BALANCING AUTHORITY OF NORTHERN CALIFORNIA

P.O. BOX 15830 • MS B305 • SACRAMENTO • CA 95852 -1830

August 22, 2024

Trends and Issues on Resource Adequacy and Next Steps for BANC Members

For Discussion Purposes

<u>Issue</u>

Growing loads, changing resource mix, behind-the-meter resource trends, and other factors are forcing an evolution of how Resource Adequacy (RA) is evaluated by policymakers. BANC is often approached by policymakers to explain how we ensure adequacy for our BAA footprint. Currently, we have a Summer Assessment to evaluate anticipated summer operations and potential restrictions. We also have a set of RA Guiding Principles, but nothing more binding. This is in contrast to the formal RA program that is a combination of CAISO and CPUC rules that are very granular and, in the case of the CPUC rules, contain stringent financial penalties for non-compliance. The CAISO rules contain backstop procurement and cost allocation mechanisms in certain instances.

For the majority of the rest of the load in the West, the Western Power Pool has stood up the Western Resource Adequacy Program (WRAP). While not yet binding, WRAP has a FERC-approved tariff that defines the obligations of “load responsible entities” and the terms and conditions of minimum Resource Adequacy requirements, transmission deliverability obligations, resource counting rules, pooling obligations, penalties for non-compliance, and related matters.

Meeting load expectations has been a growing concern throughout the West. WECC’s 2023 Resource Adequacy Assessment[1] shows growing gaps between resource additions and expected load growth. The Pacific Northwest Utilities Conference Committee has been even more specific for the Pacific Northwest, estimating an 11,000 MW gap between resources and loads by 2034 (*see* attachment).[2]

Recently, California has put a significant emphasis on new procurement, especially after the 2020 outages. In addition to directing certain immediate procurement by the IOUs, the CPUC ordered over 15,000 MW of procurement in its Mid-Term Reliability decisions.[3] A recently

[1] https://feature.wecc.org/soti/topic-sections/resources/index.html#group-section-Resource-Adequacy-Ca1PXoOLMx
[2] https://www.pnucc.org/wp-content/uploads/2024-PNUCC-Northwest-Regional-Forecast-final.pdf, p. 19
[3] *See* CPUC Decision (D.) 21-06-035 (ordering 11,500 MW of net qualifying capacity) and D.23-02-040 (ordering an additional 4,000 MW).

approved Decision recommended 10,600 MW of centrally procured resources, including enhanced geothermal, offshore wind, and long duration storage with solicitations commencing in 2026 and 2027.[4]

The CPUC Energy Division has also released a Loss of Load Expectation Study making an initial finding that its slice-of-day RA methodology will result in the need for an 18.5% Planning Reserve Margin for 2026.[5] However, Energy Division has also subsequently indicated that there are methodological errors in the study that they will be addressing which will likely result in a revision to the study results.[6]

Finally, through legislation, the CEC has been tasked with undertaking a number of examinations of public power procurement and RA practices. The CEC issued a reliability assessment earlier this year which examined POU procurement against a default methodology. Currently, the CEC has commenced a rulemaking that is developing a deficiency charge for POUs in the CAISO BAA if the POU has not met its own planning reserve margin standard and the state-funded reliability reserve is triggered to meet an operational event. Finally, the CEC was tasked under AB 1373 to examine POU planning reserve margins and RA practices as compared to those adopted by the CPUC. This exercise has not begun; it is also *not* limited to POUs in the CAISO BAA.

This procurement push, driven not only by clean energy goals, but also as a response to the grid stresses and outages over the last several years, has put additional emphasis and scrutiny on public power RA practices.

<u>Conclusion and Recommendation</u>

BANC members made a good beginning by developing the RA Guiding Principles. However, we are one of few entities that is not covered by a formal RA program, which creates risk. It is time to take the next step, especially as we contemplate participation in EDAM. While there will certainly be details in any RA program that will need to be developed to meet the characteristics and needs of BANC member loads and resources, it is time for BANC to be proactive and to develop RA policies for BANC that the members commit to and on which we would be able to make public facing showings to demonstrate adherence to program rules. While there are many details to work through, much of the issue area has been thoroughly developed. Also, we need not take steps as complex as WRAP or the CPUC. But, Staff and counsel recommend that BANC do more than what is currently in place. We anticipate that this effort would run through the Resources and Legal Committees, and would entail member efforts, as well as BANC staff and counsel, and possible assistance from an outside vendor. This is similar to the approach taken to develop the RA Guiding Principles, although we expect this effort to be more robust.

[4] *See* Proposed Decision Determining Need for Centralized Procurement of Long Lead-Time Resources Rev. 2 approved at the CPUC Voting Meeting on August 22, 2024, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M538/K554/538554732.pdf.

[5] *See* Email Ruling on Energy Division's Slice of Day Calibration Tool, served on the CPUC service list for R.23-10-011 on August 6, 2024, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M537/K135/537135544.PDF. The Ruling notes that the Slice of Day Planning Reserve Margin calibration tool used to convert the Loss of Load Expectation Study results into a recommend planning reserve margin requires revisions to correct several logic calculations. Energy Division expects to issue a revised calibration tool and transition of the Loss of Load Expectation Study result by the end of August, 2024.

[6] *See CPUC* Energy Division Loss of Load Expectation Study for 2026 Including Slice of Day Tool Analysis (recommending a Slice of Day Planning Reserve Margin of 18.5%), available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M536/K273/536273741.PDF

Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Firm Requirements										
Load [1/]	23,708	24,643	25,684	26,850	27,945	28,859	29,657	30,240	30,714	31,093
Exports	515	515	515	514	514	511	511	511	511	512
Total	24,223	25,158	26,199	27,365	28,460	29,370	30,167	30,750	31,225	31,605
Firm Resources										
Hydro [2/]	11,437	11,439	11,418	11,402	11,208	11,142	11,142	11,142	11,142	11,119
Small Thermal/Misc.	28	28	28	28	18	11	11	11	11	11
Natural Gas[3/]	5,117	5,321	5,361	5,361	5,361	5,534	5,653	5,656	5,653	5,653
Renewables-Other	289	298	298	296	295	295	292	284	275	276
Solar	443	483	502	503	505	506	506	498	484	480
Wind	1,772	1,791	1,771	1,714	1,682	1,657	1,642	1,642	1,639	1,640
Cogeneration	32	19	15	14	14	14	14	14	14	14
Imports	467	467	467	453	380	324	310	310	222	160
Nuclear	994	1,116	994	1,116	994	1,116	994	1,116	994	1,116
Coal	2,006	1,450	1,100	1,086	1,092	417	102	102	94	100
Total	22,584	22,412	21,956	21,973	21,550	21,016	20,666	20,776	20,529	20,569
Surplus (Deficit)	**(1,640)**	**(2,746)**	**(4,243)**	**(5,392)**	**(6,910)**	**(8,354)**	**(9,502)**	**(9,975)**	**(10,695)**	**(11,036)**

[1/] Load net of energy efficiency

[2/] Firm hydro for energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)

[3/] More energy may be available from natural gas power plants

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August 22, 2024

Transmission Developments and Consideration of Impacts and Opportunities on Northern CA Public Power/BANC

For Discussion Purposes

Issue

BANC is not a transmission service provider. However, our participation in markets as an EIM and contemplated EDAM Entity is affected by transmission issues in the market and the use of our participant TSP's transmission assets. Further, the resource plans and options of our members are greatly impacted by the availability of transmission both within the California footprint as well as in the West. Also, there is active discussion both within utilities that may be part of EDAM regarding the benefits of additional functionality within EDAM that may include consolidation and/or harmonization of certain elements of EDAM participants; Open Access Transmission Tariffs.

Historically, public power has been an active proponent of transmission development to ensure resource delivery to its customers. This includes, obviously, the California Oregon Transmission Project (COTP) which is operated within the BANC BAA, owned by TANC, and on which BANC members hold the predominance of rights to transfer capability. It is also true in Southern California, where major interregional lines are owned by California public power. Those lines are operated both within the CAISO and LADWP. Imperial Irrigation District has also recently been a locus of transmission development, and several CAISO approved projects are planned to reinforce transmission in the Imperial area.

Recent years have seen activity on tangible transmission development that has not been seen in decades.

The CAISO has approved major transmission projects at a significant rate in response to policy objectives of the state but also reliability needs. A partial list of major approved projects just in Northern California have included:

- A significant 500kV substation to collect solar resources in the Northern San Joaquin Valley;
- A major 500 kV substation in the Delta near existing public power facilities that is meant to be the terminus of 500kV projects to deliver Off-Shore Wind;

- A major, partially underground 500kV DC line to provide load service in the South Bay to meet expected load growth;
- Two major 500 kV lines, one running East/West, and one North/South, to deliver Off-Shore Wind resources from the Humboldt Area and to perhaps access additional enhanced geothermal resources in the North Bay, and may run parallel to existing Intertie rights-of-way; and
- Major upgrades to PG&E facilities just North of Sacramento to resolve certain contingencies and allow delivery of hydroelectric resources.

This list is partial, even as an assessment of Northern California approved projects, and does not include the significant project approvals in Southern California which, over time, have exceeded investment dollars of those proposed for Northern California. It also does not include the billions of dollars of PG&E transmission investment that does not require approval through the CAISO Transmission Planning Process.

The recently released CAISO 20-year outlook includes an additional $45-60 billion in transmission needed to meet decarbonization goals; this is beyond what has already been approved (*see* attached high-level map of resource zones).[1] This total identified need for transmission investment to meet decarbonization goals in the first 20 Year Outlook, issued just over two years ago (May 2022), was roughly $30 billion.[2]

The investment dollars slated for transmission development are obviously significant. However, it is not just the amount of transmission that is being built that is changing the transmission landscape, but the manner in which costs, cost allocations, and financing mechanisms are being developed to get projects done. The partnerships and creativity of funding vehicles exhibited in recent projects has not been seen since the CAISO was formed. At a base level, for major new transmission projects, the CAISO runs a competitive solicitation and awards bids for those projects in order to comply with the Federal Energy Regulatory Commission's Order No. 1000. Of recently awarded projects sponsors for major new transmission to meet policy goals (and that is the bulk of new facilities approved), very few are incumbent investor-owned utilities. A large majority of new major projects are awarded to third-party transmission developers. This is due to a host of factors, including availability of capital, track records of development, and willingness to take risk, sometimes in the form of cost caps or controls.

In addition, as some projects have not been amenable to socialized recovery through the TAC, new or refreshed models for cost recovery have come forward. This includes hybrid transmission and "subscriber-based transmission." Two transmission projects totaling nearly $10 billion are moving forward on the "subscriber based" model which is a new term for an old concept. These are the TransWest Express and SunZia facilities, developed by Anschutz Energy and Pattern, respectively. With subscriber-based transmission, basically the developer of the resource area is rolling into the power contract costs the transmission development costs, which can work if the underlying resources delivered are of sufficient scale. The difference here is that these lines will be under CAISO operational control, even though none of the costs are included in the TAC.

Even more creative is the hybrid SWIP-North project (see attached map), which is being developed by a third-party project and partially paid for through the TAC. The project includes Idaho Power Company and NV Energy as participants but was spearheaded by LS Power, a

[1] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook-2023-2024
[2] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook

third-party developer. These companies and the federal government are dividing transfer capability of the line, and the costs are split between CAISO through the TAC (the LS Power portion), DOE as a contract participant, Idaho Power, and NV Energy. Associated with this merchant project and relevant to BANC as far as possible resource development options, NV Energy is moving forward with its Greenlink project (see attached map) that connects Northern, Southern, and Eastern Nevada, and connects diverse clean resource zones and may be in relatively close proximity to points of Northern California interconnection.

Not all transmission initiatives are CAISO-centric. LADWP has issued a Request for Partnerships[3] to facilitate a significant transmission build out that could double its transmission footprint. LADWP has identified the need to deliver more clean energy resources from outside the LA Basin but also the need to have varying paths to ensure resiliency of the supply to protect against many risks, including wildfires around major transmission paths, something that BANC members experience regularly. LA has identified major upgrades as illustrated on the attached map:

- From the LA Basin to North of SONGS, and then though Southern CA to AZ and NM resource areas
- East out of LA mirroring the current paths of the transmission and out to Nevada and potentially Northern Nevada, similar to the existing Pacific DC Intertie
- Submarine cables that tie into PG&E's facilities in the Central Coast that may be able to deliver OSW in the Central Coast but also San Joaquin Valley solar and storage to the LA Basin over existing major transmission lines within the PG&E area

Transmission development initiatives are also not limited to California. WestTec, or the Western Transmission Expansion Coalition, was formed as part of the Western Power Pool, and has launched a self-described "West-wide effort to develop an actionable transmission plan to support the needs of the future energy grid."[4] WestTec has Department of Energy funding and is developing a study plan this year which will develop a West-wide plan focused on interregional facilities.

<u>Conclusion and Issue for Discussion</u>

It is clear that transmission totaling many tens of billions of dollars is slated for development to meet reliability, load service, and clean energy needs. Transmission will be critical to delivering the energy needed to meet increasing load projections and provide resiliency of supply in the face of heat events and wildfire risk. The initiatives, project approvals, and actual project development are largely moving forward without consideration of our needs to provide a reliable energy supply and to deliver newly developed zero-carbon resources. Historically, public power has taken a leadership role in shaping the transmission future. The question for the Commission and members, as they view and asses these transmission initiatives, is how they may impact members, and whether there is a role, whether or not through BANC, to understand and identify possible opportunities and needs to deliver resources to members and support BANC operations and success.

[3] https://www.ladwp.com/sites/default/files/2024-03/SLTRP%20Power%20System%20Vision.pdf
[4] https://www.westernpowerpool.org/about/programs/western-transmission-expansion-coalition

Figure ES-1: Transmission Development

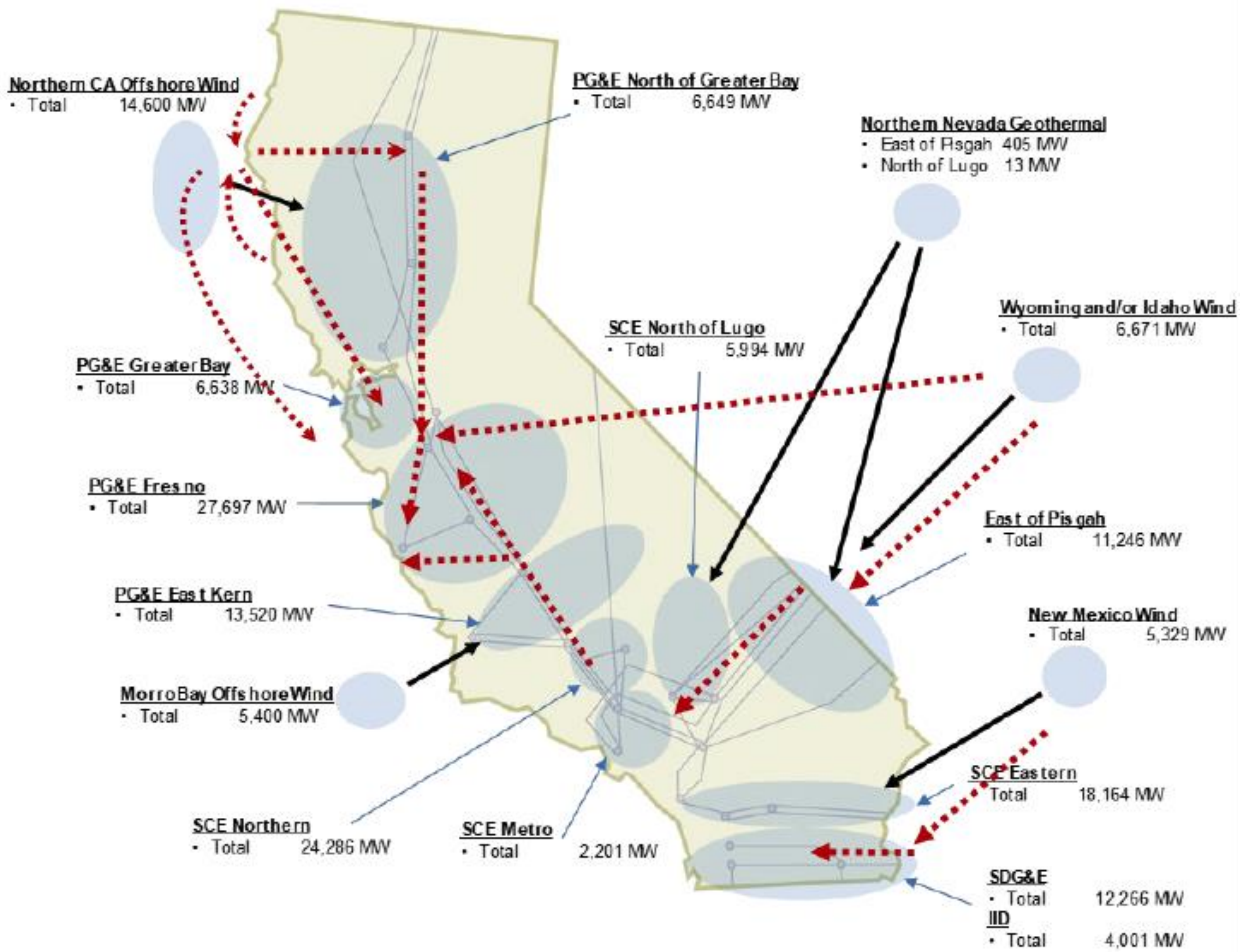

Table ES-1: provides the high-level summary of the transmission development required for upgrades to the existing ISO footprint, offshore wind integration and out-of-state wind integration along with estimated cost. The range of cost estimate is commensurate with estimates developed at this stage of planning, with the costs in constant dollars.

Attachments

Attachments

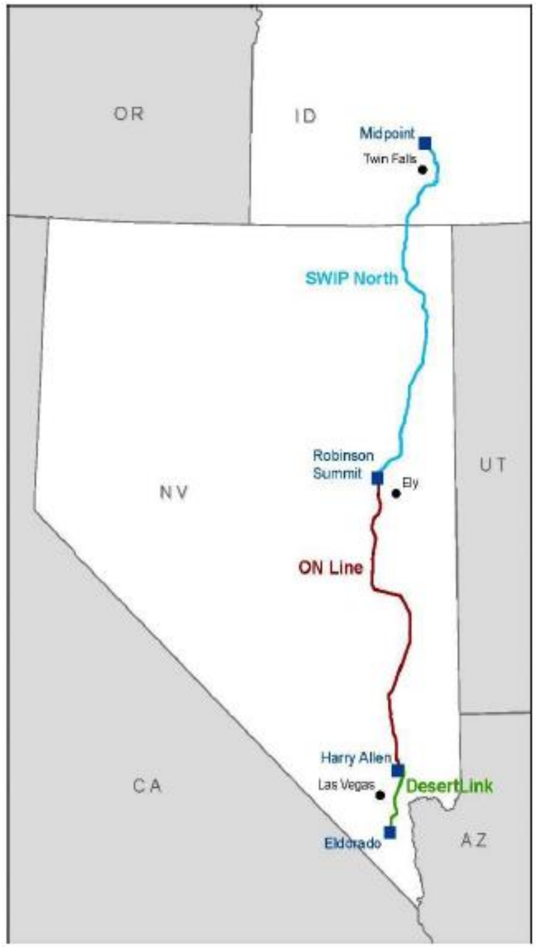

Figure 1: Transmission projects for participation.

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August 22, 2024

Should BANC Consider a More Lead Role on Detailed Market Issue Advocacy

For Discussion Purposes

Issue

BANC is very active in regional discussions on market evolution, and also was very active on numerous details of EDAM design. Nevertheless, we do not follow CAISO and related matters at the level of detail evidenced by market participants in the full CAISO market.

These detailed market issues are going to matter more in a world of full EDAM and EIM participation. Further, they will continually evolve. Even now, matters directly relevant to EDAM are the subject of ongoing stakeholder processes, even before market start-up. Below is a partial that will continually evolve over time:

- Billing, payment and credit enhancements;
- Day-Ahead market enhancements;
- Day-Ahead sufficiency;
- Extended day ahead market ISO balancing authority area participation rules;
- Gas resource management working group;
- Greenhouse gas coordination working group;
- Hybrid resources phase 2;
- Inter-SC trades in regional markets;
- Price formation enhancements;
- Storage bid cost recovery and default energy bid enhancements; and
- WEIM resource sufficiency evaluation enhancements.

This list does not include issues of broad interest that may not directly affect market design but may have relevance, such as interconnection queue reform or transmission planning matters.

Today, BANC is not active on most of these matters in a detailed fashion. As the market rules are shaped, BANC and its members will be impacted to a greater extent. While other groups, for example CMUA, cover certain matters, it is not done at a persistent and highly detailed level and tends to focus on particular issues that arise on an *ad hoc* basis that may affect CAISO POUs in particular.

Conclusion and Recommendation

It seems clear that the direct interest in the market rules for BANC and BANC members warrants a more detailed engagement. If the Commission agrees, we would create a scope, set of principles for prioritizing issues, and a workplan for how BANC may tackle these matters. There is no doubt that this may be a significant lift. We anticipate that the structure would involve a member committee engagement process through the EIM and Legal Committees, perhaps sub-teams on specific issues, regular reports and updates, comment development, and FERC filings, if necessary. This would not just be legal work; BANC Staff would anticipate that member staff would have a key role, that we would engage contract expertise to help understand complex issues and shape opinions, in addition to the work of producing and filing comments. It may be possible to coordinate and share costs with other POU BAAs, and BANC staff would explore this opportunity. However, this may introduce contract complexity and raise the possibility that divergence on both priority of issues and actual positions taken. BANC Staff and counsel would bring back recommendations during the budget development process to be finalized for 2025 engagement.

2024 20-YEAR TRANSMISSION OUTLOOK

California ISO

July 31, 2024

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Appendices

Executive Summary

California has dramatically accelerated its pace for integrating new clean resources onto the electric grid and faces an even greater need for additional renewable energy over the next 10 to 20 years. This heightened requirement is being driven by the requirements of Senate Bill 100 that renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045, and the continuing electrification of transportation and other industries. This transformation is not only driving significant investment in a technologically and geographically diverse fleet of resources, including storage, but also major transmission to accommodate all the new capacity being added. The transmission needs will range from new lines designed to open access to major generation pockets, including solar energy, offshore wind and geothermal resources located inside the state, as well as new high-voltage lines that will traverse significant distances to access out-of-state resources. Given the lead times needed for these facilities primarily due to right-of-way acquisition and environmental permitting requirements, the California Independent System Operator (ISO) and our partners in state and local government have found that a longer-term blueprint is essential to chart the transmission planning horizon beyond the conventional 10-year timeframe used in the past.

The ISO, working closely with the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), other local regulatory authorities, and members of the energy industry, has developed this 2024 20-Year Transmission Outlook (20-Year Outlook). It provides a long-term conceptual plan for the transmission grid in the year 2045 to reliably serve load and interconnect resources in alignment with planning by the state's principal energy agencies to meet state policy objectives regarding greenhouse gas reduction and renewable energy targets. The 20-Year Outlook also helps clarify the magnitude of the challenge in building major pieces of infrastructure – inside and outside the state – necessary for California to achieve the carbon-free grid envisioned under state energy policy.

The ISO released its first 20-Year Transmission Outlook in May 2022, providing a macro analysis of the broad architecture of California's future transmission network. In 2023, again in collaboration with the CPUC and the CEC, the ISO initiated work on updating the 20-Year Outlook with the objective of extending its range from 2040 to 2045. Doing so enables us to incorporate specific transmission projects approved over the last two years and to assess at a high level how the changes in load and resource forecasts since the first Outlook was drafted would affect the required transmission investments for 2045.

The CEC, CPUC, and the ISO collaborated in developing 2045 hourly load forecasts and a 2045 resource portfolio[1] for use by the ISO in this update[2]. The 2045 peak load forecast is 77,430 megawatts (MW), an increase of 3,521 MW from the 2040 forecast of 73,909 MW that was included in the original Outlook. The resource requirements also grew accordingly and, of particular note, the amount of offshore wind overall doubled from 10 GW to 20 GW in this updated 20-Year Outlook[3]. This increase took place primarily by more than tripling the forecast capacity in the North Coast area, from 4,000 MW to 14,700 MW. As the North Coast area has virtually no capacity to export offshore wind to load centers today, these volumes drive substantial increases in transmission requirements from the initial Outlook. The updated Outlook aligns with the California Energy Commission's Offshore Wind Energy Strategic Plan adopted July 10, 2024 as required by AB 525. The plan calls for up to 25,000 MW of wind energy from the California coast by 2045.

Accordingly, a comparison to the initial 20-Year Outlook shows some relatively modest additional requirements in-state for on-land resources, a relatively consistent requirement for transmission to access out-of-state resources, and substantial new requirements to access North Coast offshore wind, with the latter being the primary driver of cost differences.

In summary, the anticipated load growth to 2045 and the expectation of major offshore wind generation are driving the higher estimated cost for future transmission needs from approximately $30.5 billion over a 20-year timeframe identified in the first Outlook to the estimated $45.8 billion to $63.2 billion over the next two decades, with offshore wind development the primary driver of these higher projected costs. The range for future project cost estimates over this timeframe varies significantly due to detailed design requirements and uncertainty in permitting timelines, routing decisions, and equipment and labor costs. Also, the high-level analysis to determine feasible transmission alternatives included a bulk system power flow assessment for a range of load and resource scenarios. These costs do not include transmission that has already been approved by the ISO and is under development, but not yet in service[4].

Despite being developed over 20 years, and the costs amortized over the physical life of the transmission, the additions are significant investments. They must be considered in the context of the diverse fleet of resources they access, and the benefits provided by a diversified resource fleet in reducing total costs to consumers. The ISO recognizes and will continue to take steps to address concerns regarding the ratepayer impacts of the capital projects identified in the 20-Year Outlook and this update. Further, for a number of these additions, lead times of eight to 10 years are reasonable or even optimistic. This highlights the need for longer-term decisions to be made and development activities to be initiated in the annual transmission planning processes.

[1] Consistent with the resource planning underpinning the initial 20 Year Outlook, the CEC and CPUC relied on the CEC's SB100-related processes for achieving the state's 2045 objectives as a platform for portfolio development, and CAISO collaborated with the state agencies on an approach to develop scenarios to be studied in the Outlook.

[2] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

[3] As the amount of solar and storage continues to grow, and the reliance on gas-fired generation decreases, greater resource diversity is called for in the resource fleet.

[4] In particular, the transmission requirements identified in this updated 2024 Outlook do not include the costs of reinforcement already approved by the ISO in the 2022-2023 transmission plan since the 2022 Outlook was prepared.

The ISO will continue to work with state agencies and stakeholders to refine these options to develop the most cost-effective solutions to meet California's reliability and clean-energy objectives. It is also important to keep in mind that preliminary cost estimates are subject to change and refinement depending on what ultimately gets built and the associated cost allocation methodologies. For inter-regional transmission lines, for example, some of the costs may be shared with participants outside California, so the costs would not all be borne by California ratepayers.

Resource and Transmission Requirements:

The 2045 portfolio referenced above identified the resource development to meet forecasted load growth as well as a projected reduction of 15,000 megawatts (MW) of natural gas-fired generation from plants being retired while also providing an effective trajectory to achieving 2045 state greenhouse gas reduction objectives. The reduction in natural gas-fired generation enabled analysis of not only system-wide needs, but also the local need of major load centers dependent on natural gas-fired generation for reliable service today, and the retirement assumptions focused on age and proximity to disadvantaged communities.

To meet these needs, the 2045 portfolio called for 48,813 MW of battery energy storage, 4,000 MW of long-duration storage, 5,000 MW of generic clean firm or long-duration storage, 69,640 MW of utility scale solar, 2,332 MW of geothermal, and over 35,000 MW of wind generation – the latter split between out-of-state and in-state onshore, and in-state offshore resources. The bulk of the in-state wind resources consist of offshore wind. These total 165.1 GW of new resources for the 2045 portfolio. The 2045 portfolio also provided specific locations for the new resources, except for some portion of the out-of-state and offshore wind.

The resulting updated Outlook developed to access these resources and reliably serve load calls for significant 500 kV AC and HVDC development to access offshore wind and out-of-state wind, while also reinforcing the existing ISO footprint. Figure ES-1 provides an illustrative diagram of the transmission development required to integrate the resources of the 2045 portfolio and reliably serve the 2045 load forecast. This analysis focused on high-voltage bulk transmission, recognizing that local transmission needs and generation interconnections will ultimately need to be addressed as well.

Figure ES-1: Transmission Development

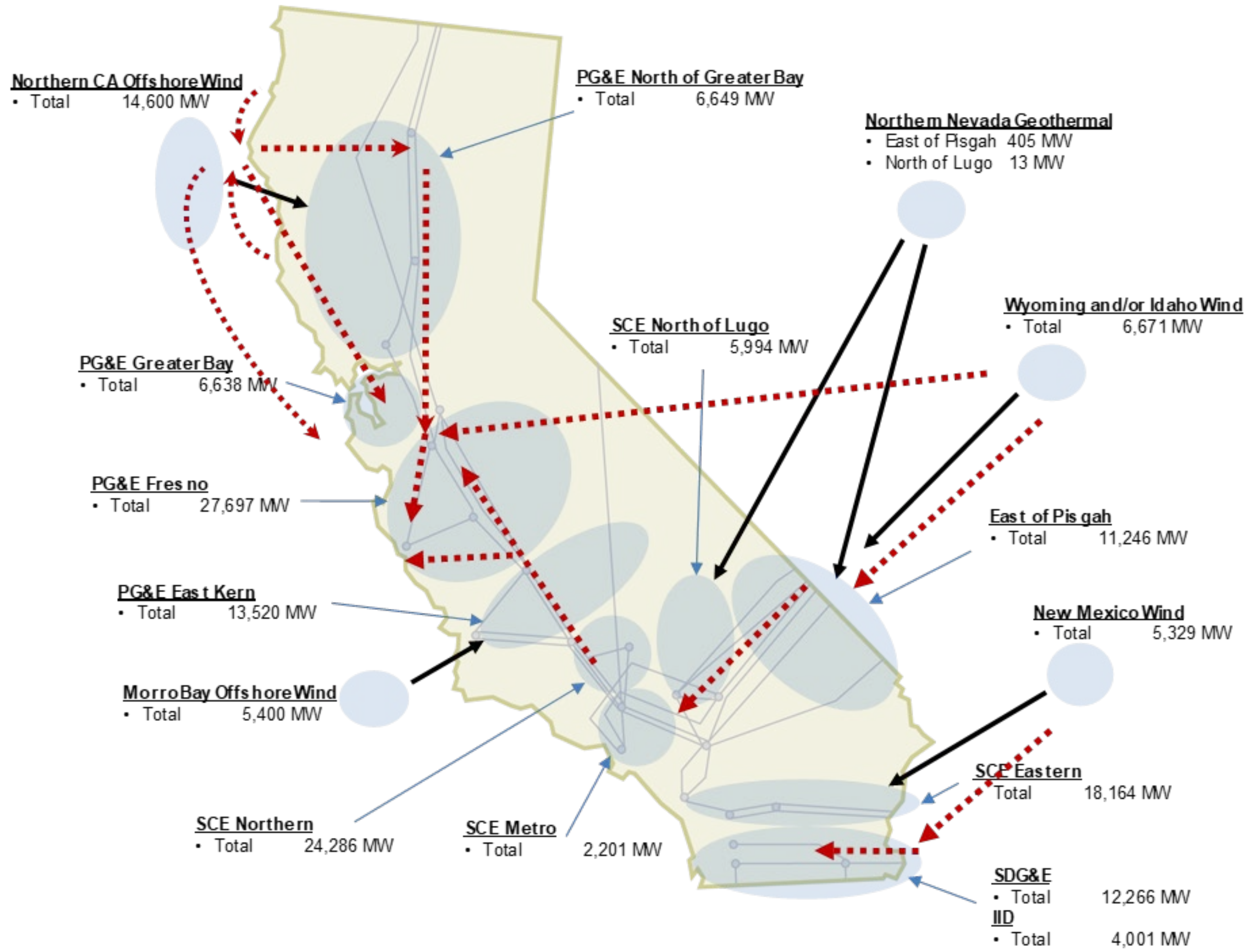

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Table ES-1: Cost estimate of transmission development to integrate resources of 2045 Scenario

Transmission Development	Estimated Cost ($ billions)
Upgrades to existing ISO bulk transmission footprint consisting of: • 230 kV and 500 kV AC lines • HVDC lines • Substation upgrades	$9.3 B – $11.5 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$25.0 B – $36.5 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$11.6 B - $15.2 B
Total estimated cost of transmission development[5]	**$45.8 B – 63.2 B**

The ISO recognizes that resource planning and procurement decisions may differ over the years ahead from some of the assumptions used to establish the baseline the 20-Year Outlook provides for longer-term planning. Those changes will be managed by adapting future plans around the baseline architecture in subsequent updates, and in the ISO's transmission planning processes that approve and initiate specific projects annually.

The ISO also plans to conduct additional stakeholder dialogue through 2024 about next steps as well as the long-term architecture set out in this 2024 20-Year Outlook. Stakeholder feedback at a meeting in January on the updated 20-Year Outlook preliminary results was overwhelmingly supportive of the 20-Year Outlook effort, and focused on how the ISO may move to initiate the transmission development it identified – or particular developments of specific interest to the individual commenters. A number of stakeholders requested analysis and detail that were beyond the scope of this year's efforts, and that feedback will be taken into account as the ISO refines its plans for developing future iterations.

Finally, this effort could not have been undertaken without the collaboration and support of the CPUC and CEC. The ISO appreciates the efforts of both organizations in supporting the development of this document.

[5] These values represent the capital cost of the identified projects; several are currently being developed under a subscriber model – with the transmission costs incorporated into the energy costs – and not rate-base projects receiving cost-of-service cost recovery that would be added to ISO transmission access charges.

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Chapter 1

1 Introduction

1.1 Purpose

The ISO released a final version of its first 20-Year Outlook in May 2022. The Outlook provided a long-term conceptual plan of the transmission grid in the year 2040 to reliably serve the load and interconnect the resources aligned with the California Energy Commission (CEC) and California Public Utilities Commission (CPUC) inputs aimed at meeting the state's greenhouse gas reduction and renewable energy objectives. The Outlook also helped clarify our vision and the magnitude of the challenge in building major pieces of infrastructure – inside and outside the state – necessary for California to achieve the carbon-free grid envisioned under state energy policy.

The CEC's SB100-related processes for achieving the state's 2045 objectives were used as a platform and the ISO collaborated with the state agencies on an approach to develop scenarios that can be studied in the Outlook, which is necessary for a number of important reasons, including:

- To ensure that the ISO's longer-term transmission plan initially articulated in 2022 remains relevant;
- That the longer-term Outlook continues to provide a longer-term view of transmission needed in California and can help inform the ISO's annual transmission planning process;
- That the ISO's transmission planning is aligned with state agency inputs on evolving resource and load projections, particularly as the need for long lead-time transmission assets grows due to increasing offshore and out-of-state wind resources and as the gas generation fleet starts retiring; and
- To provide an updated conceptual map of transmission required to meet SB100 requirements for 2045.

The update will also be informed by transmission projects that were approved as part of the ISO's 2022-2023 transmission plan and those recommended for approval in the transmission plan for 2023-2024.

In this updated 20-Year Outlook, the ISO continued to engage and collaborate with the state agencies to develop scenarios for study purposes based on extending the study timeframe to 2045 and incorporating updated resource and load forecasts. The study timeframe also aligns well with the SB100 legislation timelines requiring all retail electricity sold in California to be from renewable and zero-carbon resources by 2045.

The 20-Year Outlook Update for the ISO grid explores the longer-term grid requirements and options for meeting the State's greenhouse gas reduction and renewable energy objectives reliably and cost-effectively.

The Outlook provides:

- A transparent process to develop transmission information responsive to supporting and informing the CPUC's Integrated Resource Planning processes, the CEC's Integrated Energy Policy Report and the joint agencies' SB100 efforts
- Longer-term context for and framing of issues in the ISO's 10-Year Transmission Plan which gets updated annually

The ISO launched the effort to update the 20-Year Outlook in parallel with the 2023-2024 transmission planning cycle. The 20-Year Outlook Update provides a baseline for longer-term planning, recognizing that future resource planning and procurement decisions will differ from assumptions used in this study. Those changes will be managed by adapting future plans around the baseline architecture in future updates, and in the ISO's annual transmission planning processes that approve and initiate specific projects.

1.2 Challenges

Senate Bill (SB) 100 establishes a policy that renewable and zero-carbon resources supply 60 percent of California's retail sales and electricity procured to serve all state agencies by 2030, and 100 percent by 2045.

These goals are in addition to those established earlier via Senate Bill (SB) 350 that update the 2030 renewables goal. SB 350 set the requirement to achieve the 2030 greenhouse gas reduction targets established by the California Air Resources Board (CARB), in coordination with the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) that would also meet or exceed the current 2030 renewables portfolio standard requirement established by SB 100. It is also critical that goals focused on 2030 objectives reasonably establish a trajectory to meeting 2045 renewables portfolio standard goals that were also established in SB 100.

The ISO relies extensively on coordination with the state energy agencies for resource planning input, in particular with the CPUC, which takes the lead role in developing resource forecasts for the 10-year planning horizon and with input from the CEC and the ISO. In looking beyond the 10-year horizon, the CEC takes a more central role in establishing forecast resource requirements via the analysis the CEC leads pursuant to its SB 100 responsibilities. As it did with the original 20-Year Outlook, the ISO turned to the two state agencies for input to support the development of the 20-Year Outlook update.

The assumptions include demand, supply, and system infrastructure elements, including the renewables portfolios, and are discussed in more detail in section three.

1.3 Other Process Issues

1.3.1 Infrastructure

In the more than 10 years since the ISO redesigned its transmission planning process and subsequently adapted it to fully conform with Federal Energy Regulatory Commission (FERC) Order No. 1000 provisions, the challenges placed on the electricity system – and correspondingly on the transmission system - have evolved and grown considerably. While these past challenges were significant at the time, the energy industry is now at an inflection point marking a far more impactful increase in the rate of growth in renewable resources and the need for faster integration onto the grid. For context, it is useful to note that when the ISO prepared its 2020-2021 transmission plan, state agency-provided forecasts called for adding approximately 1,000 MW of new resources per year over the next 10 years. Now, just three years later in the ISO's draft 2023-2024 transmission plan, state agency forecasts call for adding approximately 7,000 to 8,000 MW of new resources every year for each of the next 10 years.

In addition to the reasons stated above, the accelerating resource requirements over the next decade are driven by a number of circumstances, including the escalating need to decarbonize the electricity grid in light of emerging climate change impacts, the expected electrification of transportation and other carbon-emitting industries driving higher electricity forecasts, concerns regarding reduced access to imports as neighboring systems also decarbonize, higher than anticipated impacts of peak loads shifting to later-day hours when solar resources are not available, and the need to maintain system reliability in light of retiring gas-fired generation relying on coastal waters for once-through cooling and the planned closing of the Diablo Canyon Power Plant. These resource requirements, on the path to total decarbonization of the grid, will call for greater volumes of solar photovoltaic resources and battery storage, as well as greater diversity beyond the current focus on those resource types. Geothermal resources, out-of-state resources and offshore resources all are expected to play greater roles, and create unique challenges in the planning and interconnection processes. Meeting those challenges requires adaptations and enhancements to existing processes and efforts.

At the same time as this shift in longer-term resource requirements was being established, the CPUC authorized more mid-term procurement in a June 24, 2021 decision than last year's 10-year transmission plan was based on. It was the largest single procurement ever authorized by the CPUC. Responding to these signals and previously approved authorizations, the resource development industry came forward with a record-setting number of new interconnection requests in April, 2021 – some 373 new interconnection requests received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[6] The 605 projects totaling 236,225 MW now in the queue exceeds mid-term requirements by an order of magnitude. This level of hyper competition actually creates barriers to moving forward effectively with the resources that do need to be added to the grid, and places extreme

[6] ISO Board of Governors July 7, 2021 Briefing on renewable and energy storage in the generator interconnection queue, http://www.caiso.com/Documents/Briefing-Renewables-GeneratorInterconnection-Queue-Memo-July-2021.pdf

demands on finite planning, engineering and project management resources from the ISO and transmission owners.

In parallel with enhancements in the transmission planning process, enhancements are also being pursued to more tightly synchronize state agency resource planning processes with the ISO's resource interconnection process, and in the overall coordination of the procurement and construction of new resources and related transmission network upgrades. These led to the development of a more proactive and coordinated strategic direction set forth in a joint Memorandum of Understanding (MOU)[7] signed by the three parties in December 2022. The MOU tightens the linkages between resource and transmission planning, interconnections, and procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100.

Transmission Planning:

In addition to the incremental improvements the ISO makes in each year's transmission planning cycle, the ISO has re-examined the effectiveness of certain planning processes both due to evolving issues within our own footprint, and also in response to the FERC Advance Notice of Proposed Rulemaking (ANOPR) regarding transmission planning, cost allocation and generator interconnection released on April 21, 2022.

The ISO noted in its comments responding to the ANOPR[8] that the "ISO's existing transmission planning and generator interconnection processes reflect many of the reforms and concepts discussed in the FERC's proposed rulemaking. At the same time, given the ISO's escalating challenges arising from existing supply conditions, the need to accelerate and then sustain the pace of procurement and interconnection to meet climate goals, and an "overheated" generation interconnection queue, the ISO must "get in front" of these issues and move forward with transmission planning and generation interconnection process enhancements ahead of the likely timeline for any Final Rule in the FERC proceeding. Enhancements and improvements to the ISO regional transmission planning processes are already moving forward, including the introduction of the 20-Year Outlook framework that it is outside of the tariff-based project approval planning process, and other enhancements that do not require tariff changes to implement.

In responding to the ANOPR, the ISO also acknowledged that the interregional coordination process related to transmission has not met expectations in actually leading to more interregional transmission being developed across the United States, and that there are opportunities to remove certain barriers, foster collaboration with state regulators, and promote more rigor in, and reporting on, interregional coordination efforts. Accordingly, the ISO is exploring a few alternative courses of action to advance potential interregional opportunities, drawing largely on the flexibility supported by FERC in its policy statement, "State Voluntary Agreements to Plan and Pay for Transmission Facilities" issued on June 17, 2021, in addition to

[7] http://www.caiso.com/Documents/ISO-CEC-and-CPUC-Memorandum-of-Understanding-Dec-2022.pdf

[8] COMMENTS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION ON ADVANCE NOTICE OF PROPOSED RULEMAKING, submitted October 12, 2021, FERC Docket No. RM21-17-000, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection http://www.caiso.com/Documents/Oct12-2021-Comments-AdvanceNoticeOfProposedRulemaking-BuildingTransmissionSystemoftheFuture-RM21-17.pdf

meeting all expectations, responsibilities and obligations associated with the ISO interregional coordination tariff provisions related to FERC Order No.1000.

On May 13, 2024, FERC adopted Order No. 1920, a final rule in RM21-17, largely consistent with the ANOPR of April 21, 2022. The ISO is reviewing the order, and will be developing its compliance filing and related process changes over the course of the next year. Compliance filings are due in June, 2025.

Resource Interconnection:

In 2023, the ISO launched its 2023 Interconnection Process Enhancements initiative in response to excessive volumes of interconnection requests received in recent application windows, focusing on making significant and transformative improvements regarding coordination of resource planning, transmission planning, interconnection queuing and power procurement to achieve state reliability and policy needs.

The 2023 Interconnection Process Enhancements initiative is part of a larger set of foundational framework improvements being coordinated among the CPUC, the CEC, and the ISO. The overall strategic direction is set forth in the joint Memorandum of Understanding (MOU) signed by the three parties in December 2022 to set the direction for tightening linkages among resource and transmission planning activities, interconnection processes and resource procurement. The ISO is now taking on additional reforms to the interconnection queuing process that will leverage the improved coordinated planning resulting from the MOU and help further break down barriers to efficient and timely resource development. The ISO's Interconnection Process Enhancements proposal was approved by its Board of Governors on June 12, 2024, and will be filed with FERC in August. This proposal builds on the compliance filing submitted by the ISO on May 16, 2024 in response to FERC Order No. 2023[9], which FERC issued to "ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and [which] will prevent undue discrimination."

Procurement and Project Execution:

In addition to the above processes, the ISO is also taking on additional efforts to:

- Coordinate with the CPUC, CEC, and the state of California's GO-Biz office to identify and help mitigate supply chain and other issues that could delay new resources meeting in-service dates,
- Together with the CPUC, work with participating transmission owners to improve transparency of the status of transmission projects focusing on network upgrades approved in prior ISO transmission plans, or that resources with executed interconnection agreements are dependent on,
- Provide more information publicly regarding where resources are able to connect to the grid with no or minimal network upgrade requirements, to assist load-serving entities to shape their procurement activities towards areas and resources that are better positioned to achieve necessary commercial operation dates,

[9] On July 27, 2023, the Federal Energy Regulatory Commission (FERC) issued Order No. 2023, Improvements to Generator Interconnection Procedures and Agreements. On March 21, 2024, FERC issued Order No. 2023-A, revising some requirements.

- Coordinate with the CPUC regarding the progress of procurement activities by load-serving entities and assessing the timeliness of those procured resources meeting near and mid-term reliability requirements, and,
- Continue to explore opportunities using grid-enhancing technologies – flow controllers and advanced conductors in particular – to expedite transmission capacity development and minimize costs.

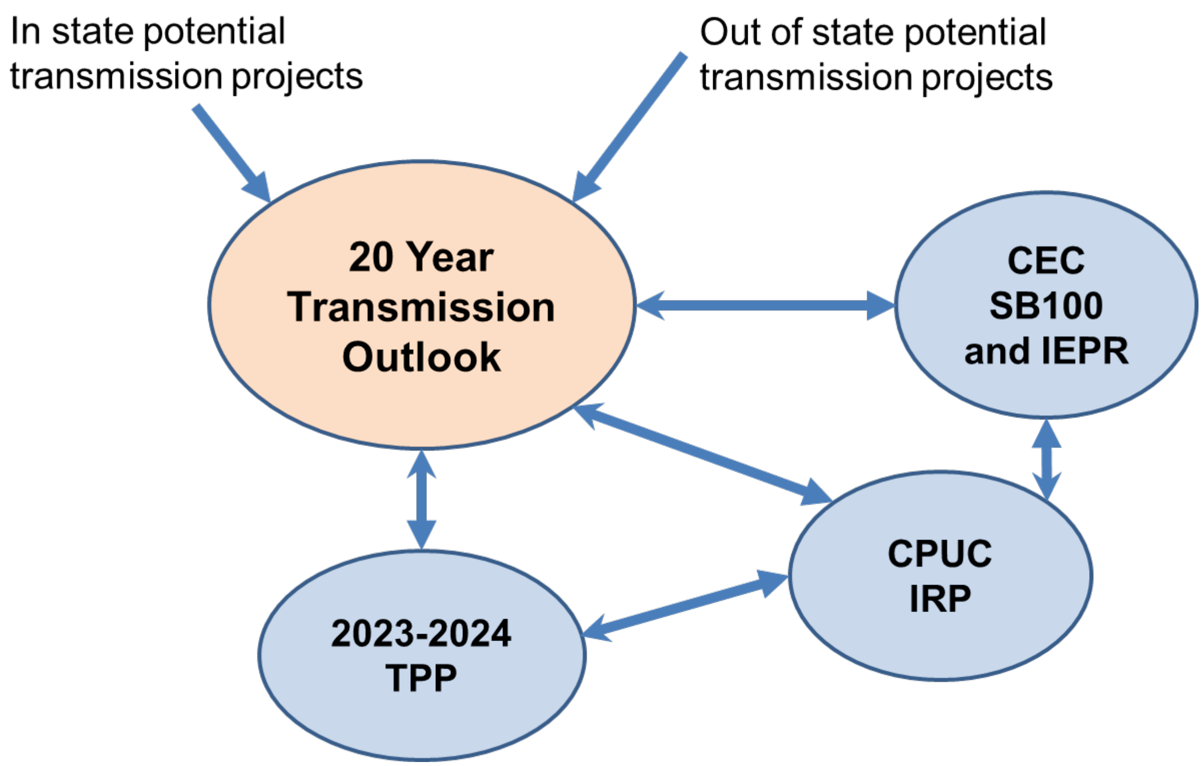
These enhancements and coordination efforts will collectively support and enable the state reaching its renewable energy objectives reliably.

Chapter 2

2 Coordination with State Agencies

The development of the 20-YearTransmission Outlook Update has been coordinated with the 2023-2024 transmission planning process and with the forecasting and planning done by the CEC and CPUC. These efforts have included ISO stakeholder calls and joint agency workshops as a part of the SB100 process.

Figure 2-1: 20-Year Outlook Update coordination with other initiatives and agencies



On June 23, 2023, the CEC held its public "Joint Agency Staff Workshop[10] on Resource Portfolio Assumptions for the Next CAISO 20-Year Outlook" with CAISO and CPUC participation to discuss resource portfolio assumptions for the 20-Year Outlook Update.

On July 14, 2023 the CEC docketed the 2045 Scenario for the Update of the ISO 20-Year Outlook[11] in its SB 100 proceeding.

[10] https://efiling.energy.ca.gov/GetDocument.aspx?tn=250717

[11] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

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Chapter 3

3 Process and Inputs

The objective of the ISO's 20-Year Outlook Update is to explore longer-term grid requirements and options for reliably meeting the state's greenhouse gas reduction goals. The 20-Year Outlook Update will provide a "baseline" vision for future planning activities. To achieve this, the ISO used a resource development scenario developed through the CEC SB100-related activities that considers:

- Diverse resources known to require transmission development such as offshore wind energy, out-of-state resources, geothermal resources; and,
- Gas power plant retirements that may require transmission development to reduce local area constraints.

The ISO also developed conceptual transmission system additions and conducted high-level technical studies to test feasibility of these alternatives, focusing on the bulk transmission system.

This basis for the 20-Year Outlook Update is to help map the broad architecture of California's future transmission network and clarify our vision and the magnitude of the challenge the state and electricity industry face in building major pieces of infrastructure – inside and outside the state – necessary for California to achieve the carbon-free grid envisioned under Senate Bill 100, which was signed into law in 2018. The Outlook Update will also allow the state to further refine long-term resource planning inputs and provide longer-term context for decisions made in the ISO's annually updated 10-year transmission planning process.

The high-level analysis to determine feasible transmission alternatives included bulk system power flow assessment for a range of load and resource scenarios.

Particular focus was applied to conducting a high-level assessment of local area (primarily the Bay Area and LA Basin) needs with gas retirement, building off the initial 20-Year Outlook, past informational studies conducted in recent ISO transmission planning studies, and other technical analyses.

3.1 Key Inputs

This section provides background and detail on key load and resource forecast inputs into the 20-Year Outlook Update process.

SB 100 requires the CEC, CPUC, and California Air Resources Board (CARB) to have developed and submitted a joint-agency report on decarbonization progress and strategies to the Legislature by January 1, 2021, and at least every four years thereafter. The CEC, CPUC, and the ISO collaborated on an approach to develop a scenario for use by the ISO in the 20-Year Outlook Update[12]. The CEC and CPUC expect that the information from the 20-Year

[12] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

Outlook Update will help inform future electric sector planning, including the next SB 100 joint-agency report.

3.1.1 Load and Distributed Energy Resources Growth Scenarios

The 2045 load and resource portfolio forecast used for the 20-year Outlook Update assessment was developed by CEC and CPUC in collaboration with CAISO and can be found on the CEC docket at the link below [13]. The hourly load forecast provided for year 2045 includes the baseline consumption, behind-the-meter PV, behind-the-meter storage, light duty vehicle charging load, medium to high duty vehicle charging load, additional available energy efficiency and additional available fuel substitute load. Within the technical studies of this 20-Year Outlook Update, the following three study cases were considered similar to the initial 20-Year Outlook:

- Net peak load
- Peak consumption
- Off-peak load

The following table provides the details of the load forecast for the three study cases:

Table 3-1: Load and Load Modifiers

Study Scenario	Date/ Time	TAC Area	Baseline_ Consumption	BTM_PV	BTM_ Storage	LDV3	MDHD3	AAEE3	AAFS3	System Load (1-in-2)	System Load (1-in-5)
Net Peak Load (HSN)	9/5/2045 HE19	PG&E	24,520	-45	-647	3,546	828	-1,402	732	27,532	28,758
		SCE	26,612	-2	-363	3,190	698	-1,600	412	28,948	30,279
		SDG&E	5,163	0	-156	652	63	-290	32	5,464	5,723
		CAISO [1]	56,450	-46	-1,166	7,388	1,589	-3,291	1,176	62,100	**64,923**
Peak Consumption (SSN)	9/5/2045 HE14	PG&E	26,043	-15,980	36	5,804	1,383	-1,452	302	16,136	17,438
		SCE	30,503	-10,439	-1	4,824	1,239	-1,986	307	24,445	25,970
		SDG&E	5,653	-3,642	2	1,588	200	-376	33	3,459	3,741
		CAISO	62,356	-30,061	37	12,216	2,822	-3,815	642	44,197	**47,315**
Off Peak [2]	4/15/2045 HE13	PG&E	13,993	-16,744	34	3,615	1,134	-935	358	1,455	1,455
		SCE	12,683	-11,550	3	3,110	1,015	-1,027	290	4,524	4,524
		SDG&E	2,737	-3,944	-2	942	163	-215	29	-291	-291
		CAISO	29,489	-32,238	35	7,666	2,312	-2,177	677	5,764	**5,764**

[1] CAISO's Baseline Consumption and System Load values include VEA load

[2] To study more stressed off peak scenario, the 1-in-2 off peak system load was studied

[13] https://www.energy.ca.gov/publications/2023/2045-scenario-update-20-year-transmission-outlook

3.1.2 Resource Planning and Portfolio Development

Table 3-2 provides the resource portfolio provided by the CPUC for use in the 2023-2024 transmission planning process for the year 2035, the resource portfolio used in the 2022 20-Year Outlook, and the resource portfolio for use in this 20-Year Outlook Update for year 2045.

Table 3-2: Resource assumptions in 2023-2024 transmission planning process for 2035 and the 20-Year Outlook resource portfolio for 2040 and 2045

Resource Type	2023-2024 TPP Base Portfolio for 2035 (MW)	Previous 20-Year Outlook (2040) (MW)	20-Year Outlook Update (2045)
Natural gas fired power plants	0	(15,000)	(15,000)
In State Biomass	134	0	134
Battery energy storage	28,374	37,000	48,814
Long-duration energy storage	2,000	4,000	4,000
Distributed Solar	125	0	125
Utility-scale solar	38,947	53,212	69,640
In-state wind	3,074	2,237	3,074
Offshore wind	4,707	10,000	20,000
Out-of-state wind	5,618	12,000	12,000
Geothermal	2,037	2,332	2,332
Generic Clean-Firm/LDES	0	0	5,000

3.1.3 Natural gas-fired power plants

Similar to the initial 20-Year Outlook, the 2045 Portfolio includes an assumption that 15,000 MW of natural gas power plant capacity would be retired by 2045.

Table 3-3 provides the assumption on total retirement of gas-fired generation by local capacity areas. The same methodology detailed in the last Outlook[14] was used in this study to implement gas retirement assumptions in different study cases.

[14] http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf (section 3.1.3)

Table 3-3: Assumed gas-fired generation retired by local capacity area

Local Capacity Area	Capacity (MW)
Greater Bay Area	4427
Sierra	153
Stockton	361
Fresno	669
Kern	407
LA Basin	3,632
Big Creek-Ventura	695
San Diego-IV	131
ISO System	3,933
Total	**14,408**

3.1.4 Battery energy storage

The 2045 Portfolio identified 48,814 MW of battery energy storage resources along with associated busbar mapping. Table 3-4 provides a summary of total battery energy storage resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-4: Battery energy storage resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	5,497
PG&E Fresno Study Area	7,990
PG&E North of Greater Bay Study Area	4,903
PG&E S500 Study Area	930
East of Pisgah Study Area	3,517
SCE Eastern Study Area	6,692
SCE Metro Study Area	2,177
SCE North of Lugo (NOL) Study Area	1,884
SCE Northern Area	9,048
SDG&E Study Area	4,676
IID	1,501
Total	**48,814**

3.1.5 Long-duration energy storage (LDES) or firm generic clean resources

The 2045 Portfolio identified 4,000 MW of LDES resources. In addition, 5,000 MW of resources identified as firm generic clean or LDES resources are also included in the portfolio. Table 3-5 and Table 3-6 provides a summary of total LDES resources and a summary of total firm generic clean or LDES resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-5: LDES resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	600
PG&E Fresno Study Area	0
PG&E North of Greater Bay Study Area	400
PG&E S500 Study Area	0
East of Pisgah Study Area	0
SCE Eastern Study Area	1,500
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	0
SCE Northern Area	1,000
SDG&E Study Area	500
IID	0
Total	**4,000**

Table 3-6: Firm generic-clean/LDES resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	0
PG&E Fresno Study Area	250
PG&E North of Greater Bay Study Area	1,650
PG&E S500 Study Area	1,500
East of Pisgah Study Area	500
SCE Eastern Study Area	0
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	600
SCE Northern Area	500
SDG&E Study Area	0
IID	0
Total	**5,000**

3.1.6 Utility-scale solar

The 2045 Portfolio identified 69,640 MW of utility-scale solar resources along with busbar mapping of the resources. Table 3-7 provides a summary of total utility-scale solar resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-7: Utility-scale solar resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	10,514
PG&E Fresno Study Area	12,317
PG&E North of Greater Bay Study Area	4,957
PG&E S500 Study Area	1,050
East of Pisgah Study Area	6,326
SCE Eastern Study Area	9,493
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	3,460
SCE Northern Area	13,378
SDG&E Study Area	5,645
IID	2,500
Total	**69,640**

3.1.7 Onshore, In-state Wind

The 2045 Portfolio identified 3,074 MW of onshore in-state wind along with busbar mapping of the resources. Table 3-8 provides a summary of total onshore in-state resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-8: Onshore, in-state wind resources for the 20-Year Outlook

CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	255
PG&E Fresno Study Area	249
PG&E North of Greater Bay Study Area	1,095
PG&E S500 Study Area	0
East of Pisgah Study Area	403
SCE Eastern Study Area	127
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	0
SCE Northern Area	345
SDG&E Study Area	600
IID	0
Total	**3,074**

3.1.8 Offshore Wind

The 2045 Portfolio identified a total of 20,000 MW of offshore wind off the North and Central Coast of California. Table 3-9 provides a summary of total offshore wind resources in different resource areas along with their point of interconnection. As shown in Table 3-9, the offshore wind in Del Norte and Cape Mendocino are not mapped to a CAISO substation. A discussion on the transmission options to interconnect these resources are provided in Section 4.2.2.

Table 3-9: Offshore wind resources for the 20-Year Outlook

CAISO Substation	Resource Area	20-Year Outlook
Diablo 500 kV or proposed Morro Bay 500 kV	Morro Bay Offshore Wind	5,400
Humboldt 500 kV (Proposed)	Humboldt Bay Offshore Wind	2,700
Unknown Substation(s)	Del Norte Offshore Wind	7,000
Unknown Substation(s)	Cape Mendocino Offshore Wind	4,900
Total		**20,000**

3.1.9 Out-of-state wind

The 2045 Portfolio identified 12,000 MW of out-of-state wind resources. Table 3-10 provides a summary of out-of-state wind resources in different resource areas along with their point of interconnection. The out-of-state wind has been identified in as either requiring new transmission to bring the resources to the ISO transmission grid (11,220 MW) or being able to use existing transmission (780 MW). TransWest Express, SWIP North, and SunZia are projects that are at different stages of development and in total provide approximately 4,800 MW of transmission capacity to the ISO[15].

Section 4.3 details the number of options that are considered in this study to interconnect 3,500 MW of Wyoming wind and 2,882 MW of New Mexico wind that are not mapped to a substation in Table 3-10.

[15] This represents the ISO's proposed share of SWIP North "North to South" capacity of 1117 MW, the 1500 MW Wyoming-Nevada capacity provided by TransWest Express, and 2131 MW representing the transmission capacity into Palo Verde from the Sunzia project, limited by its entitlements on existing transmission system from Pinal Central to Palo Verde.

Table 3-10: Out-of-state wind resources for the 20-Year Outlook

Study	Substation	Resource Type/ Location	Out-of-CAISO Transmission Utilized	20-Year Outlook
2023-2024 TPP	Mead 230 kV	SW Wind Ext Tx	Existing Tx	300
	Palo Verde 500 kV	SW Wind Ext Tx	Existing Tx	119
	Eldorado 500 kV	SW Wind Ext Tx	Existing Tx	371
	Eldorado 500 kV	Wyoming Wind	New Tx (TransWest Express)	1,500
	Harry Allen 500 kV	Idaho Wind	New Tx (SWIP North)	1,000
	Palo Verde 500 kV	New Mexico Wind	New Tx (SunZia)	2,328
20-Year Outlook mapping additions	Unknown Substation(s)	Wyoming Wind	New Tx (TBD)	3,500
	Unknown Substation(s)	New Mexico Wind	New Tx (TBD)	2,882
			Total	**12,000**

3.1.10 Geothermal

The resource portfolio identified 2,332 MW of geothermal resources in 2045 along with busbar mapping of the resources. Table 3-11 provides a summary of total geothermal resources in different CAISO study areas. Chapter 4 provides the busbar mapping of the resources for different study areas.

Table 3-11: Geothermal resources for the 20-Year Outlook

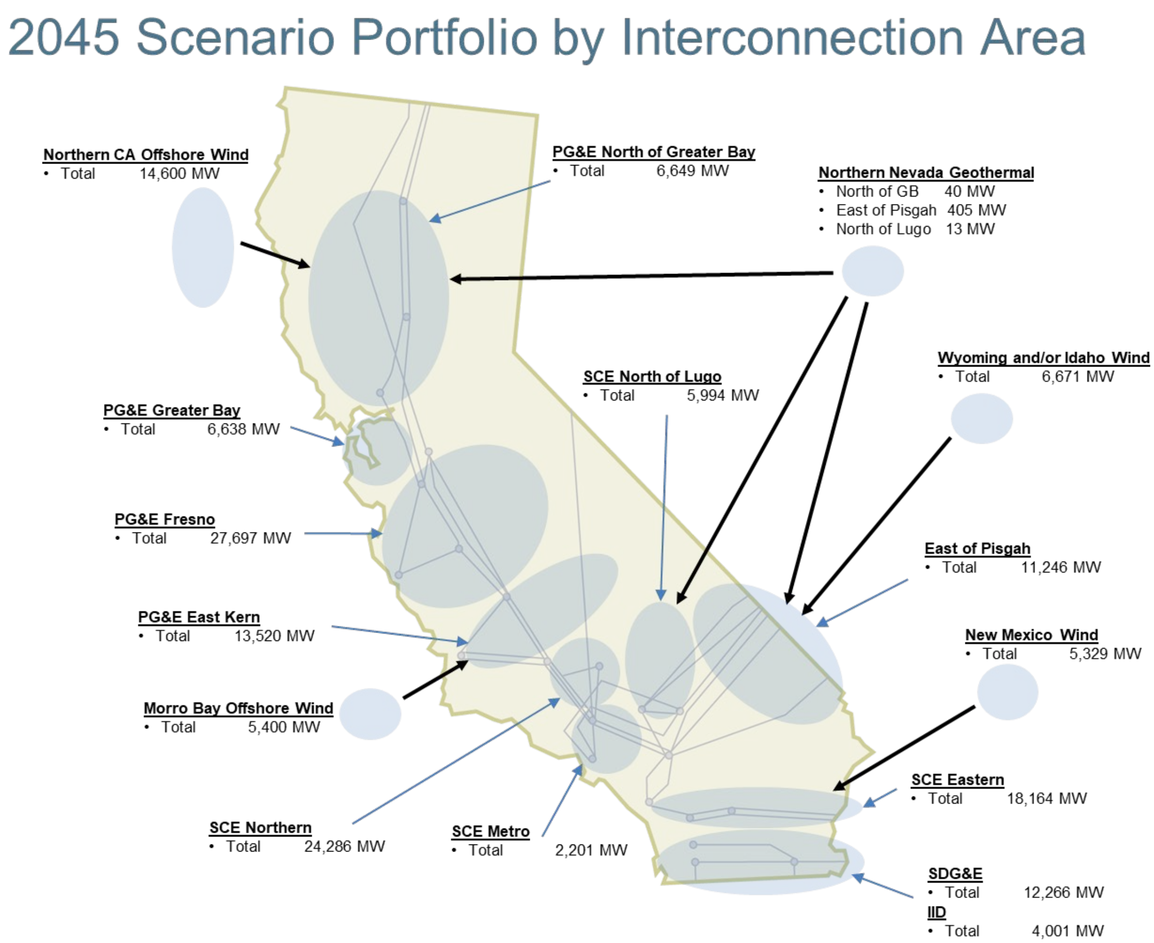
CAISO Study Area	20-Year Outlook
PG&E East Kern Study Area	0
PG&E Fresno Study Area	0
PG&E North of Greater Bay Study Area	179
PG&E S500 Study Area	0
East of Pisgah Study Area	905
SCE Eastern Study Area	850
SCE Metro Study Area	0
SCE North of Lugo (NOL) Study Area	53
SCE Northern Area	0
SDG&E Study Area	345
IID	0
Total	**2,332**

Chapter 4

4 Integration of Resources

To assess the transmission impacts and identify the transmission development concepts necessary to integrate the resources, they need to be mapped more granularly to the substations and busbars in the models. Figure 4-1 provides an illustration of the resources in the transmission zones within the ISO system.

Figure 4-1: High-level illustration of the areas of resource allocation

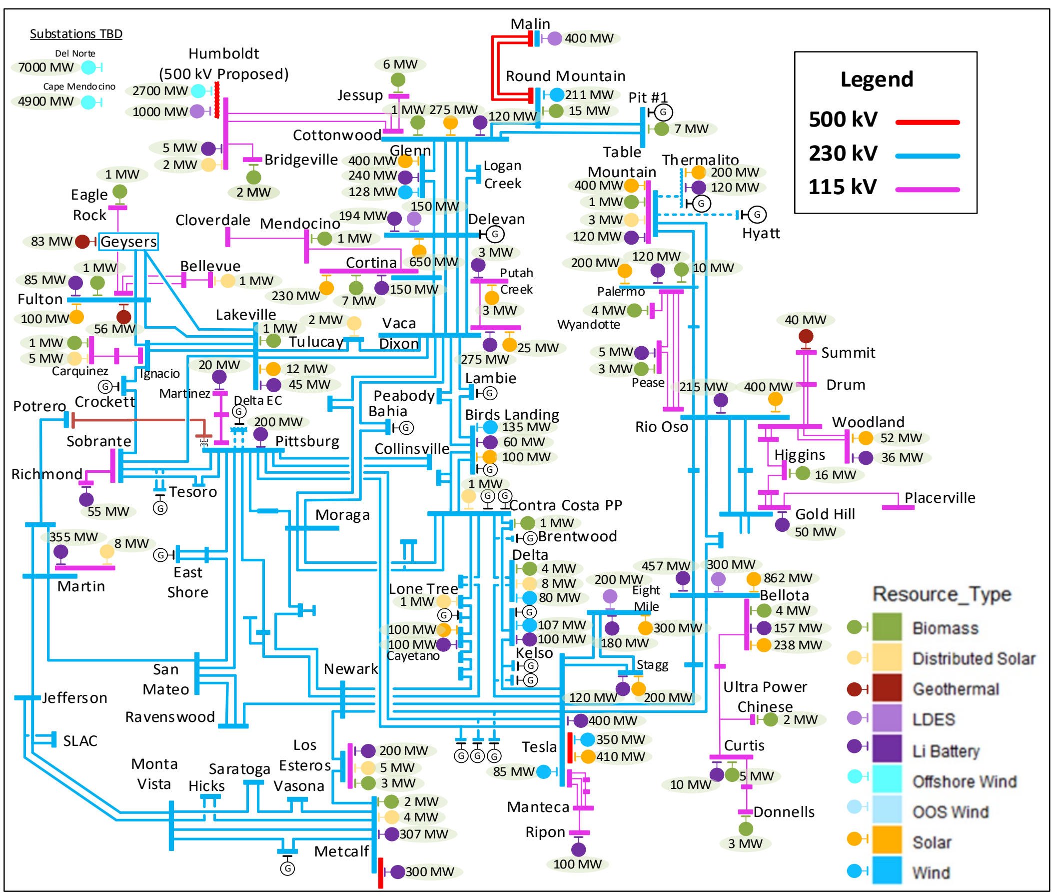


4.1 Mapping of Resources

The 2045 Portfolio identified 165,119 MW of resource capacity additions as indicated in Table 3-2. The resources have been mapped to the substations within each of the transmission zones identified in the resource portfolio. Details of busbar mapping of resources in each transmission zone are provided in tables and diagrams in the following sections:

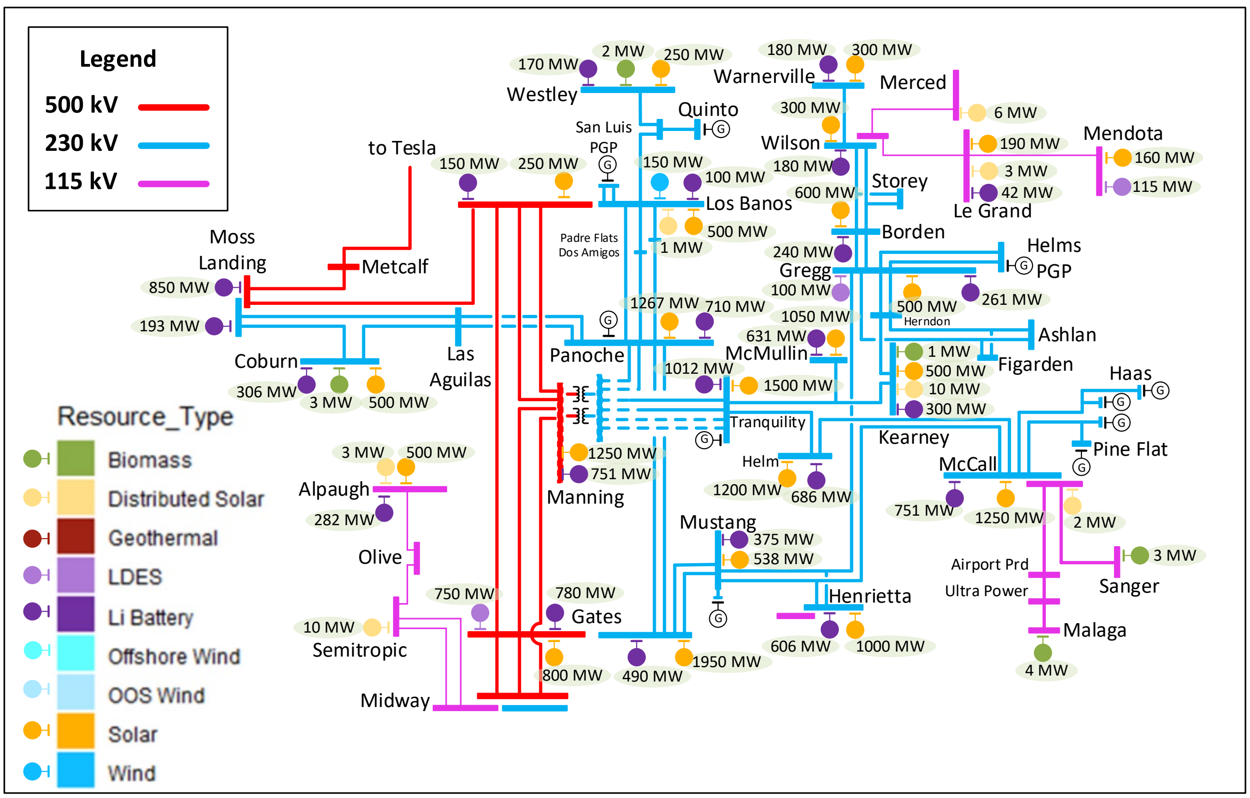
4.1.1 PG&E Greater Bay and North of Greater Bay

PG&E North of Greater Bay Study Area Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	4,903	0	4,903
Distributed Solar	40	0	40
Utility-scale Solar	1,649	3,308	4,957
Onshore Wind	912	184	1,095
Geothermal	179	0	179
Biomass/gas	102	0	102
Generic Clean-Firm/LDES	1,650	0	1,650
Offshore Wind	14,439	161	14,600
OOS Wind	0	0	0
LDES	400	0	400
TOTAL	24,274	36,53	27,927



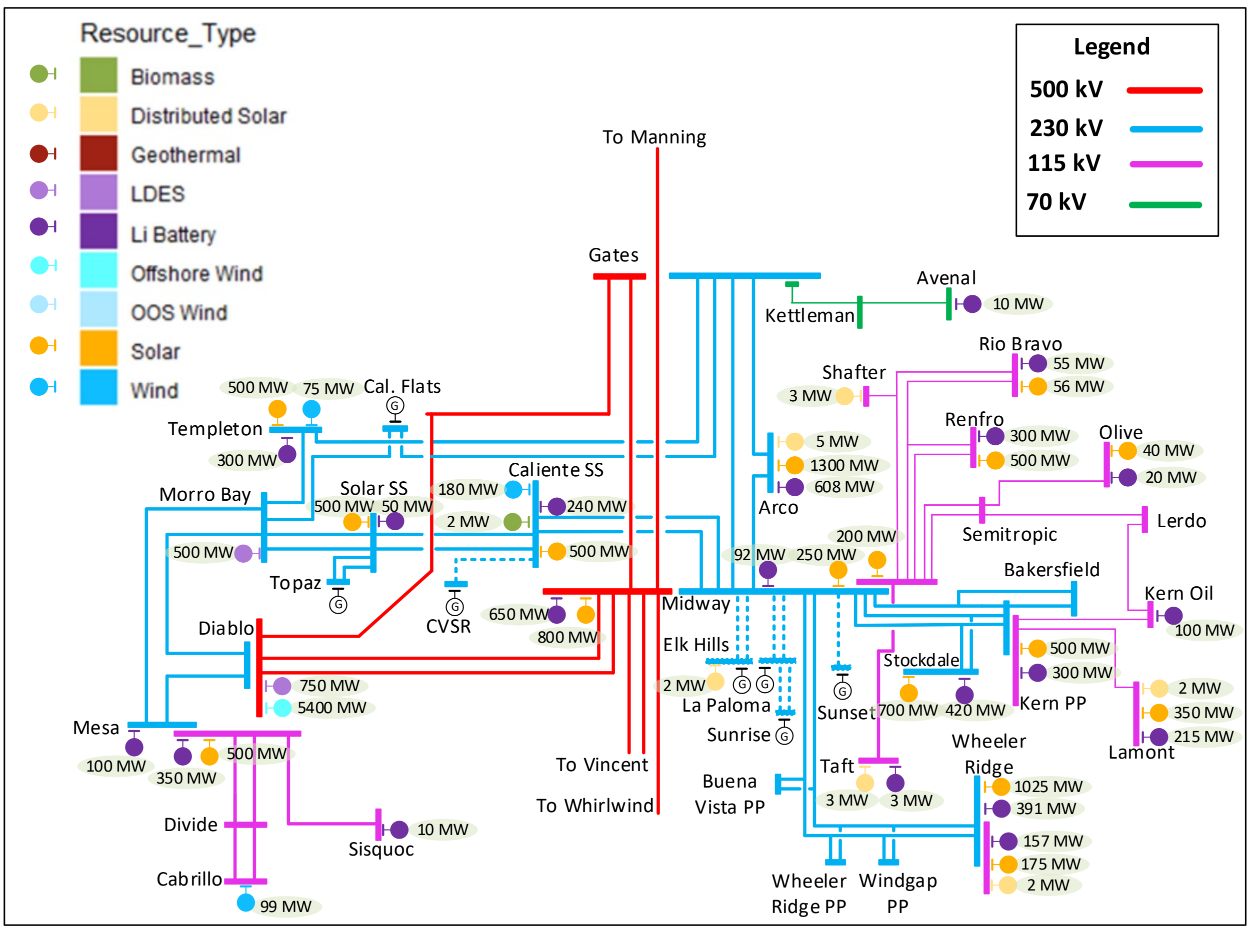
4.1.2 PG&E Fresno Study Area

PG&E Fresno Study Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	10,046	0	10,046
Distributed Solar	35	0	35
Utility-scale Solar	6,226	10,129	16,355
Onshore Wind	150	0	150
Geothermal	0	0	0
Biomass/gas	12	0	12
Generic Clean-Firm/LDES	1,000	0	1,000
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	100	0	100
TOTAL	**17,568**	**10,129**	**27,697**



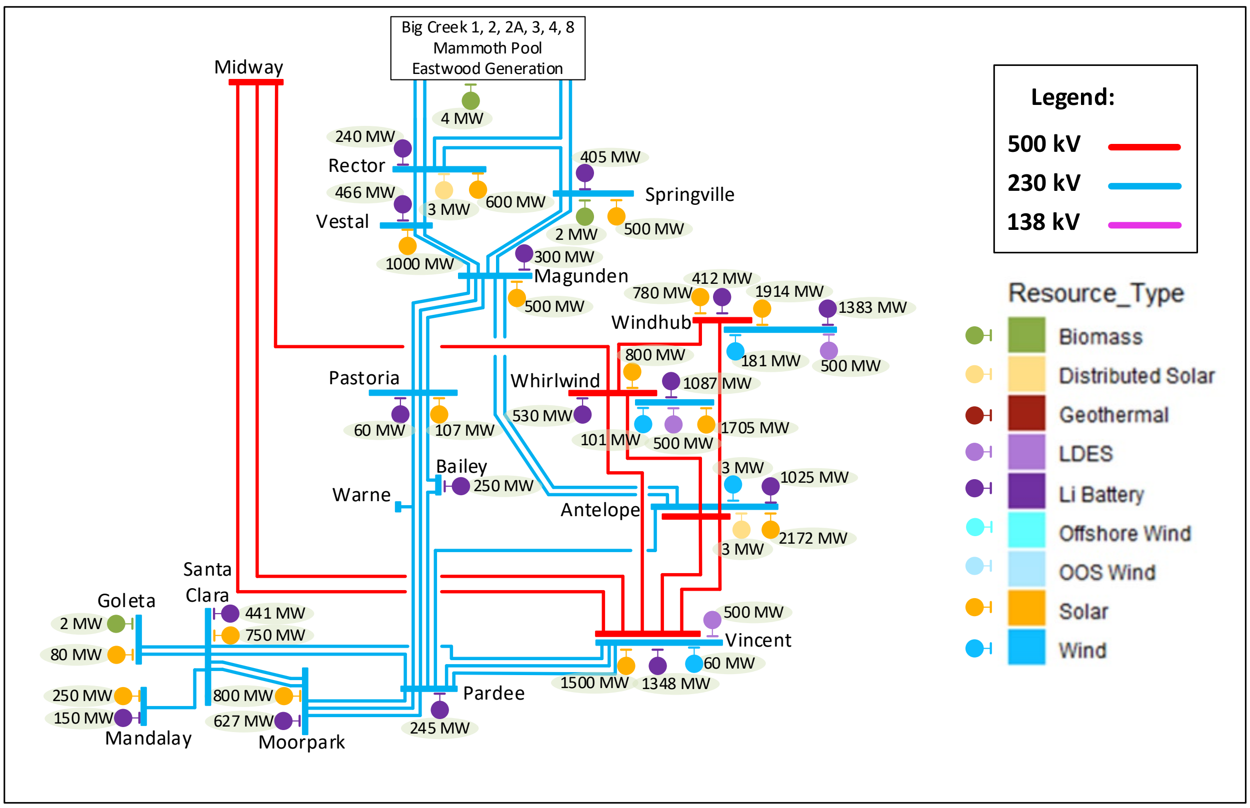
4.1.3 PG&E Kern Study Area

PG&E East Kern Study Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	4,370	0	4,370
Distributed Solar	18	0	18
Utility-scale Solar	2,406	5,120	7,526
Onshore Wind	354	0	354
Geothermal	0	0	0
Biomass/gas	2	0	2
Generic Clean-Firm/LDES	750	0	750
Offshore Wind	5,400	0	5,400
OOS Wind	0	0	0
LDES	500	0	500
TOTAL	**13,800**	**5,120**	**18,920**



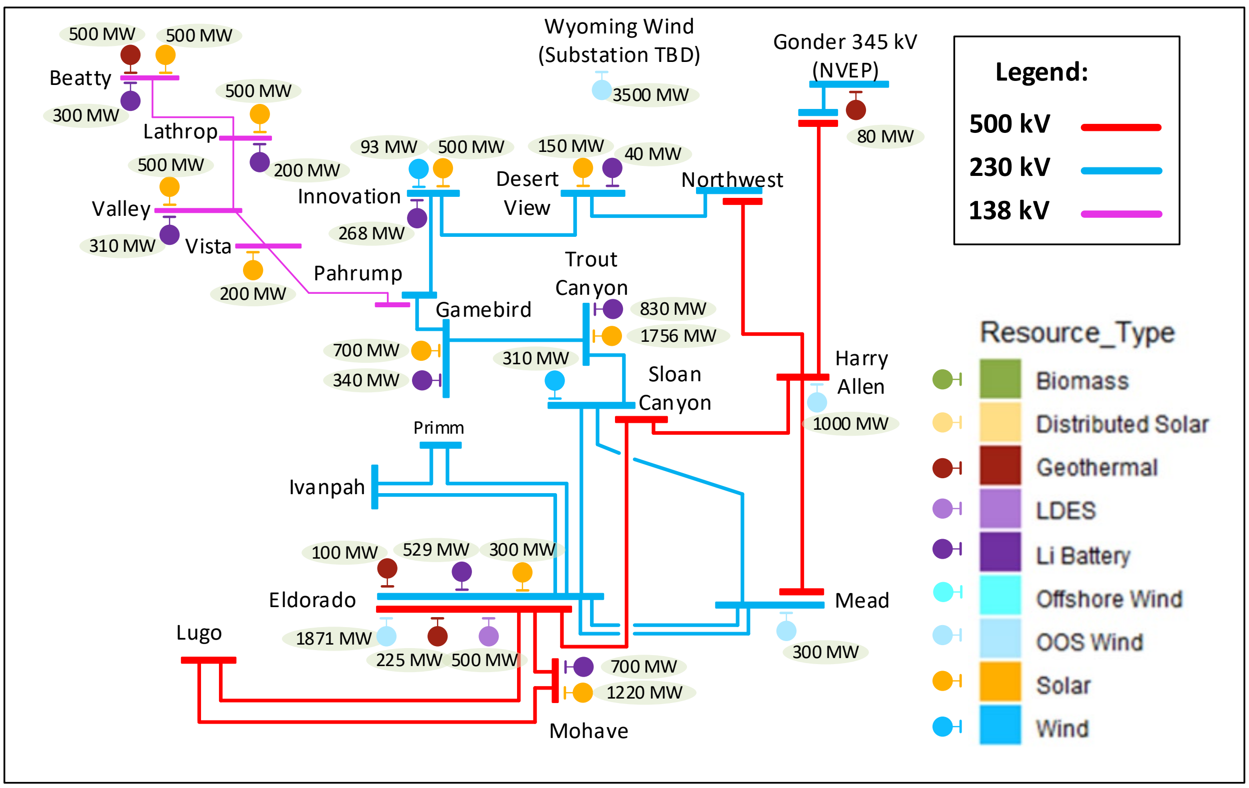
4.1.4 SCE Northern Study Area

SCE Northern Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	9048	0	9048
Distributed Solar	6	0	6
Utility-scale Solar	5,142	8,237	13,378
Onshore Wind	345	0	345
Geothermal	0	0	0
Biomass/gas	8	0	8
Generic Clean-Firm/LDES	500	0	500
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	1,000	0	1,000
TOTAL	**16049**	**8237**	**24286**



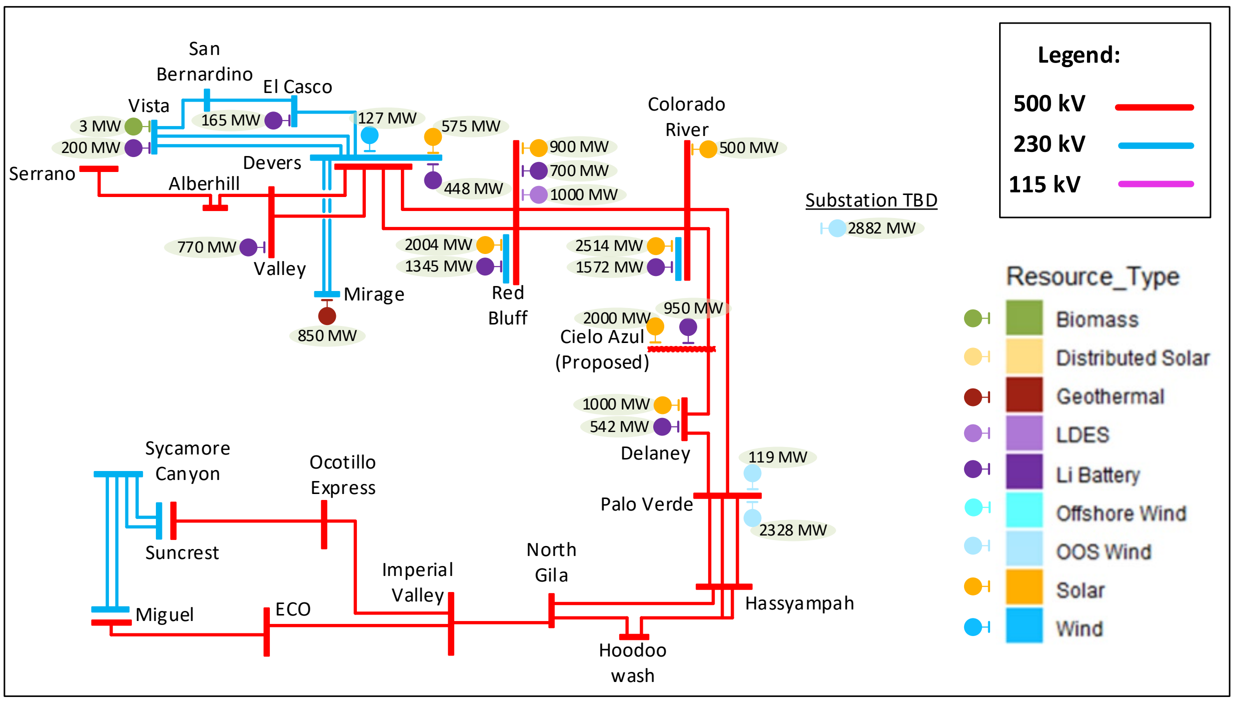
4.1.5 East of Pisgah Study Area

East of Pisgah Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	3,517	0	3,517
Distributed Solar	0	0	0
Utility-scale Solar	2,573	3,753	6,326
Onshore Wind	403	0	403
Geothermal	905	0	905
Biomass/gas	0	0	0
Generic Clean-Firm/LDES	500	0	500
Offshore Wind	0	0	0
OOS Wind	6,571	100	6,671
LDES	0	0	0
TOTAL	**14,469**	**3,853**	**18,322**



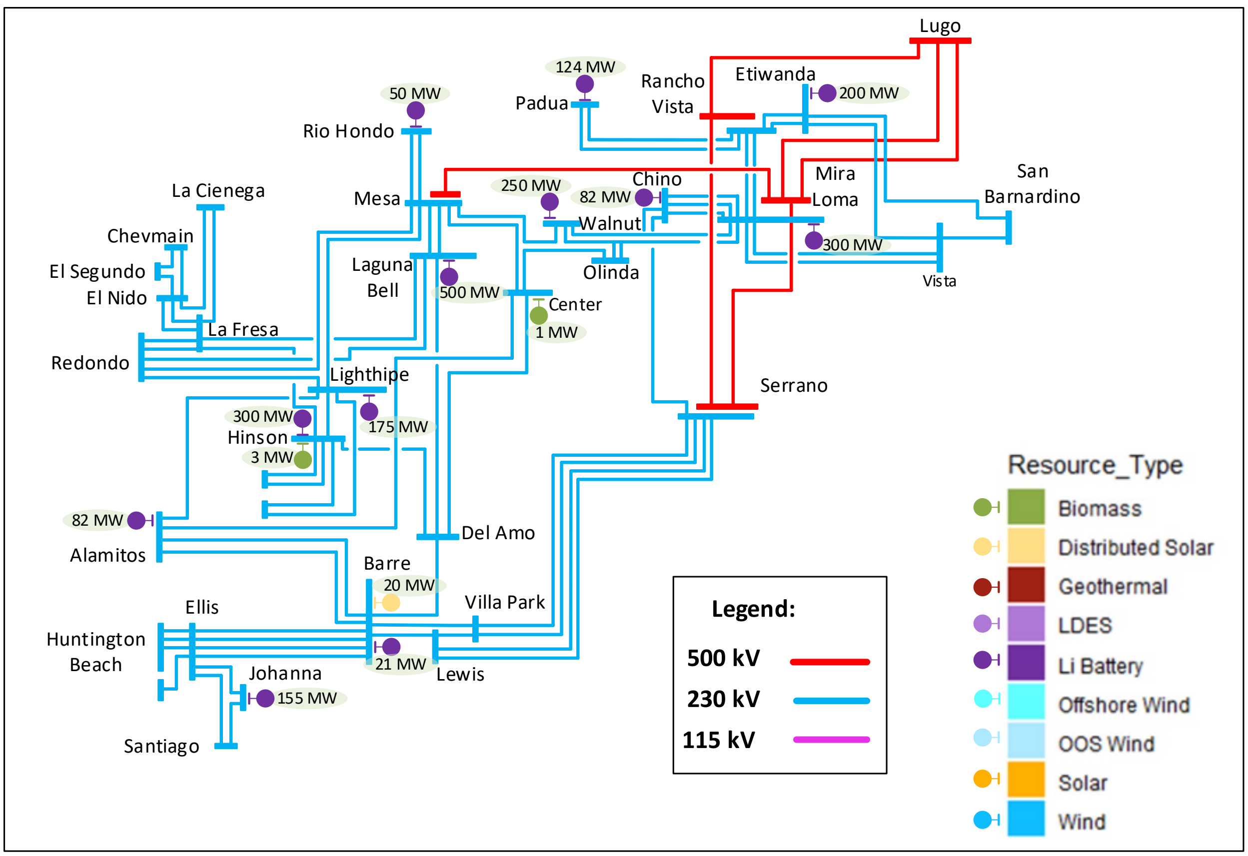
4.1.6 SCE Eastern Study Area

SCE Eastern Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	6,692	0	6,692
Distributed Solar	0	0	0
Utility-scale Solar	2,929	6,564	9,493
Onshore Wind	107	20	127
Geothermal	850	0	850
Biomass/gas	3	0	3
Generic Clean-Firm/LDES	0	0	0
Offshore Wind	0	0	0
OOS Wind	5,329	0	5,329
LDES	1,000	0	1,000
TOTAL	16,910	6,584	23,493



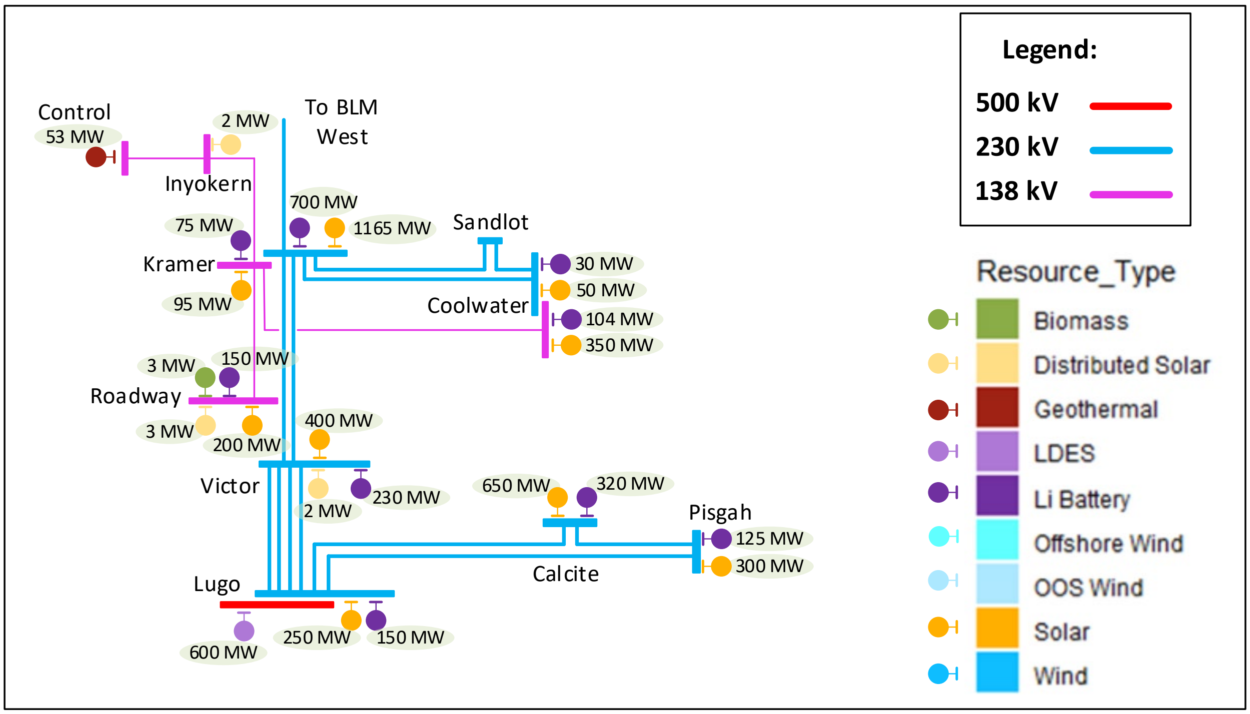
4.1.7 SCE Metro Study Area

SCE Metro Study Area	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	2,177	0	2,177
Distributed Solar	20	0	20
Utility-scale Solar	0	0	0
Onshore Wind	0	0	0
Geothermal	0	0	0
Biomass/gas	4	0	4
Generic Clean-Firm/LDES	0	0	0
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	0	0	0
TOTAL	**2,201**	**0**	**2,201**



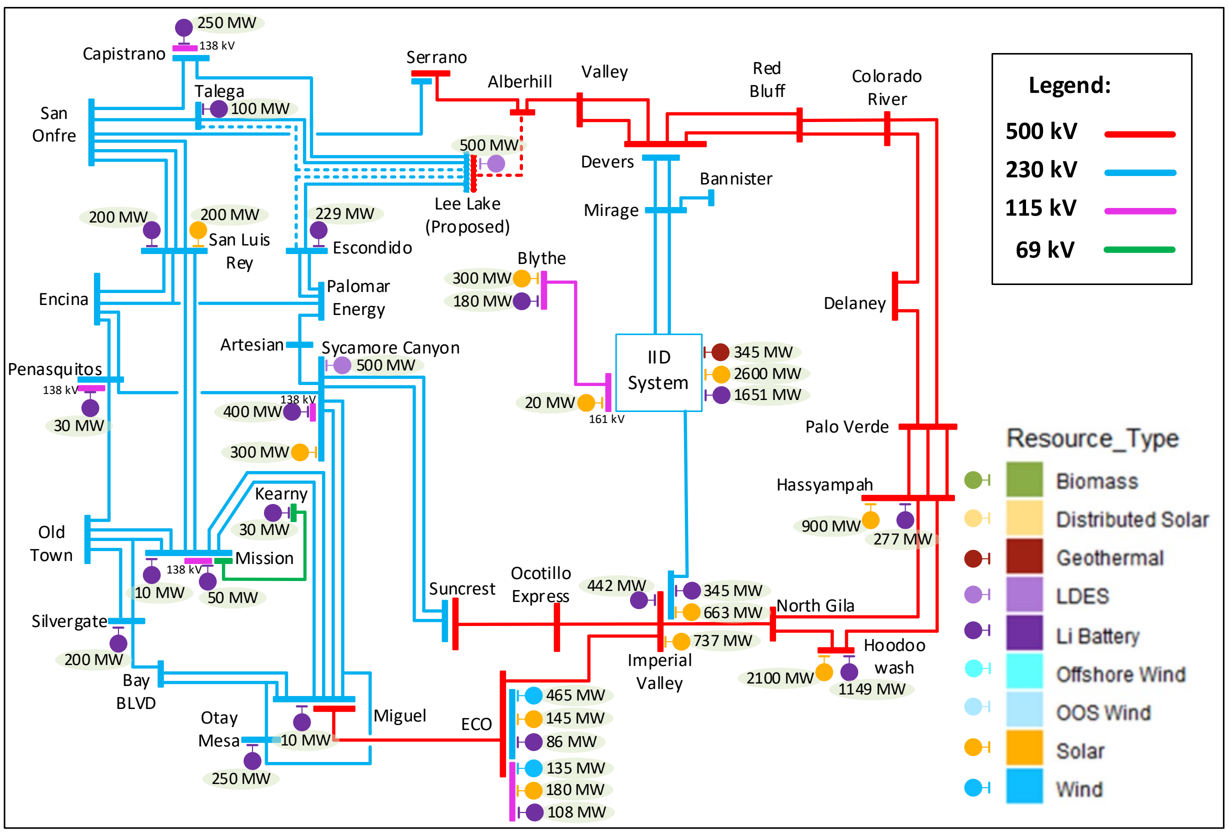
4.1.8 SCE North of Lugo Study Area

SCE North of Lugo Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	1,884	0	1884
Distributed Solar	7	0	7
Utility-scale Solar	1,550	1,910	3,460
Onshore Wind	0	0	0
Geothermal	53	0	53
Biomass/gas	3	0	3
Generic Clean-Firm/LDES	600	0	600
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	0	0	0
TOTAL	**4,097**	**1,910**	**6,007**



4.1.9 SDG&E Study Area

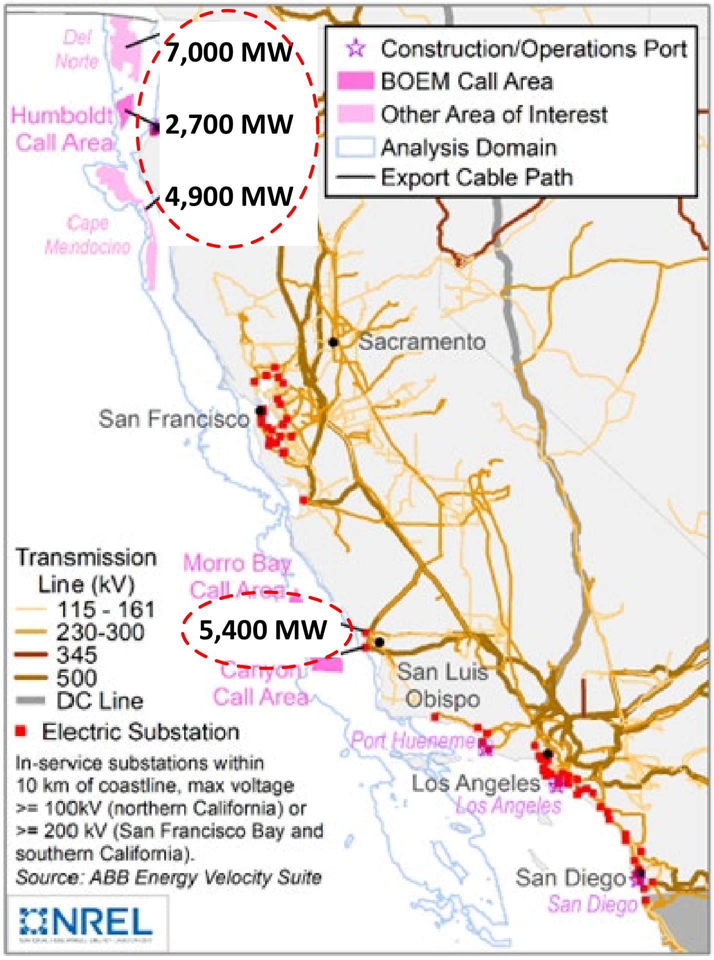
SDG&E + IID Total	FCDS (MW)	EO (MW)	Total (MW)
Li_Battery	6177	0	6177
Distributed Solar	0	0	0
Utility-scale Solar	2378	5767	8145
Onshore Wind	240	360	600
Geothermal	345	0	345
Biomass/gas	0	0	0
Generic Clean-Firm/LDES	0	0	0
Offshore Wind	0	0	0
OOS Wind	0	0	0
LDES	1000	0	1000
TOTAL	**10140**	**6127**	**16267**



4.2 Offshore Wind Interconnection

As discussed in Section 3.1.8, the 2045 Portfolio includes a total of 20,000 MW of offshore wind. Figure 4-2 shows the approximate location of the assumed offshore wind development in this study.

Figure 4-2: Offshore Wind Development Location Assumptions[16]



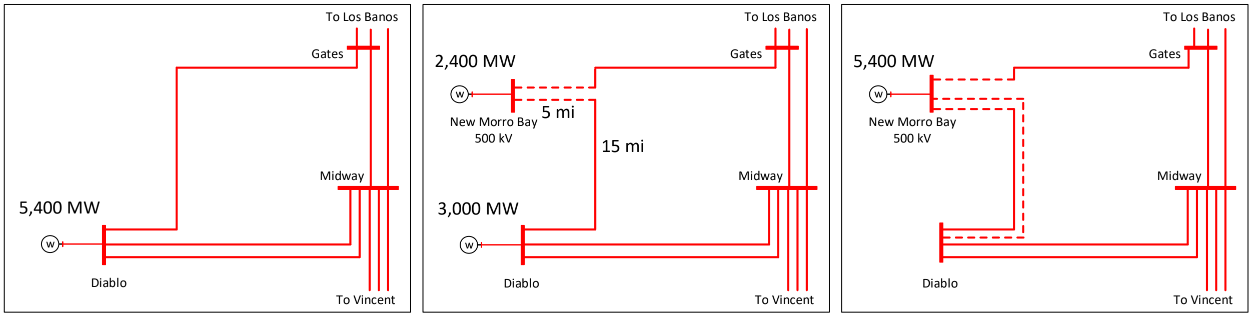
Base map source: [The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov)]

4.2.1 Interconnection of Central Coast Offshore Wind

The analysis performed as part of the 2021-2022 transmission planning process (TPP) cycle indicated that the existing 500 kV transmission system in Diablo/Morro Bay area has the capacity for interconnection of more than 5,300 MW of generation with Full Capacity Deliverability Status (FCDS). With the retirement of the Diablo Canyon Power Plant, the 5,400 MW offshore wind in the central coast could be connected at either Diablo or new Morro Bay 500 kV substation. Additional reinforcements such as a new line from Diablo to Morro Bay would be required if more than around 2,400 MW is connected to the Morro Bay substation (Figure 4-3).

[16] The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032 (nrel.gov) (Page 39)

Figure 4-3: Central Coast Offshore Wind Interconnection Options



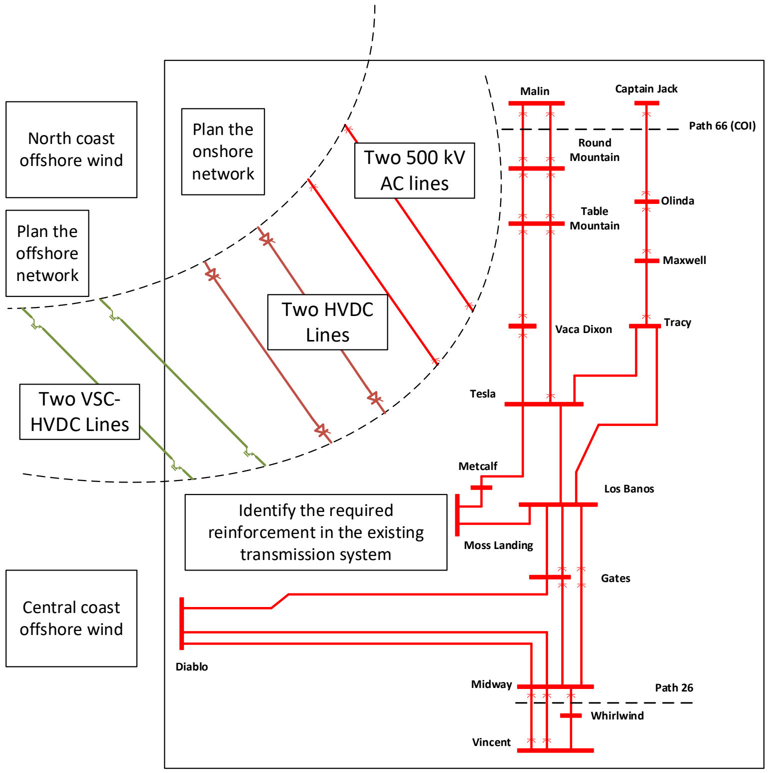
4.2.2 Interconnection of North Coast Offshore Wind

The transmission concept recommended in the 2021-2022 Transmission Plan to interconnect the North Coast offshore wind to the rest of the CAISO system is illustrated in Figure 4-4. The same transmission concepts were used as the transfer path in this 20-Year Outlook Update study. The line ratings and the interconnection points are provided in Table 4-1. The details of the overall transmission interconnection options are provided in the following sections.

Table 4-1: Rating Assumptions for Bulk Transmission Technology Options

Technology and Interconnection point	Normal Rating Assumptions (MVA)	Emergency Rating Assumptions (MVA)
500 kV AC line to Fern Road	3,500	4,500
Onshore overhead VSC-HVDC to Collinsville Substation	3,000	3,500
Offshore sea cable VSC-HVDC to a Substation in the Bay Area	2,000	2,500

Figure 4-4: North Coast Offshore Wind Interconnection Assumption



4.2.2.1 Two 500 kV AC Interconnections to Fern Road

The sensitivity analysis in the 2023-2024 transmission planning process (TPP) cycle includes 8,045 MW of offshore wind in the North Coast. The results of that study indicated that with injection of offshore wind at Fern Road, the existing transmission path between Fern Road and Tesla 500 kV substations experience overload under normal and contingency conditions. A potential mitigation for the overloads is to build two 500 kV AC lines from Fern Road to Vaca Dixon to Tesla substations.

- Alternative 1: Build two 500 kV AC lines from Fern Road to Vaca Dixon to Tesla 500 kV substation. This alternative requires a total of around 650 miles of single circuit 500 kV lines to be built but is more flexible than other alternatives as a) it could be implemented with minimal to no impact to the existing 500 kV lines from Fern Road to Tesla, and b) it makes the Fern Road a hub for interconnection of potential future major transmission projects, especially if the 500 kV lines north of Fern Road to Northwest system are also upgraded.
- Alternative 2: Build one 500 kV AC line from Fern Road to Vaca Dixon to Tesla 500 kV substation and upgrade the two existing 500 kV lines from Fern Road to Tesla 500 kV substation. This alternative requires around 450 miles of new lines and upgrade of another 400 miles of existing 500 kV lines. This alternative could potentially make better use of the existing rights of way, but significant coordination and alignment in timing is needed to ensure the required outages of the existing 500 kV lines from Fern Road to Tesla will not be scheduled when the interchange between the CAISO and the Northwest is high.

Interconnection to Tesla 500 kV:

PG&E's Transmission Interconnection Handbook[17] indicates that the Tesla 500 kV substation cannot accept new points of interconnection (POIs). Therefore it is assumed that a new substation will be built next to the existing Tesla 500 kV substation to facilitate the connection of the proposed new Fern Road – Tesla 500 kV lines as well as the interconnection of the out-of-state wind from Wyoming.

4.2.2.2 Two Overhead VSC-HVDC to Collinsville

The sensitivity analysis results in the 2023-2024 TPP cycles that included an interconnection option with two HVDC lines to Collinsville, indicated N-0 overload on the Collinsville to Pittsburg 230 kV lines. Series reactors on the Collinsville – Pittsburg lines are recommended for approval as the mitigation measure. The series reactors are assumed in the starting base case in this analysis.

4.2.2.3 Two subsea VSC-HVDC to Bay Area

The two subsea VSC-HVDC links to Bay Area were studied in two different alternative interconnections.

- Alternative 1: Both VSC-HVDC lines terminate at the BayHub converter station in the Bay area with converter station connecting to major substations (Potrero, East Shore, Los Esteros, Monta Vista, San Mateo, and Newark 230 kV substations) in the Bay Area with six 230 kV cables
- Alternative 2: One VSC-HVDC line terminates at the BayHub converter station in Bay Area with three 230 kV cables connecting the BayHub station to Potrero, East Shore and Los Esteros 230 kV substations. The second VSC-HVDC line will terminate at Moss Landing 500 kV substation.

4.2.2.4 Interconnection of Del Norte, Humboldt, and Cape Mendocino Wind

The CPUC Modelling Assumptions for the 2023-2024 TPP provided the following guidance regarding offshore wind development in the North Coast:

"... offshore wind have been mapped to ... three separate locations on the North Coast (Humboldt, Del Norte, and Cape Mendocino) to allow CAISO to identify transmission upgrades and cost information necessary to further advance offshore wind planning in line with the state's offshore wind policy goals."

Based on a recent CEC report[18], the environmental analysis performed by the Schatz Center identifies significant environmental challenges to build overhead lines along the coast from Del Norte to Humboldt to Cape Mendocino. Therefore, any transmission option interconnecting Del Norte and Cape Mendocino Point of Interconnections to Humboldt is assumed to be VSC-HVDC with either underground or subsea HVDC cable.

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[17] https://www.pge.com/assets/pge/docs/about/doing-business-with-pge/g2.pdf (Table G2)

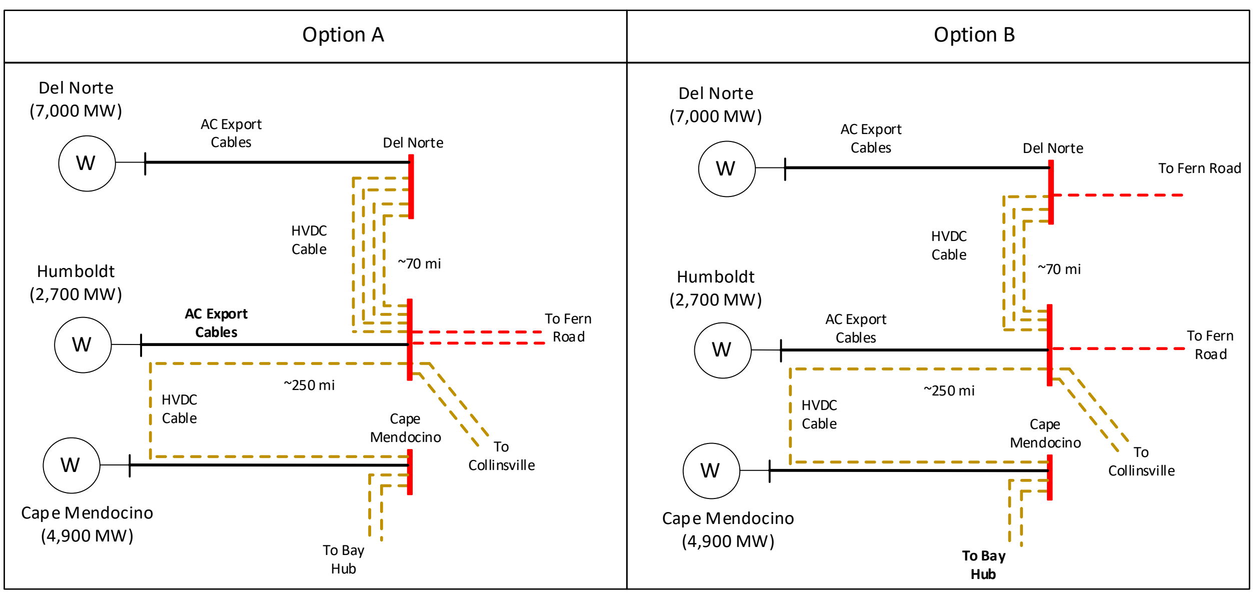
[18] Schatz Center - Northern California and Southern Oregon Offshore Wind Transmission study https://efiling.energy.ca.gov/GetDocument.aspx?tn=252604

Two options have been considered to interconnect the offshore wind in the North Coast to the rest of the system. As shown in Figure 4-5, in both alternatives, it is assumed AC export cables bring power from offshore wind plants to the onshore point of interconnections at the Humboldt, Del Norte, and Cape Mendocino substations.

In both options, the Humboldt and Cape Mendocino substations are connected through a subsea VSC-HVDC link. The reason for the length of the line (~250 mi) is the subsea canyons in the area which makes a near shore connection between Humboldt and Cape Mendocino very challenging due to seabed conditions. Therefore such an HVDC cable would need to be routed away from shore and in deeper waters. While routing the cables away from the shore may avoid the subsea canyons, the water depth may reach 4,000 m while current feasibility has been identified as only up to 1500 m. Further assessment will be required to determine whether all technical issues that may limit the feasibility of the subsea cable from North Coast to Bay Area can be addressed. If technical issues of subsea cables from North Coast to Bay Area cannot be resolved, additional onshore HVDC line(s) may be required. To have similar performance, it will be critical that the onshore HVDC line(s) could create a similar concept as Bay Hub but from different routing (i.e. from the North Bay Area west of Collinsville).

Del Norte substation is the POI for 7,000 MW of offshore wind. In Option A, four subsea HVDC cables interconnect Del Norte to Humboldt substation and two 500 kV AC lines interconnect Humboldt to Fern Road substation. In Option B, three subsea HVDC cables interconnect Del Norte to Humboldt substation and one 500 kV AC interconnects Del Norte substation to Fern Road substation. Transmission options A and option B are shown in Figure 4-5.

Figure 4-5: Transmission Options for Integration of North Coast Offshore Wind



While both options provide the required capacity to transfer the power to the shore and to the existing system, the optimum option will be determined based on the development sequence of the North Coast offshore wind and the availability of right of way for 500 kV AC lines from Humboldt and Del Norte to Fern Road substation.

Interconnection to Humboldt 115 kV System

The Humboldt area is currently supplied by local gas generation and through two 115 kV lines from Cottonwood substation around 120 miles away. To enhance the resiliency of the Humboldt 115 kV system and allow for the retirement of gas generation in the long term, in all alternatives the ISO is proposing to provide another supply to the area from the Humboldt 500 kV substation. The interconnection includes a 500/115 kV transformer at Humboldt 500 kV substation, a 115 kV line from Humboldt 500 kV to existing Humboldt 115 kV substation, and a 115kV/115 kV phase shifting transformer (PST) at Humboldt 115 kV substation. The PST will help to control the flow and prevent overload as the amount of offshore wind generation varies in real time operation. The schematic diagram of the interconnection is provided in Figure 4-6.

Figure 4-6: Interconnecting Humboldt 500 kV substation to Humboldt 115 kV substation

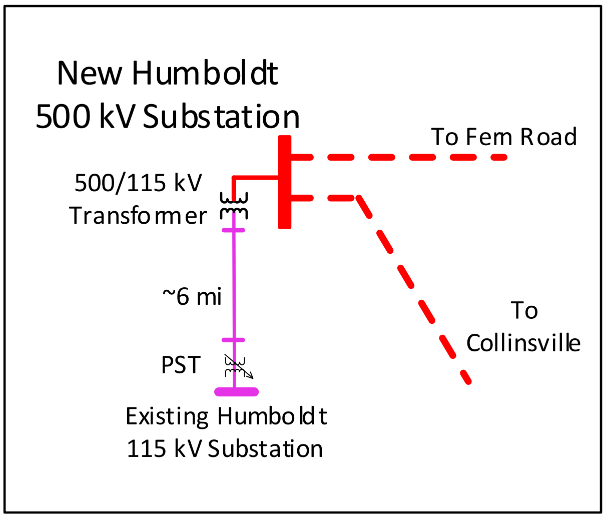


Figure 4-7 - Figure 4-10 provide four transmission concepts to integrate 14,600 MW of offshore wind in the North Coast to the rest of the CAISO system. The variations are based on whether the subsea VSC-HVDC link from Cape Mendocino terminates at Moss Landing or at Bay Hub with more 230 kV cable connections to Bay Area substations, or whether the termination of the second 500 kV AC line from Fern Road is Humboldt Bay 500 kV bus or Del Norte 500 kV bus.

Figure 4-7: Transmission Concept 20YTO-A to Integrate North Coast Offshore Wind

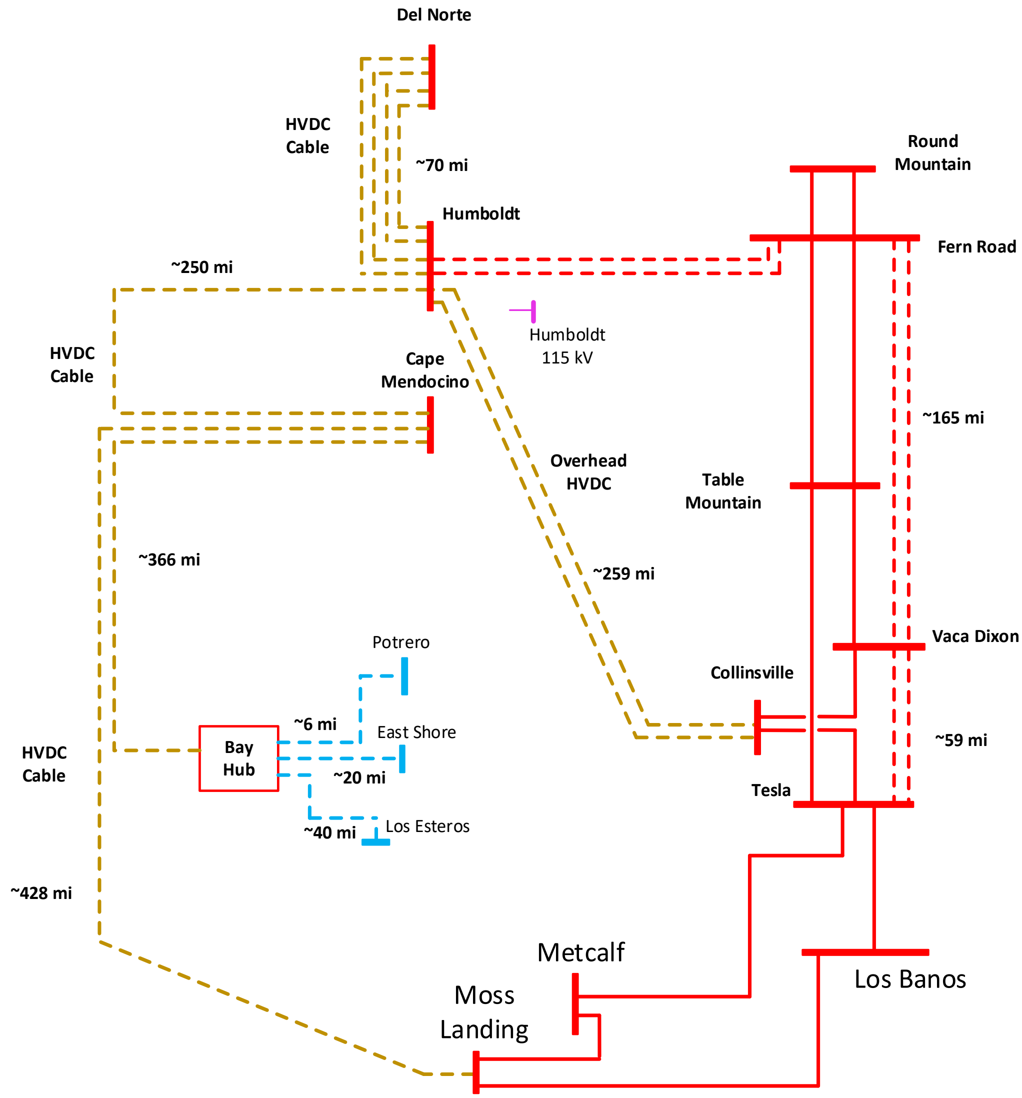


Figure 4-8: Transmission Concept 20YTO-B to Integrate North Coast Offshore Wind

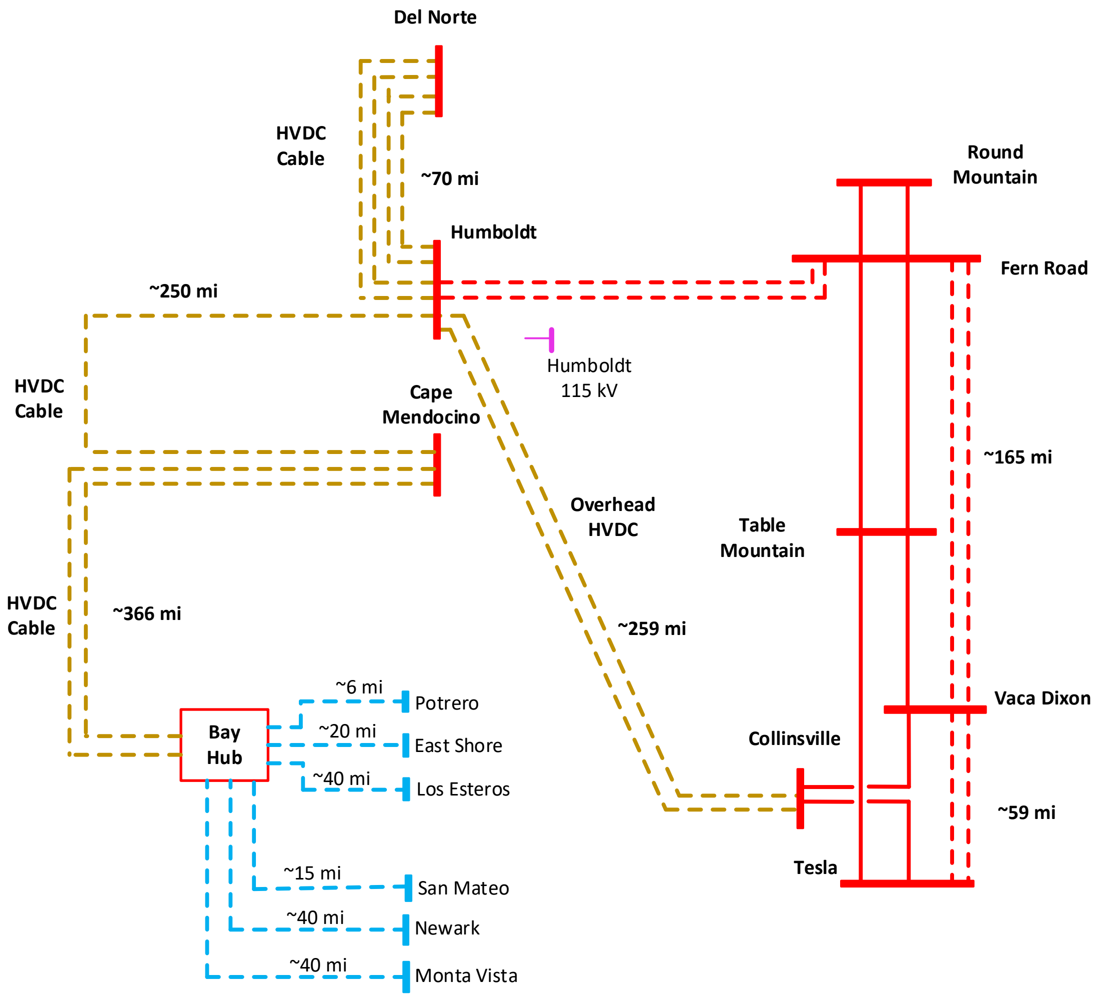


Figure 4-9: Transmission Concept 20YTO-C to Integrate North Coast Offshore Wind

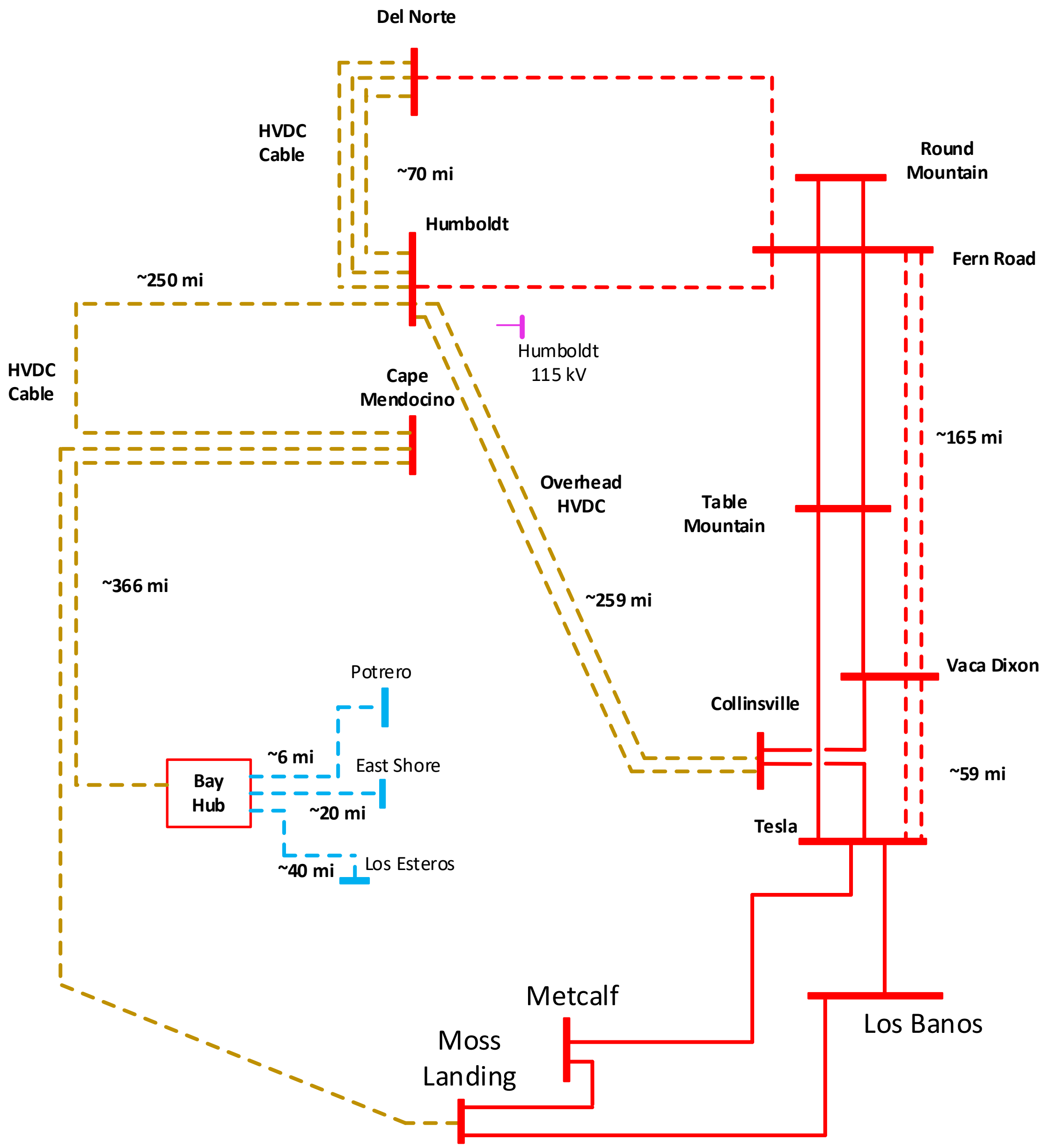
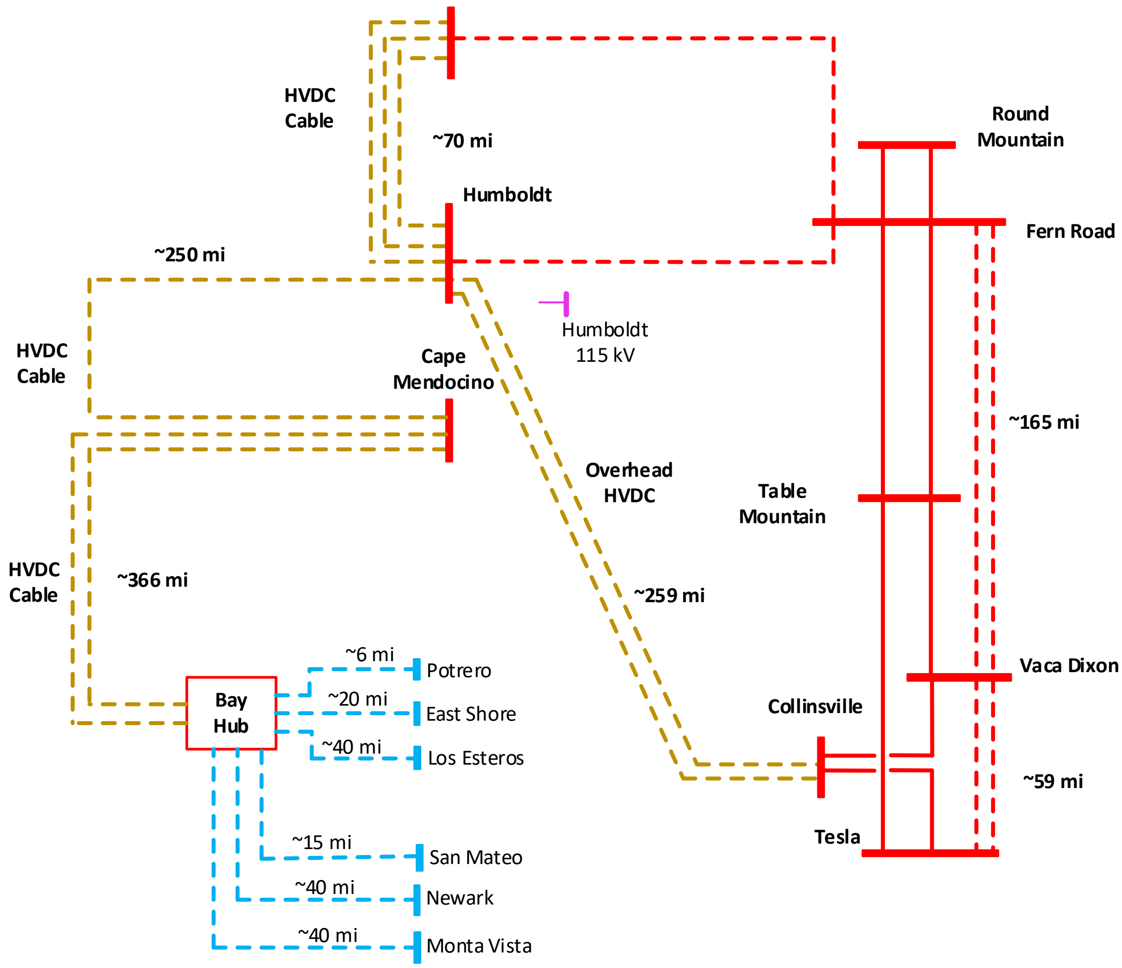


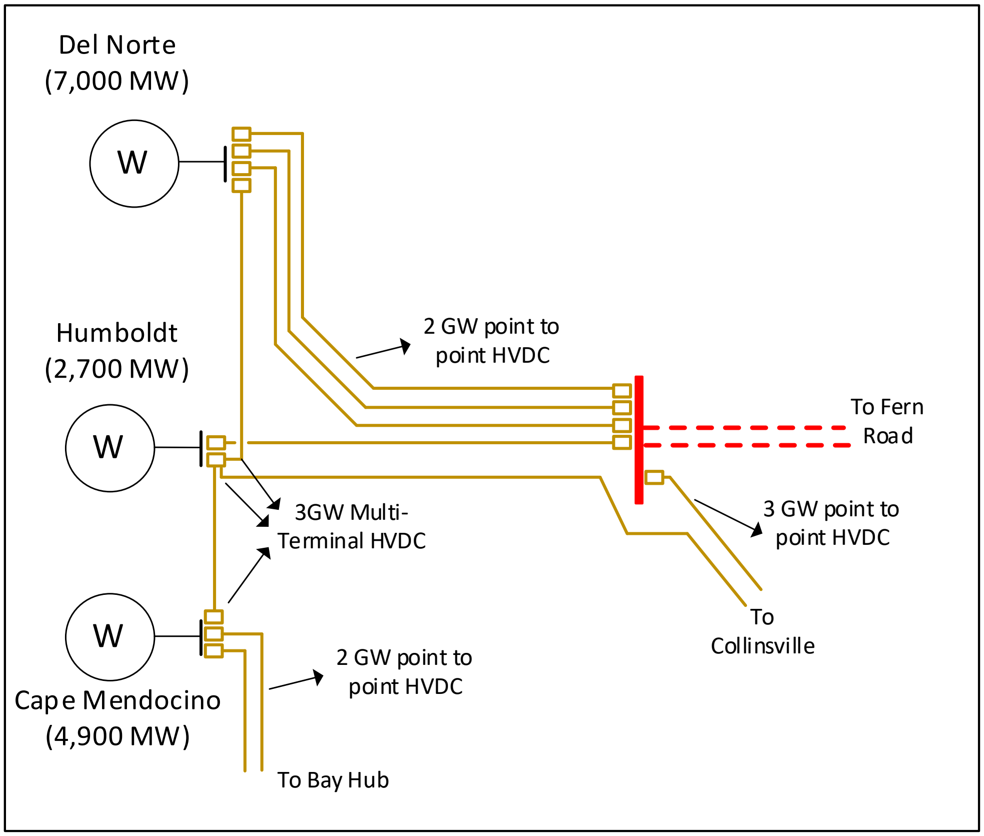
Figure 4-10: Transmission Concept 20YTO-D to Integrate North Coast Offshore Wind



4.2.2.5 Floating Offshore HVDC Converter Station and Grid

The offshore wind integration alternatives in this study so far have been based on the assumption that the export cables interconnecting the offshore wind plants to the onshore POI are AC cables. Floating offshore HVDC converter stations and HVDC dynamic cables are technologies under development that allow for fewer high capacity HVDC cables to transfer power from floating offshore HVDC converter stations to the shore. A potential concept assuming the availability of the floating offshore HVDC converter station and dynamic HVDC cables is provided in Figure 4-11.

Figure 4-11: Transmission Concept Based on Floating Offshore HVDC Converter Station



A potential advantage of such configuration is to have fewer cables coming to the shore and also increase the overall reliability of supply under contingency conditions. The idea has been explored in other systems such as New York[19] and Denmark[20].

As well, floating offshore HVDC converter stations could provide options for creating an offshore grid that could be expanded to connect to Pacific Northwest offshore wind development and further strengthen transfer capabilities between the regions.

Given that such technology does not exist at this time and as a result, feasibility, cost and ratings of such schemes are not available, no further analysis was performed on this transmission concept in this study.

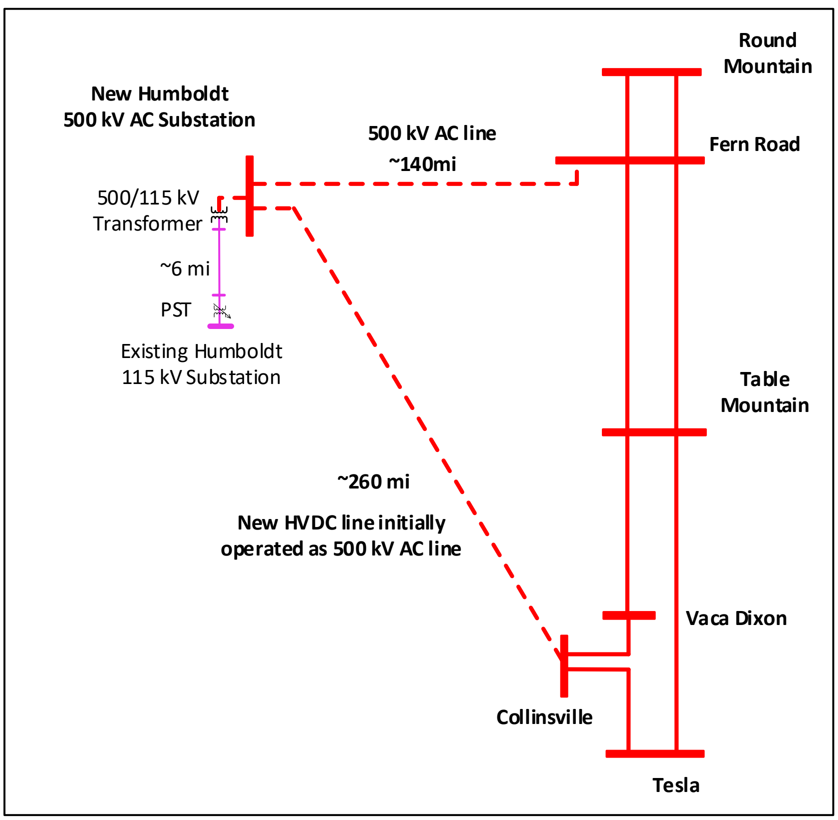
19 The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York (brattle.com)

20 A132994-2-4 Elektriske systemer for Bornholm I + II, Nordsøen II + III og Området vest for Nordsøen II + III (ens.dk) (in Danish)

4.2.3 Recommended Transmission Project for Humboldt Offshore Wind in 2023-2024 Transmission Plan

The CPUC base and sensitivity resource portfolios submitted to CAISO as part of the 2023-2024 TPP included 1,607 MW offshore wind in the North Coast in the base portfolio and 8,045 MW of offshore wind in the North Coast in the sensitivity portfolio. Chapter 3 and Appendix F of the Draft 2023-2024 Transmission Plan provide details of the analyses performed on different transmission alternatives to integrate the above offshore wind in the North Coast in the base and sensitivity portfolios and how such alternatives fit into the development of the ultimate plan in the 20-Year Outlook. Figure 4-12 provides the schematic diagram of the transmission project recommended for approval for integration of 1,607 MW of Humboldt offshore wind. The project scope includes a 500 kV AC line from the new Humboldt 500 kV station to Fern Road substation and an HVDC line, initially energized at 500 kV AC, from the new Humboldt 500 kV substation to Collinsville substation. The cost estimate for the project including mitigation measures is \$3.1B – \$4.5B. The project is recommended for approval as part of the Draft 2023-2024 Transmission Plan

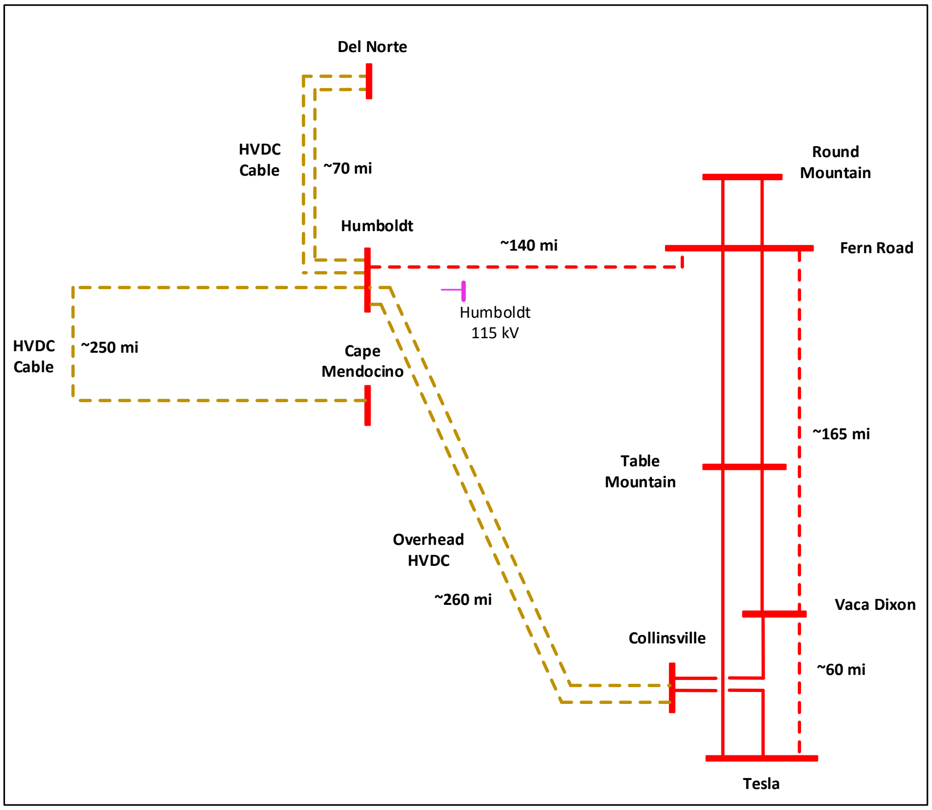
Figure 4-12: Recommended Transmission Project for Humboldt Offshore Wind



Four different alternatives were studied for the integration of 8,045 MW of offshore wind in the North Coast. One of the alternatives is shown in Figure 4-13 that includes two HVDC lines to Collinsville and a 500 kV AC line to Fern Road substation. The cost estimates for different alternatives in the sensitivity analysis are in the \$13.2B – \$21.1B range.

The recommended transmission project for approval to integrate 1,607 MW of offshore wind has the flexibility to be expanded into any of the alternatives considered for the sensitivity scenario with 8,045 MW offshore wind in the North Coast and into any of the alternatives considered for the 20-Year Outlook update with 14,600 MW of North Coast offshore wind including an offshore HVDC grid.

Figure 4-13: One of the Transmission Alternatives for 8,045 MW North Coast OSW



4.3 Out-of-State Wind Interconnection

The resource portfolio for 2045 includes 3,500 MW of Wyoming wind and 2,882 MW of New Mexico wind that will be transferred to CAISO on new transmission. These resources are not mapped to a substation in the CAISO system. The new transmission projects could either bring the out-of-state wind to the border of the ISO system, requiring additional transmission within the ISO system to bring the energy to the load centers, or could be brought to interconnection points within the ISO, such as Tesla and Lugo substations. Transmission lines to connect to interconnection points within the ISO system could potentially facilitate coordination with the Los Angeles Department of Water and Power (LADWP) and the Balancing Authority of Northern California (BANC) to bring in additional out-of-state wind that they may require for their resource portfolios. Both alternatives are evaluated in this study at a high level.

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Chapter 5

5 High-Level Assessment

5.1 Introduction

The objective of the high-level assessment is to gain insight into the transmission enhancements required to reliably transfer power from the portfolio resources to the load across the system under different load and generation conditions. Typically, production cost simulation analysis is performed to identify the system snapshots that will stress the transmission system, with power flow and transient stability analysis then performed on those stressed snapshots. However since production cost simulation was not performed as part of the high level assessment, the following snapshots were considered as candidates to identify system enhancement requirements:

Net-Peak Load Study

The Net-Peak Load study is based on the High System Need (HSN) in deliverability studies and reflects the system in early evening summer conditions. In this case, the electricity consumption is around 90 percent of the maximum but due to evening hours there is no solar or behind-the-meter photovoltaic (BTM-PV) generation. A number of HSN snapshots with varying level of wind, import, battery storage, and gas generation were developed to assess system performance under different supply scenarios.

Peak Consumption Study

The Peak consumption study is based on the Secondary System Need (SSN) in deliverability studies and reflects the system in early afternoon summer conditions. In this case, electricity consumption is at a maximum but a significant portion of it is served by the solar and the BTM-PV generation. The in-state, out-of-state, and offshore wind generation assumptions are in line with the SSN deliverability analysis and the import level is assumed to be close to zero. The battery storage is assumed to be fully charged in this case in preparation to be generating power during the evening ramp and evening hours.

Off-Peak Study

The Off-Peak study reflects the system in the middle of the day in spring when electricity consumption is low and at the same time the solar and BTM-PV generation are high. The in-state, out-of-state, and offshore wind generation assumptions are in line with the off- peak deliverability analysis and it is assumed the ISO system will export around 5,000 MW of power to the neighboring system. The battery storage is assumed to be in full charging mode in this case.

A number of base cases reflecting the above snapshots were developed for the contingency analysis to identify the potential transmission enhancement requirements. The system data and analysis of the study results are detailed in the following sections.

5.2 System Data and Study Assumptions

5.2.1 Load Forecast Assumptions

The following table provides the load and the BTM-PV generation for the three study cases. More details are provided in Section 3.1.1.

Table 5-1: Load and BTM-PV assumptions

Study Cases	Date/Time assumption	Load (MW)	BTM-PV Generation (MW)
Net peak load (HSN)	9/5/2045 HE 19	64,923	~0
Peak Consumption (SSN)	9/5/2045 HE14	77,430	30,061
Off peak	4/15/2045 HE13	29,489	32,238

5.2.2 Generation Assumptions

The following table provides the generation dispatch assumptions in the study cases. The capacity assumptions for the resource portfolio are provided in section 3.1.2 and the wind generation assumptions for the in-state, offshore and out-of-state resources under different studies are detailed in Chapter 3 of the 2023-2024 Transmission Plan.

Table 5-2: Generation dispatch assumptions

	Generation Output (MW)			
Supply Type	Net Peak 1 (HSN-00)	Net Peak 2 (HSN-01)	Net Peak 3 (HSN-02)	Net Peak 4 (HSN-03)
Gas	0	0	9,934	10,444
Hydro	5,574	5,574	5,574	5,574
Pumped hydro	2,651	2,651	2,651	2,651
Geothermal	2,004	2,004	2,004	2,004
Bio	415	415	415	415
Solar	0	0	0	0
In-State Wind	3,402	3,402	3,402	3,402
Offshore wind	20,000	20,000	20,000	0
Out-of-state wind	12,000	12,000	12,000	0
Battery Storage	19,335	29,302	19,335	51,053
BTM-PV	0	0	0	0
Import	9,944	(781)	(1,143)	(1,409)

5.2.3 Transmission Projects

In addition to all the transmission projects that have been approved in previous Transmission Planning Process (TPP) cycles, the following projects are also modelled in the starting base cases to identify which further system re-enforcements are needed at a conceptual level. More information on these projects is provided in sections 2 through 4 of the 2023-2024 Transmission Plan.

Projects Recommended in 2023-2024 TPP

- New Humboldt 500 kV Substation (with 500/115 kV transformer) and 500 kV line to Collinsville [HVDC operated as AC]
- New Humboldt to Fern Road 500 kV Line
- New Humboldt 500/115 kV Phase Shifter with 115 kV line to Humboldt 115 kV Substation
- Series reactor on Collinsville – Pittsburg 230 kV lines
- North Dublin -Vineyard 230 kV Reconductoring
- Tesla - Newark 230 kV Line No. 2 Reconductoring

Reactive Support Assumptions

Several reactive support devices are added to the system to be able to solve the cases as the system load was scaled up or down to create different study cases.

5.3 Study Methodology and Results

5.3.1 Study Methodology

Load Profile in 2045

Starting with the 2035 Summer Peak case developed in the 2023-2024 Transmission Planning Process, the load and load modifiers across the CAISO system were scaled up or down to match the required load level discussed in section 3.1.1. Given the load increase, reactive support devices were assumed at critical busses to solve the cases with increased load.

Contingency Analysis

The objective of the contingency analysis in this study is to gain insight to the required transmission enhancements across the system under different cases. Considering that objective, the following assumptions were made in the analysis:

- Generic branch contingencies created by TARA tool was considered
- 500 kV contingencies were evaluated for N-0 and N-1, and N-1-1 analysis
- 230 kV contingencies were evaluated for N-1 analysis across the system and for N-1-1 analysis only for Bay Area and LA Basin.

- No Remedial Action Scheme (RAS) action was modelled in the contingency analysis, however existing RAS that could address overloads were considered as mitigation measures in post processing of the results.
- Generators were not re-dispatched before or after the contingencies, however if re-dispatch could address an overload, it was considered as a mitigation measure in post processing of the results.
- Only power flow analysis was performed focusing on thermal overloads.
- It is assumed that local area overloads are addressed with local transmission upgrades

5.3.2 2045 Net-Peak Study Results

The Net-peak load study is based on the High System Need (HSN) study in deliverability studies and reflects the system in an early evening summer conditions without solar generation. The electricity consumption in the ISO system is around 65 GW, which is mostly supplied by battery storage, wind, imports, and hydro units. The rest of the generation is coming from other sources such as pumped hydro, geothermal, and gas generation in the Bay Area. Details of generation for this study are discussed in section 5.2.2.

The assumption on the amount of generation from different sources will have an impact on the required transmission enhancements to serve the load. Four generation scenarios to serve the net-peak load in 2045 were considered in this study. A high level summary of resources are provided in Table 5-3 below with details provided in Table 5-2 in Section 5.2.

Table 5-3: Resource Dispatches in Net Peak (HSN) Scenarios

	Wind	**Import**	**BESS**	**Gas**
2045-HSN_00	High	Ave	Ave	~0
2045-HSN_01	High	Low	High	~0
2045-HSN_02	High	Low	Ave	As needed
2045-HSN_03	Low	Low	~Max	As needed

The contingency study results are grouped based on the area of the system and the type of the contingencies as follows:

- Offshore Wind and Bay Area Results under N-0 and N-1 Contingencies
- Out-of-State Wind Interconnection Impact under N-0 and N-1 Contingencies
- Overloads under low wind, low import, max BESS (HSN-03) under N-0 and N-1 Contingencies
- Greater Bay Area Study Results under N-1-1 Contingencies
- LA Basin Area (500 kV) under N-1-1 Contingencies

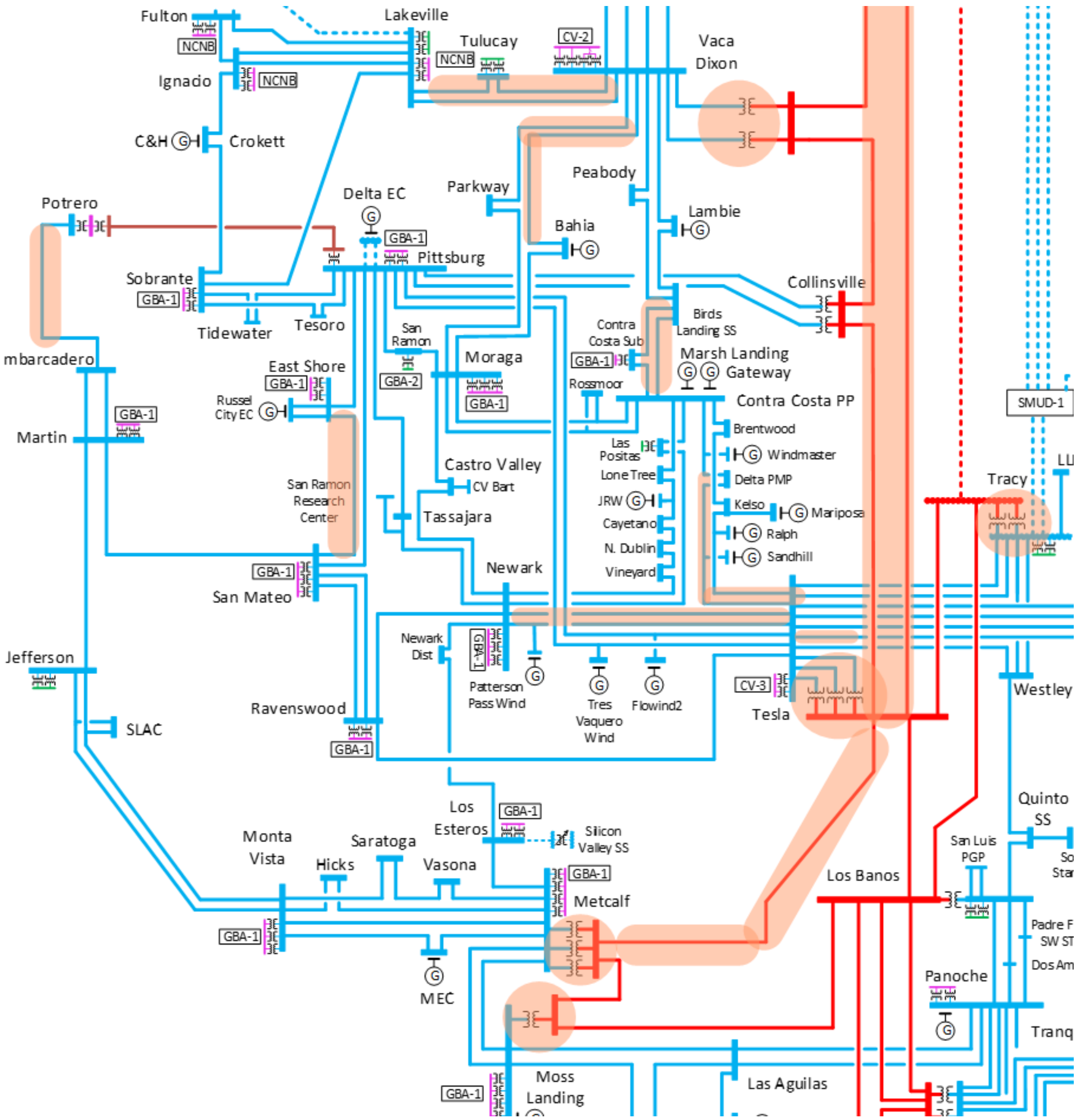
5.3.2.1 Offshore Wind and Bay Area Results under N-0 and N-1 Contingencies

Figure 5-1 shows the transmission system in the Greater Bay Area and the surrounding system. Considering the gas retirement in the area and the low dispatch of gas in the studied scenarios (HSN-00, HSN-01), there were a number of overloads are identified under N-0 and N-1 contingency conditions to transfer the north coast offshore wind to serve the load in the Greater Bay Area. The identified overloads are highlighted in Figure 5-1 and potential mitigation measures are provided in Table 5-4. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4 of this report.

Table 5-4: N-0 and N-1 Contingency Analysis Results Summary for Offshore Wind and Bay Area

Overload	Comments	Potential Mitigation
Fern Road to Tesla 500 kV lines	N-0, N-1 under high OSW	Reconductor/rebuild existing lines or build a second Fern Road - Tesla line
Vaca Dixon 500/230 kV Txes and the 230 kV lines out of Vaca Dixon (Lakeville, Bahia, Parkway)	N-1 in all, N-0 in no gas, average BESS (HSN-00)	A combination of transmission enhancements and adding BESS
Tesla 500/230 kV Txes	N-0 in all, N-1 in all but average gas, high BESS (HSN-03)	Transmission enhancements/BESS
Metcalf 500/230 kV Txes	N-1 in all scenarios with HVDC to Moss Landing	Upgrade/add transformer or two HVDC to Bay Hub option
Moss Landing 500/230 kV Tx		
Tracy 500/230 kV Txes	N-1 only in no gas, average BESS (HSN-00)	Transmission enhancements/BESS
Round Mountain - Cottonwood 230 kV		Rebuild the line or create offshore wind – COI nomogram
Table Mountain - Palermo 230 kV		
Tesla - Metcalf 500 kV	N-1 only in no gas scenarios (HSN-00, HSN-01)	Transmission enhancements/BESS
Tesla - Sand Hill - Delta, Tesla - Newark, Tesla - Eight Mile		
Birds Landing – Contra Costa		
Embarcadero - Potrero 230 kV	N-1 under high OSW	
East Shore - San Mateo	N-1 under average gas, average BESS (HSN-02)	Transmission enhancements/BESS or two HVDC to Bay Hub option

Figure 5-1: Transmission system in Bay Area and identified overloads under N-0 and N-1 Contingencies



5.3.2.2 Out-of-State Wind Interconnection Impact under N-0 and N-1 Contingencies

Details of the out-of-state wind resources in the 2045 portfolio are provided in Section 3.1.9. In the portfolio, 3,500 MW of Wyoming wind and 2,882 MW of New Mexico wind are not mapped to any substation. In this study, 1,500 MW of Wyoming wind is mapped to Tesla 500 kV substation and 2,000 MW is mapped to Eldorado 500 kV substation. Two options were considered for the interconnection of the New Mexico wind. In one option, all the 2,882 MW is mapped to Palo Verde 500 kV substation and in another option 2,882 MW is mapped to Lugo 500 kV substation. Figure 5-2 and Figure 5-3 show the transmission system transferring power from Eldorado and Palo Verde substations to the rest of the CAISO system respectively. A number of overloads were identified under N-0 and N-1 contingency conditions to transfer the out-of-state wind to the rest of the CAISO system. The identified overloads are highlighted in Figure 5-2 and Figure 5-3 and potential mitigation measures are provided in Table 5-6. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4.

Table 5-5: N-0 and N-1 Contingency Analysis Results Summary for Out-of-State Wind

Overload	Comments	Potential Mitigation
Eldorado - McCullough 500 kV	OOS wind at Eldorado	Upgrade the short line or interconnect OOS wind to a substation in the north such as Tesla
Hassayampa - North Gila - Imperial Valley	Only in high wind, average import (HSN-00)	Rebuild the lines, or interconnect the OOS wind at Lugo/Imperial Valley, or implement OOS vs. import nomogram
Lugo - Victorville 500 kV	Only in high wind, average import (HSN-00)	Build another line (Trout Canyon/Eldorado – Lugo), or terminate the OOS wind at Lugo, or implement OOS wind vs. Import nomogram
Pisgah - Lugo 230 kV	N-1, Only in high wind, average import (HSN-00)	
Calcite - Lugo 230 kV	N-0, N-1, Only in high wind, average import (HSN-00)	

Figure 5-2: Transmission system to transfer Out-of-State Wind from Eldorado and the identified overload under N-0 and N-1 contingencies

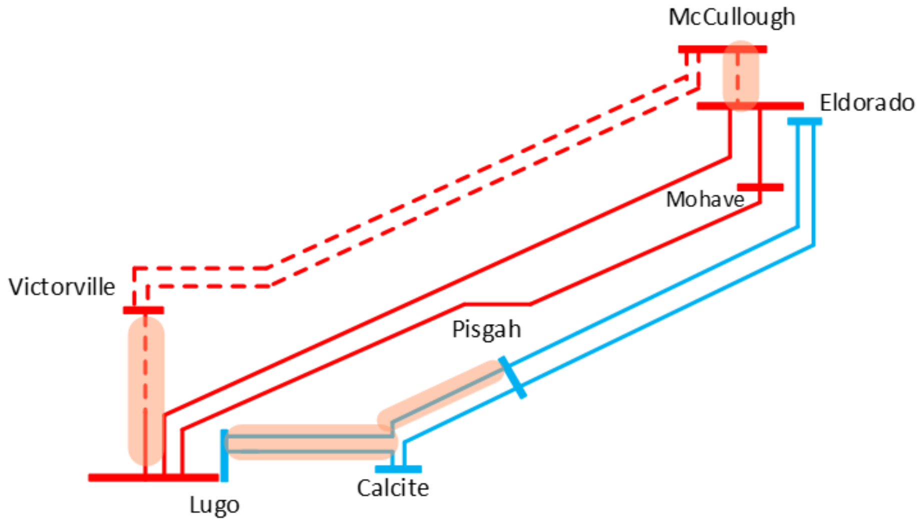
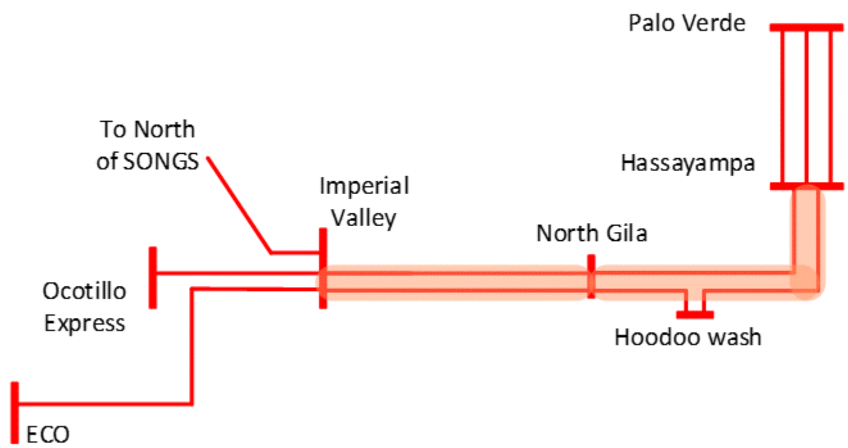


Figure 5-3: Transmission system to transfer Out-of-State Wind from Palo Verde and the identified overload under N-0 and N-1 contingencies



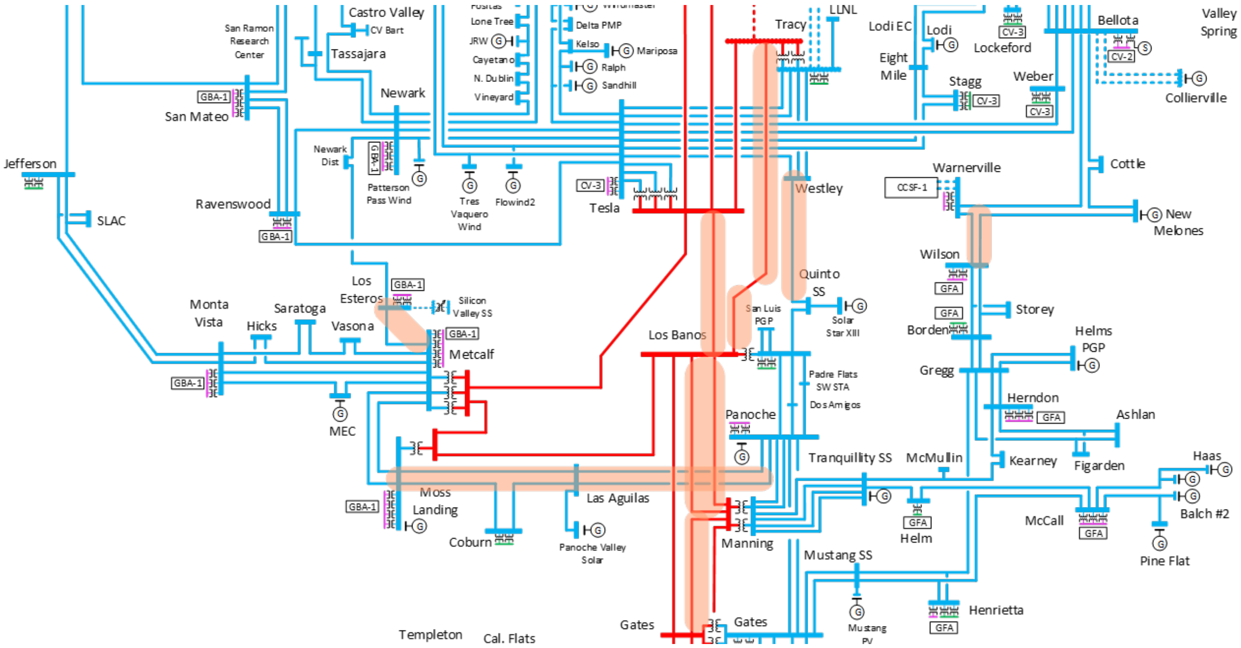
5.3.2.3 Overloads under low wind, low import, max BESS (HSN-03) under N-0 and N-1 Contingencies

Under the low wind, low import, and max BESS scenario (HSN-03) the assumption is that a significant portion of the CAISO load is served by BESS as the supply of other resources in that specific snapshot is low. Given the mapping of BESS resources in the portfolio, the transmission system is overloaded in transferring power from BESS to supply the load in the Bay Area. A number of overloads were identified under N-0 and N-1 contingency conditions in this scenario. The identified overloads are highlighted in Figure 5-4 and potential mitigation measures are provided in Table 5-6. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4.

Table 5-6: N-0 and N-1 Contingency Analysis Results Summary under HSN-03 Scenario

Overload	Comments	Potential Mitigation
Tesla - Los Banos	N-0, N-1 Only in low wind, low import, max BESS (HSN-03)	Manning – Moss Landing line (AC or DC)
Manning - Los Banos		
Warnerville - Wilson 230 kV		
Moss Landing - Las Aguilas – Panoche 230 kV		
Los Banos - Westly 230 kV		
Tracy - Los Banos 500 kV		
Metcalf – Los Esteros 230 kV		Rebuild the line or dispatch Bay Hub HVDC under no wind conditions.
Gates – Manning 500 kV		Add series compensation to Gates – Los Banos #3, Loop in Midway – Manning 500 kV line into Gates substation

Figure 5-4: Overloads Identified under Low Wind, Low Import, Max BESS Scenario (HSN-03)



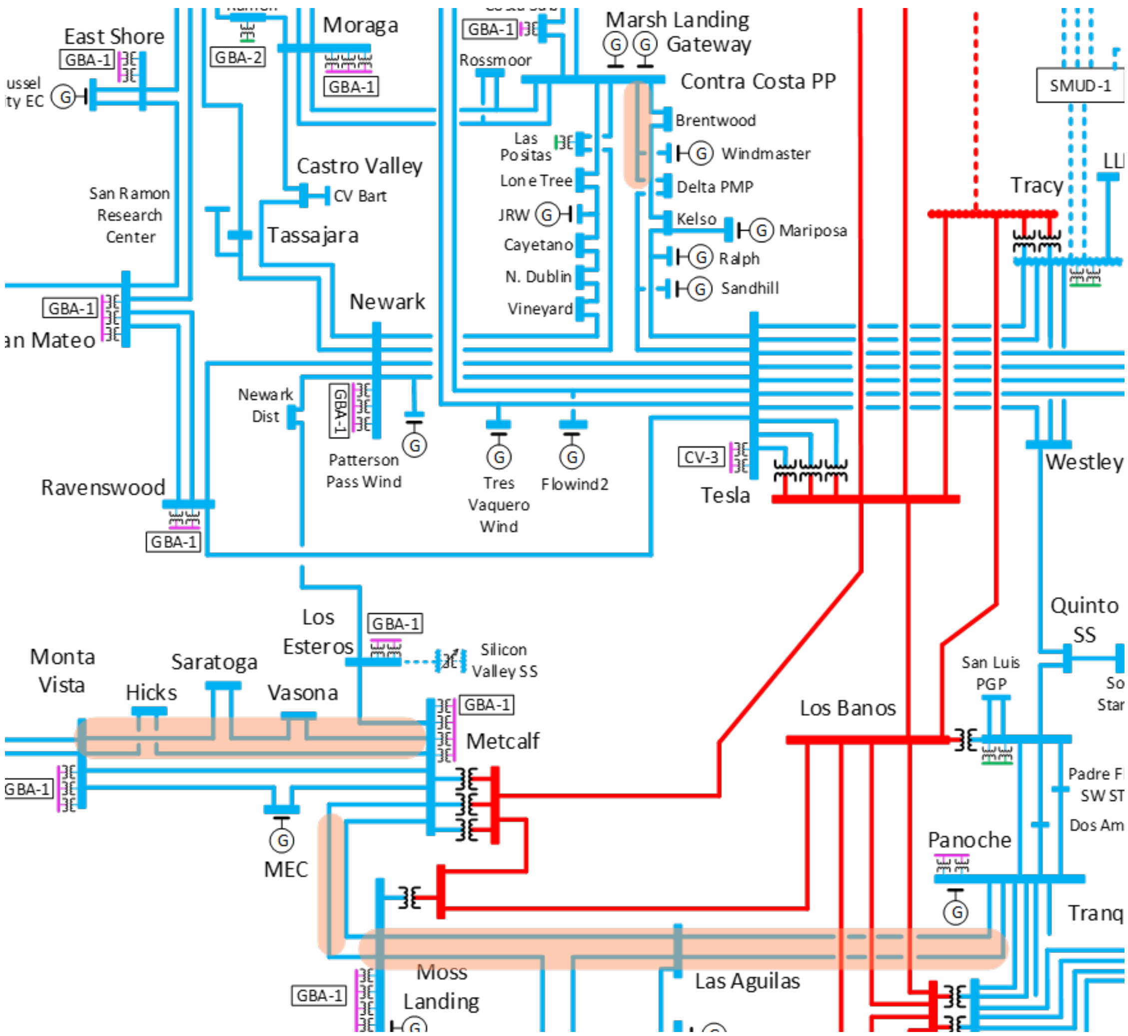
5.3.2.4 Greater Bay Area Study Results under N-1-1 Contingencies

A number of overloads were identified in the Greater Bay Area under N-1-1 contingency conditions with different HSN scenarios. These overloads are in addition to overloads identified under N-0 and N-1 contingency conditions discussed earlier in Section 5.3.2.1. The identified overloads are highlighted in Figure 5-4 and potential mitigation measures are provided in Table 5-6. Given the overloads are under N-1-1 contingencies, it may be possible to re-dispatch generators after the first N-1 contingency to prevent the identified overload following the second N-1 contingency. Such detailed analysis will be performed in local studies in the future. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4 of this report.

Table 5-7: Greater Bay Area Study Resutls Under N-1-1 Contingencies

Overload	Contingency/Scenario	Potential Mitigation
Panoche - Las Aguilas - Moss Landing 230 kV lines	Tesla - Metcalf and Los Banos - Moss Landing in low wind, low import, max BESS (HSN-03)	Manning - Moss Landing 500 kV line
Monta Vista - Hicks, Saratoga - Vasona, Metcalf - Hicks	Metcalf - Monta Vista 230 kV lines in all scenarios	Rebuild the lines, or build two Bay Hub HVDC, or re-dispatch after the first contingency
Delta - Contra Costa 230 kV line	Birds Landing - Contra Costa 230 kV lines in no gas scenarios (HSN-00 and HSN-01)	A combination of rebuilding the line and adding BESS, or re-dispatch after the first contingency
Metcalf - Moss Landing 230 kV #1 or #2	Metcalf - Moss Landing 230 kV #1 or #2 and Metcalf - Moss Landing 500 kV in no gas, average BESS (HSN-01) and no wind, max BESS (HSN-03)	Rebuild the lines or trip the remaining 230 kV line with SPS, or re-dispatch after the first contingency

Figure 5-5: Overloads identified in Bay Area under N-1-1 Contingecies



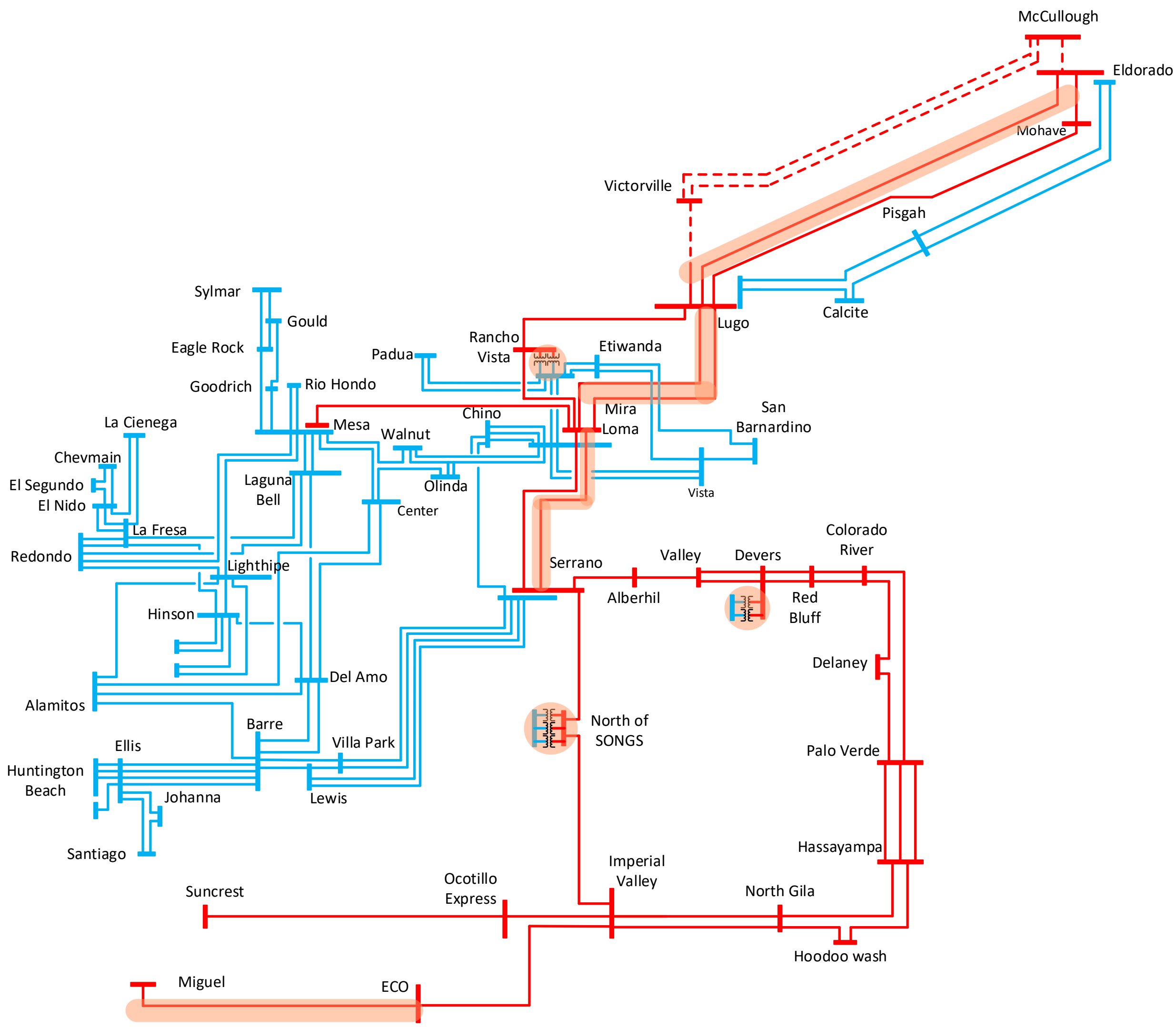
5.3.2.5 LA Basin Area (500 kV) under N-1-1 Contingencies

While no overloads were identified under N-0 and N-1 contingency conditions in the LA Basin area, a number of overloads were identified under N-1-1 contingency conditions with different HSN scenarios. The identified overloads on the 500 kV system are highlighted in Figure 5-6 and potential mitigation measures are provided in Table 5-8. The 230 kV overloads are discussed in the next section (5.3.2.6). Given the overloads are under N-1-1 contingencies, it may be possible to re-dispatch generators after the first N-1 contingency to prevent the identified overload following the second N-1 contingency. Such detailed analysis will be performed in local studies in the future. More details of the potential transmission projects to address the identified overloads are provided in Section 5.4 of this report.

Table 5-8: LA Basin 500 kV Study Resutls Under N-1-1 Contingencies

Overload	Contingency/Scenario	Potential Mitigation
Eldorado - Lugo 500 kV	Lugo - Victorville and Imperial Valley - N. of SONGS 500 kV. Only in high import, high OOS (HSN-00)	Build Trout Canyon – Lugo line, or terminate the OOS wind at Lugo, or implement OOS wind vs. Import nomogram, or Re-dispatch after the first contingency
Lugo - Mira Loma #2 or #3 500 kV	Lugo - Mira Loma #2 or #3 and Lugo - Rancho Vista 500 kV in all scenarios but HSN-03 (no OOS wind, low import, max BESS)	Re-dispatch after the first contingency
Eco - Miguel 500 kV	Imperial Valley - N. SONGS and Imperial Valley - Ocotillo or Ocotillo-Suncrest only in high import, high OOS (HSN-00)	Re-dispatch after the first contingency or implement OOS wind vs. Import nomogram
Serrano - Mira Loma #2 500 kV	Serrano or Valley - Alberhill and Serrano - Mira Loma #1 500 kV in no gas scenarios (HSN-00, HSN-01)	Re-dispatch after the first contingency
Devers 500/230 kV Tx #1 or #2	Devers 500/230 kV Tx #1 or #2 and Alberhill - Serrano or Valley 500 kV in no gas scenarios (HSN-00, HSN-01)	Re-dispatch after the first contingency
Rancho Vista #3 or #4 500/230 kV Tx	Rancho Vista #3 or #4 500/230 kV Tx and Rancho Vista - Mira Loma 500 kV in all scenarios but HSN-03 (no OOS wind, low import, max BESS)	Re-dispatch after the first contingency
Third Transformer at N. SONGS	Two transformers at N. SONGS in no gas scenarios (HSN-00, HSN-01)	Re-dispatch after the first contingency

Figure 5-6: Overloads Identified in LA Basin 500 kV Study Area under N-1-1 Contingencies



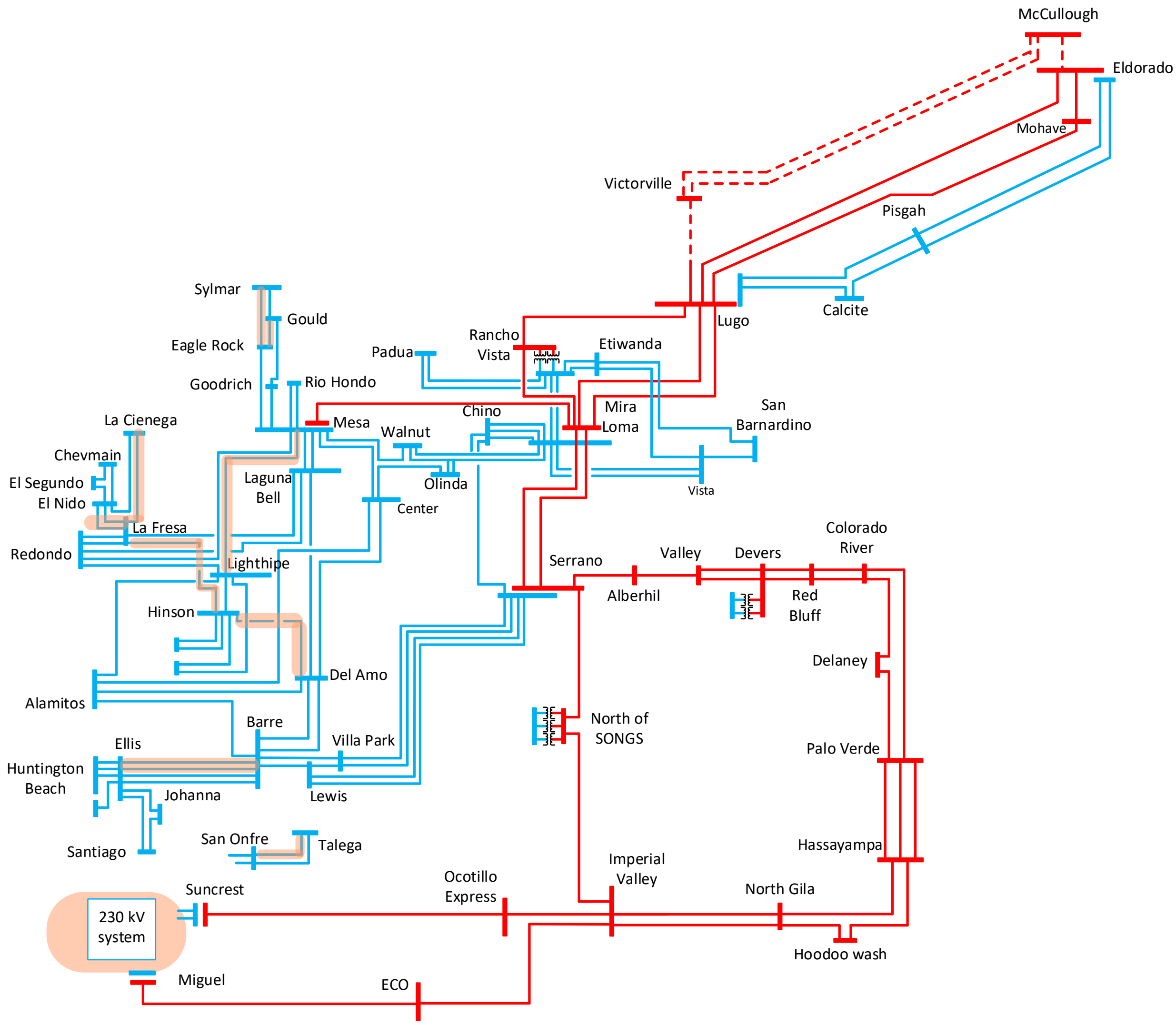
5.3.2.6 LA Basin Area (230 kV) under N-1-1 Contingencies

While no overloads were identified under N-0 and N-1 contingency conditions in the LA Basin area, a number of overloads are identified under N-1-1 contingency conditions within the different HSN scenarios. The 500 kV overloads are discussed earlier in the previous section (5.3.2.5). The identified overloads on the 230 kV system are highlighted in Figure 5-7 and potential mitigation measures are provided in Table 5-9. Given the overloads are under N-1-1 contingencies, it may be possible to re-dispatch generators after the first N-1 contingency to prevent the identified overload following the second N-1 contingency. Such detailed analysis will be performed in local studies in the future.

Table 5-9: LA Basin 230 kV Study Resutls Under N-1-1 Contingencies

<table>
<tr><th>Overload</th><th>Contingency/Scenario</th><th>Potential Mitigation</th></tr>
<tr><td>Talega - S. ONOFRE #2</td><td>Talega - S. ONOFRE #1 and Imperial Valley - ECO or ECO – Miguel only in no gas, average BESS (HSN-00)</td><td rowspan="9">Since no overload is identified in the average gas, high BESS scenarios, re-dispatching generation after the first contingency would most likely address the identified overloads Battery charging capability needs to be assessed in future local area studies</td></tr>
<tr><td>Barre - Ellis #1 or #2</td><td>Barre - Ellis #1 or #2 and Imperial Valley –N. of SONGS or Barre – Lewis only in no gas (HSN-00, HSN-01)</td></tr>
<tr><td>Eagle Rock - Gould and Eagle Rock - Sylmar 230 kV</td><td>Lugo - Victorville 500 kV and Sylmar - Gould 230 kV in all scenarios but HSN-03</td></tr>
<tr><td>La Fresa - El Nido #3 or #4 230 kV</td><td>La Fresa - El Nido #3 or #4 and La Fresa – La Cienega 230 kV in no gas (HSN-00, HSN-01)</td></tr>
<tr><td>Del Amo - Hinson 230 kV</td><td>Lighthipe - Mesa and Del Amo - Alamitos 230 kV only in no gas, average BESS (HSN-00)</td></tr>
<tr><td>La Fresa - Hinson 230 kV</td><td>La Fresa - Laguna Bell #1 and Mesa to Redondo 230 kV only in no gas (HSN-00, HSN-01)</td></tr>
<tr><td>La Fresa - La Cienega 230 kV</td><td>El Nido - La Fresa #3 and #4 230 kV only in no gas (HSN-00, HSN-01)</td></tr>
<tr><td>Lighthipe - Mesa 230 kV</td><td>Laguna Bell - Mesa - Redondo 230 kV in all scenarios but HSN-03</td></tr>
<tr><td>Overload on the underlying 230 kV</td><td>Imperial Valley - Suncrest and Imperial Valley to Miguel 500 kV only in no gas (HSN-00, HSN-01)</td></tr>
</table>

Figure 5-7: Overloads Identified in LA Basin 230 kV Study Area under N-1-1 Contingencies



5.3.3 2045 Peak Consumption and Off-Peak Study Results

The mitigation measures identified in the 2045 Net Peak analysis (HSN analysis) discussed in Section 5.3.2 were modeled in the Peak Consumption (SSN) and off-peak cases before running the contingency analysis. The contingency analysis did not identify any overloads on the bulk system that could not be resolved by re-dispatching generation or curtailing solar or wind under off peak scenarios.

In the SSN case, while the consumption is ~13 GW higher than the net peak condition (Table 5-10), there is ~30 GW of BTM-PV generation to offset the additional load and reduce loading on the bulk transmission lines.

In the off peak case, the BTM-PV is higher than the load at the given hour which will result in transmission connected solar and wind resources being used for charging the storage units.

Detailed production cost simulations could be performed in the future to assess whether economic projects could be recommended to reduce congestion instead of curtailing wind and solar generation.

Table 5-10: Load and BTM-PV assumptions

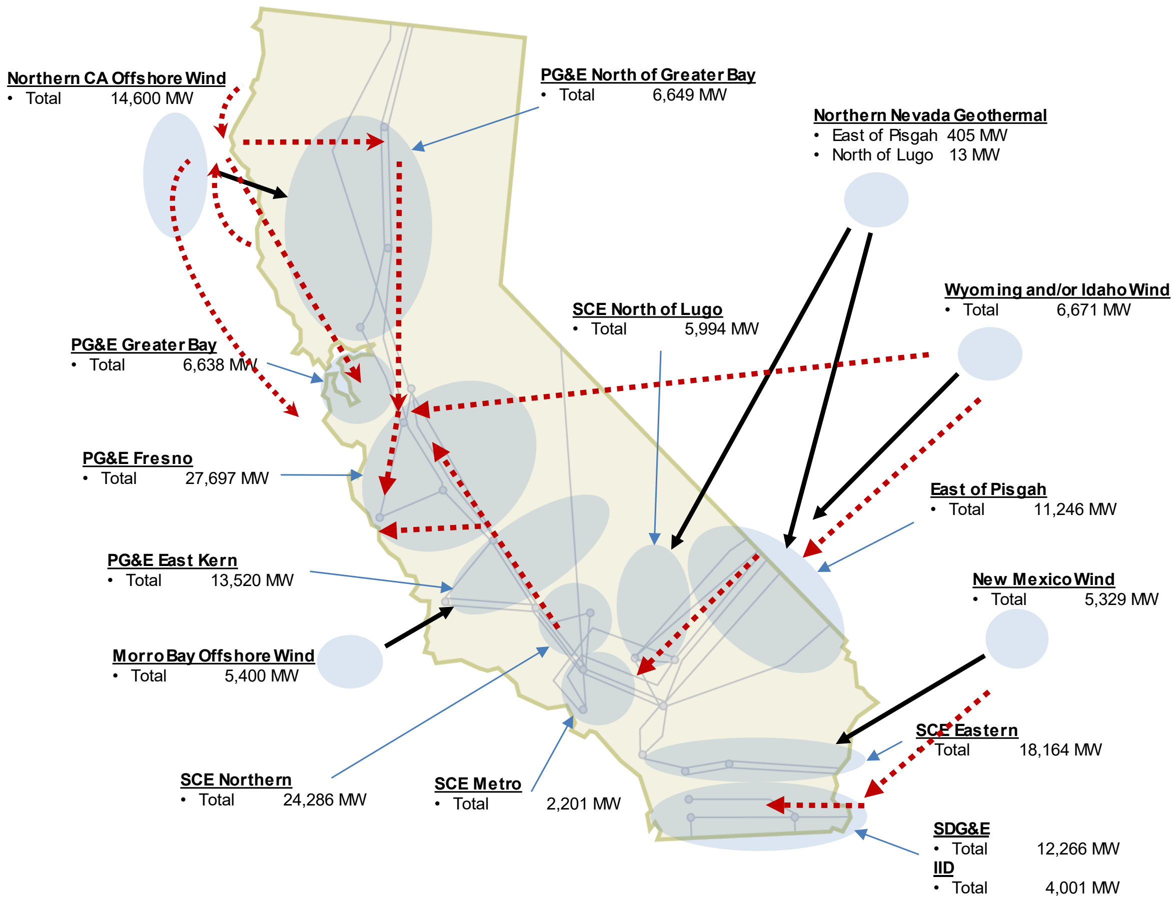
Study Cases	Date/Time assumption	Load (MW)	BTM-PV Generation (MW)
Net peak load (HSN)	9/5/2045 HE 19	64,923	~0
Peak Consumption (SSN)	9/5/2045 HE14	77,430	30,061
Off peak	4/15/2045 HE13	29,489	32,238

5.4 Transmission Development Alternatives

5.4.1 ISO System Transmission Development

Based on the analysis of the three study cases, the following system upgrades will be required, in addition to the projects already modelled in the starting base cases, to address overload issues. A high level description of the project and a schematic diagram of the area are provided in this section.

Figure 5-8: Illustrative Diagram of Transmission Development

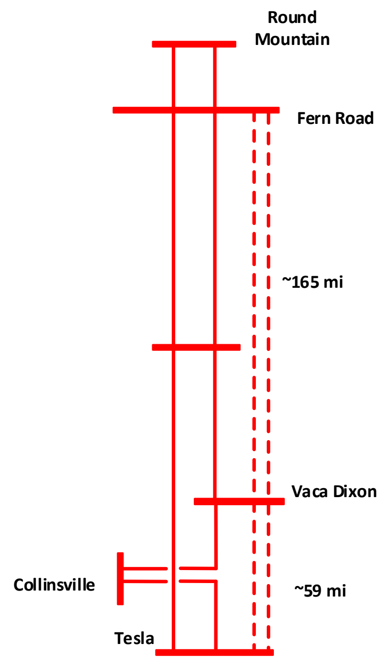


The following transmission projects described below have been identified as transmission development to accommodate the resources identified in the 2045 scenario and address the constraints identified in the high-level assessment of the bulk transmission system.

Figure 5-9: Major transmission development to existing ISO system to integrate the 2045 SB 100 portfolio scenario

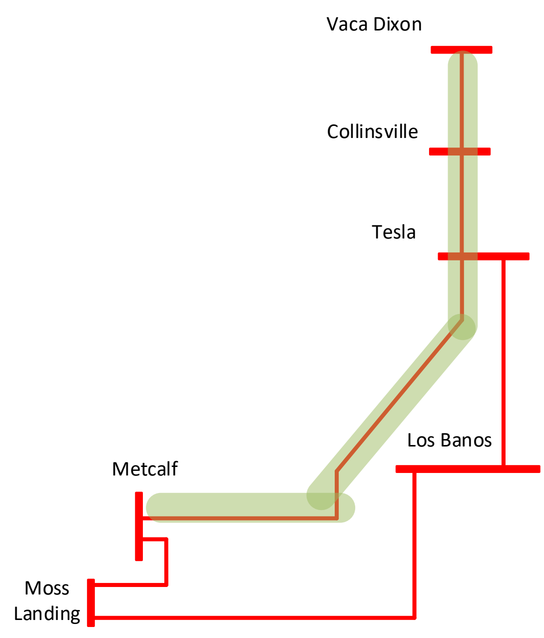
Two Fern Road to Tesla 500 kV Line Project

The 2045 portfolio includes 14,600 MW of offshore wind in the North Coast. All the recommended alternatives in this analysis include two 500 kV AC lines to Fern Road. Considering offshore wind flow injected at Fern Road, two new 500 kV lines are required to transfer power to Tesla and the rest of the system. Depending on the timing and pace of the offshore wind development, one new 500 kV line could be built and the existing lines could be reconductored with advanced conductors.



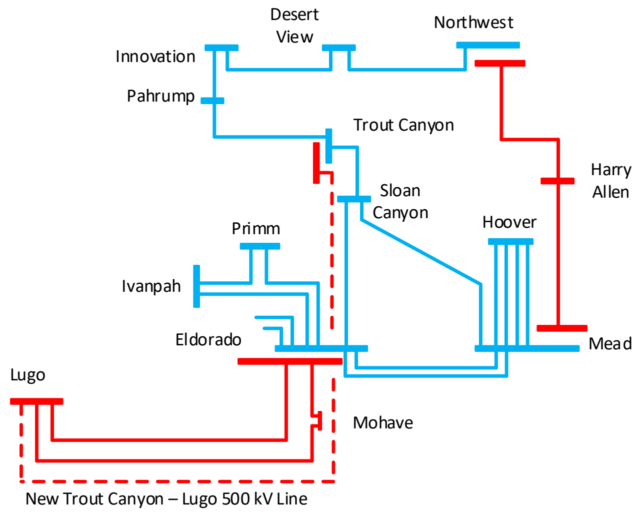
Reconductor Vaca Dixon – Collinsville – Tesla – Metcalf 500 kV Line Project

The 2045 portfolio includes more than 4 GW of gas retirement in the Bay Area. In scenarios with low local gas and high offshore wind, the existing Vaca Dixon – Collinsville – Tesla – Metcalf line overloads under base case and contingency conditions. Reconductoring the 500 kV lines with advanced conductors will address the issue. Depending on the timing and pace of the gas retirement and offshore wind development, it might be challenging to reconductor the existing lines and new lines need to be built in parallel to the existing ones.



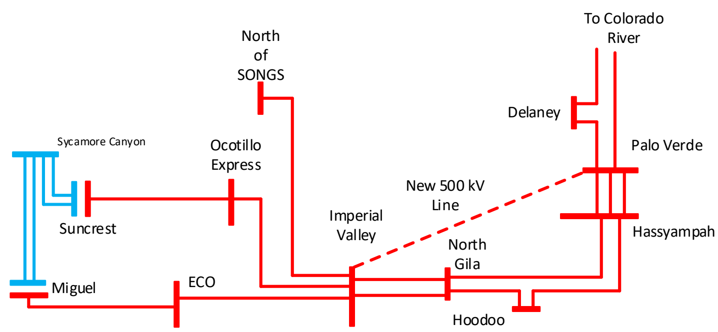
<u>Trout Canyon – Lugo 500 kV Line Project</u>

The 2045 portfolio includes solar resources in the Southern Nevada and Eldorado areas. In addition, in this study it was assumed that 3,500 MW of out-of-state wind will be injected at Eldorado 500 kV substation. Considering that the majority of these resources will flow on the Eldorado – Lugo 500 kV path, the new Trout Canyon - Lugo 500 kV line was assumed to address the overloads under normal and contingency conditions.



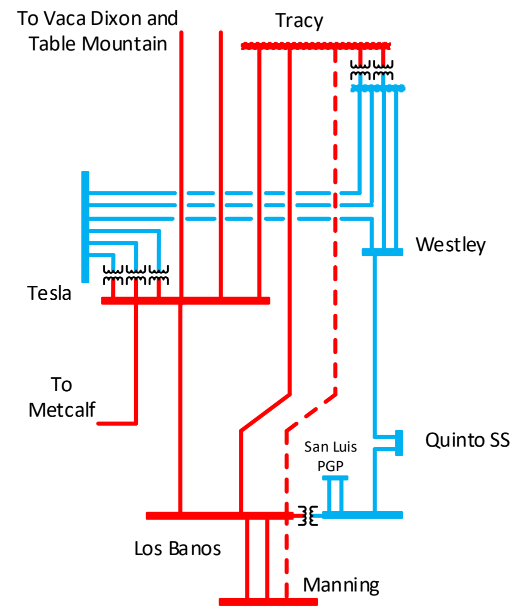
<u>Palo Verde – Imperial Valley 500 kV line</u>

The 2045 portfolio includes solar resources in Riverside and Palm Springs, Greater Imperial, and Arizona solar areas. In addition, in this study it was assumed that 2,882 MW of out-of-state wind will be injected at the Palo Verde 500 kV substation. Considering all these resource connections, a new Palo Verde – Imperial Valley 500 kV line was considered to address the overloads under normal and contingency conditions.



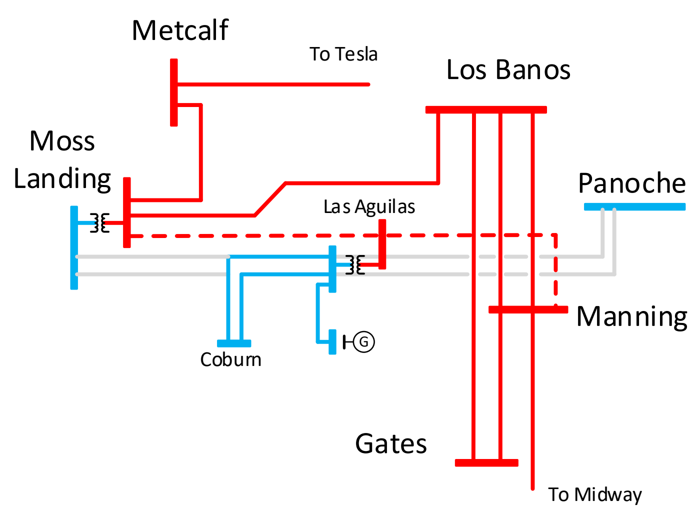
Manning - Tracy 500 kV line

As indicated in the study results, the existing Los Banos – Tracy 500 kV line overloads under normal and contingency conditions for certain scenarios. The contingency of the line also causes overload on the underlying 230 kV system. A potential mitigation considered in this study is a new Manning – Tracy 500 kV line.



Manning – Moss Landing 500 kV line

The study results indicated overload on the Manning – Los Banos 500 kV lines and on the 230 kV path from Panoche to Moss Landing. A 500 kV line from Manning to Moss Landing will address these overloads and also provides another 500 kV connection to the Bay Area to address overloads under N-1-1 contingencies.



5.4.2 Transmission Development Estimated Costs

Based on the review of per unit capital cost estimate for transmission infrastructure development in multiple sources, [21, 22] the CAISO used the information in Table 5-11 to calculate a planning level cost estimate for different transmission enhancement concepts identified in this report.

Table 5-11: Estimated cost per mile or per unit of transmission infrastructure

Transmission Infrastructure	Cost Estimate
500 kV Substation/expansion	$100 M - $150 M
500 kV AC line in the mountains	$7 M - $10 M/mi
500 kV AC line in the valley	$5 M - $7 M/mi
HVDC line onshore in the mountains	$7 M - $10 M/mi
HVDC converter station (2GW)	$400 M - $600M
HVDC converter station (3GW)	$600 M - $900M
HVDC offshore cable (2GW)	$7 M - $10 M/mi
High capacity 230 kV Cable	$15 M - $20 M/mi
Reconductor 230 kV Lines	$3.5 M – $4.5 M/mi
Reconductor 500 kV Lines	$3.5 M – $5 M/mi

The transmission development to integrate the resources in the 2045 resource portfolio has been identified in three sections, as reflected in Table 5-11:

- Upgrades to existing ISO footprint;
- Offshore wind; and
- Out-of-state wind.

[21] Schatz Center - Northern California and Southern Oregon Offshore Wind Transmission study https://efiling.energy.ca.gov/GetDocument.aspx?tn=252604

[22] https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/Participating-transmission-owner-per-unit-costs-2023

Table 5-12: Estimated cost[23] for transmission development to integrate the resources in 2045 Scenario

Transmission Development	Description	Cost Estimate
Upgrades to existing ISO footprint		**$9.3 B - $11.5 B**
Trout Canyon – Lugo 500 kV line	- 180 mi of 500 kV line - Series compensation in number of locations	$2 B
Manning – Tracy 500 kV line	107 mi of 500 kV line	$0.5 B - $0.7 B
Manning – Moss Landing 500 kV line	- 78 mi of 500 kV line - New 500/230 kV substation with two transformers ($100M)	$0.4 B - $0.5 B
Two Fern Road – Tesla 500 kV Lines	2 x 250 mi of 500 kV line	$2.5 B - $3.5 B
Palo Verde/Hassayampa – Imperial Valley 500 kV line	~200 mi of 500 kV line	$2 B
Reconductor Vaca Dixon – Collinsville – Tesla – Metcalf 500 kV line	~ 36 miles of 500 kV line	$0.4 B - $0.5 B
Upgrade 500/230 kV transformers at Vaca Dixon, Tesla, Metcalf, Moss Landing, Tracy	A total of eleven 500/230 kV transformers need to be upgraded. The assumption is that there space limitation to add new transformers.	$0.6 B - $1.1 B
Add series compensation to Gates – Los Banos #3, Loop in Midway – Manning 500 kV line into Gates substation		$0.1 B
Upgrade the following 230 kV lines	Total of 287 miles	$0.8 B - $1.1 B
• Reconductor[24] Vaca – Lakeville 230 kV lines (2 x 42 mi)		
• Reconductor Vaca – Bahia 230 kV line (33 mi)		
• Reconductor Vaca – Parkway 230 kV line (26 mi)		
• Reconductor Birds Landing – Contra Costa 230 kV lines (2 x 10 mi)		
• Reconductor Round Mountain - Cottonwood 230 kV line (34 mi)		
• Reconductor Table Mountain - Palermo 230 kV line (15 mi)		
• Reconductor Tesla - Sand Hill – Delta 230 kV line (10 mi)		
• Reconductor Tesla - Eight Mile 230 kV line (27 mi)		
• Reconductor Embarcadero - Potrero 230 kV cable (2.5 mi)		
• Reconductor East Shore - San Mateo 230 kV line (9 mi)		
• Reconductor Metcalf – Los Esteros 230 kV line (26 mi)		

23 These values represent the capital cost of the identified projects; several are currently being developed under a subscriber model – with the transmission costs incorporated into the energy costs – and not rate-base projects receiving cost-of-service cost recovery that would be added to ISO transmission access charges.

24 Reconuctoring could include use of advanced conductors

Transmission Development	Description	Cost Estimate
Offshore Wind		**$25 B – $36.5 B**
Humboldt Bay Offshore wind area	Total of 14,600 MW offshore wind connected through 500 kV AC lines, overhead HVDC, and subsea HVDC lines to Fern Road, Collinsville, and Bay Hub substations. (Figure 4-7)	$24.8 B – $36.1 B
Diablo – Morro Bay Offshore wind area	- Total of 5,400 MW offshore wind. Connected to Diablo 500 kV and the new Morro Bay 500 kV substation. - The cost estimate for a 500 kV switching station and looping in the existing Diablo – Gates 500 kV line into it is 0.15 B – 0.22 B. If more than ~2,400 MW generation is connected the new Morro Bay 500 kV substation, a second Morro Bay – Diablo 500 kV line with $100 M to $140 M will be required.	0.15 B – 0.36 B
Out-of-State Wind		**$11.6 B – $15.2 B** [25]
TransWest Express	732 Mile transmission system consisting of HVDC and 500 kV facilities to access Wyoming wind. Project is designed to potentially provide 1500 MW to LADWP at the IPP facilities in Utah and 1500 MW to the ISO at Harry Allen/Eldorado	-
SunZia	530 mile HVDC line and 35 mile 500 kV AC line plus scheduling rights on existing lines from Pinal Central to Palo Verde connecting to the ISO system to access New Mexico wind resources	-
Additional transmission for additional wind resources from Wyoming/Idaho area	HVDC transmission line from the wind resource area to northern California (Eldorado/Tesla area)	$8.1 B – $10.4 B
Additional transmission for additional wind resources from New Mexico area	HVDC transmission line from the wind resource area to southern California (Lugo area)	$3.5 B – $4.9 B
Total estimated cost for transmission Development		**$45.8 B – $63.2 B**

[25] The TransWest Express and SunZia projects are being developed providing transmission service to resources seeking access to California markets on a Subscriber Participating Transmission Owner (SPTO) model. The transmission costs would not be included in the ISO TAC.

5.5 Summary and Conclusions

The 20-Year Outlook Update builds upon the analysis performed in the last 20-Year Outlook published in May 2022 and explores the longer-term grid requirements and options for meeting the State's greenhouse gas reduction and renewable energy objectives reliably and cost-effectively. The expanded planning horizon to year 2045 provides valuable input for resource planning processes conducted by the CPUC and CEC, and provides a longer-term context and framing of pertinent issues in the ISO's ongoing annual 10-Year Transmission Plan. One of the main differences in key input assumptions in this study compared to the last 20-Year Outlook is the increase of the offshore wind resources from 10,000 MW in the last outlook to 20,000 MW in this study.

The exercise was undertaken recognizing that California is facing an unprecedented need for new clean energy resources over the next 10 to 20 years, driven by increased customer demand for clean energy, the continuing electrification of transportation and other industries and by the requirements of Senate Bill 100 that California must get 100 percent of its retail electricity from non-carbon-producing sources by 2045.

This 20-Year Outlook Update focused on meeting the needs identified through the CEC's SB100-related processes for achieving the state's 2045 objectives, with the 2045 load forecast and resource requirements developed through a collaborative approach with the CEC, CPUC, other local regulatory authorities, stakeholders and ISO staff. The planning exercise demonstrated that the energy transformation will not only drive significant investment in a technologically and geographically diverse fleet of resources, including storage, but also significant transmission to accommodate all the new capacity being added.

Table 5-13 provides the high-level summary of the transmission development required for upgrades to the existing ISO footprint, offshore wind integration and out-of-state wind integration. The range of cost estimate is commensurate with estimates developed at this stage of planning, with the costs in constant dollars.

Table 5-13: High level cost estimate of transmission development

Transmission Development	**Estimated Cost ($ billions)**
Upgrades to existing ISO footprint consisting of: • 230 kV and 500 kV AC lines • HVDC lines • Substation upgrades	$9.3 B - $11.5 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$25 B - $36.5 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$11.6 B - $15.2 B
Total estimated cost of transmission development	**$ 45.8 B – 63.2 B**

In summary, the anticipated load growth to 2045 and the expectation of major offshore wind generation are driving the higher estimated cost for future transmission needs from approximately $30.5 billion over a 20-year timeframe identified in the first Outlook to the estimated $43.8 billion to $63.2 billion in future transmission costs identified in this update. These costs do not include transmission that has already been approved by the ISO and is under development, but not yet in service.

The ISO expects to conduct additional stakeholder dialogue through 2024 about next steps as well as the long-term architecture set out in this 20-Year Outlook. Those additional efforts, along with evolving resource planning and procurement, will inform the ISO's annual transmission planning processes that approve and initiate specific projects.

APPENDIX A: 2045 Scenario

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California Energy Commission and
California Public Utilities Commission

STAFF PAPER

2045 Scenario for the Update of the 20-Year Transmission Outlook

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California Energy Commission, Siting, Transmission, and Environmental Protection Division

California Public Utilities Commission, Energy Division

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DISCLAIMER

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ABSTRACT

The *2045 Scenario for the Update of the 20-Year Transmission Outlook* staff paper describes a 2045 demand and resource scenario for use by the California Independent System Operator in the update of the 20-Year Transmission Outlook. The staff paper outlines the demand and resource assumptions within the scenario. The staff paper details the method for resource mapping the new renewable resource and energy storage capacity within the scenario.

Keywords: Demand scenario, clean energy resources, offshore wind, land use, transmission planning

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EXECUTIVE SUMMARY

California's energy transition is underway, but the next two decades will require an unprecedented amount of generation and transmission to supply clean, reliable power. The need for record-setting buildout of new utility-scale clean energy resources and energy storage is being driven by increased customer demand for clean energy, the continuing electrification of transportation and other industries to achieve the state policy of economy-wide carbon neutrality by 2045, and the state's target of 100 percent clean electricity. The 100 Percent Clean Energy Act of 2018 (Senate Bill 100, De León, Chapter 312, Statutes of 2018) sets a 2045 target of supplying all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon energy resources.

Senate Bill (SB) 100 also increases the state's Renewables Portfolio Standard (RPS) procurement target to 60 percent of retail sales by December 31, 2030, and requires all state agencies to incorporate the 2030 and 2045 targets into their relevant planning. SB 100 requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) to use programs under existing laws to achieve 100 percent clean energy and issue a joint policy report on SB 100 by 2021 and every four years thereafter.

The first 2021 Joint Agency SB 100 Report was released in March 2021 and assessed various pathways to achieve the SB 100 targets and included an initial assessment of costs and benefits. One key finding from the report was that sustained record-setting renewable generation and energy storage capacity build rates will be required to meet the target in a high electrification future, citing growing electricity demand as a significant driver. Effectively integrating 100 percent renewable and zero-carbon technologies in California by 2045 will require rigorous analysis of implementation considerations and coordinated planning across different levels of government and with grid operators throughout the state. One such track of analysis, which emerged following the 2021 Joint Agency SB 100 Report, is the California Independent System Operator's (California ISO's) 20-Year Transmission Outlook (20-year outlook).

The California ISO's 20-year outlook explores longer term grid requirements and options for meeting the state's greenhouse gas reduction and renewable energy targets reliably. The CEC, CPUC, and California ISO collaborated on an approach to translate the analysis conducted for the 2021 SB 100 Joint Agency Report into a 2040 Starting Point Scenario for use by the California ISO in the first 20-year outlook, which was released in May 2022.

Following the release of the first SB 100 Joint Agency Report, the CEC, CPUC, and California ISO, began to focus on the resource build requirements to achieve SB 100 (Docket 21-SIT-01). This collaboration includes a public stakeholder process, with several workshops held in 2021 and 2022, and is ongoing. In December 2022, the CEC, CPUC, and California ISO signed a "Memorandum of Understanding (MOU) Regarding Transmission and Resource Planning and Implementation," reinforcing cooperation and collaboration of the three parties in the timely development of resources needed to achieve the state's clean energy goals reliably and economically.

A near-term priority for collaborative efforts is providing an updated 2045 Scenario for California ISO to use in the next 20-Year Transmission Outlook, which is anticipated in 2024. The next 20-year transmission outlook will inform the 2025 SB 100 Joint Agency Report.

The *2045 Scenario for the Update of the 20-Year Transmission Outlook* staff paper describes a 2045 demand and resource scenario for use by the California ISO in the update of the 20-Year Transmission Outlook. The staff paper describes the load and resource assumptions within the scenario, which assumes 100 percent of retail sales is supplied by renewable and zero-carbon electricity resources by 2045. The staff paper details the method for resource mapping the new renewable resource and energy storage capacity within the scenario. Consistent with the scenarios from the 2021 SB 100 Joint Agency report, the 2045 Scenario for the 20-Year Outlook includes significant capacity additions by 2045.

CHAPTER 1: Background

Senate Bill 100 Targets

The 100 Percent Clean Energy Act of 2018 (Senate Bill 100, De León, Chapter 312, Statutes of 2018) sets a 2045 target of supplying all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources.[1] SB 100 also increases the state's Renewables Portfolio Standard (RPS) procurement target to 60 percent of retail sales by December 31, 2030, and requires all state agencies to incorporate the 2030 and 2045 targets into their relevant planning. SB 100 requires the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Air Resources Board (CARB) to use programs under existing laws to achieve 100 percent clean energy and issue a joint policy report on SB 100 by 2021 and every four years thereafter.

The Clean Energy, Jobs, and Affordability Act of 2022 (Senate Bill 1020, Laird, Chapter 361, Statutes of 2022) revises SB 100 targets to instead provide that eligible renewable energy resources and zero-carbon resources supply:

- 90 percent of all retail sales of electricity to California end-use customers by December 31, 2035.
- 95 percent of all retail sales of electricity to California end-customers by December 31, 2040.
- 100 percent of all retail sales of electricity to California end-use customers by December 31, 2045.
- 100 percent of electricity procured to serve all states agencies by December 31, 2035.

2021 Joint Agency SB 100 Report

The 2021 Joint Agency SB 100 Report assessed various pathways to achieve the SB 100 targets and an initial assessment of costs and benefits. One key finding from the report was that sustained record-setting renewable generation and energy storage capacity build rates will be required to meet the target in a high electrification future, citing growing electricity demand as a significant driver.[2] Effectively integrating 100 percent renewable and zero-carbon technologies in California by 2045 will require rigorous analysis of implementation considerations and coordinated planning across different levels of government and with grid operators throughout the state. One such track of analysis, which emerged following the 2021

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1 Senate Bill 100 (De León, Chapter 312, Statutes of 2018). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

2 CEC, CPUC, and CARB. 2021. *2021 SB 100 Joint Agency Report Achieving 100 Percent Clean Electricity in California: An Initial Assessment.* Publication Number: CEC-200-2021. https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349.

Joint Agency SB 100 Report, is the California Independent System Operator's (California ISO's) *20-Year Transmission Outlook*[3] (20-year outlook).

20-Year Transmission Outlook

The California ISO's 20-year outlook explores longer-term grid requirements and options for meeting the state's greenhouse gas reduction and renewable energy targets reliably. The California ISO initiated the 20-year outlook to have a longer-term outlook and stakeholder process outside the formal tariff-based Transmission Planning Process (TPP), which focuses on transmission project needs and transmission project approvals over a 10-year planning horizon. The California ISO will conduct the update of the 20-year outlook in parallel with its current 2023–2024 TPP. The 20-year outlook is intended to support state electric sector planning by providing long-term context and framing of key transmission-related issues.

The CEC, CPUC, and California ISO collaborated on an approach to translate the analysis conducted for the 2021 SB 100 Joint Agency Report into a 2040 Starting Point Scenario for use by the California ISO in the first 20-year outlook, which was released in May 2022. The first 20-year outlook identified the need for significant 500 kilovolt (kV) alternating current (AC) and high-voltage direct current (HVDC) transmission development to access offshore wind (OSW) and out-of-state wind and reinforce the transmission system within the existing California ISO footprint. Figure 1 diagrams the transmission development required to integrate the resources of the SB 100 Starting Point Scenario and high electrification load projection by 2040.

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3 California Independent System Operator. May 2022. 20-Year Transmission Outlook. http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf. Page 20.

Figure 1: Diagram of Transmission Development in the 20-Year Outlook (2022)

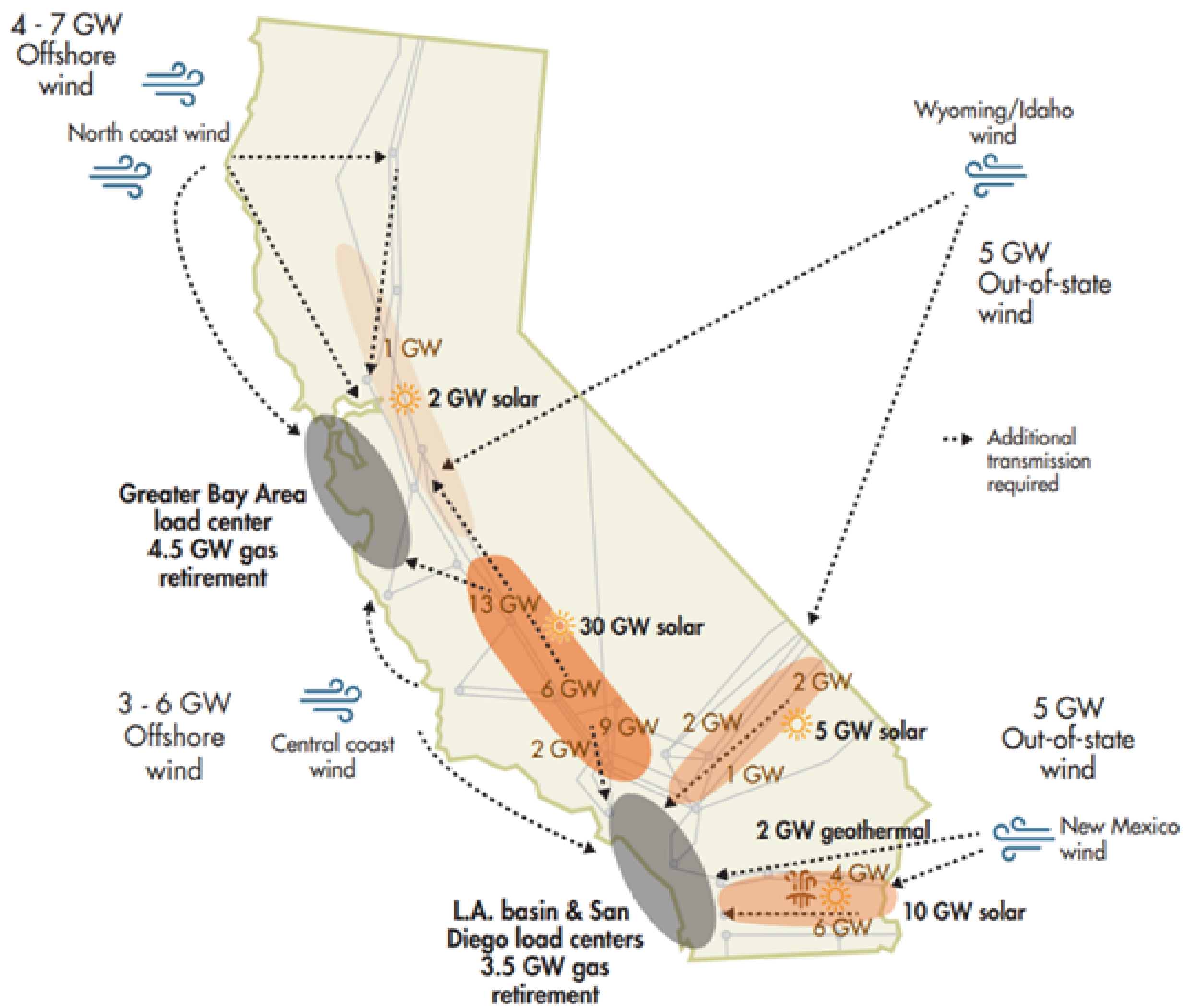

Diagram of transmission development identified in the California ISO 20-Year Outlook (May 2022).

Source: California ISO

Following the release of the first SB 100 Joint Agency Report, the CEC, CPUC, and California ISO focused on the resource build requirements to achieve SB 100 (Docket 21-SIT-01). This collaboration includes a public stakeholder process, with several workshops held in 2021 and 2022, and is ongoing. In December 2022, the CEC, CPUC, and California ISO signed the "Memorandum of Understanding (MOU) Regarding Transmission and Resource Planning and Implementation," reinforcing cooperation and collaboration of the three parties in the timely development of resources needed to achieve the state's clean energy goals reliably and economically.

A near-term priority for collaboration is providing a 2045 Scenario for California ISO to use in the next 20-Year Transmission Outlook, which is anticipated in 2024. The next 20-Year Transmission Outlook will inform the 2025 SB 100 Joint Agency Report.

The 2045 Scenario is informed by several recent long-term resource planning scenarios (Table 1). Given the 20-plus-year planning horizon, the resource and storage mix presented in this scenario does not account for the full suite of development uncertainties, such as cost, commercial readiness, technical challenges, supply chain, and permitting. Therefore, the use of the 2045 Scenario is not a commitment to the resource and storage mix included in the scenario. Instead, the 2045 Scenario is designed to provide information for a wide range of potential transmission needs driven by a combination of potential renewable and zero-carbon resource and storage opportunities. The 2045 Scenario is informational only and should not be used, on its own, to support approval of near-term infrastructure investments.

Table 1: Summary of Long-Term Planning Scenarios that Inform the 2045 Scenario

Study Name	Scenario Description	Year Studied	Links to Report
SB 100 Core Scenario	The core scenario from the 2021 Joint Agency SB 100 Report. This scenario includes retail sales and state loads, high electrification demand, and all candidate resources available. This scenario includes 145 GW of new resources by 2045.	2045	2021 SB 100 Joint Agency Report Achieving 100 Percent Clean Electricity in California: An Initial Assessment. (https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349)
2040 Starting Point Scenario	The 2040 Starting Point Scenario (2021) was developed by the CEC and CPUC for use by the California ISO in the 20-year transmission outlook (2022). This scenario includes 120 GW of new resources by 2040. This scenario also includes 15,000 of assumed natural gas retirements.	2040	SB 100 Starting Point Scenario for the CAISO 20-year Transmission Outlook. (https://efiling.energy.ca.gov/GetDocument.aspx?tn=239685&DocumentContentId=73101)
2023-2024 TPP Base Case	A base case portfolio for both reliability and policy-driven purposes produced by the CPUC and evaluated by the California ISO to determine transmission investments needed. The portfolio expects 85 GW of new resources by 2035 to be built to meet a 30 million metric ton greenhouse gas emissions target in 2030 and uses the CEC's 2021 Integrated Energy Policy Report "Additional Transportation Electrification" load scenario.	2035	Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmission Electric Resource Portfolios to California Independent System Operator for 2023-2024 Transmission Planning Process. (https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M502/K956/502956567.PDF)

Table 1 describes long-term resource planning scenarios which inform the 2045 Scenario for the 20-Year Transmission Outlook.

Source: CEC staff

CHAPTER 2: Demand Assumptions

The 2021 SB 100 Starting Point Scenario, which informed the 2022 California ISO 20-year outlook, used the PATHWAYS High Electrification demand scenario that was used in the SB 100 Core Scenario. The peak load in 2040, before accounting for behind-the-meter (BTM) solar photovoltaic (PV), was projected to be 73,900 megawatts (MW) for the California ISO region. For the 2024 California ISO 20-year outlook, a more recent demand scenario produced by the CEC is used that projects a peak load of 68,800 MW in 2040 before accounting for BTM PV.

Demand Scenario for the 2045 Scenario

The 2045 Scenario will use the CEC's 2021 Mid-Mid Case extrapolated to 2045, with the transportation load swapped for the 2022 Integrated Energy Policy Report (IEPR) Update Forecast results. The Mid-Mid Case was chosen for the 20-year transmission outlook because this is a longer-term system-wide study, in contrast to the TPP which is a localized study and relies on higher demand assumptions due to the increased uncertainty when disaggregating to the load bus level. [4] The projected peak load for this scenario in 2045 is 61,900 MW, and annual energy demand is 313,000 GWh for the California ISO region which includes generation from BTM PV.

CEC's California Energy Demand Forecast is a cornerstone component of the state's energy planning process. The forecast includes several products that are used across several energy planning proceedings such as Resource Adequacy and Integrated Resource Planning. CEC's 2021 Mid-Mid Case[5] is the main product that informs these proceedings. Each year, forecasts are updated to account for changes in key energy demand drivers and historical datasets. The 2021 Mid-Mid Case is based on economic and demographic forecast drivers, historical energy consumption data, electricity and natural gas rates projections, adoption forecasts for BTM PV and battery storage, energy efficiency, fuel substitution, and electric vehicles. Moreover, adjustments were made to the forecast to account for changes in demand due to climate

[4] For comparison, the Additional Transportation Electrification scenario adopted in May 2022 which will be used for the 2023-24 TPP projected a peak load of 55,500 MW and 281,000 annual GWh in 2035 for the California ISO region, compared to the scenario used for the 20-year outlook which projects a peak load of 54,900 MW and 265,000 annual GWh in 2035.

[5] Javanbakht, Heidi, Cary Garcia, Ingrid Neumann, Anitha Rednam, Stephanie Bailey, and Quentin Gee. 2022. Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast. California Energy Commission. Publication Number: CEC-100- 2021-001-V4.

change. As mentioned above, the 2045 Scenario swaps the 2021 Mid-Case transportation load for the *2022 IEPR Update* transportation forecast.[6]

The *2022 IEPR Update* transportation forecast provides a key update to incorporate the recently adopted vehicle regulations established by the California Air Resources Board (CARB). The Advanced Clean Cars II regulation and the Advanced Clean Fleets regulation require a much larger growth in zero-emission vehicles than forecasted in the *2021 IEPR*. Current market conditions strongly indicate that battery-electric vehicles will represent the vast majority of zero-emission vehicles. A new forecast framework was developed to account for these additional vehicles, called Additional Achievable Transportation Electrification. The adoption of these regulations results in a significant growth in electric vehicle load compared to the original 2021 Mid-Mid Case.

CEC mapped the Additional Achievable Transportation Electrification, Additional Achievable Energy Efficiency, and Additional Achievable Fuel Substitution components of the forecast to the busbar level through 2035. For 2036 through 2045, the California ISO will disaggregate the load from the transmission access charge area to busbar using a weighting approach.

Behind-the-Meter Resource Assumptions

BTM resource adoption and its associated impacts on electricity demand are imbedded in the 2021 Mid-Mid Case. The demand scenario includes approximately 42 GW of BTM PV capacity in 2045. Forecasted BTM PV adoption is based on system payback periods calculated from projections for technology costs, economic conditions, hourly BTM system performance, electricity rates, and incentives. It's important to note that cost calculations incorporate CPUC's Net Energy Metering (NEM) 2.0 tariff and the federal government's Investment Tax Credit (ITC).[7] BTM energy storage adoption was predicted from historic adoption trends for both BTM storage and solar PV. Thus, any impacts on storage adoption influenced by NEM 2.0 or ITC are assumed to be embedded in the projections. Forecasted BTM solar PV and storage adoption forecasts were adjusted to account for growth in these resources based on Title 24 standards for new buildings. Finally, annual as well as hourly demand impacts resulting from cumulative BTM resource adoption were forecasted using hourly BTM system performance data.

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[6] Bailey, Stephanie, Jane Berner, David Erne, Noemí Gallardo, Quentin Gee, Akruti Gupta, Heidi Javanbakht, Hilary Poore, John Reid, and Kristen Widdifield. 2023. Final 2022 Integrated Energy Policy Report. California Energy Commission. Publication Number: CEC-100-2022001-CMF.

7 Note that CPUC adopted NEM 3.0 in 2023 which is not reflected in the 2021 IEPR forecast. Additionally, the 2021 IEPR forecast does not reflect the extension of the ITC which was slated to end in 2023. These updates will be reflected in the 2023 IEPR forecast.

CHAPTER 3: Resource Assumptions

The 2021 SB 100 Starting Point Scenario, which informed the 2022 California ISO 20-year outlook, was developed by taking the 2040 SB 100 Core Scenario and increasing assumed natural gas power plant retirements to 15,000 MW. This increase allowed for an evaluation of the impact of more gas power plant retirements on the transmission system than was identified in the SB 100 Core scenario, in conjunction with bringing new energy storage and renewable energy resources online. In addition, to generally offset the additional assumed natural gas power plant retirements, geothermal, offshore wind (OSW), out-of-state wind, and battery-energy storage systems capacity was added to levels that are generally reflective of other 2021 SB 100 Report scenarios. The scenarios in the 2021 SB 100 Report were developed through a comprehensive interagency stakeholder process to meet a statewide 2045 policy, which includes balancing area authorities (BAA) outside the California ISO.

Table 2: Resource Assumptions in the 2040 SB 100 Starting Point Scenario

Resource Type	2040 Starting Point Scenario (MW)
Natural gas-fired power plants	(-15,000)
Utility-scale solar	53,212
In-state wind	2,837
Offshore wind	10,000
Out-of-state wind	12,000
Geothermal	2,332
Battery-energy storage	37,000
Long-duration energy storage	4,000

Table 1 details the resource assumptions in the 2040 Starting Point Scenario which the California ISO used in the 20-year transmission outlook (2022).

Source: CEC staff

Resource Assumptions for the 2045 Scenario

The 2045 Scenario was developed by taking the resource portfolio from the 2040 Starting Point Scenario with the following adjustments:

- Retain 15 gigawatts (GW) natural gas retirement assumptions.
- Increase offshore wind to 20 GW to reflect updated state policy and executive actions.
- Add resources to help offset additional natural gas retirements in-line with resources included in the previous Starting Point Scenario for the 20-year transmission outlook.

- Add 5 GW of generic clean firm resources/long-duration energy storage.
- Add resources and update resource mapping assumptions to align with resource locations in the latest IRP portfolios for the TPP.[8]

Table 2 provides an overview of the resource assumptions in the 2045 Scenario.

Table 3: New Resource Assumptions in the 2045 Scenario

Resource Type	2045 Scenario (MW)
Natural gas fired power plants	(-15,000)
Utility-scale solar	69,640
Distributed Solar	125
In-state wind	3,074
Offshore wind	20,000
Out-of-state wind	12,000
Geothermal	2,332
Biomass	134
Battery-energy storage	48,813
Long-duration energy storage	4,000
Generic clean firm/long-duration energy storage	5,000

Table 2 details the resource assumptions in the 2045 Scenario which the California ISO will use in the 20-year transmission outlook (anticipated 2024).

Source: CEC and CPUC staff

To further illustrate the 2045 Scenario, Table 3 below compares the SB 100 Core Scenario (2045), the 2040 Starting Point Scenario, and the 2023–2024 TPP base portfolio and OSW Sensitivity (2035) with the 2045 Scenario.

8 CPUC. February 2023. Modeling Assumptions for the 2023-2024 Transmission Planning Process. Staff Report. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/modeling_assumptions_2023-24tpp_v02-23-23.pdf.

Table 4: Comparison of SB 100 Core, 2040 Starting Point Scenario, CPUC IRP TPP Base and Sensitivity Portfolios, and 2045 Scenario

Resource Type (MW)	SB 100 Core (2045)	Starting Point Scenario (2040)	2023–2024 TPP Base Portfolio (2035)	2023–2024 TPP OSW Sensitivity (2035)	2045 Scenario (2045)
Natural Gas Fired Power Plants	(-4,722)	(-15,000)	-	-	(-15,000)
Utility-Scale Solar	69,640	53,212	38,947	25,746	69,640
Distributed Solar	-	-	125	125	125
In-state wind	2,837	2,837	3,074	3,074	3,074
Offshore wind	10,000	10,000	5,497	13,400	20,000
Out-of-state wind	2,837	12,000	5,618	5,618	12,000
Geothermal	135	2,332	2,037	1,149	2,332
Biomass	-	-	134	134	134
Battery-energy storage	48,813	37,000	28,373	23,545	48,813
Long-duration energy storage	4,000	4,000	2,000	1,000	4,000
Generic clean firm/long-duration energy storage	-	-	-	-	5,000

Table 3 compares resource assumptions across recent state resource and transmission planning studies.

Source: CEC and CPUC staff

Offshore Wind

The 2021 Starting Point Scenario included 10,000 MW of offshore wind in 2040. The 2045 Scenario includes 20,000 MW of offshore wind to reflect updated state policy and executive actions.

Following the publication of the 2021 Starting Point Scenario, on September 23, 2021, Governor Gavin Newsom signed into law Assembly Bill 525 (AB 525, Chiu, Chapter 231, Statutes of 2021), which took effect January 1, 2022. AB 525 requires the CEC, in coordination with federal, state, and local agencies and a wide variety of stakeholders, to develop a strategic plan for offshore wind energy deployment off the California coast in federal waters.

In a July 22, 2022, letter to the chair of the California Air Resources Board, Governor Newsom asked the CEC to establish an offshore wind planning goal of at least 20 GW by 2045, among other requested actions.[9] In August 2022, the CEC published the *Offshore Wind Energy Development off the California Coast*[10] report, which established a potentially achievable but aspirational planning goal of 25,000 MW for 2045. The CEC report also established 21.8 GW as a reference point for technically feasible capacity that the CEC will continue to evaluate in developing the AB 525 strategic plan.

The 20 GW of OSW resources assumed in the 2045 Scenario is within the range of California OSW technically feasible capacity evaluated in the 2022 CEC report.

Generic Clean Firm Resources/Long-Duration Energy Storage

The assumed retirement of 15,000 MW of gas resources creates the presumptive need for additional capacity to meet peak demand needs. After adding the additional offshore wind capacity and additional renewable resources in line with the previous 20-year transmission outlook and the 23-24 TPP base case portfolio, the CPUC and CEC staff estimate that an additional 5,000 MW of generic clean firm resources or long-duration energy storage capacity is needed. SB 423 (Stern, Chapter 243, Statues of 2021) defines "firm zero-carbon resources" as electrical resources that can individually, or in combination, deliver zero-carbon electricity with high availability for the expected duration of multiday extreme or atypical weather events, including periods of low renewable energy generation, and facilitate integration of eligible renewable energy resources into the electrical grid and the transition to a zero-carbon electrical grid.[11] Examples of zero-carbon firm resources include geothermal, biomass and resources that generate electricity from zero-carbon hydrogen. The option for long-duration energy storage resources likewise represent an array of existing and emerging long-duration storage types including pumped storage, compressed air, iron-air batteries, and other battery storage technologies. The key requirement is to be able to serve additional capacity to meet peak demand needs on the eight-hour to multi-day time frame.

Distributed Solar

The 2045 Scenario includes considerations for BTM solar and distributed solar. BTM solar is included through the load assumptions, as described in Chapter 2. In addition to BTM solar, the 2045 Scenario includes 125 MW of distributed solar. Distributed solar is separate from BTM

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9 Governor Gavin Newsom, letter to chair of the California Air Resources Board. July 22, 2022. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6.

10 Flint, Scott, Rhetta DeMesa, Pamela Doughman, and Elizabeth Huber. 2022. *Offshore Wind Development off the California Coast: Maximum Feasible Capacity and Megawatt Planning Goals for 2030 and 2045*. California Energy Commission. Publication Number: CEC-800-2022-001-REV. https://www.energy.ca.gov/publications/2022/offshore-wind-energy-development-california-coast-maximum-feasible-capacity-and

11 Senate Bill 423. (Stern, Chapter 243, Statues of 2021). Public Resources Code 25216.7(d)(2). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB423.

solar PV and represents in-front of the meter large-scale commercial rooftop to community scale solar.

CHAPTER 4: Geographic Allocation of Resources

The 20-year outlook requires geographically mapping resources to specific locations, to the extent feasible. This section describes, for each resource in the 2045 Scenario, criteria for the California ISO to use in the 20-year outlook. Wherever possible, the mapping criteria aligns with the current CPUC integrated resource plan (IRP) portfolios being studied within the 2023-2024 TPP. In Appendix B, a table with the geographic allocations for the 20-year transmission outlook for each resource is included, as applicable. All MW values discussed below are assumed to occur by 2045.

Natural Gas Power Plant Retirements

The 2045 Scenario retains the assumption from the 2021 Starting Point Scenario that 15,000 MW of natural gas power plant capacity would be retired by 2040, which is about 50 percent of natural gas power plant capacity assumed in the 2021 SB 100 Report scenarios. This assumption is made only to support the objective of California ISO's informational study and has not been analyzed or modeled through any other process. To identify the locations of assumed retirements for this 20-year transmission outlook, the California ISO should follow the criteria established in the 2021 Starting Point Scenario and first 20-year transmission outlook. These criteria are the following:

- The oldest natural gas power plants retire first, with a priority for those that are in and adjacent to disadvantaged communities.[12]
- At least 3,000 MW of the 15,000 MW of retirements are assigned to natural gas power plants that rely on the Aliso Canyon storage facility as provided by the agencies, with a priority on the oldest power plants and those that are in and adjacent to disadvantaged communities.

Table 3.1-4 in the first 20-year outlook provides an overview of the assumed natural gas-fired generation retired by local capacity area.[13]

New Energy Generation and Storage Capacity

Lithium ion-battery (Li-battery) energy storage: The 2045 Scenario includes 48,813 MW of battery energy storage. The approach used for assigning battery energy storage to transmission zones for the 20-year outlook draws on the approach applied to battery energy

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12 Disadvantaged communities are defined and identified by the California Office of Environmental Health Hazard Assessment and are available in the CalEnviroScreen 3.0 webtool at https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30. For this 2045 Scenario, a natural gas power plant "adjacent to" a disadvantaged community is defined as within a 2.5-mile radius.

13 California Independent System Operator. May 2022. [20-Year Transmission Outlook](http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf). http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf. Page 20.

storage in the CPUC's IRP process for the California ISO's TPP. As shown in Appendix B, the 48,813 MW of battery energy storage is allocated as follows:

- The 28,373 MW of battery energy storage already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes.
- The remaining 20,440 MW of battery energy storage will be allocated by expanding upon the approach from the 2023-2024 TPP base case:
    - Co-locate at substations where utility-scale solar resources are mapped.
    - Stand-alone in local capacity areas to displace gas resources.

Long-duration energy storage: Long-duration energy storage (LDES) was modeled in the 2021 SB 100 Joint Agency Report as pumped hydroelectric energy storage.[14] However, any long-duration storage technology with eight hours or longer of energy generation at maximum output would represent similar attributes. Thus, for the 2045 Scenario, any long duration energy storage technology is considered and not just limited to potential pumped storage resources. The 4,000 MW of LDES in the 2045 Scenario is allocated by building off the current 2023–2024 TPP base case, as well as current commercial interest.

The 4,000 MW of LDES is allocated by:

- 2,000 MW of LDES already mapped in the IRP resource portfolio for the 2023–2024 TPP base case.
- 2,000 MW of LDES aligned with LDES identified in the current California ISO interconnection queue.

Generic clean firm/LDES: Given the current commercial interests and development uncertainty of various emerging technologies, the 5,000 MW of generic clean firm resources and long duration energy storage resources are mapped specifically outside of local areas, near renewable generation. Mapping of these resources outside of the local reliability areas enables study of greater transmission needs into local areas.

Utility-scale solar: The 2045 Scenario includes 69,640 MW of utility-scale solar, which is consistent with the SB 100 Core Scenario from the 2021 SB 100 Joint Agency report. The approach used for allocating utility-scale solar for the 20-year outlook draws on the approach applied to mapping utility-scale solar in the CPUC's IRP process for the California ISO's TPP. As shown in Appendix B, the 69,640 MW of utility-scale solar is allocated as follows:

- 38,947 MW of utility-scale solar energy is already mapped in the IRP resource portfolio for the 2023–2024 TPP base case and is carried over without any changes.
- The allocation of the remaining 30,693 MW of utility-scale solar will be guided by these criteria, which are informed by criteria applied in busbar mapping of the IRP resource portfolios for the TPP:

14 An energy storage technology consisting of two water reservoirs separated vertically; during off-peak hours, water is pumped from the lower reservoir to the upper reservoir, allowing the off-peak electrical energy to be stored indefinitely as gravitational energy in the upper reservoir. During peak hours, water from the upper reservoir is released and passed through hydraulic turbines to generate electricity, as needed.

- *Commercial interest*: Commercial interest, as used in this 2045 Scenario, is determined by using the California ISO's publicly available interconnection queue information.[15] This information includes projects in the queue through the Cluster 14 study window.
- *Environmental and land-use evaluation*: The CEC used the core land-use screen[16] to assess whether substations that were mapped in the 2023–2024 IRP portfolios had sufficient availability of "lower implication"[17] land to map additional utility-scale solar capacity. Other substations that are on the 500 or 230/220 kV system were considered for possible distribution of new resources. Staff performed a geospatial analysis by intersecting 15-mile buffers around each substation with the area remaining outside the core land-use screen. This "lower implication" land with technical resource potential is aggregated within these buffered circles. Land with existing solar facilities were removed from this sum. A limit of 50 percent of the technical resource potential area was chosen for how much new resource could be mapped to a given substation before it was considered "full". See Appendix C for additional information on the core land-use screen.

In-state wind: The 2045 Scenario includes 3,074 MW of in-state wind resources. The 3,074 MW of in-state wind resources already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes. The allocation of in-state wind resources is shown in Appendix B.

Out-of-state (OOS) wind: The 2045 Scenario includes 12,000 MW of wind energy resources generated outside of the existing California ISO system. As shown in Appendix B, the 12,000 MW of out-of-state wind is allocated as follows:

- 790 MW from Arizona and New Mexico on existing out-of-state (OOS) transmission
- 1,000 MW from Idaho on new OOS transmission
- 5,000 MW from Wyoming on new OOS transmission
- 5,210 MW from New Mexico on new OOS transmission

Offshore wind: The 2045 Scenario includes 20,000 MW of offshore wind (OSW) resources. To identify the regions for mapping the 20,000 MW of OSW resources, the staff started with the 13,400 MW of OSW resources already mapped in the high OSW sensitivity from the IRP resource portfolio for the 2023-2024 TPP. The resources in the CPUC's high OSW sensitivity were mapped to the following locations: Morro Bay Wind Energy Area (5,400 MW), Humboldt Wind Energy Area (2,600 MW), Del Norte Interest Area (3,400 MW), and Cape Mendocino

15 http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

16 Hossainzadeh, Saffia, Erica Brand, Travis David, and Gabriel Blossom. 2023. *Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California.* California Energy Commission. Forthcoming publication.

17 In the CEC staff statewide land-use screening for electric system planning, *implication* is defined as a possible significance or a likely consequence of an action, for example, planning for energy infrastructure development in an area of higher biodiversity has *implications* for other land-use priorities.

Interest Area (2,000 MW). To inform mapping the remaining 6,600 MW of OSW resources, the staff consulted two in-progress analyses to understand a range of generation potentials and possible constraints:

- The OSW Development Scenarios under development and evaluation by the Schatz Energy Research Center for the *Northern California and Southern Oregon Offshore Wind Transmission Study*.[18] The analysis considers three scales of OSW development in Northern California, including:
    - Low Development Scenario: 4,100 MW of OSW capacity.
    - Mid-Range Development Scenario: 9,300 MW of OSW capacity.
    - High Development Scenario: 16,000 MW of OSW capacity.
- The in-development AB 525 sea space area identification. During a June 1, 2023, workshop, CEC staff presented a draft range of estimated generation potential from within lease areas and AB 525 sea space areas.[19] The additional AB 525 sea space areas identified are based on wind resource and technical characteristics, such as ocean bottom depth, ocean bottom slope, and distance to shore. These areas will likely reduce in size once screened for conflicts such as existing ocean uses and cultural and biological resources. The draft ranges are:
    - Humboldt Leases: 1,600–3,000 MW
    - North Coast AB 525 sea space: 27,000–45,000 MW
    - Morro Bay Leases: 3,000–6,000 MW
    - South Central Coast AB 525 sea space: 3,500–6,000 MW

After consulting the two in-progress analyses, staff allocated the remaining 6,600 MW of OSW to the Humboldt Wind Energy Area (100MW), the Del Norte Interest Area (3,600 MW), and the Cape Mendocino Interest Area (2,900 MW).

As shown in Appendix B, the CEC and CPUC staff allocated the full 20,000 MW of OSW as follows:

- 7,000 MW potential from Del Norte Interest Area
- 2,700 MW from Humboldt Wind Energy Area
- 4,900 MW potential from Cape Mendocino Interest Area
- 5,400 MW from Morro Bay Wind Energy Area

The geographic allocation of the OSW resources fits within the generation potential ranges under evaluation in the Schatz Energy Research Center *Northern California and Southern Oregon Offshore Wind Transmission Study* and the CEC AB 525 sea space identification.

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18 CEC AB 525 Workshop. May 25, 2023. Presentation slides available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=250371&DocumentContentId=85115. Starts at slide 41.

19 CEC AB 525 Workshop. June 1, 2023. Presentation slides available online at https://efiling.energy.ca.gov/GetDocument.aspx?tn=250471. Slide 59.

Geothermal: The 2045 Scenario includes 2,332 MW of geothermal resources. As shown in Appendix B, the 2,332 MW of geothermal resources is allocated as follows:

- The 2,037 MW of geothermal resources already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes.
- The remaining 295 MW are mapped to the Imperial region bringing the total geothermal mapped to the Imperial area to 1,195 MW. The Salton Sea area has significant geothermal resource potential beyond what was mapped to in the 23-24 TPP base portfolio and the previous 20-year outlook mapped a significant portion of the geothermal resources to the Salton Sea area.

Biomass: The 2045 Scenario includes 134 MW of biomass resources. The 134 MW of biomass resources already mapped in the IRP resource portfolio for the 2023–2024 TPP base case is carried over without any changes.

APPENDIX A
Glossary

Term	Definition
2021 SB 100 Starting Point Scenario	A scenario is a plausible description of how the future may develop based on a coherent and internally consistent set of assumptions about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts but are used to provide a view of the implications of developments and actions. The 2021 SB 100 Starting Point Scenario was developed for use by the California ISO in the 20-year transmission outlook.
Additional Achievable Transportation Electrification	A CEC transportation energy demand forecasting framework that allows for standard forecasting model modifications to account for transportation policy changes that are reasonably expected to occur. These modifications can be made even if standard economic forecasting tools do not have the ability to capture such policies. For example, standard demand forecasting can capture policies that influence the demand for electric vehicles, but supply-side policies that influence vehicle manufacturers may not be captured under standard demand forecasting techniques.
Advanced Clean Cars II regulation	Two-pronged regulation from California Air Resources Board (CARB). First, it amends the Zero-emission Vehicle Regulation to require an increasing number of zero-emission vehicles, and relies on currently available advanced vehicle technologies, including battery-electric, hydrogen fuel cell electric and plug-in hybrid electric-vehicles, to meet air quality and climate change emissions standards. These amendments support Governor Newsom's 2020 Executive Order N-79-20 that requires all new passenger

	vehicles sold in California to be zero emissions by 2035. Second, the Low-emission Vehicle Regulations were amended to include increasingly stringent standards for gasoline cars and heavier passenger trucks to continue to reduce smog-forming emissions. For more information see, Advanced Clean Cars II Regulations.
Advanced Clean Fleets regulation (ACF)	The Advanced Clean Fleets regulation is part of the California Air Resources Board's (CARB or Board) overall approach to accelerate a large-scale transition to zero-emission medium- and heavy-duty vehicles. This regulation works in conjunction with the Advanced Clean Trucks (ACT) regulation, approved March 2021, which helps ensure that zero-emission vehicles (ZEV) are brought to market. For more information see, Advanced Clean Fleets Regulation.
Aliso Canyon storage facility	Aliso Canyon is a depleted oil field that has been used to store natural gas for the Los Angeles region since 1972. SoCalGas has historically used Aliso Canyon to help balance supply and demand in the summer and to help meet peak demand in the winter. On October 23, 2015, a massive leak at the Aliso Canyon natural gas storage facility was discovered and continued until it was sealed on February 18, 2016. In response to the leak at the Aliso Canyon, the state limited its use.
Alternating current (AC)	Flow of electricity that constantly changes (alternates) direction between positive and negative sides in a sine curve. Almost all power produced by electric utilities in the United States moves in current that shifts direction at a rate of 60 times per second.
Balancing authority	A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time. Balancing authorities in California include the Balancing Authority

	of Northern California (BANC), California ISO, Imperial Irrigation District (IID), Turlock Irrigation District (TID) and Los Angeles Department of Water and Power (LADWP). The California ISO is the largest of about 38 balancing authorities in the Western Interconnection, handling an estimated 35 percent of the electric load in the West and 80 percent of the electric load in California. For more information, see the WECC Overview of System Operations: Balancing Authority and Regulation Overview Web page.
California Energy Demand Forecast (CED)	CED is a set of several forecasting products that are used in various energy planning proceedings, including the California Public Utilities Commission's (CPUC's) oversight of energy procurement and the California Independent System Operator's (California ISO's) transmission planning. The demand forecast generally includes: Ten-year annual end-use consumption forecasts for electricity and natural gas by customer sector, eight planning areas, and 20 forecast zones. Annual peak electric system load with different weather variants for eight planning areas. Annual projections of load modifier impacts including adoption of photovoltaic and other self-generation technologies, energy efficiency standards, and program impacts. For more information, see the Final 2021 Integrated Energy Policy Report Volume IV: California Energy Demand Forecast.
California ISO's 20-Year Transmission Outlook	A report published by the California ISO to provide a long-term conceptual plan of the transmission grid in 20 years, meeting the resource and electric load needs aligned with state agency input on integrated load forecasting and resource planning. The report is developed in collaboration with the California Public Utilities Commission and the California Energy Commission. For more

	information, see the 20 Year Transmission Outlook report.
Direct current (DC)	Electricity that flows continuously in the same direction rather than alternating (see above).
CPUC Integrated Resource Planning (IRP)	A planning proceeding to consider all the CPUC's electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The integrated resource planning process ensures that load-serving entities (LSEs) detail the procured and planned resources in their portfolios that allow the electricity sector to meet electricity demand while also contributing to meeting California's economywide greenhouse gas emissions reductions goals.
Kilovolt (kV)	One-thousand volts (1,000). Distribution lines in residential areas usually are 12 kV (12,000 volts).
PATHWAYS High Electrification Demand Scenario	The PATHWAYS model, developed by Energy and Environmental Economics, Inc (E3), is an economy-wide scenario tool used to identify pathways to achieve economy-wide decarbonization. For more information, see PATHWAYS Model.
Renewables Portfolio Standard (RPS)	The Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load-serving entities. The generation must be procured from RPS-certified facilities (which include solar, wind, geothermal, biomass, biomethane derived from landfill and/or digester, small hydroelectric, and fuel cells using renewable fuel and/or qualifying hydrogen gas). More information can be found at the CEC Renewables Portfolio Standard web page and the CPUC RPS Web page.
SB 100 Core Scenario	A scenario is a plausible description of how the future may develop based on a coherent and internally consistent set of assumptions

	about key driving forces (for example, rate of technological change, prices) and relationships. Note that scenarios are neither predictions nor forecasts, but are used to provide a view of the implications of developments and actions. The SB 100 Core Scenario from 2021 SB 100 Joint Agency Report is based on retail sales and in-state demand.

APPENDIX B
Resource Allocations for the 2045 Scenario for the 20-Year Outlook

Table B-1 provides an overview of the resource allocations by RESOLVE resource area[20] for the 2045 Scenario for the 20-year outlook. A full breakdown of the resources, including the mapping by substation and mapping analysis, can be found in the 2045 Scenario Portfolio Dashboard in CEC Docket 21-SIT-01.

Table B-1: Resource Allocations for the 2045 Scenario for the 20-Year Transmission Outlook

		2040 SB 100 Starting Point Scenario	23-24 TPP Base Case	2045 Scenario
		2040	2035	2045
InState Biomass	Biomass/Biogas	-	134	134
Solano_Geothermal	Geothermal	-	139	139
Northern_California_Geothermal	Geothermal	-	-	-
Inyokern_North_Kramer_Geothermal	Geothermal	-	53	53
Southern_Nevada_Geothermal	Geothermal	320	500	500
Northern_Nevada_Geothermal	Geothermal	-	445	445
Riverside_Palm_Springs_Geothermal	Geothermal	-	-	-
Greater_Imperial_Geothermal	Geothermal	2,012	900	1,195
Distributed Solar	Solar	-	125	125
Northern_CA	Solar	1,167	898	2,847
Greater_Bay	Solar	-	510	510
Central_Valley_LosBanos	Solar	809	1,208	3,391

20 CPUC. June 2023. Draft Inputs and Assumptions. 2022-2023 Integrated Resource Planning (IRP). https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/draft_2023_i_and_a.pdf

SPGE_Westlands_Fresno	Solar	12,925	4,805	14,065
SPGE_Greater_Carrizo	Solar	-	230	1,630
SPGE_Kern	Solar	6,154	2,957	6,396
Big_Creek-Magunden	Solar	-	1,205	2,600
Greater_Tehachapi	Solar	9,544	6,829	8,978
Ventura_Area	Solar	2,066	750	1,800
Greater_LA	Solar	-	-	-
Greater_Kramer	Solar	3,510	2,660	3,460
SouthernNV_Desert	Solar	2,272	4,943	6,326
Riverside	Solar	4,922	6,493	6,793
Arizona	Solar	3,952	4,497	6,000
Greater_Imperial	Solar	4,807	963	4,345
San_Diego	Solar	995	-	500
Northern_California_Wind	Wind	866	339	339
Solano_Wind	Wind	542	757	757
Humboldt_Wind	Wind	34	-	-
Kern_Greater_Carrizo_Wind	Wind	60	180	180
Carrizo_Wind	Wind	287	174	174
Central_Valley_North_Los_Banos_Wind	Wind	173	150	150
North_Victor_Wind	Wind	-	-	-
Tehachapi_Wind	Wind	275	345	345
Southern_Nevada_Wind	Wind	-	403	403
Riverside_Palm_Springs_Wind	Wind	-	127	127
Baja_California_Wind	Wind	600	600	600
Wyoming_Wind	OOS Wind	4,685	1,500	5,000
Idaho_Wind	OOS Wind	-	1,000	1,000

New_Mexico_Wind	OOS Wind	5,215	2,328	5,210
SW_Ext_Tx_Wind	OOS Wind	-	790	790
NW_Ext_Tx_Wind	OOS Wind	1,500	-	-
North_Coast_Offshore_Wind	Offshore Wind	4,000	n/a	n/a
Humboldt_Bay_Offshore_Wind	Offshore Wind	n/a	1,607	2,700
Cape_Mendocino_Offshore_Wind	Offshore Wind	n/a	-	4,900
Del_Norte_Offshore_Wind	Offshore Wind	n/a	-	7,000
Central_Coast_Offshore_Wind	Offshore Wind	6,000	n/a	n/a
Morro_Bay_Offshore_Wind	Offshore Wind	n/a	3,100	5,400
Diablo_Canyon_Offshore_Wind	Offshore Wind	n/a	-	-
Renewable Resource Total		**79,692**	**54,642**	**107,305**
Northern_CA	Li_Battery	64	674	1,843
Greater_Bay	Li_Battery	250	2,479	3,079
Central_Valley_LosBanos	Li_Battery	-	537	1,846
SPGE_Westlands_Fresno	Li_Battery	431	2,341	7,899
SPGE_Greater_Carrizo	Li_Battery	50	210	1,050
SPGE_Kern	Li_Battery	95	1,441	3,603
Big_Creek-Magunden	Li_Battery	-	575	1,411
Greater_Tehachapi	Li_Battery	4,036	4,471	6,339
Ventura_Area	Li_Battery	500	668	1,298
Greater_LA	Li_Battery	1,651	2,527	2,527
Greater_Kramer	Li_Battery	176	1,404	1,884
SouthernNV_Desert	Li_Battery	700	2,689	3,517
Riverside	Li_Battery	-	4,900	5,380
Arizona	Li_Battery	695	1,567	2,918

Greater_Imperial	Li_Battery	-	603	2,632
San_Diego	Li_Battery	720	1,289	1,589
Unspecified_Locations	Li_Battery	27,632	-	-
Li_Battery_Total		**37,000**	**28,374**	**48,814**
SPGE_Greater_Carrizo	LDES	-	300	500
SPGE_Westlands_Fresno	LDES	-	-	100
Greater_Tehachapi	LDES	-	500	1,000
Riverside	LDES	1,900	700	1,500
San_Diego	LDES	500	500	500
Northern_CA_LDES	LDES	-	-	400
Unspecified_Locations	LDES	1,600	-	-
LDES Total		**4,000**	**2,000**	**4,000**
Storage Total		**41,000**	**30,374**	**52,814**
Generic Clean-Firm or LDES	Unspecified	-	-	5,000
Total New Resources		**120,692**	**85,015**	**165,118**

APPENDIX C
Core Land-Use Screen

The core land-use screen is the primary screen established by the geospatial analysis in the CEC Land-Use Screens Report.[21] The core land-use screen identifies:

(1) areas of the state that should be excluded from resource potential consideration because of technical and economic criteria commonly applied in energy infrastructure development,[22] and

(2) areas where utility-scale renewable energy or transmission development is precluded by state or federal law, policy or regulation.[23]

The geospatial datasets consisting of these categories of data are identified and compiled into a single map at statewide scale. They are referred to as the technoeconomic exclusion layer and the protected area layer and form the base exclusions of the core land-use screen.

The other components of the core land-use screen address several state policy priorities, including sustaining agriculture, protecting natural lands that support biodiversity,[24] and conserving intact landscapes. These additional land-use planning considerations fall into three categories used in the core screen:

(1) Biological Planning Priorities: Combines mapped delineations of U.S. Fish and Wildlife Service critical habitat (including the proposed bistate sage grouse), high ranks of California Department of Fish and Wildlife's Areas of Conservation Emphasis Terrestrial Connectivity, Biodiversity and Irreplaceability, and lands classified as wetlands.

(2) Terrestrial Landscape Intactness: A multicriteria evaluation model[25] result representing landscape condition based on the extent to which human impacts such as agriculture,

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21 Hossainzadeh, Saffia, Erica Brand, Travis David, and Gabriel Blossom. 2023. *Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California.* California Energy Commission. Forthcoming publication.

22 Spatial datasets that capture technical (for example, competitive wind resource locations), physical (for example, slope, water bodies) and socioeconomic or hazardous (for example, densely populated areas, railways, airports, highways, mines) criteria. This category also includes military lands. This layer was developed by CPUC staff.

23 Example designations of lands that fall under the protected area layer are National Parks, GAP Status 1 and 2, Open Spaces, Wilderness Areas, National Conservation Lands, Scenic Areas, easements, and Recreation Areas. For a full description and list of categories see Table D-1 and Table D-2 of the California Energy Commission, *Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California.* Staff report. Forthcoming publication.

24 Executive Order N-82-20, available at https://www.gov.ca.gov/wp-content/uploads/2020/10/10.07.2020-EO-N-82-20-.pdf.

25 A multicriteria evaluation is common in geospatial analyses when multiple inputs affect an overall value decision for an area. This method allows each input data layer to be transformed onto a common scale and weights each dataset according to relative importance. The result is a summation of the input data layers into a single-gridded map.

urban development, natural resource extraction, and invasive species have disrupted the landscape across California.[26]

(3) CEC Cropland Index Model: For lands used to produce crops, CEC developed a multicriteria evaluation model that uses information on soil quality, farmland designation, and existence of crops to create a numerically weighted index for the relative suitability of an area for crop production.

The CEC Cropland Index Model and the CBI Landscape Intactness modeled results are evaluated, then partitioned at the mean to produce areas of higher and lower implication, with higher implication areas recommended for resource potential exclusion. These are then combined with the base exclusions and the biological planning priorities to produce the core land-use screen. The areas remaining outside the screen are considered as lower implication areas and can be quantified, typically in units of acres and capacity (megawatt or gigawatt), to estimate renewable resource technical potential for electric system modeling and energy resource planning.

26 Degagne, R., J. Brice, M. Gough, T. Sheehan, and J. Strittholt. 2016. "Landscape Intactness (1 km), California." Conservation Biology Institute. From DataBasin.org: https://databasin.org/datasets/e3ee00e8d94a4de58082fdbc91248a65.

RFP

Request for Proposal

Los Angeles Department of Water & Power

For
Partnership Opportunity Participating in Transmission Projects Within and Outside of California

Release Date: 12/27/2023

Request for Proposals

Partnership Opportunity

Participating in Transmission Projects

Within and Outside of California

I. INTRODUCTION

The Los Angeles Department of Water and Power (LADWP) is soliciting proposals from organizations interested in entering into a partnership with the LADWP to jointly fund the development of three transmission projects identified in the LADWP's Strategic Transmission Plan (STP), namely the Marine Cables, Eastern Corridor, and 500-kV Parallel PDCI transmission projects collectively referred to as the “Proposed Transmission Projects” or simply “Projects”. As part of this partnership, participating organizations will receive perpetual entitlement rights on these transmission lines in proportion to their respective investment levels.

The STP is a roadmap for future LADWP transmission upgrades, which has identified the necessary transmission investments to: (1) reliably meet system needs; (2) be resilient to extreme events; (3) promote operational flexibility; (4) provide an interconnection roadmap; (5) reduce long-term costs and risks; and (6) achieve LADWP's 100% clean energy goals. As a result, this Request for Proposal (RFP) has been issued by the LADWP to identify potential partners who may have similar interests in transmission rights in the Proposed Transmission Projects.

It should be noted that this is an open-ended RFP with no established end date. This RFP does not obligate the LADWP to contract for any supply or service. Respondents are advised that the LADWP will not pay any costs incurred in response to this RFP, and all costs associated with responding to this RFP will be solely at the interested party's expense.

II. BACKGROUND

LADWP is a utility established under The Charter of the City of Los Angeles, and it is the largest municipal utility in the United States, serving about 4 million residents and 1.5 million registered customers. With over a century of experience in electricity generation, transmission, and distribution, LADWP's average annual energy consumption is approximately 23,998 GW-hours (July 2021 to June 2022), and its peak demand recorded as of August 31, 2017, is 6,502 Mega Watts (MW).

As a vertically integrated electric utility, LADWP owns, controls, and operates generation, transmission, and distribution systems that span across multiple states, including 4,040 miles of overhead transmission lines and 128 miles of underground transmission cables. LADWP operates two High Voltage Direct Current (HVDC) systems, the Pacific Direct Current Intertie (PDCI), and the Intermountain Power Project Southern Transmission System Direct Current Links (STS), as well as a vast network of High Voltage Alternating Current (HVAC) transmission lines, which includes 500-kV, 230-kV, and 138-kV transmission lines. Together, these systems form a highly integrated transmission network, which is the backbone of LADWP's transmission system, enabling the utility to operate and meet demand reliably.

LADWP is currently undergoing an accelerated transformation as a result of the following: (1) enacted public policies from state and local governments, which direct LADWP to transition from fossil fuels to 100% carbon-free emitting resources; (2) anticipated load growth from transportation and building electrification; (3) new and emerging technologies to modernize its transmission system; and (3) a need to maintain reliability during extreme weather and wildfires.

To achieve its goal of 100% carbon-free energy by 2035 and meet the California Senate Bill 100 (SB100) mandate of 100% clean energy by 2045 while accommodating anticipated load growth, LADWP has developed its Strategic Long-Term Resource Plan (SLTRP) to identify the quantity and types of resources needed. Additionally, LADWP STP identifies prudent transmission investments required to make the SLTRP achievable. The STP has revealed that substantial new transmission infrastructure investment and federal support, including support from the Department of Energy, will be essential to advance the development of innovative and collaborative transmission projects with potential partners, to minimize cost shifting and overburdening LADWP customers.

Project Objectives

LADWP is looking for parties with similar interests in project development. The goal is for an innovative and collaborative approach to the development of transmission projects that will: (1) optimize transmission infrastructure investments; (2) provide cost savings; and (3) year-round system reliability for residents and businesses across LADWP's service territory. However, constructing new transmission lines in time to meet LADWP's energy policy goals of achieving 100% carbon-free resources by 2035 presents unique challenges, including but not limited to, addressing energy security and reliability risks resulting from reliance on weather-dependent renewable energy resources while combating climate-induced heat waves and wildfires. To address these challenges, LADWP is interested in transmission investments that:

- Maintain and increase system reliability
- Increase the LADWP's transfer capability to access low-cost renewable energy resources
- Help insulate LADWP customers from weather extremes and wildfires by providing operational flexibility

- Promote geographic and diverse energy sources

Project General Description

LADWP has conducted a strategic analysis of its transmission plan, which has identified several transmission projects aimed at supporting LADWP's transition to 100% carbon-free resources. Preliminary technical studies have been completed by LADWP to determine the impact of these proposed transmission projects on LADWP's electric systems. However, LADWP still needs to conduct analyses of various options for developing Proposed Transmission Projects under the National Environmental Policy Act (NEPA) and the California Environmental Quality Act (CEQA), including evaluating and selecting route and capacity options. Additionally, LADWP has not yet identified the design parameters and specifications related to the Proposed Transmission Projects.

To facilitate the development and construction of these projects, LADWP is seeking partners in three specific transmission projects out of the total projects identified in its STP. The three Proposed Transmission Projects are collectively presented in Figure 1 below and are described individually in this Section. It is important to note that the listing order does not characterize any significance, as all projects are equally important.

Figure 1: Transmission projects for participation.

Marine Cables

The LADWP has identified several key constraints that limit the ability to import attractive resources from areas, including but not limited to, Northern System of the West of the River Path (NWOR) path and LADWP's allocation of the Northern System of the East of the River Path (NEOR) path. As such, a new submarine HVDC cable from Haynes Generating Station to Scattergood Generating Station and then to Diablo Canyon area, referred hereto as "Marine Cables" has been identified to improve transfer capability to the LA Basin and will enable LADWP to meet its goals and objectives. The new Marine Cables, as shown in Figure 2 below, aims to improve the LADWP's transfer capability and provide access to offshore wind resources near Diablo Canyon and solar resources in San Luis Obispo area.

A variety of approaches will likely be utilized depending on the nature of, and joint participants to this transmission project. The new Marine Cables will likely be of mutual benefit to potential partners, as well as LADWP (the Parties). As a result, a collaborative, joint ownership approach is assumed for this project, which considers ownership shares among participants, i.e. costs, liabilities, rights, and transmission capacity between the Partie(s). If there are multiple participants, LADWP reserves the right to maintain a minimum of 50 percent ownership shares in the project based on the future needs.

Figure 2: Marine Cables Path.

Eastern Corridor

The LADWP has identified several key constraints that limit the ability to import attractive resources from areas, including but not limited to, the NWOR and the NEOR paths. Therefore, a new Los Angeles to New Mexico transmission corridor referred hereto as the “Eastern Corridor” has been identified to improve transfer capability to the LA Basin which will enable LADWP to meet its goals and objectives. The Eastern Corridor, depicted in Figure 3 below, encompasses a new 500 kV HVDC line and a 500 kV AC line. It originates from the Haynes Generating Station in the greater Los Angeles area, passes through the Pinal Central Substation in Arizona, and extends into New Mexico. This infrastructure upgrade enhances the transfer capabilities of NEOR and NWOR, while granting access to solar energy in the desert, geothermal power in Imperial Valley, and wind and solar resources in Mexico. The transmission line facilitating this is a 500 kV HVAC line following the existing transmission corridor to New Mexico.

Figure 3: Eastern Corridor Path.

In pursuit of a collaborative approach, two key projects are proposed as part of the Eastern Corridor: (i) the installation of new 500 kV HVDC and AC lines connecting the Haynes Generating Station to the Pinal Central Substation, and (ii) the establishment of a new 500 kV AC line from the Pinal Central Substation to a forthcoming substation in New Mexico, with a focus on harnessing renewable energy resources. These initiatives hold promising advantages for all involved parties. Therefore, it is envisaged that a joint ownership model will be adopted, with ownership shares across parties encompassing costs, liabilities, rights, and transmission capacity among the participating entities. In the event of multiple participants, LADWP reserves the right to maintain a minimum ownership share of 50 percent in the project based on future needs.

<u>500-kV AC Parallel PDCI</u>

The LADWP has identified several key constraints that limit the ability to import attractive resources from areas, including but not limited to, the NWOR path the NEOR path. LADWP is seeking a partner for the new 500 kV AC Parallel PDCI line project which consists of a new 500-kV transmission line originating at NV Energy's Fort Churchill Substation, part of its Greenlink project, located in the Reno area and not far from PDCI's Right of Way, will parallel the PDCI southern portion all the way to Victorville Substation and is referred hereto as "500-kV AC Parallel PDCI". The new 500-kV AC Parallel PDCI emanating from NV Energy's Fort Churchill Substation and terminating at the Victorville Substation, as shown in Figure 4 below, aims to:

- Increase access to Nevada geothermal resources;
- Increase capability for wholesale trading with CAISO; and
- Increase import capability into the LA Basin, and therefore incremental increase in resilience.

Figure 4: 500-kV AC Parallel PDCI Path.

III. PROJECT REVIEW AND PROPOSAL REQUIREMENTS

A meeting to review each selected proposal will be scheduled. Parties intending to submit a proposal are strongly encouraged to provide a contact name, phone number, email address, and business address to the LADWP's point of contact identified below so that they can be informed of the date of the project review.

The following information shall be provided in each proposal and will be utilized in evaluating each proposal submitted. Please provide the following information (Proposal) in the following order:

1. **Entity:** Name and general description of the entity.

2. **Entity Contact Information:** Name, mailing address, telephone number, facsimile number, and e-mail address of the entity's primary contact.

3. **Proposal for Jointly Funding the LADWP's Proposed Transmission Projects:** Describe the entity's participation objective to include amount of capacity desired; the amount of funding to be provided; and the expected cost sharing objectives and proposed terms and conditions.

4. **Financial Capability:** Verifiable information demonstrating that the entity is in sound financial condition and has the ability to secure the necessary financing to meet the project's requirements now and in the future. The entity's financial capability and any other responsibility determinations will be reviewed for stability and adequacy to meet its long-term capital and cash needs to carry out its role in developing the Proposed Transmission Project. If the entity plans to secure financing from an outside source, an official letter from the financier confirming the financial arrangements will be required.

5. **Environmental Stewardship:** Evidence of entity's commitment to environmental stewardship and sustainability in the design and construction of the high voltage transmission line project, a plan for minimizing environmental impacts, including the use of best available technologies and practices.

6. **Participation of Other Entities:** A brief description of any steps the entity has taken to seek interest from other entities in participating in developing the proposed project or in seeking interest in subscribers for the additional transmission capacity resulting from the Proposed Transmission Project.

7. **Conflicts:** Proposers shall verify that they have no personal or organizational conflicts of interest, as prohibited by law.

8. **Other Information:** A brief description of any other information that would be useful in evaluating the level of interest including perspectives not covered in this RFP.

IV. ADDITIONAL PROJECT PROPOSALS

Potential proposers may also propose transmission projects for LADWP's consideration provided that such proposed project is in alignment with LADWP's energy and equity strategy policy goals of achieving 100% carbon-free resources by 2035 and that the proposed transmission project:

- Provides access to low cost renewable energy resource
- Increase grid resiliency and operation flexibility
- Offers innovative approach to high voltage transmission development and construction
- Presents minimal environmental and constructability risks
- Delivers benefit to environmental justice communities

The proposer should also include the following information in the order shown below to better understand the proposer's proposed transmission project in the order presented below:

1) Brief description of proposed project
2) Project's value proposition
3) Diagram including map identifying project corridor
4) Estimated project costs

In addition, the proposer shall respond to all items under **Section III** above. If the proposer only submitted its own proposal for LADWP's consideration, the proposer shall respond to requirements 1 through 8 in Section III.

If the proposer's proposal is deemed feasible, the Parties will discuss as part of the review process their respective transmission needs, funding obligations, agree upon a proportional share of transmission capacity, annual operation and maintenance costs associated with Proposed Transmission Project capacity. The actual percentages of costs and benefits between the Parties will be determined by proposals received under this RFP and subsequent discussions.

All options for funding will be considered. In the event of multiple participants, LADWP reserves the right to maintain a minimum ownership share of 50 percent in the project; the cost-share will be allocated accordingly.

V. QUESTIONS AND TIMING

Questions

Potential proposers may submit questions on this RFP at any time. LADWP shall not be obligated to respond to any question unless it is submitted in writing to TPPARTNERSHIP@ladwp.com. LADWP will post responses to substantive issues to Regional Alliance Marketplace for Procurement (RAMP). Proposers are responsible for checking the website for any addenda. Only questions answered by formal written addenda will be binding. Oral responses, or email responses, shall not be binding on the LADWP.

Timing

This is an open-ended RFP therefore, there is no deadline at this moment for receiving proposals. However, potential proposers are advised to submit responses as early as possible to be considered as a potential partner to jointly fund the Proposed Transmission Projects as such projects may not be available for participation. Please submit your proposal via email TPPARTNERSHIP@ladwp.com.

Notification of Receipt

An e-mail acknowledgement of receipt will be provided.

All proposals, whether selected or rejected, shall become the property of the LADWP and will not be returned to the proposer.

VI. EVALUATION PROCESS

LADWP will evaluate proposals based on the information required in the RFP as well as the criteria outlined in Items 1 through 8 in Section III. The evaluation process aims to maintain transparency and objectivity, and adherence to the predefined evaluation criteria provided below, ensuring consistency in the selection of the investor(s) for the co-funding and ownership rights opportunity.

1. **Financial Capability:** This criterion assesses the financial strength and stability of the investor. It includes an evaluation of the investor's financial resources, creditworthiness, and ability to fulfill their financial commitments. The evaluation may consider factors such as the investor's financial statements, credit ratings, and past performance in funding similar projects.

2. **Experience and Expertise:** This criterion evaluates the investor's experience and expertise in developing and financing transmission projects. It considers the investor's track record in successfully completing similar projects, their technical knowledge, and the qualifications of their team members. The evaluation may also include an assessment of the investor's understanding of regulatory requirements, environmental mandates and industry best practices.

3. **Strategic Fit:** This criterion assesses how well the investor's proposed approach aligns with LADWP's clean energy transition goals and overall strategic transmission plan objectives. It considers the investor's understanding of LADWP's priorities, their ability to contribute to the integration of renewable energy sources, and their commitment to sustainability and environmental stewardship.

4. **Added Value:** This criterion evaluates the additional benefits or value that the investor brings to the project beyond financial contributions. It considers the investor's ability to provide innovative solutions, technological advancements, or unique expertise that can enhance the project's overall effectiveness and efficiency. The evaluation may also include an assessment of the investor's potential for collaboration and knowledge sharing.

5. **Proposed Terms and Conditions:** This criterion assesses the investor's proposed terms and conditions for co-funding the transmission projects and acquiring ownership rights on a portion of the transmission line capacity. It evaluates the clarity, fairness, and reasonableness of the proposed terms, including the financial arrangements and any other contractual provisions. The evaluation may also consider the compatibility of the proposed terms with LADWP's legal and regulatory frameworks.

6. **Relevant ownership, joint venture, and partnership experience:** The criterion for the Request for Proposal assesses the investor's pertinent ownership, joint venture, and partnership experience.

Furthermore, LADWP reserves the right to:

- Review the proposal, exchange information, and negotiate terms of the final agreement with any respondent(s)
- Withdraw this RFP at any time without prior notice, including after proposals have been received
- Choose not to enter an agreement with any respondent
- Enter an agreement with one respondent
- Apportion the contract among two or more respondents.

VII. CONFIDENTIALITY AND USE OF INFORMATION

LADWP acknowledges that data submitted by project participants in response to this RFP, including financing arrangements involving third parties, may be subject to public disclosure under the Freedom of Information Act (FOIA) or the California Public Records Act (CPRA). However, the LADWP recognizes that certain information may require confidential treatment to safeguard sensitive data from public disclosure. Participants have the option to request such treatment for all or part of their submitted documents, in accordance with the provisions outlined in the FOIA and CPRA.

The proposer shall be responsible for clearly marking the information that is to be treated confidential. Materials so designated and which meet the criteria stipulated in the FOIA will be treated as exempt from FOIA or CPRA inquiries, except as required to be disclosed to comply with any applicable law, order, regulation or ruling or other legal requirement, including but not limited to oral questions, discovery requests, subpoenas, civil investigations or similar processes; provided, however, the LADWP shall give the project participants timely notice of any such disclosure. Both Parties recognize that the City of Los Angeles is subject to the California Public Records Act and the Ralph M. Brown Act.

WECC

Western Assessment of Resource Adequacy

November 2023

OVERVIEW

LEARN MORE

Executive Summary

Resource adequacy remains a critical risk in the Western Interconnection and continues to challenge industry planners, operators, regulators, and partners. Resource adequacy risks over the medium and long term have increased significantly compared to last year's assessment. Three risks merit particular attention.

Increasing variability

Variability remains the greatest risk to resource adequacy in the Western Interconnection. To be resource adequate, the industry must have enough energy to meet demand under a range of possible conditions. Variable resources cannot be called on and dispatched to meet demand the same way traditional resources can. System-wide variability increased substantially between the 2022 and 2023 Western Assessments. Large, planned additions of variable resources, retirements of traditional baseload resources, and extreme weather events are three of the main drivers of resource and demand variability.

Rate of demand growth and uncertainty of future load patterns

Demand is expected to increase by 16.8% over the next 10 years, almost double the 9.6% growth reported in WECC's 2022 assessment. The biggest driver of this increase is the expansion of data centers, particularly in the Northwest. WECC sees no indications of this risk abating and expects the risk to grow and expand geographically as cloud computing and artificial intelligence needs grow. Entities outside the Northwest are starting to see increases in data center expansion.

Electrification drives load growth and uncertainty in load forecasts because it is difficult to determine how much it will be adopted in different areas and how it will affect load use patterns. Without a historical reference, entities must rely on new techniques and information to account for electrification in load forecasting. Only 40% of Balancing Authorities incorporate electrification assumptions directly into their load forecasting methods. Another 40% conduct separate electrification modeling and use the results to inform their load forecasting. This is an area in which the West must advance to ensure all entities are adequately accounting for ongoing and increasing changes from electrification.

Pace of new resource growth necessary to meet energy demand

To meet changes in demand, replace retiring resources, and cover increasing variability, the industry plans to build new resources at an unprecedented rate in the face of numerous challenges. Supply chain disruptions, increasing costs, production obstacles, and an overwhelmed interconnection queue threaten industry timelines to build new resources. While entities are trying to account for these delays in their resource plans, those plans have no room for adjustment, and there are other drivers like demand increase uncertainties and new policy changes for which the entities cannot fully account.

Risks to Reliability

WECC's Western Assessment answers two questions.

Question 1: Are current resource plans sufficient to meet future demand for the interconnection and subregions over each of the next 10 years under the range of possible system conditions?

Current resource plans are not sufficient to meet future demand over each of the next 10 years. In the near-term (2024–2025), WECC's analysis shows very few demand-at-risk hours with nominal amounts of demand at risk. However, starting in 2026, the number and magnitude of demand-at-risk hours increase by orders of magnitude. This indicates that current resource plans do not fully cover demand under a full range of potential conditions.

Question 2: How does variability in the system increase with the changes in resources and demand currently reflected in resource plans, and how does this affect resource adequacy risk?

Variability increases over the next 10 years across the interconnection and in all subregions except the NW-Northwest. This variability is driven primarily by the addition of non-dispatchable variable energy resources (VER), the retirement of dispatchable resources, and the increase in load uncertainty due to extreme weather events. Variability creates risk in the system because it increases uncertainty, which makes it more difficult to reliably plan and operate the system. By this measure, resource adequacy risk is increasing.

Actions to Address the Risks

Industry is working to address these risks. In recent years, entities and states have taken urgent action to delay the retirement of resources to ensure continued reliability, particularly under extreme conditions. Between their 2022 and 2023 resource plans, entities increased the total number of new resources they plan to build over the next 10 years. Planning entities are developing new methods for incorporating changes like electrification and extreme events into system planning. The industry continues to discuss transmission expansion and recognizes its critical role in meeting resource adequacy needs. Discussions about the interconnection queue continue. The electric power industry, its regulators, and its partners understand and are acting to maintain the reliability of the system. The question is whether the West can act quickly enough. The changes the West faces are faster, broader, and deeper than anything it has faced before, and it will take continued, concerted, and focused effort to maintain reliability.

WECC remains committed to evaluating evolving trends and risks, conducting comprehensive analyses, and providing unbiased and objective information to industry stakeholders on resource adequacy. WECC intends the 2023 Western Assessment to be a resource for planners, regulators, policymakers, and other stakeholders as they contemplate resource planning challenges and decisions.

Table of Contents

Introduction

Reliability of the bulk electric system in the Western Interconnection would be impossible to maintain without sufficient resources to serve customer load. Resource planning decisions are often made years before resources are needed, and the decisions entities make affect their neighbors and the interconnection. Consequently, a long-term, recurring assessment of resource adequacy across the interconnection is necessary to ensure the reliability of the electric grid.

WECC's Western Assessment of Resource Adequacy (Western Assessment) examines resource adequacy through an energy-based probabilistic approach, looking broadly across the entire Western Interconnection and more specifically within each of five subregions over the next 10 years (Figure 1). This analysis, together with analyses by other western stakeholders, provides valuable insight into resource adequacy risks. This information can help stakeholders target specific areas for deeper examination and mitigation.

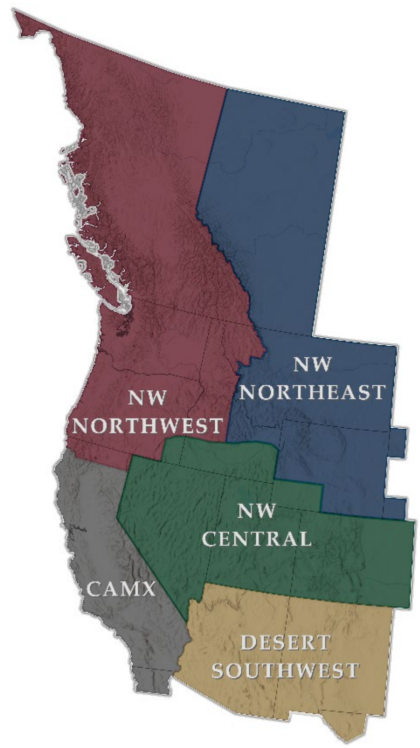


Figure 1: Western Assessment Subregions

This work examines the drivers of resource adequacy changes as well as the associated risks. The results are presented in three time frames:

- Near-term: 2024–2025
- Mid-term: 2026–2028
- Long-term: 2029–2033

As the Regional Entity responsible for ensuring the reliability and security of the Western Interconnection, WECC's work directly affects approximately 90 million people in the western United States and parts of Canada and Mexico. WECC is committed to conducting comprehensive analyses and providing objective information on resource adequacy risks throughout the Western Interconnection. These analyses rely on input and feedback from industry and other stakeholders. WECC thanks the stakeholders who provided input and recommendations that helped shape this year's Western Assessment.

Resource Adequacy Risk Drivers

Over the next decade, entities in the West plan to add 95 GW of resources to meet demand while satisfying requirements for clean energy. Demand is expected to grow at rates much higher than over the last decade. In addition, nearly 18 GW of coal and natural gas generators will be retired. Building to current plans will require a substantial increase in resource growth compared to the last 10 years. To keep pace with anticipated demand growth and retirements, industry will need to build new resources more quickly than in the past. Disruptions to the timely addition of resources pose a risk to reliability.

Western Interconnection Resource Retirements and Shutdowns

Over the next 10 years, entities plan to retire 27 GW of generation resources, mostly coal and natural gas (Figure 2). This is a 50% increase over the 18 GW of resources retired over the last 10 years. In recent years, some entities delayed retirements as a short-term way to reduce resource adequacy risk and compensate for delays in new resources. Entities continue to adjust retirement dates. In their 2023 resource plans, they further delayed retirements compared to their 2022 plans (Figure 3). These delays should help mitigate demand-at-risk hours in the near term until new resources can be built to replace resources that are scheduled to retire.

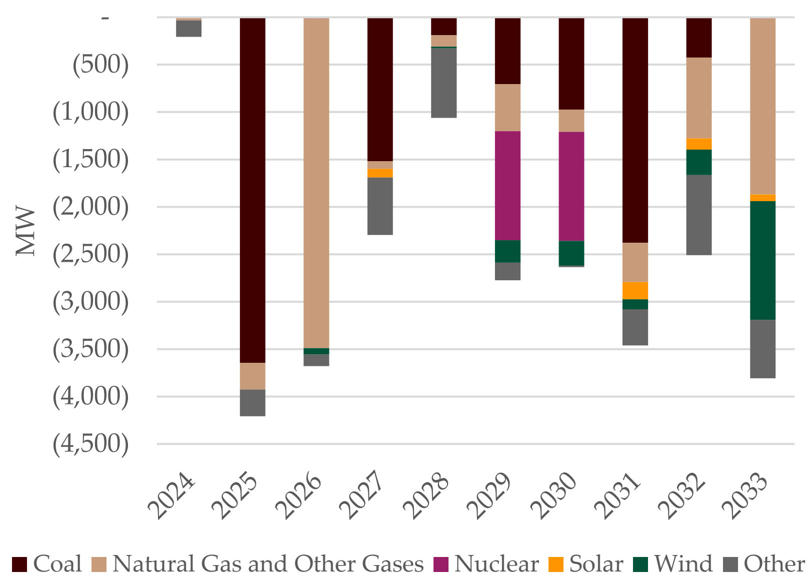


Figure 2: Western Interconnection Planned Retirements 2024–2033

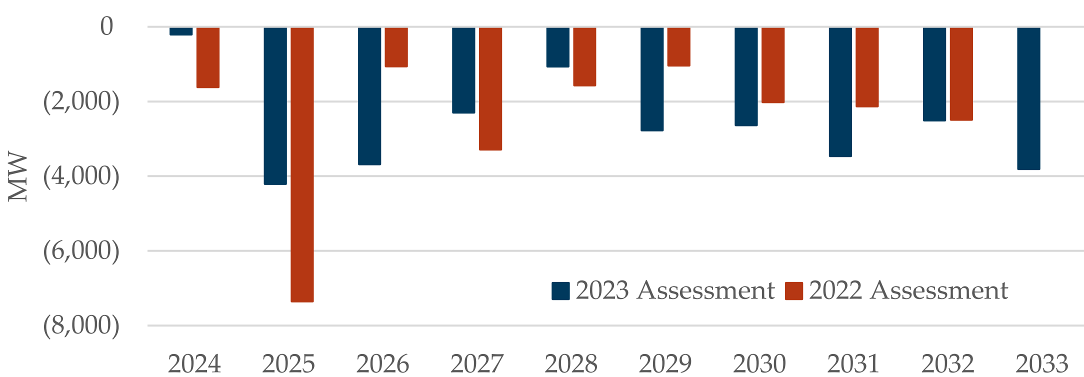


Figure 3: Comparison of Planned Retirements for 2022 & 2023 Assessments

Subregional Snapshot
Planned Resource Retirements & Shutdowns

	Near-Term (2024–2025)	Mid-Term (2026–2028)	Long-Term (2029–2033)
NW-Northwest	● 730 MW		● 660 MW ▲ 100 MW
NW-Central	● 1,260 MW ▲ 280 MW	● 1,145 MW ▲ 300 MW	● 1,650 MW ▲ 3,300 MW
NW-Northeast			● 200 MW
CAMX	● 1,230 MW	▲ 2,900 MW	
Desert Southwest	● 400 MW	● 560 MW ▲ 500 MW	● 2,000 MW ▲ 400 MW

● Coal ▲ Natural Gas

In addition to coal and natural gas, entities plan to retire 2,500 MW of early-generation wind and solar resources over the next 10 years.

According to current plans, the Diablo Canyon nuclear units will be retired in the CAMX subregion in 2029 and 2030.

Planned Resource Additions

Between their 2022 and 2023 resource plans, entities increased the total number of new resources they plan to build over the next 10 years, with most of the increase planned for the near-term (Figure 4).

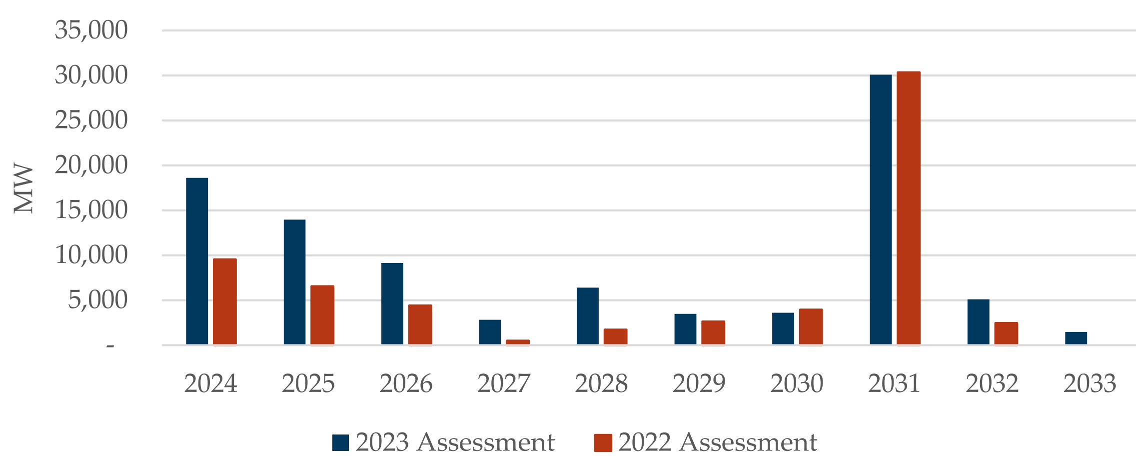


Figure 4: Comparison of Planned Resources for 2022 & 2023 Assessments

Entities plan to add 95 GW of resources in the next 10 years. Solar, energy storage, and wind make up more than 80% of these new resources (Figure 5). The new resources can help mitigate the risk of load loss due to resource shortfalls in the near term if they are built on time.

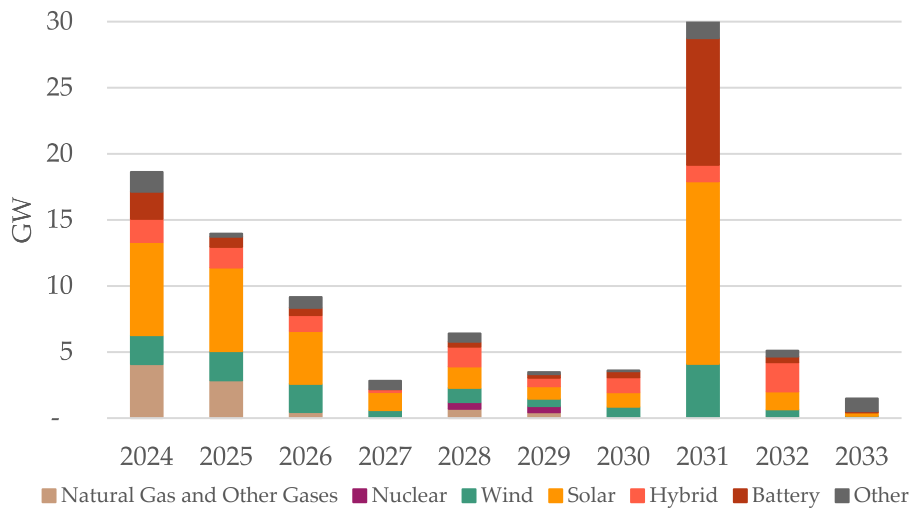
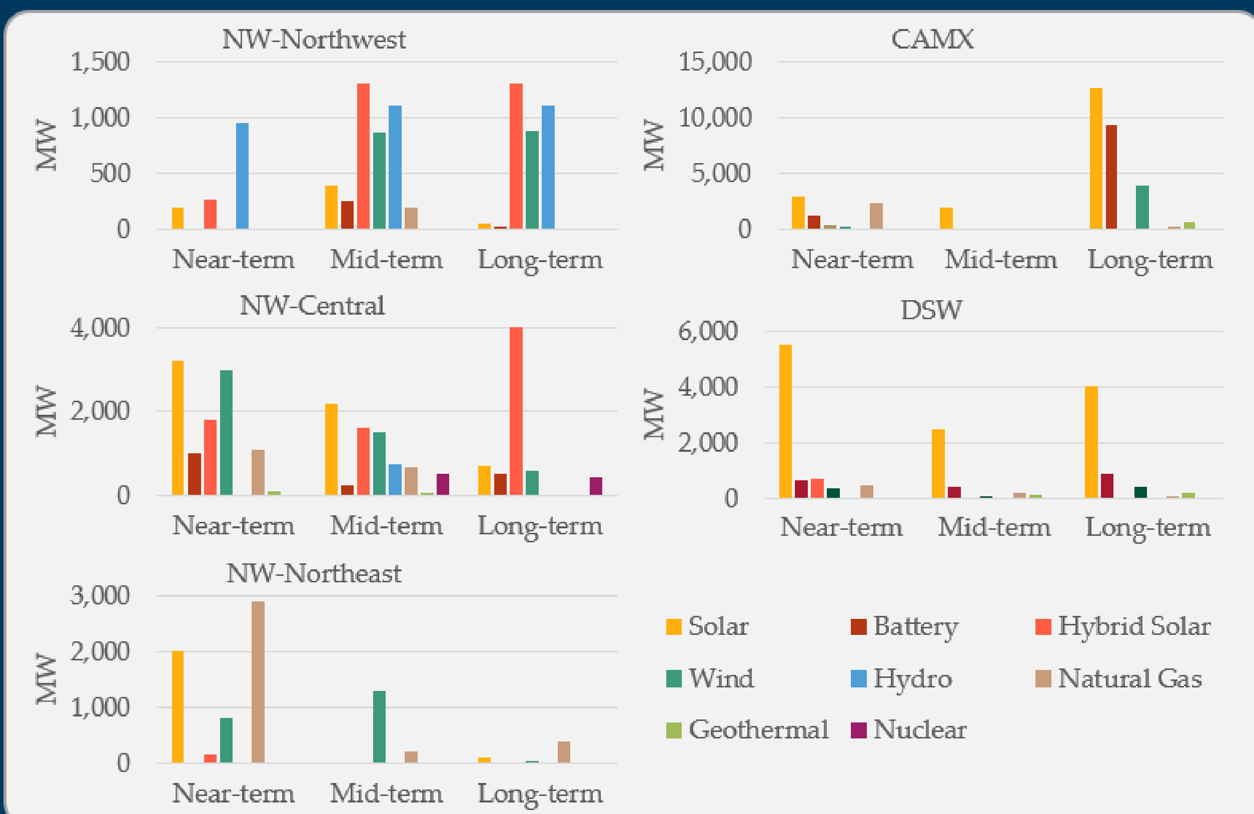


Figure 5: Western Interconnection Planned Resources 2024–2033

Subregional Snapshot
Planned Resource Additions 2024–2033



Wind Additions

Wind resources will grow over the next 10 years, but the growth rate will decrease compared to recent years. The annual growth rate has been over 6%. Current plans show a growth rate of 3%, though this translates to a significant amount of capacity. Resource plans show 1.5 times more (53 GW) wind capacity in 2033 than was operational in 2022 (34 GW) (Figure 6).

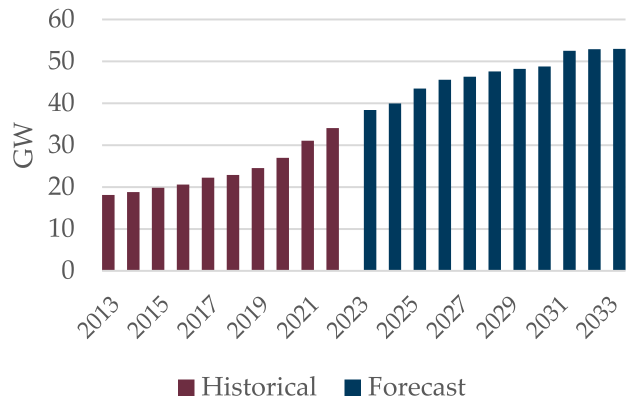


Figure 6: Cumulative Historical and Planned Wind Capacity (2013–2033)

Solar and Hybrid Solar Additions

According to 2023 plans, solar and hybrid solar (solar with storage) resources will grow the most across the interconnection over the next 10 years. In 2023, installed solar capacity will surpass the installed capacity of wind resources. Resource plans show three times (99 GW) the solar and hybrid solar capacity operational in 2033 than was operational in 2022 (31 GW) (Figure 7).

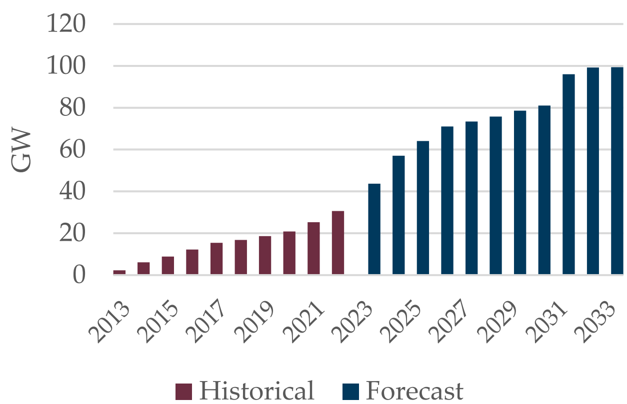


Figure 7: Cumulative Historical and Planned Solar and Hybrid Solar Capacity (2013–2033)

Energy Storage Additions

Planned energy storage, particularly battery storage, continues to grow. Current resource plans include an 800% increase in battery storage from 2022 (2.7 GW) to 2033 (21 GW) (Figure 8). The build rate for battery storage will need to increase significantly over the next decade to meet these plans. Increasing amounts of battery storage could help address some of the resource adequacy risk associated with increasing variability because the dispatch of battery storage can be controlled.

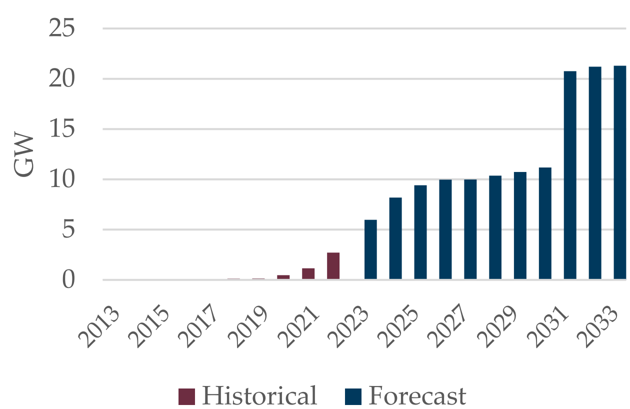


Figure 8: Cumulative Historical and Planned Battery Storage Capacity (2013–2033)

Risks to Planned Resource Additions

The addition of the planned resources listed above is critical to meeting future load. These resources need to be built as planned and on time. In addition to resource planning data, WECC asks Balancing Authorities (BA) to provide information about their resource adequacy risks. The information the BAs provide shines light on the factors that put timelines for new resources at risk.[1]

Supply Chain Disruption

Supply chain disruptions remain an obstacle to building new resources on schedule, connecting customers, and maintaining system elements. Western entities have reported delays and, in some cases, an inability to expand service in capacity-constrained areas. Lingering effects from the COVID-19 pandemic, foreign manufacturing, and shipping congestion are the main causes of delays. Longer-than-anticipated lead times for transformers, circuit breakers, conductors, and utility-scale solar panels have forced entities to revise near-term new resource timelines. Entities are already adjusting their timelines for longer-term future resources to account for possible delays. This should help reduce the risk of supply chain disruption delaying new resources in mid- and long-term forecasts.

Interconnection Queue

Delays due to congestion in the interconnection queue jeopardize industry's ability to build planned resources. Continent-wide, the interconnection backlog increased by 40% in 2022. Wait times are expected to grow as the Inflation Reduction Act (IRA) spurs more variable energy resources (VER), while state mandates push toward clean energy targets. Over 10,000 projects, representing 1,350 GW of generation capacity and 680 GW of storage, are actively seeking interconnection. Together, these projects far surpass the total generation entities plan to add over the next text 10 years, but in many cases the wait time is several years, and a great number of projects will not happen. In July, FERC addressed the issue in Order 2023, which expedites the process for connecting new generating facilities to the transmission system. The order, which took effect in November, is aimed at alleviating the backlog of projects in interconnection queues, providing greater certainty and preventing discrimination against new generation.[2]

[1] Specific responses and information about individual BAs is confidential. This page summarizes the information.

[2] FERC Order 2023, RM22-14-00

Changing Load and Demand

The biggest change to the 2023 resource plans is the increase in load forecasts. Energy policies, changes to energy use, electrification, and an influx of data centers are driving this increase.

Annual Energy

The 10-year load forecasts provided by BAs in 2023 show 16.8% load growth across the Western Interconnection (Figure 9). Load is expected to increase from a forecast 922 TWh in 2024 to 1,077 TWh in 2033. This load growth is much higher than previous projections, particularly in the near- and mid-term years. The 10-year load growth in the 2022 assessment was 9.6%. These new projections reflect electrification policies and, in the Northwest in particular, significant growth of data centers.

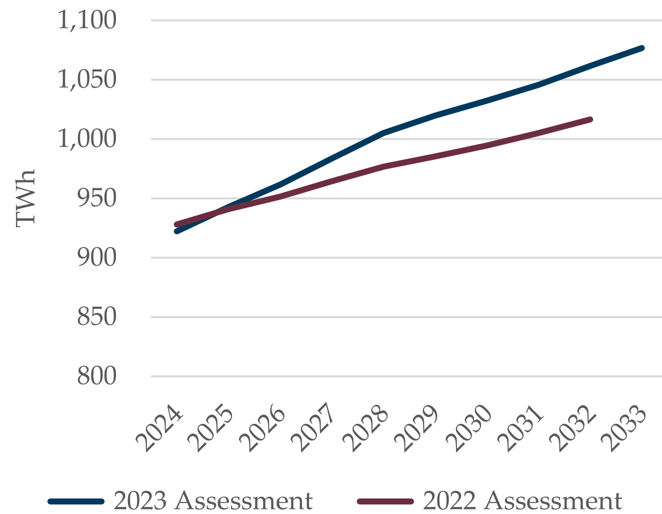


Figure 9: Comparison of Annual Energy Growth in 2022 & 2023 Assessments

Peak Demand

The interconnection-wide peak demand occurs in the summer. Over the next 10 years, peak demand is expected to grow from 159 GW in 2024 to 184 GW in 2033, a 16% increase.[3] The 2023 forecasts show a slightly lower peak demand than the 2022 forecasts (Figure 10). Data center demand profiles are relatively flat, so, while the addition of data centers is driving higher annual energy, it has less of an effect on peak demand. Other types of demand, e.g., building electrification, have a stronger effect on peak demand.

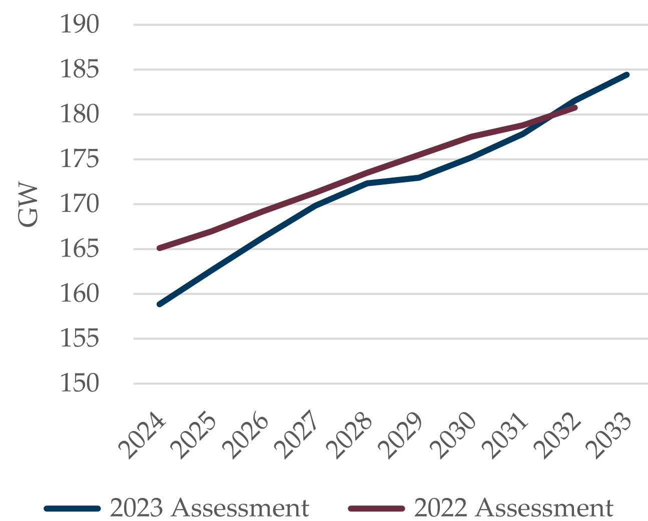
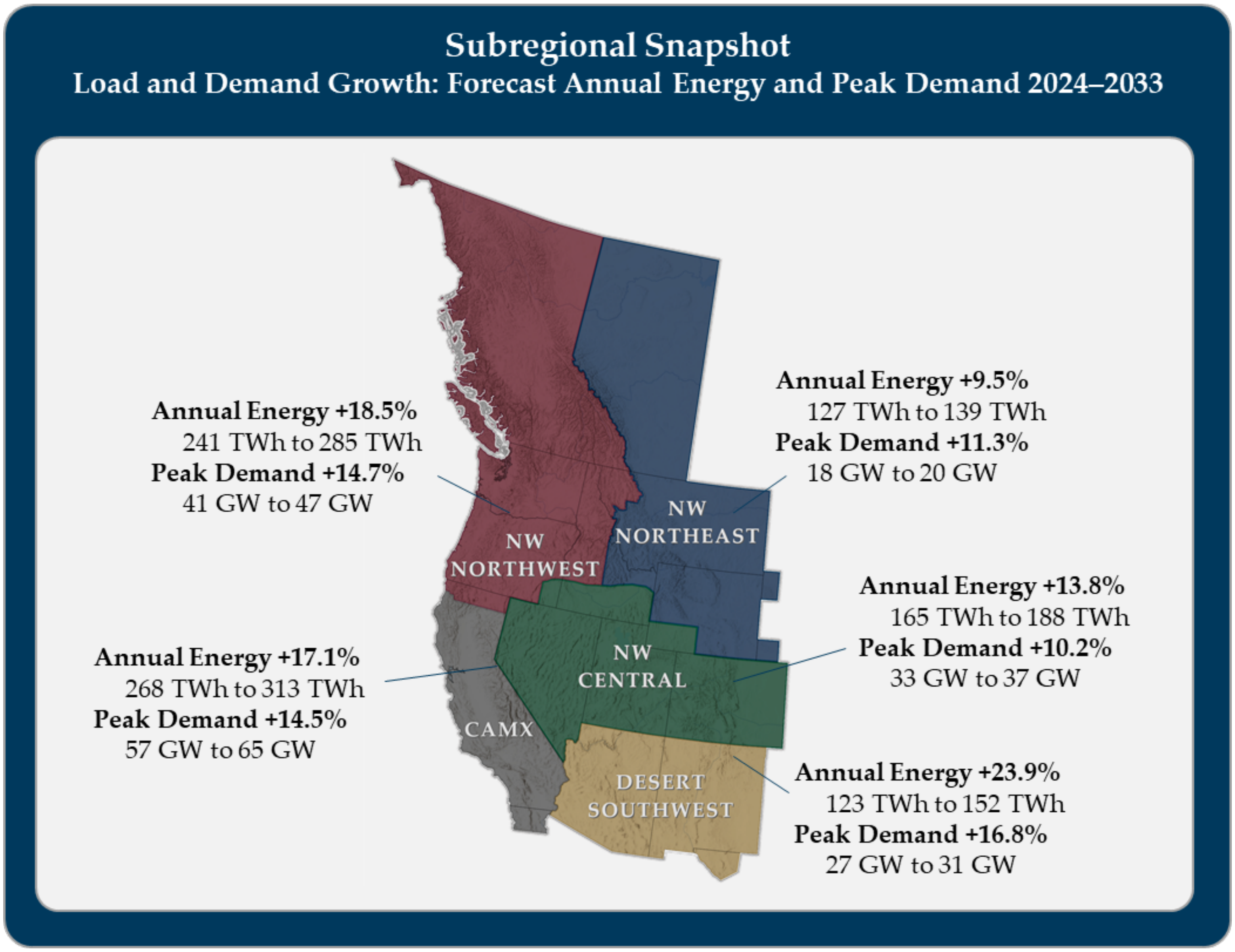


Figure 10: Comparison of Peak Demand Growth in 2022 & 2023 Assessments

[3] Peak demand refers to the expected, or 1-in-2 peak demand for the interconnection.



Causes of Increased Demand Growth

Data Centers

The anticipated increase in data centers over the near term is primarily responsible for the large load forecast increase between the 2022 and 2023 Western Assessments. Data centers require significant cooling, which further increases load. Northwest BAs project large increases in data centers, which could increase load by 50% to 200% depending on the BA. The subregional increases in the Northwest are enough to substantially affect the load forecasts for the entire interconnection. Data center expansion is being considered in other parts of the interconnection as well, including the Desert Southwest subregion. This will likely result in changes to demand forecasts in these areas like those in the Northwest.

Electrification

Electrification of transportation, buildings, and industrial customers is increasing across the West. Some estimates of the effect of full electrification adoption on load reach as much as a 75% increase in summer load and a 260% increase in winter load.[4] Only 40% of BAs in the West incorporate electrification assumptions directly into their expected load forecasts. Another 40% consider electrification as a separate forecast. Without accounting for the potential effects of electrification in their forecasts, it will be difficult for planning entities to ensure they will have adequate resources to meet load, both in terms of capacity and energy. Improvements in load forecasting for electrification are needed and should be universally employed.

Risks Associated with Demand Growth

Extreme weather conditions and growth of behind-the-meter resources create increasing variability in demand forecasts (Figure 11). The 2024 expected peak demand for the interconnection is 159 GW. However, there is a 3% chance that the 2024 peak demand could be as high as 186 GW. This might occur under an interconnection-wide heat event, for example. The variability in the peak demand forecast increases over the next 10 years. The expected summer peak in 2033 is 184 GW, and there is a 3% chance it could reach 221 GW or higher. If planning entities do not account for this variability in their resource plans they may not be resource adequate under some extreme conditions.

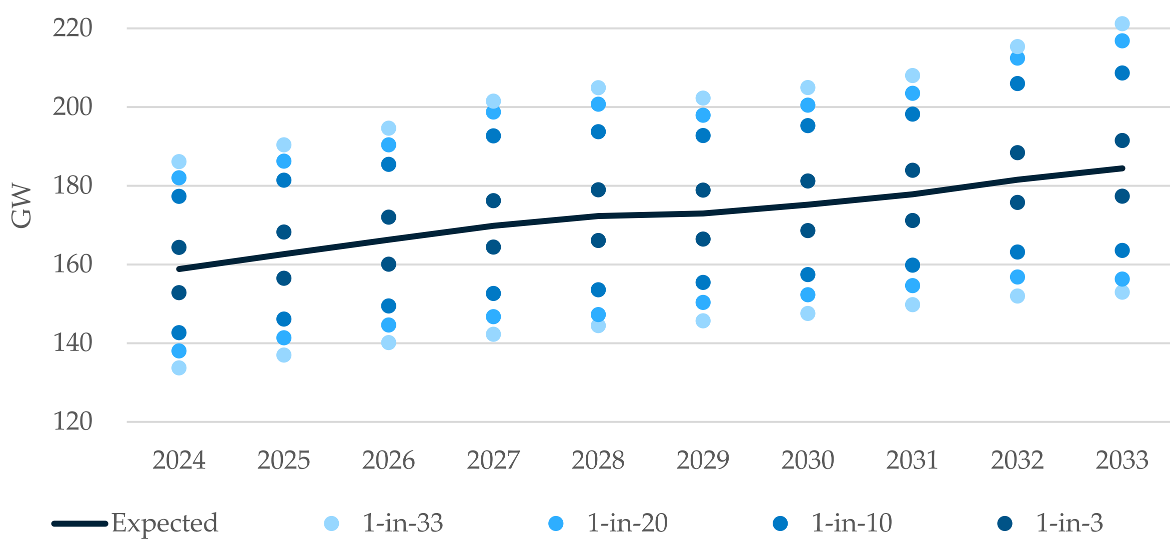


Figure 11: Western Interconnection Expected Summer Peak Demand with Uncertainty Ranges

[4] See the Seattle City Light Electrification Assessment, pages 1-7, https://powerlines.seattle.gov/wp-content/uploads/sites/17/2022/01/Seattle-City-Light-Electrification-Assessment.pdf.

Resource Adequacy Risk Analysis

WECC's analysis of resource adequacy risk focuses on answering two questions.

1. Are current resource plans sufficient to meet future demand for the interconnection and subregions over each of the next 10 years under the range of possible system conditions?
2. How does variability in the system increase with the changes in resources and demand currently reflected in resource plans, and how does this affect resource adequacy risk?

WECC uses two resource adequacy risk measures to answer these questions.[5]

Demand-at-risk Indicator (DRI): This measures the number of hours in a year when there is a risk for load loss (demand-at-risk hour) that exceeds the one-day-in-ten-year (ODITY) outage threshold. WECC calculates the probability that demand might be shed for any given hour, and, if that probability is greater than the ODITY threshold, that hour is counted in the DRI.

Variability Margin Indicator (VMI): This measures the variability of resource portfolios by calculating the reserves needed to ensure there are enough resources available to meet load under the ODITY outage threshold. As variability increases, so does the reserve margin needed to cover it. WECC measures reserve margins under a range of conditions as a proxy for system variability.[6]

Demand-at-risk Analysis

The DRI for the Western Interconnection decreased in this year's assessment (Figure 12). This is largely due to the new resources entities added to their 2023 resource plans, particularly resources planned over the next three years. However, with the increase in the demand forecasts, there are still demand-at-risk hours. Most of the demand-at-risk hours are in the NW-Northwest subregion, a result of the large demand growth that area is experiencing from data center expansion.

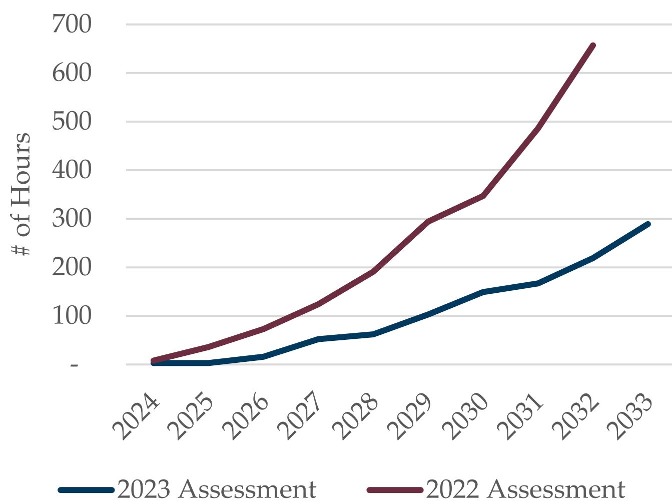


Figure 12: Comparison of DRI for the Western Interconnection in 2022 and 2023 Assessments

[5] For more information on how WECC calculates these metrics, see the 2022 Western Assessment of Resource Adequacy on WECC.org.

[6] The Variability Margin Index was previously referred to as the Planning Reserve Margin Index (PRMI).

Near-term DRI (2024–2025)

The DRI provides the number (frequency) of demand-at-risk hours each year, but it does not provide information on the amount (magnitude) of demand at risk. WECC examines the magnitude of the demand at risk in conjunction with the DRI to put the DRI value in context.

In the near term, January is the only month with demand-at-risk hours for the entire Western Interconnection. The magnitude of the demand at risk is relatively low, averaging 16 MW per at-risk hour in January 2024 and 7 MW in January 2025 (Figure 13).

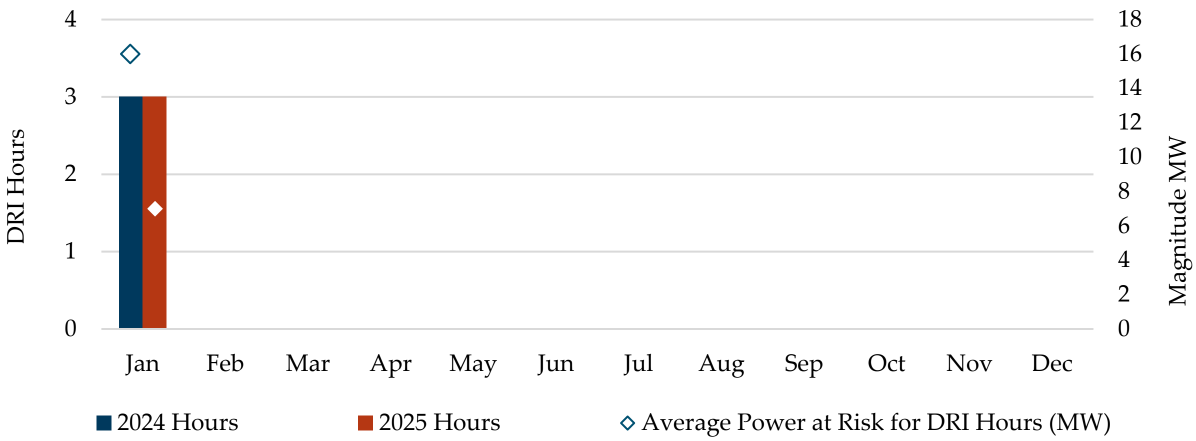


Figure 13: Near-term DRI Hours and Magnitude for the Western Interconnection

Subregional Snapshot
Near-term DRI in the Pacific Northwest

Only the NW-Northwest subregion has demand-at-risk hours over the next two years. The total demand at risk in the subregion is 47 MWh in 2024 and 22 MWh in 2025. This area is evolving into a dual-peaking region, but it is still a winter peaking area. Adding new resources quickly enough to manage demand-at-risk hours in the next two years will be difficult. Entities should monitor these hours closely in the operational time frame.

Across the other subregions, between the 2022 and 2023 assessments, the demand-at-risk hours were eliminated by reductions in demand forecasts, additions of new resources, and delayed retirements.

Mid-term DRI (2026–2028)

Demand-at-risk hours increase across the interconnection in the mid-term and spread to other months. Both the number of hours and magnitude increase, with August and December as the highest risk months each year (Figure 14).

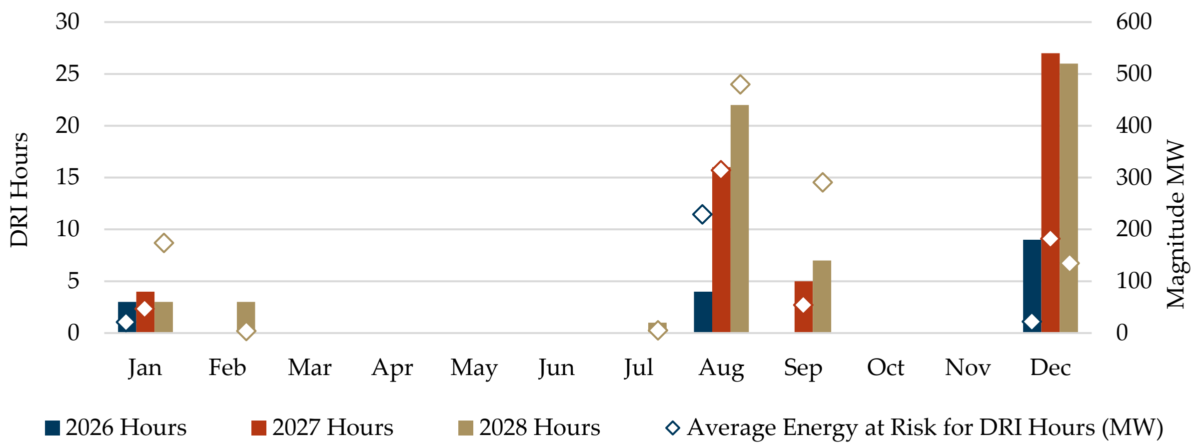
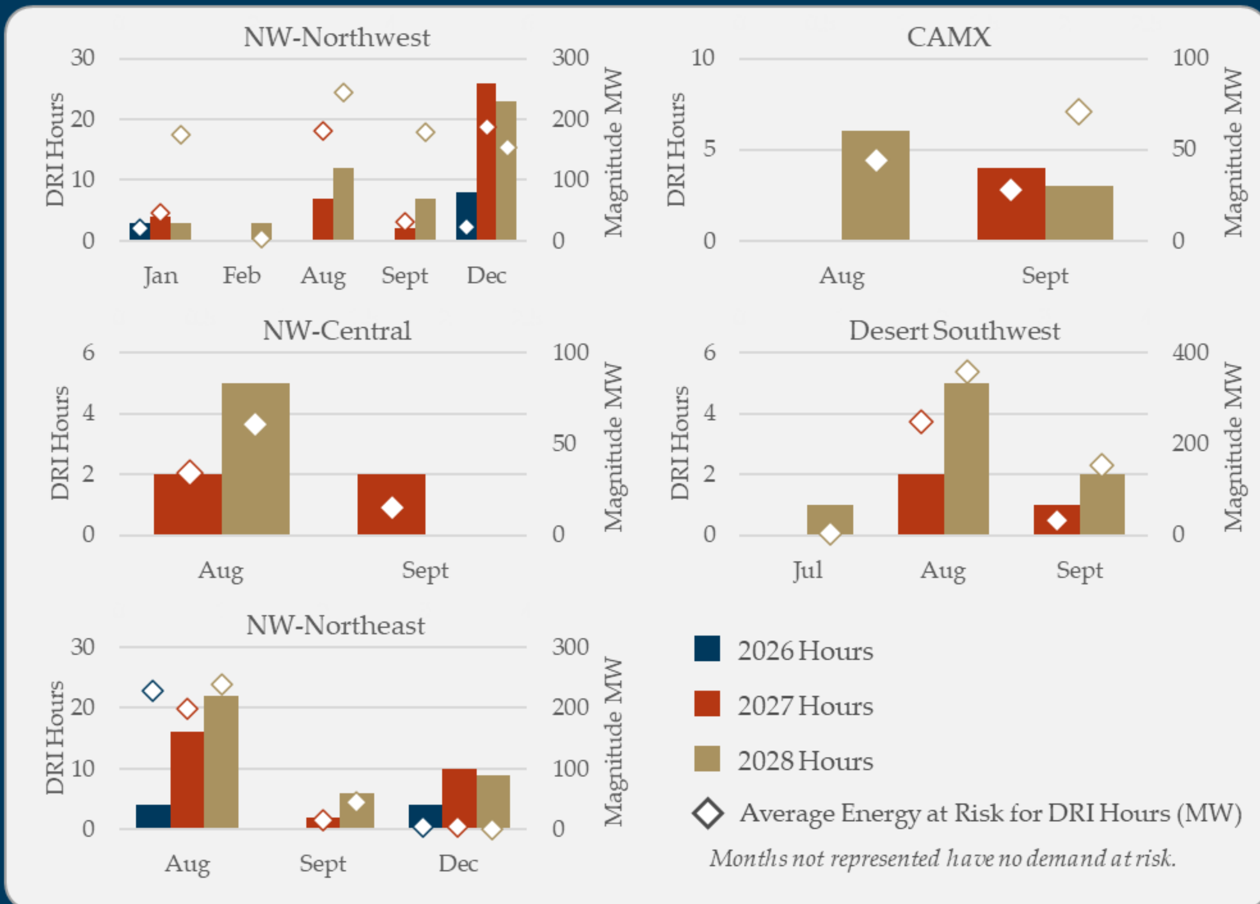


Figure 14: Mid-term DRI Hours and Magnitude for the Western Interconnection

The increase in August demand-at-risk hours is due to load and solar generation patterns in the southern subregions, specifically the timing of solar output reduction at sunset and daily peak loads. New resources will alleviate these demand-at-risk hours, but most of the new resources are planned to come online after 2028. The increase in demand-at-risk hours in December can be attributed to increased load forecasts in the NW-Northwest and relatively few new resources planned in that subregion.

In addition, many of the retirements that entities delayed to mitigate near-term resource adequacy risks were pushed into the mid-term time frame. This accounts for some of the substantial increases in demand at risk. Entities may need to extend the delays of some retirements further if they cannot mitigate these demand-at-risk hours in the next two years.

Subregional Snapshot
Mid-term DRI: Monthly Hours and Energy at Risk 2026–2028



Long-term DRI (2029–2033)

Demand at risk spreads further in the long-term timeframe, occurring 10 months of the year almost every year from 2029 through 2033 (Figure 15). The magnitude also increases, in extreme cases five or more times the greatest magnitude in the mid-term. Based on this measure of resource adequacy, the interconnection faces severe resource adequacy risks in the long-term. Entities should evaluate their long-term resource plans to ensure they can mitigate these risks. This is particularly important in cases where entities have added speculative or generic resources to later years. Identifying those resources as early as possible will help determine whether their plans result in demand-at-risk hours and whether additional measures need to be taken.

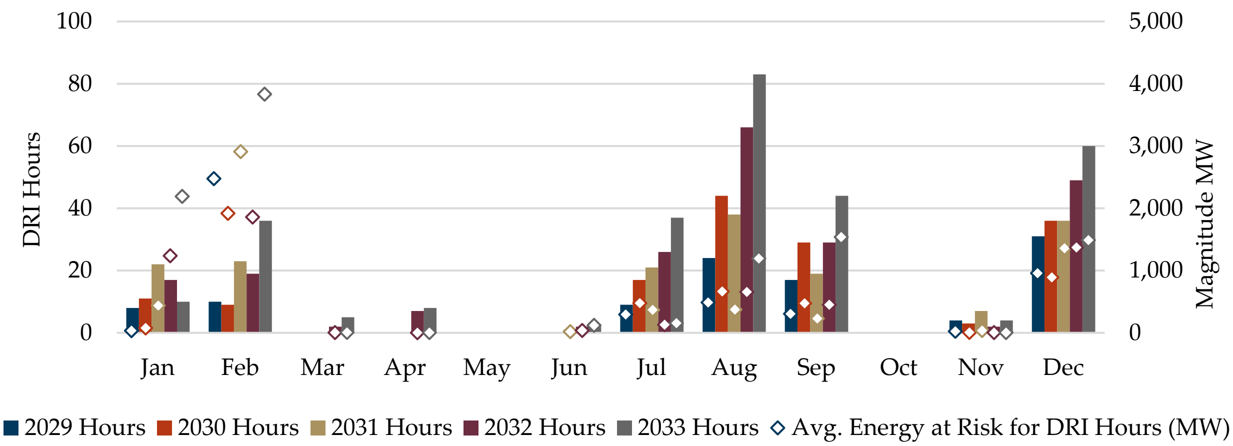
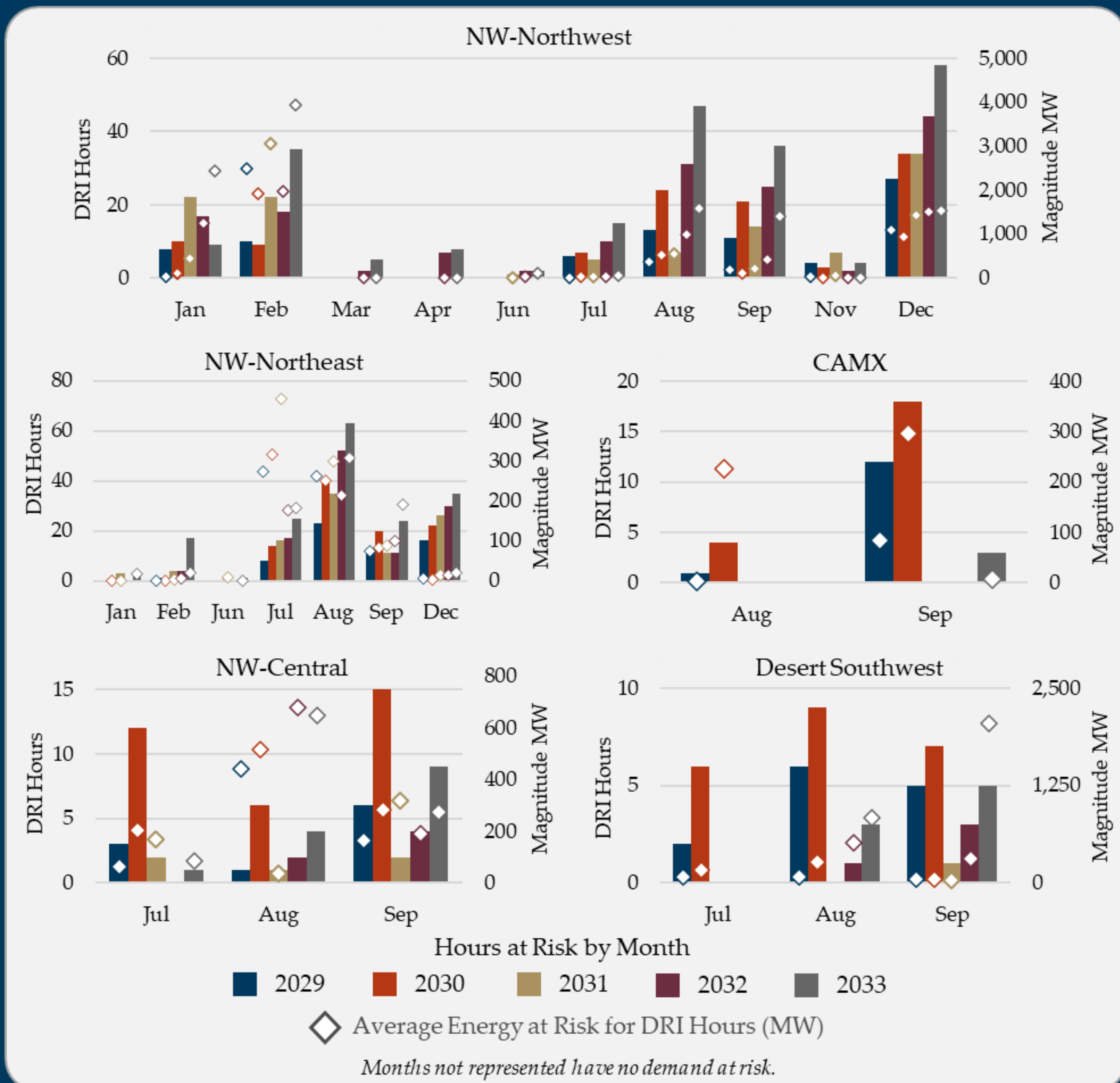


Figure 15: Long-term DRI Hours and Magnitude for the Western Interconnection

Subregional Snapshot
Long-term DRI: Monthly Hours and Energy at Risk 2029–2033



Variability Analysis

Variability represents the greatest risk to resource adequacy because variability increases uncertainty, and uncertainty creates challenges to planning, paying for, and building resources. As variable generation is added to the system, variability of the system increases. Wind and solar make up two-thirds of the resources entities plan to add over the next decade. While this is a large amount of capacity (more than 60 GW), it also adds a great amount of variability to the system. A comparison of the capacity and energy availability on the peak hours for each of the next 10 years illustrates the challenge (Figure 16). While capacity is expected to increase by 95 GW through 2033, the energy from those additional resources is only expected to increase by 15 GW, and that number can change depending on system conditions.

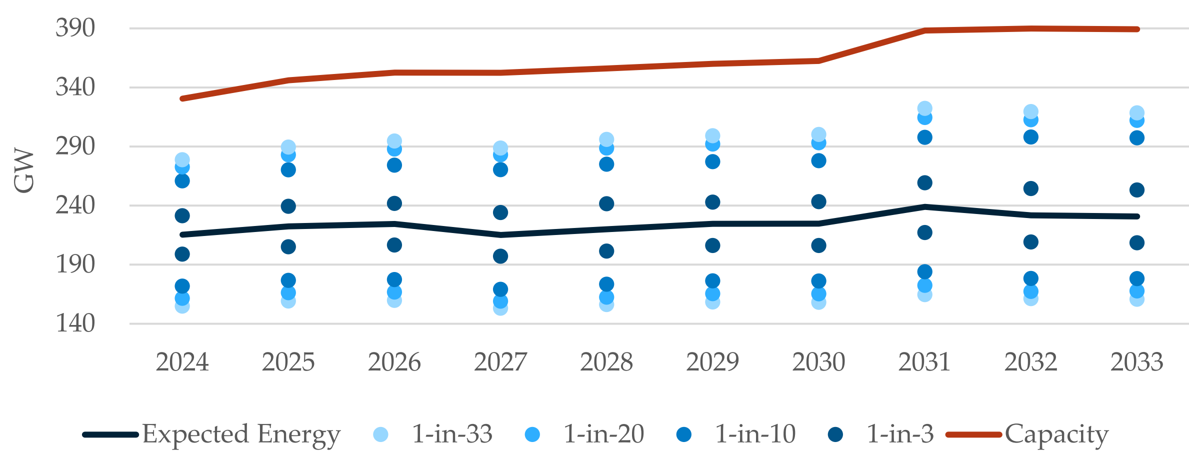


Figure 16: Comparison of Resource Capacity and Energy Variability on the Peak Hour 2024–2033

Variability Margin Analysis

The VMI for the Western Interconnection increases over the next 10 years, signaling growing risk. In addition, compared to the 2022 Western Assessment, the VMI is higher, meaning the variability in current resource plans is greater than previous plans (Figure 17). This is primarily due to increases in the number of planned variable resources. From a variability perspective, risk to the Western Interconnection has grown substantially over last year's Western Assessment.

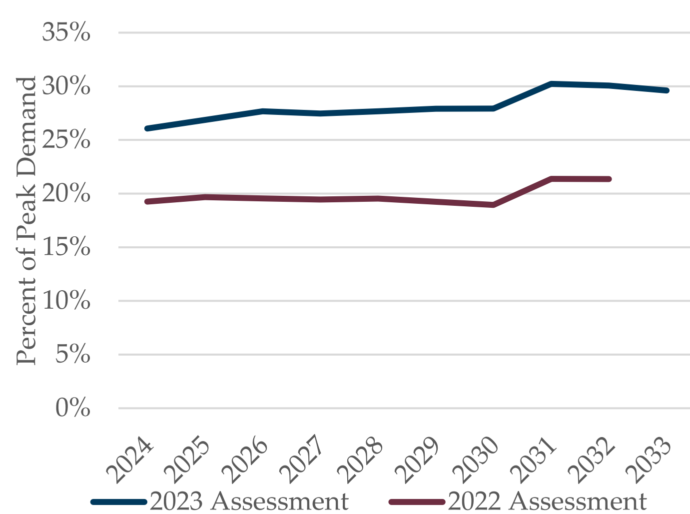


Figure 17: Comparison of VMI for the Western Interconnection in 2022 and 2023 Assessments

High levels of variability drives up demand-at-risk hours. The VMI specifically looks at variability in the resource and load mix. It does not account for actions entities take to mitigate variability, actions that can reduce demand-at-risk hours.

Subregional Snapshot
Comparison of Variability Margin Indicator for 2022 and 2023 Assessments

	2022 Assessment	2023 Assessment	
	2024 VMI	2024 VMI	2033 VMI
NW-Northwest	24.2%	▼ 23.5%	22%
NW-Central	21.3%	▲ 21.4%	25.4%
NW-Northeast	26.6%	▲ 27.4%	30%
CAMX	22%	▲ 25.4%	30.5%
Desert Southwest	18.6%	▲ 19.9%	29%

Incremental Analysis

Over the next decade, variability will increase across most of the interconnection, given current resource plans. Actions entities take to mitigate variability, such as the inclusion of additional less-variable resources, can reduce the number of hours when demand is at risk. While increasing variability is a signal of increasing risk, that risk can be mitigated. To better understand how different resource types contribute to the VMI and DRI measures above, WECC performed an incremental analysis, adding resource types one at a time to see the relative effect each type had on variability and demand-at-risk hours. Using 2030 (the year with the most demand-at-risk hours), WECC added resources in the following order:

1. Existing resources only, including known retirements
2. New non-variable resources, such as natural gas resources
3. New wind resources
4. New solar resources
5. New battery resources

Variability is lowest, but demand-at-risk hours are highest with existing resources (Figure 18). The addition of non-variable resources significantly reduces the number of demand-at-risk hours, with only a slight increase in variability. The addition of solar resources causes a large increase in variability, but a reduction in demand-at-risk hours. These results could change based on the order that resources are added. Therefore, the results should not be construed as the absolute quantification of each of the metrics shown below.

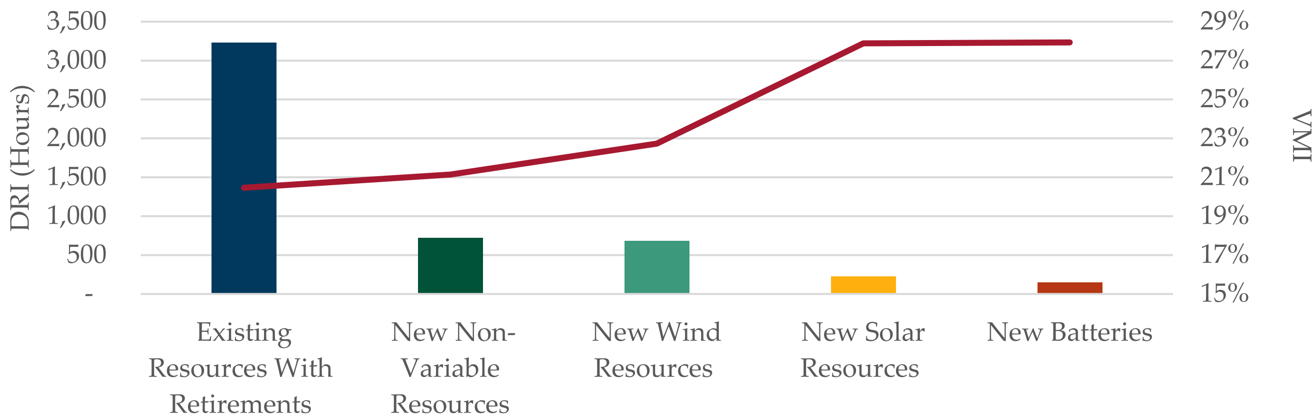


Figure 18: 2030 Western Interconnection DRI and VMI Incremental Analysis

The results for each of the 10 years in the assessment were similar to the 2030 results, but the results are more pronounced in later years (Figure 19). The VMI increases sharply in 2031 when 30 GW of new resources, mostly variable resources, are scheduled to come online. Many of these resources are speculative placeholders because they are so far in the future. In many cases, BAs lump these types of resources into one year, skewing the data. The more important takeaway is the overall increase over the 10-year period.

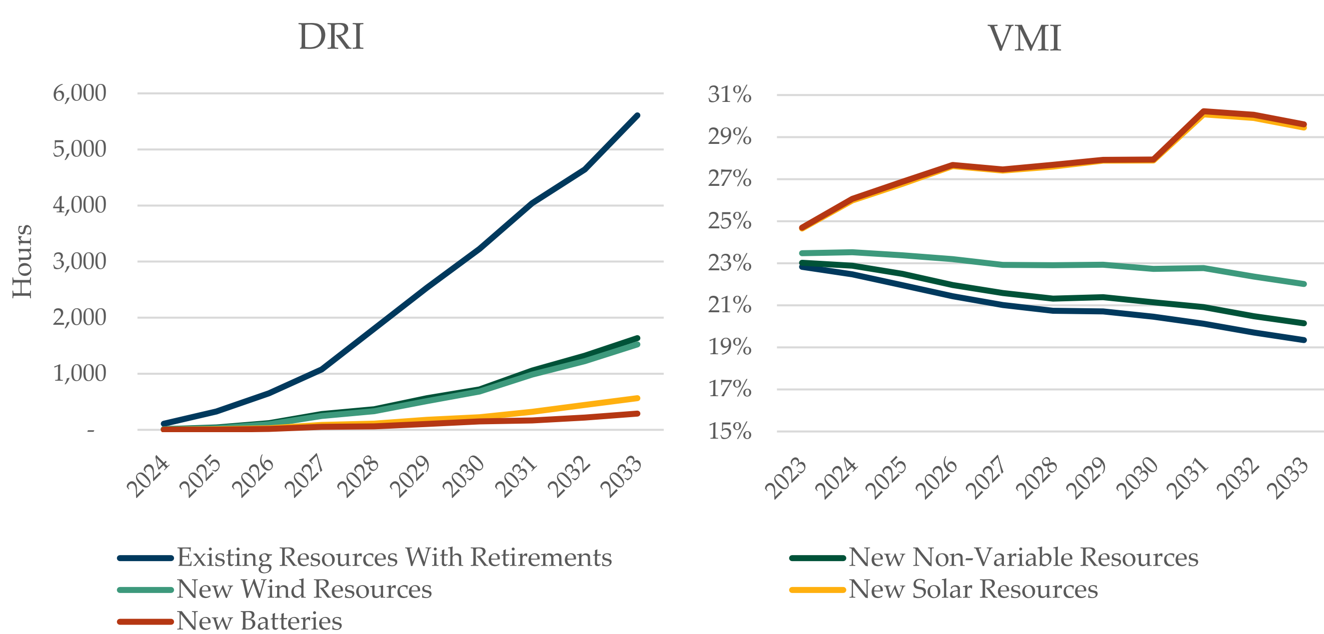


Figure 19: Western Interconnection DRI and VMI Incremental Analysis 2024–2033

Conclusions

High load growth, uncertainty in forecasting, and large amounts of new non-dispatchable resources are some of the factors that continue to challenge resource adequacy in the Western Interconnection. The recommendations and findings from WECC's 2022 Western Assessment have not changed significantly. Resource adequacy risks continue to grow. Variability remains the greatest risk because it contributes to demand-at-risk hours. To be resource adequate, industry needs to have enough energy to meet demand under a range of possible conditions. The more variable the system, the harder it is to accomplish this.

Based on the resource planning information provided by BAs, and WECC's energy-based probabilistic analysis, demand-at-risk hours increase significantly over the next 10 years, indicating that resource plans are not sufficient to meet demand under the range of conditions the interconnection could face. In addition, the variability on the system has increased since the 2022 assessment. Variability continues to increase over the next 10 years. As a measure of risk on the system, increasing variability indicates increasing risk. For these reasons, resource adequacy remains a top interconnection-wide risk.

Northwest Regional Forecast

of Power Loads and Resources

August 2024 through July 2034

PNUCC

May 2024

Special thanks to PNUCC System Planning Committee members and utility staff who provided us with this information.

Electronic copies of this report are available on the

PNUCC website

www.PNUCC.org

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2024 Northwest Regional Forecast

Executive Summary

From technological advancements to evolving consumer demands, electric utilities and industry partners are adapting to major shifts that are underway in the energy sector. Through collaboration, the Pacific Northwest Utilities Conference Committee (PNUCC) annually provides an assessment of the electric utility industry from a regional perspective. The effort is captured in the *Northwest Regional Forecast* (*Forecast*), a longstanding resource tracking power system trends, including shifts in demand, resource changes and emerging technologies. It is important to note that a gap between loads and resources in the *Forecast* does not necessarily mean the region will be unable to meet demand. Rather, the *Forecast* serves as a barometer for building increased awareness for how the picture is changing.

The *Forecast* anticipates a surge in demand for electricity in the Pacific Northwest over the next decade that surpasses PNUCC's previous projections. The increase is attributed to factors such as data center expansion, high-tech manufacturing growth and the trend toward electrification. Electric utilities across the nation are projecting increases in demand for similar reasons.

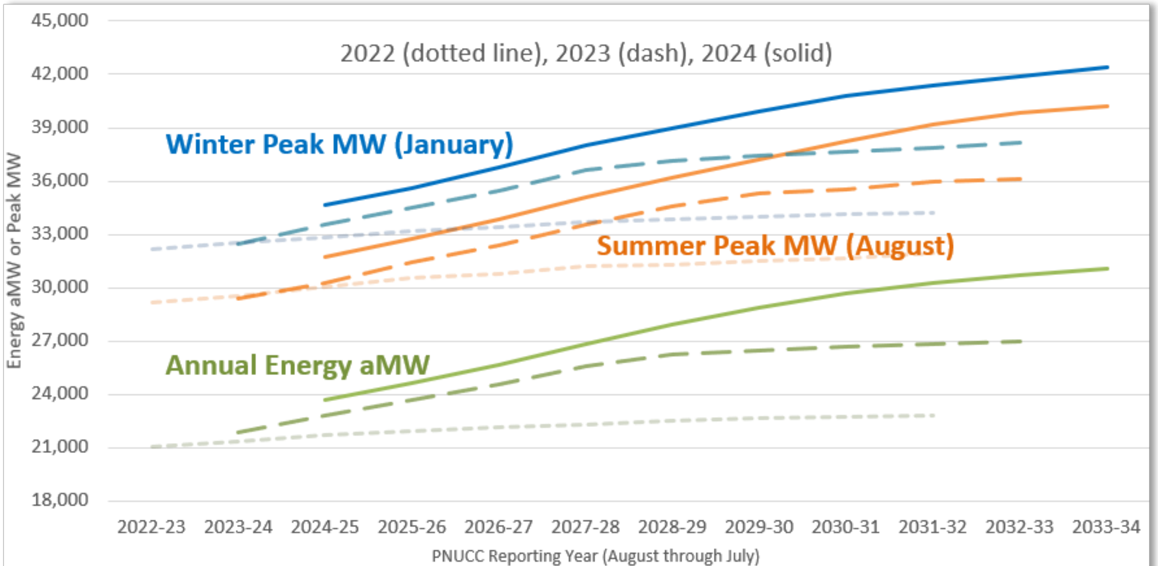
The dual challenge of extraordinary growth in demand and the transition to lower carbon-emitting generation resources translates to a tremendous and urgent need to upgrade the region's electricity infrastructure – including expanding transmission capacity and diversifying power supplies as well as accelerating the adoption of advanced grid technologies.

Surge in Projected Demand Signals End of Stagnant Growth

Demand for electricity is projected to increase from about 23,700 average megawatts (aMW) in 2024 to about 31,100 aMW in 2033 (an increase of 7,400 aMW), which is an increase in demand of over 30% in the next 10 years (as shown Figure 1). For comparison, last year's *Forecast* projected demand could rise by 24% in 10 years.

The rapid expansion of data centers is one of the reasons for the expected increased volume in the Northwest. According to a Cushman & Wakefield report that evaluates data centers by their electricity usage, the Oregon data center market ranks as the fifth largest in the nation. High-tech manufacturing and the trend toward electrification also contribute to the expected increase in demand.

Figure 1: 2024 Load Forecast Compared to 2023 and 2022



Growth Rates

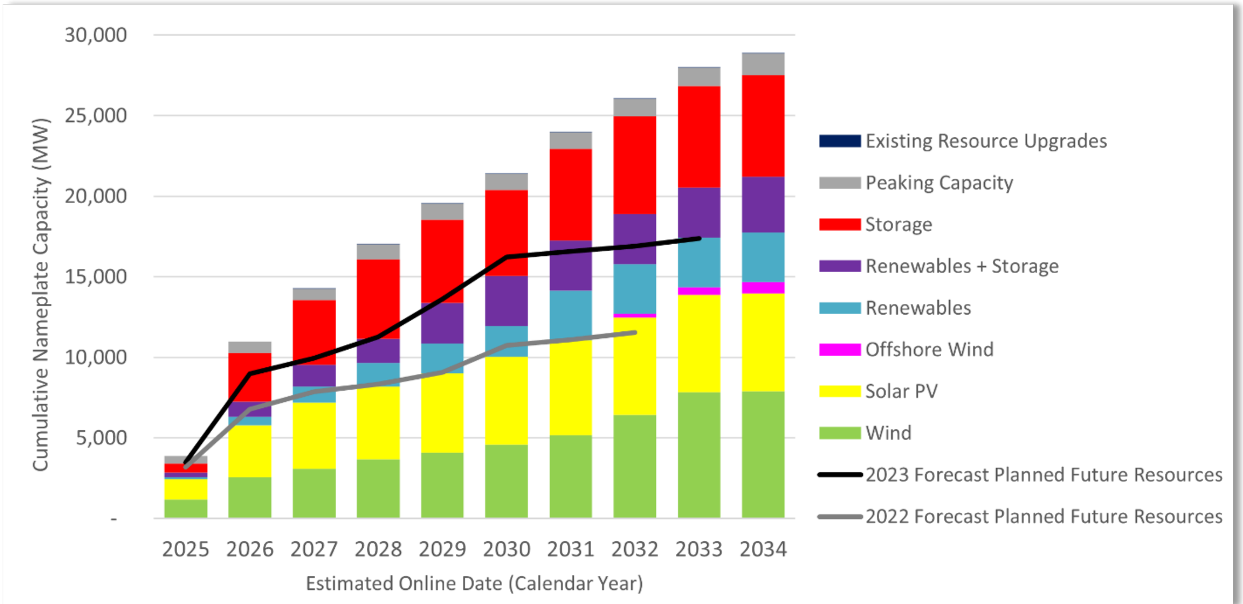
Energy	5 year	10 year	Summer Peak	5 year	10 year	Winter Peak	5 year	10 year
2024 Forecast	4.0%	3.1%	*2024 Forecast*	3.2%	2.7%	*2024 Forecast*	2.9%	2.3%
2023 Forecast	3.8%	2.4%	*2023 Forecast*	3.3%	2.3%	*2023 Forecast*	2.7%	1.8%
2022 Forecast	1.2%	0.9%	*2022 Forecast*	1.4%	1.0%	*2022 Forecast*	1.0%	0.7%

Another way to measure demand is by the annual energy load growth rate. The 10-year annual energy load growth rate for the *2024 Forecast* is 3.1% (annually compounded). Utilities in aggregate have not forecast a rate of growth for annual energy load this high since the early 1980s (which is shown in Figure 9). Three years ago, the regional annual load growth rate was forecast to be 0.9%, which was more in line with the decades long trend of about 1-2% per year. Utilities are experiencing load growth due to different factors and at varying rates. For example, some utilities are experiencing increased demand from a boom in residential growth due to population shifts, while other utilities have flat or decreasing demand forecasts because of energy efficiency investments or more stringent state and local building codes and standards.

Utility Plans Include More Resources

Over the next decade, utilities have identified plans for about 29,000 megawatts (MW) nameplate capacity of new resources to meet customer energy and capacity needs. Figure 2 shows an unprecedented development of resources on a short timeline for the industry. Past *Forecasts* showed more than 17,000 MW nameplate (solid black line) were planned by 2033 and more than 11,000 MW nameplate (solid gray line) by 2032. PNUCC aggregates utility-reported planned future resources from resource planning assessments to provide a regional picture. Utility plans are reviewed and updated frequently and are developed through comprehensive analysis with input from a stakeholder process. Consequently, these plans, particularly the longer-range elements, change over time.

Figure 2: Planned Future Resources



In Figure 2 the stacked bars amount to the cumulative nameplate for planned future resources by resource type for each year of the *Forecast*. Wind, solar and battery resources make up most of the planned generation as utilities look to decarbonize their resource portfolios. For utilities that have not been specific about the kind of renewable resources included in their plans, the resources are identified as renewables.

The data in the graph does not include committed resources for 2024 and 2025 and coal to natural gas conversions. Committed resources and coal to gas conversions get combined with existing resources in the load and resource balance picture. Further, this graph does not reflect any uncommitted independent power producer resources with which utilities or customers may acquire or enter into contracts.

Storage is a big part of the solution

Hydroelectric dams are the cornerstone of the Pacific Northwest electricity system, providing over 33,000 MW of installed capacity. They generate clean power and store water in large reservoirs behind the dams that can be used to dependably meet seasonal and peak demands. Because hydroelectric dams are flexible resources that can store fuel, they have helped integrate new variable renewable resources in the region. With the growth of wind and solar power, utilities are also starting to add battery storage resources to store surplus energy and supply it to the grid during periods of high demand, or periods when wind and solar generation decreases.

Batteries co-located with renewable generation, standalone batteries and pumped hydro increase through the *Forecast*. The most commercially available battery storage technology — utility scale lithium-ion — is designed to discharge their capacity over a four-hour period before needing to recharge. In the Northwest, which is prone to prolonged peak demand and fuel limitations over multiple cold days, long duration energy storage could be a complimentary solution. Developers are making progress on longer duration battery and compressed air energy storage technologies, but they are not yet showing up in utility planned future resources.

Energy efficiency and demand response

Energy efficiency and demand response programs have reduced the need for new resource development in the past and continue to be a critical component of an adequate power supply by helping lower energy use and peak demand.

Figure 3: Ten-year Cumulative Energy Efficiency Projections

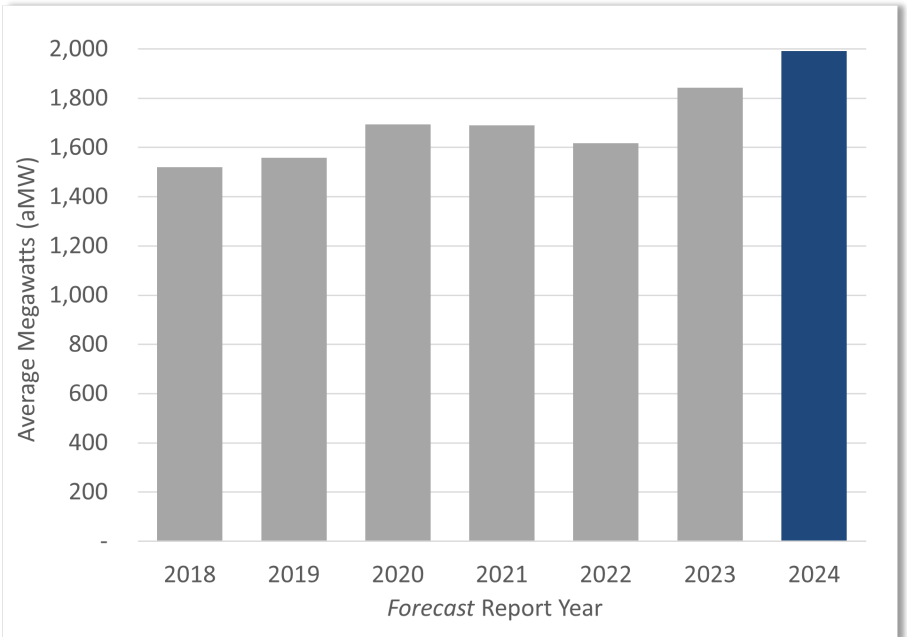
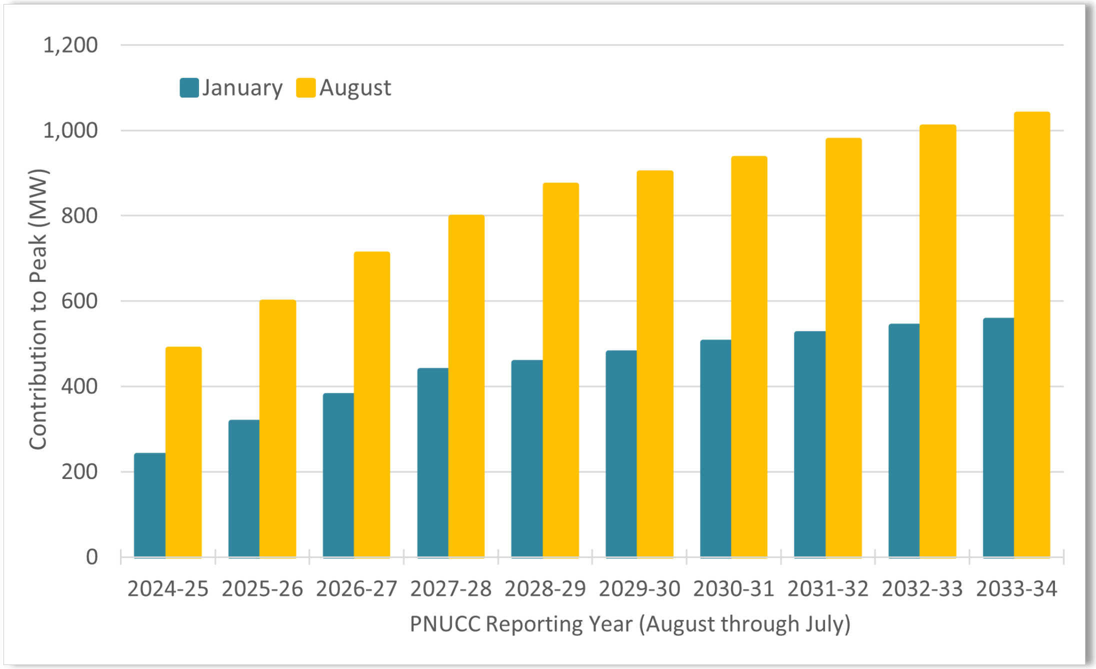


Figure 3 shows projected cumulative energy efficiency savings of around 2,000 aMW over the next 10 years – approximately 150 aMW higher this year than last year. This builds on the nearly 7,700 aMW of energy efficiency that has been acquired in the region over the past 45 years.

Energy efficiency is an important resource to meet demand now and in the future, as well as a strategy to mitigate risk from uncertainty. The Northwest Power and Conservation Council's (Council) *2021 Power Plan* recognized that some jurisdictions would need to invest in energy efficiency beyond the Council's target as part of a cost-effective strategy for reducing carbon emissions.

Figure 4: Demand Response Contribution to Peak



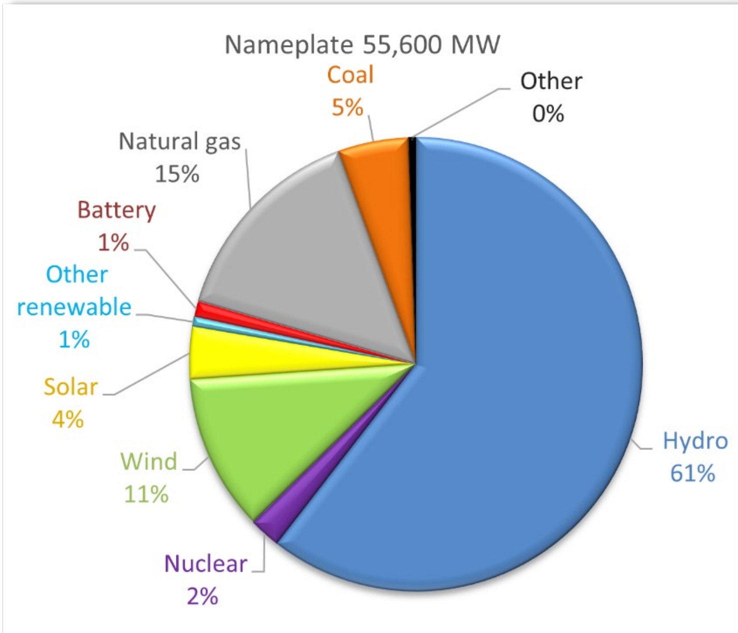
Demand response programs are an effective tool during summer and winter extreme weather events to shift consumption of electricity away from peak periods. As the grid becomes more strained, utilities are incorporating more customer demand response.

Figure 4 shows the utilities' active and projected summer and winter demand response programs. The *Forecast* projects summer demand response to double, reducing the region's one hour peak by about 500 MW in 2024 to over 1,000 MW in 2033. While summer demand response programs continue to provide almost twice the peak load reduction in comparison to winter demand response programs, the *Forecast* projects a winter demand response increase from over 200 MW in 2024 to close to 600 MW in 2033. Further, several utilities have expressed their intent to explore pilot projects and deploy new demand response programs within their service territories that are not yet showing up in the *Forecast*.

Northwest Generating Resources

The pie chart in Figure 5 shows the Northwest Utility Generating Resources for 2025. Total installed capacity for 2025 is about 55,600 MW. This year the *Forecast* includes a new category for battery storage, which has grown to 1% and is expected to quickly become an even larger share. Utilities also rely on imports from outside the region, energy efficiency and demand response to meet load.

Figure 5: Northwest Utilities Generating Resources



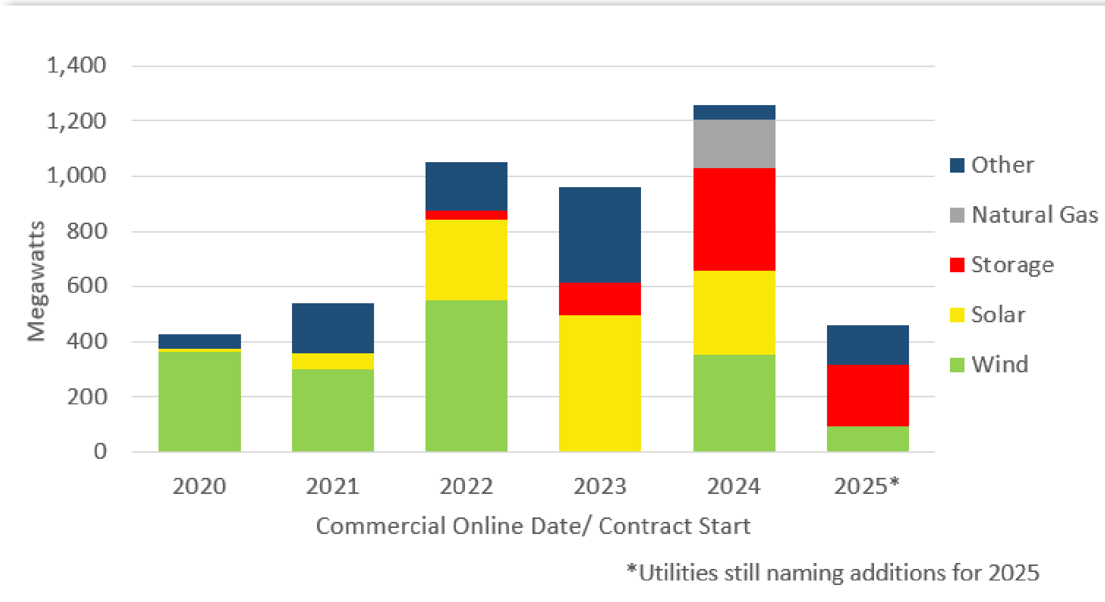
The Bar for New Resources Keeps Moving Higher

Northwest utilities have been steadily adding new resources to the regional generating mix to replace carbon-emitting resources. While the total installed capacity has increased slightly, these new resources have not significantly expanded to meet the anticipated rise in electricity demand.

Reported long-term acquisitions

Over the past five years, the majority of new generating resources have been solar and wind, with some additions of battery storage. The incremental additions reported from 2020 through 2025 are shown in Figure 6. Past *Forecasts* have not summarized this information, but the landscape is changing, and it is important to show how the picture is evolving. The data include committed resources that are named and under construction with a high degree of certainty to be added.

Figure 6: Incremental Nameplate Capacity 2020-2025 Acquisitions

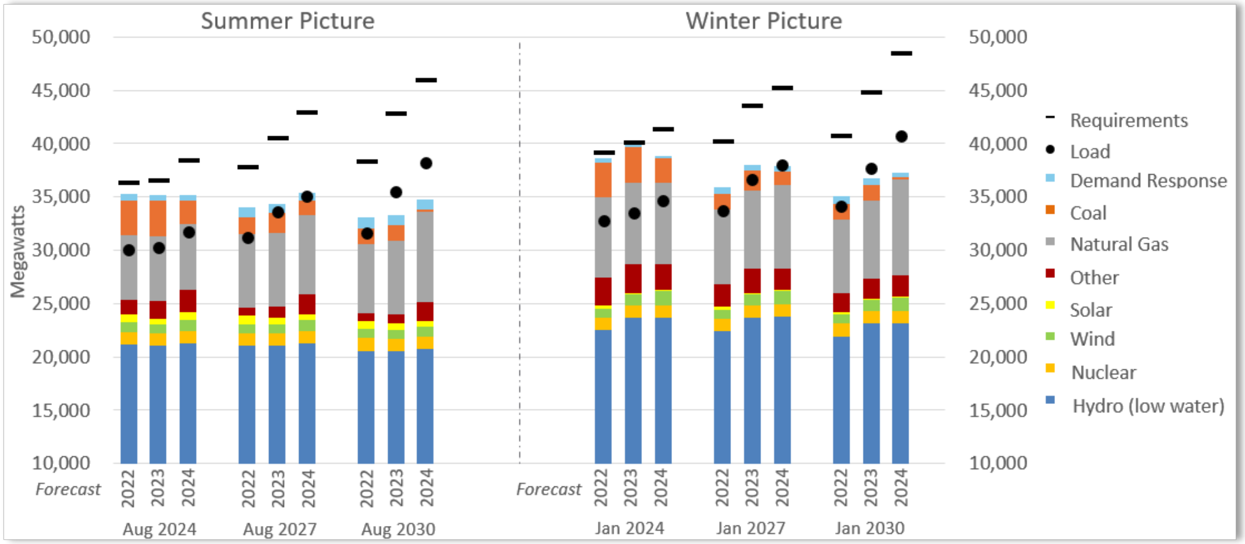


In total, utility reported resource acquisitions have increased the regional utility resource stack by approximately 4,700 MW (nameplate capacity) from 2020 through 2025. Wind additions are 1,657 MW, solar additions are 1,166 MW, storage additions are 748 MW and natural gas additions are 175 MW. The other category in Figure 6 includes imports of 335 MW, new contracts for existing regional resources of 598 MW and 12 MW of hydro upgrades. Because utilities are still naming additions for 2025, the 2025 planned future resources data in this graph appears relatively low at approximately 450 MW.

Figure 7 illustrates how the bar for future resources keeps moving higher. This graph compares the *2022 Forecast*, *2023 Forecast* and *2024 Forecast* of loads and resources for three future years in summer and winter. The colored stack bars are the utility's view of how existing and committed resources contribute to peak requirements. The stack does not include planned future resources. The black dot shows expected peak load, not extreme weather conditions. The black dash above the stack is the requirements – the sum of peak load, a 16% planning margin and export obligations. The resource contributions to peak requirements are shown based on expected operations and low water conditions. Firm imports are included in the other category, along with batteries and miscellaneous other resources that do not fit the main categories.

Tables 3 and 4 in the report provide the complete picture of 10 years of growing deficits. By the end of the forecast the projected summer and winter peak deficits are more than 13,700 MW in both seasons and utilities are forecasting that it will take about 29,000 MW of installed nameplate capacity (Table 9) to fill these gaps.

Figure 7: 2024 Load and Resource Forecast Compared to 2023 and 2022



This load and resource balance is not a resource adequacy assessment for the region. Rather, it is tracking the trend of the forecat load and resource balance to help understand how the picture is changing and to build awareness. To fill the gap, the region will need an unprecedented amount of new generation in the next 10 years that will significantly change the Pacific Northwest resource mix. Utilities are evaluating how existing and new generating resources can be counted on. The Western Resource Adequacy Program (WRAP) is helping utilities understand how much power the region will need to have an adequate system.

Projected demand driven by data center expansion

Compared to this time last year, there is a noticeable nationwide increase in awareness about the rapid expansion of data centers that are essential for advancing Artificial Intelligence (AI) and its incredible appetite for electricity. The use of AI is becoming increasingly important to the nation's economy. During a keynote address at a recent energy industry conference, Microsoft co-founder Bill Gates emphasized electricity is the critical factor determining the profitability of data centers and he expressed astonishment over the staggering amount of power AI will consume. It is challenging to forecast the extent of the potential increase and when it might show up in the region. Some companies developing new data centers are making plans that are not included in the *Forecast*.

Meeting this demand will be quite an undertaking, especially considering the evolving electricity supply. Many companies developing data centers are committed to minimizing their carbon footprints and prefer to power their facilities with carbon-free resources. Clean hydropower, affordable electricity and business incentives have attracted investment in this region, but finding enough power in the future will be a significant challenge. These companies are willing to pay to procure carbon-free, reliable power products to meet their corporate goals and are also exploring solutions that could help reduce power consumption.

Finding even more generating resources for meeting the demand from increased electrification will only increase the bar.

Electrification still to come

Utilities are trying to better understand how much energy and capacity could be needed for the electrification of buildings, transportation, and commercial and industrial applications. The overall effect of electrification is expected to increase over the next several years. Utilities are examining the implications of increased electrification in their load forecasts and updating their plans, a trend that cannot yet be fully captured in PNUCC's annual forecast.

Electric vehicle (EV) adoption among consumers has been increasing. Based on information PNUCC received from utilities, increased demand from charging EVs is projected to approach 4% of total load at the end of the 10-year period. Some utilities are expecting a higher percentage. Seattle City Light for example forecasts EV load could be 10% of their total load at the end of the 10-year period.

Electrification of buildings and industry is expected to lead to a significant increase in electricity consumption, but it will not impact utilities uniformly. Washington, for example, is incorporating building electrification mandates into statewide energy codes. Recent updates to Washington energy codes require builders to install electric heat pumps for space and water heating in most new commercial buildings and multi-family residences. Energy efficiency efforts may offset some of these increases and new load management technologies entering the market that are more controllable could help reduce peak demand when grid capacity is constrained.

Capacity concerns and transmission challenges create risk

Utilities need capacity, not just energy. The capacity contribution of wind and solar resources are dependent on several factors and actual generation can be less than installed nameplate capacity. The ability for a resource to provide power during a peak load event depends on the time of year, type of generating resource, its geographic location, access to fuel, access to transmission, and other factors that impact the capability to generate and deliver power at any given time. To maintain sufficient system resource adequacy, Pacific Northwest utilities rely heavily on the dependable capacity of hydro, nuclear, coal and natural gas. Battery storage increases dependability by storing surplus energy and supplying it later in the day when the energy is needed more, however, current commercial utility scale batteries have limits for meeting demand during multi-day events, like a cold snap in the Pacific Northwest.

While recent federal incentives have supercharged the market for clean energy and storage development and improved economic certainty for projects, other uncertainties – like grid interconnection, supply chain delays and project approvals – remain challenging. Project developers say grid interconnection is the leading cause of project delays and cancellations. Submitting an interconnection request and completing grid studies is only one of many steps in the development process; developers are also running into delays in getting agreements with landowners and experiencing increased equipment costs and delivery delays.

A good representation of how big the utility resource acquisition challenge could be is that the *2024 Forecast* shows utilities could add about 1,250 MW nameplate capacity by the end of 2024. Compared to the *2023 Forecast,* that number is about 50% less than projected last year.

The ability to build enough generation and acquire enough capacity is one thing; the ability to deliver it is another. Expanding the capacity of the transmission system will be critical for reliably serving the growing load and delivering more power from where it is produced to where it is needed. PNUCC members strongly believe the region should work across the Western Interconnection to develop a coordinated approach to grid planning that will identify transmission upgrades and expansion to address transmission constraints and reliably and affordably meet the needs of the future electric grid. Utilities, industry partners, states and others are actively engaged in building a coalition across the Western region to improve coordination in transmission planning through the Western Transmission Expansion Coalition (WestTEC). This initiative aims to identify and build support for transmission solutions that reduce reliability risks and facilitate the interconnection of new electricity generation to meet future load requirements.

Based on experience, utilities say planning is essential, but permitting new transmission lines is the biggest hurdle to expanding the electric transmission system, especially in the West. Existing permitting and siting rules and regulations foster perpetual legal challenges that have created decadal delays in the construction of new transmission projects.

Prioritizing Resource Adequacy and Reliability

Utilities are concerned about ensuring sufficient and reliable supply to meet demand, particularly during extreme weather events that are increasing in frequency due to climate change. The region needs a power and transmission system that is bigger than the weather because the region's customers demand a system that is both adequate and reliable.

The Pacific Northwest region will continue to rely on imports and West-wide collaboration is crucial for accessing diverse resources. Utilities are making commitments to broader regional wholesale electricity markets that would help make more efficient use of the existing and newly added resources and optimize transmission across a broader footprint. Organized electricity markets centrally optimize the least-cost dispatch of resources for utilities on the day-ahead through real-time operating timeframe to meet load. This allows for a centrally optimized system of matching buyers and sellers of wholesale electricity. Many Pacific Northwest utilities voluntarily participate in the Western Energy Imbalance Market (WEIM), which has become a valuable tool on a real-time interval that has delivered significant financial benefits to regional participants and improved grid reliability. Utilities are advancing efforts to develop and participate in day-ahead markets.

Extreme weather tests the system

The multi-day cold snap in January 2024 is an example of coming dangerously close to having an inadequate supply. The severe weather from January 12-16, 2024 pummeled the Pacific Northwest. Freezing temperatures were lower on the westside than they were on the eastside at the beginning of the event, which meant balancing authorities experienced system peaks at different times. Demand could have been significantly greater if temperatures across the region had dropped at the same time. The Pacific Northwest relied heavily on imports from the Desert Southwest and Rocky Mountain regions to maintain reliability due to high demand and low water conditions. Natural gas system constraints also reduced fuel supplies to gas-fired power plants, which impacted capacity and forced some utilities to rely more on imports.

The Western Power Pool, the program administrator for WRAP, provided an assessment of the January 2024 cold weather event. WPP found peak load consistently exceeded historical peaks or at or near historical peak load in many areas. "The amount of inter-regional support necessary to manage Balancing Authority (BA) operations through the cold weather event is indicative of the pressing need to address resource adequacy and potential capacity shortfalls as soon as practicable, highlighting the value of a resource adequacy program with a broad geographic footprint and diversity of load and resources," WPP wrote. WPP is calling on utilities to use the January experience to enhance preparedness and help improve the resource adequacy program.

The region's pursuit of solutions for ensuring resource adequacy includes extending the usefulness of existing infrastructure, like converting coal plants to natural gas plants, ensuring a stable natural gas supply to run natural gas plants and exploring emerging technologies.

As coal declines, natural gas is expected to increase and provide reliable supply

The regional coal and natural gas picture is shifting. Utilities continue to exit their positions in coal plants as required by state laws. On the other hand, some utilities have found it is cost-effective to repurpose existing infrastructure to reduce emissions and are planning to convert from coal to natural gas-fired generation. Natural gas can provide a bridge to meet peak demand and fill in during potential low water years until sufficient capacity and transmission infrastructure can be added.

Figure 8: NW Utility Coal and Natural Gas Plant Availability

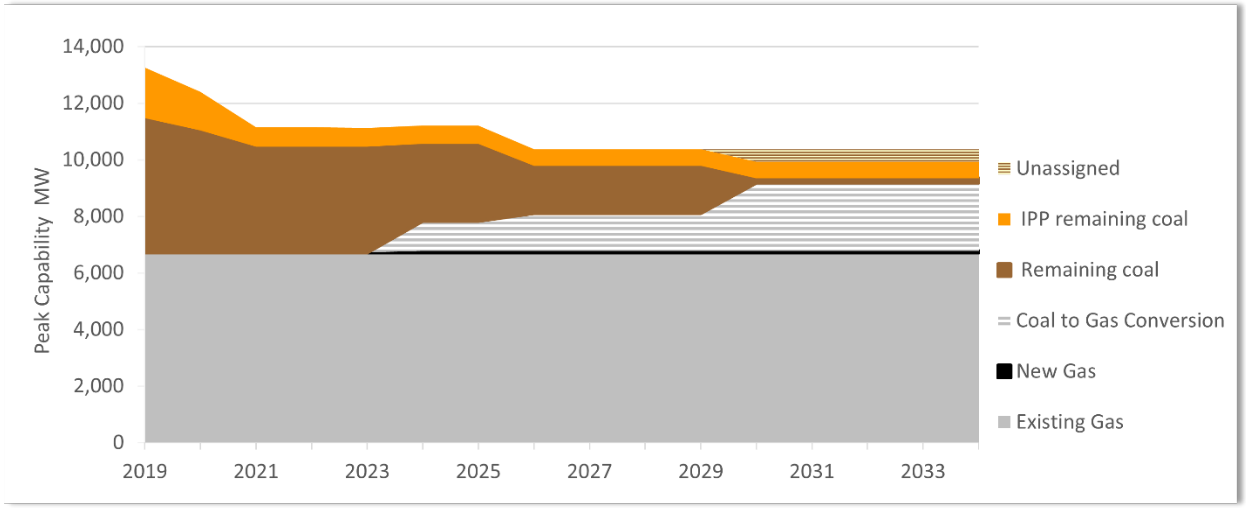


Figure 8 shows expected changes for coal and natural gas resources in the region. It begins with the picture in 2019. Looking ahead, regional coal availability declines gradually. State law requires that coal-fueled resources are eliminated from Oregon's electricity resources by January 1, 2030. Washington's Clean Energy Transformation Act (CETA) requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025. This decline shows up as retirements and coal-to-natural gas conversions. There is a remaining amount of coal that will be owned by Independent Power Producers and is not assigned to any load. A small amount of regional coal remains unassigned with no future owner identified.

Existing gas plant capability shown in the darker gray shaded area has remained steady. There is a small uptick in natural gas due to the anticipated addition of a new gas plant in 2024. Planned conversions from coal to natural gas are shown in the lighter gray area. (Figure 8 shows Jim Bridger Units 3-4 as coal to gas conversions in 2030. The picture does not reflect PacifiCorp's recently announced plans to retrofit these units with carbon capture technology by 2028 and continue operating them through 2039.)

Gas-electric coordination

Electric and natural gas system infrastructure is vital to the reliable operation of the power system. Electric energy and natural gas systems provide reliable energy to millions of people in the Pacific Northwest. The region depends on natural gas supply, storage and pipelines to fuel electric generating plants and heat homes. The interdependence of the two energy sources continues to grow as the region experiences extreme weather events more frequently and relies more on natural gas resources to meet peak demand. Building understanding and awareness of these systems and improving coordination between the electric and natural gas sectors is critical to ensure the necessary investments are made to keep the systems reliable as both sectors decarbonize.

Emerging technologies on the horizon

Regional utilities are actively exploring emerging technologies to meet future demands. Of particular interest to utilities are long duration energy storage, clean hydrogen, advanced nuclear and offshore wind. Puget Sound Energy (PSE) has announced it is partnering with Form Energy to evaluate multi-day energy storage solutions. The partnership allows both companies to collaborate on the development of a 10 MW, 100-hour iron-air battery pilot in PSE's service area. Long duration energy storage can provide power over several days as compared to most commercially available batteries that supply about four hours of energy storage. The pilot project will help PSE determine if a future utility-scale project could be deployed as early as the end of 2026.

Investor-owned and public power utilities are actively involved in the Pacific Northwest Hydrogen Hub (PNWH2), one of seven Regional Clean Hydrogen Hubs across the nation selected to receive federal funding to kick start clean hydrogen production. The PNWH2 Hub spans Washington, Oregon and Montana, and anticipates leveraging renewable resources to produce clean hydrogen exclusively via electrolysis. The economics and reach of this nascent technology will be impacted by the outcome of federal tax credit rulemaking.

There is a resurgence of interest and growing support for advanced nuclear reactors because of the role the non-emitting resource can play in supporting the transition to clean energy in a reliable way. Energy Northwest and X-Energy are jointly developing a next-generation nuclear plant in Washington. Energy Northwest has partnered with public power and investor-owned utilities to study the feasibility of building small modular nuclear reactors near the Columbia Generating Station, the state's only commercial nuclear energy facility. This year, Washington state legislators and Governor Jay Inslee supported allocating $25 million from state funds to study the pros and cons. Energy Northwest anticipates the first reactor could come online by 2031. Furthermore, PacifiCorp's 2023 IRP Update continues to show the value associated with TerraPower's nuclear demonstration project in Kemmerer, Wyoming. The nuclear power company, which is backed by Bill Gates, plans to break ground on the project this year.

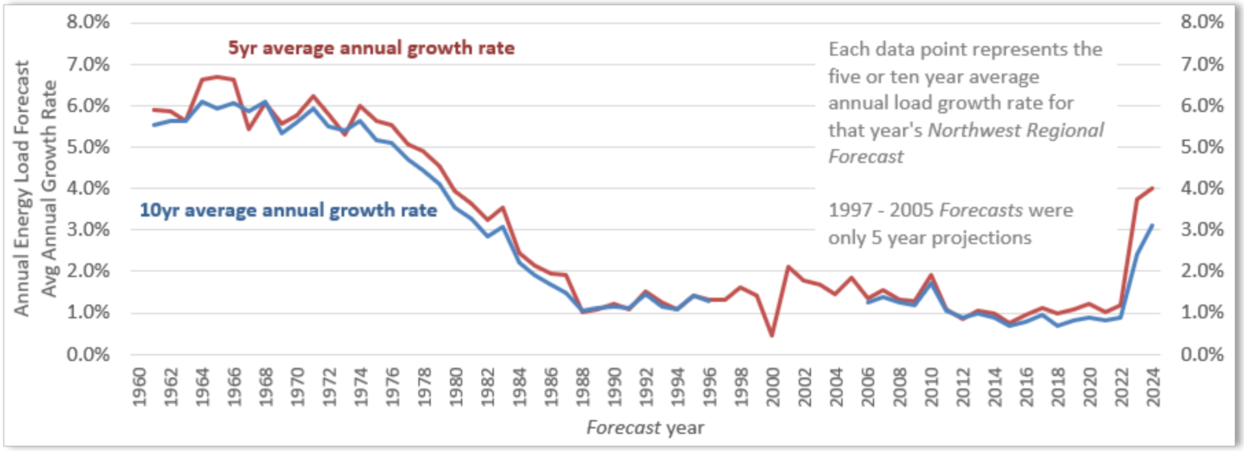
Except for offshore wind, emerging technologies such as long duration energy storage, clean hydrogen, advanced nuclear and others do not show up in the *Forecast*, but they could profoundly reshape the future regional energy landscape.

Utilities are also deploying and finding new ways to partner with customers to reduce energy use at peak times. Some utilities are exploring Virtual Power Plants (VPPs) as a way of managing customer-side resources. In general, a VPP is a portfolio of actively controlled distributed energy resources (DER). Operation of DERs is optimized to provide benefits to the power system and consumers. To a degree, VPPs have existed for decades as demand response programs. But VPPs are rapidly evolving to leverage the expanding mix of DER technologies. A VPP that reliably leverages residential load flexibility could contribute to resource adequacy.

Conclusion

Utilities in aggregate have not forecast a rate of growth for annual energy load this high since the early 1980s. This represents quite a change from the past 40 years of relatively modest growth rates of about 1-2%.

Figure 9: Historical Load Forecast Growth Rates



To accommodate the forecasted surge in demand, the region is planning to add an unprecedented 29,000 MW of new resources in 10 years while decarbonizing the electricity supply. This is an extraordinary number of new resources to develop in 10 years. A more connected grid would provide access to a wider range of resources and allow for the sharing of energy over larger distances. This would help balance the fluctuations in demand and supply, while also enhancing the resilience of the grid. Collectively, Pacific Northwest utilities are building deeper awareness of the crucial need to optimize the system, expand transmission capacity and rapidly integrate additional generating resources. By working together, the region can unlock the solutions that will keep the grid reliable and affordable.

Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The *Forecast* is a comprehensive look at the capability of existing and new electric generation, long-term firm contracts, expected savings from demand side management programs, and other components of electric supply and demand in the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the Northwest Region Requirements and Resources section. These metrics provide a multidimensional look at the Northwest's need for power and underscore the growing complexity of the power system. The information is intended to identify regional trends and general themes based on utilities' resource planning assessment results, rather than provide a precise metric of resource adequacy.

Northwest new and existing generating resources are shown by fuel type. Existing and committed resources are listed in Tables 5, 6 and 10. Table 5, Recently Acquired Resources, highlights projects and supply that became available most recently. Table 6, Committed New Supply, lists projects where construction has started or supply is firmly committed, as well as contractual arrangements that have been made for providing power at a future time. Table 10, Northwest Utility Generating Resources, is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility-contracted.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. Table 7, Demand-Side Management Programs, provides a snapshot of expected savings from these programs for the next ten years. Lastly, Tables 8 and 9, Planned Future Resources, compile what utilities have reported in their individual resource planning assessments to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington, and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above but served by BPA on the effective date of the *Act*.

Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities' requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

Average Megawatts	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Firm Requirements										
Load 1/	23,708	24,643	25,684	26,850	27,945	28,859	29,657	30,240	30,714	31,093
Exports	515	515	515	514	514	511	511	511	511	512
Total	24,223	25,158	26,199	27,365	28,460	29,370	30,167	30,750	31,225	31,605
Firm Resources										
Hydro 2/	11,437	11,439	11,418	11,402	11,208	11,142	11,142	11,142	11,142	11,119
Small Thermal/Misc.	28	28	28	28	18	11	11	11	11	11
Natural Gas 3/	5,117	5,321	5,361	5,361	5,361	5,534	5,653	5,656	5,653	5,653
Renewables-Other	289	298	298	296	295	295	292	284	275	276
Solar	443	483	502	503	505	506	506	498	484	480
Wind	1,772	1,791	1,771	1,714	1,682	1,657	1,642	1,642	1,639	1,640
Cogeneration	32	19	15	14	14	14	14	14	14	14
Imports	467	467	467	453	380	324	310	310	222	160
Nuclear	994	1,116	994	1,116	994	1,116	994	1,116	994	1,116
Coal	2,006	1,450	1,100	1,086	1,092	417	102	102	94	100
Total	22,584	22,412	21,956	21,973	21,550	21,016	20,666	20,776	20,529	20,569
Surplus (Deficit)	**(1,640)**	**(2,746)**	**(4,243)**	**(5,392)**	**(6,910)**	**(8,354)**	**(9,502)**	**(9,975)**	**(10,695)**	**(11,036)**

1/ Load net of energy efficiency

2/ Firm hydro for energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)

3/ More energy may be available from natural gas power plants

Table 2. Northwest Region Requirements and Resources – Monthly Energy shows the monthly energy values for the 2024-2025 operating year.

Average Megawatts	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Firm Requirements												
Load[1/]	23,293	21,431	21,347	23,889	26,524	26,544	25,867	23,741	22,544	21,893	22,939	24,488
Exports	775	614	455	455	455	455	455	455	455	455	533	620
Total	24,068	22,045	21,802	24,344	26,979	26,999	26,322	24,196	22,999	22,348	23,472	25,108
Firm Resources												
Hydro [2/]	11,775	9,121	9,674	11,546	12,907	11,481	10,362	10,848	9,545	11,234	15,413	13,002
Small Thermal/Misc.	26	26	27	29	31	30	30	30	30	29	22	25
Natural Gas [3/]	4,861	4,848	4,961	5,135	5,250	6,194	6,170	4,835	4,775	3,810	4,804	5,807
Renewables-Other	297	292	290	284	276	275	276	294	288	290	302	303
Solar	658	538	373	207	153	151	260	392	518	595	710	755
Wind	1,650	1,496	1,677	1,849	1,762	1,707	1,772	1,888	1,978	1,796	1,939	1,748
Cogeneration	32	32	25	33	36	37	35	32	31	30	28	33
Imports	230	220	275	481	569	519	517	433	336	326	328	331
Nuclear	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	1,116	360	409	1,116
Coal	2,057	2,058	2,054	2,076	2,066	2,082	2,060	2,080	1,951	1,782	1,774	2,036
Total	22,703	19,746	20,472	22,755	24,166	23,593	22,598	21,947	20,567	20,251	25,730	25,155
Surplus (Deficit)	**(1,365)**	**(2,299)**	**(1,330)**	**(1,589)**	**(2,813)**	**(3,406)**	**(3,724)**	**(2,249)**	**(2,432)**	**(2,097)**	**2,259**	**48**

[1/] Load net of energy efficiency

[2/] Firm hydro for energy is the generation expected assuming critical (8%) water condition (the methodology is changed for the 2023 report)

[3/] More energy may be available from natural gas power plants

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Firm Requirements										
Load [1/]	34,658	35,633	36,761	38,033	38,940	39,932	40,763	41,411	41,900	42,377
Exports	1,143	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142	1,142
Planning Margin [2/]	5,545	5,701	5,882	6,085	6,230	6,389	6,522	6,626	6,704	6,780
Total	41,346	42,476	43,784	45,259	46,312	47,462	48,427	49,178	49,746	50,299
Firm Resources										
Hydro [3/]	23,660	23,658	23,658	23,751	23,651	23,608	23,126	23,126	23,033	22,662
Demand Response	237	315	378	436	456	479	503	523	540	555
Small Thermal/Misc [4/].	801	803	801	801	783	784	785	786	788	789
Natural Gas	7,641	7,901	7,903	7,903	7,903	8,965	8,965	8,965	8,965	8,965
Renewables-Other	447	443	424	419	419	419	415	403	393	393
Solar	103	108	111	102	102	103	103	102	96	94
Wind	1,323	1,321	1,303	1,285	1,276	1,286	1,295	1,283	1,266	1,268
Cogeneration	38	18	16	16	16	16	16	16	16	16
Imports	1,164	1,293	927	696	806	873	788	493	493	493
Nuclear	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178	1,178
Coal	2,240	1,275	1,275	1,275	1,275	147	147	147	147	147
Total	38,831	38,314	37,974	37,864	37,866	37,857	37,322	37,023	36,916	36,561
Surplus (Deficit)	**(2,514)**	**(4,162)**	**(5,810)**	**(7,395)**	**(8,446)**	**(9,605)**	**(11,105)**	**(12,155)**	**(12,830)**	**(13,738)**

[1/] Expected (1-in-2) load net of energy efficiency
[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)
[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor.
[4/] Includes stand-alone storage resources

Table 4. Northwest Region Requirements and Resources – Summer Peak

The sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

Megawatts	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Firm Requirements										
Load [1/]	31,732	32,742	33,853	35,052	36,204	37,230	38,239	39,150	39,868	40,239
Exports	1,632	1,628	2,045	2,285	1,961	2,239	1,626	1,626	1,626	1,626
Planning Margin [2/]	5,077	5,239	5,416	5,608	5,793	5,957	6,118	6,264	6,379	6,438
Total	38,441	39,609	41,314	42,945	43,959	45,426	45,983	47,040	47,873	48,304
Firm Resources										
Hydro [3/]	21,275	21,368	21,275	21,275	20,700	20,700	20,700	20,700	20,700	20,608
Demand Response	487	597	710	796	871	900	934	976	1,008	1,037
Small Thermal/Misc. [4/]	747	747	746	747	747	737	738	739	740	741
Natural Gas	6,173	7,235	7,492	7,492	7,492	7,492	8,554	8,554	8,554	8,554
Renewables-Other	460	460	437	437	433	433	433	422	410	408
Solar	757	626	599	593	582	567	574	564	543	536
Wind	1,031	1,006	1,009	992	984	970	972	975	960	955
Cogeneration	54	38	19	17	17	17	17	17	17	17
Imports	637	746	475	475	375	335	341	450	185	185
Nuclear	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163	1,163
Coal	2,237	2,157	1,271	1,271	1,271	1,271	145	145	145	145
Total	35,021	36,144	35,196	35,258	34,635	34,584	34,571	34,705	34,424	34,349
Surplus (Deficit)	**(3,420)**	**(3,465)**	**(6,118)**	**(7,687)**	**(9,323)**	**(10,842)**	**(11,412)**	**(12,335)**	**(13,448)**	**(13,954)**

[1/] Expected (1-in-2) load net of energy efficiency
[2/] Planning margin is 16% of load (this assumption was updated and set with the *2018 Northwest Regional Forecast*)
[3/] Firm hydro for capacity is the generation expected assuming critical peaking capability as determined by the utility sponsor
[4/] Includes stand-alone storage resources

Northwest New and Existing Resources

Table 5. Recently Acquired Resources highlights projects that have recently become available.

Project	Fuel/Tech	Nameplate (MW)	Utility/Owner
River Road Generating Project Upgrade	Natural Gas		Clark PUD
Combine Hills 1	Wind	41	Clark PUD
2024 RFP Small Battery	Li Ion Storage	36	Idaho Power
Black Mesa Solar	Solar	40	Idaho Power
Black Mesa Battery	Li Ion Storage	40	Idaho Power
Coleman Hydro	Hydro	0.8	Idaho Power
Franklin Battery	Li Ion Storage	60	Idaho Power
Franklin Solar	Solar	100	Idaho Power
Hemingway Battery	Li Ion Storage	80	Idaho Power
Jackpot Solar	Solar	120	Idaho Power
7 Mile Solar, LLC (Oregon Schedule 126 - Community Solar Project Purchase Agreement (OR Sch. 126 CSP))	Solar	0.981	PacifiCorp
Antelope Creek Solar, LLC (OR Sch. 126 CSP)	Solar	2.25	PacifiCorp
Buckaroo Solar 1, LLC (OR Sch. 126 CSP)	Solar	2.4	PacifiCorp
Buckaroo Solar 2, LLC (OR Sch. 126 CSP)	Solar	2.99	PacifiCorp
Green Solar LLC (OR Sch. 126 CSP)	Solar	2.875	PacifiCorp
Linkville Solar, LLC (OR Sch. 126 CSP)	Solar	2.8	PacifiCorp
Orchard Knob Solar, LLC (OR Sch. 126 CSP)	Solar	2.25	PacifiCorp
Oregon Institute of Technology (OIT) Battery Energy Storage System	Li Ion Storage	2	PacifiCorp
Pine Grove Solar, LLC (OR Sch. 126 CSP)	Solar	1.4	PacifiCorp
Round Lake Solar, LLC (OR Sch. 126 CSP))	Solar	0.978	PacifiCorp
Skysol, LLC (Skysol Solar / 174 Power Global / Hanwha Group)	Solar	55	PacifiCorp
Sunset Ridge Solar, LLC (OR Sch. 126 CSP)	Solar	2.25	PacifiCorp
Clearwater Wind	Wind	311	Portland General Electric
Pachwaywit Solar	Solar	162	Portland General Electric
Short-Term Winter Market Energy Contract	Regional Contract	25	Snohomish PUD
Total (Nameplate)		**1,094**	

Table 6. Committed Resources details firm contracts and generating projects that are committed to come online. All supply listed in this table is included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate (MW)	Utility/Owner
Yellowstone County Generating Station	2024	Natural Gas	175	NorthWestern Energy
Bakeoven	2025	Solar	60	Portland General Electric
Constable	2024	Li Ion Storage	75	Portland General Electric
Daybreak	2025	Solar	140	Portland General Electric
Seaside	2025	Li Ion Storage	200	Portland General Electric
Troutdale	2024	Li Ion Storage	200	Portland General Electric
Vantage Wind	2025	Wind	90	Puget Sound Energy
Total (Nameplate)			**1,134**	

Table 7. Demand-Side Management Programs is a snapshot of the regional utilities' efforts to manage demand. The majority of the energy efficiency savings are from utility programs and included in the regional analysis of power needs. This table also shows cumulative existing plus new demand response programs reported by utilities.

	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30	2030-31	2031-32	2032-33	2033-34
Energy Efficiency (aMW)										
Incremental	183	189	196	204	214	213	216	206	190	180
Cumulative	183	372	568	772	986	1,199	1,416	1,621	1,811	1,991
Demand Response (MW) existing + forecast[1]										
Winter	237	315	378	436	456	479	503	523	540	555
Summer	385	516	629	717	807	882	879	910	936	954

[1] Values are program effectiveness, nameplate values are higher.

Table 8. Planned Future Resources catalogues future resources that utilities have identified to meet their own needs. These resources are subject to change and are not included in the regional analysis of power needs.

Project	Year	Fuel/Tech	Nameplate	Utility
Generic Capacity	2025	Peaking Capacity	225	OR Utility
Utility-scale Renewables	2025	Renewable	50	WA Utility
E. Oregon Solar	2025	Solar PV	82	WA Utility
Palouse Junction	2025	Solar PV	10	WA Utility
Pilot Rock Solar 1, LLC (Community Solar)	2025	Solar PV	1.98	Multi-State Utility
Pilot Rock Solar 2, LLC (Community Solar)	2025	Solar PV	2.99	Multi-State Utility
Pleasant Valley Solar	2025	Solar PV	3	Multi-State Utility
Solar	2025	Solar PV	300	OR Utility
Solar	2025	Solar PV	80	OR Utility
Solar	2025	Solar PV	600	OR Utility
Solar	2025	Solar PV	41	OR Utility
Tutuilla Solar, LLC Community Solar)	2025	Solar PV	1.56	Multi-State Utility
2025 RFP Battery 1	2025	Storage	120	Multi-State Utility
2025 RFP Battery 2	2025	Storage	29	Multi-State Utility
25 MW 100 MWh Battery Energy Strorage	2025	Storage	25	WA Utility
Wind	2025	Wind	110	OR Utility
Wind	2025	Wind	201	OR Utility
Wind	2025	Wind	90	OR Utility
Wind	2025	Wind	151	OR Utility
Wind	2025	Wind	24	OR Utility
Solar + Storage	2026	Renewables + Storage	250	OR Utility
Wind + Solar + Battery	2026	Renewables + Storage	250	WA Utility
Oregon Solar	2026	Solar PV	74	WA Utility
Pleasant Valley Solar 2	2026	Solar PV	125	Multi-State Utility
Solar	2026	Solar PV	375	Multi-State Utility
Solar	2026	Solar PV	220	OR Utility
MT PHES	2026	Storage	200	WA Utility
Storage - Pumped Storage	2026	Storage	35	Multi-State Utility
WA/OR PHES	2026	Storage	200	WA Utility
Clearwater Wind PPA	2026	Wind	98	Multi-State Utility
Columbia River Gorge Wind	2026	Wind	200	WA Utility
MT Wind East	2026	Wind	400	WA Utility
Wind	2026	Wind	350	OR Utility
Wind	2026	Wind	350	OR Utility
Utility-scale Renewables	2027	Renewable	50	WA Utility
Solar + Storage	2027	Renewables + Storage	400	OR Utility
SE Oregon Solar	2027	Solar PV	200	WA Utility
Solar	2027	Solar PV	150	Multi-State Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Washington Solar	2027	Solar PV	60	WA Utility
25 MW 100 MWh Battery Energy Storage	2027	Storage	25	WA Utility
4hr Storage	2027	Storage	5	Multi-State Utility
Wind	2027	Wind	400	Multi-State Utility
Utility-scale Renewables	2028	Renewable	50	WA Utility
Generic Solar	2028	Solar PV	150	WA Utility
4hr Storage	2028	Storage	5	Multi-State Utility
Generic Wind	2028	Wind	200	WA Utility
Wind	2028	Wind	400	Multi-State Utility
Post Falls Hydro Modernization	2029	Existing Resource Upgrade	8	Multi-State Utility
IRP Resource - Base Scenario	2029	Peaking Capacity	50	Multi-State Utility
Utility-scale Renewables	2029	Renewable	50	WA Utility
4hr Storage	2029	Storage	5	Multi-State Utility
Wind	2029	Wind	400	Multi-State Utility
Geothermal	2030	Renewable	30	Multi-State Utility
Solar	2030	Solar PV	500	Multi-State Utility
4hr Storage	2030	Storage	155	Multi-State Utility
Wind	2030	Wind	100	Multi-State Utility
Solar	2031	Solar PV	400	Multi-State Utility
4hr Storage	2031	Storage	5	Multi-State Utility
Wind	2031	Wind	400	Multi-State Utility
IRP Resource - Base Scenario	2032	Peaking Capacity	50	Multi-State Utility
Solar	2032	Solar PV	100	Multi-State Utility
4hr Storage	2032	Storage	205	Multi-State Utility
IRP Resource - Base Scenario	2032	Storage	100	Multi-State Utility
Wind	2032	Wind	100	Multi-State Utility
4hr Storage	2033	Storage	105	Multi-State Utility
IRP Resource - Base Scenario	2034	Peaking Capacity	18	Multi-State Utility
Natural Gas CT - for Idaho	2034	Peaking Capacity	90	Multi-State Utility
4hr Storage	2034	Storage	5	Multi-State Utility
Frame Peaker Biodiesel	2024 - 2028	Peaking Capacity	711	WA Utility
Solar + Battery	2024 - 2029	Renewables + Storage	450	WA Utility
WA East Solar	2024 - 2029	Solar PV	700	WA Utility
WA Wind	2024 - 2030	Wind	1000	WA Utility
Renewable - Utility Solar	2025 - 2027	Solar PV	1616	Multi-State Utility
Wind + Battery	2025 - 2029	Renewables + Storage	750	WA Utility
Renewable - Battery	2025 - 2029	Storage	3266	Multi-State Utility
DER Solar Ground (ground and rooftop)	2025 - 2033	Solar PV	270	WA Utility
Li-Ion 4hr	2025 - 2033	Storage	800	WA Utility
Preferred portfolio resource (Offshore wind)	2025 - 2034	Other Renewable	720	OR Utility
Preferred portfolio resource (solar & wind)	2025 - 2034	Renewable	2681	OR Utility
Preferred portfolo resource (CBRE)	2025 - 2034	Renewable	155	OR Utility

Project	Year	Fuel/Tech	Nameplate	Utility
Preferred portfolio resource (Hybrid solar + battery)	2025 - 2034	Renewables + Storage	1010	OR Utility
Preferred portfolio resource (storage)	2025 - 2034	Storage	864	OR Utility
DER Storage (BESS)	2027 - 2031	Storage	150	WA Utility
Renewable - Wind	2027 - 2033	Wind	2451	Multi-State Utility
WY East Wind	2031 - 2033	Wind	400	WA Utility
Preferred portfolio resource (capacity)	2031 - 2034	Peaking Capacity	205	OR Utility
Broadview (160MW Solar + 50MW Battery, 80 MW limit)	TBD	Renewables + Storage	160	Multi-State Utility
Meadowlark (20 MW Solar + 12.5MW Battery)	TBD	Renewables + Storage	20	Multi-State Utility
Trident (160 MW Solar + 80 MW Battery, 80 MW limit)	TBD	Renewables + Storage	160	Multi-State Utility
Jawbone	TBD	Wind	80	Multi-State Utility
TOTAL			**28,866**	

Table 9. Planned Future Resources Timeline displays the cumulative supply-side resource additions over time, combining the nameplate MW values of resources from Table 8 (NW utility owned/contracted only, IPP additions not included).

Nameplate MW	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Wind	1,176	2,574	3,074	3,674	4,074	4,574	5,174	6,443	7,825	7,905
Solar PV	1,262	3,210	4,133	4,513	4,943	5,473	5,903	6,033	6,063	6,063
Storage	558	3,021	4,004	4,934	5,164	5,344	5,689	6,094	6,299	6,304
Renewables + Storage	300	950	1,350	1,500	2,529	3,100	3,110	3,110	3,110	3,450
Offshore Wind	-	-	-	-	-	-	-	237	470	720
Renewables	119	516	995	1,470	1,849	1,911	3,066	3,066	3,066	3,066
Peaking Capacity	462	699	699	936	986	986	1,022	1,072	1,144	1,349
Existing Resource Upgrades	-	-	2	2	10	10	10	10	10	10
TOTAL	3,877	10,970	14,256	17,028	19,554	21,397	23,973	26,064	27,986	28,866

Table 10. Northwest Utility Generating Resources is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply. This table includes recently acquired and committed resources – some of the resources listed may not currently be operating. Potential resources are not included in the table.

Project	Owner	NW Utility	Nameplate (MW)
HYDRO			**33,635**
Albeni Falls	US Corps of Engineers	Federal System (BPA)	43
Alder	Tacoma Power	Tacoma Power	50
American Falls	Idaho Power	Idaho Power	92
Anderson Ranch	US Bureau of Reclamation	Federal System (BPA)	40
Arena Drop	PURPA	Idaho Power	0.5
Arrowrock Dam	Clatskanie PUD/Irr Dist	Clatskanie PUD	18
Baker City Hydro	PURPA	Idaho Power	0.2
Barber Dam	PURPA	Idaho Power	4
Bend		PacifiCorp	1
Big Cliff	US Corps of Engineers	Federal System (BPA)	18
Big Fork		PacifiCorp	5
Big Sheep Creek	Everand Jensen	Avista Corp.	0.1
Birch Creek	PURPA	Idaho Power	0.1
Black Canyon	US Bureau of Reclamation	Federal System (BPA)	10
Black Canyon #3	PURPA	Idaho Power	0.1
Black Canyon Bliss Dam	PURPA	Idaho Power	0.03
Black Creek Hydro	Black Creek Hydro, Inc.	Puget Sound Energy	4
Black Eagle	NorthWestern Energy	NorthWestern Energy	23
Blind Canyon	PURPA	Idaho Power	2
Bliss	Idaho Power	Idaho Power	75
Boise River Diversion	US Bureau of Reclamation	Federal System (BPA)	2
Bonneville	US Corps of Engineers	Federal System (BPA)	1102
Boundary	Seattle City Light	Seattle City Light	1119
Box Canyon	Pend Oreille County PUD	Pend Oreille County PUD	90
Box Canyon-Idaho	PURPA	Idaho Power	0.4
Briggs Creek	PURPA	Idaho Power	1
Broadwater Dam	Dept. of Natural Res. & Cons.	NorthWestern Energy	10
Brownlee	Idaho Power	Idaho Power	585
Bypass	PURPA	Idaho Power	10
C. J. Strike	Idaho Power	Idaho Power	83
Cabinet Gorge	Avista Corp.	Avista Corp.	265
Calispel Creek	Pend Oreille County PUD	Pend Oreille County PUD	1
Calligan Creek	Snohomish County PUD	Snohomish County PUD	6
Canyon Springs	PURPA	Idaho Power	0.1
Carmen-Smith	Eugene Water & Electric Board	Eugene Water & Electric Board	105
Cascade	US Bureau of Reclamation	Idaho Power	12
Cedar Draw Creek	PURPA	Idaho Power	2
Cedar Falls, Newhalem	Seattle City Light	Seattle City Light	33
Chandler	US Bureau of Reclamation	Federal System (BPA)	12
Chelan	Chelan County PUD	Chelan County PUD	59
Chief Joseph	US Corps of Engineers	Federal System (BPA)	2457
Clackamas	Portland General Electric	Portland General Electric	96
Clear Lakes	Idaho Power	Idaho Power	3
Clear Springs Trout	PURPA	Idaho Power	1
Clearwater 1		PacifiCorp	18
Clearwater 2		PacifiCorp	31

Project	Owner	NW Utility	Nameplate (MW)
Cochrane	NorthWestern Energy	NorthWestern Energy	62
Coleman Hydro	PURPA	Idaho Power	1
Cougar	US Corps of Engineers	Federal System (BPA)	25
Cowlitz Falls	Lewis County PUD	Federal System (BPA)	70
Crystal Springs	PURPA	Idaho Power	2
Curry Cattle Company	PURPA	Curry Cattle Company	0.2
Cushman 1	Tacoma Power	Tacoma Power	43
Cushman 2	Tacoma Power	Tacoma Power	81
Deep Creek	Gordon Foster	Avista Corp.	0.5
Derr Creek	Jim White	Avista Corp.	0.3
Detroit	US Corps of Engineers	Federal System (BPA)	100
Dexter	US Corps of Engineers	Federal System (BPA)	15
Diablo	Seattle City Light	Seattle City Light	182
Dietrich Drop	PURPA	Idaho Power	5
Dworshak	US Corps of Engineers	Federal System (BPA)	400
Dworshak/ Clearwater		Federal System (BPA)	3
Ebey Hill	Ebey Hill Hydroelectric, Inc.	Snohomish County PUD	0.2
Eight Mile Hydro	PURPA	Idaho Power	0.4
Elk Creek	PURPA	Idaho Power	3
Eltopia Branch Canal	SEQCBID	Multiple Utilities	2
Esquatzel Small Hydro	Green Energy Today, LLC	Franklin County PUD	1
Falls River	PURPA	Idaho Power	9
Faraday	Portland General Electric	Portland General Electric	27
Fargo Drop Hydro	PURPA	Idaho Power	1
Faulkner Ranch	PURPA	Idaho Power	1
Fish Creek	PacifiCorp	PacifiCorp	10
Fisheries Development Co.	PURPA	Idaho Power	0.3
Foster	US Corps of Engineers	Federal System (BPA)	20
Gem State Hydro 1	IdahoFalls-ID		23
Geo-Bon #2	PURPA	Idaho Power	1
Gorge	Seattle City Light	Seattle City Light	207
Grand Coulee	US Bureau of Reclamation	Federal System (BPA)	6494
Green Peter	US Corps of Engineers	Federal System(BPA)	80
Green Springs	US Bureau of Reclamation	Federal System (BPA)	16
Hailey CSPP	PURPA	Idaho Power	0.1
Hancock Creek	Snohomish County PUD	Snohomish County PUD	6
Hauser	NorthWestern Energy	NorthWestern Energy	19
Hazelton A	PURPA	Idaho Power	8
Hazelton B	PURPA	Idaho Power	8
Head of U Canal	PURPA	Idaho Power	1
Hells Canyon	Idaho Power	Idaho Power	392
Hills Creek	US Corps of Engineers	Federal System (BPA)	30
Holter	NorthWestern Energy	NorthWestern Energy	50
Hood Street Reservoir	Tacoma Power	Tacoma Power	0.9
Horseshoe Bend	PURPA	Idaho Power	9
Hungry Horse	US Bureau of Reclamation	Federal System (BPA)	428
Ice Harbor	US Corps of Engineers	Federal System (BPA)	603
Idaho Falls - City Plant		Federal System (BPA)	8
Idaho Falls - Lower Plant #1		Federal System (BPA)	8
Idaho Falls - Lower Plant #2		Federal System (BPA)	3
Idaho Falls - Upper Plant		Federal System (BPA)	8

Project	Owner	NW Utility	Nameplate (MW)
Jackson (Sultan)	Snohomish County PUD	Snohomish County PUD	112
Jim Ford Creek	Ford Hydro	Avista Corp.	2
Jim Knight	PURPA	Idaho Power	0.3
John Day	US Corps of Engineers	Federal System (BPA)	2160
John Day Creek	Dave Cereghino	Avista Corp.	1
Koma Kulshan	Koma Kulshan Associates	Puget Sound Energy	12
Koyle Small Hydro	PURPA	Idaho Power	1
La Grande	Tacoma Power	Tacoma Power	64
Lake Oswego Corp.		Portland General Electric	1
Lateral #10	PURPA	Idaho Power	2
Lemolo 1	PacifiCorp	PacifiCorp	32
Lemolo 2	PacifiCorp	PacifiCorp	39
Lemoyne	PURPA	Idaho Power	0.1
Libby	US Corps of Engineers	Federal System (BPA)	525
Little Falls	Avista Corp.	Avista Corp.	32
Little Goose	US Corps of Engineers	Federal System (BPA)	810
Little Mac	PURPA	Idaho Power	1
Little Wood River Ranch II	PURPA	Idaho Power	1
Little Wood Rvr Res	PURPA	Idaho Power	3
Little Wood/Arkoosh	PURPA	Idaho Power	1
Long Lake	Avista Corp.	Avista Corp.	70
Lookout Point	US Corps of Engineers	Federal System (BPA)	120
Lost Creek	US Corps of Engineers	Federal System (BPA)	49
Low Line Canal	PURPA	Idaho Power	8
Low Line Midway	PURPA	Idaho Power	3
Lower Baker	Puget Sound Energy	Puget Sound Energy	115
Lower Granite	US Corps of Engineers	Federal System (BPA)	810
Lower Malad	Idaho Power	Idaho Power	14
Lower Monumental	US Corps of Engineers	Federal System (BPA)	810
Lower Salmon	Idaho Power	Idaho Power	60
Lower Swift Creek	Lower Valley Energy, Inc.	Other Publics (BPA)	0.4
Lowline #2	PURPA	Idaho Power	3
Lucky Peak	US Corps of Engineers	Seattle City Light	113
Madison	Northwestern Energy	NorthWestern Energy	8
Magic Reservoir	PURPA	Idaho Power	9
Main Canal Headworks	SEQCBID	Multiple Utilities	26
Malad River	PURPA	Idaho Power	1
Mayfield	Tacoma Power	Tacoma Power	162
MC6 Hydro	PURPA	Idaho Power	2
McNary	US Corps of Engineers	Federal System (BPA)	980
McNary Fishway	US Corps of Engineers	Other Publics (BPA)	10
Merwin	PacifiCorp	PacifiCorp	151
Meyers Falls	Hydro Technology Systems	Avista Corp.	1
Mile 28	PURPA	Idaho Power	2
Milner	Idaho Power	Idaho Power	118
Minidoka	US Bureau of Reclamation	Federal System (BPA)	28
Mitchell Butte	PURPA	Idaho Power	2
Monroe Street	Avista	Avista Corp.	15
Mora Drop	PURPA	Idaho Power	2
Morony	NorthWestern Energy	NorthWestern Energy	49
Mossyrock	Tacoma Power	Tacoma Power	300
Mount Tabor	City of Portland	Portland General Electric	0.2

Project	Owner	NW Utility	Nameplate (MW)
Moyie River 1	BonnersFerry-ID	Other Publics (BPA)	0.5
Moyie River 2	BonnersFerry-ID	Other Publics (BPA)	2
Moyie River 3	BonnersFerry-ID	Other Publics (BPA)	2
Mud Creek/S&S	PURPA	Idaho Power	1
Mud Creek/White	PURPA	Idaho Power	0.2
Mystic	NorthWestern Energy	NorthWestern Energy	12
N-32 Canal (Marco Ranches)	PURPA	Idaho Power	1
Nine Mile	Avista Corp.	Avista Corp.	26
Nooksack	Puget Sound Hydro, LLC	Puget Sound Energy	4
North Fork	Portland General Electric	Portland General Electric	27
North Gooding Main Hydro		Idaho Power	1
Noxon Rapids	Avista Corp.	Avista Corp.	466
Oak Grove	Portland General Electric	Portland General Electric	27
Owyhee Dam Cspp	PURPA	Idaho Power	5
Oxbow	Idaho Power Company	Idaho Power	190
Packwood	Energy Northwest	Multiple Utilities	28
Palisades	US Bureau of Reclamation	Federal System (BPA)	177
PEC Headworks	SEQCBID	Avista	7
Pelton	Portland General Electric	Multiple Utilities	110
Pelton Reregulation	Warm Springs Tribe	Portland General Electric	10
Pigeon Cove	PURPA	Idaho Power	2
Port Townsend Mill 2	PortTownsend Paper	Other Publics (BPA)	0.4
Portland Hydro-Project	City of Portland	Portland General Electric	36
Post Falls	Avista Corp.	Avista Corp.	15
Potholes East Canal 66 Headworks	SEQCBID	Seattle City Light	2
Priest Rapids	Grant County PUD	Multiple Utilities	956
Pristine Springs #1	PURPA	Idaho Power	0.1
Pristine Springs #3	PURPA	Idaho Power	0.2
Prospect 1		PacifiCorp	5
Prospect 2		PacifiCorp	36
Prospect 3		PacifiCorp	8
Prospect 4		PacifiCorp	1
QF- CA		PacifiCorp	9
QF- OR		PacifiCorp	40
QF- WA		PacifiCorp	3
Quincy Chute	SEQCBID	Multiple Utilities	9
R.D. Smith	SEQCBID	Multiple Utilities	6
Rainbow	NorthWestern Energy	NorthWestern Energy	64
Reynolds Irrigation	PURPA	Idaho Power	0.3
River Mill	Portland General Electric	Portland General Electric	15
Rock Creek #1	PURPA	Idaho Power	2
Rock Creek #2	PURPA	Idaho Power	2
Rock Island	Chelan County PUD	Multiple Utilities	629
Rocky Reach	Chelan County PUD	Multiple Utilities	1300
Ross	Seattle City Light	Seattle City Light	450
Round Butte	Portland General Electric	Multiple Utilities	338
Roza	US Bureau of Reclamation	Federal System (BPA)	13
Ryan	NorthWestern Energy	NorthWestern Energy	72
Sagebrush	PURPA	Idaho Power	0.4
Sahko	PURPA	Idaho Power	1
Schaffner	PURPA	Idaho Power	1

Project	Owner	NW Utility	Nameplate (MW)
Sheep Creek	Glen Phillips	Avista Corp.	2
Shingle Creek	PURPA	Idaho Power	0.2
Shoshone #2	PURPA	Idaho Power	1
Shoshone CSPP	PURPA	Idaho Power	0.4
Shoshone Falls	Idaho Power	Idaho Power	14
Skookumchuck	-	Puget Sound Energy	1
Slide Creek	PacifiCorp	PacifiCorp	18
Smith Creek	Smith Creek Hydro, LLC	Eugene Water & Electric Board	0.1
Snake River Pottery	PURPA	Idaho Power	0.1
Snedigar Ranch	PURPA	Idaho Power	1
Snoqualmie Falls	Puget Sound Energy	Puget Sound Energy	54
Soda Springs	PacifiCorp	PacifiCorp	12
South Fork Tolt	Seattle City Light	Seattle City Light	17
Spokane Upriver	City of Spokane	Avista Corp.	16
Stone Creek	Eugene Water & Electric Board	Eugene Water & Electric Board	12
Strawberry Creek Wyoming 1	Lower Valley Energy	Other Publics (BPA)	2
Summer Falls	SEQCBID	Multiple Utilities	92
Swan Falls	Idaho Power	Idaho Power	25
Swift 1	PacifiCorp	Multiple Utilities	219
Swift 2	Cowlitz County PUD	Multiple Utilities	77
Sygitowicz	Cascade Clean Energy	Puget Sound Energy	0.4
The Dalles	US Corps of Engineers	Federal System (BPA)	1807
The Dalles North Fishway	Northern Wasco County PUD	Other Publics (BPA)	5
Thompson Falls Dam	Northwestern Energy	Northwestern Energy	94
Thousand Springs	Idaho Power	Idaho Power	9
Toketee	PacifiCorp	PacifiCorp	45
Trail Bridge	Eugene Water & Electric Board	Eugene Water & Electric Board	10
Trout Co	PURPA	Idaho Power	0.2
Tunnel #1	PURPA	Idaho Power	7
Turnbull Hydro		NorthWestern Energy	13
TW Sullivan	Portland General Electric	Portland General Electric	15
Twin Falls	PURPA	Puget Sound Energy	53
Twin Falls	PURPA	Puget Sound Energy	20
Upper Baker	Puget Sound Energy	Puget Sound Energy	105
Upper Falls	Avista Corp.	Avista Corp.	10
Upper Malad	Idaho Power	Idaho Power	8
Upper Salmon A	Idaho Power	Idaho Power	18
Upper Salmon B	Idaho Power	Idaho Power	17
Upper Swift Creek	Lower Valley Energy	Other Publics (BPA)	1
Walla Walla 1	Columbia REA	Other Publics (BPA)	2
Wallowa Falls	PacifiCorp	PacifiCorp	1
Walterville	Eugene Water & Electric Board	Eugene Water & Electric Board	8
Wanapum	Grant County PUD	Multiple Utilities	934
Weeks Falls	So. Fork II Assoc. LP	Puget Sound Energy	5
Wells	Douglas County PUD	Multiple Utilities	774
White Water Ranch	PURPA	Idaho Power	0.2
Whitefish Hydro		Ftathead Electric Cooperative	0.2
Wilson Lake		Other Publics (BPA)	8
Woods Creek	Snohomish County PUD	Snohomish County PUD	1
Wynoochee	Tacoma Power	Tacoma Power	13
Yakama Drop 2	Yakama Power		3
Yakama Drop 3	Yakama Power		2

Project	Owner	NW Utility	Nameplate (MW)
Yale	PacifiCorp	PacifiCorp	164
Yelm 1		Other Publics (BPA)	12
Youngs Creek	Snohomish County PUD	Snohomish County PUD	8
COAL			**2,792**
Colstrip #3	Talen Energy/Multiple Utilities	Multiple Utilities	740
Colstrip #4	Talen Energy/Multiple Utilities	Multiple Utilities	740
Jim Bridger #3	PacifiCorp / Idaho Power	Multiple Utilities	521
Jim Bridger #4	PacifiCorp / Idaho Power	Multiple Utilities	524
Valmy #2	NV Energy / Idaho Power	Multiple Utilities	267
NUCLEAR			**1,230**
Columbia Generating Station	Energy Northwest	Federal System (BPA)	1,230
NATURAL GAS			**8,315**
Basin Creek	NorthWestern Energy	NorthWestern Energy	52
Beaver	Portland General Electric	Portland General Electric	509
Bennett Mountain	Idaho Power	Idaho Power	179
Boulder Park	Avista Corp.	Avista Corp.	25
Carty	Portland General Electric	Portland General Electric	437
Chehalis Generating Facility	PacifiCorp	PacifiCorp	491
Coyote Springs I	Portland General Electric	Portland General Electric	252
Coyote Springs II	Avista Corp.	Avista Corp.	287
Danskin	Idaho Power	Idaho Power	90
Danskin 1	Idaho Power	Idaho Power	179
Dave Gates Generating Station	NorthWestern Energy	NorthWestern Energy	150
Encogen	Puget Sound Energy	Puget Sound Energy	166
Ferndale	Puget Sound Energy	Puget Sound Energy	244
Frederickson Generation Station	EPCOR Power L.P./PSE	Multiple Utilities	258
Fredonia 1 & 2	Puget Sound Energy	Puget Sound Energy	234
Fredonia 3 & 4	Puget Sound Energy	Puget Sound Energy	108
Fredrickson 1 & 2	Puget Sound Energy	Puget Sound Energy	149
Goldendale Generating Station	Puget Sound Energy	Puget Sound Energy	280
Hermiston Generating Project	PacifiCorp/Hermiston Generating Co.	PacifiCorp	468
Jim Bridger #1	PacifiCorp / Idaho Power	Multiple Utilities	528
Jim Bridger #2	PacifiCorp / Idaho Power	Multiple Utilities	536
Kettle Falls CT	Avista Corp.	Avista Corp.	7
Lancaster Power Project	Avista Corp.	Avista Corp.	270
Langley Gulch	Idaho Power	Idaho Power	321
Mint Farm Energy Center	Puget Sound Energy	Puget Sound Energy	276
Northeast A&B	Avista Corp.	Avista Corp.	62
Port Westward	Portland General Electric	Portland General Electric	411
Port Westward Unit 2	Portland General Electric	Portland General Electric	225
Rathdrum 1 & 2	Avista Corp.	Avista Corp.	167
River Road Generating Project	Clark Public Utilities	Clark Public Utilities	248
Sumas Energy	Puget Sound Energy	Puget Sound Energy	129
Valmy #1	NV Energy / Idaho Power	Multiple Utilities	254
Whitehorn #2 & 3	Puget Sound Energy	Puget Sound Energy	149

Project	Owner	NW Utility	Nameplate (MW)
Yellowstone County Generating Station	NorthWestern Energy	NorthWestern Energy	175
COGENERATION			**55**
Hampton Lumber	Hampton Lumber Mills	Snohomish County PUD PPA	5
International Paper Energy Center	Eugene Water & Electric Board	Eugene Water & Electric Board	26
Port Townsend Mill	Port Townsend Paper	BPA (other publics)	8
Simplot-Pocatello	PURPA	Idaho Power	12
Tasco-Nampa	Tasco	Idaho Power	2
Tasco-Twin Falls	Tasco	Idaho Power	3
RENEWABLES-OTHER			**401**
Bannock County Landfill	PURPA	Idaho Power	3
Bettencourt Dry Creek	PURPA	Idaho Power	2
Biomass One	PacifiCorp	PacifiCorp	25
Bloks Evergreen Dairy	Puget Sound Energy	Puget Sound Energy	0.2
DR Johnson Lumber	PacifiCorp	PacifiCorp	8
Columbia Ridge Landfill	Waste Management	Seattle City Light	13
Dry Creek Landfill	Dry Creek Landfill Inc.	PacifiCorp	3
Emerald City I		Puget Sound Energy	5
Emerald City II		Puget Sound Energy	5
Fighting Creek	PURPA	Idaho Power	3
Flathead County Landfill	Flathead Electric Cooperative	Flathead Electric Cooperative	2
Hidden Hollow Landfill	PURPA	Idaho Power	3
H. W. Hill Landfill	Allied Waste Companies	Multiple Utilities	37
Interfor Pacific-Gilchrist	Midstate Electric Co-op	Midstate Electric Co-op	2
Kettle Falls	Avista Corp.	Avista Corp.	51
Neal Hot Springs	U.S Geothermal	Idaho Power	33
Pico Energy, LLC	PURPA	Idaho Power	2
Pine Products	PacifiCorp	PacifiCorp	6
Plum Creek NLSL	Plum Creek MDF	Flathead Electric Cooperative	6
Pocatello Wastewater	PURPA	Idaho Power	0.5
Port of Tillamook Digester		Tillamook PUD	1
PGE non solar QFs		Portland General Electric	73
Qualco Dairy Digester		Snohomish PUD	0.7
Raft River 1	US Geothermal	Idaho Power	16
River Bend Landfill	McMinnville Water & Light	McMinnville Water & Light	5
Rock Creek Dairy	PURPA	Idaho Power	3
Seneca	Seneca Sustainable Energy, LLC	Eugene Water & Electric Board	20
Short Mountain		Emerald PUD	3
Sierra Pacific		Grays Harbor	16
SPI Biomass		Puget Sound Energy	17
Spokane Waste Energy	City of Spokane	Avista Corp.	26
Stimson Lumber	Stimson Lumber	Avista	7
Stoltze Biomass	F.H. Stoltze Land & Lumber	Flathead Electric Cooperative	3
Tamarack	PURPA	Idaho Power	5
SOLAR			**2,073**
7 Mile Solar, LLC	Community Solar OR Sch 126	PacifiCorp	1
Adams Solar Center		PacifiCorp	10
American Falls Solar	PURPA	Idaho Power	20

Project	Owner	NW Utility	Nameplate (MW)
American Falls Solar II	PURPA	Idaho Power	20
Antelope Creek Solar, LLC	Community Solar OR Sch 126	PacifiCorp	2
Ashland Solar Project		BPA	0.1
Baker Solar	PURPA	Idaho Power	15
Bear Creek		PacifiCorp	10
Bellevue Solar	EDF Renewable Energy	Portland General Electric	1
Black Cap		PacifiCorp	2
Black Cap II		PacifiCorp	8
Black Eagle Solar		NorthWestern Energy	3
Bly Solar Center		PacifiCorp	8
Brush Solar	PURPA	Idaho Power	3
Buckaroo Solar 1, LLC	Community Solar OR Sch 126	PacifiCorp	2
Buckaroo Solar 2, LLC	Community Solar OR Sch 126	PacifiCorp	3
Captain Jack Solar		PacifiCorp	3
CC Solar 1		PSE	0.01
CC Solar 2		PSE	0.01
Cleanera Apex I		NorthWestern Energy	80
OSLH Collier	Portland General	PacifiCorp	10
Daybreak Solar	Portland General	Portland General Electric	138
Durkee Solar	PURPA	Idaho Power	3
Elbe		PacifiCorp	10
Finn Hill Solar (Lake Wash SD)		Puget Sound Energy	0.4
Franklin Solar		Idaho Power	100
Grand View Solar	PURPA	Idaho Power	80
Great Divide Solar		NorthWestern Energy	3
Green Meadows Solar		NorthWestern Energy	3
Green Solar LLC	Community Solar OR Sch 126	PacifiCorp	3
Grove Solar	PURPA	Idaho Power	6
Horn Rapids		Energy Northwest	3
Hyline Solar Center	PURPA	Idaho Power	9
ID Solar 1	Boise City Solar, LLC	Idaho Power	40
IKEA Solar		Puget Sound Energy	1
Ivory		PacifiCorp	10
Jackpot Solar	Jackpot Holdings, LLC	Idaho Power	120
King Estate Solar	Lane Co. Electric Cooperative	Lane Co. Electric Cooperative	0.2
Linkville Solar, LLC	Community Solar OR Sch 126	PacifiCorp	3
Lund Hill	Lane Co. Electric Cooperative	Puget Sound Energy	150
Magpie Solar		NorthWestern Energy	3
Merrill Solar LLC		PacifiCorp	10
Millican Solar Energy		PacifiCorp	59
Morgan Solar	PURPA	Idaho Power	3
Mountain Home Solar	PURPA	Idaho Power	20
Moyer-Tolles Solar	Umatilla Electric Cooperative	Umatilla Electric Cooperative	1
MTSun LLC		NorthWestern Energy	80
Murphy Flat Power	PURPA	Idaho Power	20
Neilson Solar		Avista	19
Norwest Projects		PacifiCorp	31
Old Mill		PacifiCorp	5
Open Range Solar Center	PURPA	Idaho Power	10
OR Solar projects		PacifiCorp	64
Orchard Knob Solar, LLC	Community Solar OR Sch 126	PacifiCorp	2

Project	Owner	NW Utility	Nameplate (MW)
Orchard Ranch Solar	PURPA	Idaho Power	20
Oregon Community Solar Program	Various	0	37
OSIP		PacifiCorp	9
Pachwáywit Solar		Portland General Electric	162
PGE Solar QF		Portland General Electric	403
Pine Grove Solar, LLC	Community Solar OR Sch 126	PacifiCorp	1
Prineville		PacifiCorp	39
PSE Small Solar (5 projects)		Puget Sound Energy	15
Railroad Solar Center	PURPA	Idaho Power	5
River Bend Solar		NorthWestern Energy	2
Round Lake Solar, LLC	Community Solar OR Sch 126	PacifiCorp	1
Simco Solar	PURPA	Idaho Power	20
Skysol Solar		PacifiCorp	54
Solarize Rogue LLC	Oregon Clean Power	PacifiCorp	0.1
South Mills Solar 1		NorthWestern Energy	3
Sunnyside Solar	OneEnergy Renewables	PacifiCorp	5
Sunset Ridge Solar, LLC	Community Solar OR Sch 126	PacifiCorp	2
Thunderegg Solar Center	PURPA	Idaho Power	10
Tumbleweed		PacifiCorp	10
Vale Air Solar	PURPA	Idaho Power	10
Vale I Solar	PURPA	Idaho Power	3
Wallowa County		PacifiCorp	0.4
Wheatridge Solar	Portland General/Nextera Energy	Portland General Electric	50
Wild Horse Solar Project	Puget Sound Energy	Puget Sound Energy	1
Yamhill Solar	EDF Renewable Energy	Portland General Electric	1
WIND			**6,211**
71 Ranch LP		NorthWestern Energy	3
Bennett Creek	PURPA	Idaho Power	21
Benson Creek Wind	PURPA	Idaho Power	10
Big Timber Wind		NorthWestern Energy	25
Biglow Canyon - 1	Portland General Electric	Portland General Electric	125
Biglow Canyon - 2	Portland General Electric	Portland General Electric	163
Biglow Canyon - 3	Portland General Electric	Portland General Electric	161
Burley Butte Wind Farm	PURPA	Idaho Power	21
Camp Reed Wind Park	PURPA	Idaho Power	23
Cassia Wind Farm	PURPA	Idaho Power	11
Chopin		PacifiCorp	10
Clearwater PSE	NextEra	Multiple Utilities	661
Coastal Energy Project	CCAP	Grays Harbor PUD	6
Cold Springs	PURPA	Idaho Power	23
Combine Hills I	Eurus Energy of America	Clark Public Utilities	41
Combine Hills II	Eurus Energy of America	Clark Public Utilities	63
Condon Wind	Allete	Seattle City Light	50
Cycle Horseshoe Bend Wind		NorthWestern Energy	9
DA Wind Investors		NorthWestern Energy	3
Desert Meadow Windfarm	PURPA	Idaho Power	23
Durbin Creek	PURPA	Idaho Power	10
Elkhorn Wind	Telocaset Wind Power Partners	Idaho Power	101
Fairfield Wind		NorthWestern Energy	10
Fossil Gulch Wind	PURPA	Idaho Power	11

Project	Owner	NW Utility	Nameplate (MW)
Golden Hills	Avangrid	Puget Sound Energy	200
Golden Valley Wind Farm	PURPA	Idaho Power	12
Goodnoe Hills	PacifiCorp	PacifiCorp	94
Gordon Butte Wind		NorthWestern Energy	10
Greenfield Wind		NorthWestern Energy	25
Hammett Hill Windfarm		Idaho Power	23
Harvest Wind	Summit Power	Multiple Utilities	99
Hay Canyon Wind	Hay Canyon Wind Project LLC (Iberdrola)	Snohomish County PUD	101
High Mesa Wind	PURPA	Idaho Power	40
Hopkins Ridge	Puget Sound Energy	Puget Sound Energy	157
Horseshoe Bend	PURPA	Idaho Power	9
Hot Springs Wind	Hot Springs Wind	Idaho Power	21
Jett Creek	PURPA	Idaho Power	10
Judith Gap	Invenergy Wind, LLC	NorthWestern Energy	135
Klondike II	PPM Energy	Portland General Electric	75
Klondike III	PPM Energy	Multiple Utilities	221
Leaning Juniper	PPM Energy	PacifiCorp	101
Lime Wind Energy	PURPA	Idaho Power	3
Lower Snake River 1	Puget Sound Energy	Puget Sound Energy	343
Mainline Wind Farm	PURPA	Idaho Power	23
Marengo	Renewable Energy America	PacifiCorp	140
Marengo II	PacifiCorp	PacifiCorp	70
Mariah Wind		PacifiCorp	10
Milner Dam Wind Farm	PURPA	Idaho Power	20
Musselshell Wind 1		NorthWestern Energy	10
Musselshell Wind 2		NorthWestern Energy	10
Nine Canyon	Energy Northwest	Multiple Utilities	96
Orchard Wind		PacifiCorp	40
Oregon Trails Wind Farm	PURPA	Idaho Power	14
Oregon Wind Farms I & II		PacifiCorp	65
Orem Family Wind		PacifiCorp	10
Oversight Resources		NorthWestern Energy	3
Palouse Wind	Palouse Wind, LLC	Avista Corp.	105
Paynes Ferry Wind Park	PURPA	Idaho Power	21
Pilgrim Stage Station Wind Farm	PURPA	Idaho Power	11
Prospector Wind	PURPA	Idaho Power	10
Rattlesnake Flat Wind		Avista Corp.	146
Rockland Wind	PURPA	Idaho Power	80
Ryegrass Windfarm	PURPA	Idaho Power	23
Salmon Falls Wind Farm	PURPA	Idaho Power	22
Sawtooth Wind	PURPA	Idaho Power	22
Skookumchuck	Puget Sound Energy	Puget Sound Energy	137
South Peak Wind		NorthWestern Energy	80
Spion Kop Wind		NorthWestern Energy	40
Stateline Wind	NextEra	Multiple Utilities	275
Stillwater Wind		NorthWestern Energy	80
Thousand Springs Wind Farm	PURPA	Idaho Power	12
Three Mile Canyon	Momentum RE	PacifiCorp	10
Tuana Gulch Wind Farm	PURPA	Idaho Power	11
Tuana Springs Expansion Wind	PURPA	Idaho Power	36

Project	Owner	NW Utility	Nameplate (MW)
Tucannon	Portland General Electric	Portland General Electric	267
Two Dot Wind		NorthWestern Energy	11
Two Ponds Windfarm	PURPA	Idaho Power	23
Vansycle Ridge	ESI Vansycle Partners	Portland General Electric	24
Vantage	Invenergy Wind NA, LLC	Puget Sound Energy	90
Wheat Field Wind Project	Wheat Field Wind LLC (Horizon Energy/EDP)	Snohomish County PUD	97
Wheatridge Wind Project	PGE/Nextera Energy	Portland General Electric	300
White Creek	White Creek Wind I LLC	Multiple Utilities	205
Wild Horse	Puget Sound Energy	Puget Sound Energy	273
Willow Spring Windfarm	PURPA	Idaho Power	10
Yahoo Creek Wind Park	PURPA	Idaho Power	21
SMALL THERMAL AND MISCELLANEOUS			**236**
Colstrip Energy LP Coal	Colstrip Energy Limited Partnership	Northwestern Energy	35
Crystal Mountain	Puget Sound Energy	Puget Sound Energy	3
PGE DSG	Various	Portland General Electric	135
Puget Sound Shipyard	U.S. Navy-Bangor	BPA/Other publics	12
Yellowstone Energy LP	NRF	Northwestern Energy	52
STORAGE			**618**
Constable	Portland General Electric	Portland General Electric	75
Hemingway Battery	Idaho Power	Idaho Power	80
IPC 2024 RFP Small Battery	Idaho Power	Idaho Power	36
Oregon Institute of Technology BESS	OIT	PacifiCorp	2
Seaside Battery	Portland General Electric	Portland General Electric	200
SnoPUD 25 MW Battery	Snohomish PUD	Snohomish PUD	25
Troutdale Battery	Portland General Electric	Portland General Electric	200
Total Generating Resources			**55,567**

Report Description

This report provides a regional firm needs estimate over the ten-year study period for annual energy (August through July, *Table 1*), monthly energy (*Table 2*), winter peak-hour (*Table* 3) and summer peak-hour (*Table 4*). The monthly energy picture is provided to underscore the variability of the power need within an average year. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

This information reflects the summation of individual utilities' load forecasts and generating resources expected to meet their load, as well as the total of utilities committed and planned resources to meet future needs and policy requirements. The larger utilities, in most cases, prepare their own projections for their integrated resource plans and planning studies. Bonneville Power Administration (BPA) provides much of the information for its smaller customers. This section includes procedures used in preparing the load resource comparisons, a list of definitions, and a list of the utilities summarized by this report (*Table 11*).

Load Estimate

Regional loads are the sum of demand estimated by the Northwest utilities and BPA for its federal agency customers and certain non-generating public utilities. Direct service industrial customers are no longer a significant part of regional load. Utilities are asked to provide their native load forecast. Load projections include network transmission and distribution losses and are net of existing and forecasted energy efficiency savings (including codes & standards). Demand response program savings are not reflected in loads, rather they are included on the supply side in this report. Since the *Forecast* is completed annually, utilities may provide load forecasts that are updated and out of sync with their last resource plan.

Energy Loads

Northwest firm energy loads are provided for each month of the ten-year forecast period. This forecast reflects normal (1-in-2) weather conditions.

Peak Loads

Northwest regional peak loads are provided for each month of the ten-year forecast period. The tabulated loads for winter and summer peak are the highest estimated hourly loads for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utilities' peak loads and does not account for a utility potentially experiencing a peak load at a different day/hour than other Northwest utilities. Hence the regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional peak requirements, a planning margin is included. The planning margin is set to 16 percent of the total peak load for every year of the planning horizon.[1]

This planning margin is intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance, and project construction delays.

Demand-Side Management Programs

Savings from demand-side management (*Table 7*) are for the ten-year study period and include data provided by utilities such as utility energy efficiency programs, some market transformation, and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response programs are also tallied on *Table 7* showing the programs' winter peak and summer peak contributions to need. The regional demand response data is from the cumulative sum of all utilities' agreements with their customers (for both existing and future programs). Each program has its own characteristics and limitations that are reflected in the data provided.

Generating Resources

This report catalogues existing resources, committed new supply (including resources under construction), and planned future resources. For the assessment of need, only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis. A list of all resources included in the report load/resource tabulations is in *Table 10*.

[1] When making comparisons to *Northwest Regional Forecasts* prior to 2018, be aware that the planning margin was previously set at 12 percent for the first year of the report and grew a percent a year until it reached 20 percent and remained at 20 percent thereafter. This escalation was in part to address uncertainty of planning for generating resources with long planning and construction lead times.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using computer models that simulate reservoir operation of past hydrologic conditions with today's operating constraints and requirements. The historical stream flow record used covers the 90-year period from August 1928 through July 2018. The bulk of the hydro modeling used in this report is provided by BPA, the US Army Corps of Engineers, and/or project owners/sponsors.

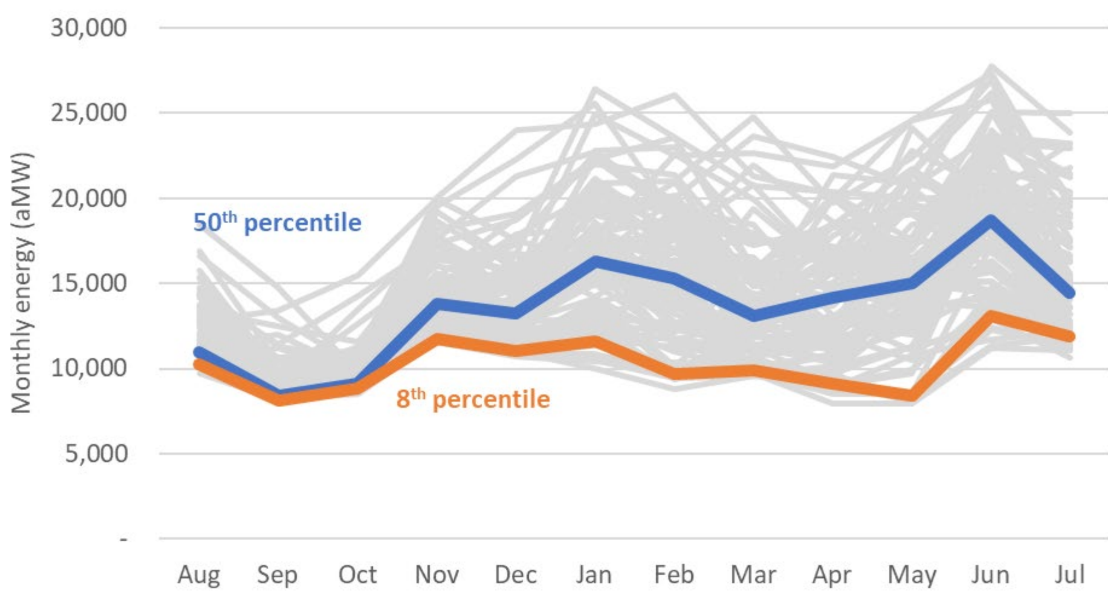
Annual and Monthly Energy

The bulk of the hydro energy data in this report comes from the US Army Corps of Engineers. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment. New this year, the firm energy capability of hydro plants is the amount of energy produced using the 8th percentile monthly energy production from the 90-year historical river flow given today's river operating criteria. This provides an updated view of the critically low value for planning. The firm annual energy capability is the average of the 8th percentile monthly generation for the 90-year period. This synthetic water year ensures each month and year are evaluated similarly and under critically low streamflow.

Variability of Hydro

The variability of hydro generation is due to the hydrology of the river systems in the Northwest. Monthly hydro energy generation estimates from the major developments in the coordinated hydro system are shown for each of the 90 different river flow conditions using current system operating criteria in Figure 10. For perspective, the 50th percentile and 8th percentile. The 8th percentile monthly energy difference is indistinguishable between the 80-year and 90-year historical river flows.

Figure 10. Monthly Hydro Generation Across 90-year historical record



Peak Capability

For this report the peak capability of the hydro system represents maximum sustained hourly generation available to meet peak demand during the period of heavy load. Hydro-project owners submit a sustained peak capability for each project.[2] The bulk of the peak data in this report come from BPA. BPA has updated its critical peak planning from 1936-37 to the 10th percentile from the most recent 30-year historical record for water conditions. This increased the Federal system winter hydropower peaking capability and slightly reduced summer peaking capability.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoirs and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis and makes up the bulk of the region's exports in this year's report.

Downstream Fish Migration

Another requirement incorporated in the hydro modeling are modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal and Renewable Resources

Thermal resources are reported in a variety of categories including coal, natural gas, nuclear and other. Other includes cogeneration, diesel and oil.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables include energy from biomass, geothermal, municipal solid waste projects, and other projects.

[2] Historically, a 50-hour sustained peak (10 hours/day for 5 days) was reported. Project owners/sponsors use a variety of peak capability metrics today.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy and peaking capabilities of plants are submitted by the projects' owners and take into consideration scheduled maintenance (including refueling), forced outages, and other expected operating constraints. Some small thermal plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy may be available from these peaking resources but is not included in the regional energy load/resource balance.

Battery Storage

In recent years battery storage resources have made their way into the region's resource mix, with a relatively large amount planned in the next 10 years. Battery storage is showing up as a standalone resource and in combination with solar and wind generation. It is reflected as supply during the peak hour of the month.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management actions, are tabulated in this report. These resources are reported as recently acquired, committed new supply, and planned future resources to reflect the different stages of development.

Recently Acquired Resources

The Recently Acquired Resources reported in *Table 5* have been acquired and will be serving Northwest utility loads as of December 31, 2023. They are reflected as part of the regional firm needs assessment.

Committed New Supply

Committed New Supply reported in *Table 6* includes projects under construction or firmly committed to meet Northwest load that are not delivering power as of December 31, 2023. These resources are included in the regional load-resource analysis. Future energy efficiency and demand response programs are included in the load-resource analysis as well (see *Table 7*).

Planned Future Resources

Planned Future Resources presented in *Table 8* includes specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans and planning studies. Projects in *Planned Future Resources* are not yet under construction, are not part of the regional analysis, and are subject to change until the time for acquiring them is closer. As the resource build date nears, more information about these resources will likely become available, and they typically move into the *Committed New Supply* category prior to coming online. Often, the utility will undergo a request for proposal process before moving a resource from *Planned* to *Committed.* Resources in this category are *referred to as Potential Resources* in some previous *Northwest Regional Forecasts*.

Contracts

Imports and exports include firm arrangements for trade with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, in California and Canada. Contracts to and from these areas are amounts delivered at the area border and include transmission losses associated with deliveries.

Long-term intraregional contracts between Northwest utilities net to zero in the regional picture and consequently are not tallied for this report. In addition, short-term and/or spot purchases from Northwest independent power producers and from out-of-region are not reflected in the tables that present the firm load resource comparisons in this report.

Non-Firm Resources

The *Northwest Regional Forecast* omits from the load/resource balance non-firm power supply that may be available to utilities to meet needs. These non-firm sources include generation from uncommitted Northwest independent power producers (IPPs), imports from power plants located outside the region, uncommitted hydro generation owned by Northwest utilities, and hydro generation likely available when water supply is greater than the assumed critical levels. Power from these resources may be available to the Northwest from the market, during high need hours, or it may have been already sold to a higher bidder outside the Northwest.

Non-firm imports depend on several factors including availability of out-of-region resources, availability of transmission, and market friction. The trend of large thermal resource retirements in the Western Interconnection could impact power available for import into the Northwest in the coming years. Looking at hydropower, the *Forecast* assumes low water (8%) during peak hours for the monthly peak calculations. Most months the water supply for the hydro system is not at critical levels. During a median water month, the region will have more water available for energy and peak needs.

Climate Change

More utilities and organizations are incorporating the impacts of a changing climate into their long-range planning. Two areas where climate change may impact utility planning is the influence of temperatures on loads and water supply for hydrogeneration. As more utilities account for changing temperature trends in their forecasting models the impact on utility loads becomes incorporated into the *Northwest Regional Forecast*. Increasing temperatures in the summer can result in higher summer load (due to air conditioning, for example) and moderately warmer temperatures in the winter can reduce winter load (reduced need for heating loads), on average across the region. The differences in geography for utilities across the Northwest means individual utilities can have varying degrees of climate change effects.

The *2024 Forecast* does not explicitly include the impact of climate change on hydroelectric generation. It is only included to the extent that it is included in a hydro-project owner/sponsor's submittal of its peak capability for the project. The report's hydroelectric data for the bulk of the hydro data rely on the historical river flows.

Table 11. Utilities Included in the Northwest Regional Forecast

Albion, City of
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec. Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

Definitions

Annual Energy

Energy value in megawatts that represents the average output over the period of one year. Expressed in average megawatts.

Average Megawatts

(aMW) Unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period.

Batteries

Batteries are some of the newest technologies being added to the regional picture. See storage definition.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal Resource

This category of generating resources includes the region's coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

These projects are under construction and/or committed resources and supply confirmed to meet Northwest load, but not delivering power as of December 31, 2023.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Direct Service Industries (DSI)

Large electricity-intensive industries such as aluminum smelters and metals-reduction plants that purchase power directly from the Bonneville Power Administration for their own use. Very few of these customers exist in the region today.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Emerging Technologies

A term used to describe future resource technologies such as advanced nuclear, offshore wind, renewable hydrogen, and long-duration storage.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

Historical Streamflow Record

A database of unregulated streamflows for 90 years (August 1928 to July 2018). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) and non-qualified facilities of independent power producers.

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2024 is August 1, 2024 through July 31, 2025.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration as referred to in Table 10.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planned Future Resources

These resources include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans and planning studies. These projects are not yet under construction, are not part of the regional analysis, and are in some ways speculative.

Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties. In the 2018 *Forecast* the planning margin changed to a flat 16% of the regional load for each year of the study. Earlier reports included a growing planning margin that started at 12% of load, increasing 1% per year until it reached 20%.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

Requirements

Include for each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems but does not include distributed solar generation.

Storage

Storage resources (i.e., batteries, pumped hydro, liquid air) store energy for release at a later time. They can help shift energy from low value to high value hours. Due to efficiency losses, they are a net consumer of energy. They are usually defined by their maximum discharge rate in MW, and their total storage capacity in MWh.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Wind Resources

This category of resources includes the region's utility-scale wind powered projects.

Western Energy Imbalance Market (WEIM)

A real-time energy market launched in 2014, operated by the California Independent System Operator.

Western Resource Adequacy Program (WRAP)

A regional reliability and compliance program in the West. It delivers a region-wide approach for assessing and addressing resource adequacy.