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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Oversight of Electric Integrated Resource Planning and Procurement Processes.	Rulemaking 25-06-019

2026 INTEGRATED RESOURCE PLAN OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

PUBLIC VERSION

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2026 INTEGRATED RESOURCE PLAN
OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

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2026 INTEGRATED RESOURCE PLAN OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E)

[PUBLIC VERSION]

Pursuant to the October 28, 2025 Assigned Commissioner's Scoping Memo and Ruling, the January 16, 2026 Administrative Law Judge's Ruling Setting Requirements for Individual Integrated Resource Plans Due June 1, 2026, and the March 20, 2026 Administrative Law Judge's Ruling Correcting Table in January 16, 2026 Filing Requirements Ruling and Confirming August 10, 2026 Integrated Resource Plan Due Date, Southern California Edison Company ("SCE") respectfully submits its 2026 Integrated Resource Plan ("IRP") to the California Public Utilities Commission ("Commission" or "CPUC").

I.
EXECUTIVE SUMMARY

A. The Commission Should Augment Portions of the IRP Process to Help Ensure Balanced Outcomes for Customers as California Continues its Progress Toward Achieving a Decarbonized Electric System

The IRP process plays a critical role in guiding California's transition to a decarbonized electric system. Through the IRP, the Commission has successfully established a resource planning process applicable to all load-serving entities ("LSEs") that identifies long-term resource needs, informs transmission planning, and establishes pathways for achieving the state's

greenhouse gas ("GHG") reduction and clean energy goals for the electric sector while maintaining system reliability. However, as California's energy transition accelerates and the state experiences a period of uncertain load growth along with increasing customer affordability concerns, limited availability of diverse clean resource types in a constrained interconnection queue, and rising costs and viability challenges for all clean resource development due to federal policy changes and other market conditions, modifications to portions of the IRP process are necessary to account for the evolving landscape and to help ensure balanced outcomes for customers.

This IRP cycle has highlighted an increasing disconnect between the resource portfolios produced through planning and the resource portfolios that can be procured in the market at all or at a reasonable cost to customers. The current IRP process can identify "optimal" portfolios that satisfy modeled reliability and GHG emissions objectives based on the Commission's assumptions about load, resource availability, transmission, and resource costs. But the IRP process could be further augmented and strengthened by evaluating whether those portfolios can realistically be developed within the required timeframes based on the resources available in the interconnection queue, supported by available transmission infrastructure, or procured in the market at an affordable cost to customers – and making adjustments where necessary. Doing so will allow the IRP to be both useful for long-term policy discussions and more effective at guiding nearer term procurement requirements and achievable outcomes.

A central tension facing the IRP is that the same portfolio is expected to simultaneously serve two distinct purposes: guide long-term transmission planning and establish near- and mid-term procurement expectations. These objectives require different levels of assumptions and outputs that reflect market realities. Long-term planning appropriately explores what infrastructure and resource investments are needed to achieve California's environmental goals over a 20-year horizon. Procurement decisions, however, must reflect current market conditions, transmission availability, permitting realities, interconnection timelines, and customer affordability.

A Preferred System Plan ("PSP") based on the Commission's assumptions, including the higher 2024 Integrated Energy Policy Report ("IEPR") load forecast, GHG emissions targets of 30 million metric tons ("MMT") by 2030, 25 MMT by 2035, and 8 MMT by 2045, and a broad set of candidate resources including those not currently available in the market, has substantial value as a long-term planning tool. By evaluating pathways to achieve the state's 2045 decarbonization goals, the PSP can provide critical information regarding future transmission needs, the resource diversity necessary to support a reliable clean energy system over the long-term, and the potential interventions required to enable development of long-lead time ("LLT") resources. Transmission planning and development decisions require a much longer planning horizon than procurement decisions. Transmission infrastructure and emerging clean resource technologies can take many years to plan, permit, finance, and construct. As a result, the PSP correctly examines resource needs under assumptions that extend beyond what is commercially feasible in the near- and mid-term.

The PSP should continue to guide the California Independent System Operator's ("CAISO") Transmission Planning Process ("TPP") to make appropriate transmission investments at the right locations and provide market signals for development of the clean firm and other LLT resource technologies needed in 2040 and beyond to meet California's GHG reduction and clean energy goals. Using the PSP for these purposes helps ensure the state continues planning for the infrastructure and resource development necessary to achieve its long-term decarbonization objectives.

The challenge arises when planning portfolios designed for long-term infrastructure planning like the PSP are used as the basis for near- and mid-term procurement requirements. As demonstrated in this IRP, the Commission's Reference Portfolio and SCE's modeling of a system portfolio with similar assumptions do not result in a resource portfolio that will be affordable or feasible to procure through 2035. Similarly, an aggregation of LSE IRP portfolios based on the same assumptions into a PSP will not provide an affordable and feasible basis for near- and mid-term procurement decisions. The PSP will appropriately reflect what may

eventually be needed to achieve long-term California's policy objectives, but it will not reflect what can reasonably be procured, interconnected, and developed over the next several years given current market conditions, transmission limitations, permitting requirements, supply-chain constraints, and resource availability.

For this reason, SCE recommends the Commission retain the PSP as a long-term planning tool while establishing a Procurement Guidance Portfolio ("PGP") to guide near- and mid-term procurement decisions. As the Commission moves toward adoption of a Reliable and Clean Power Procurement Program ("RCPPP") that can serve as a necessary link between resource planning and procurement, it is crucial that the Commission evolve the IRP framework to ensure the framework is focused on balancing affordability, feasibility, and implementation while continuing to support California's long-term decarbonization objectives. To be effective in an evolving procurement landscape, the IRP process must produce portfolios that are not only policy compliant, but also capable of being implemented under known market conditions at a reasonable cost to customers.

Under this approach, the PSP would continue to inform transmission planning and provide greatly needed long-term market signals for the LLT resources needed in 2040 and beyond, while the PGP would provide an achievable foundation for procurement targets and compliance obligations through 2035. In short, the PSP and PGP serve complementary functions. The PSP identifies where California's electric sector ultimately needs to go; the PGP identifies what can be achieved along the way. Together, these portfolios would allow the Commission to continue planning for California's long-term clean energy future while ensuring that procurement requirements remain affordable and capable of being successfully implemented under existing market conditions.

In future IRP cycles, SCE recommends the Commission develop a PGP in advance of LSEs' IRP filings. For this IRP cycle, the Commission should develop a PGP based on SCE's recommended assumptions in conjunction with the PSP. As discussed below, SCE has

developed an example PGP for the CAISO system ("System PGP") that would best support near- and mid-term procurement decisions.

A PGP would allow the Commission to more explicitly evaluate the tradeoffs among affordability, feasibility, and emissions reductions before planning assumptions become procurement requirements. It would also create a framework for developing procurement targets that are grounded in resource availability and development expectations while preserving the PSP's role in identifying the long-term investments necessary to achieve California's clean energy goals. Importantly, establishing a PGP does not require abandoning the state's long-term climate objectives. Rather, it recognizes that achieving those objectives requires a credible pathway for implementation. Indeed, SCE's System PGP shows that near- and mid-term procurement targets will still require a very ambitious new resource build-out through 2035 under challenging market conditions. Therefore, it remains critical that the future RCPPP provide LSEs with adequate flexible compliance mechanisms. By establishing a complementary PGP, the Commission can strengthen the likelihood that planning outcomes translate into efficient resource deployment and successful achievement of California's reliability and decarbonization objectives.

Additionally, SCE recommends that the Commission, CAISO, and California Energy Commission ("CEC") accelerate development of the transmission infrastructure needed to support California's long-term clean energy transition, recognizing that many of the resources necessary to achieve the state's GHG reduction goals – particularly geothermal, other LLT resources, and out-of-state wind – will not be developed at scale unless the necessary transmission infrastructure is planned and constructed in advance. Just as proactive transmission expansion enabled development of California's renewable energy resources in the Tehachapi region, proactive transmission planning will be essential to unlocking the next generation of clean energy resources needed to achieve decarbonization. Given the time it takes to develop transmission, expediting these investments is critical to ensuring the Commission's planning portfolios remain both feasible and implementable and the state achieves its climate goals.

Finally, instead of continuing with the perfect capacity ("PCAP")-based reliability standard focusing on a single-point planning reserve margin ("PRM") and counting resources' contribution to reliability based on their annual marginal effective load carrying capability ("ELCC") value, the Commission should move to a slice-of-day ("SOD") framework for IRP reliability planning. The SOD reliability framework has already been thoroughly vetted and adopted by the Commission for the Resource Adequacy ("RA") program. Incorporating the SOD framework into the IRP process will better identify the resources that can meet both system capacity and energy needs and better align the planning process with the RA program. Moreover, SCE's modeling demonstrates that using the existing single-hour PRM requirement rather than an SOD approach unnecessarily drives the selection of higher-cost resources in 2045. As such, moving to an SOD framework for IRP reliability planning will likely result in lower cost portfolios, while still meeting reliability needs and making the resulting procurement more affordable for customers.

In summary, SCE requests the following in this IRP filing, as discussed further below:

- As a complement to the PSP, the Commission should develop a PGP based on SCE's recommendations to guide procurement targets through 2035.
- The Commission, CAISO, and CEC should accelerate the development of the necessary transmission infrastructure to meet California's long-term decarbonization objectives, with an emphasis on the transmission needed to interconnect geothermal, other LLT resources, and out-of-state wind.
- The Commission should adopt an SOD framework for IRP reliability planning.
- The Commission should approve SCE's IRP and 8 MMT Bundled Portfolio ("Conforming Bundled Portfolio").
- The Commission should authorize SCE to flexibly procure up to the resource needs identified in its Conforming Bundled Portfolio.

B. The Resource Portfolios Based on the Commission's Assumptions Should be Further Augmented to Inform Near- and Mid-Term Procurement Targets

The success of California's clean energy transition depends not only on identifying resource portfolios that satisfy reliability and GHG reduction objectives in planning models, but also on ensuring that those portfolios can be procured, financed, developed, and interconnected under actual market conditions. This IRP cycle demonstrates a growing disconnect between modeled portfolio outcomes and the practical realities of resource development and customer affordability given the evolving procurement landscape. As a result, the Commission's PSP risks being more aspirational than actionable, making it less effective as a guide for actual near- and mid-term procurement.

The Commission's portfolios, and as a result, LSEs' plans, are based on assumptions that do not fully account for the challenges facing resource development today. SCE's analysis demonstrates the PSP currently under development is likely to be unachievable and raises affordability concerns because it does not accurately reflect resource availability in the near- and mid-term, maintains existing GHG targets without evaluating their cost or feasibility, and does not adequately account for transmission and market constraints. Additionally, it relies on the 2024 IEPR load forecast which includes significant future load growth stemming from state and federal environmental policies that have since been rolled back and removed from the updated 2025 IEPR load forecast.

The Commission's Reference Portfolio would require 28.1 gigawatts ("GW") of new solar, 5.5 GW of out-of-state wind, 1.3 GW of in-state wind, 2.4 GW of geothermal, and 11.1 GW of various durations of energy storage to be procured, financed, developed, interconnected, and come online by 2030, less than four years from now.[1] That required new resource build-out increases significantly by 2035, to a cumulative 53.4 GW of solar, 7 GW of out-of-state wind,

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[1] *See* Administrative Law Judge's Ruling Correcting Table in January 16, 2026 Filing Requirements Ruling and Confirming August 10, 2026 Integrated Resource Plan Due Date, R.25-06-019, March 20, 2026, at 2.

6.3 GW of in-state wind, 3.2 GW of geothermal, and 22.3 GW of energy storage.[2]

The Commission's Reference Portfolio would require the system to add approximately 10 GW of new resources per year through 2035 – up to two times the accelerated pace of new resource development over the past five years. For reference, California added about 5 GW of new resources annually between 2020 and 2025, which was already considered to be a record-breaking pace.[3] Given historically observed timelines for new construction, as well as the status of the existing generation queue, this would not reflect an achievable new resource build-out to be completed by 2035.

Moreover, the Commission's Reference Portfolio assumes a mix of resources that are not available in the CAISO interconnection queue and the market. The Reference Portfolio includes 13.3 GW of new wind and 3.2 GW of new geothermal coming online by 2035. But these resources are not in the CAISO interconnection queue and will not be available and interconnected by 2035. The current CAISO interconnection queue is 93 percent battery storage or solar paired with storage and only includes an estimated 7 GW ***total*** of non-solar, non-storage technologies, some of which may not be viable projects that can be online by 2035.[4] Using a more queue-informed assumption that mostly solar and storage will be available by 2035 with

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[2] *See id.*

[3] *See* Commission, Resource Tracking Data, Data current as of December 2025, at 6, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf. This report shows approximately 29 GW of new in-CAISO nameplate capacity and approximately 31 GW of new total nameplate capacity, including imports, came online between 2020 and 2025.

[4] As of June 2026, the CAISO active interconnection queue includes 104 GW of new resources, of which 93 percent is battery storage or solar paired with storage. Thus, the CAISO interconnection queue only includes an estimated 7 GW total of non-solar, non-storage technologies. *See* https://caiso-queue.streamlit.app.

some limited wind would significantly increase the already unprecedented new resource built-out required by 2035 to achieve the objectives reflected in the Commission's Reference Portfolio.[5]

Based on observed timelines, it is also not possible to build the transmission infrastructure needed to interconnect these resources by 2035. Because new transmission infrastructure often requires ten years or more to develop and construct, transmission availability cannot be assumed to materialize within the timeframes needed to support aggressive near- and mid-term resource build-outs. By 2035, SCE's Conforming Bundled Portfolio alone would require significant transmission upgrades not already approved in the TPP. The IRP portfolios used for procurement decisions must account for necessary transmission upgrades and associated timelines for their permitting, engineering, procurement, and construction informed by actual experience.

In addition, there are major challenges to near-term diverse and clean resource development that will make achieving even a more modest trajectory of new resources additions more difficult and costly. Despite the mid-term reliability ("MTR") procurement orders' success in developing new resources, SCE has seen significant delays in bringing resources online due to interconnection and permitting-related issues. As noted above, the CAISO interconnection queue is heavily concentrated (approximately 93 percent) with solar and storage resources, illustrating the lack of clean firm and other diverse resources in the queue. While it was expected that the CAISO's Interconnection Process Enhancements would streamline and speed up the interconnection process, early indications for projects in queue cluster 15 are showing later than expected online dates, with many projects that were expecting early 2030 online dates now showing mid- to late-2030 online dates. The market has also experienced delays due to

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[5] SCE's 8 MMT CAISO System Base Case Portfolio ("System Base Case Portfolio") includes less new resource additions than the Commission's Reference Portfolio and selects a somewhat different resource mix; however, it still requires a new resource build-out of 50.6 GW of solar, 7 GW of out-of-state wind, 6.2 GW of in-state wind, 1.9 GW of geothermal, and 24.8 GW of various durations of storage by 2035, which supports the infeasibility of using resource portfolios based on these assumptions for near- and mid-term procurement targets.

supply chain constraints and price volatility of batteries, among other issues. Many of these market constraints remain today, along with several new challenges.

The elimination of federal tax credits for wind and solar resources placed in service after December 1, 2027 under the One Big Beautiful Bill Act ("OBBB") signed into law on July 4, 2025 is causing some projects to lose their expected tax credits and pass that added cost to LSEs, ultimately shifting the cost burden to customers.[6] In addition, the OBBB has implemented restrictions on claiming investment tax credits ("ITCs") and production tax credits ("PTCs") if projects source materials or use equipment manufactured in countries designated as prohibited foreign entities ("PFEs"). With the vast majority of solar panels and battery cells coming from China, one of the PFEs identified within the OBBB, SCE is expecting further cost pressures for renewable generation and energy storage developers. This is all in addition to the disruptions and cost increases of the on-again-off-again threat of increased tariffs levied on imports from certain countries. In July 2025, the United States Department of the Interior also required final review by the Interior Secretary for numerous requests related to wind and solar energy facilities including leases and right of ways, construction and operational plans, and environmental reviews,[7] resulting in potential delays and viability concerns for projects on Bureau of Land Management land. These market impacts and uncertainties greatly affect the viability of projects and will significantly increase costs to customers, highlighting the importance of considering feasibility and affordability in the portfolios used to guide procurement decisions.

In addition to feasibility, the affordability implications of procurement under current planning assumptions also warrant careful consideration. Achieving California's reliability, clean energy, and GHG reduction objectives will require significant investment in renewable generation, storage, transmission, and distribution infrastructure – while also maintaining

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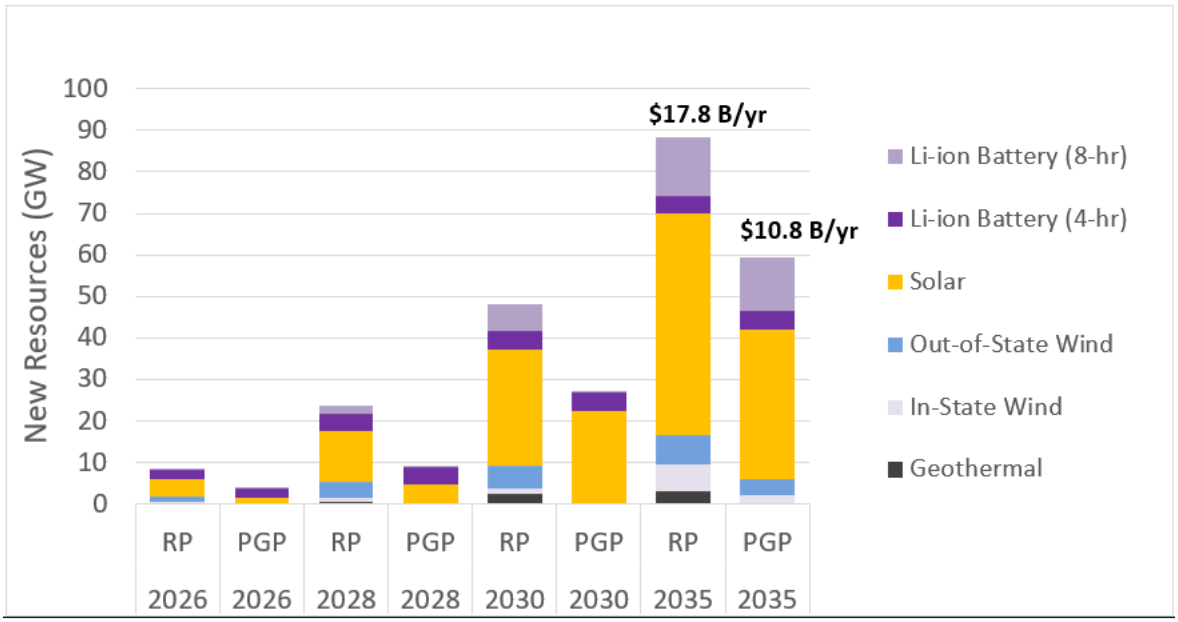
6 Wind and solar projects can also retain tax credits if they started construction by July 4, 2026.

7 *See* United States Department of the Interior, Departmental Review Procedures for Decisions, Actions, Consultations, and Other Undertakings Related to Wind and Solar Energy Facilities, July 15, 2025, available at: https://www.doi.gov/media/document/departmental-review-procedures-decisions-actions-consultations-and-other.

customer affordability. Affordability is not merely a customer protection objective, but a statutory prerequisite to the long-term success of California's clean energy policies.[8]

Procurement based on the Commission's Reference Portfolio or a PSP based on the same assumptions would put significant upward pressure on rates for customers. Figure I-1 below shows the differences in the new resource build-outs through 2035 between the Commission's Reference Portfolio and SCE's alternative System PGP.

Figure I-1
Cumulative Capacity Additions for Commission's Reference Portfolio and SCE's System PGP



[8] The Public Utilities Code directs the Commission to ensure that LSEs' IRPs "[e]nable each electric corporation to fulfill its obligation to serve its customers at just and reasonable rates" and "[m]inimize impacts on ratepayers' bills." Cal. Pub. Util. Code § 454.52(a)(1)(C)-(D). The portfolio of resources identified by the Commission is also required "to ensure a reliable electricity supply that provides optimal integration of renewable energy and resource diversity in a cost-effective manner." Cal. Pub. Util. Code § 454.51(a). Additionally, in Executive Order N-5-24, Governor Newsom emphasized that it is "essential that electric service remains affordable, reliable, and safe for all Californians during our clean energy transition" and directed state agencies to identify ways to reduce electric costs while maintaining California's commitment to carbon neutrality and a 100 percent clean electricity system. Executive Order N-5-24, October 30, 2024, available at: https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

The annualized system cost in 2035 for the new resources in the Commission's Reference Portfolio is estimated to be $17.8 billion per year, compared to $10.8 billion per year for SCE's System PGP (in 2024$). This represents a decrease in cost (and savings for customers) of approximately $7 billion per year or 40 percent for SCE's System PGP relative to the Commission's Reference Portfolio.

Customer rate affordability remains a central concern for the Commission, LSEs, other stakeholders, and the entire state. Developing a PGP to be used for near- and mid-term procurement targets will help advance the state's affordability concerns by achieving substantial cost savings for customers.

C. The Commission Should Distinguish Between Long-Term Planning and Near- and Mid-Term Procurement Portfolios and Establish a PGP to Complement the PSP

As discussed above, the PSP being developed in this IRP cycle serves an important role in identifying the transmission infrastructure and LLT resources needed to achieve California's long-term GHG reduction and clean energy objectives. However, the PSP will not serve as an effective procurement roadmap for near- and mid-term procurement decisions. Because procurement decisions must reflect current market conditions, resource availability, development timelines, and customer affordability considerations, the Commission should establish a PGP to complement the PSP and guide procurement targets through 2035.

The PGP is intended to provide a practical implementation path that bridges California's long-term policy objectives and the realities of resource procurement. Unlike the PSP, which appropriately evaluates long-term resource needs under broader planning assumptions, the PGP incorporates assumptions that more closely reflect expected market conditions during the next ten years. Accordingly, the PGP provides a more appropriate foundation for procurement and for evaluating near- and mid-term progress toward the state's clean energy goals.

SCE has developed a System PGP as discussed in more detail below to serve as an example portfolio for the Commission's PGP. SCE recommends the Commission develop a

PGP through the 2035 planning horizon to guide the RCPPP and upcoming procurement. The PGP should depart from the Commission's assumptions in three key areas.

1. The Commission Should Use the 2025 IEPR Load Forecast (or the Most Recent Available IEPR Load Forecast) Instead of the 2024 IEPR

The 2024 IEPR load forecast is outdated and reflects substantial projected load growth associated with federal and state environmental policies that have since been rolled back. These policy shifts are incorporated in the 2025 IEPR and the changes especially impact the estimates of medium-duty and heavy-duty transportation electrification and building electrification. Although there remains value in using high load forecasts for long-term planning purposes to ensure that California identifies the infrastructure necessary to accommodate future growth, portions of the 2024 IEPR load growth estimates are highly unlikely to materialize given current federal and state policy.

Using the 2025 IEPR forecast or the most recent available IEPR load forecast for the PGP provides a more measured and achievable basis for procurement decisions in the near- and mid-term. As discussed below, the high load growth assumed in the 2024 IEPR forecast is a primary factor driving the increased costs and expanded resource build-out compared to the prior IRP cycle. The 2025 IEPR appropriately recognizes the recent policy shifts and has tempered near-term growth in annual energy sales.[9] In addition, SCE's analysis indicates that updating the load forecast from the 2024 IEPR to the 2025 IEPR reduces annual incremental resource costs in 2035 by approximately $4 billion, or roughly 25 percent. Utilizing the 2024 IEPR load forecast to guide procurement between now and 2035 – assuming it is even physically feasible – would also likely increase costs beyond those estimated by the Commission's Reference Portfolio due to limited resource availability and diversity.

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[9] *See* CEC, Final 2025 Integrated Energy Policy Report, July 2026, at 2, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=271454&DocumentContentId=108996.

Given the substantial procurement and customer cost implications of the higher load forecast, the Commission should base procurement decisions on the most current and plausible assessment of expected demand while continuing to use a PSP based on the 2024 IEPR load forecast to evaluate the infrastructure that may ultimately be needed if higher growth materializes. SCE's analysis also shows that Diablo Canyon Nuclear Power Plant ("Diablo Canyon"), if extended, would provide an effective reliability hedge if the load growth assumed in the 2024 IEPR materializes.

2. The Commission Should Limit Resource Availability to Resources Supported by Existing or In-Progress Transmission Infrastructure

The PGP should also limit resource availability assumptions to technologies that can reasonably be supported by existing transmission infrastructure or transmission projects that are already approved or moving through development. This recommendation reflects the reality that resource procurement is constrained not only by technology availability, but also by the ability to interconnect and deliver those resources to load.

The PSP appropriately assumes access to a broad set of future resources to evaluate pathways toward California's longer-term decarbonization goals. However, most of the wind and geothermal resources reflected in the Commission's Reference Portfolio do not exist in meaningful quantities in the interconnection queue and depend on transmission infrastructure that will not be available by 2035. Using these improbable resource availability assumptions will understate the new capacity needed to meet 2030 and 2035 targets. For example, SCE's analysis finds that meeting the 25 MMT GHG target by 2035 with only solar, storage, and a limited amount of wind, the only technologies available in the CAISO interconnection queue in meaningful quantities, would increase the new capacity need by approximately 14 percent.[10] As demonstrated by SCE's analysis, limiting resource availability to resources that can

[10] SCE's System Base Case Portfolio for 2035 identifies a new resource build-out of 111 GW, while a Market-Constrained portfolio that achieves the same objectives requires 126 GW. Lithium-ion battery capacity is expressed in 4-hour equivalent capacity.

reasonably be developed and interconnected by 2035 substantially affects the resource mix selected by the model and highlights the scale of procurement required under actual market conditions.

Using more likely resource availability assumptions improves transparency regarding the challenges California faces in achieving future GHG emissions targets. If procurement is expected to rely primarily on solar and storage resources because other technologies are not commercially available, the Commission's assumptions should reflect that reality so that policymakers can evaluate the resulting reliability, affordability, and implementation barriers and implement the solutions needed to meet the state's goals. Further, the CAISO can study the PGP alongside the PSP in its TPP to distinguish between near- and long-term transmission needs.

3. The PGP Should Plan to the Previous 38 MMT by 2030 and 30 MMT by 2035 IRP Electric Sector GHG Targets

Lastly, the PGP should be based on the previous IRP electric sector GHG emissions targets of 38 MMT by 2030 and 30 MMT by 2035 rather than the more stringent 30 MMT by 2030 and 25 MMT by 2035 targets currently reflected in the Commission's Reference Portfolio and the prior PSP. Importantly, these earlier targets remain within the planning range adopted by the California Air Resources Board ("CARB") and therefore are fully consistent with California's broader decarbonization framework.[11] This recommendation should not be understood as a proposal to reduce California's long-term decarbonization ambition. Rather, it recognizes that procurement targets must be achievable in the timeframe in which LSEs are expected to procure resources. A near- and mid-term procurement portfolio that assumes resources, transmission, or cost reductions that are unlikely to materialize risks creating

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[11] *See* CARB, Resolution 22-21, 2022 Climate Change Scoping Plan for Achieving Carbon Neutrality, December 15, 2022, at 12 ("Be it further resolved that the Board hereby determines that the Final Plan provides the basis for establishing the revised planning target range for the electricity sector of 30-38 million metric tons of carbon dioxide equivalent (MMTCO2e) in 2030 for use in Integrated Resource Plans pursuant to SB 350."), available at: https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2022/res22-21.pdf.

compliance obligations that do not translate into actual emissions reductions. Using a more achievable GHG trajectory under the PGP would improve the likelihood that procurement targets result in real resource deployment, while preserving the PSP's role in identifying the longer-term pathway to deeper decarbonization.

When the Commission adopted the current GHG targets, it concluded the cost differences between the portfolios based on the different targets "were relatively small, driven in part by additional incentives from the federal [Inflation Reduction Act]."[12] However, as discussed in Section I.B, federal policy changes affecting tax credits, increasing costs associated with interconnection and permitting, transmission constraints, supply-chain challenges, and uncertainty regarding future tariffs have since significantly increased the cost and difficulty of achieving the more aggressive GHG emissions trajectory adopted in the 2023 PSP. Moreover, SCE's analysis explained in Section III.A.1 demonstrates that the marginal cost of emissions reductions increases significantly as GHG emissions targets become more stringent, particularly when clean firm and other emerging technologies are not yet available.

Having the PGP plan to the previous GHG targets of 38 MMT by 2030 and 30 MMT by 2035 allows California to continue achieving substantial GHG emissions reductions while focusing procurement on the most cost-effective and achievable reductions available during the next decade. It also preserves flexibility for future planning cycles to incorporate additional GHG emissions reductions as technology availability, transmission infrastructure, and market conditions evolve.

Importantly, the PGP should not be viewed as a conservative or easy-to-achieve portfolio. Even with more achievable assumptions regarding load growth, resource availability, and GHG emissions trajectories, SCE's System PGP still requires an unprecedented level of new resource development through 2035. The PGP contemplates substantial additions of solar generation, energy storage, and transmission infrastructure at a pace that remains well above historical

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[12] Decision ("D.") 24-02-047 at 63.

development levels. As a result, achieving the PGP will still require significant investment, continued policy support, and successful execution by LSEs, developers, transmission providers, regulators, and other stakeholders.

Moreover, the challenges affecting clean resource development today, including transmission constraints, interconnection delays, permitting requirements, federal policy uncertainty, and changing market conditions, will continue to affect project development under the PGP. While the PGP better reflects the resources that are likely to be available through 2035 and provides a more achievable path toward California GHG reduction goals, it does not eliminate the significant implementation risks associated with developing a clean energy system of this scale.

For this reason, any future RCPPP should include robust flexible compliance mechanisms. LSEs should not be penalized when resource development is delayed or affected by factors outside of their control, including interconnection delays, permitting challenges, transmission development schedules, supply-chain constraints, federal policy changes, or developer performance issues. Instead, the Commission should provide compliance flexibility, alternative compliance pathways, and other tools that recognize the realities of developing the unprecedented amount of clean energy resources required by California's clean energy transition in an increasingly challenging market environment.

D. California Must Expedite the Approval of the Necessary Transmission Infrastructure to Meet the State's Decarbonization Goals

Transmission infrastructure is one of the key foundations upon which California's decarbonized future will be built. While much of the focus of IRP is on generation and storage resources, the ability to develop, interconnect, and deliver those resources to customers ultimately depends on the availability of sufficient transmission infrastructure. Although SCE recommends that procurement decisions be guided by a PGP that accurately reflects the near-term market, the PSP remains essential for transmission planning because transmission projects

generally require significantly longer development timelines than generation resources. Because major transmission investments can take a decade or more to plan, permit, and construct, transmission planning cannot wait until resources appear in substantial amounts within the interconnection queue before identifying and developing the infrastructure needed to support them. Likewise, LSEs cannot procure and bring new resources online in the near- and mid-term if there is not already approved transmission infrastructure in place to support the interconnection of those resources.

Interconnecting the new resources required to meet the state's GHG goals will require the construction of significant new transmission infrastructure that has not yet been approved in the CAISO TPP. SCE's Conforming Bundled Portfolio alone would require several transmission upgrades by 2035 that are not already approved in the TPP. The necessary transmission infrastructure for the CAISO system resource build-out will be much greater and therefore, proactive planning must begin now if these resources are going to be interconnected.

This issue is particularly important for LLT and geographically-constrained resources such as geothermal, enhanced geothermal systems ("EGS"), out-of-state wind, and other non-solar PV clean technologies. Unlike solar and battery storage resources, which often have multiple development locations available, these resources are largely limited to specific areas where the underlying resource exists. Their successful development frequently depends on transmission infrastructure being planned and constructed well in advance of commercial deployment. If transmission planning relies primarily on current interconnection activity or existing deliverability conditions, California risks creating a self-reinforcing cycle in which transmission is not built because projects are not advancing, while projects are not advancing because the necessary transmission has not been built.

Transmission development is also critical for enabling broader resource diversity, including access to out-of-state wind resources that can provide valuable GHG reduction and reliability benefits. While out-of-state wind is not a LLT resource in the same manner as geothermal or EGS, its ability to contribute to California's clean energy portfolio depends on

sufficient transmission capability between resource-rich regions and California's high-demand load centers. The Commission's Reference Portfolio includes 5.5 GW of new out-of-state wind by 2030, increasing to a cumulative 7 GW by 2035, showing the importance of the necessary transmission infrastructure to interconnect out-of-state wind resources to California.

SCE's modeling demonstrates the emissions-reduction effectiveness of solar and storage declines as the system approaches deeper levels of decarbonization; thus, portfolios become increasingly difficult and expensive to achieve when transmission availability limits access to diverse clean resources. Conversely, transmission expansion improves access to resource diversity, reduces reliance on more expensive alternatives, and supports development of clean firm technologies that are critical to maintaining reliability as California continues to decarbonize through 2045.

California must embrace, as it has in the past, a "if you build it, they will come" approach for key transmission investments supporting LLT and out-of-state wind resources. For resource types that require major infrastructure development and long planning horizons, transmission must precede resource deployment rather than follow it. The success of the Tehachapi Renewable Transmission Project demonstrates the importance of proactively developing transmission infrastructure ahead of resource development. By constructing transmission to a high-quality renewable resource area before generation was fully developed, California enabled significant private investment and large-scale renewable deployment that may not otherwise have occurred. The state should follow that model for the geothermal, other LLT, and out-of-state wind resources needed for decarbonization.[13]

Accordingly, SCE recommends that the Commission, CAISO, and CEC: (1) improve coordination between resource planning and transmission planning so that transmission infrastructure can be proactively developed on timelines consistent with LLT and out-of-state

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[13] SCE's study, "When Clean Firm Resources Become Competitive: A Geothermal Cost Sensitivity Analysis," is included as Appendix D to this IRP. This study evaluates what resources could potentially be substituted if pro-active transmission development is able to reduce the cost of geothermal resources.

wind resource deployment needs; (2) incorporate planning assumptions that more fully reflect expected future LLT and out-of-state wind resource development, even where current interconnection activity may be limited; (3) allow busbar mapping to account for state policy objectives and long-term resource needs, in addition to current transmission availability and queue conditions; and (4) ensure the mapping methodology identifies transmission needs necessary to enable future development of geographically constrained resources rather than solely reflecting existing grid conditions.

E. The Commission Should Adopt an SOD Framework for IRP Reliability Planning

Maintaining reliability is one of the core objectives of the IRP process.[14] As California's resource mix evolves, the Commission's reliability planning framework must evolve as well. Reliability is no longer driven by the ability to meet load in a single peak hour. Instead, reliability increasingly depends on maintaining sufficient capacity and energy across multiple hours as net load peaks broaden and the system becomes more dependent on solar generation, battery storage, and other energy-limited resources.

The Commission's current reliability planning framework relies on a single-hour PRM requirement and annual marginal ELCC values to represent each resource's reliability contribution. Although marginal ELCC may provide information regarding the marginal reliability contribution of resources, it does not directly measure whether a portfolio can reliably serve load across all hours when reliability risks occur. As a result, the current framework can achieve reliability "only on paper" and drive portfolio outcomes that are heavily influenced by accreditation values rather than system reliability needs.

The problem is that single annual marginal ELCC values are being used in IRP in a way that can obscure and not reflect the reliability hourly contributions of the added new resources, especially for renewable and storage resources with energy limits and different hourly contributions. As California becomes more dependent on solar generation, battery storage, and

[14] *See* Cal. Pub. Util. Code §§ 454.51(a), 454.52(a)(1)(E).

other energy-limited resources, reliability planning must evaluate whether the full portfolio can serve load across all hours with respect to their hourly contributions, not merely whether individual resources receive sufficient annual accreditation values to meet a single-hour threshold. A 24-hour SOD framework provides that portfolio-level test and considers the hourly contributions of renewables and storage.

This distinction is important because resource accreditation and portfolio reliability are not the same exercise. Accreditation assigns a planning value to individual resources, while portfolio reliability planning should test whether the combined portfolio can meet load and reserve needs across the hours when reliability risks arise. A portfolio may appear sufficient under annual accreditation values but still be insufficiently matched to the system's hourly reliability needs, particularly if it relies heavily on resources with correlated output profiles or energy-duration limitations. Conversely, a portfolio may fail to satisfy a single-hour PRM requirement due to low accreditation values but still meet the 0.1 loss-of-load expectation ("LOLE") reliability standard. An SOD approach better connects the planning constraint to the actual operational problem the portfolio must solve.

The Commission has already recognized these challenges in the RA proceeding by adopting a 24-hour SOD framework and finding that it represents "a durable framework that can evolve as the state's energy and environmental policy goals, which include widespread electrification, transform the generation supply portfolio and demand requirements."[15] The IRP proceeding should similarly adopt an SOD-based framework for its reliability planning.

An SOD framework evaluates resources based on their actual hourly contribution to reliability rather than a single annual accreditation value. It explicitly captures storage duration limits, state-of-charge constraints, renewable generation profiles, and multi-hour reliability needs. By evaluating reliability across all critical hours rather than a single hour, SOD provides a more transparent and operationally meaningful assessment of system needs, more accurately

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[15] D.22-06-050 at 75.

utilizes energy-limited renewable and storage resources, and allows the model to select the least-cost portfolio capable of meeting reliability requirements throughout the year.

SCE's analysis demonstrates that the choice of reliability framework materially affects long-term planning outcomes. In 2035, GHG reduction requirements remain the primary driver of portfolio selection under both approaches. By 2045, however, the Commission's single-hour PRM and marginal ELCC construct becomes the binding planning constraint, driving selection of higher-cost resources based largely on accreditation values rather than overall system needs and economics. For example, the model favors longer-duration storage resources because of their higher marginal ELCC values despite their higher costs. Under an SOD framework, reliability is evaluated based on actual hourly system needs, allowing the model to identify a lower-cost portfolio while continuing to satisfy the same 0.1 LOLE reliability standard.

The Commission's current framework can therefore result in portfolios that are more expensive without providing a corresponding reliability benefit. SCE's modeling shows that SOD produces a more cost-effective portfolio because it focuses on actual reliability performance rather than annual accreditation values. By evaluating resources based on their true hourly contribution to reliability, an SOD approach avoids the distortions that can occur when planning decisions are driven by marginal ELCC values and better aligns reliability planning with how the resources operate. Importantly, SCE is not proposing to lower the Commission's reliability standard. SCE's SOD-based portfolios are validated against the same 0.1 LOLE reliability standard. The difference is that SOD identifies a lower-cost portfolio that meets that standard by evaluating the portfolio's actual hourly contribution to serve load. This makes SOD a reliability-preserving, cost-reducing improvement to the IRP framework rather than a relaxation of reliability requirements.

Accordingly, the Commission should adopt an SOD framework for IRP reliability planning. Doing so will improve the accuracy of long-term planning, better reflect the operational characteristics of California's evolving resource mix, produce lower-cost portfolios,

and ensure that reliability planning remains aligned with the state's long-term decarbonization objectives.

F. Summary of SCE's Modeling Results for SCE's System Base Case Portfolio, System PGP, and Conforming Bundled Portfolio and Action Plan

1. SCE's System Base Case Portfolio

SCE developed a least-cost CAISO system-wide resource plan – SCE's System Base Case Portfolio – designed to meet electric sector GHG targets of 30 MMT by 2030, 25 MMT by 2035, and 8 MMT by 2045 while maintaining reliability and satisfying renewable and clean energy requirements. SCE developed this portfolio through an iterative process using capacity expansion modeling, production cost simulations, and LOLE reliability analysis. Instead of relying on the Commission's single-hour PRM and marginal ELCC-based approach, the portfolio applies an SOD reliability framework that evaluates reliability needs across critical hours, allowing SCE to identify a more cost-effective resource mix that remains consistent with long-term decarbonization goals.

Applying this methodology, SCE's System Base Case Portfolio achieves comparable reliability and GHG reduction outcomes at lower cost, with estimated savings of approximately 9 percent by 2035 and 13 percent by 2045. These savings are primarily driven by greater reliance on solar and 8-hour storage and reduced dependence on higher-cost, LLT resources such as 12-hour storage. SCE's analysis indicates that the Commission's marginal ELCC-based reliability framework can lead to more expensive procurement than necessary, while the SOD framework identifies a lower-cost portfolio that satisfies the Commission's reliability standard.

To test the robustness of its System Base Case Portfolio, SCE conducted sensitivity analyses to evaluate uncertainties affecting procurement needs, costs, GHG emissions, reliability, affordability, and feasibility. The analyses focused on three key areas: (1) the Updated Load Scenario using the 2025 IEPR load forecast instead of the 2024 IEPR and identifying the impact of using the new load forecast on cost, resource selection, and trajectory through 2035 only;

(2) the Market-Constrained Scenario assuming only solar and storage resources are available through 2030 with wind available beginning in 2031 up to the Commission's Limited Wind Sensitivity and identifying the impact of near-term resource availability on GHG target achievement and portfolio mix through 2035 only (this scenario also includes high GHG target bookends of 38 MMT by 2030 and 30 MMT by 2035 and low GHG bookends of 30 MMT by 2030 and 25 MMT by 2035); and (3) the Diablo Extended Scenario assuming Diablo Canyon's operation is extended through at least 2035 and comparing against the other scenarios to understand how Diablo Canyon serves as a hedge against feasibility concerns and/or load forecast changes through 2035 only.

This section summarizes some of the key findings from SCE's System Base Case Portfolio and the other scenarios:

- SCE's System Base Case Portfolio demonstrates that California can meet the 8 MMT electric sector GHG target by 2045 while satisfying reliability requirements, including the 0.1 LOLE reliability standard, under modeled assumptions, at a lower cost than the Commission's Reference Portfolio.
- The Updated Load Scenario shows that load forecast assumptions are the primary driver of future procurement needs and customer costs. Using the updated 2025 IEPR load forecast instead of the higher 2024 IEPR load forecast reduces cumulative resource additions by roughly 21 GW by 2035 and lowers annual system costs by approximately $4 billion, or about 25 percent.
- A resource mix centered on solar, battery storage, and wind provides the lowest-cost pathway to deep decarbonization, with 8-hour storage supporting reliability, renewable integration, and reduced curtailment.
- Resource availability and real-world development constraints materially affect portfolio feasibility. Permitting, transmission availability, supply-chain limitations, interconnection queue realities, and resource development challenges should be reflected in the portfolios used to inform procurement decisions.

- The Market-Constrained Scenario demonstrates that achieving GHG targets becomes more difficult and costly when resource availability is limited to technologies that are available based on commercial and CAISO interconnection queue data, particularly if expected wind resources do not materialize.
- The Diablo Extended Scenario shows that continued operation of Diablo Canyon can reduce procurement needs, lower GHG emissions, improve reliability, and hedge against potentially higher load growth.
- The SOD reliability framework can identify more cost-effective portfolios than ELCC planning approaches by better aligning procurement needs with hourly system requirements.

2. SCE's System PGP

As discussed above, SCE's System PGP was developed as an alternative portfolio intended to complement the PSP by better reflecting market conditions, resource availability constraints, affordability considerations, and updated load. SCE's System PGP was based on SCE's Market-Constrained Scenario including only solar and storage through 2030 and wind beginning in 2031 up to the Commission's Limited Wind Sensitivity. The System PGP was also based on the 2025 IEPR load forecast and GHG targets of 38 MMT by 2030 and 30 MMT by 2035. This portfolio incorporates near- and mid-term feasibility and affordability considerations through 2035 and was developed to provide an example PGP for the Commission. The Commission should develop a PGP based on SCE's recommendations to inform the RCPPP and other procurement decisions through 2035 as explained above.

This section summarizes some of the key findings from SCE's System PGP:

- The System PGP is intended to serve as a procurement-focused complement to the PSP, not a replacement for it. SCE's System PGP is designed to guide procurement through 2035, while the PSP will continue to provide long-term planning signals for

transmission expansion and development of clean firm and other LLT resources needed beyond 2040.

- By using updated load assumptions, resource availability constraints based on CAISO interconnection queue and commercial data, and an alternative GHG trajectory, SCE's System PGP reduces annual system costs by approximately $7 billion per year (roughly 40 percent) in 2035 relative to the Commission's Reference Portfolio.
- SCE's System PGP remains highly ambitious and will require an unprecedented build-out of new transmission infrastructure, solar, storage, and wind resources through 2035, demonstrating the continued need for flexible compliance mechanisms. Even under the PGP's planning framework, significant development, interconnection, transmission, permitting, and supply-chain risks remain. As a result, the RCPPP and any future procurement decisions should include flexible compliance mechanisms that accommodate delays and implementation risks outside the control of LSEs.
- The 2024 IEPR load forecast is a major driver of increased procurement needs and cost. The System PGP's use of the updated 2025 IEPR load forecast better reflects current federal and state policy while producing materially lower resource needs and system costs.
- Resource availability constraints materially affect portfolio feasibility. SCE's System PGP recognizes the resources currently available in the market and interconnection queue are heavily concentrated in solar and storage, making the resource mix assumed in the Commission's planning portfolios difficult to achieve by 2035.
- SCE's System PGP demonstrates that meaningful GHG reductions can still be achieved with a more pragmatic mid-term planning trajectory. By planning to GHG emissions targets of 38 MMT by 2030 and 30 MMT by 2035 within CARB's approved planning range and emphasizing the most cost-effective emissions reductions, the System PGP maintains progress toward California's long-term climate goals while reducing procurement risk and affordability impacts to customers.

3. SCE's Conforming Bundled Portfolio and Action Plan

Based on its Commission-assigned bundled load forecast, SCE developed a least-cost resource portfolio for its bundled service customers to meet its share of the 8 MMT 2045 GHG target using capacity expansion modeling and verifying the Commission's GHG emissions and reliability requirements are met using the Clean System Power ("CSP") Calculator and Resource Data Template ("RDT"). SCE's Conforming Bundled Portfolio achieves its share of the electric sector 8 MMT target by reaching 1.92 MMT of GHG emissions in 2045, a 83 percent Renewables Portfolio Standard ("RPS") in 2030, and 100 percent clean energy by 2045.[16] Least-cost optimization modeling results indicate that cost-effective wind resources are selected first until available development limits are reached, after which solar generation paired with 8-hour battery storage becomes the preferred resource solution for meeting incremental energy, capacity, and GHG emissions requirements.

As discussed above, SCE recommends that the Commission adopt a PGP to guide the RCPPP and any future procurement. Until an RCPPP is implemented, SCE is procuring to meet its D.26-02-057 procurement requirements and consistent with its procurement authorization in D.24-02-047. In D.24-02-047, the Commission authorized SCE to conduct procurement activities as market conditions indicate, including solicitations and bilateral negotiations, to procure the resources needs identified in its 2022 IRP portfolio designed to meet the 25 MMT GHG target by 2035.[17] Similar to the flexible procurement authorization in D.24-02-047, SCE requests Commission authority to flexibly procure up to the resource needs identified in SCE's Conforming Bundled Portfolio. Rather than prescribing specific technologies or procurement schedules, SCE's action plan seeks flexibility to acquire least-cost, best-fit resources through competitive solicitations, bilateral negotiations, and other authorized procurement mechanisms. This approach enables SCE to respond to changing market conditions, resource availability,

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[16] SCE's Conforming Bundled Portfolio also meets SCE's share of the 30 MMT GHG target by 2030 and the 25 MMT GHG target by 2035.

[17] *See* D.24-02-047 at Ordering Paragraph ("OP") 9.

transmission development, and evolving customer needs while maintaining progress toward the state's climate goals and is consistent with the procurement authority granted by the Commission in the last IRP cycle.

G. Organization of SCE's IRP

SCE's IRP follows the Narrative Template provided by the Commission. Section II – Study Design describes how SCE approached the process of developing its IRP and discusses the objectives and methodology for SCE's IRP analytical work, including modeling tools, modeling approach, and assumptions. Section III – Study Results presents the results of SCE's IRP analytical work as described in Section II, including portfolio results and detailed information on SCE's System Base Case Portfolio and other scenarios, SCE's System PGP, and SCE's Conforming Bundled Portfolio, and discusses GHG emissions results, local air pollutant minimization, disadvantaged communities, cost and rate analysis, and other sections required in the Narrative Template. Section IV – Action Plan describes the action plans, barrier analysis, and requests for Commission action associated with SCE's Conforming Bundled Portfolio, as well as the status of various categories of procurement, programs, and other activities addressed in the Narrative Template. Section V – Lessons Learned discusses SCE's suggested changes to the IRP process for consideration by the Commission.

Finally, SCE includes the RDT and CSP Calculator for the Conforming Bundled Portfolio as Appendices B and C, respectively.

II.

STUDY DESIGN

This section describes the objectives and methodology used to develop SCE's System Base Case Portfolio and other system scenarios, SCE's System PGP, and SCE's Conforming Bundled Portfolio.

SCE's System Base Case Portfolio is a comprehensive system-wide resource plan designed to meet specified GHG targets, be operable and feasible on an expected basis, and

achieve a 1-in-10 LOLE reliability standard. The portfolio was developed through a three-step iterative process to: (1) identify a least-cost portfolio using capacity expansion ("CE") modeling; (2) validate that the portfolio can operate on an expected and deterministic basis and satisfy key constraints and targets, including emissions and RPS/zero-carbon targets, using production cost modeling ("PCM") simulation; and (3) assess system reliability using an LOLE analysis. As further discussed below, SCE also modeled several additional scenarios on its System Base Case Portfolio, including the Updated Load Scenario, Market-Constrained Scenario, Diablo Extended Scenario, and SCE's System PGP.

For SCE's bundled load, SCE's Conforming Bundled Portfolio is designed to meet SCE's allocated share of the 8 MMT GHG target in 2045 and satisfy applicable reliability criteria. The bundled portfolio was developed using CE modeling to identify the least-cost bundled resource portfolio that satisfies SCE's bundled load share of the GHG emissions and reliability targets. SCE then used the Commission's RDT and CSP Calculator to verify that the portfolio meets Commission requirements for GHG emissions and reliability. If the initial bundled portfolio developed through SCE's CE modeling process did not meet these criteria, it was iteratively refined through additional CE modeling until the portfolio met the Commission's requirements.

A. Objectives

SCE's overall objectives for its IRP analytical work are consistent with the state's goals for the IRP process. Specifically, SCE aims to develop optimized portfolios that reduce California's economy-wide GHG emissions in a reliable and cost-effective manner while also meeting other state goals[18] and the operational requirements of the CAISO system.

[18] *See* Cal. Pub. Util. Code §§ 454.51(a), 454.52(a)(1).

1. Objectives in Developing the CAISO System Portfolios

Consistent with prior IRP cycles, SCE has conducted independent modeling of the CAISO system to evaluate the Commission's portfolios, assess the implications of an SOD-based reliability framework relative to the Commission's marginal ELCC-based approach, and analyze additional scenarios that quantify the impacts of using the Commission's prescribed inputs and assumptions, including considering differences in load growth, resource availability, and nuclear retention. A summary of SCE's CAISO system modeling and the objectives of each portfolio and scenario are detailed below:

Table II-1
SCE's CAISO System Portfolio Modeling and Objectives

Scenarios	Objectives	Demand	Resource Assumptions	GHG Target
Base Case Portfolio	• Identify annual near-, mid-, long-term system capacity needs for 2028 through 2035, 2040, and 2045 • Identify annual near-, mid-, long-term system clean energy resource needs for 2028 through 2035, 2040, and 2045 • Parallel modeling to confirm reasonableness of CPUC's Reference and TPP Portfolios and understand impact of using ELCC vs. SOD in capacity expansion • Establish a CAISO system annual PRM and optimal resource portfolio under SOD framework that can be compared to the Commission's Reference and TPP Portfolios that were created under the ELCC framework • Basis of SCE's bundled conforming portfolio	2024 IEPR	TPP I&A	2030: 30MMT 2035: 25MMT 2045: 8MMT
Updated Load Scenario (through 2035 only)	• Identify impact of using the new load forecast on cost, resource selection, trajectory	2025 IEPR	TPP I&A	2030: 30MMT 2035: 25MMT
Market-Constrained Scenario (through 2035 only)	• Identify impact of limited near-term resource availability on GHG target achievement and portfolio mix • **Scenario serves as the basis for SCE's Procurement Guidance Portfolio (PGP) – see below**	2025 IEPR	Only solar and storage available through 2030 Wind available beginning 2031 up to Limited Wind Sensitivity	**Low GHG Bookend** 2030: 30MMT 2035: 25MMT **High GHG Bookend** 2030: 38MMT 2035: 30MMT
Diablo Extended Scenario (through 2035 only)	• Assume Diablo is extended beyond current dates through at least 2035 • Compare w/ other scenarios to understand how Diablo serves as a hedge against feasibility concerns and/or load forecast changes	2024 IEPR	TPP I&A + Diablo through 2035	2030: 30MMT 2035: 25MMT
SCE's Procurement Guidance Portfolio (through 2035 only)	• Portfolio that incorporates near- and mid-term feasibility and affordability considerations • PGP is tested for reliability using LOLE study • Conduct various sensitivities to estimate emissions from PGP under different situations • **Procurement:** PGP provides more feasible trajectory to guide RCPPP, while PSP identifies resources needed in the long-term • **Transmission:** Pair PSP with PGP to distinguish near- vs. long-term transmission needs	2025 IEPR	Only solar and storage available through 2030 Wind available beginning 2031 up to Limited Wind Sensitivity	2030: 38MMT 2035: 30MMT

Through its CAISO system modeling, SCE also sought to develop lessons learned and proposals for improvements to the IRP CAISO system modeling process.

2. Objectives in Developing SCE's Conforming Bundled Portfolio

SCE's objectives in developing its Conforming Bundled Portfolio are to achieve SCE's share of the prescribed GHG emissions benchmarks for 2030, 2035, and 2045, meet SCE's annual bundled energy and capacity needs, and identify differences, if any, between bundled resource portfolios that satisfy SCE's internal modeling criteria and bundled resource portfolios that satisfy the Commission's RDT and CSP Calculator criteria, and develop lessons learned and proposals for improvements.[19]

B. Methodology

1. Modeling Tool(s)

SCE utilized Hitachi[20] CE modeling and PLEXOS PCM simulation software for its CAISO system modeling. As discussed below, SCE also used Hitachi CE modeling for its bundled modeling. Table II-2 below provides information on specific modeling software used by SCE to develop its IRP.

Table II-2
Modeling Software Specifications

Model Type	Model	Vendor	Version Number
Capacity Expansion	Hitachi CE	Hitachi	24.3
Production Cost	PLEXOS	Energy Exemplar	11.0 R05

SCE selected Hitachi CE over the Commission's RESOLVE tool due to its commercial availability and additional modeling capabilities. For example, Hitachi CE evaluates all study years rather than relying on the seven sample years in RESOLVE.[21] It also models each thermal generating unit individually and can simultaneously co-optimize investment, dispatch, and

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[19] SCE limited the selection of shared system resources (*e.g.*, existing transmission and import/export capability) and candidate generation resources to its bundled load share to help avoid challenges when combining all LSEs' portfolios into the Commission's PSP.

[20] Since Hitachi acquired ABB at the end of 2022, the name of the CE modeling software has changed; however, the software itself is the same as SCE used for previous IRP filings.

[21] The 2026 IRP Commission's Reference Portfolio RESOLVE results viewer provides seven study years: 2026, 2028, 2030, 2031, 2035, 2040, and 2045.

retirement or refurbishment decisions. In addition, Hitachi CE directly incorporates 8,760 hourly load, renewables, and hydropower data to develop representative monthly "typical weeks" for optimization. Based on these additional functionalities, SCE has observed more economical CAISO system resource build-outs from Hitachi CE compared to RESOLVE.[22]

2. Modeling Approach

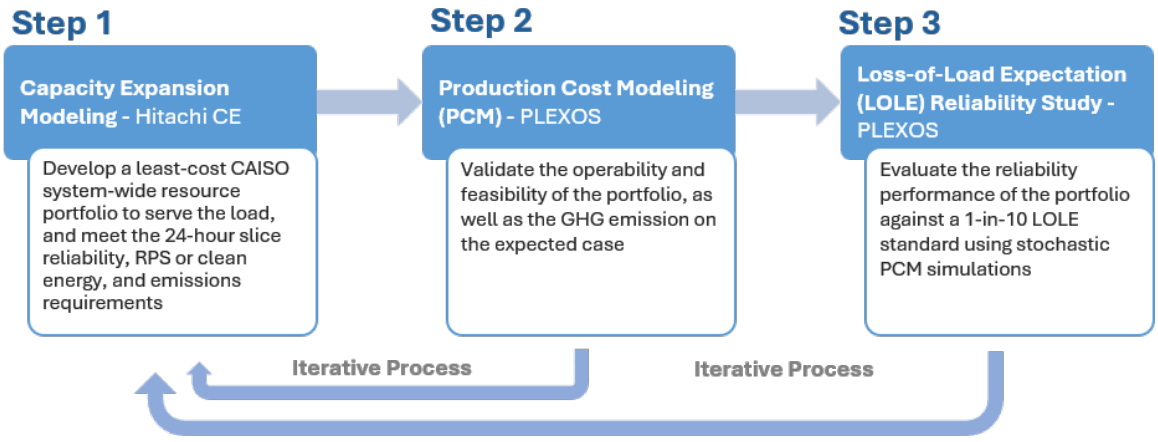
This section discusses the methodology used to develop SCE's resource portfolios. First, SCE describes the modeling tools, assumptions, and approach used for its CAISO system modeling. Second, SCE describes the modeling tools, assumptions, and approach used for its bundled modeling to develop the Conforming Bundled Portfolio. SCE generally used the same methodology to develop its system and bundled portfolios and has identified any differences in the sections below.

a) System Base Case Portfolio Methodology

The following Figure II-2 provides an overview of the process used by SCE to ensure its System Base Case Portfolio is operable and feasible in terms of sufficient generating resources to serve the CAISO hourly load, satisfy the ancillary services requirements, meet the CAISO system share of the 8 MMT GHG target and RPS/zero-carbon requirements, and meet the 1-in-10 LOLE reliability standard.

[22] For example, the 25 MMT CAISO System-Wide portfolio identified in SCE's 2022 IRP using the Hitachi (ABB) CE model was approximately 25 percent less expensive in 2035 than the comparable portfolio identified by the Commission using RESOLVE. *See* Integrated Resource Plan of Southern California Edison Company (U 338-E), R.20-05-003, November 1, 2022, at 47. *See also* Integrated Resource Plan of Southern California Edison Company (U 338-E), R.16-02-007, September 1, 2020, at 24. SCE discusses how its System Base Case Portfolio compares to the Commission's Reference Portfolio in Section III.A.1.b.1.

Figure II-2
Modeling Tools and Approach Used in Development of SCE's System Base Case Portfolio



Specifically, SCE used the following three-step iterative process:

1. Step 1: Build the optimized system portfolio using the Hitachi CE model to meet the CAISO system share of an 8 MMT GHG target,[23] as well as RPS/zero-carbon requirements, SOD reliability requirements, and to serve the load of the CAISO system. This step is based on all assumptions related to baseline and candidate resources, transmission system limitations, and other key inputs. To facilitate efficient optimization, the 8,760-hourly load data is simplified on an annual basis.
2. Step 2: Perform detailed PLEXOS PCM simulation to validate whether the system portfolio produced by the Hitachi CE model can operate both on an expected and deterministic basis. This validation assesses the portfolio's ability to meet the 2024 IEPR load forecast and associated hourly ancillary services and ramping requirements, while satisfying transmission limitations and individual generation constraints. It also incorporates more detailed emissions calculations that reflect the variations in load and generation to ensure compliance with the annual GHG target.

[23] SCE used a straight-line approach to apply declining GHG targets as annual constraints for its CAISO system portfolio development, consistent with the Administrative Law Judge's Ruling Setting Requirements for Individual Integrated Resource Plans Due June 1, 2026, R.25-06-019, January 16, 2026.

This step uses detailed generator characteristics, operating constraints, and ancillary service requirements. If there are any unserved load or violations of the above limitations, constraints, and targets, the Hitachi CE model is rerun with adjusted constraints to ensure the final resource portfolio meets all the requirements.

3. Step 3: Assess system reliability by the LOLE study using 529 PLEXOS Monte Carlo simulations considering the uncertainties on load, wind and solar generation, and gas generation outages. If the CAISO system portfolio does not meet the 1-in-10 LOLE reliability standard, the SOD reliability requirement is increased to rerun the Hitachi CE model and create a new system resource portfolio and establish the required annual PRM to meet the 1-in-10 LOLE reliability standard under the SOD reliability construct.

Each step is described in further detail in the sections below.

(1) Step 1: CE Methodology to Identify Least-Cost Resource Portfolio

The CE model is a critical component of the IRP process, as it is used to develop a least-cost resource portfolio that serves CAISO system load while meeting GHG, RPS/zero-carbon, and reliability requirements and accounting for transmission and import/export constraints.

(a) Modeling Tool(s) Used for CE

SCE continues to use the Hitachi CE model to develop its system portfolios. Hitachi CE is a commercially available, long-term resource planning tool developed by Hitachi Enterprise Software Company. Hitachi CE is capable of optimizing a well-defined power system to meet GHG requirements, transmission and import/export limits, reliability requirements, and energy balance requirements at least cost.

Table II-3 provides a summary of differences between the Hitachi CE model and RESOLVE and an explanation of how those differences should be considered during evaluation of SCE's portfolios.

Table II-3
Differences Between RESOLVE and Hitachi CE Models

RESOLVE	**Hitachi CE**	**How differences should be considered during evaluation of portfolios**
Aggregated super thermal generators	Detailed individual generator modeling	Hitachi CE enables a more detailed thermal supply stack representation by modeling each thermal generator individually. The result is a more realistic estimate of fuel use and GHG emissions.
Includes ancillary service requirements	Does not include ancillary service requirements	Ancillary service requirements, as operational reliability requirements, are better evaluated in PCM simulations where detailed generator characteristics and 8,760 hourly demand are evaluated. SCE evaluates these requirements in PLEXOS PCM simulations.
Investment decisions on: • New generation (gas and renewables) • New storage • Generation retirement • New demand response	Investment decisions on: • New generation (gas and renewables) • New storage • Generation retirement • Generation refurbishments • Purchase and sale power contracts • Demand-side management programs • New transmission • Cap-and-trade emission allowance transactions • Fuel purchases	Hitachi CE has additional functionality when considering investment decisions. Although SCE did not use all functionalities in this IRP, the additional functionality makes Hitachi CE a more integrated model that would help the Commission achieve its goals for the IRP process if it were adopted as the IRP's primary modeling tool for future cycles.
For each year in the analysis horizon, RESOLVE models operations for 36 typical	For each year in the analysis horizon, Hitachi CE model applies the "typical	Hitachi CE provides a better representation of electrical load and renewable generation because there is greater variability from its "typical week" sampling method compared

days	week" method to scale down the number of hours	to RESOLVE's 36 days. "Typical week" sampling results in 84 types of days (one week for each month) – more than twice as many as RESOLVE. Some months in RESOLVE have only one type of day associated, leaving no room for even a weekday-weekend differentiation.
Correlated 36 shapes for load, renewables, and hydropower	36 days mapped to 8,760 shapes for load, renewables, and hydropower	Loads between the two models are comparable because SCE translated the RESOLVE 36 load, renewables, and hydropower shapes into 8,760 hourly shapes before populating Hitachi CE.
Aggregated hydropower with daily energy limit corresponding to 36 days	Allows individual hydropower modeling as either baseload, peak shaving, or limited energy. Both or either of daily or monthly energy limits are available.	SCE converted the RESOLVE daily energy limit into a monthly energy limit in Hitachi CE. The annual hydropower generation between RESOLVE and Hitachi CE are consistent.
Financial model minimizes Net Present Value ("NPV") of all-in resource cost	Financial model minimizes resources' Real Economic Carrying Charge	Hitachi CE has a comparable financial valuation method to RESOLVE. Hitachi CE values costs based on the difference of NPVs from purchasing resources in perpetuity when resource life is longer than 2035. Similarly, RESOLVE calculates an additional weight on the NPVs incurred in 2035.
Simulates selected sample years. In this IRP cycle, RESOLVE simulated years 2026, 2028, 2030, 2031, 2035, 2040, and 2045	Simulates every single year in the planning horizon (every year through 2035, 2040, and 2045)	Hitachi CE optimizes the resource build-out and has the capability to closely examine the SOD reliability requirement for each individual year. In this IRP cycle, SCE implemented SOD modeling for 2028, 2035, 2040, and 2045.
Uses the single-hour PRM for reliability planning requirement	Replaces the single-hour PRM with SOD reliability requirement	The SOD reliability requirement ensures the system has enough capacity to satisfy its load and PRM in all 24 hours on the CAISO's highest load day in that year and results in a more optimal resource portfolio than the single-hour PRM reliability requirement.

(b) Modeling Assumptions

Table II-4 summarizes the assumptions used by SCE in its system CE modeling, including differences from the assumptions used by the Commission in RESOLVE.

Table II-4
Assumptions Used in SCE's CAISO System CE Modeling

CAISO System	2026 IRP Assumptions
Run Horizon	• 2026-2035, 2040, and 2045 with SOD modeling in 2028, 2035, 2040, and 2045
Load	• 2024 IEPR managed net load
RPS/Zero-Carbon Regulation	• 60% RPS in 2030; beyond 2030, SCE used linear interpolation to reach 100% renewable and zero-carbon target in 2045, which also met 90% by 2035 and 95% by 2040 targets • RESOLVE Tx loss assumption applied to RPS or clean energy regulation
Emissions Regulation	• 7.38 MMT by 2045 (from system CSP Calculator)
Reliability Constraint	• 24-hour SOD reliability modeling
Existing RPS	• Reliability contribution based on 24-hourly SOD accreditation
Hydro	• Non-CAISO and CAISO Hydro calibrated with IRP Inputs & Assumptions (I&As) 2026
Existing Gas	• Calibrated with CAISO generator master file • Does optimize for economic retirement
Retirement and Procurement Requirement Assumptions	• D.26-02-057 procurement requirements enforced • Assembly Bill ("AB") 1373 central procurement of minimum geothermal and 12-hour storage enforced • All additional requirements calibrated with RESOLVE and the Commission generator list, including extension of in-front-of-the-meter combined heat and power resources through 2035

(c) Approach for Incorporating a 24-Hour SOD Reliability Framework

SCE modified its CE modeling in prior and current IRP cycles to incorporate the 24-hour SOD framework in place of the single-hour PRM requirement as the reliability planning standard, while continuing to account for other constraints including energy, GHG emissions, and RPS/zero-carbon requirements. In this IRP cycle, SCE implemented a SOD constraint that applied a PRM across all 24 hours during the "worst" summer day of the year for years 2028, 2035, 2040, and 2045. In 2040 and 2045, SCE also implemented the SOD constraint for the "worst" winter day. The CE model selects the most economical resource portfolio to ensure all the constraints are met for individual years in the planning horizon. Because the process for

modeling the GHG emissions, RPS/zero-carbon target, load, and generation balance requirements is unchanged from SCE's 2022 IRP and generally consistent with RESOLVE, the following section focuses on the method used to incorporate the SOD reliability framework.

The 24-hour SOD reliability framework, which is consistent with the SOD framework adopted by the Commission in its RA program, replaces the single-point PRM constraint historically used in the CE process to ensure the CAISO system portfolio meets the reliability planning standard, among other requirements.

The SOD approach assesses reliability across all hours on the highest load day of the year to ensure that the CAISO system has sufficient capacity to satisfy its load profile plus PRM in all 24 hours. It also includes an additional test to ensure that both capacity and energy are sufficient for the use-limited resources. In particular, the SOD approach ensures sufficient excess non-storage capacity during the 24-hour period to meet the charging needs of stand-alone storage resources. To implement this approach, SCE scales the hourly load forecast for the highest load day of the year (*i.e.*, the day with the highest managed peak load forecast) across all hours applying an assumed PRM of 18 percent across the full horizon.[24] Resource contributions to this reliability framework are based on their availability in each hour. Subsequently, the PRM of 18 percent for all model years were confirmed by the LOLE analysis to meet the 1-in-10 reliability standard for these years. For this IRP submission, SCE used SOD modeling for both the summer and winter peak load day for 2040 and 2045 to account for winter peaks becoming significant by these years in the IEPR load forecast.

SCE's SOD approach differs from the reliability modeling approach used by the Commission. First, as mentioned above, the Commission's method checks the single managed peak hour while SCE's method checks every hour for the highest load day of the year. Second, the Commission uses a PCAP PRM applied to the gross peak while SCE uses an Installed

[24] SCE confirms the portfolios developed using these assumed PRMs meet the 0.1 standard in the LOLE analysis. If the assumed starting point PRMs used in CE did not result in a reliable portfolio, SCE would have iteratively adjusted the PRMs to identify the level needed to meet the 0.1 industry LOLE reliability standard.

Capacity ("ICAP") PRM applied to the managed peak. Third, resource contribution under the Commission's method is based on Unforced Capacity ("UCAP") for thermal resources and marginal ELCC for renewable and storage resources, while SCE uses the same Qualifying Capacity ("QC") methodologies used in the RA proceeding under the SOD framework. Specifically for solar and wind resources, hourly exceedance profiles from the Commission's RA/IRP common dataset are used.[25] For thermal, hydro, non-solar and wind renewables, and imports, the assumptions provided by the Commission in the 2026 IRP cycle are used. Further, for storage resources, SCE's implemented SOD methodology requires that sufficient non-storage capacity must be shown to ensure there is sufficient charging energy, even after accounting for efficiency losses. Compared to the Commission's existing method based on the single-hour PRM requirement, the SOD approach effectively addresses challenges related to solar, wind, storage resources, and load variability, and ensures energy sufficiency for reliable system operations while advancing California's environmental goals.

(2) Step 2: PCM to Validate Feasibility and Operability of Portfolio

PCM simulations were conducted on the System Base Case Portfolio to validate the operational feasibility and performance of the portfolio built by the CE model for the CAISO system. A PCM simulation approach is used to dispatch generation resources to meet the demand and ancillary service requirements of the system on an hourly basis, while satisfying all the generator operational constraints, transmission constraints, and other system reliability requirements. Ancillary services, such as operating reserves and frequency response, are necessary requirements managed by the CAISO to ensure operational reliability and stability of the power system. Compared to the CE model, the PCM, which considers detailed generator

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[25] *See* Commission, 2026 Resource Adequacy and Slice of Day Guide, September 23, 2025, at 19-20, available at: https://webproda.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2026-ra-slice-of-day-filing-guide.pdf.

characteristics, ramping capabilities, and load balancing requirements on an hourly basis, is an effective tool to assess the operational feasibility of resource portfolios in a power system.

SCE used PLEXOS, a commercial software program with a mixed integer programming optimization engine, to perform the PCM simulation for the CAISO system and mimic CAISO day-ahead market operations and conduct a LOLE analysis. PLEXOS co-optimizes energy and ancillary services and generates the commitment and dispatch of available generation resources to meet demand and reserve requirements at least cost, subject to transmission and individual generation resource constraints. SCE's PLEXOS model is set to a CAISO-only, zonal model for the CAISO system.

(3) Step 3: LOLE Analysis to Validate Reliability of Portfolio

To assess the reliability of SCE's System Base Case Portfolio, SCE conducted a LOLE analysis using PLEXOS Monte Carlo simulations of 529 trials considering the uncertainties of load, wind and solar generation, and gas generation outages. SCE leveraged the Commission's System Reliability Modeling Datasets 2025, including load, solar, and wind profiles, to conduct the stochastic analysis.[26] Additionally, SCE adopted the Commission's interpretation of a 1-in-10 LOLE reliability standard, where a loss-of-load event is defined as a day in which at least one hour has insufficient capacity to meet load and/or reserve requirements.[27] SCE used a CAISO zonal modeling approach in the PLEXOS PCM platform to conduct the study.

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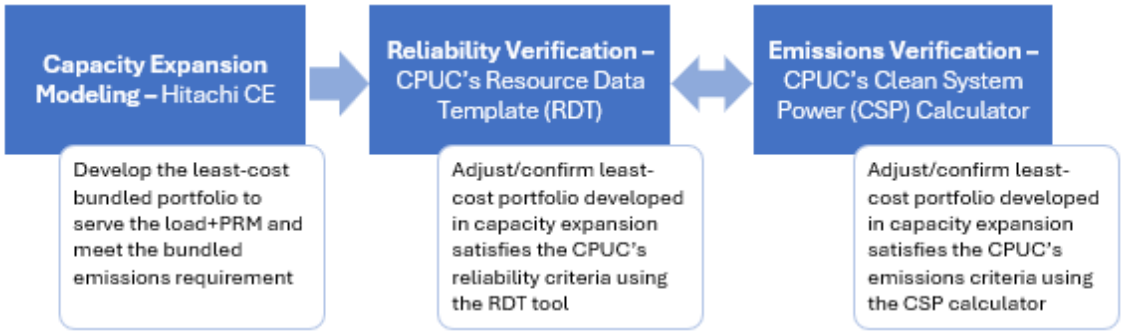
[26] *See* System Reliability Modeling Datasets 2025, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/energy-modeling/servm-inputs-2025.

[27] *See* Energy Resource Modeling Section, Energy Division, Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies, March 29, 2019, at 12, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/utilitiesindustries/energy/energyprograms/electpowerprocurementgeneration/irp/2018/unified-rairp-ia-final-20190329.pdf.

b) Bundled Portfolio Methodology

SCE's Conforming Bundled Portfolio was developed using the Hitachi CE model, the RDT, and the CSP Calculator as shown in Figure II-3 below.

Figure II-3
Modeling Tools Used in Development of SCE's Conforming Bundled Portfolio



SCE used the Hitachi CE model to develop least-cost resource portfolios that meet its GHG emissions benchmarks for bundled service customers. A straight-line approach was used to represent these declining GHG targets as annual constraints. The SOD framework used in SCE's bundled modeling follows the same methods as in the CAISO system modeling. In the bundled case, however, SOD is incorporated every year rather than only in key years (2028, 2035, 2040, 2045). The resulting bundled portfolio is the least-cost bundled portfolio that satisfies SCE's bundled load share of the GHG emissions (8 MMT) and reliability targets. SCE then used the Commission's RDT and CSP Calculator tools to verify the portfolio meets the Commission's GHG emissions and reliability criteria. If the bundled portfolio developed in SCE's modeling process did not "pass" either of the reliability or GHG emissions tests in the RDT and CSP Calculator, respectively, SCE would iteratively adjust the resource portfolio to arrive at a final bundled portfolio that satisfied the RDT and CSP Calculator criteria.

(1) CE Methodology to Identify Least-Cost Bundled Portfolio

(a) Hourly Load Shape Development for SCE Bundled Load

SCE developed hourly load shapes for its bundled service area for use in CE modeling in full compliance with the January 16, 2026 Administrative Law Judge's Ruling Setting Requirements for Individual Integrated Resource Plans Due June 1, 2026, which addresses load forecasts, peak demand, and behind-the-meter ("BTM") photovoltaic ("PV") assumptions. Specifically, SCE utilized the Commission-provided annual energy sales forecasts and coincident peak demand values assigned to SCE's bundled load and ensured that all modeled load inputs are fully consistent with these prescribed annual quantities. SCE did not modify the assigned annual energy forecast, consistent with filing requirements, and used the Commission-provided BTM PV assumptions embedded within the load forecast framework.

For CE modeling, SCE developed its own hourly load shapes rather than relying on the default shapes derived from the 2024 IEPR forecast. These customized hourly profiles were constructed to preserve SCE-specific temporal load characteristics while ensuring exact consistency with the Commission-assigned annual energy and peak demand values required for conforming portfolios. The resulting hourly load shapes were developed for each modeled year through 2035, with representative projections extended to 2040 and 2045 for CE modeling purposes.

SCE's methodology begins with a baseline hourly load profile reflecting the expected diurnal, weekly, and seasonal load patterns of its bundled service area. This baseline profile is then systematically adjusted through a deterministic scaling procedure to ensure simultaneous alignment with both the assigned annual energy and peak demand targets. First, the hourly profile is uniformly scaled so that total annual energy exactly matches the Commission-provided forecast. Second, the profile is adjusted around its annual average so that the maximum hourly load equals the assigned coincident peak demand, while preserving the annual energy established

in the first step. This two-step approach ensures that both planning targets are satisfied without distorting the fundamental shape of the load profile.

Additional safeguards are incorporated to ensure physical plausibility and numerical accuracy. The methodology ensures that all hourly values remain non-negative, including through proportional redistribution in the unlikely event that intermediate adjustments would otherwise produce negative values. A final rebalancing step eliminates any residual numerical discrepancies, ensuring exact compliance with both annual energy and peak demand requirements. The adjustment process is fully deterministic and reproducible, supporting auditability and transparency.

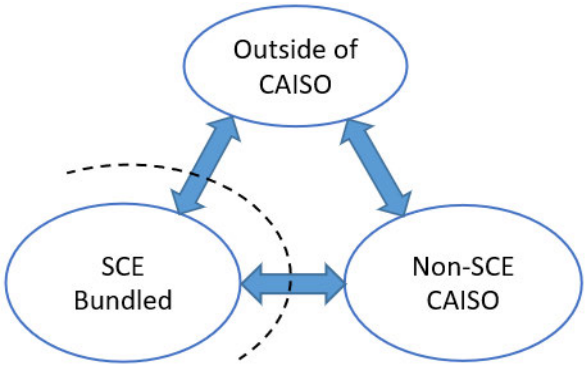
This approach preserves the intrinsic temporal characteristics of SCE's load – maintaining realistic daily, weekly, and seasonal variation – while strictly adhering to the Commission's assigned forecast quantities. As a result, the hourly load shapes used in SCE's CE modeling provide a robust and policy-compliant representation of bundled load, ensuring consistency with IRP filing requirements.

(b) Transmission Limits Enforced in CE

The modeling approach represented the system as three linked transmission areas: SCE bundled, the remainder of CAISO, and the rest of the Western Electricity Coordinating Council ("WECC"). This was done for two reasons: (1) to ensure that shared resources (*e.g.*, CAISO system resources, major transmission lines, and import/export lines) are not excessively used by any one LSE; and (2) to more precisely account for GHG emissions attributable to SCE bundled service customers.[28] Figure II-4 below depicts the regional structure of the SCE bundled system.

[28] SCE enforced a PRM of 18 percent in development of its bundled portfolios consistent with the assumption applied in the CAISO system modeling. PCM simulation is not needed for bundled portfolios because bundled portfolios represent a small portion of the overall system resources.

Figure II-4
SCE Bundled System Topology



To limit resource sharing among the three regions, transmission limits were estimated based on both the load share and the physical, simultaneous transmission limits. The following Table II-5 and Table II-6 summarize the interregional transmission limits enforced in the SCE bundled system. SCE applied the SCE bundled load share of the final import cap shape assumed in the Commission's modeling,[29] with a 4,000 megawatt ("MW") maximum import limit, plus Palo Verde and Hoover, to set its import limit. Additionally, SCE used an imported power CO2 emissions rate of 0.428 metric tons per megawatt-hour ("MWh") between its bundled system and the rest of the WECC. Applying this emissions rate accounts for CAISO system emissions generated on behalf of SCE's bundled service customers and is consistent with the Commission's assumed emissions rate for unspecified imports.[30]

[29] *See* Energy Division, Final 2025 Inputs and Assumptions (I&A) for the 2024-2026 IRP Cycle, February 2026, at 158, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_slides-20260210.pdf.

[30] *See* Greenhouse Gas and Criteria Pollutant Accounting Methodology for use in Load-Serving Entity Portfolio Development in 2026 Integrated Resource Plans, March 19, 2026, at A-7, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/csp-tool-documentationupdated-03192026ver2.pdf.

Table II-5
Rest of WECC to SCE Bundled Transmission Limits[31]

Year	Assumed SCE Bundled Import RA Capacity (MW)	Methodology
2026	1,228	SCE bundled peak load share of a 4,000 MW maximum import limit
2027	1,230	
2028	1,233	
2029	1,230	
2030	1,227	
2031	1,225	
2032	1,223	
2033	1,221	
2034	1,219	
2035	1,217	
2040	1,182	
2045	1,143	

Table II-6
Rest of CAISO to SCE Bundled Transmission Limits

Transmission Lines	Import Limit on the Path (MW)	Methodology
SCE Bundled to Rest of CAISO	3,000	Path 26 South to North transmission limit
Rest of CAISO to SCE Bundled	4,000	Path 26 North to South transmission limit

(c) Allocation of Shared Resources

For the SCE resources subject to the Cost Allocation Mechanism ("CAM"), the resource share that contributes to SCE's bundled portfolios is the proportional share determined by SCE's bundled energy load to the total non-bundled and bundled peak energy load from the 2025 year-

[31] SCE's share of Hoover and Palo Verde were accounted for separately.

ahead RA allocations.[32] SCE's IRP only includes its pro-rata share of the capacity from the CAM-eligible resources. Additionally, SCE's IRP only includes its pro-rata share of the clean energy from CAM-eligible storage resources.

Pursuant to D.21-05-030, renewable attributes from RPS-eligible resources procured on behalf of customers who have now departed bundled service are eligible to be allocated or sold through the Voluntary Allocation and Market Offer ("VAMO") process. For purposes of this IRP, and consistent with D.22-01-004, SCE assumes all quantities eligible for VAMO are either allocated or sold and cannot be used toward SCE's RPS/zero-carbon targets. As set forth in Advice 5173-E, SCE is not holding another VAMO process for 2026 and beyond. As a result, SCE did not allocate short-term Market Offer volumes, as those contracts are terminated. Voluntary Allocation contracts signed in the previous VAMO process (2024) are still forecasted as allocated and sold.

D.21-05-030 also authorized, on an interim basis, a GHG-free allocation process to allocate the "clean energy" attributes from nuclear and large hydro resources to customers who have departed bundled service but have elected to receive their pro-rata share.[33] On June 8, 2023, the Commission adopted D.23-06-006, directing investor-owned utilities ("IOUs") to indicate whether they would provide interim allocations of large hydroelectric energy for 2024. SCE subsequently elected, via Advice 5081-E, to provide voluntary allocations of hydroelectric and GHG-free nuclear energy in 2024 and to transition LSE elections to a multi-year term aligned with RPS compliance periods. SCE later elected to continue voluntary allocations of large hydro and Power Charge Indifference Adjustment ("PCIA")-eligible GHG-free nuclear energy for 2025-2027, completing allocations for this period, with no additional allocations planned until 2028. For purposes of this IRP, SCE assumes clean energy attributes from nuclear

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[32] In its RDT, SCE used its proportional share of CAM resources based on its 2025 initial year-ahead share of total coincident peak load as assigned in the RA process and kept that share static throughout the IRP planning horizon.

[33] Unlike VAMO, the GHG-free allocation process does not have a market offer component to sell the clean energy attributes that are eligible to be allocated but declined by LSEs.

and large hydro resources continue to be allocated beyond 2026 and uses historical allocation rates by technology type to determine the quantities that cannot be used toward SCE's clean energy targets.[34]

Finally, a small share of SCE's D.19-11-016 procurement was completed on behalf of non-IOU LSEs who opted out of their procurement requirements. Consistent with D.22-05-015 and SCE's Advice 4831-E, SCE's IRP assumes a share of the D.19-11-016 resources are allocated to those opt-out LSEs and cannot be used toward SCE's requirements.[35]

(d) Assumed Share of System Resources

When considering candidate resources, defined by SCE as new resources and resources from SCE's portfolio that expire in the IRP planning horizon, for its bundled portfolio, SCE partitioned the candidate resources on a pro-rata basis according to the SCE bundled load share to the CAISO system load. If this candidate resource partitioning approach is used by all LSEs, it will ensure that the total selected resources for each category will not exceed the maximum available potential when the Commission combines LSEs' IRPs to form the PSP.

Capping LSEs' ability to select up to its load-share of candidate resources is particularly important for technologies that are limited in availability and expected to be in high-demand, such as thermal and wind resources. SCE assumed it would contract its pro-rata share of existing thermal resources in each year. SCE also assumed it would have access to its pro-rata share of new and existing wind resources. Specifically, SCE's expiring contracts with existing wind resources were added to its pro-rata share of the new wind potential and assumed to be the same cost as new resources of the same class.

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[34] Eligible LSEs may elect to receive a vintaged load share of the clean energy attributes from nuclear and large hydro resources. Because allocation rates varied by technology based on LSEs' elections, and in certain cases LSEs declined the attributes altogether, SCE used historical allocation rates to forecast future allocations.

[35] Additionally, SCE's IRP assumes a small share of D.19-11-016 procurement done on behalf of opt-out LSEs that are now non-operational is subject to CAM. *See* D.22-05-015 at OP 10.

3. Alternative Assumptions

a) Cost Assumptions

SCE conducted its IRP analysis using the 2026-2027 TPP resource cost assumptions rather than the cost assumptions specified in the 2024-2026 IRP Inputs and Assumptions ("I&As"). The 2026-2027 TPP cost assumptions reflect more recent federal policy developments and market conditions, including updated tax credit availability and applicable tariff impacts, and are therefore better aligned with expected procurement economics over the planning horizon. While the I&A cost assumptions were also reviewed for reference and comparability, SCE determined that the 2026-2027 TPP assumptions, with one exception as described below, provides a more accurate representation of likely future costs and supports more informed evaluation of portfolio feasibility, cost-effectiveness, and reliability outcomes. Table II-7 summarizes the cost assumptions from the IRP I&As and the 2026-2027 TPP (which were used in the SCE system and bundled system modeling).

Table II-7
Comparison of IRP I&As and 2026-2027 TPP Resource Costs

	Costs are Levelized Fixed Costs with PTC/ITC ($/kW-yr, 2024$)					
Resource Category	**Cost Scenario**	**2028**	**2030**	**2035**	**2040**	**2045**
Utility Solar	I&A	$77	$70	$55	$43	$33
	TPP	$109	$135	$116	$103	$92
In-State Wind	I&A	$127	$124	$113	$104	$95
	TPP	$148	$179	$168	$158	$148
Out-of-State Wind	I&A	$219	$215	$205	$197	$189
	TPP	$239	$287	$276	$267	$258
Offshore Wind	I&A	$1,067	$1,070	$741	$606	$556
	TPP	$1,135	$1,377	$948	$771	$707
Geothermal	I&A	$707	$691	$652	$640	$630
	TPP	$737	$719	$679	$946	$928
Enhanced Geothermal ("EGS")	I&A	$967	$928	$843	$827	$813
	TPP	$996	$952	$867	$1,247	$1,223
Out-of-State EGS	I&A	$1,002	$963	$879	$863	$848
	TPP	$1,015	$971	$886	$1,258	$1,234
Biomass	I&A	$481	$480	$472	$464	$456

	TPP	$484	$483	$475	$643	$628
Li Battery 4hr	I&A	$139	$135	$126	$117	$109
	TPP	$209	$130	$121	$150	$139
Li Battery 8hr	I&A	$235	$225	$209	$193	$179
	TPP	$365	$221	$205	$257	$237
Long-Duration Storage – Generic (12-hr)	I&A	$409	$400	$377	$355	$335
	TPP	$413	$404	$380	$529	$497
Long-Duration Storage – Constrained (12-hr)	I&A	$179	$180	$180	$180	$180
	TPP	$182	$182	$182	$277	$277
Final costs in table above are averaged by individual candidate resource in each resource category						

SCE used the TPP costs for all its resource cost assumptions with the exception of location-constrained 12-hour storage. The Commission's I&As assume all 10.4 GW of candidate location-constrained 12-hour storage resources are available at one representative cost, the cost of pumped hydro with a specific configuration, despite those resources being highly site-specific with different project economics.[36] Furthermore, the cost selected to represent the cost of all location-constrained 12-hour storage is significantly lower than the cost of generic long-duration storage resources, with the constrained costs assumed to be lower than even generic 8-hour lithium-ion through 2035, as seen in Table II-7 above.

It is not reasonable to assume that all location-constrained 12-hour storage should cost less than generic lithium-ion storage because location-constrained resources are, by definition, limited to a small number of geographically viable projects and typically rely on capital-intensive infrastructure that is specific to the economics of the site and project. These projects face significant siting, permitting, transmission, and development costs. To avoid selection of unreasonable quantities of this resource like the Commission's Reference Portfolio, which selected 3.9 GW of 12-hour location-constrained storage by 2035 and 8.5 GW by 2045, SCE

[36] *See* 2024-2026 Integrated Resource Planning (IRP), Inputs & Assumptions, February 2026, at 101-102 (describing how "Pumped Storage Hydropower – One New Reservoir, Class 3" costs represent the cost of all candidate pumped hydro storage and adiabatic compressed air storage), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf.

applied the TPP cost assumptions for generic 12-hour storage technology to location-constrained 12-hour storage resources.

b) AB 1373 Resources

SCE's CAISO system-level and bundled portfolios include a certain amount of LLT resources authorized under D.24-08-064 pursuant to AB 1373. Specifically, for its CAISO system modeling, SCE assumed the maximum amount of geothermal (1,000 MW) and 50 percent of the 12-hour storage (500 MW) authorized under D.24-08-064 will be centrally procured by the Department of Water Resources ("DWR") and allocated to all LSEs under the Commission's IRP purview. SCE enforced these amounts as "must build" commitments in its system-level modeling. SCE's assumptions reflect an achievable implementation of AB 1373 by incorporating procurement from resources with demonstrated commercial viability and credible development pathways, while avoiding reliance on offshore wind and multi-day storage whose costs, deployment timelines, and achievable scale are less certain within the planning horizon.

For its bundled portfolio, SCE included its respective full allocations of geothermal, 12-hour storage, and multi-day storage from AB 1373 procurement. As SCE describes in Section III.A.2, SCE assumed more AB 1373 procurement for its bundled portfolio than its system modeling to transparently identify the additional resources needed to make a bundled portfolio that is already reliable under an SOD standard to be reliable under the Commission's ELCC-based reliability metric. SCE has not included any assumed procurement of offshore wind by DWR in its bundled portfolio.

Table II-8
AB 1373 Procurement Assumed in SCE's Analysis

	CAISO System Base Case		SCE Conforming Portfolio	
Resource Type	**GW**	**Online Year**	**GW**	**Online Year**
Geothermal	1.00	2032	0.29	50% in 2032, 50% in 2035
Long Duration Storage (12-Hr)	0.50	by 2040	0.36	50% in 2034, 50% in 2035
Multi-Day Storage (24-Hr)	-	-	0.36	50% in 2032, 50% in 2033

c) D.26-02-057 Procurement Order

D.26-02-057 requires LSEs to procure 6,000 MW of net qualifying capacity ("NQC") from new resources to come online in the 2030-2032 timeframe and specifies that 1,500 MW NQC (25 percent) must be met with long-duration storage (≥8-hour duration) and/or clean firm generation resources.[37] Because ELCC values associated with this order were not available (expected release on August 31, 2026 for the 2030 and 2031 requirements and December 31, 2027 for the 2032 requirements),[38] SCE implemented this required procurement in the following manner:

- SCE's system modeling enforces a minimum build constraint for the 1,500 MW NQC long-duration storage and/or clean firm requirement but does not "force-in" the remaining 4,500 MW NQC of generic new capacity because other IRP planning constraints will drive the model to add the needed new resources. Under this assumption, SCE's system portfolios are set to include at least 1,500 MW NQC of new LLT resources (750 MW NQC from ≥8 hour storage and 750 MW NQC from geothermal or other "clean firm" generation) by 2032. These values are implemented as minimum additions in the CE model, with the corresponding nameplate capacities calculated using current IRP marginal ELCC values for 8-hour storage and geothermal in 2032 to approximate their NQC contribution.

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37 *See* D.26-02-057 at OP 1-2.
38 *See id.* at OP 9. On July 27, 2026, the Commission's Executive Director granted Energy Division's request to extend the deadline for releasing the 2030 and 2031 ELCC values to August 31, 2026.

- SCE's bundled modeling enforces a minimum build constraint for its share of the entire D.26-02-057 requirement, including the generic capacity portion. SCE's initial bundled modeling, which used the same approach for D.26-02-057 procurement as the system modeling described above, did not identify sufficient new capacity for SCE to satisfy the entire D.26-02-057 order by 2032. As such, SCE modified its assumption to "force-in" additional solar and storage resources to reasonably account for the procurement required by D.26-02-057. SCE estimated the nameplate capacity required to satisfy the order using the current IRP marginal ELCC values. However, during Energy Division's 2026 IRP Filing Requirements Office Hours held on February 17, 2026, Staff indicated the ELCC values that will be used for D.26-02-057 compliance purposes are likely to be higher than the IRP's marginal ELCC values for 4- and 8-hour storage. Therefore, the values SCE included to account for the D.26-02-057 procurement in its bundled portfolio may be over-stated, limiting its value to potentially inform procurement decisions.
- SCE's assumptions recognize that D.26-02-057 establishes procurement requirements that will materially shape the resources available to support California's clean energy transition. Incorporating these procurement obligations into portfolio development ensures that modeled portfolios account for resources expected to be procured pursuant to Commission decision.

d) Minor Modification to the RDT Calculation for Hydro Resources

The reliability check within the RDT applies the technology-specific ELCC factors to either the nameplate capacity (if solar, storage, or wind) or the September NQC value (all other technologies, including hydro) of each resource to determine its "effective MW" contribution to the LSE's reliability requirement. Applying the ELCC factors to the September NQC, rather than nameplate capacity, underestimates the reliability contribution of those resources because it results in two capacity accreditation adjustments when only one adjustment is appropriate.

Applying ELCC factors to NQC mistakenly assumes that NQC requires further adjustments for reliability. However, NQC is itself a reliability-adjusted capacity metric intended to represent the amount of dependable capacity that a resource contributes toward RA requirements after accreditation and CAISO adjustments.[39]

Conceptually, ELCC values should be applied to an undistorted measure of resource capability, such as nameplate capacity, rather than to an already-accredited NQC value. The RDT appropriately applies ELCC values to nameplate capacity for solar, wind, and storage resources, but applies ELCC values to the September NQC for all other resource technologies. This approach has the greatest impact on hydro resources, which have September NQC values that are significantly lower than their nameplate capacity and have ELCC factors that range from 20-70 percent. Accordingly, SCE has modified the RDT's formula for hydro resources to apply the ELCC factor to the nameplate capacity, rather than September NQC.

e) User-Specified Storage Resource Custom Profiles

SCE incorporated a user-specified custom battery charging profile in the CSP Calculator, which is allowed per the filing requirements, as an alternative assumption to better reflect observed battery charging behavior and improve alignment with actual system operations.[40] As shown in Figure II-5 below, the default battery charging profile in the CSP Calculator concentrates peak charging power in the mid-morning hours, whereas observed CAISO operational data indicate that storage charging energy is more heavily concentrated during the mid-day and afternoon periods, coincident with high solar generation.

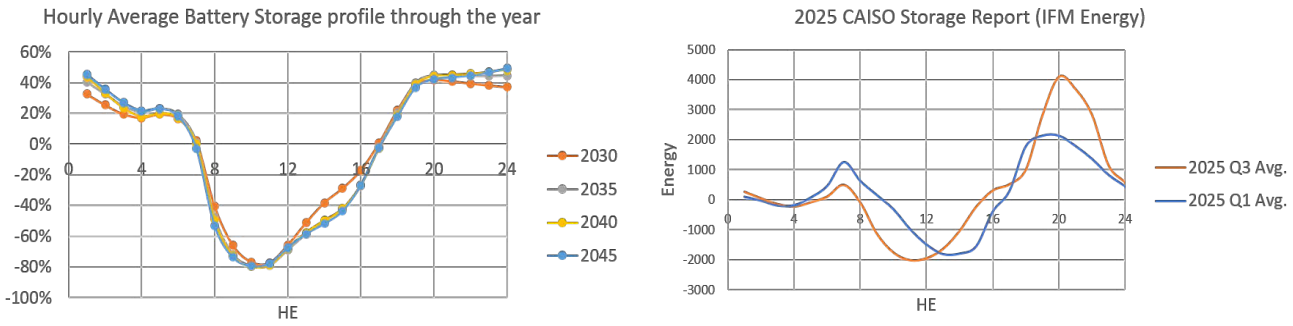
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[39] *See* CAISO, CAISO Resource Adequacy Overview, November 16, 2023, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=253146&DocumentContentId=88349.

[40] The Commission's updated filing requirements specifically allow LSEs to use a custom profile in the CSP Calculator for storage resources if "the hourly production profile ranges between -1 (charging at max) to 1 (discharging at max) and is normalized to the contracted_nameplate_capacity for the resource," and "the hourly profile should not be a net producer of energy and will likely be a net consumer of energy as a result of round-trip efficiency losses from storage." 2026 IRP Filing Requirements Overview, March 19, 2026, at 5.

Figure II-5
Comparison of Battery Charging Profiles in CSP Calculator and in CAISO Operation

In CSP peak charging power occurs around 10am	From CAISO Operation data, peak charging energy occurs around noon and afternoon



To address this divergence, SCE developed a custom battery charging profile derived from PCM simulation results and calibrated through validation against observed CAISO storage operations, using 2009 weather-year conditions.[41]

The custom battery profile exhibits improved alignment with solar generation by shifting charging behavior toward high-solar hours, consistent with system conditions observed in CAISO operations. The profile reflects realistic storage performance characteristics, including approximately 85 percent round-trip efficiency and annual utilization in the range of approximately 70 to 74 percent. SCE implemented this profile in a manner that is fully compliant with the updated IRP filing requirements governing user-specified storage resource custom profiles. Specifically, the hourly profile ranges from –1 for maximum charging and 1 for maximum discharging and is normalized to contracted nameplate capacity. It is not a net producer of energy over the year and reflects net energy consumption consistent with round-trip efficiency losses. All CSP Calculator supply input validation checks associated with the custom

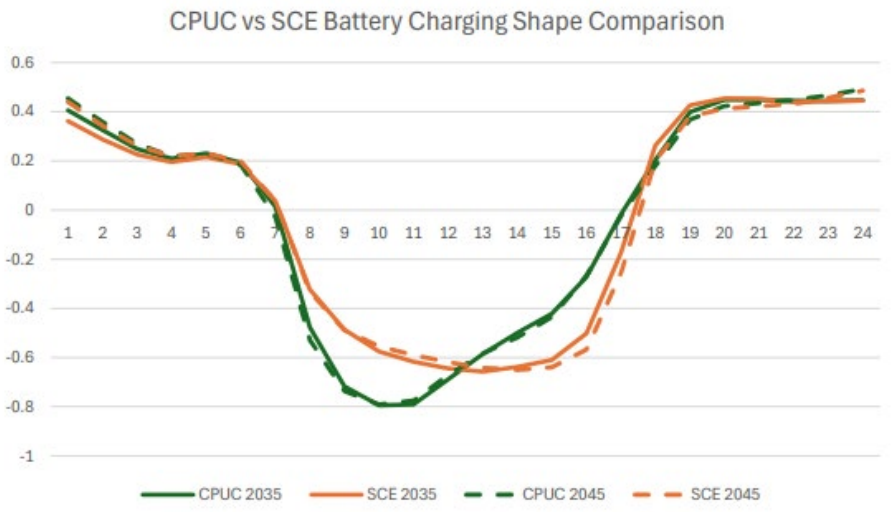
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[41] *See* Greenhouse Gas and Criteria Pollutant Accounting Methodology for use in Load-Serving Entity Portfolio Development in 2026 Integrated Resource Plans, March 19, 2026, at A-12 (requesting LSEs use 2009 weather conditions when developing custom resource profiles), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/csp-tool-documentationupdated-03192026ver2.pdf.

storage profile were satisfied. The capacity for the storage resource custom profile input for the CSP was calculated by dividing the battery storage energy output (MWh) from the RDT by the weighted average duration of SCE's total online bundled storage resources in each year. Figure II-6 below shows a comparison between the Commission's and SCE's battery charging shapes.

SCE's assumptions reflect a reasonable representation of storage operations by utilizing custom dispatch profiles that better align charging and discharging behavior with expected system conditions and periods of renewable overgeneration. This approach better reflects modeled resource performance and produces planning results that align with expected real-world operations.

Figure II-6
Comparison of Commission and SCE Battery Charging Shapes



III.

STUDY RESULTS

A. Conforming and Alternative Portfolios

As explained above, SCE developed its System Base Case Portfolio, System PGP, and additional sensitivity scenarios – including the Updated Load Scenario, Market-Constrained

Scenario, and Diablo Extended Scenario – to evaluate how key planning assumptions affect portfolio affordability, feasibility, reliability, and GHG reduction outcomes. Collectively, these analyses provide the analytical foundation for SCE's recommendations to reform portions of the IRP process: establish a PGP to guide near- and mid-term procurement decisions, accelerate transmission development, and better align reliability planning with operational needs.

SCE's System Base Case Portfolio evaluates the implications of the Commission's current planning assumptions and illustrates the scale of resource development and investment required to achieve the 30 MMT by 2030, 25 MMT by 2035, and 8 MMT by 2045 GHG targets. The sensitivity scenarios examine how portfolio outcomes change under alternative assumptions regarding load growth, resource availability, market constraints, and continued operation of Diablo Canyon. These scenarios help identify the primary drivers of portfolio cost, feasibility challenges, and implementation risk and provide insight into the tradeoffs among affordability, reliability, and GHG emissions reductions.

SCE's System PGP serves a different purpose. It evaluates whether California can continue making substantial progress toward its reliability and decarbonization objectives using assumptions that more closely reflect expected market conditions, resource availability, transmission constraints, and customer affordability considerations. SCE's System PGP is not intended to replace the Commission's PSP, which remains an important tool for long-term transmission planning and identifying the resources needed to achieve California's 2045 clean energy goals. Rather, SCE's System PGP demonstrates how a procurement-focused portfolio can better balance affordability, feasibility, and implementation realities while continuing to support reliability and meaningful GHG emissions reductions through 2035. The Commission should develop a PGP based on SCE's recommendations to inform near- and mid-term procurement targets for the RCPPP and any other procurement requirements through 2035.

Finally, for its bundled load, SCE developed its Conforming Bundled Portfolio, which is also SCE's Preferred Conforming Portfolio. SCE's Conforming Bundled Portfolio evaluates

how SCE can meet its allocated share of the Commission's prescribed GHG benchmarks while satisfying bundled customer energy and capacity needs.

The sections below describe the resource build-out results for: (1) SCE's System Base Case Portfolio and related scenarios; (2) SCE's System PGP; and (3) SCE's Conforming Bundled Portfolio.

1. SCE's System-Wide Portfolio Results

a) Key Findings from SCE's System Modeling

The following are key findings from the results of SCE's CAISO system analysis, including SCE's System PGP and other alternative scenarios.

- **2024 IEPR load assumptions are the primary driver of near-term resource build-out pressure and cost:** SCE's Updated Load Scenario analysis finds that using updated load assumptions based on the 2025 IEPR instead of the 2024 IEPR materially reduces new resources needs in 2035, lowering the cumulative build-out by approximately 21 GW compared to SCE's System Base Case Portfolio based on the 2024 IEPR. This results in an annual cost reduction of approximately $4 billion per year, or 25 percent. Most importantly, the 2025 IEPR load forecast supports a more gradual and feasible deployment of solar and battery storage. Using the 2025 IEPR load forecast reduces reliance on building large quantities of solar and storage resources over the next ten years and allows for a more achievable trajectory of new resource additions. By contrast, the 2024 IEPR load forecast would, as the Commission acknowledged, require "solar build rates that are several multiples of any recent year's accomplished development."[42]
- **Limited resource availability will make achieving the GHG targets more difficult and expensive:** SCE's Market-Constrained Scenario, which limited resource

[42] D.26-02-057 at Finding of Fact ("FOF") 25.

availability to those resources that will more realistically be available to LSEs, finds that meeting the 2030 and 2035 GHG targets with solar, storage, and a limited amount of wind, the only resources available at scale in the CAISO interconnection queue, will require an unprecedented level of new build. Further details are included in Section III.A.1.b.2.b.

- **The PGP is intended to serve as a procurement-focused complement to the PSP, not a replacement for it:** A PGP similar to SCE's System PGP should be used to guide procurement through 2035; however, the PSP should continue to provide long-term planning signals for transmission expansion and development of clean firm and other LLT resources. SCE's analysis continues to show the long-term value of these diverse clean resources.
- **SCE's System PGP provides a more affordable pathway to 2035 than portfolios based on the Commission's current assumptions:** By using updated load assumptions, CAISO interconnection queue-informed resource availability constraints, and an alternative GHG trajectory, SCE's System PGP reduces annual system costs by approximately $7 billion per year (roughly 40 percent) in 2035 relative to the Commission's Reference Portfolio.
- **SCE's System PGP remains highly ambitious and requires unprecedented resource development:** Although more achievable than the Commission's Reference Portfolio, the System PGP still requires an unprecedented build-out of new solar, storage, and wind resources through 2035 and demonstrates the continued need for flexible compliance mechanisms. Even under the PGP's planning framework, significant development, interconnection, transmission, permitting, and supply-chain risks remain. As a result, the RCPPP and any future procurement decisions should include flexible compliance mechanisms that accommodate delays and implementation risks outside the control of LSEs.

- **SCE's System PGP demonstrates that meaningful GHG reductions can still be achieved with a more measured near-term planning trajectory:** By planning to GHG emissions targets of 38 MMT by 2030 and 30 MMT by 2035 within CARB's approved planning range and emphasizing the most cost-effective emissions reductions, the System PGP maintains meaningful progress toward California's long-term climate goals while reducing procurement risk and affordability impacts.
- **Diablo Canyon, if extended, reduces build-out pressure and can be used as a hedge against load growth risk:** Continued operation of Diablo Canyon would enable the system to maintain reliability and reduce GHG emissions with significantly less new solar, storage, and geothermal additions. Although the Commission is statutorily precluded from including Diablo Canyon in its adopted resource plans under current law,[43] it can and should pragmatically recognize the plant's ability to protect against resource shortfalls if significant load growth materializes before the system can reasonably accommodate it.

  As discussed above, using the 2025 IEPR load forecast to guide planning and procurement through 2035 would significantly reduce costs for customers and result in a more feasible required resource build-out compared to relying on the 2024 IEPR forecast. SCE finds it prudent to plan for procurement based on the 2025 IEPR because it is the most updated load forecast adopted by the CEC and because an extension of Diablo Canyon provides an effective hedge against both reliability and GHG emissions risks if the higher load growth assumed in the 2024 IEPR materializes. Specifically, SCE's LOLE-based reliability analysis on its System PGP shows that a portfolio designed to achieve 30 MMT by 2035 under the 2025 IEPR load forecast can reliably serve the higher load levels projected in the 2024 IEPR, provided Diablo Canyon is extended and existing gas resources are retained

[43] *See* Cal. Pub. Util. Code §§ 454.52(f)(1)-(2).

("System PGP Reliability Analysis"). While GHG emissions from this portfolio would exceed the 30 MMT target if 2024 IEPR load levels occur, Diablo Canyon still serves as a partial emissions hedge, reducing total emissions by approximately 4 MMT.

- **Long-term planning should use the SOD reliability framework because it promotes the development of more cost-effective resource build-outs:** In 2035, GHG emissions reduction is the sole binding constraint for both the Commission's and SCE's system portfolios; thus, the different reliability frameworks do not impact resource selection in that timeframe. However, the single-hour PRM requirement based on marginal ELCC becomes the binding constraint in 2045 in the Commission's model, driving selection of higher-cost resources with relatively high ELCC values (*e.g.,* longer duration 12-hour storage with a 19 percent ELCC, compared to 8-hour storage with a 13 percent ELCC). By contrast, GHG emissions continue to be the sole binding constraint in 2045 in SCE's modeling because the SOD-based framework is inherently more aligned with the binding GHG requirement (*i.e.,* both consider hourly needs). Accordingly, SCE's portfolio relies more heavily on solar paired with 8-hour batteries because of their higher round-trip efficiency and lower cost.[44]
- **Retaining gas-fired generation supports the energy transition**: SCE's System PGP Reliability Analysis illustrates how the existing gas fleet helps ensure reliability when load growth exceeds forecasts or when new clean energy resources experience development, permitting, transmission, or interconnection delays. Although the Commission's and SCE's System Base Case Portfolio modeling identify an opportunity to retire gas-fired generation, SCE's System PGP Reliability Analysis demonstrates that retaining gas resources as a near- to mid-term cost containment

[44] SCE's PCM simulation confirmed 8-hour duration is optimal for solar charging profiles.

measure supports a more measured clean energy transition. As SCE discussed in its RCPPP comments, the Commission should consider developing a directed procurement program for maintaining a fleet of existing gas-fired generation that is deemed strategically needed to support reliability while continuing to significantly reduce GHG emissions and meet decarbonization goals.[45]

b) Summary of SCE's System Base Case Portfolio

SCE's System Base Case Portfolio is constructed using different modeling tools but the same load forecast as the Commission's Reference and TPP Portfolios and the same resource cost and availability assumptions as the Commission's TPP Portfolio. SCE's System Base Case Portfolio modeling is intended to validate the reasonableness of the Commission's portfolios, offer insight into how alternative reliability frameworks – such as an SOD approach – perform under identical assumptions, and explore sensitivities that illuminate the implications of key inputs and modeling choices. Rather than serving as a competing framework, SCE's analysis is designed to enhance understanding and inform the Commission's efforts to identify the most cost-effective pathway to achieving California's reliability and clean energy goals.

Figure III-7 below includes the new resource build-out from SCE's System Base Case Portfolio. SCE's System Base Case Portfolio is based on the 2024 IEPR load forecast, meets the annual SOD requirements for 2028, 2035, 2040, and 2045, and meets GHG emissions requirements of 30 MMT by 2030, 25 MMT by 2035, and 8 MMT by 2045. SCE performed LOLE analysis on its System Base Case Portfolio and found it satisfies the 1-in-10 reliability criteria in 2035 (0.0 LOLE)[46] and 2045 (0.085 LOLE). The analysis also indicates that existing gas resources provide optionality: while the portfolio could support the retirement of up to 5 GW of gas resources in 2035 and 8 GW in 2045 under modeled assumptions, retaining some or all of those resources could serve as a reliability hedge if higher load growth materializes or if clean

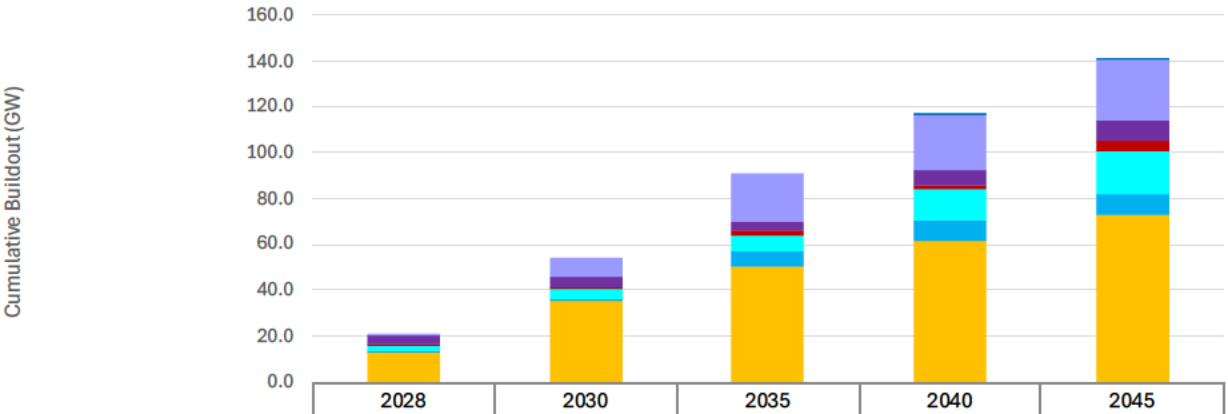
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[45] *See* Southern California Edison Company's Comments on Ruling Seeking Comments on Reliable and Clean Power Procurement Program Staff Proposal, R.20-05-003, July 15, 2025, at 22.

[46] The value of 0.0 LOLE corresponds to a scenario where no gas resources are retired.

resource development, interconnection, or transmission expansion is delayed. Additionally, SCE's System Base Case Portfolio passes the RDT's reliability requirements in 2030, 2035, and 2045[47] and the CSP Calculator's GHG emissions requirements in all compliance years.[48]

Figure III-7
SCE's System Base Case Portfolio – Cumulative Capacity Additions[49]



	2028	2030	2035	2040	2045
Long Duration Storage (12-Hr)	0.0	0.0	0.0	0.5	0.5
Li-ion Battery (8-Hr)	0.1	8.0	20.4	23.3	26.3
Li-ion Battery (4-Hr)	4.4	4.4	4.4	6.8	9.1
Geothermal	0.1	0.8	1.9	2.1	3.9
Out-of-State Wind	2.9	4.4	7.0	13.5	19.0
In-State Wind	0.7	1.1	6.2	8.4	8.7
Solar	12.7	35.3	50.6	62.0	73.3

SCE's System Base Case Portfolio modeling finds that the GHG emissions constraint is the major driver for the resource build-out through 2045. The most cost-effective resources to reduce GHG emissions differ between the near-, mid-, and long-term.

New utility-scale solar remains the lowest cost resource for reducing GHG emissions over the next decade because it can be paired with the state's rapidly expanding storage fleet to increase clean energy supply, reduce curtailment, and displace higher-emitting generation across

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47 SCE's System Base Case Portfolio passes the RDT's reliability requirements in 2030, 2035, and 2045 with an excess net capacity position (effective MW) of 5.4 GW, 1.6 GW, and 2.3 GW, respectively.

48 The CSP Calculator GHG emissions from SCE's System Base Case Portfolio in years 2030, 2035, and 2045 are 15.5, 13.8, and 7.0 MMT, respectively.

49 Although 1 GW of assumed AB 1373 geothermal procurement was included in SCE's System Base Case Portfolio by 2035, the model selected over this quantity in that year, indicating that it would have been economically selected even without AB 1373 procurement.

more hours of the day. SCE's analysis indicates that through 2030, additional stand-alone solar is needed (new solar-to-storage ratio ranges between 1.75-2 MW solar-to-1 MW 4-hour equivalent storage)[50] to fully utilize existing storage resulting from MTR procurement orders.

As 2035 approaches and the existing/in-development storage is fully utilized, the need shifts toward solar paired with storage, with the ratio of new solar-to-storage tightening to 1.16-1.27 MW solar-to-1 MW 4-hour equivalent storage.[51] SCE's analysis identifies a need for longer duration clean energy dispatch to meet reliability and GHG emissions reduction objectives and consistently selects 8-hour storage over two 4-hour storage resources based on the assumed costs; the only 4-hour storage resources included in SCE's portfolios are the 4.4 GW of "Planned – Contracted" resources specified in (*i.e.,* not selected by) RESOLVE. SCE notes that multiple shorter duration batteries can satisfy the identified need and LSEs may continue to rely primarily on 4-hour storage resources if 8-hour storage is more expensive or less available than assumed in the Commission's I&As.

Wind resources play a critical role in the portfolio because of their relatively low cost and ability to complement a solar-heavy portfolio. Near-term in- and out-of-state wind deployment through 2035 is capped by build limits specified in the Commission's assumptions and nearly exhausted up to its total resource potential by 2045.[52] As further demonstrated in the Market-Constrained Scenario discussion below, system costs will increase if wind does not materialize because a disproportionate amount of solar and storage would be required to fill this gap.

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[50] SCE's System Base Case Portfolio for 2030 identifies 35 GW of solar and 20 GW of 4-hour equivalent storage and the Updated Load Scenario for 2030 identifies 21 GW of solar and 10 GW of 4-hour equivalent storage.

[51] SCE Base Case Portfolio for 2035 identifies 51 GW of solar and 44 GW of 4-hour equivalent storage and the Updated Load Scenario for 2035 identifies 33 GW of solar and 26 GW of 4-hour equivalent storage.

[52] The Commission's I&As limit in- and out-of-state wind by 2035 based on assessment of the interconnection queue (in-state), project lead time, commercial development, and estimates of existing and hypothetical new transmission development (out-of-state). After 2035, in- and out-of-state wind is allowed up to its resource potential.

Clean firm generation is ultimately needed for reliability and deep decarbonization as 2045 approaches. SCE's 2045 LOLE analysis finds there are reliability risks in winter and summer, with 60 percent of unserved load hours occurring in winter morning hours. SCE's analysis therefore selects additional geothermal resources to round out the system portfolio.

(1) Comparison with Commission's Reference Portfolio

SCE's System Base Case Portfolio achieves the same 0.1 LOLE reliability standard and electric sector GHG targets as the Commission's Reference Portfolio at lower total cost (about 9 percent lower by 2035 and 13 percent lower by 2045) with a resource mix that includes less LLT resources and more solar and storage.[53] The Commission's portfolio generally includes more expensive LLT resources (geothermal, 12+-hour storage) due, in part, to its use of the marginal ELCC-based reliability constraint, while SCE's portfolio foregoes most of those high-cost additions in favor of lower-cost solar and 8-hour battery storage. The following sections describe the differences in resource selection between SCE's System Base Case Portfolio and the Commission's Reference Portfolio for planning years 2035 and 2045.

(a) 2035 Planning Year Portfolio Differences are Largely Driven by Differences in LLT Resource Assumptions

Table III-9 below compares the total new/selected capacity in 2035 under SCE's System Base Case Portfolio and the Commission's Reference Portfolio.[54]

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[53] SCE's System Base Case Portfolio assumes 1 GW of geothermal and 0.5 GW of 12-hour storage are centrally procured by DWR pursuant to AB 1373 based on SCE's assessment of current commercial availability. It is unclear what, if any, AB 1373 procurement is assumed in the Commission's Reference Portfolio.

[54] Costs of the Commission's Reference Portfolio are expressed using the resource costs described in Section II.B.3.a) (*i.e.,* 2026-2027 TPP Portfolio resource costs, replace constrained 12-hour storage costs with generic 12-hour storage costs) to facilitate an apples-to-apples comparison.

Table III-9
2035 Portfolio Comparison

	CPUC's 2026 IRP Reference Portfolio	**SCE's 2026 IRP Base Case Portfolio**
Resource Type	Total Selected Capacity **2035** (GW)	
Biomass	0.0	0.0
Geothermal	3.2	1.9
Geothermal (Enhanced)	0.0	0.0
LDS (Generic 12-hour)	0.0	0.0
LDS (Constrained 12-hour)	3.9	0.0
Li_Battery_4hr	4.4	4.4
Li_Battery_8hr	14.0	20.4
Solar	53.4	50.6
In-State Wind	6.2	6.2
Out-of-State Wind	7.0	7.0
Total	**92**	**91**
Annualized Capital Cost of New Resources (2024$B/year) *	17.8	16.1
Cost Comparison SCE to CPUC		-9%

The portfolios are largely comparable; however, SCE's System Base Case Portfolio achieves a 9 percent cost savings in 2035 compared to the Commission's portfolio due to SCE's selection of solar and 8-hour storage over more expensive 12-hour storage and geothermal resources. As described in Section II.B.3.a, the Commission's Reference Portfolio selects nearly 4 GW of location-constrained 12-hour storage by 2035 based on the unrealistic cost assumption that all projects will be available at the same cost as pumped hydro (of which there is a limited quantity). In contrast, SCE's System Base Case Portfolio includes no location-constrained 12-hour storage in 2035, finding it uneconomic at realistic costs, and instead builds an additional 6 GW of 8-hour storage compared to the Commission's Reference Portfolio.

(b) 2045 Planning Year Portfolio Differences are Driven by the Commission's Use of an ELCC-Based Reliability Methodology

Table III-10 provides a similar comparison between SCE's System Base Case Portfolio and the Commission's Reference Portfolio for 2045.

Table III-10
2045 Portfolio Comparison

	CPUC's 2026 IRP Reference Portfolio	**SCE's 2026 IRP Base Case Portfolio**
Resource Type	Total Selected Capacity **2045** (GW)	
Biomass	0.0	0.0
Geothermal	3.2	3.9
Geothermal (Enhanced)	0.7	0.0
LDS (Generic 12-hour)	0.0	0.5
LDS (Constrained 12-hour)	8.5	0.0
Li_Battery_4hr	6.8	9.1
Li_Battery_8hr	21.1	26.3
Solar	82.7	73.3
In-State Wind	10.9	8.7
Out-of-State Wind	19.0	19.0
Total	**153**	**141**
Annualized Capital Cost of New Resources (2024$B/year) *	30.2	26.5
Cost Comparison SCE to CPUC		-13%

Both SCE's System Base Case Portfolio and the Commission's Reference Portfolio achieve California's 8 MMT 2045 GHG target and satisfy the 0.1 LOLE reliability standard. However, the Commission's Reference Portfolio's larger and more costly new resource build-out by 2045 is driven by its ELCC-based reliability methodology. Because SCE's SOD reliability methodology focuses on hourly needs across the year rather than a single peak hour, the solar and 4- and 8-hour storage resources that are being cost-effectively selected in large quantities to satisfy the GHG target in 2045 are still meaningfully contributing to the reliability requirement. By contrast, because the Commission's RESOLVE model assumes those resources' reliability

contribution is significantly declining (based on their diminishing marginal ELCC values), it identifies reliability as a binding constraint in 2045 and consequently selects more high-cost firm capacity resources with higher ELCC values, including an additional 4.6 GW of location-constrained 12-hour storage (beyond the 3.9 GW already identified by 2035) and 0.7 GW of EGS, compared to SCE's System Base Case Portfolio. Stated differently, only the Commission's portfolio was required to add new resources to maintain reliability in 2045, which caused RESOLVE to select additional and more costly resources beyond what GHG compliance alone required.[55]

(2) Comparison with SCE's Sensitivity Scenarios

SCE developed several sensitivity scenarios, incorporating different assumptions and planning targets, to evaluate how load forecasts, more realistic market-constrained resource availability, and a potential extension of Diablo Canyon could affect the new resource build-out required to meet the state's reliability and clean energy goals through 2035. A comparison of the assumptions used in each scenario is included in Table III-11 below:

[55] Both SCE's and the Commission's portfolios for 2035 were governed by GHG emissions targets rather than reliability requirements, meaning the ELCC vs. SOD difference did not impact 2035 outcomes.

Table III-11
Comparison of Sensitivity Scenario Assumptions

Scenarios	Demand	Resource Assumptions	GHG Target
Base Case Portfolio	2024 IEPR	TPP I&A	2030: 30MMT 2035: 25MMT 2045: 8MMT
Updated Load Scenario (through 2035 only)	2025 IEPR	TPP I&A	2030: 30MMT 2035: 25MMT
Market-Constrained Scenario (through 2035 only)	2025 IEPR	Only solar and storage available through 2030 Wind available beginning 2031 up to Limited Wind Sensitivity	**Low GHG Bookend** 2030: 30MMT 2035: 25MMT **High GHG Bookend** 2030: 38MMT 2035: 30MMT
Diablo Extended Scenario (through 2035 only)	2024 IEPR	TPP I&A + Diablo through 2035	2030: 30MMT 2035: 25MMT

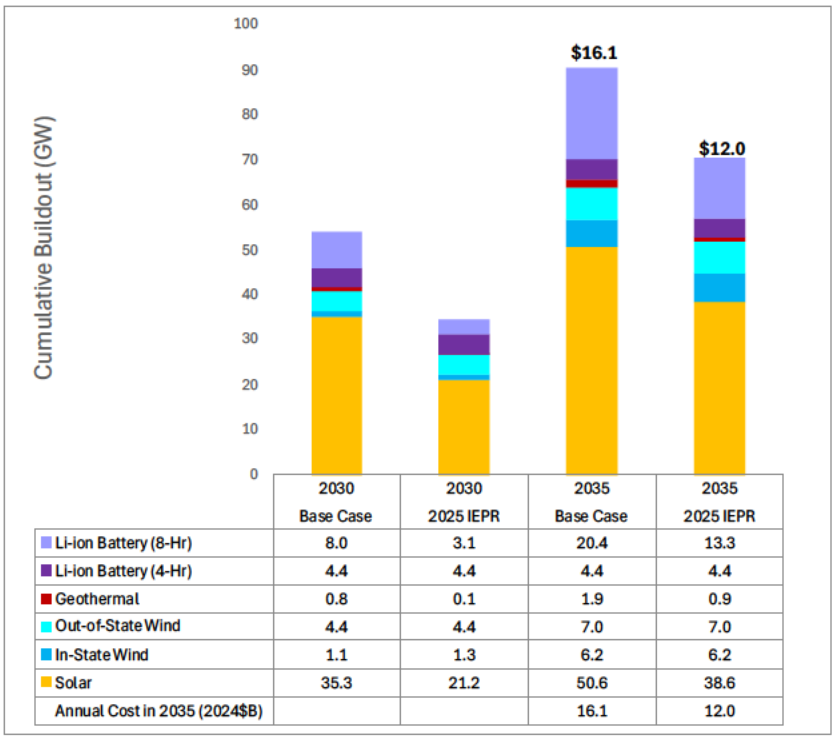
The results and conclusions from those scenarios are described below. Together, these sensitivity scenarios demonstrate the need for a practical implementation path that bridges California's long-term policy objectives with real-world resource procurement constraints, underscoring the importance of feasibility and affordability in portfolios used to guide procurement decisions.

(a) 2024 IEPR Load Assumptions are the Primary Driver of Near-Term Resource Build-out Pressure and Cost

SCE's Updated Load Scenario studies the impact through 2035 of updating the load forecast from the 2024 IEPR to the 2025 IEPR.[56] All other assumptions and planning targets are the same as those used in the System Base Case Portfolio. A comparison of System Base Case Portfolio and Updated Load Scenario build-out in 2030 and 2035 is included in Figure III-8 below:

[56] D.26-02-057 procurement was forced-in to the Updated Load Scenario; AB 1373 resources were not.

Figure III-8
System Base Case Portfolio and Updated Load Scenario Comparison for 2030 and 2035



	2030 Base Case	2030 2025 IEPR	2035 Base Case	2035 2025 IEPR
Li-ion Battery (8-Hr)	8.0	3.1	20.4	13.3
Li-ion Battery (4-Hr)	4.4	4.4	4.4	4.4
Geothermal	0.8	0.1	1.9	0.9
Out-of-State Wind	4.4	4.4	7.0	7.0
In-State Wind	1.1	1.3	6.2	6.2
Solar	35.3	21.2	50.6	38.6
Annual Cost in 2035 (2024$B)			16.1	12.0

A higher load forecast – such as the 2024 IEPR forecast – makes GHG emissions reduction goals much more difficult to achieve. The electric system must meet significantly more energy demand while simultaneously reducing overall GHG emissions requiring more clean generation, storage, transmission, and other zero-emitting resources before any incremental GHG reductions can be realized. As a result, the same GHG target becomes more challenging and costly to achieve under a higher load forecast than under a lower one.

Updating the load assumptions to the more recent 2025 IEPR load forecast significantly reduces required resource additions and cost of the portfolio, making it more feasible and affordable to achieve. The 2025 IEPR-based Updated Load Scenario requires far less renewable resource build-out in the near term, with 36 percent less total resource additions in 2030 compared to SCE's System Base Case Portfolio. The gap begins to narrow later in the planning horizon, with the Updated Load Scenario's 2035 portfolio being approximately 25 percent smaller and less expensive than SCE's System Base Case Portfolio. Wind development nears

the assumed cap in both the Updated Load Scenario and the System Base Case Portfolio, demonstrating its critical role under any load scenario. While geothermal is one GW lower in the Updated Load Scenario, SCE expects its selection is deferred and not avoided, as geothermal resources' clean firm attributes will ultimately be needed under any load scenario at deeper levels of decarbonization.

Most importantly, using the more updated 2025 IEPR load forecast allows for a more measured deployment of solar generation and battery storage. The overall resource plan becomes less dependent on building large quantities of solar and storage resources over the next ten years and, instead, provides for a more gradual and manageable build-out trajectory that can more realistically be achieved in the market at a reasonable cost to customers. By contrast, using the 2024 IEPR load forecast would, as the Commission acknowledged, "[require] solar build rates that are several multiples of any recent year's accomplished development."[57]

(b) Limited Resource Availability Will Make Achieving GHG Targets More Difficult and Expensive

SCE is concerned that the resource portfolios being considered by the Commission rely on technologies and project volumes that are not sufficiently represented in the active development pipeline. More conservative resource technology availability assumptions may increase modeled procurement requirements and portfolio costs in the near- and mid-term but improve the likelihood that IRP-selected portfolios can be successfully implemented by aligning resource build-out expectations with realistic development, supply chain, permitting, and interconnection constraints. Accordingly, SCE developed a Market-Constrained Scenario to study the impact that limiting resource availability to solar, storage, and small amounts of wind – the only resources currently available in meaningful quantities in the CAISO interconnection

[57] D.26-02-057 at FOF 25.

queue or likely to be available by 2035 – will have on the resource build-out required to meet load and GHG targets in 2030 and 2035.[58]

Specifically, SCE's analysis assumes only solar and storage resources are available through 2030, and solar, storage, and limited amounts of in- and out-of-state wind resources, up to the cap reflected in the Commission's 2026-2027 TPP Limited Wind Sensitivity Portfolio, are available from 2031-2035. For this scenario, limiting in-state wind to 2.5 GW and out-of-state wind to the capacity available on existing transmission where the CAISO has rights is a reasonable assumption, given the growing difficulty of permitting wind projects within the state and changes in federal policy affecting wind development.[59] SCE excluded LLT resources such as geothermal, due to the limited quantities currently available in the CAISO interconnection queue and the low likelihood that new projects (and associated transmission upgrades) can be developed within the next ten years.[60] SCE's Market-Constrained Scenario does not apply any limits to the quantity of solar and storage that can be selected, other than the I&As' annual 4,000 MW limit on solar through 2028.[61] Thus, while the identified build-out may be more realistic in terms of resource mix, it does not necessarily reflect the quantity that can reasonably be deployed over the next decade, considering the development, transmission, permitting, supply-chain, and interconnection constraints.

SCE's Market-Constrained Scenario uses the 2025 IEPR load forecast. SCE shifted to the 2025 IEPR load forecast after its initial analysis using the 2024 IEPR load forecast

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[58] As of June 2026, the CAISO active interconnection queue includes 104 GW of new resources, of which 93 percent is battery storage or solar paired with storage. Thus, the CAISO interconnection queue only includes an estimated 7 GW ***total*** of non-solar, non-storage technologies. *See* https://caiso-queue.streamlit.app.

[59] *See* D.26-02-057 at 72-73.

[60] Restricting the selection of LLT resources prevents the analysis from simply replacing the System Base Case Portfolio wind with technologies that are just as, if not more, infeasible in the studied timeline. For example, the Commission's Limited Wind Sensitivity Portfolio for the TPP generally replaced wind with significant quantities of geothermal.

[61] *See* 2024-2026 Integrated Resource Planning (IRP), Inputs & Assumptions, February 2026, at 77, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/2025_inputs_and_assumptions_report_20260210.pdf.

demonstrated that satisfying the higher load forecast would require roughly 66 GW of new solar (34 GW) and storage (32 GW 4-hour equivalent) resources by 2030. That level of procurement need is extraordinarily large and is not realistically achievable given current and expected market, supply chain, siting, permitting, and interconnection constraints. Because the initial portfolio exceeded any realistic market availability, SCE adopted the 2025 IEPR load forecast for its Market-Constrained Scenario to provide a more pragmatic assessment of resource procurement challenges and system needs.

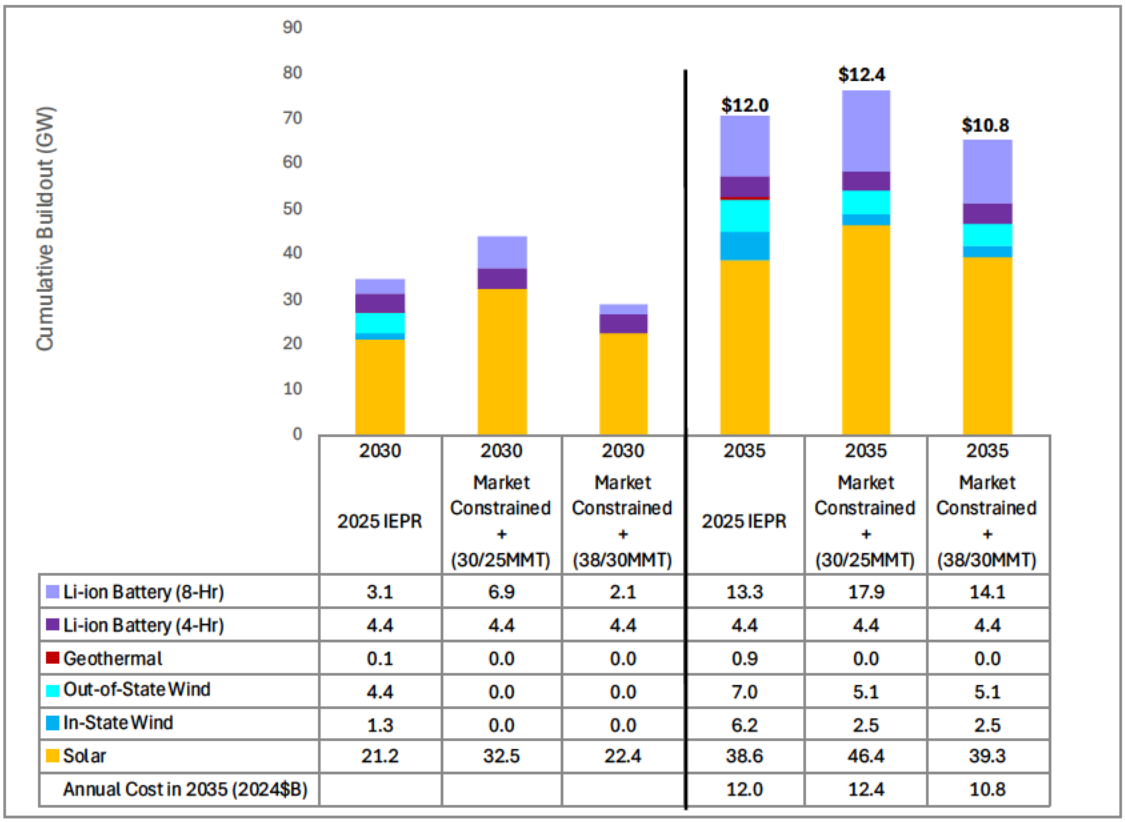
Finally, SCE's Market-Constrained Scenario compares the build-out required to meet two sets of GHG targets: the 30 MMT by 2030 and 25 MMT by 2035 targets required for LSEs' 2026 IRPs and the 38 MMT by 2030 target adopted by the Commission for its 2021 PSP (and a 30 MMT by 2035 target to reflect the same trajectory).[62] As discussed in Section III.A.1.c.2, the Commission lowered its GHG target in D.24-02-047 because it found, in part, the "cost differences between the 30 MMT and 25 MMT … portfolios were relatively small."[63] Given the significant changes in the load forecast, resource availability, and the overall market for clean resources since that finding, SCE's Market-Constrained Scenario seeks to quantify the difference between planning to the two sets of GHG targets.

Figure III-9 compares the level of new resource additions required to meet different 2030 and 2035 GHG emissions targets assuming full resource availability (*i.e.,* the Commission's assumptions) and more realistic market-constrained resource availability.

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62 *See* D.22-02-004 at OP 7.
63 D.24-02-047 at 63.

Figure III-9
Updated Load Scenario (Full Resource Availability) Comparison with Market-Constrained Scenario for 2030 and 2035



	2030 2025 IEPR	2030 Market Constrained + (30/25MMT)	2030 Market Constrained + (38/30MMT)	2035 2025 IEPR	2035 Market Constrained + (30/25MMT)	2035 Market Constrained + (38/30MMT)
Li-ion Battery (8-Hr)	3.1	6.9	2.1	13.3	17.9	14.1
Li-ion Battery (4-Hr)	4.4	4.4	4.4	4.4	4.4	4.4
Geothermal	0.1	0.0	0.0	0.9	0.0	0.0
Out-of-State Wind	4.4	0.0	0.0	7.0	5.1	5.1
In-State Wind	1.3	0.0	0.0	6.2	2.5	2.5
Solar	21.2	32.5	22.4	38.6	46.4	39.3
Annual Cost in 2035 (2024$B)				12.0	12.4	10.8

SCE's analysis finds that, even if load is updated to the 2025 IEPR forecast, the system would need 51 GW of new solar and 4-hour equivalent storage by 2030 to meet the 30 MMT GHG target and 95 GW of new solar, 4-hour equivalent storage, and wind by 2035 (cumulative) to meet the 25 MMT GHG target. This roughly translates to 9.5 GW of new solar and storage annually. For reference, California added about 5 GW of new resources annually over the 2020 to 2025 period.[64] Meeting the prior IRP GHG targets of 38 MMT by 2030 and 30 MMT by 2035 would require approximately 7 GW annually, which would be a very challenging, but more reasonable trajectory in the current market environment.

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[64] *See* Commission, Resource Tracking Data, Data current as of December 2025, at 6, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf. This report shows approximately 29 GW of new in-CAISO nameplate capacity and approximately 31 GW of new total nameplate capacity, including imports, came online between 2020 and 2025.

SCE's Market-Constrained Scenario, like the System Base Case Portfolio, fully exhausts wind up to the specified limits in both the 25 MMT by 2035 and 30 MMT by 2035 portfolios. If the selected 8 GW of wind does not materialize by 2035, an additional 9 GW and 10 GW of solar and storage (4-hour equivalent), respectively, would be required, a replacement that would be 22 percent more expensive.[65]

(c) Diablo Extended Scenario

Although Public Utilities Code Section 454.52(f)(1) prevents the Commission from counting Diablo Canyon in adopted IRP portfolios, evaluating a portfolio that assumes the plant remains online through at least 2035 remains a valuable planning exercise. Diablo Canyon provides a significant source of carbon-free energy, capacity, and reliability services, and its continued operation could materially affect the timing, magnitude, and composition of future resource needs.

A Diablo Canyon extension sensitivity scenario is particularly valuable given potential policy changes or other factors that may affect California's future load. Recent changes between the 2024 and 2025 IEPR forecasts demonstrate that projected demand can change materially over a relatively short period due to changes in federal and state environmental policy. Evaluating a portfolio that includes Diablo Canyon helps assess whether continued operation of Diablo Canyon could reduce the need for accelerated procurement of new resources to serve potential significant load growth forecast like the levels reflected in the 2024 IEPR.

Such analysis is also important given growing concerns about the availability and timing of new resource development. Supply-chain constraints, federal policy changes, interconnection backlogs, permitting challenges, and competition for commercially viable projects will limit the pace at which new capacity can be contracted and brought online in the near- and mid-term. By examining a scenario in which Diablo Canyon remains available through 2035, stakeholders

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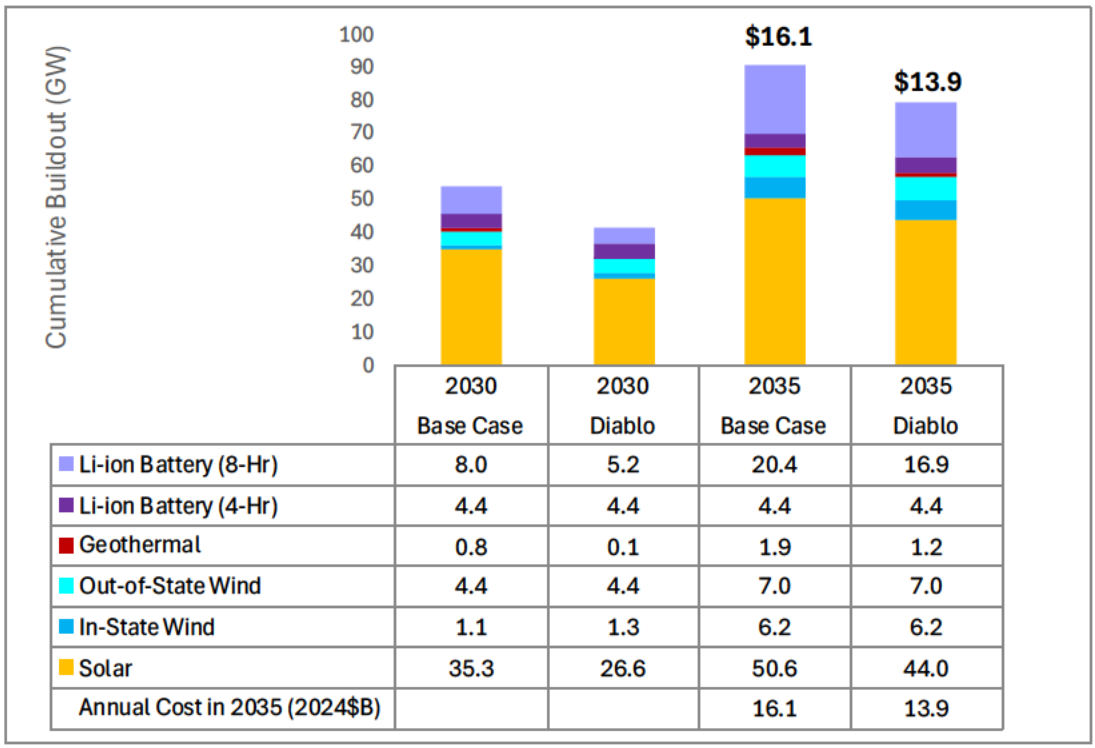
[65] 9 GW and 10 GW of solar and 4-hour-equivalent storage, respectively, would be 22 percent more expensive than 8 GW of in- and out-of-state wind.

can better understand the potential reliability, cost, GHG reduction, and procurement implications of retaining an existing resource versus relying exclusively on the development of new generation and storage resources under increasingly challenging market conditions.

Figure III-10 compares SCE's System Base Case Portfolio build-outs for 2030 and 2035 with the build-outs under SCE's Diablo Extended Scenario. SCE's Diablo Extended Scenario uses the 2024 IEPR load forecast, achieves GHG emissions of 30 MMT by 2030 and 25 MMT by 2035, and relies on the Commission's resource cost and availability assumptions. SCE's analysis finds that assuming Diablo Canyon is operational through 2035 significantly reduces the new solar, storage, and geothermal resources needed for 2030 and 2035. As parties observed in response to similar analysis developed by Commission Staff to support the 2026-2027 TPP, a Diablo Extended Scenario includes a solar build rate from 2028-2031 that falls within the historic range,[66] while all other portfolios that plan to the 2024 IEPR load forecast require solar build rates that are several multiples of any recent year's accomplished development.[67] This analysis demonstrates how Diablo Canyon, if extended, reduces build-out pressure, mitigates development risk, and acts as a hedge against load growth risk.

[66] *See* D.26-02-057 at 84.
[67] *See id.* at FOF 25.

Figure III-10
System Base Case Portfolio and Diablo Extended Scenario Comparison for 2030 and 2035



	2030 Base Case	2030 Diablo	2035 Base Case	2035 Diablo
Li-ion Battery (8-Hr)	8.0	5.2	20.4	16.9
Li-ion Battery (4-Hr)	4.4	4.4	4.4	4.4
Geothermal	0.8	0.1	1.9	1.2
Out-of-State Wind	4.4	4.4	7.0	7.0
In-State Wind	1.1	1.3	6.2	6.2
Solar	35.3	26.6	50.6	44.0
Annual Cost in 2035 (2024$B)			16.1	13.9

c) Summary of SCE's System PGP

The Commission should complement its forthcoming PSP with a PGP that is specifically designed to guide near- and mid-term procurement targets through 2035. The PSP remains an important long-term planning tool that identifies the resources, transmission infrastructure, and system transformations that may ultimately be needed to achieve California's 2045 decarbonization goals. However, because the PSP will be developed using the outdated 2024 IEPR load forecast, resource availability assumptions that are not consistent with what is currently available in the market, and 30 MMT by 2030 and 25 MMT by 2035 near-term GHG targets, the PSP will not reflect the resources that can reasonably be procured, interconnected, and developed over the next decade. A PGP is needed to provide an achievable implementation pathway that balances California's climate ambitions with affordability, feasibility, and market realities.

To fulfill that role, the PGP should be based on assumptions that better reflect expected conditions through 2035, including:

- Using the 2025 IEPR load forecast, or the most recently adopted IEPR forecast, to reflect a more updated projection of future load growth;
- Resource availability assumptions limited to technologies that are broadly commercialized and represented in meaningful quantities within the CAISO interconnection queue or supported by existing and planned transmission infrastructure; and
- Planning to the previously adopted electric sector GHG targets of 38 MMT by 2030 and 30 MMT by 2035, which remain within the CARB's approved planning range.

The need for a PGP is particularly important as the Commission develops an RCPPP. A PSP based on assumptions that substantially exceed demonstrated market capability provides limited value as a procurement benchmark because its near- and mid-term resource trajectory is unlikely to be achievable from the outset. If actual procurement differs significantly from the resource mix assumed in the PSP, tracking progress toward statewide GHG reduction objectives becomes more difficult and assessing future reliability needs becomes increasingly uncertain. A PGP addresses this issue by providing a procurement-focused portfolio that reflects the resources, transmission capabilities, and development timelines that are reasonably expected to be available through 2035.

SCE's System PGP demonstrates that California can continue making substantial progress toward its reliability and decarbonization goals while significantly improving affordability and feasibility. SCE's System PGP satisfies the 0.1 LOLE reliability criteria under both the 2025 IEPR load forecast and, if Diablo Canyon is assumed to be available and gas resources are retained, the 2024 IEPR load forecast. SCE's System PGP new resource build-out is about 28 percent smaller (65.5 GW required by 2035 compared to 90.7 GW) and 33 percent

less expensive ($10.8 billion compared to $16.1 billion) than its System Base Case Portfolio.[68] Similarly, the annualized system cost for 2035 for the new resources in SCE's System PGP is about 40 percent less expensive than the Commission's Reference Portfolio ($10.8 billion compared to $17.8 billion).[69]

Importantly, the PGP should not be viewed as an easy-to-achieve portfolio. Even under SCE's System PGP assumptions, California must deploy significant quantities of new solar generation, energy storage, wind resources, transmission infrastructure, and other clean energy resources through 2035. The PGP therefore represents a more realistic pathway – not an easy one. Achieving even the PGP will require sustained investment, timely transmission expansion, and the successful development and interconnection of new resources at an unprecedented scale. For that reason, as discussed in Section I, any future RCPPP should include robust flexible compliance mechanisms that recognize the permitting, interconnection, transmission, supply chain, financing, and development risks that remain outside the control of individual LSEs.

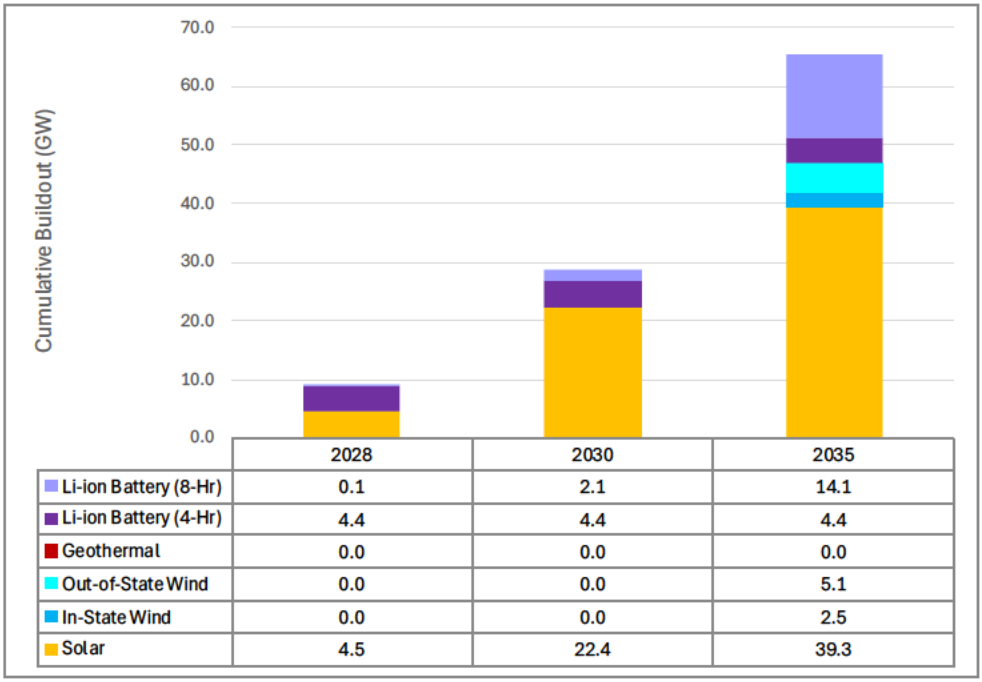
Figure III-11 below illustrates SCE's System PGP resource build-out. The portfolio is consistent with the resource additions identified in SCE's 38 MMT by 2030 and 30 MMT by 2035 Market-Constrained Scenario (Section III.A.1.b.2.b) and demonstrates that California can continue making meaningful progress toward its long-term decarbonization goals while pursuing a procurement strategy that is affordable, feasible, and implementable under expected market conditions.

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[68] Neither SCE's System Base Case Portfolio nor SCE's System PGP includes the operational cost of Diablo Canyon.

[69] *See* also Figure I-1 comparing the Commission's Reference Portfolio to SCE's System PGP.

Figure III-11
SCE's System PGP[70]



	2028	2030	2035
Li-ion Battery (8-Hr)	0.1	2.1	14.1
Li-ion Battery (4-Hr)	4.4	4.4	4.4
Geothermal	0.0	0.0	0.0
Out-of-State Wind	0.0	0.0	5.1
In-State Wind	0.0	0.0	2.5
Solar	4.5	22.4	39.3

(1) The PGP Can Use the 2025 IEPR Load Forecast Because Diablo Canyon Serves as a Critical Hedge Against Load Forecast Changes

Although SCE's System PGP plans to the 2025 IEPR load forecast, SCE also performed PCM simulation analysis dispatching the System PGP against the higher 2024 IEPR load forecast to identify if there are reliability risks in using the updated and lower load forecast. This analysis concludes that, if Diablo Canyon is assumed to be operational through at least 2035 and all gas resources are retained, the System PGP based on the 2025 IEPR can still meet the 0.1 LOLE standard if the load growth assumed in the 2024 IEPR were to materialize.[71]

[70] SCE's System PGP was built using the modeling tools identified in Section II. SCE's System PGP satisfies the SOD reliability criteria and meets the 38 MMT by 2030 GHG target adopted in D.22-02-004 (and a 30 MMT by 2035 GHG target).

[71] SCE's System PGP is designed to meet a 30 MMT GHG emissions reduction target by 2035 assuming 2025 IEPR load. If the load growth assumed in the 2024 IEPR materializes, this portfolio would produce 40 MMT emissions. If operational, Diablo Canyon would provide a partial emissions hedge by reducing system emissions to 36 MMT.

As such, while the Commission is statutorily prohibited from including Diablo Canyon in its adopted plans, it should recognize and utilize it as insurance against load growth risk. SCE's Updated Load Scenario demonstrates how requiring the rapid procurement of thousands of MW to meet forecast load growth estimates that are unlikely given current federal and state policies will cost customers significantly more than planning to the updated 2025 IEPR. Given the current uncertainty around load growth, a more measured assessment of future system needs is prudent, especially when SCE and the Commission Staff's own Diablo Canyon analysis[72] demonstrates that continued operation of Diablo Canyon could help reduce the cost and risk associated with the high build rates required under a 2024 IEPR load forecast. Using the 2025 IEPR, or the most recent available IEPR load forecast, in the PGP allows the Commission to capture Diablo Canyon's load change hedge benefits while continuing to plan for its eventual retirement.

(2) The PGP Should Plan to the Prior 38 MMT by 2030 and 30 MMT by 2035 GHG Targets

The Commission reduced the electric sector IRP GHG targets from 30 MMT by 2035 to 25 MMT by 2035 in the 2022-2023 IRP cycle because it found, in part, the "cost differences between the 30 MMT and 25 MMT … portfolios [to be] relatively small."[73] However the

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[72] *See* Energy Division Staff, 26-27 Transmission Planning Process RESOLVE Modeling Results, September 30, 2025, at 101 (noting extension of Diablo Canyon would reduce the near term (2026-2031) solar and storage build rates necessary to meet the GHG target, relative to the least-cost comparison and base cases: solar from 6 GW/year to 4.5 GW/year and storage from 3 GW/year to 2.4 GW/year), available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp/ruling_26-27_tpp_results.pdf.

[73] D.24-02-047 at 63.

forecast cost of meeting the 25 MMT by 2035 GHG target has increased by nearly 66 percent,[74] due, in large part, to the increased load forecast reflected in the 2024 IEPR, as explained in Section III.A.1.b.2.a above.[75]

Other facts have changed considerably since the Commission adopted the more ambitious GHG trajectory for 2030 and 2035, all resulting in higher costs and increased uncertainty for the needed resource portfolio to achieve this trajectory. In addition to the higher load forecast, there have also been many changes in the market that have made clean resource development more difficult and costly, including a constrained interconnection queue that is almost entirely filled with solar and storage resources, permitting challenges, the accelerated phase-out and new requirements of federal tax credits for clean resources, and tariff uncertainty. There is currently no procedural opportunity to evaluate whether the D.24-02-047 GHG targets continue to be appropriate for this IRP cycle's PSP. SCE's Updated Load and Market-Constrained Scenarios demonstrate how achieving the current 30 MMT by 2030 and 25 MMT by 2035 GHG targets under either 2024 or 2025 IEPR load forecasts will be significantly more difficult and expensive

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[74] The Total Resource Costs in 2035 of the 2023 PSP was approximately $23.5 billion, while the 2026-2027 TPP estimates it to be approximately $38.9 billion. These costs include the cost of baseline resources and the new resource build-out to facilitate an apples-to-apples comparison. *See* RESOLVE Public Release 02-14-2024 link, available at: https://files.cpuc.ca.gov/energy/modeling/LTPP/Public%20Release%2002-14-2024.zip, "RV – CPUC IRP PSP -v1128.xlsm" file. Costs include the "generation rev req" and "total optimized costs" categories and are escalated to $2024. *See also* 26-27 RESOLVE Workbooks and Public Case Results Reviewers link, available at: https://files.cpuc.ca.gov/energy/modeling/LTPP/RESOLVE%20Workbooks_and_Public%20Case%20Results%20Viewers.zip, "RESOLVE RV – Proposed Base Case.xlsx" file. Costs include the "Non-Optimized Generation: Baseline" and "Total Optimized" cost categories. Additionally, RESOLVE modeling for the 2026-2027 TPP modeled 2031 and 2036; the 2035 cost represented here is based on a simple extrapolation.

[75] The 2025 IEPR load forecast for 2035 represents a mid-point between the 2021 IEPR, which was the basis for the D.24-02-047 decision, and the 2024 IEPR. Specifically, the 2025 IEPR peak load forecast for 2035 is 7 percent higher than the 2021 IEPR while the 2024 IEPR is 14 percent higher, and the 2025 IEPR energy forecast is 21 percent higher than the 2021 IEPR while the 2024 IEPR is 35 percent higher.

than the Commission anticipated in 2024,[76] while procuring to the previous targets and the 2025 IEPR load forecast will be more feasible and affordable (albeit still challenging).

Developing a PGP that considers these changed conditions and modifies the near- and mid-term GHG emissions trajectory is a much-needed supplement to the record evidence being developed in this proceeding.

(3) The PGP Should Limit Resource Availability

As discussed in Section III.A.1.b.2.b, limiting resource availability to technologies that are widely available in the CAISO interconnection queue will dramatically change the resource mix (*i.e.,* appropriate ratio of solar to storage) and procurement quantities needed to meet the Commission's planning objectives. Having a more realistic view of what and how much LSEs can procure over the next ten years is a needed complement to the PSP for a number of reasons.

First, the reliability and estimated GHG emissions reduction of a portfolio is heavily dependent on the resource mix. There is limited value in comparing a procured portfolio exclusively comprised of solar and storage resources with a reference portfolio that includes a diverse mix of resources, because the IRP process's findings on the reliability and estimated GHG emissions of the reference portfolio will not apply to the procured portfolio. By contrast, a PGP with a resource mix that more closely resembles a portfolio that can be procured can serve as a more meaningful benchmark and identify resource gaps.

Next, limiting the PGP's near-term candidate resources to technologies that are well represented in the CAISO interconnection queue and using it as the basis for an ELCC forecast can improve the stability of ELCC estimates[77] from one planning cycle to the next. The PGP is a better basis for an ELCC forecast than the PSP because it reflects a resource mix that is more

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[76] Assuming the new resource build-out cost in 2035 for the Updated Load Scenario is approximately $4 billion less annually than the 2024 IEPR-based portfolio, the forecast total cost (baseline and new resources) of meeting the 25 MMT GHG target in 2035 using the 2025 IEPR is still almost 50 percent higher than the total forecast cost of the 2023 PSP ($34.9 billion compared to $23.5 billion).

[77] As described in Section I.E, SCE continues to urge the Commission to reduce its reliance on an ELCC-based reliability framework and adopt an SOD-based reliability framework for IRP.

likely to occur in practice. The near- to mid-term ELCC values should not swing significantly from one study to the next because the portfolio will be grounded in real-world project pipelines rather than speculative assumptions about future technology development and procurement.

Lastly, the PGP can be paired with the PSP to provide a more robust plan to study in the TPP. Studying both plans can help the CAISO delineate between immediate and more long-term needs so it can shift deliverability reservations, as appropriate.

2. SCE's Conforming Bundled Portfolio

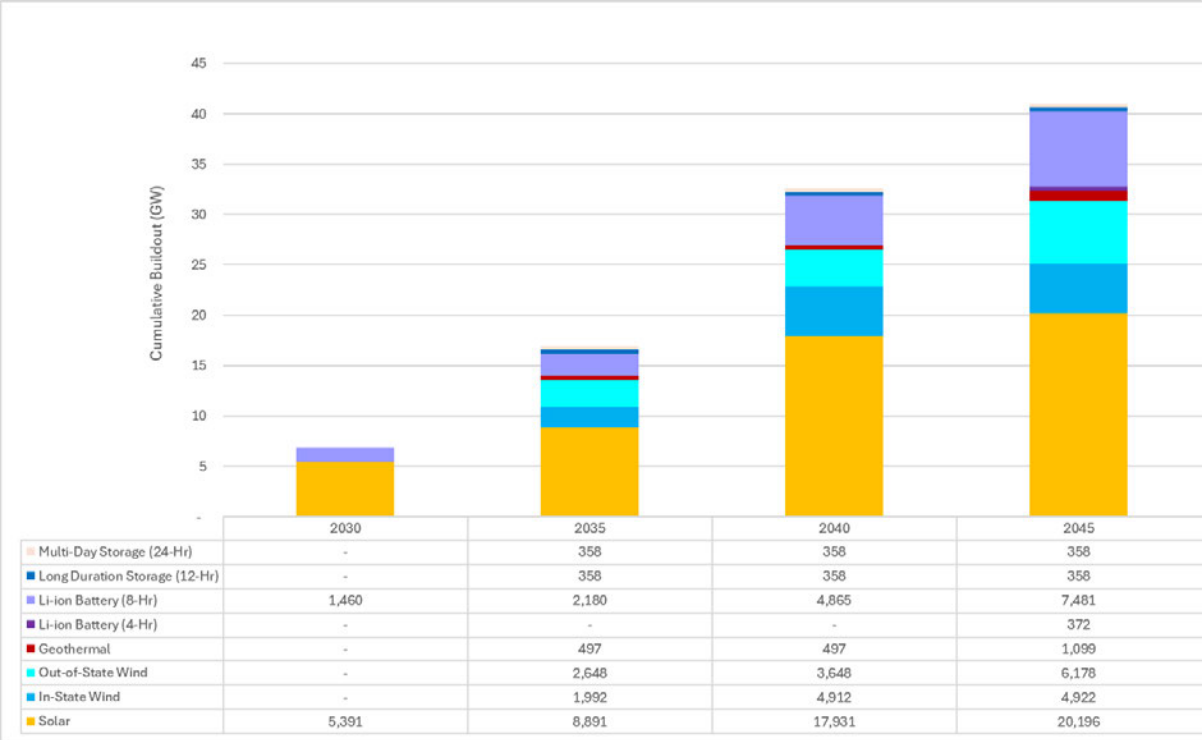
SCE's Conforming Bundled Portfolio, which is also SCE's Preferred Conforming Portfolio, was developed to satisfy its reliability requirements and meet SCE's bundled load share of the 30 MMT by 2030, 25 MMT by 2035, and 8 MMT by 2045 electric sector GHG targets. SCE first developed its bundled portfolio by enforcing SOD reliability and GHG emissions requirements for every year from 2026-2035, 2040, and 2045 using the methodology and modeling tools described in Section II.B. SCE then supplemented its bundled portfolio to include a reasonable estimate of what will be procured pursuant to D.26-02-057.[78] Finally, SCE evaluated if its bundled portfolio met the reliability and GHG requirements using the Commission's tools (ELCC-based annual reliability requirements in the RDT and milestone year GHG emissions requirements in the CSP Calculator) and made adjustments, as necessary.

Figure III-12 below illustrates the incremental capacity additions (not the total capacity) selected for SCE's Conforming Bundled Portfolio. The identified resource build-out includes the new contracts (either new contracts with existing resources or new resources) that will be needed to replace existing renewable contracts that are set to expire in the IRP planning horizon. The identified build-out also includes SCE's share of certain AB 1373 resources and an estimate

[78] The nameplate capacity required to satisfy D.26-02-057 procurement requirements will not be known until the Commission finalizes its ELCC studies for resources due online by 2030 and 2031 by August 31, 2026 and for resources due online by 2032 by December 31, 2027. Since SCE did not have this information in preparing its IRP, SCE used the RDT's ELCC values for 2030, 2031, and 2032 to estimate what, if any, of its originally-planned procurement may be moved forward to satisfy D.26-02-057 procurement requirements.

of the resources that will be procured pursuant to D.26-02-057 but excludes contracted not-yet-online resources (which are included in SCE's baseline and fully satisfies SCE's D.21-06-035 and D.23-02-040 procurement requirements).[79]

Figure III-12
Incremental Build-Out for SCE Conforming Bundled Portfolio



	2030	2035	2040	2045
Multi-Day Storage (24-Hr)	-	358	358	358
Long Duration Storage (12-Hr)	-	358	358	358
Li-ion Battery (8-Hr)	1,460	2,180	4,865	7,481
Li-ion Battery (4-Hr)	-	-	-	372
Geothermal	-	497	497	1,099
Out-of-State Wind	-	2,648	3,648	6,178
In-State Wind	-	1,992	4,912	4,922
Solar	5,391	8,891	17,931	20,196

The existing and new resources included in SCE's Conforming Bundled Portfolio are identified in the RDT for that portfolio (Appendix B). This includes the existing resources that SCE owns or has under contract, including SCE's share of CAM- and PCIA-eligible resources, and resources under development that may or may not have Commission-approved contracts (collectively, these are consistent with the definitions for "Online" and "Development" in the RDT-defined "contract_status").

As explained in Section II.B.2.b.1.d, SCE limited thermal and wind resources in its plan to its bundled load share to avoid over-subscribing technologies with limited availability and

[79] The Commission's Reference Portfolio and SCE's System Base Case Portfolio by extension include resources that were contracted after January 2024 but are not-yet-online in the identified build-out.

anticipated high demand. SCE assumed it would contract its pro-rata share of existing thermal resources in each year and have access to its pro-rata share of both new and existing wind resources. Specifically, SCE's expiring contracts with existing wind resources were added to its pro-rata share of the new wind potential and assumed to be the same cost as new resources in the same class. Selected capacity with existing thermal and wind resources is reflected in SCE's RDT and is listed as "PlannedExisting" resources in the RDT "contract_status" field.

SCE generally plans to meet the need for new resources additions in its SCE's Conforming Bundled Portfolio through future procurement activities, including those described in Section IV. SCE's planned new resources (consistent with the definition of "PlannedNew" in the RDT-defined "contract_status") also include SCE's yet to be executed D.26-02-057 procurement.

a) SCE's Conforming Bundled Portfolio Meets Reliability and GHG Emissions Reduction Requirements and Satisfies Existing Procurement Orders

SCE first used its Hitachi CE model to develop an initial optimal bundled portfolio using the GHG emissions and SOD reliability requirement constraints described in Section II.B. Other assumptions enforced in the model were consistent with SCE's system-wide modeling. This includes the assumption that half of D.26-02-057's LLT procurement requirement is met with geothermal and the other half is met with 8-hour battery storage and that DWR procures 50 percent of the authorized AB 1373 12-hour storage and 100 percent of the authorized geothermal, with no offshore wind or multi-day storage procurement.

The bundled portfolio identified through CE showed no need for additional storage, beyond the amount forced in for the D.26-02-057 LLT procurement requirement, before 2034. SCE adjusted its bundled portfolio to move forward solar and storage procurement to 2030-2032 in response to the Commission's strong recommendation to reflect D.26-02-057 procurement in

LSE plans.[80] The quantity pulled forward, approximately 2,050 MW, each, of solar and storage to 2030-2032, was determined residually assuming the same ELCC values provided in the RDT.[81]

This "adjusted" bundled portfolio was then evaluated using the Commission's RDT and CSP Calculator and further modified to satisfy the Commission's marginal ELCC-based reliability criteria to arrive at SCE's final Conforming Bundled Portfolio.[82] SCE's adjusted portfolio, which was built to satisfy existing procurement requirements and an SOD-based reliability requirement, did not pass the RDT reliability check because: (1) the rapid and substantial decline in ELCC values for solar and storage in the RDT understates their reliability contribution relative to an SOD framework; (2) SCE's single-point peak load-based share of the RDT's reliability requirement is significantly higher than the SOD-based share assumed in the CE modeling; and (3) SCE's analysis was developed using milestone years after 2035 (2040 and 2045 only), while the RDT evaluates reliability in every year between 2035 and 2045.

SCE sought to minimize additional modifications because the adjusted bundled portfolio already complies with the Commission's existing procurement mandates, including prior Commission procurement orders and the RA program's SOD-based requirements. Requiring earlier or incremental procurement solely to satisfy the RDT planning requirement would overstate the resources SCE expects to procure under currently-adopted Commission programs. As such, SCE primarily relied on its remaining AB 1373 allocations for 12-hour and multi-day storage (not "forced-in" to its system modeling or originally assumed in its bundled CE modeling) to close the gap between the adjusted bundled portfolio and final Conforming Bundled Portfolio. SCE also moved forward 280 MW, each, of solar and storage from 2037 to

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[80] *See* D.26-02-057 at 127.

[81] Specifically, SCE first assumed all resources selected by CE in 2030-2032 could count towards the order, then residually determined the MW of paired solar and storage needed to satisfy the rest of the order assuming the IRP ELCC values.

[82] SCE's adjusted bundled portfolio also fell slightly short of the CSP Calculator requirement in 2030. SCE moved forward a small amount of paired solar and storage from 2031-2032 to 2030 to bring the portfolio into compliance with the CSP Calculator requirements.

2035, and all the solar and storage identified in 2044 and 2045 (approximately 1,000 MW, each, of solar and storage) to 2040, 2041, and 2043. This final Conforming Bundled Portfolio satisfies the requirements in the Commission's RDT and CSP Calculator tools.

Both SCE's Conforming Bundled Portfolio and SCE's System Base Case Portfolio economically select 8-hour storage over two 4-hour storage resources to meet an identified need for longer-duration clean energy dispatch. However, actual resource costs or availability may differ from the Commission's I&As from which these modeling results are derived. Therefore, SCE notes that 4-hour storage resources may continue to be procured in equivalent amounts to 8-hour storage need depending on relative costs.

b) SCE's Conforming Bundled Portfolio is Consistent with System-Wide Modeling Results

Consistent with SCE's System Base Case Portfolio, SCE's Conforming Bundled Portfolio features a resource mix that relies heavily on paired solar and 8-hour storage, as well as in-state and out-of-state wind up to maximum build limits. However, because SCE's existing bundled portfolio already exceeds its load share of the renewable and battery storage resources identified in the system portfolio, the additional build-out initially proceeds more slowly than in the system-wide case, as seen below in Table III-12. The in- and out-of-state wind resources in SCE's Conforming Bundled Portfolio exceed its load share of SCE's System Base Case Portfolio because the Conforming Bundled Portfolio includes re-contracting with existing wind resources with contracts that are set to expire over the study period. Lastly, there is more long-duration storage in SCE's Conforming Bundled Portfolio because, as described in Section II.B.3.b, SCE's bundled modeling assumes more AB 1373 procurement than its system modeling.

Table III-12
SCE Conforming Bundled Portfolio Compared to SCE Load Share of System Base Case Portfolio

	SCE Conforming Portfolio				SCE Load Share of Base Case			
Cumulative Buildout (GW)	**2030**	**2035**	**2040**	**2045**	**2030**	**2035**	**2040**	**2045**
Solar	5.4	8.9	17.9	20.2	8.4	12.1	14.9	17.7
In-State Wind	-	2.0	4.9	4.9	0.3	1.5	2.0	2.1
Out-of-State Wind	-	2.6	3.6	6.2	1.1	1.7	3.2	4.6
Geothermal	-	0.5	0.5	1.1	0.2	0.5	0.5	0.9
Li-ion Battery (4-Hr)	-	-	-	0.4	1.1	1.1	1.6	2.2
Li-ion Battery (8-Hr)	1.5	2.2	4.9	7.5	1.9	4.9	5.6	6.3
Long Duration Storage (12-Hr)	-	0.4	0.4	0.4	-	-	0.1	0.1
Long Duration Storage (24-Hr)	-	0.4	0.4	0.4	-	-	-	-
Total	6.9	16.9	32.6	41.0	12.9	21.6	28.0	33.9

As required in the Narrative Template, SCE also provides the following comparison of SCE's Conforming Bundled Portfolio with its share of the 2025-2026 TPP Portfolio in Table III-13 below. This comparison provides limited value because the Commission comprehensively updated its assumptions after finalizing the 2025-2026 TPP Portfolio. Thus, differences between SCE's Conforming Bundled Portfolio and its load share of the 2025-2026 TPP Portfolio are largely driven by changes in system needs and assumed resource costs, rather than SCE-specific preferences or needs. For example, SCE's System Base Case Portfolio includes significantly more solar and 8-hour storage than the 2025-2026 TPP Portfolio due to the increased load forecast and replaces the 2025-2026 TPP Portfolio's offshore wind with in- and out-of-state wind due to the updated resource costs. Variances between SCE's Conforming Bundled Portfolio and its load share of the 2025-2026 TPP Portfolio are largely driven by the same factors.

Table III-13
SCE Conforming Bundled Portfolio Compared to SCE Load Share of 2025-2026 TPP Portfolio

	SCE Conforming Portfolio				SCE Load Share of 25-26 TPP Portfolio			
Cumulative Buildout (GW)	**2030**	**2035**	**2040**	**2045**	**2030**	**2035**	**2040**	**2045**
Solar	5.4	8.9	17.9	20.2	3.5	4.7	10.8	14.9
In-State Wind	-	2.0	4.9	4.9	1.2	1.9	1.9	2.2
Out-of-State Wind	-	2.6	3.6	6.2	1.1	2.1	2.6	3.8
Offshore Wind	-	-	-	-	-	1.1	1.1	1.1
Geothermal	-	0.5	0.5	1.1	0.4	0.4	0.4	0.4
Li-ion Battery (4-Hr)	-	-	-	0.4	2.8	3.7	3.8	3.8
Li-ion Battery (8-Hr)	1.5	2.2	4.9	7.5	0.3	0.7	2.9	5.1
Long Duration Storage (12-Hr)	-	0.4	0.4	0.4	0.1	0.2	0.2	0.2
Other LDES (8-24-Hr)	-	0.4	0.4	0.4	0.1	0.1	0.1	0.1
Total	6.9	16.9	32.6	41.0	9.5	14.9	23.7	31.5

B. Preferred Conforming Portfolio

Detailed descriptions of SCE's Conforming Bundled Portfolio and the justifications for the selections made in that portfolio are included in Section III.A.2 above. The Conforming Bundled Portfolio reflects a diversified resource mix, with significant solar and 8-hour storage augmented with in-state and out-of-state wind and geothermal generation. Overall, the portfolio aligns with SCE's long-term GHG reduction objectives and reliability requirements by supporting a balanced, resilient system capable of advancing California's clean energy transition. However, as explained above, SCE has significant concerns with the feasibility and affordability of procuring to meet any portfolio based on the Commission's current assumptions in the near- and mid-term, including SCE's Conforming Bundled Portfolio. Accordingly, SCE recommends that the Commission develop a PGP to guide the RCPPP and procurement requirements through 2035.

1. SCE's Conforming Bundled Portfolio Satisfies the Statutory Requirements in Public Utilities Code Section 454.52(a)(1)

The following sections discuss how SCE's Conforming Bundled Portfolio meets the statutory requirements in Public Utilities Code Section 454.52(a)(1).

Meeting the GHG emissions reduction targets established by CARB, in coordination with the Commission and CEC (Section 454.52(a)(1)(A)). As shown in Section III.C, SCE's Conforming Bundled Portfolio meets SCE's respective 2030, 2035, 2040, and 2045 GHG emissions benchmarks based on the CSP Calculator results.

Procuring at least 60 percent eligible renewable energy resources by 2030 (Section 454.52(a)(1)(B)). SCE's Conforming Bundled Portfolio includes expected levels of eligible renewable energy resources exceeding California's 60 percent RPS goal by 2030. It achieves 79 percent RPS-eligible resources in 2030.

Enabling each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates and minimizing impacts on ratepayers' bills (Sections 454.52(a)(1)(C) and (D)). SCE's Conforming Bundled Portfolio represents the least-cost portfolio available to satisfy SCE's Commission-adopted reliability requirements and GHG emissions benchmarks under the required 2024 IEPR load forecast and other Commission-mandated assumptions. However, the fact that SCE identified a least-cost compliant portfolio does not alleviate broader concerns regarding the feasibility and affordability of portfolios developed using those assumptions. As demonstrated throughout this IRP, the Commission's assumptions require resource build-outs that exceed available market capacity, rely on resource availability and transmission development that remain uncertain, and significantly increase customer costs. For these reasons, SCE recommends that the Commission develop and utilize a PGP to guide near- and mid-term procurement decisions so that procurement requirements are grounded in more achievable assumptions regarding load growth, resource availability, transmission constraints, and customer affordability while continuing to advance California's long-term reliability and GHG reduction goals.

Ensuring system and local reliability on both a near-term and long-term basis (Section 454.52(a)(1)(E)). As discussed in Section III.F, SCE's Conforming Bundled Portfolio passes the reliability standards in the Commission's RDT.

Complying with paragraph (1) of subdivision (b) of Section 399.13 (Section 454.52(a)(1)(F)). SCE has and will continue to rely primarily on long-term contracts for new renewable resources to meet its RPS targets and to help the state meet its clean energy policies and objectives. Currently, over 90 percent of SCE's RPS-eligible contracts have contract lengths of 10 years or more, far exceeding the 65 percent required by Public Utilities Code Section 399.13.

Strengthening the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities (Section 454.52(a)(1)(G)). As explained in Section III.M, the 2035 bundled portfolio would require additional transmission upgrades, including Lugo and Whirlwind mitigation and new 500 kV lines from Devers to Red Bluff and Rancho Vista. These needs are not yet approved in the latest TPP, and final requirements will depend on actual resource locations, development levels, and further CAISO TPP analysis for all LSEs in the SCE Transmission Access Charge ("TAC") area.

The transmission needs identified for SCE's Conforming Bundled Portfolio reinforce the importance of proactively developing transmission infrastructure to support California's long-term decarbonization goals. As discussed in Section I.D, many of the geothermal, other LLT, and out-of-state wind resources needed to achieve the state's clean energy objectives depend on transmission infrastructure that must often be planned and constructed before resource development occurs. Just as transmission investments in the Tehachapi region enabled large-scale renewable development, timely transmission expansion will be essential to unlocking the next generation of clean energy resources and ensuring that future resource portfolios remain feasible, implementable, and affordable.

SCE's Conforming Bundled Portfolio also includes significant additions of energy storage that can provide greater flexibility on the transmission and distribution systems. Moreover, SCE's Conforming Bundled Portfolio will strengthen local communities by reducing GHG emissions and criteria pollutants, as shown in Section III.D.1.

Enhancing distribution systems and demand-side energy management (Section 454.52(a)(1)(H)). SCE's Conforming Bundled Portfolio aligns with the demand-side assumptions in the Commission's I&As. The portfolio includes significant energy storage that should enhance the distribution system.

Minimizing localized air pollutants and other GHG emissions with early priority on disadvantaged communities (Section 454.52(a)(1)(I)). SCE's Conforming Bundled Portfolio reduces GHG emissions and criteria pollutants as shown in Sections III.C and III.D.1. Additionally, SCE has taken other actions to minimize GHG emissions and local air pollutants in disadvantaged communities as discussed in Section III.D.2. Finally, SCE's Conforming Bundled Portfolio meets the state policy to supply 100 percent of all retail sales of electricity from eligible renewable energy resources and zero-carbon resources by 2045, as well as the interim targets of 90 percent by 2035 and 95 percent by 2040.[83] SCE's Conforming Bundled Portfolio does not include any new natural gas resources, but does assume SCE will contract with its bundled load share of existing natural gas resources for RA purposes throughout the study period. SCE's Conforming Bundled Portfolio prioritizes clean energy procurement and reflects a continued transition toward a lower-emitting electric system. However, the portfolio retains existing natural gas resources, up to SCE's load share, because they continue to provide RA value and operational reliability that cannot reasonably or cost-effectively be met by commercially available zero-emitting alternatives alone. SCE does not anticipate significant reliance on the energy output of these resources but maintains contracts to ensure sufficient dispatchable capacity during peak demand periods, extreme weather conditions, and prolonged renewable generation shortfalls while the clean energy transition continues.

Maintain a diverse portfolio of energy resources, which may include eligible energy resources procured by the DWR. Figure III-12 and Tables III-12 and III-13 above show the diverse portfolio of energy resources SCE expects to target for procurement over the planning

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[83] *See* Cal. Pub. Util. Code § 454.53(a).

horizon. SCE's Conforming Bundled Portfolio includes solar, storage of varying durations, geothermal, and in- and out-of-state wind. The portfolio also includes SCE's share of assumed procurement of AB 1373 resources by DWR for geothermal, 12-hour storage, and multi-day storage.

While SCE's Conforming Bundled Portfolio reflects a diverse mix of technologies, including solar, storage, geothermal, and in- and out-of-state wind, significant challenges remain in the near- and mid-term to procuring many of these resources at the scale and pace assumed in current planning portfolios. As discussed in Section I.B, the CAISO interconnection queue remains overwhelmingly concentrated in solar and storage resources, with comparatively limited quantities of wind, geothermal, and other clean firm resources. At the same time, permitting challenges, transmission constraints, interconnection delays, supply chain disruptions, and evolving federal policies continue to negatively impact the timing, availability, and cost of new resource development.

These market realities underscore the importance of the Commission developing a PGP to guide procurement decisions through 2035. While the state's long-term decarbonization objectives will ultimately require a diverse portfolio of clean resources, procurement requirements through 2035 should be informed by assumptions that reflect what can realistically be developed, interconnected, and financed under expected market conditions. The PGP provides a practical framework for assessing progress toward those objectives by recognizing current resource availability constraints while continuing to support development of the diverse resource mix needed to achieve California's long-term reliability and GHG reduction goals.

2. Key Differences Between SCE's Conforming Bundled Portfolio and SCE's 2022 25 MMT Bundled Portfolio

Although both portfolios were designed to support achievement of a 25 MMT by 2035 GHG target, SCE's 2026 Conforming Bundled Portfolio differs materially from the 25 MMT Bundled Portfolio submitted in SCE's 2022 IRP. The differences do not reflect a simple change

in SCE's preferred resource quantities. Instead, they reflect substantial changes in the planning environment since 2022 – most importantly, a materially higher Commission-assigned load forecast, updated information regarding resource costs and commercial availability, and the need to demonstrate compliance under the Commission's current reliability and portfolio validation requirements.

Table III-14 below compares the 2035 cumulative capacity additions in SCE's 2026 Conforming Bundled Portfolio with SCE's 2022 IRP 25 MMT Bundled Portfolio, net of resources that came online from 2023 to 2025.[84] Because the 2022 and 2026 portfolios use different resource classifications and baseline procurement assumptions, particularly for battery and long-duration storage, the individual storage categories are not directly comparable. Nevertheless, the comparison demonstrates the principal shift from offshore wind and aggregated long-duration storage assumptions in the 2022 portfolio toward solar, onshore in-state and out-of-state wind, and 8-hour battery storage in the 2026 portfolio.

[84] SCE applied the Commission's Resource Tracking Data current as of December 2025, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf, with SCE's bundled load share of 29 percent to estimate the resources that came online from 2023 to 2025.

Table III-14
Comparison of 2035 Cumulative Capacity Additions from 2026 in SCE's 2026 Conforming Bundled Portfolio and SCE's 2022 IRP 25 MMT Bundled Portfolio

Resource category	**2022 IRP 25 MMT Bundled Portfolio — 2035 cumulative additions (MW)**	**Resource Category**	**2026 Conforming Bundled Portfolio — 2035 cumulative additions (MW)**
Solar	6,451	Solar	8,891
Onshore wind	332	In-state wind	1,992
Out-of-state wind	NA	Out-of-state wind	2,648
Offshore wind	1,798	Offshore wind	0
Geothermal	367	Geothermal	497
4-hour and 5-hour storage	0 (2,817 MW fully procured)	4-hour storage	0
Long-Duration storage	1,100	8-hour storage	2,180
		12-hour storage	358
		24-hour storage	358
Total incremental resources from 2026 (Nameplate MW)	**10,048**	**Total incremental resources (Nameplate MW)**	**16,924**

The load forecast change is a particularly important driver of changes from 2022 to 2026. The Commission-required 2024 IEPR load forecast incorporates greater anticipated load growth than the forecast used in the 2022 IRP, having higher annual energy requirements and higher peak demand. Consequently, SCE must plan for a larger quantity of energy and dependable capacity even before accounting for the additional resources needed to reduce GHG emissions. SCE's analysis of the 2026 System Base Case Portfolio likewise finds that the higher load assumptions are a primary cause of near- and mid-term resource additions and costs, and that changing the load forecast has a larger effect on the 2035 build-out requirement than a change in the GHG trajectory.

SCE's Conforming Bundled Portfolio also reflects information that was not available in 2022 concerning the cost and development status of emerging technologies. The 2022 portfolio included significant contributions from resources that were expected to become available during

the planning horizon, including offshore wind. Development of those resources has not proceeded at the scale, timing, or cost anticipated in the earlier planning assumptions. Updated cost information causes the 2026 modeling to rely more heavily on technologies with established development pathways. In particular, after available wind resources are selected up to assumed development limits, the 2026 modeling generally identifies solar paired with 8-hour battery storage as the more cost-effective means of meeting incremental energy, reliability, and GHG emissions requirements. The resulting change in technology mix should not be interpreted as a conclusion that emerging technologies will have no future role. However, it reflects the portfolio that is supportable using current cost and availability information.

These changes also help explain why the 2026 portfolio contains a substantially larger nameplate capacity build-out than the 2022 portfolio. Replacing assumed contributions from emerging resources with commercially available variable generation and battery storage generally requires a greater quantity of installed capacity to provide comparable energy, GHG emissions, and reliability outcomes. That effect is compounded by the higher load forecast. Accordingly, the difference in total build-out is not appropriately attributed to the GHG target alone; it results from the combined effects of higher demand, updated resource economics, revised expectations regarding technology availability, and the current reliability validation framework.

In summary, SCE's 2026 Conforming Bundled Portfolio represents an updated path to the Commission's GHG objectives: it serves materially greater forecast demand, relies less on emerging technologies that have not yet developed as previously anticipated, and therefore requires substantially larger additions of resources that are currently more commercially mature and scalable.

C. GHG Emissions Results

SCE evaluated the GHG emissions from its Conforming Bundled Portfolio using the Commission's CSP Calculator, as modified with the custom battery charging profile described in

Section II.B.3.e, against SCE's 2030, 2035, 2040, and 2045 GHG emissions benchmarks established by the Commission. SCE's Conforming Portfolio generates GHG emissions consistently under the targets established by the Commission. The results are shown in Table III-15 below.

Table III-15
GHG Emissions Using CSP Calculator for SCE's Conforming Bundled Portfolio (MMT)

CSP Calculator Results	2030	2035	2040	2045
SCE Portfolio	4.00	2.46	2.99	1.92
Targets	5.45	4.49	3.74	1.94

D. Local Air Pollutant Minimization and Disadvantaged Communities

1. Local Air Pollutants

As shown in Table III-16 below, SCE's Conforming Bundled Portfolio significantly reduces criteria pollutants by 2045 based on the CSP Calculator. In SCE's Conforming Bundled Portfolio, criteria pollutants decrease by an average of 21 percent in 2035 and 80 percent in 2045 when compared to 2030. Ultimately, this can be directly linked to reduced reliance on natural gas generation.

Table III-16
Conforming Bundled Portfolio Criteria Pollutants

	2030	2035	2040	2045
PM2.5 (metric tons)	288	201	206	156
SO2 (metric tons)	46	37	23	18
NOx (metric tons)	504	401	190	176
PM2.5 - % Change from 2030		-30%	-28%	-46%
SO2 - % Change from 2030		-18%	-49%	-61%
NOx - % Change from 2030		-20%	-62%	-65%

2. Focus on Disadvantaged Communities

a) Pollution Reduction

SCE's Conforming Bundled Portfolio reduces PM2.5, SO_2, and NOx emissions, along with GHG emissions, over the planning horizon. As demonstrated quantitatively in Section

III.D.1, PM2.5, SO_2, and NOx emissions continuously decline from 2035 through 2045. These reductions are associated with increased deployment of renewable and storage resources and reduced utilization of existing fossil-fueled generation, which lower criteria pollutant emissions from resources that have historically contributed to air quality burdens in disadvantaged communities ("DACs").

The Commission's CSP Calculator methodology estimates criteria pollutant emissions at the portfolio level and does not provide sufficient granularity to assess emissions reductions at the individual DAC level. SCE therefore supplements these portfolio-level results with the resource-level locational mapping described in Sections III.D.2.e and f below.

While SCE's Conforming Bundled Portfolio does not include new natural gas generation, existing natural gas resources remain part of the portfolio to maintain system reliability. SCE's portfolio modeling shows utilization of these resources declining over the planning horizon as new clean energy resources come online, reducing criteria pollutant emissions from facilities that have historically operated in or near DACs.

b) DAC Prioritization

These emissions reductions benefit DACs and other communities throughout California, including those located outside of SCE's service area that are impacted by generation resources and system power relied upon to meet SCE's load. SCE addresses reduction of local air pollutants and GHG emissions, with early priority on DACs, through complementary approaches:

- Examining the locations of proposed and existing resources and incorporating DAC proximity into procurement evaluation and selection, as described in Section III.D.2.d below;
- Advancing transportation electrification and building electrification efforts that reduce on-site and nearby combustion emissions in DACs as described in Section III.D.2.g, as well as Sections IV.A.8 and IV.A.9; and

- Other customer programs and outreach as discussed in Sections II.D.2.h and i.

Together, these approaches reflect both direct and indirect pathways through which SCE's portfolio reduces emissions, including: (1) reducing emissions from contracted and system power resources; and (2) lowering combustion-related emissions within DACs.

c) Geographic Scope

Consistent with Commission direction, SCE takes an expansive view of portfolio impacts, recognizing that resource decisions may affect DACs both within and outside its service area. SCE's service area contains over 1,000 census tracts[85] and 13 tribal communities[86] designated as DACs, distributed across multiple counties. SCE's portfolio decisions therefore have the potential to influence air quality outcomes across a broad geographic area.

Additionally, SCE's resource portfolio decisions, including reliance on system power and contracted generation, affect emissions in communities elsewhere in California. Reduced utilization of fossil-fueled generation within the portfolio contributes to broader statewide reductions in criteria pollutants, benefiting DACs across California.

d) Large-Scale Procurement and DACs

SCE prioritizes DACs through its procurement processes by combining targeted solicitations, explicit siting preferences, and qualitative scoring criteria within a least-cost, best-fit framework. At the programmatic level, SCE administers dedicated solicitations such as the DAC Green Tariff Request for Offers ("RFO"), which procures new in-front-of-meter clean energy resources in or within five miles of DACs, thereby directly advancing state policy objectives to increase renewable generation in communities that experience disproportionate economic, environmental, and health burdens.

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[85] In the 2020 census, there were 9,129 census tracts in California. 2,310 of those census tracts are DACs.

[86] *See* Tribal Communities, available at: https://www.sce.com/partners/3rd-party-energy-providers/tribal-communities.

More broadly, in large-scale solicitations such as SCE's MTR and Clean Energy RFOs, SCE embeds DAC prioritization into eligibility and evaluation criteria by expressing a preference for preferred and energy storage resources located in DACs. SCE has applied these criteria in past and ongoing procurement efforts as discussed in Section IV.B. In its procurement activities, SCE will continue to provide qualitative preferences to projects that provide benefits to DACs or other communities meeting the criteria in Public Utilities Code Section 399.13(a)(8)(A), as applicable.

SCE's procurement strategy also supports minimizing criteria pollutants and reducing reliance on fossil-fueled generation. By prioritizing the procurement of renewable and zero-emitting resources, as well as long-duration and battery storage resources that can provide RA capacity, SCE advances a structural shift away from fossil-fueled generation, including plants historically located in or near DACs. This approach is particularly important for reducing dependence on short-term thermal resources for RA needs; instead, SCE emphasizes long-term clean energy and storage solicitations that can reliably meet system requirements without increasing local pollution burdens. As a result, procurement design incorporates equity and pollution-burden considerations, helping align resource selection with broader goals to improve air quality in DACs and displace higher-emitting generation.

SCE's resource-level locational mapping, described in Sections III.D.2.e and f below, further supports the identification of feasible procurement opportunities to reduce reliance on fossil-fueled facilities located in or near DACs by identifying where existing emitting facilities are concentrated and, correspondingly, where new clean energy and storage resources can deliver the greatest local air quality benefit.

e) Resource-Level Mapping

All incremental resources in SCE's Conforming Bundled Portfolio are renewables and energy storage, with no proposed new natural gas generation. This transition away from fossil-

fueled generation contributes to emissions reductions from existing fossil-fueled resources that disproportionately impact DACs.[87]

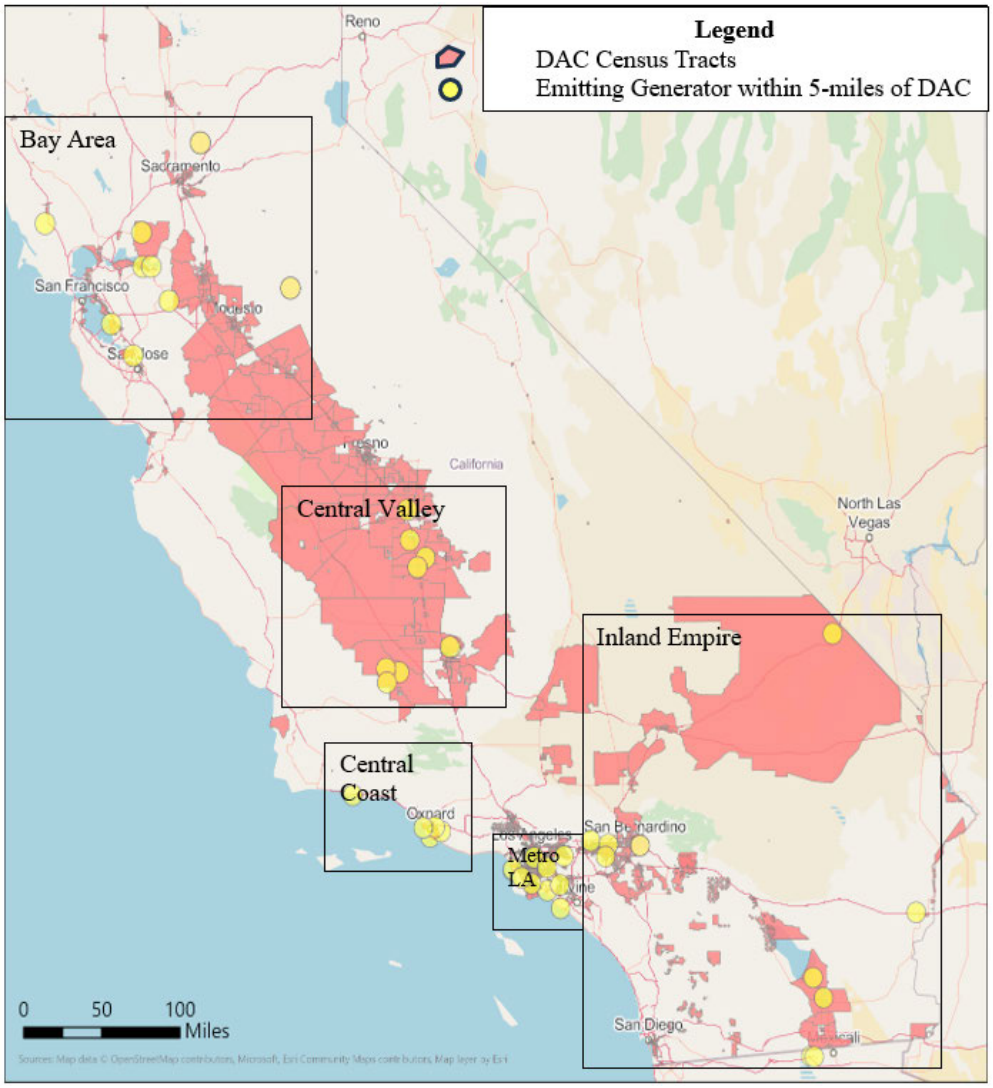
In response to the requirement that LSEs describe which DACs, if any, are located within a five-mile radius of generation facilities that are under contract and included in the LSE's Preferred Conforming Portfolio, SCE has identified the DAC-designated census tracts located within five miles of emitting generating facilities that are contracted to, or owned by, SCE and included in its Conforming Bundled Portfolio, which is SCE's Preferred Conforming Portfolio. Consistent with the Commission's recognition that prioritizing emissions reductions in DACs requires LSEs to identify the DACs they serve and evaluate programs that support clean energy access and equity, SCE has identified DACs in proximity to emitting generating resources based on the Commission's five-mile radius criterion. To support this mapping, SCE used ArcGIS to evaluate layered data from the Senate Bill ("SB") 535 Disadvantaged Communities dataset, SCE's system geolocation data, and the ArcGIS layer for county subdivision boundaries. Tribal lands are identified separately by tribes to ensure that the demographic characteristics of individual tribes are clearly represented. In Figure III-13 below, the red areas identify DACs and the yellow circles indicate the five-mile radius around the SCE emitting generators. More detailed information, mapping the county census tracts located within five miles of emitting generating resources, is provided in Appendix A.

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[87] For purposes of the 2026 IRPs, the Commission defined a DAC consistent with the final designation of DACs adopted by the California Environmental Protection Agency. This designation defines a DAC as: (1) Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0; (2) Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores; (3) Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0; and (4) Lands under the control of federally recognized Tribes. *See* Narrative Template at 9-10.

Figure III-13
Emitting Generators Owned by or Contracted with SCE
that are Within Five Miles of a DAC

Circles are the five-mile radius around emitting generators in the vicinity of the DAC census tract.



f) Methodology

SCE's locational analysis is conducted at the census tract level, the finest level of granularity contemplated by the Commission consistent with CalEnviroScreen 4.0 and the SB 535 Disadvantaged Communities designations. SCE used ArcGIS to evaluate layered data from the SB 535 Disadvantaged Communities dataset, SCE's system geolocation data, and county subdivision boundaries to identify DACs within proximity to emitting generation facilities.

SCE does not define specific locations for new resources in its IRP, as project siting is determined by developers and is not specified at the portfolio modeling stage. SCE instead gathers locational information, including proximity to DACs, for specific projects through the procurement process and evaluates these factors as part of bid evaluation and selection, as described above.

g) Transportation Electrification and DACs

Many communities, particularly DACs, are situated near heavily traveled freight corridors where the concentration of air pollutants often exceeds health-based standards.[88] In CARB's 2024-2025 Zero-Emission Vehicle Action Plan, CARB emphasized that the state's most vulnerable populations, "children, older adults, and especially lower-income households and communities of color—bear a disproportionate burden of pollution and have the most to gain as transportation moves to zero emissions."[89] Electrification of the transportation sector will help greatly improve local air quality – an urgent need across California, particularly within DACs in Southern California. In response to federal actions in 2025 that repealed the state's clean vehicle standards, including the Advanced Clean Cars II ("ACCII")[90] and Advanced Clean Trucks ("ACT")[91] standards, the state reaffirmed its commitment to zero-emission vehicle ("ZEV") deployment.

For example, Governor Newsom's Executive Order N-27-25: (1) directs CARB to develop and propose an Advanced Clean Cars III ("ACCIII") regulation to advance new strategies for emissions reduction for passenger cars, light-duty vehicles and medium-duty

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88 Electrification in areas such as the I-710 corridor between Long Beach and Los Angeles promotes environmental justice by ensuring that climate investments provide near-term air quality benefits to a broad set of communities.

89 CARB, Zero-Emission Vehicle 2024-2025 Action Plan, at 1, available at: https://business.ca.gov/wp-content/uploads/CARB-ZEV-Action-Plan-2025.pdf.

90 CARB adopted ACCII in 2022, which required a phased transition to 100 percent zero-emission new passenger vehicle and light-duty truck sales in California by 2035.

91 ACT is a CARB regulation that required medium- and heavy-duty vehicle manufacturers to sell an increasing percentage of zero-emission trucks in California.

heavy-duty ("MDHD") vehicles; (2) updates the state's purchasing requirements to align with manufacturers that continue complying with the state's clean car regulations; (3) prioritizes funding for state incentive programs for clean manufacturers and fleets; (4) continues the Clean Truck Partnership; and (5) directs state agencies to assess additional actions for ZEV adoption and issue recommendations within 60 days.[92] Following the Executive Order, CARB, along with several other state agencies, released an action plan to keep ZEV deployment on track despite federal policy shifts while focusing on affordability, infrastructure readiness, and cost certainty.[93]

The report outlines six priority action areas – private investment, incentives, infrastructure, fuel pricing, regulations, and procurement – to maintain market momentum, improve affordability and reliability, and ensure overburdened communities benefit from emissions reductions. Key recommendations include sustaining the Low Carbon Fuel Standard ("LCFS") to attract private capital, backfilling expiring federal tax credits with state incentives, and improving charger reliability and access (including for multi-family housing). The action plan also recommends that state agencies and partners maintain sustained community engagement, particularly with low income and pollution burdened communities, to ensure equitable outcomes and durable progress toward California's air quality and climate goals.

Additionally, CARB launched the Drive Forward Initiative to support the development of the next phase of the state's vehicle emissions regulations, incentive programs, outreach and education, and complementary programs and policies to enable ZEV deployment.[94] The new zero emission light-duty incentive program administered by CARB will provide a point-of-sale

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[92] *See* Executive Order N-27-25, June 12, 2025, available at: https://www.gov.ca.gov/wp-content/uploads/2025/06/CRA-Response-EO-N-27-25_-bl-formatted-GGN-Signed-6-11-954pmFinal.pdf.

[93] *See* Report to the Governor in Response to Executive Order N-27-25 on Zero-Emission Vehicle Deployment, August 2025, available at: https://ww2.arb.ca.gov/sites/default/files/2025-08/August%202025%20Report%20to%20the%20Governor%20in%20Response%20to%20Executive%20Order%20on%20ZEV%20Deployment%20FINAL_0.pdf.

[94] *See* CARB, Drive Forward, available at: https://ww2.arb.ca.gov/drive-forward.

rebate matched by participating car manufacturers to reduce the upfront cost of new and used electric vehicles.

In 2023, the Commission initiated a proceeding to address emerging transportation electrification challenges and to continue the development of policies and infrastructure supporting California's ZEV goal, including addressing the rapid adoption of ZEVs and its effects on grid planning and rate affordability.[95] This proceeding paused the $1 billion statewide BTM rebate program due to affordability issues for customers, energization delays caused by needed upgrades to distribution infrastructure, and the near-term availability of non-ratepayer funds for BTM transportation electrification infrastructure.[96] However, SCE continues to help accelerate transportation electrification in its service area, by delivering transportation electrification programs with benefits in DACs. By increasing electric vehicle adoption, SCE's transportation electrification programs help improve local air quality and reduce GHG emissions broadly and within DAC communities.

h) Customer Programs and DACs

SCE also prioritizes clean air and clean energy in DACs through its customer programs. SCE has many current and planned customer programs and activities that economically benefit low-income customers and DACs. Many of these programs also reduce local emissions and contribute to air quality improvements within DACs either directly or indirectly. For example, programs that replace fossil fuel vehicles with electric vehicles or natural gas stoves with induction stovetops result in direct local emission reductions. Rooftop solar and battery system installations and demand-side management programs result in less fossil fuel use system-wide. Time-of-use and load shifting programs similarly reduce emissions system-wide by shifting peak electricity use from high-emitting sources to low- or no-emitting sources. SCE implements and manages a diverse portfolio of energy products, programs, and services for

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[95] *See* Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure and Closing Rulemaking 18-12-006, R.23-12-008, December 14, 2023.

[96] *See* Assigned Commissioner's Scoping Memo and Ruling, R.23-12-008, April 12, 2024.

its customers to help with bill affordability, energy efficiency, electric vehicles, and renewable energy adoption. While these programs are offered to customers throughout SCE's service area, there may be some programs in which greater marketing and outreach to DACs may occur, DAC or low-income customers receive a greater financial benefit than other customers, or program benefits are restricted to DACs and other specified geographic areas.

(1) Residential and Business Customer Programs with a Net Air Quality Benefit

Tables III-17 and Table III-18 below list those residential and business customer programs that are expected to result in a net positive air quality benefit to DACs.

Table III-17
Residential Programs

Residential Customer Tariffs	
Program	**Details**
Standard Time-of-Use Tariff	Pricing incentives encourage customers to shift electricity use to times when energy supply is more abundant, including periods with greater renewable generation or when lower emitting fossil fuel resources provide power.
Standard Green Tariff	Customers can choose energy from either a 50 percent or 100 percent guaranteed renewable energy mix.
DAC-Green Tariff	Provides an additional 20 percent rate discount for a 100 percent renewable energy allocation compared to the otherwise applicable tariff rate for customers eligible for the California Alternate Rates for Energy ("CARE") or Family Electric Rate Assistance ("FERA") programs.
Income-Qualified and Residential Energy Programs	
Program	**Details**
Energy Savings Assistance ("ESA") Program	No-cost energy-efficient appliance replacement for eligible customers, based on income qualifications or participation in select public assistance programs.
Multifamily Residential Direct Install Program	Direct installation of no-cost energy efficiency measures to residential multi-family building customers and common areas. All customers are targeted, with a special focus on DACs.
Residential Energy Solutions	Direct installation of no-cost energy efficiency measures to residential single-family and manufactured/mobile home customers. All customers are targeted, with a special focus on DACs.
Summer Discount Plan	Provides bill credits for allowing SCE to temporarily cycle central A/C during energy events.

Smart Energy Program[97]	Provides bill credits to residential and business customers[98] with qualifying smart thermostats in return for participation in energy events.
Smart Heat Pump Water Heater Program ("SmartShift Rewards Hot Water")	Financial incentives for customers to install smart communication and control devices on heat pump water heaters (and qualifying electric resistance water heaters) to enable automated shifting of water-heating electricity use away from peak hours.
Wildfire and Natural Disaster Resilience Rebuild ("WNDRR") Program *aka* Rebuilding Incentives for Sustainable Electric "RISE" Homes	Provides incentives and support for all-electric rebuilding of residential properties destroyed or red-tagged by wildfires or other natural disasters (since January 1, 2017), including eligible single-family and multi-family homes in jurisdictions with a declared Local Emergency Proclamation.
Residential Customer Pilot Programs	
Program	**Details**
ESA Building Electrification Pilot ("ESA BE Pilot")	Direct-install pilot under the ESA Program designed to evaluate the deployment of no-cost electrification retrofits to income-qualified customers in single-family homes, with priority targeting of DACs. SCE has proposed to integrate the ESA BE Pilot into the main ESA program in 2028 (pending Commission approval).
ESA Plus/Deep Pilot ("ESA Whole Home Pilot")	A joint pilot administered by SCE in collaboration with Southern California Gas Company designed to achieve deeper, whole-home energy savings for high-usage, income-qualified customers.
Statewide Market Transformation and Electrification Programs	
Program	**Details**
Technology and Equipment for Clean Heating ("TECH") Initiative (including for multi-family properties and Aliso Canyon)	A statewide market-transformation initiative administered by the Commission's Energy Division, with SCE serving as the contracting agent. Provides midstream incentives for heat pump water heaters and heat pump HVAC systems installed by TECH-enrolled contractors. Enhanced incentives are available for income-qualified and equity-eligible customers.
Residential Customer Transportation Electrification Programs[99]	
Program	**Details**
Pre-Owned Electric Vehicle Rebate	Rebate of $1,000 on the purchase or lease of a pre-owned electric vehicle. Eligible income-qualified customers may receive a rebate of $4,000.
Charge Ready Home	Residential customers can receive up to $4,200 to upgrade electrical panels and install Level 2 chargers. Income-qualified and DAC households receive priority.
Affordable Public Charging[100]	Low-income drivers receive pre-loaded debit cards to offset the cost of public charging to an amount comparable to the CARE rate at home.

[97] Listed under both residential and business programs.
[98] The Smart Energy Program was expanded to business customers in November 2025.
[99] Not customer funded.
[100] Program to be launched in Q4 2026.

Residential Customer Renewable Energy Programs	
Program	**Details**
Solar on Multifamily Affordable Homes ("SOMAH")	Allows multi-family building owners to offset the cost of installing a new solar energy system for common areas and/or to reduce energy costs for low-income tenants.
DAC-SASH[101]	Provides up-front financial incentives towards the installation of solar generating systems on homes of low-income customers who are resident-owners of single-family homes in DACs.
Green Tariff Shared Renewables - Green Rate	Green Rate enabled customers to support renewable energy procurement without installing solar equipment. While the legacy program allowed customers to enroll at 50 percent or 100 percent renewable participation levels, D.24-05-065 and D.26-06-006 require SCE to transition to a Modified Green Tariff that uses a "top-off" approach. Under this approach, customers will remain on their otherwise applicable tariff and receive additional clean energy to bring their participation level to 100 percent clean energy. Existing Green Rate customers will remain on their current tariff until the Modified Green Tariff and customer transition plan are approved and implemented.
Green Tariff Shared Renewables - Community Renewables	A customer can agree to purchase a share of a community renewable project directly from a developer, and in exchange, will receive a credit from SCE for the customer's avoided generation procurement.
Self-Generation Incentive Program ("SGIP")	Provides rebates to customers who install qualifying types of distributed generation to meet all or a portion of their own energy needs. Beginning in April 2020, customers living in low-income, DAC, and high fire risk areas were eligible for increased equity resiliency incentives to offset most of the cost to install an energy storage system. AB 209 (2022) provided ~$280M in state-funded SGIP incentives through the Residential Solar and Storage Equity ("RSSE") program to support low-income households in installing paired solar and battery systems.[102]

[101] *See* D.18-06-027 at 2-3.

[102] RSSE funding is currently fully subscribed and operating on a waitlist.

Table III-18
Business Programs

Tariffs	
Program	**Details**
Smart Energy Program[103]	Provides bill credits to residential and business customers[104] with qualifying smart thermostats in return for participation in energy events.
Simplified Savings Program	Program delivers energy bill savings to small and medium business customers, with a focus on DACs and hard-to-reach segments by partnering with local trade allies and community-based organizations to provide energy education, bill analysis, and no-cost direct install measures and incentives.

(2) Charging Infrastructure and Commercial Vehicle Rebate Programs

In addition to the above listed programs directly targeting residential and business customer facilities, SCE prioritizes clean air in DACs by investing in numerous transportation electrification charging infrastructure programs that support the adoption of light-, medium- and heavy-duty electric vehicles, particularly along the goods movement corridors, with a focus on the seaports, the I-710 freeway, and the Inland Empire. The projects funded under these programs are expected to directly benefit air quality in DACs. Programs that are currently in operation are listed below in Table III-19. This list includes programs that are funded by ratepayer funds and by LCFS funds.

Table III-19
Systemwide Charging Infrastructure Programs

Charging Infrastructure Programs	
Program	**Details**
Charge Ready Light-Duty ("Charge Ready 2")	Expected to result in over 20,000 light-duty electric vehicle charging ports, 50 percent in DACs.
Charge Ready Transport ("CRT")	Expected to supply the make ready infrastructure needed to support customer chargers for 8,490 procured or converted medium- and heavy-duty electric vehicles. A minimum of 40 percent of the budget will support installations in DACs.

[103] Listed under both residential and business programs.
[104] The Smart Energy Program was expanded to business customers in November 2025.

Shared Fleet Charging Rebate Program	Provides financial incentives to support the installation of electric vehicle charging infrastructure for public and shared-private medium- and heavy-duty fleet customers.
TE Advisory Services – EV Readiness Studies	Provides site-specific assessments to support commercial customers in planning electric vehicle projects, including evaluation of electrical capacity, infrastructure upgrade needs, site and cost considerations. Since program inception, 42 percent of completed studies have been in DACs.

SCE also offers several programs intended to facilitate the conversion of MDHD trucks to fully electric vehicles. Removal of diesel emissions that disproportionately affect DACs is one of the most effective ways to improve air quality for those communities. Table III-20 lists currently offered LCFS-funded programs.

Table III-20
MDHD Truck Conversion Programs

LCFC Funded MDHD Truck Conversion Programs	
Program	**Details**
Drayage Truck Rebate	Funding for 800 Class 7/8 trucks operating in a drayage capacity in and around the ports and intermodal facilities.
ReCharge Rebate	Funding for Internal Combustion Engine ("ICE") to Battery Electric Vehicle ("BEV") retrofit conversions in the historically underrepresented MD BEV space.
California Clean Fuel Rewards ("CCFR")	Point-of-purchase reward to offset price of Class 2B to Class 8 Commercial Vehicles. While DAC metrics will not be tracked, a significant percentage of mileage for the MDHD commercial vehicle sectors is known to occur adjacent to DAC corridors.
Shared Fleet Charging Rebate ("SFCR")	The SFCR is an SCE program that provides financial incentives to support installation of electric vehicle charging infrastructure for MDHD fleets where charging is shared across multiple users or publicly accessible.

i) DAC Outreach

In addition to SCE programs and activities that prioritize air quality in DACs, SCE also collaborate with and directly support the DAC community through community-based organizations ("CBOs"), community-based projects, and joint information sharing activities focused on clean energy, air quality improvement, and GHG reduction. A few of SCE's more significant collaborations are described below.

(1) Clean Energy Access Working Group

In 2017, SCE partnered with The Greenlining Institute ("Greenlining") to form the Clean Energy Access Working Group ("CEAWG"), a forum consisting of community leaders from DACs across SCE's service area. The group's shared goal was to develop community-centric solutions for clean energy access, air quality, and climate change issues. Since its formation, CEAWG members have worked to craft and support state and local policies and programs to improve air quality for environmentally impacted communities and bring clean energy technology investment, clean energy jobs, and job training to communities. CEAWG developed the Energy Ambassador Program, and SCE provides a stipend to members to be used for clean energy, air quality, or related projects. SCE regularly consults with CEAWG members when developing new clean energy programs and services to obtain their input and adjust programs to better reflect the learned experience of the DAC community. SCE's IRP team engaged with CEAWG on the IRP's role in shaping clean energy outcomes as discussed in Section IV.B.

(2) Valley Clean Air Now

SCE also partners individually with local non-profits to improve air quality in underserved communities. One such partner is Valley Clean Air Now ("Valley CAN"), a non-profit organization committed to improving air quality in the San Joaquin Valley, a region that contains a disproportionate share of California's DAC census tracts. The San Joaquin Valley has among the highest per-capita rates of gross-polluting, older, and unregistered cars in the state, as well as among the worst air quality. In response, Valley CAN partnered with the San Joaquin Air Pollution Control District to develop two award-winning programs that reduce emissions while providing real-world solutions for low-income drivers.

The Tune In & Tune Up program hosts weekend events where residents receive a free emissions test to determine whether their vehicle qualifies for free repairs at a local STAR-certified smog shop. Over four percent of all Valley households have attended one of these events and more than 200,000 smog repair vouchers have been issued since 2014.

Based on the success of this approach, in 2014 Valley CAN piloted a vehicle replacement program for residents who would prefer to trade in their older unreliable and polluting vehicles for a new or used plug-in electric vehicle in lieu of performing expensive smog repairs. This pilot program was so successful that it evolved into the statewide Clean Cars 4 All program, recognized as a very effective program to bring equitable access to ZEVs in DACs. Valley CAN now conducts Community Clean Car Clinics, where residents can bring in their paperwork to determine if they qualify for the Clean Cars 4 All Incentives and receive assistance with their application.

(3) Empower Program

Empower is a longstanding non-profit-managed collaboration enabled by SCE that uses CBOs as one-stop-shop marketers for clean energy programs in underserved communities in Los Angeles County, the Inland Empire, and San Joaquin Valley. The program has undergone several iterations through the years, but its goal remains to be focused on developing more effective ways to deliver available home and vehicle upgrade incentives to those communities suffering from the greatest adverse air quality and socioeconomic impacts.

The current Empower Gateway project follows five years of iterative program development led by Liberty Hill Foundation and Valley CAN. In 2023, SCE partnered with Gateway Cities Council of Governments to bring Empower to the 27 local governments in Southeast Los Angeles, one of California's most severely impacted regions based on its environmental and socioeconomic burdens. This strong partnership is helping to take the program model to the next level while identifying ways to further improve the delivery of available electrification resources to the families that most need the help.

E. Cost and Rate Analysis

Customer affordability remains one of the most significant challenges facing California's clean energy transition. As discussed in Section I.B, resource portfolios developed using the Commission's current assumptions require unprecedented levels of new resource development,

including resources not currently available in the interconnection queue and the market in meaningful quantities. These factors, combined with changes in load growth estimates, transmission constraints, interconnection delays, permitting challenges, supply-chain risks, and increasing resource costs associated with changing federal policies, create significant upward pressure on customer rates. While SCE's Conforming Bundled Portfolio represents the least-cost portfolio available to satisfy the Commission's adopted reliability requirements and GHG emissions benchmarks, the resulting costs underscore the importance of developing an alternate PGP to guide near- and mid-term procurement decisions.

In this section, SCE discusses the forecasted revenue requirements and system average rates for SCE's Conforming Bundled Portfolio, as well as a baseline scenario for comparison.[105] SCE's Conforming Bundled Portfolio would result in an 8.2 percent increase in estimated 2035 bundled system average rates over the Baseline Portfolio, a significant rate increase when compared with the 4.7 percent increase projected in SCE's 2022 IRP filing. Moreover, this bill impact analysis provides limited value because it simply reflects the forecast customer cost of meeting the Commission's established IRP requirements. A more relevant and meaningful analysis is to compare, at a CAISO system level, the cost of different planning and procurement requirements to ensure all adopted policies (including the load forecast, resource availability assumptions, and GHG targets) explicitly consider customer affordability. Developing a PGP can help to provide this comparison and ensure that the IRP process appropriately focuses on customer affordability in the near- and mid-term and results in procurement and other policies at a reasonable cost to customers.

[105] Late in the analysis process, SCE moved forward a small amount of generation in its Conforming Bundled Portfolio to come online earlier than assumed in the rate analysis. This change resulted in a 0.7 percent change in SCE's forecast fuel and purchased power budget, which SCE determined would not materially affect SCE's rate analysis. Therefore, the cost and rate analysis included in this section was performed for SCE's Conforming Bundled Portfolio before making these final modifications.

1. Cost and Rate Analysis Assumptions

SCE's Baseline scenario uses the same cost assumptions as SCE's Conforming Bundled Portfolio but excludes all generic resource additions. The Baseline scenario represents SCE's fuel and purchased power expenditures based on the current resources it has under contract or expects to contract with through 2045. The Baseline scenario does not include new build generic resources that SCE needs to meet reliability or GHG goals as required by the Narrative Template; nor does it includes the additional transmission investments needed to support SCE's Conforming Bundled Portfolio's build-out.[106] Additionally, the Baseline scenario assumes that load and RA needs are to be met through generic RA and market purchases in lieu of building or contracting for energy storage and renewable resources. The Baseline scenario is not a meaningful or viable planning scenario because it does not build the new resources needed to meet system reliability and GHG reduction requirements.

SCE used RESOLVE's resource costs for the new resources needed to develop its Conforming Bundled Portfolio as discussed in Section II.B.3.a. To calculate the total portfolio revenue requirements and system average bundled rates shown in Tables III-21 and III-22, SCE broke down the revenue requirements by categories and included the modeling assumptions for each category. SCE's cost and rate forecast started with the revenue and rates that were in effect as of June 1, 2026. The 2026 revenue and rates are based on the 2025 General Rate Case ("GRC") (2026 attrition year) and assume a net zero balance for most of SCE's balancing and memorandum accounts in the future years. For non-fuel and purchased power costs from 2027 through 2035, forecasted costs associated with all pending applications before the Commission are included in this revenue forecast, as are forecasted costs for all approved proceedings. More specifically, the revenue forecast is based on SCE's 2025 GRC[107] through attrition year 2028 with an assumed 2.44 percent inflation increase in years 2030 through 2035. The fuel and

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[106] *See* Narrative Template at 10.

[107] The 2026 attrition year is based on SCE's 2026 Post Test Year Revenue Requirement, which was submitted and approved by the Commission through Advice 5725-E effective January 1, 2026.

purchase power revenue and rate forecasts for 2028 through 2045 use load and fuel and purchased power expenditure forecasts as presented in this document with an expected forecast of $0.8 billion ($2024) in GHG revenue credits by 2045.[108] Some of the revenue requirements assumed to be implemented in 2027 will likely be delayed until future years, but at the time of this IRP filing, these assumptions represent SCE's filed requests with the Commission. The fuel and purchased power expenditures associated with New System Generation and GHG rates are also included in the generation cost category.

Within the delivery rate, SCE assumes Federal Energy Regulatory Commission ("FERC") revenue is based on the approved 2026 FERC formula rate with an assumed long run escalation of from 2.29 percent to 2.44 percent from 2030 through 2045. The forecast includes all revenue associated with SCE's transportation electrification programs, including Charge Ready 1 Pilot, Charge Ready Bridge extension, and Charge Ready 2 as well as the Transportation Electrification Priority Review Pilots and Standard Review Programs. Additionally, the forecast assumes all requested cost recovery applications, which are driving the 2026 revenue requirement forecast, for example the 2024 Wildfire Mitigation/Vegetation Management Application, Woolsey and Thomas Kincade Montecito Catastrophic Event Memorandum Account events, Tax Adjustment Memorandum Account, the Woolsey Assembly Bill 1054 Securitization, and the Wildfire Fund Charge.

As stated in Section III.M, SCE includes four additional transmission projects in the portfolio because the Conforming Bundled Portfolio requires new transmission infrastructure beyond currently approved TPP projects to accommodate the proposed resource additions to meet the 2024 IEPR load forecast and GHG emissions benchmarks while maintaining system reliability and addressing transmission and short-circuit-duty constraints. The four identified projects are the Lugo 500 kV Collector Station Short Circuit Duty ("SCD") mitigation ($178

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[108] The 2028 to 2045 revenue and rate forecast uses SCE's bundled load forecast as provided in the Administrative Law Judge's Ruling Setting Requirements for Individual Integrated Resource Plans Due June 1, 2026, R.25-06-019, January 16, 2026, at 7-8.

million), Whirlwind 230 kV Split SCD mitigation ($104 million), Devers–Red Bluff No. 3 500 kV Transmission Line ($1.5–$2.5 billion), and Devers–Rancho Vista 500 kV Transmission Line ($1.1 billion). Although the need for these upgrades has been identified in prior reliability and generator interconnection studies, none are currently approved in the latest TPP, making them necessary additional transmission needs to support the planned resource portfolio by 2035. SCE has incorporated these project costs into the 2035 planning timeframe and evaluated the associated estimated revenue requirement impacts to customers.[109]

Financial assumptions underlying the revenue forecast include: asset lives of 60 years for distribution substation equipment, 33 to 66 years for distribution poles and lines, 20 years for meters, 45 years for transmission station equipment, 45 to 70 years for transmission lines and towers, and 45 years for general building; capitalization of eligible operation and maintenance ("O&M") expenses at 52.9 percent for pension and benefits and 32.4 percent for administrative and general; 3 percent for O&M cost escalation and zero percent for capital related cost escalation; a weighted average cost of capital of 7.59 percent; federal income taxes at 21 percent; state income taxes at 8.84 percent; and other tax related assumptions such as bonus depreciation and tax repair eligibility that were in place at the time of SCE's 2025 GRC Application.

2. Cost and Rate Analysis Results

As shown in Table III-21 and Table III-22 below, the estimated 2035 bundled system average rate is 22.53 cents[110] per kWh for SCE's Conforming Bundled Portfolio, an 8.2 percent increase over the 20.83 cents per kWh for the Baseline scenario. If the actual load that materializes is only 10 percent lower than the 2024 IEPR load forecast, the bundled system average rate would increase to 25.03 cents per kWh in 2035, a 20.2 percent increase over the Baseline scenario, though some portion of the assumed incremental transmission projects might

[109] SCE calculated the estimated capital-related revenue requirement by using the 2026 Revenue Requirement Multiplier of 15.91 percent as specified in SCE's Preliminary Statement Part LL multiplied by the total capital expenditures stated in Section III.M.

[110] System average rates ("SAR") are presented in 2024 dollars and are unique to this proceeding and may differ from SAR presented in other Commission proceedings.

not be needed to be constructed prior to 2035 as assumed in this analysis. Furthermore, because SCE and other LSEs will be competing for a very limited supply of clean energy resources to reach the lower GHG targets, these costs and rates represent the floor of what may materialize by 2035.

An additional observation regarding the revenue requirements analysis for SCE's Conforming Bundled Portfolio is that generation revenue costs (line number 3a) increase, on a 2024 dollar basis, through 2045. This increase is driven by the increase in load across the forecast period. SCE used the CAISO Capacity Procurement Mechanism soft offer cap forecast to estimate the costs for market RA in the future. SCE recommends that in future IRP cycles, as part of the I&As, the Commission provide LSEs an assumed RA capacity price forecast that can be applied consistently across LSEs' IRPs.

Table III-21
Revenue Requirements and System Average Bundled Rules for SCE's Baseline
(in million 2024 dollars, unless otherwise noted)

Line No.	Cost Category	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045
1	Distribution	10,238	9,791	9,293	9,254	9,307	9,355	9,395	9,428	9,461	9,497	9,682	9,598
2	Transmission	1,458	1,350	1,323	1,300	1,307	1,314	1,320	1,324	1,329	1,334	1,361	1,351
3a	Generation[1/]	5,464	5,423	5,490	5,761	5,984	6,205	6,365	6,429	6,546	6,479	6,789	7,000
3b	Generation - GHG Revenue (AB 32)[2/]	(418)	(570)	(703)	(892)	(1,020)	(1,048)	(1,071)	(1,093)	(1,113)	(1,132)	(894)	(549)
4	Demand Side Programs	56	54	53	52	52	52	53	53	53	53	54	54
5	Other[3/]	1,933	1,812	1,745	1,735	1,724	1,721	1,720	1,712	1,710	1,710	1,609	1,523
6 (sum lines 1-5)	**Total Revenue Requirement**	**18,730**	**17,859**	**17,201**	**17,210**	**17,353**	**17,600**	**17,782**	**17,853**	**17,986**	**17,942**	**18,602**	**18,977**
7	System Sales (GWh)	81,015	83,313	86,099	89,342	92,828	96,180	99,632	103,285	107,149	111,069	123,167	129,786
8	Bundled Sales (GWh)	51,960	53,228	55,101	57,415	59,894	62,331	64,829	67,499	70,325	73,210	82,474	87,549
9a	System Average Delivery Rate[4/]	16.37	14.93	13.60	12.81	12.25	11.85	11.46	11.06	10.68	10.32	9.59	9.23
10	Bundled Generation Rate (¢/kWh)[5/]	10.36	11.15	10.63	10.57	10.54	10.74	10.84	10.78	10.79	10.51	10.84	11.70
11	Bundled System Average Rate (¢/kWh)[6/]	26.73	26.07	24.23	23.39	22.79	22.59	22.30	21.84	21.47	20.83	20.43	20.93

1/ The Generation revenues reflected in this table includes both the bundled system generation and CCA generation revenues.
2/ GHG Revenue returned through the distirbution rate component to all customers (Bundled and CCA).
3/ Includes revenues not identified in the rows above such as New System Generation, Public Purpose, Fixed Recovery Charge, TMNBC and BMNBC related revenues.
4/ The System Average Delivery rate shown in this table excludes the revenue requirement for the Transmission (IRP) Incremental Impact.
5/ The Bundled Generation Rates reflected in this table excludes CCA generation related rates.
6/ The Bundled System Average Rate reflects the sum of Line 9a and 10 and does not include the incremental transmission project impact.

Table III-22
Revenue Requirements and System Average Bundled Rates for SCE's Conforming Bundled Portfolio
(in million 2024 dollars, unless otherwise noted)

Line No.	Cost Category	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2040	2045
1	Distribution	10,238	9,791	9,293	9,254	9,307	9,355	9,395	9,428	9,461	9,497	9,682	9,598
2	Transmission	1,458	1,350	1,323	1,300	1,307	1,314	1,320	1,324	1,329	1,334	1,361	1,351
2a	Transmission (IRP) Incremental Impact[1/]										364	329	297
3a	Generation[2/]	5,464	5,423	5,490	5,896	6,135	6,386	6,719	7,026	7,184	7,329	7,992	8,122
3b	Generation - GHG Revenue (AB 32)[3/]	(418)	(570)	(703)	(892)	(1,020)	(1,048)	(1,071)	(1,093)	(1,113)	(1,132)	(894)	(549)
4	Demand Side Programs	56	54	53	52	52	52	53	53	53	53	54	54
5	Other[4/]	1,933	1,812	1,745	1,735	1,724	1,878	2,043	2,036	2,044	2,054	2,330	2,653
6 (sum lines 1-5)	**Total Revenue Requirement**	**18,730**	**17,859**	**17,201**	**17,344**	**17,504**	**17,938**	**18,458**	**18,773**	**18,958**	**19,501**	**20,854**	**21,525**
7	System Sales (GWh)	81,015	83,313	86,099	89,342	92,828	96,180	99,632	103,285	107,149	111,069	123,167	129,786
8	Bundled Sales (GWh)	51,960	53,228	55,101	57,415	59,894	62,331	64,829	67,499	70,325	73,210	82,474	87,549
9a	System Average Delivery Rate[5/]	16.37	14.93	13.60	12.81	12.25	12.01	11.78	11.37	10.99	10.63	10.18	10.10
9b	Incremental Transmission Rate (¢/kWh)										0.33	0.27	0.23
10	Bundled Generation Rate (¢/kWh)[6/]	10.36	11.15	10.63	10.82	10.81	11.06	11.45	11.79	11.85	11.90	12.95	13.59
11	Bundled System Average Rate (¢/kWh)[7/]	26.73	26.07	24.23	23.63	23.06	23.07	23.23	23.16	22.84	22.53	23.12	23.69

1/ Per Section III.M SCE anticipates four additional resources and assumes ownership of these assets.
2/ The Generation revenues reflected in this table includes both the bundled system generation and CCA generation revenues.
3/ GHG Revenue returned through the distirbution rate component to all customers (Bundled and CCA).
4/ Includes revenues not identified in the rows above such as New System Generation, Public Purpose, Fixed Recovery Charge, TMNBC and BMNBC related revenues.
5/ The System Average Delivery rate shown in this table excludes the revenue requirement for the Transmission (IRP) Incremental Impact.
6/ The Bundled Generation Rates reflected in this table excludes CCA generation related rates.
7/ The Bundled System Average Rate reflects the sum of Line 9a and 10 and does not include the incremental transmission project impact.

F. System Reliability Analysis

SCE developed a System Base Case Portfolio that is reliable and operable. SCE's Conforming Bundled Portfolio also contributes SCE's share to system reliability and renewables integration. Below, SCE provides the results for its System Base Portfolio and Conforming Bundled Portfolio using the Commission's reliability standard.

As explained in Section II.B.2, SCE did not use the Commission's PCAP and marginal reliability need-based reliability methodology in CE to build its system or bundled portfolios. Instead, SCE developed its portfolios by enforcing SOD reliability and GHG emissions requirements using the methodology and modeling tools described in Section II.B. Finally, SCE evaluated if its bundled portfolio met the reliability and GHG requirements using the Commission's tools (ELCC-based annual reliability requirements in the RDT and milestone year GHG emissions requirements in the CSP Calculator) and made adjustments, as necessary.

The portfolios developed by SCE's models passed the Commission's RDT reliability test. However, SCE continues to be concerned with the Commission's reliance on a single-point reliability framework and an annual marginal ELCC-based methodology and urges the

Commission to adopt the SOD framework in the IRP for modeling and planning purposes. For instance, although the initial bundled portfolio developed by SCE met the SOD reliability requirement, it did not pass the RDT validation tool. Consequently, additional resources were added into the portfolio to achieve compliance with the RDT tool and meet the ELCC-based annual reliability requirements.

1. System Reliability Results for SCE's System Base Case Portfolio

SCE inputted its System Base Case Portfolio into the Commission's RDT checking tool to confirm it passes the Commission's single-point framework reliability criteria in 2030, 2035, and 2045. SCE applied the marginal ELCC values included in the RDT to calculate the System Total Supply (effective MW) and compared it to the CAISO marginal reliability need (*i.e.,* input 100 percent as the LSE managed peak share percentage). The results are detailed in Table III-23 below.

Table III-23
System Load and Resource Table by Contract Status –
SCE's System Base Case Portfolio

	2030	2035	2045
System reliability need (MW)	**45,606**	**53,922**	**63,906**
ELCC by contract status (effective MW)			
Online and In-Development	39,303	36,679	34,014
PlannedNew	10,265	16,702	29,760
BTM PV	1,468	2,143	2,381
System total supply (effective MW)	**51,036**	**55,525**	**66,155**
Net capacity position (+ve = excess, -ve = shortfall) (effective MW)	5,430	1,603	2,250

2. System Reliability Results for SCE's Conforming Bundled Portfolio Under Commission's Reliability Standard

The following Table III-24 includes the Load and Resource Table by Contract Status for SCE's Conforming Bundled Portfolio for the milestone years 2030, 2035, and 2045. RDT

results for each year of the planning horizon, including charts, are included in Appendix B and show there is no shortfall in SCE's net capacity position.

Table III-24
SCE's Load and Resource by Contract Status – Conforming Bundled Portfolio

	2030	2035	2045
LSE reliability need (MW)	**13,985**	**16,403**	**18,261**
ELCC by contract status (effective MW)			
Online	5,684	4,804	1,962
Development	1,447	1,118	136
Review	-	-	-
PlannedExisting	6,336	6,360	6,467
PlannedNew	1,132	3,682	9,152
BTM PV	350	542	635
LSE total supply (effective MW)	**14,949**	**16,506**	**18,351**
Net capacity position (effective MW)	**964**	**103**	**90**

G. Existing Resource Planning

SCE evaluated the contribution of existing resources in its Conforming Bundled Portfolio to ensure that planned levels are reasonable and consistent with expected system conditions. SCE's assessment considers the availability of existing resources based on historical participation, market conditions, and anticipated competition among LSEs. SCE also identifies potential risks associated with reliance on existing resources, including competition for limited supply and uncertainty in market availability. These considerations are incorporated to ensure that the portfolio does not assume availability beyond what can be reasonably supported.

Consistent with Commission guidance, SCE ensures that its reliance on existing resources does not exceed the resources represented in the baseline and avoids over-subscription of shared or system resources. This approach supports the development of a portfolio that is reflective of actual system constraints. SCE suggests the Commission take action to ensure LSEs do not over-rely on any shared resources (*e.g.*, CAISO system resources, major transmission lines, and import/export lines). The Commission should consider not only LSEs'

use of resources in the RDT with contract statuses of "online" and "planned existing," but also LSEs' reliance on imports and transmission lines.

As described in Section II.B.2.b.1.d, SCE's bundled modeling limits SCE's selection of shared system resources, existing transmission, and import and export capability to its bundled service customer share of overall system load. This allows SCE's bundled portfolios to use system resources without over-relying on the system. Relatedly, SCE generally limits candidate generation resources to its bundled load share to prevent over-subscribing the technical potential of economic resources and urges the Commission to adopt this approach for all LSEs.

For the 2022 IRP, SCE revised its treatment of existing resources in response to the 2020 IRP finding that LSE portfolios had over-subscribed such resources, informing development of its 25 MMT and 30 MMT Bundled Portfolios. SCE did not assume re-contracting of existing renewables; instead, existing non-thermal resources were modeled as part of a combined pool of new and existing resources limited to SCE's bundled share of CAISO system load, with expiring contracts returned to the pool and valued at new-build costs of the same class. For natural gas, SCE assumed a pro-rata share aligned with its load share, without new builds or long-term re-contracting (≥5 years), while ensuring sufficient contracting to meet LOLE requirements. The resulting portfolios achieved SCE's GHG benchmarks across the planning horizon with limited gas utilization.

For the 2026 IRP, the following restrictions were imposed on the quantity of resources of all types that were allowed to be selected in the modeling to avoid over-subscribing existing generation resources:

- For the existing generation resources with expiring SCE contracts within SCE's TAC area, SCE limited the amount of these resources to a pro-rata amount of SCE's bundled load share in SCE's TAC area.
- For existing generation resources in the CAISO system outside of SCE's TAC area, SCE limited the selectable existing generation resources to a pro-rata amount of SCE's load share in the CAISO system.

- For other CAISO system shared resources, *i.e.*, new build candidate resources, imports, and transmission, SCE limited the selectable existing resources to a pro-rata amount of SCE's load share in the CAISO system.

Table III-25 below shows the total existing generation resource capacity used for modeling in SCE's 2022 and the 2026 IRPs. Specifically, Table III-25 provides the amount of existing generation resources assumed in SCE's 2026 IRP Conforming Bundled Portfolio and the amount of existing resources assumed in SCE's 2022 IRP for SCE's 25 MMT and 30 MMT Bundled Portfolios, which were identical.

Table III-25
Amount of Existing Resource Capacity Used in SCE's 2022 IRP 25 MMT Portfolio and SCE's 2026 IRP Conforming Bundled Portfolio

Modeling Year	IRP Year 2022 (MW)	IRP Year 2026 (MW)
2023	25,175	
2024	22,694	
2025	21,171	
2026	21,116	36,139
2027	20,839	32,054
2028	20,743	31,403
2029	20,743	31,639
2030	20,707	30,605
2031	20,524	30,182
2032	19,993	30,252
2033	19,070	29,911
2034	17,856	28,913
2035	14,943	27,640
2040		16,544
2045		5,898

SCE has developed a methodology that ensures it does not exceed its pro-rata share of existing resources, which is a reasonable expectation for all LSEs. As illustrated previously, SCE does not exceed its pro-rata share of available resources for natural gas resources. In the case of renewable and clean energy resources, SCE assumes contracted wind resources are added back to the pool of available candidate wind resources after the contracts expire.

For these reasons, SCE's 2026 IRP Conforming Bundled Portfolio will not contribute to the over-subscription of system resources. It is reasonable to assume that the amount of existing resources in SCE's portfolio will be available in the market. Potential barriers to procurement are discussed in more detail in Section IV.A.

H. Hydro Generation Risk Management [111]

1. Risk of In-State Drought

a) SCE Hydroelectric Resources and Operating Constraints

There has been no material change to how SCE plans to manage the risk of its utility-owned hydropower resources since SCE filed its 2022 IRP. SCE's utility-owned hydro resources can be divided into two groups: the Big Creek system (including the Eastwood pumped storage facility) and the remaining smaller hydro facilities across California. The Big Creek system consists of multiple reservoirs, water conveyance tunnels, and powerhouses, most of which are reservoir storage plants. Big Creek is directly interconnected to the bulk transmission system. In aggregate, Big Creek (including Eastwood) represents the majority of SCE's utility-owned hydro capacity.

Big Creek operations are governed by a layered set of constraints and obligations. Water management is subject to FERC licenses, water rights, contractual commitments, and stakeholder requirements. These requirements include minimum flow and reservoir management provisions that shape how water can be stored and released across seasons. Because SCE's hydro facilities must be operated consistent with these obligations, hydro generation flexibility is not solely a function of hydrology; it is also a function of operational and compliance constraints.

SCE's remaining smaller hydro facilities are resources located across several regions of California and are typically interconnected to sub-transmission or distribution systems. Many of these facilities have limited storage and are operated largely as run-of-river resources.

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[111] This section only addresses hydro facilities that are under SCE's operational control; it does not address SCE's contract for a share of output from Hoover.

Accordingly, their energy production is more directly tied to streamflow and operating availability.

b) How Drought Risk Manifests

Hydrologic conditions are inherently uncertain early in the water year. Snowpack, precipitation patterns, and reservoir inflows evolve over the season, and forecasts can change materially as conditions develop. Operational planning therefore requires continual monitoring and periodic updates to expectations for hydro generation.

Drought risk manifests as uncertainty in water availability and therefore uncertainty in hydro energy capability, particularly at seasonal and annual time scales. Multi-year drought conditions are generally the most consequential because they can reduce reservoir carryover and limit operational flexibility over extended periods.

For planning purposes, the key portfolio issue is not the complete loss of hydro capability. Instead, drought changes the amount and timing of hydro energy that is available to serve load. When hydro energy is lower than assumed, the portfolio must rely more on other resources and on market transactions to serve load. Depending on system conditions, this substitution can increase expected costs and GHG emissions.

c) Portfolio Dependence and Comparison to the 2025-2026 TPP Portfolio with Updates

Hydroelectric resources are largely fixed existing assets, with output variability driven by hydrologic conditions rather than planning decisions. Hydro contributes approximately [redacted] in SCE's generating resources, and under dry conditions can decline to roughly [redacted]. As a result, there is limited reliance on hydro, and drought-related impacts on overall portfolio outcomes are correspondingly limited. In the 2025-2026 TPP Portfolio, hydro capacity remains constant throughout the planning horizon at 8.52 GW, consisting of 6.66 GW within the CAISO balancing authority area and 1.86 GW imported from the Northwest external region. Hydro's share of installed capacity declines from

approximately 4.7 percent in 2035 to 3.4 percent in 2045. In SCE's Conforming Bundled Portfolio, hydro total capacity holds constant at [redacted].

2. Risks and Planning

a) GHG Emissions

Hydro variability can affect GHG emissions through changes in portfolio dispatch and market purchases. When hydro energy is lower than assumed, the system must rely more on other resources to serve load. If marginal replacement energy is served by emitting resources, portfolio emissions may increase relative to an average-hydrology expectation.

b) Reliability

Drought poses a more limited direct risk to reliability than to annual energy and emissions outcomes because reservoir-based hydro resources generally retain discretion over the timing of water releases, subject to compliance obligations. Even during dry conditions, available water can be managed to support periods of higher system need. However, during sustained drought, operational flexibility can narrow, particularly late in the dry season before precipitation and runoff replenish storage for the following water year.

From a reliability planning perspective, the Commission's methodology for calculating RA capacity for dispatchable hydroelectric resources incorporates historical availability and operational constraints. This methodology provides a conservative estimate of hydro capacity and can be updated as hydrologic conditions evolve.

In addition, SCE's overall resource portfolio is designed to maintain reliability across a range of operating conditions. Hydro provides operational value, but SCE's Conforming Bundled Portfolio is not structured such that system reliability depends on hydro performance.

c) Expected Costs

Hydro variability can affect expected costs through: (1) changes in energy available to serve load, and (2) changes in market revenues associated with hydro production. Because many hydro-related costs are predominantly fixed while energy output varies with hydrology, drought conditions can shift net market exposure on a year-to-year basis.

d) Hedging and Contingency Planning

SCE manages variability in hydroelectric generation primarily through operational flexibility, conservative RA treatment, and diversified portfolio planning. Operationally, SCE schedules and dispatches available hydro resources, particularly within the Big Creek system, to meet system needs subject to hydrologic, environmental, and regulatory constraints, with available water used strategically to support higher-value periods such as peak demand hours, while run-of-river resources vary directly with streamflow.

From a reliability and procurement perspective, SCE applies Commission-approved RA counting methodologies that assign hydro resources a reduced NQC based on historical dry-year performance, ensuring that planning assumptions reflect potential drought conditions and are updated as conditions change. In procurement and portfolio operations, SCE does not rely on hydro to meet marginal needs; instead, it maintains reliability through a diversified resource mix, with hydro variability managed through increased dispatch of other generation or market purchases when needed.

I. Long-Duration Storage Planning

SCE defined long-duration storage ("LDS") for purposes of this IRP as storage resources capable of discharging at maximum capacity for at least eight hours, including 8-hour, 12-hour, and 24-hour storage technologies represented in the modeling. SCE included these resources as candidate technologies in its CE modeling and in the development of its CAISO system and bundled portfolios to evaluate their role in meeting near-, mid-, and long-term reliability and

clean energy needs. SCE determined the amount of LDS included in its bundled portfolio through CE modeling that co-optimizes resource selection subject to cost, GHG targets, reliability requirements, and resource availability constraints. In modeling, LDS competes directly with other clean firm and flexible resources *(e.g.*, solar paired with shorter-duration storage, geothermal, and imports) and is selected when it provides a cost-effective contribution to meeting reliability requirements.

SCE's Conforming Bundled Portfolio includes 7,481 GW of 8-hour storage by 2045, which includes the 8-hour storage required to satisfy half of the LLT D.26-02-057 procurement requirement. As described in Section III.A.1, SCE's analysis consistently selects 8-hour storage over two 4-hour storage resources based on the assumed costs. Multiple shorter-duration batteries can also generally satisfy the pre-2040 identified need for longer-duration clean energy dispatch (*i.e.,* before deeper levels of decarbonization). As such, LSEs may continue to rely primarily on 4-hour storage resources if 8-hour storage is more expensive or less available than assumed in the Commission's assumptions.

SCE's Conforming Bundled Portfolio also includes its allocated share of 12-hour and 24-hour storage[112] that DWR is authorized to centrally procure pursuant to AB 1373. As SCE explained in Sections II.B.3 and III.A.2, SCE's system and initial bundled modeling analysis assumed DWR procured half of the 12-hour storage authorized in D.24-08-064. However, due to differences between SCE's SOD-based and the Commission's ELCC-based reliability approaches, SCE's optimally identified bundled portfolio did not meet the Commission's ELCC-based RDT requirement. Rather than moving forward or adding resources to satisfy the RDT planning requirement, SCE assumed its remaining share of the AB 1373 12-hour and 24-hour storage resources so the incremental resources could be transparently identified. No storage with a longer duration than eight hours was optimally selected in either its system or bundled

[112] The Commission's current I&As no longer include a stand-alone "multi-day storage" category and instead represent LDS using 12-hour, 24-hour, and 100-hour storage resources. Accordingly, SCE uses 24-hour storage as the representative LDS resource associated with the multi-day storage procurement authorized under D.24-08-064.

modeling, only the 12-hour and 24-hour storage assumed to be procured pursuant to AB 1373 and "forced-in." SCE's modeling results indicate that, at currently assumed costs, clean firm resources, such as geothermal, are a more cost-effective solution for maintaining reliability and reducing GHG emissions as 2045 approaches than 12-hour and 24-hour storage.

The inclusion of LDS in SCE's portfolio mix provides several benefits, including improved system reliability and enhanced integration of variable renewable resources, particularly during shoulder and overnight hours. At the same time, LDS introduces several risks and uncertainties, including higher relative cost compared to shorter-duration storage and solar-plus-storage combinations and potential utilization risk, depending on actual system conditions and market design evolution. These factors contribute to a measured level of LDS deployment in SCE's Conforming Bundled Portfolio rather than large-scale early adoption.

SCE's approach to LDS planning has evolved since the 2022 IRP in several important respects: introduction of new procurement requirements and authorizations, including D.26-02-057's requirement to procure additional LDS or clean firm resources and D.24-08-064's authorization for DWR to centrally procure 12-hour and multi-day storage; updated load forecasts and system conditions, which affect the timing and magnitude of capacity needs; and continued cost differentials, with solar-plus-storage remaining highly cost-competitive, and limiting the scale of LDS selection absent policy or reliability drivers. Consistent with these factors, SCE's 2026 Conforming Bundled Portfolio reflects a greater but still targeted role for LDS compared to 2022, with deployment increasing in later years as system needs evolve.

As further explained in Section IV.A, SCE is already procuring pursuant to its D.24-02-047 procurement authorization and to meet its D.26-02-057 procurement requirements and requests authority to begin procuring up to the incremental resource additions identified in SCE's Conforming Bundled Portfolio. To achieve the least-cost, best-fit portfolio for its customers, SCE procures on a technology-neutral basis and does not support resource-specific carve-outs. SCE intends to solicit resources that can provide the attributes provided by the 8-hour storage identified in SCE's Conforming Bundled Portfolio, although SCE assumes that the 12-hour and

multi-day storage will be centrally procured by DWR. SCE's procurement decisions will be made based on the market response to achieve the best procurement solution for our customers.

J. Clean Firm Power Planning

Clean firm resources remain an important component of California's long-term reliability and decarbonization strategy because they can contribute capacity and energy across all hours of the day while reducing reliance on GHG emitting resources. SCE developed its portfolios by selecting the most cost-effective combination of clean firm, clean non-firm, variable, and baseload resources to satisfy reliability, energy, and GHG reduction requirements. Unlike weather-dependent resources, clean firm resources can continue to support reliability during extended weather events and other periods when solar and wind generation may be limited, making them an important source of portfolio diversity and system resilience.

In the prior 2022 IRP, SCE's 25 MMT Bundled Portfolio included 379 MW of geothermal capacity by 2035. In the current IRP, SCE's Conforming Bundled Portfolio includes 351 MW of new geothermal capacity beginning in 2032, increasing cumulatively to 497 MW by 2035 and 1,099 MW by 2045. While geothermal and other clean firm resources provide significant reliability and decarbonization benefits, their selection remains limited because of their relatively high costs and, importantly, the challenges associated with large-scale deployment within the planning horizon.

A significant constraint is that geothermal and other clean firm resources are not currently represented in the CAISO interconnection queue in quantities consistent with the levels assumed in many long-term planning portfolios. The interconnection queue remains overwhelmingly concentrated with solar and battery storage resources, with relatively limited clean firm, geothermal, and other dispatchable clean technologies. As a result, portfolios that rely on substantial near- and mid-term deployment of geothermal and other clean firm resources do not reflect what can reasonably be developed and interconnected by 2035. SCE recommends

that the Commission develop a PGP with more queue-informed resource availability assumptions to inform near- and mid-term procurement decisions.

In addition, many geothermal, EGS, and other LLT resources are geographically constrained and depend on transmission infrastructure that does not yet exist and are not currently being planned. Unlike solar and storage resources that often have multiple development opportunities, these resources are typically located in specific areas where significant transmission investments must be planned, approved, permitted, and constructed before large-scale development can occur. Consequently, limited interconnection queue activity for these resources is often a function of transmission availability rather than resource potential.

These realities reinforce the importance of proactive transmission planning. If California expects geothermal and other clean firm resources to play a meaningful role in achieving the state's long-term reliability and GHG reduction goals, the required transmission infrastructure must often be developed before the resources themselves can be procured at scale. Waiting for substantial interconnection queue activity to emerge before planning transmission risks creating a self-reinforcing cycle in which projects do not advance because transmission is unavailable, while transmission is not developed because projects have not yet advanced.

SCE is already procuring pursuant to its D.24-02-047 procurement authorization and to meet its D.26-02-057 procurement requirements and, as explained in Section IV.A, requests authority to begin procuring up to the incremental resource additions identified in SCE's Conforming Bundled Portfolio. To achieve the least-cost, best-fit portfolio for its customers, SCE procures on a technology-neutral basis and does not support resource-specific carve-outs. SCE intends to solicit resources that can provide the attributes provided by clean firm resources identified in SCE's Conforming Bundled Portfolio. However, SCE expects that the limited clean firm resources in the interconnection queue and the lack of transmission infrastructure necessary to interconnect these resources will continue to be barriers to near- and mid-term procurement.

In addition to SCE's other recommendations, SCE suggests that the Commission expand LSEs' ability to submit good faith efforts extension requests on the MTR LLT procurement

requirements to allow for extensions beyond 2031 given the challenges in meeting the firm zero-emitting MTR procurement requirements and the lack of resources qualifying for this category in the interconnection queue. Transmission infrastructure for some of these projects will likely not be available by 2031 and imposing a strict 2031 cut-off may jeopardize the viability of the projects altogether. Allowing LSEs who can demonstrate that they have made good faith efforts to meet the LLT procurement requirements to extend the required online date beyond 2031 would maximize LSEs' ability to meet the LLT procurement requirements and actually bring these needed resources online.

K. Non-CAISO, including Out-of-State, Wind Planning

SCE included out-of-state wind as a candidate resource in both its System Base Case and Conforming Bundled Portfolios. SCE's assumptions on resource cost and potential are consistent with the Commission's assumptions, including assumptions on the cost (2026-2027 TPP cost assumptions), timing, and potential for out-of-state wind. In-state wind and out-of-state wind are selected in the CE modeling first until available build limits are exhausted, reflecting their relative cost-effectiveness and ability to complement a solar- and storage-heavy portfolio. For the system case, all wind limits are exhausted through 2035 and out-of-state wind limits are exhausted through 2045. Approximately 2.5 GW of available in-state wind was not selected due to the selection of 2 GW of geothermal resources for reliability instead.

SCE's Conforming Bundled Portfolio build-out includes out-of-state wind deployment beginning in the early 2030s and increasing through 2045 (6.2 GW), exhausting all available wind resources and demonstrating that out-of-state wind can play a role in meeting long-term clean energy and reliability needs under updated load, reliability, and procurement constraints. SCE determined the quantity of out-of-state wind included in its portfolios through CE modeling that co-optimizes resource selection subject to cost, GHG targets, reliability requirements, and resource availability constraints.

Including out-of-state wind in SCE's portfolio mix provides several potential benefits, including resource diversity and geographic diversity, which can improve production profiles and reduce correlation with in-state renewable output Out-of-state wind may also provide access to high-quality wind regimes, particularly in interior WECC regions, which may offer stronger and more consistent output, and contribution to long-term decarbonization goals by providing incremental zero-emission energy supply. At the same time, out-of-state wind introduces several risks and uncertainties: (1) transmission dependency, including the need for sufficient transfer capability and potential reliance on future transmission expansion; (2) deliverability and import constraints, particularly during peak system conditions when transmission may be congested; and (3) regulatory and market uncertainty associated with imports and evolving RA accreditation frameworks.

Specifically, the out-of-state wind resources included in SCE's Conforming Bundled Portfolio rely on the availability of transmission paths to deliver energy to the CAISO balancing authority area. SCE's modeling framework represents transmission constraints between CAISO and the broader WECC region and limits the ability to utilize out-of-state resources based on assumed transfer capabilities. Consistent with the IRP framework, SCE's Conforming Bundled Portfolio assumes that delivery of out-of-state wind will depend on a combination of existing transmission capacity and potential future transmission upgrades identified through the CAISO TPP. At the portfolio development stage, SCE does not assume specific new transmission projects beyond those already being developed to support out-of-stand wind but relies on the Commission and CAISO planning process to evaluate and identify any required upgrades to support resource deliverability.[113]

[113] The transmission assessment presented in Section III.M evaluates the portfolio using existing transmission assumptions and does not identify or estimate the specific transmission facilities, network upgrades, or costs that may be required to interconnect or deliver the out-of-state wind resources included in this portfolio. Additional transmission planning studies would be required to evaluate such transmission needs.

SCE's treatment of out-of-state wind in the 2026 IRP is largely consistent with SCE's treatment of this resource in the 2022 IRP. In both IRP cycles, out-of-state wind is included as a candidate resource with assumptions aligned with Commission inputs and is generally selected up to TPP limits due to wind resources' value relative to other resources including a mix of cost, clean energy potential, and reliability potential. The limits from the TPP are meant to capture realistic limitations on transmission and resource availability.

L. Offshore Wind Planning

In the 2022 IRP, SCE's 25 MMT CAISO System-Wide Portfolio build-out included 1,947 MW of new offshore wind in 2030 increasing to a cumulative 7,348 MW by 2035. SCE's 25 MMT Bundled Portfolio build-out also included 501 MW of incremental offshore wind in 2030 increasing to a cumulative 1,798 MW in 2035. SCE's assumptions on offshore wind resource cost and potential were consistent with the Commission's assumptions at that time. In the previous IRP, SCE's model identified offshore wind as more economic and optimal compared to other resources such as solar paired with storage due to the Commission's cost and performance assumptions and SCE's use of an SOD-based reliability framework. Specifically, offshore wind was selected economically as soon as it was assumed to be available due to its high energy contribution during the evening and late-night peak hours – hours that are not directly considered under a single-point PRM reliability construct – as well as its ability to reduce GHG emissions.[114]

SCE evaluated offshore wind as a potential resource in developing its 2026 IRP portfolios; however, no offshore wind capacity was selected in either its System Base Case Portfolio or Conforming Bundled Portfolio. This outcome reflects the resource's relative cost-effectiveness and system contribution compared to alternative technologies under the 2026 assumptions.

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[114] For the 2022 IRP, SCE ran a "no offshore wind" sensitivity on its 25 MMT CAISO System-Wide Portfolio that assumed offshore wind was not available in the 2022-2035 planning horizon. In that sensitivity, SCE's model replaced nearly all of the offshore wind with out-of-state wind.

In both the SCE-selected portfolios and the Commission's Reference Portfolio, offshore wind was not selected. The modeling results indicate that system needs for reliability and GHG-free energy are more cost-effectively met through a combination of utility-scale solar, onshore wind, lithium-ion battery storage, and geothermal. In particular, solar and storage comprise approximately 70 percent of selected builds in the Commission's least-cost portfolio, with storage – especially longer-duration configurations – providing significant reliability value. Consistent with these results, SCE's portfolios replace the offshore wind resources identified or assumed in prior Commission IRP and TPP analyses with increased deployments of solar and 8-hour lithium-ion battery storage. These resources provide comparable or superior contributions to both energy and reliability needs at lower modeled system costs, particularly given updated cost assumptions and improved storage performance inputs. Notably, the Commission's Reference Portfolio similarly results in zero offshore wind, reinforcing the conclusion that offshore wind is not selected under cost-optimized conditions in this IRP cycle.

In summary, while offshore wind remains a potentially important long-term resource for California, it is not selected in SCE's 2026 IRP portfolios under least-cost optimization. Instead, SCE's portfolios rely on a combination of solar, storage (including 8-hour lithium-ion batteries), onshore wind, and other firm resources to meet reliability and GHG reduction requirements more cost-effectively. This approach is consistent with Commission modeling results and reflects current market conditions, technology maturity, and system needs.

M. Transmission Planning

Any known transmission upgrades for SCE's contracted resources, including expected online dates, are included in the RDT included as Appendix B. For SCE's Conforming Bundled Portfolio in 2035, incremental resources within SCE transmission zones were strategically placed to avoid exceeding known transmission capability limits and short circuit duty constraints when possible and to minimize transmission upgrades. SCE utilized the full capacity deliverability status ("FCDS") capability estimates from CAISO's latest transmission capability white

paper,[115] the most recent CAISO Board-approved Transmission Plan, which is 2025-2026 at the time of writing this document,[116] the most recent Final Busbar Mapping Results for the Proposed Base Case (26-27 TPP Base Case),[117] and the CAISO interconnection queue,[118] as guides to locate new resources within transmission zones. SCE evaluated the feasibility of siting these new resource amounts and their impact to the transmission system by modifying and utilizing power flow and Short Circuit Duty base cases that were originally developed for the 2025-2026 TPP.

This limited analysis did not consider Category P1-P7[119] contingency outages since Remedial Action Schemes ("RAS") would be used to address any thermal overloads or stability issues during single or double facility outage conditions, consistent with the generation interconnection process. This assumes that such RAS can be implemented simply and manageably, which was additionally not examined within the scope of this analysis. Furthermore, a significant number of resources were sited on 500 kV buses in order to avoid triggering bulk level transformer banks, resources were placed in a manner not to exceed CAISO single and double facility outage generation tripping limitations, and new energy storage was assumed to offset the power flow impacts of additional generation resources.[120] Utilizing the sources mentioned above, resource capacity was placed away from known transmission

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115 *See* CAISO, Transmission Capability Estimates for use in the CPUC's Resource Planning Process, August 28, 2024, available at: https://www.caiso.com/documents/transmission-capability-estimates-white-paper-2024.pdf.

116 *See* CAISO, 2025-2026 Transmission Plan, May 19, 2026, available at: https://stakeholdercenter.caiso.com/RecurringStakeholderProcesses/2025-2026-Transmission-planning-process.

117 Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan/2024-2026-irp-cycle-events-and-materials/assumptions-for-the-2026-2027-tpp/compact-dashboard-for-the-pd-26-27-tpp-base-case.xlsx.

118 Resource Interconnection Management System, queue viewing instruction available at: https://rimspub.caiso.com/rimsui/logon.do.

119 *See* North American Electric Reliability Corporation, Reliability Standard TPL-001-5.1, available at: https://www.nerc.com/globalassets/standards/reliability-standards/tpl/tpl-001-5.1.pdf.

120 CAISO Planning Standards limit RAS tripping to 1,150 MW for single contingencies and 1,400 MW for double contingencies. *See* CAISO, California ISO Planning Standards, effective February 2, 2023, available at: https://www.caiso.com/documents/iso-planning-standards-effective-feb22023.pdf.

constraint areas as much as possible and allocated down to the busbar level. Table III-26 shows the placement of capacity additions in each SCE transmission zone for SCE's Conforming Bundled Portfolio in 2035.

Table III-26
Busbar Placement of Conforming Bundled Portfolio in 2035

SCE Transmission Zone	Substation Bus	Resource Type	MW	Additional Transmission Needs (Not TPP-approved)[121]	Transmission Dependencies (TPP-approved)
SCE - East of Pisgah	Eldorado 500 kV	LDS	231	Lugo 500 kV SCD Mitigation	Trout Canyon - Lugo 500 kV Line Eldorado 230 kV Short Circuit Duty Mitigation Project Eldorado 500 kV SCD Mitigation
SCE - East of Pisgah	Eldorado 500 kV	Solar	1093		
SCE - East of Pisgah	Mohave 500 kV	LDS	400		
SCE - East of Pisgah	Mohave 500 kV	Solar	2470		
SCE - East of Pisgah	Mohave 500 kV	Wind	333		
SCE - East of Pisgah	Eldorado 500 kV	OOS Wind	718		TransWest Express Project
NVE	Harry Allen 500 kV	OOS Wind	262		SWIP-North Transmission Line
SCE - Eastern	Colorado River 500 kV	Solar	1300	Devers – Red Bluff No.3 500 kV Line Devers – Rancho Vista 500 kV Line	Devers 230 kV SCD Upgrade
SCE - Eastern	Red Bluff 500 kV	Geothermal	427		
SCE - Eastern	Red Bluff 500 kV	Solar	1425		
SCE - Eastern	Mirage 230 kV	Geothermal	70		
SRP	Palo Verde 500 kV	OOS Wind	698		Sunzia Project
SCE - Metro	Hinson 230 kV	LDS	150	None	Walnut 230 kV SCD Upgrade
SCE - Metro	Walnut 230 kV	LDS	150		
SCE - Northern	Whirlwind 230 kV	LDS	300	Whirlwind 230 kV Split	None
SCE - Northern	Whirlwind 230 kV	Solar	1441		
SCE - Northern	Whirlwind 500 kV	Solar	1032		
PGE - Fresno	Gregg 230 kV	Wind	170	None	None
PGE - Fresno	Los Banos 230 kV	Wind	170		
PGE - Fresno	Wilson 230 kV	Wind	190		
PGE - NGBA	Bridgeville 115 kV	Wind	175		
SDGE	Hassayampa 500 kV	LDS	856	None	Southern Area Reinforcement Projects
SDGE	Sycamore Canyon 230 kV	LDS	500		

[121] Future TPP studies may identify the need for these upgrades to address reliability, economic, or policy-driven transmission needs.

SDGE	ECO 230 kV	Wind	350		
SDGE	Imperial Valley 500 kV	Wind	50		
SDGE	Ocotillo Express 500 kV	Wind	53		
		Total:	15014		

The expected additional transmission network upgrades triggered by SCE's Conforming Bundled Portfolio in 2035 include the following:

- Lugo 500 kV Collector Station SCD mitigation (approximate cost estimate $178 million)
- Whirlwind 230 kV Split SCD mitigation (approximate cost estimate $104 million)
- Devers – Red Bluff No. 3 500 kV Transmission Line (approximate cost estimate $1.5-2.5 billion)
- Devers – Rancho Vista 500 kV Transmission Line (approximate cost estimate $1.1 billion)

The need for these upgrades has been identified in previous reliability and/or generator interconnection studies; however, none of these upgrade projects were approved in the latest TPP. RAS within SCE's Eastern area have become full since the previous IRP filing, resulting in "Additional Transmission Needs" identified in Table III-26. The preliminary high-level cost estimates are included for informational purposes and should only be used to establish the rough order of magnitude of the Additional Transmission Needs. The analysis demonstrates that these capacity additions in SCE's planning area can be integrated with the Additional Transmission Needs and "Transmission Dependencies" identified in Table III-26 and existing RAS.

Transmission Dependencies are defined as projects required to achieve SCE's Conforming Bundled Portfolio in 2035 that already have an approved TPP project in place. Additional Transmission Needs are defined as new projects required to achieve SCE's Conforming Bundled Portfolio in 2035 that do not have an approved TPP project in place. These upgrades would be required by or before the year 2035, depending on how actual generation development occurred. The upgrade costs do not include any impacts to existing

RAS nor was RAS feasibility within the scope of this analysis. This conclusion is dependent upon the precise placement and amount of resources as demonstrated above. Any deviation from what is shown would require an additional transmission system analysis and may necessitate additional transmission upgrades to mitigate local area or export transmission grid reliability issues.

Furthermore, since SCE's Conforming Bundled Portfolio reflects SCE's bundled load share only, a subset of the overall SCE TAC area load, transmission upgrades may still be required and identified through the ongoing CAISO TPP to collectively support the resource needs of all LSEs. Potential Maximum Import Capability ("MIC") expansion requirements and any associated transmission upgrades have not been identified at this time. Determination of the need for MIC expansion and the identification of any required transmission reinforcements are performed periodically by CAISO through its TPP based on system studies and applicable planning criteria, and this information is made publicly available. Therefore, any potential MIC expansion needs would require further CAISO assessment through its annual TPP.

More broadly, this analysis demonstrates the importance of proactive transmission planning to support California's long-term reliability and decarbonization objectives. Although SCE's Conforming Bundled Portfolio was intentionally designed to minimize transmission upgrades by locating resources in areas with existing or expected transmission capability, substantial new transmission infrastructure is still required to support the portfolio. The need for additional transmission investment is likely to be even greater for the statewide resource portfolios contemplated in the IRP process, particularly as California seeks to develop larger quantities of geothermal, EGS, other LLT resources, and out-of-state wind through 2045.

Many of these resources are geographically constrained and depend on transmission infrastructure that must be planned, permitted, and constructed years before significant resource deployment can occur. As discussed in Section I.D, the absence of substantial interconnection queue activity for these resources should not be interpreted as a lack of resource potential. Instead, it often reflects the lack of transmission infrastructure needed to enable development.

Waiting for projects to advance before planning transmission risks creating a self-reinforcing cycle in which resource development is delayed because transmission is unavailable, while transmission development is delayed because resources have not yet advanced.

Accordingly, California's transmission planning process must remain forward-looking and identify the infrastructure needed to support future resource development, not simply reflect existing grid conditions and interconnection activity. Just as proactive transmission investments such as the Tehachapi Renewable Transmission Project enabled large-scale renewable development, timely transmission expansion will be critical to unlocking the next generation of clean firm and geographically constrained resources needed to achieve California's GHG reduction goals. Accelerating development of the necessary transmission infrastructure will improve the feasibility of future planning portfolios, support resource diversity, and increase the likelihood that the state's long-term reliability and decarbonization objectives can be successfully achieved.

IV.

ACTION PLAN

SCE's action plan identifies the activities necessary to implement its Conforming Bundled Portfolio, including planned procurement activities, key implementation barriers, DAC considerations, and requested Commission actions. While the Conforming Bundled Portfolio represents the least-cost portfolio available to SCE to satisfy the Commission's adopted reliability requirements and GHG emissions benchmarks using the prescribed assumptions, significant questions remain regarding whether portfolios built on those assumptions can be procured, interconnected, and developed at the scale and pace required. As such, SCE's Conforming Bundled Portfolio presents significant near-term and mid-term feasibility risks and affordability concerns.

As discussed throughout this IRP, the Commission's current planning assumptions require unprecedented levels of solar, wind, storage, and other clean resource development

within a relatively short period. Achieving those outcomes will depend on the availability of resources that are not currently represented in meaningful quantities in the CAISO interconnection queue, successful development of major transmission infrastructure that has not yet been approved or constructed, continued access to financing and supply chains, and timely permitting and interconnection of new projects. Shifting estimates of future load growth, including electrification and data center demand, further increase the risk that procurement requirements will diverge from what can reasonably be delivered under actual market conditions at an affordable cost to customers. These barriers and risks all apply to SCE's Conforming Bundled Portfolio.

These challenges highlight the importance of distinguishing between long-term planning objectives and near- and mid-term procurement requirements. The PSP remains a valuable tool for identifying the resources, transmission infrastructure, and system transformations that may ultimately be needed to achieve California's long-term decarbonization goals. However, near- and mid-term procurement obligations should be guided by a portfolio that reflects current market realities, resource availability, transmission constraints, and customer affordability considerations. For this reason, the Commission should establish a PGP to guide future procurement through 2035, including the RCPPP, while retaining the PSP for long-term transmission planning and development of the LLT resources needed in 2040 and beyond.

Accordingly, this action plan should be understood in the context of both SCE's obligation to comply with the Commission's adopted planning assumptions and SCE's broader recommendation that future procurement requirements be grounded in a more affordable, feasible, and implementable path for achieving California's reliability, clean energy, and GHG reduction goals. SCE discusses the actions needed to implement its Conforming Bundled Portfolio and requests Commission authority to flexibly procure up to the resource needs identified in that Conforming Bundled Portfolio. But SCE strongly urges the Commission to develop a PGP to guide near- and mid-term procurement and compliance obligations.

Importantly, even the PGP reflects a highly ambitious resource development trajectory and should not be viewed as an easy-to-achieve alternative. The PGP still requires substantial additions of solar, storage, wind, and other clean energy resources at a pace that exceeds historical development trends. Achieving even the PGP will require sustained investment, timely transmission development, and coordinated execution across developers, transmission providers, regulators, and other market participants. Therefore, any future RCPPP or other procurement requirements should incorporate robust flexible compliance mechanisms that recognize the implementation risks associated with developing clean energy resources at this scale, including permitting, interconnection, transmission, financing, supply chain, and other factors that remain outside the control of individual LSEs.

A. Proposed Procurement Activities and Potential Barriers

This section discusses SCE's proposed procurement activities and other programs to implement its Conforming Bundled Portfolio. As further discussed below, SCE is currently procuring toward the resource needs authorized under D.24-02-047 and to meet its 2030-2032 procurement requirements in D.26-02-057.[122] SCE also plans to launch an RFO in 2026 for resources to meet its requirement to procure long-duration storage and/or clean firm resources pursuant to D.26-02-057. In addition to these ongoing efforts, SCE requests Commission authority to flexibly procure to meet up to the incremental resource needs identified in SCE's Conforming Bundled Portfolio.

SCE requests Commission authority to procure up to its Conforming Bundled Portfolio under the flexible framework established in D.24-02-047, which preserves SCE's discretion to respond to market conditions to procure those resource needs in a way that is in the best interests

[122] *See* D.24-02-047 at OP 9; D.26-02-057 at OP 1-2, OP 15.

of its customers.[123] Consistent with the Commission's recognition that procurement obligations should not be dictated by prescriptive resource mandates or procurement pathways, SCE seeks authority to meet its share of identified system need through bilateral contracting and competitive solicitations, enabling it to assemble a least-cost, best-fit portfolio tailored to its customers' load characteristics, risk profile, and operational needs.

SCE uses a least-cost, best-fit approach to evaluate and select the resources that will best meet a specified need through competitive solicitations and bilateral negotiations. It is not beneficial or realistic to procure the exact resource mix identified in a long-term resource plan. Therefore, as approved in D.24-02-047,[124] SCE's procurement will ultimately be determined by what offers it receives from developers and the actual resources and proposed pricing may not match up with the assumptions used in IRP analysis, especially when procurement often occurs months or years after an IRP portfolio is developed. Imposing technology carve-outs may only increase costs for customers at a time when there is already upward pressure on rates and bills.

Consistent with D.24-02-047,[125] the Commission should authorize SCE to procure up to the resource needs identified in its Conforming Bundled Portfolio through a flexible procurement construct that preserves discretion over the mix, timing, and contract structures for eligible resources in light of evolving market conditions, technology costs, interconnection realities, and updated reliability assessments. SCE should have the option to hold solicitations based on market conditions, or to conduct bilateral negotiations, but to make a final determination on whether to hold a solicitation and how much of its need to procure in each solicitation based on the market response. SCE should be authorized to submit any resulting contracts to the Commission for cost recovery through Tier 3 advice letters unless the contracts are otherwise

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[123] *See* D.24-02-047 at 43-45 (approving SCE's flexible procurement approach); OP 9 (authorizing the IOUs to "conduct procurement activities as market conditions indicate, including solicitations and bilateral negotiations, to procure the resource needs identified in their 2022 individual integrated resource plans with the portfolios designed to meet the 25 million metric ton greenhouse gas emissions target by 2035.").

[124] *See id.* at 43-45.

[125] *See id.* at 43-45, OP 9.

authorized pursuant to another Commission order in another proceeding, and cost recovery should be through the Portfolio Allocation Balancing Account based on the calendar year of original contract execution unless another cost recovery mechanism is authorized (*e.g.*, D.26-02-057 procurement should continue to follow that decision's cost recovery mechanism).[126]

SCE discusses its planned procurement activities and programs and potential risks and barriers for various resource categories in the sections below.[127]

1. Resources to Meet IRP Mandated Procurement Requirements, Including D.21-06-035, D.23-02-040, and D.26-02-057, and SCE's Conforming Bundled Portfolio Resource Needs

SCE has undertaken extensive and ongoing efforts to solicit and procure new clean energy resources to meet Commission procurement requirements and California's reliability needs and clean energy goals. Through its MTR RFO, SCE has contracted sufficient resources to meet its MTR procurement requirements from D.21-06-035 and D.23-02-040. Additionally, SCE launched its 2024 Clean Energy RFO on October 7, 2024 to solicit clean energy resources to undertake SCE's D.24-02-047 procurement authorization to procure the resource needs identified in SCE's 2022 IRP portfolio, which included significant incremental solar and battery storage additions through 2035. SCE's Clean Energy RFO has already resulted in the execution of 10 contracts for 1,405 MW of solar PV and 688 MW of energy storage.

SCE continues to conduct market outreach, evaluate both existing and newly submitted proposals, and pursue negotiations on a rolling basis to procure additional resources. Following enactment of the OBBB in July 2025, SCE issued an August 1, 2025 market notice seeking RPS-eligible resources, including solar, wind, geothermal, and biomass, along with RPS-

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[126] *See id.* at OP 9; Resolution E-5445 at 14-15, OP 5.

[127] The quantities identified below include the new contracts (either with existing resources or new resources) that will be needed to replace SCE's existing renewable contracts that are set to expire in the IRP planning horizon. The identified resource build-out also includes SCE's share of certain AB 1373 resources and an estimate of the resources that will be procured pursuant to D.26-02-057 but excludes contracted not-yet-online resources (which are included in SCE's baseline and fully satisfies SCE's D.21-06-035 and D.23-02-040 procurement requirements).

eligible resources paired with storage to preserve potential customer benefits associated with evolving federal tax credit treatment. SCE further demonstrated its commitment to ongoing procurement by issuing an additional market notice on February 2, 2026 to continue procuring toward SCE's D.24-02-047 procurement authorization as well as SCE's procurement needs under the proposed decision that resulted in D.26-02-057. Collectively, these efforts have resulted in additional offers, shortlisted competitive projects, advanced negotiations, and additional contracted resources, demonstrating SCE's continuous engagement with the market and proactive pursuit of new clean energy resources as market conditions evolve.

Solar and wind resources are expected to play a central role in achieving California's clean energy goals. However, current market realities indicate that the scale of procurement assumed in the Commission's planning scenarios may significantly exceed near-term resource availability. Solar and wind costs are also expected to face upward pressure as federal tax incentives phase down while demand for these resources continues to outpace available supply. This imbalance between strong procurement demand and limited near- and mid-term development capacity is likely to increase pricing and further challenge affordability if procurement requirements are not calibrated to market conditions. As a result, while SCE remains supportive of continued investment in renewable resources, procurement expectations should be anchored in assessments that reflect what the market can deliver within required timelines.

The current procurement environment presents significant challenges to cost-effective and timely resource development. Recent market conditions, including the scheduled expiration of key federal tax credits, permitting challenges, and interconnection delays, have increased both the cost and risk of new resource procurement. These factors are already manifesting in higher bid prices, reduced or non-existent offer volumes for certain technologies, and extended development timelines, particularly for projects requiring significant new transmission infrastructure. In this environment, strict adherence to aggressive procurement targets without

accounting for evolving market conditions risks driving uneconomic outcomes for customers and increasing the likelihood of procurement shortfalls or delays.

Procurement challenges are further exacerbated by the absence of finalized rules and implementation details for the RCPPP. Although the Commission has articulated high-level objectives for an integrated procurement framework, key elements such as the overall framework and procurement obligations, resource counting, allocation methodologies, compliance mechanisms, and treatment of portfolio deviations remain undefined. This uncertainty creates difficulties as LSEs are unable to align procurement strategies to clear regulatory requirements. Procurement in advance of defined procurement rules risks inefficient or duplicative contracting, misalignment between planning and execution, and potential stranded costs. Establishing a clear, durable, feasible, and affordable RCPPP framework is therefore critical to enabling coordinated, cost-effective procurement that supports both reliability needs and decarbonization objectives.

SCE will continue to make best efforts to meet its existing procurement obligations while remaining prepared to address any incremental requirements that may emerge from the 2026 IRP cycle. In doing so, SCE will carefully balance reliability, cost-effectiveness, and feasibility considerations in an increasingly constrained and uncertain market environment, including evolving resource availability and development risks. Consistent with the challenges and uncertainties outlined above, SCE urges the Commission to develop a PGP consistent with SCE's recommendations to inform near- and mid-term procurement, to authorize SCE to flexibly procure up to the resource needs in its Conforming Bundled Portfolio, and to prioritize the timely development and finalization of a workable and affordable RCPPP that continues to provide LSEs with reasonable flexible compliance rules to address delays outside their control.

a) Existing D.21-06-035, D.23-02-040, and D.26-02-057 Requirements

SCE has contracted and received Commission approval for sufficient resources to meet its MTR procurement requirements from D.21-06-035 and D.23-02-040. A subset of these MTR

resources is still under development and expected to come online by, or within three years of their tranche online date under the alternative compliance mechanism established under D.25-09-007.

SCE is also procuring to meet its D.26-02-057 procurement requirements through its Clean Energy RFO. SCE requested Commission authority to count three contracts in excess of its MTR procurement requirements that were previously approved by the Commission toward SCE's D.26-02-057 procurement requirements.[128] SCE may request Commission authority to count more of its approved contracts in excess of MTR requirements towards the D.26-02-057 procurement requirements. In 2026, SCE is planning to launch a separate RFO to meet its 522 MW NQC LLT long-duration energy storage and/or clean firm procurement requirement pursuant to D.26-02-057. SCE's plans may be refined once Commission Staff release their marginal ELCC studies containing values that will determine how resources will count toward the D.26-02-057 procurement order.

However, SCE notes that the firm zero-emitting/clean firm category presents unique implementation challenges. Firm zero-emitting resources, including geothermal and EGS, are not currently represented in the CAISO interconnection queue in quantities sufficient to support the level of deployment contemplated in long-term planning portfolios. In addition, many of these resources are geographically constrained and depend on transmission infrastructure that may require years to plan, permit, and construct before projects can successfully interconnect and achieve commercial operation.

These challenges underscore the importance of providing additional flexibility for firm zero-emitting procurement requirements. In particular, given the limited availability of qualifying projects and the likelihood that transmission infrastructure needed to support some of these resources will not be available by the applicable compliance deadlines, SCE recommends that the Commission expand LSEs' ability to obtain good faith effort extensions for MTR LLT

[128] *See* SCE Advice 5814-E.

procurement requirements beyond 2031. A strict compliance deadline that does not account for transmission development schedules, interconnection timelines, permitting requirements, or other factors outside the control of LSEs may ultimately undermine development of the very resources the program seeks to encourage. The Commission may also consider additional flexibility for the D.26-02-057 procurement, although that requirement can be satisfied by either firm zero-emitting or long-duration storage resources.

Allowing LSEs that can demonstrate good faith efforts to procure and develop firm zero-emitting and other LLT resources additional time to achieve commercial operation would maximize the likelihood that these projects are ultimately constructed and placed into service. Such flexibility would better align compliance obligations with the realities of developing geographically constrained clean firm resources while supporting California's long-term reliability and decarbonization objectives.

b) Solar Resources

Solar resources represent the vast majority of SCE's Conforming Bundled Portfolio. Solar is needed in significant quantities beginning in 2029, with approximately 9 GW needed by 2035. The pace of solar additions increases between 2036 and 2040, with approximately 18 GW (cumulative) needed by 2040, before eventually plateauing between 2041 and 2045. As discussed above, SCE has pursued, and is continuing to pursue, procurement of solar resources.

SCE's Conforming Bundled Portfolio does not identify a need for storage until 2030, when it is needed to comply with D.26-02-057 procurement requirements and at a much lower level than the identified solar. Stated differently, SCE identifies a near-term need for stand-alone solar, not necessarily paired with storage, to complement the stand-alone storage it has already procured to meet its existing procurement requirements. However, there are very few stand-alone solar resources available. This is demonstrated in the CAISO interconnection queue information where the vast majority of solar seeking interconnection is paired with storage, and

what little stand-alone solar is being developed rarely has deliverability. This creates affordability pressures since procuring the needed solar may also require procuring significant amounts of storage that is not needed in that same timeframe. Additional procurement mandates for 8-hour or more duration storage resources in D.26-02-057 further exacerbate this inefficiency issue for reasons explained in the following section below.

c) Lithium-ion Battery Storage Resources

SCE's Conforming Bundled Portfolio identifies the ongoing need for new storage procurement beginning in 2030, with approximately 2.2 GW of 8-hour storage needed by 2035 (including an estimated 1.1 GW[129] that is required to be from 8-hour or longer storage resources, pursuant to D.26-02-057),[130] 4.9 GW of 8-hour storage (cumulative) needed by 2040, and 7.5 GW of 8-hour storage (cumulative) needed by 2045.

SCE's analysis shows that needs for storage are driven by multi-hour system conditions, such as extended evening ramps and overnight energy sufficiency, not by a requirement that all incremental storage resources be individually long-duration. These needs can be met through a portfolio of resources, including combinations of shorter-duration storage, solar paired with storage, and other flexible resources operating together to provide sustained coverage across the day.

Flexible procurement requirements are therefore essential. Shorter-duration storage resources can provide the same operational capabilities needed to support reliability across multi-hour net load events, while also enabling procurement of paired solar resources that are already in development. These resources may provide greater near-term value and lower execution risk

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[129] As described in Section II.B.3.c, SCE assumes half of the system-wide D.26-02-057 procurement requirement for long-duration storage or clean firm resources is met with geothermal and half is met with 8-hour lithium-ion battery storage. SCE applies the same assumption for its bundled modeling by assuming half of its 522 MW NQC requirement is met with geothermal and half is met with 8-hour lithium-ion battery storage. The nameplate quantities are estimated using the marginal ELCC values provided in the IRP RDT.

[130] The 2.2 GW needed by 2035 includes what SCE expects to procure to satisfy D.26-02-057 procurement requirements.

than prescriptive long-duration storage mandates because they reflect resources that are currently available in the market and can support both renewable integration and reliability needs.

This flexibility is also important from an RA and charging sufficiency perspective. Many 4-hour storage resources co-located with solar are expected to have sufficient paired generation to support charging needs, particularly in common one-to-one configurations. By contrast, an 8-hour storage configuration paired with the same level of solar generation may require additional stand-alone energy resources to support charging sufficiency if they are needed to fully charge and discharge on a daily basis. Prescriptive long-duration requirements could therefore create incremental procurement complexity and cost without necessarily improving reliability outcomes. Prescriptive requirements will likely also result in storage procurement that is much higher than needed, since the shorter duration storage paired with solar may need to be procured regardless to satisfy solar targets.

d) In- and Out-of-State Wind

Wind resources play a critical role in the portfolio because of their relatively low assumed cost and ability to complement a solar-heavy portfolio. Consistent with SCE's System Base Case Portfolio results, SCE's Conforming Bundled Portfolio selects in- and out-of-state wind up to its load-share of the build limits specified in the Commission's assumptions through 2035 and nearly up to its load-share of the total resource potential by 2045.[131] SCE has been soliciting wind technologies on an ongoing basis, including in the solicitations described above to meet identified needs from D.24-02-047 and D.26-02-057.

While the modeling assumptions around wind and its cost leads to its inclusion in SCE's Conforming Bundled Portfolio, those assumptions have not necessarily manifested. Actual wind availability and relative costs have made its actual procurement consistently lower than what IRP

[131] The Commission's I&As limit in- and out-of-state wind by 2035 based on assessment of the interconnection queue (in-state), project lead time, commercial development, and estimates of existing and hypothetical new transmission development (out-of-state). After 2035, the in- and out-of-state wind is allowed up to its resource potential.

modeling has shown. This lack of availability is highlighted in the CAISO interconnection queue information, where wind makes up an extremely small portion of resources seeking interconnection. Additionally, lack of defined rules regarding future GHG reduction compliance makes it difficult to assess whether the higher price of wind, relative to solar, still allows wind to be effective in meeting GHG targets.

SCE continues to monitor the progress of out-of-state wind development and transmission into California. SCE's assumptions on resource cost and potential are consistent with the Commission's assumptions, including assumptions on the cost, timing, and potential for out-of-state wind. Out-of-state wind procurement depends on timely transmission expansion to deliver resources to load. Given the uncertainty in development timelines, a flexible procurement framework is necessary to adapt to evolving transmission availability.

e) Geothermal Resources

SCE's Conforming Bundled Portfolio includes 497 MW of geothermal nameplate capacity by 2035,[132] which includes 204 MW that is assumed to be procured to satisfy the D.26-02-057 procurement requirement for clean firm or long-duration storage resources[133] and 293 MW that is assumed to be centrally procured by DWR pursuant to AB 1373 and D.24-08-064 and allocated to SCE.[134] SCE has been soliciting firm zero-emitting technologies on an ongoing basis, including in the solicitations described above to meet identified needs from D.24-02-047 and D.26-02-057. Geothermal resources remain an important component of California's long-term clean energy transition, providing firm zero-carbon generation that can support reliability across all hours and complement variable renewable resources. SCE's modeling continues to

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[132] In addition to the 497 MW identified in SCE's Conforming Bundled Portfolio, SCE has already procured geothermal, which is still currently in-development, to satisfy its D.21-06-035 LLT MTR procurement requirement. Contracted and in-development resources are considered as "planned" and not included in the incremental build-outs identified in SCE's portfolio build-out figures.

[133] SCE's system and bundled modeling both assume half of the D.26-02-057 LLT requirement is met with 8-hour storage and half is met with geothermal. *See* Section II.B.3.c.

[134] SCE's system and bundled modeling both assume DWR procures up to its authorized limit for geothermal, or 1,000 MW. *See* Section II.B.3.b.

include geothermal as a candidate clean firm resource; however, its deployment is limited due to significant feasibility, cost, and market availability constraints.

SCE remains committed to the long-term development of geothermal as part of a diverse, reliable, and decarbonized resource mix. However, procurement must reflect both affordability and feasibility considerations. While geothermal has clear reliability and decarbonization benefits, the scale assumed in planning frameworks is not currently aligned with observable market conditions. Transmission availability and development timelines constrain the pace at which geothermal can be deployed, which is why SCE's System PGP assumes no additional geothermal, beyond what has already been contracted, will be available by 2035. Pursuing geothermal at any cost, particularly in an environment of limited supply, risks driving disproportionate cost increases for customers without commensurate benefits. A balanced approach is needed, where geothermal is pursued alongside other clean resources in a least-cost, best-fit framework that allows for substitution and flexibility across technologies as market conditions evolve.

To enable geothermal to play a larger role over time, transmission constraints must be addressed. Transmission availability is a critical constraint on geothermal development, as many high-quality geothermal resource areas are located in regions with limited existing transmission capacity into CAISO. A key first step in addressing the lack of transmission availability is ensuring the geothermal included in TPP portfolios is correctly mapped to regions with demonstrated commercial interest.

More broadly, California's transmission planning process should proactively identify and advance the infrastructure needed to support future geothermal, EGS, and other firm zero-emitting resources rather than relying solely on existing interconnection activity as an indicator of future development. Many of these resources are geographically constrained and require transmission infrastructure that can take a decade or more to plan, permit, and construct. As discussed in Section I.D, transmission must often be developed before these resources can be procured and interconnected at scale.

These challenges are particularly relevant to the Commission's firm zero-emitting procurement requirements. Given the limited number of qualifying projects currently in the interconnection queue, the lengthy development timelines associated with geothermal and other clean firm technologies, and the uncertainty regarding when the necessary transmission infrastructure will become available, compliance deadlines may not always align with the realities of project development. Accordingly, SCE recommends that the Commission provide additional flexibility for MTR LLT procurement requirements by expanding the availability of good faith effort extensions beyond 2031. Allowing LSEs that can demonstrate diligent efforts to procure and develop these resources additional time to achieve commercial operation will maximize the likelihood that needed firm zero-emitting resources are ultimately constructed and placed into service rather than abandoned because of factors outside the control of LSEs. Such flexibility would better support California's long-term reliability and decarbonization objectives while recognizing the practical realities of developing these critical resources.

f) 12- and 24-hour Long-Duration Storage

SCE's Conforming Bundled Portfolio includes 358 MW, each, of 12- and 24-hour duration storage by 2035, which is SCE's load-share of the AB 1373 procurement, assuming DWR successfully centrally procures the maximum authorized by D.24-08-064. SCE recognizes the potential reliability and decarbonization benefits these emerging technologies may provide over the long term and supports efforts to advance their commercial development. However, given the limited commercial deployment of such resources today and the uncertainty surrounding their cost, scalability, and deployment timelines, SCE remains uncertain that DWR will be able to successfully procure the full authorized quantities by the mid-2030s. Accordingly, while SCE includes these resources in its portfolio assumptions consistent with DWR's procurement authorization and to help its bundled portfolio satisfy the Commission's RDT requirements (as described in Section III.A.2), SCE does not support procurement at any

cost and emphasizes that any procurement should remain subject to demonstrated value and reasonable costs to customers.

2. Plans for Resources that Are Currently Non-Candidate in Commission's IRPs Not Described Above

Carbon capture and storage ("CCS") technologies have the potential to play an important role in supporting a reliable and cost-effective clean energy transition by enabling emissions reductions from existing and future firm resources. However, to fully realize their benefits, clear and consistent accounting rules are needed to determine how captured emissions are treated under established GHG targets. Establishing these frameworks would provide greater certainty for developers and LSEs, support investment in emerging technologies, and ensure that CCS can be appropriately recognized as part of a compliance pathway toward California's long-term decarbonization goals. This work is particularly timely given recent state and federal policy developments, including enhancements to the federal Section 45Q tax credit and California's ongoing implementation of SB 905, which are expected to improve the economics of CCS and increase the likelihood that these resources become viable options in future clean energy portfolios.

SCE urges the Commission to provide guidance on how CCS resources will be counted within the RCPPP framework. Additionally, future CE modeling should study CCS and other emerging technologies and identify scenarios in which they become part of the optimal CAISO resource portfolio.

3. Other Renewable and/or Zero Carbon Resources Not Described Above

SCE's Conforming Bundled Portfolio does not include any incremental renewable or zero carbon resources not included in the resource categories above.

4. Other Energy Storage Not Described Above

SCE's Conforming Bundled Portfolio does not include any incremental energy storage not included in the resource categories above.

5. Other Demand Response Not Described Above

On December 6, 2022 and December 20, 2023, the Commission issued D.22-12-009 and D.23-12-005,[135] respectively, approving SCE's demand response ("DR") programs, pilots, and budgets for 2023 through 2027.[136] SCE has the largest and most diverse utility DR portfolio in California, consisting of over 680 MW[137] and 480,000 enrolled customers. SCE has achieved significant strides over the current DR program cycle (2023-2027) and aims to continue its leadership in the DR space.

SCE's DR portfolio reflects a vision of a modernized portfolio of programs and pilots that preserve and build upon legacy programs that have proven successful, while continuing to improve their effectiveness and change with the grid's needs. SCE's DR portfolio provides stable load reduction with approximately 670 MW RA capacity, and meets key objectives, including cost-effectiveness, customer adoption, customer experience simplification, and connecting customers with customer-side technologies for broader-based, more automated DR participation. Key features of this DR portfolio include:

- Core event-based DR programs[138] continuing to provide RA and support grid reliability, while maintaining customer retention and pursuing new customer engagement and enrollment. SCE's portfolio is driving towards an automated,

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[135] On December 18, 2024, the Commission issued D.24-12-029, correcting errors in D.23-12-005, which did not make any material changes to SCE's DR programs or budgets.

[136] *See* Application of Southern California Edison Company for Approval of Demand Response Programs and Budgets for 2023-2027, A.22-05-004, May 2, 2022.

[137] *See* Southern California Edison Company's Program Year 2025 Load Impact Reports Executive Summary Pursuant to Load Impact Protocols, A.22-05-002, April 22, 2026, Table 11 (SCE September 2026 Portfolio SCE 1-in-2 ex-ante total load impacts (MW)).

[138] Core DR programs, include Base Interruptible Program ("BIP"), Agricultural & Pumping Interruptible ("AP-I") Program, Capacity Bidding Program-Elect ("CBP-E"), Summer Discount Plan ("SDP") Program, Smart Energy Program ("SEP"), DR Contracts, and Critical Peak Pricing ("CPP").

technology agnostic, mass market approach that seeks to capture the full potential of customer-side DR participation.

- The Emergency Load Reduction Program ("ELRP") Pilot remains stable in the near-term to support and be available for grid reliability needs.

SCE's DR portfolio continues to evolve and adapt to changes in the electric sector due to changes in customers' usage patterns, new technologies, climate change impacts, clean energy initiatives, and significant expected growth of electricity consumption from electrification of vehicles and buildings. While recognizing the effects of recent climate-driven reliability events, such as those that occurred during the summers of 2020 and 2022, SCE's approach emphasizes the long view, in which DR helps underpin the stability of the electric system beyond emergency situations.

SCE considers multiple factors in developing a portfolio that must address future load requirements and flexibility, as SCE pursues its path to California's 2045 clean energy goals. As emphasized in SCE's Pathway 2045 white paper,[139] SCE projects a 60 percent increase in electricity consumption with a 40 percent increase in peak load by 2045, resulting from the growth of electrification necessary to achieve the state's GHG reduction goals. This incremental load is significant in scale and requires judicious short- and long-term planning to ensure SCE customers and California can enjoy the benefits of reliable, safe, and clean electricity.

Lastly, SCE's DR portfolio focuses on supporting and enabling customers to meet their energy needs. SCE's DR portfolio has demonstrated cost-effectiveness, adherence to Commission directives, and strategic positioning as consequential elements of a portfolio needed to enhance grid reliability and safety, not only in the near term, but also to develop foundational capabilities required for future DR portfolio expansion, including greater participation, reduced attrition, and flexibility.

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[139] SCE's 2045 Pathway analysis white paper and appendices are available at: https://www.edison.com/home/our-perspective/pathway-2045.html.

6. Other Energy Efficiency Not Described Above

In March 2026, SCE filed an application seeking approval of its 2028-2031 Energy Efficiency ("EE") Portfolio Plan and 2032-2035 Business Plan[140] The proposed portfolio reflects a forward-looking, system-focused approach to EE as a core resource for meeting California's load, affordability, and decarbonization objectives. Consistent with recent state policy direction, including Executive Order N-5-24[141] and the state's 2025 audit of EE programs,[142] SCE's proposal emphasizes disciplined portfolio sizing, cost-effectiveness, and measurable system value. The portfolio includes a reduced budget of approximately $997 million for the 2028-2031 period, representing a 40 percent decrease from the prior cycle while still forecasting approximately $874 million in Total System Benefits, equivalent to 135 percent of Commission goals, and achieving an estimated 6.882 MMT of GHG emissions reductions.[143]

SCE's EE portfolio is designed to function as a cost-effective demand-side resource within the broader IRP framework, reducing energy and peak demand, mitigating the need for incremental generation and infrastructure investment, and supporting long-term ratepayer affordability. As SCE's Pathway 2045 white paper provides, "[d]ecarbonization is achieved through powering 100% of retail sales with carbon-free electricity, electrifying transportation and buildings, and using low-carbon fuels for technologies that are not viable for electrification."[144] As a follow-up to this analysis, in September 2021, Edison International, SCE's parent company, released Mind the Gap: Policies for California's Countdown to 2030,

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[140] *See* Application of Southern California Edison Company for Approval of its Energy Efficiency 2028-2031 Portfolio Plan and 2032-2035 Business Plan, A.26-03-010, March 16, 2026.

[141] *See* Executive Order N-5-24, October 30, 2024, available at: https://www.gov.ca.gov/wp-content/uploads/2024/10/energy-EO-10-30-24.pdf.

[142] *See* California State Auditor, The California Public Utilities Commission: Without Improving Its Oversight, the Benefits of Energy Efficiency Programs May Not Be Worth Their Cost to Ratepayers, Report 2023-127, March 18, 2025, available at: https://www.auditor.ca.gov/wp-content/uploads/2025/03/2023-127-Report.pdf.

[143] *See* Direct Testimony of Southern California Edison Company in Support of its Application for Approval of its Energy Efficiency 2028-2031 Portfolio Plan and 2032-2035 Business Plan, A.26-03-010, Exhibit SCE-01, March 16, 2026, at 1.

[144] SCE, Pathway 2025, Update to the Clean Power and Electrification Pathway, November 2019, at 1, available at: https://www.edison.com/clean-energy/pathway-2045.

which identifies the policy changes needed to achieve a 40 percent reduction in GHG emissions by 2030, a milestone necessary to reach economy-wide decarbonization by 2045.[145] Consistent with this framework, customer adoption of EE programs plays a key role by ensuring that increasing electric load from transportation and building electrification is met as efficiently as possible, thereby minimizing the incremental clean energy resources required to serve that demand. The portfolio accordingly prioritizes energy savings during high-value system hours, improved alignment of savings with avoided cost signals, and expanded use of meter-based measurement approaches to better reflect realized system benefits.[146] Additionally, SCE incorporates building electrification and fuel substitution strategies where cost-effective, supporting California's trajectory toward economy-wide decarbonization while managing near-term cost.

The proposed portfolio also reflects operational and market realities affecting EE performance, including increasing program costs, evolving load shapes driven by electrification, and diminishing availability of low-cost efficiency opportunities. In response, SCE advances targeted portfolio design and policy recommendations to improve performance, including enhanced cost-effectiveness discipline, streamlined program delivery, and improved regulatory alignment across program administrators. These efforts are intended to ensure that EE continues to deliver reliable, scalable, and cost-effective system benefits within California's evolving resource mix, supporting both near-term system needs and long-term climate goals.

7. Other Distributed Generation Not Described Above

SCE oversees the following current distributed generation programs for its service area: Self-Generation Incentive Program ("SGIP"), Solar on Multifamily Affordable Homes ("SOMAH"), Single Family Affordable Solar Homes ("SASH"), Disadvantaged Community

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[145] The Mind the Gap white paper is available at: https://www.edison.com/clean-energy/mind-the-gap.

[146] *See* Direct Testimony of Southern California Edison Company in Support of its Application for Approval of its Energy Efficiency 2028-2031 Portfolio Plan and 2032-2035 Business Plan, A.26-03-010, Exhibit SCE-01, March 16, 2026, at 23-25.

SASH ("DAC-SASH"), and Multifamily Affordable Solar Homes ("MASH"). Additional details on SOMAH and SGIP are included below.

The SOMAH program provides financial incentives for installing solar PV energy systems on multifamily affordable housing. The program was created by AB 693 (2015) and D.17-12-022 established the program's budget, incentive structure, and eligibility policies, among other things. SOMAH is available to utility and community choice aggregator customers in the Pacific Gas and Electric Company ("PG&E"), SCE, San Diego Gas & Electric Company ("SDG&E"), Liberty Utilities Company, and PacifiCorp service areas. SOMAH is jointly administered by the Association for Energy Affordability, Center for Sustainable Energy,® and GRID Alternatives. SOMAH is funded through GHG allowance auction proceeds, has a program budget of up to $100 million annually for 10 years, and an overall target to install at least 300 MW of generating capacity by 2030. As reported in the July 1, 2025 to December 31, 2025 SOMAH Semiannual Progress Report, there is a statewide total 66.9 MW of project capacity from applications that are earmarked, pending reservation, reserved, or completed; this includes 22.6 MW of project capacity from applications in SCE's territory that are pending reservation, reserved or completed.[147]

SGIP was originally established in 2001 in D.01-03-073 in response to AB 970 (2000) to provide incentives for customer distributed generation resources to reduce peak energy demand. Since 2001, the Legislature has refined and extended the SGIP several times and those modifications were implemented by various decisions. D.16-06-055, pursuant to SB 861 (2014) and AB 1478 (2014), modified SGIP to be administered on a continuous basis with incentive levels declining based on the capacity reserved in the program, rather than making additional funds available every year; and divided the incentive budgets into two broad categories of energy storage and generation with most incentives allocated towards storage. D.20-01-021, pursuant to

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[147] *See* SOMAH Semiannual Progress Report, July 1, 2025-December 31, 2025, at 13, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/somah/somah-semi-annual-report-pa/pa_2026_jan_somah-semiannual-progress-report.pdf.

SB 700 (2018), extended the program from January 1, 2021 to January 1, 2026, and authorized ratepayer collections of $166 million annually through 2024 to fund SGIP. SCE was authorized to collect $56 million annually through 2024 and administers SGIP for its service area. D.25-12-003, pursuant to AB 209 (2022), allocated $280 million from the Greenhouse Gas Reduction Fund for the SGIP Residential Solar and Storage Equity budget exclusively for eligible low-income residential customers.

D.25-12-003 additionally ordered the return of all unallocated ratepayer funds and closing out of all activities related to the ratepayer-funded portion for SGIP. AB 209 (2023-2024) allocated $87.3 million by taxpayers, and applications for the AB 209 funds may be submitted through June 30, 2028. Program Administrators must return any unspent AB 209 funds by January 31, 2033. From program inception to May 22, 2026, over $756 million in incentives have been paid or committed to projects in SCE's service area.[148]

8. Transportation Electrification, Including Any Investments That Correspond to Different Levels Than What is Included in IEPR

On June 3, 2024, an Administrative Law Judge's Ruling Initiating Track 1 and Inviting Party Comment was issued in R.23-12-008 pausing the $1 billion statewide BTM rebate program, including funding for the Locally Invested Transportation ("LITE") pilot program, which was available only to low-income customers and small fleets in DACs and was designed to fill equity gaps of the statewide rebate program.[149] On December 5, 2025, the Commission issued a decision in Track 1 (D.25-12-005) that continued to pause the statewide BTM rebate program. Although the Commission has paused the statewide BTM rebate program, the decision clarified that the IOU-administered Technical Assistance ("TA") Program, which provides targeted support to non-residential customers through the transportation electrification process,

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[148] Based on data reported in the statewide SGIP application database, available at: www.selfgenca.com.
[149] *See* Administrative Law Judge's Ruling Initiating Track 1 and Inviting Party Comment, R.23-12-008, June 3, 2024.

will continue as it can address "ongoing needs related to timely energization."[150] SCE will implement its TA Services Program within 30 days of the Commission's approval of the statewide TA Services Program Handbook.[151]

9. Building Electrification, Including Any Investments That Correspond to Different Levels Than What is Included in IEPR

In June 2021, SCE received approval in the Low-Income Program Decision (D.21-06-015) to implement several building electrification pilot programs (ESA BE and ESA Whole Home Pilots) that target residential customers detailed in Table III-17. SCE is proposing to integrate the ESA BE Pilot into the main ESA program in 2028, pending Commission approval. SCE also enables building electrification by supporting the statewide TECH program that provides upstream incentives for heat pump water and space heaters in DAC communities (the TECH program has funding available for multifamily properties and in Aliso Canyon). Additionally, SCE may collaborate with Southern California Gas Company on potential, future SB 1221 pilots[152] that would transition a select set of customers within an identified Priority Neighborhood Decarbonization Zone from natural gas service to an electric service (pilots have yet to be proposed and would require Commission approval).

10. Potential Centralized Procurement, Pursuant to AB 1373

As described in Sections II.B.3.b and III.A.2, SCE's Conforming Bundled Portfolio assumes DWR successfully centrally procures the maximum authorized geothermal and 12- and 24-hour storage resources. SCE does not assume DWR will successfully procure offshore wind due to permitting uncertainty, constraints in supply chain and port infrastructure, and significant transmission requirements. However, if DWR is able to procure offshore wind, SCE would likely reduce its planned in- and out-of-state wind procurement.

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[150] D.25-12-005 at 15.
[151] SCE Advice 5784-E et al., submitted on April 6, 2026, is pending disposition.
[152] Framework for the SB 1221 pilots is being decided within R.24-09-012.

B. Disadvantaged Communities (DACs)

SCE is engaged in various activities to support DACs in its TAC area, including ongoing direct communication with its customers, procurement practices supportive of DACs, outreach on climate-related issues, and activities promoting emissions reductions in DACs. Sections III.C, III.D.1 and III.D.2 include details on SCE's emissions results showing reductions created by its proposed portfolio, the benefits of SCE transportation electrification activities, as well as details on customer programs and pilots, and ongoing outreach and education. Section III.D.2.i includes additional information on SCE's more formal DAC outreach activities.

SCE utilizes procurement practices centered around a least-cost, best-fit methodology to evaluate and select resources to meet specified needs through competitive solicitations. This approach provides the benefit of evaluating both economic criteria and non-economic criteria such as impacts to DACs. Consideration of DAC-related impacts in a portfolio are addressed as part of the best-fit analysis (along with other factors). This is consistent with Public Utilities Code Section 454.52(a)(2)(B), which allows the Commission to approve procurement that will reduce overall GHG emissions from the electric sector and meet other IRP goals, such as early prioritization of DACs, even if the resource does not compete favorably in terms of price with other resources. In addition, SCE administers solicitations to procure renewables exclusively in and near DACs, such as the DAC Green Tariff RFO, which ensure direct new clean energy investment to DACs.

SCE also engages in an independent review of its procurement activities through the Procurement Review Group ("PRG"). The PRG, which meets on a scheduled cadence or as needed, is designed to provide an independent assessment that ensures the procurement activities being proposed meet all required criteria. The PRG generally includes members from the Commission's Energy Division, Public Advocates Office, The Utility Reform Network, Union of Concerned Scientists, and Earth Justice, and includes participation by Independent Evaluators as needed.

In SCE's recent RFOs for clean energy resources, including its System Reliability RFO, MTR RFO, and Clean Energy RFO, SCE expressed a preference for preferred and energy storage resources located in DACs. Two energy storage and one DR project contracted pursuant to D.19-11-016, fifteen energy storage projects and one solar PV project contracted pursuant to D.21-06-035 and D.23-02-040, and three energy storage projects and two solar PV projects contracted pursuant to D.24-02-047 are all located in a DAC.[153] In its procurement activities, SCE will continue to provide qualitative preferences to projects that provide benefits to DACs or other communities meeting the criteria in Public Utilities Code Section 399.13(a)(8)(A) as applicable.

All new resources selected in SCE's Conforming Bundled Portfolio are clean energy or storage resources. SCE's Conforming Bundled Portfolio does not include new non-RPS emitting resources and SCE is not proposing to develop any new natural gas generation or recontract with non-RPS emitting resources for a contract period of five years or more. However, SCE's IRP modeling does show a need to retain most of the existing natural gas fleet for reliability, though those plants will be operating less frequently as new clean energy resources come online. SCE's plans for increasing electrification and clean resource procurement will benefit all communities, including maximizing benefits to DACs by planning to significantly reduce fuel gas use to serve electric loads and by reducing reliance on fossil fuels to generate electricity and operate vehicles. As shown in Sections III.C and III.D.1, the GHG emissions and criteria pollutants calculated from SCE's Conforming Bundled Portfolio continue to show reductions through the planning horizon.

As introduced in Section III.D.2.i, SCE launched the CEAWG in partnership with The Greenlining Institute, environmental and community groups, and faith-based organizations in

[153] In addition, another solar PV contracted pursuant to D.24-02-047 is partially located in a DAC.

2017.[154] On May 19, 2026, SCE's IRP team met with the CEAWG to conduct outreach and brief them on the IRP process to receive input from them as representatives of DACs. At that time SCE had not yet concluded its IRP modeling, so SCE met with the CEAWG again on July 10, 2026 to receive further input.[155] Comments received, shown in Table IV-27 below, at the May 19, 2026 meeting were centered on questions regarding increasing the use and availability of distributed resources in DACs, tradeoffs between supply-side and demand-side solar, electrification, and how resiliency can be increased with distributed resources.

SCE has taken the input received from DAC representatives into account in its IRP. Electrification assumptions are a driver of future load forecasts used in the IRP, and distributed generation and its expected adoption are incorporated as load modifiers in the CEC's IEPR load forecast, which the Commission directs LSEs to use in their IRP modeling to form the basis for IRP portfolio planning.

Table IV-27
Comments Received During CEAWG Meeting on May 19, 2026
Responding to SCE Presentation on IRP

Comment	Relevance to IRP
Distributed solar should be considered in addition to utility-scale solar.	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.
It may be difficult to convince some customers to convert to electric from gas cooking.	Electrification is a load driver incorporated in the IEPR load forecast used in SCE's IRP modeling.
Virtual power plants should be considered.	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.

[154] The CEAWG is a diverse cross-sector, multi-issue-area body that meets to tackle clean energy priorities within traditionally underserved communities. The CEAWG seeks to address these challenges through long-term collaboration, skillful facilitation, strategic community engagement, and cross-sector relationships. In order to produce meaningful and appropriate benefits, investments, and outcomes, the CEAWG prioritizes and centers community voices from underserved communities, trusting their local expertise and lived experiences to inform solutions best for their own historically underrepresented communities. Parties represent a variety of areas including the Los Angeles basin, the central valley, churches, ethnic groups, etc.

[155] In the subsequent CEAWG meeting on July 10, 2026, parties were asked if they had any additional thoughts or comments on the IRP process. The comments were generally limited to distributed energy resources (*e.g.*, more rooftop solar in DACs).

Should be covering more vacant lots with solar (*e.g.*, Willowbrook project).	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.
Need more distributed generation.	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.
Church setting an example for others in the community to follow by being the first to add solar/storage.	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.
Some other utilities use distributed generation to assist with circuit reliability.	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.
Solar carports and solar patio covers are currently too expensive to implement widely.	Distributed generation is a load-modifier incorporated in the IEPR load forecast used in SCE's IRP modeling.

C. LSE's Tribal Customers

All federally recognized tribal lands were categorized as DACs in May 2022. There are over 30 federally recognized tribes in SCE's service area, of which 13 are serviced by SCE.[156] SCE also provides services to over 20 other non-federally recognized tribal communities that fall outside this definition. SCE partners with our tribal nations in many areas including reducing wildfires, clean energy development, electrification, energy efficiency, and philanthropy. SCE has four tribal liaisons that ensure our tribal partners are up to date on all relevant issues, including available SCE programs, services, and opportunities, and how to obtain help to resolve issues. SCE holds individual meetings with each tribal customer to provide information and obtain input on important issues. SCE also holds an annual Tribal Leaders Clean Energy Summit to share information and get elected leader input from all tribes simultaneously.

[156] SCE's 13 federally-recognized tribal customers: Agua Caliente Band of Cahuilla Indians, Benton Utu Utu Gwaitu Paiute Tribe, Bishop Paiute Tribe, Bridgeport Indian Colony, Chemehuevi Indian Tribe, Colorado River Indian Tribes (CRIT), Morongo Band of Mission Indians, Pechanga Band of Luiseño Indians, Yuhaaviatam of San Manuel Nation, Soboba Band of Luiseño Indians, Timbi-Sha Shoshone Tribe, Tule River Indian Tribe, and Twenty-Nine Palms Band of Mission Indians, available at: https://www.sce.com/partners/3rd-party-energy-providers/tribal-communities.

D. Procurement Products

SCE anticipates that its procurement to meet the resource needs identified in its Conforming Bundled Portfolio will largely be done through long-term contracts. In addition, SCE will use the physical and financial products authorized in its Bundled Procurement Plan for procurement activities associated with its Conforming Bundled Portfolio.[157]

E. Commission Direction of Actions

Based on the study results set forth in Section III and the proposed procurement activities set forth in Section IV.A, SCE requests the following direction and actions from the Commission:

- As a complement to the PSP, the Commission should develop a PGP based on SCE's recommendations to guide procurement targets through 2035.
- The Commission, CAISO, and CEC should accelerate the development of the necessary transmission infrastructure to meet California's long-term decarbonization objectives, with an emphasis on the transmission needed to interconnect geothermal, other LLT resources, and out-of-state wind.
- The Commission should adopt an SOD framework for IRP reliability planning.
- The Commission should approve SCE's IRP and Conforming Bundled Portfolio.
- The Commission should authorize SCE to flexibly procure up to the resource needs identified in its Conforming Bundled Portfolio. SCE should be authorized to submit any resulting contracts to the Commission for cost recovery through Tier 3 advice letters unless the contracts are otherwise authorized pursuant to another Commission order in another proceeding, and cost recovery should be through the Portfolio

[157] *See* Southern California Edison Company's Proposed Updates to its Bundled Procurement Plan, R.25-06-019, June 1, 2026, Attachment B, Proposed Appendices to SCE's Proposed 2026 Bundled Procurement Plan, Appendix A Authorized Procurement Products For Energy And Energy-Related Products, Appendix B, Authorized Non-Standard Products.

Allocation Balancing Account based on the calendar year of original contract execution unless another cost recovery mechanism is authorized.

V.

LESSONS LEARNED

SCE offers the following lessons learned to enhance the effectiveness and efficiency of the IRP process.

A. Prioritizing System-level Affordability and Feasibility

One of the most important lessons learned from this IRP cycle is that affordability and feasibility are most meaningful when evaluated at the system level rather than solely through the lens of the rate impact of an individual LSE's portfolio. Because resource needs and costs are largely driven by statewide policy objectives, GHG targets, load forecasts, reliability standards, resource availability assumptions, and transmission planning decisions, the key policy questions often involve the tradeoffs among alternative system portfolios rather than the costs associated with any individual LSE's portfolio.

This IRP cycle demonstrated that system portfolios can produce significantly different outcomes depending on the assumptions used regarding load growth, resource availability, and GHG emissions targets. As discussed throughout this IRP, planning portfolios that satisfy reliability and GHG requirements in a model may nevertheless prove infeasible to implement if they require resource build-outs that exceed expected market capability, depend on transmission infrastructure that has not yet been developed, or result in customer costs that are not sustainable over the long term. These considerations underscore the need for the Commission to evaluate not only whether a portfolio meets policy objectives, but also whether it can reasonably be developed, interconnected, financed, and executed under expected market conditions at an affordable cost to customers.

SCE's System PGP demonstrates the value of this approach. By evaluating alternative assumptions regarding load growth, resource availability, and GHG constraints, SCE's System

PGP provides insight into the tradeoffs among reliability, GHG emissions reductions, customer costs, and feasibility. The analysis shows that California can continue making substantial progress toward its long-term decarbonization goals while pursuing an achievable pathway through 2035. It also provides a meaningful benchmark for assessing statewide progress because it reflects the resources, transmission infrastructure, and development timelines that are reasonably expected to be available. The Commission should develop a PGP based on SCE's recommendations to guide procurement through 2035.

Additionally, future IRP cycles should place greater emphasis on system-level affordability and feasibility analysis and explicitly compare planning alternatives before policy objectives are established and LSEs' IRPs are submitted. The Commission should evaluate not only the cost, reliability, and GHG emissions characteristics of competing portfolios, but also the feasibility of achieving the required resource build-outs given current market conditions, transmission constraints, interconnection timelines, and resource availability. Incorporating these considerations into portfolio development would improve transparency, support more informed policy decisions, and help ensure that future procurement requirements are grounded in realistic implementation pathways rather than solely in modeled outcomes. As was done in the 2017-2018 and 2019-2020 cycles, the Commission should engage in a formal process (ruling, comments, decision) to finalize key assumptions (*e.g.,* limiting near-term resource potential based on current market conditions and transmission availability) and policy objectives for each cycle.

B. Adaptive and Transparent Portfolio Development

Another clear lesson from this IRP cycle is that planning outcomes are highly sensitive to assumptions that can change significantly over the course of a planning cycle. Load forecasts, federal tax credits and policy, resource availability, interconnection constraints, and market conditions evolved materially between the development of the Commission's assumptions and the filing of LSEs' IRPs. Given these rapidly changing developments, it is possible that

elements of the PSP ultimately approved in February 2028 will be outdated before it is even finalized because they will be based on I&As that were principally developed in 2024. As a result, portfolios developed using assumptions established early in the planning process may become increasingly disconnected from the conditions under which procurement and resource development ultimately occur.

This IRP cycle demonstrates that load forecasts and resource availability assumptions are among the most significant drivers of portfolio cost and feasibility. For example, the differences between the 2024 and 2025 IEPR load forecasts materially affect required resource build-outs and customer costs. Similarly, changes in federal policy, interconnection timelines, clean firm resource availability, and transmission development expectations can significantly alter the feasibility and affordability of adopted planning portfolios. Rather than relying exclusively on assumptions that may now be outdated, the IRP process should provide opportunities to refresh key assumptions and evaluate alternative portfolios when material changes occur. This is particularly important when planning portfolios are used to establish procurement targets, compliance obligations, or other implementation requirements.

SCE performed its sensitivity analysis and developed its System PGP specifically to elevate these issues for Commission and stakeholder consideration now, as the Commission starts the process of aggregating plans and developing the PSP. SCE's sensitivity analysis demonstrates that reasonable variations in key assumptions can produce materially different portfolio outcomes, underscoring the importance of maintaining transparency and flexibility regarding the assumptions that drive planning decisions.

Future IRP cycles should incorporate a structured and transparent assumption-refresh process that identifies material changes in planning inputs, evaluates their implications for portfolio cost and feasibility, and provides stakeholders with opportunities to discuss potential adjustments before portfolios are finalized or used to guide procurement. SCE recommends that, if the Commission maintains its current IRP development process, the Commission introduce a workshop and comment opportunity between finalization of the I&As to be used in LSE plans

and development of the PSP where material new information can be considered.[158] The workshops should be focused and time-limited, with the goal of determining whether new information materially affects portfolio feasibility, affordability, reliability, or GHG reduction outcomes.

SCE's proposed assumption refresh process would not require the Commission to continuously reopen the IRP record or delay procurement decisions. Rather, SCE recommends the Commission establish clear criteria for determining when new information warrants targeted portfolio updates or sensitivities. Relevant criteria could include whether the information materially changes expected load, resource availability, project online dates, transmission deliverability, resource costs, or the feasibility of meeting near- and mid-term procurement targets. If these criteria are met, the Commission should retain discretion to depart from or override elements of LSE-proposed portfolios and adopt revised planning outcomes that better reflect current conditions, costs, and resource availability. Alternatively, it could adopt a complementary portfolio, like SCE's System PGP, to ensure procurement requirements reflect the most current information reasonably available.

C. Aligning the IRP Reliability Framework with RA

Since the 2022 IRP cycle, the Commission has continued to refine its reliability framework. In the current cycle, PRM targets and ELCC values have been updated based on SERVM results, and the ELCC methodology has been enhanced to better reflect interactions among solar resources and storage of varying durations. The Commission has advanced efforts to better align RESOLVE CE outputs with SERVM reliability validation, strengthening the overall consistency of IRP modeling.

Despite these improvements, the current IRP reliability construct remains complex and only partially aligned with the RA program. Modeling conducted during this cycle shows that

[158] Such new information could include load forecasts, interconnection queue status, transmission availability, project development timelines, resource costs, federal policy changes, and market conditions.

portfolios capable of meeting reliability objectives under adopted probabilistic reliability metrics may nevertheless appear deficient under simplified compliance screens, while some portfolios may require incremental procurement offering limited reliability benefits relative to costs. These outcomes indicate that greater integration between IRP and the RA program's SOD reliability framework could improve planning efficiency and reduce procurement needs and costs to customers.

As the system transitions toward higher electrification and greater reliance on variable and duration-sensitive resources, SCE continues to recommend aligning IRP reliability modeling with the 24-hour SOD framework adopted for RA program. This alignment would improve transparency, better reflect multi-hour reliability challenges, and reduce the risk of misalignment between long-term planning and near-term procurement. A reliability framework that more directly reflects hourly system needs would provide clearer procurement signals, improve visibility into resource contributions, and help avoid both under-procurement and unnecessary over-procurement. These improvements would facilitate the Commission's ability to maintain reliability while simultaneously advancing affordability and decarbonization objectives. In addition, a more formal and structured stakeholder process for developing and reviewing key reliability assumptions would improve confidence in IRP outcomes.

D. Earlier Stakeholder Engagement and Better Modeling Transparency

This IRP cycle also demonstrates that stakeholder engagement is most effective when it occurs early enough to meaningfully influence key planning assumptions and analytical approaches. Several stakeholders, including LSEs with extensive modeling and procurement experience, identified opportunities for earlier engagement regarding critical inputs such as reliability assumptions, ELCC methodologies, scenario design, resource availability assumptions, and portfolio feasibility assessments.

Once assumptions are embedded in formal modeling results, there are often limited opportunities to evaluate alternative approaches or incorporate lessons learned. Earlier technical

workshops and more targeted engagement on major modeling decisions could improve analytical quality and confidence in the results while reducing the need for subsequent revisions or corrective actions. In addition, greater transparency regarding modeling assumptions, feasibility screens, and benchmark development methodologies would improve stakeholder understanding of portfolio outcomes and facilitate broader consensus around planning decisions. These improvements would strengthen confidence in IRP results and increase the likelihood that adopted portfolios can be successfully implemented.

E. Incorporating Climate Change Impacts into IRP Planning

The Commission has achieved meaningful progress in integrating climate change impacts into IRP planning. The adopted I&As now treat climate impacts as explicit demand-side modifiers in the 2024 IEPR load forecast, ensuring that climate-driven changes in electricity consumption are incorporated into all LSE plans. Additionally, the Commission has extended the weather year range to 2000-2022 for reliability modeling and begun explicitly derating thermal generation output based on ambient temperature, better reflecting how recent climate extremes affect supply availability. These steps improve upon the 2022 IRP cycle, when climate and IRP geographic data lacked spatial compatibility with climate projections.

The Commission also updated the IRP resource geography by disaggregating the CAISO system into distinct PG&E, SCE, and SDG&E zones, which further improves spatial granularity in IRP modeling, allowing for variability in climate data across these zones to be reflected. This greater granularity will help more effectively map localized climate projections (*e.g.*, temperature, wind, insolation) onto specific resource locations and load centers. These advancements represent important progress toward more realistic system planning.

However, additional work is needed to better capture the interaction between climate-driven increases in demand, temperature-related impacts on renewable resources, and system performance under extreme conditions. SCE recommends that the Commission continue expanding the use of scenario-based and stress-test approaches to evaluate system performance

under a range of plausible climate futures, rather than relying solely on deterministic assumptions. Continued development of these methodologies will improve the IRP process's ability to identify reliability risks under increasingly extreme and uncertain operating conditions.

Respectfully submitted,

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Dated: August 10, 2026

RULE 1.11 VERIFICATION

I am an officer of the applicant corporation herein and am authorized to make this verification on its behalf. I am informed and believe that the matters stated in the foregoing document are true.

I declare under penalty of perjury that the foregoing is true and correct.

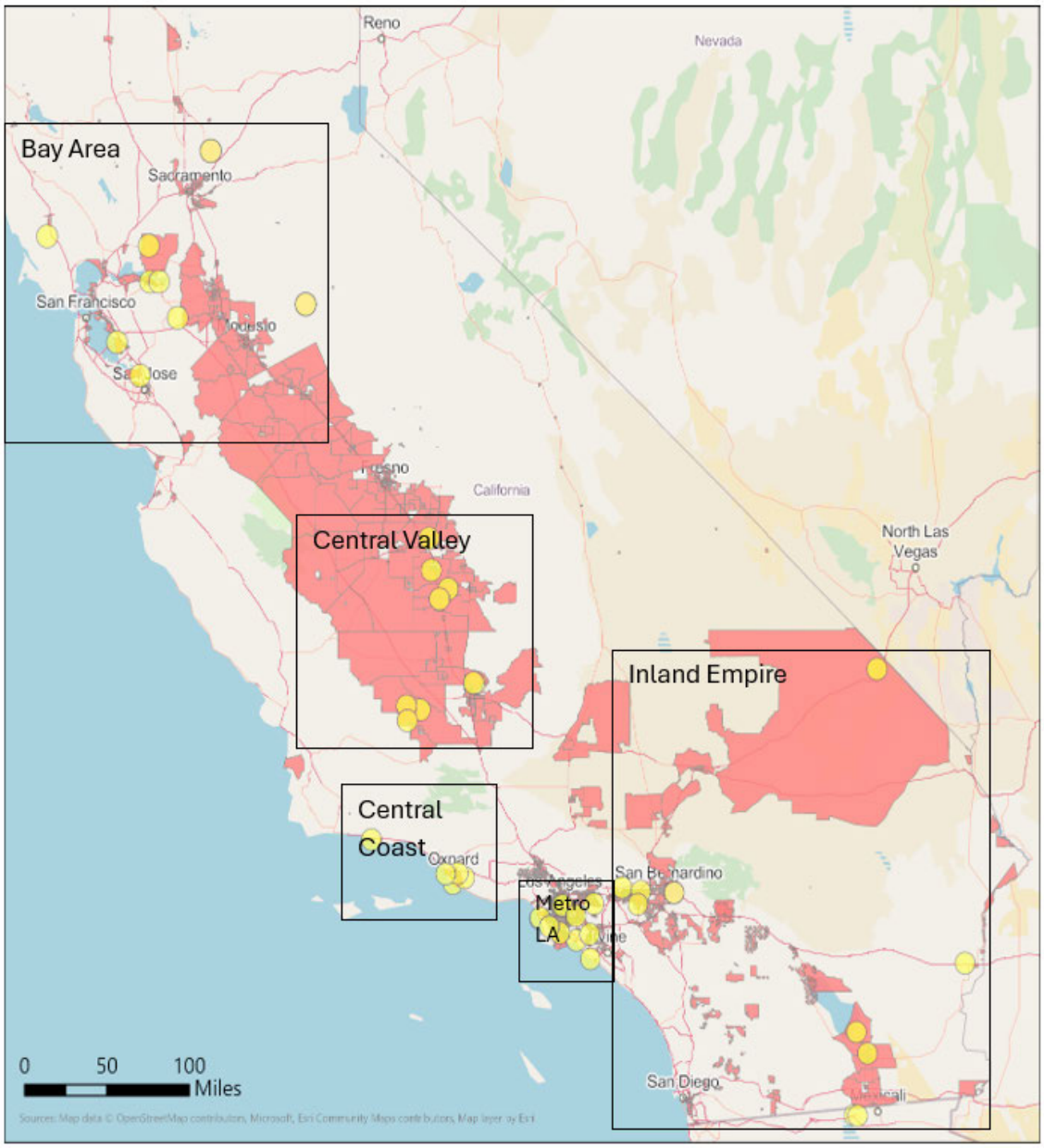
Executed this 10th day of August 2026 at Rosemead, California.

/s/ Erica Bowman
Erica Bowman
Vice President, Strategy, Planning & Performance
SOUTHERN CALIFORNIA EDISON COMPANY

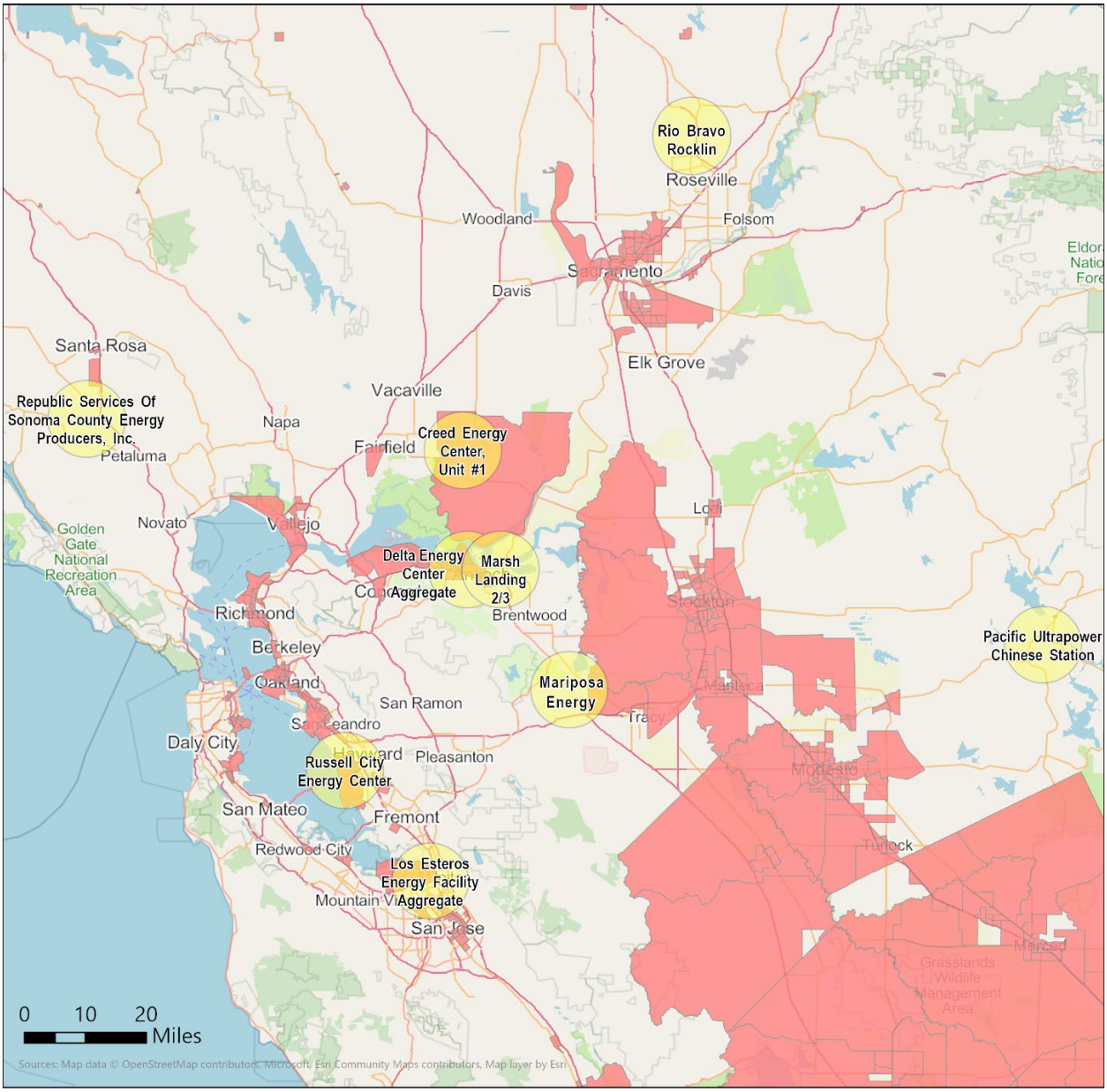
Appendix A

Emitting Generators Owned by or Contracted with SCE That are Within Five Miles of a DAC

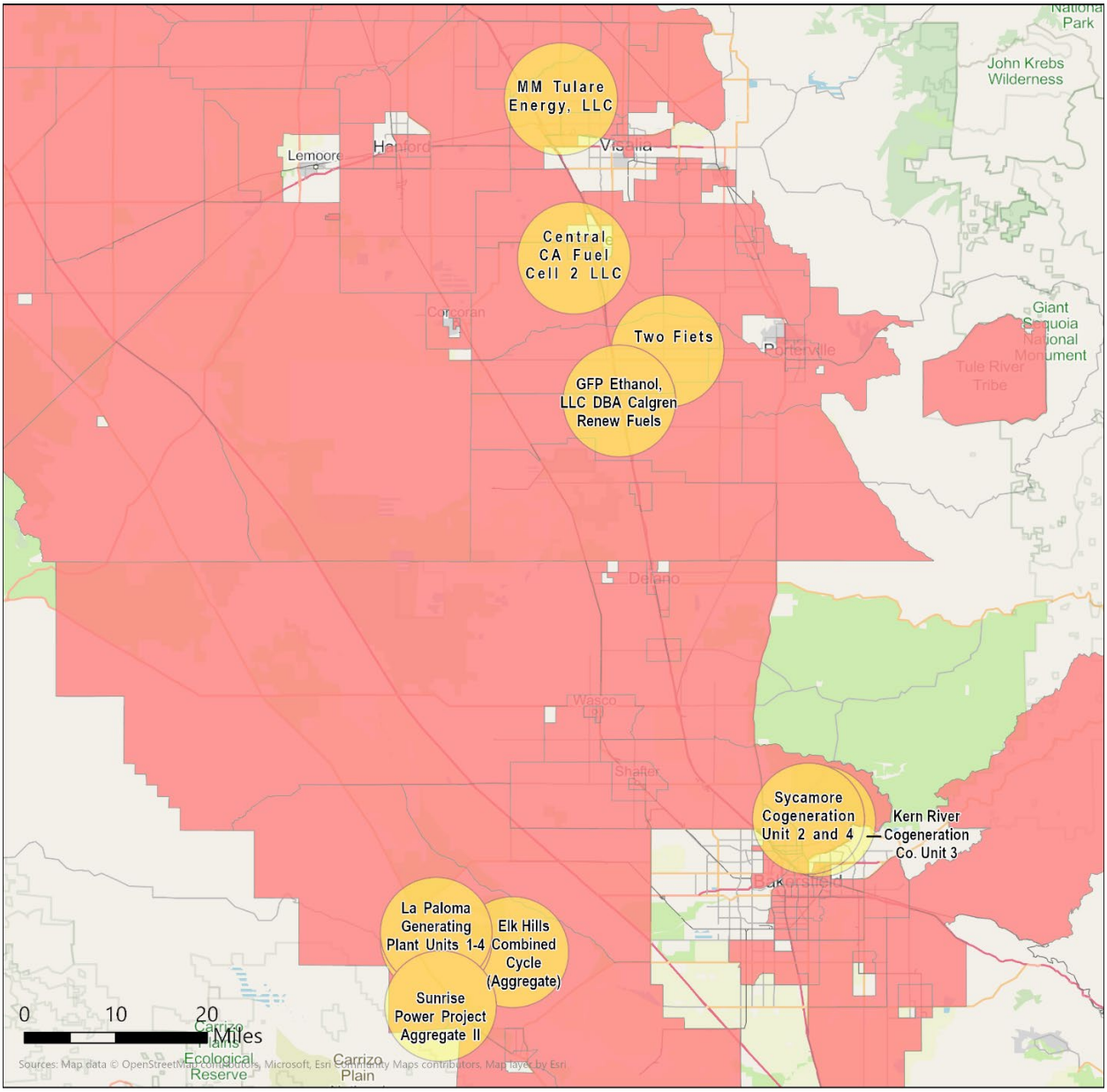
Below are maps and a table showing which DACs are located within a five-mile radius of emitting generation facilities that are owned or under contract and included in SCE's Conforming Bundled Portfolio. The red areas are the DAC census tracts and the yellow circles are the five-mile radius around emitting generators in the vicinity of the DAC census tract.



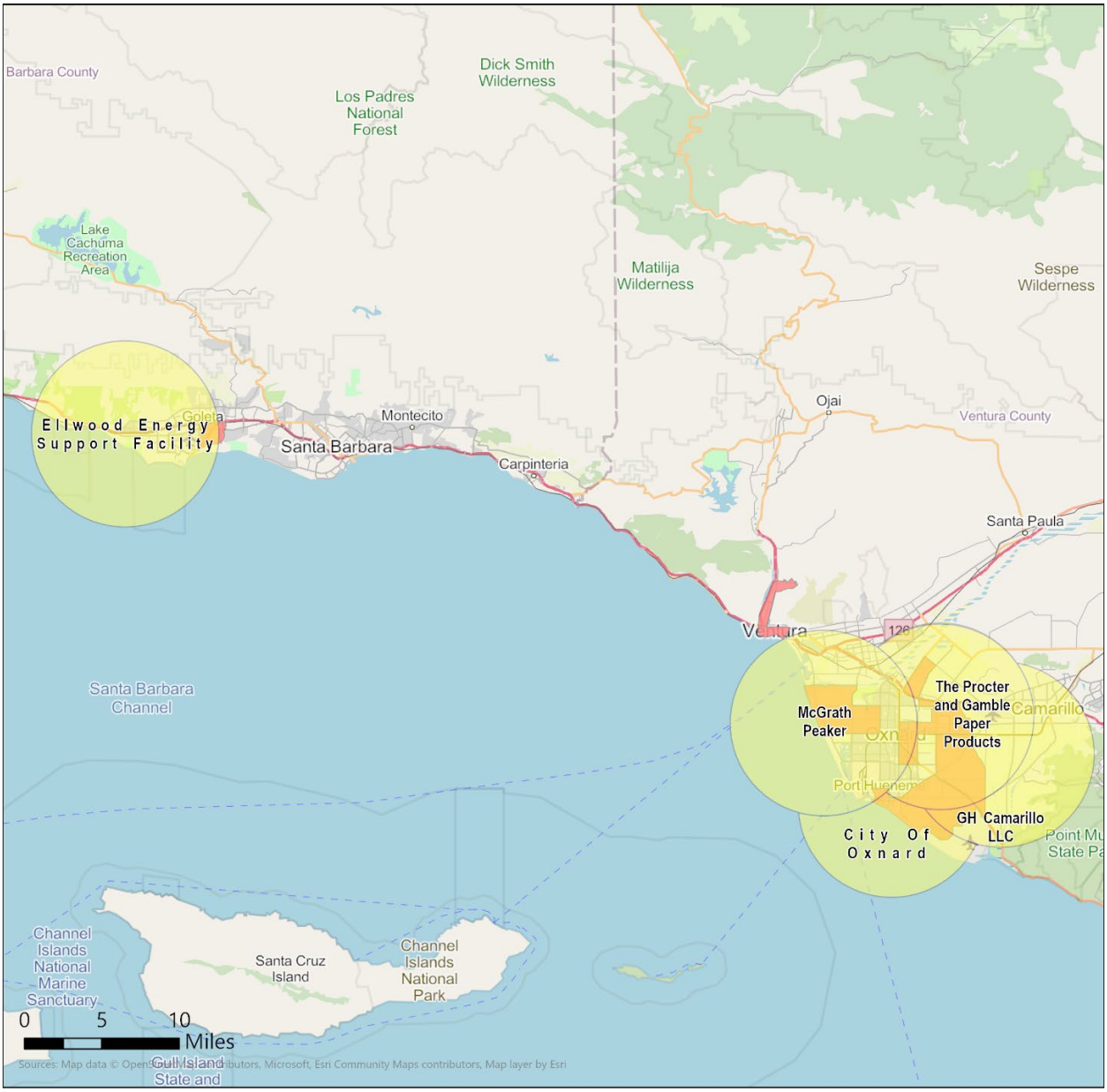
Bay Area Detail Map



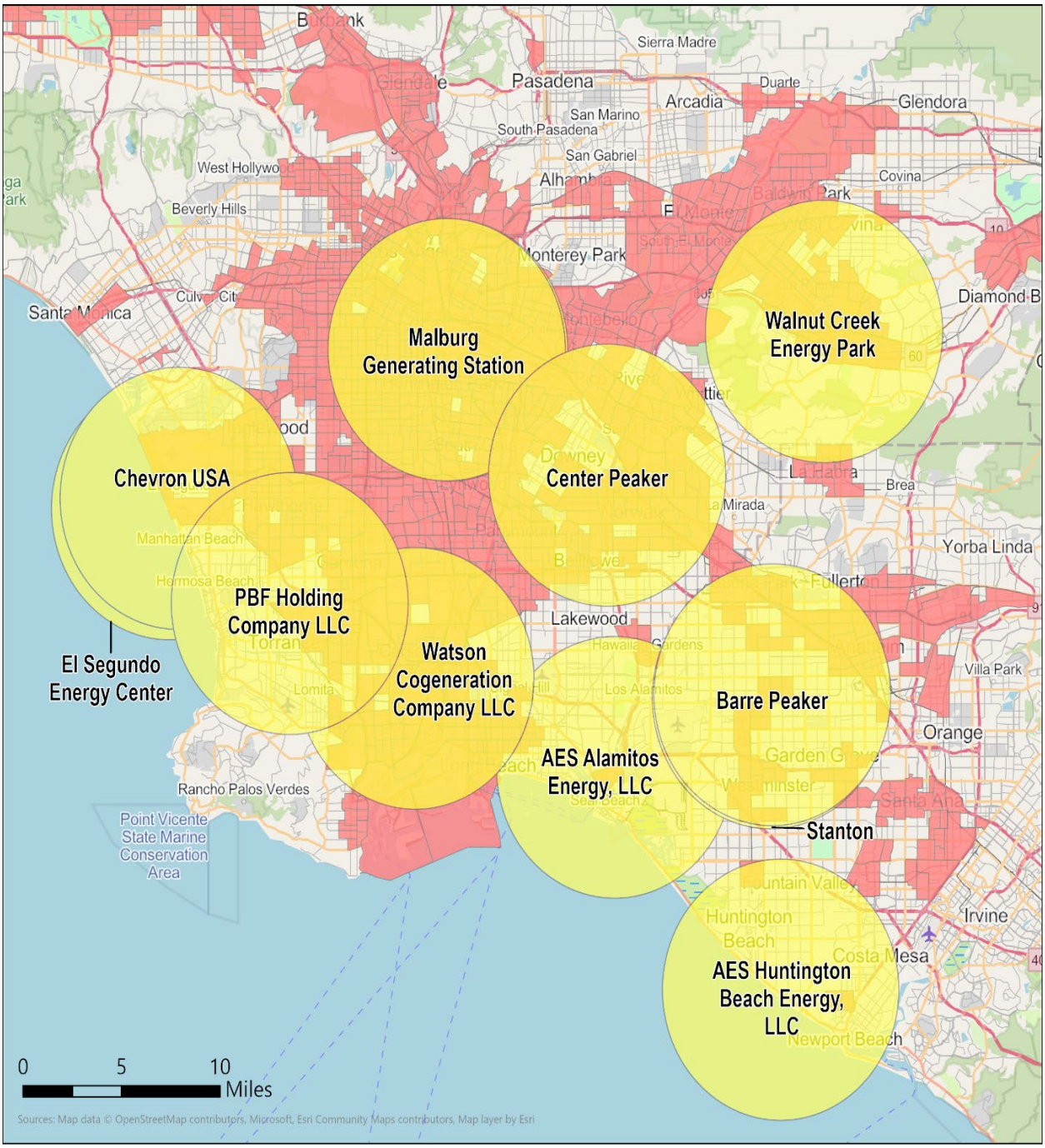
Central Valley Detail Map



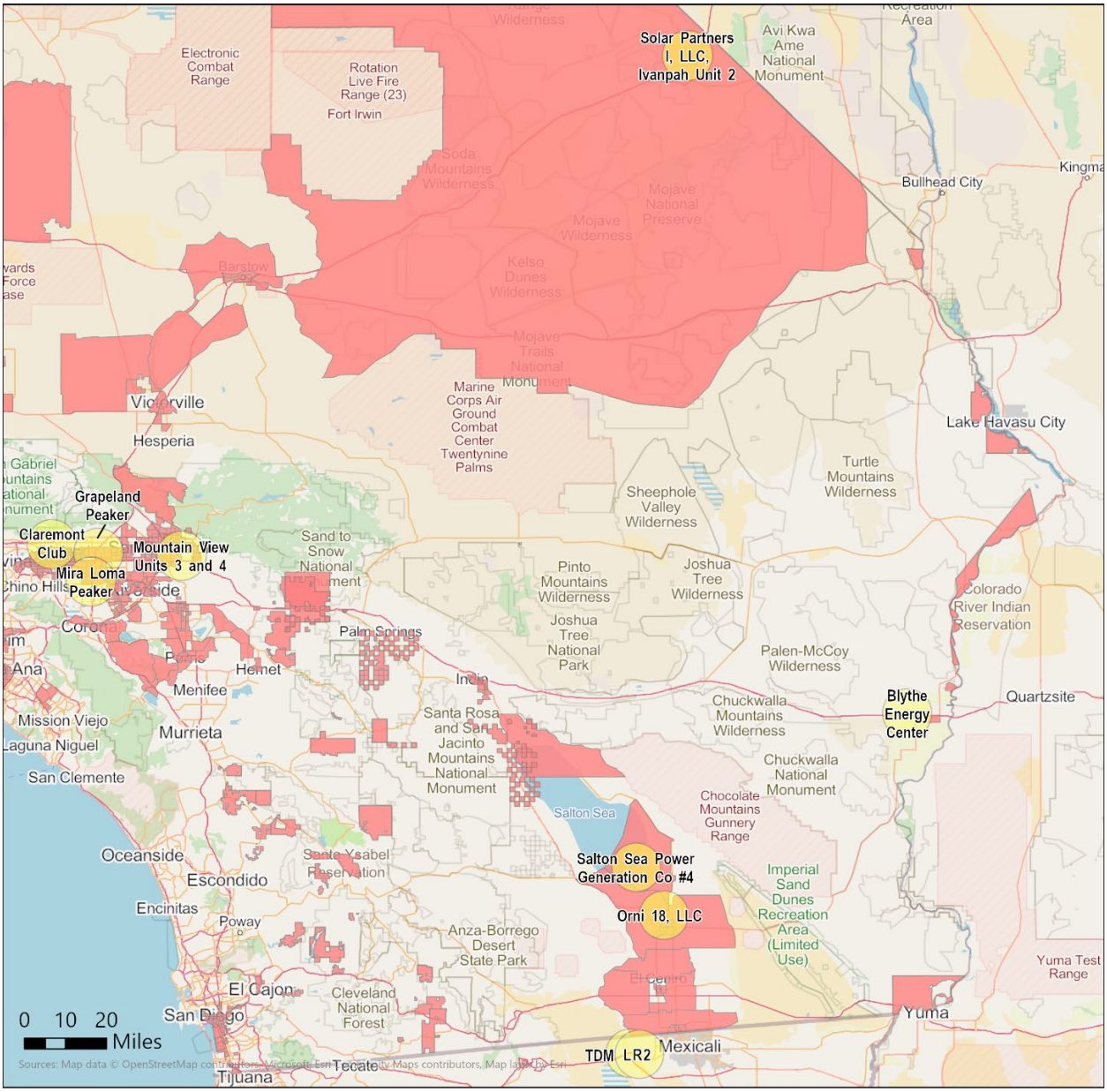
Central Coast Detail Map



Metro LA Detail Map



Inland Empire Detail Map



Project Name / Counterparty	Address	Cumulative Contract Capacity (MW)	Technology	Number of Census Tracts or Tribal Areas Within 5 Miles	Primary Area of Impact
AES Alamitos Energy, LLC	690 North Studebaker Road, Long Beach, CA, 90803	674.7	Gas Fired	23	Long Beach
AES Huntington Beach Energy, LLC	21730 Newland Street, Huntington Beach, CA, 9264(	673.8	Gas Fired	4	Costa Mesa
Barre Peaker	10613 Dale Ave, Stanton, CA, 90680	49	Gas Fired	48	Anaheim
Blythe Energy Center	385 N Buck Blvd, Blythe, CA, 92225	493.63	Combined Cycle	1	Unincorporated Riverside County area
Center Peaker	11359 Dumont Ave, Norwalk, CA, 90650	47.3	Gas Fired	122	Norwalk
Central CA Fuel Cell 2 LLC	1875 South West Street, Tulare, CA, 93274	2.8	Biomass	8	Unincorporated Tulare County area
Chevron USA	324 W. El Segundo Blvd., El Segundo, CA, 90245	170.7	Cogeneration	47	Hawthorne
City Of Oxnard	6001 South Perkins Road, Oxnard, CA, 93033	1.5	Cogeneration	8	Oxnard
Claremont Club	1777 Monte Vista Ave., Claremont, CA, 91711	0.28	Cogeneration	49	Ontario
Creed Energy Center, Unit #1	6150 Creed Road, Suisun City, CA, 95620	35	Combustion Turbine	1	Unincorporated Solano County area
Delta Energy Center Aggregate	1200 Arcy Ln, Pittsburg, CA, 94565	124.63	Combined Cycle	15	Pittsburg
El Segundo Energy Center 5/6	301 Vista Del Mar, El Segundo, CA, 90245	548.62	Combined Cycle	38	Hawthorne
El Segundo Energy Center 7/8	301 Vista Del Mar, El Segundo, CA, 90245	516.48	Combined Cycle	38	Hawthorne
Elk Hills Combined Cycle (Aggregate)	Elk Hills Rd, Fellows, CA, 93276	240	Combined Cycle	2	Unincorporated Kern County area
Ellwood Energy Support Facility	30 Las Ramas Rd, Goleta, CA, 93117	18	Combustion Turbine	1	Goleta
GFP Ethanol, LLC DBA Calgren Renew Fuels	11518 Road 120, Pixley, CA, 93256	5	Cogeneration	3	Unincorporated Tulare County area
GH Camarillo LLC	645 W. Laguna Rd, Camarillo, CA, 93012	12.711	Cogeneration	5	Oxnard
Grapeland Peaker	12408 6th St, Rancho Cucamonga, CA, 91739	45.9	Gas Fired	30	Ontario
Kern River Cogeneration Co. Unit 3	1546 China Grade Loop, Bakersfield, CA, 93306	25	Combustion Turbine	15	Bakersfield
La Paloma Generating Plant Unit #1	1760 Skyline Rd, McKittrick, CA, 93251	258.85	Combined Cycle	1	Unincorporated Kern County area
La Paloma Generating Plant Unit #2	1760 Skyline Rd, McKittrick, CA, 93251	245	Combined Cycle	1	Unincorporated Kern County area
La Paloma Generating Plant Unit #3	1760 Skyline Rd, McKittrick, CA, 93251	256.15	Combined Cycle	1	Unincorporated Kern County area
La Paloma Generating Plant, Unit #4	1760 Skyline Rd, McKittrick, CA, 93251	245	Combined Cycle	1	Unincorporated Kern County area
Los Esteros Energy Facility Aggregate	800 Thomas Foon Chew Way, San Jose, CA, 95134	125	Combined Cycle	4	San Jose
LR2	Mexicali, Baja California, Mexico	100	Combined Cycle	1	Unincorporated Imperial County area
Malburg Generating Station	4963 S Soto S, Vernon, CA, 90058	85	Combined Cycle	302	Los Angeles
Mariposa Energy	4887 Bruns Road, Byron, CA, 94514	15	Combustion Turbine	2	Unincorporated San Joaquin County area
Marsh Landing 2	3201 Wilbur Ave, Antioch, CA, 94509	402.7	Combustion Turbine	9	Antioch
Marsh Landing 3	3201 Wilbur Ave, Antioch, CA, 94509	402.45	Combustion Turbine	9	Antioch
Mcgrath Peaker	251 N Harbor Blvd, Oxnard, CA, 93035	49	Gas Fired	6	Oxnard
Mira Loma Peaker	13568 Milliken Ave, Ontario, CA, 91761	49	Gas Fired	25	Ontario
MM Tulare Energy, LLC	32982 Road 80, Visalia, CA, 93291	1.5	Biomass	4	Unincorporated Tulare County area
Mountain View, Unit 3	2492 W San Bernardino Ave, Redlands, CA, 92374	555	Gas Fired	48	San Bernandino and San Manuel Reservation
Mountain View, Unit 4	2492 W San Bernardino Ave, Redlands, CA, 92374	555	Gas Fired	48	San Bernandino and San Manuel Reservation
ORNI 18, LLC	4999 Western Ave, Brawley, CA, 92227	33.178	Geothermal	7	Brawley
Pacific Ultrapower Chinese Station	8755 Enterprise Drive, Jamestown, CA, 95327	18	Biomass	2	Chicken Ranch Rancheria
PBF Holding Company LLC	3700 W. 190th St., Torrance, CA, 90504	41.9	Cogeneration	75	Hawthorne
Republic Services Of Sonoma County Energy Producers, Inc.	500 Mecham Road, Petaluma, CA, 94952	5	Biomass	1	Unincorporated Sonoma County area
Rio Bravo Rocklin	3100 Thunder Valley Court, Lincoln, CA, 95648	24.4	Biomass	1	Auburn Rancheria
Russell City Energy Center	3862 Depot Rd, Hayward, CA, 94545	65	Combined Cycle	5	Hayward
Salton Sea Power Generation Co #4	6922 Crummer Rd, Calipatria, CA, 92233	36	Geothermal	2	Unincorporated Imperial County area
Solar Partners I, LLC, Ivanpah Unit 2	100302 Yates Well Road, Nipton, CA, 92364	117	Solar Thermal (Tower)	1	Unincorporated San Bernardino County area
Stanton 1	10711 Dale Ave, Stanton, CA, 90680	49	Combustion Turbine	48	Anaheim
Stanton 2	10711 Dale Ave, Stanton, CA, 90680	49	Combustion Turbine	48	Anaheim
Sunrise Power Project Aggregate II	12857 Sunrise Rd, Fellows, CA, 93224	376	Combined Cycle	2	Unincorporated Kern County area
Sycamore Cogeneration Unit 2	1546 China Grade Loop, Bakersfield, CA, 93308	50	Combustion Turbine	15	Bakersfield
Sycamore Cogeneration Unit 4	1547 China Grade Loop, Bakersfield, CA, 93308	1	Combustion Turbine	15	Bakersfield
TDM	Mexicali, Baja California, Mexico	5	Combined Cycle	1	Unincorporated Imperial County area
The Procter And Gamble Paper Products	800 North Rice Avenue, Oxnard, CA, 93030	40.072	Cogeneration	9	Oxnard
Two Fiets	14808 Road 152, Tipton, CA, 93272	0.8	Biomass	5	Unincorporated Tulare County area
Walnut Creek Energy Park Unit 1	911 Bixby Drive, City of Industry, CA, 91745	96.43	Combustion Turbine	51	Baldwin Park
Walnut Creek Energy Park Unit 2	911 Bixby Drive, City of Industry, CA, 91745	96.91	Combustion Turbine	51	Baldwin Park
Walnut Creek Energy Park Unit 3	911 Bixby Drive, City of Industry, CA, 91745	96.65	Combustion Turbine	51	Baldwin Park
Walnut Creek Energy Park Unit 4	911 Bixby Drive, City of Industry, CA, 91745	96.49	Combustion Turbine	51	Baldwin Park
Walnut Creek Energy Park Unit 5	911 Bixby Drive, City of Industry, CA, 91745	96.65	Combustion Turbine	51	Baldwin Park
Watson Cogeneration	22850 S Wilmington Ave, Carson, CA, 90749	50	Cogeneration	114	Long Beach
LLC	22850 S Wilmington Ave, Carson, CA, 90745	305	Cogeneration	114	Long Beach

Appendix B

Resource Data Template

Public Version

The public version of this appendix is in Excel format and can be accessed via the instructions provided in SCE's Notice of Availability.
This appendix will be filed via mixed media with the Commission's Docket Office.

Appendix C

Clean System Power Calculator

Public Version

The public version of this appendix is in Excel format and can be accessed via the instructions provided in SCE's Notice of Availability.
This appendix will be filed via mixed media with the Commission's Docket Office.

Appendix D

When Clean Firm Resources Become Competitive: A Geothermal Cost Sensitivity Analysis

When Clean Firm Resources Become Competitive: A Geothermal Cost Sensitivity Analysis

Introduction

Interconnecting the new resources required to meet the state's GHG goals will require the development and construction of significant new transmission infrastructure that has not yet been approved in the CAISO TPP. Proactive planning and development of transmission infrastructure must begin now to enable the successful deployment of geographically-constrained resources, such as geothermal, by 2045. As SCE explains in Section I.D of this IRP, California must embrace, as it has in the past, an "if you build it, they will come" approach for key transmission investments supporting LLT and geographically-constrained resources. For resource types that require major infrastructure development and long planning horizons, transmission must precede resource deployment rather than follow it.

The success of the Tehachapi Renewable Transmission Project demonstrates the importance of proactively developing transmission infrastructure ahead of resource development. By constructing transmission to a high-quality renewable resource area before generation was fully developed, California enabled significant private investment and large-scale renewable deployment that may not otherwise have occurred.

Building on this experience, proactive transmission development for geothermal[1] resource areas can reduce the cost to develop geothermal by lowering the development risk and incentivizing larger-scale geothermal deployment. Greater access to cost-competitive geothermal resources could provide a clean firm alternative to some of the marginal solar and

[1] Geothermal was the resource chosen for this study as both SCE's System Base Case Portfolio and the Commission's Reference Portfolio already identify the effectiveness of wind resources, should they be available for procurement across the entire IRP study horizon. Out-of-state wind availability has recently increased with the SunZia transmission project. In contrast, less than 50 MW of geothermal has come online in the past five years. *See* Commission, Resource Tracking Data, Data current as of December 2025, at 6, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/summer-2021-reliability/tracking-energy-development/resource-tracking-data-december-2025-release.pdf. This report shows approximately 41 GW of new in-CAISO nameplate geothermal capacity came online between 2020 and 2025.

storage resources selected in deep decarbonization portfolios, reducing the overall cost of achieving the state's long-term climate goals through lower generation and overall system costs.

Study Overview

SCE's IRP modeling shows that solar and storage become less effective at reducing GHG emissions as the system approaches deeper levels of decarbonization. In later stages of GHG emissions reduction, incremental additions of solar and storage resources provide diminishing marginal emissions benefits. Despite this declining effectiveness, the models continue to select solar and storage throughout most of the study horizon because their levelized costs remain below those of clean firm alternatives.

Proactive transmission development to interconnect geothermal resources could significantly reduce its cost and make it economically competitive with the solar and storage additions selected in the later portfolio years. Thus, SCE's study evaluates when additional geothermal capacity becomes cost-competitive, the scale at which it is selected, and the amount of solar and storage it could displace.

Studying the resource mix in 2040 provides a reasonable timeframe for evaluating the potential benefits of transmission-enabled geothermal development because it reflects the long lead times required for transmission planning, permitting, and construction. Since major transmission projects often require a decade or more to progress from planning to operation, investments initiated today could support resource deployment by 2040. This timeframe also coincides with California's need to achieve substantial additional GHG emissions reductions, allowing the analysis to determine whether proactive transmission development can enable geothermal resources to become a cost-effective component of the state's long-term decarbonization strategy.

Study Design and Results

SCE performed a sensitivity analysis using SCE's System Base Case Portfolio for 2040 ("Baseline") as a starting point. The analysis progressively reduced the cost of candidate

geothermal resources and re-optimized the portfolio to identify the point at which additional geothermal capacity became cost-competitive and displaced previously optimized solar and 8-hour storage resources. The results are shown in Table D-1 below.

Table D-1: Increase in Selected Geothermal Build-out and Associated Decrease in Solar and Storage in 2040

2040 Cost Scenario	Solar Decreased (GW)	Storage Decrease (4-Hr Equiv) (GW)	Geothermal Increase (GW)
Baseline	-	-	-
Geo Costs (-5% to -30%)	-	-	-
Geo Costs (-35%)	7.3	6.2	2.4
Geo Costs (-40%)	10.6	9.6	3.6

The analysis identifies a clear inflection point in geothermal deployment. The model does not select additional geothermal beyond the Baseline portfolio until geothermal costs are reduced by approximately 35 percent relative to the 2040 Baseline.[2] At that threshold, geothermal becomes cost-competitive with solar and storage, and between a 35 percent and 40 percent cost reduction, the model rapidly deploys all remaining available conventional geothermal resources. Each incremental 1 GW of geothermal added to the portfolio displaces approximately 5.5 GW of solar and 4-hour storage equivalent, demonstrating geothermal's potential to substitute a significant quantity of variable renewable and storage resources once it reaches this cost inflection point. Furthermore, the decreased solar and storage capacity should also result in lower transmission costs.

Near-term procurement will still need to rely on currently-available resources, for which costs and deployment trajectories are relatively well understood and less likely to change significantly. However, this study shows that beyond the 2035 timeframe, if available at

[2] Average cost for conventional geothermal resources from the 2026-2027 TPP inputs in $2024 is $946/kW-yr in the Baseline, as shown in Table II-7. A cost reduction of 35 percent yields an average geothermal cost of $615/kW-yr, while a cost reduction of 40 percent yields an average cost of $568/kW-yr.

competitive costs, geothermal resources can effectively supplement an existing solar- and storage-heavy portfolio, providing greater system-wide resource diversity and increasing the share of clean firm generation on the grid. These findings suggest that actions taken today to lower geothermal development costs, including proactive transmission investment, could unlock a valuable resource option for the later stages of decarbonization. Broader cost-effective geothermal deployment will reduce California's reliance on increasingly marginal solar and storage additions and lower the overall cost of achieving the state's 2045 climate goals.