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# 2024 Integrated Resource Plan

Imperial Irrigation District

IID
A century of service.

April 2024

# Forward

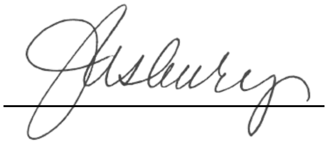
Jamie L. Asbury
General Manager

On behalf of the Imperial Irrigation District, I am pleased to present the District's 2024 Integrated Resource Plan (IRP). The energy industry is constantly evolving and adapting to new requirements and technologies designed to meet ever growing need for power. IID has experienced the transition first-hand over the last decade but especially in the last five years. IID's last IRP was completed in late 2018 just as IID's remaining coal-fired capacity was retired. Now, five years later, the imperative to act to address and mitigate the threat of climate change is no less urgent and has brought clean energy objectives to the forefront. IID, as one of California's publicly owned utilities, has an outsize role in realizing the achievement of these goals as both a transmission provider and load serving entity. Clean, renewable power generation like solar, wind, and geothermal energy, complemented by storage, other capacity resources, transmission additions, and energy efficiency improvements, are all tools the District has used and will continue to use to modernize and decarbonize its portfolio for a sustainable, electrified future.

A comprehensive roadmap is essential for guiding and informing our strategy for achieving ambitious green energy targets while maintaining reliable, affordable power for our customers. Transition take time; careful planning and timing of needed investments with a long-term plan and strategy will keep IID's progress toward clean energy targets in sight and on track. As significant as the changes to the electricity sector over the past decades have been, the next decade promises to be even more transformational. IID looks forward to being part of that change!

This IRP is the culmination of a multi-year planning and collaboration effort across the entire IID team. We appreciate the diligent and thoughtful input from Transmission and Distribution, Generation, Operations, Special Programs, Finance, and the Resource Planning divisions, all of which provided unique perspectives to ensure that this report covers the District's entire energy outlook. We appreciate the support of Ascend Analytics for providing comprehensive analyses and working with IID staff to assist in completion of this important roadmap.

Sincerely,



Jamie L. Asbury

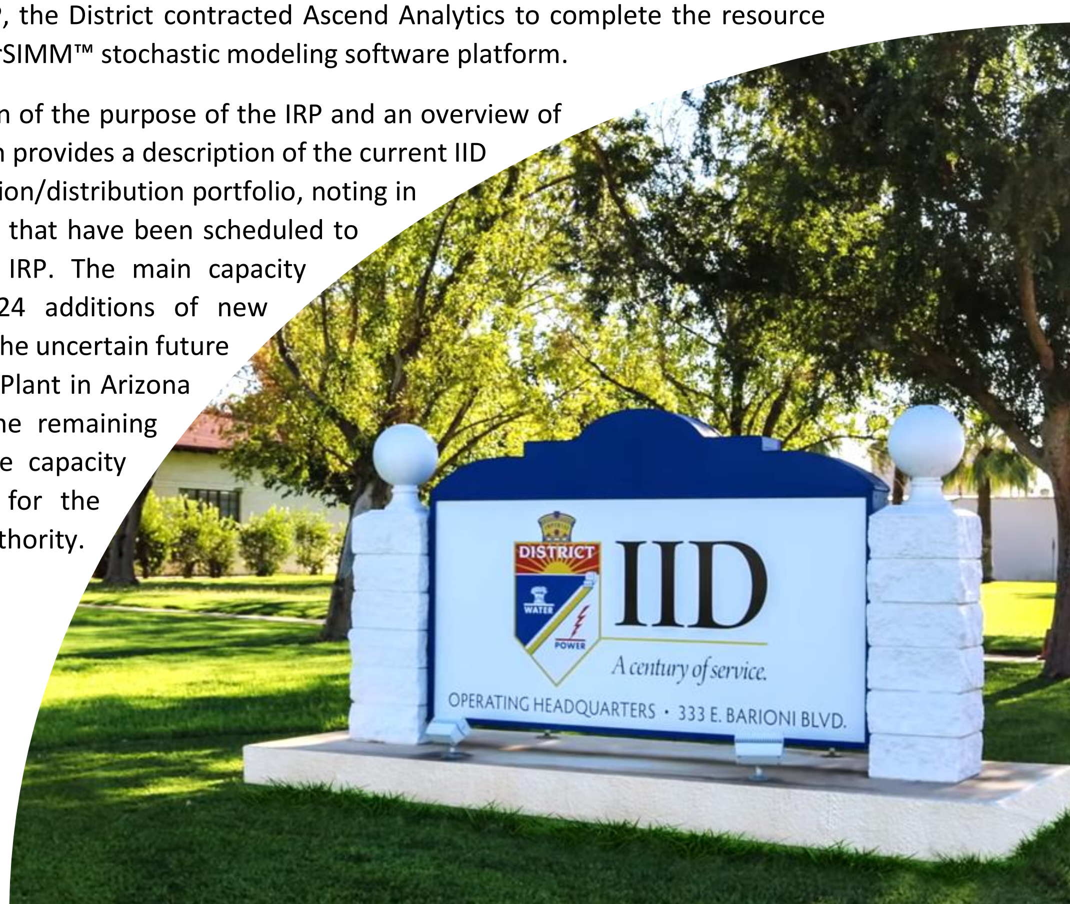
General Manager

# Executive Summary

This report presents the 2024 integrated resource plan (IRP) of the Imperial Irrigation District (IID), a publicly owned utility (POU) in south-eastern California and the sixth-largest by peak load (1,152 MW in 2023). As of December 2023, IID serves 163,579 customers across the residential, commercial, and industrial categories. The IRP describes how IID plans to meet its energy and capacity resource needs, policy goals, comply with clean energy policy goals, and balance the physical and operational constraints in its role as Balancing Authority, all while continuing to provide safe, reliable, and affordable power to its customers. The period of study in this IRP runs from 2024 through 2045 which is an extension of the 2030 planning horizon in the previous IRP iteration. The IRP incorporates the latest legal requirements, such as the 100% zero-carbon electricity by 2045 target established by Senate Bill 100, as well as the changes in IID's resource portfolio, such as the pending retirement of fossil generation at Yucca. The IRP development process is a significant undertaking that requires input from a diversity of departments, including the Transmission, Distribution, Operations, Finance, and Special Programs groups. This report is the five-year update to the 2019 Integrated Resource Plan (IRP)[1], pursuant to Public Utilities Code (PUC) Section 9622 as codified by the Clean Energy and Pollution Reduction Act of 2015 (SB 350).

The methodology section of this report describes the modeling process used to develop the IRP. The modeling process consists of three main phases: resource adequacy, capacity expansion, and production cost. Resource adequacy modeling determines IID's capacity needs and the effective load carrying capability (ELCC) value of different resources to meet customer load. Capacity expansion modeling selects the least-cost portfolio of resources that meets IID's energy needs, clean energy targets, and reliability standards. Production cost modeling simulates the hourly operation of IID's system and provides insights into the energy mix, emissions, and costs of the selected portfolio. For this IRP, the District contracted Ascend Analytics to complete the resource planning modeling using the PowerSIMM™ stochastic modeling software platform.

This report begins with a discussion of the purpose of the IRP and an overview of the methodology employed. It then provides a description of the current IID generation resource and transmission/distribution portfolio, noting in particular, the changes in capacity that have been scheduled to come online since the previous IRP. The main capacity differences are the planned 2024 additions of new geothermal and storage capacity. The uncertain future of IID's assets at the Yucca Steam Plant in Arizona has important implications for the remaining thermal fleet in providing reliable capacity and balancing ancillary services for the District in its role as a Balancing Authority.




[1] Integrated Resource Plan 2018. Imperial Irrigation District. https://www.iid.com/home/showpublisheddocument/9280/636927586520070000

## Fundamental Macro-Level Drivers

Fundamental macro economic drivers underpin many of the modeling assumptions used in the resource planning phase. Both federal and state-level policy drivers are at play. Recent federal legislation—namely the Infrastructure Investment and Jobs Act and the Inflation Reduction Act (IRA)—both entail significant, wide-ranging effects for the clean energy transition. In particular, the IRA's tax credit incentives are expected to significantly shape the market for traditional renewable technologies of wind and solar and also the more nascent energy storage and hydrogen sectors.  At the State level, the passage of SB 100 in 2018 and SB 1020 in 2022 established key decarbonization policy targets for POUs, specifically the 60% Renewable Portfolio Standards target for 2030 and the 100% Zero-Carbon[2] electricity by 2045 target, as well as the interim targets for both of these goals. A schematic representation of how these policy and macro drivers form a fundamental foundation for the rest of the modeling assumptions, such as power or fuel market prices, load forecasts, and technology costs, is illustrated in Figure ES-1.

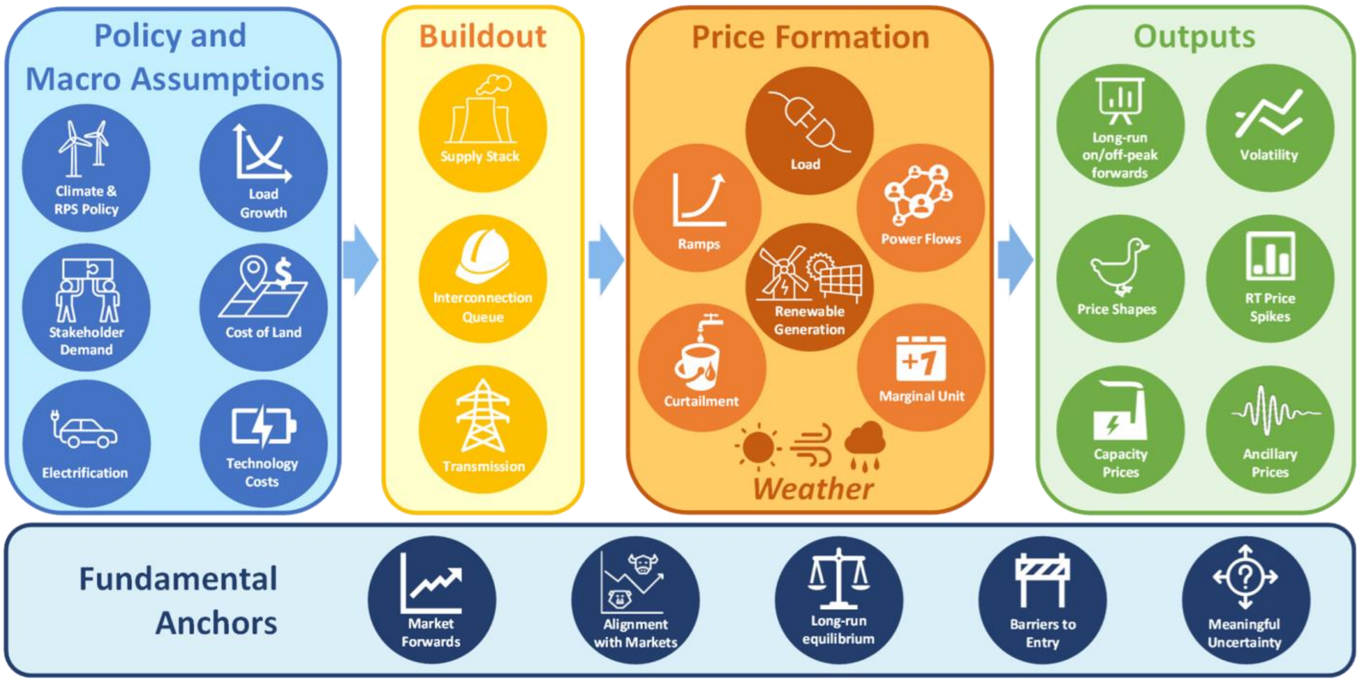



**FIGURE ES-1. ASCEND FUNDAMENTAL MODELING FRAMEWORK**

[2] The distinction between electricity which qualifies for Renewable Portfolio Standards (i.e., is "RPS-eligible") and that which qualifies as "Zero-Carbon" is that the former category excludes nuclear generation and large hydroelectric generation. This distinction comes into play when considering two components of IID's portfolio: 1) IID's allotment of large-hydroelectric generation on several WAPA projects, and 2) IID's SCPPA allotment of nuclear power from Palo Verde Generating Station. Both of these resources qualify as zero-carbon but are not RPS-eligible.

## Candidate Resources

The other key phase of modeling assumption development is the establishment of the set of "Candidate Resources" that are to be considered in the capacity expansion resource planning phase. The inclusion of a candidate resource does not necessarily mean that the capacity expansion model will select it as part of its optimized selection of the lowest-cost portfolio (subject to constraints on resource availability, capacity needs, and clean energy targets). Rather, these technologies represent options that the District believes are feasible to be acquired within the planning period to achieve its resource planning goals. For this IRP, the candidate resources were as follows:

- **PV Solar** – The District's dry and sunny desert climate boasts some of the best solar resource in the entire country. Indeed, IID has already procured significant solar energy through PPAs and some ownership agreements. This candidate resource is assumed to be sighted locally.
- **Southern California Wind** – While annual wind generation profiles in California are more suited to IID's load shape, there is expected to be relatively little availability for such projects. As such, this candidate resource is permitted but build-out is modeled up to a maximum of 100 MW.
- **New Mexico Wind** – Out-of-state wind resource from New Mexico perhaps tying into the existing Palo Verde electricity trading hub from which IID already has transmission capacity is another prospective wind resource option. Unlike the in-state California wind, however, the generation profile of New Mexico wind poorly matches IID's load shape; it peaks in the winter when IID's load is lowest and is lowest in the summer months when IID's needs are highest.
- **Geothermal –** The District also has some of the premier geothermal resources in the country, concentrated in the Salton Sea Geothermal Field. Geothermal's stable, flat generation is both a blessing and a curse when it comes to the IID system – while it would provide needed firm capacity for a portfolio with increased penetration of variable generation renewables, the year-round generation profile means that overgeneration in the non-summer months becomes a concern.
- **RICE (Natural Gas)** – Natural gas-fired Reciprocating Internal Combustion Engine (RICE) represents a cost-effective near-term solution for addressing the District's capacity needs in its ability to serve as a dispatchable peaking resource. With the imminent retirement of the District's resources at Yucca, this capacity need will intensify in coming years.
- **4-hour Li-ion Battery** – The District's solar-heavy portfolio can greatly utilize energy storage technology to shift some of that daytime generation into the evening ramp, especially in summer months when air conditioning loads remain high well into the evening hours. Lithium-ion battery represents a commercially available technology to provide the three-fold benefit of capacity, energy arbitrage, and provision of ancillary services in place of retiring thermal generation. With several projects either already operating or planned, storage is already growing into an important part of the IID portfolio.
- **8-hour Li-ion Battery** – As opportunities for energy arbitrage become exhausted by shorter duration storage assets, longer duration options such as an 8-hour battery start to make economic sense in shifting energy for the flatter, longer net peak in the later years of the planning horizon. 2030 is the earliest allowed build time for 8-hour battery capacity in the capacity expansion model.
- **Long Duration Storage** – While not yet fully commercialized, interest is growing in options for providing long-duration (>100hr) seasonal storage, especially for annual load patterns like IID's which are extremely summer-heavy. The low demand periods in the fall, winter, and spring present an opportunity to store excess generation from the district's renewable generation portfolio for use later in the summer months when demand (and power prices) are highest. This technology-agnostic option was considered only in an Alternate Scenario to examine potential long-term cost savings for the District.

A summary of the key assumptions for each candidate resource is presented in Table ES-1. Costs for each technology vary depending on the year the capacity expansion model chooses to build them, as shown in Figure ES-2 as forecast by Ascend's Market Intelligence unit. Of the RPS-eligible technologies, PV solar is forecast to have the lowest cost over the study period, in the $30-$50/MWh range. The wind resources are the next most expensive, in the $50-$100/MWh range. Geothermal is the most expensive RPS option considered, at $90-$180/MWh. For the storage options, the 4-hour storage PPA forecast remains relatively stable, from $13-$17/kW-month. The 8-hour storage duration option ranges from $21-$29/kW-month.

**TABLE ES-1. COST ASSUMPTIONS FOR CANDIDATE RESOURCES**

| Candidate Resource Technology | Cost Range | Earliest Allowed Build Year | Capacity Factor |
|---|---|---|---|
| SoCal Wind | $55 – $100 / MWh | 2027 | 30% |
| New Mexico Wind | $50 – $74 / MWh [3] | 2027 | 40% |
| PV Solar | $24 – $48 / MWh | 2027 | 31% |
| Geothermal | $89 – $178 / MWh | 2027 | ~ 100% |
| 4hr Storage | $13 – $17 / kW-mo. | 2027 | N/A |
| 8hr Storage | $21 – $29 / kW-mo. | 2030 | N/A |
| RICE (Natural Gas) | $1.3MM – $2.6MM / MW | 2027 | N/A |
| Long Duration Storage | N/A [4] | 2035 | N/A |

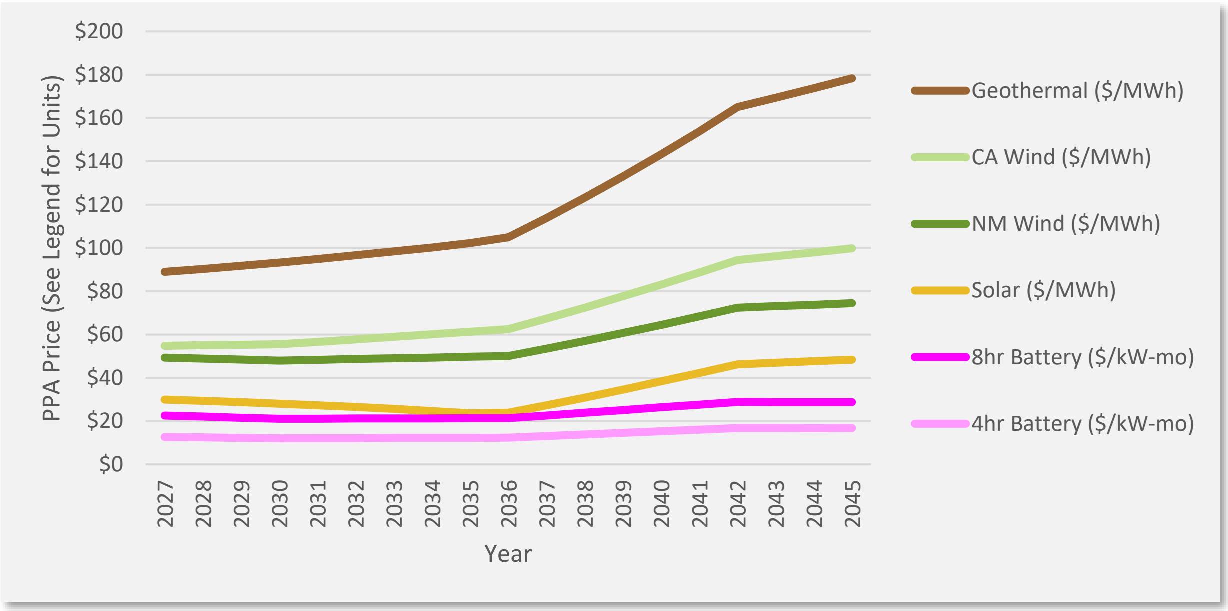



**FIGURE ES-2. ASSUMED PPA COSTS FOR NON-FOSSIL CANDIDATE RESOURCES (SOURCE: ASCEND MARKET INTELLIGENCE)**

[3] Includes a $10/MWh transmission adder for the out-of-state resource.

[4] The generic 'Long Duration Storage' technology was not evaluated with an associated cost. Inclusion of the technology in the LDES Alternative scenario provides an understanding of the relative value such a project could provide to the IID portfolio and establishes a conservative upper bound on a reasonable cost for such technology in the absence of current commercially viable options.

## Reliability Analysis

A critical component of the IRP process is establishing capacity needs for the District. To quantitatively determine this need, a loss-of-load probability (LOLP) analysis was conducted[5] to determine the amount of firm capacity needed to reach the well-established 1-day-in-10-years ("1 in 10") reliability metric. For this analysis, a conservative approach was taken here by assuming no import capability for meeting load—in other words, in the reliability analysis, load must be met with generation within the District's portfolio. Robustly modeling occurrences with the infrequency of a loss of load event requires many stochastic iterations—potential futures—of load, renewable generation, and forced outages on the dispatchable assets in any given hour. Each of these stochastic simulations is driven in PowerSIMM by an initial simulation of 250 different weather futures—hourly weather simulations from 2023 through 2045 upon which all other simulated parameters are derived. The benefit of such stochastic LOLP analysis is two-fold:

1) It enables a quantification of the District's short position in any given year, which is used by the capacity expansion model to size and time the addition of capacity resource additions to the portfolio to ensure the reliability target is met for the duration of the planning period. It can also help inform the procurement of near-term capacity contracts for the summer peak.
2) The establishment of "effective load carrying capability" (ELCC) for each candidate technology option is another benefit of LOLP analysis. ELCC quantifies the incremental additional contribution to firm-equivalent capacity that a resource provides. This is especially important for variable generation resources like solar and wind which are not dispatchable; their contribution to reliability must be considered on a probabilistic basis.

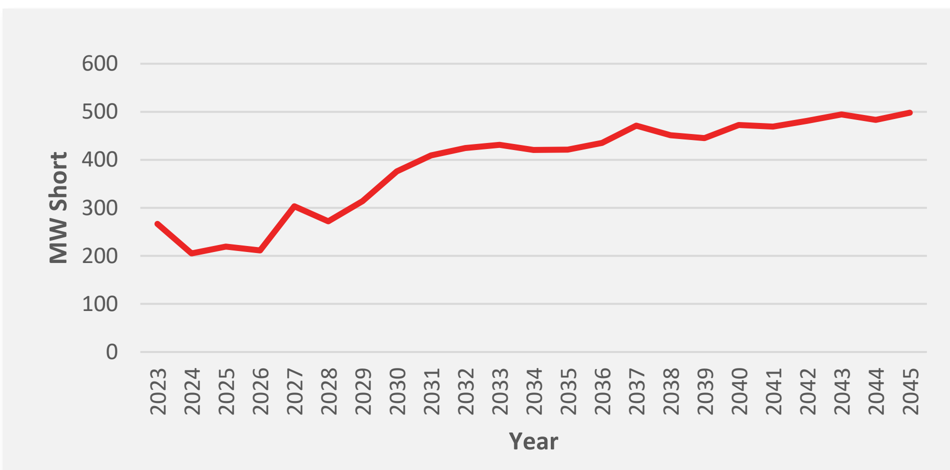



**FIGURE ES-3. IID ELCC-ADJUSTED ANNUAL PORTFOLIO CAPACITY SHORTFALL AT A TARGET LOLE OF 0.1**

Figure ES-3 shows the high-level takeaway result of the LOLP analysis. It indicates that IID's current portfolio is short by approximately 200 MW in 2024 and that this shortage grows to approximately 500 MW by 2045. The growth in this short position is due to the combination of the assumed annual increase in load (2022 CEC Mid case), the retirement of existing generation capacity over time, the expiration of renewable PPA contracts, and the absence of any new capacity additions in this Baseline analysis. In practice, IID imports power to meet load

[5] Note: this reliability analysis was conducted for the District's portfolio as of January 2023; any subsequent changes to available or planned capacity that might affect the estimated capacity short position are not captured by this analysis.

in the peak hours of the summer, but in the resource adequacy analysis which treats the system as an 'island,' where no such imports are permitted, additional generation and storage resources would be required to meet the 2.4 LOLH per year target metric.

## Baseline Scenario - Capacity Expansion

The baseline or reference scenario serves as the default planning scenario in this IRP update. Given the assumed fuel and power market prices, the forecast load, the variable generation profiles, PPA costs for each technology, and allowable build quantities and timeframes, the Automated Resource Selection (ARS) functionality of PowerSIMM™ was leveraged to obtain an optimal capacity expansion portfolio which satisfies the constraints on RPS targets, zero-carbon resources, capacity, and energy requirements at minimized cost.  Some key takeaways from this scenario are provided below:

- Initial builds of RICE units and four-hour storage in 2027 (the earliest allowable build year for any technology) improve reliability metrics by reducing the short capacity position of IID starting in 2027, the earliest allowed year for resource builds.
- The initial capacity builds are complemented by substantial builds of renewables (mainly solar, along with some in-state wind) in the late 2020s through mid-2030s. The RPS builds ensure that IID hits both its RPS energy targets and carbon emissions targets for the planning period.
- Continued build-out of additional four- and eight-hour energy storage resources in the later modeling years toward the end of the planning horizon ensure continued reliability and mitigate overgeneration concerns for load served predominantly by variable renewable generation.

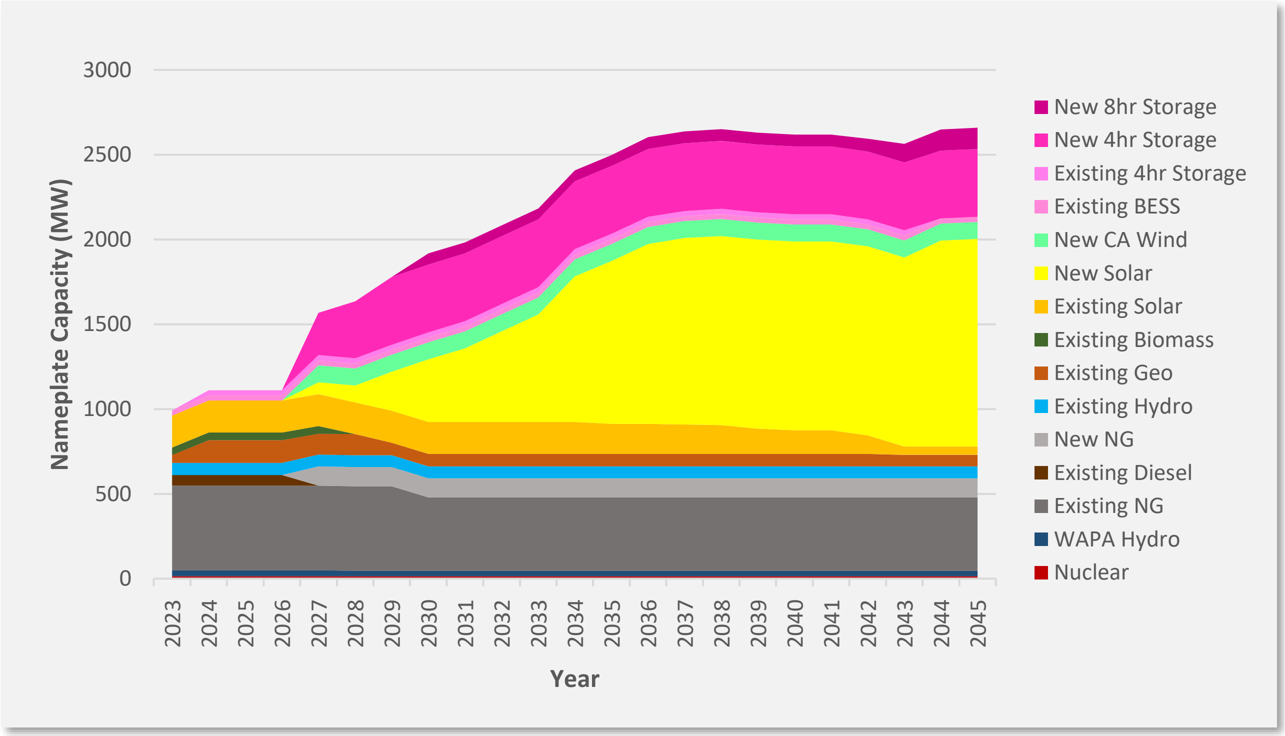



**FIGURE ES-4. BASELINE SCENARIO CAPACITY EXPANSION, 2023-2045**

Figure ES-4 shows the capacity expansion results for the Baseline scenario as cumulative capacity over the planning period. In 2027, the first allowed year of capacity selections, ARS selects 530 MW of new resources comprised of approximately 100 MW of in-state wind, 70 MW of solar, 250 MW of 4-hour storage capacity, and 110 MW of RICE thermal units. These builds, especially the storage and thermal capacity, help IID to establish a resource adequate portfolio, given that the existing portfolio was currently found to be short approximately 200 MW of capacity.

From 2027 through the mid-2030s, solar capacity is steadily added to the portfolio to meet the 2030 RPS target of 60% (measured as a percentage of retail sales) and the subsequent zero-carbon targets of 90% retail sales by 2035, 95% of retail sales by 2040, and 100% of retail sales by 2045. New solar capacity reaches 370 MW by 2030, increasing to 960 MW by 2035 and 1225 MW by 2045. The model prefers to build the majority of this new solar capacity in the mid-2030s time period when solar PPA prices are forecast to be the lowest of the planning period. The other RPS-eligible builds come from the relatively modest amount of in-state wind (100 MW). This is a reasonable, if optimistic, limit on the amount of in-state, commercially-viable wind resource that can be considered available in the relative near-term. A modest amount of longer duration eight-hour storage is added to the portfolio starting in 2030, starting with 65 MW in 2030 and reaching 125 MW by 2045. ARS does not select other RPS-eligible resources (geothermal, NM wind) in the Baseline scenario. Nameplate capacity in the Baseline scenario approaches 2.7 GW by the end of the planning period, representing a substantial increase from the roughly 1 GW of nameplate capacity in the current portfolio.

## Baseline Scenario - Production Cost Modeling

A stochastic model of 100 future price, load, and variable generation instances was used to simulate economic load dispatch of the thermal and storage units. Production cost modeling enables an assessment of overall portfolio costs to serve load, expected capacity factors, carbon emissions, storage cycling patterns, as well as individual unit revenues, costs, and any curtailment of renewables.

Key takeaways from the production cost modeling:

- The production cost modeling confirms that the upcoming RPS and zero-carbon emissions targets are met by the Baseline capacity expansion portfolio.
- The portfolio-wide carbon emissions are in line with the CARB target ranges established for IID. $CO_2$ emissions for the Baseline scenario are within the target range, with a mean emissions level of 672,000 metric tons of $CO_2$ in 2030. This will fulfill IID's contribution to California's electricity sector-wide emissions reduction goals, pursuant to SB 350.
- As shown in Figure ES-5, total portfolio cost is projected to rise from $367 million in 2024 to $411 million by 2030, to $450 by 2040, and to $496 million by 2045. This equates to an annualized increase of about 1.4%. The main components of the total portfolio cost are renewable PPA costs, natural gas fuel, purchased energy, and storage contracts. The aggregate natural gas costs for operating the thermal plants gradually wind down as those units run less and less often over the planning period.

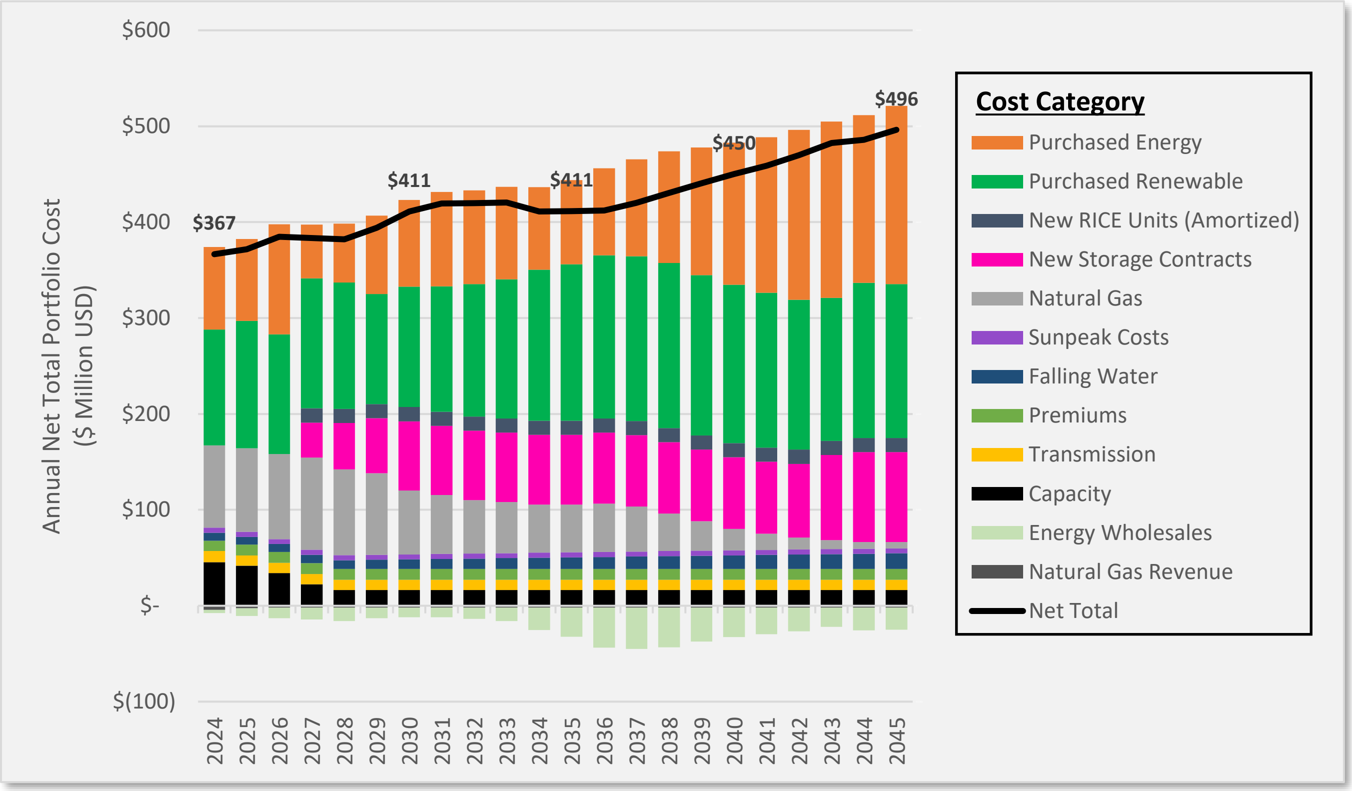



**FIGURE ES-5. BASELINE SCENARIO TOTAL COST OF SUPPLY, BY COST CATEGORY**

## Baseline Scenario – Reliability Modeling

As a final step of the resource planning phase for the Baseline scenario, another LOLP analysis was conducted on the capacity expansion portfolio. The results confirm that the capacity builds in the Baseline ensure that the 1-in-10 reliability target of 2.4 loss of load hours per year is achieved and maintained throughout the IRP planning period. This is illustrated by Figure ES-6, where the number of hours with a loss-of-load event in any given year is, on average across the 250 stochastic future simulations, less than or equal to 2.4 hours per year, or 1 day in 10 years. Recall that this LOLP analysis is a conservative estimate because it removes import capability from the model. All load must be served by the District's existing and planned generation and storage assets in the LOLP analysis.

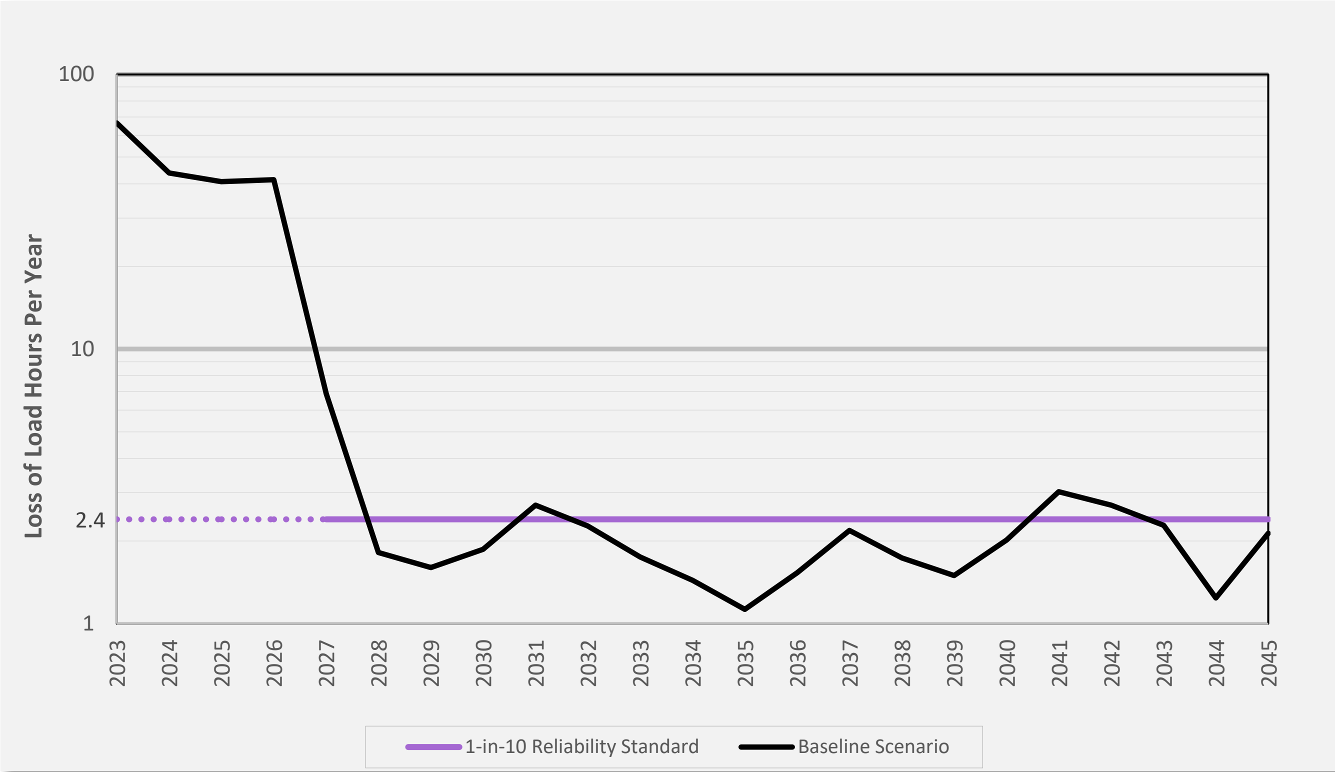



**FIGURE ES-6. RELIABILITY ANALYSIS RESULTS FOR BASELINE SCENARIO**

## Alternative Scenarios

While the "Baseline" scenario of the IRP resource planning process is given the most attention, several other scenarios were modeled as well. These scenarios reflect alternate sets of assumptions and highlight specific concerns and challenges faced by the District in planning for the future. The alternative scenarios are summarized below:

- **Geothermal-Focused** – This scenario removes wind as a candidate resource in the capacity expansion modeling. The reasoning for this is two-fold, reflecting the realities of wind procurement for the District. The first is that Baseline scenario additions of in-state wind capacity could be considered optimistic. Limited amounts of wind can be procured in-state. And, while more plentiful options are expected to be available out-of-state in the future, such as in New Mexico, the annual profile for out-of-state wind generation does not align well with IID's demand profile, peaking in the winter when IID's demand is lowest. RPS-eligible geothermal resource available within the District's service territory is considered in place of the wind. Production cost impacts of such a change are considered.
- **Solar-Focused** – This scenario removes both wind and geothermal as candidate resources in the capacity expansion modeling, leaving solar as the predominant RPS option. This scenario considers a reality where wind and geothermal availability may be limited for the District, especially in the near term.
- **Reduced Small Hydro** – This scenario considers an adverse water availability situation where flows through the hydroelectric turbines on the canal are reduced to the point where generation is effectively zero after 2030. This is not to suggest that such a scenario is likely to occur; rather, it presents a potential

upper bound on how the capacity build-out would need to adjust to make up for the loss of RPS-eligible small hydro resources in the District's portfolio.

- **High Load** – In the Load Forecast section, three CEC load forecasts were presented. The Baseline scenario used the Mid load scenario. This alternative scenario considers the High load case, where additional capacity is needed to satisfy the capacity and energy constraints imposed on the resource selection optimization.
- **Low Load** – Similar to the High Load scenario, this scenario considers the Low load forecast. Flatter future demand here means that fewer resources are needed to satisfy capacity and energy constraints.
- **Long Duration Storage** – This scenario considers the potential benefit that a generic seasonal or long duration storage resource could provide to the District's portfolio. In particular, this scenario is aimed at addressing the risk of overgeneration in a future with significant renewables build out and the long position the District may find itself in during the winter months when demand is lowest. Such technology is intentionally kept vague, with a focus on key parameters such as sizing, duration, and round trip efficiency. Two sub-alternatives are presented, reflecting 25% and 40% round trip efficiency.
- **Accelerated Decarbonization** – The constraints imposed on the Baseline scenario capacity expansion optimization may lead the model to suggest procurement for satisfying such constraints at the latest year possible. This scenario considers what it would take to reach 100% RPS generation by 2035, 10 years earlier than the SB 100 mandate. As it turns out, the Baseline scenario sees value in reaching this goal early anyway due to assumed lower solar PPA prices in the mid-2030s, so this Accelerated scenario is very similar to the Baseline scenario.
- **Delayed Solar Builds** – As an opposing case to the Accelerated Decarbonization scenario, this scenario delays builds of solar resources until the last possible year which would allow for satisfying the RPS and zero-carbon targets. The model is no longer able to take advantage of procuring what it sees as less expensive solar PPAs early on and must buy at the price forecast just before the 2035, 2040, and 2045 zero-carbon constraints come into effect. The slightly higher total cost of doing so is discussed.
- **Regionalization** – Lastly, a scenario is considered in which IID participates in CAISO's EDAM and EIM markets or the SPP Markets+ offering. Assuming CAISO or SPP is responsible for balancing as of a certain date, say 1/1/2035, IID's supply portfolio is then dispatched economically from that point forward. Cost implications of such a change are considered.

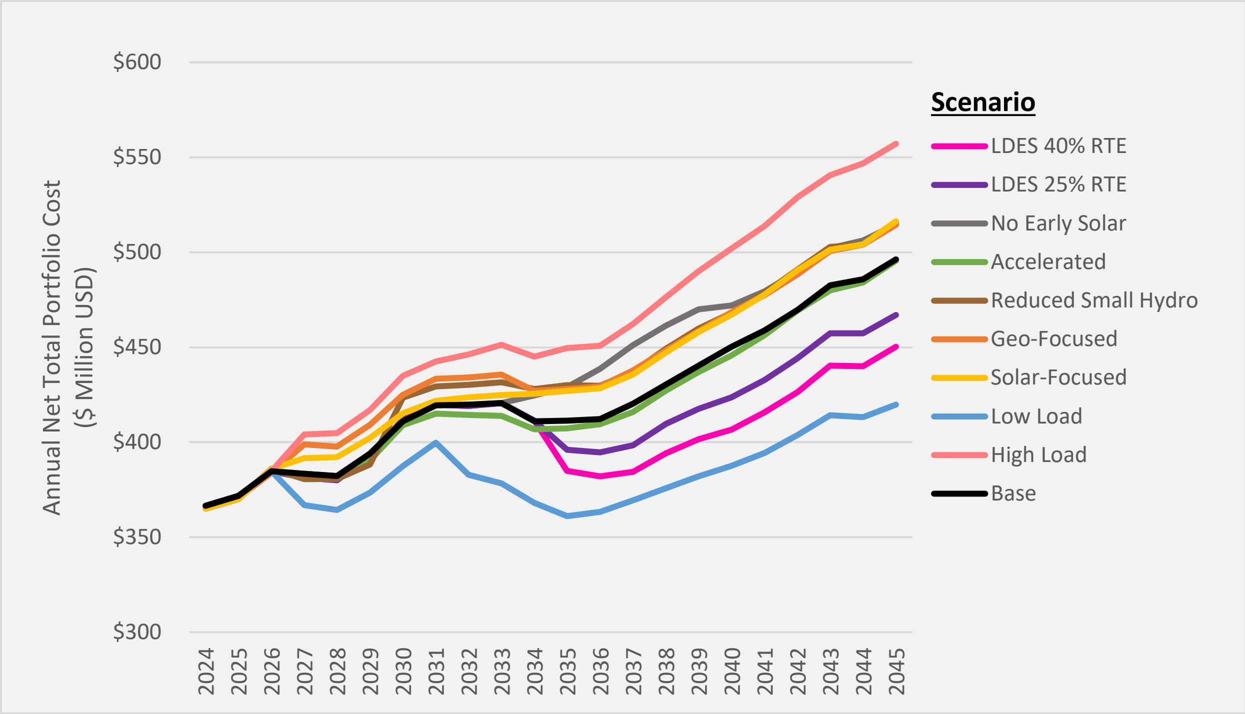



**FIGURE ES-7. ANNUAL COSTS ACROSS THE DIFFERENT SCENARIOS CONSIDERED, 2024-2045**

As shown in Figure ES-7, annual costs show generally similar trends across all scenarios. The greatest variability is exhibited by the load sensitivity scenarios, with the High Load (red) and Low Load (blue) cases reaching the highest and lowest annual portfolio costs, respectively.

Each of the alternate scenarios reaches and maintains the 1-in-10 reliability target. In addition, all scenarios are within or below the 2030 $CO_2$ emissions target range in 2030 and beyond.

## Transmission and Distribution Planning and Challenges

IID Transmission Planning has identified power system deficiencies and proposed several projects to address these issues over a ten-year period. These projects include the creation of a new 230kV transmission circuit between IID's Ramon Substation and SCE's Mirage Substation to increase system resiliency, upgrades to the 92kV CN & CL Lines, and the construction of the new Grapefruit Switching Station. Additionally, a 92kV capacitor bank was identified as a necessary system upgrade, and most breakers at ECSS are set to be replaced due to being overburdened. A spare 230:92kV transformer is also required and currently held in stock. Lastly, ECSP Unit 2-2 and its GSU are set to receive redundant protection upgrades by 2024. These initiatives aim to mitigate the observed issues and enhance the reliability and stability of the power system.

The Coachella Valley area is experiencing a surge in development requests for various projects, forecasting a need for 14 new bank additions and 22 new substations over the next 10-20 years. Challenges include high numbers of electric vehicle charging station installation requests and potential installation of Microgrids. The Imperial Valley is also seeing potential clients seeking interconnection at the transmission level, particularly load-only entities like electrical commercial fleets. This will impact the IID at the transmission and substation levels, requiring new substations to meet energy demands. IID's ongoing implementation of Advanced Metering Infrastructure (AMI) will allow for data collection at the customer and panel level, aiding in distribution system planning. This data, combined with SCADA demand, will facilitate the development of loading profiles and lead to a more accurate loading forecast.

The IID system area frequently experiences potential thermal overloads, particularly during high-demand summer months when PV generation decreases while system load remains high. This necessitates the start-up of generation in the Coachella Valley area and running of 10-40 MW of GTs for one to three hours to mitigate the issue. Overloads of the 92 kV CL and CN lines have been identified, with reconductoring of these lines recommended. Additionally, an N-2 contingency scenario in the Coachella Valley area could result in overloads at the terminal end of the 92 kV CD and CS lines, with load shedding being the only available response. The use of energy storage devices to manage loading on these loops is suggested as a cost-effective mitigation strategy.

## Energy Efficiency and Demand Response

Several energy efficiency programs have been implemented by the District in recent years:

- The **Energy Rewards Rebate Program** provides standardized incentives to both residential and non-residential IID customers to implement energy-saving technologies in their homes and businesses. The program offers incentives for a variety of measures, including attic insulation, lighting, motors, and HVAC equipment.
- The **Custom Energy Solutions Program** (CESP) promotes energy efficiency by offering financial incentives to commercial customers who install energy-efficiency equipment. Measures incentivized include interior and exterior lighting, process loads, and HVAC/refrigeration. IID offers technical expertise to assist customers in identifying energy efficiency measures and cost saving opportunities.
- The **Keep Your Cool Program** provides energy efficient refrigeration measures for non-residential facilities such as schools and grocery stores. This program offers commercial customers direct installation refrigeration upgrades, which fall into three categories: measures that reduce air leakage from cooled spaces, higher efficiency equipment, and equipment controls.
- The **Quality AC Tune-Up Program** allows small commercial customers to receive HVAC services which include duct test and seal (DTS) and/or a refrigerant charge adjustment (RCA), with inspection of all electrical connections and tightening, inspection of all moving parts and lubrication, inspection of condensate drain, inspection of system controls and thermostat setting, as well as cleaning of evaporator and condenser air conditioning coils.
- The **Residential Weatherization Program** allows participating IID electric customers to receive up to $1,000 in recommended energy saving services and equipment for their residence. The program is open to all IID residential customers on a first-come, first-serve basis. IID partners with a service provider that can evaluate and suggest a home's energy efficiency improvements.
- The **Tree for All Program** provides customers with a free shade tree planted to maximize energy savings.
- The **Green Grants Program** is offered to non-profit organizations located in IID's service area. Funding is limited to energy efficiency/management upgrades and investments in renewable resources that are not covered under any other existing public benefit program offered by IID.

For demand response, IID offers the Emergency Summer Load Reduction Program to incentivize commercial customers to reduce energy consumption during peak demand hours, thereby reducing strain on the IID electric grid and minimizing power shortages. The program, which runs from June to September, involves customers reducing their energy demand to a pre-determined level for two hours during peak evening hours. Customers are notified of events a day in advance and can participate in up to three events per month. Participants receive a monthly billing credit of $10 per kW for each successful load reduction event. If a customer cannot meet the pre-determined reduction level, they receive a credit proportional to the amount reduced.

## Localized Air and Water Pollution in Disadvantaged Communities

In 2017, Assembly Bill 617 was signed to develop a program aimed at reducing air pollution exposure and preserving public health. The bill mandates the California Air Resources Board (CARB) and local air districts, including the Imperial County Air Pollution Control District (APCD), to protect communities disproportionately affected by air pollution. CARB developed a Community Air Protection Blueprint to implement AB 617, which includes community-level air monitoring, a state strategy and community-specific emission reduction plans, accelerated review of retrofit pollution control technologies, enhanced emission reporting requirements, and increased penalty provisions for polluters. CARB may also direct additional grant funding to communities with the highest air pollution burden. Several communities in the Imperial Irrigation District (IID) service territory, particularly near El Centro, are in the higher pollution burden percentiles.

In May 2022, CalEPA updated its Designation of Disadvantaged Communities (DACs) for SB 535, incorporating public input and the latest data. Four categories of areas were designated as disadvantaged, including certain census tracts and lands under the control of federally recognized tribes. This designation, effective from July 1, 2022, guides funding decisions for programs under California Climate Investments.

A significant portion of the territory served by the IID is considered a DAC. This Integrated Resource Plan provides a roadmap toward achieving a cleaner, modernized power infrastructure while continuing to provide affordable, reliable power to all communities in the service territory. The technologies in the IRP study are operationally flexible, emit less, and are geographically dispersed, allowing IID to increase renewable energy levels while reducing carbon emissions and pollution levels. The fossil fuel capacity in the proposed plan can run on renewable hydrogen blended with natural gas. Further, El Centro Generating Station (ECGS) is developing project alternatives to treat and reuse wastewater generated from power generation operations, aiming to eliminate surface water discharge and approach a zero liquid discharge facility.

## Conclusions and Recommendations

The IRP process is the first phase in fulfilling IID’s long term power needs. Through the IRP process, IID identified the need to add capacity resources to maintain resource adequacy as well as clean and zero-carbon generation to meet the California clean energy goals.

The Baseline Scenario adds 113 MW of new RICE units, 465 MW of energy storage, 100 MW of wind, and 370 MW of new solar to the IID system by 2030 to meet the goals of the IRP. The first goal of the IRP is to demonstrate the need for new resources to reduce the capacity shortfall in the system. The second goal is to determine the necessary renewable generation to meet a 60% RPS requirement in 2030.

To procure the necessary resources to follow the plan laid out in the 2024 IRP, IID will begin work on procuring new resources in 2024. The focus should be on the RICE units, new solar and wind projects, and storage. The time it takes from the beginning of the procurement process to bringing new resources online underlines the importance of acting on the IRP plan.

# Contents

# Tables and Figures

# List of Acronyms

| Acronym | Definition |
|---|---|
| AAA | Additive error, Additive trend, Additive seasonality exponential smoothing algorithm |
| AMI | Advanced Metering Infrastructure |
| AQMD | Air Quality Management District |
| ARS | Automated Resource Selection |
| ATB | Annual Technology Baseline |
| BTM | Behind-the-Meter |
| CAISO | California Independent System Operator |
| CARB | California Air Resources Board |
| CC | Combined Cycle |
| CCA | Community Choice Aggregator |
| CEC | California Energy Commission |
| CEDU | California Energy Demand Update |
| CPUC | California Public Utilities Commission |
| CUPA | Certified Unified Program Agency |
| EFOR | Effective Forced Outage Rate |
| EIM | Energy Imbalance Market |
| ELCC | Effective load carrying capability |
| ERR | Eligible Renewable Resource |
| ETA | Energy Transition Act |
| EUE | Expected unserved energy |
| EV | Electric Vehicle |
| FERC | Federal Electricity Reliability Coordinator |
| GBM | Geometric Brownian Motion |
| GHG | Greenhouse Gas |
| GHI | Global Horizontal Irradiance |
| GW | Giga Watt |
| GWh | Gigawatt hour |
| IEPR | Integrated Energy Policy Report |
| IID | Imperial Irrigation District |
| IOU | Investor-owned utility |
| IRA | Inflation Reduction Act |
| ISO | Independent System Operator |
| ITC | Investment Tax Credit |
| kWh | Kilowatt hour |
| LBNL | Lawrence Berkeley National Lab |
| LDES | Long Duration Energy Storage |
| LOLE | Loss of Load Expectation |
| LOLH | Loss of Load Hours |
| LOLP | Loss of Load Probability |

| | |
|---|---|
| **LSE** | Load Serving Entity |
| **MIDAS** | Mixed Data Sampling |
| **MMBTU** | Million British Thermal Units |
| **MMT** | Million Tons |
| **MTR** | Mid-term Reliability Order |
| **MWh** | Megawatt |
| **MWh** | Megawatt hour |
| **MVA** | Mega Volt-Ampere |
| **NEM** | Net Energy Metering |
| **NPV** | Net Present Value |
| **NREL** | National Renewable Energy Laboratory |
| **NSRDB** | National Solar Radiation Database |
| **OTC** | Once-Through-Cooling |
| **PHEV** | Plug-in Hybrid Electric Vehicle |
| **P.V.** | Palo Verde |
| **POU** | Publicly-owned utility |
| **PPA** | Power Purchase Agreement |
| **PTC** | Production Tax Credit |
| **PV** | Photovoltaic |
| **RA** | Resource Adequacy |
| **RICE** | Reciprocating Internal Combustion Engine |
| **RPS** | Renewable Portfolio Standard |
| **SAM** | System Advisor Model |
| **SCE** | Southern California Edison |
| **SGIP** | Self Generation Incentive Program |
| **SPP** | Southwest Power Pool |
| **UCM** | Unobserved Components Model |
| **WAPA** | Western Area Power Administration |
| **WECC** | Western Electricity Coordinating Council |
| **ZEV** | Zero Emission Vehicle |

# Purpose and Approach

*Ash Main Canal, Imperial Valley. June 2011.*

## Purpose

Pursuant to Public Utilities Code (PUC) Section 9622 as codified by the Clean Energy and Pollution Reduction Act of 2015 (SB 350), publicly owned utilities (POUs) such as Imperial Irrigation District (IID) are required to submit integrated resource plans (IRPs) at least every five years. An IRP is an electricity system plan that describes how a utility plans to meet its energy and capacity resource needs, policy goals, physical and operational constraints, and other utility priorities. PUC Section 9621 applies to local POUs with an average electrical demand exceeding 700 gigawatt-hours, as determined on a three-year average commencing January 1, 2013. IID qualifies as one of sixteen such "Filing POUs" alongside the City of Anaheim, the City of Burbank, the City of Glendale, the City of Palo Alto, the City of Pasadena, the City of Redding, the City of Riverside, the City of Roseville, the City of San Francisco, the City of Vernon, Los Angeles Department of Water & Power, Modesto Irrigation District, Sacramento Municipal Utility District, Silicon Valley Power, and Turlock Irrigation District.

IID last submitted an IRP in 2019[6], and this 2024 version serves as the five-year update of that report. There have been a few important changes, both internally specific to IID and externally, between the 2019 iteration and the present update:

- Pursuant to PUC Section 9621 and the latest IRP guidelines, the planning horizon for the IRP has been extended from 2030 in the 2019 edition to include the period 2024 through 2045 in this updated edition.
- The passage of Senate Bill 100 in 2018 established the 100% zero-carbon electricity by 2045 target. At the time of the previous IRP submission, this impactful legislation had only just passed and so was only qualitatively discussed. SB 100 also increased the Renewable Portfolio Standards target for POUs to 60% by 2030, up from the 50% target established by SB 350.
- The passage of Senate Bill 1020 in 2022 established intermediate zero-carbon energy targets of 90% and 95% in 2035 and 2040, respectively.
- The 2023 SB 350 California Air Resources Board (CARB) update (currently still pending) will update the 2030 electricity GHG emissions target range for POUs.
- At the time of the 2019 IRP, IID was ending its ownership portion of the coal-fired San Juan Generating Station which until that point had supplied roughly 20% of IID's annual energy. Now in 2024, the District is in the process of retiring its owned portion of the aging Yucca Steam Plant in Arizona.
- New renewable energy and storage contracts have been procured by the District since the 2019 IRP to facilitate compliance with existing and upcoming clean energy targets as well as to ensure continued provision of reliable, affordable power to its customers.

The 2024 IRP incorporates all of these new developments, along with updated forecasts of energy demand and profiles, power prices, gas prices, PPAs for renewables and storage, and new transmission infrastructure. As its name suggests, developing an IRP truly is an *integrated* process—it requires collaboration and input from a broad array of stakeholders within the POU and beyond. Within the District's Energy Department, the Integrated Resources Planning group worked with colleagues in the Transmission, Distribution, Operations, Finance, Special Programs, and others to compile this IRP update.

## Planning Methodology

Resource planning is used to determine a path from the current energy supply portfolio to the capacity and energy needs of the utility. Planning for the future requires a clear understanding of where the energy supply is today. The key benchmark metrics for the current portfolio are reliability and energy mix. Modeling system reliability allows the planning process to make inferences about what resources are necessary to serve load in reliably in the future. Modeling the energy mix helps chart a path to meeting clean energy goals and requirements in the future.

The first phase of modeling for the IRP is to establish IID's capacity needs and the value of incremental generation to the system. The current capacity position is modeled using resource adequacy models. The outcome of this initial phase of modeling determines the inputs used in the capacity expansion model to ensure adequate new capacity is built to maintain a reliable system. The second outcome of the initial reliability modeling is to determine effective load carrying capacity (ELCC) for intermittent resources. ELCC is a metric that shows how much capacity value a resource has in terms of meeting IID customer load.

[6] https://www.iid.com/home/showpublisheddocument/9280/636927586520070000

After using initial resource adequacy modeling to establish IID's capacity needs, the modeling process turned to the capacity expansion phase to determine the least-cost buildout that meets both capacity and energy needs. In capacity expansion modeling, the energy needs for IID are determined by customer load, Renewable Portfolio Standard (RPS) requirements, and clean energy requirements set by SB350, SB100, and SB1020. California state law imposes a 60% RPS by 2030 and 100% clean energy by 2045. To meet the RPS and clean energy requirements, IID must add new resources to existing supply resources in the portfolio. The candidate resources available to the capacity expansion model to select are discussed further in the Candidate Resources section.

The portfolios selected in capacity expansion are required to meet constraints on an annual basis. Resource adequacy requirements for balancing authorities (BA) set the standard of one day in 10 years or 2.4 hours per year where the BA is not able to serve customer load. The second phase of resource adequacy modeling ensures that all selected portfolios maintain reliability throughout the study period. If any portfolio does not meet the reliability standards, a second iteration of capacity expansion and reliability analysis must be performed.

The final phase of modeling for the IRP is production cost modeling. Production cost modeling provides a view into the hour-by-hour operations of the IID system. Production cost modeling seeks to provide insight into the energy mix of the portfolio, emissions, and variable costs. This final phase of modeling provides a demonstration of the portfolio's compliance with RPS, clean energy, and emissions requirements as well as rates and total system costs. For this IRP, IID contracted the services of Ascend Analytics to perform the resource plan modeling and develop this report document. Ascend's flagship resource planning model is PowerSIMM™, a stochastic modeling software that has been used by utilities, public power entities, community choice aggregators, and developers for both short- and long-term portfolio management, project optimization, and planning purposes. A more complete description of how PowerSIMM works and was utilized for this IRP is given in **Appendix B – PowerSIMM Modeling.**

*Imperial Dam on the California/Arizona border*

# System Description

As of December 2023, IID's Energy Department provides electric power to 163,579 customers in southeastern California, with a service territory spanning from the Coachella Valley to the Imperial Valley and parts of Riverside and San Diego counties, as shown in Figure 1. This includes 140,906 residential customers, 21,868 commercial customers, and 805 industrial customers.

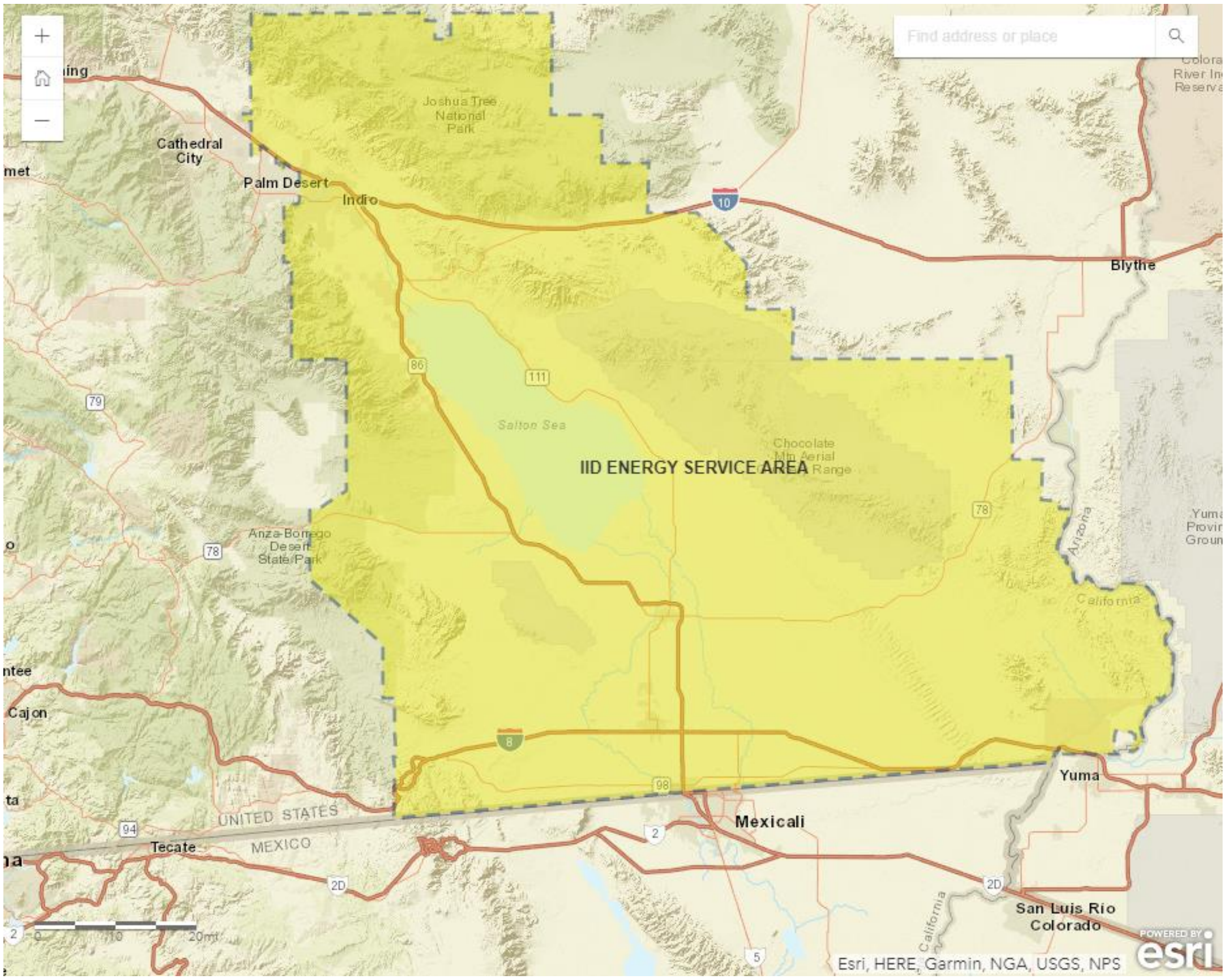



**FIGURE 1. CURRENT IID ENERGY SERVICE TERRITORY IS DENOTED BY THE YELLOW-SHADED REGION.**

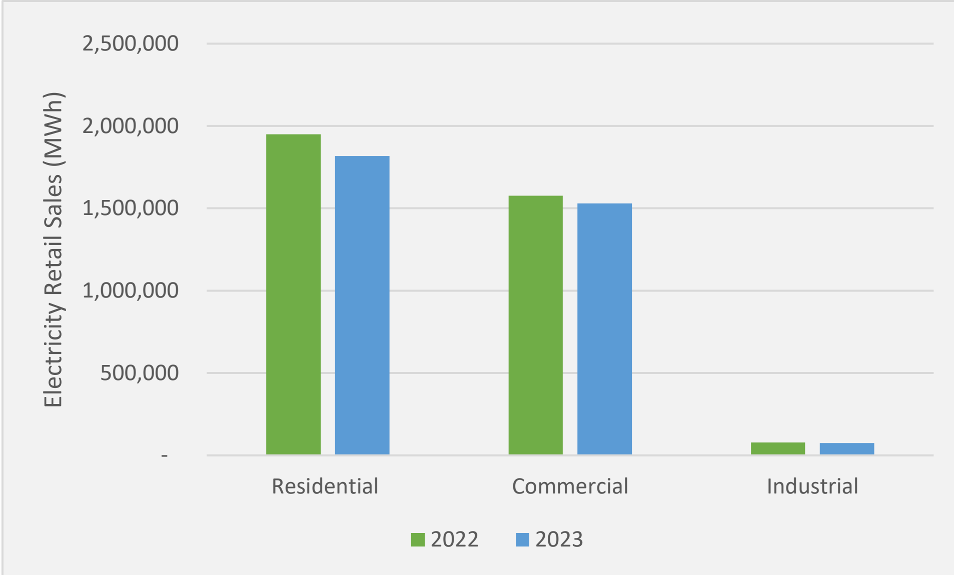



**FIGURE 2. IID SYSTEM ELECTRICITY CONSUMPTION BY CATEGORY, 2022 AND 2023**

In 2023, IID's peak electrical demand was 1,152 MW[7], which makes IID the sixth-largest utility in California on that metric. The 2023 peak demand represents an increase of 5.7% over 2022 peak demand (1,090 MW). Energy sales totaled approximately 3,422 GWh, a decrease of about 5% over 2022 sales. Retail sales are concentrated in the residential and commercial sectors, as shown in Figure 2.

As a consumer-owned utility, IID works to efficiently and effectively meet customers' demands at the best possible rates, tying the IID area's low cost of living directly with low-cost utilities. This is accomplished by producing power locally when feasible, using efficient, low-cost hydroelectric facilities, steam-generation facilities, as well as several natural gas turbines. Environmentally friendly operations are emphasized by employing as many renewable resources as available to effectively meet the state's renewables portfolio standards. IID's diverse resource portfolio provides customers with some of the lowest cost rates in Southern California and this standard of quality service will be a continued focal point of IID's future activities.

*Agriculture accounts for about 8% of the District's annual energy demand.*

[7] This occurred during a heat wave on July 20, 2023 at approximately 5 p.m. Temperatures in the city of Imperial reached 116 °F around this time. (https://www.wunderground.com/history/daily/us/ca/imperial/KIPL/date/2023-7-20)

# Transmission and Distribution Portfolio

*The 500kV Southwest Powerlink transmission line, as seen from Imperial County Route 24*

The IID transmission and sub transmission system covers an extensive area. It includes approximately 1,800 miles of overhead transmission lines and the accompanying distribution system includes 4,404.3 miles of overhead lines and 1,744.1 miles of underground lines.

## 500 kV Transmission System

The IID owns a portion of the Southwest Power Link 500 kV line. This transmission line connects the Palo Verde Substation, a major wholesale electric trading hub, to the North Gila 500 kV-69 kV Substation near Yuma, Arizona. The line continues from North Gila to the Imperial Valley 500 kV-230 kV Substation in El Centro. IID also owns a portion of the 500 kV HANG2 line that connects Hassayampa to North Gila 500 kV Substations.

## 230 kV Transmission System

There are two major components that comprise the IIDs 230 kV transmission system. The first is a single circuit line between IID's El Centro Switching Station in El Centro and the Imperial Valley Substation that is jointly owned by the IID and San Diego Gas & Electric (SDG&E) (the 'S' line). The second is a double-circuit transmission line that runs south to north through IID service territory and interconnects it with Southern California Edison (SCE) at the Devers and Mirage substations (KN/KS lines).

The KN/KS line is also known as the IID 'collector system' that runs south to north across the IID service area to SCE’s Mirage Substation. One circuit interconnects at Mirage Substation and the second circuit continues west to Devers Substation through SCE’s 230 kV line.

Four transmission substations interconnect to the collector system – from Highline in the southern part of the system through Midway, then Coachella Valley, and finally Ramon Substation. The interconnection with SCE is established at Coachella Valley Substation with the Coachella Valley - Mirage 230 kV 'KN' line and at Ramon Substation with the Ramon-Mirage 230 kV 'KS' line. The IID-SCE interconnection is defined as WECC-Path 42.

The 230 kV collector system was constructed in 1983 for the primary purpose of delivering over 500 MW of 'power generating facilities,' mostly consisting of renewable resources in the IID system and contracted to SCE at that time.

## 161 kV Transmission System

The 161 kV transmission system consists of two separate lines across the IID service area that interconnect several 161 kV/92 kV transmission stations, providing transformation capacity from the 161 kV system to the 92 kV system. It also provides interconnection to Western Area Power Authority through two 161 kV transmission lines, from IID's Niland Substation to Western’s Blythe substation, and from the IID Pilot Knob Substation to Western’s Knob Substation, as well as one interconnection from the IID Pilot Knob Substation to the APS Yucca Substation.

This 161 kV system has met the load serving requirements of the IID for over 50 years. However, as load continues to grow in all regions of the IID service area, planning for necessary system upgrades has been ongoing. The existing system has also experienced additional stresses due to generating resources constructed near the edge of the IID service territory

## 92 kV Transmission System

The 92 kV transmission/subtransmission system consists of multiple transmission lines that provide interconnection to the distribution substations (92 kV/13.2 kV) that are constantly constructed and upgraded to provide transformation capacity to the distribution system.

## Generation Resource Portfolio

IID's generation portfolio comprises a diverse mix of generation and storage technologies that serve load within the service territory. These technologies include biomass, hydroelectric, geothermal, nuclear, solar, and thermal generation, as well as lithium-ion battery storage. A core component of the IRP is examining the existing generation portfolio in detail to understand how the system operates today, and to form the baseline for capacity expansion modeling used to inform the optimal resource mix to meet future load and reliability targets. This section provides a summary of current existing and confirmed forthcoming generation resources in IID's portfolio, organized by technology type. A summary of operating generation capacity by technology type is provided in Figure 3 below.

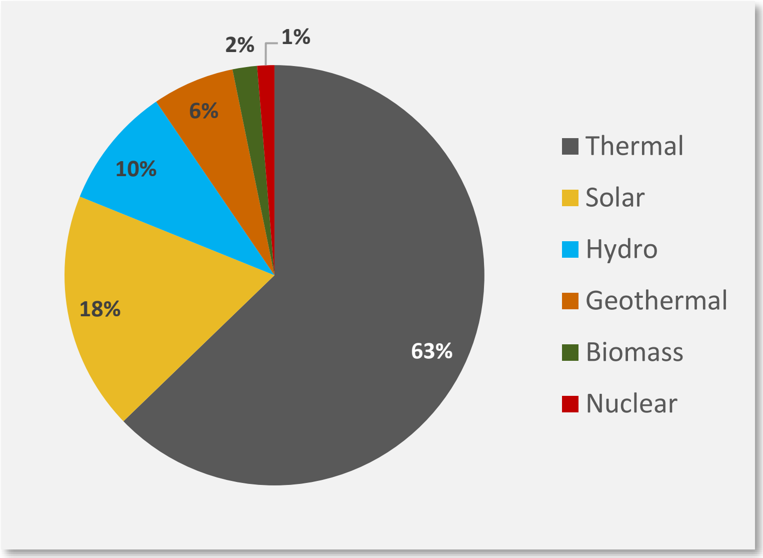



**FIGURE 3. NAMEPLATE CAPACITY OF IID GENERATION PORTFOLIO (EXCLUDING STORAGE), AS OF SUMMER 2023**

## Thermal Resources

The IID generation portfolio contains several thermal generation units located in and around the IID service territory. These include the Coachella, El Centro, Niland, and Rockwood generating stations, as well as a portion of the Yucca Power Plant in Yuma, Arizona. With an operating capacity totaling just under 600 MW and supplemented by a fleet of three mobile generation units, the dispatchable thermal assets provide energy and ancillary services for the IID Balancing Authority.

IID-owned thermal assets are maintained and operated according to the original equipment manufacturers' recommendations. Improvements are made to each unit based on an identified need for improved safety, environmental and regulatory compliance, reliability, or efficiency.

A summary of specifications for these assets is provided in Table 1, with further description of each asset discussed in the sections below.


*El Centro Generating Station in El Centro, California.*

**TABLE 1. IID THERMAL GENERATION SPECIFICATIONS AS OF JANUARY 2023**

| Generator Unit | Location | Commercial Online Year | Generator Type | Fuel Type | Capacity Rating (MW) |
|---|---|---|---|---|---|
| **Coachella 1** | Coachella, CA | 1973 | Gas Turbine | Dual Fuel | 18.6 |
| **Coachella 2** | Coachella, CA | 1973 | Gas Turbine | Dual Fuel | 19.0 |
| **Coachella 3** | Coachella, CA | 1974 | Gas Turbine | Dual Fuel | 18.3 |
| **Coachella 4** | Coachella, CA | 1976 | Gas Turbine | Dual Fuel | 18.0 |
| **El Centro 2 (Repower)** | El Centro, CA | 1993 | 1x1 CC | Dual Fuel | 105.2 |
| **El Centro 3 (Repower)** | El Centro, CA | 2012 | 2x1 CC | Natural Gas | 120.2 |
| **El Centro 4** | El Centro, CA | 1968 | Steam | Natural Gas | 67.6 |
| **Mobile – Bravo** | Calexico, CA | 2021 | Gas Turbine | Diesel | 21 |
| **Mobile – Mall** | El Centro, CA | 2021 | Gas Turbine | Diesel | 21 |
| **Mobile – Terminal** | El Centro, CA | 2021 | Gas Turbine | Diesel | 21 |
| **Niland 1** | Niland, CA | 2008 | Gas Turbine | Natural Gas | 43.7 |
| **Niland 2** | Niland. CA | 2008 | Gas Turbine | Natural Gas | 42.6 |
| **Rockwood 1** | Brawley, CA | 1979 | Gas Turbine | Dual Fuel | 23.2 |
| **Rockwood 2** | Brawley, CA | 1980 | Gas Turbine | Diesel | 23.0 |
| **Yucca CT (GT21)** | Yuma, AZ | 1979 | Gas Turbine | Diesel | 18.9 |
| **Yucca Steam** | Yuma, AZ | 1959 | Steam | Natural Gas | 74 |
| | | | | | **Total: 655.3 MW** |

### Coachella Generating Station

Located in the city of Coachella in Riverside County, California, the Coachella Generating Station is composed of four General Electric MS-5000 (Frame 5) gas turbine units. Each unit has a summer operating capacity of about 21 MW, depending on ambient air temperature[8] as higher temperatures adversely affect gas turbine performance. The gas turbine units were brought online between 1973 and 1976 to meet growing system-wide electricity demand, especially in the Coachella Valley. The Coachella units are dual fuel, meaning they can run on natural gas or diesel. Typically, the plants run on natural gas, which is supplied by a SoCal Gas pipeline to the facility. Today, the plant operates primarily as peaking capacity, and each unit has an annual operating limit of 200 hours. Coachella's air emissions and hazardous materials are regulated by the South Coast Air Quality Management District (AQMD) and the Riverside County Department of Environmental Health. The units provide voltage support, non-spin reserve capacity, and reactive regulation for the IID Balancing Authority, in addition to being black start capable and able to operate isolated from the grid.

### El Centro Generating Station

Located in the City of El Centro, Imperial County, California, the El Centro Steam Plant was originally constructed from 1947 to 1949 as part of the District's 1945 Power Development Project[9]. The plant was inaugurated on April 25, 1949 with a 20 MW dual-fuel capable steam unit coming online[10]. The El Centro plant has since been expanded and, more recently, repowered. Unit 2 was added in 1952 and repowered in 1993 as a 1x1 combined-cycle with a nameplate capacity of 124 MW (operating capacity 105 MW). Unit 3 was added in October 1957 and repowered in October 2012 as a 2x1 combined-cycle with a nameplate capacity of 152 MW (120 MW operating capacity). Unit 4 was completed in 1968 and has a nameplate capacity of 82 MW (68 MW operating capacity). Unit 1 (the original steam unit constructed in 1949) was retired in 1995. El Centro's air emissions are regulated by the Imperial County Air Pollution Control District; the Imperial County Certified Unified Program Agency (CUPA) regulates hazardous materials and the California Regional Water Control Board regulates water discharge. The El Centro Generating Station continues to serve as one of the major components of IID's thermal generation portfolio, operating as intermediate-duty generation within the District's power resources.

### Niland Generating Station

Completed in May 2008, the Niland Generating Station is located about a mile northeast of Niland, Imperial County, California and consists of two aeroderivative gas turbine units. The turbines are General Electric LM6000 PD SPRINT NxGen combustion turbine generators with inlet air chiller coils and a zero liquid discharge (ZLD) wastewater treatment system. Each unit has a nameplate capacity of 60.5 MW and an operating capacity around 44 MW. Niland operates as a peaking generator, with an annual limit of 6,000 hours of operating time shared between the two units. Niland's air emissions are regulated by the Imperial County Air Pollution Control District; hazardous materials are regulated under the Imperial County CUPA. Natural gas for the facility is supplied by two SoCal Gas transmission pipelines. The plant also provides important voltage support, spinning and non-spinning reserve capacity, reactive regulation, and 10-minute fast-start dispatchability.

### Rockwood Generating Station

Located about a mile south of the city of Brawley, Imperial County, California, the Rockwood Generating Station consists of two aeroderivative gas turbine units. Unit 1 began operation in June 1979, is a dual-fuel generator, and

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[8] Each 10°F rise in temperature can result in as much as a 3-4% decrease in output and a 1% rise in heat rate. (Source: https://recorder.imperialcounty.org/wp-content/uploads/2022/08/Rockwood-Gas-Turbine-Unit-1.pdf)
[9] Annual Report 1945. Imperial Irrigation District. Accessed December 5, 2023. https://www.iid.com/home/showpublisheddocument/20526/637963224241200000
[10] Annual Report 1949. Imperial Irrigation District. Accessed December 8, 2023. https://www.iid.com/home/showpublisheddocument/20530/637963224277770000

is black start capable. Unit 2 came online in 1980 and runs on diesel. Both units are Pratt & Whitney FT4C-3F gas turbines, each having a nameplate capacity of 26 MW and an operating capacity of 23 MW. Natural gas for the facility is supplied by a SoCal Gas transmission pipeline. Rockwood operates as peaking capacity within the IID portfolio, with an annual operating limit of 400 hours on each unit. Rockwood's air emissions are regulated by the Imperial County Air Pollution Control District; hazardous materials are regulated under the Imperial County CUPA.

### Yucca Power Plant

Located in Yuma, Arizona, the Yucca Power Plant, including IID assets, is operated by Arizona Public Service (APS). Steam Unit 1 (also known as Axis) was the first generator at Yucca and represents the oldest current member of IID's thermal portfolio, coming online in March 1959. It has a nameplate capacity of 87 MW (74 MW operating capacity) and typically operates on natural gas supplied by the Yuma Lateral of TC Energy's North Baja pipeline system (in service as of March 2010)[11]. The steam unit can also run in an alternative configuration using fuel oils #4 – #6, or in a co-firing configuration with a combination of both natural gas and fuel oil. Together with the El Centro Generating Station, the Yucca steam unit forms the core of IID's thermal generation portfolio. In addition to the steam unit, IID's other thermal capacity at Yucca comes in the form of a 23 MW nameplate capacity (19 MW operating capacity) gas turbine which was put into service in December 1979. Running exclusively on diesel, this generator (known as GT21) seldom operates due to its low efficiency. The steam unit and combustion turbine were purchased from SCE in April 1993. Air emissions and hazardous materials for the Yucca Power Plant are regulated by the Arizona Department of Environmental Quality; the Bureau of Reclamation regulates water discharge. Due to the uncertainty around the future status of Yucca generation, it is excluded from the IRP resource planning.

### APR Mobile Diesel Generators

In May 2021, IID entered into a power supply and service agreement with APR Energy, LLC to install three temporary mobile turbine generators at strategic points within the IID system. All three are GE TM2500+ Gen 7 units rated at 25 MW. They entered commercial service in June 2021 at the Bravo, Mall, and Terminal substations. The mobile generators provide additional capacity between the peak net load hours of 2 p.m. and 10 p.m. from mid-June through mid-October. In January 2022, APR and IID extended the agreement to cover the summer 2022 period, and in 2023 the agreement was further extended for three additional years through summer 2025. The units are primarily diesel-fueled but can run on several types of fuel oil. Air emissions are regulated by the Imperial County Air Pollution Control District.

## Solar Resources

Given the favorable operating conditions, many utility-scale PV solar installations have already been constructed and are operating in the IID region. Among those, several projects have come about through partnership with IID and/or are contracted to provide energy to the IID system. The following sections describe each of the solar projects currently in IID's portfolio; key features of these projects are also summarized in Table 2 below.

[11] "About North Baja Pipeline, LLC." TC Energy. Accessed December 5, 2023. https://www.tcplus.com/North%20Baja

**TABLE 2. IID SOLAR PHOTOVOLTAIC GENERATION SPECIFICATIONS**

| Solar Project | Location | Commercial Online Date | Project Type | Nameplate Capacity (MW) |
|---|---|---|---|---|
| Augustine Solar Energy Park | Coachella, CA | Feb. 2009 (1.1 MW)<br>July 2012 (2.2. MW) | PPA (20 yr.) | 3.3 |
| Citizens | Calipatria, CA | 8/7/2019 | PPA (23 yr.) | 30 |
| El Centro Solar Park (ECPV) | El Centro, CA | 10/31/2013 | PPA (25 yr.) | 20 |
| Heber (Imperial Solar) | Heber, CA | 4/23/2014 | PPA (20 yr.) | 10 |
| Imperial Valley College Solar | Imperial, CA | Q1 2017 | IID-owned | 2.54 |
| Midway Solar II (96WI8ME) | Calipatria, CA | 5/3/2017 | PPA (25 yr.) | 30 |
| SDSU PV 1 | Brawley, CA | 6/13/2014 | PPA (25 yr.) | 5 |
| SEPV East | Dixieland, CA | 1/1/2017 | FIT PPA (20 yr.) | 2 |
| SEPV West | Dixieland, CA | 1/1/2017 | FIT PPA (20 yr.) | 3 |
| Seville #2 | Ocotillo Wells, CA | 6/1/2016 | PPA (25 yr.) | 30 |
| IVSC Sun Peak 1 | Niland, CA | 6/1/2012 | IID-owned | 23 |
| IVSC Sun Peak 2 | Niland, CA | 8/6/2015 | PPA (30 yr.) | 20 |
| Valencia 1 | Westmorland, CA | 8/31/2017 | FIT PPA (20 yr.) | 3 |
| Valencia 2 | Brawley, CA | 11/16/2020 | FIT PPA (20 yr.) | 3 |
| Valencia 3 | Imperial CA | 3/5/2021 | FIT PPA (20 yr.) | 3 |
| | | | | **Total: 188 MW** |

*IID/Citizens Low-Income Community Solar Project*

### Augustine Solar Energy Park

In 2008, the Augustine Band of Cahuilla Indians completed installation of a 1.1 MW solar plant on reservation land to supply power to the nearby Augustine Casino and other nearby homes and businesses. The project was planned as part of a 2006 grant from the US Department of Energy First Steps program[12]. In 2012, a second 2.2 MW project was completed at the same site, bringing the current Augustine Solar Energy Park capacity to about 3.3 MW across roughly 25,000 solar panels. IID obtains the excess power from this facility that is not otherwise used by the casino or nearby buildings. Annual energy supplied from this project for IID's portfolio is approximately 3,000-4,000 MWh.

### IID/Citizens Low-Income Community Solar Project

Commissioned on September 25, 2019, the IID/Citizens Low-Income Community Solar Project is a 30 MW solar facility about six miles northeast of the City of Calipatria, Imperial County, California. It consists of approximately 107,000 solar panels and connects to the IID grid at the nearby Midway Substation. The power purchase agreement with Citizens Energy is for 23 years, and IID has the option to purchase the project at the end of the agreement.

### Heber Solar Energy Facility

In 2011, IID solicited offers through an RFP for local development of renewable resources. One of the selected offers was Ormat's 10 MW Heber Solar facility. Located about a mile south of Heber, Imperial County, California, the facility (now owned by Renewable Energy Trust Capital, Inc.) began supplying power to the IID system in April 2014 under a 20-year PPA; it produces approximately 25,000 MWh annually.

### Imperial Valley College (IVC) Solar

In 2017, a 2.5 MW solar facility was completed on 17 acres of land north of the campus of Imperial Valley College in Imperial County, California. IID purchased the solar farm in 2022. Annual energy supplied from this project for IID's portfolio is approximately 5,900 MWh.

### Midway II Solar Project

On November 18, 2014, IID executed a PPA with the joint venture partnership of 8minute Energy and Gesamp Solar for a 30 MW solar energy facility. The project, then known as "Calipatria Solar Complex", was transferred to Solar Frontier, LLC (now known as Idemitsu Renewables) in 2015 and then sold to Dominion Energy in 2017. The Midway II project (also known as 98WI 8me LLC) is located about three miles northwest of Calipatria, Imperial County, California and began commercial operation in May 2017. IID obtains approximately 73,000 MWh of solar power from the project annually under the 25-year PPA.

### Seville II

In May 2014, IID executed a PPA with Regenerate Power, LLC for 30 MW of solar energy. Member interest in the project was transferred to Kruger Energy in October 2014 and then to Duke Energy in June 2015. The Seville II project is located in Imperial County just south of Route 78, about 8 miles east of the community of Ocotillo Wells, and it began commercial operation in June 2016. IID obtains approximately 83,000 MWh of energy from the project; the PPA term is 25 years.

### NRG Community 1 Solar Generating Facility (SDSU Brawley PV)

In December 2011, IID executed a PPA for 5 MW of solar energy with Sol Orchard Community Solar 1, LLC. The project is located on approximately 37 acres on the eastern side of the Brawley site of San Diego State University

[12] Turner, Paul. 2008. "Augustine Band of Cahuilla Indians Energy Conservation and Options Analysis - Final Report." United States. https://doi.org/10.2172/934737

Imperial Valley campus, about three miles east of the city of Brawley, Imperial County, California. The project was transferred to NRG in 2014 and began commercial operation in June of that year. IID obtains approximately 14,000 MWh per year from the facility; the PPA term is 25 years.

### El Centro Solar Park (ECPV)

In 2011, IID solicited offers through an RFP for local development of renewable resources. One of the selected offers was Sol Orchard Imperial 1 LLC’s 20 MW El Centro PV (ECPV) facility. Located adjacent to the El Centro Generating Station and El Centro Substation, this facility began commercial operation in October 2013 under a 25-year PPA and generates approximately 50,000 MWh annually. The project is now known as El Centro Solar Park and was acquired by Excelsior Renewable Energy Investment Fund I LP from Grupo T-Solar in April 2019.

### IVSC Sun Peak 1 and 2

In August 2010, IID executed a PPA for 23 MW of solar energy with Imperial Valley Solar Company 1, LLC (a subsidiary of SunPeak Solar). This 'Sun Peak 1' project began commercial operation in August 2012. IID obtains approximately 43,000 MWh per year from this project. While the original PPA term was for 30 years, IID exercised its purchase option in 2018 and now owns the facility.

In December 2011, IID executed a PPA for 20 MW of solar energy with IVSC 2’s 'Sun Peak 2' project. The project was transferred to Dominion Energy in June 2015. The project began commercial operation in August 2015; IID obtains approximately 46,000 MWh from this project; the PPA term is 30 years.

The Sun Peak projects are located next to the Niland Generating Station and the Niland Substation, about a mile northeast of Niland, Imperial County, California.

### Feed-in-Tariff (FIT) Projects

California Senate Bill 1332 (SB 1332) was signed into law on September 27, 2012 and required all investor-owned utilities (IOUs) and publicly-owned utilities (POUs) with more than 75,000 customers to implement a feed-in-tariff (FIT) program by July 1, 2013. IID met the criteria to implement such a program, and the District’s proportional

*El Centro Solar Park*

share of the statewide cap of 750 MW of capacity installed under FIT programs was approximately 14 MW. The IID board adopted a standard form power purchase agreement on June 25, 2013. Presently, there are five FIT projects in IID’s renewable power portfolio totaling 14 MW of capacity. These projects are summarized below.

### SEPV Dixieland East and West

Solar Electric Solutions submitted FIT requests to IID for two solar projects— SEPV Dixieland East and West. SEPV East is a 2 MW project and SEPV West is a 3 MW project. They are located on either side of Dixieland Substation in Imperial County, about five miles west of the community of Seeley, California. Commercial operation for the projects began in January 2017; their combined energy output is approximately 15,000 MWh annually. The PPAs associated with these projects each have a term of 20 years.

### Valencia 1, 2, and 3

Green Light Energy Corporation submitted FIT requests to IID for two solar projects— Valencia 1 and 2. Both are 3 MW facilities. Valencia 1 became operational in summer 2017 and is located in the city of Westmorland, Imperial County, California. Valencia 2 reached commercial operation in November 2020 and is located about five miles south of Brawley, Imperial County, California on Route 111.

In 2015, IID executed a FIT PPA with Imperial Water Ventures, LLC for the 3 MW Valencia 3 solar project. This project began commercial operation in March 2021 and is located about three miles northeast of the city of Imperial, Imperial County, California.

## Geothermal Resources

*Heber -1 Geothermal Project*

IID is uniquely located to take advantage of geothermal generation within the IID service territory. Since 2016, IID has contracted with five geothermal projects for a total of 117 MW.

**TABLE 3. IID GEOTHERMAL GENERATION SPECIFICATIONS AS OF JANUARY 2023**

| Geothermal Project | Location | Contract Start Date | Project Type | Nameplate Capacity (MW) |
|---|---|---|---|---|
| CalEnergy Operations (BHE) | Calipatria, CA | 1/1/2019 | PPA (10 years) | 50 |
| Heber 1 | Heber, CA | 2/2/2016 | PPA (10 years) | 12 |
| Hell's Kitchen Geothermal Project | Niland, CA | 7/15/2024 (Planned) | PPA (25 years) | 50 |
| Ormat Ormesa | Holtville, CA | 1/1/2018 | PPA (25 years) | 5 |
| | | | | **Total: 117 MW** |

### CalEnergy Operations (BHE Renewables)

CalEnergy is a subsidiary of BHE Renewables and has geothermal projects in the Salton Sea Geothermal Field. Since the 10-year PPA was signed in 2019, CE GEN operations have been contracted to provide 50 MW of RPS-eligible geothermal energy to IID through 2029.

### Heber-1 Geothermal Project (Ormat)

In the second quarter of 2013, IID signed a 10-year power sales agreement with SCPPA in a joint participation project with LADWP to purchase the production at the existing Heber-1 Geothermal Facility starting in 2016. The agreement is for 33% of the plant output in the first three years and 22% in the remaining term. Heber-1 provided IID with about 15 MW (minimum of 13 MW and maximum of 19 MW) in the first three years of the agreement. After the first three years, IID's portion became 10 MW (minimum of 8 MW and maximum of 12 MW). The PPA term expires in 2026.

### Hell's Kitchen Geothermal Project

Scheduled to come online in Q3 2024, Hell's Kitchen Geothermal Project is a planned 50 MW project located in Niland, CA. The PPA term will run for 25 years, ending in 2049.

### Ormesa Geothermal Complex (Ormat)

IID's other contracted geothermal project with Ormat is the Ormesa Geothermal Complex located in Holtville, CA. The 25-year PPA for 5 MW of RPS-eligible geothermal generation began in 2018 and will continue until 2043.

## Hydroelectric Resources

The IID portfolio includes several small, RPS-eligible hydroelectric plants. These were constructed between 1941 and 1984 with subsequent refurbishment and repowering of some units in the years since. The small hydro resources are 'run of river' and depend on irrigation flows through the canals on which they are situated. IID also has two allotments of large, zero-carbon eligible hydroelectric power through Western Area Power Administration (WAPA): the first is a 3 MW share of the Boulder Canyon project and the second is a share of the Parker Davis hydroelectric project, which is a capacity share that varies between 32 MW in the summer and 26 MW in the winter. Each of these resources is described in more detail below.

**TABLE 4. IID-OWNED OR -ALLOCATED HYDROELECTRIC GENERATION SPECIFICATIONS**

| Hydroelectric Resource | Location | Commercial Online Date | Project Operator | Operating Capacity (MW) |
|---|---|---|---|---|
| Double Weir | Central Main Canal | 3/20/2005 | IID | 0.36 |
| Drop 1 | All-American Canal | 11/16/1984 (Unit 1)<br>10/23/1984 (Unit 2)<br>10/19/1984 (Unit 3) | IID | 6 |
| Drop 2 | All-American Canal | 12/5/1953 (Unit 1)<br>12/30/1953 (Unit 2) | IID | 10 |
| Drop 3 | All-American Canal | 2/20/1941 (Unit 1)<br>11/23/1966 (Unit 2) | IID | 10 |
| Drop 4 | All-American Canal | 8/9/1950 (Unit 1)<br>3/30/2006 (Unit 2) | IID | 21 |
| Drop 5 | All-American Canal | 3/1/1982 (Unit 1)<br>3/1/1982 (Unit 2) | IID | 4 |
| East Highline | All-American Canal | 9/12/1984 | IID | 2.4 |
| Pilot Knob | All-American Canal | 1/31/1957 | IID | 16.5 |
| Turnip | Westside Main Canal | 10/1/1964 | IID | 0.42 |
| Boulder Canyon | Hoover Dam, Colorado River (NV/AZ) | 1936 | WAPA | 3 |
| Parker Davis | Davis Dam (AZ/NM)<br>Parker Dam (AZ/CA) | 1954 | WAPA | 32 (Summer)<br>26 (Winter) |
| | | | | **Total: 106 MW** |

## Double Weir

Double Weir is IID's smallest small hydro facility. Initially constructed in 1961 and repowered in 2005, Double Weir is located on the Central Main Canal. The capacity of the unit is 0.36 MW and it began operating in March 2005.

## Drop 1

Drop 1 consists of three turbines totaling 6 MW of capacity and began operating in 1984. It is located on the All-American Canal.

## Drop 2

Drop 2 consists of two turbines totaling 10 MW of capacity and began operating in 1953. It is located on the All-American Canal.

## Drop 3

Drop 3 consists of two turbines totaling 10 MW of capacity. Unit 1 began operation in 1941 and Unit 2 was added in 1966. It is located on the All-American Canal.

## Drop 4

Drop 4 consists of two turbines totaling 21 MW of capacity. Initially constructed in 1941, Unit 1's current capacity came online in 1950, and Unit 2 was refurbished in 2006. It is located on the All-American Canal.

### Drop 5

Drop 5 consists of two turbines totaling 4 MW of capacity. Both units began operating in 1982. It is located on the All-American Canal.

### East Highline

East Highline has one turbine with a capacity of 2.4 MW. It began operation in 1984 and is located on the All-American Canal.

### Pilot Knob

Pilot Knob entered operation in 1957 with two 16.5 MW turbines. It is located on the All-American Canal. Today, one of the units is rarely operational due to low flow conditions and was not considered for IRP planning purposes.

### Turnip

Turnip is a 0.42 MW plant located on the Westside Main Canal. It was installed in 1964.

### Boulder Canyon

As a part of the Lower Colorado River system via the WAPA-Parker/Davis agreement, IID was allotted a portion of the upgraded Hoover Dam/Boulder Canyon Project. The amount equates to about 3 MW and costs will range approximately between $25-30/MWh.


*Sign outside of the East Highline hydroelectric facility*

## Parker Davis

The IID has an entitlement of 32.6 MW (summer) in the Parker-Davis Hydroelectric Project (Parker-Davis) in western Arizona. Energy from Parker-Davis is provided by Western at the rate of 3,679 MWh per MW of capacity per month. Parker-Davis energy can be primarily used during on-peak periods, although a small portion of the energy must be scheduled during off-peak periods due to water management requirements of the Parker and Davis dams by Western. While Parker-Davis is a hydroelectric project, it is not considered a renewable project by the state for RPS requirements. Hydroelectric projects must be less than 30 MW to qualify as renewable projects. Parker-Davis capacity is a source of inexpensive capacity and energy. As such, IID is continually defending its allocation from claims by other eligible entities, primarily Native American tribes and the Department of Defense.

IID's current allocation expires in 2028 and is assumed to be renewed at the same levels for the duration of the study period. A reduction in allotted generation would bring additional challenges for achieving zero-carbon targets from 2035 onward, potentially requiring zero-carbon resource procurement beyond the amounts suggested in the Baseline scenario capacity expansion scenario of this IRP.

## Biomass Resources

Desert View Power (DVP) is a 45-megawatt renewable energy power plant located approximately 40 miles east of Palm Springs in Riverside County, California, and is located on the Cabazon Band of Cahuilla Indians Reservation.

Prior to 2011, Desert View Power acquired the Colmac Biomass Plant and solicited the output of the plant to IID. IID agreed to a 10-year term PPA that places IID as the sole off-taker of the 45 MW plant.

The payment for the output of the plant comprises all environmental attributes, including Category 1 RPS RECs from an Eligible Renewable Resource (ERR). A part of the agreement provides that the seller has about two months out of the year to perform regularly scheduled maintenance. During these times, IID will receive approximately half of the total maximum plant output. Even though the plant fully qualifies as an ERR under the CEC, which governs the RPS, the plant is located on an Indian Reservation, and the California Air Resources Board (CARB) considers this type of resource to be what is known as a 'specified resource.' This designation places this resource into a category that is not exempt from the cap-and-trade allowance system so the output from the plant is estimated to utilize about 15,000 $MTCO_2e$ of allowances each year. Over the course of a year, the plant is expected to produce nearly 325,000 MWh of RPS-eligible generation.

The current Desert View PPA runs through March 2027.

**TABLE 5. IID BIOMASS GENERATION RESOURCE SPECIFICATIONS**

| Biomass Resource | Location | PPA Start Date | Project Operator | Operating Capacity (MW) |
|---|---|---|---|---|
| Desert View | Riverside County, CA | 2011 | Greenleaf Power | 45 |

## Nuclear Resources

The IID has a small entitlement (through Southern California Public Power Authority) of capacity in each of three units at the Palo Verde Nuclear Generating Station (PVNGS). IID's total (delivered) capacity is 14 MW (5 MW from each of the three PVNGS units, less losses). As a zero-carbon resource, nuclear generation within the IID portfolio can be counted toward the 2035+ zero-carbon targets.

**TABLE 6. IID NUCLEAR GENERATION RESOURCE SPECIFICATIONS**

| Nuclear Resource | Location | Start Date | Project Operator | Allotted Capacity (MW) |
|---|---|---|---|---|
| Palo Verde | Tonopah, Arizona | August 1981 | Arizona Public Service | 14 |

## Energy Storage Resources

*The District's 30MW Battery Energy Storage System (BESS) next to El Centro Generating Station*

Energy storage is becoming a more and more important resource as variable generation resources such as solar and wind are increasingly adopted and integrated into the District's portfolio. Energy storage can help address overgeneration concerns and meet evening ramps while reducing the need for generation from gas-fired generation or market sources. In IID's case, overgeneration is of particular concern in the non-summer months, where electricity demand is lowest. Some battery capacity already exists within the District's portfolio, providing reliability, energy arbitrage, and ancillary services benefits. Energy storage plays a central role in the capacity expansion analysis of this IRP; indeed, more capacity is already planned to come online in the near future. Table 7 provides an overview of IID's existing and planned energy storage resources; each project is discussed in greater detail below.

**TABLE 7. EXISTING OR PLANNED IID STORAGE RESOURCE SPECIFICATIONS AS OF JANUARY 2023**

| Hydroelectric Resource | Location | Commercial Online Year | Project Owner | Power Capacity (MW) | Storage Capacity (MWh) |
|---|---|---|---|---|---|
| Battery Energy Storage System (BESS) | El Centro, CA | 10/1/2016 | IID | 30 | 20 |
| Holtville BESS | Holtville, CA | Planned Q1 2024 | Greenbacker Capital Management[13] | 30 | 120 |
| | | | | Total: 60 MW | Total: 140 MWh |

## El Centro Battery Energy Storage System

To address potential operational issues, IID installed a 30 MW/20 MWh battery storage facility that greatly reduces the volatility of impact from intermittent resources. IID's ability to balance its load and resources in the current environment with the solar resources online ensures compliance with NERC balancing reliability standards. In fact, IID is highly compliant based on Control Performance Standard No 1 and 2 (CPS1 and CPS2) measures. With the expectation that IID will add additional solar resources to its portfolio, the ability to comply with NERC balancing standards may become more of a challenge. IID limits existing ramping capability for its resources to effectively integrate the committed solar projects while maintaining reliable operation. As additional intermittent renewable resources are added to the IID system, there will be an increased requirement for fast-ramping resources that can control those fluctuations. IID has been analyzing different applications of fast-ramping resources that can respond to solar intermittency. The cost of integration will be considered while analyzing future renewable projects. Additionally, the battery has a round trip efficiency of 85%, so the dispatch price must be at least 15% better when strategically dispatching the battery to address system needs. Further, IID has determined that the battery storage facility installed is capable of offering black start services.

## Holtville BESS

Imperial Irrigation District's Energy Department issued a solicitation in 2021 for an energy storage solution to be installed on the IID system. The solicitation sought an engineering, procurement, and construction transaction whereby a contractor would build a stand-alone storage solution for IID. Based on the responses IID received during the solicitation process, it was determined that the cost was exponentially higher than IID initially estimated. IID received an unsolicited letter of intent and proposal from SunCode containing four options for a battery energy storage solution. IID evaluated the options and determined that a single option, a 30 MW/120 MWh (four-hour) battery energy storage system to be sited near IID's Holtville Substation and procured under a Power Purchase Tolling arrangement, was the best choice.

The project was acquired from SunCode by Greenbacker Capital Management in June 2023 and is slated to come online in Q3 2023.

[13] Acquired from SunCode in June 2023.

# Fundamental Macro-Level Drivers

Ascend maintains a unique fundamental modeling framework to support resource planning and valuation activities, purposefully designed to capture the dynamics of structural change in the electricity sector. Figure 4 shows the general schematic of the Ascend approach.

All Ascend forecasting remains anchored by several fundamental drivers, shown at the bottom of Figure 4, and macro assumptions, shown in the top left. All forecasts align to market forwards in the near term; these reflect the consensus market expectation of all macro level assumptions, including greenhouse gas (GHG) and renewable portfolio standard (RPS) policy, economic growth, electrification, and technology costs. Ascend forecasts also adhere to long-run equilibrium, which ensures that resources earn normal returns, since supernormal returns would drive market entry and subnormal returns would drive retirement or deter entry.

While Ascend forecasts enforce equilibrium on average and in the long run, regulatory and logistic barriers to entry create time lags between market signals and resource buildout. These barriers lead to temporary disequilibrium periods. Geographic barriers, such as land costs, population density, bodies of water, mountains, interconnect boundaries, and variation in renewable resource potential, all lead to geographic variation in returns that can persist in the long run with limited mitigation potential. Finally, Ascend considers stakeholder demand and its influence on policy directions and procurement decisions, going beyond the unrealistic forecast scenario of only considering currently enacted policies. By focusing on these key policy, economic, and physical constraints that govern resource buildout and dispatch, Ascend forecasts focus on the most important drivers of uncertainty and risk in long-term planning and valuation.

All these drivers directly lead to the evolution of the supply stack serving the CAISO footprint, while aligning to a probability-weighted success rate for the interconnection queue in the near term. The forecasted supply stack, load characteristics, and transmission constraints then lead to a weather-driven model of the supply and demand balance, and ultimately to regional patterns in price formation. This price formation model accounts for the impact of load, net load, and net load ramps on marginal generators, renewable curtailment, geographic heterogeneity and basis, ultimately generating forecast outputs for long-run forwards, price shapes, price volatility, and capacity prices, while also modeling and forecasting the evolution of price dynamics for real-time energy markets and ancillary services.

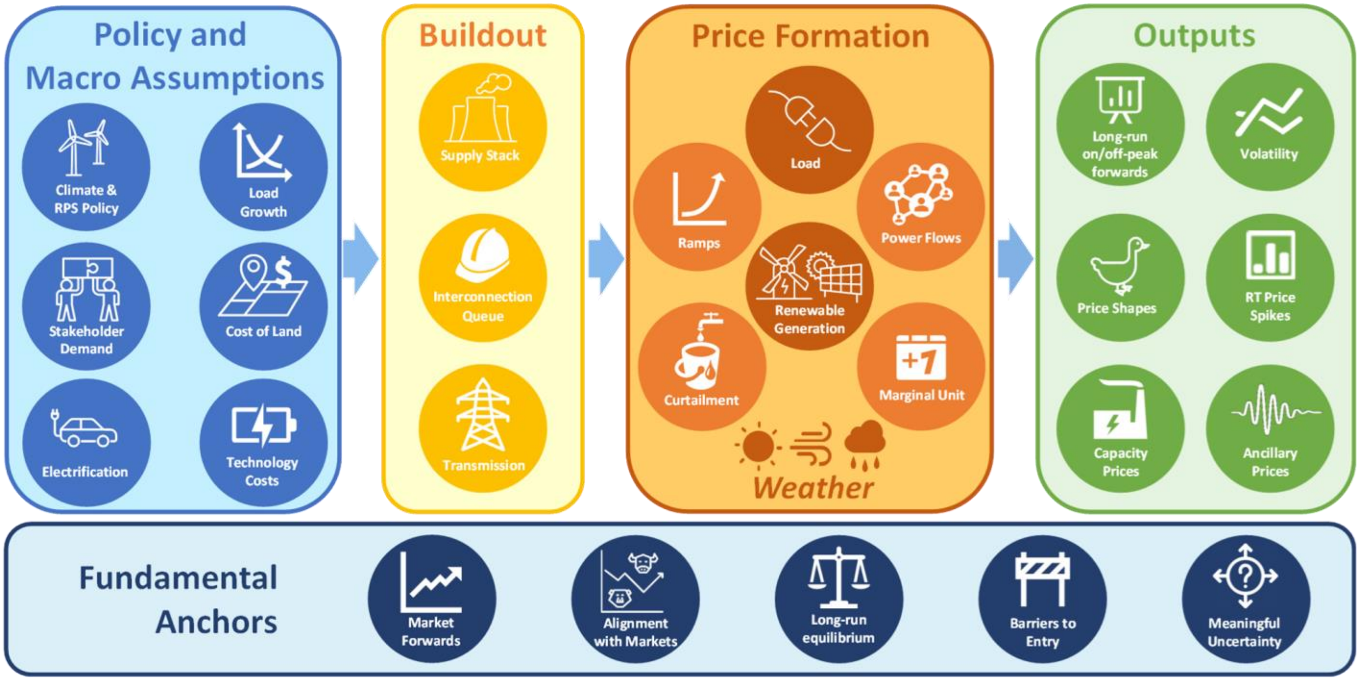


**FIGURE 4. ASCEND FUNDAMENTAL MODELING FRAMEWORK**

## Market and Regulatory Structure

The power sector regulatory landscape in California is highly fragmented, with a mixture of both competitive wholesale electricity markets and a heavy emphasis on top-down planning for a transition to zero GHG emissions, which creates both economic and reliability risks and challenges. Load is served by three large investor-owned utilities (IOUs) (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric), several municipal utilities and irrigation districts, including IID, and a growing share of community choice aggregators (CCAs), which function as local non-profit energy retailers, typically with a focus on clean energy. Peak demand in CAISO has historically been ~45 GW, but the system reached 52 GW in September 2022, setting a new system record and narrowly avoiding blackouts.

Rather than the ISO running a capacity auction to ensure resource adequacy, such as in PJM or ISO-NE, resource adequacy requirements are instead primarily prescribed by the California Public Utilities Commission (CPUC) onto the CCAs and IOUs, with input from CAISO. Load-serving entities (LSEs) that are not members of the CAISO are exempt from the CPUC resource adequacy program. This can lead to differences between the capacity needs identified by CAISO and what the CPUC requires of the California LSEs, as occurred in 2020. In addition, California lacks clear delineation between different parts of the power system: IOUs serve retail energy in addition to providing generation and running transmission and distribution systems, the CCAs serve retail energy only, and several large municipal utilities serve a similar role to the IOUs but are regulated by the California Energy Commission (CEC) rather than the CPUC. At the same time, environmental groups continue to exert severe pressure against thermal generation and carbon emissions regardless of CAISO and CPUC concerns about system reliability. This mixture, in which multiple entities provide a myriad of services under the supervision of several different regulatory bodies with different stakeholders, will likely lead to ongoing resource planning and coordination challenges in California, thereby creating risks of shortages or high costs due to unnecessary procurement. The impacts of drought and extreme weather on demand and hydro power availability both in the Pacific Northwest and in-state only compound the reliability challenges.

## Current Policies

The Ascend fundamental forecast is based on the following federal and state policies and contexts for the CAISO footprint:

### Federal Policies

#### Infrastructure Investment and Jobs Act

The Bipartisan Infrastructure Law includes several programs designed to bolster the country's energy grid and promote clean energy technologies.[14, 15] Key provisions include:

- The Transmission Facilitation Program creates a loan fund to support transmission developers by securing funding for larger scale projects and upgrades.
- The Civil Nuclear Credit Program will provide financial support to nuclear generators that are at risk of premature retirement due to economic factors.
- The National Electric Vehicle Infrastructure Program will invest nearly $5 billion in expanding the electric vehicle charging network across the US, with a focus on the interstate highway system.
- Additionally, the Infrastructure Bill allocates funds to strengthen domestic battery supply chains and continue research and development in green hydrogen systems.

#### Inflation Reduction Act

The Inflation Reduction Act (IRA) is a national spending law that extends and expands several tax credits and funding for clean energy development.[16] Key provisions include:

- **Energy Tax Credits**

  *Note: The following credits start at a base credit with a 5x multiplier if facilities meet prevailing wage and apprenticeship requirements, discussed below. The ITC is 30% with the multiplier and the PTC is an inflation-adjusted $15/MWh with the multiplier, with the 2022 value at $26/MWh. Credits are set to phase out when power sector emissions reach 75% below 2022 levels or in 2032, whichever is later. Once this phaseout threshold is passed, facilities will be able to claim 100% of the credit value for one more year. In the second year after the phaseout threshold is passed, facilities can claim 75% of the credit. In the third year after the phaseout threshold is passed, they can claim 50%, and no credits will be granted thereafter.*

  - **The production tax credit (PTC) and the investment tax credit (ITC) will be restored to their full value and extended** to include projects that begin construction before January 1, 2025. Solar is again eligible for the PTC and Ascend expects most solar projects to opt for the PTC.
  - **New technology-neutral tax credits** will be based on emissions criteria, extending full credit rates for storage and clean energy projects that produce no greenhouse gas emissions, and which are placed in service after 2024 and begin construction before 2033.

[14] Infrastructure Bill, Department of Energy
[15] Infrastructure Bill, Department of Transportation
[16] Inflation Reduction Act, H.R. 5376

- **An ITC for standalone storage facilities** will apply to storage facilities with a capacity of at least 5 kWh that begin construction before January 2025. The credit is not available for projects that begin service in 2022.
- **A new PTC for hydrogen** produced at a facility that begins construction before 2033, with an inflation-adjusted base rate of $0.60/kg and increasing to $3/kg, if wage and apprenticeship requirements are met. The rate is then multiplied by a PTC percentage based on the associated emissions, with emissions below 0.45kg $CO_2$/kg of H2 getting 100% of the PTC value.
- **A nuclear power production credit** for existing nuclear plants, with a base rate of $30/MWh. This PTC will apply to electricity produced and sold after 2023 and will terminate in 2032. The credit will be gradually reduced by a 'reduction amount' as the price of electricity exceeds $25/MWh.
- **A 30% tax credit for residential solar systems**. This marks both an increase and an extension from the pre-IRA 26% tax credit that applied to residential solar systems installed in 2022. This 30% credit will last until 2032 before dropping to 26% in 2033, 22% in 2034, and ending in 2035.
- **Additional credits** will provide incentives for development in carbon capture, advanced energy projects, advanced manufacturing production, and clean fuels.

- **Credit Adders and Multipliers**

  *Note: The low-income adder is only applicable to eligible projects that elect the ITC. The domestic content adder and energy community adder are applicable to eligible projects that elect either the ITC or PTC. Adders for the PTC are in relative terms (e.g. 10% increase), while adders for the ITC are in absolute terms (e.g. 10 percentage point increase)*

  - **'Prevailing Wage and Apprenticeship Requirements' allow for a 5x increase** for the tax credits. To meet these requirements, prevailing wages must be paid during construction and for any alteration or repair in the first five years (for the ITC) or the first ten years (for the PTC) of operation. In addition to prevailing wages, there is a set percentage of hours (including construction, alteration, and repairs) that must be performed by qualified apprentices to fulfill the credit multiplier requirements. The percentage of hours required depends on the year construction begins: for facilities starting construction in 2022, 10%; for facilities starting in 2023, 12.5%; for facilities starting in 2024 or later, 15%. For the PTCs, the base credit amount would increase from $3/MWh to $15/MWh. For the ITC, the credit rate would increase from 6% to 30%. Projects with a capacity less than 1 MW do not need to meet wage and apprenticeship requirements for the 30% ITC.
  - **A low-income credit adder** will apply to wind and solar facilities less than 5 MW in certain communities.
    - The adder is 10% for projects that are located in low-income communities or on Native land but ***are not*** a part of qualified low-income residential building project or economic benefit project.
    - The adder is 20% for projects that are located in low-income communities or on Native land ***and are*** part of a qualified low-income residential building project or economic benefit project.
  - A **10% domestic content credit adder** will apply to facilities that meet conditions regarding domestically sourced construction materials. The required amount of domestically manufactured materials in a project to claim the domestic content adder depends on the year construction begins, starting at 40% for projects beginning construction in 2025 and rising gradually to 55% for projects beginning construction in or after 2027.

    - A **10% energy community credit adder** will apply to facilities that are sited in certain 'energy communities' including brownfield sites and communities that have historically had significant employment tied to oil, coal, or natural gas.
- **Miscellaneous**
    - The IRA contains provisions **allowing direct pay** for most of the incentives mentioned above if the claimant is a tax-exempt organization, local or state government, or tribal entity, and **transferability of tax credits** in general.
        - Direct pay will allow non-profits, including municipal utilities and rural electric co-operatives, to develop projects and receive cash payments in the amount of the value of their tax incentives, rather than having to enter into PPA arrangements.
        - The transferability provision allows the transfer of tax credits between unrelated parties. Credits may be sold only once, but the original credit can be split and sold to more than one buyer instead of being consolidated and sold to one entity that has a sufficiently large tax liability. This expands the pool of potential buyers and substantially reduces the need for complex tax equity agreements with banks and other large investors who have enough tax liability to use the tax credit.
        - Unlike tax equity arrangements, buyers of tax credits and receivers of direct pay cannot capture the depreciation value of the underlying asset. Buyers also take on a recapture risk: if the developers do not meet the conditions of the tax credit, the IRS can reclaim the unvested portion of the tax credit value from the buyers. Transferability of credits and direct pay will take effect in 2023.
    - The IRA contains several incentives to support electrification and efficiency activities, including up to $7,500 in tax credits for homeowners to purchase a new electric vehicle, up to $2,000 for heat pump installations, and up to $1,200 for other home energy efficiency efforts, such as new windows or doors, or an induction stove.

## Key State Energy Policies and Market Context

California has shown aggressive decarbonization and renewable energy efforts. Key legislation and programs address a variety of sectors on a statewide level but are not all necessarily applicable to IID:

### Emissions and Renewables

- **SB 100 (2018)** – Updated the preceding RPS (**SB 350, 2015**)[17] to require 100% of retail electricity sales to be zero-carbon by 2045, with interim targets of 44% by 2024, 52% by 2027, and 60% by 2030.[18] **SB 1020 (2022)** added interim targets requiring clean electricity to make up 90% of retail sales by 2035 and 95% by 2040.[19] **SB 350** also requires greenhouse gas reductions of 40% below 1990 levels by 2030 and 80% by 2050 and imposes integrated resource planning (IRP) processes to align the targets prescribed in the bill.
- **AB 32 (2006)** – Established a greenhouse gas emission reduction goal of 1990 levels by 2020.[20] It also institutes California's cap-and-trade law that remains in force through the forecast period, providing a carbon price.
- **AB 1279 (2022)** – Codifies the goals laid out in Executive Order B-55-18, requiring the state to achieve net zero greenhouse gas emissions by 2045 and to maintain net negative emissions thereafter.[21]

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[17] SB 350
[18] SB 100
[19] SB 1020
[20] AB 32
[21] AB 1279

- **CWA 316(b) Once-through-cooling (OTC) Regulation (2010)** – Mandates the retirement of several coastal thermal power plants, mostly located in southern California. After summer scarcity conditions in August 2020, extensions were granted to several plants in September 2020 and are reflected in this report.
- **CPUC Rulemaking 20-05-003 (2021)** – Also known as the mid-term reliability order (MTR), replaces retiring capacity from the Diablo Canyon nuclear plant and the OTC thermal facilities with 11.5 GW of new, zero-emissions or RPS-eligible accredited capacity procurement. The requirements include 2 GW by 2023, 6 GW by 2024, 1.5 GW by 2025, and an additional 2 GW by 2026. The 2026 additions are required to be long-lead-time resources, with half from long-duration storage and the other half from zero-emitting or RPS-eligible resources with a capacity factor of 80%. Procurement requirements will be assigned to each load-serving entity according to its proportional share of peak load.
- **SB 846 (2022)** – Authorizes the delay of the retirement of Diablo Canyon Nuclear Power Plant Units 1 and 2 from 2024 and 2025, respectively, to 2029 and 2030. Authorized a forgivable loan of $1.4 billion to Pacific Gas and Electric to relicense the plant.[22] Expedited the permitting and relicensing processes by limiting the review of the extension applications to 180 days and exempting it from the California Environmental Quality Act. Authorizes cost recovery through ratepayer fees for each megawatt hour generated.
- **AB 525 (2021)** – Requires the Energy Commission to develop and submit a strategic plan for offshore wind development by the end of 2022. The plan shall identify resource potential, sea space for development, infrastructure and workforce needs, permitting processes, and potential impacts on coastal resources, fisheries, and Native American populations. Also requires the Commission to establish megawatt offshore wind goals for 2030 and 2045 by June 1, 2022.[23]
- In August 2022, the CEC established preliminary offshore wind goals. The first goal is 2-5 GW of offshore wind by 2030, with a second goal of 25 GW by 2045.[24]
- **California Energy Commission Offshore Investment (2022)** – The California Energy Commission approved a $10.5 million investment into upgrades to the Port of Humboldt Bay. The upgrades will allow the port to accommodate the cumbersome infrastructure that will be needed for offshore wind development.[25]
- **AB 242 (2021)** – Requires all retail suppliers of electricity consumed in California to publicly disclose their sources of electricity and the associated greenhouse gas emissions intensities for the previous calendar year.[26]

### Transport

- **Advanced Clean Cars II (2022)** – The California Air Resources Board (CARB) adopted a new rule requiring an annually increasing proportion of all new passenger cars and light-duty trucks sold to be zero-emission vehicles (ZEVs). The rule establishes yearly standards, requiring EVs to make up 35% of sales in 2026, increasing annually to reach 68% by 2030 and 100% by 2035.[27]
- **Executive Order B-48-18 (2018)** – Sets a goal of 5 million EVs on the road by 2030.[28]
- **Executive Order N-79-20 (2020)** – Calls for the elimination of sales of new internal combustion passenger vehicles by 2035. Extended to trucks and other vehicles weighing more than 8,500 lbs. by 2045.[29]

[22] SB 846
[23] AB 525
[24] Offshore Wind Energy Development off the California Coast
[25] California Energy Commission Offshore Investment
[26] AB 242
[27] Advanced Clean Cars II
[28] Executive Order B-48-18
[29] Executive Order N-79-20

## Demand-Side

- **SB 700 (2018)** – Extends funding for the Self-Generation and Incentive Program (SGIP), providing $1 billion in additional funds for behind-the-meter storage systems through the end of 2024.[30] These funds are eligible for residential and non-residential installations served by the state's major Load Serving Entities (LSEs).
- **2022 Building Energy Efficiency Standards (2021)** – Makes electric heat pumps the standard energy efficiency technology and increases costs for builders that include gas hookups in new construction.[31]

## Storage

- **AB 2514 (2010)** – Requires California's three investor-owned utilities to procure at least 1,325 MW of battery storage by the end of 2020 and to be installed no later than 2024.[32]
- **AB 205 (2022)** – Authorizes funding for and creates the Strategic Reliability Reserve to provide power (up to 5 GW) to the grid when load is abnormally high and the system is under stress. This capacity can include generation that was previously scheduled to retire, new generation, new storage projects, clean backup generation, diesel, natural gas, or customer load reduction. The Strategic Reliability Reserve will operate after procurement by load serving entities, and it does not reduce utilities' obligations to meet reliability requirements. This bill also expands the CEC's siting authority to include solar, onshore wind, and non-nuclear and non-fossil thermal plant projects with 50 MW or more, storage facilities greater than 200 MWh, and transmission lines from a generator or storage facility that interconnects with the grid. Also requires the CEC to implement the Long-Duration Energy Storage Program to establish financial incentives for storage systems of at least one MW that can discharge for at least eight continuous hours.[33]
- **AB 2868 (2016)** – Approves the procurement of an additional 500 MW of behind-the-meter storage systems among the three LSEs.[34]
- **Hybrid Resources Policy (2020)** – Supports the participation of hybrid resources in CAISO by pooling resources under one resource ID, which affords resource operators more control of their assets and enhances their ability to contribute to grid reliability.[35]

## Regulatory Structure

- **AB 327 (2013)** – Signed by former Governor Jerry Brown, this bill gives the CPUC authority to change rate structures and extends net energy metering. Requires the Commission to ensure that low-income customers are not overburdened by monthly energy expenditures given their level of need, and requires this assessment every three years.[36]
- **Interconnection Queue (2022)** – In June 2022, CAISO submitted a set of interconnection process revisions to FERC to address the backlog of the projects in its queue, and FERC approved the changes in August.[37] The reforms are intended to expedite the process for those projects that are closest to commercial operation. The rules was issued by FERC in 2023 with Order No. 2023. FERC is requiring investor-owned utilities to institute in the pro forma generator interconnection procedures and agreements reforms to help streamline the generator interconnection process. Reforms include speeding the processing time of generator interconnection queues, transitioning from a "first-come, first-served" interconnection process to a "first-

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[30] Self-Generation Incentive Program
[31] 2022 Building Energy Efficiency Standards
[32] AB 2514
[33] AB 205
[34] AB 2868
[35] Hybrid Resources Policy
[36] AB 327
[37] FERC, Interconnection Queue Reform

ready, first-served" cluster study process, and accounting for alternative, technological advancements in the interconnection process. CAISO and investor-owned utilities across the West, such as Arizona Public Service Company (APS), are in the process of adopting these Order No. 2023 reforms. Further, APS in 2023 obtained FERC acceptance of its own interconnection queue reforms that are separate from and are intended to work with FERC Order No. 2023. Capacity deliverability allocations help determine the network upgrade costs associated with interconnecting projects, and these allocations are necessary for a project to receive resource adequacy payments. Under the new interconnection process, capacity deliverability allocations will be prioritized for those projects that have reached commercial operation and secured a power purchase agreement. In addition to projects that meet these readiness metrics, CAISO will prioritize projects from public power and municipal utilities that serve their own load. CAISO will also increase the financial deposits for developers who do not have exclusive control of their project site. For small generators (<20), the deposit will increase from $100,000 to $250,000. For larger generators, the deposit will increase from $250,000 to $500,000. If an interconnection customer withdraws from the queue without demonstrating site exclusivity more than 30 days after the scoping meeting, 50% of the deposit is nonrefundable. If the customer can demonstrate site exclusivity after 30 days, they are still eligible for a refund. Additionally, CAISO will allow emergency interconnections for projects with network upgrades of $1 million or less. The projects would only be valid for three years from the online date. If the owner wants to continue operating beyond this limit, they must go through the standard interconnection process.

- **Resource Adequacy (2022)** – The CPUC is reforming its RA accounting methodology to better account for the contributions from renewable resources.[38] Historically, the CPUC has used an average monthly ELCC for each resource to determine how much of its capacity could be used toward RA requirements. The CPUC is now transitioning to a month-hour '12x24 - Slice of Day' approach that utilizes an exceedance methodology to assess renewable generation over periods when the system is tight. The currently proposed exceedance method creates a month-hour matrix that determines solar and wind production based on a set exceedance value. For example, a 70% exceedance value states a renewable resource can reasonably generate the quantity of power observed in 70% of historical time intervals for a given month-hour. Using month-hour exceedance values, the CPUC can create a generation profile to see a more granular view of what resources will contribute to the power grid and when they are available. The CPUC will compare the historical or forecasted peak load day with the exceedance profile for that day to identify the month-hour with the narrowest reserve margin. The CPUC assumes that if the system can be built to maintain the target reserve margin during the most strained month-hour, it will have a large enough reserve margin during all other month-hours of the year.

CAISO would then use the resource-specific exceedance values to determine the most efficient resource buildout to meet the target reserve margin for the given month-hour. Additionally, they test the portfolio to determine whether it has enough excess wind and solar capacity for batteries to charge while maintaining the target reserve margin. Batteries are either given a pass or a fail, depending on whether they can successfully charge on the system. If the batteries fail, then the portfolio fails, and the system would not meet its RA requirements. Ascend expects the value of RA for each slice to be a function of how short the system is from the target reserve margin for that specific hour and the revenue for each resource to reflect how much it improves grid reliability, similar to ELCC-derived results.

[38] Resource Adequacy Reform Working Group Report

As of 2021, California's fuel distribution was 49% natural gas, 17.4% solar, 8.4% nuclear, 7.9% wind, 7.4% hydroelectric, 5.8% geothermal, 2.9% biomass, and 1.2% other.[39] In recent years, several pieces of energy-related legislation failed to pass. Of note in 2020 was AB 2255, which would have required the Public Utilities Commission and State Energy Resources Conservation and Development Commission to incorporate the use of long-duration energy storage systems into their energy resource planning, indicating the start of a push toward longer-duration storage.[40] SB 413, introduced in 2021, would have established a certification process for offshore wind generation facilities analogous to that for thermal generators, but the bill failed in 2022 before receiving a vote.

## Anticipated Policies and Other Drivers

Ascend does not anticipate that the targets set through SB 100 are at risk of being loosened or unmet given the increasing cost-effectiveness of renewables and storage, as well as the continued acceleration of clean energy targets. Moreover, trends in stakeholder engagement and activism, community choice aggregator (CCA) and corporate demand for clean energy, as well as declining costs for solar, wind, and storage, suggest California will reach and exceed its targets ahead of schedule. Additionally, these trends suggest a high likelihood of additional legislation to accelerate the decarbonization timeline, following pressure from environmental groups. The CPUC originally had a planning target of 46 MMT of carbon emissions by 2030, but later adopted a 38 MMT target. Most recently, the CPUC announced it would use a 30 MMT by 2030 scenario for the 2023-2024 Transmission Planning Process. Ascend expects California to continue moving forward with the 30 MMT target, with the support of various environmental groups.[41]

Ascend also anticipates the expansion of the CAISO day-ahead market to the surrounding region, as part of an expansion of the Energy Imbalance Market (EIM). With FERC's 2023 acceptance of the Extended Day-Ahead market (EDAM) and PacifiCorp and Balancing Authority of Northern California set to join the EDAM there is at least one viable option for a day-ahead market in California. State laws requiring utilities to join regional wholesale markets are likely to encourage this expansion, with similar legislation having already been enacted in Nevada[42] and Colorado[43], although Colorado has agreed to join SPP's competing market expansion. Several other western utilities are also likely to join SPP's market expansion. At the same time, renewable and clean energy targets will continue to expand in neighboring states that constitute the Western Energy Coordinating Council (WECC). For example, New Mexico has passed the Energy Transition Act (ETA), which also mandates 100% clean energy by 2045. Colorado, Nevada, and Washington also have 100% clean energy goals and standards for 2045, while Oregon has a 100% clean energy by 2040 standard. While the extension of a regional day-ahead market would provide some relief in curtailments and volatility, tightening targets throughout the region will still likely result in an oversupply of renewable generation and region-wide correlations in system conditions, both during periods of surplus and shortage, as was evidenced during the heat wave in summer 2020. The regional variation in demand and renewable generation supply is not likely to be sufficiently complementary to absorb generation surpluses or easily manage evening net-load ramps. Long-duration storage, flexible electric vehicle charging, and curtailment will all likely be needed to manage these conditions.

In December 2021, the CPUC announced their intention to revise the current Net Energy Metering (NEM) tariff that has been in place since 2016. The goal of the proposal was to value the contributions of BTM solar more accurately and to incentivize BTM battery adoption to help address evening load ramps. The December proposal would have decreased compensation for the excess energy that residential solar systems produce, charged

[39] Spot for Clean Energy. California
[40] AB 2255, Died
[41] CPUC 30 MMT Scenario
[42] Nevada, SB 448
[43] Colorado, SB 21-072

residential solar owners a monthly 'grid participation charge' of $8/kW for the size of their system, and provided a 10-year storage incentive of $5.25/kW per month.[44] The proposed tariff received pushback from solar advocates, who argued that the changes would make rooftop solar inaccessible to many Californians and hurt the industry, causing the CPUC to restructure their NEM proposal.

In November 2022, the CPUC released a new proposed decision to reform NEM.[45] None of the proposals will impact the owners of existing residential solar systems. The CPUC dropped the proposed monthly grid participation charge for residential solar systems. However, the retail export compensation rate for residential solar-only systems will be based on the Avoided Cost Calculator, which will prevent those systems from receiving compensation greater than the wholesale price of electricity in that hour. The California Solar and Storage Association estimated that this rate change will reduce the average export rate from $0.30/kWh to $0.08/kWh, marking a roughly 75% reduction in compensation. To mitigate the effects of this reduced rate, the proposed decision creates a nine-year incentive payment for every kWh exported to the grid for customers who install rooftop solar within the first five years of tariff implementation. The per-kWh payment amount decreases each year after implementation and will not be available to customers who install systems after the five-year transition period. The CPUC analysis indicates that the payback period for both standalone solar systems and solar-plus-storage will be less than nine years. In addition, the proposal will switch to time-of-use rates to differentiate on-peak and off-peak costs. This element of the proposed decision will incentivize customers to shift consumption to lower-cost hours and will add a financial benefit to those BTM storage systems that can export energy during on-peak hours after solar production ramps down. The CPUC unanimously voted to approve this proposal in December, and NEM 3.0 was implemented in April 2023.

Ascend also expects the implementation of an 'imbalance reserve' ancillary product within CAISO at some point during 2025. Resources providing this product would have an obligation to deliver economic energy bids to the real-time market, and only those resources that are dispatchable in the 15-minute market will be eligible.[46] Implementing this product will improve the efficiency of maintaining flexibility in a volatile system with high renewable penetrations. It would also deepen the overall ancillary markets but would result in reallocations of revenue among different revenue streams for resources, such as batteries, capable of providing it. Ascend also expects that the new ancillary product will reduce price volatility in real-time markets, but the reduction in revenue from this volatility will be offset by the ancillary revenues from this product. The depth of the market is projected to be an average of 4,000 MW, which is still expected to be saturated by storage in the mid-2020s. While the allocation of revenues between products for flexible assets may change, long-run economic equilibrium will be maintained.

In addition, Ascend expects CAISO to restructure its pricing signals for battery deployment to ensure batteries can discharge when the grid most needs backup capacity. In September 2022, a heat wave settled over a large portion of the western US, straining California's electric grid and presenting the first major test for California's expanding battery fleet. The heat wave from September 5-10 saw CAISO reach a record-breaking peak demand of over 52 GW on the evening of September 6.[47] While CAISO's Flex Alerts proved pivotal in managing surging demand over this period, batteries also played a crucial role in managing the crisis and, at the same time, highlighted the challenges ISOs will face in sending accurate price signals during times of grid stress. Batteries deployed most often during the evening hours, discharging over 3 GW to help meet peak period demands and to help prevent the grid from resorting to rolling blackouts. However, price signals also led batteries to discharge during daylight

[44] NEM Revisions
[45] Proposed NEM Decision
[46] Day-Ahead Market Enhancements
[47] CAISO Peak Load History

hours, while solar capacity was still producing and before the grid was in real need of additional capacity to balance supply and demand. Energy storage systems, under the current system, automatically deploy when the market clearing price hits $1,000/MWh. CAISO reached that threshold by the early afternoon, which caused batteries to discharge even though solar power was still abundant in the system and the stored energy would have been more impactful in the evening hours when the system was tightest. CAISO issued several manual instructions to storage facilities during the heat wave to prevent them from discharging in the early afternoon when solar was still abundant. In December 2022, CAISO approved reforms that will provide compensation to storage facilities that follow instructions to delay discharge, even when price signals prompt them to discharge.[48] These reforms will require FERC approval and are likely to be enacted. Figure 5 shows electricity demand and battery participation for select days during the 2022 heat wave.

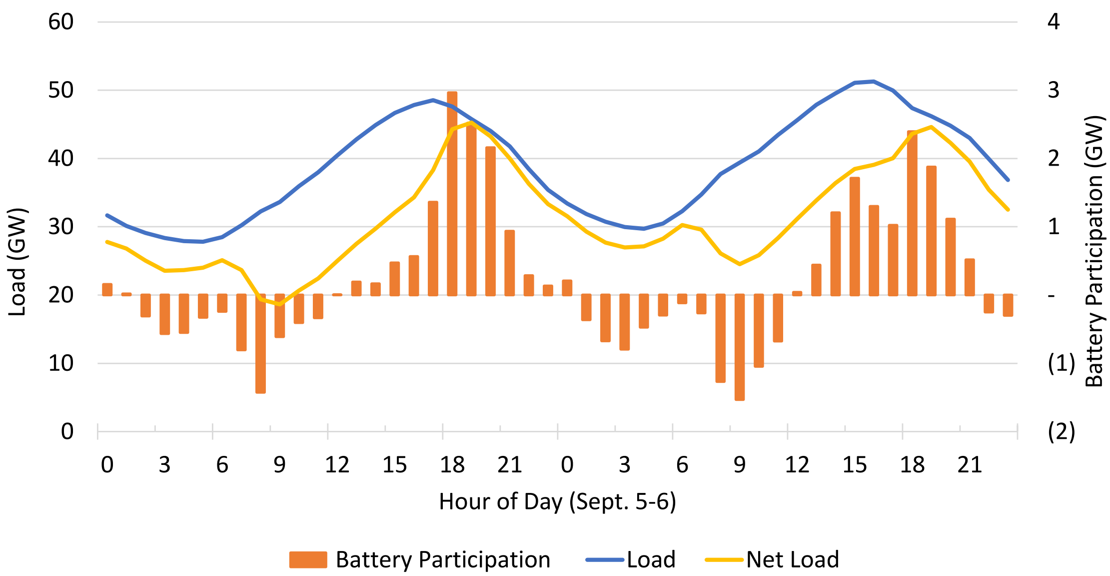



**FIGURE 5. LOAD AND BATTERY PARTICIPATION IN CAISO DURING THE SEPTEMBER 2022 HEAT WAVE**

Ascend also expects growing demand in CAISO for offshore wind as that market matures across the US, despite California's deep-water coast likely requiring floating platforms. The California state legislature and CAISO are taking action to prepare for offshore wind energy development in the next several years. AB 525[49] was enacted in 2021, requiring the California Energy Commission to develop an offshore wind plan. The CEC published its proposal for offshore wind targets in August 2022, aiming for 2-5 GW by 2030 and 25 GW by 2045. In March 2022, the Commission approved $10.5 million in spending to upgrade the Port of Humboldt Bay to prepare it for offshore development. Governor Newsom has proposed similar investments in his 2022-2023 budget proposal, including

[48] CAISO Storage Participation Enhancement
[49] AB 525

an additional $45 million to advance capabilities for deploying offshore wind energy, $100 million toward green hydrogen, and $380 million toward long-duration storage projects over the next two years.[50]

In addition to state legislative activities surrounding offshore wind, CAISO has conducted studies on the impact of offshore wind on its transmission systems, commenting to the Federal Energy Regulatory Commission (FERC) that it can adapt to policy changes and accommodate the assessment of offshore wind integration.[51] CAISO has identified that the central coast area transmission system could accommodate 5-6 GW of offshore wind generation after the retirement of the Diablo Canyon Power Plant, but the north coast area would require transmission investments to accommodate new offshore generation.[52] A CAISO sensitivity study is set to assess the costs of developing transmission systems to accommodate 8.3 GW of offshore wind capacity, with potential to increase to 21.1 GW.[53] The Bureau of Ocean Energy Management held an offshore wind energy lease auction in December 2022 for five lease areas along the central and northern coast of California.[54] This auction was the first to offer leases in the Pacific Ocean and all five lease areas were awarded; however, the revenue from this auction, nearly $760 million, was much less than that generated by New York's and New Jersey's offshore lease auctions. This is largely due to the need for floating wind turbines in the deeper waters of the Pacific Ocean, as well as the lack of firm policy backing the state's offshore wind industry. Given the accelerating activity in offshore wind nationwide, the Biden administration's goal of 30 GW of offshore wind by 2030,[55] California's lack of overnight clean generation, and the requirements of AB 525, Ascend expects California to enact legislative offshore wind targets within the next few years.

[50] 2022-2023 Budget
[51] CAISO Comments on Offshore Wind Integration
[52] 2020-2021 Transmission Plan
[53] CAISO Comments on Wind Integration in RTOs/ISOs
[54] BOEM, California
[55] White House, Offshore Wind

# Modeling Assumptions

## Technology Costs

Technology cost forecasts are a critical input to Ascend's supply stack forecasting. Ascend relies on a variety of sources for its forecasts, including both internal and publicly available sources.

### Storage

As Figure 6 shows, battery cell costs are expected to experience a near-term inflationary surge before dropping about 23% between 2024 and 2030, pushing system prices down by 15%. For solar-paired storage, adjusted prices that account for the ITC available by year fall more gradually. As the load-serving entities and the CPUC increasingly look to long-duration storage for clean reliability, the marginal capacity resource may shift away from lithium-ion batteries. At the time of this report, several long-duration storage technologies exist in addition to lithium-ion, but it remains unclear how this segment of the industry will evolve.

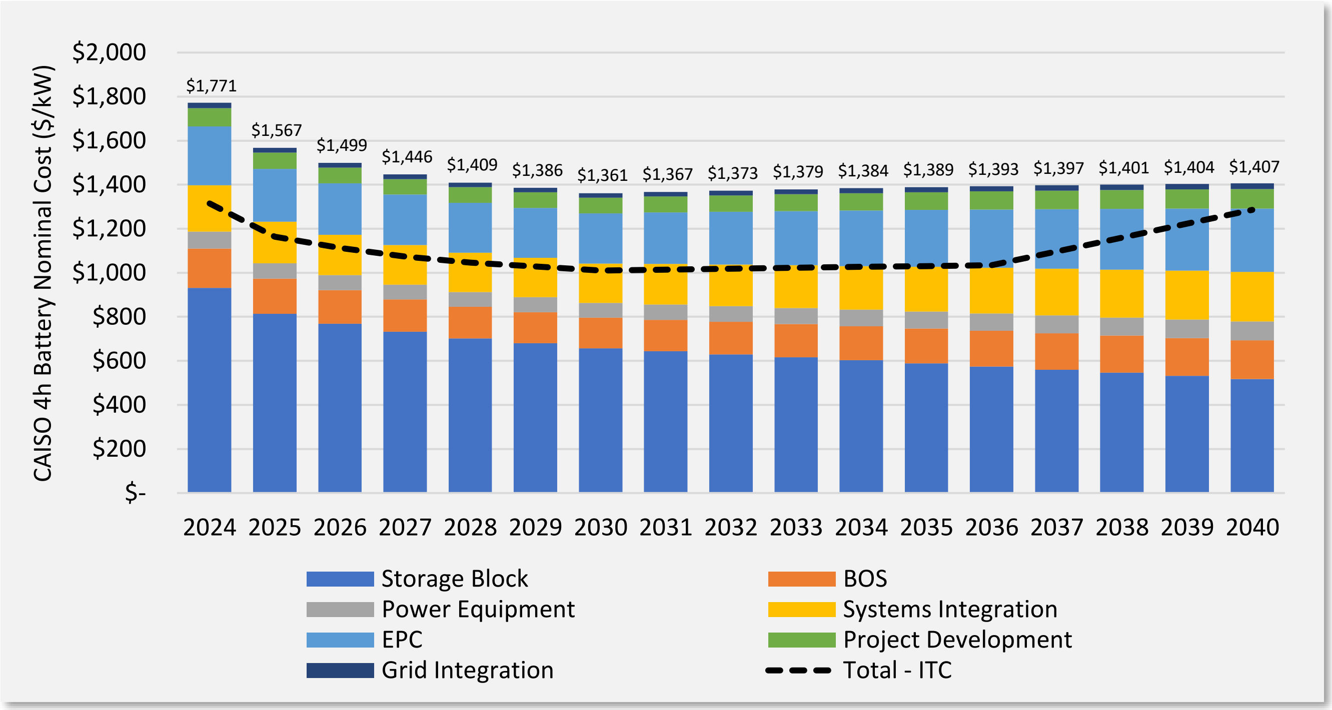



**FIGURE 6. BATTERY INSTALLED COST FORECAST FOR A FOUR-HOUR SYSTEM WITH IRA ADJUSTED TOTAL**

### Renewables

Ascend relies on several internal sources for representative current renewable PPA prices, calibrated against public works such as those produced by LBNL.[56] These prices are then projected forward based on NREL annual technology baseline (ATB) forecasts[57] and expected changes in policies and subsidies.

[56] LBNL solar and wind market reports can be found at: LBNL Solar and LBNL Wind

[57] NREL 2022 Electricity ATB

## Thermal

Ascend forecasts the costs for thermal generation to stay relatively constant in real terms for traditional technologies, staying in line with National Renewable Energy Lab Annual Technology Baseline[58] (NREL ATB) and Lazard[59] analysis. Additionally, Ascend expects minimal new build of fossil generation in CAISO due to stakeholder opposition, although some renewable fuel burning capacity is expected to be built in the 2030s, along with some conversions of natural gas capacity to be able to burn renewable fuels.

## Load Forecast

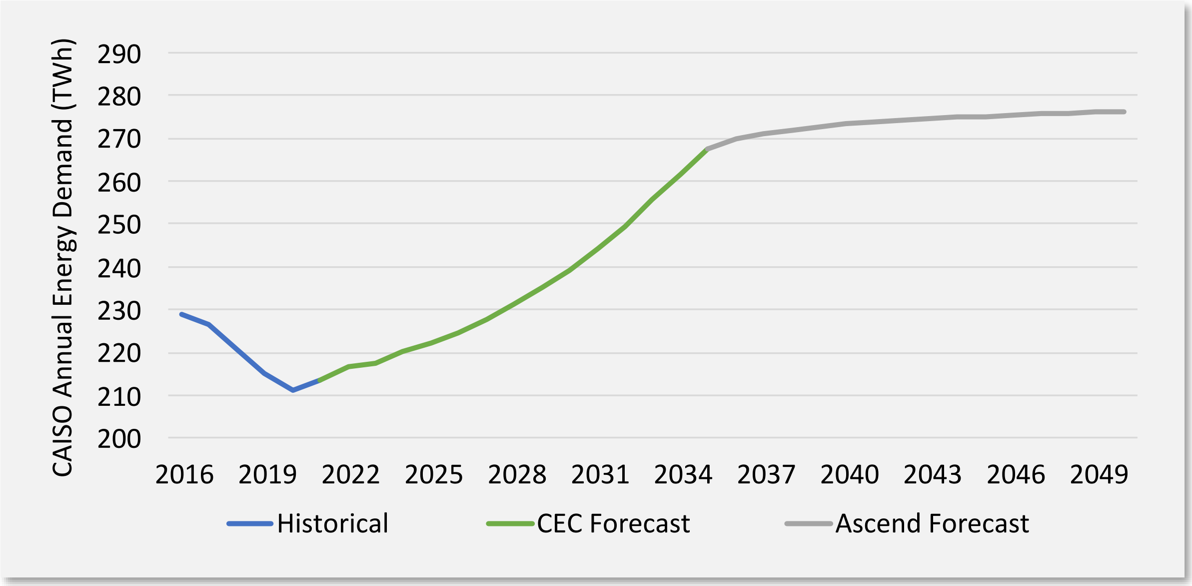
Ascend's load model uses the California Energy Commission (CEC) 2021 Integrated Energy Policy Report (IEPR) Mid Demand / Mid AAEE-AAFS Case as the starting point for the CAISO peak demand and total energy forecasts, using the 1-in-10 coincident case for peak demand.[60]

Figure 7 shows that load has been decreasing since at least 2016 and fell sharply in 2020 during the COVID-19 pandemic. After falling by 5% in 2020, load recovered in 2021 and is expected to continue to grow through 2024, when demand reaches 2019 levels. Increased adoption of EVs, electrification, and climate change effects support modest demand growth during the latter half of the 2020s, outpacing improvements in demand-side efficiency and BTM generation.

[58] https://atb.nrel.gov/

[59] Lazard Levelized Cost of Energy Analysis

[60] 2021 Integrated Energy Policy Report



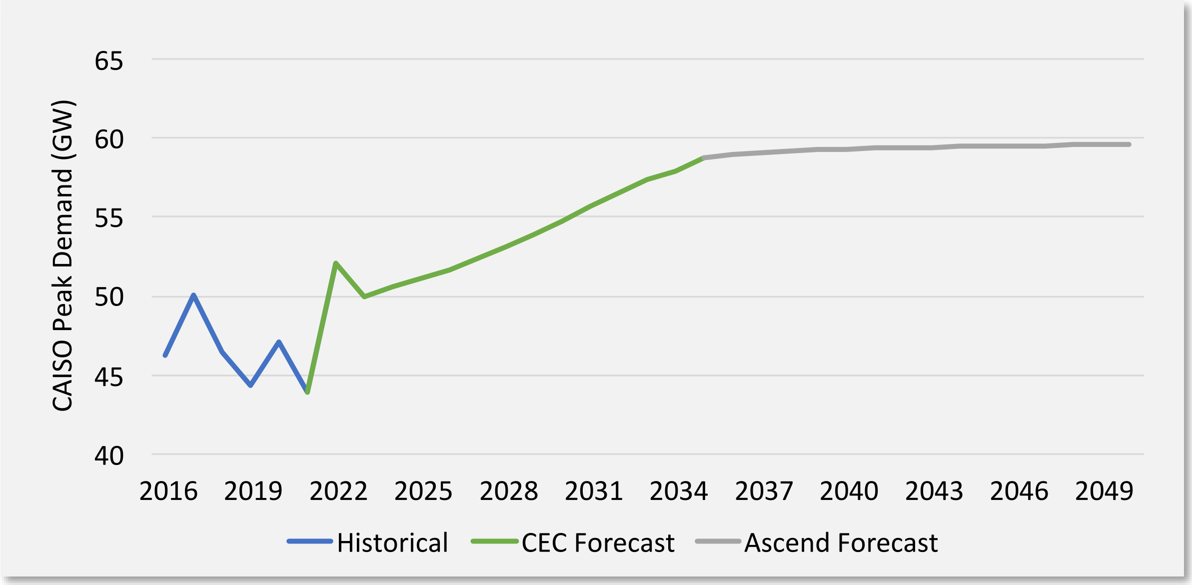




**FIGURE 7. CEC 2020 IEPR MID DEMAND/MID-AAEE ENERGY AND PEAK FORECAST FOR CAISO**

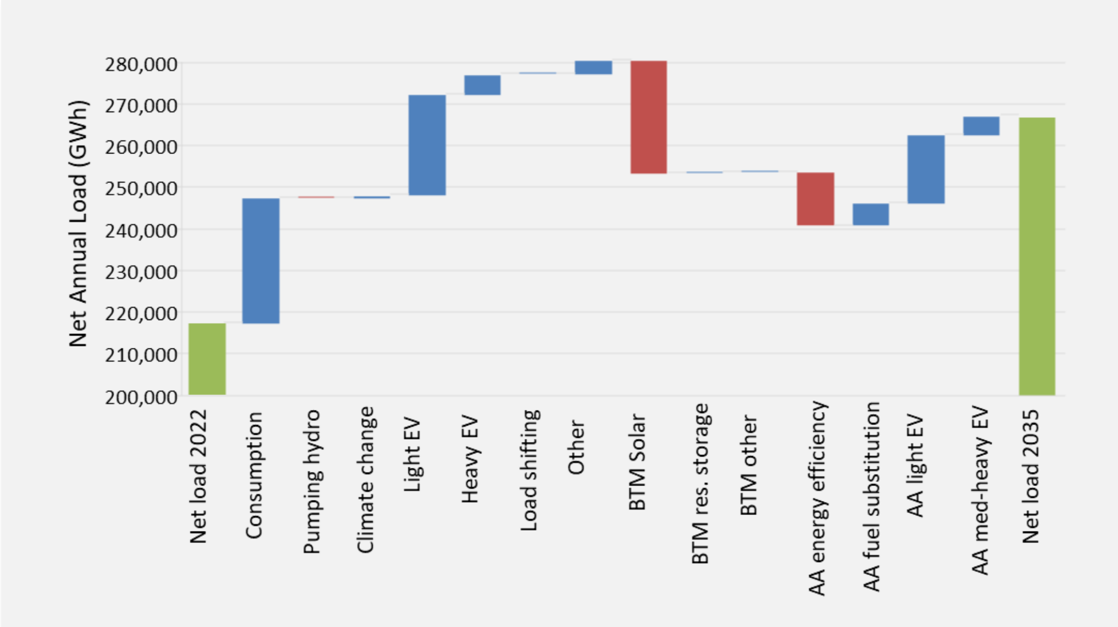



**Figure 8. Impacts on annual net load in CAISO, 2022-2035**[61]

Figure 8 shows how various factors will impact net load by 2035. The 'additional achievable energy efficiency' (AAEE) in the forecast refers to electricity efficiency savings beyond current committed programs. AAEE savings include both 'traditional' utility program savings as well as additional savings estimated in support of SB 350. These energy savings are projected to reach 14,000 GWh in 2030.[62] Savings are at the customer sector level—among categories such as HVAC systems, cooking, home and street lighting, water heating, refrigeration, plug load, etc.—without any distribution or transmission losses. BTM solar generation also decreases the total system generation to serve load, which is expected to accelerate due to increased funding for programs such as the Self-Generation Incentive Program (SGIP) over the past year, as well as increased deployment of battery storage systems. The amount of generation served by BTM solar installation is expected to more than double between 2020 and 2030, providing about 18,000 GWh in 2020 and reaching 67,000 GWh in 2035. Regarding economic growth, the mid-demand forecast assumes an economic rebound through 2024, leveling off thereafter. Gross state product, a measure of economic growth, increases by 2.4% on average in the mid-case, while wage growth averages 1.8% per year, as trade uncertainty limits business investment alongside a slowing household and population growth.[63]

The Integrated Energy Policy Report (IEPR) forecast then increases load, assuming consumption growth in the residential, commercial, industrial, agricultural, and transportation sectors. By 2030, the fleet of light-duty ZEVs is expected to grow to over 3.7 million. Electric vehicles will generate over 19,000 GWh of additional demand by 2035, aided by legislative mandates requiring the electrification of heavier vehicles at airports, public transit agencies, and other institutions. Climate change impacts add 800 GWh to load in 2035 due to residential and commercial heating/cooling demand. These conditions are not expected to dissipate, so after 2030 Ascend maintains the CEC's demand growth trend.

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[61] 2021 Integrated Energy Policy Report
[62] 2021 Integrated Energy Policy Report
[63] 2021 Integrated Energy Policy Report

## Candidate Resources

A fundamental component of the capacity expansion analysis involves identifying the set of candidate resources, which are generic versions of each candidate technology type considered in capacity expansion optimization modeling. For IID, these candidate technologies include photovoltaic solar, California-based wind, New Mexico-based wind, geothermal, four-hour lithium-ion battery storage, eight-hour lithium-ion battery storage, reciprocating internal combustion engines (RICE), and, in some scenarios, long-duration storage options such as hydrogen storage, pumped hydro storage, or flow batteries. Generation profiles for each of the candidate solar or wind technologies were sourced from NREL's System Advisor Model (SAM) for representative locations of typical weather conditions: recall that PowerSIMM's stochastic modeling approach relies on weather simulation as a starting point for all subsequent analysis. Cost assumptions are provided in Table 8 and Figure 9.

**TABLE 8. COST ASSUMPTIONS FOR CANDIDATE RESOURCES**

| Candidate Resource Technology | Cost Range | Earliest Allowed Build Year | Included Scenarios |
|---|---|---|---|
| SoCal Wind | \$55 – \$100 / MWh | 2027 | All except "Geo-Focused and Solar-Focused" |
| New Mexico Wind | \$50 – \$74 / MWh [64] | 2027 | All except "Geo-Focused" and "Solar-Focused" |
| PV Solar | \$24 – \$48 / MWh | 2027 | All |
| Geothermal | \$89 – \$178 / MWh | 2027 | All |
| 4hr Storage | \$13 – \$17 / kW-mo. | 2027 | All |
| 8hr Storage | \$21 – \$29 / kW-mo. | 2030 | All |
| RICE (Natural Gas) | \$1.3MM – \$2.6MM / MW | 2027 | All |
| Long Duration Storage | \$2.3MM – 2.7MM / MW [65] | 2035 | LDES |

[64] Includes a \$10/MWh transmission adder for the out-of-state resource.

[65] The generic 'Long Duration Storage' technology was not evaluated with an associated cost. Inclusion of the technology in the LDES scenario provides an understanding of the relative value such a project could provide to the IID portfolio and establishes a conservative upper bound on a reasonable cost for such technology in the absence of current commercially viable options.

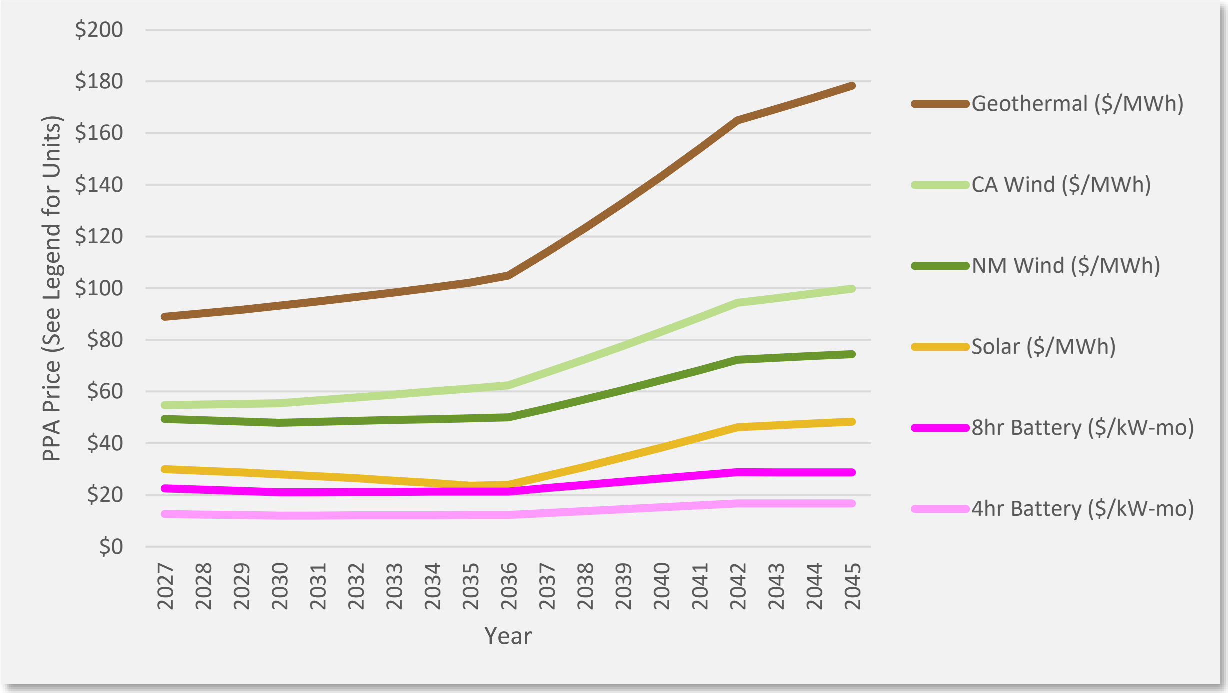


**Figure 9. Assumed PPA Costs for Non-Fossil Candidate Resources**

## Candidate Solar Resources

The desert climate of Coachella Valley and Imperial Valley offers some of the best solar energy resources in the entire country. One metric commonly used in photovoltaic (PV) contexts to measure how much sunlight hits the earth's surface is known as Global Horizontal Irradiance (GHI). Data from the National Solar Radiation Database (NSRDB) (see Figure 10) show that Imperial County has an average GHI exceeding 5.75 kilowatts per square meter per day (kW/m2/day), which puts it firmly in the highest solar resource class as categorized by NREL's Annual Technology Baseline (ATB). The approximate location of the IID service territory is outlined in Figure 10. Only about 3.8% of the country's surface area qualifies for this Class 1 category[66].

[66] Annual Technology Baseline: "Utility Scale PV". National renewable Energy Lab. https://atb.nrel.gov/electricity/2022/utility-scale_pv

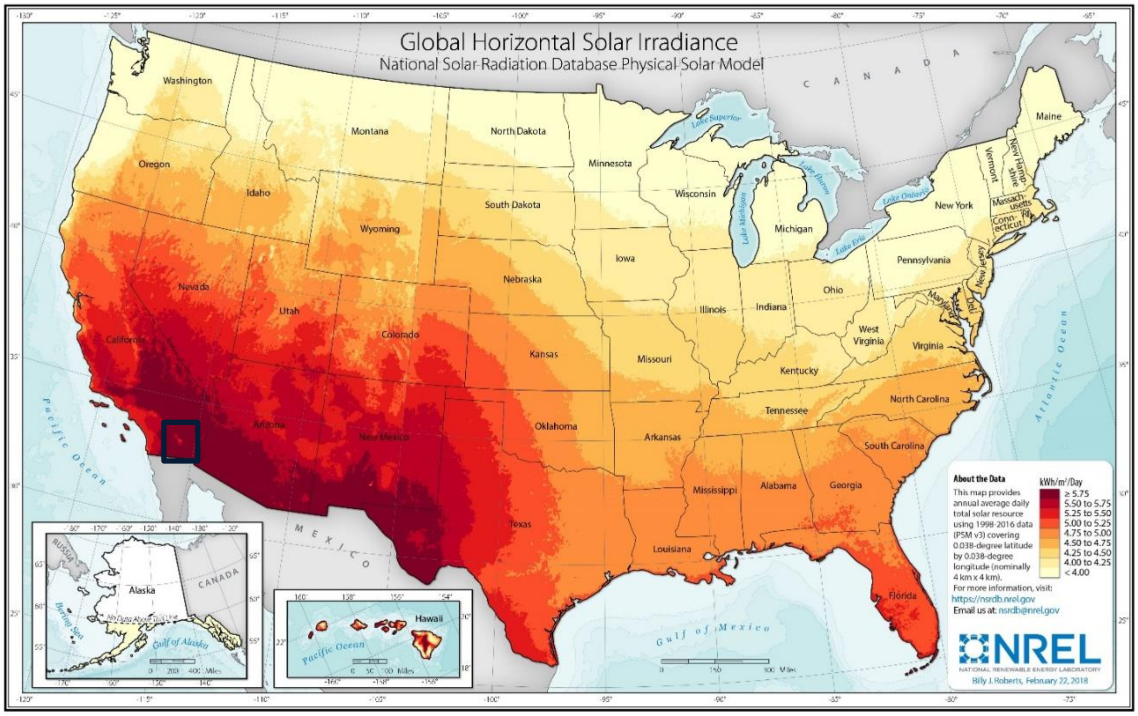


**FIGURE 10. AVERAGE ANNUAL GLOBAL HORIZONTAL SOLAR IRRADIANCE (GHI) FOR THE UNITED STATES (1998–2016)[67].**

Simulated historical solar generation data for a generic, locally sourced PV solar project in Imperial County were obtained from NREL's SAM. Historical weather years 2017-2020 were used to establish the relationship between hourly generation behavior and existing weather data in PowerSIMM. The historical generation profile was also used to estimate the monthly forecast for the solar resource and scaled to an annual capacity factor of 30%, which is consistent with existing IID solar projects. The assumed monthly capacity factor for this resource can be seen in Figure 11. No degradation of the solar resource is assumed over the forecast period, analogous to a PPA contracted at a fixed capacity and expected annual capacity factor.

[67] Citation: Sengupta, M., Y. Xie, A. Lopez, A. Habte, G. Maclaurin, and J. Shelby. 2018. "The National Solar Radiation Data Base (NSRDB)." *Renewable and Sustainable Energy Reviews* 89 (June): 51-60.

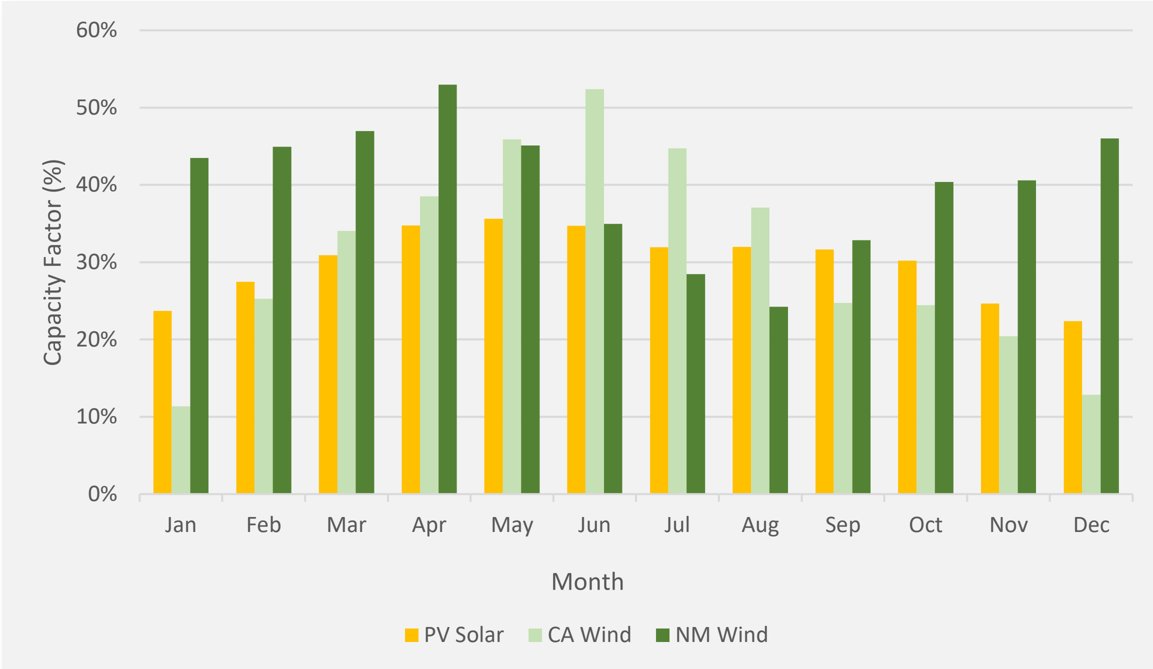


**FIGURE 11. CANDIDATE RESOURCE MONTHLY CAPACITY FACTORS**

## Candidate Wind Resources

Several sourcing options are available to IID when it comes to wind resources. Local wind resources in the Greater Imperial Valley area are attractive due to annual generation profiles that more closely align with IID's load shape. However, the availability of resources having both a commercially attractive capacity factor and environmentally-compliant siting may be limited. This IRP also includes alternate scenarios that consider wind resources from a wider scope, such as out-of-state wind in places like western New Mexico. Out-of-state wind is both plentiful, high-quality (>40% capacity factor), and lower-cost. It is not without its downsides, though. One challenge with wind is overgeneration outside of peak times (on the hourly or monthly scale). Wind generation tends to peak in nighttime hours, outside IID's net peak load hours just after sunset. In addition, especially in the case of New Mexico-sourced wind, the annual generation profile may not align well with the months of highest energy demand. Wind capacity factors in the New Mexico region peak in the winter and are lowest in months where IID demand is highest (July and August).

Two candidate wind resource locations were considered: Greater Imperial Valley (local) and New Mexico (out-of-state). SAM was used to generate simulated historical hourly generation for the years 2011-2014, which was then used to establish the relationship in PowerSIMM between hourly generation behavior and the historical hourly weather data for representative weather stations within these two locations. Monthly capacity factor profiles for these resources are presented in Figure 11. No degradation of the wind resources is assumed over the forecast period, analogous to a PPA contracted at a fixed capacity and expected capacity factor.

The Greater Imperial Valley and New Mexico wind profiles have annual capacity factors of 31% and 40%, respectively. Note that the California wind profile peaks in early summer and is lowest in winter, while the New Mexico profile is highest in winter and spring but is lowest in mid-to-late summer.

## Candidate Thermal Resources

Given the relatively low ELCCs for the variable generation wind and solar candidate resources, there remains a need for establishing sufficient, cost-effective generation capacity for reliability purposes, even if such generation doesn't run all that frequently. IID's existing thermal generation fleet serves as a substantial portion of the firm capacity in the portfolio. However, given the age of generators in this fleet, the assumed retirement of Yucca and ECGS Unit 4, the expected steady peak load growth, and the fact that the reliability analysis conducted in the initial phases of this IRP identified the existing 'islanded' IID portfolio as being short several hundred megawatts of capacity, there is a need to procure additional firm capacity resources.

The reciprocating internal combustion engine (RICE) is a modern, modular technology for providing dispatchable firm capacity with fast startup/shutdown time. The candidate resource option modeled can run solely on natural gas or on a blend of hydrogen and natural gas. This IRP assumes a capital cost of approximately $1.3 MM USD per MW of capacity for such technology, with variable operating and maintenance (VOM) costs of roughly $5/MWh.

## Candidate Geothermal Resources

IID's service territory contains some of the best geothermal resource in the entire country. As shown in Figure 12, the Salton Sea area belongs to the "Most Favorable" geothermal resource category, with many identified hydrothermal sites. Indeed, many existing geothermal projects exist in the IID service territory and the IID portfolio.

Geothermal energy profiles as a high-capacity factor and high-ELCC resource with a dependably flat baseload generation profile. This generation profile presents a challenge when considering candidate resources to meet IID's very summer-heavy load, similar to the issue addressed earlier with regard to New Mexico wind resources. Such a profile means that for every MWh of geothermal energy procured to help meet the high summer peak, a MWh of geothermal is also procured for winter or spring months when demand is low. Nevertheless, this IRP contains alternative scenarios where increased penetration of flat geothermal generation is paired with long-duration energy storage capacity to shift some of that power from periods of low demand to the summer peak.

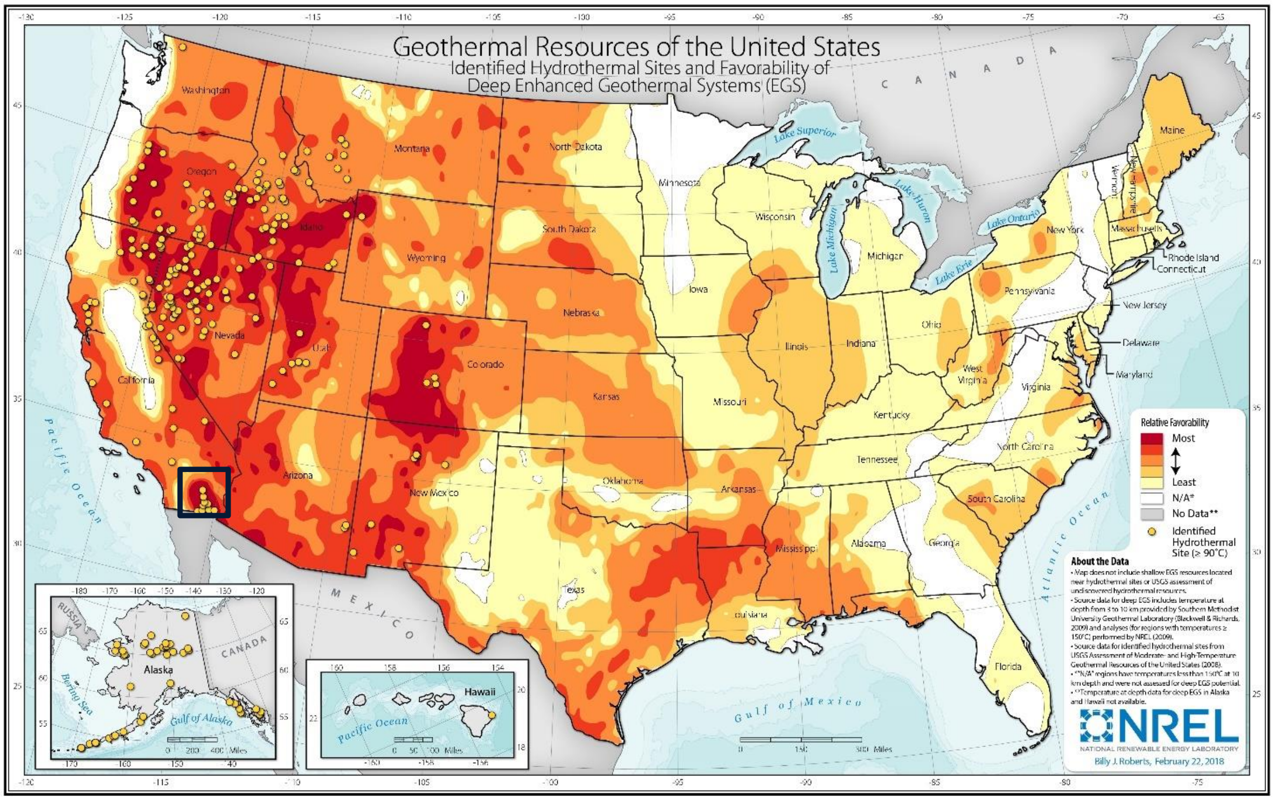


**FIGURE 12. U.S. GEOTHERMAL RESOURCE: BLACK RECTANGLE ROUGHLY BOUNDS IID'S SERVICE TERRITORY[68].**

## Candidate Storage Resources

In a portfolio with increasing adoption of variable generation resources like wind and solar, it becomes more desirable – and important – to have a means of storing energy from these sources that was generated in times of low demand so that it can be used in periods of higher demand. Energy storage is therefore a critical class of candidate resources to consider in the IRP process. This analysis considered two durations of lithium-ion battery storage and one representative 'long duration' energy storage option.

The lithium-ion battery storage duration options considered are four-hour and eight-hour, meaning that a given capacity of the resource would be able to discharge at full capacity for four or eight hours, respectively. These are the two most commonly seen and commercially available battery storage options on the market today. For both battery durations, a round trip efficiency of 85% is assumed, along with an effective forced outage rate (EFOR) of 5% with a mean outage of time of one day and a 365-cycle limit per year. It is assumed that eight-hour storage can only be chosen after 2030 to give a realistic timeframe for when this storage option could be procured and would be most effective (i.e., after the benefits of increasing penetration of four-hour storage built earlier in the capacity expansion scenarios start to diminish due to a widening, flattening peak).

[68] Citation: Roberts, Billy J. February 2018. "Geothermal Resources of the United States." National Renewable Energy Lab.

# Demand and Price Forecast Assumptions

## Demand Forecasts

The California Energy Commission (CEC) releases demand forecasts periodically for IID and other BAs in California as part of the Integrated Energy Policy Report (IEPR). The most current IEPR is the 2022 Update, which included the 2022 California Energy Demand Update (CEDU). This iteration of the demand forecast has projections for both overall energy consumption by year as well as 1-in-X peak load expectations, where X could be two, five, 10, or 20 years. In prior IEPR releases, different load scenarios were released, including Low, Mid, and High projections. For the 2022 update, only a 'Mid' case was released. For the Baseline scenario analysis in this IRP, the Mid case is the assumed demand trajectory for the 2022-2035 period. For the Low- and High-Demand scenarios, the prior 2021 IEPR IID demand forecasts (2022-2035) were used, as those were the latest years in which low- and high-demand CEC forecasts were available. All demand forecasts, for both energy and peak load, were extrapolated through 2045 using Microsoft Excel's FORECAST.ETS function, which is an additive error, additive trend, and additive seasonality (AAA) exponential smoothing algorithm specifically designed for forecasting time series data trends. To estimate monthly energy demand values, the historical proportion of each month's load to the annual total was used to disaggregate the forecast annual totals. The assumed monthly energy and 1-in-10 peak load forecasts are provided below in Figure 13 and Figure 14.

Annual values for the IID system demand forecast are provided in the table below:

**TABLE 9. ANNUAL ENERGY DEMAND AND 1-IN-10 PEAK LOAD FORECAST FOR LOW, MID, AND HIGH DEMAND FORECASTS**

| | Annual Energy Demand (GWh) | | | 1-in-10 Peak Load (MW) | | |
|---|---|---|---|---|---|---|
| Year | Low | Mid | High | Low | Mid | High |
| 2023 | 3,908 | 4,009 | 4,126 | 1,140 | 1,141 | 1,177 |
| 2024 | 3,937 | 4,050 | 4,179 | 1,153 | 1,154 | 1,196 |
| 2025 | 3,966 | 4,094 | 4,233 | 1,168 | 1,167 | 1,215 |
| 2026 | 3,998 | 4,139 | 4,297 | 1,183 | 1,181 | 1,234 |
| 2027 | 4,028 | 4,186 | 4,361 | 1,198 | 1,194 | 1,254 |
| 2028 | 4,058 | 4,232 | 4,426 | 1,214 | 1,209 | 1,276 |
| 2029 | 4,076 | 4,271 | 4,482 | 1,226 | 1,219 | 1,294 |
| 2030 | 4,088 | 4,306 | 4,537 | 1,239 | 1,229 | 1,313 |
| 2031 | 4,087 | 4,337 | 4,581 | 1,249 | 1,240 | 1,330 |
| 2032 | 4,078 | 4,365 | 4,624 | 1,254 | 1,250 | 1,345 |
| 2033 | 4,059 | 4,387 | 4,666 | 1,257 | 1,258 | 1,360 |
| 2034 | 4,026 | 4,403 | 4,702 | 1,258 | 1,264 | 1,374 |
| 2035 | 3,981 | 4,412 | 4,734 | 1,254 | 1,268 | 1,387 |
| 2036 | 3,988 | 4,438 | 4,780 | 1,259 | 1,276 | 1,400 |
| 2037 | 3,999 | 4,470 | 4,830 | 1,266 | 1,284 | 1,413 |
| 2038 | 4,009 | 4,503 | 4,880 | 1,272 | 1,293 | 1,427 |
| 2039 | 4,019 | 4,535 | 4,929 | 1,278 | 1,301 | 1,441 |
| 2040 | 4,030 | 4,567 | 4,979 | 1,284 | 1,309 | 1,455 |
| 2041 | 4,040 | 4,599 | 5,028 | 1,291 | 1,318 | 1,469 |
| 2042 | 4,050 | 4,631 | 5,078 | 1,297 | 1,326 | 1,482 |
| 2043 | 4,061 | 4,663 | 5,128 | 1,303 | 1,334 | 1,496 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2044 | 4,071 | 4,695 | 5,177 | 1,309 | 1,343 | 1,510 |
| 2045 | 4,081 | 4,727 | 5,227 | 1,315 | 1,351 | 1,524 |

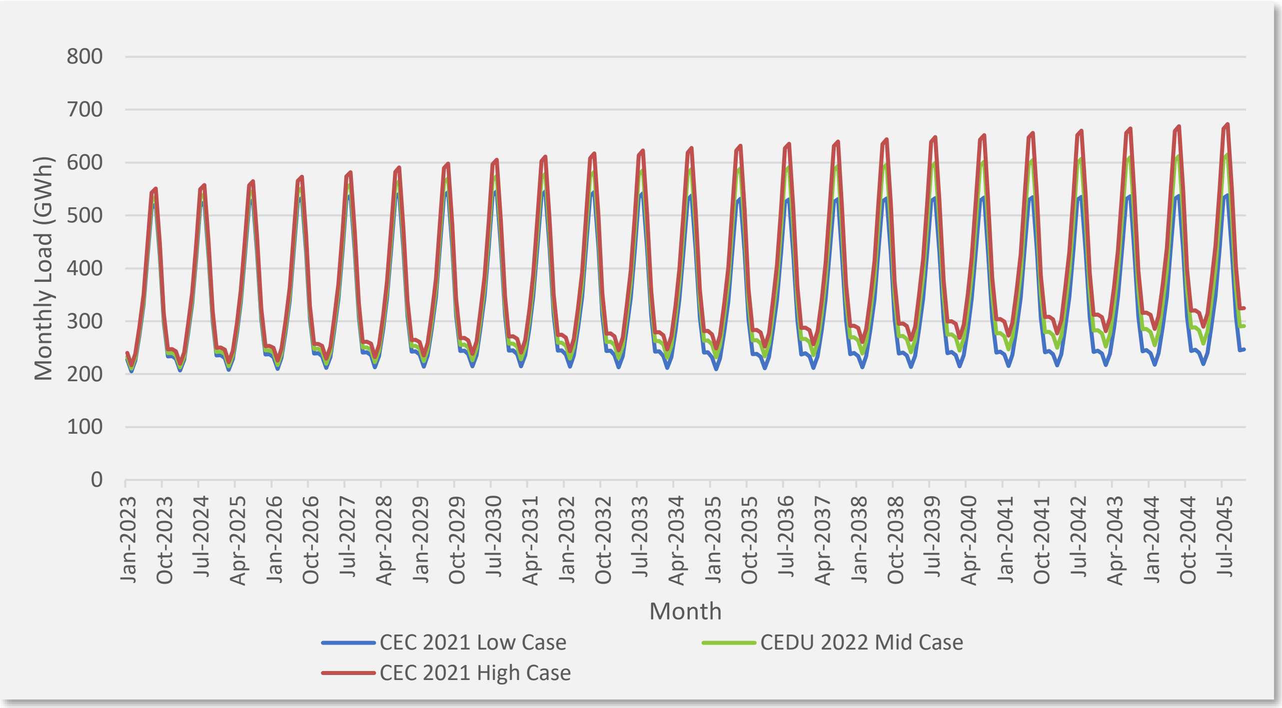


**FIGURE 13. MONTHLY DEMAND FORECASTS FOR IID SYSTEM, 2023-2045**

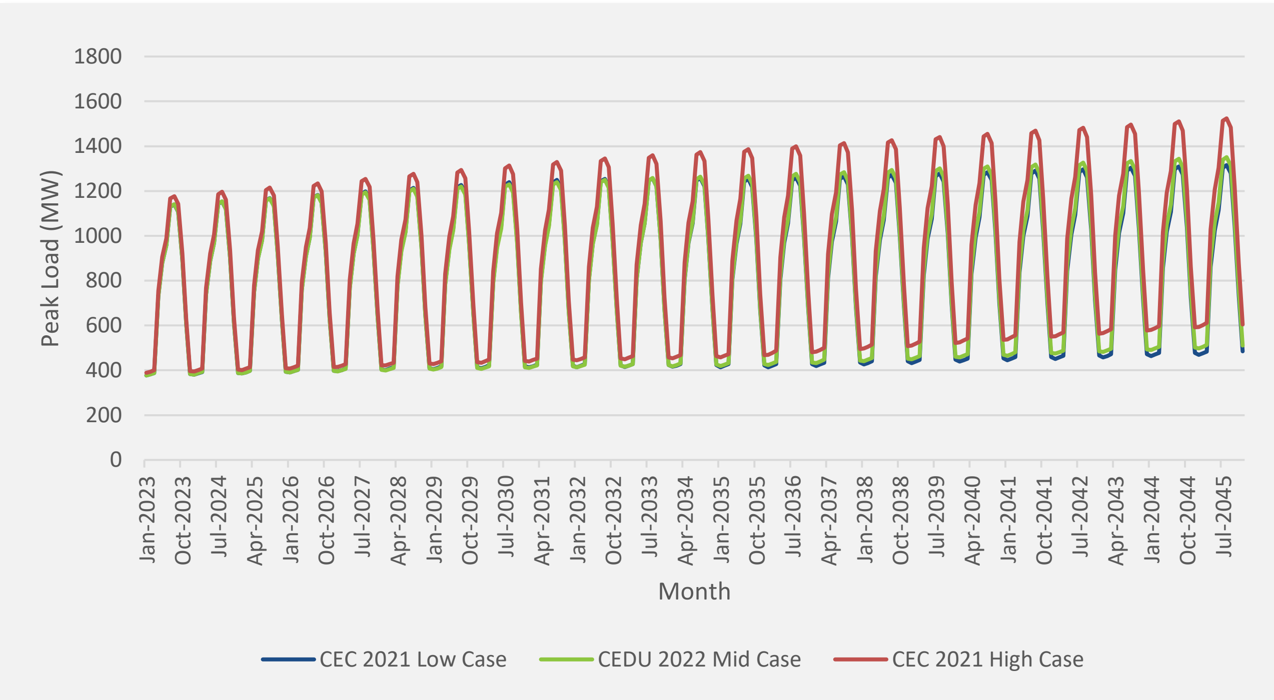


**FIGURE 14. MONTHLY PEAK DEMAND FORECASTS FOR IID SYSTEM, 2023-2045**

The expected monthly demand and peak demand are highest in August and lowest in February. Seasonal fluctuations in demand are primarily driven by cooling needs in the hot climate of the IID service territory. The average daily maximum temperature for Imperial, California in July and August is around 104 degrees Fahrenheit, with an annual maximum temperature of 114 degrees Fahrenheit.

# Price Forecasts

## Electricity Prices

**Figure** 15 illustrates the Ascend SP-15 power forward price forecast. Market forwards for SP-15 power prices decline through the early 2030s as renewable penetration increases. The on-peak and off-peak market forwards cross in 2025, with on-peak prices suppressed by increasing solar curtailment until the arrival of renewable fuels raises prices during evening peaks, putting upward pressure on on-peak prices through the late 2030s. Off-peak prices remain high due to carbon costs and elevated gas prices, which have a greater impact off-peak than the solar-dominated on-peak period. As green hydrogen displaces gas, reduced carbon price impacts and declining green hydrogen costs drive declining power prices in the later years of the forecast.

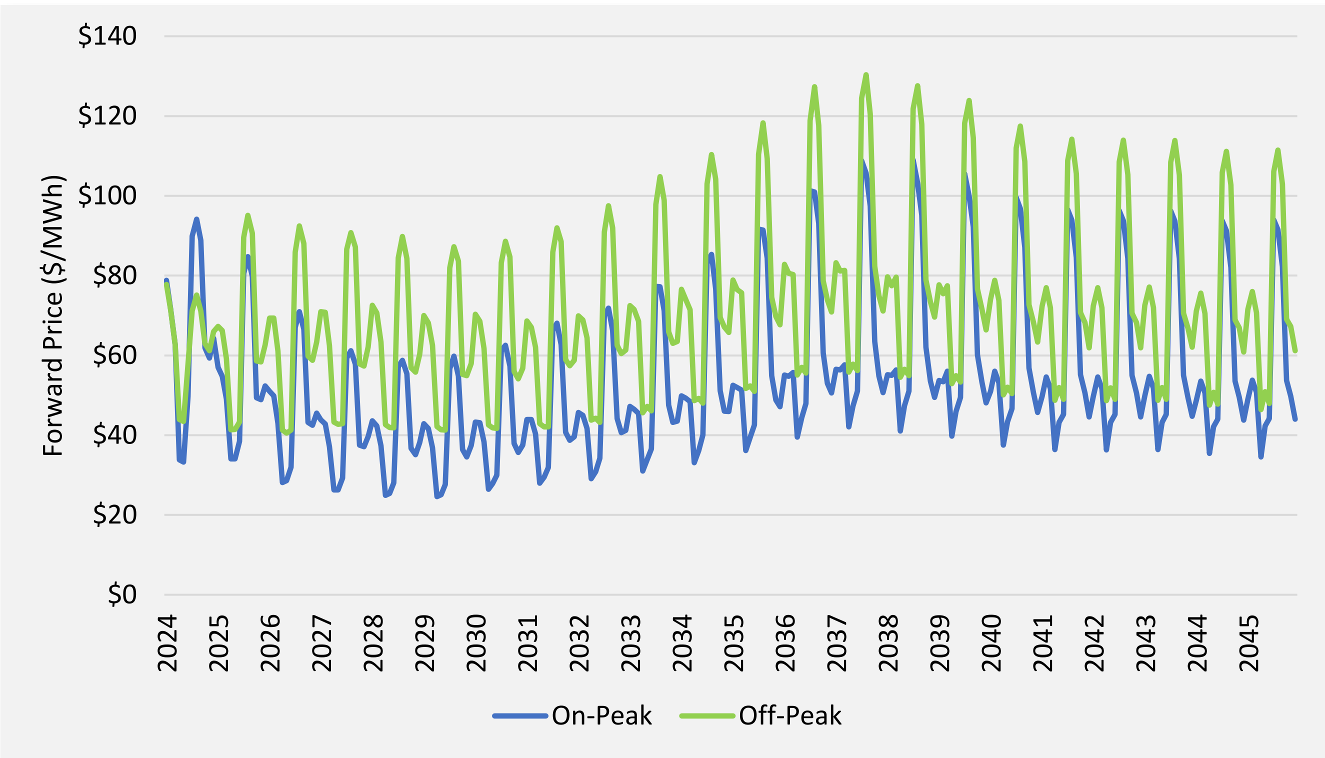


**FIGURE 15. SP-15 MARKET PRICE PROJECTIONS, 2024-2045.**

## Fuel Prices

**SoCal Citygate**

The natural gas price forecast uses the Pindyck approach,[69] which takes market forward data and then indexes by inflation after the liquidity period. Pindyck's analysis showed that using this method for natural gas forecasting is more reliable than a fundamentals-based approach, as price changes can drive a variety of unforeseen developments, including efficiency gains, alternative sources, and fuel switching. Figure 16 illustrates the Ascend SoCal Citygate forward price forecast.

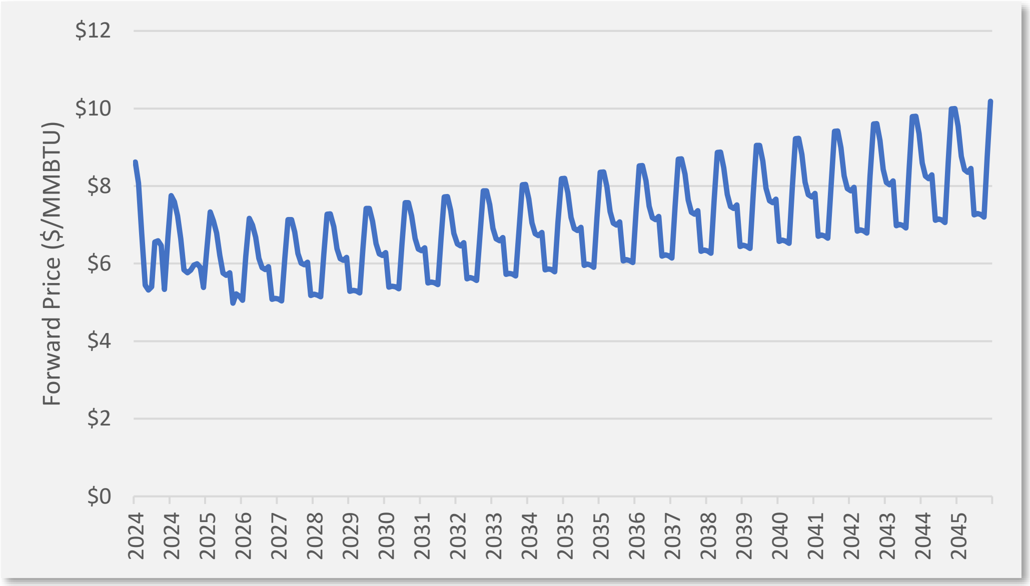


**FIGURE 16. SOCAL CITYGATE GAS FORWARD PRICE FORECAST, 2024-2045**

## Carbon Prices

California carbon prices have historically been close to the price floor, but recent auction settlement prices have been much higher which, in addition to increased legislative and lobbying activity, signals an appetite for higher carbon prices to drive faster decarbonization. As a result, Ascend forecasts California to increase the price floor for carbon by the late 2020s to the 20% allowance price threshold,[70] as FIGURE 17 shows.

These changes to the carbon price are driven by several factors. The price of carbon in California has traditionally traded at the price floor, which increases by 5% each year with an adjustment for inflation. However, in 2022, the average price in California's carbon market climbed to $28.50/tonne from its price floor of about $17.40/tonne in 2021.[71] This dramatic increase was driven mostly by speculators seeking refuge from surging inflation, rather than

[69] Pindyck, "The Long-Run Evolution of Energy Prices," The Energy Journal, 1999

[70] The 20% allowance price threshold is defined as 20% of the difference between the prescribed maximum allowance price and the floor price each year, plus the floor price.

[71] California Cap-and-Trade Auction Results

scarcity or lack of allowances driving up demand.[72] Ascend expects these higher prices to last through early 2024 based on expectations of higher inflation and costs in the short term, as well as by forward auction prices.

In the long term, Ascend does not expect supply and demand dynamics to drive price increases, as the market is flush with banked allowances. Some market experts believe that the market is oversupplied with an excess of 300 million banked allowances, which is more than the prescribed emissions cuts over the next decade. These banked allowances have raised concerns among policymakers that the state may miss its emissions reduction targets and prompted some to explore opportunities to rectify this imbalance.[73] One proposed solution is to raise the carbon price floor, with the expectation that the sale of excess allowances will push prices back down to a higher floor.[74] Given these conditions, Ascend expects California to adopt this increase to the price floor.

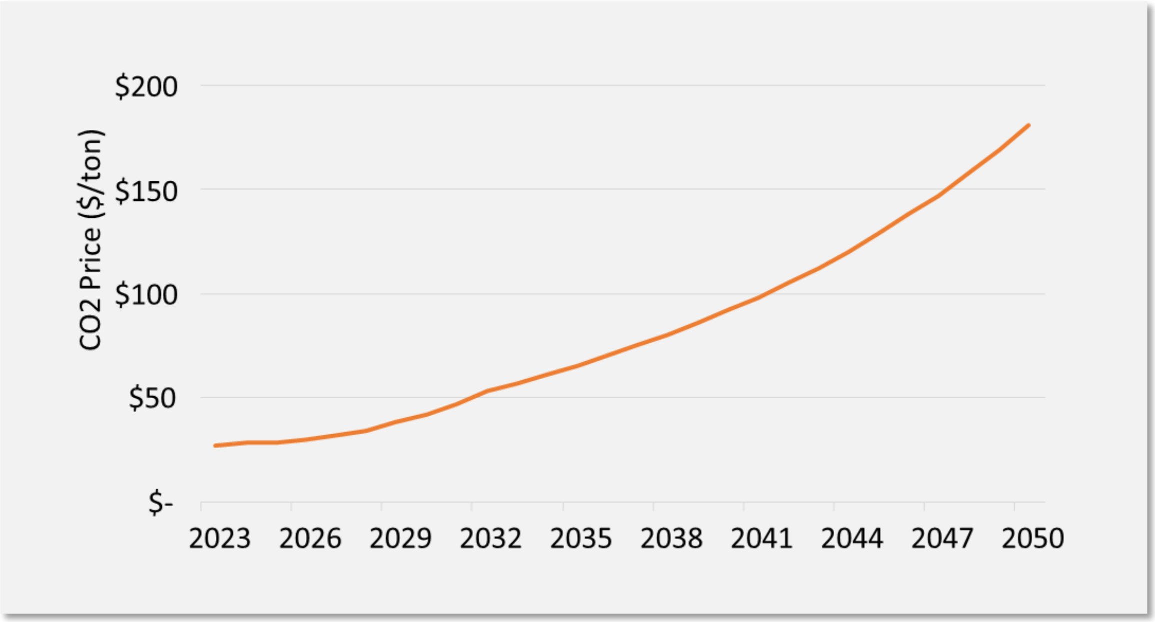


**FIGURE 17. CALIFORNIA CARBON PRICE FORECAST, 2023-2050.**

[72] Bloomberg, California Carbon Market
[73] CalMatters, Carbon Credit Oversupply
[74] 2021 Annual Report of the Independent Emissions Market Advisory Committee

# Resource Adequacy Modeling

A critical component of the IRP process involves understanding how well IID's current portfolio can meet customers' energy demand, both today and in the future. Reliability metrics such as loss-of-load hours (LOLH) and expected unserved energy (EUE) can be used to quantify the degree to which the system can adequately meet demand throughout the planning period. Forecasts of energy demand and peak load for 2023 – 2045 were discussed in the Load Forecast section. Once an understanding of the current portfolio's resource adequacy has been established, the incremental reliability benefit of adding new resources can be established through effective load carrying capability (ELCC) for each technology type.

Each of these concepts, as well as their associated modeling results, will be covered in greater detail in the following sections.

## Loss of Load Hours / Expected Unserved Energy

Loss of load hours (LOLH) refers to the number of hours over a given period (typically annual) in which generation is insufficient to meet load. Every loss of load hour is treated the same regardless of the depth of the shortfall; the metric simply reflects a count of how many times hours IID is unable to serve customer load.

A related but slightly different metric is expected unserved energy (EUE). EUE is measured in MWh and is the sum of the unserved energy across all loss of load hours that occur in a given year. For this reason, EUE is preferred to LOLH as a reliability metric for ELCC analysis because it captures more detail about the magnitude of loss of load events in the study period. These related concepts are illustrated in Figure 18 below. In the figure, the hours with the red numbers indicate loss of load hours, and the area in yellow shows EUE.

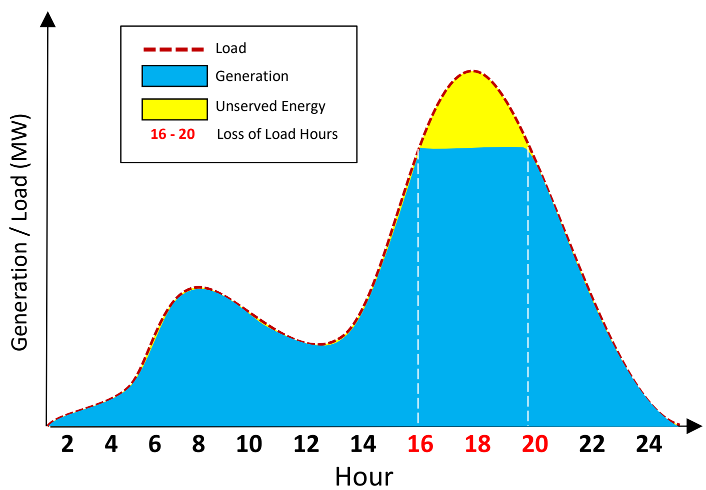


**FIGURE 18. SIMPLIFIED LOSS-OF-LOAD HOUR (LOLH) AND EXPECTED UNSERVED ENERGY (EUE) DEPICTION**

As a starting point for the resource adequacy modeling for this IRP, the current IID portfolio (as of January 2023) of existing and planned generation and storage assets, along with the assumed future load projection (see Load

Forecast section), was modeled in PowerSIMM. An LOLP analysis study was conducted on this portfolio for the period of 2023-2045. A common reliability metric of one day of load loss in 10 years (2.4 LOLH/yr) was used as a calibration or target metric. By determining the amount of additional 'perfect' capacity (i.e. dispatchable capacity with a forced outage rate of 0%) required in each year for the portfolio to reach the target reliability metric, a baseline capacity short estimate was established. The results of this analysis for the Mid load (Baseline) scenario considered in this IRP is presented in Figure 19.

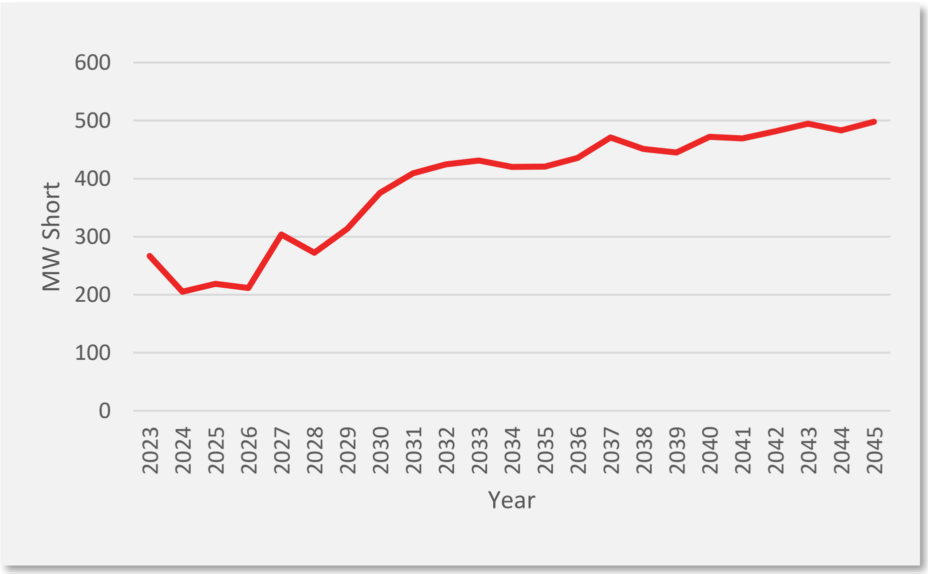


**FIGURE 19. IID ELCC-ADJUSTED ANNUAL PORTFOLIO CAPACITY SHORTFALL AT A TARGET LOLE OF 0.1 FOR CEDU 2022 MID-CASE DEMAND FORECAST.**

Figure 19 shows that IID's current portfolio is short by approximately 200 MW in 2024 and that this shortage grows to approximately 500 MW by 2045. The growth is due to the combination of the assumed annual increase in load, the retirement of existing generation capacity over time, the expiration of renewable PPA contracts, and the absence of any new capacity additions in this Baseline analysis. In practice, IID imports power to meet load in the peak hours of the summer, but in the resource adequacy analysis which treats the system as an 'island,' where no such imports are permitted, additional generation and storage resources would be required to meet the 2.4 LOLH per year target metric.

## Effective Load Carrying Capability

ELCC analysis serves as an essential tool for determining the contributions that can be expected from non-dispatchable assets in reaching reliability targets. Energy output from variable generation sources such as wind and solar may not (and often does not) coincide with the peak energy demands of the system. This contrasts with a dispatchable asset such as a natural gas-fired power plant which can be called on to serve load at specific times of day when demand is greatest. Simulating how the inclusion of a new variable generation resource affects overall system reliability targets allows IID to effectively calculate the equivalent amount of firm (dispatchable) capacity that would need to be added to the system to achieve that same level of improved reliability. The ratio between this firm capacity and the nameplate capacity of the variable generation resource added to the portfolio is the ELCC for that resource, typically expressed as a percentage.

$$ELCC\ (\%) = \frac{Firm\ capacity\ equivalent\ (MW)}{Nameplate\ capacity\ of\ resource\ (MW)} * 100\%$$

Standard practice involves assessing ELCC values within a portfolio that has been calibrated to the reliability target of interest (in this case, 2.4 LOLH/year). As stated previously, if the portfolio is short capacity (i.e., LOLP analysis concluded that the reliability metric for the current portfolio was greater than 2.4 LOLH/yr), additional 'perfect' capacity is added to the portfolio to calibrate it. At this point, ELCC analysis can begin.

For each candidate resource type, excluding geothermal and long duration storage (which were assumed to have 100% ELCC in the scenario where they were modeled), incremental 100 MW blocks of capacity were successively added to the portfolio. At each increment, an LOLP study was run to assess the EUE at various additional 'perfect capacity' increments. The equivalent amount of firm capacity that yielded the same reduction in EUE in the previous iteration's portfolio (i.e., the 'baseline' portfolio for that iteration) could be determined, which then yielded the marginal ELCC for that resource amount. That incremental portfolio then became the baseline portfolio for the subsequent iteration, and the process repeats for a total of five iterations, up to 500 MW of capacity for each candidate resource type. The five marginal ELCC values obtained form a downward sloping curve, which is the expected behavior as additional increments of the same resource type are added to the portfolio. A graph and table of the marginal ELCC values at each capacity increment are provided below in Figure 20 and Table 10, respectively.

**TABLE 10. CANDIDATE RESOURCE MARGINAL ELCC CURVES**

| Candidate Resource Technology | 0 – 100 MW | 100-200 MW | 200-300 MW | 300-400 MW | 400-500+ MW |
|---|---|---|---|---|---|
| SoCal Wind | 30.5% | 18.1% | 10.8% | 7.0% | 5.0% |
| New Mexico Wind | 19.9% | 12.0% | 7.4% | 4.9% | 3.7% |
| PV Solar | 15.2% | 10.0% | 6.6% | 4.6% | 3.3% |
| Geothermal | 96% | 96% | 96% | 96% | 96% |
| 4hr Storage | 57.8% | 44.8% | 40.6% | 32.4% | 21.4% |
| 8hr Storage | 91.3% | 82.1% | 54.7% | 23.7% | 13.0% |
| Long Duration Storage | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |
| RICE (Natural Gas) | 96.0% | 96.0% | 96.0% | 96.0% | 96.0% |

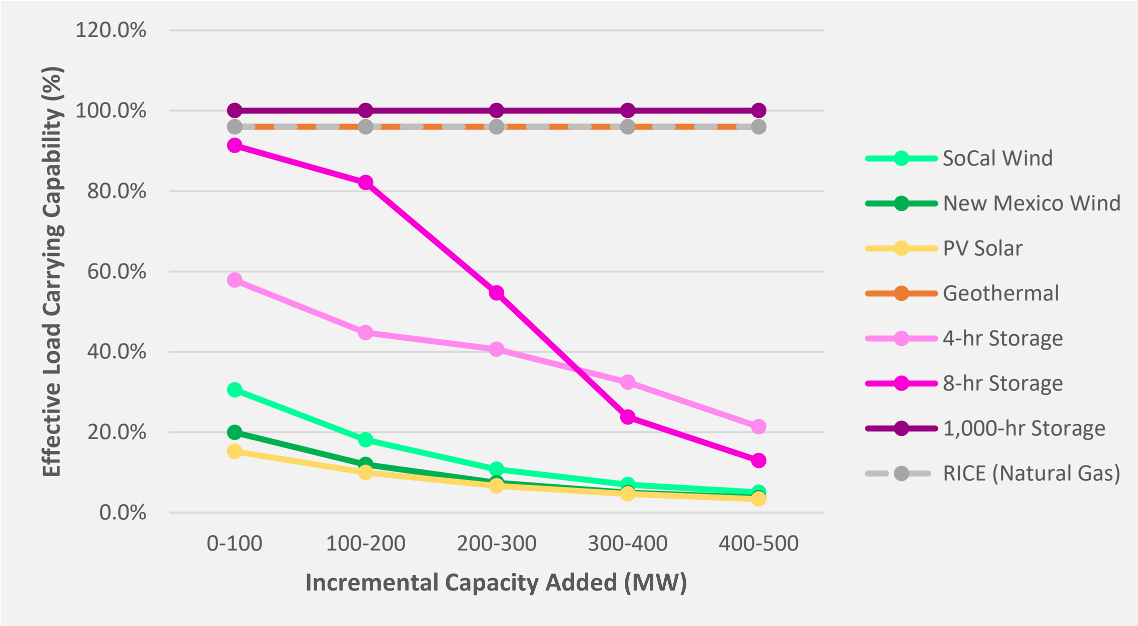


**FIGURE 20. CANDIDATE RESOURCE MARGINAL ELCC CURVES**

Several trends become apparent when examining the marginal ELCC curves. First, in comparing the wind resource types, it is evident that SoCal wind exhibits a higher ELCC than the New Mexico wind. The California wind profile aligns more closely to the IID peak load shape, peaking in the late spring and early summer months. In contrast, the New Mexico wind profile is lowest during summer months. Despite having a lower annual capacity factor (30% vs. 40%), California wind contributes better to reliability capacity needs in peak load summer months.

The marginal ELCC curves for four- and eight-hour storage resources reveals another important trend. While initial additions of lithium-ion storage contribute a substantial portion of their nameplate capacity to reliability needs, increased storage penetration eventually reduced the reliability contribution of that resource as the load peak is flattened to longer durations. Eight-hour storage is generally able to maintain high ELCCs through higher penetrations given its longer duration but it, too, exhibits much lower ELCCs at sufficiently high penetration. Similar trends in marginal ELCCs as a percentage of system peak were identified in other studies[75]. An important caveat in this marginal ELCC analysis approach is that it measures the ELCC of resources independently of each other – that is, without any other types of resource additions to the reference portfolio. Synergistic 'diversity,' or benefits from a combination of resources, may be greater than the sum of the benefits of the individual components. The canonical example of this potentially synergistic benefit is the combined reliability benefit of storage paired with solar generation, where solar energy can then be shifted later into the day (effectively raising the solar ELCC), while the additional solar generation increases the energy available for the energy-limited storage resource to charge (increasing the storage ELCC). Conversely, antagonistic effects may exist between resource types, such as different storage options (for example, increasing eight-hour storage penetration may reduce the four-hour storage ELCC). Diversity benefits and antagonistic effects are difficult to quantify a priori in a reliability or capacity expansion analysis due to the multi-dimensional surface of likely non-linear interactions created when combinations of resources are considered. Therefore, an iterative approach is employed in this study which only

[75] https://www.utilitydive.com/news/moving-beyond-rules-of-thumb-for-smart-cost-effective-storage-deployment/553674/}.

counts the independent ELCC contributions from resource builds during the capacity expansion phase of the analysis, and then the overall reliability of the resulting portfolio is checked in a final resource adequacy study. In the case where the resulting reliability metrics differ significantly from the target (in this case, 2.4 LOLH/yr), the initial resource ELCCs or ELCC-adjusted capacity target assumptions can be adjusted to approximate the diversity benefits, repeating this process until reliability metrics align. In practice, only the capacity target is adjusted during this iterative process, in lieu of a 'fair' or robust way of distributing ELCC adjustments among the candidate resources.

## Reserve Margin

The stochastic nature of the PowerSIMM modeling approach means that satisfying a reserve margin requirement is handled more robustly than in conventional deterministic capacity expansion approaches. Rather than setting a fixed reserve margin requirement of, say, 15%, as would be done in a deterministic analysis, PowerSIMM utilizes the resource adequacy analysis discussed in the Methodology section to set the target annual capacity so that IID remains at or below 2.4 LOLH in each year of the study. This capacity target is set equal to the ELCC-adjusted capacity of the existing portfolio plus the additional capacity shortfall identified. The distribution of peak loads relative to the mean is given in Figure 21, which illustrates how the stochastic model captures a range of peak load scenarios. Compare the range of stochastic scenarios (enclosed by the dashed red lines) to the median peak load profile (solid red line). For the final scenario analysis, 250 simulations were used to establish a distribution of load scenarios with maximum values in any given year averaging out to 116% of the corresponding median annual peak. On average, the maximum peak load across all simulations as a percentage of the median peak load for each year is approximately 116%.

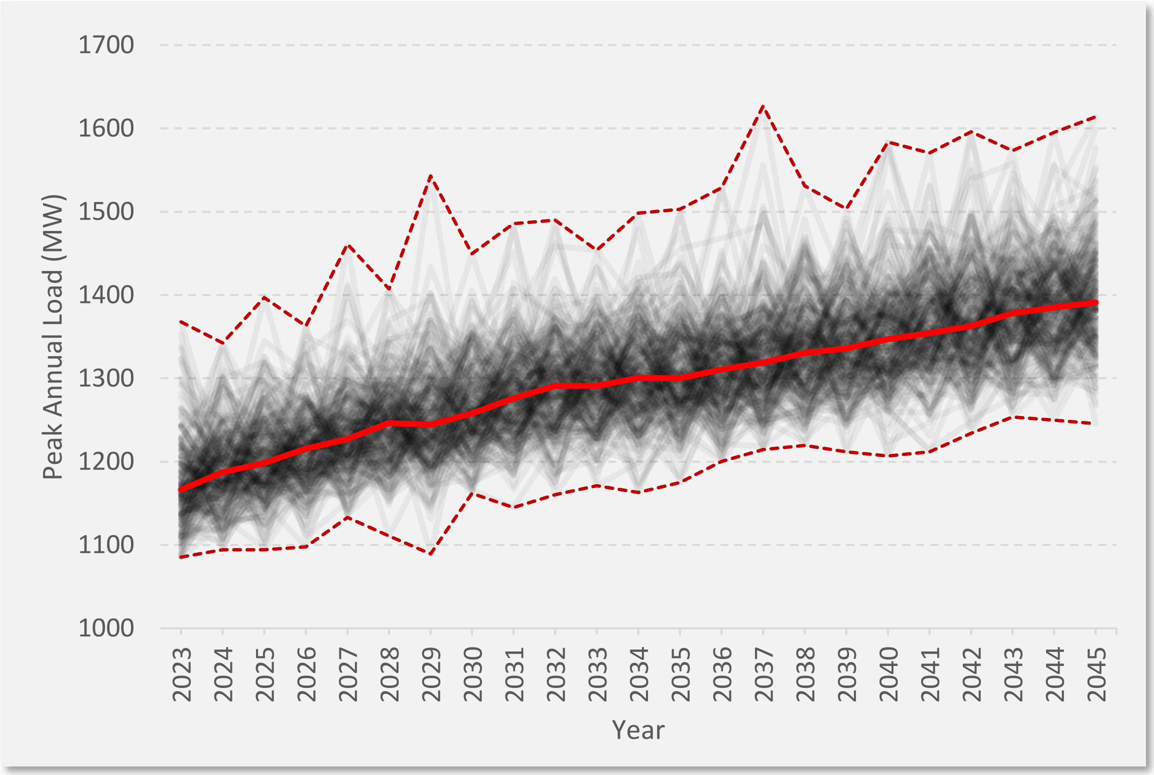


**FIGURE 21. ANNUAL PEAK IID SYSTEM LOAD BY STOCHASTIC SIMULATION FOR THE MID LOAD GROWTH SCENARIO (DEFAULT).**

# Baseline Scenario

The baseline or reference scenario serves as the default planning scenario in this IRP update. It is the scenario against which all alternative scenarios are compared. The technology options of new solar, wind, geothermal, four hour BESS, eight-hour BESS, and RICE thermal units are allowed options for ARS in this scenario, with the earliest allowed build years for each technology type given in Table 8 of the Candidate Resources section. This scenario establishes a capacity expansion pattern that is reflected to varying degrees by most of the alternative scenarios. Some key takeaways from this scenario are provided below and explained in greater detail in the following sections.

- Initial builds of RICE units and four-hour storage in 2027 (the earliest allowable build year for any technology) improve reliability metrics by reducing the short capacity position of IID starting in 2027.
- The initial capacity builds are complemented by substantial builds of renewables (mainly solar, along with some in-state wind) in the late 2020s through mid-2030s. The RPS builds ensure that IID hits both its RPS energy targets and carbon emissions targets for the planning period.
- The total portfolio cost in this scenario is projected to rise to $496 million annually compared to $367 million in 2024. Cost per MWh of served load is projected to increase from approximately $90/MWh in 2024 to $105/MWh in 2045.
- The capacity builds ensure that the 1-in-10 reliability target of 2.4 loss of load hours per year is achieved and maintained throughout the IRP planning period.

## Capacity Expansion Results

Automated Resource Selection (ARS), the capacity expansion model within PowerSIMM selects the least cost portfolio that meets three sets of constraints:

- Annual capacity targets (planning reserve margin) necessary to achieve a 1-day-in-10 years reliability standard.
- RPS energy and zero-carbon energy targets established collectively by SB 350, SB 100, and SB 1020.
- IID's BA-specific carbon emissions target range established by CARB.

Figure 22 shows the capacity expansion results for the Baseline scenario as cumulative capacity over the planning period. In 2027, the first allowed year of capacity selections, ARS selects 530 MW of new resources comprised of approximately 100 MW of in-state wind, 70 MW of solar, 250 MW of 4-hour storage capacity, and 110 MW of RICE thermal units. The first year that new resources can be added to the portfolio is set at 2027 to account for the length of the procurement process. There are three to five years of work that is necessary to bring new resources online after establishing the need through the IRP. These builds, especially the storage and thermal capacity, help IID to establish a resource adequate portfolio, given that the existing portfolio was found to be short approximately 200 MW of capacity currently.

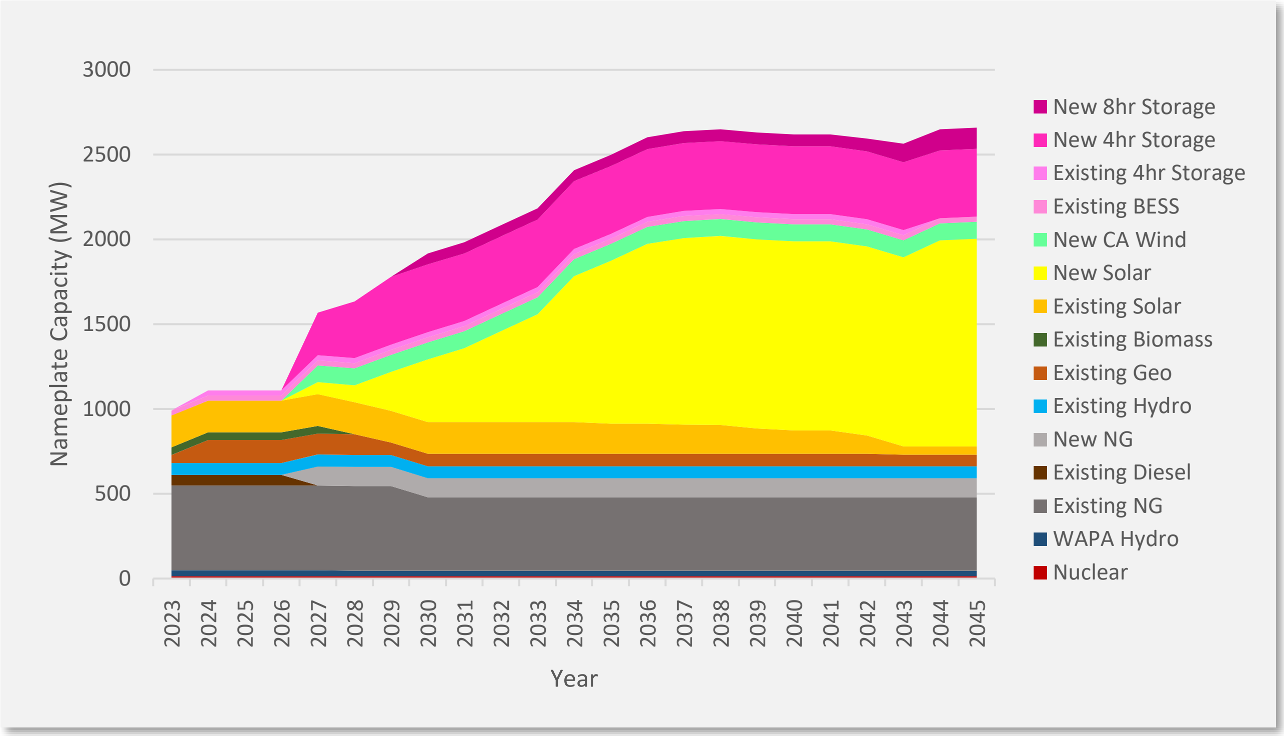


**FIGURE 22. BASELINE SCENARIO CAPACITY EXPANSION, 2023-2045**

**TABLE 11. BASELINE SCENARIO CAPACITY EXPANSION AT FIVE YEAR INCREMENTS**

| | Cumulative Nameplate Capacity (MW) by Year | | | | |
|---|---|---|---|---|---|
| Resource | 2025 | 2030 | 2035 | 2040 | 2045 |
| New 8hr Storage | - | 65 | 65 | 70 | 125 |
| New 4hr Storage | - | 400 | 400 | 400 | 400 |
| New Solar | - | 370 | 960 | 1,115 | 1,225 |
| New CA Wind | - | 100 | 100 | 100 | 100 |
| New RICE | - | 113 | 113 | 113 | 113 |
| Planned 4hr Storage | 30 | 30 | 30 | 30 | - |
| Existing BESS | 30 | 30 | 30 | 30 | 30 |
| Existing Solar | 188 | 188 | 178 | 139 | 49 |
| Existing NG | 499 | 433 | 433 | 433 | 433 |
| Existing Diesel | 63 | - | - | - | - |
| WAPA Hydro | 35 | 32 | 32 | 32 | 32 |
| Small Hydro | 70 | 70 | 70 | 70 | 70 |
| Existing/Planned Geo | 115 | 73 | 73 | 73 | 68 |
| Existing Biomass | 45 | - | - | - | - |
| Nuclear | 14 | 14 | 14 | 14 | 14 |

From 2027 through the mid-2030s, solar capacity is steadily added to the portfolio to meet the 2030 RPS target of 60% (measured as a percentage of retail sales) and the subsequent zero-carbon targets of 90% retail sales by 2035, 95% of retail sales by 2040, and 100% of retail sales by 2045. New solar capacity reaches 370 MW by 2030, increasing to 960 MW by 2035 and 1225 MW by 2045. The model prefers to build the majority of this new solar capacity in the mid-2030s time period when solar PPA prices are forecast to be the lowest of the planning period (see pricing assumptions section). The other RPS-eligible builds come from the relatively modest amount of in-state wind (100 MW). This is an optimistic yet reasonable limit on the amount of in-state, commercially-viable wind resource matching the generation profile established (see Candidate Resource section). A modest amount of longer duration eight-hour storage is added to the portfolio starting in 2030, from 65 MW in 2030 and reaching 125MW by 2045. ARS does not select other RPS-eligible resources (geothermal, NM wind) in the Baseline scenario. Nameplate capacity in the Baseline scenario approaches 2.7 GW by the end of the planning period, representing a substantial increase from the roughly 1 GW of nameplate capacity in the current portfolio.

## Production Cost Analysis

As described in the methodology section, production cost analysis simulates hourly dispatch of the capacity expansion portfolio for the forecast period. A stochastic model of 100 future price, load, and variable generation simulations was used to model economic load dispatch of the thermal and storage units. Unless otherwise noted, the results presented from the production cost analysis reflect the mean outputs across these 100 simulations. Production cost modeling enables an assessment of overall portfolio costs to serve load, expected capacity factors, carbon emissions, storage cycling patterns, as well as individual unit revenues, costs, and any curtailment of renewables.

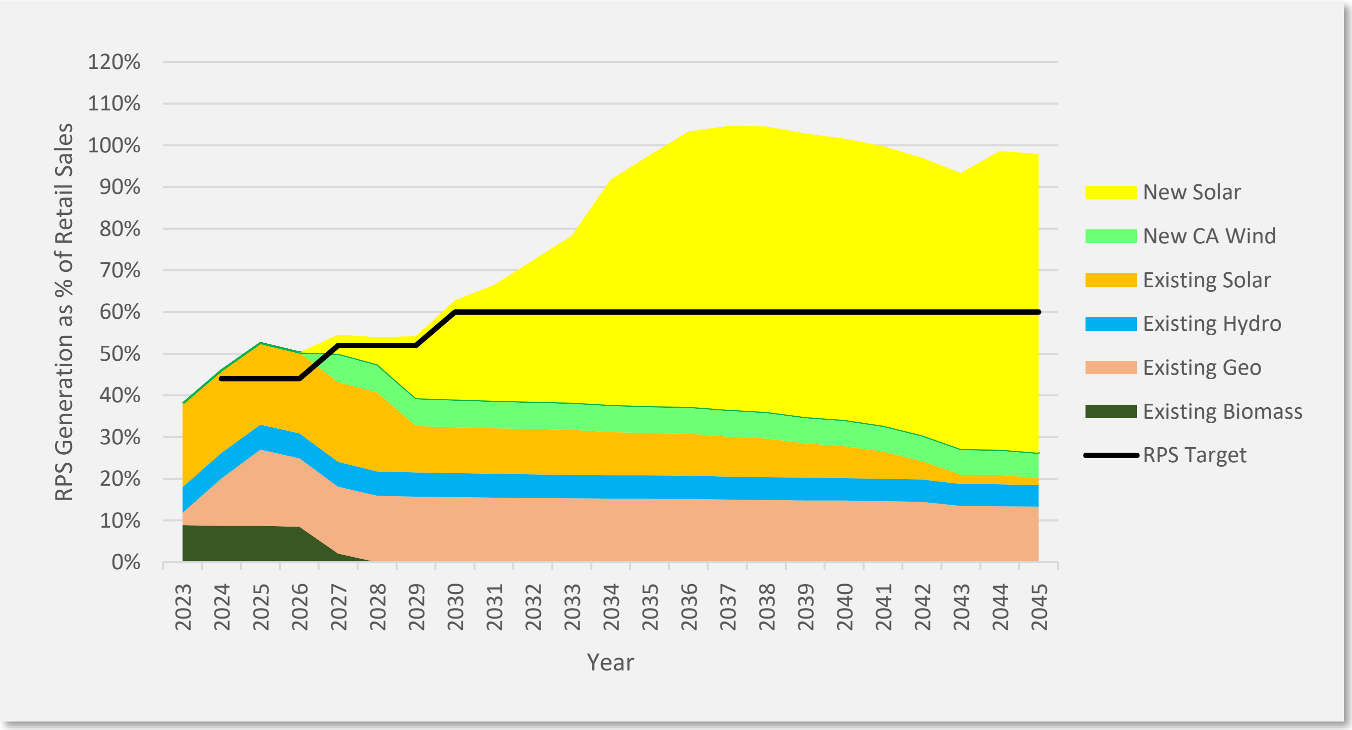


**FIGURE 23. GENERATION MIX FOR MEETING BASELINE SCENARIO RPS TARGET**

As shown in Figure 23, the shorter-term compliance period for RPS targets established by SB 100 – 40% by December 31, 2024; 52% by December 31, 2027 and 60% by December 31, 2030 – are met by a combination of existing RPS-eligible generation and future procurements of RPS-eligible resources. The earliest compliance period (2024-2026) is already met by existing solar, small hydro, geothermal, and biomass resources. The capacity expansion model achieves the established RPS standard in the next compliance period ending in 2027 by suggesting the procurement of in-state wind power and some solar power. This largely offsets the reduction in RPS generation due to the ending of the Desert View biomass contract in 2027.

Looking to the later clean energy targets established by SB1020 and SB100, the Baseline scenario maps out a trajectory for IID to achieve zero-carbon generation for 90% of retail sales by 2035, 95% by 2040, and 100% by 2045, as shown in Figure 24. It is important to note that some resources in IID's portfolio that are not RPS-eligible do count for zero-carbon generation – namely, the WAPA large-scale hydro projects and the Palo Verde nuclear generation. Still, the majority of the zero-carbon targets in the later years of the Baseline scenario are satisfied by the significant additional solar resource procurements.

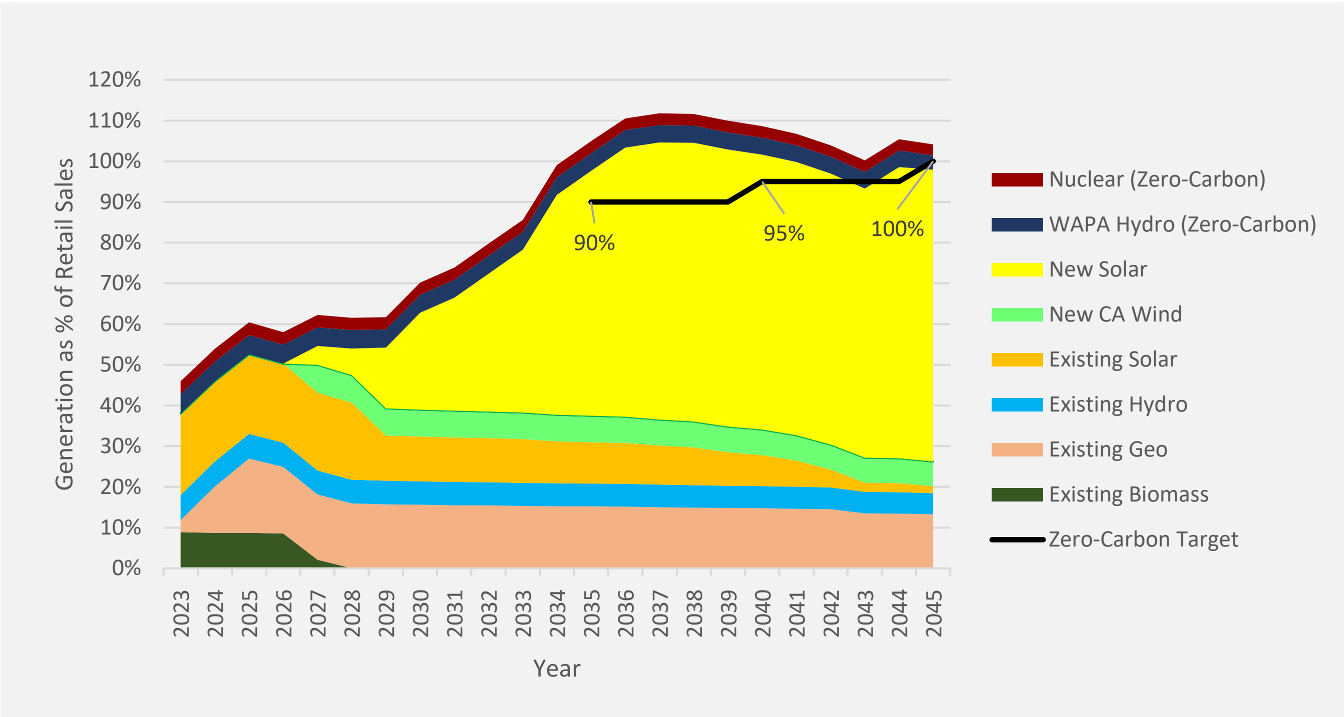


**FIGURE 24. GENERATION MIX FOR MEETING BASELINE SCENARIO ZERO-CARBON TARGETS**

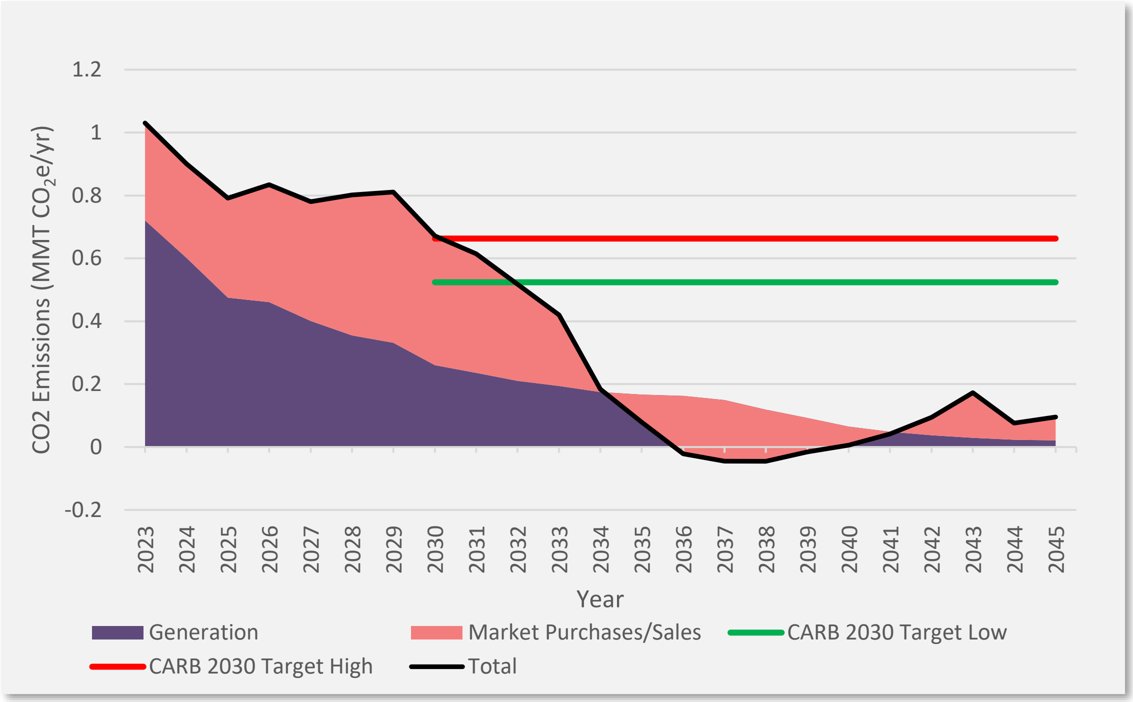


**FIGURE 25. ANNUAL $CO_2$ EMISSIONS FOR BASELINE SCENARIO, INCLUDING CARB EMISSIONS TARGETS FOR 2030 ONWARD**

The production cost modeling also confirms the portfolio-wide carbon emissions reductions and ensures that those fall in line with the established CARB target ranges for IID. $CO_2$ emissions accounting for the Baseline scenario are depicted in Figure 25**.** IID must achieve a target range of between 524,000 and 667,000 metric tons of $CO_2$ per year by 2030[76]. The Baseline scenario model was calculated to have a mean emissions level of 660,000 metric tons of $CO_2$ in 2030, within the target range. From there, emissions continue to decline through the study period as additional renewable and storage procurements, combined with increasing carbon allowance prices, mean the fossil-fired generation fleet runs for fewer and fewer hours per year.

Importantly, the emissions calculation methodology includes not only IID-portfolio generator emissions, but also emissions attributed to net purchases of power from the market. A standard unspecified import emission factor of 0.428 metric tons $CO_2$/MWh was assigned to the net imports. Calculated annual carbon emissions drop below 0 MMT from 2036 to 2039 as negative net imports on an annual basis more than offset the small amount of remaining thermal generation $CO_2$ emissions in those years. Increased reliance on imports in the latest years of the study (2040 onward) explains the subsequent, modest rise in emissions for that period. By 2045, total portfolio $CO_2$ emissions are estimated to be 91% lower than 2023 levels.

However, the "unspecified imports" emissions factor is a flat metric that does not depend on the hours in which power is imported. The marginal unit selling power on the market may have a vastly different emissions level depending on the time of year or even the time of day. Imports in the middle of the day may be primarily from excess solar generation without associated emissions, while evening imports after sunset may be primarily fossil in origin (especially in the earlier modeled years) and thus entail a higher emissions factor. Conversely, treating the unspecified import emissions factor as a credit on exported power relies on the assumption that such exports are offsetting generation with a relatively high emissions factor that would otherwise be running in the absence of the export sale. For exports from a solar-heavy portfolio as modeled in the Baseline scenario, such an

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[76] CARB. Senate Bill 350: Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets: 2023 Update

assumption may be unrealistic if most exports are occurring in the middle of the day. Thus, the “unspecified imports” emissions factor offers an imprecise method of accounting for $CO_2$ emissions and claiming emissions reductions on exported power.

## Portfolio Costs

As its name suggests, a primary aim of production cost modeling involves optimally minimizing the cost of serving load over the study period. PowerSIMM outputs several categories of costs within the optimized economic load dispatch results suite, and these can then be aggregated across resources and timescales to summarize the overall costs expected for the portfolio. Each of these cost components is described below:

- **Thermal** generation resource costs include:
  - Fuel costs (natural gas cost).
  - Variable O&M cost for each unit.
  - Startup costs, including startup fuel costs.
  - The cost associated with obtaining carbon allowances for the emissions of the unit in any given year, pursuant to California’s cap-and-trade program. In PowerSIMM this is modeled as carbon price attributed to each unit of carbon emitted when the plant is operating.
  - Fixed O&M costs for existing thermal assets are not directly captured in PowerSIMM or in the figures below and do not vary from scenario to scenario but are included later in the analysis for determining potential rate impacts.
  - In the case of the planned RICE generation capacity, an assumed CapEx for purchasing said units, amortized over an assumed 20-year resource lifetime.
- **Renewable** resource costs include:
  - PPA cost per MWh of generation is by far the most common component of the renewable costs. For future resource procurements, a PPA price forecast provided by Ascend’s Market Intelligence team is assumed, for simplicity. Maintaining the capital expense (e.g. 'IID ownership') cost accounting approach for new builds gets more complicated due to the required additional assumptions on long-term service agreement O&M costs. These are assumed to be priced into the PPA, which is otherwise closely tied to the assumed CapEx for each resource type in the capacity expansion phase of the analysis. The PPA cost approach also makes more sense given the likely nature of acquiring the new renewable generation through an RFO process.
  - IID-owned small-hydro projects have assumed maintenance and falling water costs per MWh.
- **Storage** costs are also modeled on a full-toll PPA basis rather than a capital expense basis, analogous to renewable resources given that storage too would most likely be procured via a request for offer (RFO). The assumed storage price projections in $/kW-mo were provided by Ascend’s Market Intelligence team and reflect the current (as of mid-2023) market environment for such resources, as explained in the Methodology section.
- **Sales and Purchases** of power are assumed to occur in the spot market, abstracting away the realities and complexities of bilateral energy contracts that may be negotiated far in advance. Thus, sales and purchases in a given hour reflect the quantity bought or sold multiplied by the modeled trading hub spot price for power in that hour. The model is configured with the current transmission constraints into and out of IID’s two main trading hubs – CAISO SP15 and Palo Verde. See the Methodology section for more details on how these market interactions were modeled in PowerSIMM for this IRP.

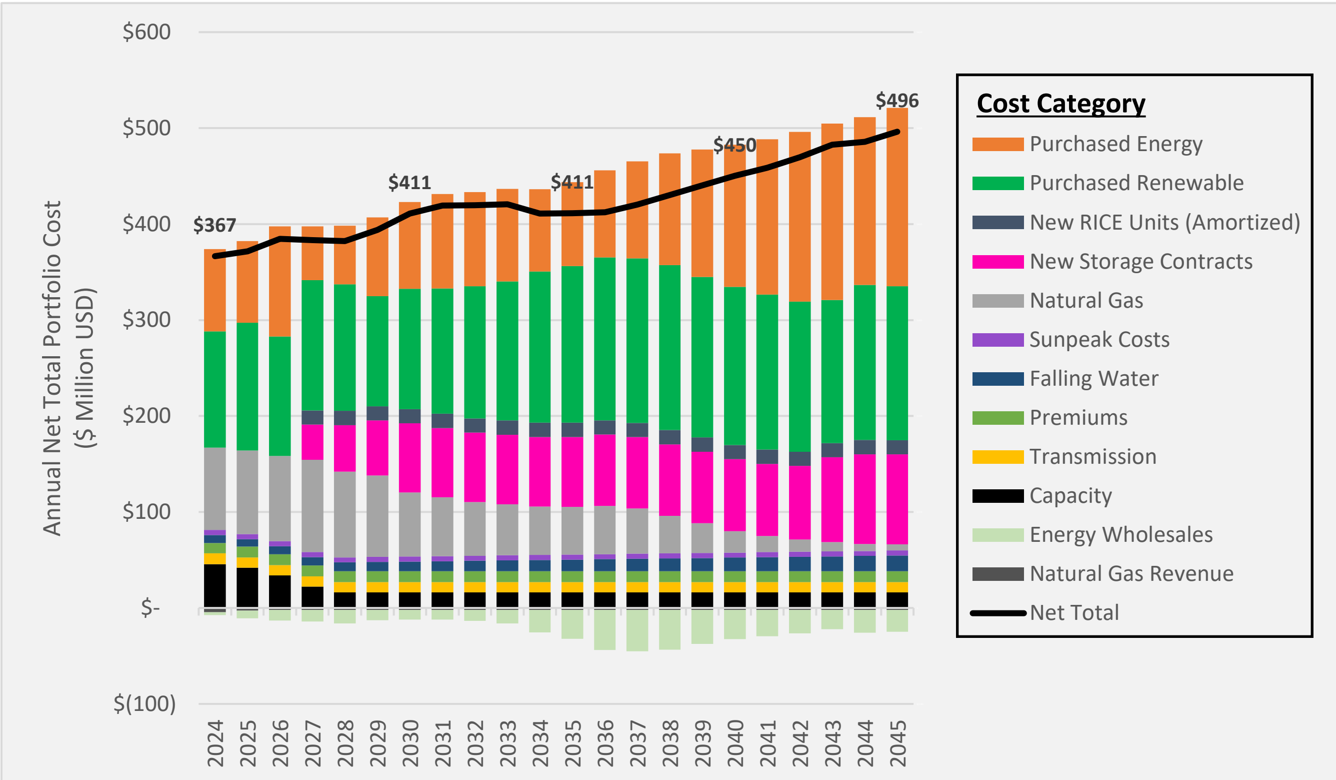



**FIGURE 26. BASELINE SCENARIO TOTAL COST OF SUPPLY, BY TYPE**

As shown in Figure 26, total costs in the Baseline scenario rise from $367 million in 2024 to $496 million by 2045. A significant portion of portfolio costs now and over the planning period come from renewable PPA contracts (green area of chart). Annual purchased renewable PPA costs are estimated to be $121 million (33% of total) in 2024, growing to $160 million (32%) by 2045. The large procurement of renewables, especially solar, suggested by the capacity expansion analysis results in a 35% increase in overall cost. The falling average cost per MWh for RPS resources, from $73/MWh in 2024 to just $36/MWh in 2045, as well as some revenue from sales of excess generation, lessen the cost increase from the new capacity. This observation is in line with the procurement timetable identified by the capacity expansion phase (heavy procurement of solar in the mid-2030s) aligning with the forecast trend of relatively low solar PPA prices in that mid-2030s timeframe, as discussed in the Methodology section.

Other trends observed in the total costs chart are the reduction in thermal-related costs, especially fuel costs (grey area of chart). With increased renewables penetration and rising natural gas and carbon allowance costs, the thermal units run much less in the later years of the forecast period than in the earlier ones (pre-2030). This translates most evidently into reduced fossil fuel costs, from about $86 million in 2024 to just $6 million in 2045, a 92% reduction. Startup and VOM costs associated with thermal operations are similarly reduced.

As thermal costs decline, energy storage costs increase as significant new capacity is added to the portfolio, starting in 2027 in the Baseline scenario. Energy storage costs go from accounting for less than 3% of total portfolio costs in 2024 to around 19% by 2045. This includes both the four-hour and eight-hour duration storage resource types procured over the planning period.

Other than generation and storage, the other major components of total portfolio cost come from purchases and sales of power. Given IID's very summer-heavy load profile, it is common for the District to be 'short' power in the summer months and 'long' in the winter months. While traditionally focus has been on the procurement of resources to meet the sharp summer peak, the winter 'long' situation may become more of a concern as variable generation resources become the dominant resource type in the generation portfolio. Excess solar power in winter months may not command a very high price in the market at such times and may need to be curtailed. Market interactions (green area of the chart) vary over the study period. 2024 purchases less sales are modeled as accounting for $78 million, or about 21% of total costs. This portion decreases up until about 2036 when net purchases make up just 11% of total costs. Beyond that point, net purchases start to rise commensurate with increasing load and end up accounting for about $58 million, or 32% of total costs in 2045.

**Stochastic Distribution of Portfolio Costs**

One of the advantages of PowerSIMM's stochastic approach to production cost modeling involves being able to look beyond the mean value returned for portfolio costs and see the distribution across the 100 simulated futures. The figures below demonstrate this capability by outputting the spread of total portfolio costs for selected years in the analysis, starting with 2024, the first year of the production cost study, to demonstrate how PowerSIMM captures the variability in expected total portfolio costs for the current portfolio. As shown in Figure 27, the spread of the variable portion of total costs ranges from $240 million to $380 million per year. This is a significant spread around the mean of $286 million. In contrast, by 2027, the distribution of variable costs is more concentrated around the mean of $281 million and ranges from $240 million to $330 million per year, as shown in Figure 28. This reduction in variability can be attributed to the reduction in required market purchases, which in turn is due to the additional RICE thermal and four-hour storage capacity beginning in 2027 of the Baseline scenario capacity expansion plan. In 2045 (Figure 29), the range of variable portfolio costs has once again widened as market purchases become more important to serving load. In that year, the variable costs range from $290 million to $420 million per year, with a mean of $343 million.

While not considered in detail here, the stochastic distribution of costs can enable a determination of the value-at-risk or other financial risk metrics.

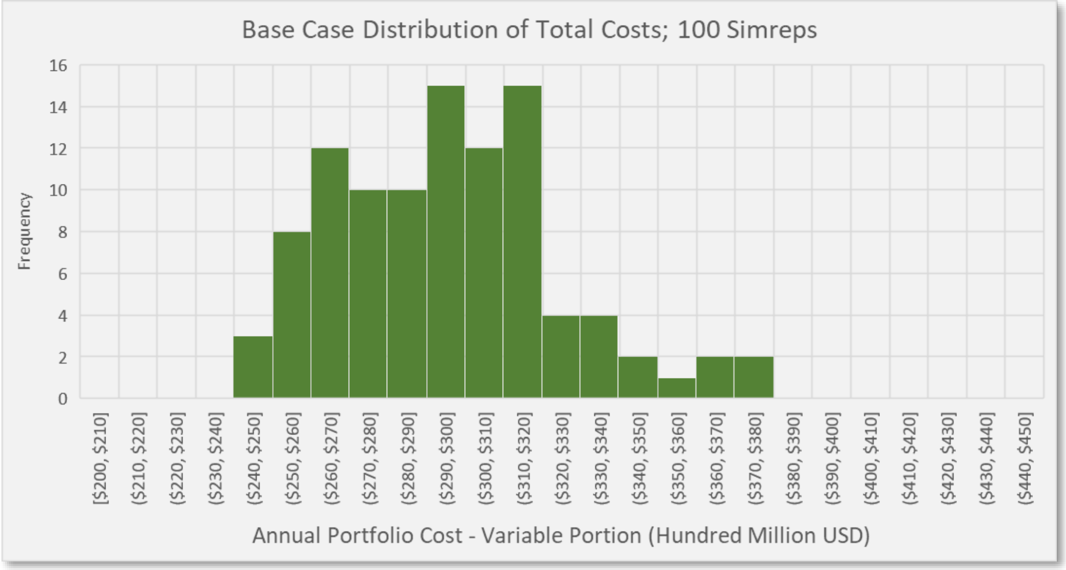



**FIGURE 27. 2024 DISTRIBUTION OF VARIABLE PORTFOLIO COSTS ACROSS 100 SIMULATIONS (MEAN = $286 MILLION/YEAR)**

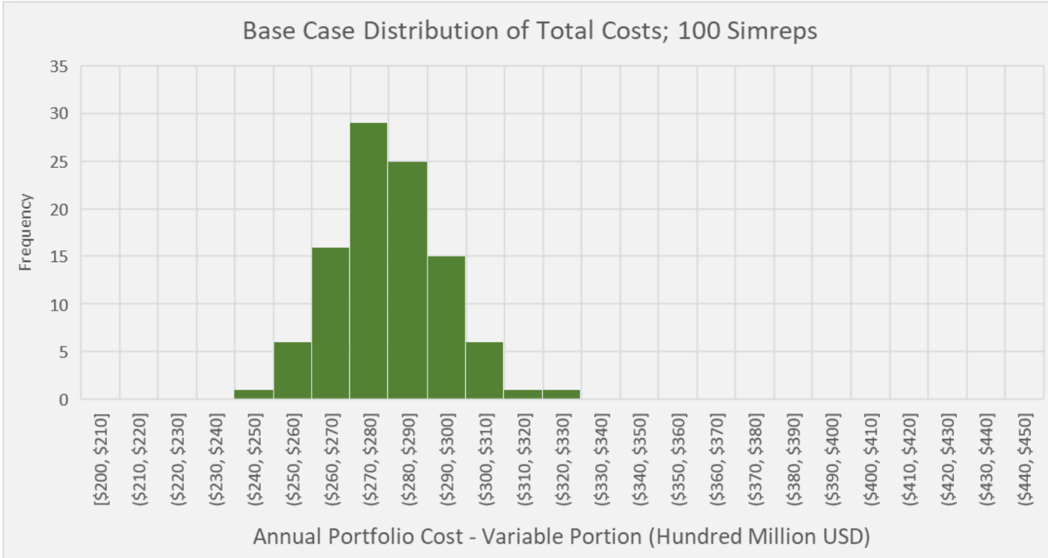



**FIGURE 28. 2027 DISTRIBUTION OF VARIABLE PORTFOLIO COSTS ACROSS 100 SIMULATIONS (MEAN = $281 MILLION/YEAR)**

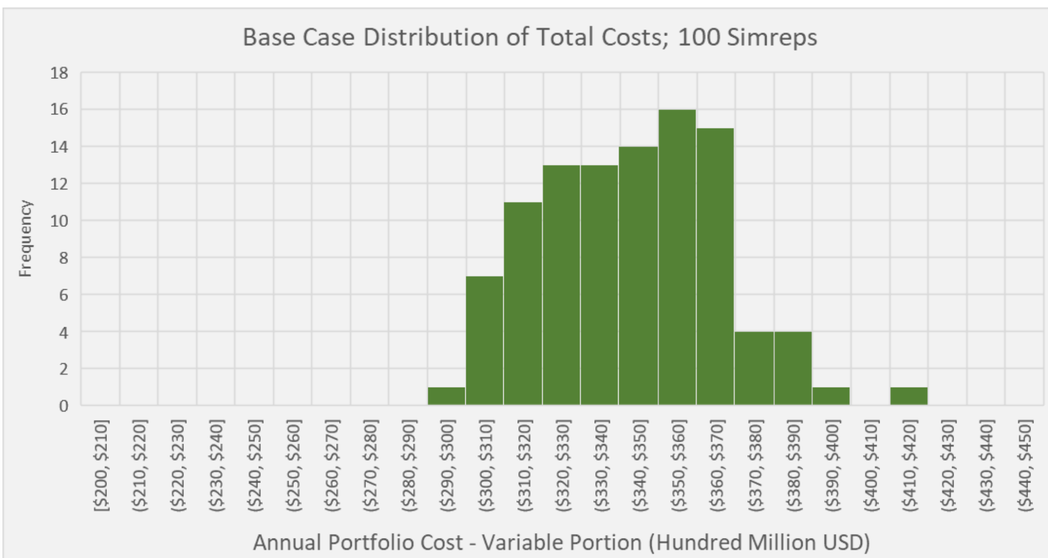



**FIGURE 29. 2045 DISTRIBUTION OF VARIABLE PORTFOLIO COSTS ACROSS 100 SIMULATIONS (MEAN = $343 MILLION/YEAR)**

## Rate Impacts Analysis

IID provides electric power to more than 163,000 customers in the Imperial and parts of the Riverside and San Diego counties. As the sixth-largest utility in California, IID controls more than 1,100 megawatts of capacity derived from a diverse resource portfolio that includes its own generation, and long-and short-term power purchases.

As a consumer-owned utility, IID works to efficiently and effectively meet its customers' demands at the best possible rates, tying our area's low cost of living directly with low-cost utilities. Located in a region with abundant sunshine, enviable geothermal capacity, wind, and other renewable potential, IID has met or exceeded all Renewable Portfolio Standard requirements to date, procuring renewable energy from diverse sources, including biomass, biowaste, geothermal, hydroelectric, solar, and wind. Its environmentally friendly operations provide its customers with some of the lowest cost rates in California.

As an electric utility, IID is exposed to a wide variety of operational and financial risk factors that cause uncertainty in IID's financial performance. As far as IID's electric system operations, risk factors include, but are not limited to, load uncertainty, generation availability and production uncertainty, fuel price volatility, capacity and wholesale energy price volatility, and transmission system import/export uncertainty.

To manage the mentioned risks, IID has an Energy Risk Management Policy and a gas, energy, and capacity hedging program. With this program, IID Energy proactively manages energy risk to optimize the balance between customer rate competitiveness, power affordability, and stability, while fulfilling all applicable system reliability standards, balancing authority operational requirements, financial integrity metrics as well as other laws and regulations.

With respect to the Energy Risk Management Policy, IID's primary objectives are:

1. Provide competitive, affordable, and stable electric rates
2. Supply cost advantages by developing a least-cost power supply portfolio that meets load requirements, state renewable energy mandates, and IID's balancing authority requirements as a member of the West Electric Coordinating Council
3. Maximize revenues from the sales of surplus energy, capacity, and transmission wheeling services

IID is a not-for-profit, locally-owned public utility and its electric rates are intended to collect only the cost of service to its customers while maintaining healthy financial operational parameters. The costs to serve IID's ratepayers include the debt service to own, operate and maintain its, operational infrastructure as well as the costs to fund its different public programs and employee obligations.

The ratemaking process is typically composed of determining the revenue requirements by completing a cost-of-service analysis, and rate design.

The revenue requirements are determined by analyzing the total amount of revenue IID needs to collect to fund expenses such as routine capital, capital investment, customer service, overhead, power-related costs, debt service obligations, operations, and maintenance expenses.

The cost-of-service analysis is performed to not only identify the revenue requirements but also ensure that each customer class is paying its fair share of total system costs. This is done by determining what it costs to serve each customer class. These analyses allow for a detailed rate design which includes determining the portion of the rates that are fixed and variable to recover specific system's cost.

The customer classes of services in IID are: Residential Service, Agricultural General Service, General Wholesale Power Service, Outdoor Area Lighting Service, Distributive Self-Generation Service, Economic Development, Large

General Service, General Service, High Voltage Discount, Interruptible Rate Schedule, Master Metered Mobile Home/RV Park Service, Metered Light Service, Net Metering, Agricultural Pumping Service, Public Benefits Charge, Municipal Service, Street and Highway Lighting Service, and State Highway Lighting Service.

A cost-of-service analysis typically involves three steps: functionalization, classification, and allocation of costs. During the functionalization, IID categorizes its operations and maintenance expenses and net assets (original cost minus depreciation or book value) into system functions such as generation, transmission, distribution, other plant and customer service. The classification is to identify costs by function types including energy, demand, customers and meters. These costs are allocated to the different customer classes based on their share of costs.

The rate design is performed to recover the pertaining operational costs from each customer class of service. This may vary between and within customer classes.

IID has made a tremendous effort to keep the rates as low as possible, and the base rate has not increased in several years. IID has maximized the use of retail revenue, transmission wheeling services, sales of excess power and gas as well as reducing costs.

Currently, IID offers interruptible high-voltage rates for its large commercial and industrial customers and also offers Key Customer Demand Response Program (Interruptible Load Program). This program was developed in 2010 with a target participation of 25 MW within three years. Program guidelines require enrolled large commercial and individual customers with onsite backup generation to curtail a minimum of 500 kW upon timed notice by IID. Failure to curtail contracted reductions will result in a financial penalty. This generation can be used to reduce load during times of system stress either due to transmission or generation curtailments or if load exceeds forecasted demand.

In the High Voltage Rate Discount Program, IID's customers take electric service at 34.5 kV or above at a single point of interconnection. The customer maintains all necessary step-down transformation and facilities beyond the transformer, which IID would normally own. In return, IID will provide a discount on the maximum demand energy charge and energy cost adjustment charge. The reduced electric rate offsets some of the customer's costs for the facilities, maintenance, and necessary substation equipment.

Given expected load growth and changes in power consumption profiles as a result of transportation electrification, current discussions with possible lithium extraction, as well as current discussions with potential green hydrogen production customers, IID will have to consider revising and updating its current rate structure.

Another possible impact on IID's rates would be the approval of currently identified capital improvement projects and the development of future projects studied under this current IRP.

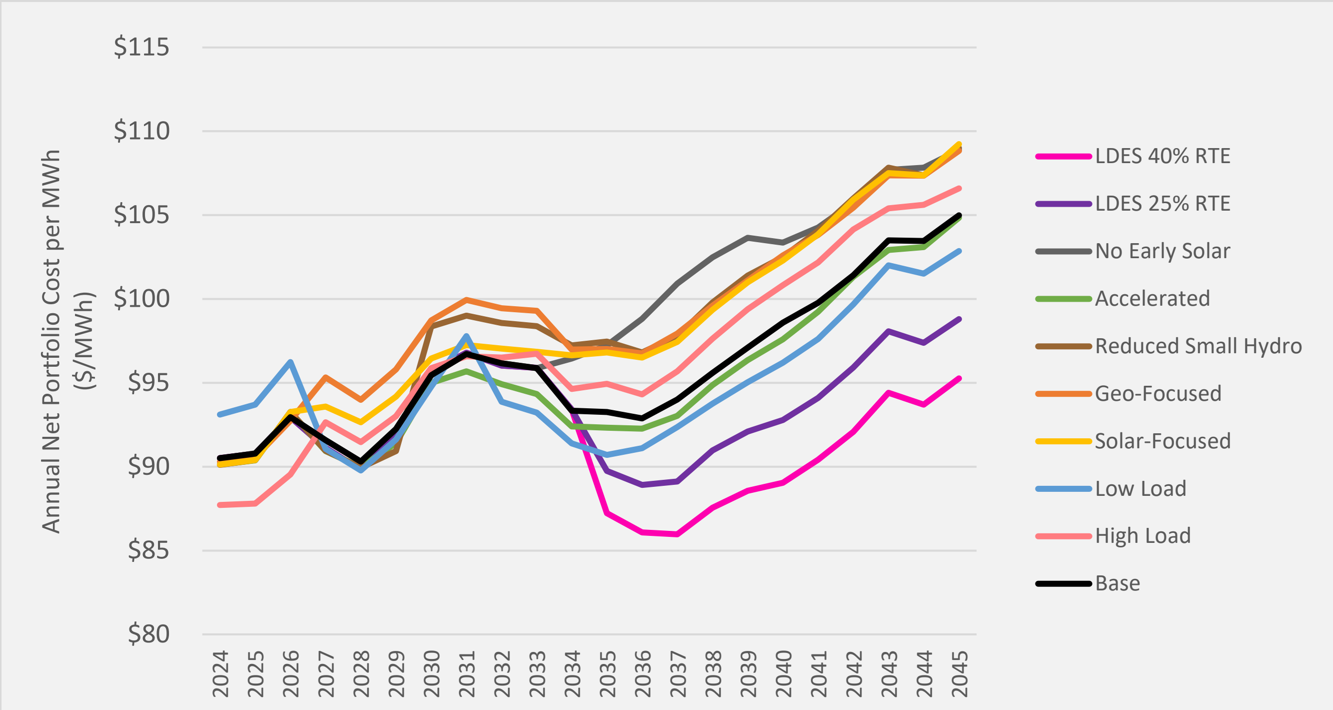



**FIGURE 30. ANNUAL NET PORTFOLIO COST PER MWH COMPARISON ACROSS SCENARIOS.**

Figure 30 shows the annual net portfolio cost divided by the forecast annual energy demand, giving a $/MWh metric that can be used to compare the Baseline scenario to the alternate scenarios. This comparison is particularly useful for scenarios with differing load assumptions, such as the High Load and Low Load scenarios. In general, total cost per MWh increase from around $87-$93/MWh in 2024 to a wider spread by 2045 (excluding the LDES scenarios[77]) of between $102/MWh and $110/MWh.

## Hourly Dispatch

Gaining a deeper understanding of some of the production cost modeling results for the Baseline scenario requires examining the hourly dispatch stack, as well as what resources are utilized to serve load at various times of the day for certain times of year and at different points along the planning horizon.

Figure 31 shows hourly dispatch for a typical summer week in early August, which is often the time of year with the hottest temperatures and highest load in the IID service territory. The dispatch stack of available resources (color bars) can be seen alongside the simulated hourly load (solid black line) and hourly spot prices at the two trading hubs (SP15 and P.V.; represented as overlaid dashed lines associated with the secondary price axis on the right of the figure). The most prominent features of dispatch during this period are the heavy reliance on market purchases (red bars) and thermal generation (gray bars). Combined, they account for the majority of the energy served during this week. The diurnal peaks (i.e., the portion of load rising above around 600 MW) are covered almost entirely by market purchases, with some contribution from solar assets (yellow) and from additional thermal generation during the highest-priced evening hours: note the spikes in the dashed hub prices during those

[77] The two LDES scenarios did not assign a cost to the LDES technology, since the scenarios are used to understand the potential benefit that such not-yet commercialized technologies may bring.

hours. Baseload power comes from a combination of biomass (dark green), small- (light blue) and large- (dark blue) hydro, and geothermal (brown) resources. Note the slight variation in scheduled WAPA hydro (dark blue) between the maximum during on-peak hours and the minimum for off-peak hours. There is a very small amount of exported power from thermal generation during some of the overnight periods (red bars below the x-axis). Similar negative values are observed in the lowest-priced mid-day hours when storage resources are charging (pink bars below the x-axis). These storage assets subsequently discharge during the highest-priced hours. We also note the small amount of runtime for the mobile APR units in the highest-priced hours (the very dark gray bars).

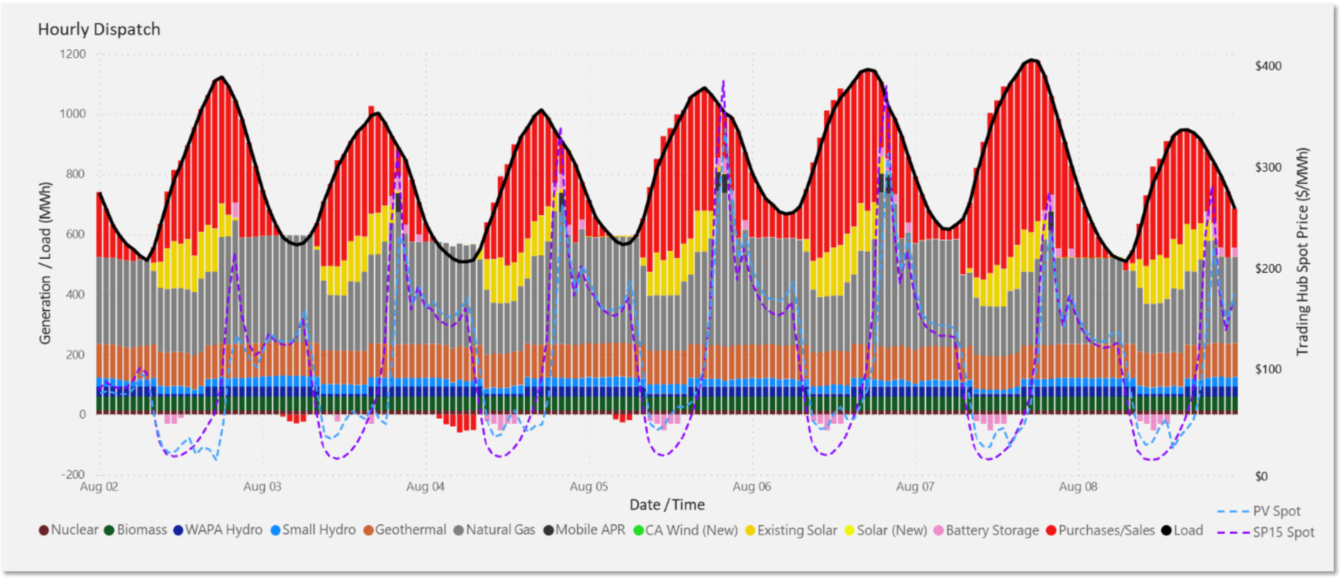



**FIGURE 31. HOURLY DISPATCH FOR CURRENT PORTFOLIO—A TYPICAL WEEK IN SUMMER 2026**

In contrast, a typical winter week in 2026 (Figure 32) reflects a markedly different load profile, though with a somewhat similar dispatch. Load peaks at about 375 MW during this time, significantly lower than what was observed during the peak summer period. Nevertheless, load during this time is primarily met by thermal generation and some market purchases when prices are favorable. Geothermal resources, along with some hydro and biomass, constitute the bulk of the baseload generation during this period. As in summer months, batteries charge during the lowest price mid-day hours and discharge during the evening peak. Spot power prices overall are also considerably lower than those seen in summer, topping out at around $80/MWh during this winter week vs. $400/MWh in the summer. The steep drop in biomass production on January 7 comes from the periodic capacity reduction at Desert View when one of its two units is scheduled to be offline.

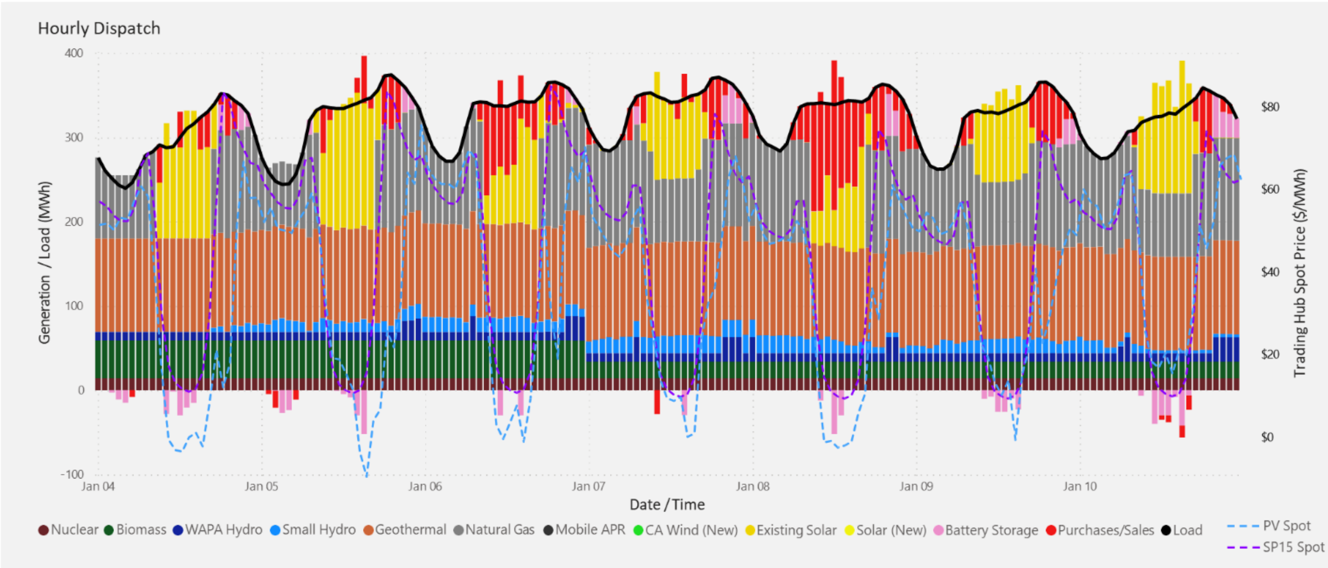



**FIGURE 32. HOURLY DISPATCH FOR CURRENT PORTFOLIO – A WINTER WEEK IN 2026**

Figure 33 fast forwards four years in the Baseline scenario to 2030 and reveals a substantially different summer dispatch profile than that seen in 2026. With substantial procurements of solar power and four-hour storage, these two resource classes now play a significant role in meeting the daytime and evening load, respectively. Storage charges during the lowest-priced hours, and requires additional imports of power during that time to fully charge the storage in advance of the evening peak where prices are five to six times higher. Newly procured solar capacity (lighter yellow) fills a growing portion of the first half of the diurnal peaks, with market purchases and discharging storage making up the later half. The baseload has continued, albeit reduced, thermal generation paired with the newly procured in-state wind (light green) and the usual geothermal and hydro contributions.

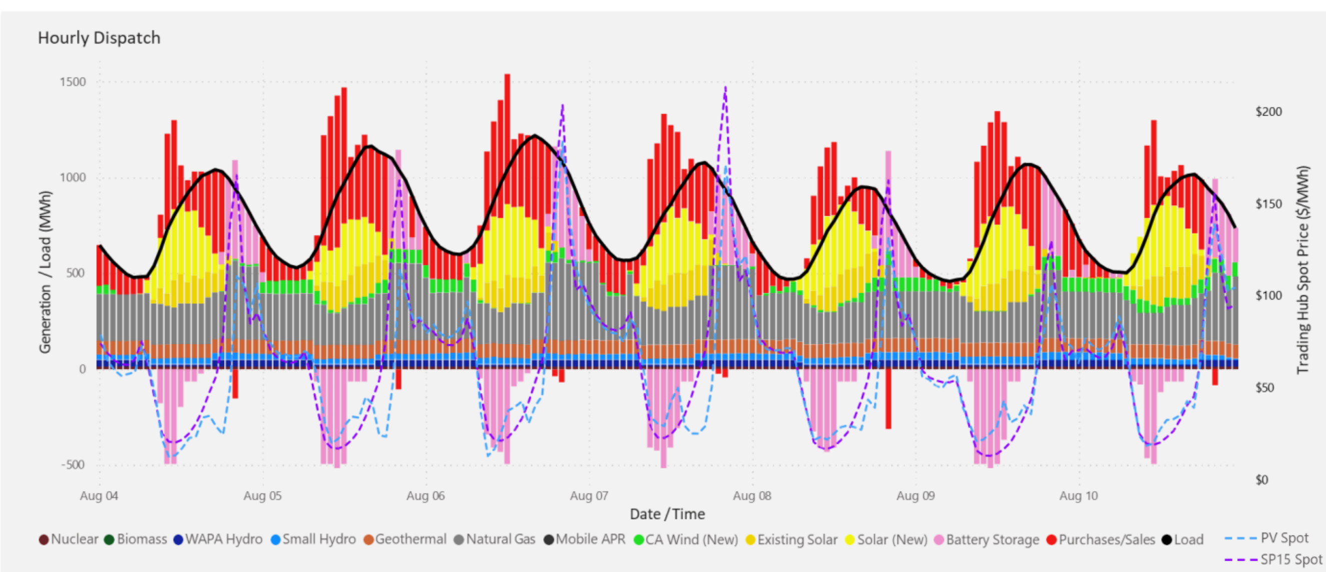



**FIGURE 33. HOURLY DISPATCH FOR A SUMMER WEEK IN 2030 OF THE BASELINE SCENARIO CAPACITY EXPANSION PORTFOLIO**

A typical winter week of the same year (2030) produces an even more dramatic contrast with 2026, as shown in Figure 34. There is virtually no thermal generation during this period. In its place, the newly procured solar and storage work in tandem to supply the majority of the relatively flat 300-400 MW load profile, with some market purchases and the baseload renewables to make up the difference. Such a dispatch pattern at this point in the planning period makes it clear that renewables are beginning to comprise a substantial portion of the overall supplied energy. Indeed, the RPS target of 60% of retail sales goes into effect starting in 2030, up from 52% in the previous compliance period (2027-2029).

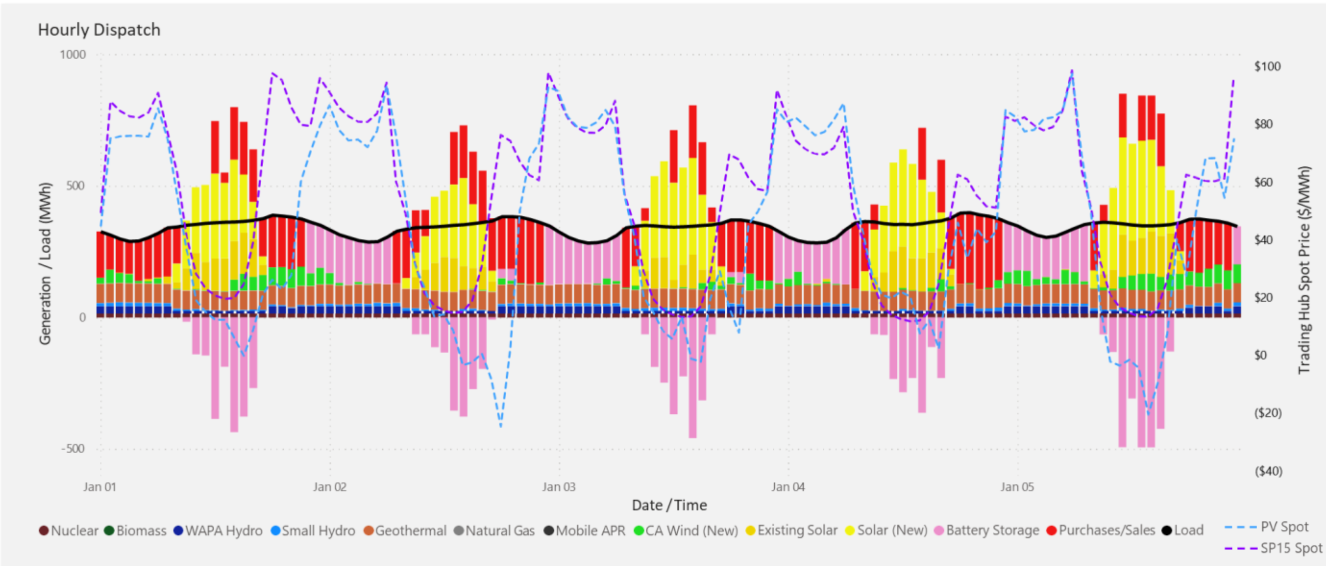



**FIGURE 34. HOURLY DISPATCH FOR A TYPICAL WEEK IN JANUARY 2030 OF THE BASELINE SCENARIO CAPACITY EXPANSION PORTFOLIO**

The final summer weekly dispatch snapshot fast-forwards again to 2045, the final year of the planning period. As shown in Figure 35, at this point in the planning period summer load is served almost entirely by zero-carbon resources paired with storage and market purchases. Surplus solar power in daytime hours charges the battery capacity which serves a portion of the evening peak, with the balance made up for by market purchases. Peak load is approaching 1,500 MW by this time period, and yet the aggregate renewable generation gets close to that 1,500 MW level in the earlier part of the day.

The summer (Figure 35) and winter (Figure 36) dispatch profiles in 2045 are fairly similar, with the main difference being the level of load required to be served in the winter as well as the amount of market purchases required to balance out the renewable and storage operations. Excess solar beyond what the storage can utilize to charge must be sold to the market, while hardly any imports and essentially zero thermal generation are required to meet load in any hour.

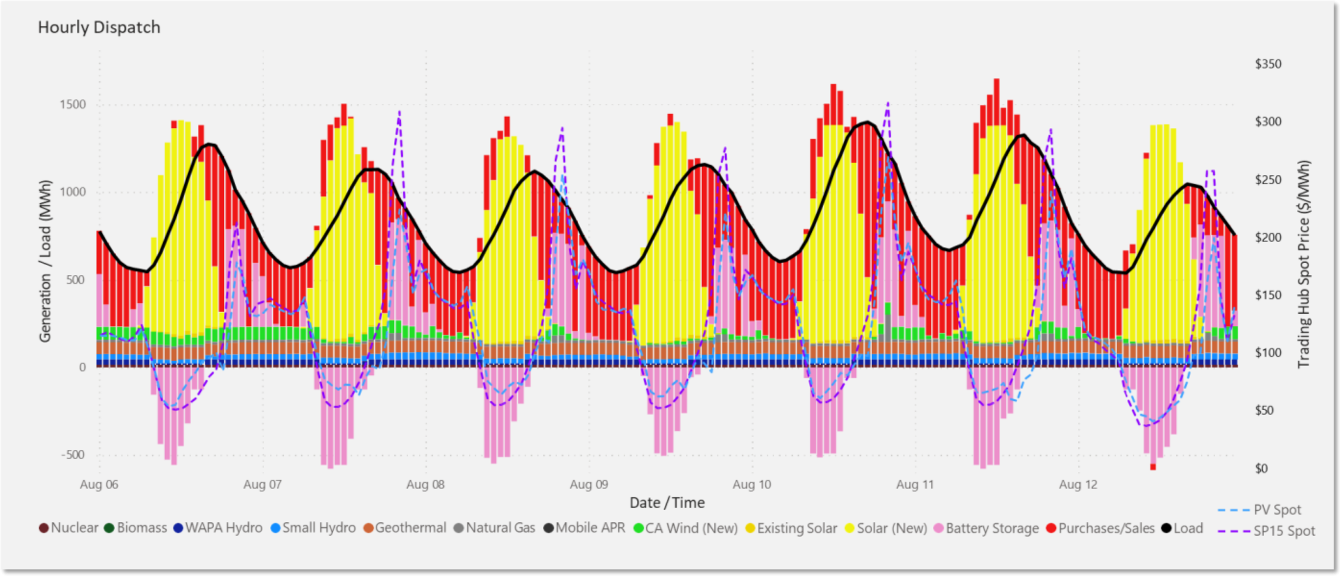



**FIGURE 35. HOURLY DISPATCH FOR A TYPICAL WEEK IN AUGUST 2045 OF THE BASELINE SCENARIO CAPACITY EXPANSION PORTFOLIO**

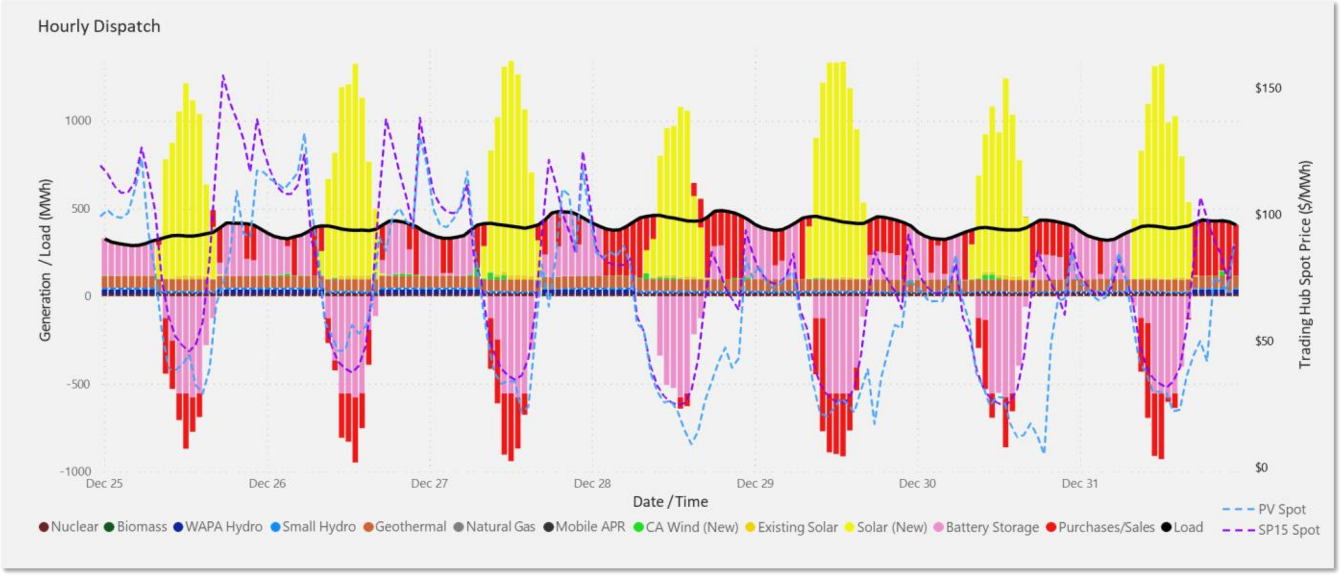



**FIGURE 36. HOURLY DISPATCH FOR A TYPICAL WEEK IN DECEMBER 2045 OF THE BASELINE SCENARIO CAPACITY EXPANSION PORTFOLIO**

## Reliability Analysis

The final phase of the Baseline scenario analysis serves as a check on the initial assumptions around needed capacity additions, specifically as they pertain to achieving the 1-day-in-10-years reliability target. Even though marginal ELCC values for each resource were established a priori and used as the assumed 'firm' contribution to meeting peak load including the reserve margin, there may be synergistic and antagonistic effects between the modeled resources regarding their ability to meet the reliability target. In other words, the ELCCs assumed for the candidate resources serve more as a guideline for how much capacity each resource provides toward reliability, but the total ELCC-adjusted capacity established by the capacity expansion planning study may either over- or under-shoot the reliability metric. Thus, conducting a reliability analysis on the planned portfolio establishes an understanding of how close the planned capacity additions go toward meeting the reliability target. As with the initial LOLP analysis conducted prior to the capacity expansion analysis, the portfolio is assumed to be 'islanded,' (no import capability to the system). In other words, load must be served by resources in the planned portfolio.

The results of this reliability study are given in Figure 37. The reliability target of 2.4 LOLH per year (purple line in the figure; equivalent to 1 day in 10 years) will be achieved by 2028 and generally maintained for the duration of the study period. Individual annual LOLH values vary between one and three load-shedding hours per year (black line), presenting a narrow enough range to conclude that the portfolio is suitably resource adequate and that the planned capacity is neither underbuilt nor overbuilt.

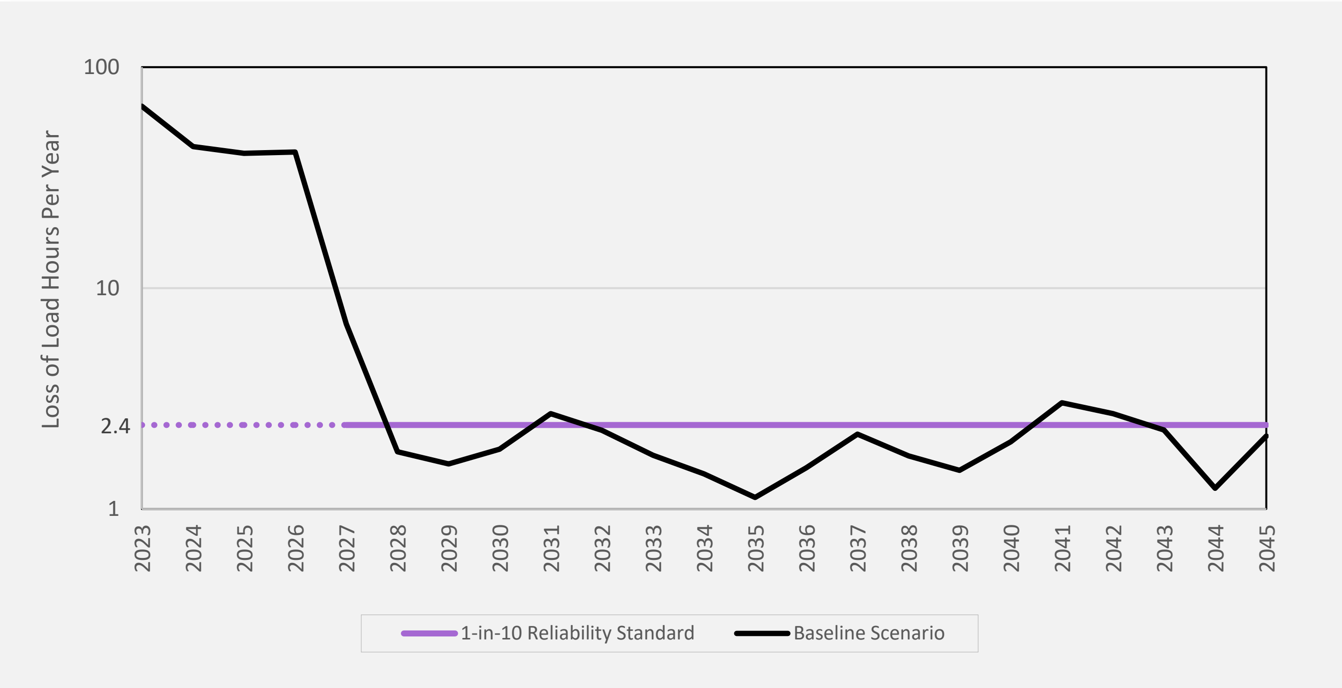



**FIGURE 37. RELIABILITY ANALYSIS RESULTS FOR BASELINE SCENARIO (NOTE THE LOG SCALE)**

# Alternate Scenarios

While the Baseline scenario of the IRP resource planning process is given the most attention, several other scenarios were modeled as well. These scenarios reflect alternate sets of assumptions and highlight specific concerns and challenges faced by the District in planning for the future. The alternative scenarios are summarized below:

- **Geothermal-Focused** – This scenario removes wind as a candidate resource in the capacity expansion modeling. The reasoning for this is two-fold, reflecting the realities of wind procurement for the District. The first is that Baseline scenario additions of in-state wind capacity could be considered optimistic. Limited amounts of wind can be procured in-state. And, while more plentiful options are expected to be available out-of-state in the future, such as in New Mexico, the annual profile for out-of-state wind generation does not align well with IID's demand profile, peaking in the winter when IID's demand is lowest. RPS-eligible geothermal resource available within the District's service territory is considered in place of the wind. Production cost impacts of such a change are considered.
- **Solar-Focused** – This scenario removes both wind and geothermal as candidate resources in the capacity expansion modeling, leaving solar as the predominant RPS option. This scenario considers a reality where wind and geothermal availability may be limited for the District, especially in the near term.
- **Reduced Small Hydro** – This scenario considers an adverse water availability situation where flows through the hydroelectric turbines on the canal are reduced to the point where generation is effectively zero after 2030. This is not to suggest that such a scenario is likely to occur; rather, it presents a potential upper bound on how the capacity build-out would need to adjust to make up for the loss of RPS-eligible small hydro resources in the District's portfolio.
- **High Load** – In the Load Forecast section, three CEC load forecasts were presented. The Baseline scenario used the Mid load scenario. This alternative scenario considers the High load case, where additional capacity is needed to satisfy the capacity and energy constraints imposed on the resource selection optimization.
- **Low Load** – Similar to the High Load scenario, this scenario considers the Low load forecast. Flatter future demand here means that fewer resources are needed to satisfy capacity and energy constraints.
- **Long Duration Storage** – This scenario considers the potential benefit that a generic seasonal or long duration storage resource could provide to the District's portfolio. In particular, this scenario is aimed at addressing the risk of overgeneration in a future with significant renewables build out and the long position the District may find itself in during the winter months when demand is lowest. Such technology is intentionally kept vague, with a focus on key parameters such as sizing, duration, and round trip efficiency. Two sub-alternatives are presented, reflecting 25% and 40% round trip efficiency.
- **Accelerated Decarbonization** – The constraints imposed on the Baseline scenario capacity expansion optimization may lead the model to suggest procurement for satisfying such constraints at the latest year possible. This scenario considers what it would take to reach 100% RPS generation by 2035, 10 years earlier than the SB 100 mandate. As it turns out, the Baseline scenario sees value in reaching this goal early anyway due to assumed lower solar PPA prices in the mid-2030s, so this Accelerated scenario is quite similar to the Baseline scenario.
- **Delayed Solar Builds** – As an opposing case to the Accelerated Decarbonization scenario, this scenario delays builds of solar resources until the last possible year which would allow for satisfying the RPS and

zero-carbon targets. The model is no longer able to take advantage of procuring what it sees as less expensive solar PPAs early on and must buy at the price forecast just before the 2035, 2040, and 2045 zero-carbon constraints come into effect. The slightly higher total cost of doing so is discussed.

- **Regionalization** – Lastly, a scenario is considered in which IID participates in an ISO or RTO market, assuming CAISO or SPP is responsible for balancing as of a certain date, say 1/1/2035. IID's supply portfolio is then dispatched economically from that point forward. Cost implications of such a change are considered.

## Geothermal-Focused Scenario

This alternate planning scenario has no wind resources being procured. Given limited options for obtaining commercially viable in-state wind with a generation profile that reasonably aligns with IID's seasonal, summer-peaking load profile, and given that other out-of-state wind options may have less certain costs and deliverability characteristics, it is plausible to envision a scenario where wind resources are not feasible for the District to procure. To support a diverse resource mix in an already solar-heavy profile, the procurement of modest amounts of new geothermal capacity is emphasized in this scenario. IID's service territory contains some of the highest quality geothermal resources in the country, and this technology provides clean, firm generation which can help the District meet both capacity and RPS needs.

### CAPACITY EXPANSION RESULTS

The tradeoff with this additional constraint, given the same RPS and zero-carbon targets as the Baseline scenario, is that the 100 MW of in-state wind chosen in the Baseline scenario are no longer present. Thus, the model must make up for this difference by selecting additional quantities of renewable power from the options that remain available, as seen in Figure 38. 30 MW of geothermal capacity is procured in this scenario to make up for the wind generation that is no longer present. Given the roughly 30% capacity factor for wind versus the 95% capacity factor for geothermal, this amount of geothermal capacity is essentially equivalent from an RPS-eligible energy perspective on an annual basis. RICE and storage builds remain unchanged from the Baseline scenario.

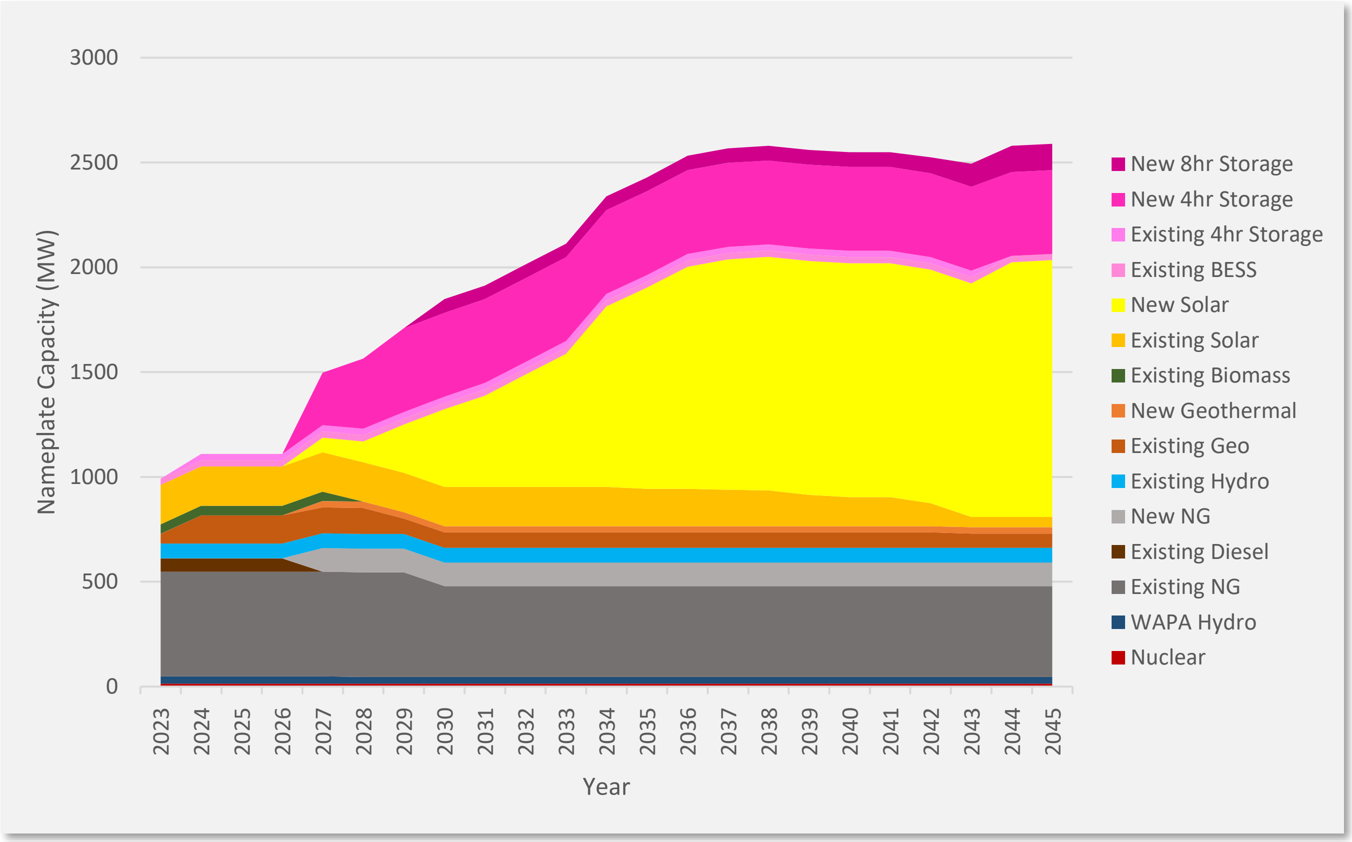



**FIGURE 38. GEOTHERMAL-FOCUSED SCENARIO CAPACITY EXPANSION, 2023-2045**

## PRODUCTION COST ANALYSIS

Total portfolio costs for the Geothermal-Focused scenario are depicted in Figure 39. The general trend in total portfolio costs between the Geothermal-Focused and the Baseline scenarios are fairly similar. Both rely heavily on increasing amounts of solar builds. In the end, the Geothermal-Focused scenario is modestly more costly given the more expensive geothermal resource needed to offset the lack of wind energy and capacity in the portfolio. Total portfolio costs reach $514 million by 2045. Costs associated with the operation of the existing thermal fleet, renewables procurement, and storage contracts, along with market purchases/sales, generally follow similar trends to those in the Baseline scenario. The total dollar value of market purchases is 3% higher in the Geothermal-Focused scenario relative to the Baseline scenario.

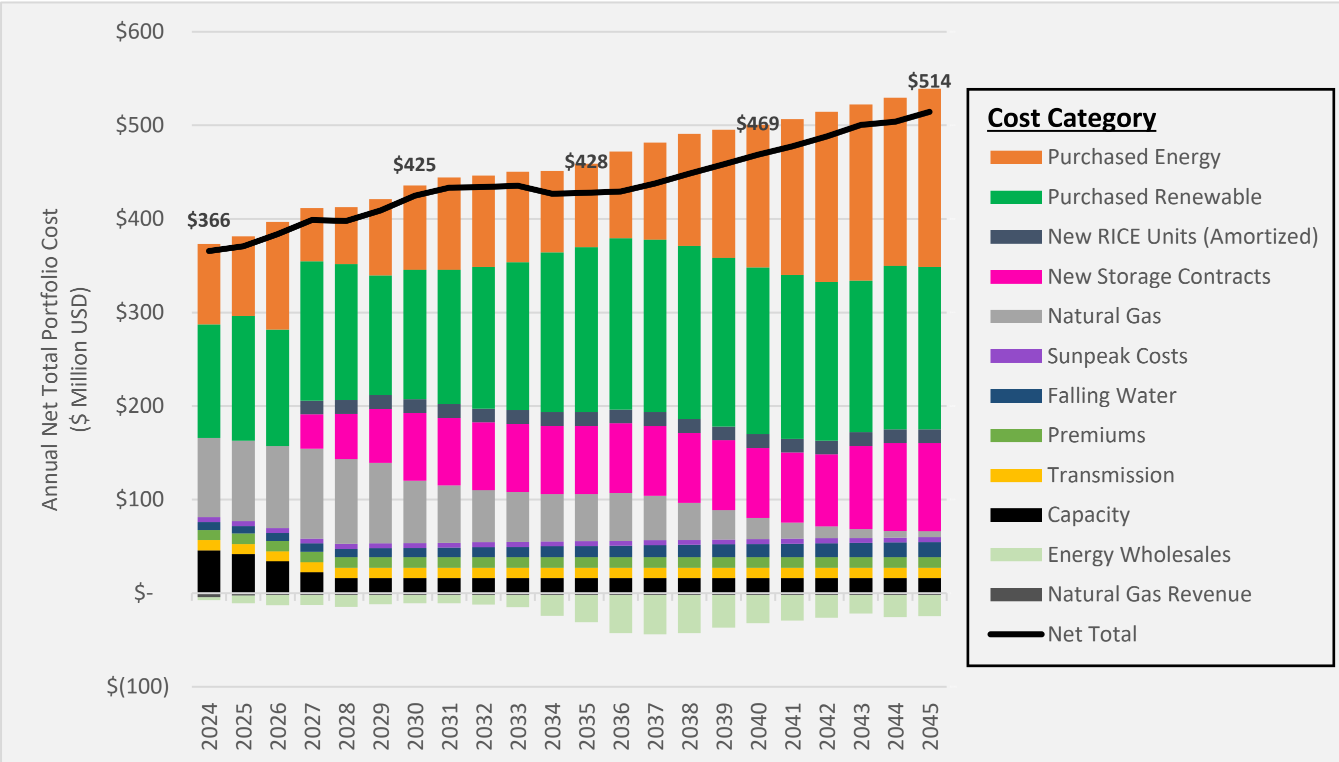



**FIGURE 39. GEOTHERMAL-FOCUSED SCENARIO TOTAL PORTFOLIO COST, 2024-2045**

## Solar-Focused Scenario

This alternate planning scenario has no new wind or geothermal resources being procured. Given the uncertainty regarding the availability of wind and geothermal resources near-term, it is plausible to envision a scenario where neither of these resources is available for the District to procure.

### CAPACITY EXPANSION RESULTS

The tradeoff with this additional constraint, given the same RPS and zero-carbon targets as the Baseline scenario, is that the 100 MW of in-state wind chosen in the Baseline scenario and the 30 MW of geothermal chosen in the Geothermal-Focused scenario are no longer available. Thus, the model must make up for this difference by selecting additional quantities of PV solar, as seen in Figure 40. Solar's low ELCC at higher penetrations means that despite choosing more solar for RPS purposes to make up for the lack of wind or geothermal *generation*, the model also selects additional resources to make up for the missing wind or geothermal *capacity* contribution. This comes in the form of an additional 19 MW RICE unit in 2027 and slightly higher battery storage builds. Storage capacities total 425 MW of four-hour and 135 MW of eight-hour in this scenario, compared to the Baseline scenario 2045 capacities of 400 MW of four-hour and 125 MW of eight-hour. By 2030, new solar capacity is 36% higher in the Solar-Focused scenario relative to the Baseline scenario, reaching 505 MW compared to 370 MW, respectively. By 2045, total solar builds (1,335 MW) are 9% higher than those in the Baseline scenario, (1,225 MW).

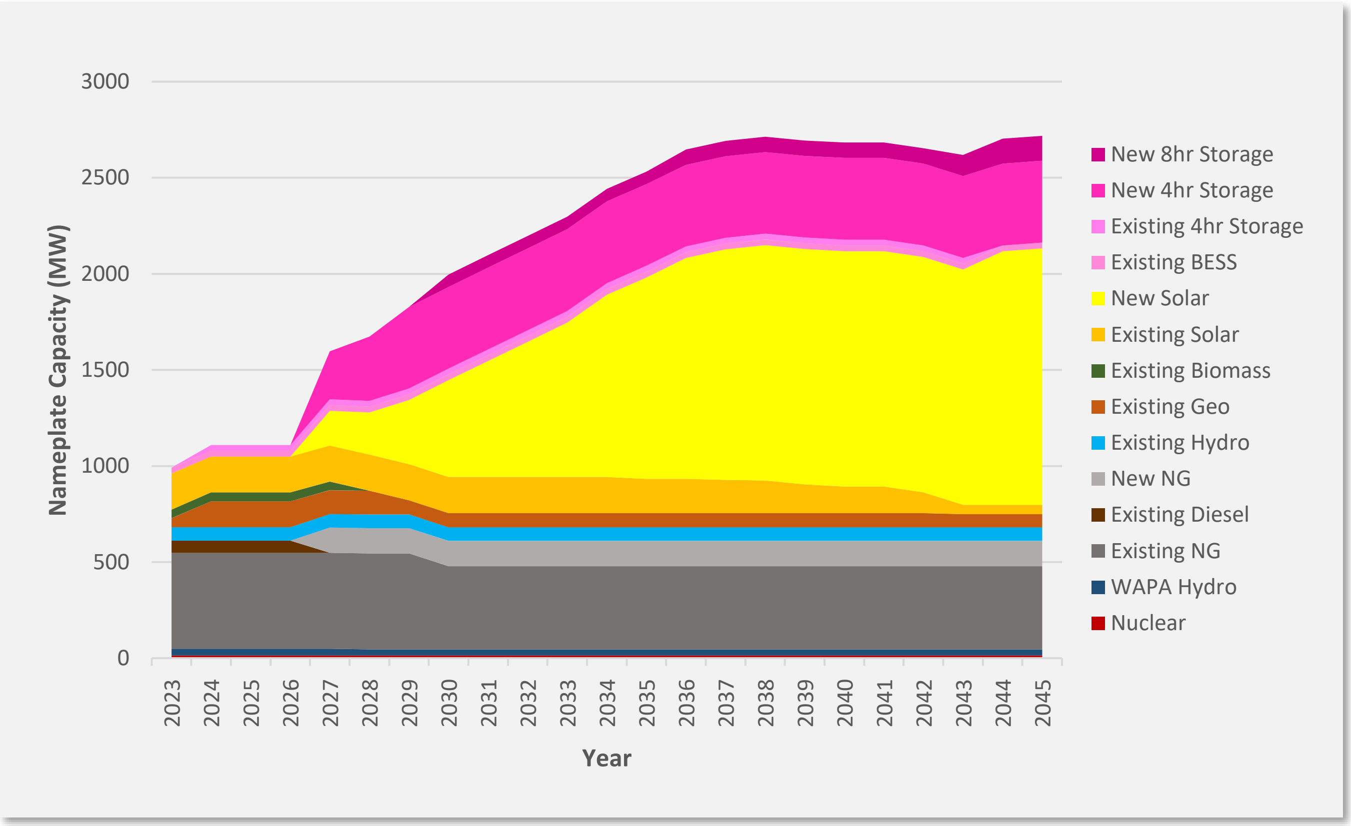



**FIGURE 40. SOLAR-FOCUSED SCENARIO CAPACITY EXPANSION, 2023-2045**

## PRODUCTION COST ANALYSIS

Total portfolio costs for the Solar-Focused scenario are depicted in Figure 41**.** The general trend in total portfolio costs between the no wind and the Baseline scenario are fairly similar. In the end, the Solar-Focused scenario is modestly more costly given the requisite increase in RICE, storage, and solar procurements needed to offset the lack of wind and geothermal energy and capacity in the portfolio. Total portfolio costs reach $516 million by 2045. Costs associated with the operation of the existing thermal fleet, renewables procurement, and storage contracts, along with market purchases/sales, generally follow similar trends to those in the Baseline scenario. The total dollar value of market purchases is about 8% higher in the Solar-Focused scenario relative to the Baseline scenario.

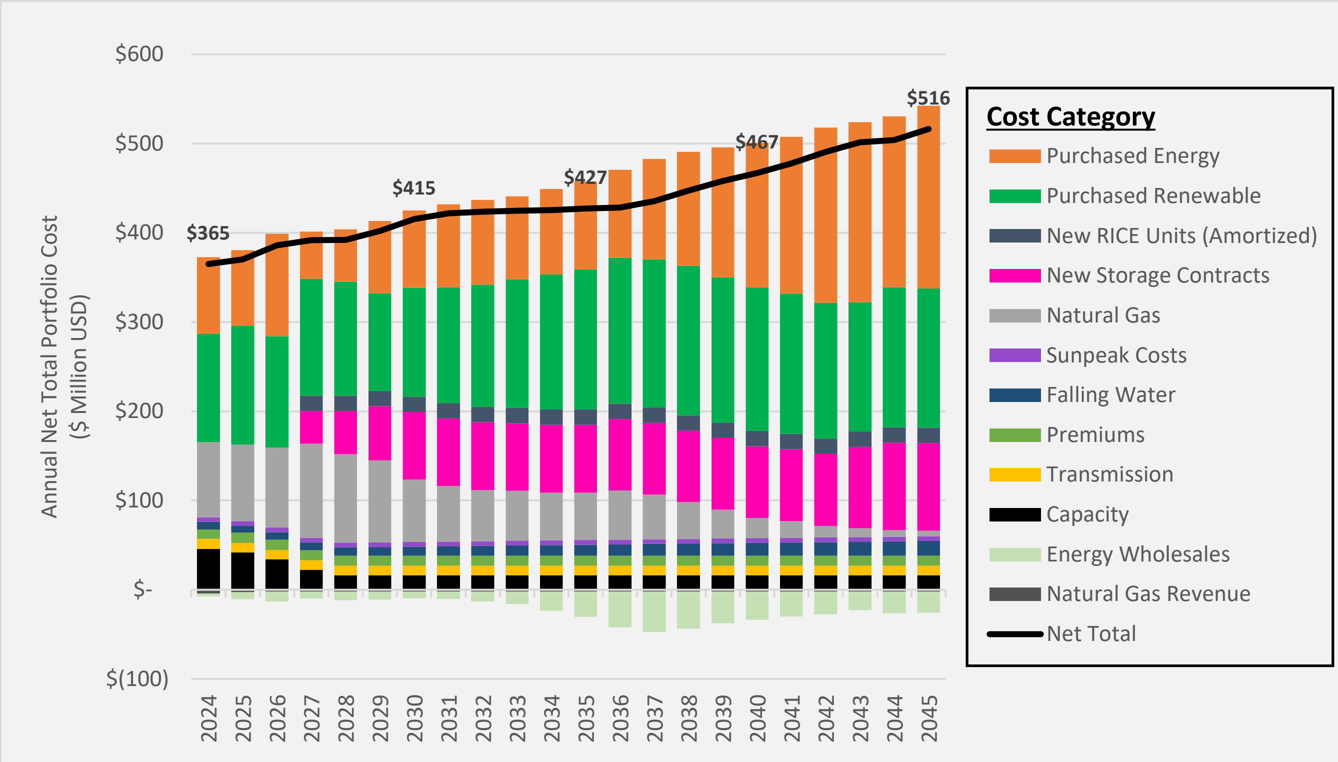



**FIGURE 41. SOLAR-FOCUSED SCENARIO TOTAL PORTFOLIO COST, 2024-2045**

## Reduced Small Hydroelectric Scenario

This scenario envisions a situation where generation from the portfolio of small-scale hydroelectric plants ceases in 2030. Recognizing this is an extreme case and that in all likelihood a decent portion of the small hydro portfolio will continue to operate through the planning period, this more severe scenario is intended to highlight the potential impact to the overall generation portfolio from losing the small hydro fleet due to one or both of the following causes:

1. **Aging infrastructure renders the hydroelectric projects inoperable beyond 2030.** The oldest hydro plants in the portfolio will be approaching or even exceeding 100 years of operation by the end of the planning period, and there have already been instances of significant repairs and refurbishment required for some units in the portfolio. If it becomes uneconomical to make such repairs, aging units may begin to come offline permanently.
2. **Low flow conditions on the irrigation canals.** As observed in drier years, there is a real possibility of flow rates through the canals being reduced in the future, thereby reducing or perhaps even eliminating the ability to generate power from the hydro turbines. This situation has already been experienced at Pilot Knob to the extent that one of its generating units was not even considered in this IRP analysis.

## CAPACITY EXPANSION RESULTS

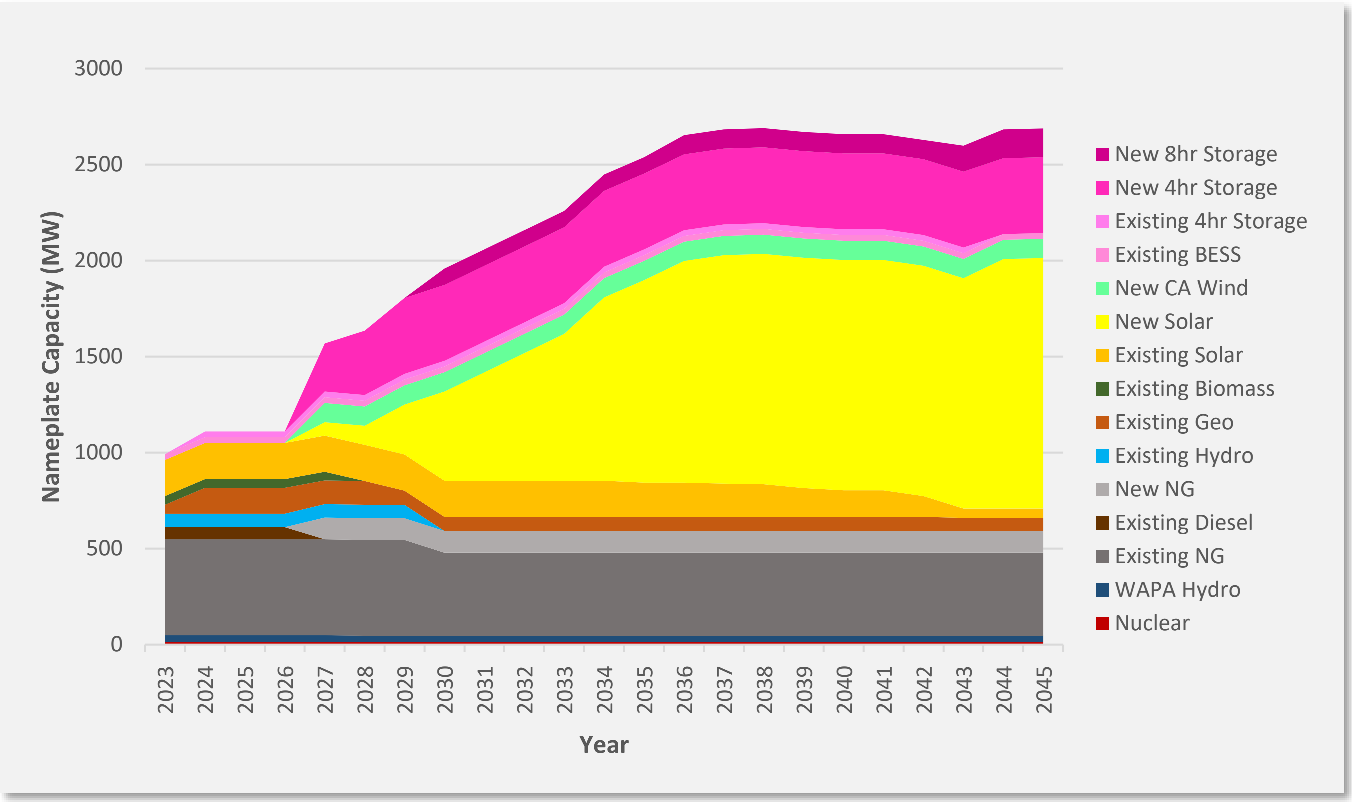



**FIGURE 42. REDUCED SMALL HYDROELECTRIC SCENARIO CAPACITY EXPANSION, 2023-2045**

The capacity expansion results for the Reduced Small Hydro scenario are depicted in Figure 42. Note the light blue 'small hydro' bar is no longer present starting in 2030. In its place, increased solar, wind, and eight-hour storage capacity are chosen by the model. By 2030, solar builds are 26% higher (465 MW vs. 370 MW) and eight-hour storage is 31% higher (85 MW vs. 65 MW) than the Baseline scenario. By 2045, solar builds are 7% higher (1,305 MW vs 1,225 MW), in-state wind is 10% higher (110 MW vs. 100 MW), and eight-hour storage is 20% higher (150 MW vs. 125 MW) than the Baseline scenario.

## PRODUCTION COST ANALYSIS

Total portfolio costs for the Reduced Small Hydro scenario are depicted in Figure 43. The general trend in total portfolio costs between the Reduced Small Hydro scenario and the Baseline scenario are fairly similar. In the end, the Reduced Small Hydro is modestly more costly given the requisite increase in RICE, storage, and solar procurements needed to offset the lack of RPS-eligible hydro energy and capacity in the portfolio after 2030. Total portfolio costs reach $515 million by 2045. Costs associated with the operation of the existing thermal fleet follow similar trends to those in the Baseline scenario. The total dollar value of market purchases is slightly higher in the Reduced Small Hydro scenario.

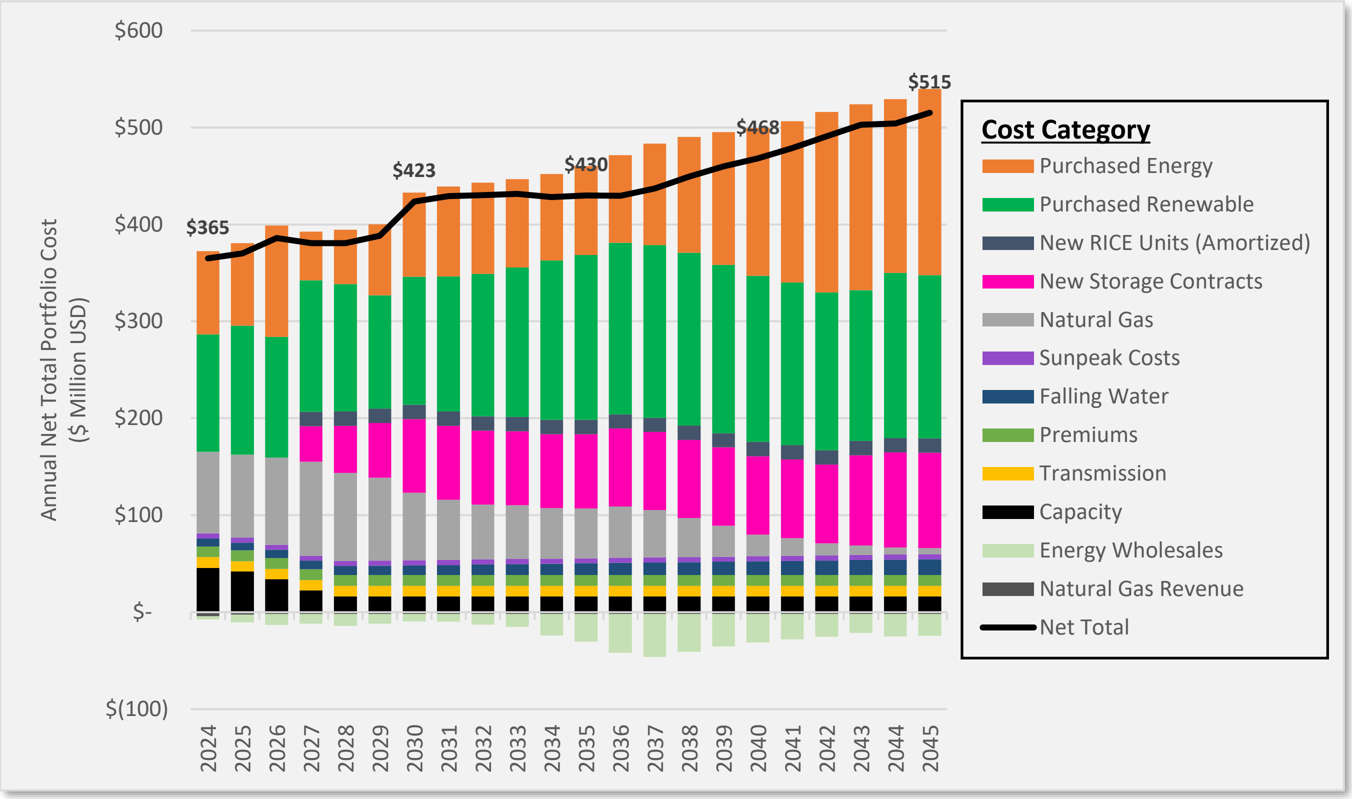



**FIGURE 43. REDUCED SMALL HYDROELECTRIC SCENARIO PORTFOLIO COSTS, 2024-2045**

## Load Sensitivity Scenarios

Two additional load sensitivities were considered – High Load and Low Load scenarios, based on the corresponding CEC 2021 demand forecast cases. The alternate load scenarios resulted in capacity expansion solutions that differ more dramatically from the Baseline scenario, compared to other alternate scenarios which only show slight differences in capacity builds and portfolio costs. Thus, the alternate load cases are some of the more interesting alternate scenarios considered in this IRP analysis.

### HIGH LOAD SCENARIO – CAPACITY EXPANSION RESULTS

The High Load scenario assumes that annual electricity demand is approximately 3.2% higher than the Mid-Case load growth in 2024, growing to 5.4% higher by 2030, and 11% higher by 2045. This has implications for the necessary amount of RPS- and zero-carbon-eligible resources that must be procured to achieve the percentage of retail sales targets in 2030, 2035, 2040, and 2045. With more demand, more energy generated from such sources on an absolute basis will be required to meet the same percentage of retail sales.

Peak load in the High Load scenario is anticipated to be 3.6% higher in 2024, 6.8% higher in 2030, and 13% higher in 2045, relative to the Mid Case. This has implications for the procurement of capacity resources and ensuring the reliability target continues to be met.

As shown in Figure 44, the general capacity expansion pattern for the High Load scenario looks similar to that of the Baseline scenario, in that new builds of capacity are predominantly solar, RICE thermals, and storage. The important difference involves the magnitudes of these selections. By 2030, the High Load scenario has 15% more solar capacity (425 MW) vs. the Baseline scenario (370 MW). By 2045, that difference is also 15% (1,410 MW vs. 1,225 MW).

Increased capacity needs are reflected in the RICE and storage builds. In the High Load scenario, 188 MW of RICE capacity is procured, 67% more than in the Baseline scenario (113 MW). Additional eight-hour storage builds compared to the Baseline scenario become apparent by 2045 (155 MW vs 125MW, or 24% higher). Four-hour storage builds end up being similar or even slightly below that of the Baseline scenario (375 MW vs. 400 MW), as capacity needs are made up for by the longer duration battery and thermals.

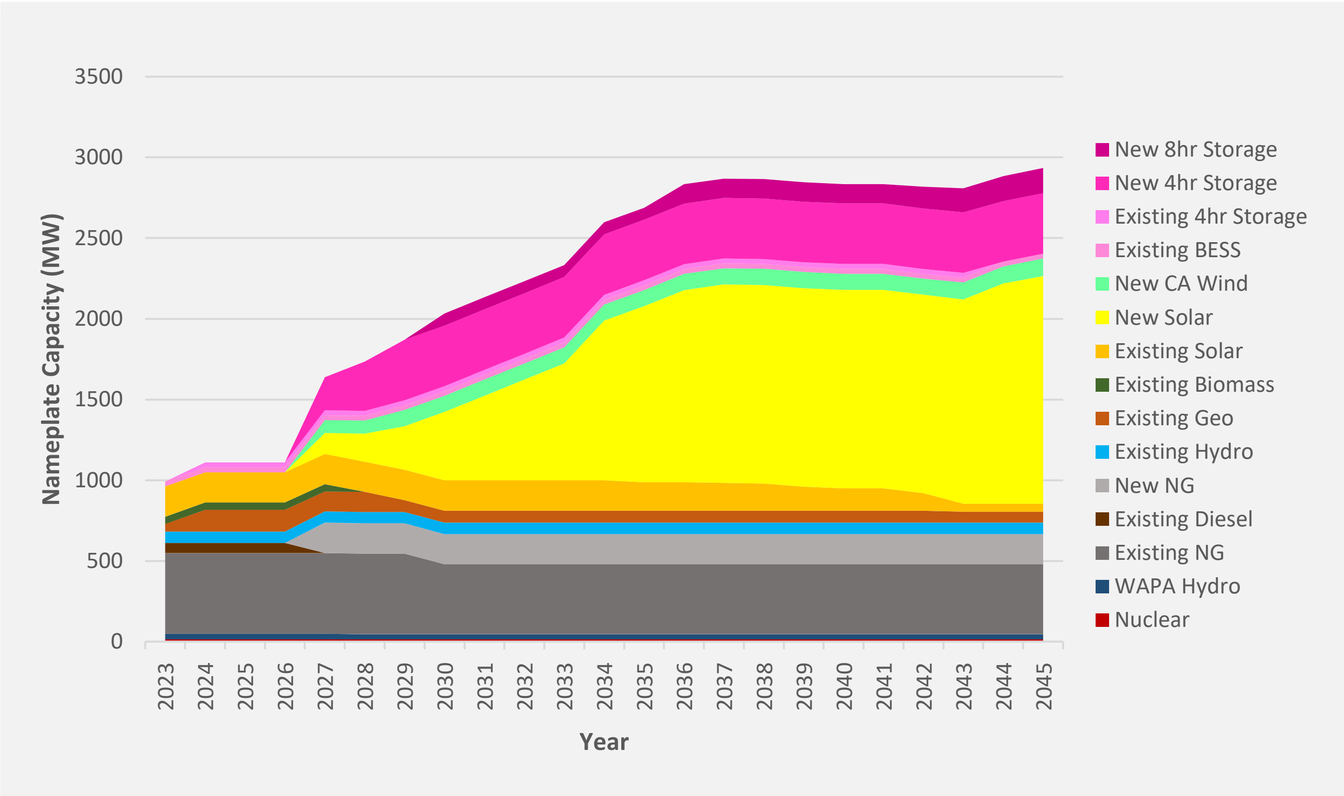



**FIGURE 44. HIGH LOAD SCENARIO CAPACITY EXPANSION, 2023 – 2045**

## HIGH LOAD SCENARIO – PRODUCTION COST ANALYSIS

Figure 45 shows the total portfolio cost for the High Load scenario. In general, costs are notably higher, as would be expected in a higher load scenario. By 2045, the total annual cost reaches $557 million, which is about 12% higher than in the Baseline scenario and consistent with annual energy demand being about 11% higher in 2045 in this scenario.

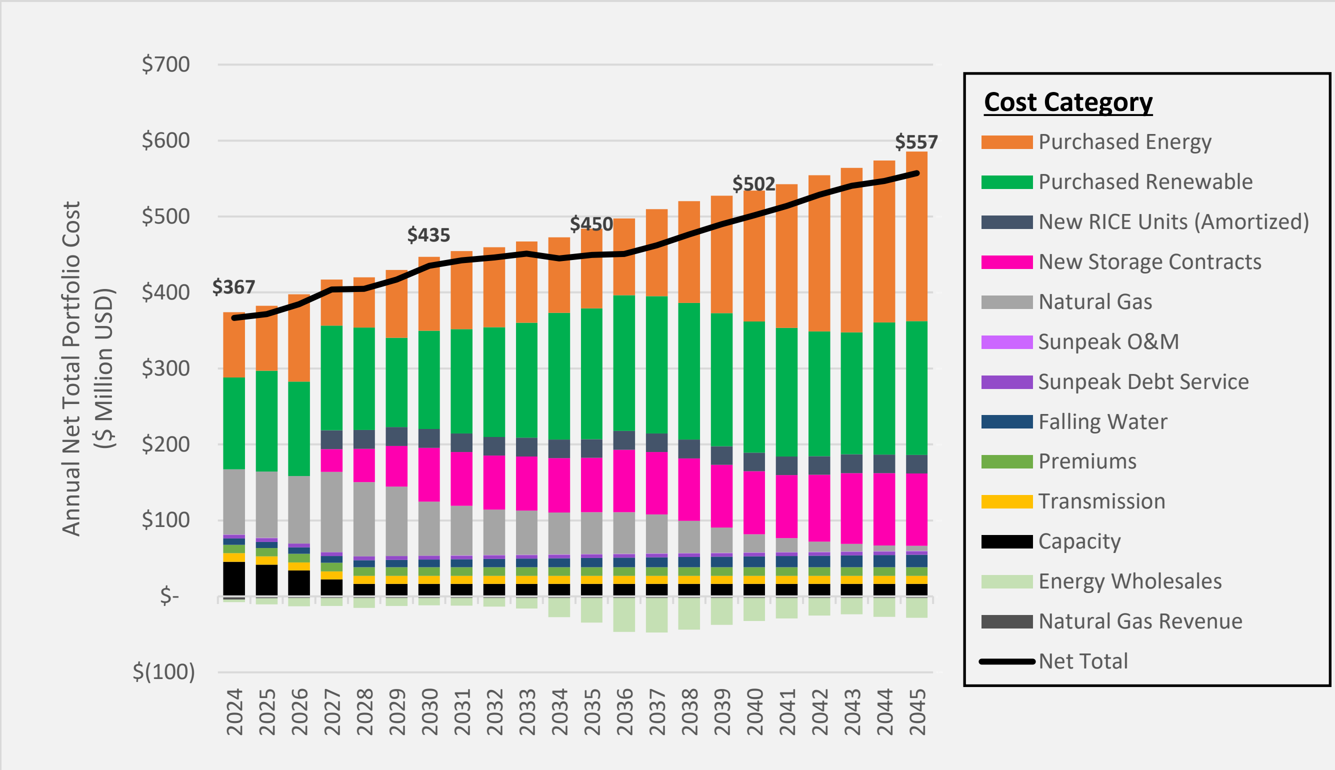



**FIGURE 45. HIGH LOAD SCENARIO TOTAL PORTFOLIO COSTS, 2024-2045**

## LOW LOAD SCENARIO – CAPACITY EXPANSION RESULTS

The Low Load scenario assumed an annual electricity demand of approximately 2.8% lower than the Mid-Case load growth in 2024, 5.1% lower by 2030, and 14% lower by 2045. This has implications for the necessary amount of RPS- and zero-carbon-eligible resources that must be procured to achieve the percentage of retail sales targets in 2030, 2035, 2040, and 2045. With less demand, less energy generated from such sources on an absolute basis will be required to meet the same percentage of retail sales.

Peak load in the Low Load scenario is anticipated to be about the same in 2024, falling to 2.6% lower in 2045, relative to the Mid Case. This has implications for the procurement of capacity resources and for ensuring that over-procurement does not occur (i.e. that reliability does not exceed the target level such that the capacity chosen is cost-ineffective).

Figure 46 shows the capacity expansion trajectory for the Low Load scenario. Lower builds of RICE, solar, and storage relative to the Baseline scenario are the cost-minimizing optimal solutions. Selected RICE capacity is 50% lower than the Baseline scenario (56.4 MW vs 112.8 MW). Solar capacity by 2045 is 970 MW, a 21% reduction compared to the Baseline scenario. Storage builds are fairly similar between the two: the majority of the necessary capacity reduction in the Low Load scenario is taken up by the reduced RICE capacity.

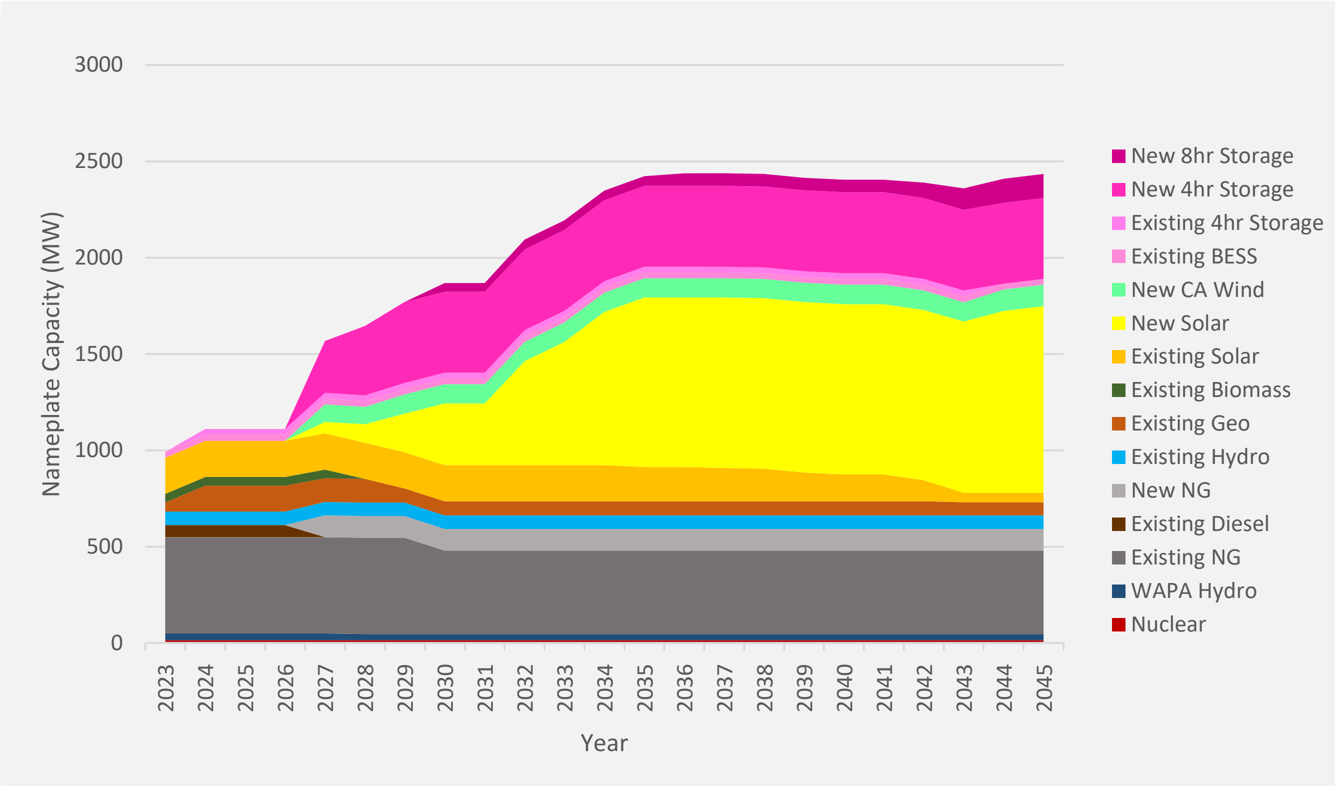



**FIGURE 46. LOW LOAD SCENARIO CAPACITY EXPANSION, 2023-2045**

## LOW LOAD SCENARIO – PRODUCTION COST ANALYSIS

Figure 47 depicts the total portfolio costs for the Low Load scenario. As expected, absolute total costs run below those of the Baseline scenario by about 15% by 2045, at about $420 million per year. Less reliance on market purchases, as well as the reduction in PPA costs for renewable procurements, serve as the main sources of the cost reductions. The other trends, such as the reduction in thermal operating costs and costs associated with storage PPAs, are similar to the Baseline scenario.

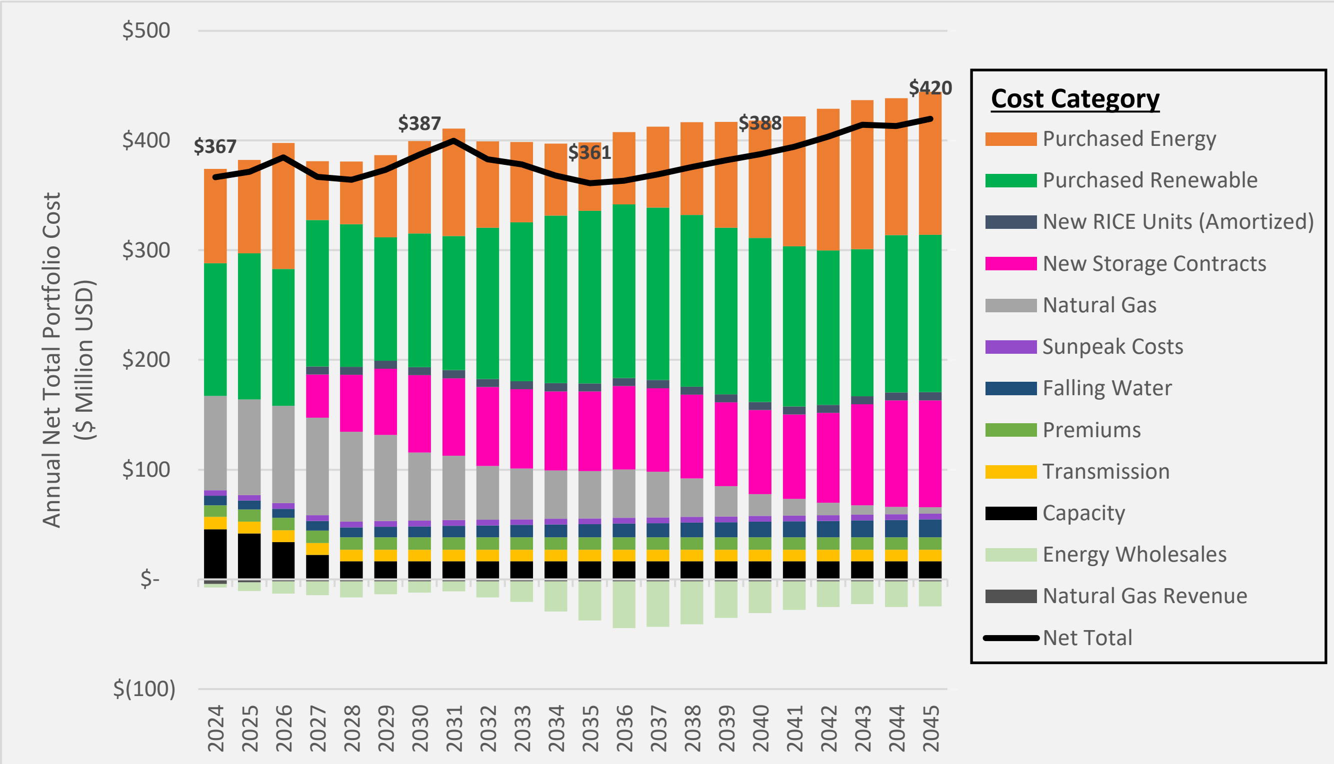



**FIGURE 47. LOW LOAD SCENARIO TOTAL PORTFOLIO COST, 2024-2045**

## Long-Duration Storage Scenarios

The next scenario involved modeling a situation where a long-duration energy storage (LDES) resource (such as hydrogen, flow batteries, pumped storage, or perhaps even some combination of these) is employed to transfer surplus energy from variable renewables during low-load winter months to meet the much higher demand of the peak summer months. Characteristics of such storage technology are not yet concretely defined as commercially viable options, although some recent developments indicate that such technologies may be gaining traction, such as the hydrogen production tax credit included in the Inflation Reduction Act, as well as some utility-scale iron-air battery pilot projects.

The technology option modeled is a storage system capable of delivering 200 MW of maximum power output, with a capacity of 200,000 MWh, and is assumed to enter the portfolio no sooner than 2035, for several reasons. First, 2035 is far enough into the planning period that long-run technological progress may enable such an option to become commercially viable. By that point, the steady additions of renewables in the portfolio to meet RPS targets are such that non-summer months are beginning to get fairly long by this point in the Baseline scenario, with increasing amounts of market sales of excess power at low market prices.

Another defining characteristic of this modeled LDES technology is the assumed round-trip efficiency. Two options were considered: 40% and 25%. A 40% round-trip efficiency is analogous to that claimed by current but not-yet-commercialized iron-air batteries or that of a hydrogen-based storage system assuming state-of-the-art electrolysis, minimal storage losses, and more efficient (but also more expensive) fuel-cell redox generation on the discharge side of the cycle. The more conservative round-trip efficiency of 25% is analogous to a hydrogen storage system using ammonia storage and generation in a hydrogen-fuel-compatible combustion turbine. Ammonia cracking and storage may be a more cost-effective solution than cryogenic hydrogen storage if underground cavern storage is not an option. Note that both of these assumed RTEs are far below the 85% level assumed for conventional lithium-ion batteries operating at shorter discharge durations.

In either case, the task of the production cost optimization model is to understand how surplus non-summer generation from the increased renewables penetration can be utilized to build up sufficient storage of energy that can be discharged during peak summer periods. Related benefits include a reduction in renewables curtailment during the 'long' non-summer periods and reduced need for significant and potentially costly market interactions (less need to sell excess power at low power prices during non-summer daylight hours, and reduced purchases during the high-priced summer evening peak).

## PRODUCTION COST ANALYSIS

The analysis of the production modeling results for LDES scenarios begins by examining how demand is met on a monthly basis for the period beginning in 2035. This scenario shares an identical portfolio to that of the Baseline scenario, with the exception of the addition of the 200 MW LDES technology. As shown in Figure 48, seasonal storage charging (dashed purple area) occurs in the non-summer peak, soaking up some of the excess solar generation that would have otherwise been sold in the Baseline scenario. Then, in the summer peak, some of this stored energy dispatches during peak hours (solid purple area), reducing the amount of imported power (red area) that must be purchased to meet that high summer demand.

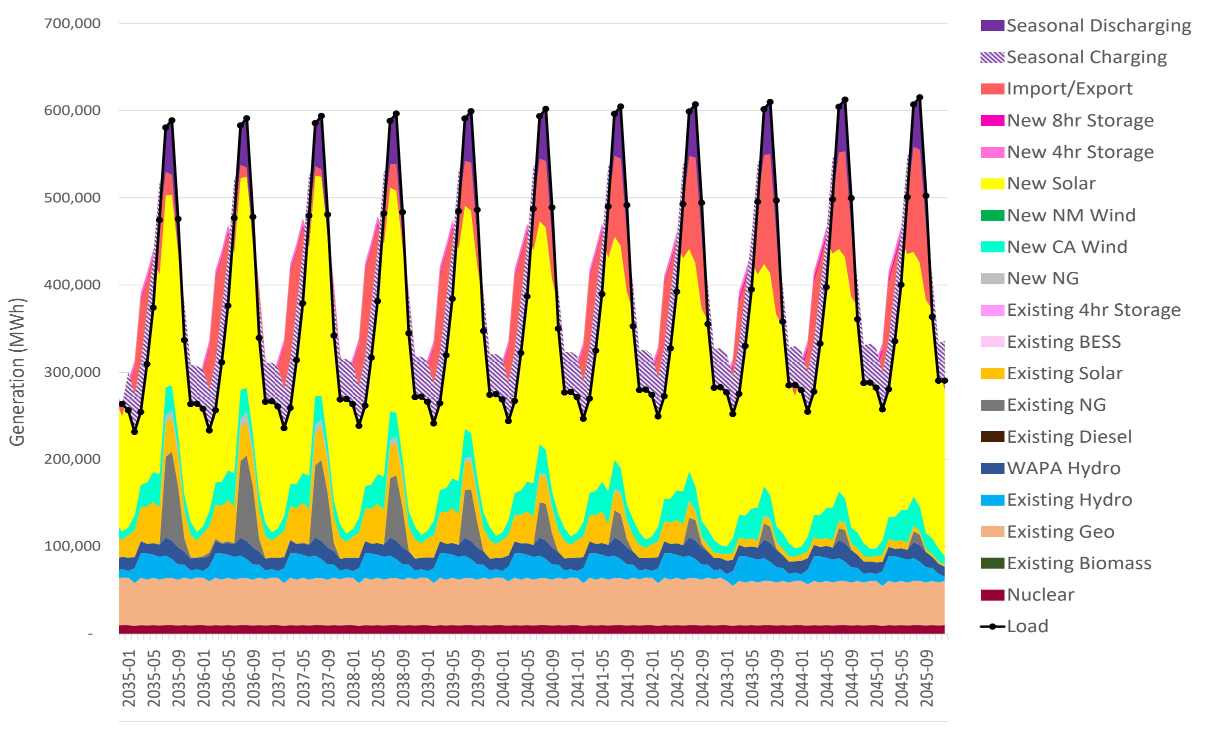



**FIGURE 48. MONTHLY ENERGY TO MEET LOAD IN THE LDES 40% RTE SCENARIO, 2035-2045**

Next, hourly dispatch during representative weeks in the summer and non-summer periods was examined to see how the LDES behaves on a more granular level. Starting with the charging phase, a winter week is depicted in Figure 49. The purple bars below the x-axis represent the charging that routinely takes place during daylight hours utilizing the excess solar generation (yellow bars). Note how comparatively little market selling (red bars below x-axis) is required compared to the Baseline scenario winter week in the late planning period (Figure 36).

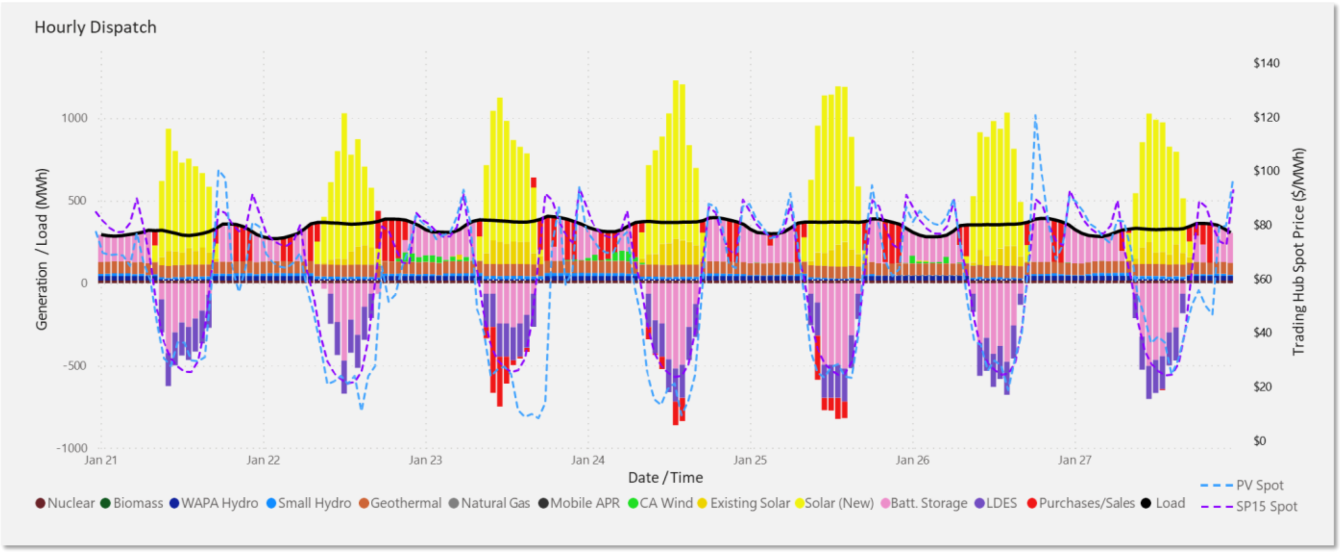



**FIGURE 49. HOURLY DISPATCH FOR LDES SCENARIO: A TYPICAL WINTER WEEK IN 2035**

Contrast this seasonal charging profile with the seasonal discharging profile depicted in Figure 50 for a typical August week in 2035, which shows the LDES discharging during afternoon and evening hours after sunset (purple bars), even discharging more in some hours to take advantage of higher prices for exported power. Market purchases in the peak of summer are significantly reduced by the introduction of the LDES technology.

By 2045, the benefit of the LDES can still be observed in the discharge pattern during the evening and overnight hours, as shown in Figure 51, which shows a typical week in summer 2045. Batteries and LDES discharge in the evening hours, with greatly reduced thermal generation. Imports are once again required to supplement in non-solar hours. However, demand has grown to the extent that market purchases are once again required to meet load. Perhaps an investigation of the potential benefits and costs of higher levels of LDES in these even later planning period years would be insightful, although they were not considered in this alternate scenario.

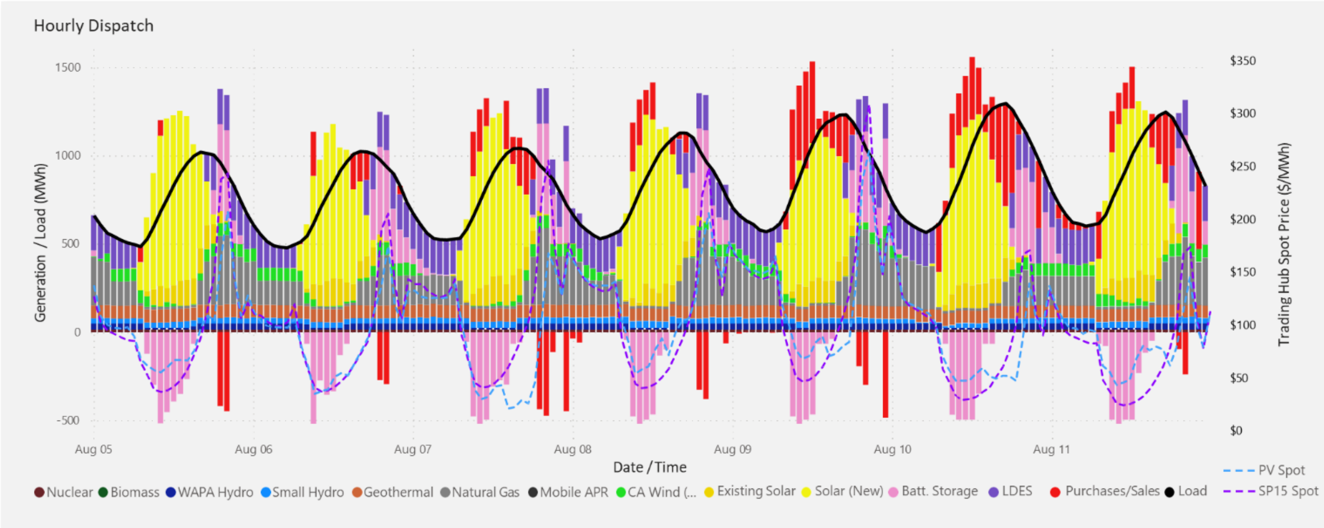



**FIGURE 50. HOURLY DISPATCH FOR LDES SCENARIO: A TYPICAL SUMMER WEEK IN 2035**

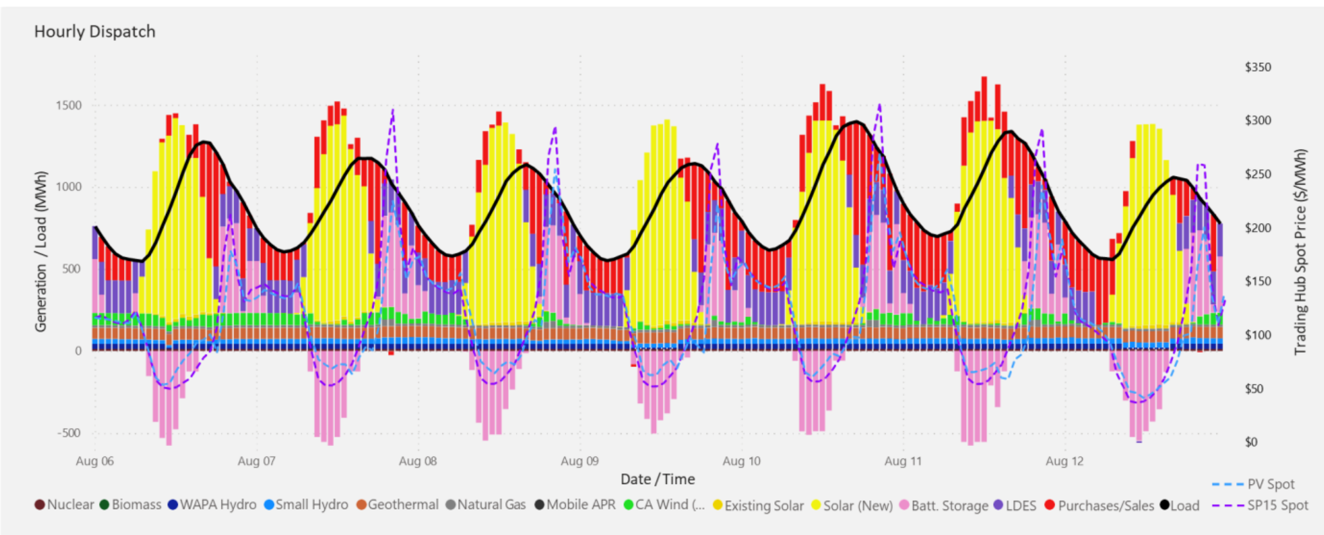



**FIGURE 51. HOURLY DISPATCH FOR LDES SCENARIO: A TYPICAL SUMMER WEEK IN 2045**

Arguably the most important finding of this alternate scenario involves the overall impact on total costs from the introduction of this technology, as shown in Figure 52 and Figure 53. As discussed in the Candidate Resources section of the methodology, a cost of $0 was assigned to this technology as a means of understanding the relative benefit of adding it to the portfolio: this was an attempt to figure out how much might make sense to invest in it and still come out ahead on cost savings or at least 'break even.' This analysis resulted in an overall portfolio cost of about $23 million per year less than that in the Baseline scenario for the 25% RTE case, with cumulative savings over the 11-year period from 2035 through 2045 of about $260 million. For the 40% RTE case, annual savings are around $39 million per year for a cumulative 11-year savings of $431 million.

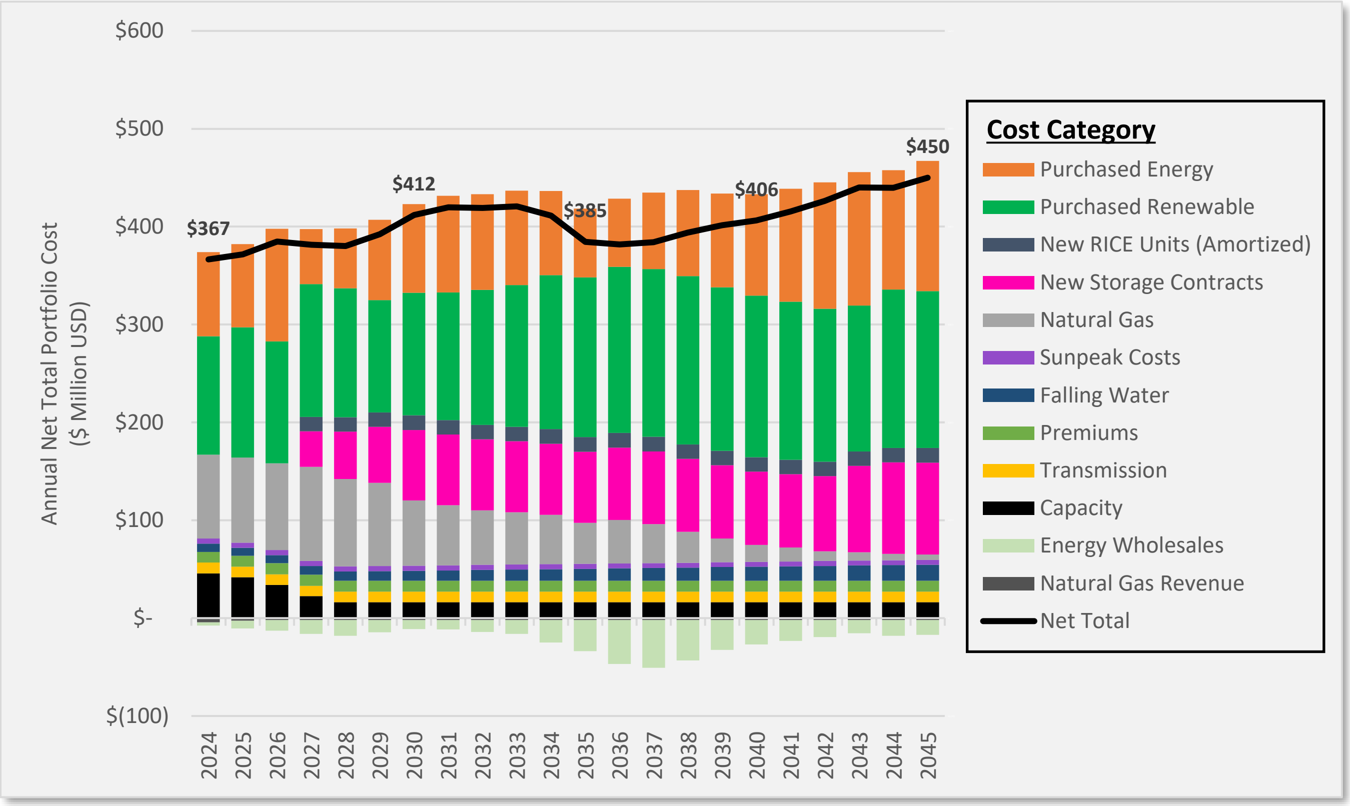



**FIGURE 52. TOTAL PORTFOLIO COSTS FOR LDES 40% RTE CASE, 2024-2045**

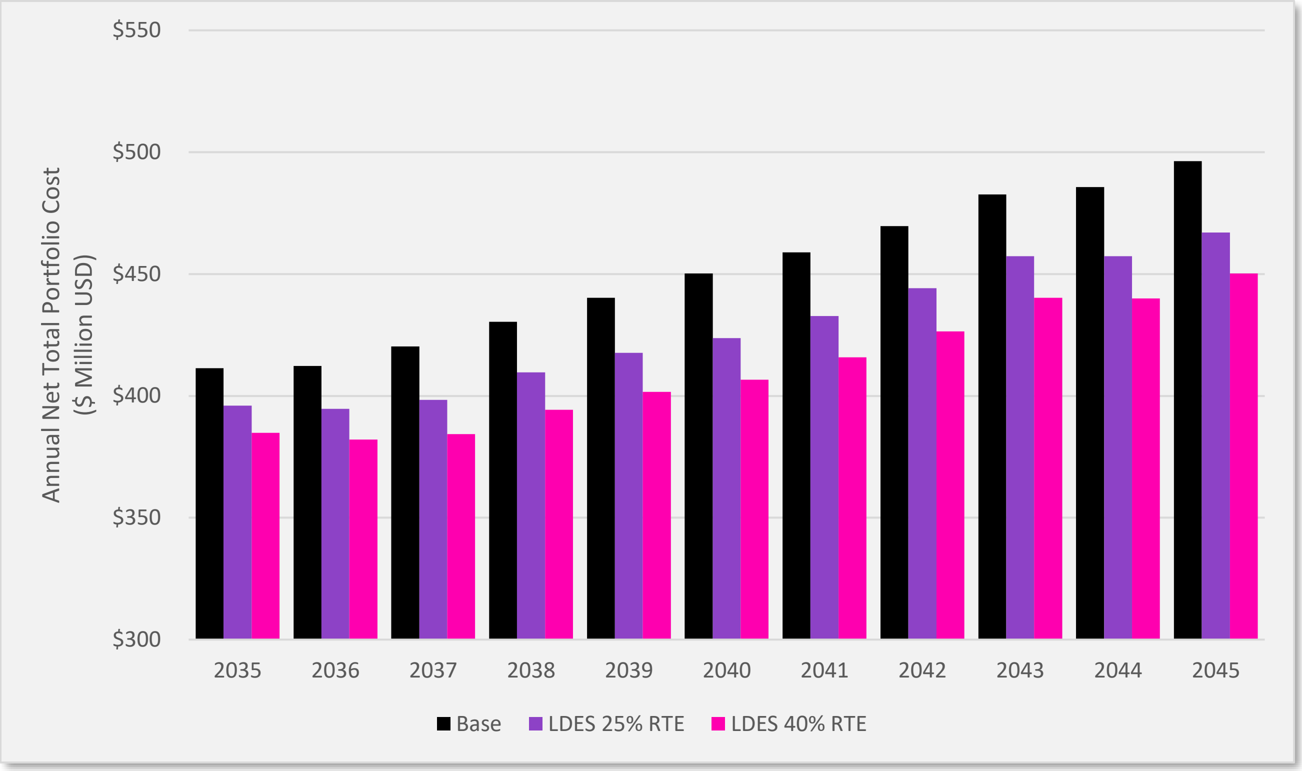



**FIGURE 53. COMPARISON OF TOTAL PORTFOLIO COSTS BETWEEN BASELINE SCENARIO AND LDES SCENARIOS**

## Accelerated Timeline Scenario

The Accelerated Timeline scenario was designed to understand the differences in resource selections and costs associated with achieving the clean energy target of 100% of retail sales by 2035, instead of the current target of 90% by 2035, 95% by 2040, and 100% by 2045, mandated by SB 1020 and SB100.

Interestingly, the Baseline scenario essentially achieves this accelerated timeline even without the additional constraint. Due to solar PPA forecast projected to reach a minimum in the mid-2030s, the optimal solution returned by the capacity expansion model for the baseline scenario is for the bulk of the solar capacity to be added in that timeframe, including zero-carbon capacity that will be needed eventually for the 2045 target. In other words, the capacity expansion model suggests procuring renewable capacity ahead of time when prices are relatively lower, instead of waiting until right before the capacity is needed and prices are higher. As a consequence, the 2035 and 2040 zero-carbon targets in the Baseline scenario are not only met but are exceeded (see Figure 24 in the Baseline scenario Capacity Expansion Results section).

This means that the 'Accelerated' scenario is essentially equivalent to the Baseline scenario. Thus, a 'Delayed Solar Builds' scenario was developed. This scenario demonstrates the modest additional cost that would be incurred if the requisite renewable capacity for each target – and no more – were precisely obtained in the target year.

## Delayed Solar Builds Scenario

As stated above, due to the earlier zero-carbon procurement suggested by the capacity expansion in the Baseline scenario, given the renewables price forecast, in this Delayed Solar Builds scenario the model was restricted to only build the amount of zero-carbon capacity the portfolio needs to precisely hit each target in 2035, 2040, and 2045. The result is a smoother capacity buildout, shown in Figure 54, albeit with slightly higher PPA costs due to the assumed price forecast where solar prices are lowest in the mid-2030s and rise from 2036 through 2045.

## CAPACITY EXPANSION RESULTS

Given the restriction on build quantities, a more gradual accumulation of solar capacity is modeled, rather than the large procurement in the early 2030s in the Baseline scenario. Figure 54 depicts these gradual additions through the forecast period, with similar buildouts of storage, wind, and RICE capacity relative to the Baseline scenario. In the Delayed Solar Builds scenario, solar capacity, at 725 MW, is 24% lower than the 960 MW seen in the Baseline scenario. By 2040, solar builds are 20% lower than the Baseline scenario, at 890 MW compared to 1,115 MW. The zero-carbon targets are hit precisely in each year they go into effect, as shown in Figure 55.

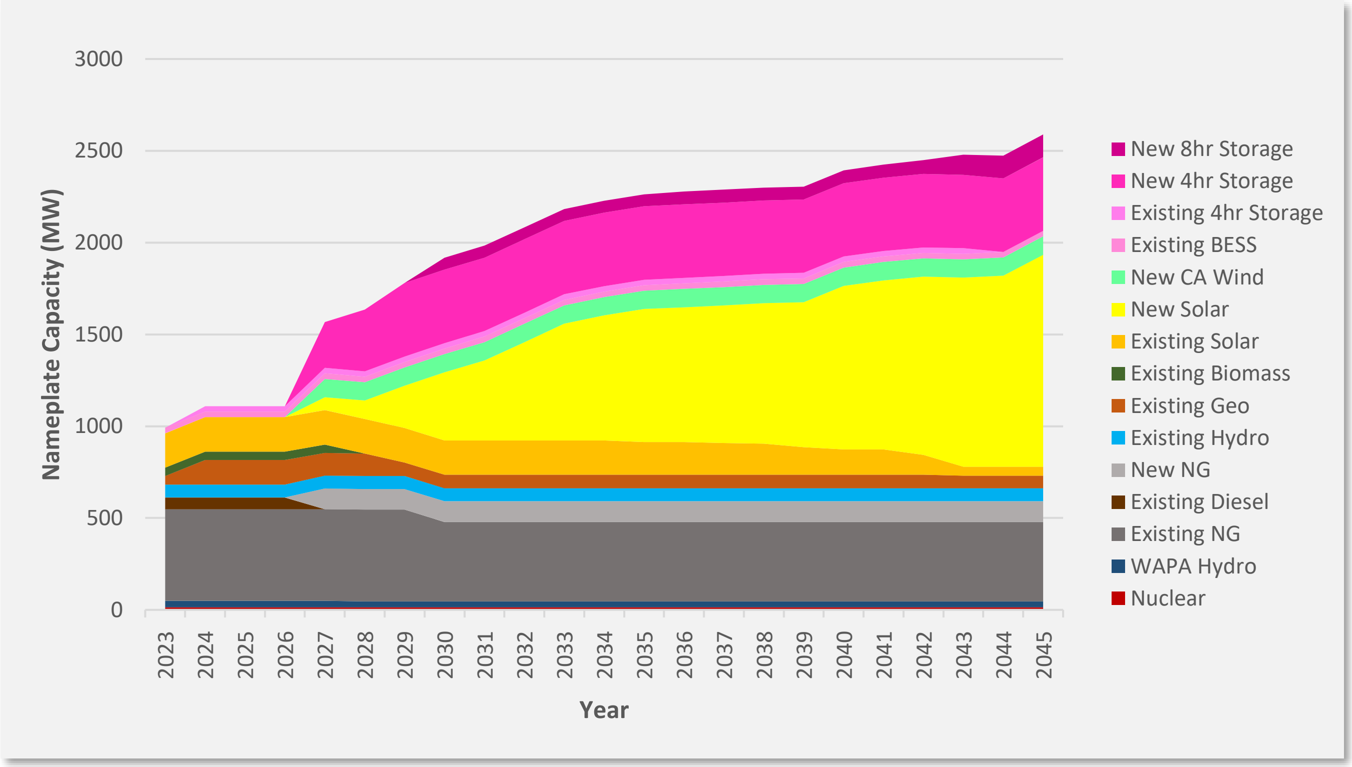



**FIGURE 54. DELAYED SOLAR BUILDS CAPACITY EXPANSION RESULTS, 2023-2045**

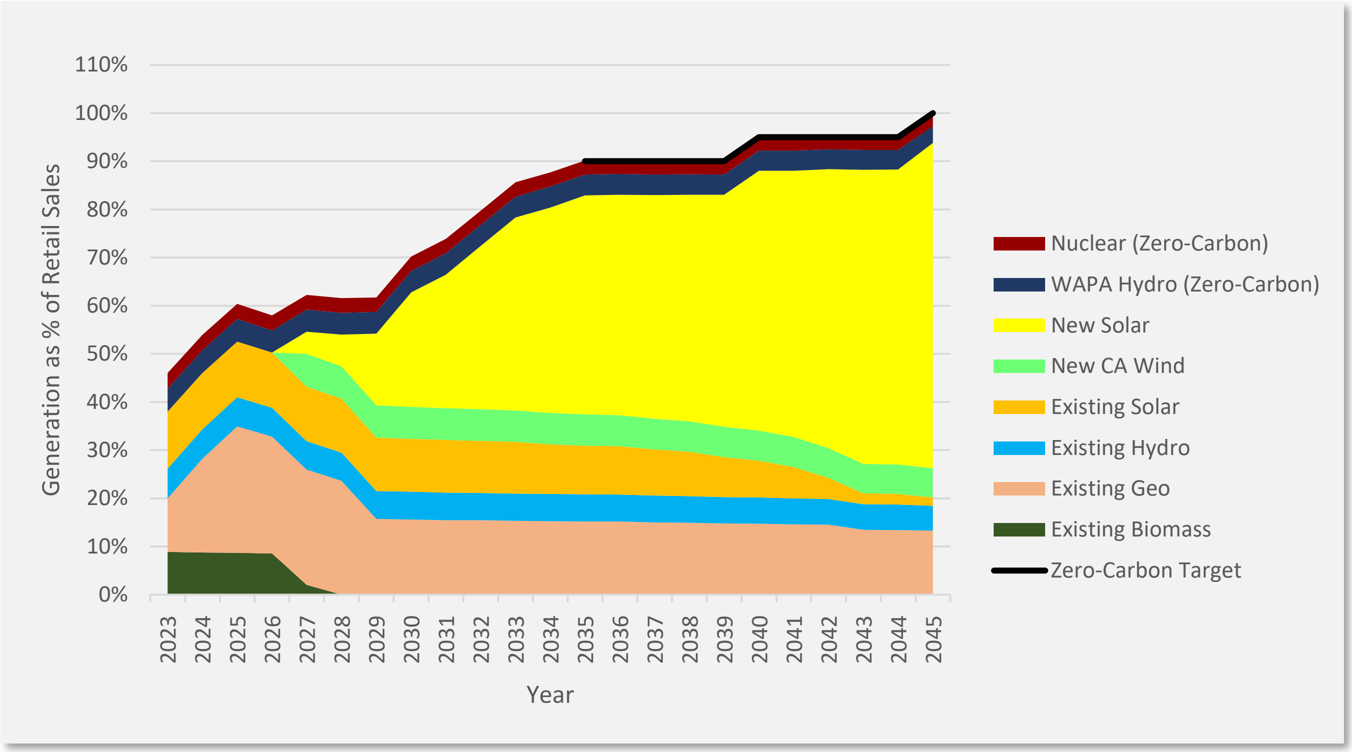



**FIGURE 55. ANNUAL GENERATION TO MEET ZERO-CARBON TARGETS IN THE DELAYED SOLAR BUILDS CASE, 2023-2045**

### PRODUCTION COST ANALYSIS

Costs in the Delayed Solar Builds scenario are slightly higher than in the Baseline scenario, due to the former scenario not taking advantage of assumed lower solar prices ahead of time. As shown in Figure 56, total annual portfolio costs are estimated to be about $515 million by 2045, about 4% higher than in the Baseline scenario. The increased amount of required market purchases more than offsets the reduction in PPA costs in the middle portion of the planning period, leading to slightly higher costs.

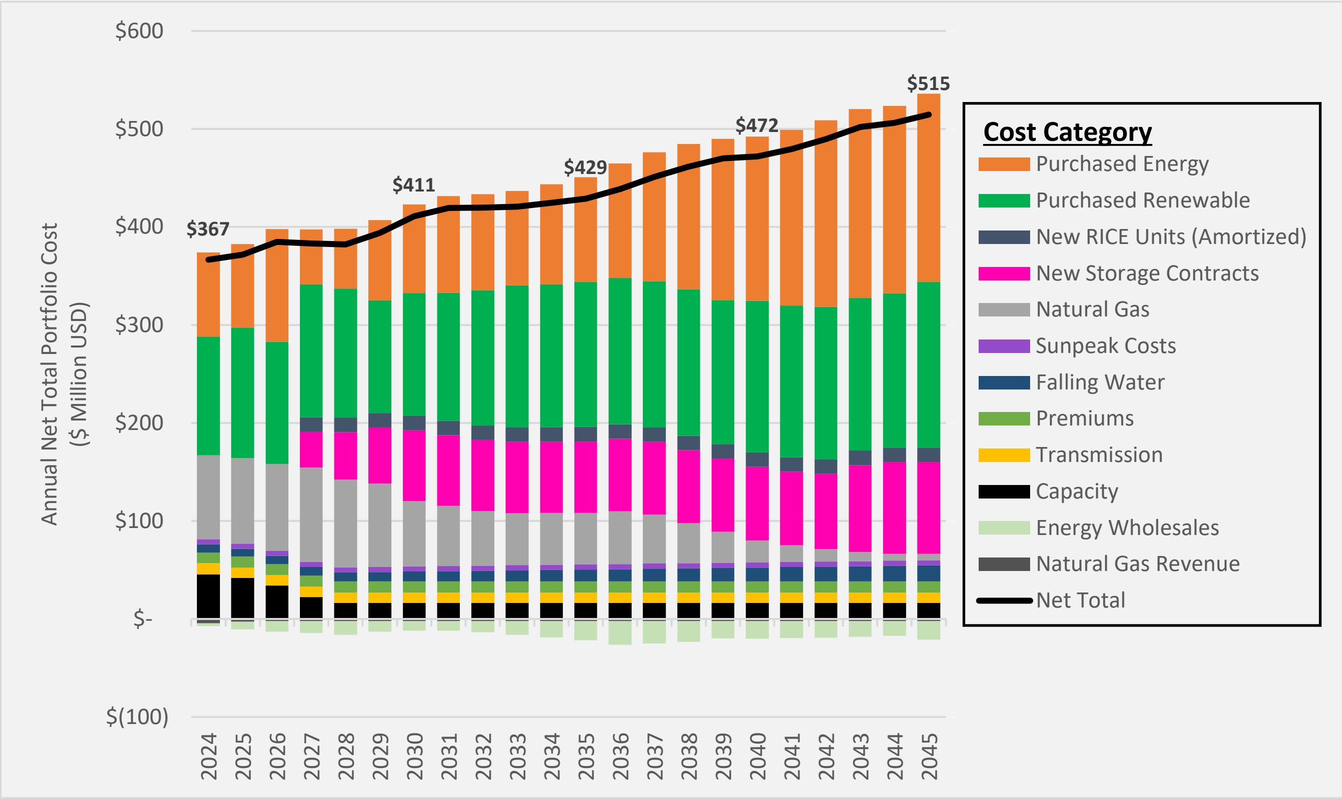



**FIGURE 56. TOTAL COSTS FOR DELAYED SOLAR BUILDS CASE, 2024-2045**

## Regionalization Scenario

Western grid regionalization, the concept of expanding the CAISO footprint to cover a large portion of the Western Interconnect, has been a policy discussion since 2018. Grid regionalization is supposed to provide generation and load diversity across the West to create a more reliable grid without having to build new resources. Proponents of regionalization argue that an interconnected western grid will reduce costs and increase reliability for all utilities within the reginal ISO footprint. The critics of regionalization point to the fact that California would have to change state law to allow for a new appointment process for directors of the ISO as well as complications in adding new utility members to the ISO. For the 2024 IRP regionalization scenario, IID is assumed to join a western ISO starting in 2035 though the remainder of the study period.

The regionalization scenario focuses on IID participation in an ISO or RTO market. IID's supply portfolio is dispatched economically, assuming the market operator is responsible for balancing as of 1/1/2035. The resulting difference in net revenue relative to the Baseline scenario is illustrated in Figure 57. Modest reductions in the total cost of around $4.5 million, resulting from differences in thermal and battery dispatch patterns, along with a small contribution from WAPA hydro dispatch, are estimated for the 2035-2037 timeframe. Starting in 2038, the cost reduction begins to decrease, dropping to just $1.7 million in 2040 and to less than $0.5 million in 2045. Very low thermal capacity factors in later forecast years (2040+) combined with similar dispatch patterns for the battery assets relative to the Baseline scenario are responsible for this decline in the difference between the two scenarios.

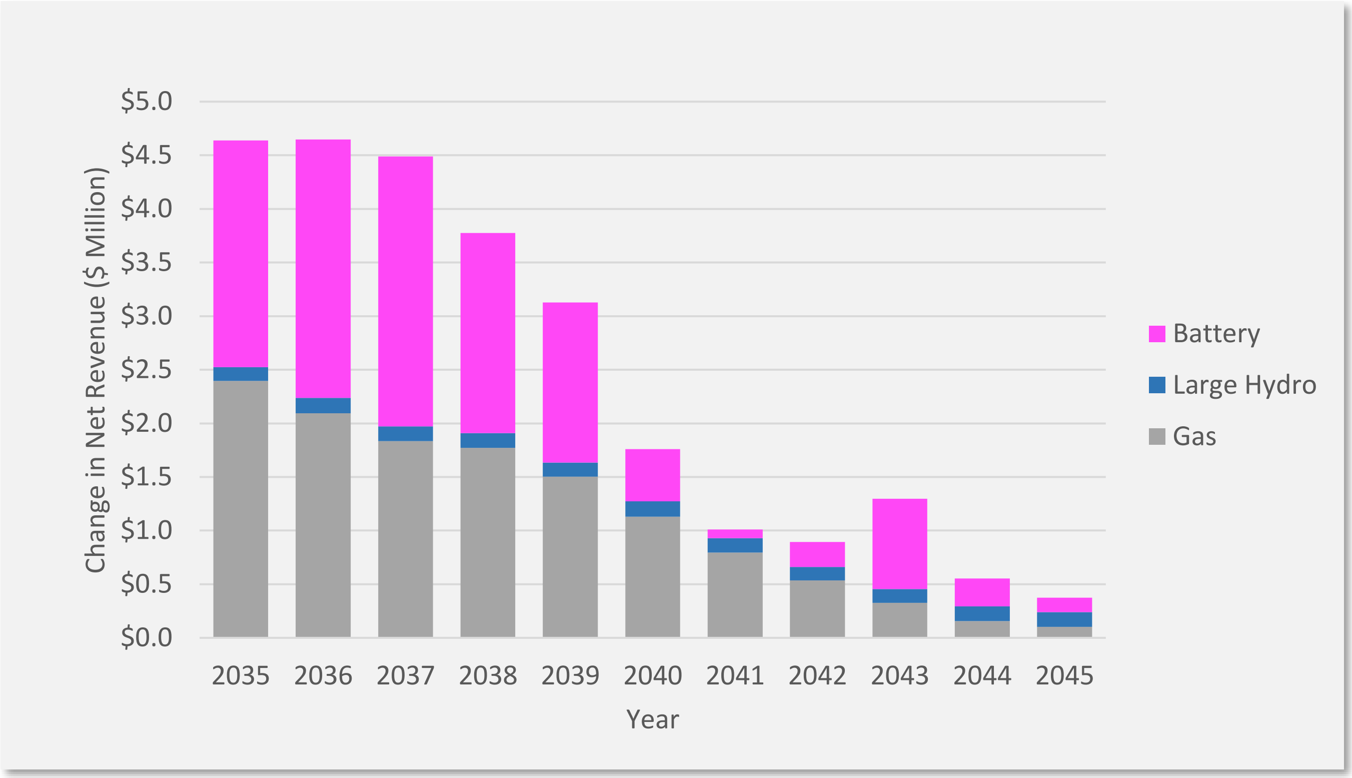



**FIGURE 57. CHANGE IN NET REVENUE BETWEEN REGIONALIZATION SCENARIO AND BASELINE SCENARIO, BY REVENUE SOURCE, 2035-2045.**

Regionalization represents an operational risk to the District. Joining an ISO or RTO will change the way the District performs long term planning as well as short term operations. Regionalization represents an operational risk to the District. Joining an ISO or RTO will change the way the District performs long term planning as well as short term operations. While operating costs will decrease as a function of increased efficiency in the regional ISO, the capacity needs of the District will be very different. IID will have to comply with a regional resource adequacy program that will derive capacity value for resources as a function of the full grid and not just the IID service territory. Today, solar provides the District with significant capacity value given the summer peak load. Under a regional resource adequacy program, the new solar projects recommended in the 2024 IRP would likely provide far less capacity value.

The modeling for the 2024 IRP focused on operational impacts of regionalization but did not evaluate the change in capacity resource needs that would result from the District joining a regional market. The operational costs decrease slightly under regionalization compared to the baseline scenario but there are substantial political and market based risks that are outside of the scope of the IRP.

## Comparison Across Alternative Scenarios

This section summarizes comparisons for various metrics across the different IRP scenarios considered. Total portfolio cost, reliability, and carbon emissions are considered.

### Portfolio Cost Comparisons

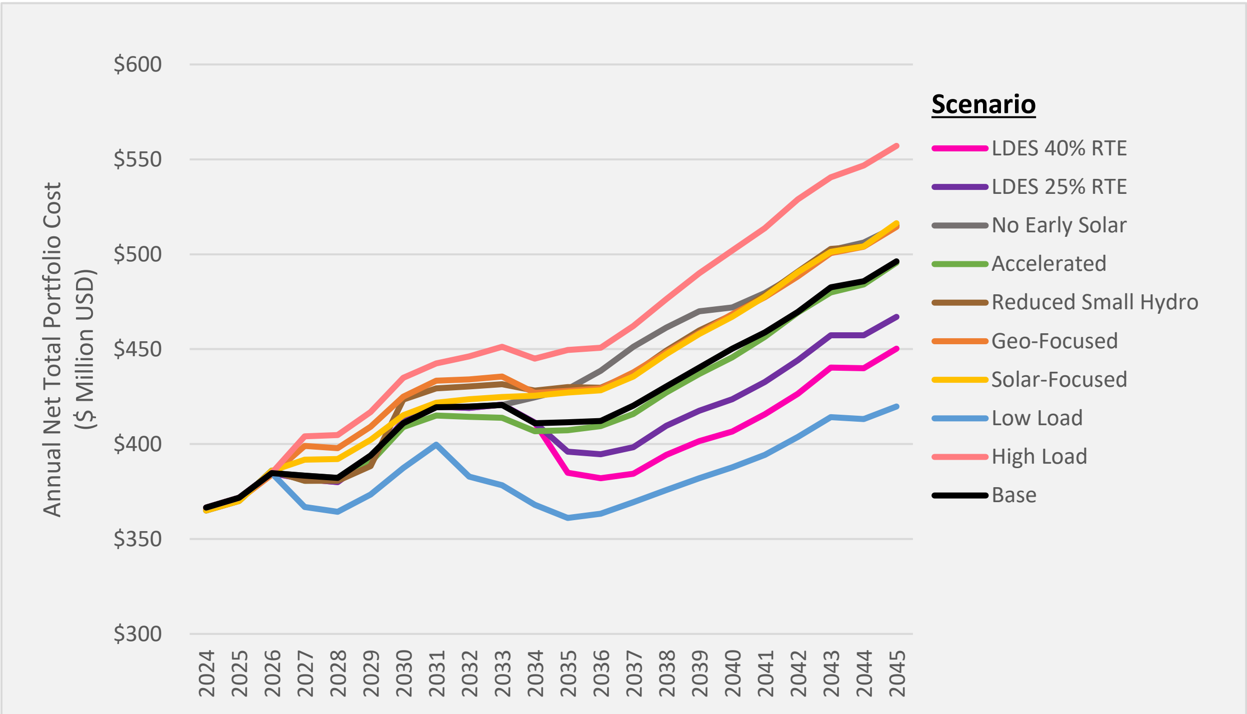



**Figure 58. Annual costs across the different scenarios considered, 2024-2045**

As shown in Figure 58, annual costs show generally similar trends across all scenarios. The greatest variability is exhibited by the load sensitivity scenarios, with the High Load (red) and Low Load (blue) cases reaching the highest and lowest annual portfolio costs, respectively. On a Net Present Value (NPV) basis across all years, a similar pattern is observed, with the High Load and Low Load sensitivities having the highest and lowest NPV cost at $5.29 billion and $4.57 billion, respectively, as shown in Figure 59. The remainder of the scenarios have slightly higher costs than the Baseline scenario, reflecting the additional constraints imposed on the capacity expansion resource selection in those scenarios. The one exception is the Long Duration Energy Storage scenario (purple line in Figure 58), which exhibits lower overall portfolio cost due to no cost being attributed to that technology, by design, to establish an upper bound on potential cost savings from a not-yet-commercialized storage option (see the LDES scenario section for more detail).

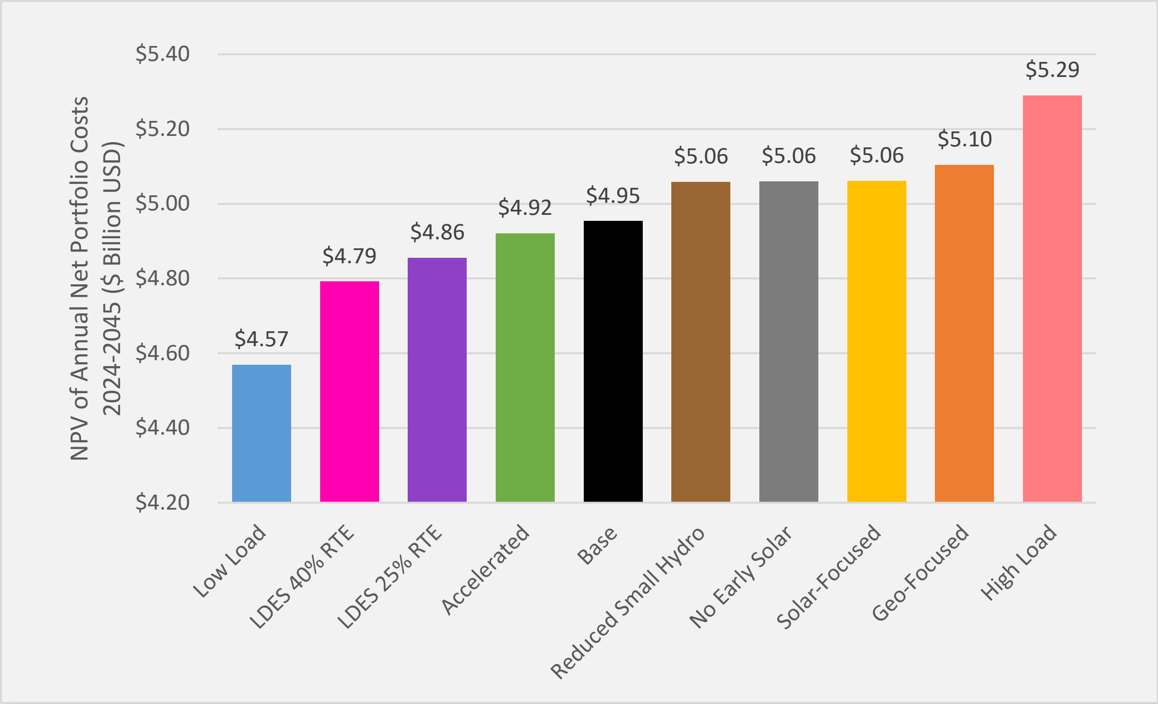



**FIGURE 59. NET PRESENT VALUE OF ANNUAL PORTFOLIO COSTS, BY SCENARIO**

## Reliability Comparisons

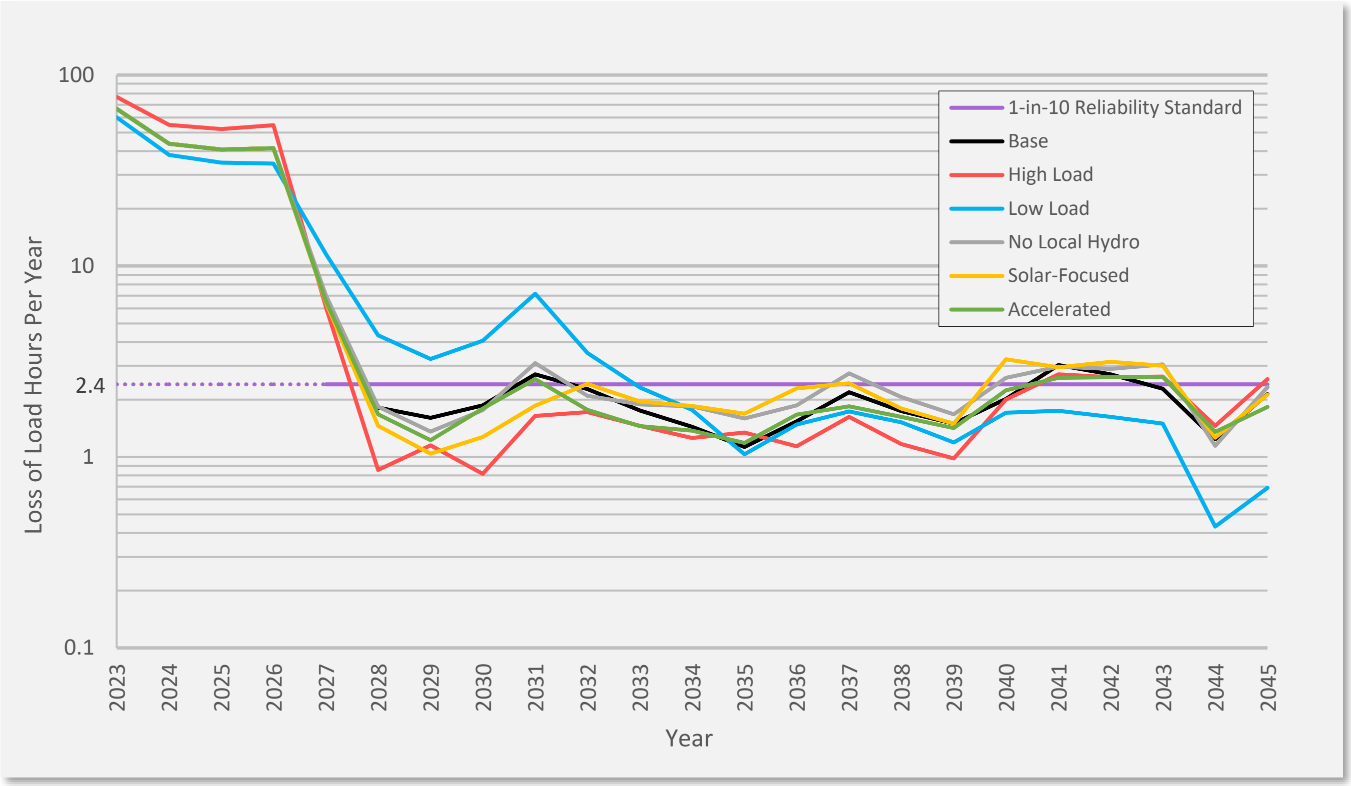



**FIGURE 60. RELIABILITY COMPARISON ACROSS THE DIFFERENT CAPACITY EXPANSION PORTFOLIOS FOR EACH SCENARIO: ALL PORTFOLIOS REACH AND MAINTAIN THE TARGET 1-IN-10 RELIABILITY METRIC THROUGH THE STUDY PERIOD.**

As shown in Figure 60, all alternative scenarios reach and generally maintain the desired 1-in-10 (2.4 LOLH/yr) target during the planning period. Total LOLH in any given year from the LOLP simulations averages between 1 and 2 hours per year. The lower additions of capacity resources (such as the RICE thermal units and storage) selected in the Low Load scenario explains the slightly inferior reliability metric for this scenario's first few years, but this effect dissipates as additional storage resources come online and load growth plateaus in the later years of the Low Load scenario.

## Carbon Dioxide Emissions Comparisons

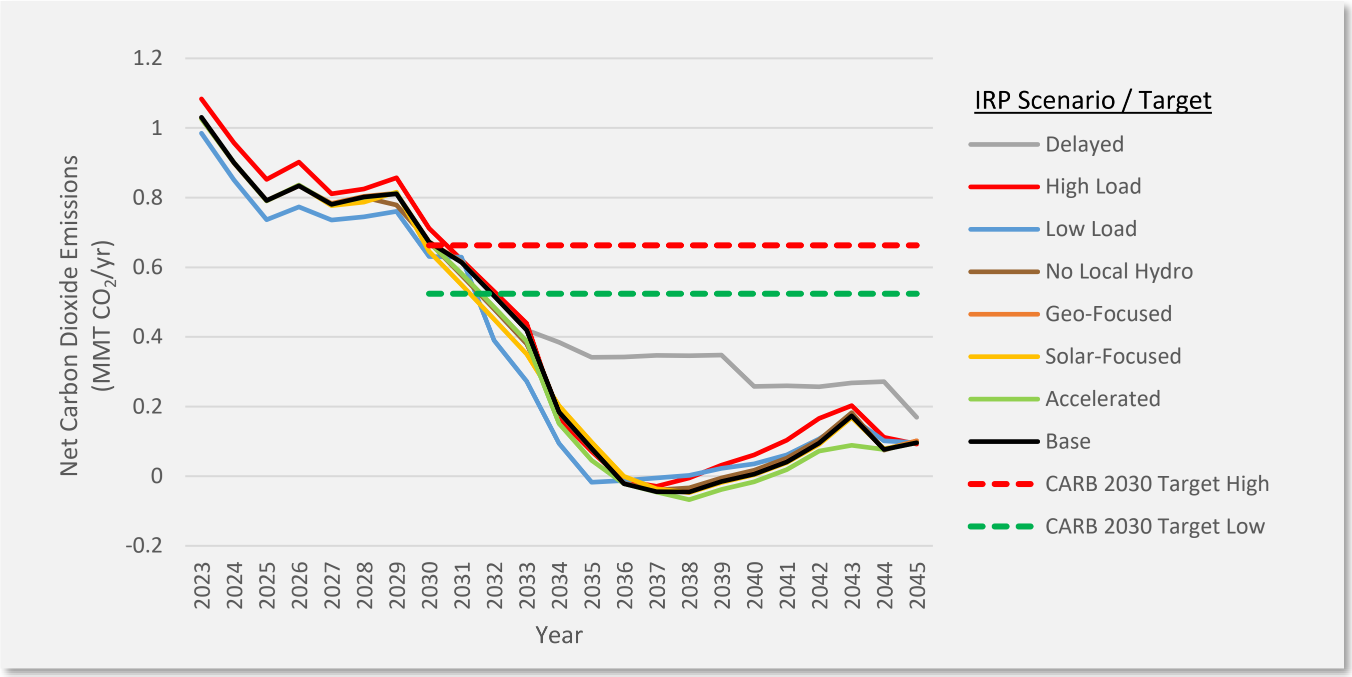
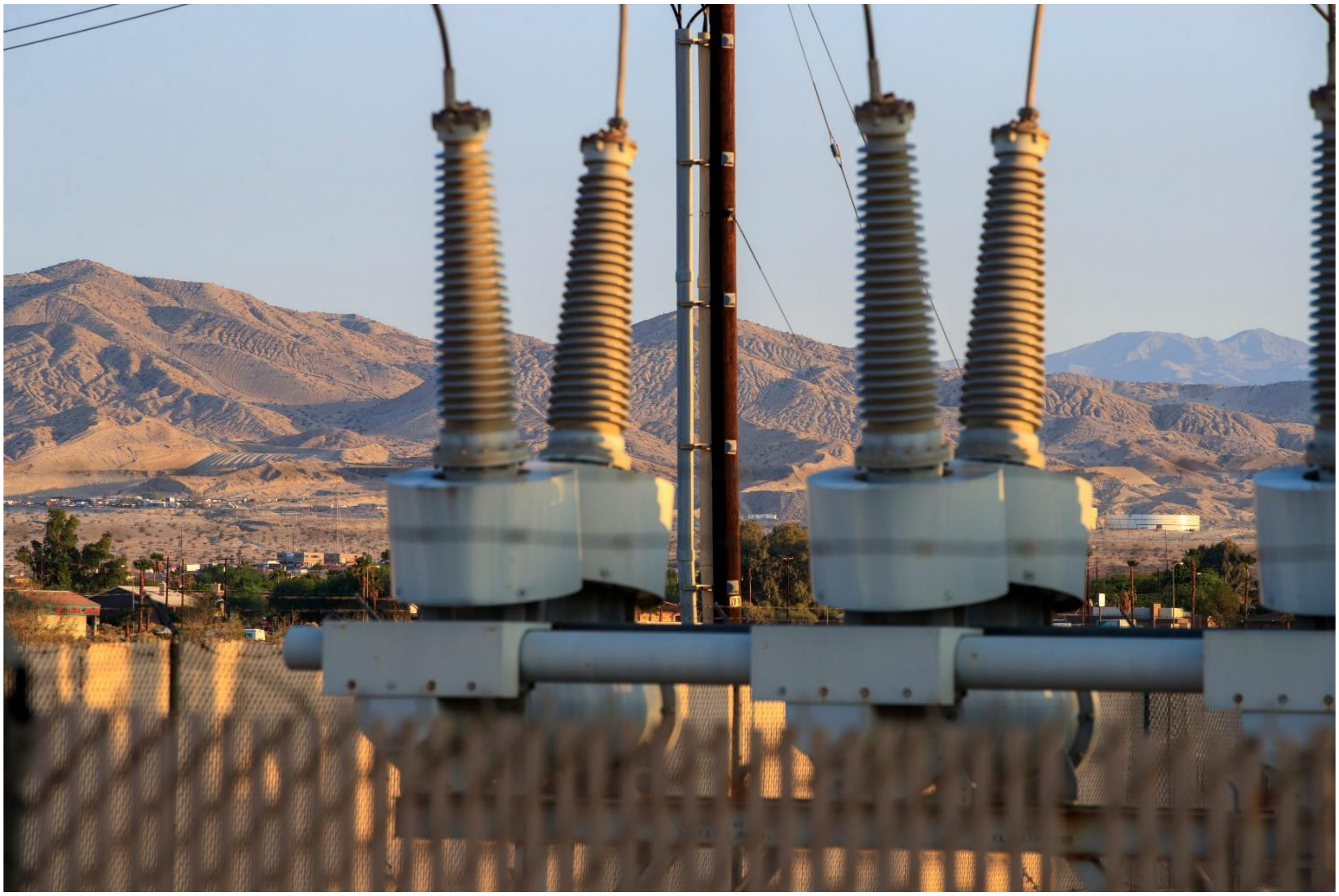



**FIGURE 61. ANNUAL $CO_2$ EMISSIONS FROM IID PORTFOLIO, INCLUDING FROM BOTH GENERATION AND NET PURCHASES: INCLUDES 2030 GHG TARGETS ESTABLISHED BY CARB'S 2023 UPDATE**

Under the Clean Energy and Pollution Reduction Act (SB 350), the California Air Resources Board (CARB) established 2030 greenhouse gas (GHG) planning targets for publicly owned utilities (POUs) and load-serving entities (LSEs). In September 2023, CARB released an update to the SB 350 Electricity GHG Planning Targets. The 2030 electricity sector GHG planning target range in the 2023 Update is 30–38 $MMTCO_2e$. The upper limit of this range has a more aggressive target than the 2020 update (which set the 2030 upper limit of the target range at 53 MMT). IID's commensurate proportion of this updated target range is 1.745%, which equates to between 524,000 and 663,000 MT.

IRP modeling of the Baseline scenario and alternative scenarios was performed prior to the finalized release of the 2023 updated CARB targets. Nevertheless, the Baseline scenario and the majority of sensitivity cases are in line with the upper limit of the target range by 2030, as shown in Figure 61. Annual emissions then fall substantially in the ensuing years and stay well below the target range through 2045. The High Load scenario is slightly above the target limit in 2030, at 710,000 MT $CO_2$.

# Transmission and Distribution Planning



*IID Substation in Thousand Palms, California. August 2021.*

With numerous substations, over 1,800 miles of overhead transmission lines, 4,400 miles of distribution lines and 1,700 miles of underground lines, the District has a substantial amount of existing grid infrastructure to maintain. On top of that, increasing demand—especially in parts of the Coachella Valley area—has been identified as a key issue facing the District in the coming decades. To proactively address this additional load while also grappling with grid stresses from more frequent, longer, and more intense heat waves and other severe weather, several projects have been identified that will enable the District to maintain grid reliability now and in the future. A snapshot of such projects either proposed or currently underway is highlighted in this section of the report.

## Transmission

IID Transmission Planning, through its ten-year reliability assessments, has found areas for reinforcement within the transmission system. The staff have proposed and developed multiple projects ranging from simple capacitor banks to new transmission lines to mitigate the issues observed. The projects identified through this process are the following:

- **230kV Ramon – Mirage #2:**
  A new 230kV Transmission circuit between IID's Ramon Substation and SCE's Mirage Substation. Due to reliability and system stability issues discovered during Transmission Planning's TPL-001-5 assessment, a new circuit is required to provide system resiliency. The simulations performed as part of Transmission Planning's annual assessment indicated that IID's system will not meet WECC CRT reliability criteria due to Fault Induced Delayed Voltage Recovery (FIDVR) found during heavy summer conditions when either P6 or P7 contingencies[78] are applied that affect Path 42. The installation of a second 230kV circuit between Ramon and Mirage would increase the resiliency of the system and bring performance within IID and WECC criteria.

- **92kV CN and CL upgrade:**
  The 92 kV CN & CL Lines Upgrade Project consists of reconstructing approximately five circuit miles of wood poles, the reinforcement of one mile of existing double circuit lattice towers, and the installation of 3.5 miles of fiber optic cable. The five circuit miles of existing two wood pole single circuit lines running parallel through the same right of way will be replaced with two single circuit lines with a single wood pole design using a 1033 kcmil ACSS TW conductor. The one mile of reinforcements to the existing double circuit lattice towers carries two circuit miles which will be re-conductored as well with the same 1033 kcmil ACSS TW conductor. There is a total of seven circuit miles between Coachella Valley Substation and Coachella Switching Station.

- **92kV Grapefruit Switching Station:**
  The Grapefruit Switching Station Project consists of the design and construction of a new switching station, rerouting six transmission lines from the Coachella Switching Station to the new switching station. The Grapefruit Switching Station will functionally replace the existing Coachella Switching Station. The distribution banks will remain in the existing location. The project requires that the majority of the lines interconnecting at Coachella Switching Station stay in service during the construction phase, which requires a very detailed scope of work and sequence of activities.

- **Ave 52 capacitor bank:**
  The 92kV capacitor bank was found to be a necessary system upgrade in the annual Transmission Planning assessment (performed in 2022 to cover the 2023 - 2032 timeframe) to cover the NERC TPL-001 standard. Multiple N-1 scenarios on the 92kV K-Line caused voltage issues on various IID 92kV buses.

- **92kV ECSS breaker replacement:**
  Most breakers were found to be overburdened at ECSS during the short circuit portion of the annual Transmission Planning assessment and have thus been incorporated into a breaker replacement plan.

- **Spare 230:92kV transformer:**
  A spare 230:92kV transformer was found to be required as a spare during the simulations performed during the spare equipment strategy simulations required by TPL-001-5. IID is currently holding one in stock.

[78] See NERC Standard TPL-001-5 for definitions of these contingency categories.

- **ECSP Unit 2-2 and GSU Redundant protection upgrade:**
  ECSP Unit 2-2 and its GSU were found to lack redundant protection systems during the P5 simulations required by TPL-001-5. The work is estimated to be completed in 2024.

In addition to the projects listed above, numerous network upgrades are triggered by the interconnection of merchant generation into the IID BAA as well as through agreements with neighboring Balancing Authorities. A listing of those projects is as follows:

- **230kV S-line upgrade:**
  The S-Line project is being upgraded as a result of an agreement between CAISO and IID. The S-Line project is currently in the development phase, which entails the upgrade of 18.6 miles of the S-Line 230kV transmission line with work at the El Centro Switching Station and the Imperial Valley Substation. The existing 230kV transmission line is a single circuit built on wood structures that spans from the El Centro Switching Station to the Imperial Valley Substation. Portions of scope expansion have also been deemed as network upgrades to support Interconnection Customers.
- **230kV ECSS Bank #5:**
  A new 230:92kV transformer, Bank #5, is to be installed in parallel to the existing Bank 4 at El Centro Switching Station. The installation of this transformer would increase the Total Transfer Capability (TTC) on the new S-line as well as increase system reliability. It also includes the addition of one 92kV bay double bus double breaker and the relocation of several 92kV circuits. This project is a result of negotiations with CAISO stemming from the S-line agreement.
- **New 230kV Salton Sea Transmission Line:**
  The project will consist of interconnecting three new geothermal plants in Calipatria, CA with a combined output of approx. 350MW to IID's grid via a new collector station and a new 230kV line to run from the customer facilities to IID infrastructure. When the new line intersects the existing line, old structures will be replaced with double circuit steel structures to run both circuits up to Coachella Valley Sub. The new line will continue to Ramon Sub. Transmission between Ramon and Devers will utilize the existing corridor. Additional work at Ramon Sub and Coachella Valley Sub will be needed to accommodate this project.
- **92kV R-line upgrade:**
  This project will upgrade approximately 33.8 miles of the R-Line (92kV) transmission line from Dixieland to Anza Substation with 900 kcmil ACSS TW "Canary". The R-Line between Dixieland and Anza has two taps (Superstition and San Felipe) as well as some incomplete transpositions at the Anza arrival. The line is also currently made up of several different types of conductors (397 MCM AAC, 2/0 Copper, 4/0 Copper, and 795 MCM AAC). Dixieland Substation is located 1/3 miles n/o Evan Hewes Hwy to Anza Substation w/o Hwy 78. This upgrade has been deemed a network upgrade that is required by an interconnection customer.

Other projects that the IID is looking into for a combination of economic and reliability benefits are participation in the North Gila – Imperial Valley #2 project and the 92kV K-line hardening project:

- **North Gila – Imperial Valley #2:**
  The project is an 85-mile 500kV transmission line from the North Gila facility to the Imperial Valley facility. The line is to run parallel to the exiting 500kV NGIV line. The project will include a 500/230kV Dune substation which will allow a 500kV loop in of the line and a 230kV interconnect to IID's 230kV Nelson switching station. The project aims to provide redundancy to the single 500kV South West Power Link (SWPL) circuit between North Gila and Imperial Valley Substations. The lack of redundancy on this SWPL

section has historically impacted and limited the operation of the Desert South West transmission system. The project will allow additional import/export capacity to IID's system while relieving congestion issues on IID's 230kV KN/KS lines. IID, in collaboration with other transmission developers, including Valley Power Connect LLC and Citizens Energy Corporation, has submitted proposals into the CAISO competitive solicitation process.

- **92kV K-line Hardening:**
  The project consists of storm hardening 28 miles of the 92kV K-line between the Niland Substation and the Mecca Substation. The intent is to attain a grant through FEMA's BRIC program for financial assistance. The project has already been short-listed by FEMA BRIC. This upgrade is intended to mitigate the effects of significant outages from extreme climate events and add new breakers to allow for the isolation of outages thus reducing the overall impact on the community.

## Distribution

**The Coachella Valley** area has recently received a large number of developer requests for residential, commercial, industrial, cannabis, resort, and entertainment projects, for a forecasted 816 MVA that will require the construction of 14 new bank additions and 22 new substations within the next 10-20 years, as outlined in the 10 Year Coachella Valley Expansion Plan.

The Coachella Valley area is experiencing challenges that stem from new loading requirements, in addition to the standard project development load. These include:

- High number of electric vehicle (EV) charging stations requests, between 1-2 MW each.
- Coachella Valley Project Development and Distribution section has been approached by several developers for the potential installation of Microgrids in the area to serve commercial, industrial, and residential load. For this purpose, IID completed the revision of Rule 21 – Interconnection of Distributed Generation Facilities, including the addition of Interconnection Guidelines on March 7, 2023.
- Currently, the Coachella Valley distribution system planning unit is evaluating the long-term impact on substation/feeder capacity by Fleet Electrification and EV charging stations and incorporating extra capacity needed as part of the 10 Year Coachella Valley Expansion Plan.

**The Imperial Valley** has a significant number of potential clients who are seeking interconnection at the transmission level, specifically those who are load-only entities such as electrical commercial fleets. There is a newly formed group known as the Transmission Customer Service Proposal (TCSP) responsible for handling the administrative aspects of this process. The actual impact on the Interconnection and Integration Division will be felt at the transmission and substation levels. The projected load of these potential customers falls within the range of 25 MW to 40 MW and new substations will be required since this level of energy demand cannot be adequately met through distribution feeders alone.

**Advanced Metering Infrastructure** - IID's advanced metering infrastructure (AMI) implementation is currently ongoing. The District intends to plan for a system that can serve peak demand within loading and voltage limits, as well as provide reliable service to customers. With the implementation of AMI, the District will be able to collect data at the customer and panel level, including demand, voltage, power factor, and billing data. This information is becoming increasingly important for distribution system planning to determine service levels, loading at panels, transformers, loading factors, coincident factors, and voltage levels on circuits with distributed generation. This data can be studied in combination with SCADA demand, voltage levels for feeders, and transformer banks at substations. IID expects to have all AMI meter data available and integrated with DNV GL software for distribution system planning circuit analysis, which will facilitate the development of loading profiles and lead to a more accurate loading forecast, in addition to a distribution management system/GIS integration for operation and reliability enhancements.

## Local Reliability Area

The IID system area consistently experiences potential thermal overloads, which necessitates the start-up of generation in the Coachella Valley area. This issue becomes apparent on high-demand days (summer months), particularly during the intermediate hours when PV generation diminishes while system load remains high. One particular contingency scenario involves the potential overloading of the 92 kV CL line, which subsequently overloads the 92 kV CN line, and vice versa. Given the operational paradigm of the System Operating Limit methodology, IID System Operations runs 10-40 MW of GTs for one to three hours to mitigate the issue. This overload has been documented in NERC TPL studies and transmission planners have recommended the reconductoring of the CN and CL lines.

Another challenge in the Coachella Valley area involves an N-2 contingency scenario where the loss of the 92 kV CD and CS lines originating from Ave 58 results in overloads at the remaining terminal end of these loops. In response to this contingency, the sole measure available to alleviate potential overloads is load shedding. Similarly, these potential overloads are seen during peak load days. Employing energy storage devices to manage loading on these loops can present a cost-effective strategy to mitigate this issue.

## Distributed Generation

*Rooftop solar installation in California. Credit: Thomas Kelsey/U.S. Department of Energy Solar Decathlon*

Residents and businesses in the IID service territory have demonstrated significant interest in distributed generation projects. As of October 2023, 131 MW of distributed capacity has already been installed – over 6,000 systems totaling 83 MW in Coachella Valley and 2,600 systems totaling 48 MW in Imperial Valley. Further, the rate of applications has grown as well, as shown in Figure 62, from less than 50 applications per month in 2020 to over 100 per month through September 2023. In June 2023 alone there were approximately 240 applications for distributed solar systems. Figure 62 shows monthly distributed solar applications from January 1, 2020 through October 9, 2023.

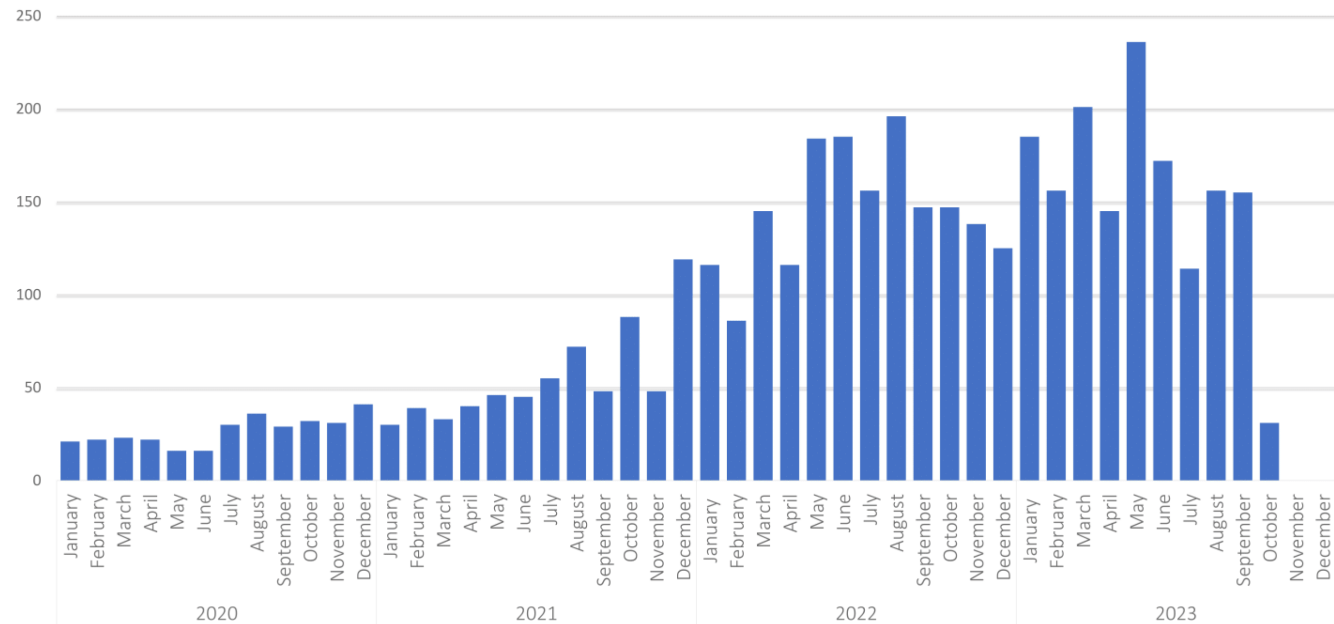



**FIGURE 62. DISTRIBUTED GENERATION APPLICATIONS PER MONTH, 2020-2023**

## Transportation Electrification

California recently passed legislation outlawing the sale of new gasoline-powered cars by 2035. This comes as electric vehicle adoption in the state is already gaining traction, with more than 16% of new vehicles sold in the state being zero-emission or plug-in hybrids[79]. This fraction will increase through the next decade, as shown in Figure 63**.** IID has two programs in place to contribute toward reaching these statewide goals, "Evolve" and "ReCharge!" These programs are summarized below.

[79] CARB Advanced Clean Cars II

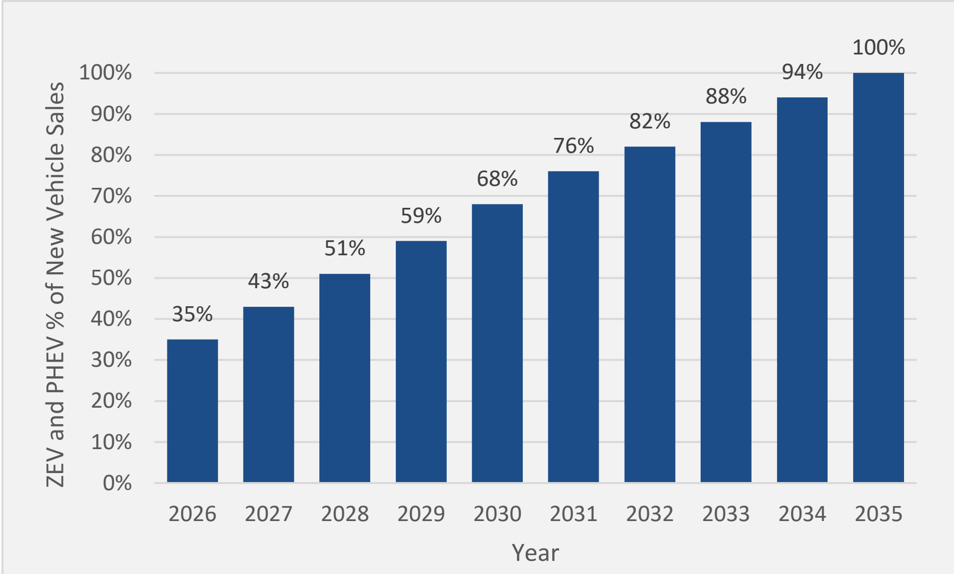



**FIGURE 63. CARB ADVANCED CLEAN CARS II TRAJECTORY FOR NEW ELECTRIC VEHICLE SALES IN CALIFORNIA, 2026-2035.**

**EVolve**

IID's EVolve online electric vehicle platform is designed to educate customers about electric vehicles and explore used car options. It includes a total cost of ownership calculator and access to a dealer directory. The comprehensive electric vehicle platform, which connects IID customers with electric cars, vehicle chargers, charging stations, and incentives, is also available in Spanish.

Designed to promote awareness of the benefits of electric vehicles, the EVolve platform offers tools to educate customers about EVs. Using EVolve, customers can:

- Assess almost every electric-powered vehicle on the market, including new and used plug-in hybrids and ZEVs.
- Refine the search for EVs on the website by price, driving range, and size.
- Calculate the total cost of EV ownership, including resale value, insurance fees, electric rates, and vehicle maintenance expenses.
- Identify EV dealers within the IID service territory to schedule a test drive or purchase an EV.
- Access rebates and other incentives offered by federal, state, and local entities, including IID's ReCharge! Rebate program for EV chargers.
- Locate charging stations anywhere in the U.S. using zip codes.

IID developed the EV reference platform in conjunction with New York-based ZappyRide in mid-2020.

In addition, IID promotes EV ownership through marketing campaigns throughout the year that include www.iid.com, social media channels, newsletters, radio, and print advertising.

**ReCharge!: IID's EV Charger rebate program**

For those who have chosen to go electric, IID offers rebates of up to $500 to customers who purchase and install a Level 2 (240-volt) plug-in electric vehicle charger. IID began offering this rebate in 2019 and has processed just over 500 EV Charger applications to date.

Requirements for the EV charger rebate program:

- Rebates are only available for existing homes. New construction does not qualify.
- Electric vehicle supply equipment (EV charger) must be Level 2 (240V) and utilize the SAE J1772 charging plug or Tesla's High Power Wall Connector and be UL- or equivalent listed. Chargers with greater capacity will be considered on a case-by-case basis. Chargers must be wall- or pedestal-mounted. Chargers must be designed for electric vehicles that are DOT-approved for highway application (chargers for golf carts, neighborhood carts, motorcycles, electric scooters or bicycles, and other low-speed vehicles are not eligible)[80].

[80] https://www.iid.com/customer-service/save-energy-and-money/your-home/ev-charger-rebates

# Energy Efficiency and Demand Response


*Summer high temperatures in the IID service territory routinely exceed 110 F.*

With summer high temperatures in the District frequently exceeding 110°F, cooling needs are often at a premium. These are the periods when IID's grid infrastructure is strained the greatest, so all contributions to reducing peak energy demand, even small ones, help maintain the reliability of the grid. To that end, IID has several ongoing energy efficiency and demand response programs with a demonstrated record of helping both residential, commercial, and industrial customers in the service territory be more efficient, avoid wasted electricity, and save money. These programs are discussed below.

## Energy Efficiency

This section covers efficiency programs initiated by IID in recent years, including:

- Energy Rewards Rebate
- Custom Energy Solutions
- Keep Your Cool

- Quality AC Tune-Up
- Residential Weatherization
- Tree for All
- Green Grants

## Summary of Programs

Below is a brief description of each program.

- The **Energy Rewards Rebate Program** provides standardized incentives to both residential and non-residential IID customers to implement energy-saving technologies in their homes and businesses. The program offers incentives for a variety of measures, including attic insulation, lighting, motors, and HVAC equipment.
- The **Custom Energy Solutions Program** (CESP) promotes energy efficiency by offering financial incentives to commercial customers who install energy-efficiency equipment. Measures incentivized include interior and exterior lighting, process loads, and HVAC/refrigeration. IID offers technical expertise to assist customers in identifying energy efficiency measures and cost saving opportunities.
- The **Keep Your Cool Program** provides energy efficient refrigeration measures for non-residential facilities such as schools and grocery stores. This program offers commercial account customers direct installation refrigeration measures, which fall into three categories: measures that reduce air leakage from cooled spaces, higher efficiency equipment, and equipment controls.
- The **Quality AC Tune-Up Program** allows small commercial account customers to receive HVAC services which include duct test and seal (DTS) and/or a refrigerant charge adjustment (RCA), with inspection of all electrical connections and tightening, inspection of all moving parts and lubrication, inspection of condensate drain, inspection of system controls and thermostat setting, as well as cleaning of evaporator and condenser air conditioning coils.
- The **Residential Weatherization** Program allows participating IID electric customers to receive up to $1,000 in recommended energy saving services and equipment for their residence. The program is open to all IID residential customers on a first-come, first-serve basis. IID partners with a service provider that can evaluate and suggest a home's energy efficiency improvements.
- The **Tree for All** Program provides customers with a free shade tree planted to maximize energy savings.
- The **Green Grants** Program is offered to non-profit organizations located in IID's service area. Funding is limited to energy efficiency/management upgrades and investments in renewable resources that are not covered under any other existing public benefit program offered by IID.

Table 12 and Table 13 document the savings from some of these programs, as covered in IID's 2019-2021 Select Programs Evaluation Report. Overall, the projects realized 92% of expected energy savings on an expected/verified kW basis and a cumulative verified net savings of over 35 GWh.

## Overall Verified Savings

**TABLE 12. OVERALL GROSS SAVINGS REPORTED IN 2019-2021 SELECT PROGRAMS EVALUATION REPORT**

| Program | Expected kWh | Verified kWh | kWh Realization Rate | Expected kW | Verified kW | kW Realization Rate |
|---|---|---|---|---|---|---|
| Energy Rewards Rebate | 10,144,637 | 10,123,831 | 99.8% | 5,196.94 | 5,452.57 | 104.9% |
| Custom Energy Solutions | 16,968,901 | 19,476,608 | 114.8% | 5,299.48 | 3,817.03 | 72.0% |
| Keep Your Cool | 2,818,736 | 2,742,994 | 97.3% | 337.75 | 323.02 | 95.6% |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Quality AC Tune-Up** | 2,989,976 | 2,851,922 | 95.4% | 1,736.22 | 1,976.18 | 113.8% |
| **Totals:** | **32,922,250** | **35,195,355** | **106.9%** | **12,570.39** | **11,568.80** | **92.0%** |

**Note: The Refrigeration Recycling, Green Grants, and Weatherization programs were not evaluated in the 2019-2021 Select Programs Evaluation Report*

**Table 13: Overall Net Savings reported in 2019-2021 Select Programs Evaluation Report**

| Program | Verified kWh | Verified kW | NTGR | Net kWh | Net kW |
|---|---|---|---|---|---|
| **Energy Rewards Rebate** | 10,219,305 | 5,456.79 | 86.8% | 8,870,103 | 4,799.22 |
| **Custom Energy Solutions** | 19,476,608 | 3,817.03 | 83.5% | 16,254,311 | 3,187.82 |
| **Keep Your Cool** | 2,742,994 | 323.02 | 95.0% | 2,605,844 | 306.87 |
| **Quality AC** | 2,851,922 | 1,976.18 | 74.3% | 2,118,308 | 1,664.87 |
| **Totals:** | **35,290,829** | **11,573.02** | **84.6%** | **29,848,566** | **9,958.78** |

**Note: The Refrigeration Recycling and Weatherization programs were not evaluated in the 2019-2021 Select Programs Evaluation Report*

## Energy Rewards Rebate Program

The overall Energy Rewards Rebate verified net savings for each program year are:

- **2019:** 2,283,651 kWh and 828.40 kW
- **2020:** 3,332,867 kWh and 1,477.65 kW
- **2021:** 3,253,585 kWh and 2,493.17 kW

Well-established and popular, the program has been operating for over a decade and regularly meets or exceeds planned savings goals and enrollment expectations.

**Key Program Limitations and Requirements[81]:**

- **Existing homes only.** Rebates are only available for existing homes. New construction does not qualify.
- **Limited funding**. Rebates are limited, not guaranteed, and may be terminated without prior notice. Residential rebates are capped at $5,000 annually per customer account.
- **Self-installation**. Customers who self-install products do not need to work with a contractor but must pull required building permits from their local jurisdiction.
- **Participating contractor requirements**. If replacing a heating, ventilating, and air conditioning (HVAC) system or installing attic insulation, these projects must be completed by a contractor on IID's Participating Contractor List, unless the customer is self-installing the product.
- **Rebate frequency**. A customer may only receive a rebate for the same product type once every five years.
- **Self-generating customers**. Self-generating customers' rebate amounts will be determined by the percentage of their total energy usage that is not offset by their photovoltaic system. For example, if only 25% of a self-generating customer's energy is supplied by IID, their incentive is reduced to 25% of the rebate amount listed on the application.

[81] https://www.iid.com/home/showpublisheddocument/20872/638236324420070000

- **Building permit requirements**. Building permits are a requirement of the local jurisdiction (city, county, etc.) for certain projects, including the replacement of an HVAC system.
- **Rebate-Specific Considerations**. There are additional requirements related to each rebate category that are not covered in the summary of this program provided in this IRP.

For 2023, Energy Rewards program rebates are shown in the table below:

**Table 14. 2023 Energy Rewards Rebates**[82]

| Product/Service | Rebate |
|---|---|
| A. ENERGY STAR® Refrigerator | $75/unit |
| B. ENERGY STAR® Clothes Washer | $75/unit |
| C. ENERGY STAR® Electric Clothes Dryer | $75/unit |
| D. ENERGY STAR® Dish Washer | $75/unit |
| E. ENERGY STAR® Dual-Pane Windows | $2/sq. ft. |
| F. Shade Screens | $1/sq. ft. |
| G. ENERGY STAR® Variable-Speed Pool Pump[83] | $200/unit |
| H. Attic Fan | $75/electric unit<br>$125/solar unit |
| I. Attic Insulation | $0.30/sq. ft. |
| J. Radiant Barrier | $0.30/sq. ft. |
| K. ENERGY STAR® Room Air Conditioner | $100/unit |
| L. Evaporative Cooler[84] | $300/unit |
| M. Ductless Mini-Split System | $200/unit |
| N. ENERGY STAR® Thermostat[85] | $50/unit |
| O. HVAC – Gas to Electric | $400/ton |
| P. HVAC System | Tier 1: $125/ton<br>Tier 2: $200/ton<br>Tier 3: $300/ton |

## Custom Energy Solutions Program

Overall verified CESP net savings for each program year are:

- **2019:** 8,703,865 kWh and 1,685.93 kW
- **2020:** 6,067,364 kWh and 1,040.04 kW.
- **2021:** 1,483,082kWh and 461.85 kW.

[82] https://www.iid.com/customer-service/save-energy-and-money/your-home/residential-rebates
[83] www.energystar.gov/productfinder/
[84] Qualifying Evaporative Cooler List
[85] https://www.energystar.gov/productfinder/product/certified-connected-thermostats/results

Well-established and popular, the CESP program has been in operation for over 10 years. Incentives are comparable to similar programs in other, similar, California municipal utilities and the program sees consistent, strong participation, and produces reliable annual savings for IID.

The CESP program has always exceeded its original kWh savings estimates but has achieved less of a verified peak kW reduction than expected. The high kWh savings are driven by verified savings accounting for HVAC interactions and reduced cooling load as a result of more efficient lighting equipment in conditioned areas. Interaction factors were applied to both kWh and kW calculations, though the effect of the factors on kW calculations is overshadowed by the inclusion of peak kW coincidence factors in verified calculations. Peak CFs account for the percent chance that the lighting is in operation during the peak time and were not included in *ex ante* calculations. This was particularly detrimental to verified peak kW in lighting installed in school and exterior spaces, as the percent chance lighting will be operating in those spaces during peak times is 2% and 0%, respectively. The driver of the high kWh realization is the inclusion of HVAC interactive factors in verified savings calculations, and the driver of the low kW realization is the inclusion of the peak CF in verified savings calculations.

### Keep Your Cool

2021 Keep Your Cool net savings were 2,605,844 kWh and 306.87 kW. Participants reported high levels of satisfaction. All respondents reported they were very satisfied with both the program in general and the steps to participate.

### Quality AC Tune-Up

The 2019 Quality AC net savings were 1,976.18 kWh and 1,664.87 kW. Despite issues with the program implementor, the 2019 program year realized significant savings. The overall 2019 Quality AC savings were 2,851,922 kWh and 1,976.18 kW, 95.4 % and 113.8% of expected savings, respectively. This program is no longer in effect.

### Tree for All

The Tree for All[86] program is very popular. The most recent sign-up period (October 2023), which offered 800 trees to IID customers, reached full capacity due to high demand. Trees available through this program have been carefully selected for their specific characteristics and ability to survive in the region’s warm desert climate.

### Green Grants

Applicant must be a non-profit entity. This includes educational institutions and government agencies.

Proposed projects must align with one of the four key funding areas:

- Energy efficiency/management upgrade
- Income-qualified assistance
- Renewable resources
- Research, development, and demonstration of emerging energy management technology

Looking ahead to future years, the District’s adopted energy savings targets as of 2021 were as shown in Table 15 below.

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[86] https://www.iid.com/customer-service/save-energy-and-money/your-home/tree-for-all

**TABLE 15. IID ENERGY SAVINGS TARGETS, 2022-231.** [87]

| Year | MWh (Market Potential from Programs) | MWh (Codes and Standards) | MWh Total |
|---|---|---|---|
| **2022** | 12,450 | 27,333 | 39,783 |
| **2023** | 12,643 | 27,105 | 39,747 |
| **2024** | 12,941 | 25,752 | 38,693 |
| **2025** | 13,156 | 24,841 | 37,997 |
| **2026** | 13,172 | 22,933 | 36,105 |
| **2027** | 13,256 | 21,152 | 34,408 |
| 2028 | 13,098 | 18,740 | 31,838 |
| 2029 | 13,163 | 16,398 | 29,561 |
| 2030 | 13,167 | 13,793 | 26,960 |
| 2031 | 13,468 | 11,937 | 25,405 |

## Demand Response

IID offers the Emergency Summer Load Reduction Program [88], an incentive to commercial customers who participate in reducing energy consumption during peak demand hours. This will help reduce strain on the IID electric grid and minimize power shortages in the IID service area. The program is similar to typical demand response schemes except that the mechanism of participation is not automated.

IID commercial customers can receive financial incentives for reducing energy use during times of high grid stress and emergencies. Participation is voluntary and there is no penalty if a customer cannot participate in an event. Participating customers will be compensated for participating. Non-residential customers who have a monthly energy demand of 1,000 kW or greater are eligible to participate.

The following steps are a general outline of how the Emergency Summer Load Reduction Program operates:

- This program runs between June and September, the months of the year at which IID's load is highest.
- The customer will provide IID with the pre-determined level of energy reduction.
- When notified, the customer must be able to reduce their energy demand to the pre-determined level for 2 hours during the hours of 5 p.m. to 9 p.m.
- An event notification will be sent to participating commercial customers by IID one day in advance of a scheduled event via phone, text, or email.
- When the event is over, the customer will receive a notice of event completion.
- A customer can participate in up to three events per month during the summer months.

Participants will receive a credit on their monthly IID electric bill for having reduced energy demand to the pre-determined level during the event. Customers will receive a $10 per kW monthly billing credit when they have

[87] Resolution No. 19-2021; Public Benefits Energy Efficiency Portfolio. April 6, 2021.
[88] Emergency Summer Load Reduction Program. https://www.iid.com/customer-service/emergency-summer-load-reduction-program

reduced their energy load to the pre-determined level during an event. Customers will only receive a credit on their monthly electric bill for each load reduction two-hour event in which they successfully participate. If a customer cannot reduce their energy demand to the pre-determined level, they will receive only a percentage of the amount of the reduced level.

**AB 617 BACKGROUND**

In 2017, Governor Brown signed Assembly Bill 617[89] to develop a new community-focused program to reduce exposure to air pollution more effectively and preserve public health. This bill directs the California Air Resources Board (CARB) and all local air districts, including the Imperial County Air Pollution (APCD), to take measures to protect communities disproportionally impacted by air pollution. With input from communities and air districts throughout California, CARB developed a Community Air Protection Blueprint to implement AB 617[90].

There are five central components to the AB 617 mandate:

- Community-level air monitoring
- A state strategy and community specific emission reduction plans
- Accelerated review of retrofit pollution control technologies on industrial facilities subject to Cap-and-Trade
- Enhanced emission reporting requirements
- Increased penalty provisions for polluters

Additionally, CARB may direct additional grant funding to communities determined to have the highest air pollution burden[91]. Figure 64 extracted from the Cal EnviroScreen maps shows that several communities in the IID service territory, especially communities in the southern part of the service territory near El Centro, are in the higher pollution burden percentiles.

[89] C. Garcia, Chapter 136, Statutes of 2017. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB617

[90] "Community Air Protection Blueprint". https://ww2.arb.ca.gov/our-work/programs/community-air-protection-program/community-air-protection-blueprint

[91] "About AB 617". https://www.icab617community.org/about-ab-617

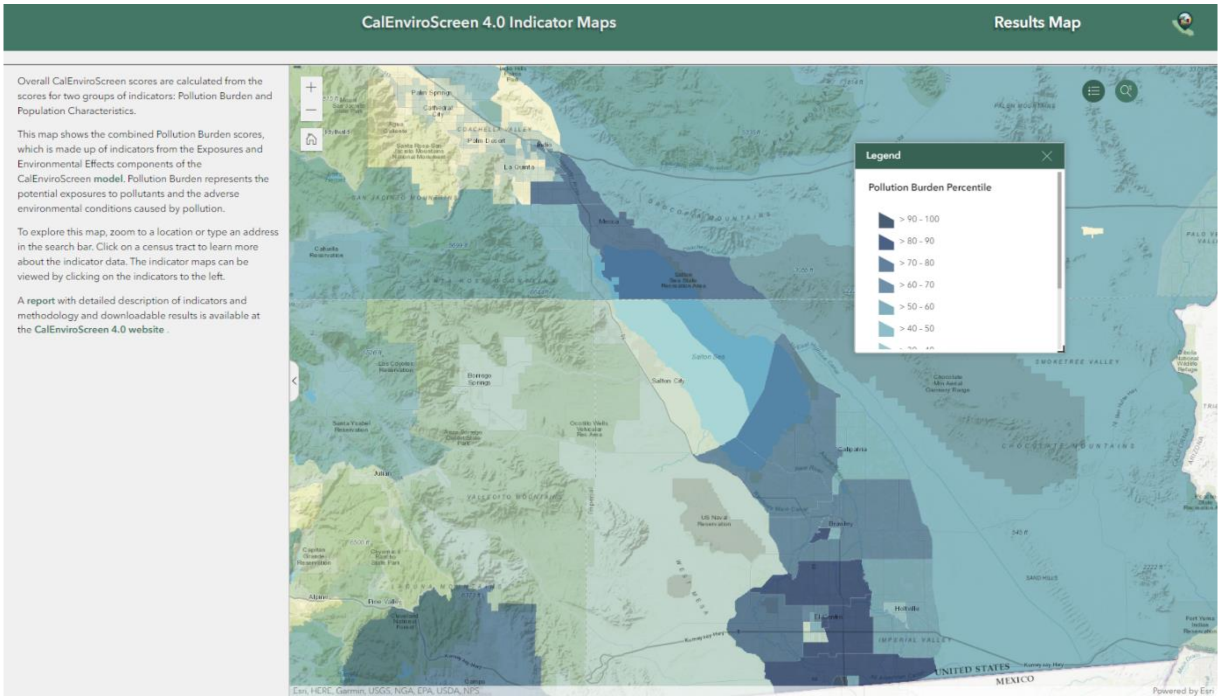


**Figure 64. Pollution Burden Percentiles for IID Service Territory Communities[92].**

**SB 535 BACKGROUND**

After receiving public input at workshops and in written comments, in May 2022, CalEPA released its updated Designation of Disadvantaged Communities[93] for SB 535. In this designation, CalEPA formally designated four categories of geographic areas as disadvantaged:

1. Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts).
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 (19 tracts).
3. Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (305 tracts).
4. Lands under the control of federally recognized Tribes.

The designation considers the latest and best available data as well as factors related to data unavailability. This designation went into effect on July 1, 2022, at which point programs funded through California Climate Investments will use the designation in making funding decisions.

As shown in the disadvantaged communities map in Figure 65, a large portion of the territory served by IID is considered a disadvantaged community. IID is well aware of this situation and its IRP is founded on the principles of compliance with federal, state, and local emissions restrictions, mandates, and operational

[92] CalEnviroScreen 4.0 https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40

[93] Final Designation of Disadvantaged Communities Pursuant to Senate Bill 535. May 2022. https://calepa.ca.gov/wp-content/uploads/sites/6/2022/05/Updated-Disadvantaged-Communities-Designation-DAC-May-2022-Eng.a.hp_-1.pdf

requirements. IID is developing and studying energy and capacity portfolios that not only are affordable and reliable but help it meet the load serving projections including the planning reserve margins.

The dispatchable technologies included in the IRP study are very flexible from an operational standpoint, have less emissions, are geographically dispersed, and will allow IID to incorporate additional levels of renewable energy while lowering overall emissions and reliably serving projected loads. The portion of fossil fuel components in the proposed portfolio will have the capability to run renewable hydrogen blended with natural gas, besides the typical components of Best Available Control Technology (BACT).

Regarding wastewater discharges, El Centro Generating Station (ECGS) is developing project alternatives to address treatment and reuse of wastewater generated as part of electrical power generation operations. ECGS staff have made it clear that, due to possible non-compliance issues along with stricter National Pollution Discharge Elimination System (NPDES) permit requirements, the primary project goal involves eliminating surface water discharge and approaching a zero liquid discharge (ZLD) facility via the construction of evaporation ponds.

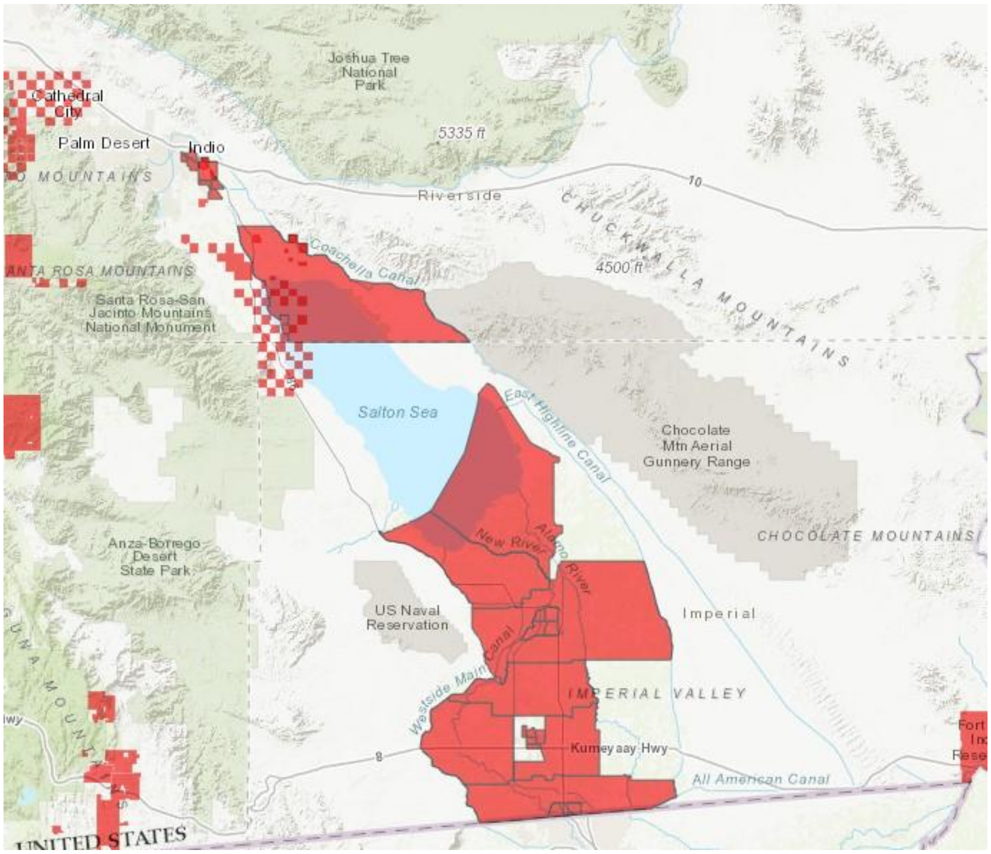


**FIGURE 65. DISADVANTAGED COMMUNITIES IDENTIFIED BY SB535 (2022 UPDATE)**[94]

[94] SB 535 Disadvantaged Communities (2022 Update). https://oehha.ca.gov/calenviroscreen/sb535

# Conclusions and Recommendations

Looking across the scenarios that were modeled for this IRP, several commonalities emerge. These commonalities represent no regrets decisions for IID, decisions that will be the most prudent decision regardless of which scenario from the IRP most accurately represents the future.

The recommendations for the 2024 IRP rely on IID's ability to procure new resources. The steps needed to bring new resources online take three years or more, between running a competitive RFO process, contract negotiation, and construction time. For this reason, IID must quickly begin the process to procure the resources that are expected to come on line in the late 2020s.

## Recommendations

The foremost recommendation is for IID to make significant investment in RPS and zero-carbon resources necessary to meet SB100 and SB1020 requirements. The dominant technology in reaching these goals is solar, given its favorable cost, high quality and availability within the service territory, and alignment with IID's highly seasonal load demands. Across all scenarios considered, solar is responsible for the majority of renewable energy generation to satisfy the RPS and Zero-Carbon goals.

Taking increased solar builds as a likely future outcome, attention then focuses on creating a suitably diverse generation and capacity mix to provide a reliable system. Two capacity resources appear consistently across all scenarios considered—the addition of RICE thermal units for initial capacity near-term, followed by increased energy storage builds in the intermediate and long-term. These resources can contribute the necessary capacity to improve IID's short summer position. They also provide ancillary services for IID to utilize in its role as a Balancing Authority. Storage synergizes well with new solar resources and is recommended for procurement in tandem with new renewable generation. A combination of shorter-duration 4-hour storage procurements initially, combined with longer-duration 8-hr+ storage, or potentially even long duration energy storage, beyond 2030, will ensure that the District continues to operate reliably without having to rely as much on its aging fossil generator fleet.

Beyond solar, the balance of RPS and zero-carbon resources is less well defined. The District's small-scale hydroelectric units on the canal system currently provide modest contributions, although concerns over their age, water availability, and the necessary investment to rehabilitate some of their turbines means these RPS-eligible resources are not a given. The District has contracted several nearby geothermal resources that supply steady RPS-eligible power to the District. To supplement solar generation and the existing geothermal generation, both wind and additional geothermal resources were considered in the scenarios analyzed for this IRP. Given questions regarding the availability of high quality in-state wind resources, it is recommended that the District continue to explore opportunities for procuring local, high quality, reasonably-priced geothermal resources to supplement the increase in solar builds. Whether this is feasible in the near term will depend on availability of projects on the market.

An important takeaway from the capacity expansion modeling undertaken in this report is that the optimization model utilized will always look for the absolute lowest-cost option and will take the price forecast it sees as a given. While it is tempting to assume a technology cost forecast will be perfectly accurate, it is important to remember the uncertainty in forecasting future prices for technologies like solar, geothermal, wind, and storage. A common theme in the results of the capacity expansion analysis was the model's insistence on procuring solar earlier (i.e., early 2030s) when it sees a lower solar price than in later years when more stringent RPS targets come into play. The Delayed Solar Builds scenario attempts to remedy this by restricting the amount of added RPS-eligible capacity to align with the RPS and zero-carbon target dates, and not earlier. This scenario is useful to establish a sort of "lower bound" on new RPS procurements required in each year, irrespective of cost.

## Conclusion

The IRP process is the first phase in fulfilling IID's long term power needs. Through the IRP process, IID identified the need to add capacity resources to maintain resource adequacy as well as clean and zero-carbon generation to meet the California clean energy goals.

IID recommends pursuing the geothermal heavy scenario as the recommended scenario from the 2024 IRP. The geothermal heavy scenario is recommended for two reasons. First and foremost, the geothermal heavy scenario does not rely on procuring California wind. California wind has been difficult for LSEs to procure in recent years. The inclusion of California wind in the recommended scenario would then reduce the feasibility of the recommended scenario. If instate wind becomes available for the District to procure, IID should strongly consider procuring California wind. The second reason is cost. The geothermal heavy scenario does not significantly increase the cost of the plan.

After adoption of the 2024 IRP, IID should work to procure additional solar resources, storage, and the RICE units. The procurement of these resources will position the District to provide reliable power to it's customers while complying with the state clean energy requirements.

# Appendix A: RPS Procurement Plan

An analysis of loads and resources and expected load provides a simple net position of IID. It could be appreciated that IID has a variety of resources and currently meeting its renewable goals as well as its emissions goals, but it is also clear how short it is in capacity and energy for the next few years. Currently IID covers its needs by relying on market purchases. Such purchases present some volatility and price escalations when compared to other internal resource options. IID is currently short in capacity, mostly for June to September, and as we advance to 2035, the capacity shortage expands to include April to October.

In general, the hours of capacity and energy needs remain constant with a few hours added to shortage as time passes. As the time of the peak hour changes through the years, IID also experiences specific needs that will drive the district to explore different technologies and possible solutions. IID is experiencing an increase in capacity needs for the hours HE23 and HE24, and those are estimated to increase 2-4% on a yearly basis.

For the year 2026, before summer, IID needs to cover a position of around 180 MW via a PPA or developing internal generation. Given the proposed rulemaking by CARB regarding carbon offsets and allowances, IID needs to pay close attention to the types of future technology and energy sources in its portfolios to minimize the economic impact exceeding allowed emissions. With the current PPAs in place and their expected CODs, IID needs additional 50 MW of renewable energy around the clock from June to September by 2026. This will allow IID to target the off-peak hours while generating a large number of RECs for our renewable portfolio. Also, given the uncertainty in allowances by proposed rulemaking, this will allow IID to have more base generation online and reduce fossil fuel generation. By the year 2027, IID will need about 160 MW/640MWh of renewable energy storage from April to October. The product with storage would provide the ability to shape the capacity coverage for the hours in need. Most of the hours in need are HE12 - HE22. This type of product would cover the most expensive market hours, reduce market exposure, and increase reliability for IID. Given our existing RPS position, this would allow IID to continue in REC compliance as there will be a large number of RECs transferred. Given the reliability and ancillary service needs imposed by operating a BA, IID is in need of modernization, or repowering/replacing existing fossil fuel generation with generators that would possess operational flexibility, low emissions, competitive heat rate, and enough dispatchability that would allow additional renewables integration.

# Appendix B: PowerSIMM™ Modeling

Ascend's proprietary PowerSIMM software program simulates the performance of an electric power system with high spatial and temporal granularity. This section provides an overview of PowerSIMM's key features and capabilities. In the IRP analysis, PowerSIMM was used for the following applications:

1. **Capacity expansion optimization** – provides a roadmap of future resource procurements to meet policy or reliability needs at the lowest cost.
2. **Production cost modeling** – simulates power system operations, including transmission constraints, on an hourly or sub-hourly timestep for use in decision making for portfolio management or resource planning.
3. **Resource adequacy analysis** – determines how well a portfolio of resources can serve customer load over a defined period of time on an hourly basis.

All applications listed above start with simulations of weather, load, renewables, forced outages, and market prices. The only exception is in resource adequacy models, where prices are not used.

## Simulations in PowerSIMM

PowerSIMM simulations start with weather as the fundamental driver of load, renewable generation, and market prices. Weather simulations rely on daily maximum and minimum temperatures. PowerSIMM uses historical temperatures to construct future simulations of weather with a time-series model that includes seasonal inputs.

Renewable items require hourly historical generation data coupled with weather data from a nearby station to determine the structural relationship between daily minimum and maximum temperatures and renewable generation. PowerSIMM constructs a model for each renewable item using inputs that include daily minimum and maximum temperatures, month, and hour. Future simulations are generated with the model using weather simulations as an input. Generation output is scaled to meet future expectations for monthly energy generation and capacity limits.

For load, PowerSIMM creates a structural model using hourly load data, daily minimum and maximum temperatures, hour, day of the week, and month. Load simulations are based on weather simulations and scaled to match load forecasts for monthly energy and peak demand.

The simulation of market prices follows a similar construct, but there are more structural variables observed in both historic and forecast values. There are also more parameters used as inputs. For market price simulations, PowerSIMM adheres to market expectations (i.e. forward prices and option quotes for volatility in prices) by scaling simulations so that the average price exactly meets the forward curves for monthly average prices for natural gas, on-peak power, off-peak power, and carbon emissions. The stochastic price ranges hold to future expectations of price volatility, correlations across time and commodities, and daily price shapes.

## Dispatch in PowerSIMM

Simulations of weather, load, renewables, and spot prices roll into the dispatch module. PowerSIMM models dispatch by optimizing supply resource options in a 'dispatch to load' or 'dispatch to price' model. In a dispatch to load model, PowerSIMM calculates dispatch decisions to serve load at the least cost, while accounting for transmission system congestion. Market purchases are generally, but not always, included as an option for serving load. The dispatch to price model calculates dispatch decisions to maximize market revenue from generation.

Dispatch calculations rely on inputs to define the physical and economic characteristics of supply resources, including thermal resources, energy storage, hydro resources, or demand-side options. Users can also define transmission lines to represent constraints, such as import or export limits, or line losses. Ancillary services can be included in dispatch models where PowerSIMM will co-optimize supply resources to serve load and fulfill ancillary requirements. PowerSIMM ancillary product dispatch can include regulation up, regulation down, spinning reserves, and non-spinning reserves. PowerSIMM can also perform multiphase dispatch.

PowerSIMM uses a mix-integer linear programming algorithm in the dispatch calculations. The objective function in the algorithm is the minimization of cost to supply energy and ancillary requirements. Included in the total cost are startup costs, variable operations, and maintenance (O&M) costs, fixed O&M costs, fuel costs, fuel delivery costs, electric power purchases, and power sales. Power sales are treated as negative costs.

The decision variables for the dispatch algorithm include the online state of dispatchable generators, the generation setting for all dispatchable generators, the assignment of ancillary services for units capable of providing ancillary services, the charge or discharge state of energy storage resources, and the amount of market purchases. PowerSIMM iterates over a range of possible values to settle on the decision variables that provide the lowest possible cost within the model constraints.

Dispatch constraints are set for all units in the model such as economic maximum generation, economic minimum generation, ramp rates, must-run requirements, minimum generation, etc. There are also constraints attributable to transmission limits and the requirement to meet load.

Variable generation from wind, solar, and geothermal items are not considered dispatchable, but PowerSIMM may elect to curtail variable resources if system conditions require it. For example, wind generation may be curtailed due to transmission limits.

## Resource Planning Modeling

PowerSIMM was used to run a variety of models for this resource plan, including the following:

### PRODUCTION COST MODELING

PowerSIMM's most common resource planning application involves production cost modeling, which shows many detailed aspects of system operations over a future time period. Production cost models can run with dispatch modeled across a range of simulated future conditions.

Outputs from production cost models include generation costs, fuel consumption, renewable generation, carbon emissions, and a long list of additional variables used to make investment and operational decisions. Example uses for PowerSIMM include analyzing options to hedge fuel price risk, evaluating new generation resource options, or conducting a study to determine renewable additions for RPS mandates.

Production cost model outputs allow users to understand how the system will operate with the assumed inputs. **Figure B-1** shows hourly dispatch results of a production cost model. Comparing outputs from two or more production cost models allows a user to understand how changes in resource mix, price forecast, operational constraints, or other aspects of the system will affect future outcomes.

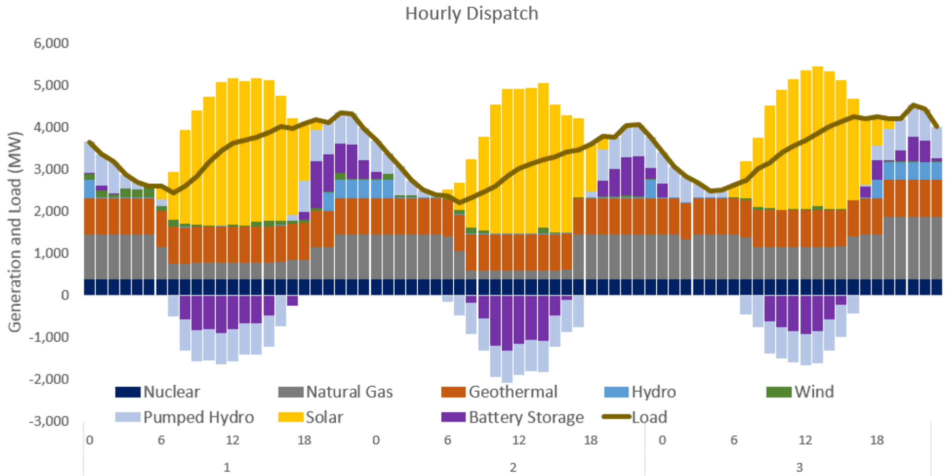


**FIGURE B-1. DISPATCH OUTPUTS OVER A THREE-DAY PERIOD FROM A PRODUCTION COST MODEL PLOTTED AGAINST LOAD**

Key inputs for production cost models include the simulated system conditions[95] and supply resource operating parameters. The operating parameters of dispatchable generation assets in the portfolio – such as ramp rates or start-up times for thermal assets, leakage rates, and round-trip efficiencies for battery storage, or spill requirements for hydro – guide dispatch optimization to ensure the model adheres to the actual physical capabilities and attributes of the resources in the portfolio.

## CAPACITY EXPANSION OPTIMIZATION

A second common resource planning application of PowerSIMM involves capacity expansion optimization, which provides the least-cost selection of future resources over time, subject to user-specified constraints. Such constraints may include resource adequacy requirements, annual energy positions, renewable portfolio standards, or carbon emission limits. The PowerSIMM Automatic Resource Selection (ARS) module contains the capacity expansion model. ARS evaluates the performance of a portfolio of existing resources and candidate resources across a range of future operating conditions to assess their likely revenues, costs, and other characteristics (e.g., carbon emissions). Based on user inputs and constraints, the model determines the optimal resource additions (or retirements) for minimizing total costs while ensuring the generation portfolio can serve load without violating loss-of-load standards or emissions constraints. Figure B-2 illustrates an ARS model that adds candidate resources to a portfolio to serve load at the lowest cost.

[95] Weather, load, renewables, and market prices for fuel and power, when not a dispatch to load without intertie purchases.

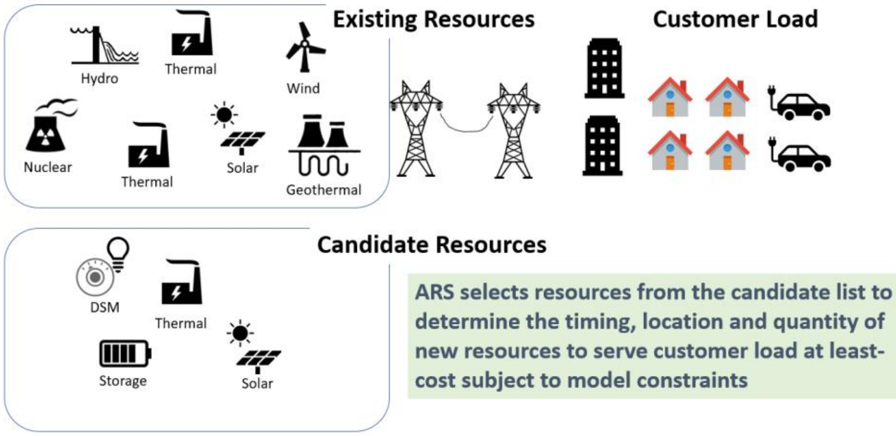


**FIGURE B-2. ARS SCHEMATIC, IN WHICH THE PORTFOLIO OF EXISTING RESOURCES AND CUSTOMER LOAD ARE EVALUATED WITH CANDIDATE RESOURCES ACROSS A RANGE OF FUTURE CONDITIONS TO SELECT THE OPTIMAL PORTFOLIO COMPOSITION UNDER INPUT CONSTRAINTS**

Input data requirements for ARS are generally the same as for production cost modeling except for additional project cost information (e.g. new candidate resources), accredited capacity (e.g. existing and new resources), and project-specific constraints such as annual build limits for new resources. Users must also define model constraints to apply in the resource selection process, such as requirements for capacity, energy, or renewable generation.

## RESOURCE ADEQUACY ANALYSIS

The third main application of PowerSIMM in resource planning involves resource adequacy analysis, which assesses the probability that a system will have adequate generation resources to meet load over a wide range of conditions. Common metrics for this assessment include loss-of-load probabilities (LOLP), expected unserved energy (EUE), and capacity deficit (the amount of additional capacity needed to meet reliability targets), among others. PowerSIMM's resource adequacy module can also be used to assess the capacity contribution from specific resources or technology types, which is typically measured with the effective load-carrying capability (ELCC) metric. As shown in Figure B-3, PowerSIMM's simulation engine provides simulations of load, renewables, and forced outages used to analyze the ability of a portfolio of resources to serve load. Resource adequacy models may also include transmission constraints. These simulations measure common metrics, including loss-of-load probabilities, expectations, or hours (LOLP, LOLE, or LOLH), expected unserved energy (EUE), and capacity deficit (MW Short).

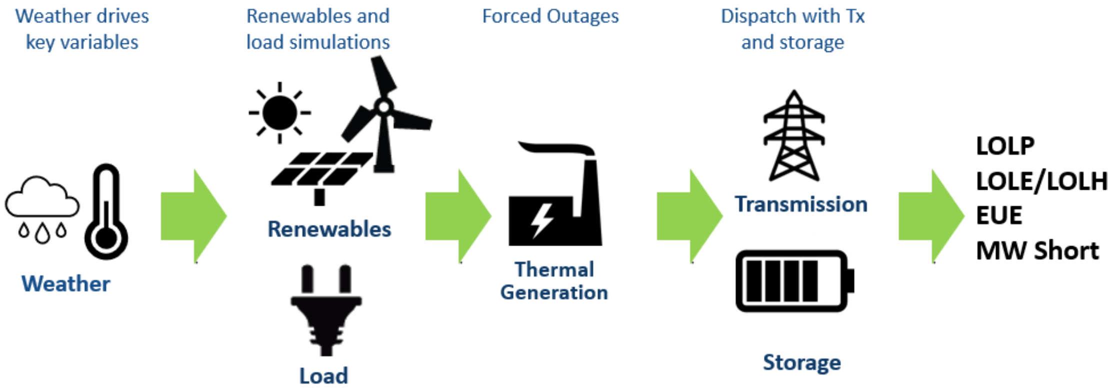


**FIGURE B-3. THE POWERSIMM RESOURCE ADEQUACY MODEL CONSIDERS WEATHER VARIABILITY AS A KEY DRIVER TO RENEWABLE AND LOAD SIMULATION.**

The dispatch algorithm in a resource adequacy model differs from that used in production cost or capacity expansion models. Resource adequacy models evaluate systems based on how well they can meet system needs, so the ability to import power is typically eliminated (or significantly restricted). The model dispatches resources to minimize load shedding without regard to dispatch cost. Market prices also have no bearing on the dispatch decision in a resource adequacy model. Instead, the important inputs driving resource adequacy results include forced outage rates, correlation between load and renewables, and operational constraints. In each simulated hour of a resource adequacy study, the model calculates hourly load requirements and compares this to the sum of total renewable generation, available thermal capacity (i.e., not on forced or scheduled outage), and available energy in storage (which is charged with excess energy when it is available). The model then dispatches thermal and energy storage resources chronologically (hour-by-hour) to determine how much (if any) load cannot be met in each hour.

Resource adequacy models provide metrics to evaluate the reliability of a system. Additionally, resource adequacy models provide a useful means of determining the capacity contribution of a specific resource, known as the effective load carrying capacity (ELCC). The standard approach for an ELCC analysis involves three model runs. The reliability contribution of the ELCC resource is then compared to the reliability contribution from a 'perfect' generator to determine the capacity value of the ELCC resource.

## Simulation Details

### WEATHER SIMULATION

PowerSIMM has the ability to simulate weather across dozens of weather variables. Weather simulations in PowerSIMM typically include daily maximum and minimum dry bulb temperatures. These temperatures are then used as fundamental drivers for the load and alignment with renewable simulations. The weather simulation engine requires historical daily maximum and minimum temperatures from weather stations in proximity to the weather-related resources in the model. PowerSIMM stores historical data for hundreds of weather stations via automated data pulls from the National Climate Data Center. PowerSIMM users can select weather stations to create weather zones for use in specific studies.

PowerSIMM creates weather simulations by decomposing historical daily maximum and minimum temperature data into seasonal and irregular components. The seasonal component represents a smooth function showing how temperature changes over the year. The irregular component captures fluctuations around the seasonal component and represents the day-to-day variability in weather, which is the stochastic part of the weather simulations. The model structure for the irregular component includes 30-day, 60-day, and 90-day moving averages combined in a linear fashion with autoregression and random error terms. Annual patterns drive most of the temperature simulations, but the irregular component of the model allows for deviations from annual and seasonal norms, enabling potential periods of cooler weather in the summer and warmer days in the winter.

PowerSIMM's default method for creating temperature simulations does not use a temperature forecast or include trends in temperature. The result is a set of simulations that resemble historical weather conditions. However, the models can be configured to account for changes in future temperatures that reflect predictions of a changing climate.

The following steps outline the process for creating simulations of daily maximum and minimum temperatures:

1. Pull historical weather data – minimum and maximum daily dry bulb temperatures for all selected weather stations.
2. Use an unobserved components model (UCM) to separate temperatures into a seasonal component that captures annual patterns, and an irregular component that captures the uncertainty in temperature data.
3. Apply a transform to the irregular portion of the temperature data to obtain a normally distributed dataset.
4. Fit a mixed data sampling (MIDAS) regression model to the transformed irregular temperature data.
5. Simulate future timeseries for the irregular component of temperatures using the MIDAS model, maintaining the correlations between error terms for each weather station pair.
6. Apply an inverse transformation to the irregular temperature data to bring it back to the original form.
7. Add the seasonal component back into the simulations. The resulting simulations should reasonably match historical data.

Figure B-4 shows an example of daily maximum temperature simulations. The stochastic framework captures variations in weather conditions and extreme events. PowerSIMM has the capability to modify the statistical parameters of the temperature distribution to capture extreme events. Ascend runs validations to ensure that simulated temperatures align with historical values at the mean level along with the fifth percentile and ninety-fifth percentile.

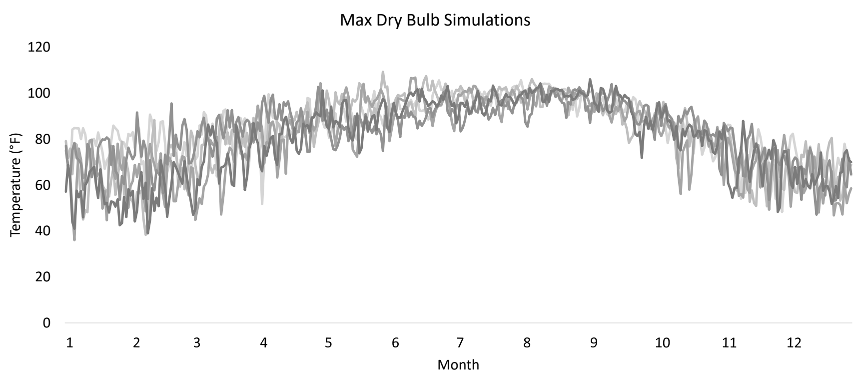


**FIGURE B-4. MULTIPLE SIMULATIONS OF DAILY MAXIMUM DRY BULB TEMPERATURE ACROSS A SINGLE YEAR**

## LOAD SIMULATION

PowerSIMM creates realistic simulations of load that maintain a strong non-linear relationship between load and temperature. The load simulations capture the range of uncertainty exhibited in historical load data. After fitting historical load data to a time series model, PowerSIMM scales the load simulations to match future expectations for energy consumption, peak demand growth, and daily load shapes.

Simulations of load rely on past data to create accurate representations of the utility load that matches historical statistics in the near term while matching the load forecast inputs through the simulation time frame. By scaling load simulations to forecast values, PowerSIMM produces accurate simulations of load that provide a realistic range of future load values around the expected mean. Figure B-5 shows a time series of multiple load simulations while Figure B-6

Figure B-6 shows the load-temperature relationship maintained in the load simulations.

Load simulations are conducted by using the following steps:

1. Gather historical load data, historic temperature data, and temperature simulations.
2. Perform a log transformation on the historical load data to improve the model fit.
3. Decompose the transformed load data with a UCM model into an annual shape, a trend, a cycle, and an irregular component. The decomposed parts will be fit to separate models.
4. Fit a two-component linear regression model to the historical data to determine the break point in the historical load data. The break point is the temperature associated with the lowest load levels where an increase or decrease in temperature results in higher load.
5. The cyclical component of the load data decomposed in the UCM model, found in step 3, is fit to a time series model to determine the effects on load due to the day or week, holidays, temperature (relative to the breakpoint temperature), hour of day, and autoregressive terms. The results provide average hourly load over a variety of conditions.
6. In the load simulations, the output from step 5 provides a method to simulate the cyclical portion of load as a function of the variables estimated in step 5. The cyclical portion is recombined with the annual load trend and shape components determined in step 3 and with a random irregular load component to provide the stochastic nature of the load simulations.
7. An inverse transform applied to the simulations reverses the log transform from step 2.
8. The loads are scaled to match the forecasts input by the user for energy and peak demand.

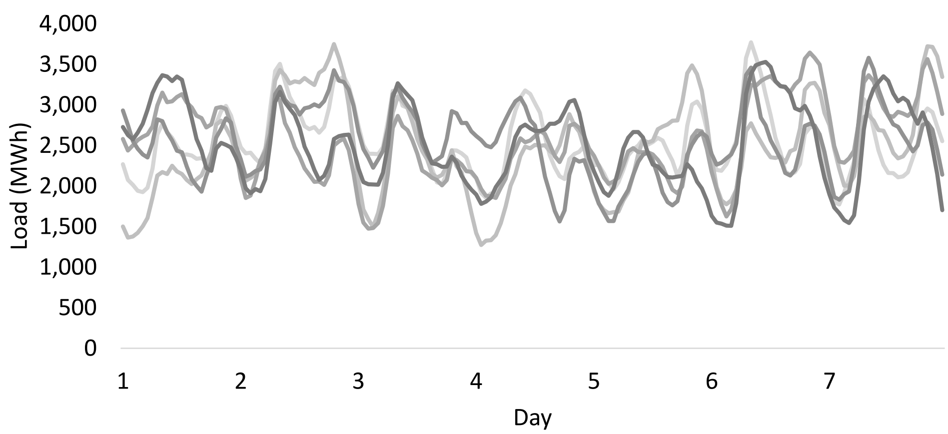


**FIGURE B-5. MULTIPLE SIMULATIONS OF LOAD OVER A SINGLE WEEK**

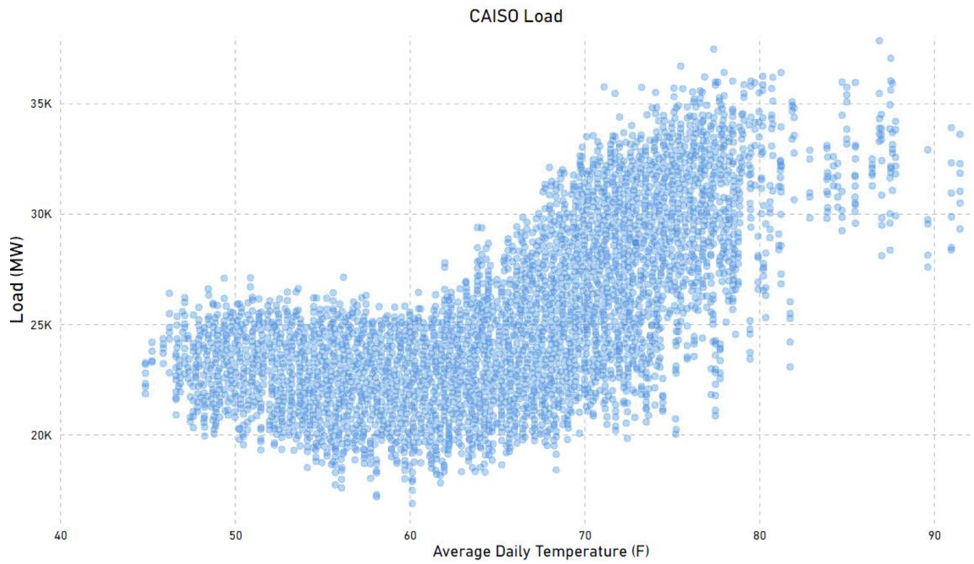


**FIGURE B-6. LOAD VS TEMPERATURE: WHEN TEMPERATURES ARE AT THEIR HIGHEST LOAD IS AT ITS HIGHEST, DRIVEN BY THE NEED TO COOL**

## WIND AND SOLAR SIMULATION

PowerSIMM generates simulations of renewables with time series models fit to hourly historical data. Accurate wind and solar generation simulations are an essential part of power system modeling for determining cost of service, loss of load risks, resource valuation, and many other modeling outputs used in utility decision making.

Wind and solar simulation models use a structure that assumes generation is a function of maximum and minimum temperature inputs from the weather simulations. The model also allows structural variables, like time of day and month of year, to affect generation. For example, if generation is typically highest on afternoons in spring, even apart from the influence of temperature, then the model will be able to capture that. Finally, the model includes autoregressive terms to capture the influence of generation in the previous hour to the current hour's generation. In addition to daily temperatures, hour, and month, solar simulations include the solar irradiance calculated at the location of the solar resource. Solar irradiance is a function of the time of day, day of the year, and the longitude and latitude of a project.

PowerSIMM scales monthly wind and solar simulations to match monthly forecasts.

The general simulation process for wind and solar items uses the following steps:

1. Pull historical hourly wind or solar generation and daily minimum and maximum temperature data.
2. Transform the historical generation data by fitting the data to a Beta distribution and mapping to a Normal distribution, resulting in a well-behaved dataset.
3. Fit the transformed data to the time series model.
4. Simulate future wind or solar generation with the temperature simulations used as inputs to the simulations.
5. Perform an inverse transformation on the simulated data to bring it back to the original form of generation.
6. Scale the simulated generation time series so that it matches forecasts on average. For example, the average of all simulations will match the forecast values for energy and expected peak generation. Simulated values will also be kept at or below the input nameplate capacity.
7. For sub-hourly studies, expand hourly simulations with interpolation and added noise at the sub-hourly level.

Realistic simulations of variable renewable energy generation lead to accurate analysis of the value of renewable assets and the effect of renewables in production cost studies, resource adequacy, or capacity expansion. Figure B-7 and Figure B-8 provide examples of solar and wind simulations over a week.

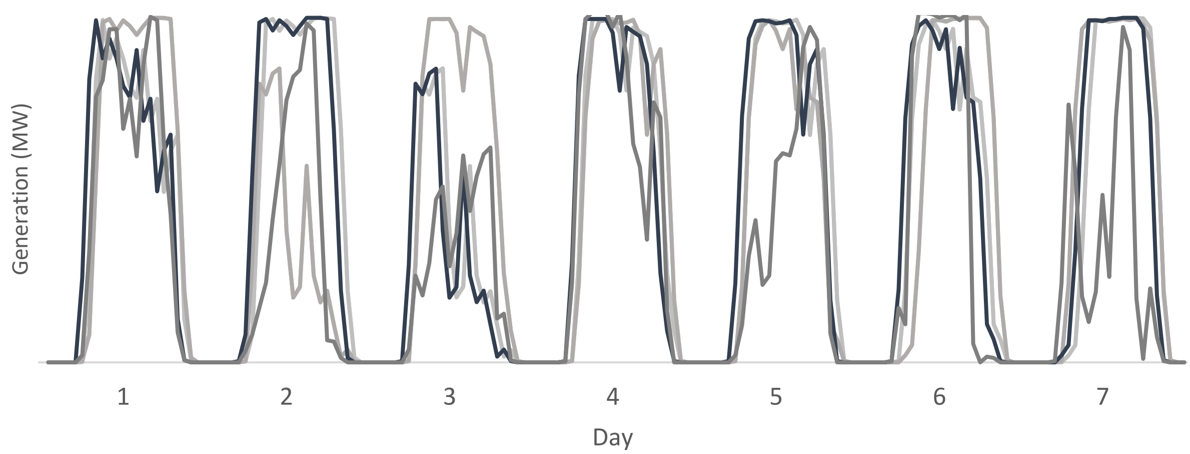


**FIGURE B-7. MULTIPLE SIMULATIONS OF SOLAR GENERATION OVER A SINGLE WEEK**

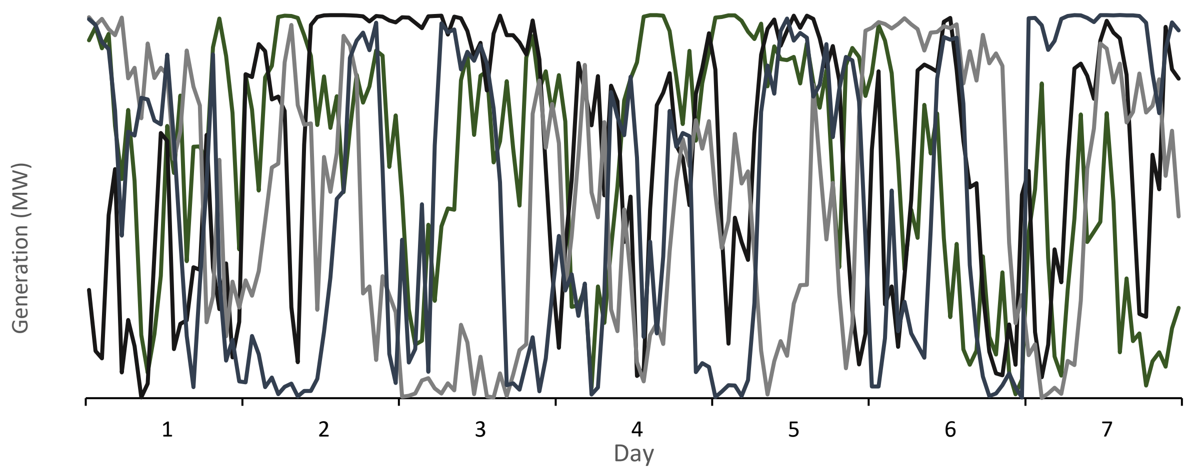


**FIGURE B-8. MULTIPLE SIMULATIONS OF WIND GENERATION OVER A SINGLE WEEK**

## SMALL HYDRO SIMULATION

PowerSIMM models small hydro resources as run-of-the-river hydro. Dispatchable hydro resources are set up as a hydro project in PowerSIMM. As with analysis of other variable renewable resources in PowerSIMM, hydro simulations use a time series model fit to historical hourly generation data. The outcome is a set of simulations that capture the full range of potential hydro generation to provide accurate results for utility decision making.

While the structural details of the hydro simulation model differ from the wind and solar simulation models, the general inputs are similar. Hydro simulation models also assume generation is a function of maximum and minimum temperature inputs from the weather simulations. Like wind and solar simulations, the model used for hydro simulations also allows structural variables, like time of day and month of year, to affect the generation. The hydro model also includes autocorrelation terms.

Hydro simulations are scaled to match future expectations for monthly generation and capacity. PowerSIMM ensures that average monthly hydro simulations match the hydro forecast values. Figure B-9 shows hydro simulations over a one-week period.

The general simulation process for hydro items uses the following steps:

1. Pull historical hourly hydro generation and daily minimum and maximum temperature data.
2. Transform the historical generation data by fitting the data to a Beta distribution and mapping the Beta Cumulative Distribution Function (CDF) to a Normal CDF, resulting in a well-behaved dataset.
3. Fit the transformed data to the time series model.
4. Simulate future hydro generation with the temperature simulations used as inputs for hydro generation.
5. Perform an inverse transformation on the simulated data to bring it back to the original form of generation.
6. Scale the simulated generation time series so that it matches forecasts on average. For example, if the model uses 100 simulations, the average of all simulations will match the forecast values for energy and expected peak generation. Simulated values will also be kept at or below the input nameplate capacity.
7. For sub-hourly studies, expand hourly simulations with interpolation and added noise at the sub-hourly level.

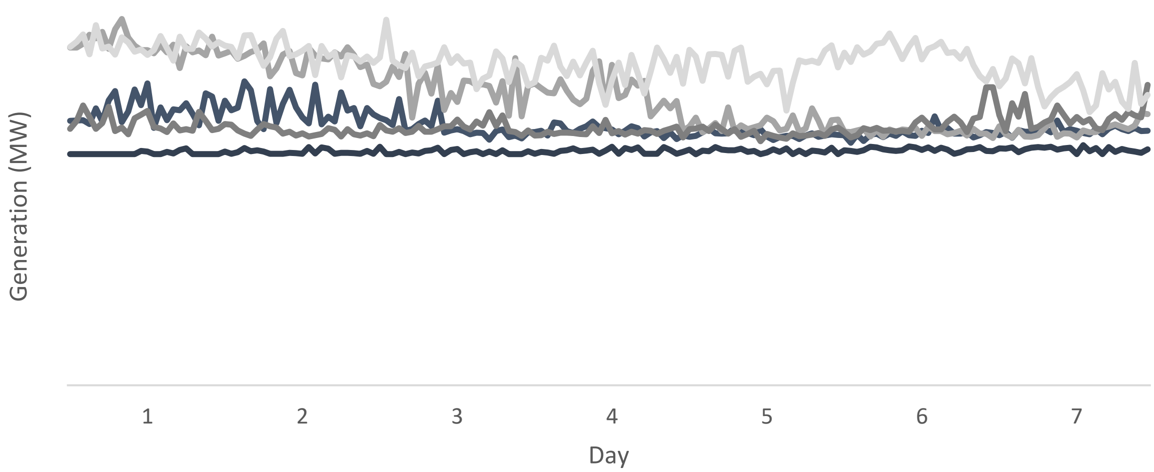


**FIGURE B-9. MULTIPLE SIMULATIONS OF HYDRO GENERATION OVER A SINGLE WEEK**

## FORWARD PRICE SIMULATION

PowerSIMM simulates forward curves using a stochastic model with parameters derived from recent historical transaction dates and defined user inputs (as applicable). PowerSIMM constructs a system of equations for forward contracts that includes the stochastic component of the forward price, as well as the correlation with neighboring contract months, and other commodities. This framework produces price simulations that are realistic, benchmark well to historical data, and produce a payoff of cash flows consistent with market option quotes at multiple strike prices.

Forward contract prices are modeled with an autoregression (AR) model with volatilities and correlations maintained in accordance with historical data or with inputs provided in the forward price constraints. PowerSIMM uses an AR lag of one while limiting the coefficient to a value of less than one. An AR coefficient less than one is equivalent to a Geometric Brownian Motion (GBM) model with mean reversion. Thus, as shown in Figure B-10, the forward prices tend to do a random walk with a constant pull back to the monthly mean values.

Forward simulations are conducted by using the following steps:

1. Calculate the log prices of all historical data.
2. Calculate a target covariance matrix between contracts using historical log price data.
3. Apply any user-input correlation constraints to the calculated target covariance matrix (internally stored as a correlation matrix and vector of variances). Correlation constraints in the model force the forward simulations to maintain expected correlations between forward prices for gas, on/off peak power, coal, carbon, and other commodity prices in the model.
4. Fit a time series model with autoregression and moving average terms to the historical log price data (from step 1) while respecting any autoregression or moving average restrictions input by the user. PowerSIMM uses separate models for each commodity (natural gas, on-peak power, off-peak power, coal, etc.).
5. Set the target covariance matrix as the initial residual covariance matrix.
6. Iterate the following steps to construct the forward price simulations while meeting the correlation inputs:
    a. Simulate future forward contract log prices using the autoregressive terms, moving average, and intercept parameters fit above and the current residual covariance matrix. The error terms in these simulations are drawn from a normal distribution, with correlations and variances specified by the residual covariance matrix.
    b. Calculate correlation and variance of simulated price paths.
    c. Adjust current residual covariance matrix based on the difference between:
        i. Simulated correlation and target correlation
        ii. Simulated variances and target variances
    d. Adjust residual covariance matrix to ensure it is positive semi-definite.
7. Calculate volatility of the simulated price paths.
8. Adjust daily log returns of simulated price paths to enforce any volatility constraints.
9. Scale the average of simulated prices to input forecast if indicated by user (those are usually forecasted based on market fundamentals).

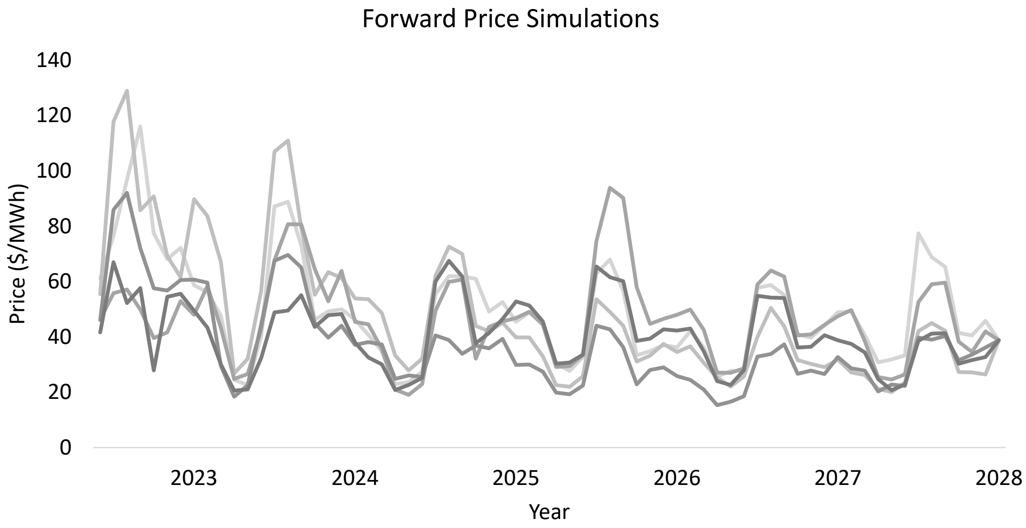


**FIGURE B-10. MULTIPLE SIMULATIONS OF FORWARD PRICES: THE MEAN ACROSS ALL SIMULATIONS EQUALS TO THE INPUT FORECAST**

## SPOT PRICE SIMULATION

PowerSIMM simulates spot prices beginning with the market expectations of monthly blocks of energy represented as the average forward or forecast price over the monthly block. Following the forward price simulations, spot prices are simulated with a hybrid approach that captures the uncertainty in price risk in power markets and trading hubs, including variability in weather, load, renewable output, congestion risk, and Locational Marginal Prices (LMPs), while maintaining consistency with forward price simulations. A sample of hourly spot price simulations is shown in Figure B-11 over the course of a week.

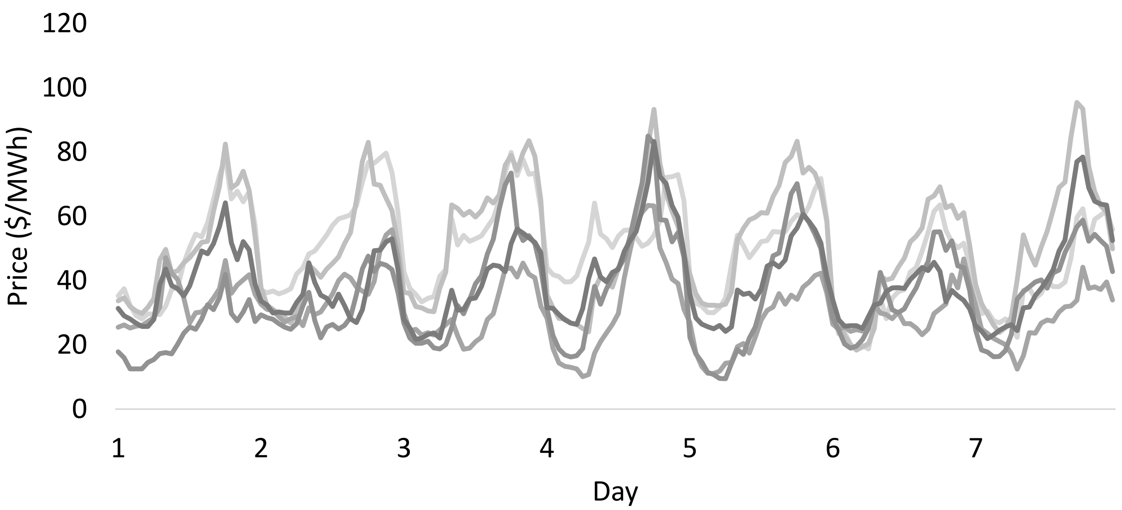


**FIGURE B-11. SIMULATIONS FOR SPOT PRICES OVER A SINGLE WEEK**

## BASIS PRICE SIMULATION

Basis price items in PowerSIMM allow for models to contain multiple pricing nodes. The main market configuration in PowerSIMM must select a primary forward price and spot price for use in the price simulations. PowerSIMM derives basis prices as 'structural' (regression-based model) or 'basic' (random noise) items from the main spot price configured in the model. Basis prices are an important feature of PowerSIMM because they allow for market interactions and simulate locational marginal prices of different nodes.

Scalars applied in the Basis model allow users to set up expected deviations in prices between the basis price (node) and the reference spot price (hub). Users may set up scalars as a constant value across all hours or as random variables where the parameters are a function of time. The Basis module can also be used to produce sub-hourly simulations and ancillary services prices.

Basic model simulations can be broken down into the following steps:

1. Generate a time series of values, drawn from a user-defined distribution (such as normal distribution, lognormal, triangular, etc.) with autoregressive and moving average terms included based on the input configuration for that basis.
2. Scale resulting values using input scalers, most often fundamental basis projections.
3. Add values from step 2 to reference price to produce final basis price.
4. Output simulated prices to the database.

Structural model simulations can be broken down into the following steps:

1. Gather historical basis price data and simulated and historical main market gas and power price.
2. Transform the historical price data (typically using a power transformation, though log, beta and arcsinh transformations are also available).
3. Fit a daily model to the historical basis price data.
4. For hourly electric basis prices, fit an hourly model to the residuals of the daily basis price model.
5. Simulate daily basis prices and hourly price residuals and sum the hourly residuals to the daily prices to obtain simulated hourly basis prices.
6. Scale prices to the forward curve, which represents the price forecast for the basis node. Recall that scaling a price to a forward curve means the average monthly prices will match the forward prices, while some simulations will be higher, and some will be lower.
7. Summarize to monthly peak period values.
8. Output simulated values to the database.

# Appendix C: Standardized Tables

## TABLE C1 - CAPACITY RESOURCE ACCOUNTING TABLE (CRAT)

State of California
California Energy Commission
**Standardized Reporting Tables for Public Owned Utility IRP Filing**
**Capacity Resource Accounting Table**
Form CEC 109 (May 2017)

**Scenario Name: Mid/Expected Load Case**

Yellow fill relates to an application for confidentiality.
Data input by User are in dark green font.

Units = MW

| | PEAK LOAD CALCULATIONS | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Forecast Total Peak-Hour 1-in-2 Demand | 1,074 | 1,067 | 1,067 | 1,123 | 1,135 | 1,090 | 1,091 | 1,103 | 1,115 | 1,129 | 1,142 | 1,155 | 1,165 | 1,175 |
| 2 | [Customer-side solar: nameplate capacity] | 62 | 74 | 87 | 96 | 102 | 105 | 108 | 109 | 110 | 110 | 110 | 110 | 110 | 110 |
| 2a | [Customer-side solar: peak hour output] | 20 | 24 | 27 | 29 | 31 | 32 | 33 | 34 | 34 | 34 | 34 | 33 | 33 | 33 |
| 3 | [Peak load reduction due to thermal energy storage] | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | [Light Duty PEV consumption in peak hour] | | | 2.20 | 2.68 | 3.18 | 3.68 | 4.20 | 4.70 | 5.22 | 5.73 | 6.24 | 6.73 | 7.24 | 7.74 |
| 5 | Additional Achievable Energy Efficiency Savings on Peak | | | | | | | | | | | | | | |
| 6 | Demand Response / Interruptible Programs on Peak | | | | | | | | | | | | | | |
| 7 | **Peak Demand (accounting for demand response and AAEE) (1-5-6)** | **1,074** | **1,067** | **1,067** | **1,123** | **1,135** | **1,090** | **1,091** | **1,103** | **1,115** | **1,129** | **1,142** | **1,155** | **1,165** | **1,175** |
| 8 | Planning Reserve Margin | 161 | 160 | 160 | 168 | 170 | 164 | 164 | 165 | 167 | 169 | 171 | 173 | 175 | 176 |
| 9 | Firm Sales Obligations | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 10 | **Total Peak Procurement Requirement (7+8+9)** | **1,235** | **1,227** | **1,227** | **1,291** | **1,305** | **1,254** | **1,254** | **1,268** | **1,283** | **1,298** | **1,313** | **1,328** | **1,340** | **1,351** |

**EXISTING AND PLANNED CAPACITY SUPPLY RESOURCES**

**Utility-Owned Generation and Storage (not RPS-eligible):**

**For fuel type, choose from list or enter value**

| | [list resource by name] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11a | Coachella 1 | Natural Gas | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 11b | Coachella 2 | Natural Gas | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 11c | Coachella 3 | Natural Gas | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 11d | Coachella 4 | Natural Gas | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| 11e | **EL Centro #2** | Natural Gas | 99 | 99 | 99 | 99 | 99 | 99 | 99 | 105 | 105 | 105 | 105 | 105 | 105 | 105 |
| 11f | EL Centro #3 | Natural Gas | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 | 130 |
| 11g | EL Centro #4 | Natural Gas | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 |
| 11h | Yucca GT 21 | Natural Gas | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 11i | Niliand 1 | Natural Gas | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 43 |
| 11j | Niliand 2 | Natural Gas | 43 | 43 | 43 | 43 | 43 | 43 | 43 | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| 11k | Rockwood 1 | Natural Gas | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| 11l | Yucca Steam | Natural Gas | 75 | 75 | 75 | 75 | 75 | 75 | 75 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11m | Rockwood 2 | Natural Gas | 23 | 23 | 23 | 23 | 23 | 23 | 23 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| 11n | IID Bess (20MW) | Battery Storage | 20 | 20 | 20 | 19 | 19 | 18 | 18 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |

**Long-Term Contracts (not RPS-eligible):**

| | [list contracts by name] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11h | Augustine | Unspecified/System Power | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| 11i | BCP/Hoover+Tribes | Large Hydroelectric | **0** | **6** | **6** | **6** | **6** | **6** | **6** | **6** | **6** | **6** | **6** | **6** | **6** | **6** |
| 11j | Parker_Davis | Large Hydroelectric | 33 | 33 | 33 | 33 | 33 | 33 | 33 | 32 | 32 | 32 | 32 | 32 | 32 | 32 |
| 11k | SCAPPA Nuclear | Nuclear | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| 11l | San Juan Coal | Coal | 102 | | | | | | | | | | | | | |
| 11m | Mobile APR Units | Diesel | | | | | | | 63 | 63 | 63 | 63 | | | | |
| 11n | SunCode BESS | Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| 11 | **Total peak dependable capacity of existing and planned supply resources (not RPS-eligible) (sum of 11a...11n)** | | **763** | **667** | **667** | **666** | **666** | **665** | **728** | **679** | **679** | **679** | **616** | **616** | **615** | **616** |

**Utility-Owned RPS-eligible Resources:**

| | [list resource by plant or unit] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12a | DROPS (planned capacity is 32; actual nameplate capacity is 85) | Small Hydroelectric | 32 | 32 | 32 | 32 | 32 | 32 | 32 | 22 | 22 | 22 | 22 | 22 | 22 | 22 |
| 12b | IVSC1 | Solar PV | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 | 10 | 10 | 10 | 10 | 10 | 8 |
| 12b | IVC Solar | Solar PV | | | | | | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |

***Long-Term Contracts (RPS-eligible):**

| | [list contracts by name] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12c | 8 Min Energy (30MW) | Solar PV | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 20 | 22 | 22 | 22 | 22 | 22 | 21 |
| 12d | Biomass SB859 (2.4MW) | Biofuels | 0 | 1 | 2 | 2 | 2 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12e | Desert View Colmac (45MW) | Biofuels | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 0 | 0 | 0 |
| 12f | ECPV (20MW) | Solar PV | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 12 | 13 | 13 | 13 | 13 | 13 | 13 |
| 12g | Feed-in-tariff Programs (14MW) | Solar PV | 4 | 6 | 11 | 11 | 11 | 11 | 11 | 8 | 10 | 10 | 10 | 10 | 10 | 8 |
| 12h | Heber Solar (10MW) | Solar PV | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 7 | 7 | 7 | 7 | 7 | 7 |
| 12i | Ormat Geo (10-15MW) | Geothermal | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 0 | 0 | 0 | 0 | 0 |
| 12j | Ormat Ormesa Geo (5MW) | Geothermal | 0 | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| 12k | REC YCWUA (6MW) | Small Hydroelectric | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12l | Regenerate (30MW) | Solar PV | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 24 | 26 | 26 | 26 | 26 | 26 | 23 |
| 12m | SDSU PV1 (5MW) | Solar PV | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| 12n | SunPeak 2 (20MW) | Solar PV | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 8 |
| 12o | Cal Energy | Geothermal | 0 | 0 | 30 | 30 | 30 | 30 | 30 | 38 | 38 | 38 | 38 | 38 | 0 | 0 |
| 12p | Citizens (20MW+10MW donated) | Solar PV | 0 | 0 | 15 | 15 | 15 | 15 | 15 | 20 | 20 | 20 | 20 | 20 | 20 | 19 |
| 12q | GeoGenCo | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| 12r | Hell's Kitchen-CTR | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| 12s | IVC Solar | Solar PV | 2 | 2 | 2 | 2 | 2 | 2 | 2 | | | | | | | |
| 12 | **Total peak dependable capacity of existing and planned RPS-eligible resources (sum of 12a...12s)** | | **169** | **177** | **228** | **228** | **228** | **229** | **227** | **291** | **301** | **289** | **288** | **243** | **205** | **195** |
| 13 | **Total peak dependable capacity of existing and planned supply resources (11+12)** | | **932** | **844** | **895** | **894** | **893** | **895** | **955** | **970** | **980** | **967** | **904** | **858** | **820** | **811** |

**GENERIC ADDITIONS**

**NON-RPS ELIGIBLE RESOURCES:**

| | [list resource by name or description] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14a | New 8hr Storage | Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 78 |
| 14b | New 4hr Storage | Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 141 | 174 | 192 | 192 |
| 14c | New RICE Units | Natural Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 108 | 108 | 108 | 108 |
| 14d | | | | | | | | | | | | | | | | |
| 14e | | | | | | | | | | | | | | | | |
| 14f | | | | | | | | | | | | | | | | |
| 14g | | | | | | | | | | | | | | | | |
| 14h | | | | | | | | | | | | | | | | |
| 14i | | | | | | | | | | | | | | | | |
| 14j | | | | | | | | | | | | | | | | |
| 14k | | | | | | | | | | | | | | | | |
| 14l | | | | | | | | | | | | | | | | |
| 14m | | | | | | | | | | | | | | | | |
| 14n | | | | | | | | | | | | | | | | |
| 14 | **Total peak dependable capacity of generic supply resources (not RPS-eligible)** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **249** | **282** | **300** | **378** |

**RPS-ELIGIBLE RESOURCES:**

| | [list resource by name or description] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15a | New Solar | Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 | 15 | 27 | 33 |
| 15b | New Geothermal | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 31 | 31 | 31 | 31 |
| 15c | | | | | | | | | | | | | | | | |
| 15 | **Total peak dependable capacity of generic RPS-eligible resources** | | | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **41** | **46** | **58** | **64** |
| 16 | **Total peak dependable capacity of generic supply resources (14+15)** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **291** | **328** | **358** | **441** |

**CAPACITY BALANCE SUMMARY**

| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17 | **Total peak procurement requirement (from line 10)** | **1,235** | **1,227** | **1,227** | **1,291** | **1,305** | **1,254** | **1,254** | **1,268** | **1,283** | **1,298** | **1,313** | **1,328** | **1,340** | **1,351** |
| 18 | **Total peak dependable capacity of existing and planned supply resources (from line 13)** | **932** | **844** | **895** | **894** | **893** | **895** | **955** | **970** | **980** | **967** | **904** | **858** | **820** | **811** |
| 19 | **Current capacity surplus (shortfall) (18-17)** | **(303)** | **(383)** | **(332)** | **(397)** | **(412)** | **(359)** | **(300)** | **(298)** | **(303)** | **(331)** | **(409)** | **(470)** | **(520)** | **(540)** |
| 20 | **Total peak dependable capacity of generic supply resources (from line 16)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **291** | **328** | **358** | **441** |
| 21 | **Planned capacity surplus/shortfall (shortfalls assumed to be met with short-term capacity purchases) (19+20)** | **(303)** | **(383)** | **(332)** | **(397)** | **(412)** | **(359)** | **(300)** | **(298)** | **(303)** | **(331)** | **(119)** | **(142)** | **(162)** | **(99)** |

# TABLE C2 - ENERGY BALANCE TABLE (EBT)

State of California
California Energy Commission
**Standardized Reporting Tables for Public Owned Utility IRP Filing**
**Energy Balance Table**
Form CEC 110 (May 2017)

**Scenario Name: Mid/Expected Load Case** **Units = MWh**

Yellow fill relates to an application for confidentiality.

Historical Data

| | **NET ENERGY FOR LOAD CALCULATIONS** | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Retail sales to end-use customers | 3,441,632 | 3,472,081 | 3,381,908 | 3,412,319 | 3,448,335 | 3,489,372 | 3,534,379 | 3,731,836 | 3,772,049 | 3,813,137 | 3,856,029 | 3,899,148 | 3,934,380 | 3,966,284 |
| 2 | Other loads | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Net energy for load | 3,738,002 | 3,762,810 | 3,666,911 | 3,824,154 | 3,833,629 | 3,939,229 | 3,755,413 | **4,065,181** | **4,108,986** | **4,153,744** | **4,200,467** | **4,247,437** | **4,285,817** | **4,320,571** |
| 4 | Retail sales to end-use customers (accounting for AAEE impacts) | 3,441,632 | 3,472,081 | 3,381,908 | 3,412,319 | 3,448,335 | 3,489,372 | 3,534,379 | 3,731,836 | 3,772,049 | 3,813,137 | 3,856,029 | 3,899,148 | 3,934,380 | 3,966,284 |
| 5 | Net energy for load (accounting for AAEE impacts) | 3,738,002 | 3,762,810 | 3,666,911 | 3,824,154 | 3,833,629 | 3,939,229 | 3,755,413 | 4,065,181 | 4,108,986 | 4,153,744 | 4,200,467 | 4,247,437 | 4,285,817 | 4,320,571 |
| 6 | Firm Sales Obligations | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | **Total net energy for load (accounting for AAEE impacts) (5+6)** | **3,738,002** | **3,762,810** | **3,666,911** | **3,824,154** | **3,833,629** | **3,939,229** | **3,755,413** | **4,065,181** | **4,108,986** | **4,153,744** | **4,200,467** | **4,247,437** | **4,285,817** | **4,320,571** |
| 8 | [Customer-side solar generation] | | | | | | | | 182,978 | 182,640 | 180,984 | 179,762 | 176,458 | 174,246 | 172,127 |
| 9 | [Light Duty PEV electricity consumption/procurement requirement] | | | | | | | | 14,958 | 16,589 | 18,210 | 19,823 | 21,423 | 23,015 | 24,598 |
| 10 | [Other transportation electricity consumption/procurement requirement] | | | | | | | | | | | | | | |
| 11 | [Other electrification/fuel substitution; consumption/procurement requirement] | | | | | | | | | | | | | | |

**EXISTING AND PLANNED GENERATION RESOURCES**

**Utility-Owned Generation Resources (not RPS-eligible):**

| | [list resource by name] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12a | Coachella 1 | Natural Gas | 264 | 303 | 390 | 2,681 | 524 | 511 | 1,069 | 1,005 | 975 | 891 | 538 | 462 | 330 | 230 |
| 12b | Coachella 2 | Natural Gas | **602** | **1,863** | **2,191** | **1,210** | **1,679** | **551** | **76** | 1,052 | 1,015 | 924 | 567 | 487 | 351 | 244 |
| 12c | Coachella 3 | Natural Gas | 309 | 368 | 1,474 | 859 | 1,216 | 1,074 | 703 | 987 | 952 | 870 | 531 | 456 | 327 | 230 |
| 12d | Coachella 4 | Natural Gas | 904 | 273 | 904 | 1,320 | 533 | 416 | 529 | 954 | 920 | 849 | 512 | 445 | 314 | 221 |
| 12e | EL Centro #2 | Natural Gas | 406,974 | 149,008 | 161,567 | 138,862 | 275,125 | 288,582 | 242,297 | 303,586 | 230,812 | 219,280 | 194,837 | 167,858 | 159,756 | 156,502 |
| 12f | EL Centro #3 | Natural Gas | 626,677 | 568,012 | 472,610 | 458,547 | 586,179 | 670,790 | 715,721 | 756,374 | 594,927 | 610,371 | 501,077 | 467,757 | 441,401 | 338,758 |
| 12g | EL Centro #4 | Natural Gas | 16,986 | 12,527 | 11,676 | 43,842 | 112,750 | 103,458 | 152,380 | 121,560 | 85,912 | 72,564 | 55,090 | 48,108 | 47,614 | 0 |
| 12h | Yucca GT 21 | Oil | 113 | 43 | 130 | 121 | 110 | 425 | 131 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12i | Niliand 1 | Natural Gas | 40,070 | 45,983 | 43,348 | 40,601 | 45,383 | 43,973 | 39,497 | 41,833 | 41,721 | 38,392 | 25,274 | 19,453 | 15,551 | 12,301 |
| 12j | Niliand 2 | Natural Gas | 29,654 | 20,319 | 37,928 | 67,392 | 43,787 | 56,782 | 47,612 | 46,797 | 43,386 | 38,849 | 28,927 | 26,450 | 25,205 | 24,269 |
| 12k | Rockwood 1 | Natural Gas | 1,937 | 815 | 630 | 715 | 2,132 | 1,793 | 3,569 | 2,382 | 2,411 | 2,090 | 705 | 613 | 354 | 184 |
| 12l | Yucca Steam | Natural Gas | 163,247 | 287,816 | 265,754 | 243,069 | 182,680 | 104,088 | 1,306 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12m | Rockwood 2 | Oil | 137 | 217 | 287 | 245 | 787 | 1,101 | 334 | 356 | 463 | 213 | 47 | 62 | 35 | 29 |
| 12n | IID Bess (20MW) | Battery Storage | | | (3,496) | (3,646) | (2,848) | (3,193) | (2,938) | (496) | (500) | (492) | (498) | (498) | (497) | (499) |

**Long-Term Contracts (not RPS-eligible):**

| | [list contracts by name] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12h | Augustine | Solar | 1,918 | 1,805 | 1,604 | 3,060 | 3,124 | 3,158 | 2,325 | 4,393 | 4,393 | 4,393 | 4,393 | 4,393 | 4,393 | 4,393 |
| 12i | BCP/Hoover+Tribes | Large Hydro | **2,129** | **10,732** | **10,465** | **11,047** | **10,859** | **9,973** | **8,165** | 26,352 | 26,280 | 26,280 | 26,280 | 26,352 | 26,280 | 26,280 |
| 12j | Parker_Davis | Large Hydro | 155,746 | 155,749 | 155,741 | 155,745 | 155,745 | 155,737 | 155,750 | 155,585 | 155,639 | 155,748 | 155,575 | 155,750 | 155,745 | 155,690 |
| 12k | SCAPPA Nuclear | Nuclear | 124,874 | 119,440 | 122,836 | 121,098 | 121,546 | 122,601 | 121,363 | 122,976 | 122,640 | 122,640 | 122,640 | 122,976 | 122,640 | 122,640 |
| 12l | San Juan Coal | Coal | 614,028 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12m | Mobile APR Units | Diesel | 0 | 0 | 0 | 0 | 1,149 | 1,372 | 964 | 2,491 | 2,983 | 1,385 | 0 | 0 | 0 | 0 |
| 12n | SunCode BESS | Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | (5,002) | (5,039) | (4,896) | (4,242) | (4,192) | (4,545) | (4,553) |
| 12 | **Total energy from existing and planned supply resources (not RPS-eligible) (sum of 12a…12n)** | | **2,186,569** | **1,375,273** | **1,286,039** | **1,286,768** | **1,542,460** | **1,563,192** | **1,490,853** | **1,583,185** | **1,309,891** | **1,290,351** | **1,112,252** | **1,036,933** | **995,253** | **836,921** |

**Utility-Owned RPS-eligible Generation Resources:**

| | [list resource by plant or unit] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13a | DROPS | Small Hydro | 151,690 | 139,898 | 214,160 | 208,737 | 230,777 | 224,740 | 176,646 | 235,037 | 235,027 | 235,025 | 235,014 | 235,098 | 235,068 | 235,016 |
| 13b | IVSC1 | Solar | 51,706 | 51,970 | 47,398 | 43,493 | 33,218 | 28,556 | 33,641 | 43,334 | 43,334 | 43,334 | 43,334 | 43,334 | 43,334 | 43,334 |
| 13c | IVC Solar | Solar | | | | | | | 3,708 | 5,899 | 5,899 | 5,899 | 5,899 | 5,899 | 5,899 | 5,899 |

**Long-Term Contracts (RPS-eligible):**

| | [list contracts by name] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13d | 8 Min Energy | Solar | 71,792 | 86,543 | 80,274 | 73,903 | 73,320 | 71,796 | 67,753 | 73,151 | 73,151 | 73,151 | 73,151 | 73,151 | 73,151 | 73,151 |
| 13e | Biomass SB859 (Sunk to CASO) | Biomass | 12,623 | 0 | 0 | 0 | 0 | 0 | 0 | - | - | - | - | - | - | - |
| 13f | Desert View Colmac | Biomass | 345,748 | 329,671 | 342,279 | 320,278 | 308,328 | 281,569 | 211,401 | 336,434 | 338,237 | 335,179 | 82,152 | - | - | - |
| 13g | ECPV | Solar | 49,024 | 48,258 | 46,676 | 41,332 | 40,108 | 43,694 | 45,981 | 40,414 | 40,414 | 40,414 | 40,414 | 40,414 | 40,414 | 40,414 |
| 13h | Feed-in-tariff Programs | Solar | 15,136 | 21,492 | 21,220 | 22,536 | 34,745 | 36,807 | 32,165 | 38,017 | 38,017 | 38,017 | 38,017 | 38,017 | 38,017 | 38,017 |
| 13i | Heber Solar | Solar | 26,129 | 25,648 | 26,014 | 24,539 | 25,610 | 25,766 | 25,521 | 25,596 | 25,596 | 25,596 | 25,596 | 25,596 | 25,596 | 25,596 |
| 13j | Ormat Geo | Geothermal | 102,650 | 102,980 | 78,087 | 73,223 | 72,202 | 32,000 | 55,063 | 72,059 | 72,058 | 6,551 | - | - | - | - |
| 13k | Ormat Ormesa Geo | Geothermal | 4,206 | 38,284 | 29,870 | 36,823 | 41,004 | 39,447 | 37,998 | 40,891 | 40,891 | 40,891 | 40,891 | 40,891 | 40,891 | 40,891 |
| 13l | REC YCWUA | Small Hydro | 13,965 | 12,977 | 13,551 | 14,690 | 10,548 | 13,318 | 10,948 | 15,295 | 15,252 | 15,252 | 15,252 | 15,295 | 15,252 | 15,252 |
| 13m | Regenerate | Solar | 91,655 | 89,745 | 84,761 | 85,112 | 82,993 | 87,150 | 83,039 | 83,178 | 83,178 | 83,178 | 83,178 | 83,178 | 83,178 | 83,178 |
| 13n | SDSU PV1 | Solar | 13,644 | 13,243 | 13,876 | 14,288 | 13,665 | 14,092 | 14,016 | 13,739 | 13,739 | 13,739 | 13,739 | 13,739 | 13,739 | 13,739 |
| 13o | SunPeak 2 | Solar | 48,291 | 48,557 | 47,351 | 43,989 | 45,908 | 45,178 | 38,371 | 45,660 | 45,660 | 45,660 | 45,660 | 45,660 | 45,660 | 45,660 |
| 13p | Cal Energy | Geothermal | 0 | 0 | 339,813 | 355,609 | 311,729 | 337,156 | 372,950 | 310,942 | 310,941 | 310,941 | 310,941 | 310,942 | - | - |
| 13q | Citizens | Solar | 0 | 0 | 27,433 | 79,727 | 76,787 | 71,943 | 64,581 | 76,941 | 76,941 | 76,941 | 76,941 | 76,941 | 76,941 | 76,941 |
| 13r | GeoGenCo | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 121,293 | 160,964 | 160,964 | 160,964 | 161,405 | 160,964 | 160,964 |
| 13s | Hells Kitchen Geo | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 203,343 | 436,526 | 436,526 | 436,526 | 437,724 | 436,526 | 436,526 |
| | IVC Solar | Solar | | | | 2,531 | 5,916 | 6,296 | 0 | - | - | - | - | - | - | - |
| 13 | **Total energy from RPS-eligible resources (sum of 13a…13t, and 13z)** | | **998,259** | **1,009,266** | **1,412,763** | **1,440,810** | **1,406,858** | **1,359,508** | **1,273,782** | **1,781,223** | **2,055,825** | **1,987,258** | **1,727,669** | **1,647,284** | **1,334,630** | **1,334,578** |
| 13z | **Undelivered RPS energy** | | | | | | | | | | | | | | | |
| 14 | **Total energy from existing and planned supply resources (12+13)** | | **3,184,828** | **2,384,539** | **2,698,802** | **2,727,578** | **2,949,318** | **2,922,700** | **2,764,635** | **3,364,408** | **3,365,716** | **3,277,610** | **2,839,921** | **2,684,217** | **2,329,883** | **2,171,499** |

**GENERIC ADDITIONS**

**NON-RPS ELIGIBLE RESOURCES:**

| | [list resource by name or description] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15a | New 8hr Storage | Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - | - | - | - | - | - | -26,773 |
| 15b | New 4hr Storage | Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - | - | - | -38,611 | -49,891 | -63,941 | -63,338 |
| 15c | New RICE Units | Natural Gas | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - | - | - | 64,869 | 51,808 | 46,079 | 43,425 |
| 15 | **Total energy from generic supply resources (not RPS-eligible)** | | | | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **0** | **26,258** | **1,917** | **(17,862)** | **(46,686)** |

**RPS-ELIGIBLE RESOURCES:**

| | [list resource by name or description] | Fuel type | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16a | New Solar | Solar PV | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **0** | 183,960 | 262,800 | 604,440 | 972,360 |
| 16b | New Geothermal | Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **0** | 262,800 | 263,520 | 262,800 | 262,800 |
| 16c | | | | | | | | | | | | | | | | |
| 16 | **Total energy from generic RPS-eligible resources** | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **0** | **446,760** | **526,320** | **867,240** | **1,235,160** |
| 17 | **Total energy from generic supply resources (15+16)** | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **0** | **0** | **0** | **473,018** | **528,237** | **849,378** | **1,188,474** |
| 17z | **Total energy from RPS-eligible short-term contracts** | | | | | | | | | | | | | | | |

**ENERGY FROM SHORT-TERM PURCHASES**

| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | **Short term and spot market purchases:** | 686,388 | 1,472,900 | 1,032,563 | 1,215,567 | 997,888 | 1,107,606 | 1,116,175 | 735,502 | 787,920 | 906,255 | 956,799 | 1,107,240 | 1,162,783 | 1,022,551 |
| 18a | **Short term and spot market sales (only report sales of energy from resources already included in the EBT):** | **99,275** | **91,404** | **45,562** | **108,722** | **117,076** | **89,926** | **125,744** | 34,729 | 44,650 | 30,121 | 69,271 | 72,257 | 56,227 | 61,953 |

**ENERGY BALANCE SUMMARY**

| | | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | **Total energy from supply resources (14+17+17z)** | **3,184,828** | **2,384,539** | **2,698,802** | **2,727,578** | **2,949,318** | **2,922,700** | **2,764,635** | **3,364,408** | **3,365,716** | **3,277,610** | **3,312,939** | **3,212,454** | **3,179,261** | **3,359,973** |
| 19a | **Undelivered RPS energy (from 13z)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| 20 | **Net Short term and spot market purchases (18 - 18a)** | **587,113** | **1,381,496** | **987,001** | **1,106,845** | **880,812** | **1,017,680** | **990,431** | **700,773** | **743,270** | **876,134** | **887,528** | **1,034,983** | **1,106,556** | **960,598** |
| 21 | **Total delivered energy (19-19a+20)** | **3,771,941** | **3,766,035** | **3,685,803** | **3,834,423** | **3,830,130** | **3,940,380** | **3,755,066** | **4,065,181** | **4,108,986** | **4,153,744** | **4,200,467** | **4,247,437** | **4,285,817** | **4,320,571** |
| 22 | **Total net energy for load (from 7)** | **3,738,002** | **3,762,810** | **3,666,911** | **3,824,154** | **3,833,629** | **3,939,229** | **3,755,413** | **4,065,181** | **4,108,986** | **4,153,744** | **4,200,467** | **4,247,437** | **4,285,817** | **4,320,571** |
| 23 | **Surplus/Shortfall (21-22)** | **33,939** | **3,225** | **18,892** | **10,269** | **(3,499)** | **1,151** | **(347)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |

## TABLE C3 - GHG EMISSIONS ACCOUNTING TABLE (GEAT)

State of California
California Energy Commission
**Standardized Reporting Tables for Public Owned Utility IRP Filing**
**GHG Emissions Accounting Table**
Form CEC 111 (May 2017)

**Scenario Name: Mid/Expected Load Case**

Yellow fill relates to an application for confidentiality.

**Emissions Intensity Units = mt CO2e/MWh**
**Yearly Emissions Total Units = Mmt CO2e**

**GHG EMISSIONS FROM EXISTING AND PLANNED SUPPLY RESOURCES**

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Utility-Owned Generation (not RPS-eligible):** | | | | | | | | | | | | | | | |
| | [list resource by name] | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 1a | Coachella 1 | 0.5996 | 0.0002 | 0.0003 | 0.0003 | 0.0024 | 0.0005 | 0.0005 | 0.0012 | 0.0006 | 0.0006 | 0.0005 | 0.0003 | 0.0003 | 0.0002 | 0.0001 |
| | Coachella 2 | 0.5994 | 0.0005 | 0.0016 | 0.0020 | 0.0011 | 0.0015 | 0.0006 | 0.0001 | 0.0006 | 0.0006 | 0.0006 | 0.0003 | 0.0003 | 0.0002 | 0.0001 |
| | Coachella 3 | 0.5994 | 0.0003 | 0.0003 | 0.0013 | 0.0006 | 0.0010 | 0.0009 | 0.0008 | 0.0006 | 0.0006 | 0.0005 | 0.0003 | 0.0003 | 0.0002 | 0.0001 |
| | Coachella 4 | 0.5994 | 0.0008 | 0.0002 | 0.0008 | 0.0011 | 0.0004 | 0.0004 | 0.0026 | 0.0006 | 0.0006 | 0.0005 | 0.0003 | 0.0003 | 0.0002 | 0.0001 |
| | EL Centro #2 | 0.5018 | 0.2017 | 0.0752 | 0.0820 | 0.0692 | 0.1354 | 0.1413 | 0.1171 | 0.1525 | 0.1158 | 0.1100 | 0.0978 | 0.0842 | 0.0801 | 0.0785 |
| | EL Centro #3 | 0.4088 | 0.2619 | 0.2424 | 0.2008 | 0.1918 | 0.2459 | 0.2804 | 0.2971 | 0.3095 | 0.2442 | 0.2501 | 0.2050 | 0.1910 | 0.1795 | 0.1377 |
| | EL Centro #4 | 0.6351 | 0.0121 | 0.0080 | 0.0076 | 0.0282 | 0.0719 | 0.0657 | 0.0959 | 0.0777 | 0.0548 | 0.0461 | 0.0348 | 0.0303 | 0.0300 | 0.0000 |
| 1b | Yucca GT 21 | N/A | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1c | Niliand 1 | 0.5283 | 0.0222 | 0.0247 | 0.0232 | 0.0218 | 0.0243 | 0.0236 | 0.0272 | 0.0221 | 0.0221 | 0.0203 | 0.0133 | 0.0103 | 0.0082 | 0.0065 |
| 1d | Niliand 2 | 0.7185 | 0.0153 | 0.0110 | 0.0202 | 0.0357 | 0.0232 | 0.0300 | 0.0277 | 0.0310 | 0.0293 | 0.0269 | 0.0216 | 0.0203 | 0.0197 | 0.0192 |
| 1e | Rockwood 1 | 0.8843 | 0.0015 | 0.0007 | 0.0005 | 0.0006 | 0.0018 | 0.0001 | 0.0005 | 0.0021 | 0.0021 | 0.0018 | 0.0006 | 0.0005 | 0.0003 | 0.0002 |
| 1f | Yucca Steam | N/A | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1g | Rockwood 2 | 0.8843 | 0.0002 | 0.0003 | 0.0003 | 0.0003 | 0.0009 | 0.0011 | 0.0004 | 0.0003 | 0.0004 | 0.0002 | 0.0000 | 0.0001 | 0.0000 | 0.0000 |
| | **Long-Term Contracts (not RPS-eligible):** | | | | | | | | | | | | | | | |
| | [list contracts by name] | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 1h | Augustine | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1i | BCP/Hoover+Tribes | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1j | **Parker_Davis** | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1k | SCAPPA Nuclear | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1l | San Juan Coal | 1.1050 | | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1m | Mobile APR Units | 0.0064 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | | | 0.0020 | 0.0024 | 0.0011 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1n | SunCode BESS | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 1 | **Total GHG emissions of existing and planned supply resources (not RPS-eligible) (sum of 1a…1n)** | | **0.5167** | **0.3647** | **0.3390** | **0.3528** | **0.5069** | **0.5447** | **0.5706** | **0.5996** | **0.4734** | **0.4588** | **0.3746** | **0.3379** | **0.3185** | **0.2426** |
| | **Utility-Owned RPS-eligible Generation Resources:** | | | | | | | | | | | | | | | |
| | [list resource by plant or unit] | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 2a | DROPS | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2b | IVSC1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2c | IVC Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2d | | | | | | | | | | | | | | | | |
| 2e | | | | | | | | | | | | | | | | |
| 2f | | | | | | | | | | | | | | | | |
| 2g | | | | | | | | | | | | | | | | |
| 2h | | | | | | | | | | | | | | | | |
| 2i | | | | | | | | | | | | | | | | |
| 2j | | | | | | | | | | | | | | | | |
| 2k | | | | | | | | | | | | | | | | |
| 2l | | | | | | | | | | | | | | | | |
| 2m | | | | | | | | | | | | | | | | |
| 2n | | | | | | | | | | | | | | | | |
| | **Long-Term Contracts (RPS-eligible):** | | | | | | | | | | | | | | | |
| | [list contracts by name] | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 2o | 8 Min Energy | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Biomass SB859 (Sunk to CASO) | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Desert View Colmac | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | ECPV | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Feed-in-tariff Programs | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Heber Solar | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Ormat Geo | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Ormat Ormesa Geo | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | REC YCWUA | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Regenerate | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2p | SDSU PV1 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| sq | SunPeak 2 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2r | Cal Energy | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2s | Citizens 20MW | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2t | GeoGenCo | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| | Hell's Kitchen | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 2 | **Total GHG emissions from RPS-eligible resources (sum of 2a…2t)** | | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** |
| 3 | **Total GHG emissions from existing and planned supply resources (1+2)** | | **0.5167** | **0.3647** | **0.3390** | **0.3528** | **0.5069** | **0.5447** | **0.5706** | **0.5996** | **0.4734** | **0.4588** | **0.3746** | **0.3379** | **0.3185** | **0.2426** |

**EMISSIONS FROM GENERIC ADDITIONS**

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **NON-RPS ELIGIBLE RESOURCES:** | | | | | | | | | | | | | | | |
| | [list resource by name or description] | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 4a | New 8hr Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4b | New 4hr Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 4c | New RICE Units | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0290 | 0.0232 | 0.0206 | 0.0194 |
| 4d | | | | | | | | | | | | | | | | |
| 4e | | | | | | | | | | | | | | | | |
| 4f | | | | | | | | | | | | | | | | |
| 4g | | | | | | | | | | | | | | | | |
| 4h | | | | | | | | | | | | | | | | |
| 4i | | | | | | | | | | | | | | | | |
| 4j | | | | | | | | | | | | | | | | |
| 4k | | | | | | | | | | | | | | | | |
| 4l | | | | | | | | | | | | | | | | |
| 4m | | | | | | | | | | | | | | | | |
| 4n | | | | | | | | | | | | | | | | |
| 4 | **Total GHG emissions from generic supply resources (not RPS-eligible)** | | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0290** | **0.0232** | **0.0206** | **0.0194** |
| | **RPS-ELIGIBLE RESOURCES:** | | | | | | | | | | | | | | | |
| | [list resource by name or description] | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| 5a | New Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 5b | New Geothermal | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 5 | **Total GHG emissions from generic RPS-eligible resources** | | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** |
| 6 | **Total GHG emissions from generic supply resources (4+5)** | | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0290** | **0.0232** | **0.0206** | **0.0194** |

**GHG EMISSIONS OF SHORT TERM PURCHASES**

| | | Emissions Intensity | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | **Net spot market/short-term purchases:** | 0.428 | **0.2513** | **0.5913** | **0.4224** | **0.4737** | **0.3770** | **0.4356** | **0.4239** | **0.2999** | **0.3181** | **0.3750** | **0.3799** | **0.4430** | **0.4736** | **0.4111** |

**TOTAL GHG EMISSIONS**

| | | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | **Total GHG emissions to meet net energy for load (3+6+7)** | **0.7680** | **0.9560** | **0.7615** | **0.8266** | **0.8839** | **0.9802** | **0.9945** | **0.8995** | **0.7915** | **0.8338** | **0.7835** | **0.8040** | **0.8127** | **0.6731** |

**EMISSIONS ADJUSTMENTS**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8a | **Undelivered RPS energy (MWh from EBT)** | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 8b | **Firm Sales Obligations (MWh from EBT)** | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 8c | **Total energy for emissions adjustment (8a+8b)** | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 8d | **Emissions intensity (portfolio gas/short-term and spot market purchases)** | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 | 0.428 |
| 8e | **Emissions adjustment (8Cx8D)** | 0.0000 | 0 | 0.0000 | 0 | 0.0000 | 0 | 0.0000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

**PORTFOLIO GHG EMISSIONS**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8f | **Adjusted Portfolio emissions (8-8e)** | 0.7680 | 0.9560 | 0.7615 | 0.8266 | 0.8839 | 0.9802 | 0.9945 | 0.8995 | 0.7915 | 0.8338 | 0.7835 | 0.8040 | 0.8127 | 0.6731 |

**GHG EMISSIONS IMPACT OF TRANSPORTATION ELECTRIFICATION**

| | | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | **GHG emissions reduction due to gasoline vehicle displacement by LD PEVs** | **0.0035** | **0.0048** | **0.0066** | **0.0087** | **0.0110** | **0.0137** | **0.0165** | **0.0195** | **0.0226** | **0.0258** | **0.0291** | **0.0323** | **0.0355** | **0.0387** |
| 10 | **GHG emissions increase due to LD PEV electricity loads** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.0000** | **0.00000** | **0.00114** | **0.00101** | **0.00100** | **0.00103** | **0.03453** | **0.03771** |
| 11 | **GHG emissions reduction due to fuel displacement - other transportation electrification** | | | | | | | | | | | | | | |
| 12 | **GHG emissions increase due to increased electricity loads - other transportation electrification** | | | | | | | | | | | | | | |

Note: Additional GHG reductions will depend on the method of counting 0 carbon resources. As described in Chapter 7 of the IRP report, IID assumes that customer side program reductions will allow IID to meet deeper reductions of GHG pending the scoping plan final requirement.

# TABLE C4 - RESOURCE PROCUREMENT TABLE (RPT)

State of California
California Energy Commission
**Standardized Reporting Tables for Public Owned Utility IRP Filing**
**RPS Procurement Table**
Form CEC 112 (May 2017)

**Scenario Name: Mid/Expected Load Case**

**Units = MWh**

| | **RPS ENERGY REQUIREMENT CALCULATIONS** | **Beginning balances Start of 2017** | **Compliance Period 3** | | | | | **Compliance Period 4** | | | | | **Compliance Period 5** | | | | **Compliance Period 6** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | **2017** | **2018** | **2019** | **2020** | | **2021** | **2022** | **2023** | **2024** | | **2025** | **2026** | **2027** | | **2028** | **2029** | **2030** | |
| 1 | Annual Retail sales to end-use customers (accounting for AAEE impacts) (From EBT) | | 3,441,632 | 3,472,081 | 3,381,908 | 3,412,319 | | 3,448,335 | 3,489,372 | 3,534,379 | 3,731,836 | | 3,772,049 | 3,813,137 | 3,856,029 | | 3,899,148 | 3,934,380 | 3,966,284 | |
| 2 | Green pricing program Exclusion, (may include other exclusions like self generation | | 0 | 0 | 13,140 | 13,140 | | 13,140 | 13,140 | 13,140 | 13,140 | | 13,140 | 13,140 | 13,140 | | 13,140 | 13,140 | 13,140 | |
| 3 | Soft target (%) | | 27.00% | 29.00% | 31.00% | 33.00% | | 35.75% | 38.50% | 41.25% | 44.00% | | 46.00% | 50.00% | 52.00% | | 54.67% | 57.33% | 60.00% | |
| 4 | Required procurement for compliance period | | 4102191.43 | | | | | 5655169.03 | | | | | 5627398.81 | | | | 6744413.95 | | | |
| | **Category 0, 1 and 2 Resources (bundled with RECs)** | | | | | | | | | | | | | | | | | | | |
| 5 | Excess balance at beginning/end of compliance period | | | | | | 0 | | | | | 247,995 | | | | 699,743 | | | | 1,241,104 |
| 6 | RPS-eligible energy procured (copied from EBT) | | 998,259 | 1,009,266 | 1,412,763 | 1,440,810 | | 1,406,858 | 1,359,508 | 1,273,782 | 1,781,223 | | 2,055,825 | 1,987,258 | 2,174,429 | | 2,173,604 | 2,201,870 | 2,569,738 | |
| 6A | Amount of energy applied to procurement obligation | | 929,241 | 1,006,904 | 1,048,392 | 1,126,065 | | 1,406,858 | 1,359,508 | 1,157,147 | 1,649,863 | | 1,917,014 | 1,834,733 | 2,014,018 | | 2,003,071 | 2,021,424 | 2,379,357 | |
| 7 | Net purchases of Category 0, 1 and 2 RECs | | | | 0 | 0 | | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | |
| 7A | Excess balance and REC purchases applied to procurement obligation | | | | 0 | 0 | | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | |
| 8 | Net change in balance/carryover (RECs and RPS-eligible energy) (6+7-6A-7A) | | 69,018 | 2,362 | 364,371 | 314,745 | | 0 | 0 | 116,635 | 131,361 | | 138,811 | 152,525 | 160,411 | | 170,533 | 180,446 | 190,382 | |
| | **Category 3 Resources (unbundled RECs)** | | | | | | | | | | | | | | | | | | | |
| 9 | Excess balance at beginning/end of compliance period | | | | | | 0 | | | | | 0 | | | | 0 | | | | 0 |
| 10 | Net purchases of Category 3 RECs | | 0 | 0 | 0 | 0 | | 0 | 0 | 116,635 | 131,361 | | 138,811 | 152,525 | 160,411 | | 170,533 | 180,446 | 190,382 | |
| 11 | Excess balance and REC purchases applied to procurement obligation | | 0 | 0 | 0 | 0 | | 0 | 0 | 116,635 | 131,361 | | 138,811 | 152,525 | 160,411 | | 170,533 | 180,446 | 190,382 | |
| 12 | Net change in REC balance | | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | | 0 | 0 | 0 | |
| 13 | Total generation plus RECs (all Categories) applied to procurement requirement (6A + 7A + 11) | | 4,110,601 | | | | | 5,821,371 | | | | | 6,217,513 | | | | 6,945,213 | | | |
| 14 | Over/under procurement for compliance period (13 - 4) | | 8,410 | | | | | 166,202 | | | | | 590,114 | | | | 200,799 | | | |