U.S. DEPARTMENT OF ENERGY

Office of ENERGY EFFICIENCY & RENEWABLE ENERGY

West Coast Offshore Wind Transmission Literature Review and Gaps Analysis

February 2023

Disclaimer

Authors

The authors of this report are:

T. Douville, Pacific Northwest National Laboratory (PNNL)

M. Severy, PNNL

J. Eisdorfer, PNNL

L. He, PNNL

B. Pamintuan, PNNL.

Acknowledgments

This work was prepared by the Pacific Northwest National Laboratory for the United States Department of Energy (DOE) Energy Efficiency and Renewable Energy Wind Energy Technologies Office (WETO).

The authors would like to acknowledge the valuable guidance and input provided during the drafting of this report by the following list of contributors:

Jian Fu, WETO

Cynthia Bothwell, WETO

Jocelyn Brown-Saracino, WETO

Melissa Pauley, Grid Deployment Office

Hannah Taylor, WETO

Necy Sumait, Bureau of Ocean Energy Management (BOEM)

Jean Thurston-Keller, BOEM

Kenneth Clark, BOEM

Dmitry Kosterev, Bonneville Power Administration

Ebrahim Rahimi, California Independent System Operator

Melinda Marquis, National Renewable Energy Laboratory

List of Acronyms

AB	Assembly Bill
AC	alternating current
ADS	anchor data set
BA	balancing authority
BOEM	Bureau of Ocean Energy Management
BPA	Bonneville Power Administration
CA	California
CAISO	California Independent System Operator
CCA	community choice aggregators
CEC	California Energy Commission
CEM	capacity expansion model
COU	consumer-owned utility
CPUC	California Public Utilities Commission
DC	direct current
DOE	United States Department of Energy
EDAM	Extended Day-Ahead Market
EIM	Energy Imbalance Market
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GW	gigawatts
HBGS	Humboldt Bay Generating Station
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IOU	investor-owned utility
IRP	Integrated Resource Plan
ISO	Independent System Operator
kV	kilovolt
LCC	line-commutated converter
MW	megawatts
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
OR	Oregon
OSW	offshore wind
PCM	production cost model
PG&E	Pacific Gas and Electric Company
PMA	Power Marketing Administration
PNNL	Pacific Northwest National Laboratory
PNW	Pacific Northwest
POI	point of interconnection
RTO	Regional Transmission Operator
VSC	voltage source converter
WEA	Wind Energy Area
WECC	Western Electricity Coordinating Council
WETO	Wind Energy Technologies Office
WRAP	Western Resource Adequacy Program

Table of Contents

List of Figures

List of Tables

Purpose

To access the nation's most robust wind energy resources on the West Coast, electric transmission facilities need to be coordinated and developed. West Coast wind resources are located over waters hundreds to thousands of feet deep, requiring floating turbine foundations and substations to meet engineering challenges. Most of the best wind resources are in areas with limited nearby electricity transmission capacity, making it difficult to interconnect large wind projects to customer load. West coast topography, location of load centers, requirements for floating generation and transmission components, state decarbonization policies (Appendix A), and electricity policies, markets, and transmission networks (Appendix C) present unique considerations. If guided intentionally, west coast offshore wind may provide critical contributions to the bulk electricity transmission system through geographic and technological diversity. However, modifying transmission systems to accommodate these resources incurs long planning processes, uncertain siting requirements and construction timelines, and potentially high costs. Thus, planning and developing transmission for floating offshore wind energy has arisen as a technical challenge that should be evaluated alongside wind resource potential and the maturation of floating offshore wind technology.

As a companion study to the Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis, the objectives of this document are to:

- Survey west coast offshore wind transmission analyses to date (Appendix B) that support state and Biden Administration goals,
- Identify gaps in the body of literature, and,
- Inform potential investments through analysis and stakeholder convening, which may guide federal and state entities, tribal nations, transmission operators, utilities, and private developers to maximize the value of west coast offshore wind.

Background

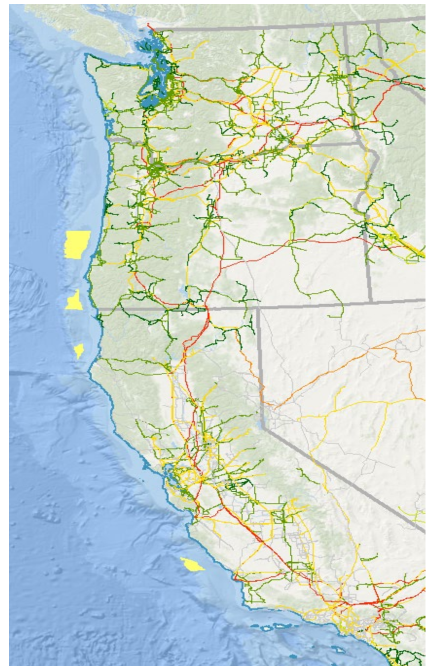

Figure 1. From south to north, shown in yellow, Morro Bay and Humboldt WEAs, and Brookings and Coos Bay Call Areas. Onshore transmission line voltage increasing from green to red.

Required in deep waters off the West Coast, floating offshore wind is expected to grow quickly in the U.S. Globally, the floating offshore wind development pipeline nearly doubled to 60 gigawatts (GW) from 2021 to 2022. Over the next 10 years, competitive opportunities for floating offshore wind deployment are expected on the West Coast following the Biden Administration's floating offshore wind target of 15 GW by 2035, the U.S. Department of Energy's (DOE's) Floating Offshore Wind Shot, California and Oregon offshore wind goals (Appendix A), and projected cost reductions, despite limited existing transmission to most of the coastline. Transmission access and coordination in west coast states will be essential for transmitting offshore wind energy from coast to load and thus enabling state and national ambitions.

West Coast Lease Activities

There are currently two Bureau of Ocean Energy Management (BOEM) Wind Energy Areas (WEAs) off the coast of California (separated by approximately 400 miles and comprising five lease areas) and two Call Areas off the shore of Oregon (separated by approximately 100 miles). With the exception of the Morro Bay WEA, these areas are relatively isolated from high-capacity transmission (Figure 1). In May 2022, BOEM delineated three lease areas within the Morro Bay WEA and two within the Humboldt WEA. Also in 2022, the Brookings and Coos Bay call areas in Oregon were announced. These areas could host approximately 4.7 GW and 14 GW of offshore wind capacity off the coasts of California and Oregon, respectively (Table 1). Additional lease areas will be required to meet California's floating offshore wind goals.

On December 6–7, 2022, BOEM hosted an offshore wind energy auction of the California lease areas, and five distinct winners were identified. A similar activity is planned in Oregon during 2023. BOEM's process timeline suggests that after a lease auction, up to seven years are needed until a Construction and Operations Plan is approved.[1] Under this timeframe, west coast offshore wind could be installed within the next 10 years. No call areas in Washington have been announced to date.

Table 1. Summary of Size and Potential Capacity of Offshore Wind Locations along the West Coast

BOEM Area	Area (km^2)	Potential Capacity[2] (GW)
Morro Bay Wind Energy Area	1,033	3.1
Humboldt Wind Energy Area	534	1.6
California Total	***1,567***	***4.7***
Brookings Call Area	1,160	3.5
Coos Bay Call Area	3,532	10.5
Oregon Total	***4,692***	***14.0***

[1]BOEM updates information and timing requirements through Construction and Operations Plan Guidelines.
[2]Assuming 3 MW per kilometer squared (km^2) (Musial et al., 2019)

Policies, Markets, and Transmission Planning in the West

The development of west coast offshore wind will be influenced by the particulars of western state policies, markets, and transmission systems. In particular, the energy markets of the west coast states will determine the potential for offtake contracts, transmission paths, and transmission solutions. California, Oregon, and Washington have all adopted policies that support clean energy, require greenhouse gas (GHG) emission reductions from the electricity sector, and/or establish offshore wind-specific objectives (Appendix A).

In the Northwest, the bulk of buying and selling electricity occurs through bilateral transactions between utilities, marketers, and generators. The six Northwest investor-owned utilities (IOUs) are rate-regulated, vertically integrated utilities owning distribution, generation, and transmission assets. They are responsible for serving load within their service territory, which entails planning all aspects of service, securing energy resources or contracts and associated transmission rights, and building new generation and transmission if needed. The Northwest IOUs plan for and build transmission assets as approved by their state regulators. Appendix C provides more information about transmission policies, markets, and transmission in the western U.S.

There are more than 150 consumer-owned utilities (COU) and tribal utilities in the four northwest states (Washington, Oregon, Idaho, and Montana). COUs can own generation and buy and sell power in the market, but COUs have preferential cost-based access to the output of the Federal Columbia River Power System (FCRPS) marketed by the Bonneville Power Administration (BPA) through federal statute. BPA is a Federal Power Marketing Administration that markets the output of the FCRPS and owns and operates most of the transmission system in the region. Many COUs rely fully on BPA to serve their loads and manage transmission issues. BPA participates in regional planning activities with NorthernGrid and the IOUs, but there is no organized transmission operation for the Northwest. There are 38 balancing authority (BA) areas in the Western Interconnection including 17 in the four northwest states. Within each BA, operators are responsible for maintaining the balance between load and generation. In contrast, the California Independent System Operator (CAISO) manages the flow of electricity for about 80 percent of California's load, and the rest is managed by local public power companies. CAISO's electric energy markets allow buyers and sellers to bid to purchase or sell wholesale electricity, which is economically dispatched to optimize available transmission.

Many of the large IOUs and COUs in California have become participating transmission owners in CAISO. These utility owners continue to own transmission assets but have turned over operational control to CAISO. The utilities are compensated on a just and reasonable basis from the revenues collected by CAISO through access charges paid by users of the transmission system operated by CAISO. CAISO's Western Energy Imbalance Market (EIM), which is a real-time energy market, is also open to owners of generation outside of California.

CAISO is responsible for planning transmission within its control area. Requested and informed by the California Public Utilities Commission (CPUC) Integrated Resource Plan (IRP), CAISO analyzes proposed transmission based on reliability needs, public policy, and economic needs, which results in an annual Transmission Plan that identifies needed transmission solutions. If necessary, CAISO creates a competitive solicitation for developers to build and own new regional transmission facilities. Separately, CAISO has initiated 20-year planning to project longer-term grid requirements and options for meeting California's clean energy goals.

West Coast Offshore Wind Transmission Analyses

As floating offshore wind has emerged as a potential large-scale source of electricity on the West Coast, transmission system operators, transmission planners, national laboratories, consultants, and academics have conducted transmission studies to assess system impacts and plan for the integration of offshore wind.

Criteria for West Coast Offshore Wind Transmission Analyses

Many assumptions are built into a transmission analysis to define system load, onshore and offshore transmission routes, interconnection points, and other design factors. The Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis set out minimum criteria for conducting *comprehensive, proactive* transmission analysis. These same criteria are used to assess the west coast offshore wind transmission studies, along with two additional criteria:

- Analysis that includes **onshore capital cost estimates** for new and upgraded transmission infrastructure.
- Analysis that considers **interregional coordination** to interconnect and transmit power between transmission systems and across state borders.

Recent and Ongoing West Coast Offshore Wind Transmission Analysis

Over 30 west coast electricity generation and transmission studies were reviewed as of December 2022. Select studies that evaluated the capabilities, constraints, and required upgrades of the transmission system to interconnect offshore wind (OSW) on the West Coast are summarized in Table 2, with further detail provided in Appendix B. Studies not explicitly focused on offshore wind transmission were excluded from Table 2. For example, resource and cost feasibility studies from National Renewable Energy Laboratory (NREL) for California and Oregon, broad summaries of value (e.g., Rose et al., 2021), planning studies from the California Energy Commission (CEC) that do not model transmission, some multi-disciplinary studies from the Schatz Energy Research Center concerning offshore wind feasibility in northern California, and DOE's National Transmission Planning Study that primarily considers land-based transmission. All of these studies have been reviewed, and the lessons learned inform the findings of this gaps analysis.

Several themes arise across the set of studies:

- Coastal interconnection points and transmission networks on the West Coast, particularly in northern California, lack capacity to connect offshore wind at the scale of lease and call areas.
- Geographically, many studies have concentrated on the northern coast of California or the southern coast of Oregon, where transmission is limited. Existing studies largely consider each region separately, but two current studies consider both regions together. In central California, transmission analyses of the Morro Bay lease areas have pointed toward the same solution. Northern Oregon or Washington have not been a focal point of any studies.
- A few early studies relied on production cost analysis with direct current (DC) power flow assumptions to conclude the near-term potential for offshore wind transmission.[3] Several

[3] Production cost models balance load and dispatch generation under a DC active power flow assumption, neglecting transmission losses and assuming perfect reactive power management. In contrast, AC power flow models simulate both active and reactive power flows and losses. These are needed to understand voltage and frequency stability on the system under normal and contingency conditions and identify system upgrades necessary for reliability.

more recent studies published in 2020 onward use alternating current (AC) power flow analyses, including those from Pacific Gas and Electric Company (PG&E) and Schatz (Northern CA), CAISO (CA), PacifiCorp and BPA (OR), and studies in progress from Pacific Northwest National Laboratory (PNNL) and NorthernGrid (OR).

- Timescales considered in production cost studies span from sub-hourly to seasonal. Full annual, hourly (8,760 hours) resolution enabled several studies to understand transmission flow as a result of supply and demand fluctuations over the year. One study from NREL used multiple weather years to evaluate DC power flow with natural generation variability.
- Several studies highlight the capacity value of offshore wind. These studies note that daily and seasonal patterns and a relatively consistent power profile for offshore wind help balance load with supply in a future resource portfolio mix.
- Few studies have considered resilience. The evaluation of resilience work has been primarily qualitative to examine how offshore wind may mitigate impacts from heat waves and wildfires. Resilience benefits could be provided by 1) using offshore wind generation to serve coastal areas with currently limited local generation that would otherwise be isolated during emergency events, and 2) using new transmission that is built to support offshore wind could increase interregional transmission capacity to meet loads during contingencies and peak demand events.
- Though most studies assess multiple points of interconnection (POIs), their scope is often limited to a single state or system. Only a few suitable POIs exist near offshore wind areas, so similar POIs have appeared in multiple studies.
- There is no consensus from the studies about optimized ocean grid infrastructure or offshore transmission networks on the West Coast. Most studies did not consider ocean grid infrastructure or offshore transmission networks, even though offshore transmission networks might be a cost-effective option at specific locations. Studies that did consider subsea transmission options, including analyses from CAISO, PG&E, and Schatz Energy Research Center, are preliminary studies that require follow-up work to fully identify feasible cable landfalls and POIs and understand grid impacts under multiple design alternatives.
- Rough estimates of capital and operating costs of onshore and offshore transmission were provided in early studies. Rough estimates from early studies are being refined through contributions from system operators.

The studies to date have yielded helpful background information and spurred state legislation and development targets. However, additional work is needed to fully illuminate the west coast offshore wind opportunity, particularly if pursued in a coordinated fashion.

In addition to the studies described in Table 2, the CEC will evaluate the transmission investments needed to support California's offshore wind planning goals of 2 to 5 GW by 2030 and 25 GW by 2045 (see Appendix A). Section 25991.4 of California Assembly Bill (AB) 525 tasks the CEC to assess "transmission investments and upgrades necessary, including potential subsea transmission options." CEC outlined a schedule for the AB 525 Transmission Analysis to release a draft report in April/May 2023 that documents the needs, costs, and long-term development strategies for offshore wind transmission. This report is omitted from Table 2 because the analytical approach, tools, and assumptions are not clearly defined in the bill text or presentation materials.

Table 2. Summary of West Coast Offshore Wind Transmission Studies as of December 2022

Study[4]	CA1 UC Berkeley/E3, Economic Value	CA2 PG&E/Schatz, North Coast OSW Feasibility	CA3 Schatz, Transmission Alternatives for North Coast OSW	CA4 CEC, SB100 Pathways
Region	CA	North Coast CA	North Coast CA	CA
Publish Year	2019	2020	2022	2021
Study Year	2030-2050	2029	2030	2045
OSW Generation	1-20 GW[5]	48, 144, 1,836 MW	144, 168, 288, 480 MW + storage	0-10 GW[5]
POI[6]	No	Both	Exist	No
HVAC/HVDC[7]	N/A	Both	HVAC	N/A
Data Hours[8]	888 (37 days) for CEM	Peak & off-peak	Peak & off-peak; 8,760 for PCM	888 (37 days)
G+T Co-Opt[9]	No	No	No	No
Production Cost	Yes	No	Yes	Yes
Contingency[10]	No	Yes	Yes	No
Stability	No	No	No	No
Costs	No	Yes	Yes	No
Resilience	No	No	No	No
Interregional Flow	No	No	No	No
Key Findings or Objectives	• Capacity expansion model without consideration of transmission • Assumes transmission capacities without a power flow analysis	• Scenario-based power flow modeling by IOU • 48 MW: Thermal overloads require line upgrades • 144 MW: Further upgrades required • 1,836 MW: Extensive HVAC or subsea HVDC upgrades required	• Upgrades to Humboldt-Bridgeville 115 kV and Humboldt-Trinity 115 kV are the most critical constraints to offshore wind interconnection • Energy storage did not significantly reduce curtailment • OSW plant size >480 MW requires major 500 kV expansion	• Evaluates pathways to meet 100% clean energy targets • Natural gas capacity is maintained for resource adequacy • Transmission expansion is assumed and included as a fixed cost • 10 GW of OSW built to meet clean energy goals by 2045

[4] For each study, the author(s) is listed first, followed by an abbreviated title of the study.
[5] Onshore power injection aggregate (as opposed to nameplate capacity).
[6] Indicates whether POIs were chosen from existing substations or assumed new substations. No indicates generic injection.
[7] High-voltage alternating current (HVAC) or high-voltage direct current (HVDC).
[8] 8,760 refers to hourly data for one year and C indicates coincident (i.e., the same weather year for loads, other renewable energy generators, and OSW).
[9] Indicates whether generation and transmission designs were co-optimized.
[10] Indicates whether an extensive transmission contingency analysis was performed. 'Peak' indicates contingency analysis only during peak load hours.

Study	CA5 CAISO, 2021-2022 Transmission Plan	CA6 CAISO, 20-year Outlook	OR1 PNNL, Grid Value	OR2 NREL, Grid Impact
Region	CA	CA	OR	OR
Publish Year	2022	2022	2020	2021
Study Year	2030	2040	2028	2024, 2036
OSW Generation	8 GW, 21 GW	10 GW, 22.8 GW[5]	0-5 GW[5]	0-5 GW
POI[6]	Both	Both	Exist	Exist
HVAC/HVDC[7]	Both	Both	HVAC	HVAC
Data Hours[8]	Peak & off-peak for power flow, 8,760 for PCM	Peak & off-peak for power flow	8,760 for PCM	8,760C (7 met yrs) for PCM 17 for CEM
G+T Co-Opt[9]	No	No	No	No
Production Cost	Yes	No	Yes	Yes
Contingency[10]	Yes	Yes	No	No
Stability	No	No	No	No
Costs	Yes	Yes	No	No
Resilience	No	No	Yes	No
Interregional Flow	No	No	Yes	Yes
Key Findings or Objectives	• The Morro Bay substation needs to loop into the Diablo-Gates 500 kV line to increase capacity for offshore wind interconnection • In northern CA, major transmission build-out is required for all scenarios • Congestion on California-Oregon Intertie occurs during spring months when flow is from south to north	• Central CA OSW: 3 GW to Diablo 500 kV and 3 GW to new Morro Bay 500 kV (loop into existing Diablo-Gates 500 kV line) • To connect 4 GW in northern CA, need two 500 kV AC lines to new Fern Road, 500 kV substation, and an HVDC line to Collinsville 500/230 kV sub (either land or subsea), or alternately an HVDC subsea cable to the "Bay-hub", a hypothetical DC converter station in the San Francisco Bay Area • Development of 500 kV lines in northern CA will increase the transfer capacity between CA & PNW.	• Existing transmission may interconnect 2-3 GW with minimal transmission investment and energy export from OR • OSW serves coastal loads, relieves east-to-west transmission flows	• Approximately 2.6 GW of installed OSW may be integrated in OR without major upgrades to trans-Coast Range transmission • Cross-Cascade non-wires alternative value is limited due to low correlation of production with peak flows

Study	OR3 BPA, TSEP Deliverability	OR4 PacifiCorp, Integrated Resource Plan	OR5 NorthernGrid, Economic Study	OR/CA1 PNNL, Grid Strategy	OR/CA2 CEC, Transmission Infrastructure Assessment
Region	OR	S. OR	S. OR	S. OR & N. CA	S. OR & N. CA
Publish Year	2022	2022	In progress	In progress	In progress
Study Year	2027, 2031	2032	2032	2030, 2030+	TBD
OSW Generation	2.2 GW	1.0-3.5 GW[5]	3 GW[5]	TBD, ~3-15 GW	TBD
POI[6]	Exist	New	Exist	Exist	Yes
HVAC/HVDC[7]	HVAC	HVAC	HVAC	Both	TBD
Data Hours[8]	Peak	Peak	Peak, 8,760C	Peak, 8,760C	TBD
G+T Co-Opt[9]	No	No	No	G then T	TBD
Production Cost	Yes	Yes	Yes	Yes	TBD
Contingency[10]	Peak	Peak	Peak	Peak	TBD
Stability	No	No	No	Yes	TBD
Costs	Yes	Yes	Yes	Yes	Yes
Resilience	No	No	No	Yes	Yes
Interregional Flow	No	No	Yes	Yes	Yes
Key Findings or Objectives	• Transmission service requests of S. OR OSW to Portland • Evaluated transmission capacity of 600 MW at Fairview & 1,600 MW at Rogue to serve Portland loads	• 500 kV upgrades targeted to deliver OSW to central OR • OSW could be interconnected in Coos Bay, transmitted across the Coast Range, south through Klamath Falls, and then north to central OR	• Post-transient contingency analysis will inform a transmission solution to enable 3 GW of S. OR OSW (1,800 MW through Fairview + 1,200 MW through Wendson) • Incorporates loading, generation, and transmission submittals in the 2023 NorthernGrid Planning Cycle	• Technoeconomic valuation of OSW through dispatch and power flow simulations to compare generation and transmission options • Three generation & transmission scenarios to be analyzed which span two future representations of the WECC	• Will provide a geospatial and infrastructure expansion analysis in N. CA and S. OR • Will map attributes of existing energy infrastructure to provide accurate picture of energy landscape • Will develop infrastructure scenarios to accommodate a range of OSW generation that quantifies infrastructure needs and costs

Gaps Assessment

After a review of the existing west coast offshore wind transmission studies, a series of topics emerge as impactful on the development of offshore wind. Several needs map the infrastructure required to deliver, transmit, and produce electricity from offshore wind plants, and others more broadly apply to floating offshore wind.

Interregional coordination has not been prioritized. Though the potential benefits of proactive and coordinated offshore transmission have been shown in other regions,[11] comprehensive analysis and realistic development pathways, including supporting **onshore transmission** development, have not been examined across the West Coast. The increasing reliance of utilities in the West on electricity transported over long distances makes effective interregional coordination of transmission vital. Focused central planning analysis (including expanded regional planning in Washington and Oregon and interregional planning with California) could bring together the large number of western entities to develop a holistic plan for offshore wind integration. Interregional studies also have not co-optimized the development of renewable power plants with transmission investment, which may lead to suboptimal transmission investment to reach the best energy resources instead of balancing tradeoffs.

Representation of future supply and demand patterns have been limited. Numerous west coast studies have considered multiple future scenarios when investigating the system impacts of offshore wind, but even more scenarios will help illuminate the impact. Analysis is incomplete without consideration of the interregional portfolio of loads and generation resources and how these may change over time as a function of state policy objectives, ocean co-use and community impacts, generator interconnections, and transmission network upgrades. Approaches such as multi-value planning that holistically capture the potential economic, reliability, and resilience value of offshore wind transmission are needed. Stability studies over the range of grid strength scenarios are needed to fully capture the technologies required for reliable high penetration renewable integration. These scenarios should also incorporate accurate POI capacities for offshore wind integration with and without upgrades, the potential use of grid-enhancing technologies, and the design of onshore transmission upgrades and integrated energy storage systems for benefits to coastal communities.[12]

The technological readiness of floating transmission and offshore wind plant infrastructure is relatively low, and viable subsea cable routes are not defined. The design of wind plant collector systems, substations, converter stations, and offshore transmission infrastructure has not been clearly established for distant (up to 65 miles from shore) floating offshore wind sites on the West Coast. Generic static and dynamic electrical models of floating offshore wind plants, as well as multi-terminal HVDC models, are lacking. Capacity limitations and technological readiness of some hardware elements, such as dynamic export cables and HVDC circuit breakers, are constraints. Finally, only a few studies in northern California have analyzed offshore wind transmission cable routes, including right-of-way availability and width, sea floor depth and slope, geophysical constraints for cable burial and landfall, seismic and gas venting hazards, and environmental permitting considerations for subsea cables.

[11] National Grid UK and New York

[12] Including pumped hydro and in the long-term, hydrogen production through electrolysis and its use as a transportation or manufacturing fuel or re-conversion to electricity through fuel cells when needed.

Generation attributes are not fully validated. Offshore wind generation characteristics are likely to influence the locations and designs of offshore transmission, which should be analyzed on the 2030 and 2045 horizons, consistent with west coast state offshore wind targets.[13] As on the Atlantic Coast, West Coast DOE LIDAR buoy measurement campaigns have indicated that spatial and temporal validations of offshore wind models are incomplete. Also, a decarbonization pathways analysis across the Western Interconnection that projects the role of offshore wind alongside other generation options is needed to capture resource interactions and define state and federal offshore wind efforts in coordination with other decarbonization actions.

Techno-socio-economic valuations need to be enhanced at scale. Both technical and economic feasibility will influence the development of west coast offshore wind. While promising reductions in the conventional cost of energy at turbine and power plant levels have been shown, major west coast load centers are not located nearby potential offshore wind development areas, and analyses that stop at the POI need to be extended to include the costs of electricity delivered to loads. These analyses should consider impacts across the Western Electricity Coordinating Council (WECC) system and account for the net energy, capacity, grid support services, and resilience values derived from offshore wind generation and transmission additions. Optimization of generation and transmission footprints should be governed by such comprehensive valuations, to the extent feasible. Analyses should also include sharper definitions of offshore grid infrastructure, including component reliability and repair procedures, and the corresponding capital and operational costs. And they should be accomplished with respect to a changing generation mix, a realistic evolution of onshore transmission to support it, and alterations in load patterns due to building and transportation electrification.

Any benefit-cost analysis should include social, cultural, environmental, and economic impacts on coastal and ocean co-use communities, which have been absent from the offshore wind transmission literature to date and have been cited as stakeholder concerns.

New developments warrant study updates. Significant legislative and policy changes in recent months stand to impact the pace and reach of west coast offshore wind transmission, necessitating a refocus of offshore wind transmission studies. Both the Transmission Facilitation Program launched by the Infrastructure Investment and Jobs Act and the significant resources reserved for transmission in the Inflation Reduction Act may impact where and when electricity transmission is developed. Meanwhile, the prioritization by the federal government of floating offshore wind has brought a focus to west coast transmission. At the state level, Oregon has completed a planning study calling for a comprehensive state strategy for offshore wind, and California has established aggressive offshore wind planning goals through AB 525. However, California has moved to delay the retirement of the Diablo Canyon nuclear plant by five years until 2030,[14] which postpones some of the available transmission capacity that was anticipated for Central Coast offshore wind and could force new transmission construction to accommodate offshore wind generation in that region. CAISO has also identified the types of transmission upgrades that would be required to harness nearly 15 GW of offshore wind on California's north coast (CAISO, 2022a).

---

[13] Biden Administration offshore wind targets also exist on 2030, 2035, and 2050 horizons. However, state planning targets are more likely to drive transmission development through state utility commissions and permitting agencies.
[14] Postponement of retirement has been legislated in California SB 846. See https://calmatters.org/environment/2022/09/diablo-canyon-legislature-california/

Role for Convening

In addition to analytical efforts aimed at the gaps in west coast offshore wind transmission research, the guidance of studies by and circulation of findings among active participants and stakeholders in the areas of transmission planning, technology advancement and standardization, economics, environmental impact, siting and permitting, and policy development are necessary to drive impact.

On the East Coast, DOE and the Department of the Interior have followed this model by hosting a series of convening workshops, which have been conducted in coordination with, though distinct from, the Atlantic Offshore Wind Transmission Study. The convening workshops have spanned transmission planning and development, economics and policy, and siting and permitting topics with decision-makers from federal agencies, tribal nations, state agencies (public utility commissions, state energy offices, state environmental and natural resource agencies, etc.), Independent System Operators (ISOs) and Regional Transmission Operators (RTOs), consumer advocates, electric reliability organizations, and current BOEM leaseholders. The broader offshore wind stakeholder community has also been engaged in this effort to hone a set of recommendations and an associated action plan for addressing near-, medium-, and long-term offshore wind transmission challenges for the Atlantic Coast.

A similar convening effort would be valuable on the West Coast. State and transmission operator guidance on study approaches and interpretation of findings within the context of public policy and transmission planning processes would inform decision criteria beyond those in the scope of a techno-socio-economic analysis. Coordination between CAISO and transmission operators in the Pacific Northwest (PNW) and their respective states would also be reinforced through a central convening effort. Finally, through this forum, realistic pathways toward the maximum net benefits of west coast offshore wind transmission can be identified.

Conclusion

Floating offshore wind energy is an emerging technology that west coast states will deploy within large-scale decarbonization campaigns. Within this context, transmission has arisen as a technical opportunity that needs to be considered alongside the evaluation of resource potential and the maturation of floating offshore wind technology. Gaps exist both in transmission studies to integrate offshore wind and in the research and development of technologies to support floating offshore wind transmission.

Recent studies indicate that existing onshore transmission, particularly in northern California, is insufficient to integrate offshore wind from current BOEM lease and call areas. Several analyses are considering multiple, full weather years to capture supply side variability. Some studies have focused on production cost impacts specifically on one state or region within a state, while others have considered interregional impacts, primarily between the Northwest and California. Consideration of transmission reliability is improving, but additional contributions are needed.

Following the literature review, key gaps were extracted and organized. A responsive research effort would span the entire West Coast through 2045 and incorporate the following five tenets:

1. **Incorporate regional and interregional perspectives.** Central planning across the interconnected system is required alongside diverse stakeholder conversations. Coordination between policymakers, regulators, transmission planning organizations, and grid operators enables reliability and economic value.
2. **Leverage best available information.** The west coast energy landscape is dynamic. Analysis should include robust projections of supply and demand patterns, up-to-date representations of federal and state policies, and detailed models of onshore transmission.
3. **Mature floating offshore wind transmission and plant models.** Electrical models that represent emerging offshore wind plant and multi-terminal HVDC system characteristics should be developed in coordination with industry. Analysis of offshore transmission should include feasible cable routes, landing points, points of interconnection, and their associated environmental and community impacts.
4. **Increase understanding of offshore wind characteristics.** Validation of temporal and spatial wind energy generation, including its variability and uncertainty, is fundamental to understanding interactions with system load, supply, and transmission resources.
5. **Expand valuation scope.** Technoeconomic valuation should include more accurate definitions of transmission costs extended to delivery to load. A range of potential futures that enable critical risk mitigation and resilience value should be considered. The social, cultural, environmental, geotechnical, and economic impacts for coastal and ocean co-use communities should be incorporated.

Coordinated investments in transmission research and convening key federal, state, local, and industry stakeholders and tribal nation representatives would fully inform decision criteria and accelerate development toward western states’ and the Biden Administration’s offshore wind and decarbonized electricity goals.

Appendix A – State Policies and Decarbonization Potential

Three states on the West Coast have set 100 percent clean energy targets that will remove electricity generators that produce carbon dioxide emissions from retail electricity sales, and two states have established offshore wind-specific targets. Several studies have proposed pathways to decarbonization in the West, but only two have specified the role for offshore wind within the future clean energy generation mix to date.

State Policies

In 2018, Senate Bill (SB) 100 revised California's renewable portfolio standard to require 100 percent of electricity to be from renewable or carbon-free sources by 2045. AB 525 (2021) requires the CEC to determine the maximum feasible capacity of offshore wind power that can be deployed off California's coast by 2030 and 2045. In August 2022, CEC released the report for AB 525, which set a preliminary planning goal of 2–5 GW of offshore wind by 2030 and 25 GW by 2045.

In 2021, Oregon enacted House Bill (HB) 2021, which requires the largest electric utilities to reduce GHG emissions from baseline levels by 100 percent by 2040. The act bans new fossil fuel power plants and reinforces Oregon's Renewable Portfolio Standard of 50 percent renewable energy by 2040. The legislature established an offshore wind planning goal of up to 3 GW by 2030 in HB 3375. The Oregon Department of Energy published the Floating Offshore Wind Study in 2022, which recommended a state offshore wind development strategy, additional stakeholder engagement, and regional collaboration.

In 2019, the Washington State Legislature passed the Washington Clean Energy Transformation Act (SB 5116) to set a requirement for 100 percent of electricity to be from renewable and non-carbon-emitting resources by 2045. This act also requires all electric utilities to remove coal-fired power plants from their generation mix by 2025 and be GHG neutral by 2030.

Decarbonization Contribution of West Coast Offshore Wind

With sufficient transmission planning and development, west coast offshore wind may offer meaningful contributions to Biden Administration offshore wind goals and toward Biden Administration and state decarbonization targets from 2030-2050. The technical capacity potential for floating offshore wind development has been projected at 201 GW in California, 62 GW in Oregon, and 42 GW in Washington (Optis et al., 2020; Musial et al., 2016).

California examined the contribution of 10 GW of offshore wind toward 100 percent decarbonization by 2045 in a capacity expansion study (Gill et al., 2021). Offshore wind contributions were shown to increase from roughly 5 GW in 2040 to a pre-defined cap of 10 GW in 2045. In a similar study, 20 GW of offshore wind were modeled to assist decarbonization in Oregon by 2050 (Evolved Energy Research, 2021). Similarly, a study conducted for the Washington Department of Commerce modeled up to 4 GW of additional offshore wind capacity by 2050 to meet deep decarbonization goals (Evolved Energy Research, 2020).

Appendix B – Analysis Summaries

[CA1] California Offshore Wind: Workforce Impacts and Grid Integration

[CA2] California North Coast Offshore Wind Study – Interconnection Feasibility Study Report

[CA3] Transmission Alternatives for California North Coast Offshore Wind

[CA4] SB 100 Joint Agency Report: Charting a path to a 100% Clean Energy Future

[CA5] CAISO 2021 – 2022 Transmission Plan

[CA6] CAISO 20-year Transmission Outlook

[OR1] Exploring the Grid Value of Offshore Wind Energy in Oregon

[OR2] Evaluating the Grid Impact of Oregon Offshore Wind

[OR3] BPA 2022 Transmission Service Request Study and Expansion Process Cluster Study

[OR4] PacifiCorp 2023 Integrated Resource Plan

[OR5] NorthernGrid Southern Oregon Offshore Wind Economic Study

[OR/CA1] Offshore Wind Energy Development Strategy to Maximize Electricity System Benefits in Southern Oregon and Northern California

[OR/CA2] Northern California & Southern Oregon Mission Compatibility and Transmission Infrastructure Assessment Project

[CA1] California Offshore Wind: Workforce Impacts and Grid Integration

Published: 2019, by Collier et al. (Collier et al., 2019) [UC Berkeley, E3]

Study year: 2030-2050

Time increments: 37 weather days (888 hours) in CEM

Geographic region: California

Offshore wind region: California coast (Diablo Canyon Call Area, Morro Bay Call Area, Humboldt Call Area)

Offshore wind integration level: 1-20 GW

Transmission options considered: N/A

Interconnection points considered: N/A

Analysis conducted:

- Identified zones for potential offshore wind development.
- Curated hourly wind speed data and simulated hourly power generation from the future wind turbines.
- High-level transmission screening to quantify the offshore wind capacity from each zone that could be interconnected with the grid without triggering the need for costly onshore transmission upgrades.
- Modeled the cost competitiveness of the newly defined offshore wind resources in terms of resource savings and cost savings.

Tools used:

- Capacity expansion model, RESOLVE

Summary of findings:

Found five wind resource zones totaling 21 GW of potential generation (25percent of the state's energy needs).

- Study does not include a detailed analysis of transmission expansion or contingencies. Transmission constraints are assumed rather than modeled.
- Assumes transmission capacities are 668 MW for Morro Bay, 3,933 MW for Diablo Canyon, and minimal for Humboldt Bay, Cape Mendocino, and Del Norte.
- Avoided costs from offshore wind are expected to increase over time.
- Offshore wind's avoided costs would not significantly diminish at increased scale.
- Offshore wind's value would differ slightly among the studied zones; Morro Bay appears to be the most economically viable zone for future development.
- Offshore wind would offer additional economic upside if future land-use for solar were constrained by environmental protections or if the state aimed to achieve its GHG goals at an accelerated pace.
- Offshore wind would retain significant value, even if alternative out-of-state wind resources were developed or solar and storage costs fell faster than expected.

[CA2] California North Coast Offshore Wind Study - Interconnection Feasibility Study Report

Published: September 2020, by PG&E (Pacific Gas and Electric Company, 2020) [Schatz Energy Research Center]

Study year: 2029

Time increments: Power flow analysis under heavy summer peak and spring off peak scenarios

Geographic region: Northern California

Offshore wind region: Humboldt WEA

Offshore wind integration level:

- 48 MW (4, 12-MW turbines)
- 144 MW (12, 12-MW turbines)
- 1836 MW (153, 12-MW turbines)

Transmission options considered: HVAC and subsea HVDC

Interconnection points considered:

- 48 and 144 MW options assume interconnection at the Humboldt Bay 115 kV substation.
- 1836 MW option to be interconnected at a new 500 kV substation by Humboldt Bay by building a 500 kV line to a substation at Round Mountain, Vaca Dixon, or a new substation in the San Francisco Bay Area.

Analysis conducted: Power flow modeling to assess three different offshore wind unit options and identify:

- Transmission system impacts caused by the potential turbines/lines.
- System reinforcements needed to handle the impacts under various system conditions.
- Facilities required for system reinforcements with a non-binding good faith estimate of cost of responsibility.

Tools used:

- Scenario-Based Power Flow Modeling using PSLF Software
- 2020 PG&E Proposed Generator Interconnection Unit Cost Guide.

Summary of findings:

- 48 MW option—Thermal overloads. Need new 115 kV lines from Humboldt to Cottonwood to support full output. Potential upgrades cost between $365M and $730M.
- 144 MW option—Thermal overloads. Need additional upgrades to add new 115 kV lines from Humboldt to Bridgeville. Potential upgrades cost between $669M and $1.34B.
- 1,836 MW option—Identified three alternative configurations. 1) new 500 kV line from Humboldt Bay to Round Mountain costs $1.4B to $2.4B, 2) new 500 kV line from Humboldt Bay to Vaca-Dixon costs $1.4B to $2.4B, and 3) subsea HVDC transmission to new Bay Area substation costs $3.5B to $5.8B.

[CA3] Transmission Alternatives for California North Coast Offshore Wind

Published: March 2022, by Daneshoopy and Anilkumar (Daneshopy & Anilkumar, 2022) [Schatz Energy Research Center]

Study year: 2030 summer and winter peak conditions from PG&E in Humboldt Region for power flow; 2030 ISO Planning Base Case for production cost.

Time increments: N/A

Geographic region: Northern California

Offshore wind region: Humboldt WEA

Offshore wind integration level: 144, 168, 288, 480 MW + 15 MW Li-ion battery storage

Transmission options considered: HVAC

Interconnection points considered: 115-kV lines run east from Humboldt Substation, which is connected by either:

- Submarine cable landing through south split and under Humboldt Bay to Humboldt Bay substation, and then through a 115 kV line to Humboldt Substation.
- Submarine cable landing on north spit and overhead around Arcata Bay through a 115 kV line to Humboldt substation.

Analysis conducted: Identify options for developing offshore wind within the bounds of the existing regional transmission infrastructure and assess the associated economics.

Tools used:

- CA20 dataset for wind resource
- Power Flow Modeling (software tool not disclosed in report)
- Production cost model, GridView
- Offshore Regional Cost Analyzer (OR/CA) for turbine procurement/O&M/financing
- Offshore Renewables Balance-of-System and Installation Tool for procurement costs of additional offshore wind equipment and installation costs.

Summary of findings:

- Existing transmission limited to 174 MW for energy-only offshore wind interconnection (231 MW with higher load growth); capacity limited to 30 MW of offshore wind for full-deliverability without upgrades.
- Upgrades to Humboldt-Bridgeville 115 kV and Humboldt-Trinity 115 kV are the most critical constraints to offshore wind interconnection.
- 480 MW requires major expansion to 500 kV plus consideration of Path 66 interactions.
- Addition of a 15 MW, 60 MWh battery storage system "did not significantly reduce plant curtailment due to its relatively small size, but it helped increase plant revenues by participation in arbitrage and ancillary service markets."
- Interactions between HBGS and offshore wind must be considered. "Due to the resource adequacy contracts at Humboldt and their reliability must-run status, output from HBGS [Humboldt Bay Generating Station] minimizes the available transmission capacity on the existing network. Their operation as the must-run units for reliability purposes influences the curtailment trends at the OSW [offshore wind] sites."
- Most favorable size for an initial Energy Only project on the order of 140 to 150 MW.
- Upgrades for 144 / 288 / 480 MW full deliverability cost up to $238M / $329M / $1.04B.

[CA4] SB 100 Joint Agency Report: Charting a Path to a 100% Clean Energy Future

Published: March 2021, by Gill et al. (Gill et al., 2021) [CEC]

Study year: 2045

Time increments: 37 weather days (888 hours) in CEM

Geographic region: California

Offshore wind region: California coast

Offshore wind integration level: 0-10 GW

Transmission options considered: N/A

Interconnection points considered: N/A

Analysis conducted:

- Identifies pathways to support California SB 100 policy to provide 100 percent clean energy in California by 2045.
- Provides an initial assessment of costs and benefits.
- Projects future generation and transmission through capacity expansion modeling.

Tools used:

- Capacity expansion model, RESOLVE

Summary of findings:

- When offshore wind is allowed as an option, it is capped at 10 GW statewide capacity.
- In all scenarios, offshore wind is selected as a low-cost resource.
- 170 GW of new renewable are needed to meet resource adequacy.
- Transmission expansion is assumed and included as a fixed cost.
- Location, capacity, and type of transmission upgrades are not provided as results from this analysis.
- Recommends further analysis and actions by the joint agencies.

[CA5] CAISO 2021 – 2022 Transmission Plan

Published: March 2022, by CAISO (CAISO, 2022a)

Study year: 2030

Time increments: One year, 8760 hours in PCM

Geographic region: California

Offshore wind region: Humboldt Call Area, Morro Bay Call Area, Diablo Canyon Call Area, plus future hypothetical offshore wind areas in northern California.

Offshore wind integration level: 8,350 MW, including north coast – Humboldt Bay (1,607 MW), and central coast – Diablo Canyon (4,419 MW), Morro Bay (2,324 MW). Plus future outlook scenario with Del Norte (6,605 MW) and Cape Mendocino (6,216 MW)

Transmission options considered: HVAC and HVDC

Interconnection points considered:

- Humboldt Bay: a) 500-kV AC connection to the new Fern Road substation and a new 500-kV line from Fern Road to the Tesla substation, b) subsea voltage source converter (VSC)-HVDC connection to a new Bay Hub substation with three connections to load centers in the Bay area, c) LCC-HVDC connection to the Collinsville substation.
- Diablo and Morro Bay: Diablo offshore wind connection to the Diablo 500 kV substation, and Morro Bay offshore wind to a new Morro Bay 500 kV substation.

Analysis conducted: Transmission contingency analysis and a peak and off-peak deliverability assessment with 8 GW and 26 GW of offshore wind for capacity expansion modeling.

Tools used:

- Production cost model, GridView
- AC power flow model, PSLF

Summary of findings:

- The Morro Bay substation needs to loop into the Diablo-Gates 500 kV line to increase capacity for offshore wind interconnection. The Morro Bay substation would need to be 500 kV.
- A major transmission upgrade is required in northern California. An AC option and a VSC-HVDC option are presented for near term 1.6 GW (Humboldt Call Area), and a combination approach is proposed for 14 GW (outlook of northern California) that would include HVAC, LCC-HVDC, and VSC-HVDC.
- Production cost model results can achieve an 8 percent curtailment in central California and 3 percent curtailment in Humboldt when connecting through the new Fern Road 500 kV substation.
- Congestion on California-Oregon Intertie occurs during spring months when flow is from south to north. Humboldt offshore wind aggravates congestion on Vaca Dixon-Tesla 500 kV when injecting power to Fern Road. This congestion is least impacted by the Bay Hub interconnection.

[CA6] CAISO 20-year Transmission Outlook

Published: May 2022, by CAISO (CAISO, 2022b)

Study year: 2040

Time increments: N/A

Geographic region: California

Offshore wind region: Diablo and Morro Bay call areas (6,000 MW) and Humboldt Call Area/hypothetical Del Norte area/hypothetical Cape Mendocino area (4,000 MW).

Offshore wind integration level: 10 GW

Transmission options considered: HVAC and HVDC

Interconnection points considered: (a) central coast – Diablo 500 kV substation, Morro Bay 500 kV substation looping in the existing Diablo-Gates 500 kV line, (b) north coast – 500 kV AC lines connected to Fern Road substation and HVDC line to the Collinsville 500/230 kV substation.

Analysis conducted: Exploration of the longer-term grid requirements and options for meeting California's GHG reduction and renewable energy objectives. Conducted transmission contingency analysis.

Tools used:

- Tools not specified

Summary of findings:

- Connect 6,000 MW of offshore wind in central California with: 3 GW to Diablo 500 kV and 3 GW to new Morro Bay 500 kV (loop into existing Diablo-Gates 500 kV line).
- Connect 4,000 MW of offshore wind in California by: two 500 kV AC lines to Fern Road 500 kV substation and a HVDC line to Collinsville 500/230 kV sub (either land or subsea) – or alternately a HVDC subsea cable to the Bay-hub station.
- The development of offshore wind 500 kV lines in northern California will increase the transfer capacity between CA and the PNW through a new strong point at Fern Road, which will require coordination with offshore wind development in the PNW.

[OR1] Exploring the Grid Value of Offshore Wind Energy in Oregon

Presentations: BOEM Webinar, 6/17/2020: https://www.boem.gov/sites/default/files/documents/regions/pacific-ocs-region/BOEM-2020-026-Presentation.pdf

Published: May 2020, by Douville et al. (Douville et al., 2020) [PNNL]

Study year: 2028

Time increments: One year, 8760 hours in PCM

Geographic region: Oregon

Offshore wind region: Port Orford, Reedsport, Newport, and Astoria

Offshore wind integration level: 0-5 GW

Transmission options considered: HVAC (land-based study only)

Interconnection points considered: Four 230 kV BPA transmission substations: Rogue, Tahkenitch, Toledo, and Clatsop

Analysis conducted: Using six years of sub-hourly offshore windspeeds and the WECC 2028 Anchor Data Set (ADS) production cost model, quantifies:

- complementarity of offshore wind with other emerging forms of variable renewable energy power generation,
- complementarity of offshore wind with system needs as represented through load profiles and peak load periods, and
- impacts to coastal and regional power flows.

The study did not include contingency analysis that would be required to interconnect generation, according to North American Electric Reliability Corporation (NERC) Reliability Standards.

Tools used:

- Production cost model, GridView 2028 ADS
- Modeled sub-hourly wind power production using technoeconomic WIND Toolkit

Summary of findings:

- The existing Oregon transmission system is shown to accommodate 2-3 GW of offshore wind without significant infrastructure investment or power export from Oregon.
- Offshore wind energy would relieve historic east-to-west transmission flows, serve coastal loads, and free transmission for additional inland generation east of load centers.
- Offshore wind resource has greater complementarity to load than terrestrial wind resources in the region and could complement increasingly constrained hydropower resources.

[OR2] Evaluating the Grid Impact of Oregon Offshore Wind

Published: October 2021, by Novacheck and Schwartz (Novacheck & Schwartz, 2021) [NREL]

Study year: Current (2024) and Future (2036)

Time increments: One year, 8,760 hours[15] in PCM; 17 time slices[16] in CEM

Geographic region: Oregon

Offshore wind region: Five offshore wind sites located in North, North Central, Central, South Central, and South of Oregon

Offshore wind integration level: Three scenarios: base (0 GW), mid (2.6 GW), or high (5 GW)

Transmission options considered: HVAC (land-based study only)

Interconnection points considered: Clatsop, Tillamook, Toledo, Wendson, and Fairview

Analysis conducted: Using high resolution data sets, including seven meteorological years, capacity expansion projections, and production cost models, we quantified the value of offshore wind integration into Oregon's power system and investigated transmission flow impacts. The study did not include the contingency analysis that would be required to interconnect generation, according to NERC Reliability Standards.

Tools used:

- Capacity expansion model, Regional Energy Deployment System
- Production cost model, PLEXOS
- Modeled wind speed data using CA20 dataset

Summary of findings:

- Approximately 2.6 GW of installed offshore wind may be integrated without major upgrades to trans-coastal transmission. The 2.6 GW was distributed as follows across the POIs: Clatsop (361 MW), Tillamook (553 MW), Toledo (156 MW), Wendson (613 MW), and Fairview (941 MW).
- Without upgrades to the trans-coastal transmission system, storage co-located with offshore wind POIs can relieve curtailment by about 15 percent in a 5 GW scenario. Storage is sized to be 10 percent of the offshore wind capacity (i.e., 100 MW for every 1 GW installed) and assumed to have a 24-hour storage duration.
- Ranges of system value of offshore wind exceed 2032 projections of cost of energy.
- Results suggest that offshore wind may not be a good substitute for cross-Cascade transmission that brings power from resources on the east side of the Cascade Mountain range to load centers on the western side of the range due to the low correlation of offshore wind production with peak power flows.

[15] Though time increments were hourly and considered all hours over a year, seven distinct meteorological years were considered in this analysis.
[16] Time slices modeled in Renewable Energy Deployment System. See: https://www.nrel.gov/docs/fy21osti/78195.pdf

[OR3] BPA 2022 Transmission Service Request Study and Expansion Process Cluster Study

Published: July 19, 2022, by BPA (BPA, 2022)[17]

Study year: 2027 and 2031

Time increments: Peak 2027 and 2031 Heavy Summer Cases. Eight different scenarios: a) summer sunset hour with no wind, b) summer sunset hour with wind, c) summer off-peak hour with extra light load and no renewables, d) summer peak hour with no wind, e) summer peak hour with high renewables, f) spring night hour with runoff and northwest wind off and Montana wind on, g) winter mid-day hour with high renewables, and h) winter peak hour with wind only.

Geographic region: Oregon

Offshore wind region: Southern Oregon coast

Offshore wind integration level: 2,200 MW

Transmission options considered: HVAC

Interconnection points considered: Fairview 230 kV, Fairview-Rogue 230 kV (Port Orford), Rogue 115/230 kV.

Analysis conducted: Annual transmission service request and expansion process studies. Full contingency analysis per NERC TPL-001-4 Transmission Planning Standard.

Tools used: Not specified.

Summary of findings:

- The study evaluated transmission capabilities of 600 MW from Fairview and 1600 MW from Rogue to serve Portland loads.
- New 500 kV substations are required at Rogue and Fairview.
- New 65-mile double circuit 500 kV line is required from Rogue to Fairview.
- New 120-mile single-circuit 500-kV line is required from Fairview to Lane.
- New 97-mile single-circuit 500-kV line is required from Fairview to Alvey.
- Total transmission expansion equates to 262 circuit miles of 500 kV lines.
- Cost estimate is approximately $904M.

[17] BPA (2022). Transmission Service Request Study and Expansion Process: 2022 Cluster Study Report. BPA-TS TPP 2022-094. https://www.bpa.gov/about/newsroom/news-articles/2022/20220804-over-11-gw-studied-in-2022-cluster-study-almost-doubling-the-2021-reques

[OR4] PacifiCorp 2023 Integrated Resource Plan

Presentations: 2023 Integrated Resource Plan IRP Public-Input Meeting, September 1-2, 2022; https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/IRP_PIM_Sept%201-2_2022.pdf

Published: September 2022, by PacifiCorp (PacifiCorp, 2022)

Study year: 2032

Time increments: Peak

Geographic region: Oregon

Offshore wind region: Southern Oregon and Northern California

Offshore wind integration level: 1.0 & 3.5 GW

Transmission options considered: HVAC (land-based study only)

Interconnection points considered: Coos Bay

Analysis conducted:

- Power Flow, 2032 Heavy Summer WECC based case
- N-1 and N-2 contingencies
- Identification of transmission requirements to deliver offshore wind to PacifiCorp's existing and prospective load centers at various generation levels
- Route is Coos Bay – Dixonville – Chiloquin North (Whispering Pines) – Ponderosa

Tools used: Power Flow Analysis software not specified

Results:

- 500 kV upgrades are required to deliver offshore wind to central Oregon.
- Offshore wind could be interconnected in Coos Bay, transmitted across the Coast Range, then across the Cascade Range, and then north to central Oregon.
- Two transmission options could be available by 2032:
    - Incremental transmission for 1000 MW costs $947M
    - Incremental transmission for 3500 MW costs $1.115B

[OR5] NorthernGrid Southern Oregon Offshore Wind Economic Study

Published: In-work, by NorthernGrid (NorthernGrid, 2022)

Study year: 2032

Time increments: Peak and one year, 8,760 hours in PCM

Geographic region: Oregon

Offshore wind region: Coos Bay and Brookings

Offshore wind integration level: 3 GW

Transmission options considered: HVAC (land-based study only)

Interconnection points considered: Fairview (1,800 MW) and Wendson (1,200 MW)

Analysis conducted: TBD. Planned scope is as follows:

- Steady-State reliability:
    - Starts with Power Flow Analysis of the 2032 Heavy Summer WECC base case
    - Incorporates loading, generation, and transmission submitted into the 2022-2023 NorthernGrid Planning Cycle
    - Develops a northbound and southbound base case
    - Adds 3.0 GW of offshore wind power flows injected in southern Oregon
    - Conducts post-transient contingency analysis with four cases: northbound without offshore wind, northbound with offshore wind, southbound without offshore wind, and southbound with offshore wind
- Production cost modeling:
    - Starts with 2032 ADS
    - Incorporates loading, generation, and transmission submitted into the 2022-2023 NorthernGrid Planning Cycle
    - Adds southern Oregon offshore wind with the transmission solution for reliability developed above
    - Runs economic dispatch simulations of Western Interconnection

Tools used:

- Production Cost Model, Grid View 2032 ADS + modifications
- Power Flow Modeling, PowerWorld

Preliminary results/objectives:

- The report will identify the maximum reliable output for each POI before network upgrades are needed.
- A transmission solution needed for steady-state reliability will be developed.
- Economic impacts will be summed from net cost estimates of the transmission solution and the Production Cost Model outputs.

[OR/CA1] Offshore Wind Energy Development Strategy to Maximize Electricity System Benefits in Southern Oregon and Northern California

Published: In-work, by PNNL/Hitachi Energy/POET (NOWRDC, 2022)

Study year: 2030, 2030+

Time increments: Peak and one year, 8,760 hours in PCM

Geographic region: Oregon and California

Offshore wind region: Southern Oregon and Northern California

Offshore wind integration level: 3.5 GW, TBD GW

Transmission options considered: HVAC and HVDC

Interconnection points considered: TBD

Analysis conducted: Technoeconomic valuation of offshore wind through dispatch and power flow simulations of three generation and transmission scenarios that span two future representations of the WECC.

Tools used:

- Production cost model, GridView using 2030 ADS + custom base cases
- Grid Reserve and Flexibility Planning Tool (GRAF-Plan)
- Chronological Alternating Current Power Flow Automated Generation
- Frequency Response Analysis Tool
- Power Flow Modeling, PowerWorld
- Power Flow Modeling, PSLF

Preliminary results/objectives:

- System valuation methodology composed and documented
- 3.5 GW southern Oregon offshore wind to be added to ADS 2030
- Generation footprints optimized for energy and capacity value
- Base case modified to include additional decarbonization of electricity sector
- Additional POIs in the PNW and California identified for additional offshore wind scenarios.

[OR/CA2] Northern California & Southern Oregon Mission Compatibility and Transmission Infrastructure Assessment Project

Published: In-work, by Schatz Energy Research Center (CEC, 2022)

Study year: TBD

Time increments: TBD

Geographic region: Southern Oregon and Northern California

Offshore wind region: TBD in Southern Oregon and Northern California

Offshore wind integration level: Capacity TBD; three scenarios from low end (to meet California/Oregon goals), medium (regional goals), and high end (WECC goals)

Transmission options considered: TBD

Interconnection points considered: TBD

Analysis conducted: Geospatial and infrastructure expansion analysis for existing electricity infrastructure is needed to support the transition to a diversified power generation portfolio compatible with the U.S. Department of Defense mission. Analysis will be conducted using production cost modeling and transmission contingency analysis.

Tools used:

- Tools to be determined

Preliminary results/objectives: This study, which is underway, will first map existing energy infrastructure, including spatial generation and transmission footprints, transmission capacity, and expandability. The project will then develop infrastructure scenarios to accommodate a range of offshore wind generation that quantifies transmission needs and costs.

Appendix C – Policies, Markets, and Transmission in the West

The development of west coast offshore wind will be influenced by the specific elements of western state policies, markets, and transmission systems. In particular, the resource and transmission markets of the west coast states will determine the potential for offtake contracts and transmission solutions. These dynamics are different from those found on the East Coast, from the Northeast to the Mid-Atlantic, where offshore wind projects are currently under active development. Here we briefly review the intertwined resources, transmission, and markets in the West with an emphasis on the pacific coast states.

Context in the West

The Western Interconnection ranges from the West Coast to the Rocky Mountain states and from north of the Canadian border to south of California and into Mexico. It is comprised of approximately 136,000 miles of transmission lines through all or part of 14 states (NWPCC, 2021 Power Plan supporting materials, 2021). The western United States has numerous major load centers spread out over hundreds of thousands of square miles, and the transmission system is designed to connect those load centers with often remote sources of generation.

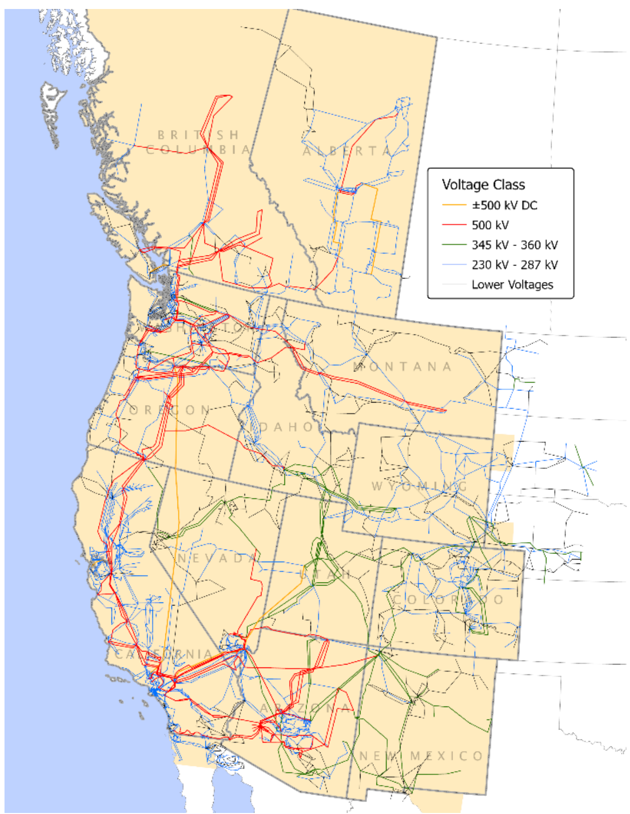

Figure C.1. WECC Interconnection Map

Within the large area of the Western Interconnection, there are multiple transmission operators rather than a single entity like a RTO or an ISO. Instead, there is a patchwork of BA that are responsible for maintaining load and resource balance within their geographic area and for coordinating with neighboring BAs. There are 38 BA areas in the Western Interconnect, which include utilities, BPA, and CAISO. The BAs work independently to balance the loads and resources while maintaining a consistent electric frequency within their transmission control area (NERC Reference Document, 2021). Reliability standards are set by NERC and enforced through the WECC. For the most part, these entities operate separately, but can coordinate on reserve sharing and transmission expansion.

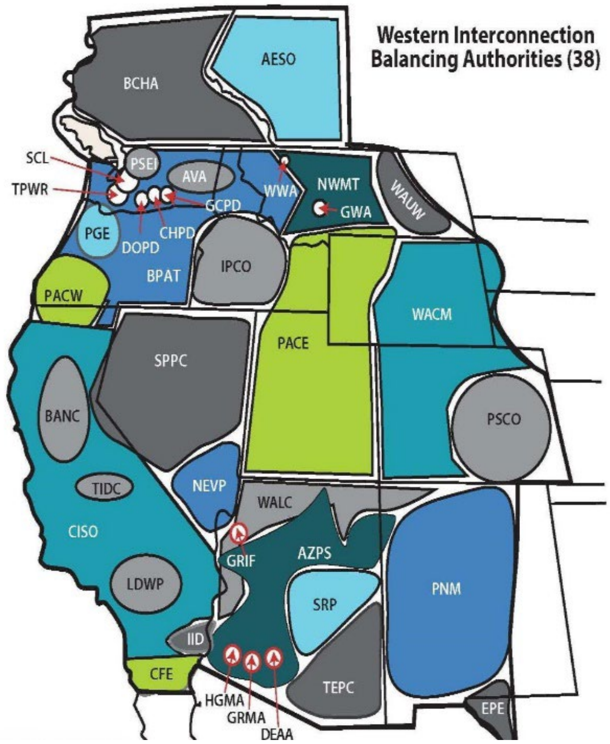

Figure C.2. Balancing Authorities in the West. Full names of Balancing Authorities are also defined by WECC.

There are 17 BA areas in the three West Coast states, and many of the functions performed by RTOs along the East Coast are conducted by individual utilities in the West (outside of CAISO). In the West, there is a wide arrangement of utility types, including IOU and COU (municipal utilities, public utility districts, and cooperatives). In general, the IOUs are still vertically integrated, owning distribution, transmission, and generation assets. The IOUs are regulated by state commissions operating under state laws that may be similar but are not the same. The IOUs are generally responsible for serving load within their service territories, which means planning for, funding, and building generation and transmission assets. COUs are overseen by locally elected boards and do not fall under the general jurisdiction of state regulatory commissions, except occasionally regarding safety practices. COUs may have statutory preferential rights to power marketed by the federal Power Marketing Administration (PMA) and may engage in resource acquisition on their own or through COU cooperatives.

There are two PMAs in the West whose territories span all states in the Western Interconnect. BPA operates in the Northwest states (Washington, Oregon, Idaho, and western Montana), and the Western Area Power Administration serves 15 other western states. The two PMAs operate under different sets of federal statutes, but in general, they own and operate thousands of miles of transmission assets and market the output of federal hydroelectric facilities and other related generation assets.

Resource Supply and Planning

Given the connected nature of the acquisition of energy and capacity resources with the operation of the transmission system and how both resources and transmission are planned for differently on the West and East coasts, a review of resource planning and ownership in the West may be helpful.

Pacific Northwest

In the PNW, as in much of the West, the bulk of the buying and selling of electricity occurs through bilateral transactions between utilities, marketers, and generators. The six Northwest IOUs are rate-regulated, vertically integrated utilities owning distribution, generation, and transmission assets. They are responsible for serving load within their service territory, which entails planning all aspects of service and building generation and transmission if needed. In general, these utilities will first serve their own load with owned generation or purchased power and may sell surplus power to the market. Each one of the IOUs has its own BA area. Depending on state statute and regulatory approval, some large customers may discontinue energy services from the IOU and purchase energy services from a third-party electricity service supplier.

IOUs, as directed by their regulators, will engage in integrated resource planning that examines load needs over a 20-year period and explores the timing, amount, and type of demand and supply side resources needed to serve that load (Oregon Dept. of Energy, RTO Study, 2021). Generally, each IOU will then engage in a resource acquisition process that ends with a rate case that seeks recovery of capital costs associated with an owned generation resource. IOUs in the Northwest are responsible for the determination of the amount and types of generating resources, including potentially offshore wind. Transmission that may be associated with new generation, including potentially offshore wind, would also be considered in an IRP, and the capital costs would be recovered through a rate case. The IOUs do not act in concert with each other either in the timing or type of generating resource acquisitions.

There are more than 150 COUs and tribal utilities in the four Northwest states. COUs tend to be smaller than IOUs, but there are exceptions, including Seattle City Light. COUs can own generation and buy and sell power in the market, but COUs have preferential access to the output of the FCRPS in the PNW, marketed by BPA under federal statute. As preference customers, many COUs rely fully on BPA to serve their loads and manage transmission issues. These COUs are locally managed by boards and are not subject to state rate regulation.

BPA is the federal Power Marketing Administration in the Northwest. It markets the output of the FCRPS, which includes dams owned by the U.S. Army Corps of Engineers and the Bureau of Reclamation (within the U.S. Department of the Interior) and includes one nuclear facility, the Columbia Generating Station. A series of federal statutes creates preference rights for COUs for the output of the federal system and creates regional rights to the output by putting limitations on out-of-region sales. While some COUs may engage in resource planning individually, high-level planning for the BPA supply system occurs through the Northwest Power Planning and Conservation Council. This Council is an interstate compact created by the Northwest Power Act in 1980 that conducts a regionwide planning process for demand-side, energy, and capacity needs and the role BPA should play in meeting those needs.

Load-serving entities and BPA engage in bilateral power transactions, with the Mid-Columbia trading hub setting daily and forecast power prices. Over the last several years, a number of utilities and BPA have also joined CAISO's EIM, which is described below, as an optional augment to regional bilateral trading.

California

IOUs, COUs, electricity service providers, and community choice aggregators (CCA) provide energy services to customers in California. The state's IOUs and COUs continue to provide a distribution system and other billing services. CCA programs allow local governments to procure energy for their residents while still receiving distribution and transmission services from the local utility. California is also home to the CAISO, which manages transmission planning and operations as well as providing market services.

The CPUC regulates the IOUs and some aspects of their role with the CCAs. CCA programs allow local governments to procure power on behalf of their residents. COUs and CCAs are locally managed. IOUs and some COUs own the distribution system, some transmission assets, and some generating assets.

California SB 350 (2015) requires large utilities to develop IRPs that describe how the utility will meet customer needs, reduce GHG emissions, and increase the use of clean energy. In 2022, the CPUC approved 20 IRPs of load serving entities under its purview (IOUs, Electric Service Providers, CCAs, and a few cooperatives) and adopted a Preferred System Plan that is, in part, an aggregation of the IRPs and acts as a signal to the load serving entities and to CAISO concerning the loads, the type and amount of renewable resources to be acquired over the next decade, including offshore wind, and the potential need for transmission upgrades (CPUC 2021 Preferred System Plan, adopted 2022).

The COUs are not subject to the CPUC order, but some of the larger COUs must submit their own IRP. For example, the Los Angeles Department of Water and Power has produced a Power Strategic Long-Term Resource Plan to guide demand side and supply side investments.

CAISO is the only ISO in the West, and as part of that management, it operates real-time and day-ahead markets. Associated with CAISO is the Western EIM, in which participants, including those outside of California, can buy and sell power to meet demand not contemplated in their day-ahead schedules. The EIM balances supply and demand and accounts for congestion on the transmission system, which results in greater efficiencies, lower cost, and GHG emission reductions. To date, participants located throughout the West include IOUs, COUs, BPA, and Powerex in Canada. CAISO and many parties in the West are developing an Extended Day-Ahead Market (EDAM) which would extend participation in CAISO's day-ahead market to EIM participants (CAISO, EDAM design, 2020). This would allow participants to participate in the day-ahead market activity without requiring full integration into the CAISO.

Transmission Service, Planning, and Investment

Northwest

Federal Energy Regulatory Commission (FERC) Order 888 requires all FERC-regulated transmission providers that own, operate, or control interstate transmission to offer transmission to eligible customers on the same terms and conditions as their own use, functionally separate transmission and power functions, and maintain an Open Access Transmission Tariff that sets out rates and terms and conditions for service. The intent of FERC Order 888 was to promote competition and ensure open access to the nation's transmission grid on a non-preferential basis.

In jurisdictions without an RTO or ISO, buyers and sellers of energy and capacity must separately reserve transmission rights in advance of the transaction through transmission contracts. Generally, owners of generation seek to have long-term, firm transmission rights associated with the sale of the output of owned generation. A long-term, firm transmission right reserves a certain capacity on a transmission segment between two points at all times. However, power sales can be associated with non-firm transmission rights, which indicates that power delivery may be curtailed or interrupted based on other transmission system needs. In these cases, transmission system pathways may be thought of in terms of both physical and contractual rights limitations. Long-term firm contracts are in effect whether or not there is contracted-for power flowing on that pathway. If there is available transmission capacity for a limited period of time, transmission providers are required to market that product in real-time per FERC Order 889.

Transmission associated with power sales that cross more than one BA area may be subject to multiple layers of transmission charges called pancaking. This results in an accumulation of transmission charges for services that use the transmission facilities of multiple transmission providers.

As previously discussed, in the PNW, BPA owns and operates the majority of the region's transmission system. Much of BPA's capacity is committed via legacy long-term firm contracts. A new resource will have to both go through an interconnection request and secure a corresponding transmission along a particular path. With limited availability of long-term firm capacity, it must be determined whether transmission service requests will require new system investments. Long-term transmission requests from generators will be placed in a queue according to the timing of the request and then analyzed in a cluster of similar requests to determine whether the request can be served or if additional system investment must be made to serve the request. A position in the queue or inclusion in a cluster study does not mean a particular generation project will be completed, which creates ongoing uncertainty in the transmission service analysis.

Generally speaking, utilities and load-serving entities outside of CAISO must plan for and acquire transmission assets in the same way that they would plan for and acquire generation or distribution assets to serve load. Vertically integrated IOUs will include transmission upgrades or new transmission line segments in their integrated resource planning filings with state regulators as part of the plan to serve their core customers over the next 10 or 20 years. Approval by state regulators of the utility's planning and cost recovery for transmission assets can be complicated by state requirements that an asset must be a benefit to the customer in that state. Transmission assets are expensive, and limiting the accounting of benefits to the utility's customer may discount benefits to customers in other utility service territories or customers in other states. In addition to the financing and cost recovery elements, transmission assets must go through a state facility siting proceeding via a public process.

Utilities may agree to joint ownership of a new transmission line. The 290-mile long, 500 kV Boardman to Hemingway is an example of joint ownership between PacifiCorp and Idaho Power. While this would spread costs across customers of two utilities and allow for the determination of a wider customer benefit, it also means that the transmission line must be considered in IRPs spanning two utilities and several states.

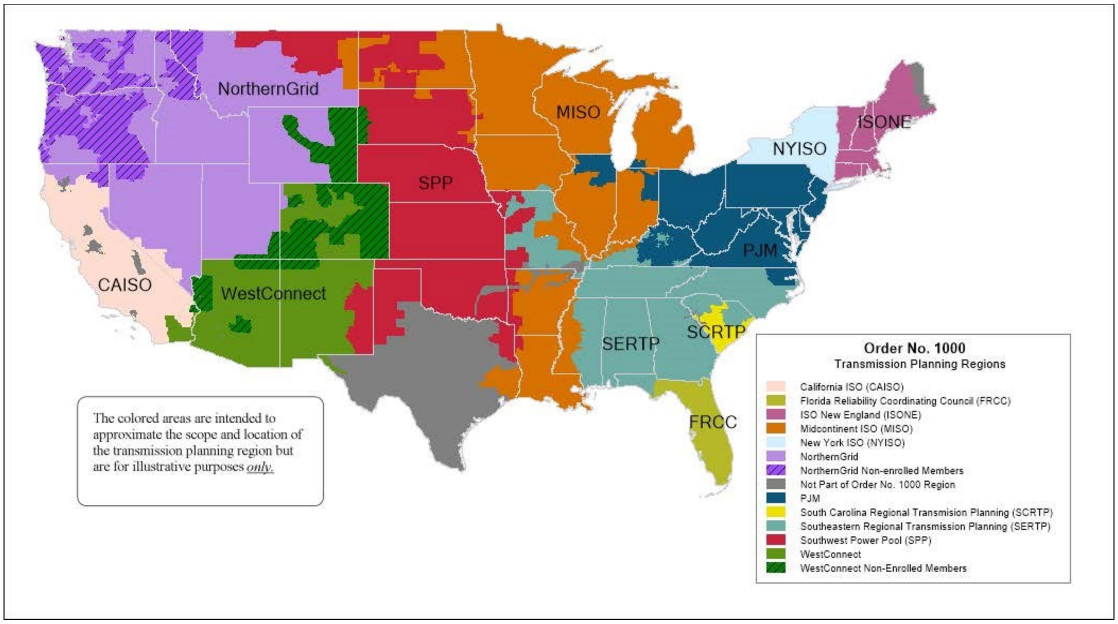

Figure C.3. FERC Order 1000 Transmission Planning Regions

In the Northwest, NorthernGrid is a collaboration of regional transmission providers created to facilitate regional transmission planning. The value of regional collaboration is to employ a common set of data, jointly identify regional transmission projects through a single forum, and avoid duplicative administrative processes (NorthernGrid, 2022). NorthernGrid fulfills the FERC Order 1000 direction to engage in regional transmission planning and to improve coordination with neighboring regional transmission processes. WestConnect is a regional planning organization that serves the same purpose in areas of the West not included in NorthernGrid or CAISO.

While NorthernGrid serves a convening and analytical role and creates valuable insight for all stakeholders, it has no decision-making authority. Transmission providers, including BPA and IOUs, still must define and construct transmission projects and concern themselves with cost recovery.

California

CAISO manages the flow of electricity for about 80 percent of California. CAISO's wholesale day-ahead and real-time energy market platform economically dispatches supply offered into these markets. CAISO does not provide for the reservation of transmission; rather, the market optimizes available transmission. This is in contrast to bilateral markets, where transmission rights must be reserved to accompany energy and capacity sales.

Many of the large utilities in California have become participating transmission owners in CAISO. These utility owners continue to own the transmission assets but have turned over operational control to CAISO. The utilities are compensated on a just and reasonable basis from the revenues collected by CAISO through access charges paid by users of the transmission system operated by CAISO.

As an ISO, CAISO is responsible for planning transmission within its footprint. Distinct from the utility-by-utility bottom-up approach in bilateral markets, CAISO transmission planning and acquisition is more of a top-down approach. The CAISO produces a transmission plan that identifies needed transmission solutions and leads to cost recovery via regulatory approval. The plan analyzes needed transmission based on reliability needs, public policy direction[18], and economic needs (CAISO Transmission Plan, 2022).

First, CAISO will work with the CPUC and its Preferred System Plan, which signals to the load serving entities and to CAISO the forecasted loads, the type and amount of needed generation, and the potential need for transmission upgrades. CAISO is also informed by energy plans produced by the CEC, including specific plans such as that for offshore wind. Based on these and other inputs, CAISO develops assumptions and models for use in the planning studies. Then CAISO performs technical studies, holds stakeholder meetings, and develops the Transmission Plan. Finally, if necessary, CAISO creates a competitive solicitation for developers to build and own new regional transmission facilities of a certain threshold size.

In addition, CAISO conducts coordination with its neighboring Western Planning Regions (NorthwestGrid and WestConnect) as directed by FERC Order 1000 (CAISO Transmission Plan, 2022). This coordination allows for a review of each region's planning process, the sharing of data and analysis, and the identification of potential interregional transmission solutions. The timing of planning and methods of each planning region are not necessarily aligned, so continued coordination is important.

Organized Markets in the West

The concept of an organized market, or markets, in the West has been a hot topic for many years. Many studies, including those sponsored by state collaboratives, have been conducted analyzing the cost efficiencies and GHG emission-reduction potential of an RTO or ISO (Energy Strategies, 2021; WEIB, 2019). Studies indicate that, with significant penetration of variable renewable energy resources and difficulties with building new transmission, an RTO with a more efficient economic dispatch, broader geographic inclusion of generating assets, and regional transmission planning could capture efficiencies in the electricity system.

BPA, regional utilities, state agencies, and public interest groups convened in 1995 in an effort to develop an independent grid operator, but agreement could not be reached among the parties. Following the issuance of FERC Order 2000 in 1999, the parties tried again, but their efforts failed once more. The arguments for and against RTO formation, particularly in the PNW, are complex. While there is a general acceptance of the position that RTO market coordination and transmission planning can produce significant efficiencies compared to bilateral markets, there has been concern that the benefits to the Northwest from public and regional preference for the FCRPS and legacy transmission contracts with BPA may be lost with an RTO (NWPCC Energy Topics, 2022). In addition to the calculation of gained versus lost energy benefits, there are administrative difficulties with an RTO operating federally owned transmission assets and dispatching federal hydropower assets. Furthermore, early discussion of RTO participation focused on CAISO expansion, but issues around expanded CAISO governance have been difficult to resolve.

This is not to say that the PNW or the West as a whole have been inactive on market reforms. Most PNW utilities are now participants in the Western EIM in conjunction with CAISO, including most recently BPA. Other utilities throughout the West have joined or will join the

[18] Public policy transmission solutions are those needed to enable the grid to support local, state, and federal policy directives.

Southwest Power Pool's Western Energy Imbalance Service Market. Conversations about the EDAM are progressing. In August 2022, the Western Resource Adequacy Program (WRAP) filed a tariff with FERC to become a regional resource adequacy program. Starting in the PNW, WRAP participants now include members in the Southwest, California, and Canada. WRAP will address resource adequacy by taking advantage of operating efficiencies, resource diversity, and the sharing of pooled resources among the broad footprints of its participants.

Conversations about western RTO market design also continue. Nevada and Colorado have passed legislation requiring their large utilities to join an RTO if feasible. A dozen utilities have come together to form the Western Markets Exploratory Group, which is intended to develop long-term solutions to improve market efficiencies in the West, including a western RTO. CAISO continues to engage western states to explore the expansion of that footprint outside the state of California. The Southwest Power Pool is engaging utilities across the West about expanding that RTO west from its Midwest footprint.

U.S. DEPARTMENT OF
ENERGY

Office of
ENERGY EFFICIENCY &
RENEWABLE ENERGY

For more information, visit:
energy.gov/eere/wind

DOE/EE-2690 • February 2023