrade costs for the 48-MW and 144-MW project scenarios are greater than the capital costs for the entire wind farm development at these scales (see wind farm cost estimates from Hackett and Anderson, 2020). The imbalance in transmission cost and project cost raises the question whether there are alternative approaches to reduce transmission upgrade requirements at this scale. Several approaches could be used to reduce the impact to the transmission grid, as described below. However, these approaches must be incorporated into the PG&E's and CAISO's transmission modeling framework for planning and approval.

- Curtailment - An offshore wind farm could curtail power output during periods of transmission congestion to reduce its impact on the grid. Curtailment would reduce the overall energy output from a wind farm but would likely reduce the cost of transmission upgrades.
- Energy storage - Electricity can be stored during periods of transmission congestion and subsequently delivered to the grid when there is available capacity. Energy storage technologies could include batteries, pumped storage, and others.
- Load development - Increased regional load would allow more offshore wind energy to be used locally. Load development may require regional transmission upgrades within Humboldt County but could limit the extent of transmission upgrades connecting to the bulk transmission network. Load development could result from increased population, industrial development, hydrogen generation (e.g. for fuel), or electrification of transportation and buildings.
- Nameplate Capacity - Adjusting the wind farm nameplate capacity will change the transmission requirements. Transmission upgrade costs will not scale linearly with nameplate capacity for small-scale project because there are thresholds that trigger a new set of upgrades that require initial capital costs. Evaluating additional wind farm scales will help identify what scale wind farm has the lowest transmission upgrade cost per installed capacity.

These alternative approaches to wind farm design and operation were not evaluated as part of this first initial study. Further analysis of each alternative would quantify the costs and benefits of different approaches and help inform planning efforts for offshore wind.

Large-scale development, such as the 1.8-GW scenario in this study, require a different approach to connect with major load centers, such as a 500-kV transmission line connecting to the Central Valley transmission corridor or a HVDC subsea cable connecting directly into major load centers (see Section 3.3). Transmission cost estimates for these scenarios closely match expected costs based on recent values from literature. Construction at this capacity or greater is expected to scale directly with capacity and line distance, as indicated by the literature values included in Figure 8. It is expected that there will be fewer opportunities for developing operational schemes to minimize the transmission cost for large scale development.

5.3 Steps for Long-Term Transmission Public Policy Support

Public policy support for transmission is generated through the process described in Section 2.2. State policy defines California's broad energy goals and directive, then the CEC and CPUC evaluate progress towards meeting the targets and describe how to achieve them. Based on the recommendations from CEC and CPUC, CAISO evaluates how future plans may impact the transmission system and makes recommendations for improvements where needed to address reliability concerns. Once recommended, a transmission project would go back to the CPUC and other agencies for permitting and siting.

There is not a single policy decision that would recommend construction of transmission for north coast offshore wind. The decision is not solely one made by CAISO; rather, there are a series of steps to evaluate California's infrastructure needs to meet the state's energy policy targets. Transmission upgrades can be one of the outcomes. Since California has clean energy targets in place, including SB 100, which requires 100% clean energy in the state by 2045, the CEC and CPUC will evaluate current and expected energy trends to meet these goals. For offshore wind to be considered as an important resource for state policy to support, it needs to be included in the outcomes and recommendations from their reports. As offshore wind technology and costs are rapidly changing, using realistic and up-to-date inputs for offshore wind in the state-wide energy modeling framework is important for it to be evaluated against other renewable resources such as solar and land-based wind.

5.4 Accuracy of Cost Estimation Methods

The transmission cost estimates provided in Section 4. of this study directly reflect the assumptions that were built into the study (see assumptions described in Section 3. and Pacific Gas and Electric Company, 2020). The study evaluated the offshore wind generator's impact on the transmission system when delivering full power during peak summer conditions while also assuming that all other regional generators were simultaneously providing full output. These assumptions model the worst-case scenario for transmission congestion and follow the accepted practices for evaluating transmission requirements for new interconnection to ensure a safe and reliable transmission network. Further, transmission upgrades are built to avoid blackouts in the case of a single component failure. These contingencies, called N-1 contingencies, are planned for during generator interconnection studies.

The interconnection study was completed for a scenario in 2029 using a 10-year load forecast. The power flow model assumed that all current power plants in Humboldt County were still operational. There are two older biomass facilities (25 MW and 15 MW nameplate capacity) that have short-term power purchase agreements (PPA) with a local community choice aggregator, Redwood Coast Energy Authority. The 25-MW Humboldt Redwood Company power plant has a contract through 2023 (RCEA, 2017) and the 15-MW DG Fairhaven power plant has a contract expiring in December 2020 with options to renew every 12 months (RCEA, 2019). While it is possible the plants will continue operation beyond that timeline, if they were to go offline, this would reduce the required upgrades for the smaller scale offshore wind developments (48 and 144 MW). At the same time, it is possible that new local generators (e.g. utility-scale solar power projects) will be added by 2029, and they would add generation capacity.

6. ACRONYMS

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

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APPENDIX A - TRANSMISSION UPGRADE CASE STUDIES

Transmission cost, capacity, and line distance data were collected from a Lawrence Berkeley National Laboratory report on transmission for wind energy (Mills et al., 2009) and online transmission reviews (Dombek, 2012; TransmissionHub, 2018), and are depicted in Table A-1.

Table A-1. Summary of data and sources for transmission upgrade case studies.

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