20 YEAR
TRANSMISSION OUTLOOK

California ISO

May 2022

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Appendices

Executive Summary

California is facing an unprecedented need for new renewable resources over the next 10 to 20 years. This heightened requirement is being 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 renewable energy and zero-carbon resources supply 100 percent of electric retail sales to end-use customers by 2045. This 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. The transmission needs will range from high-voltage lines that traverse significant distances to access out-of-state resources, as well as major generation pockets, including offshore wind and geothermal resources located inside the state. Given the lead times needed for these facilities primarily due to right-of-way acquisition and environmental permitting requirements, the ISO has found that a longer-term blueprint is essential to chart the transmission planning horizon beyond the conventional 10-year timeframe that has been used in the past.

The ISO embarked on creating this 20-Year Transmission Outlook for the grid in collaboration with the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) with the goal of exploring the longer-term grid requirements and options for meeting the State's greenhouse gas reduction and renewable energy objectives reliably and cost-effectively.

We also intend for this expanded planning horizon to provide valuable input for resource planning processes conducted by the CPUC and CEC, and to provide a longer-term context and framing of pertinent issues in the ISO's ongoing annual 10-Year Transmission Plan.

To achieve this, the objective of the 20-Year Transmission Outlook is 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. In particular, it was critical that the resource planning was developed through a transparent process, taking into account the best currently available information, including potential transmission costs, in establishing a baseline resource profile.

This 20-Year Outlook for transmission planning therefore focused on meeting the needs identified through the CEC's SB100-related processes for achieving the state's 2045 objectives. The CEC, CPUC, and the ISO, in fact, collaborated on an approach to translate the analyses conducted for the first SB 100 joint-agency report into a Starting Point scenario for use by the ISO in this 20-year outlook[1]. The ISO started with the SB100 Core statewide high electrification load projection, in which the 2040 peak load is 82,364 megawatts (MW). This is an 18,288 MW, or 28.5 percent increase from the CEC's Integrated Energy Policy Report (IEPR) 2020 load forecast of 64,076 MW in 2031[2]. The ISO footprint's share of the forecast load is 73,909 MW.

[1] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-SIT-01

[2] The load forecast scenario is the CEC's "Mid 1-in-2 forecast"

The load to be served by the system was then again lowered by the forecast of behind-the-meter resources.

The Starting Point then identified the resource development that could meet these needs as well as a projected reduction of 15,000 MW of natural gas-fired generation 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 Starting Point called for 37 GW of battery energy storage, 4 GW of long-duration storage, over 53 GW of utility scale solar, over 2 GW of geothermal, and over 24 GW of wind generation – the latter split between out-of-state and in-state resources. The bulk of the in-state resources consist of offshore wind. These total 120.8 GW

The ISO identified the system needs by mapping resources to the appropriate regions, identifying the transmission additions necessary to add those resources to the grid, and then examining the need to deliver those resources over the bulk transmission system.

The resulting transmission plan calls for significant 500 kV AC and HVDC development to access offshore wind and out-of-state wind, and reinforce the existing ISO footprint. Figure ES-1 provides an illustrative diagram of the transmission development required to integrate the resources of the SB100 Starting Point scenario and high electrification load projection by 2040.

Figure ES-1: Illustrative Diagram of Transmission Development

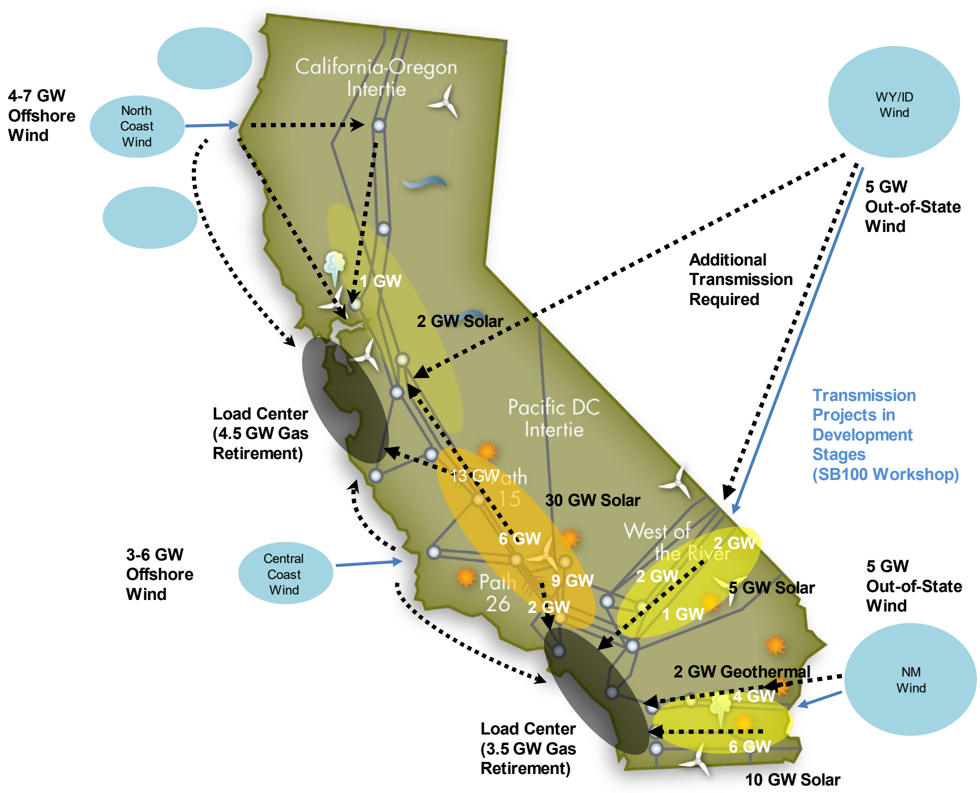

Table ES-1: provides the high-level summary of the transmission development required for upgrades to the existing ISO footprint, offshore wind integration and out-of-state wind integration.

Table ES-1: Cost estimate of transmission development to integrate resources of SB100 Starting Point 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	$ 10.74 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$ 8.11 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$ 11.65 B
Total estimated cost of transmission development[3]	**$ 30.5 B**

This analysis focuses on the high-voltage bulk transmission, recognizing that local transmission needs and generation interconnections will ultimately need to be addressed as well.

Despite being developed over 20 years, and the costs amortized over the physical life of the transmission, the transmission additions are significant investments. The ISO recognizes and appreciates concerns regarding the ratepayer impacts of the capital projects identified in the 20-Year Outlook. 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, and the ISO will be working with state agencies and stakeholders to refine these options to develop the most overall cost-effective solutions to meet California's

> In response to stakeholder comments, the impact of all the transmission costs identified in this 20-Year Outlook were translated into an annualized cost impact assuming the projects to be phased in between 2030 and 2040. Using the economic parameters employed by the ISO in its annual transmission planning process, these costs translate to approximately 1.5 cents per kWh, phased in between 2030 and 2040. This impact 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.

[3] 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.

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 will be paid by participants outside California, so the costs would not all be borne by California ratepayers.

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

The ISO also expects to conduct additional stakeholder dialogue through 2022 about next steps as well as the long-term architecture set out in this 20-Year Outlook. Stakeholder feedback on the draft 20-Year Outlook shared in January was overwhelmingly supportive of the 20-Year Outlook effort, and focused on how the ISO may move to initiate the transmission development it set out – or particular developments of specific interest to the individual commenters. A number of stakeholders requested analysis and detail that was 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, and the ISO appreciates the efforts of both organizations in supporting the development of this document.

Chapter 1

1 Introduction

1.1 Purpose

The 20-Year Transmission Outlook 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 10-Year Transmission Plan

The ISO launched the effort to develop a 20-Year Outlook for the ISO grid in parallel with the 2021-2022 transmission planning cycle to provide a less structured framework for open discussion outside of the tariff-based 10-Year Transmission Plan that focuses on transmission project needs and approvals over the 10-year planning horizon. The 20-Year Outlook is not a tariff-based project approval process that focuses on project approvals. Instead, it is meant to engage with stakeholders in more informal yet meaningful discussion.

A number of current circumstances call for this effort to be launched at the present time. Resource requirements to meet state policy goals and reliability needs are climbing sharply over the next 10 years from the pace established over the last five years, and the pace will escalate again for the following decade. This acceleration will stress all aspects of the resource planning, procurement, engineering, supply chain and construction. It will also accelerate the need for new transmission approvals, permitting and construction.

The 20-Year Outlook provides a baseline to establish expectations for longer-term planning, recognizing that resource planning decisions and procurement decisions will differ over the years ahead from the assumptions used to establish this baseline. 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[4] and 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[5]. 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 350 responsibilities. The ISO turned to the two state agencies for input to support the development of the 20-Year Outlook.

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 meet FERC Order No. 1000 provisions, the challenges placed on the electricity system – and correspondingly on the transmission system - have evolved and grown. While these challenges appeared significant in the past and at the time, the ISO considers that the industry is at an inflection point marking a significant increase in the rate of growth in renewable resources and renewable integration resources. Last year's transmission plan was based on state agency-provided forecasts calling for approximately 1,000 MW of additions per year over the next 10 years. This year's plan is based on a 10-year projection adding 2,700 MW per year, and current drafts being proposed for next year's plan call for over 4,000 MW per year[6]. This latter value represents a fourfold increase in annual requirements from the 2020-2021 Transmission Plan approved in March, 2021. The 2021-2022 transmission plan will

[4] SB 350, The Clean Energy and Pollution Reduction Act of 2015 (Chapter 547, Statutes of 2015) was signed into law by Governor Jerry Brown on October 7, 2015. Among other provisions, the law established clean energy, clean air, and greenhouse gas (GHG) reduction goals, including reducing GHG to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050. The law also established targets to increase retail sales of qualified renewable electricity to at least 50 percent by 2030 that have now been superseded by the provisions of Senate Bill (SB) 100.

[5] SB 100, the 100 Percent Clean Energy Act of 2018, also authored by Senator Kevin De León, was signed into law by Governor Jerry Brown on September 10, 2018. Among other provisions, SB 100 built on existing legislation, including SB 350, and revised the previously established goals to achieve the 50 percent renewable resources target by December 31, 2026, and to achieve a 60 percent target by December 31, 2030. The bill also set out the state policy that eligible renewable energy resources and zero-carbon resources supply 100 percent of retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100

[6] Page 11, Day 2 Presentation, September 27-28, 2021 Stakeholder Meeting, http://www.caiso.com/InitiativeDocuments/Day2Presentation-2021-2022TransmissionPlanningProcessSep27-28-2021.pdf

provide a transitional step recognizing the ISO and industry at-large are not yet positioned inside the current planning cycle to address the full impact of this pivot to the new challenges.

The accelerating resource requirements over the next 10 years 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 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 its June 24, 2021 decision than last year's 10-year plan was based on, and which 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 interconnections requests in April, 2021, with 373 new interconnection requests being received in the ISO's Cluster 14 open window, layered on top of an already heavily populated interconnection queue.[7] 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 commandeers precious 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 in the coordination of state agency resource planning processes as well as the ISO's resource interconnection process, and in the overall coordination of the procurement and construction of new resources and related transmission network upgrades.

Transmission Planning:

In addition to the incremental improvements the ISO makes in each year's transmission planning cycles, the ISO has re-examined the effectiveness of certain planning processes both due to emerging concerns in our own footprint, and also in response to the recent FERC Advance Notice of Proposed Rulemaking (ANOPR) regarding transmission planning, cost allocation and generator interconnection.

[7] 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

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 ANOPR. That being said, the ISO has 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. Accordingly, 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 this 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.

The ISO also acknowledged that the interregional coordination process has not met expectations 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 explore potential interregional opportunities in addition to meeting all expectations, responsibilities and obligations associated with the ISO interregional coordination tariff provisions related to FERC Order No.1000. The ISO also intends to continue to participate in the ANOPR process and seek broader reforms within that process as well.

Resource Interconnection:

Consistent with the ISO comments responding to the ANOPR, the ISO has initiated a 2021 Interconnection Process Enhancement (IPE) initiative focused on the interconnection process and enhancements specifically, and other tracks of process improvement will proceed through other efforts. Accordingly, the 2021 IPE initiative is discussing and addressing interconnection-related issues the ISO and stakeholders have identified given current circumstances, and seeks to resolve concerns that have surfaced since the last IPE initiative in 2018.[9] The ISO seeks to consider potential changes to address the rapidly accelerating pace of new resources needing connection to the grid to meet system reliability needs and exponentially increasing levels of competition among developers resulting in excessive levels of new interconnection requests being received.

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 GO-Biz office to identify and help mitigate issues that could delay new resources meeting in-service dates
- Together with the CPUC, working with the participating transmission owners to improve the transparency of the status of transmission projects focusing on network upgrades

[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

[9] For more information on the 2018 IPE initiative please refer to the initiative webpage at: California ISO - Interconnection process enhancements (caiso.com).

approved in prior ISO transmission plans, or that resources with executed interconnection agreements are dependent on

- Providing 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, and
- Coordinating 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.

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

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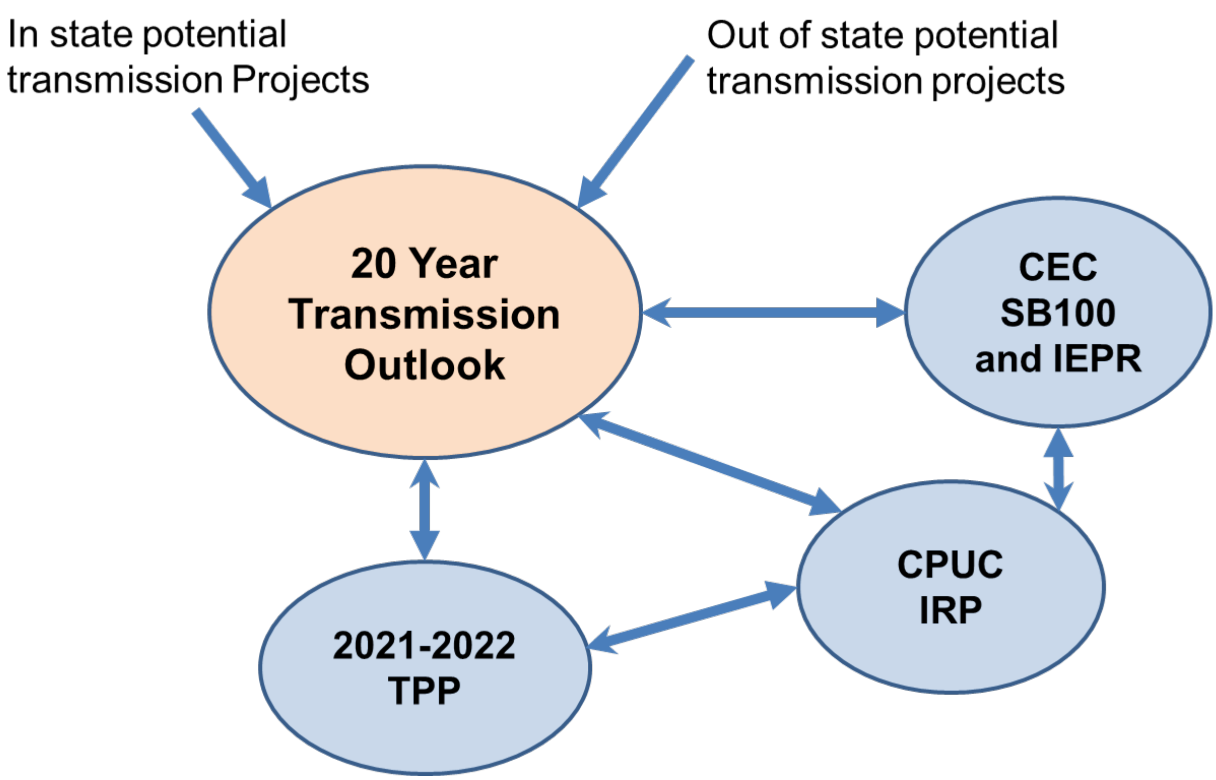
Chapter 2

2 Coordination with State Agencies

The development of the 20-Year Transmission Outlook has been coordinated with the 2021-2022 transmission planning process along with the initiatives of the California Energy Commission and the California Public Utilities Commissions. These have included ISO stakeholder calls and joint agency workshops as a part of the SB100 process.

Figure 1.3-1: 20-Year Transmission Outlook coordination with other initiatives and agencies



On September 13, 2021 the California Energy Commission docketed the SB100 Starting Point for the ISO 20-Year Transmission Outlook.

2.1 SB100 Workshops

The ISO has coordinated with the joint agencies on the next steps to plan for the SB100-driven resource build that has been used as inputs to the 20-Year Transmission Outlook. These steps have included workshops on potential transmission projects and resource mapping.[10] The ISO actively participated in the following joint agency workshops:

[10] https://www.energy.ca.gov/sb100/sb-100-events-and-documents

- June 2, 2021 Joint agency workshop on next steps to plan for SB 100 resource build
- July 22, 2021 Joint agency workshop on next steps to plan for SB 100 resource build – Transmission
- August 12, 2021 Joint agency workshop on next steps to plan for SB 100 resource build – Resource Mapping

2.1.1 Joint agency workshop on next steps to plan for SB 100 resource build – Transmission[11][12]

The ISO participated in the CEC joint agency workshop on July 22, 2021 with the focus on transmission currently under various stages of development that should be considered to facilitate the integration of the resource by 2040. Workshop presentations were made on the following transmission projects by the project developers,[13] with the projects being presented primarily to facilitate the integration of out-of-state wind into the ISO system:

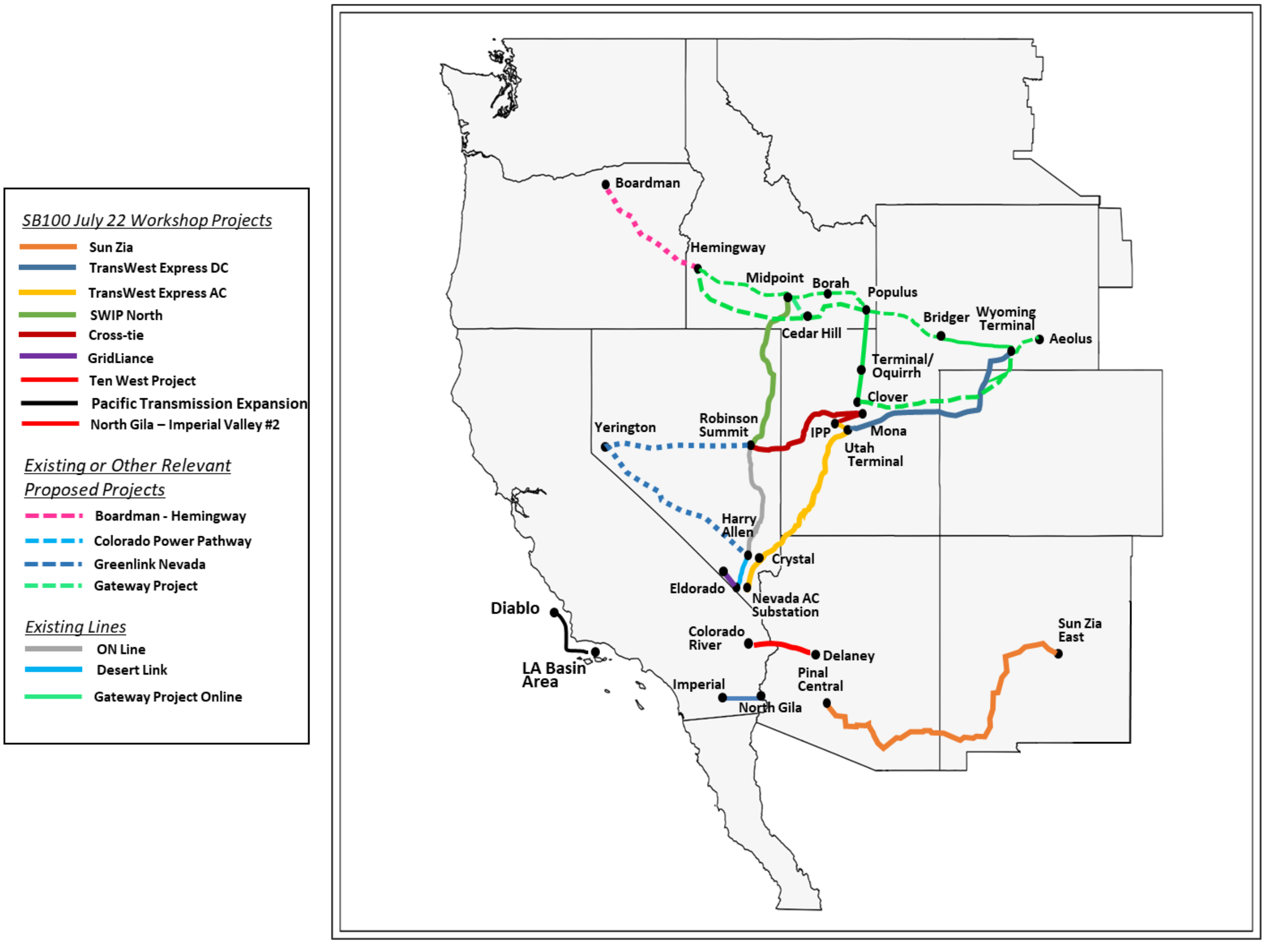
- Pacific Transmission Expansion Project
- North Gila Imperial Valley #2 Transmission Project
- TransWest Express Transmission Project
- Southwest Intertie Project (SWIP) North
- Cross Tie Project
- Sunzia Southwest Transmission Project
- Starwood Energy – Ten West
- Southline Transmission
- Lucky Corridor Transmission Project
- GridLiance West

[11] https://www.energy.ca.gov/event/workshop/2021-07/session-1-joint-agency-workshop-next-steps-plan-senate-bill-100-resource

[12] https://www.energy.ca.gov/event/workshop/2021-07/session-2-joint-agency-workshop-next-steps-plan-senate-bill-100-resource

[13] https://www.energy.ca.gov/sites/default/files/2021-07/July%2022%20Workshop%20SB%20100%20Transmission_Master%20v4.pdf

Figure 2.1-1: Illustration of potential transmission projects identified at CEC SB100 workshop



2.1.2 Joint agency workshop on next steps to plan for SB 100 resource build – Resource Mapping[14]

The CEC jointly conducted a workshop with the CPUC and the ISO to discuss an approach to examine potential environmental and land-use implications of developing renewable energy resources required to achieve the goals of Senate Bill 100 (SB 100).

The purpose of the workshop was to present and solicit stakeholder feedback on the methods and data to be used for developing the resource mapping of the Starting Point scenario to be provided to the ISO for use in the 20-Year Transmission Outlook, taking into consideration environmental and land-use data.

[14] https://www.energy.ca.gov/event/workshop/2021-08/joint-agency-workshop-next-steps-plan-senate-bill-100-resource-build

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Chapter 3

3 Process and Inputs

The objective of the ISO's I20-Year Transmission Outlook is to explore longer-term grid requirements and options for meeting the state's greenhouse gas reduction goals reliably. The 20-Year Transmission Outlook will provide a "baseline" vision for future planning activities. To achieve this, the ISO:

- Used a "Starting Point" 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, and geothermal resources; and,
  - Gas power plant retirements that may require transmission development to reduce local area constraints.
- 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 will help scope the challenges the electricity industry faces in meeting California's aggressive climate policies, allow the state to further refine long-term resource planning inputs, and provide longer-term context for decisions made in the ISO's 10-year transmission planning process.

The high-level analysis to determine feasible transmission alternatives considered load scaled to high electrification levels and bulk system power flow assessment case development of a range of load periods.

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

3.1 Key Inputs

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

SB 100 requires the CEC, CPUC, and California Air Resources Board (CARB) to develop and submit a joint-agency report 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 translate the analyses conducted for the first SB 100 joint-agency report into a Starting Point scenario for use by the ISO in the 20-Year Outlook[15]. The Starting Point scenario, and the criteria for using that scenario to study the transmission required for a particular portfolio of resources studied in the 2021 SB 100 Report, are described below. This initial portfolio is not an endorsement of any

[15] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-SIT-01

particular resource or potential transmission solution. The CEC and CPUC expect that the information from the 20-Yar Outlook will help inform future electric sector planning, including the next SB 100 joint-agency report.

3.1.1 Load Forecasting and Distributed Energy Resources Growth Scenarios

The ISO 20-Year Transmission Outlook assessed the ISO transmission system in the year 2040. The Starting Point scenario is largely based on the 2021 SB 100 Report Core (SB 100 Core) scenario, which also assumes high electrification of load. The ISO used the same high electrification load assumption in the 20-Year Transmission Outlook; however the transmission planning studies require the modeling of detailed load information the joint agencies did not have. Specifically, the transmission planning studies need the geographic location where loads increase and the load profiles. To overcome this challenge, the ISO developed an approach to apply the high electrification load assumption in the SB 100 Core scenario to the 20-Year Transmission Outlook.

The ISO started with the SB 100 Core statewide high electrification load projection of 82,364 MW in 2040. The load forecast from the CEC 2020 IEPR for 2031 Mid-Mid (1-in-2 weather) scenario for the total coincident statewide load is 64,076 MW. This is an 18,288 MW (28.5 percent) increase from the IEPR 2020 load forecast in 2031 to the high electrification forecast base of the SB 100 Core scenario in 2040.

The ISO then scaled the load in California up at each load bus in the 2031 base case by 28.5 percent. The ISO and joint agencies recognize that an across-the-board scaling was a simplifying assumption due to the lack of a detailed high electrification forecast with sufficient granularity necessary for transmission modeling. In actuality, electrification may result in uneven increases in loads at individual buses, dependent on the geographic distribution of the end-uses that are electrified. For the high-level assessment and technical studies of the bulk transmission system (500 kV and 230 kV) within the 20-Year Transmission Outlook, it is expected that the even upscaling of bus bar loads provides representative results.

It is expected, based on the SB 100 Core scenario, that the total behind-the-meter photovoltaic (PV) (BTM-PV) in the state of California to reach 33,807 MW in year 2040.

Within the technical studies of the 20-Year Outlook, the following three study cases were assessed:

- Peak consumption
- Net peak, and
- Off-peak loading conditions

The above assumptions on statewide peak load of 82,364 MW in 2040 along with hourly CEC load profile in year 2030 are used to estimate the load and behind-the-meter PV generation for the three study cases.

Figure 3.1-1 provides hourly power consumption in California in per unit of the peak load. In this study the same profile is assumed in different areas of the state and therefore load across the state is scaled to the required levels.

Figure 3.1-1: CEC 2020 IEPR California state annual hourly load profile for 2030

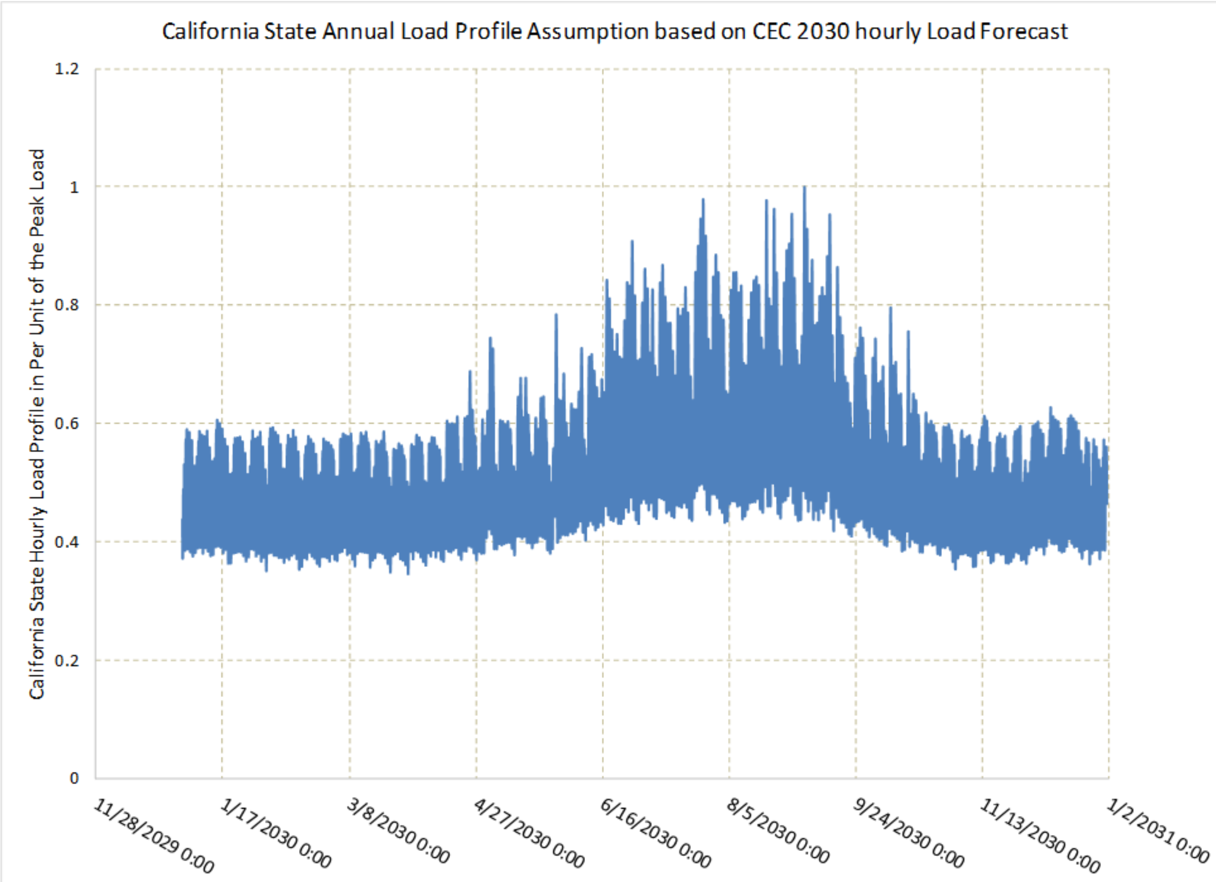
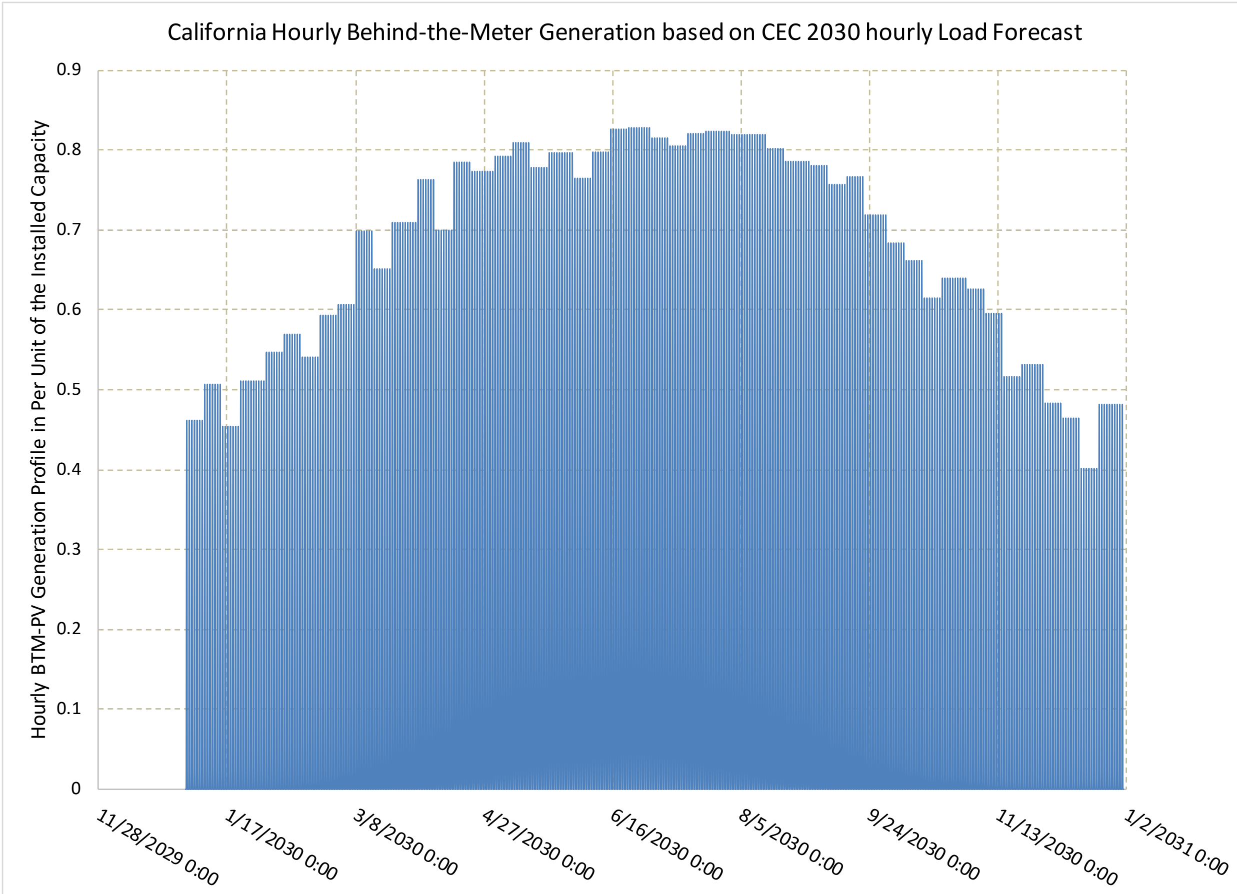


Figure 3.1-2 provides the hourly behind-the-meter generation in California in per unit of the installed capacity. In this study, the same profile is assumed in different areas of the state and therefore behind-the-meter generation across the state is scaled to the required levels.

Figure 3.1-2: CEC 2020 IEPR behind-the-meter hourly profile for 2030



The following table provides a summary of the load, installed BTM-PV capacity and the BTM-PV generation in the state as well as the ISO system.

Table 3.1-1: Load and installed behind-the-meter solar forecast

Load and Installed BTM-PV	State [1]	ISO [2]
CEC peak consumption forecast in 2031	64,076 [3]	57,498 [4]
SB-100 peak consumption in 2040	82,364 [5]	73,909 [7]
BTM-PV installed capacity in CEC 2031 forecast	25,092 [7]	22,655 [4]
BTM-PV in SB-100 in 2040	33,807 [6]	30,336 [7]

[1] State load is 1-in-2 peak load
[2] ISO load refers to the 1-in-5 load in areas SDG&E (area 22), SCE (area 24), and PG&E (area 30). Note that while area 30 is named PG&E in our study cases, it also includes the load of SMUD and other balancing authorities that are geographically located in northern California.
[3] as per CEC 2020 IEPR
[4] as per 2021-2022 TPP studies
[5] 20-year outlook study assumptions
[6] CEC forecast for 2040
[7] These values are calculated assuming that the 1-in-5 ISO load and the ISO BTM-PV are 90 percent of the 1-in-2 state load and the state BTM-PV installed capacity.

Table 3.1-2 provides the load (consumption) and the BTM-PV generation for the three study cases. The values are calculated based on the profiles discussed and shown in figures 1 and 2 above.

Table 3.1-2: Load and BTM-PV

Study Cases	Date/Time assumption	Load (MW)	BTM-PV Generation (MW)
Peak Consumption (SSN)	9/2/2040 3 pm	73,909	18,966
Net peak load (HSN)	9/2/2040 7 pm	65,199	~0
Off peak	4/6/2040 1 pm	34,851	23,114

3.1.2 Resource Planning and Portfolio Development

The Starting Point scenario was developed by taking the 2040 SB 100 Core scenario and increasing assumed natural gas power plant retirements to 15,000 MW. This allows 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. Additionally, to generally offset the additional assumed natural gas power plant retirements, geothermal, offshore wind, out-of-state wind and battery energy storage systems capacity were added to levels that are generally reflective of other 2021 SB 100 Report scenarios.

Table 3.1-3 provides the base resource portfolio provided by the CPUC for use in the 2021-2022 transmission planning process for the year 2031 and the resource portfolio of the SB100 Starting Point scenario used in the 20-Year Transmission Outlook.

Table 3.1-3: Resource assumptions in 2021-2022 transmission planning process for 2013 and the SB100 starting point scenario for 2040

Resource Type	2021-2022 TPP Base Portfolio for 2031 (MW)	2040 Starting Point Scenario (MW)
Natural gas fired power plants	0	(15,000)
Battery energy storage	9,368	37,000
Long-duration energy storage	627	4,000
Utility-scale solar	13,044	53,212
In-state wind	1918	2,237
Offshore wind	0	10,000
Out-of-state wind	2,087[16]	12,000[17]
Geothermal	651	2,332

[16] 1,062 MW on new transmission and 1,025 MW on existing transmission.

[17] 9,900 MW on new transmission and 2,100 MW on existing transmission.

3.1.3 Natural gas-fired power plants

The SB100 Starting Point scenario includes an assumption that 15,000 MW of natural gas power plant capacity would be retired by 2040. The Starting Point scenario did not specifically identify which resources should be retired and provided a criteria to select the resources assumed to be retired in the assessment as follows:

- That the oldest natural gas power plants retire first, with a priority on those that are in and adjacent to disadvantaged communities (DAC)
    - Disadvantaged communities are defined and identified by the California Office of Environmental Health Hazard Assessment and are available in the CalEnviroScreen 3.0 webtool.[18]
    - For purposes of this Starting Point scenario a DAC adjacent community is within a 2.5-mile radius of a natural gas power plant.
- At least 3,000 MW of the 15,000 MW of retirements are assigned to 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 DACs.

For the 20-Year Transmission Outlook, the ISO assessed approximately 15,000 MW of gas-fired generation retired in the ISO system. There is approximately 2,000 MW of gas-fired generation connected to the ISO system that rely on the Aliso Canyon storage facility as provided by the agencies.

Applying the age, DAC and DAC-adjacent criteria with the 2,000 MW of gas-fired generation in the ISO system relying on Aliso Canyon, the following is retirement of gas-fired generation by local capacity area:

Table 3.1-4: 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**

[18] https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30.

There is approximately the following gas-fired generation outside the ISO identified in DAC and DAC 2.5 adjacent based upon the data provided by the state agencies.

- 3.8 GW within a DAC
- 0.6 GW within DAC 2.5 adjacent.

The agencies also identified approximately 2,000 MW of gas-fired generation connected outside of the ISO system that rely on the Aliso Canyon storage facility with allow the resources identified being within a DAC or DAC 2.5 adjacent.

3.1.4 Battery energy storage

The SB100 Starting Point scenario identified 37,000 MW of battery energy storage resources in 2040. The approach used for assigning battery energy storage to transmission zones for the 20-Year Transmission Outlook utilizes the approach applied to battery energy storage in the CPUC's Integrated Resources Planning (IRP) process for the ISO's 2021-2022 transmission planning process.

The 37,000 MW of selected battery energy storage is allocated as follows:

- 9,368 MW of battery storage already allocated in the IRP resource portfolio for the 2021-2022 TPP base case has been carried over without any changes.
- The remaining battery energy storage were to be allocated by expanding upon the approach from the 2021-2022 TPP base case:
  - Co-locate in transmission zones where renewable resources are concentrated.
  - Allocate battery storage based on system needs identified in the study.

3.1.5 Long-duration energy storage

The SB100 Starting Point scenario identified 4,000 MW of long duration energy storage resources in 2040. The long-duration energy storage (LDES) in the SB 100 Core scenario was to be allocated by building off the current 2021-2022 transmission planning process base case as well as current commercial interest.

The 4,000 MW of LDES was to be allocated by:

- 627 MW of pumped hydroelectric already mapped in the IRP resource portfolio for the 2021-2022 TPP base case
- 2,400 MW of pumped hydroelectric as described in the current ISO interconnection queue
- 1,600 MW of location unconstrained LDES that is unassigned should be assigned to transmission zones based on a combination of geologic and technological factors and system needs.

3.1.6 Utility-scale solar

The Starting Point scenario identified 53,212 MW of utility-scale solar resources in 2040. In allocating the utility-scale solar to the transmission zones, the Starting Point scenario utilizes known commercial interest to allocate solar development to transmission zones rather than carrying forward the allocations made by the RESOLVE model. In addition the CEC utilized a high-level environmental screen to assess whether the commercial interest allocation had resulted in a clearly disproportionate assignment of solar build out to any of the transmission zones relative to the availability of "lower implication" land in each zone.

Figure 3.1-3 shows the in-state transmission zones as a starting point for where solar might be developed based on the re-allocation of solar based on commercial interest.

Figure 3.1-3: SB100 Starting Point Solar in Transmission Zones

The 53,212 MW installed capacity of utility-scale solar identified SB100 Starting Point scenario was allocated to the following transmission zones in Table 3.1-5.

Table 3.1-5: Solar resource allocation to transmission zones

Resource	Transmission Zone	Capacity (MW)
Greater_Imperial_Solar	SCADSNV_Z3_GreaterImperial	6,407
Inyokern_North_Kramer_Solar	GK_Z2_InyokernAndNorthOfKramer	2,162
Kern_Greater_Carrizo_Solar	SPGE_Z2_KernAndGreaterCarrizo	6,154
North_Victor_Solar	GK_Z3_NorthOfVictor	674
Sacramento_River_Solar	Norcal_Z3_SacramentoRiver	998
Solano_Solar	Norcal_Z4_Solano	169
Tehachapi_Solar	Tehachapi	9,544
Westlands_Solar	SPGE_Z1_Westlands	12,655
Pisgah_Solar	GK_Z4_Pisgah	674
RiversideAndPalmSprings Solar	RiversideAndPalmSprings	4,922
CentralValleyAndLos Banos Solar	CentralValleyAndLosBanosSolar	1,079
Tehachapi Outside of Constraint Zones	Tehachapi Outside of Constraint Zones	2,066
Greater ImpOutside Constraint Zones		995
Mountain_Pass_El_Dorado_Solar	Mountain_Pass_El_Dorado	248
Southern_Nevada_Solar	SCADSNV-GLW_VEA	2,024
Arizona_Solar	SCADSNV-Riverside_Palm_Springs	2,352

3.1.7 In-state Wind

The Starting Point scenario identified 2,237 MW of in-state wind in 2040. In the SB 100 Core scenario, the RESOLVE model selected all of the available in-state wind resource potential. This is similar to the 1,918 MW included in the CPUC IRP portfolios being studied in the 2021-2022 transmission planning process base case portfolio.

3.1.8 Offshore Wind

The Starting Point scenario identified 10,000 MW of offshore wind in 2040 which is consistent with other SB 100 scenarios. Within the 2021-2022 TPP the ISO is studying offshore wind energy as a sensitivity and in an outlook study.

Detailed studies have been performed to identify the transmission needs for resources in the following offshore wind call areas.

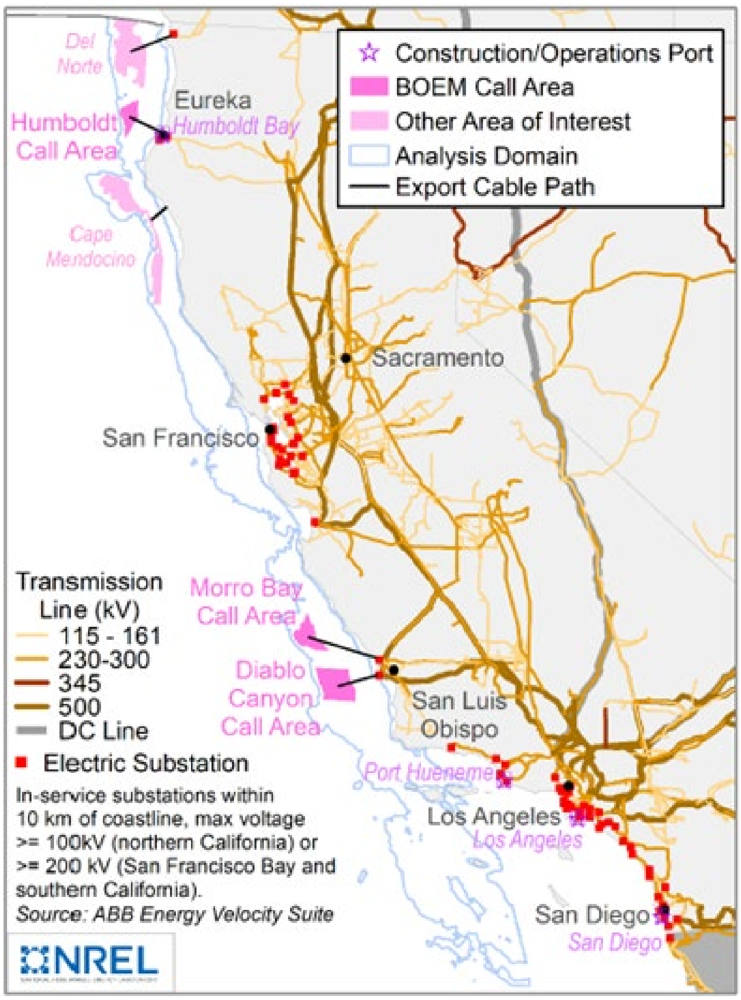
- Humboldt: 1.6 GW
- Morro Bay: 2.3 GW
- Diablo Canyon: 4.4 MW

In addition, an outlook assessment has been undertaken to accommodate an additional 12.8 GW of offshore wind resources at the following call areas:

- Del Norte: 6.6 GW
- Cape Mendocino: 6.2 GW

The sensitivity analysis on offshore wind in the 2021-2022 Transmission Plan, section 3.5.7 has been utilized for the analysis of the 10 GW of offshore wind in the SB100 Starting Point scenario. Figure 3.1-4 illustrates the call areas of the offshore wind that were assessed.

Figure 3.1-4: BOEM Offshore Wind Call Areas [19]



[19] NREL "The Cost of Floating Offshore Wind Energy In California Between 2019 and 2032" https://www.nrel.gov/docs/fy21osti/77384.pdf

The Bureau of Ocean Energy Management (BOEM) current California activities[20] are in the Morro Bay and Humboldt offshore wind areas where they are planning for potential offshore renewable energy leasing and development activities.

3.1.9 Out-of-state wind

The Starting Point scenario identified 12,000 MW of out-of-state wind resources in 2040. The out-of-state wind that has been identified as either requiring new transmission to bring the resource to the ISO transmission grid (9,900 MW) or on existing transmission (2,100 MW) as

On new transmission

- Wyoming 4,685 MW
- New Mexico 5,215 MW

On existing transmission

- Northwest 1,500 MW
- Baja California 600 MW

As indicated in section 2.1.1, at the July 22, 2021 CEC SB100 workshop[21] a number of projects were identified that could bring out-of-state wind power to ISO system. The identified transmission development projects could provide for a portion of the transmission required to access 10,000 MW of out-of-state wind resources. Additional transmission either to the border of the ISO system or to interconnection points within the ISO will likely be required.

3.1.10 Geothermal

The Starting Point scenario identified 2,332 MW of geothermal resources in 2040. As a starting point for the 20-Year Outlook, and to more fully understand the ability for geothermal to scale in and around the Salton Sea region the agencies allocated most (2,012 MW), but not all, of the geothermal capacity to the Imperial transmission zone. The remainder of the geothermal capacity (320 MW) was identified in the southern Nevada area.

[20] https://www.boem.gov/renewable-energy/state-activities/california

[21] https://efiling.energy.ca.gov/GetDocument.aspx?tn=238965&DocumentContentId=72387

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Chapter 4

4 Integration of Resources

To assess the transmission impacts and identify feasible alternatives for the transmission development necessary to integrate the resources, they need to be mapped more granularly to the substations and bus bars in the models. Figure 4.0-1 provides an illustration of the solar, wind and geothermal resources in the transmission zones within the ISO system.

Figure 4.0-1: High-level illustration of the areas of solar, wind and geothermal resource allocation

4.1 Mapping of solar resources

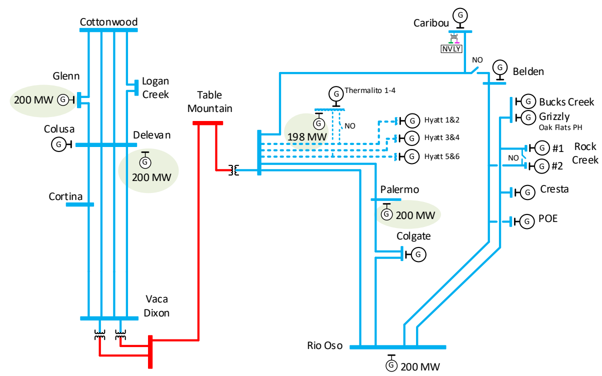
The SB100 Starting Point scenario identified 53,212 MW of solar capacity in the following transmission zones as indicated in Table 3.1-4. The solar resources have been mapped to the following substations within each of the transmission zones identified in the SB100 Starting Point scenario.

The solar resources have been mapped to existing facilities with the exception of the Westlands area. The Manning Substation project recommended for approval in the 2021-2022 Transmission Plan has been included to interconnect the resources within this transmission zone.

Figure 4.1-1: Interconnection of solar resources to substation in ISO system

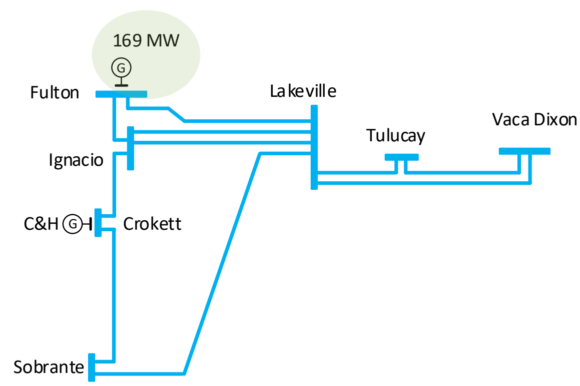
Sacramento River: 998 MW

Zone Total	998.0
Delevan 230kV	200
Glenn 230kV	200
Palmero 230kV	200
Rio Oso 230kV	200
Thermalito 230kV	198



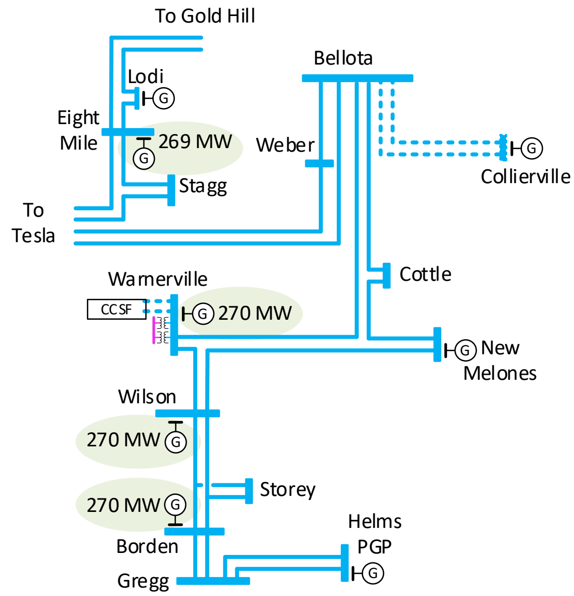
Norcal Solano: 169 MW

Zone Total	169.0
Fulton 230kV	169
Contra Costa 230kV	0
Tulucay 230kV	0
Vaca-Dixon 500kV	0



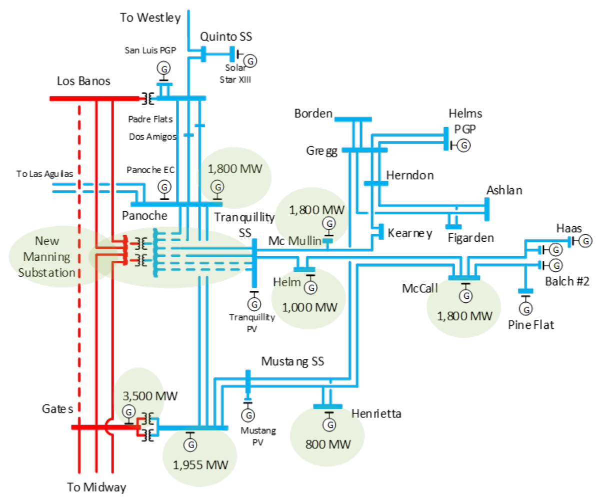
Central Valley and Los Banos: 1,079 MW

Zone Total	1,079.0
Wilson 230 kV	270.0
Borden 230 kV	270.0
Warnerville 230 kV	270.0
Eight Mile 230 kV	269.0



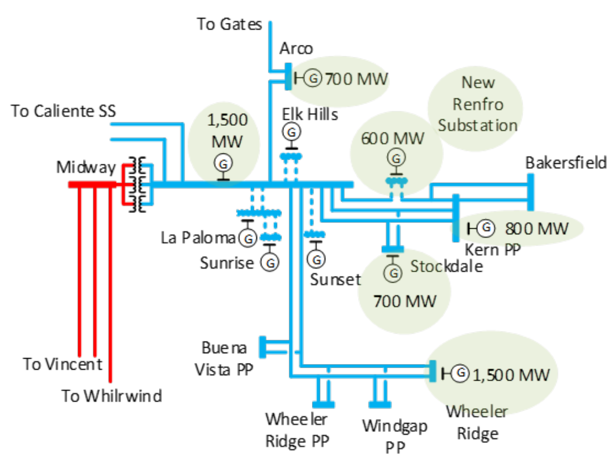
Westlands: 12,655 MW

Zone Total	12,655.0
Gates 230kV	1,955.0
Helm 230kV	1,000.0
Henrietta 230kV	800.0
Mc Call 230kV	1,800.0
Mc Mullin 230kV	1,800.0
Panoche 230kV	1,800.0
Gates 500kV	3,500.0



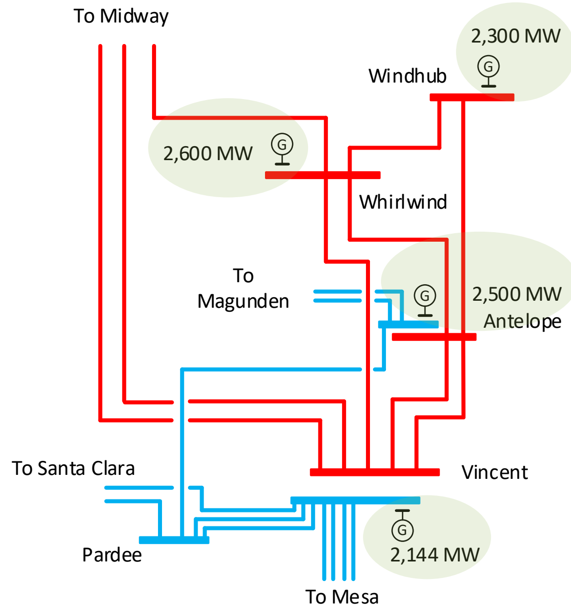
Kern and Greater Carrizo: 6,154 MW

Zone Total	6,154.0
Arco 230kV	700.0
Midway 230kV	1,500.0
Renfro 230kV	600.0
Stockdale 230kV	700.0
Wheeler Ridge 230kV	1,500.0
Kern PP	800.0
Lamont 115 kV	354.0



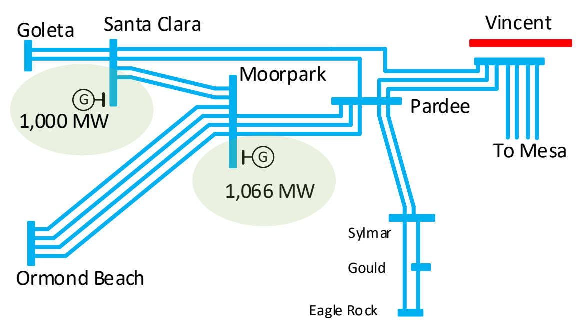
Tehachapi: 9,544 MW

Zone Total	9,544.0
WindHub 500kV	2,300.0
Whirlwind 500kV	2,600.0
Antelope 230kV	2,500.0
Vincent 230kV	2,144.0



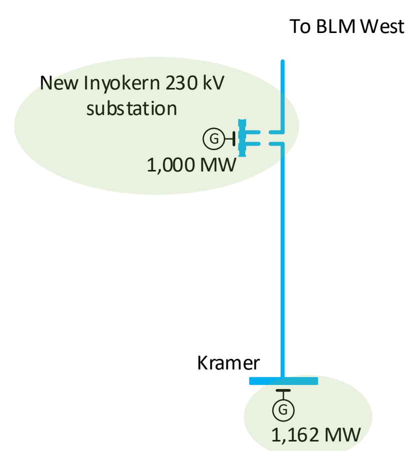
Tehachapi Outside of Constraint Zones: 2,066 MW

Zone Total	2,066.0
S.CLARA 230kV	1000
MOORPARK 230kV	1066



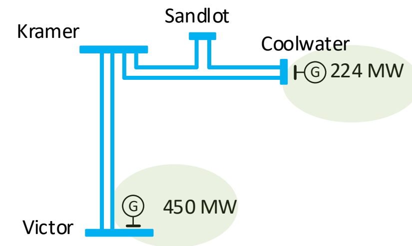
Inyokern and North of Kramer: 2,162 MW

Zone Total	2,162.0
KRAMER 230kV	1162
INYOKERN 230kV	1000



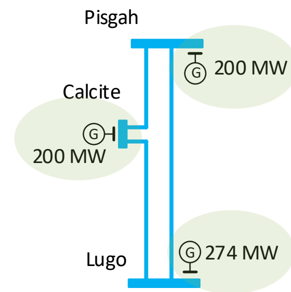
North of Victor: 674 MW

Zone Total	674.0
Victor 230kV	450.0
Coolwater 230kV	224.0



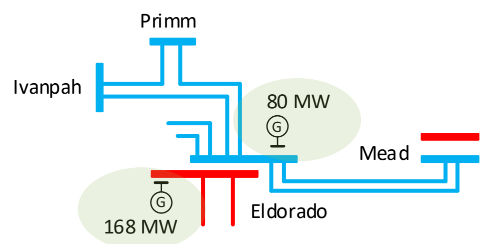
Pisgah: 674 MW

Zone Total	674.0
Calcite	200.0
Lugo	274.0
Pisgah	200.0



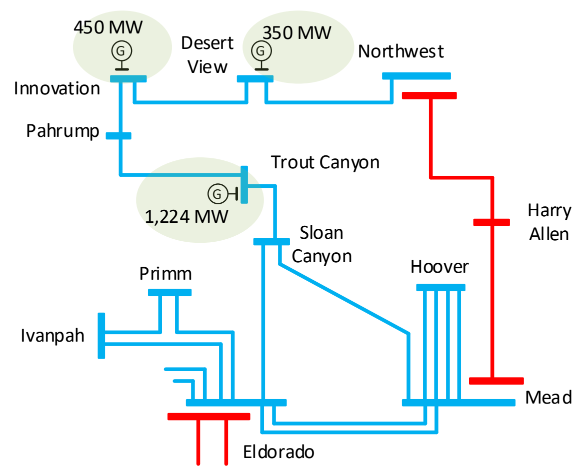
Mountain Pass - Eldorado: 248 MW

Zone Total	248.0
El Dorado 230kV	80.0
EL Dorado 500kV	168.0



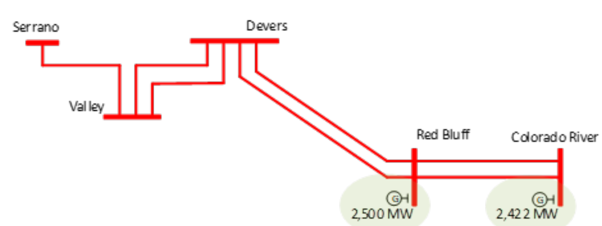
Southern Nevada: 2,024 MW

Zone Total	2,024.0
Innovation 230kV	450.0
Desert View 230kV	350.0
Crazy Eyes/Trout Canyon 230kV	1,224.0



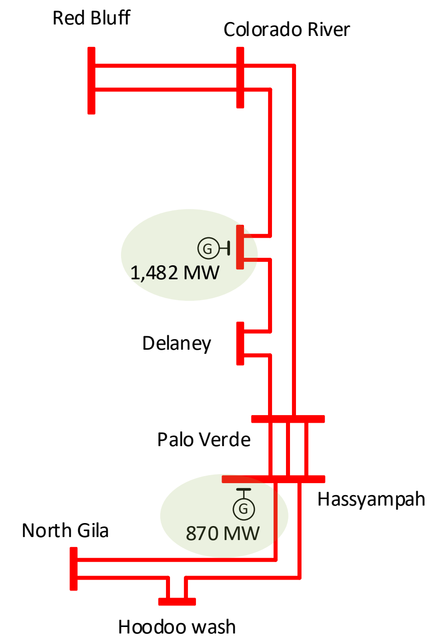
Riverside and Palm Springs: 4,992 MW

Zone Total	4,922.0
REDBLUFF 500kV	2,500.0
COLRIVER 500kV	2,422.0

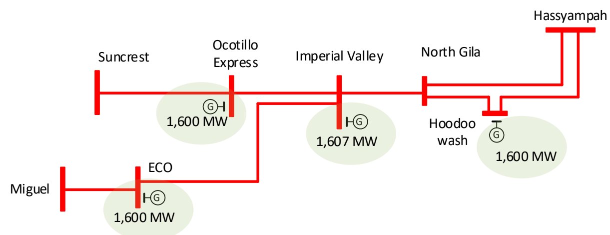


Arizona Solar: 2,352 MW

Zone Total	2,352.0
Hassayampa 500kV	870.0
Delaney-Colorado 500kV	1,482.0

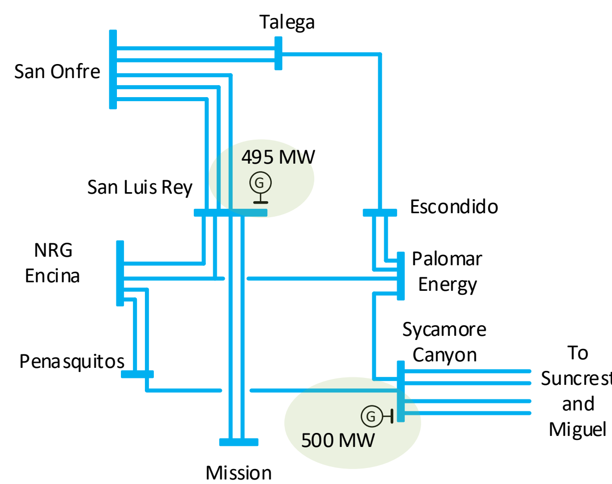


Zone Total	6,407.0
Imperial Valley 500kV	1,607.0
Ocotillo Express 500kV	1,600.0
Hoodoowash 500 kV	1,600.0
ECO 500kV	1,600.0



Greater Imperial Outside Constraint Zone: 995 MW

Zone Total	995.0
SANLUSRY 230kV	495.0
SYCAMORE 230kV	500.0

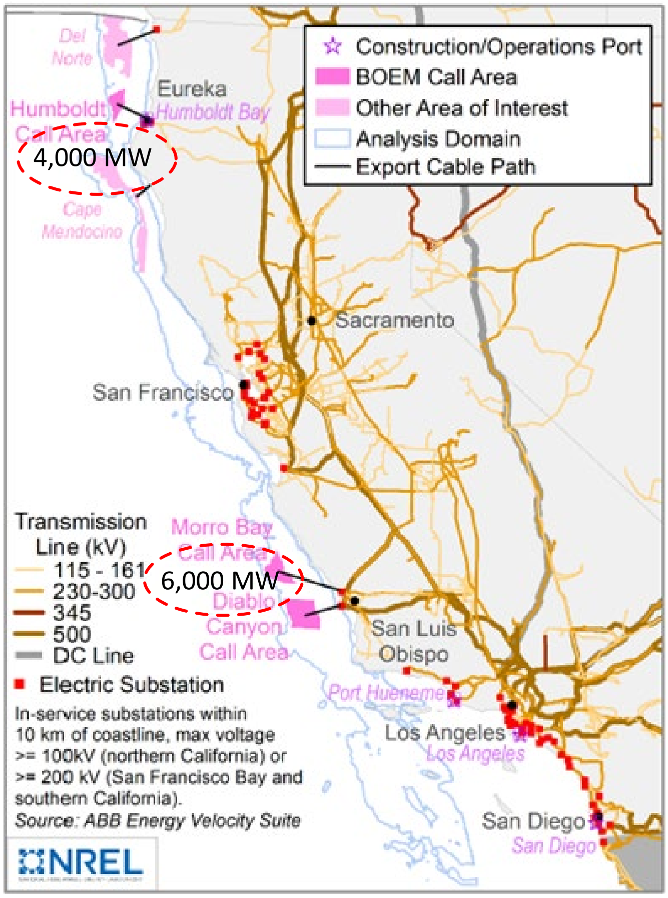


4.2 Offshore Wind Interconnection

The Starting Point resource development scenario includes 10,000 MW of offshore wind resources. In the ISO 2021-2022 Transmission Plan as a part of the policy sensitivity portfolio provided by the CPUC, detailed analysis of the transmission required to interconnect offshore wind was conducted in section 3.7and the following is based upon this analysis.

In the 20-Year Outlook, of the 10,000 MW of offshore wind that is identified, it is assumed that 6,000 MW will be in Diablo and Morro Bay areas in the central coast and 4,000 MW in Del Norte/ Humboldt Bay/ Cape Mendocino areas in the north coast of California. Figure 4.1-1 shows the approximate location of the assumed offshore wind development in this study.

Figure 4.1-1: Offshore Wind Development Location Assumptions[22]

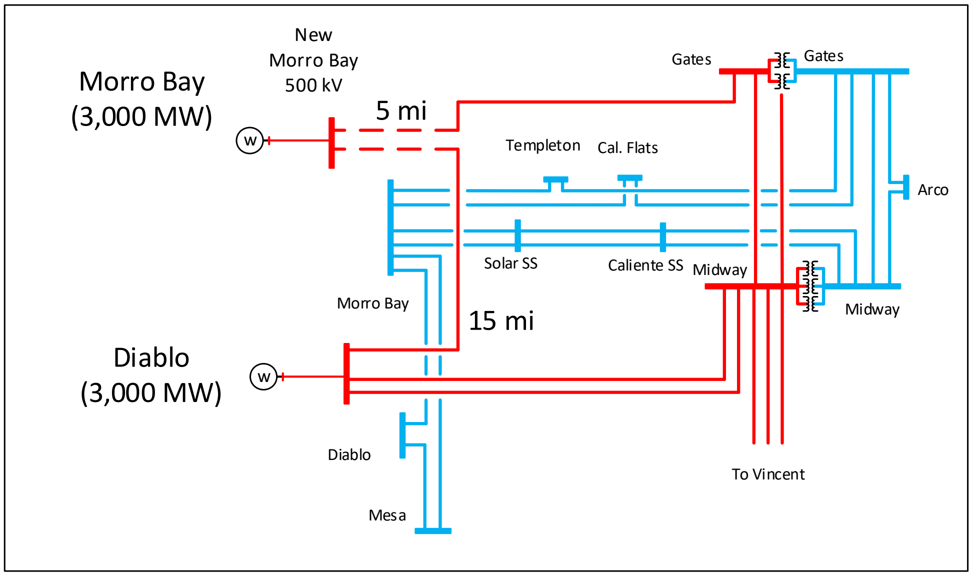


4.2.1 Interconnection of Central Coast Offshore Wind

The central coast offshore wind is assumed to interconnect to Diablo 500 kV substation and a new Morro Bay 500 kV substation looping in the existing Diablo – Gates 500 kV line (Figure 4.1-2). In this study it is assumed that 3,000 MW will be connected to Diablo and 3,000 MW will be connected to Morro Bay 500 kV substations.

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

Figure 4.1-2: Central Coast Offshore Wind Interconnection Assumption



4.2.2 Interconnection of North Coast Offshore Wind

Of the 10,000 MW of offshore wind in the SB100 Starting Point scenario, 4,000 MW has been assumed in the north coast area. In the sensitivity study in the 2021-2022 Transmission Plan, the Humboldt wind energy area[23] was identified in the main assessment, which is one of the Bureau of Ocean Energy Management's current California activity areas where it is planning for potential offshore renewable energy leasing and development activities. Two other potential additional offshore wind areas were identified in the sensitivity portfolio in the 2021-2022 Transmission Plan as the Cape Mendocino and Del Norte areas in a less detailed outlook assessment as illustrated in Figure 3.1-4.

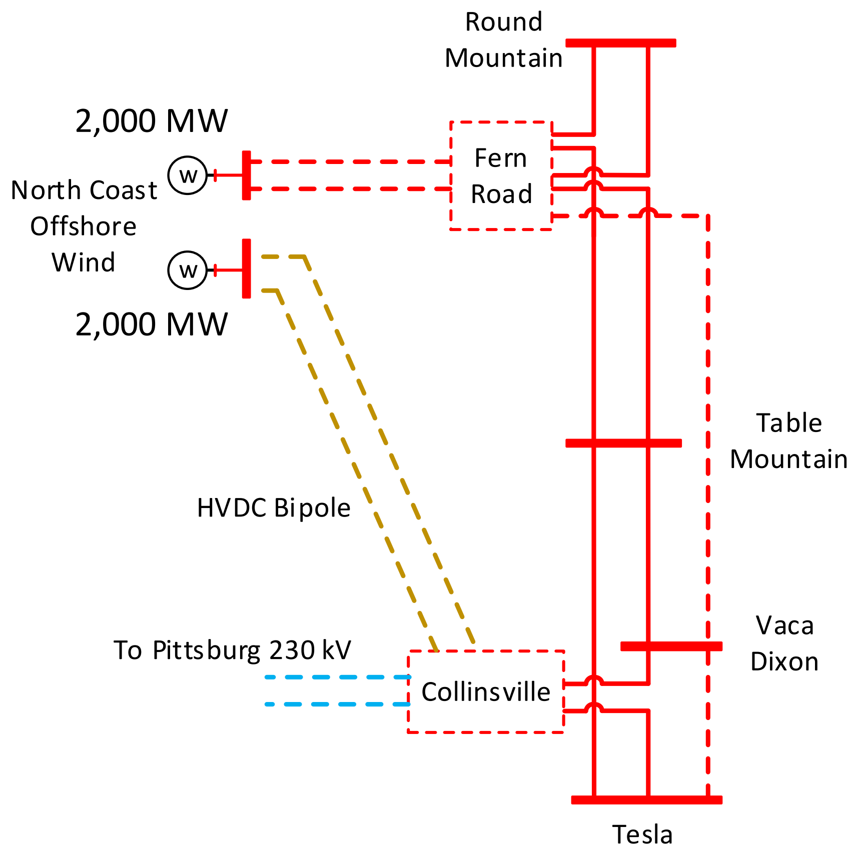
To facilitate the interconnection of the 4,000 MW of offshore wind in the north coast to the ISO system, the ISO identified the need for two 500 kV AC lines connecting to the Fern Road 500 kV substation and a HVDC line to the Collinsville 500/230 kV substation as illustrated in Figure 4.1-3. The HVDC line could be an over-land option or sea cable connection to Collinsville. One other alternative considered in the ISO's 2021-2022 Transmission Plan is an HVDC-VSC deep sea cable to a new station referred to as Bay-hub located in the Greater Bay Area.

The initial offshore wind development in the north coast has been assumed to be in the Humboldt wind energy area of approximately 2,000 MW with the remaining 2,000 MW to be in either the Cape Mendocino or Del Norte areas. In addition to the 500 kV AC lines and the HVDC lines, additional transmission would be required to interconnect the 500 kV AC and HVDC systems together and to the offshore wind farms in the two wind development areas. These facilities would depend on where the second wind development occurs and could either consist of onshore or offshore grid development. Within the 20-Year Outlook, it has been assumed that the HVDC-VSC deep-sea alternative to a Bay-hub substation would be best after further development of the call areas beyond the current Humboldt call area under consideration and

[23] https://www.boem.gov/renewable-energy/state-activities/humboldt-wind-energy-area

future leasing through the BOEM processes. The HVDC-VSC technology could be used to interconnect the offshore wind areas as well as provide additional transmission capacity to the load centers in the Bay area as the offshore wind capacity increases off the northern California coast.

Figure 4.1-3: North Coast Offshore Wind Interconnection Assumption



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Chapter 5

5 High-Level Assessment

5.1 Introduction

The objective of the high-level assessment is to gain an insight into the transmission enhancement required to reliably transfer the power from resources in the Starting Point resource development scenario 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 this high-level assessment was performed before production cost simulation analysis and therefore the following snapshots were considered as candidates to identify system enhancement requirements:

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 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.

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 BTM-PV generation. The in-state, out-of-state, and offshore wind generation assumptions are in line with the HSN deliverability analysis and the import level is assumed to be around 10,000 MW. The battery storage is assumed to the rest of the required power to serve load.

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 power to the neighboring system. The battery storage is assumed to be in full charging mode in this case.

Three 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 5.2-1: Load and BTM-PV assumptions

Study Cases	Date/Time assumption	Load (MW)	BTM-PV Generation (MW)
Peak Consumption (SSN)	9/2/2040 3 pm	73,909	18,966
Net peak load (HSN)	9/2/2040 7 pm	65,199	~0
Off peak	4/6/2040 1 pm	34,851	23,114

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 2021-2022 Transmission Plan.

Table 5.2-2: Generation dispatch assumptions

	Generation Output (MW)		
Supply Type	Peak Consumption	Net Peak	Off Peak
Gas	2,030	2,030	0
Hydro	2,933	6,736	4,001
Pumped hydro	0	1,827	(1,527)
Geothermal	1,870	1,870	1,870
Bio	325	325	325
Solar	36,194	0	41,362
In-State Wind	1,582	4,832	4,832
Offshore wind	4,700	10,000	6,530
Out of state wind	3,200	6,000	0
Battery Storage	0	19,033	(42,593)
BTM-PV	18,957	0	23,115
Import	(2)	10,742	(4,870)

Most of the battery storage in the portfolio is assumed to be co-located with the solar generation.

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 what further system re-enforcements are needed at a conceptual level. More information on these projects are provided in sections 2 through 4 of the 2021-2022 Transmission Plan.

Projects Recommended in 2021-2022 TPP

- Manning 500/230 kV Project
- Collinsville 500/230 kV Project
- Newark – Los Esteros – NRS HVDC
- Metcalf – San Jose B HVDC
- Mesa – Laguna Bell Reconductor
- GLW Proposed Upgrades

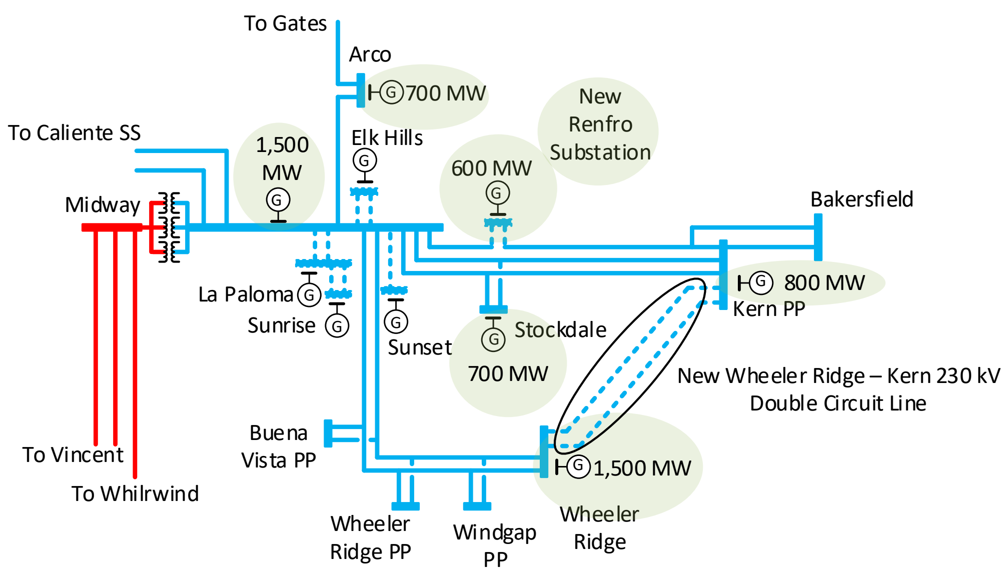
System Upgrades Required for Starting Point Generation Interconnection

The following system upgrades are required to facilitate the interconnection of the solar resources in the Starting Point scenario:

<u>Wheeler Ridge – Kern 230 kV DCTL Project</u>

The Starting Point scenario includes 6,154 MW of solar resources in the Kern and Greater Carrizo area. The following diagram shows the assumed project interconnection points and their capacity at each location. To prevent overload under normal and contingency conditions, a new 230 kV double circuit line from Wheeler Ridge to Kern was assumed in this study.

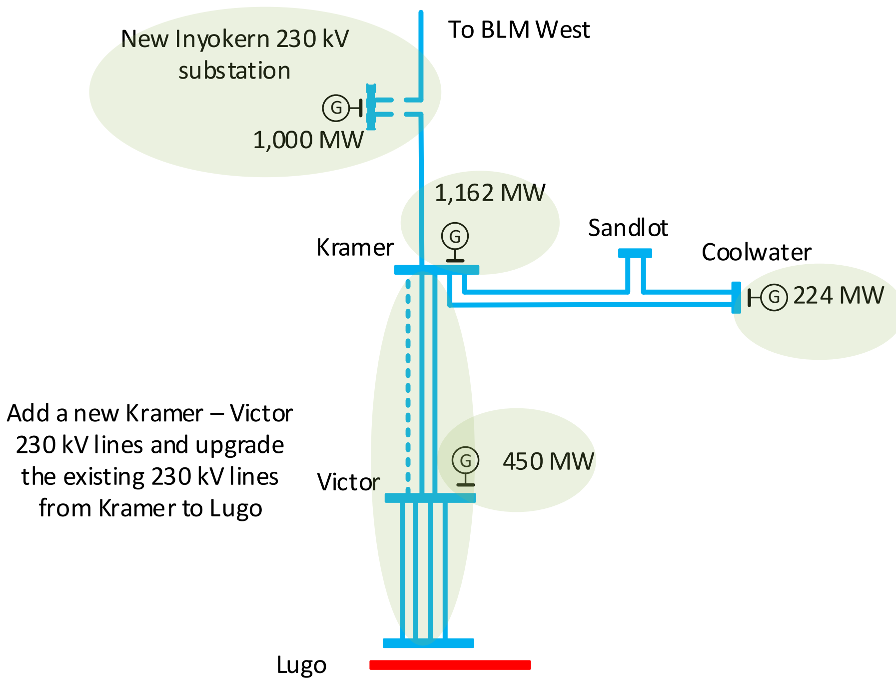
Figure 5.2-1: Illustration of Wheeler Ridge – Kern 230 kV DCTL Project



Kramer – Victor – Lugo Path Upgrade Project

The Starting Point scenario includes 2,162 MW of solar resources in the Inyokern and North of Kramer area and 674 MW in the North of Victor area. The following diagram shows the assumed solar project interconnection points and their capacity at each location. To prevent overload under normal and contingency conditions, a new 230 kV line from Kramer to Victor was considered along with upgrading the existing Kramer – Victor and Victor – Lugo 230 kV lines.

Figure 5.2-2: Illustration of Kramer – Victor – Lugo Path Upgrade Project



Reactive Support Assumptions

In addition to above upgrades, 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 2040

Starting with 2031 Summer Peak case, the load across California was scaled up or down to match the required load level discussed in section 3.1.1. Given the significant load increase up to close to 30 percent, reactive support devices were assumed in critical busses to be able to solve the cases with increased load.

Contingency Analysis

The objective of the contingency analysis in this study is to gain an 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
- Only 230 kV and 500 kV contingencies were evaluated for N-1 analysis
- Only 500 kV contingencies were evaluated for N-1-1 analysis
- No RAS action was modelled in this study
- Generators were not re-dispatched before or after the contingencies
- 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 2040 Peak Consumption Study Results

The peak consumption study is based on the SSN study in deliverability studies and reflects the system in early afternoon summer conditions. The electricity consumption in ISO system is around 74 GW which is mostly (80 percent) supplied by solar, wind, and BTM-PV. With assumption of no import, the rest of generation is coming from other sources such as hydro, geothermal, gas generation in the Bay area. Details of generation for this study is discussed in section 5.2.2.

5.3.2.1 N-0 Overloads

N-0 overloads were identified on number of lines which for the most part are on the path of transferring power from solar plants in Westland and Kern areas to the load center in the Bay area. The required power transfer is high due to high electrification load and only around 2,000 MW of local gas generation in the Bay area.

Table 5.3-1 Peak consumption N-0 constraints

Monitored Element	Base Case Overload	Potential Mitigation
Manning – Gates 500 kV line	163%	Diablo – North HVDC Westland 500/230 kV station
Lugo 500/230 kV TB #1 and #2	161%	Lugo 500/230 kV TB #3 and #4
Loss Banos – Manning #1 and #2 500 kV lines	152%	Diablo – North HVDC
Loss Banos – Tesla 500 kV line	138%	Diablo – North HVDC Second Los Banos – Tracy 500 kV line
Loss Banos – Tracy 500 kV line	117%	Second Los Banos – Tracy 500 kV line
Los Banos – Moss Landing 500 kV line	116%	Diablo – North HVDC Manning – Moss Landing 500 kV
Moss Landing – Las Aguilas 230 kV	133%	Manning – Moss Landing 500 kV
Westley – Los Banos 230 kV line	123%	Second Los Banos – Tracy 500 kV line
Panoche – Los Banos 230 kV line	119%	Westland 500/230 kV station
Collinsville – Pittsburg 230 kV lines	116%	Third Collinsville – Pittsburg 230 kV line
Lighthipe – Mesa 230 kV line	108%	HVDC lines to LA Basin

5.3.2.2 Overload Results for N-1 of 230 kV and 500 kV Lines

High overloads were identified on the lines that were overloaded under N-0 conditions. The following table only lists the overloads that only occurred following N-1 contingencies and not in the base case.

Table 5.3-2: Peak consumption N-1 constraints

Monitored Element	N-1 Contingency	Overload	Potential Mitigation
Elements overloaded under N-0	*Various contingencies*	*Up to 166%*	*Discussed in N-0 section*
Devers – Red Bluff 500 kV #1 or #2 line	Devers – Red Bluff 500 kV #2 or #1 line	122%	Colorado River – Devers 500 kV line
Panoche – Las Aguilas #1 or #2 230 kV line	Panoche – Las Aguilas #2 or #1 230 kV line	113%	Manning – Moss Landing 500 kV
Laguna Bell – Mescals #2 230 kV line	Laguna Bell – Mesa #1 230 line	112%	HVDC lines to LA Basin
Los Banos – Dos Amigos 230 kV line	Los Banos – Panoche 230 kV #1 or #2 lines	110%	Second Load Banos – Tracy 500 kV line
Miguel 500/230 kV TB #1	Miguel 500/230 kV TB #2	110%	Sycamore – Alberhill HVDC
Mesa 500/230 kV TB #3 or #4	Mesa 500/230 kV TB #4 or #3	110%	HVDC lines to LA Basin
Eldorado – McCullough 500 kV line	Eldorado – Lugo 500 kV line	108%	New Eldorado – Lugo 500 kV line
Gates 500/230 TB #11	Gates 500/230 TB #12	105%	Westland 500/230 kV substation

5.3.2.3 Overload Results for N-1-1 of 500 kV Lines

Under certain N-1-1 contingencies, higher overloads were identified that were already overloaded under N-0 and N-1 contingency conditions. The following table lists the overloads that only occurred following N-1-1 contingencies.

Table 5.3-3: Peak consumption N-1-1 constraints

Monitored Element	N-1-1 Contingency	Overload	Potential Mitigation [1]
Elements overloaded under N-0 and N-1	*Various contingencies*	*Up to 219%*	*Discussed in N-0 and N-1 sections*
N/A	Two of the following 500 kV lines: Los Banos – Tracy Los Banos – Tesla Los Banos – Moss Landing	Voltage collapse	Second Los Banos – Tracy 500 kV line and Diablo – North HVDC
N/A	Los Banos – Manning #1 and #2	Voltage collapse	Diablo – North HVDC and Westland 500/230 kV station
Remaining 500 kV line	Two of the following lines: Manning – Gates 500 kV Los Banos – Gates 500 kV Midway – Manning 500 kV	Up to 158%	Diablo – North HVDC, Westland 500/230 kV station
Remaining Metcalf 500/230 kV TB	Two of the Metcalf 500/230 kV TBs	Up to 133%	Diablo – North HVDC
Otay Mesa – Tijuana I 230 kV	Suncrest – Ocotillo 500 kV Miguel – Eco 500 kV	156%	Sycamore – Alberhill HVDC
Metcalf – Moss Landing 230 kV #1 and #2 lines	Tesla – Los Banos 500 kV Metcalf – Moss Landing 500 kV	127%	Diablo – North HVDC
Moss Landing 500/230 kV TB #9	Tesla – Los Banos 500 kV Metcalf – Moss Landing 500 kV	120%	Diablo – North HVDC

[1] All the transmission projects listed to mitigate the N-1-1 overloads are needed to address N-0 and N-1 overloads. Note that not all the N-1-1 overloads are fully addressed by the identified mitigation measures. For some contingencies, system adjustments and generation re-dispatch should be applied in preparation for the next contingency. There are other overloads that are not listed here as they all could be addressed by generation re-dispatch after the first contingency.

5.3.3 2040 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 ISO system is around 65 GW which is mostly (90 percent) supplied by battery storage, wind, import, and hydro units. The rest of generation is coming from other sources such as pumped hydro, geothermal, gas generation in the Bay area. Details of generation for this study is discussed in section 5.2.2.

5.3.3.1 N-0 Overloads

N-0 overloads were identified on a number of lines on the path from the solar plants transferring power to the load center in the LA Basin area for the most part. The required power transfer is high due to high electrification load and local gas retirement in the LA Basin area.

Table 5.3-4: Net Peak N-0 constraints

Monitored Element	Base Case Overload	Potential Mitigation
Lighthipe – Mesa 230 kV line	128%	HVDC lines to LA Basin
Serrano 500/230 kV TB #1, #2 and #3	119%	Sycamore – Alberhill HVDC HVDC lines to LA Basin
North Gila – Imperial Valley 500 kV Line	113%	Second North Gila – Imperial Valley 500 kV Line
Diablo – Gates 500 kV line	113%	Diablo – North or Diablo – South HVDC
Devers – Red Bluff 500 kV #1 and #2 Lines	112%	Colorado River – Devers 500 kV line
Hassayampa – North Gila #2 500 kV line	110%	Sycamore – Alberhill HVDC
Barre – Lewis 230 kV line	113%	HVDC lines to LA Basin
Barre – Ellis #1, #2, #3, and #4	105%	HVDC lines to LA Basin

5.3.3.2 Overload Results for N-1 of 230 kV and 500 kV Lines

High overloads were identified on the lines that were overloaded under N-0 conditions. The following table only lists the overloads that only occurred following N-1 contingencies and not in the base case:

Table 5.3-5: Net sales N-1 constraints

Monitored Element	N-1 Contingency	Overload	Potential Mitigation
Elements overloaded under N-0	*Various contingencies*	*Up to 189%*	*Discussed in N-0 section*
N/A	North Gila – Imperial Valley 500 kV line	Voltage collapse	Second North Gila – Imperial Valley 500 kV Line
Devers 500/230 kV TB #1 or #2	Devers 500/230 kV TB #2 or #1	140%	HVDC lines to LA Basin
Barre – Villa Park 230 kV line	Barre – Lewis 230 kV line	132%	HVDC lines to LA Basin
Eldorado – McCullough 500 kV line	Eldorado – Lugo 500 kV #1 line	131%	Eldorado – Lugo 500 kV #2 Line
Mesa Cal – Center 230 kV line	Laguna Bell – Mesa Cal 230 kV line	128%	HVDC lines to LA Basin
Serrano – Villa Park #1 230 kV line	Serrano – Villa Park #2 230 kV line	119%	HVDC lines to LA Basin
Lugo – Victorville 500 kV Line	El Dorado – Lugo 500 kV #1 Line	114%	El Dorado – Lugo 500 kV #2 Line
Mesa 500/230 kV TB #3 or #4	Mesa 500/230 kV TB #4 or #3	113%	HVDC lines to LA Basin
Devers – Valley #1 500 kV line	Devers – Valley #2 500 kV line	112%	Devers – LA Basin HVDC
Mira Loma 500/230 TB #1 or #2	Mira Loma 500/230 TB #2 or #1	110%	HVDC lines to LA Basin
Colorado River – Red Bluff 500 kV #1 line	Colorado River – Red Bluff 500 kV #2 line	105%	Colorado River – Devers 500 kV line
Devers – Red Bluff 500 kV #1 and #2 Line	El Dorado – Lugo 500 kV #1 Line	105%	Colorado River – Devers 500 kV line

5.3.3.3 Overload Results for N-1-1 of 500 kV Lines

Under certain N-1-1 contingencies, higher overloads were identified that were already overloaded under N-0 and N-1 contingency conditions. The following table lists the overloads that only occurred following N-1-1 contingencies.

With overloads under normal condition and heavy overload under N-1 contingency conditions, the N-1-1 contingencies on 500 kV lines resulted in several contingencies causing voltage collapse. While mitigation measures considered to address N-0 and N-1 overloads, will help to prevent voltage collapse, they will be sufficient to address all the overloads. Operating measures to take action after the first contingency or Remedial Action Scheme (RAS) to take action after the second contingency would be required to address all the overloads.

Table 5.3-6: Net sales N-1-1 constraints

Monitored Element	N-1-1 Contingency	Overload	Potential Mitigation [1]
N/A	Several contingencies involving the following 500 kV lines: - Vincent – Mesa - Devers – Red Bluff #1 or #2 - Lines west of North Gila - Lines from Diablo/Morro Bay Offshore wind	Voltage Collapse	Colorado River – Devers 500 kV line Eldorado – Lugo 500 kV line Sycamore – Alberhill HVDC HVDC lines to LA Basin Diablo – North HVDC
Mira Loma – Chino 230 kV line	Mira Loma 500/230 kV TB #1 and #2	136%	HVDC lines to LA Basin
Sylmar A – Sylmar S 230 kV line	Lugo – Victorville 500 kV Lugo – Eldorado 500 kV	130%	Eldorado – Lugo 500 kV #2 line
Panoche – Gates 230 kV #1 and #2 line	Manning – Gates 500 kV Midway – Manning 500 kV	121%	Westland 500/230 kV station

[1] All the transmission projects listed to mitigate the N-1-1 overloads are needed to address N-0 and N-1 overloads. Note that not all the N-1-1 overloads are fully addressed by the identified mitigation measures. For some contingencies, system adjustments and generation re-dispatch should be applied in preparation for the next contingency. There are other overloads that are not listed here as they all could be addressed by generation re-dispatch after the first contingency.

5.3.4 2040 Off-Peak Study Results

The Off-peak load study is based on the off-peak study in deliverability studies and reflects the system condition in the middle of the day in the spring conditions in which the consumption is around 50 percent of the peak load and the generation from BTM-PV is high. In this study it is assumed that all the Battery Energy Storage Systems (BESS) units are in charging mode absorbing around 40 GW from the system. With 40 GW battery charging and 35 GW of ISO load, the total electricity consumption under this study is around 75 GW, which is entirely supplied by solar, wind, and BTM-PV generation. In this study it is assumed that ISO system is exporting 5 GW to the neighboring systems. Details of generation for this case is discussed in section 5.2.2.

5.3.4.1 N-0 Overloads

N-0 overloads were identified on a number of lines which for the most part are on the export path to transfer power from solar plants to the neighboring systems. The required power transfer is high due to low load, high solar and BTM-PV generation.

Table 5.3-7: Off-peak N-0 constraints

Monitored Element	Base Case Overload	Potential Mitigation
Lugo 500/230 kV TB #1 and #2	155%	Lugo 500/230 kV TB #3 and #4
Table Mountain 500/230 kV TB #1	126%	Table Mountain 500/230 kV TB #2
Gates – Mustang 230 kV #1 and #2 Lines	119%	Westland 500/230 kV substation

5.3.4.2 Overload Results for N-1 of 230 kV and 500 kV Lines

High overloads were identified on the lines that were overloaded under N-0 conditions. The following table only lists the overloads that only occurred following N-1 contingencies and not in the base case.

Table 5.3-8: Off-peak N-1 constraints

Monitored Element	N-1 Contingency	Overload	Potential Mitigation
Manning 500/230 kV TB #1 or #2	Manning 500/230 kV TB #2 or #1	122%	Westland 500/230 kV substation
Olinda 500/230 kV TB #1	Round Mountain 500/230 kV TB #1	114%	Round Mountain 500/230 kV TB #2
Tesla – Eight Mile 230 kV Line and several other 230 kV lines	Table Mountain 500/230 kV TB #1	168%	Table Mountain 500/230 kV TB #2

5.3.4.3 Overload Results for N-1-1 of 500 kV Lines

Under certain N-1-1 contingencies, higher overloads were identified that were already overloaded under N-0 and N-1 contingency conditions. The following table lists the overloads that only occurred following N-1-1 contingencies.

Table 5.3-9: Off-peak N-1-1 constraints

Monitored Element	N-1-1 Contingency	Overload	Potential Mitigation [1]
Mustang – Gates 230 kV #1 and #2 lines	Manning 500/230 kV TB #1 and #2	137%	Westland 500/230 kV station
Diablo – Gates 500 kV line	Diablo – Midway 500 kV #2 and #3 lines	130%	Diablo – North and Diablo – South HVDC

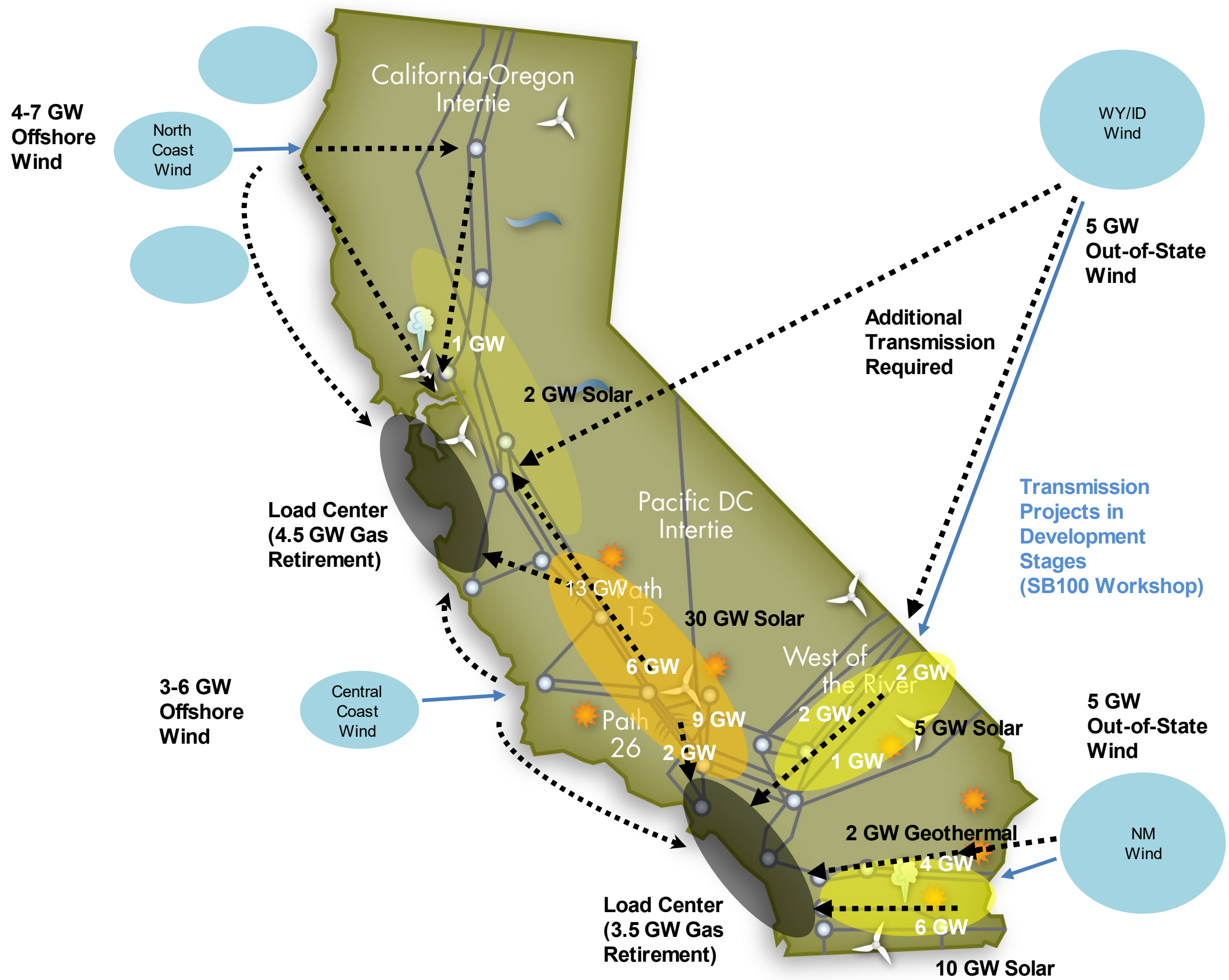
[1] All the transmission projects listed to mitigate the N-1-1 overloads are needed to address N-0 and N-1 overloads. Note that not all the N-1-1 overloads are fully addressed by the identified mitigation measures. For some contingencies, system adjustments and generation re-dispatch should be applied in preparation for the next contingency. There are other overloads that are not listed here as they all could be addressed by generation re-dispatch after the first contingency.

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 5.4-1: Illustrative Diagram of Transmission Development

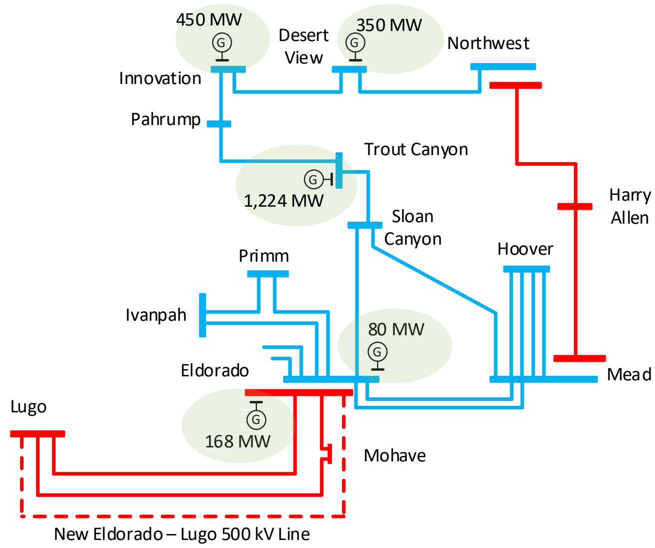


The following transmission projects described below have been identified as transmission development to accommodate the resources identified in the SB100 Starting Point scenario and address the constraints identified in the high-level assessment of the bulk transmission system.

Figure 5.4-2: Transmission development to existing ISO system to integrate the SB100 Starting Point scenario

Eldorado – Lugo 500 kV Line Project

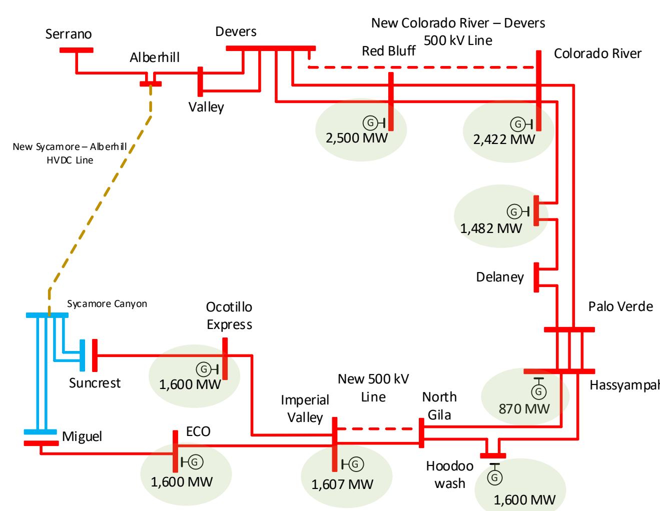
The Starting Point scenario includes 2,024 MW solar resources in Southern Nevada and 248 MW in Mountain Pas – Eldorado areas. In addition, in this study it was assumed that 3000 MW of out-of-state wind will be injected at Eldorado – 500 kV substation. Considering that the majority of these resources will flow on the Eldorado – Lugo 500 kV path, with all these resources, a new Eldorado 500 kV line was assumed to address the overloads under normal and contingency conditions.



Colorado River – Devers 500 kV Line
North Gila – Impreial Valley 500 kV Line
Sycamore – Alberhill HVDC

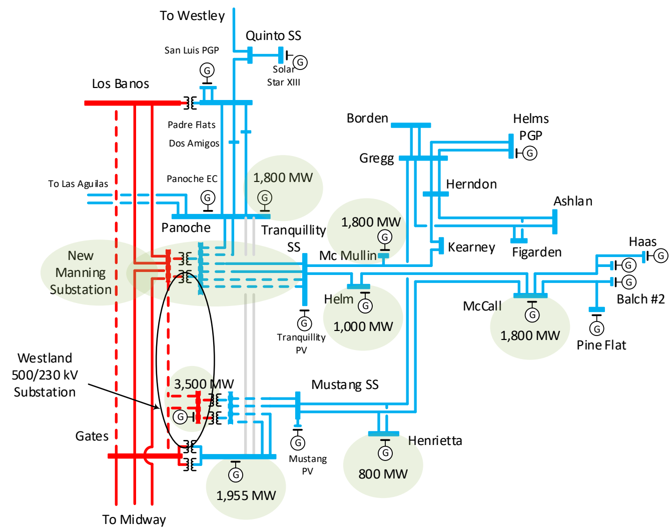
The Starting Point scenario includes 4,922 MW solar resources in Riverside and Palm Springs, 6,407 MW in Greater Imperial, and 2,352 MW in Arizona solar areas. In addition, in this study it was assumed that 3000 MW of out-of-state wind will be injected at Palo Verde 500 kV substation. Considering all these resources connections, a new Colorado - Devers 500 kV line and a new North Gila – Imperial Valley 500 kV line were considered to address the overloads under normal and contingency conditions.

The study results also indicated overload on the Hassayampa – North Gila 500 kV line as well as Serrano 500/230 kV transformers under normal conditions which were mitigated by the new Sycamore – Alberhill HVDC project.



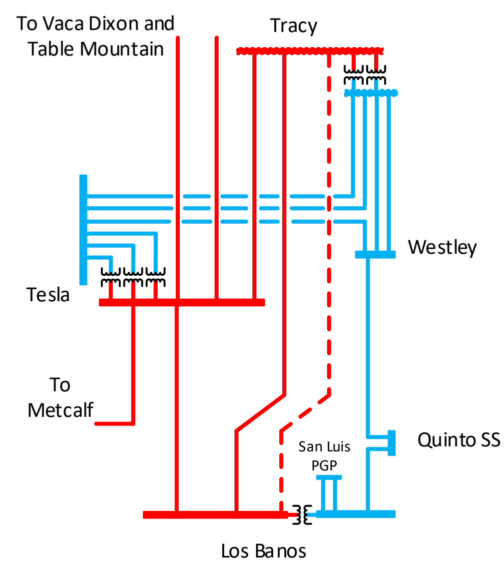
Westland 500/230 kV substation

The Starting Point scenario includes 12,655 MW solar resources in the Westland area and a large portion of it is modelled at Gates 500 kV substation in our studies. In addition, the study results showed overload on the Panoche – Gates and Mustang – Gates 230 kV lines. The Westland 500/230 kV substation project is considered in this study to mitigate normal and contingency overload and to facilitate interconnection of resources. The scope of the project is to replace the Gates – Panoche 230 kV lines with a 500 kV line from Gates to Manning substation. The Westland 500/230 kV substation will be build close to Mustang substation looping in the Mustang – Gates 230 kV lines and the new Manning – Gates 500 kV line. If required in the future, a Manning – Los Banos line could be built to further increase the transfer capability.



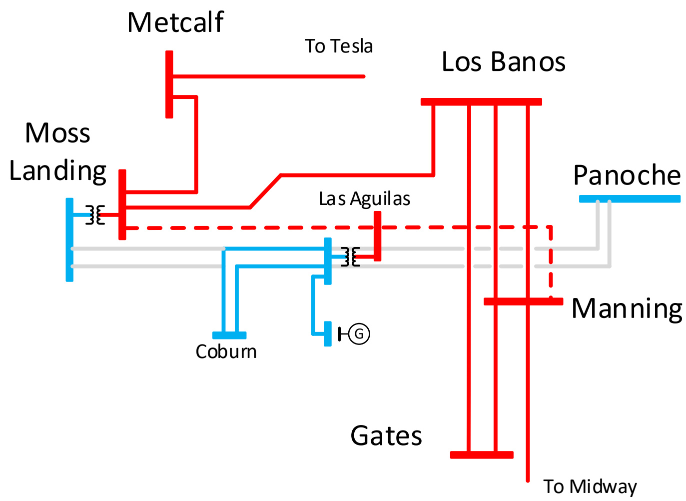
Second Los Banos - Tracy 500 kV line

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 Los Banos – Tracy 500 kV line.



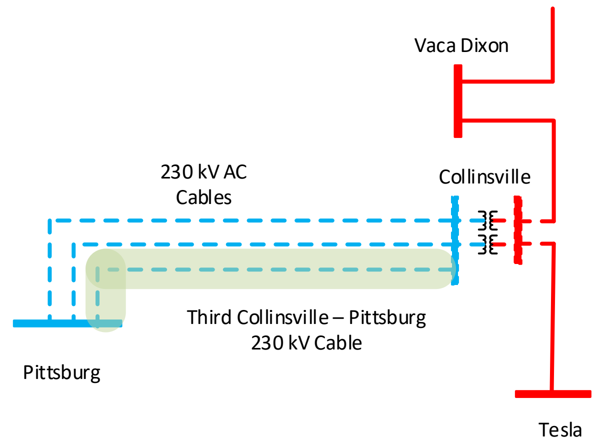
Manning – Moss Landing 500 kV line

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.



Third Collinsville – Pittsburg 230 kV cable

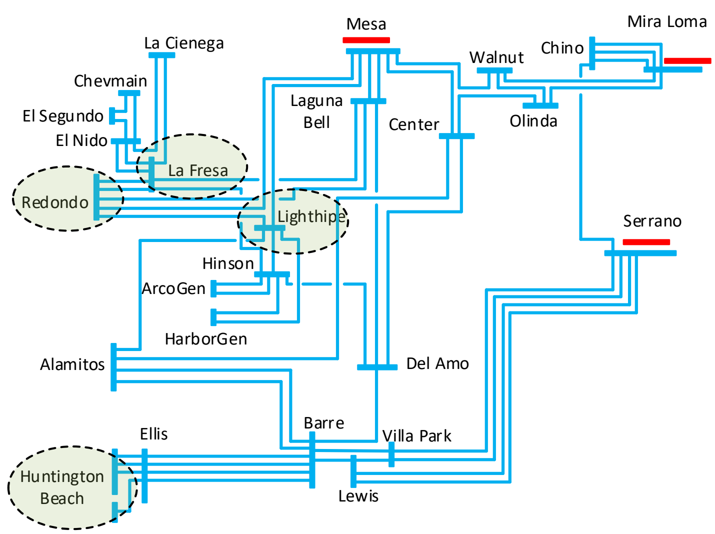
To mitigate the contingency overload on the Collinsville – Pittsburg 230 kV cables, a third Collinsville – Pittsburg cable was considered in this study.



Diablo – South, Lugo – LA Basin, and Devers – LA Basin HVDC projects

With 3,500 MW of gas retirement in the LA Basin area, transmission projects are needed to bring power from strong resources such as Diablo, Lugo and Devers 500 kV substations to the load centers in LA Basin. Without these projects, normal and contingency overloads occur on the existing 500/230 kV transformers and on the underlying 230 kV system.

Redondo, La Fresa, Lighthipe and Huntington Beach 230 kV substation are examples of locations that the HVDC converter station can connect



to and effectively address the overload issues. Pacific Transmission Expansion (PTE) project is an example of such HVDC links that transfers power from Diablo area and injects it to Redondo and Huntington Beach substations through a mulit-terminal HVDC link.

Diablo – North HVDC Project

The Diablo – North HVDC project helps to mitigate the overload on the Diablo – Gates 500 kV line and the Midway – Los Banos 500 kV path. It also provides power directly to the Bay area which provides another source to the area following the N-1-1 contingency of Metcaf – Mosslanding and Los Banos – Moss Landing 500 kV lines. While the schematic diagram shows connection at Moss Landing 500 kV bus, a more detailed study will determine the optimum configuration regarding point-to-point or multi-terminal HVDC and the interconnection points.

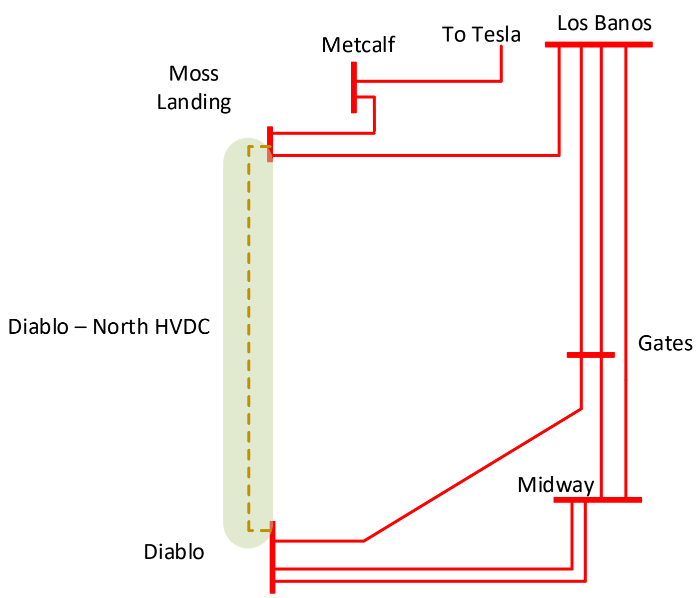
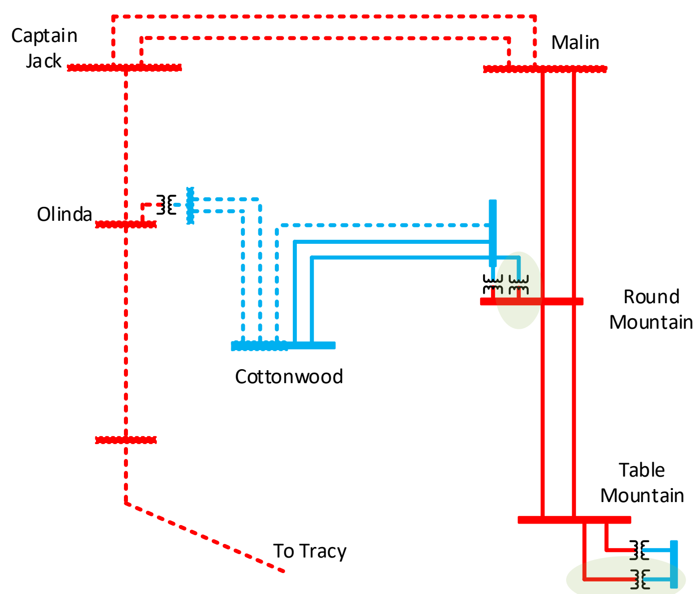


Table Mountain and Round Mountain 500/230 kV Transformers

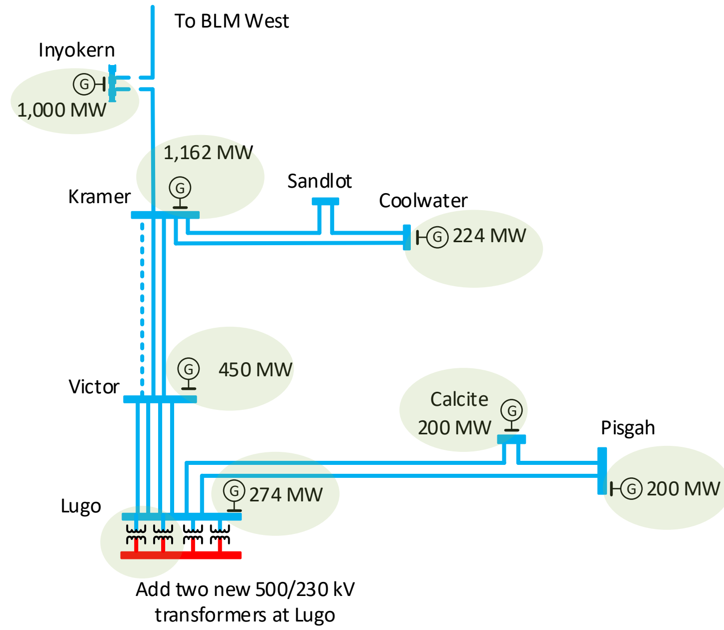
Second 500/230 kV transformer at Table Mountain substation will mitigate the normal overload on the existing Table mountain 500/230 kV transformer.

Contingency of either Olinda or Round Mountain 500/230 kV transformer overloads the other one. Second 500/230 kV transformer at Round Mountain substation will mitigate both overload issues.



Lugo 500/230 kV Transformers

Interconnection of more than 3,500 MW of solar resources to the 230 kV system terminating at Lugo 230 kV bus results in normal and contingency overload on the existing two 500/230 kV transformers at Lugo. Two additional transformers would be needed to address both normal and contingency overload.



5.4.2 Offshore Wind Transmission Development

The transmission development to integrate the 10,000 MW of offshore wind has been identified in section 3.1.8 above. The 6,000 MW of offshore wind resources in the central coast area can be interconnected to the existing 500 kV system in the Diablo/Morro Bay area. The 4,000 MW of offshore wind resources in the north coast area will require some significant 500 kV and HVDC facilities to interconnect to the existing 500 kV system to integrate the offshore wind into the ISO grid, as the transmission system in the north coast area is predominantly 115 kV and 60 kV. The ISO identified the need for two 500 kV AC lines connecting to the Fern Road 500 kV substation and a HVDC line to the Collinsville 500/230 kV substation as illustrated Figure 4.1.3 would be required. The HVDC line could be an over-land option or sea cable connection to Collinsville. One other alternative considered in the ISO's 2021-2022 Transmission Plan is an HVDC-VSC deep-sea cable to a new station referred to as Bay-hub located in the Greater Bay Area.

The initial offshore wind development in the north coast has been assumed to be in the Humboldt wind energy area of approximately 2,000 MW with the remaining 2,000 MW to be in either the Cape Mendocino or Del Norte areas. In addition to the 500 kV AC lines and the HVDC lines there would be additional transmission required to interconnect 500 kV AC and HVDC systems together and the offshore wind farms in the two wind development areas. These facilities would depend on where the second wind development occurs and could either consist of onshore or offshore grid development. Within the 20-Year Outlook, it has been assumed that the HVDC-VSC deep-sea alternative to a Bay-hub substation would be best after further development of the call areas beyond the current Humboldt call area under consideration and future leasing through the BOEM processes. The HVDC-VSC technology could be used to interconnect the off-shore wind areas as well as provide additional capacity to the load centers as the off-shore wind capacity increases off the shore of the norther California coast.

Offshore Grid Considerations

One option for offshore wind connection to the system on the shore is to interconnect each wind project with the system through a dedicated cable. In this configuration, there would be no power flow between different offshore wind projects. An alternative approach is to have an offshore grid to interconnect a number of projects offshore and bring the aggregated power to the shore. The 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[24] and Denmark[25].

It should be noted that offshore wind developments in California and other systems might have a major difference considering the depth of the water which may require solutions that are specifically designed for deep-water applications.

Increased Transfer Capacity between California and Pacific Northwest

The interconnection solution along with the mitigation measures studied in the assessment will potentially create two strong connection points in California that enable more interconnections between California and the Pacific Northwest. One strong point would be the Fern Road 500 kV substation which with the addition of Fern Road – Tesla 500 kV line will have capacity available for another connection to Pacific Northwest similar to Malin – Round Mountain 500 kV lines. Another strong point could be either the offshore or the onshore grid required for north coast wind development. This will also require coordination with the offshore wind potential in the Pacific Northwest and need to further explore the concept of an offshore grid, as indicated above, to collect the resources from the offshore wind farms off the California coast and connect to offshore wind developments in the Pacific Northwest that could also increase the transfer capabilities between the regions.

5.4.3 Out-of-State Wind Transmission Development

The Starting Point scenario identified 12,000 MW of out-of-state wind resources in 2040. The out-of-state wind has been identified as either requiring new transmission to bring the resource to the ISO transmission grid (9,900 MW) or on existing transmission (2,100 MW) as follows.

On new transmission

- Wyoming 4,685 MW
- New Mexico 5,215 MW

On existing transmission

- Northwest 1,500 MW
- Baja California 600 MW

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

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

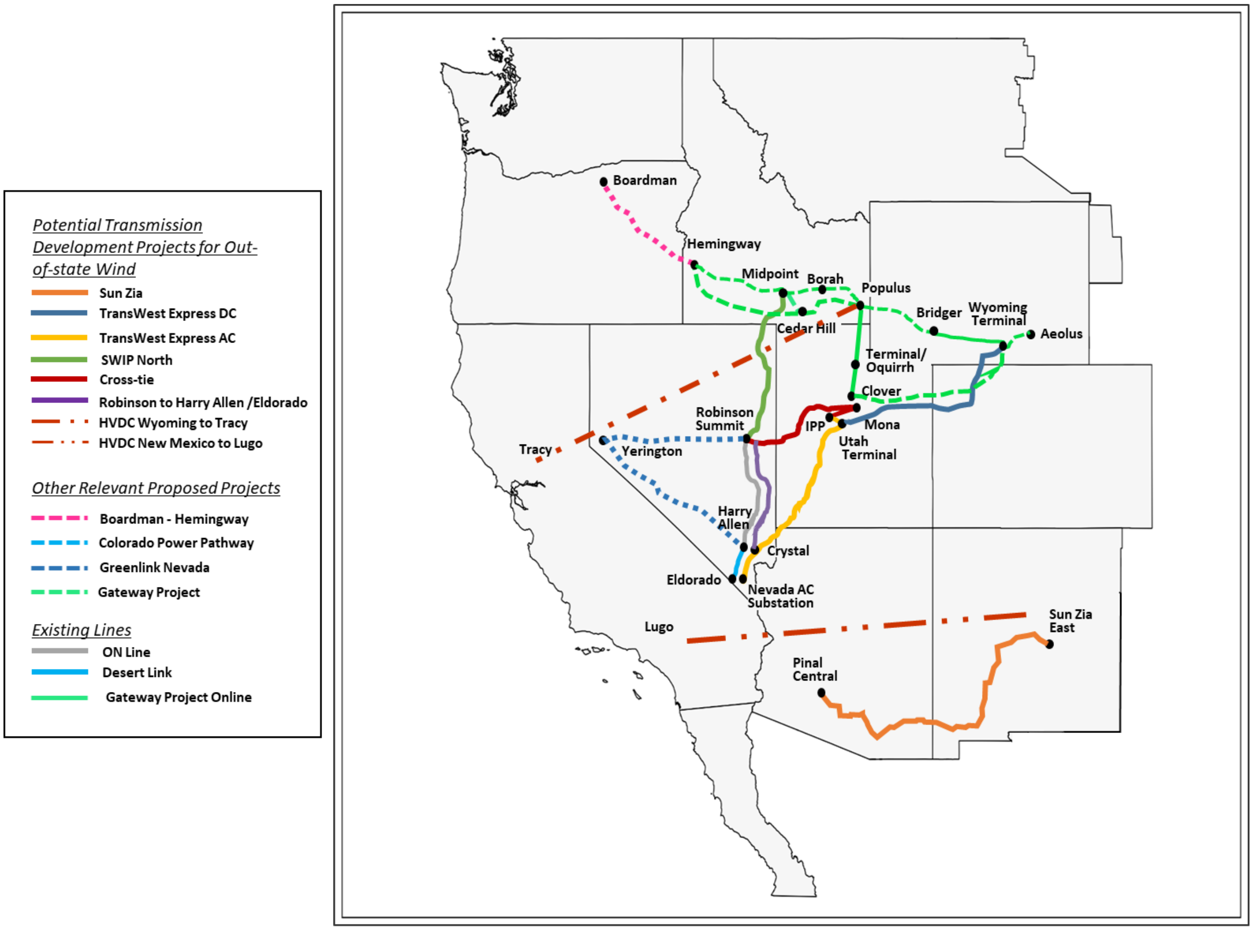
The transmission projects listed in Table 5.4-1, which were presented at the July 22, 2021 SB100 workshop, would be able transfer approximately 6,000 MW of the 9,900 MW of out-of-state wind in the SB100 Starting Point scenario to the ISO system.

Table 5.4-1: Potential transmission development projects for out-of-state wind resources

Transmission Development Project	Wind Area	Capacity (MW)
SunZia Project • Plus scheduling rights on existing lines from Pinal Central to Palo Verde connecting to the ISO system	New Mexico	2,000 – 3,000
TransWest Express • Also provides potential for 1,500 MW to LADWP	Wyoming	1,500
SWIP-North • With upgrades and scheduling rights On Line from Robinson to Harry Allen	Idaho	1,000
Cross-tie • Would require additional 500 kV line between Robinson to Eldorado	Wyoming	1,000

The studies conducted assumed approximately 6,000 MW of out-of-state wind injecting into the ISO system at Eldorado and Palo Verde that would be accommodated on the identified projects above as illustrated in Figure 5.4-3. The additional 3,900 MW of out-of-state wind in the SB100 Starting Point scenario would require additional transmission development beyond the projects that have currently been identified. The additional 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 as examples of such illustrated in Figure 5.4-3 will likely be required. Transmission lines to connect to interconnection points within the ISO system could potentially facilitate coordination with LADWP and BANC to bring in additional out-of-state wind that they may require for their resource portfolios.

Figure 5.4-3: Transmission to Accommodate Out of State Wind



5.4.4 Transmission Development Estimated Costs

The transmission development to integrate the resources in the SB100 Starting Point scenario have been identified in sections

Table 5.4-2: Estimated cost estimates[26] for transmission development to integrate the resources in SB100 Starting Point scenario

Transmission Development	Description	Cost Estimate
Upgrades to existing ISO footprint		**10.74**
Eldorado – Lugo 500 kV line	- 180 mi of 500 kV line - Series compensation in number of locations	$1 B
Colorado River – Devers 500 kV line	- Devers – Red Bluff 500 kV line - Ref Bluff – Colorado River 500 kV line	$1.2 B
North Gila – Imperial Valley 500 kV line	- 85 mi of 500 kV line - Series compensation	0.5 B
Westland 500/230 kV station	- 50 mi of 500 kV line - New 500/230 kV substation with two transformers ($200M)	0.5 B
Second Los Banos – Tracy 500 kV line	- 67 mi of 500 kV line	$0.33 B
Third Collinsville – Pittsburg 230 kV cable	- 230 kV cable	$0.14 B
Manning – Moss Landing 500 kV line	- 78 mi of 500 kV line - New 500/230 kV substation with two transformers ($100M)	$0.50 B
Devers – La Fresa HVDC	- 100 mi of DC cables - Two VSC HVDC converter	$1.2 B
Lugo – LA Basin HVDC	- 80 mi of DC cables - Two VSC HVDC converter	$1.0 B
Sycamore – Alberhill HVDC	- 82 mi of DC cables - Two VSC HVDC converter	$1.0 B
Diablo – South HVDC	- Four VSC converter stations - 250 miles HVDC cables	$1.85 B
Diablo – North HVDC	- Four VSC converter stations - 200 miles HVDC cables	$1.60 B
Round Mountain 500/230 kV Transformer	- Add one 500/230 kV transformer	$0.1 B
Lugo 500/230 kV Transformers	- Add one 500/230 kV transformer	$0.1 B

[26] 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.

Transmission Development	Description	Cost Estimate
Offshore Wind		**$8.11 B**
Humboldt Bay Offshore wind area	Total of 4,000 MW offshore wind connected through two of the following options: - Option 1 (Fern Road): $2.3 B - Option 2 (Bay Hub): $4.0 B - Option 3 (Collinsville): $3.0 B Facilities required to interconnect the transmission options connecting to the different offshore wind areas: $0.5B-$1.0 B.	$5.8 B– $8.0 B
Diablo – Morro Bay Offshore wind area	- Total of 6,000 MW offshore wind. Connected to Diablo 500 kV and the new Morro Bay 500 kV substation. - The cost estimate is only for a 500 kV switching station and looping in the existing Diablo – Gates 500 kV line into it.	0.11 B
Out-of-State Wind		**$11.65 B**
SWIP-North	275 mile 500 kV line from Midpoint to Robinson substation with upgrades to On Line from Robinson to Harry Allen to access Idaho wind resources	$0.64 B
Cross-Tie	214 mile 500 kV line from Robinson to Mona/Clover to access Wyoming wind resources	$0.67 B
Robinson-Eldorado	500 kV transmission line from Robinson to Harry Allen/Eldorado	$0.64 B
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	$2.1 B[27]
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	$2.6 B[28]

[27] The TransWest Express and Sunzia projects are being developed providing transmission service to resources seeking access to California markets on a subscriber model. The transmission costs would not be included in the ISO TAC.

[28] http://sunzia.net/wp-content/uploads/2021/12/SunZia-Economic-Analysis-Executive-Summary-FINAL.pdf

Transmission Development	Description	Cost Estimate
Additional transmission for additional wind resources from Wyoming/Idaho area	HVDC transmission line from the wind resource area to northern California (Tesla area)	$2.5 B
Additional transmission for additional wind resources from New Mexico area	HVDC transmission line from the wind resource area to southern California (Lugo area)	$2.5 B
Total estimated cost for transmission Development		**30.5**

5.5 Summary and Conclusions

The 20-Year Transmission Outlook 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 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.

The exercise was undertaken recognizing that California is facing an unprecedented need for new renewable 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 Transmission Outlook for transmission planning focused on meeting the needs identified through the CEC's SB100-related processes for achieving the state's 2045 objectives, with the resource requirements developed through a collaborative approach with the CEC, CPUC, and the ISO, translating the analyses conducted for the first SB 100 joint-agency report into the Starting Point scenario used by the ISO in this 20-year transmission outlook. The ISO also evaluated the system in 2040 utilizing the SB100 Core statewide high electrification load projection. 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 5.5-1 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.

Table 5.5-1: Cost estimate of transmission development to integrate resources of SB100 Starting Point scenario

Transmission Development	**Estimated Cost ($ billions)**
Upgrades to existing ISO footprint consisting of: • 230 kV and 500 kV AC lines • HVDC lines • Substation upgrades	$ 10.74 B
Offshore wind integration consisting of: • 500 kV AC lines • HVDC lines	$ 8.11 B
Out-of-state wind integration consisting of: • 500 kV AC lines • HVDC lines	$ 11.65 B
Total estimated cost of transmission development	**$ 30.5 B**

The ISO expects to conduct additional stakeholder dialogue through 2022 about next steps as well as the long-term architecture set out in this 20-Year Outlook. Those additional efforts, together with the 20-Year Outlook and evolving resource planning and procurement, will inform the ISO's annual transmission planning processes that approve and initiate specific projects.

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APPENDIX A: SB100 Starting Point Scenario

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DOCKETED	
Docket Number:	21-SIT-01
Project Title:	21-SIT-01, SB100 Implementation Planning for SB100 Resource Build
TN #:	239685
Document Title:	SB 100 Starting Point for the CAISO 20-year Transmission Outlook
Description:	SB 100 Starting Point for the CAISO 20-year Transmission Outlook
Filer:	Mary Dyas
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	9/13/2021 4:03:52 PM
Docketed Date:	9/13/2021

Introduction

Following the release of the "2021 SB100 Joint Agency Report" (2021 SB 100 Report) in March 2021, the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and California Independent System Operator (CAISO) initiated a collaborative process to focus on the resource build requirements to achieve The 100 Percent Clean Energy Act of 2018 (SB 100, De León, Chapter 312, Statutes of 2018).[1] This collaborative process is on-going and includes a public stakeholder process.

As described at a public workshop on August 12, 2021, one of the priorities for the SB 100 resource build process is using the analysis from the 2021 SB 100 Report to inform the CAISO's recently initiated 20-year transmission outlook ("20-year outlook") process.[2]

This document describes the Starting Point scenario, based on the SB 100 Report, for CAISO's use as the basis for the 20-year outlook process. The Starting Point scenario description in this document includes the allocation of resources in the scenario, and where applicable, how those resources are geographically mapped.

The objective of CAISO's 20-year outlook is to explore longer term grid requirements and options for meeting the state's greenhouse gas reduction goals. With this objective in mind, the Starting Point scenario is designed to provide information for a wide range of potential transmission needs driven by a combination of potential resource opportunities.

The 2021 SB 100 Report presents scenarios to reach 100 percent clean energy, including "core scenarios" and "study scenarios," intended to provide additional information to support broader state energy, climate planning, and public health efforts. The Starting Point scenario is largely based on the 2021 SB 100 Report Core scenario (SB 100 Core) but draws from other scenarios in the 2021 SB 100 Report as well. The potential resource opportunities include, for example, diverse resources known to require transmission development such as offshore wind energy and out-of-state resources, but also gas power plant retirements that may require transmission development to reduce local area constraints. Through this effort, the state aims to understand what transmission development would be required to make any one of these elements possible, thereby allowing the state to then refine resource planning.

The Starting Point scenario (including supporting documents) is intended to provide an immediately useful starting point for the CAISO in its 20-year outlook. The use of the Starting Point scenario for the 20-year outlook is not a commitment to the resource and storage mix included in the scenario. Instead, the energy agencies intend to continue to consider a range of scenarios in forthcoming reliability assessments and stakeholder work on resource build requirements. The Starting Point scenario is informational only and should not be used, in itself, to support approval of near-term infrastructure

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[1] On May 21, 2021 the CEC opened a new docket, 21-SIT-01, for SB 100 Implementation Planning for SB 100 Resource Build: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=21-SIT-01. Workshop materials and public and stakeholder comments are available in the docket.

[2] See the workshop webpage for the SB 100 Resource Build: Resource Mapping https://www.energy.ca.gov/event/workshop/2021-08/joint-agency-workshop-next-steps-plan-senate-bill-100-resource-build

investments. Underlying data and information that is incorporated into the Starting Point scenario, as well as input and additional information obtained in the public process, may be cited as appropriate.

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 of the CAISO. The CEC, CPUC, and CAISO appreciate the interest expressed by non-CAISO BAAs in collaborative technical work to support this process.

Background

SB 100 establishes a policy that renewable and zero-carbon resources supply 100 percent of California's retail sales and electricity procured to serve all state agencies by 2045. Among other things, SB 100 requires the CEC, CPUC, and California Air Resources Board to develop and submit a joint-agency report to the legislature by January 1, 2021, and at least every four years thereafter.

The first joint-agency report published on March 15, 2021 recommends updates of land use information to reflect the increased resource requirements of SB 100, to further consider the potential impact of emerging resources and technologies, and to integrate into SB 100 planning the social costs and non-energy benefits of land-use impacts, public health, air quality, water supply and quality, economic impacts, and resilience.

The 2021 SB 100 Report indicates that achieving the 2045 goal is technically feasible but that it will require sustained record setting build rates of renewable resources, zero-carbon technologies and integration solutions.

Effectively integrating 100 percent renewable and zero-carbon technologies in California by 2045 will require rigorous analysis of implementation considerations and coordinated planning across the different levels of government and with grid operators throughout the state. Statewide planning will ensure that California has a safe and reliable electricity system as new renewable and zero-carbon resources and transmission infrastructure is developed, consistent with the state's clean energy and environmental priorities and goals.

To build-off of the 2021 SB 100 Report, the CEC, CPUC, and the CAISO collaborated on an approach to translate the analyses conducted for the first SB 100 joint-agency report into a Starting Point scenario for use by the CAISO in the 20-year outlook. The Starting Point scenario, and the criteria for using that scenario to study the transmission required for a particular portfolio of resources studied in the 2021 SB 100 Report, are described below. This initial portfolio is not an endorsement of any particular resource or potential transmission solution. The CEC and CPUC expect that the information from the 20-year outlook will help inform future electric sector planning, including the next SB 100 joint-agency report.

CAISO's 20-year transmission outlook

The objective of the 20-year outlook is to conduct a long-term assessment of transmission needs and grid development options for meeting SB 100.[3] The CAISO is conducting its 20-year outlook in parallel

[3] See the 20-year transmission outlook webpage: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/20-Year-transmission-outlook

with its current 2021-2022 Transmission Planning Process (TPP). The TPP is the CAISO's annual tariff-based 10-year transmission planning process.[4]

The CAISO initiated the 20-year outlook to have a more flexible framework and stakeholder process outside of the formal tariff-based TPP, which focuses on transmission project needs and transmission project approvals over a 10-year planning horizon. The 20-year outlook may support state electric sector planning, including the next joint-agency SB 100 report, the CPUC's SB 350 Integrated Resource Planning (IRP) processes, and the CEC's Integrated Energy Policy Report.

SB 100 joint-agency report scenarios

The analyses for the 2021 SB 100 Report developed resource portfolios using the RESOLVE California model, a capacity expansion model developed by Energy and Environmental Economics, Inc. (E3). The RESOLVE model produces a least-cost resource portfolio, given policy and reliability constraints. The inputs and assumptions used in the RESOLVE model for the 2021 SB 100 Report built upon previous capacity expansion planning, including the CPUC's IRP proceedings, and were informed through public and stakeholder comments.[5]

The 2021 SB 100 Report included a range of scenarios and sensitivities to evaluate possible pathways to achieve the SB 100 policy and only resources that are commercialized or near commercialization and aligned with other state policies are included. Table 1 is from the 2021 SB 100 Report and represents a possible future mix of resources based on the best information at the time. The agencies recognize that there are emerging and potentially new technologies that may become part of the zero-carbon resource mix in the future. Table 1 below is a list of the scenarios explored in the 2021 SB 100 Report.

[4] See the 2021-2022 TPP webpage: http://www.caiso.com/planning/Pages/TransmissionPlanning/2021-2022TransmissionPlanningProcess.aspx.

[5] For more information on the scenarios modeled as part of the first joint-agency report, see: https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349

Table 1: SB 100 Core and Study Scenarios from the 2021 SB 100 Joint-Agency Report

Scenario Classification	Scenario Description
Core Study Scenarios	
60% RPS (Counterfactual)	60% RPS through 2045
SB 100 Core Scenario	Core Load Coverage[6]; High Electrification Demand; All candidate resources available
SB 100 Core, Demand Sensitivities	Change: Demand Scenarios or Load Shape
SB 100 Core, Resource Sensitivities	Change: Candidate Resource Availability
Study Scenarios	
Expanded Load Coverage	Core Load Coverage plus storage and T&D losses; High Electrification Demand; All candidate resources available
Expanded Load Coverage, Demand Sensitivities	Change: Demand Scenarios
Expanded Load Coverage, Resource Sensitivities	Change: Candidate Resource Availability
Zero Carbon Firm Resources	Add generic zero carbon firm resources to candidate resources as a proxy for emerging zero-carbon technologies
Accelerated Timelines	Accelerate 100% target to 2030, 2035, and 2040
No Combustion	No conventional combustion resources included (fossil and biomass based); retire all in-state combustion resources by 2045

Source: 2021 SB 100 Joint-Agency Report: https://www.energy.ca.gov/sb100

The Starting Point Scenario

The Starting Point scenario was developed by taking the 2040 SB 100 Core scenario and increasing assumed natural gas power plant retirements to 15,000 MW. This allows 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. Additionally, to generally offset the additional assumed natural gas power plant retirements, geothermal, offshore wind, 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.

While the Starting Point scenario will be used for the 20-year outlook, the agencies expect to use a range of scenarios to inform subsequent analytical and stakeholder work (e.g. reliability assessments and land use analysis).

To illustrate the Starting Point scenario, Table 2 below compares the SB 100 Core scenario for 2040 with the Starting Point scenario.

[6] The "SB 100 core" load coverage target is consistent with the joint agencies' interpretation of SB 100, and 100 percent of retail sales plus state agency loads in 2045 are met by zero-carbon generation. Interim years include a linear zero-carbon target from 2030 to 2045.

Table 2: Comparison of 2040 SB 100 Core and Starting Point Scenario

Resource Type	2040 SB 100 Core Scenario (MW)	2040 Starting Point Scenario (MW)
Natural gas fired power plants	(4,722)	(15,000)
Battery energy storage	32,093	37,000
Long duration energy storage	4,000	4,000
Utility-scale solar	53,212	53,212
In-state wind	2,237	2,237
Offshore wind	5,256	10,000
Out of state wind	10,315	12,000
Geothermal	135	2,332

Source: RESOLVE Model results viewer, SB 100 joint-agency model: https://www.energy.ca.gov/sb100

The next section discusses how the Starting Point scenario could be reflected in the 20-year outlook.

Resource allocations for the starting point scenario

The CAISO's 20-year outlook will require geographically mapping resources to specific locations, to the extent feasible. The RESOLVE model includes a coarse-level of geographic information by transmission zone for the new-build renewable energy resources. However, the Starting Point scenario makes some modifications to the allocations of certain resources to transmission zones as described below. In addition, RESOLVE does not include geographic information for potential natural gas power plant retirements or new energy storage facilities.

This section describes, for each resource in the portfolio, criteria for the CAISO to use in the 20-year outlook. The information builds off the current CPUC IRP portfolios being studied for the year 2031 within the 2021-22 TPP.

At the end of this section, a table with initial geographic allocations for the 20-year outlook for each resource is included, as applicable.

Natural gas power plant retirements

The Starting Point scenario includes an assumption that 15,000 MW of natural gas power plant capacity would be retired by 2040, which is approximately 50 percent of natural gas power plant capacity assumed in the 2021 SB 100 Report scenarios. To identify locations of these retirements in the 20-year outlook, the CAISO should use information provided by the agencies to assume that the oldest natural gas power plants retire first, with a priority on those that are in and adjacent to disadvantaged communities (DAC).[7] In addition, to understand the electric transmission implications of having no natural gas storage capacity at the Aliso Canyon natural gas storage facility, the CAISO should ensure that at least 3,000 MW of the 15,000 MW of retirements are assigned to gas power plants that rely on the Aliso Canyon storage facility as provided by the agencies, with a priority on the oldest power plants

[7] 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 purposes of this Starting Point scenario a DAC adjacent community is within a 2.5 mile radius of a natural gas power plant.

and those that are in and adjacent to DACs.[8] The CEC and CPUC staff will coordinate with the CAISO to identify the natural gas capacity assumed retired in the Starting Point scenario.

New-build energy storage

The RESOLVE model outputs do not include locational information for battery energy storage or long duration storage. Below is the criteria that informs the allocation for each energy storage type.

Battery energy storage

In the SB 100 Core scenario, RESOLVE selects 32,093 MW of battery energy storage in 2040. In the Starting Point scenario the CAISO will study 37,000 MW of battery energy storage in the 20-year outlook. The approach used for assigning battery energy storage to transmission zones for the 20-year outlook draws on the approach applied to battery energy storage in the CPUC's IRP process for the CAISO's TPP.[9] As shown in Table 3 at the end of this section, the 37,000 MW of selected battery energy storage is allocated as follows:

- 9,368 MW of battery storage already allocated in the IRP resource portfolio for the 2021-2022 TPP base case is carried over without any changes.
- The remaining battery energy storage will be allocated by expanding upon the approach from the 2021-2022 TPP base case:
    - Co-locate in transmission zones where renewable resources are concentrated.
    - Allow CAISO to allocate battery storage based on system needs identified in the study.

Long-duration energy storage

Long-duration energy storage (LDES) was modeled in the 2021 SB 100 Report as pumped hydroelectric energy storage.[10] However, any long-duration storage technology with eight hours or longer of energy generation at maximum output would represent similar attributes. The 4,000 MW of long-duration energy storage in the SB 100 Core scenario will be allocated by building off the current 2021-2022 TPP base case as well as current commercial interest.

The 4,000 MW of LDES will be allocated by:

- 627 MW of pumped hydroelectric already mapped in the IRP resource portfolio for the 2021-2022 TPP base case.

[8] If 3,000 MW of Aliso Canyon dependent gas power plants are not identified when assuming retirement for the oldest gas power plants in and adjacent to DACs statewide, then the CAISO should apply the aged based and DAC proximity criteria to a list of Aliso Canyon dependent gas power plants, until 3,000 MW is identified, and then the CAISO should apply the aged based and DAC proximity criteria to the remaining fleet of in-state natural gas power plants to derive the full 15,000 MW of assumed retirements.

[9] The methodology applied when mapping the IRP resource portfolios for the 2021-2022 TPP can be found here: Final Methodology for Resource-to-Busbar Mapping & Assumption for the 2021-2022 TPP

[10] 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 may be released and passed through hydraulic turbines to generate electricity as needed.

- 2,400 MW of pumped hydroelectric as described in the current CAISO interconnection queue.
- 1,600 MW of location unconstrained LDES that is unassigned should be assigned to transmission zones based on a combination of geologic and technological factors and system needs. The CAISO and agencies will work together with stakeholders and other California BAAs to continue assessing LDES opportunities, including locational factors for different technology types. [11]

New-build renewable energy

In contrast to the resources discussed above, new build renewable energy was assigned to transmission zones by the RESOLVE model. This section describes how the RESOLVE model assigned new build renewable resources to locations and summarizes the adjustments made to these allocations for the CAISO 20-year outlook.

RESOLVE renewable energy resource assumptions

The renewable resource potential used in the RESOLVE model formed the basis of geographic assumptions for the locations of renewable energy resources in the SB 100 scenarios. Renewable resource potential is based on raw technical potential and is calculated for each renewable resource type within RESOLVE transmission zones. The raw technical potential is then "filtered" through a set of environmental screens to produce the renewable resource potential that RESOLVE uses to select new-build renewable energy. The RESOLVE model includes six options for environmental screens:[12]

1. Base: includes RETI Category 1 exclusions only;
2. Environmental Baseline (EnvBase): includes RETI Category 1 and 2 exclusions;
3. NGO1: first screen developed by environmental NGOs;
4. NGO1&2: second screen developed by environmental NGOs;
5. DRECP/SJV: includes RETI Categories 1 and 2 plus preferred development areas only in the DRECP (Desert Renewable Energy Conservation Plan) and San Joaquin Valley (SJV); and,
6. Conservative: the potential when all the above screens are applied simultaneously

Additionally, a non-spatial calculation is applied to the renewable resource potential that discounts the resource potential by 80 percent to generically reflect development constraints and build in a preference for geographic diversity of renewable resources. Also, planned renewable energy resources with an online date after December 31, 2018 that are included in the baseline inputs of RESOLVE are subtracted from the available renewable resource potential in each transmission zone.

The RESOLVE model used for the 2021 SB 100 Report applied the DRECP/SJV resource screen. As a starting point, the map in Figure 1 below displays the renewable resource potential for the DRECP/SJV resource screen for each renewable resource type by transmission zone.

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[11] While there are 4.5 GW of pumped hydro energy storage in California, new longer-duration energy storage systems (for example, 100 or more hours of energy storage) are in the development phase and may be deployed within the next decade with the right market signals. Longer-duration storage technologies, such as advanced batteries, thermal energy storage, liquid air energy storage, and compressed air energy storage, can support reliability and further promote achievement of SB 100 goals.

[12] See the SB 100 RESOLVE model Inputs and Assumptions: https://efiling.energy.ca.gov/GetDocument.aspx?tn=234532&DocumentContentId=67359

RESOLVE renewable resource assignments and starting point adjustments

For each renewable resource type, this section summarizes the process for making adjustments to the RESOLVE selections as a starting point for the 20-year outlook and further stakeholder discussion.

Utility-scale solar

In the Starting Point scenario, which is the same as the SB 100 Core scenario, 53,212 MW of solar capacity is assumed to be built in 2040. This would require 372,484 acres with current technology, assuming that 7 acres are required per MW.

For the CAISO 20-year outlook, the Starting Point scenario utilizes known commercial interest to allocate solar development to transmission zones rather than carrying forward the allocations made by the RESOLVE model. The CEC utilized a high-level environmental screen to assess whether the commercial interest allocation had resulted in a clearly disproportionate assignment of solar build out to any of the transmission zones relative to the availability of "lower implication" land in each zone. In one transmission zone, the CEC took the additional step of reallocating some solar capacity to a different transmission zone based on that review.

As shown in Table 3 below, the SB 100 RESOLVE model did not select solar resources from outside of California. However, to maintain consistency with the CPUC IRP and CAISO TPP the agencies allocate 4,624 MW of the total solar portfolio to transmission zones in Southern Nevada and Arizona.

Commercial interest

Commercial interest, as used in this Starting Point scenario, is determined by using the CAISO's publicly available interconnection queue information.[13] This includes projects in the queue through the Cluster 13 study window. The queue information was summarized by technology and assigned to the RESOLVE transmission zones. The agencies use the approximate proportional calculation of the solar projects in the queue, by transmission zone, to re-allocate the solar capacity selected by RESOLVE, and discounted by the out of state solar allocations, to transmission zones for this starting point. As shown in the table at the end of this section, applying the proportional calculation of commercial interest results in a different allocation of solar resources in RESOLVE transmission zones. The table also includes commercial interest by transmission zone for non-solar resource types, however these resources are not re-allocated based on commercial interest.

The map in Figure 2 below shows the in-state transmission zones as a starting point for where solar might be developed based on the re-allocation of solar based on commercial interest.

Environmental information

The re-allocation of resources based on proportions of commercial interest are compared to environmental information.[14] The CEC has mapped environmental and land use information to develop a high-level information screen for renewable energy resource areas. The screen is primarily based on

[13] http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx

[14] See the workshop webpage for the SB 100 Resource Build: Resource Mapping https://www.energy.ca.gov/event/workshop/2021-08/joint-agency-workshop-next-steps-plan-senate-bill-100-resource-build

terrestrial biological information maintained by the California Department of Fish and Wildlife and several ecological models developed for the CEC landscape energy planning activities. This information helps identify landscapes that are important for species habitat, habitat connectivity, and provide intact landscapes. Taken together, these areas are best suited for long-term conservation of species and habitats and for climate resiliency. Renewable energy resources that are outside of these areas are considered to be areas better suited for renewable energy development.

For purposes of this review, it is assumed that these areas are where the potential future build-out of solar generation would occur. Additionally, the CEC assumed that up to 25 percent of the area might be buildable, due to other non-technical constraints. The acreage needed to achieve the buildout of solar capacity assigned by the RESOLVE model is based on the assumption of 7 acres per MW. The CEC next considered whether the re-allocation of resources based on proportions of commercial interest resulted in any obvious outliers in terms of our high-level estimates of the percentage build out of the more buildable land in each transmission zone.

Based on that comparison, the re-allocation of solar resources to the Tehachapi transmission zone is 58 percent of the more buildable area, while other re-allocations to transmission zones are between 1 and 29 percent. As described in the table, the CEC adjusted the re-allocation of solar capacity in the Tehachapi transmission zone to the current commercial interest amount, which is approximately 35 percent of the more buildable land.[15]

The agencies recognize that more work remains to be done to vet the environmental screening methodology developed by the CEC, including appropriate uses of these kinds of data and analytical tools as well as the assembly and interpretation of the underlying data and look forward to engaging further with stakeholders on this topic.

In-state wind

In the SB 100 Core scenario, the RESOLVE model selects all of the available in-state wind resource potential. As shown in Table 3 at the end of this section, RESOLVE selects 2,237 MW, which is similar to the 1,981 MW included in the CPUC IRP portfolios being studied in the 2021-2022 TPP base case. As shown in the renewable resource map (Figure 1), wind energy resources are selected by the model in regions of the state that have very limited, and in some cases no wind energy development. Stakeholders have questioned whether these selections may use out of date information to characterize resource potential. The agencies support the recommendation to conduct further engagement with stakeholders to improve the inputs and assumptions used for in-state wind resource potential.[16]

Offshore wind

In the SB 100 Core scenario, RESOLVE selects 5,256 MW of offshore wind in 2040. In the Starting Point scenario the CAISO will study 10,000 MW of offshore wind energy in the 20-year outlook which is

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[15] The use of the environmental and land use information in this exercise was for the purpose of providing a comparison of these transmission zone areas. This information is used as a "starting point" and is intended to encourage discussion and input from stakeholders. This landscape level information does not address site specific issues or project level environmental assessments.

[16] See comment from the California Wind Energy Association in response to the August 12, 2021 resource build workshop: https://efiling.energy.ca.gov/GetDocument.aspx?tn=239406&DocumentContentId=72864

consistent with other SB 100 scenarios. In the 2021-2022 TPP the CAISO is studying offshore wind energy as a sensitivity and in an outlook study. There is more than 10,000 MW being assessed by the CAISO as part of the 2021-2022 TPP and the results of those studies will inform how offshore wind energy is included in the 20-year outlook. By looking beyond 10,000 MW of offshore wind energy for the 20-year outlook, the CAISO's analysis will provide important information to update the inputs and assumptions used to characterize offshore wind energy potential in future energy resource planning, including the next SB 100 joint-agency report.

Out-of-state wind

In the SB 100 Core scenario RESOLVE selects 10,315 MW of out of state wind resources in 2040 and in the Starting Point scenario the CAISO will study 12,000 MW in the 20-year outlook, which is consistent with other SB 100 scenarios. As shown in Table 3 at the end of this section, in the SB 100 Core scenario, RESOLVE selects 12,000 MW of out of state wind resources in 2040 and is allocated by:

- 2,087 MW already allocated in the IRP resource portfolio for the 2021-2022 TPP base case.
    - 530 MW from the Northwest
    - 495 MW from Baja California
    - 1,062 MW from Wyoming/Idaho or New Mexico
- An additional 1,938 MW of out of state wind on new transmission, for a total of 3,000 MW are also being studied as a sensitivity study in the 2021-2022 TPP and are allocated as:
    - 1,500 MW from Wyoming/Idaho
    - 1,500 MW from New Mexico
- For the capacity of out of state wind energy that was selected in the SB 100 Core scenario, but is not currently being studied in the 2021-2022 TPP, the transmission projects presented at the July 22, 2021 SB 100 resource build workshop will be a source of input for allocating these additional out of state wind energy resources.[17] The CAISO will consider the nature of transmission that would be required to integrate these resources, and where these resources should be interconnecting into the CAISO system.
- These allocations are just a starting point. Additional outreach to project developers, as well as collaboration with California BAAs and stakeholders to assess additional resource locations and transmission opportunities will be done to support the 20-year outlook.

Geothermal

In the Core scenario RESOLVE selects 135 MW of geothermal resources in 2040. In the Starting Point scenario the CAISO will study 2,332 MW of geothermal resources in 2040, which is consistent with other SB 100 scenarios and is nearly all of the resource potential assumed in the RESOLVE model. As shown in

[17] The SB 100 resource build workshop that focused on transmission included presentations from project developers with transmission projects under development. Of the projects that were presented, the majority were related to bringing out of state wind to California.

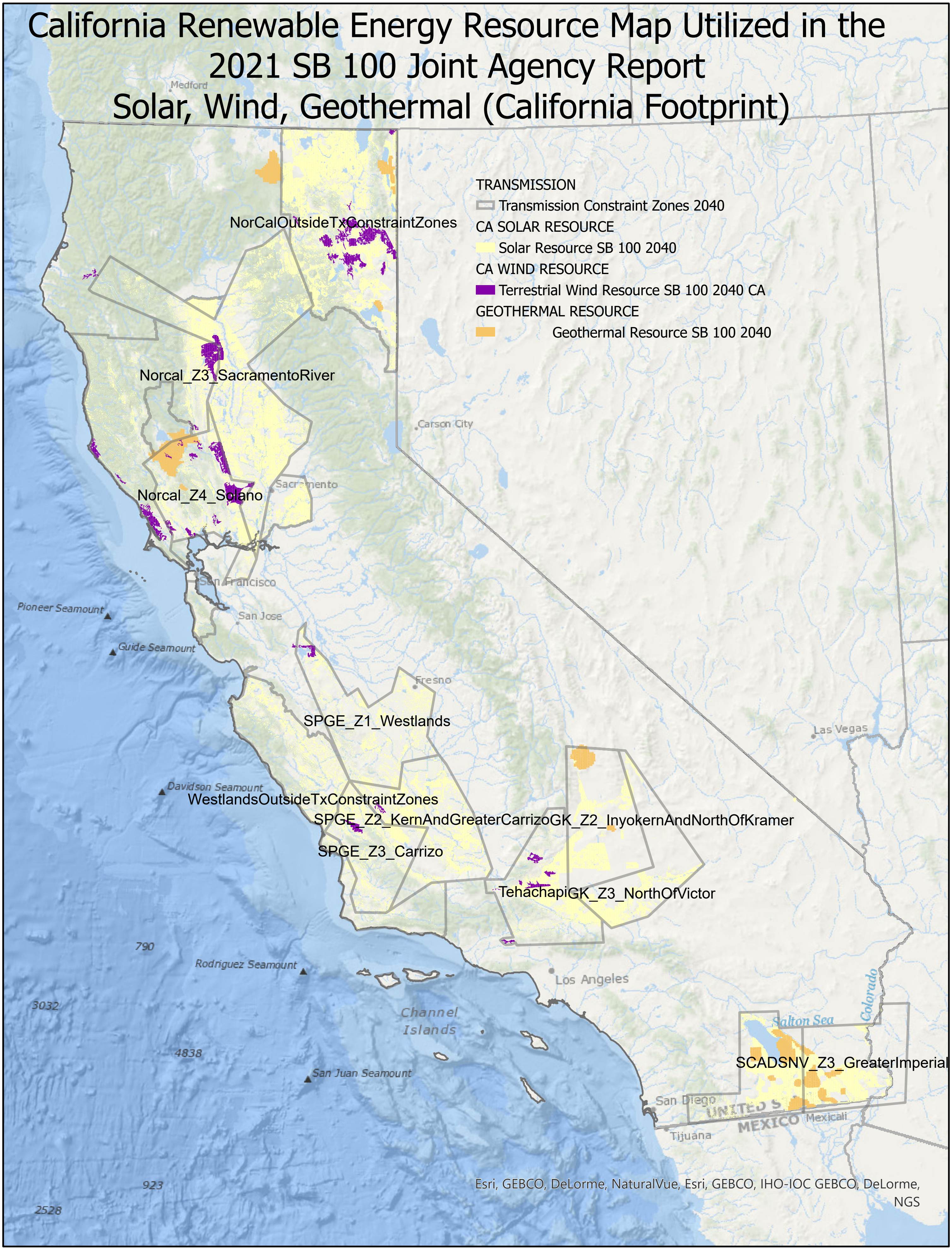
the map in Figure 1, some of the geothermal energy resources assumed in the model are located in regions of the state that have very limited, and in some cases no geothermal energy development.

As a starting point for the 20-year outlook, and to more fully understand the ability for geothermal to scale in and around the Salton Sea region the agencies allocated most, but not all, of the geothermal capacity to the Imperial transmission zone. Studying the transmission implications of this level of geothermal development in the Imperial transmission zone can improve the inputs and assumptions in future energy system planning, including the next SB 100 joint-agency report. The agencies will also conduct stakeholder engagement on other geothermal areas.

Table 3: SB 100 Build Scenario for CAISO 20 Year Transmission Outlook

Resource	Transmission Zone	Assumptions from RESOLVE CPUC IRP and CAISO TPP Base Case	Assumptions from RESOLVE CPUC IRP and CAISO TPP Base Case	Assumptions from 2021 SB 100 Core Scenario 2040	Commercial Interest (solar only)	Starting Point Scenario (with adjustments to SB 100 RESOLVE Outputs)	NOTES
Terrestrial Wind (In-State Footprint)		FD	EO		MW		
Humboldt_Wind	Sacramento_River-Humboldt		34	34			
Carrizo_Wind	SPGE_Z3_Carrizo	187		287		SB 100 RESOLVE selects 2,237 MW, which is similar to the 1,981 MW included in the CPUC IRP portfolios being studied in the 2021-2022 TPP base case.	
Central_Valley_North_Los_Banos_Wind	SPGE_Z1_Westlands	173		173			
Kern_Greater_Carrizo_Wind	SPGE_Z2_KernAndGreaterCarrizo	20		60			
Northern_California_Ex_Wind	NorCalOutsideTxConstraintZones	767		866			
Solano_Wind	Norcal_Z4_Solano	462		542			
Tehachapi_Wind	Tehachapi	275		275			
Wind (Out-State Footprint on Existing Transmission)							
NW_Ext_Tx_Wind		530		1,500		As selected by SB 100 RESOLVE	
Southern_Nevada_Wind		-		none			
Baja_California_Wind		495		600		As selected by SB 100 RESOLVE	
Geothermal (In-State Footprint)							
Greater_Imperial_Geothermal	SCADSNV_Z3_GreaterImperial	600	600	none		2,012	The geothermal resources are allocated in the Starting Point scenario to the Imperial transmission zone.
Inyokern_North_Kramer_Geothermal	GK_Z2_InyokernAndNorthOfKramer			none		none	
Northern_California_Ex_Geothermal	NorCalOutsideTxConstraintZones			none		none	
Riverside_Palm_Springs_Geothermal				none		none	
Solano_Geothermal	Norcal_Z4_Solano	51		135		none	
Geothermal (Out-State Footprint)							
Southern_Nevada_Geothermal	Mountain_Pass_El_Dorado-SCADSNV			none		320	
Solar (In-State Footprint)							
Carrizo_Solar	SPGE_Z3_Carrizo		-	9,907	none	none	
Greater_Imperial_Solar	SCADSNV_Z3_GreaterImperial		548	1,300	3,800	6,407	
Inyokern_North_Kramer_Solar	GK_Z2_InyokernAndNorthOfKramer			97	1,282	2,162	
Kern_Greater_Carrizo_Solar	SPGE_Z2_KernAndGreaterCarrizo		700	8,329	3,650	6,154	
North_Victor_Solar	GK_Z3_NorthOfVictor	300		300	400	674	
Northern_California_Ex_Solar	NorCalOutsideTxConstraintZones			866	none	none	
Sacramento_River_Solar	Norcal_Z3_SacramentoRiver			23,484	592	998	
Solano_Solar	Norcal_Z4_Solano	57		622	100	169	
Tehachapi_Solar	Tehachapi	3,880	800	4,801	9,544	9,544	Projected MW Allocation exceeds 50% low implication land area. Allocation set to commercial interest. This area needs further evaluation and discussion in the SB 100 Implementation stakeholder process. 6,549 MW was reallocated to Westlands TX Zone.
Westlands_Ex_Solar	WestlandsOutsideTxConstraintZones	1,779		1,779	none	none	
Westlands_Solar	SPGE_Z1_Westlands	468		618	3,621	12,655	Projected MW Allocation augmented with reassigned MW from Tehachapi Solar (6,549 MW).
SCADSNV_Solar	SCADSNV	230	338	none	none	none	
Pisgah_Solar	GK_Z4_Pisgah	201		none	400	674	
Additional Solar Resources with Commercial Interest (In-State Footprint							
RiversideAndPalmSprings Solar	RiversideAndPalmSprings			none	2,919	4,922	
CentralValleyAndLos Banos Solar	CentralValleyAndLosBanosSolar			none	640	1,079	
Tehachapi Outside of Constraint Zones	Tehachapi Outside of Constraint Zones			none	1,225	2,066	
Greater ImpOutside Constraint Zones				none	590	995	
Subtotal					**28,763**	**48,500**	
Solar (Out-State Footprint)							
Mountain_Pass_El_Dorado_Solar	Mountain_Pass_El_Dorado	248		248		248	Mountain Pass_El Dorado Solar not selected in SB 100 RESOLVE Model. MW carried forward from CPUC IRP PSP 2031 46MMT Portfolio (248 MW). MW subtracted from In State Solar MW Total to adjust In State Build
Southern_Nevada_Solar	SCADSNV-GLW_VEA	624	1,400	none		2,024	Southern Nevada Solar not selected in SB 100 RESOLVE Model. MW carried forward from CPUC IRP PSP 2031 46MMT Portfolio (2,024 MW). MW subtracted from In State Solar MW Total to adjust In State Build
Arizona_Solar	SCADSNV-Riverside_Palm_Springs	772	1,580	none		2,352	Arizona Solar not selected in SB 100 RESOLVE Model. MW carried forward from CPUC IRP PSP 2031 46MMT Portfolio (2,352 MW). MW subtracted from In State Solar MW Total to adjust In State Build
Out of State Wind (Out-State Footprint)							
Wyoming_Wind_T1	SCADSNV_Z5_SCADSNV	1,062		3,000		As selected by SB 100 RESOLVE	
Wyoming_Wind_T2				none		1,685	
New_Mexico_Wind_T1	Riverside_Palm_Springs-SCADSNV			3,000		As selected by SB 100 RESOLVE	
New_Mexico_Wind_T2	Riverside_Palm_Springs-SCADSNV			2,215		As selected by SB 100 RESOLVE	

Figure 1



California Renewable Energy Resource Map Utilized in the
2021 SB 100 Joint Agency Report
Solar, Wind, Geothermal (California Footprint)
TRANSMISSION
Transmission Constraint Zones 2040
CA SOLAR RESOURCE
Solar Resource SB 100 2040
CA WIND RESOURCE
Terrestrial Wind Resource SB 100 2040 CA
GEOTHERMAL RESOURCE
Geothermal Resource SB 100 2040
NorCalOutsideTxConstraintZones
Norcal_Z3_SacramentoRiver
Norcal_Z4_Solano
SPGE_Z1_Westlands
WestlandsOutsideTxConstraintZones
SPGE_Z2_KernAndGreaterCarrizo
GK_Z2_InyokernAndNorthOfKramer
SPGE_Z3_Carrizo
Tehachapi
GK_Z3_NorthOfVictor
SCADSNV_Z3_GreaterImperial
Medford
Carson City
Sacramento
San Francisco
San Jose
Fresno
Las Vegas
Los Angeles
San Diego
Tijuana
Mexicali
Salton Sea
Colorado
UNITED S
MEXICO
Pioneer Seamount
Guide Seamount
Davidson Seamount
Rodriguez Seamount
San Juan Seamount
Channel Islands
790
3032
4838
923
2528
Esri, GEBCO, DeLorme, NaturalVue, Esri, GEBCO, IHO-IOC GEBCO, DeLorme, NGS

Figure 2


California SB 100 Buildout Renewable Energy Resource Starting Point Map - Adjusted Solar (California Footprint)
Transmission Constraint Zones 2040 Adjusted
SolarResource_SB100 2040
Norcal_Z3_SacramentoRiver
Norcal_Z4_Solano
SPGE_Z4_CentralValleyAndLosBanos
SPGE_Z1_Westlands
SPGE_Z2_KernAndGreaterCarrizo
GK_Z2_InyokernAndNorthOfKramer
Tehachapi
GK_Z3_NorthOfVictor
GK_Z4_Pisgah
TehachapiOutsideTxConstraintZones
SCADSNV_Z4_RiversideAndPalmSprings
GreaterImpOutsideTxConstraintZones
SCADSNV_Z3_GreaterImperial
Carson City
Sacramento
San Francisco
San Jose
Fresno
Las Vegas
Los Angeles
San Diego
Tijuana
Mexicali
MEXICO
Salton Sea
Channel Islands
Pioneer Seamount
Guide Seamount
Davidson Seamount
Rodriguez Seamount
San Juan Seamount
790
3032
4838
923
2528
Esri, GEBCO, DeLorme, NaturalVue, Esri, GEBCO, IHO-IOC GEBCO, DeLorme, NGS