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2023 Integrated Resource Plan

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PREFACE

Vernon Public Utilities' Integrated Resource Plan (IRP) serves as a comprehensive planning strategy and long-term road map for procuring a Renewable Portfolio Standards (RPS) compliant and zero-carbon resource portfolio that meets California statutory and regulatory requirements while ensuring reliability and affordability for its customers.

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1. Executive Summary

Founded as an exclusively industrial city, the City of Vernon (City) is a vital economic engine, supplying necessary goods across the state, country and globally. The City is comprised of 5.2 square miles located southeast of downtown Los Angeles in Southern California, supporting over 1,900 businesses that employ a workforce from neighboring cities of approximately 55,000 people.

As such, Vernon Public Utilities (VPU) is an essential resource for the City's ever-growing and evolving business community. VPU's principal responsibility and core mission is to serve its predominantly commercial and industrial customer base with high-quality, reliable competitive and stable utility rates while providing extremely responsive customer service. To achieve these goals, VPU must procure sufficient resources to meet current and future customer needs while complying with state requirements for capacity and renewable and clean energy generation.

VPU's 2023 Integrated Resource Plan (IRP) comprises four founding pillars (Figure 1): a reliable and resilient electric grid, sustainable generation, a prudent and equitable transition to clean energy, and competitive and stable rates for its customers.

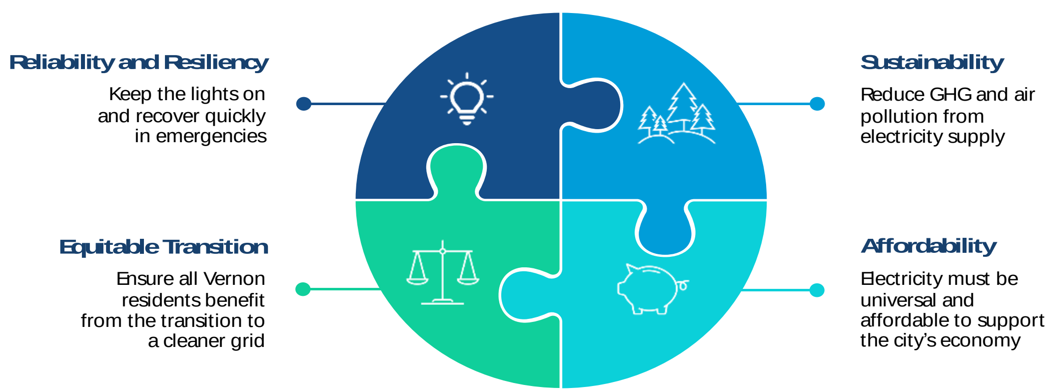


Figure 1. Four Foundational Pillars of the IRP

The 2023 IRP is a comprehensive document that outlines the City's plan to meet its customers' needs and comply with statutory requirements. The IRP utilizes VPU'S current daily operations as a planning starting point. It also forecasts the City's future capacity and energy needs and identifies and evaluates renewable and clean energy resources to meet those needs. In addition, the IRP provides an overview of numerous state laws and regulatory requirements that the City must meet.

The IRP chronicles an extensive research, forecasting, and planning process that VPU performs daily to make critical decisions and execute action plans needed to satisfy statewide requirements and customer needs.

COMPLYING WITH CLEAN ENERGY AND CUSTOMER-CENTRIC GOALS

VPU developed this IRP by employing an integrated planning approach that considers various key goals and strategies. As a result, the implementation of this IRP:

- Supplies reliable and affordable energy to meet the expected increasing energy needs of VPU's customers through a diversified resource portfolio to meet demand with supply.
- Procures adequate renewable generation to meet the state's 60 percent Renewable Portfolio Standard (RPS) by 2030 (as mandated by Senate Bill (SB) 350 and updated by SB 100).
- Achieves a 100 percent zero-carbon generation portfolio by 2045 (also mandated by SB 100), with interim goals of 90 percent zero-carbon generation by 2035 and 95 percent zero-carbon generation by 2040 (as mandated by SB 1020).
- Reduces greenhouse gas (GHG) emissions by 40 percent from 1990 levels by 2030 (as mandated by SB 350) and by 85 percent from 1990 levels by 2045 (as mandated by AB 1279).
- Complies with California Independent System Operator's (CAISO) Resource Adequacy (RA) Program requirements to ensure safe and reliable electric service.
- Facilitates the adoption of distributed energy resources (DERs), primarily by subsidizing customer-sited rooftop solar photovoltaic (PV) and storage systems.
- Ensures baseload local generation to maintain system reliability.
- Identifies a strategic plan for increasing energy savings through energy efficiency measures and demand-side management (DSM) programs.
- Reviews the feasibility of utilizing battery energy storage systems (BESS).
- Advances the transition for transportation electrification by developing on-site and public electric vehicle (EV) charging infrastructure.
- Supports the transition to building electrification.
- Fosters economic, social, and electric rate benefits for low-income customers and disadvantaged communities (DACs).

The IRP considered two planning cycles:

- Short-term: from the present through 2030 when the RPS requirements must be met.
- Long-term: when GHG and zero-carbon requirements must be met.

Overall, the entire long-term planning period runs from 2023 through 2045.

Over the short term, the IRP demonstrates how VPU's resource portfolio will be comprised of at least 60 percent RPS-compliant renewable generation. Over the long term, the IRP illustrates how VPU's resource portfolio will be 90 percent zero-carbon by 2035, 95 percent zero-carbon by 2040, and 100 percent zero-carbon by 2045.

While the primary focus of an IRP is resource acquisition and resource retirement considerations, the IRP considers three other components: DER penetration, customer engagement, and distribution system improvements. This IRP encourages the growth of DERs, fosters customer engagement, and looks to improve the resiliency of the VPU distribution system, all in keeping with VPU's core mission. These four interrelated components contain several subcomponents that VPU manages daily to ensure safe, affordable, and reliable operations.

Together, these aforementioned components form the basis of an integrated planning approach. A robust distribution system is a necessity for developing the two-way flow of energy required with increasing penetration of DERs and behind-the-meter (BTM) local battery storage. These factors will directly affect the bulk power system portfolio mix. Transitioning to building and transportation electrification, including adding EV charging stations across the city will result in higher electricity demand. Additional energy efficiency measures stand to decrease the electric demand. The planning performed in the IRP takes into account customer outreach, engagement, and feedback.

IRP CONCLUSIONS

The IRP considered several resources for inclusion in a preferred portfolio. These resources included both renewable generation in the form of geothermal, solar PV, and wind, along with clean energy generation, such as hydrogen, carbon capture and sequestration (CCS), BESS, and nuclear. The IRP resulted in three portfolio scenarios: Portfolio 1, Portfolio 2, and Portfolio 3. Each scenario was extensively and comprehensively modeled and analyzed.

The three portfolios revolve around the future status of the Malburg Generating Station (MGS), which began commercial operation in 2005. VPU must reduce emissions generated at MGS by 2030. The most favorable option for accomplishing this emissions reduction is to stop operating one of MGS's combustion turbines (CTs) to run in concert with its steam turbine (ST) and operate the unit less frequently outside the summer months when the grid demands the most electricity. Thus, starting in 2030, the model assumes that MGS will operate in a 1x1 configuration (one CT and one ST) with limited strategic dispatch in the off-peak months. In 2035, the model assumes that, after 30 years of operation, MGS is planned to stop operating to help VPU meet the state's renewable and clean energy requirements. When MGS stops operating, VPU is expected to meet over 90 percent of its load with carbon free resources.

The 2023 IRP is expected to be updated in five years, however, the 2023 IRP can be updated as necessary to respond to any number of evolving situations (such as emerging renewable generation technologies; changing community needs; or sudden changes in regulatory, financial, or operational policies). The action plans in the 2023 IRP are flexible and adaptable to these factors and unforeseen changes, including any strategic and operational decisions regarding MGS.

The Preferred Portfolio

Through production cost modeling simulation results identified Portfolio 1 as the preferred portfolio because it is the least-cost, best-fit option. This portfolio combines wind, solar, and energy storage resources to replace MGS. Solar and wind provide renewable diversity to the portfolio, while a 4-hour battery energy storage system provides capacity. The results align with cost projections for future resources: wind, solar, and a 4-hour BESS represent the least cost option.

Figure 2 shows the Capacity Resource Accounting Table (CRAT) for the preferred portfolio. It depicts the annual peak capacity requirements (in MW) and contributions from existing and future resources to meet them. The CRAT depicts MGS transitioning to a 1x1 configuration in 2030 and with no generation from MGS in 2035. H. Gonzales 1 and 2 will continue to provide minimal natural gas generation during peak hours.

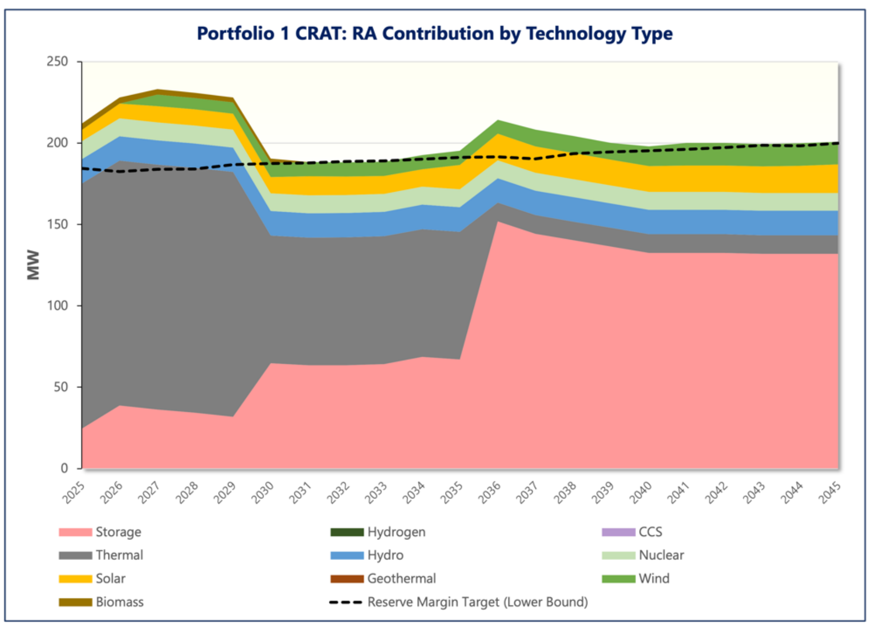


Figure 2. Preferred Portfolio Capacity Resource Accounting Table (CRAT)

Resources included in the CRAT include storage, thermal, hydro, nuclear, solar, wind, and biomass. Resources that were not selected include hydrogen, geothermal, and CCS.

Figure 3 shows the Energy Balance Table (EBT) for the preferred portfolio. It depicts the annual energy needs (in MWh) and the amount procured from each portfolio resource. The capacity expansion model identified the need for new energy storage to come online in 2030 to cover the capacity drop from MGS's transition to a 1x1 operation and again in 2035 when MGS is expected to reach its life expectancy. H. Gonzales 1 and 2 will remain online to provide minimal natural gas generation during peak hours.

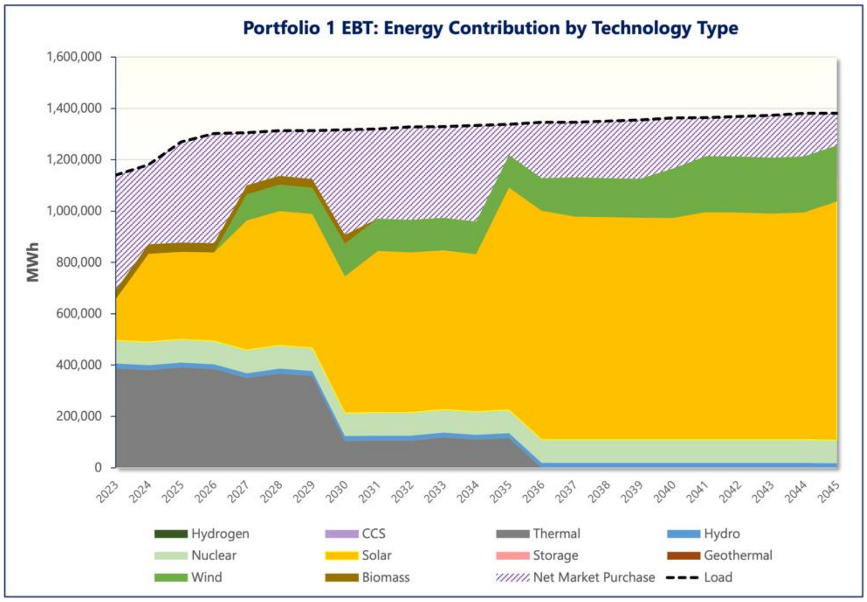


Figure 3. Preferred Portfolio Energy Balance Table (EBT)

Capacity Expansion Resource Mix

The IRP must create a path to meet the state's RPS requirement in 2030 and the zero-carbon generation requirements of 90 percent by 2035 and 95 percent by 2040.

Figure 4 depicts the VPU energy mix in 2030. This portfolio meets the 60 percent RPS compliance requirements for 2030. Of that 60 percent, 53.54 percent comes from VPU resources and the remaining 6.46 percent comes from REC purchases. Figure 5 depicts the VPU energy mix in 2045. This complies with all RPS and zero-carbon requirements.

The percentage of solar PV and wind increases by approximately 60 percent between 2030 and 2045, while the amount of thermal generation diminishes to an infinitesimal level as H. Gonzales 1 and 2 continue to provide minimal natural gas generation during peak hours.

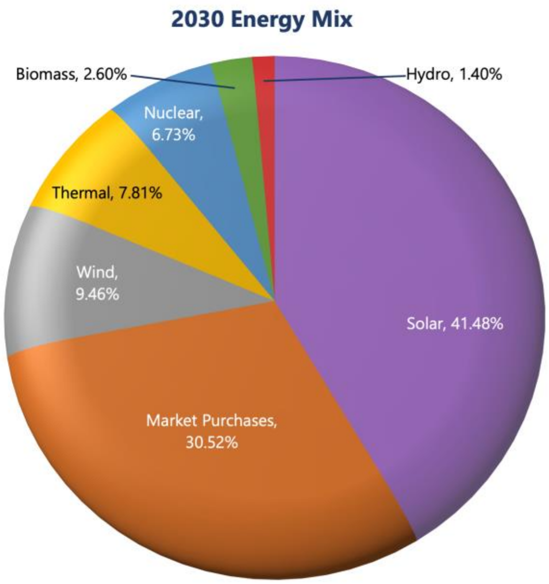


Figure 4. 2030 Energy Mix

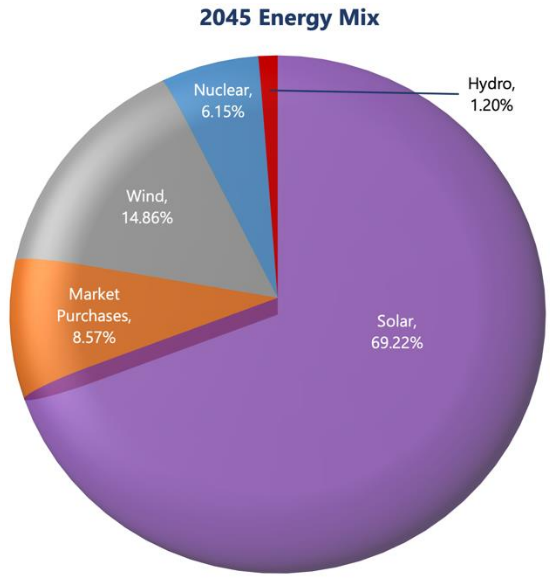


Figure 5. 2045 Energy Mix

Rationale for the Preferred Portfolio Selection

In all three modeled portfolio scenarios, VPU would meet its RA Program requirement through the entire long-term planning period. Meeting the RA requirements means that VPU will continue to provide highly reliable service to its customers.

The actual capacity values of all resources, however, are determined by CAISO, in its annual study. Therefore, the RA values shown in the CRAT for the preferred portfolio are based on capacity accreditation projections that could be lower or higher than the actual values experienced over time.

Portfolio 1 was chosen as the preferred option because the candidate resource options included in the other two portfolios—geothermal and hydrogen—are estimated to be much more expensive than 4-hour storage and solar resources. As such, total supply costs for Portfolio 2 and Portfolio 3 are higher than the total supply cost for Portfolio 1. These costs are a function of the expected resource costs ten to fifteen years from now, which include a significant amount of uncertainty and risk.

Acquisition Timeline

VPU looks to provide the industry's best reliability, offer highly competitive and affordable rates, and improve the lives along with supporting the livelihood of its customers, especially in disadvantaged communities, during its twenty-plus year clean energy transition. VPU currently has a long standing history of adding renewable resources to its portfolio.

The capacity expansion software begins replacing 72 MW of MGS generation with renewable resources by 2030 and replacing the remaining 67 MW by 2035 when MGS is projected to stop operating. During those years, the power purchase agreements (PPAs) for Puente Hills Landfill Gas (10 MW), Astoria II Solar PV (30 MW), and Antelope DSR 1 Solar PV (25 MW) are scheduled to expire.

VPU's capacity expansion consists of adding, in the aggregate, a combination of 360 MW of solar PV, 80 MW of wind, and 380 MW of energy storage over the entire planning period.

Figure 6 shows the amount of energy storage, solar PV, and wind that is planned to be added.

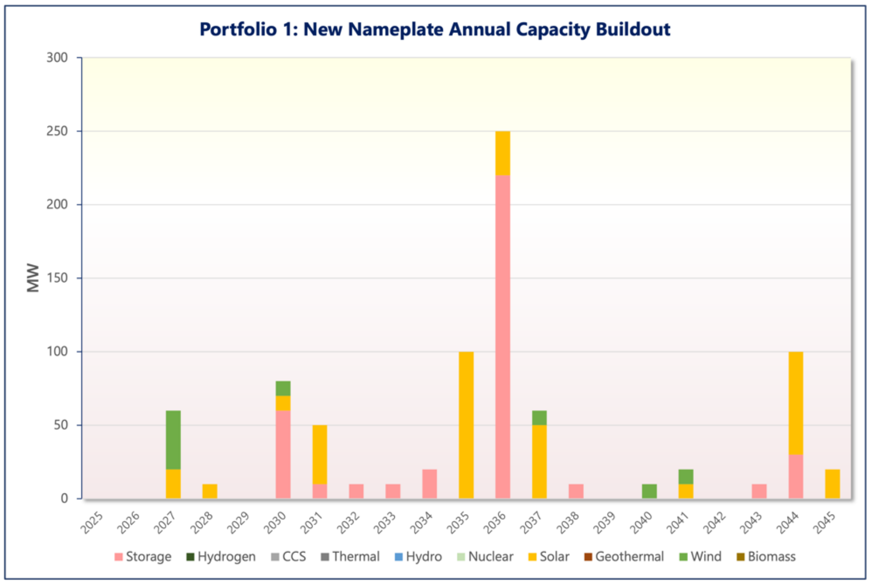


Figure 6. New Nameplate Annual Capacity Expansion for the Preferred Portfolio

The first step in VPU's action plan is to ensure that two new PPAs come online as contracted: Daggett Solar PV plus BESS by the end of 2023 and Sapphire Solar PV plus BESS in 2026. These new resources play a crucial role in VPU's carbon reduction strategy and put VPU on course to meet SB 1020's future clean energy mandates.

COST CONSIDERATIONS

The preferred portfolio identifies the lowest cost resource portfolio. The IRP is based upon nominal cost estimates, financial costs, and capital forecasts, which represent current year costs not adjusted for inflation. It is important to note many factors contribute to the overall electric rates; generation costs are only one factor. Although these costs have a direct impact on electric rates, the costs provide a high-level estimate and do not represent an actual cost of service analysis and rate design study.

Figure 7 estimates the twenty-year net present value (NPV) cost (by MWh) of the three modeled portfolio scenarios compared to the current total portfolio cost.

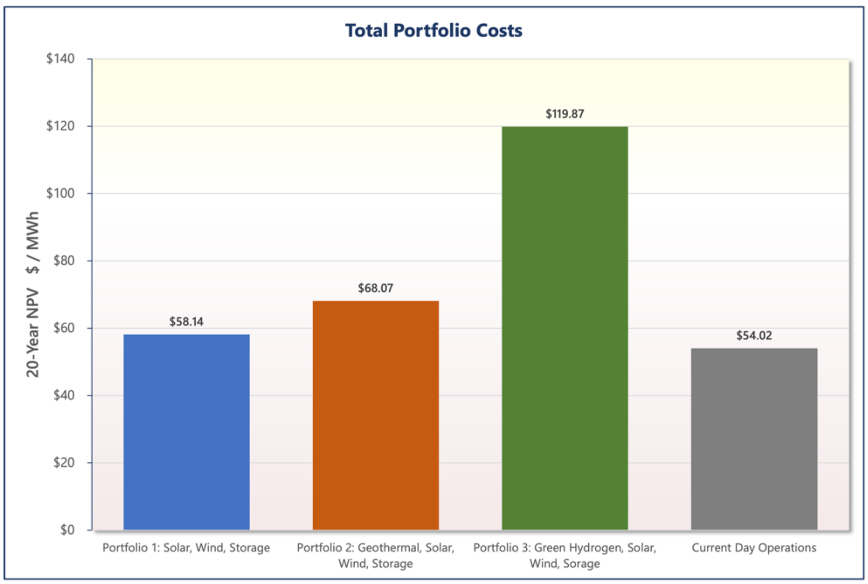


Figure 7. Total Net Present Value Cost of Load for Each Portfolio

These total NPV costs indicate that replacing MGS with wind, solar PV, and energy storage through the preferred portfolio only results in a modest increase in estimated supply costs. The cost of the geothermal and green hydrogen in the other two portfolios, however, is estimated to result in much higher costs.

DRIVING FACTORS FOR THIS IRP

The IRP process considered numerous statutory and regulatory driving factors to determine how to meet generation needs, both in the short-term (until 2030) and in the long-term (until 2045).

These factors include the following:

- The statewide goal of reducing GHG emissions by 85 percent from 1990 levels by 2045. Several statutes complement this overarching goal.
- SB 350 and SB 100 established an RPS goal that requires 60 percent of VPU's customer electricity load (excluding municipal load) be supplied by renewable energy. This includes energy from solar, wind, biogas, geothermal, and small hydroelectric generation.
- SB 100 required all generation be derived from clean energy sources by 2045. SB 1020 added interim goals of 90 percent clean energy by 2035 and 95 percent by 2040. These resources include nuclear generation (including small modular reactors) and large hydroelectric.
- Savings from energy efficiency measures and DSM programs must be doubled from 2020 levels on a statewide basis by 2030 as mandated by SB 350.
- Vehicle transportation must continue to be electrified to comply with the Advanced Clean Car II (ACC II) rule that forecasts the addition of over five million zero-emission vehicles (ZEVs) by 2030. The rule states that all new cars and light trucks allowed on road or new purchases should be ZEVs by 2035. To support ACC II, regulations require the permitting process for private EV charging stations be efficient and streamlined.
- Building systems must be electrified in new buildings and major renovations. While the regulations are still in flux, building electrification must be promoted and considered in future energy needs.
- Customer adoption of DERs must continue to be promoted.

In addition, VPU conducted a 12-question survey to better understand the priorities of its customers and stakeholders with regard to available services and the resource portfolio that will generate the power they consume. In concert with the survey, VPU held three in-person meetings with stakeholders to review the IRP process, discuss the survey results, and to present the content and conclusions of the three prospective portfolios modeled for the IRP. VPU presented its stakeholders with legislative and regulatory context, analytical insights, and perspective into the IRP planning process.

These factors were critical considerations in the planning, input, modeling, analysis, and development of the 2023 IRP. Furthermore, VPU utilized these factors in selecting a preferred generation portfolio to meet forecasted energy needs and develop an action plan to implement the IRP findings.

TRANSMISSION AND DISTRIBUTION UPGRADES

The City of Vernon has limited real estate to site additional generation resources. Thus, a robust transmission system is necessary to import the renewable and zero-carbon resources necessary to reliably satisfy demand while meeting state energy and environmental goals.

Toward that end, VPU is benefiting from upgrades to the Laguna Bell-Mesa and the Lighthipe-Mesa 230 kV transmission lines, as well as upgrades to the Laguna Bell substation (owned by Southern California Edison) and the repowering of the Huntington Beach transmission line. These upgrades mitigate three levels of power loss contingencies (P3, P6, and P7) and increase each transmission line's capacity.

Locally, VPU has just completed a $25 million Capital Improvement Plan (CIP), upgrading the aging distribution system to increase its load carrying capacity and increase system reliability.

Actions that are part of the upcoming Five-Year CIP include the following:

- Continue to replace and upgrade distribution infrastructure to increase capacity, maintain system reliability, and system resilience.
- Implement additional distribution system automation by installing intelligent line switches and automatic reclosers to improve VPU's smart grid and diminish the impact of electric system outages on customers.
- Upgrade line conductors, transformers, and complete voltage conversions at electric substations to foster higher reliability and increase capacity.
- Replace obsolete and aging circuits, cables, and relays with state-of-the-art technology.
- Proactively replace utility poles in a strategic manner.
- Perform system undergrounding in conjunction with development and City projects for improved system reliability.

These efforts provide VPU the opportunity to engage with various commercial and industrial customers interested in increasing their existing capacity to serve expanding demand, and electrifying their fleet by installing EV charging infrastructure. In addition, the City and VPU are actively transitioning toward a clean commerce future that includes adding mixed-use customer developments and increase residential housing options.

VPU plans to implement these upgrades and improvements throughout the course of this IRP planning cycle and plans to complete them, and all other resource planning actions, by the next IRP cycle in five years.

2. Background and Planning Goals

Vernon Public Utilities, an integrated part of the City of Vernon, consists of a dedicated team committed to providing essential services that contribute to this vibrant community's overall well-being and functionality.

The City of Vernon is a primarily industrial city of 5.2 square miles located just to the southeast of Downtown Los Angeles in Southern California. The City's business-friendly environment, low-cost utilities, and proximity to ports, trucking, and rail transport make Vernon an ideal location for industrial uses. VPU serves about 1,900 mainly commercial and industrial electric customers with electric sales of approximately 1,151 GWh annually and peak loads of approximately 189 MW in the summer and 174 MW in the winter.

VPU rates for the larger commercial and industrial classes, such as TOU-V and TOU-Vt, are extremely competitive, including comparisons with the Los Angeles Department of Water and Power and Southern California Edison. The utility has a mission to offer the lowest rates in California by 2030.

VPU's electric system includes generation and distribution facilities that are completely located within VPU's electric service territory in the LA Basin. VPU does not own or operate any transmission facilities. VPU has two generation facilities within VPU service territory. MGS is a 139 MW combined-cycle natural gas-fired plant and two H. Gonzales units is a combined 11.5 MW natural gas plant. VPU has 119 miles of distribution lines and 27 miles of 66 kV sub-transmission lines.

THE INCEPTION OF THE INTEGRATED RESOURCE PLAN

On October 7, 2015, the California Senate passed Senate Bill (SB) 350, the Clean Energy and Pollution Reduction Act. This legislation required a dramatic reduction in greenhouse gas (GHG) emissions, fundamentally altering how electricity consumed within the state was generated.

Among its numerous provisions, the bill required the California Public Utilities Commission (CPUC) to adopt a process for Investor-Owned Utilities (IOUs), Community Choice

Aggregators (CCAs), and Electric Service Providers (ESPs) to file an Integrated Resource Plan (IRP) to:

- Meet the GHG emissions reduction targets established by the California Air Resources Board (CARB) for the electricity sector.
- Procure at least 50 percent eligible renewable energy resources by December 31, 2030, consistent with the RPS. (The RPS requirement was raised to 60 percent in 2018.)
- Minimize impacts on ratepayers' bills.
- Ensure system and local reliability.
- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems and local communities.
- Enhance distribution systems and demand-side energy management.
- Require Publicly-Owned Utilities (POUs) to adopt IRPs according to similar standards, subject to review by the California Energy Commission (CEC).[1]

The bill also required a diversified procurement portfolio consisting of both short-term and long-term electricity, electricity-related programs, and demand response products.

The CEC's publication, *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines, Revised Third Edition*, which was last updated in August 2022, details twelve main areas of compliance, and included filing and review procedures.

ABOUT THIS IRP

The VPU 2023 Integrated Resource Plan presents a comprehensive 20-year strategy that outlines how the City of Vernon plans to continue to meet the electric service needs of customers with reliable and environmentally responsible energy development and procurement at competitive and stable rates. It outlines how VPU plans to not only meet these energy and capacity needs, but also comply with various regulatory and statutory initiatives to generate clean energy, consider physical and operational constraints, and meet other state and local priorities.

The IRP outlines a process for charting a resource acquisition strategy that balances supply and demand. It favors procuring reliable, affordable, renewable, and zero-carbon energy balanced against forecasted growth, and coupled with transportation and building electrification demands, energy efficiency and demand-side management initiatives, and DERs.

[1] https://trackbill.com/bill/california-senate-bill-350-clean-energy-and-pollution-reduction-act-of-2015/1126101/

Figure 8 depicts this balance of demand with supply.

Figure 8. IRP Balances Demand with Supply

The foundation of the 2023 IRP is based on maintaining and improving the utility's ongoing commitment to excellence: its generation and distribution systems continue to rank among the most reliable nationwide.

The Goal of the IRP

VPU developed this IRP by implementing an integrated approach that considered several key goals and strategies. It details a forward-looking view of available resource options and a plan that:

- Supplies reliable and affordable energy to customers through a diversified resource portfolio to meet demand with supply.
- Achieves the 2030 target of 60 percent RPS by procuring adequate renewable generation, as mandated by SB 350 and updated by SB 100.
- Achieves a 100 percent zero-carbon generation portfolio by 2045, also mandated by SB 100, with interim goals of 90 percent zero-carbon generation by 2035 and 95 percent zero-carbon generation by 2040 as mandated by SB 1020.
- Reduces GHG emissions by 40 percent from 1990 levels by 2030 as mandated by SB 350.
- Ensures adequate baseload local generation after 2028 to maintain system reliability.
- Identifies a strategic plan for increasing energy efficiency savings.
- Facilitates the adoption of DERs.
- Addresses the integration of battery energy storage systems (BESS).
- Supports the transition to transportation and building electrification.
- Fosters economic, social, and electric rate benefits for low-income residents and neighboring disadvantaged communities.
- Ensures compliance with all statutory and regulatory requirements.

Planning Horizon

The IRP serves as a roadmap for both short-term and long-term decisions. It encompasses a short-term planning period through 2030 when the 60 percent RPS goal must be achieved, and a long-term planning period through 2045 when the 100 percent zero-carbon portfolio mandate must be achieved. Figure 9 depicts a roadmap for complying with state requirements for procuring renewable and zero-carbon clean energy.

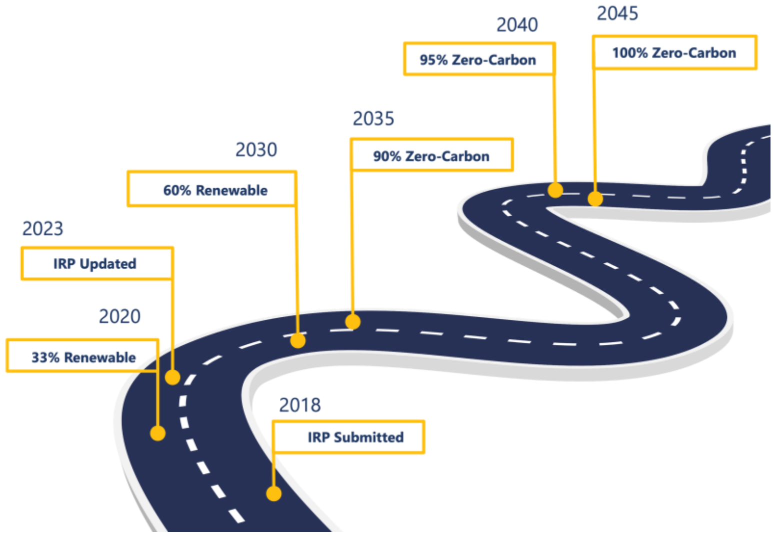


Figure 9. IRP Roadmap of Resource Compliance

The culmination of the IRP is an action plan to be implemented over the next five years with an eye toward attaining long-term goals.

Four Components of the IRP Planning Process

While the primary focus of an IRP is resource acquisition, the IRP focuses on three other components of its operations: DER penetration, customer engagement, and distribution system improvements. This focus encourages the growth of DERs, fosters customer engagement, and improves the resiliency of the VPU distribution system, all in keeping with VPU's core mission.

Figure 10 depicts the elements of the four main components of the IRP.

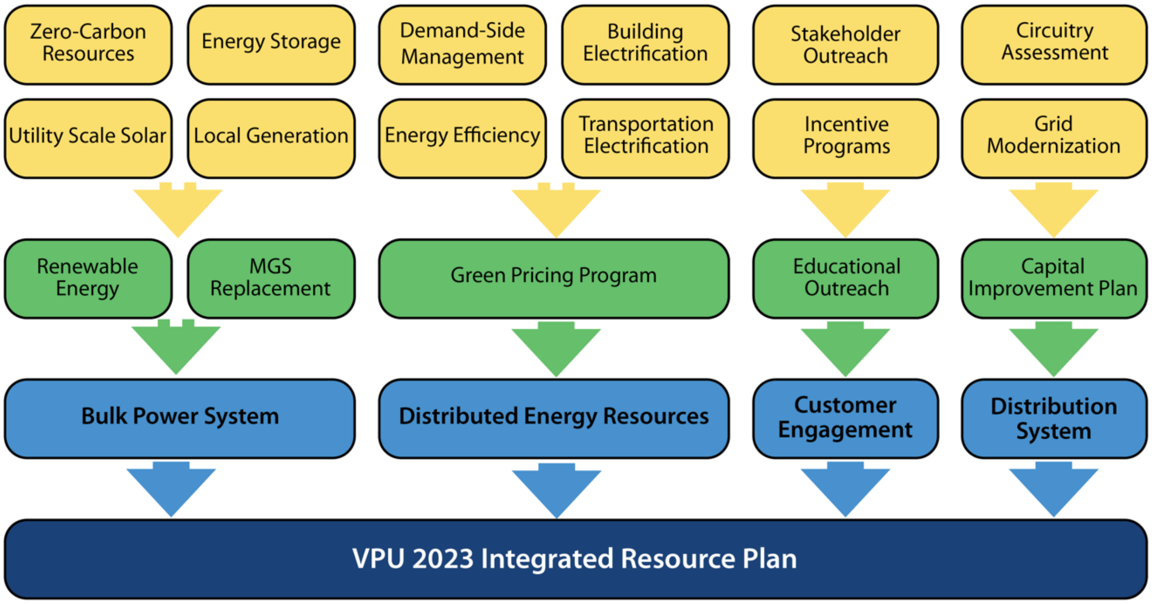


Figure 10. Four Components of the IRP Process

These four interrelated components form the basis of an integrated planning approach. A robust distribution system is a necessity for developing the two-way flow of energy required with increasing penetration of DERs and behind-the-meter (BTM) local battery storage. The increased penetration of DERs directly affects the bulk power system portfolio mix. Transitioning to building and transportation electrification, including the development of EV charging stations across the city, results in higher demand. Implementation of energy efficiency measures decreases demand. VPU's short- and long-term planning approach considers customer outreach and their resultant input.

While the next IRP is not due for another five years, the 2023 IRP can be updated as necessary in the interim to respond to any number of evolving situations (such as emerging renewable generation technologies; changing community needs; or sudden changes in regulatory, financial, or operational policies). The action plans in the VPU 2023 IRP are flexible and adaptable to these and other unforeseen changes, including any strategic and operational decisions regarding the status of MGS.

VPU's Approach for Creating the IRP

Ensuring adequate resources to meet current and future demand is at the heart of the IRP. The IRP informs a process for implementing a short- and long-term resource acquisition strategy. The process for creating the IRP was based on evaluations of several key areas:

Internal Considerations. Existing resources; distribution system; resource portfolio; physical and operational constraints; and current energy efficiency, demand response, and demand-side management measures.

External Considerations. Applicable statutory and regulatory requirements, stakeholder input, and potential current and emerging resource technologies including energy storage and DERs, and transmission system constraints.

Generation Resources. Solar, wind, hydroelectric, geothermal, biogas and biomass, battery storage, nuclear, and natural gas.

Various Inputs. Reliability standards, risk management policies, rates, and financial incentives and goals.

Forecasts. Demand, energy, transportation electrification, building electrification, cost of service, and how they contribute to resource adequacy.

Increasing amounts of variable renewable energy impacts the ability to provide adequate dispatchable baseload and load-following generation. VPU contracted with Ascend Analytics to design potential future scenarios that encompass various resource mixes. Ascend then modeled and analyzed the different scenarios to arrive at a preferred portfolio of resources to procure. The preferred portfolio examined the amount, timing, and type of sustainable resources that can provide the energy needs of VPU's customers at the lowest reasonable cost while meeting sustainability and reliability requirements.

Ascend designed and modeled three potential future resource portfolios that can meet these requirements. To varying degrees, the IRP employed an integrated approach for assessing resource investment tradeoffs and stranded risk possibilities to ensure reliability, environmental stewardship, statutory and regulatory compliance, and rate considerations.

During the planning process, VPU engaged its stakeholders as a means of seeking guidance and direction on key decisions for preferred portfolios of generation, demand, and distributed resources.

The strategic outcome is a power supply transition roadmap that enables VPU to evaluate and update various power supply objectives. The resultant preferred portfolio incorporates a prudent mix of generation, distribution, and transmission resources together with energy efficiency measures balanced against reliability, sustainability, and financial goals to meet the energy needs of its customers now and over the next two decades. Over time, VPU's power supply requirements and related costs will continue to evolve.

The IRP ensures timely resource investments that maintain a reliable power system. VPU intends to implement the IRP together with its Capital Improvement Plan and other forward-looking management plans, including a cost of service analysis and rate design study, to ensure supply reliably meets demand at competitive and stable rates.

The IRP complies with California Public Utilities Code (PUC) Section 9621 and the *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines, Revised Third Edition* issued by the CEC in August 2022. These guidelines dictate the content of an IRP and require VPU to file an IRP at least every five years.

OUTCOMES FROM 2018 IRP RECOMMENDATIONS

Among several options, the 2018 IRP recommended diversifying VPU's resource mix by procuring a cumulative total of 93 megawatts (MW) of solar capacity by 2027, 27 MW of wind capacity in 2025, 20 MW of geothermal capacity in 2029, and an additional 1 MW per year of energy storage starting in 2023 with an increase of 15 MW more in 2029. Recommended solar procurement was for 65 MW in 2021, 20 MW in 2023, and 8 MW in 2026. One other recommendation was for VPU to develop a plan to accommodate the additional 1.7 MW of load due to a forecasted increase in EV penetration and charging requirements.

In the last five years, VPU has signed power purchase agreements (PPAs) for two solar facilities: Daggett Solar for 60 MW of nameplate capacity with a commercial operation date (COD) of December 20, 2023, and Sapphire Solar for 39 MW of nameplate capacity with a COD of December 31, 2026. As part of these PPAs, VPU will acquire a total of almost 50 MW of 4-hour Lithium-Ion battery energy storage: 30 MW from Daggett and 19.67 MW from Sapphire, far surpassing the recommended 5 MW by 2027. Procuring the recommended wind and geothermal resources has yet to be realized due to their current cost prohibitive pricing.

In late 2021, VPU repurchased the MGS from Bicent Power LLC, which allows VPU to use the plant more efficiently depending on operating and market conditions.

In the interim, VPU added more than 40 EV charging stations for city employees and the municipal fleet. As of May 2023, daily peak usage has been 80 kilowatts (kW). VPU expanded its EV charging infrastructure with the following projects:

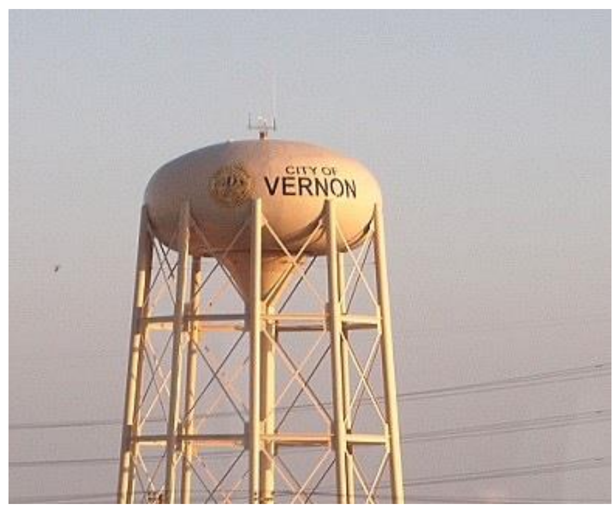
- One publicly available Level 3 (L3) charging depot that opened in July 2023, equipped with ten ChargePoint direct current fast chargers (DCFCs) and eight Tesla V3 Superchargers.
- 43 Level 2 (L2) EV chargers installed at Vernon City Hall, available to employees, the city fleet, and the public.
- One more publicly available L3 charging depots is currently under development, which will also be equipped with DCFCs and Tesla V3 Superchargers. The site is scheduled to be completed in calendar year 2024.

As of May 2023, the peak charging usage was 80 kW with a maximum daily usage of 674 kW.

VPU's publicly available EV fast charging depots also help address the lack of DCFCs in disadvantaged communities (DACs), as defined under CalEnviroScreen criteria. The California Office of Environmental Health Hazard Assessment created the CalEnviroScreen criteria to help CalEPA identify disadvantaged communities based on geographic, socioeconomic, public health and environmental hazard criteria, as required by SB 535. All of the current and proposed depots are close to several major interstate and intrastate highways. As a result, Vernon's public EV charging depots provide the necessary infrastructure to support battery electric vehicles in the Gateway Cities region and help encourage the adoption of zero ZEVs in underserved communities.

ABOUT VERNON PUBLIC UTILITIES

Throughout the years, Vernon Public Utilities has remained steadfast in its mission: to provide its customers with reliable, safe, and affordable energy in a manner consistent with California's progressive, cleaner energy goals.



VPU continues to build a resilient, full-service utility that meets the energy challenges and capitalizes on emerging technologies and strategic opportunities. In addition to electric services, VPU provides water, gas, and fiber optic services. VPU operates in a financial and environmentally responsible manner while remaining dedicated to reliability, safety, sustainability, and affordability through a customer-focused vision. As a publicly owned utility, VPU's stakeholders are its customers, residents, current and prospective property and business owners, property developers, business employees and customers, the Business and Industry Commission, the Vernon Green Commission, the Vernon Chamber of Commerce, the City Council, and commissioners.

VPU is a steward of the Vernon community. With Vernon City Council acting as its governing board, local control affords the utility the opportunity to offer critical advantages to VPU's customers: transparency of governance; competitive and stable rates; the opportunity to tailor utility policies, create beneficial programs, and have a voice in the utility decision-making process, all to serve community priorities. The City Council and City Administration take a leadership role in supporting the efforts expended by VPU staff. VPU is committed to partnering with the local community in shaping and constructing a sustainable energy future for the City of Vernon.

Customer Base

A key feature that makes VPU unique is a customer base that is predominantly comprised of commercial and industrial businesses. Over the past decade, the breakdown of customers and the total number of customers has remained relatively the same. Since 2012, VPU's customer count has increased a modest 1.64 percent (see Table 1) while energy consumed by those customers has grown at a similar rate of 1.57 percent.

Customer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	28	28	28	28	74	74	74	74	74	74	74
Commercial	1,168	1,182	1,191	1,205	1,210	1,210	1,218	1,223	1,231	1,238	1,262
Industrial	600	591	573	558	555	539	531	524	514	503	503
Municipal	100	98	97	96	95	93	93	94	93	90	88
Total	1,896	1,899	1,889	1,887	1,934	1,916	1,916	1,915	1,912	1,905	1,927

Table 1. VPU Historic Customer Count

For most electric utilities, a majority of their customer base is comprised of residential customers. However, at VPU, an overwhelming majority of the customers fall under the commercial and industrial segment.

VPU serves approximately 1,900 commercial and industrial accounts, with a service territory home to manufacturing and production employing close to 55,000 skilled workers. The primary industries found within the City of Vernon include food service distribution and manufacturing, glass and plastic equipment manufacturing, and metalworking. About half of Vernon's residents live in city-owned housing and are employed by private businesses within the city. In 2015, VPU's residential accounts more than doubled after the city opened its first privately-owned apartment complex.

While commercial and industrial customers make up almost 92 percent of VPU's electricity accounts, they also consume over 99 percent of its demand and energy sales. In addition, VPU's customer base includes many industrial and commercial businesses have been in Vernon for many decades. Some of VPU's largest customers average over 31 years of operations in the city.

Figure 11 shows VPU's customer breakdown, while Figure 12 shows the energy consumed by each customer category. All amounts are from 2022.

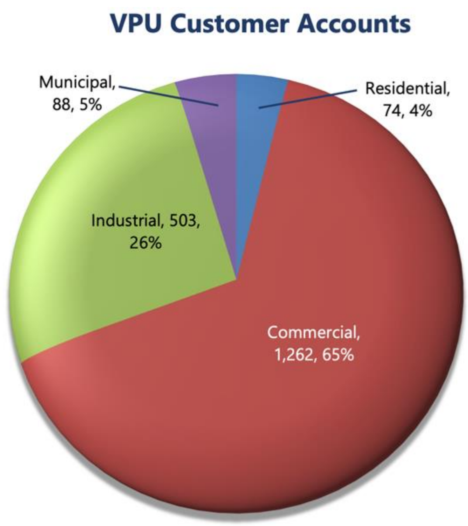


Figure 11. VPU Customer Count

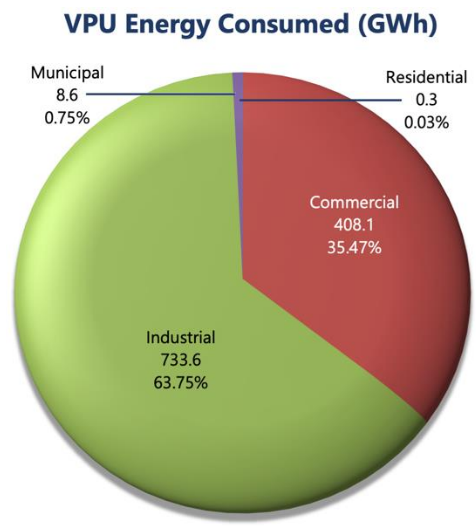


Figure 12. VPU Energy Consumed

VPU customers consumed 1,150.6 GWh of energy in 2022, with a winter peak load of 174 MW and summer peak load of 189 MW. The proximity of VPU's summer and winter peak loads results in an annual load factor over 70 percent, with a large industrial customer base as a major contributing factor.

Award Winning Grid Reliability and Service

The American Public Power Association (APPA) designates Reliable Public Power Provider recognition (RP3) to utilities that demonstrate exceptional proficiency in four key areas: safety, reliability, workforce development, and system improvement. Consistent with its mission, VPU strives for excellence in these areas.

APPA has awarded VPU its highest, Diamond Level, RP3 designation for three consecutive terms, encompassing nine years from 2016–2019, 2019–2022, and 2022–2025. VPU earned these honors by providing exceptionally reliable and safe electric service. VPU is one of only 26 of the more than 2,000 public power utilities across the United States to achieve Diamond Level RP3 designation for the period of 2022–2025.

APPA also awarded VPU the Safety Award for Excellence in 2022 as there were no reportable safety incidents. In addition, the City of Vernon earned a Tree City USA Designation in 2019, 2020, and 2021—one of only 3,500 communities in the nation to be named.

Membership in SCPPA

VPU is a member of the Southern California Public Power Authority (SCPPA). SCPPA is a Joint Powers Authority, created in 1980, to provide joint planning, financing, construction, and operation of transmission and generation projects. Comprised of eleven municipal utilities and one irrigation district, SCPPA's members serve more than 5 million Californians across a service area of 7,000 square miles. SCPPA members supply 16 percent of California's power.

SCPPA's twelve members are:

Anaheim Public Utilities Department	Burbank Water and Power
Azusa Light & Water	City of Banning
Cerritos Electric Utility	City of Colton
Vernon Public Utilities	Glendale Water and Power
Imperial Irrigation District	Los Angeles Department of Water & Power
Pasadena Water and Power	Riverside Public Utilities

SCPPA members continue to seek new energy solutions to meet the clean energy goals set by the state of California. Today, each member delivers energy through a combination of fuel sources and renewable generation, offset by energy efficiency measures, to meet the diverse needs of their customers and to comply with state mandates. The biggest benefit of SCPPA is economies of scale, joint procurement at lower overall cost and understanding lessons learned from other POU's.

VPU derives several benefits from its SCPPA membership.

Decarbonization. SCPPA champions decarbonization efforts for its member communities through collective projects, programs, and services to meet sustainability goals while maintaining reliability, low costs, and local control.

Emerging Issues. SCPPA helps members thrive and excel in the long term by exploring technological and operational solutions to emerging industry challenges and opportunities.

Collaboration. SCPPA fosters collaboration and professionalism with its working groups to maximize its value to members and the communities they serve.

Assets. SCPPA is a trustworthy steward of public funds through responsible administration of financial and physical assets and obligations.

Advocacy. SCPPA emphasizes the unique needs of member communities by facilitating proactive advocacy.

Energy Resource Mix

VPU's generation portfolio continues to evolve with state mandates for renewable energy and zero carbon generation. Vernon participates in the CAISO wholesale energy markets under a metered subsystem agreement (MSSA). Five years ago, approximately 59 percent of VPU's energy resource mix was supplied by natural gas generation from MGS and market purchases. The remaining energy came from 7.7 percent nuclear, 1.6 percent large hydroelectric, and approximately 32 percent renewables.

VPU's energy mix for 2024 is depicted in Figure 13.

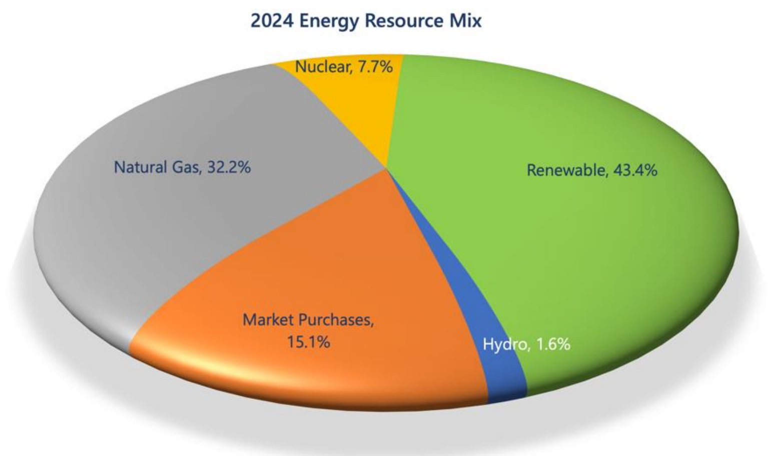


Figure 13. 2024 Energy Resource Mix

Generation from natural gas has been reduced to 32.2 percent (from 59 percent) of VPU's portfolio while renewable generation has increased to 43.4 percent (from 31 percent). This renewable generation comprises 29.0 percent solar, 3.1 percent biomass, and 11.3 percent renewable energy credits (RECs). In addition to renewable generation resources, the 7.7 percent nuclear and 1.6 percent hydro are both zero-carbon resources.

One of VPU's central goals of the 2023 IRP is to increase its renewable generation penetration to 60 percent by 2030 as directed by California statute.

For a detailed discussion about generation requirements as directed by statute, refer to "California Policy Requirements" on page 3-1 and "Statewide Planning Considerations" on page 3-11. For specific generation resources, refer to "Resource Portfolio Overview" on page 8-1.

STAKEHOLDER OUTREACH EFFORTS

VPU expends a considerable amount of time and energy on stakeholder outreach by engaging its customers through in-person stakeholder meetings and comprehensive surveys to foster transparency, inform stakeholders about the IRP process, and garner input for developing the IRP. The outreach aimed to inform stakeholder of the major issues facing VPU and to gather valuable insights about how these issues can be addressed. Outcomes from these meetings and results from the survey helped shape the different portfolio scenarios considered and acted as a guide to inform the decision making process.

VPU's stakeholders include city residents, current and prospective property and business owners, property developers, business employees and customers, the Business and Industry Commission, the Vernon Green Commission, the Vernon Chamber of Commerce, the City Council, and commissioners—essentially the entire Vernon community.

Principal Results. Through stakeholder meetings and the survey results, Vernon customers made clear that their top two priorities are reliable electric service and low rates, with an emphasis on reliability.

Stakeholder Meetings

To engage VPU stakeholders directly, VPU held three in-person stakeholder meetings. VPU and Ascend Analytic representatives gave a presentation at each meeting and facilitated a discussion with attendees. All three meetings took place at the Council Chambers in Vernon City Hall. The Green Vernon Commission, Business and Industry Commission, and community members attended all three meetings.

The first stakeholder meeting was held on March 15, 2023. The meeting's presentation introduced the IRP process, statutory requirements, deadlines, and the IRP's goals. An overview of VPU's current resource portfolio, along with a stakeholder survey requesting valuable attendee feedback was also included.

The second stakeholder meeting was held on May 11, 2023. The meeting's presentation detailed the results of the stakeholder survey, key insights, discussion regarding VPU's current/future renewable contracts, overview of the different portfolio scenarios and available resource options for capacity expansion.

The third and final stakeholder meeting was held on June 21, 2023. The meeting's presentation reviewed the IRP process and Ascend's capabilities, the modeling process, details regarding the three modeled scenarios and associated costs.

Attendees were allowed the opportunity to comment and share their thoughts on the IRP process. VPU incorporated the stakeholder feedback into the IRP analysis and utilized stakeholder feedback to select the preferred resource portfolio.

VPU Stakeholder Survey and Results

VPU conducted a 12-question survey to better understand customer thoughts regarding priorities about reliable power, affordable rates, renewable generation, EV charging, DERs, and MGS. VPU promoted the survey during stakeholder meetings community events, and asked attendees for input. This feedback enabled the utility to make decisions about the IRP and to gauge customer interest on essential factors that shape VPU's energy future.

VPU created a webpage detailing the IRP process, included a frequently asked questions (FAQs) page, and a link to the survey. The survey was available for approximately 2 months, via link and QR code, which was displayed prominently on a survey flyer. (See Figure 95 on page C-4 for a copy of the flyer.)

VPU publicized the survey through several outreach channels, including public meetings, advertisements, social media platforms, printed mail, email, and phone calls. In addition, VPU also leveraged its business partnerships and distribution of flyers at numerous community events held throughout the city. (Refer to Appendix Stakeholder Survey and Results on page C-3 for a more thorough list.) In total, VPU received a total of 126 survey responses.

Key Insights

Survey results indicate that the primary concern for VPU customers is maintaining system reliability followed closely by offering affordable rates. VPU garnered several vital insights from the survey responses.

- Over 80 percent of respondents were either satisfied or very satisfied with the service provided by VPU.
- Over 80 percent of respondents ranked reliable electric service as one of the top two priorities, with affordable rates being a close second.
- Over 70 percent of respondents do not believe VPU should exceed the state mandated RPS target.
- Most respondents were very interested in more significant electrification incentives and support for installing distributed generation and energy storage.
- Over 60 percent of community members were not aware of the capabilities of MGS.
- Over 37 percent of respondents expressed great interest in a further transition toward electrification.

Refer to Appendix E. Stakeholder Outreach for in-depth information about the stakeholder meetings as well as the questions and responses from the stakeholder survey.

3. Planning Drivers

Many external factors influence VPU's operation and profoundly affect its long-term resource planning. As this operating environment continues to evolve, there can be a great deal of uncertainty in resource acquisitions strategies and introduces a fair amount of risk. In particular, external factors include:

- Emission-related legislation and regulations
- Renewable resource requirements
- Regional and global economic conditions
- Power market evolutions affecting supply and pricing
- VPU's local planning priorities
- Advancement in technologies

Four main areas directly affect VPU's operation: California policy requirements, statewide planning considerations, regionalization evolution and risk, and cost of service and rate impacts. Each is discussed at length in this chapter.

CALIFORNIA POLICY REQUIREMENTS

For almost two decades, the California legislature has introduced and passed several Assembly Bills (ABs) and Senate Bills (SBs) to combat the impacts of climate change and mandate substantial reductions in GHG emissions based on 1990 emission levels.

The series of bills set the foundation for all other subsequent legislations substantially altering the operation of electric utilities across the state, and acted as planning drivers for the development of VPU's IRP. Most notably, the RPS mandate set levels for increasing the amount of renewable and zero-carbon generation in VPU's resource portfolio mix.

Other legislation complemented these mandates. These statutes include:

- Establishing incentives for customer-owned generation (mostly from rooftop solar photovoltaic systems).
- Setting standards for cap-and-trade programs designed to lower GHG emissions.

- Designing and maximizing the effects of energy efficiency measures and demand side management programs funded through the Public Benefits surcharge.
- Building the necessary infrastructure for installing electric vehicle charging stations and streamlining the permitting process.
- Simplifying the process for participating in energy storage markets.

Greenhouse Gas Emission Reduction Statutes

Several legislative statutes mandated aggressive reductions in GHG emissions with requirements set for 2020, 2030, 2045, and 2050.

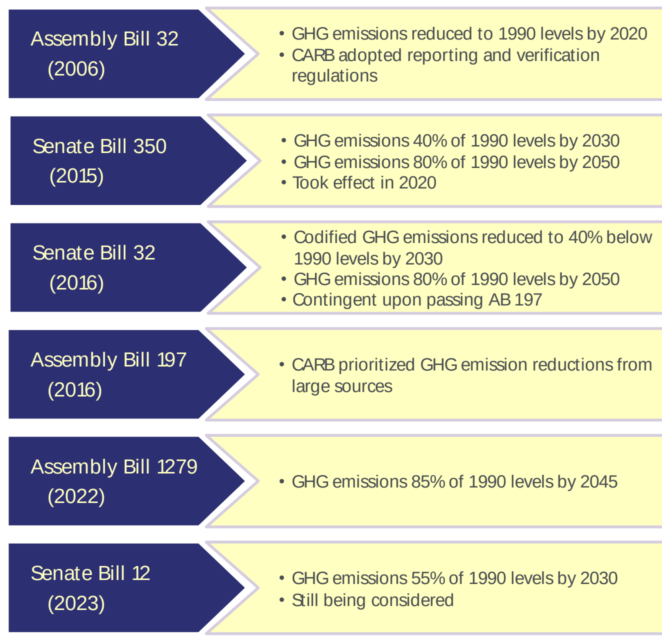


Figure 14. Greenhouse Gas Emission Reduction Legislation

Assembly Bill 32: California Global Warming Solutions Act of 2006. AB 32 required that aggregated GHG emissions be reduced to the levels measured in 1990 by 2020. CARB is required to continue and coordinate the overall climate change policies. CARB is also required to monitor and enforce compliance through a process for utilities to report and self-verify its emission reductions. CARB adopted a regulation for the "Mandatory Reporting of Greenhouse Gas Emissions" and a "Cost of Implementation Fee Regulation".

AB 32 also contained a provision for a cap-and-trade program (see page 3-8).

Senate Bill 350: Clean Energy and Pollution Reduction Act of 2015. Following passage of SB 350 in 2015, the bill included a provision to set precise levels of GHG emission reductions: 40 percent of 1990 levels by 2030 and 80 percent of 1990 levels by 2050. Due to the substantial impact of the bill's provisions, SB 350 took effect in 2020, almost five years after it was signed into law.

SB 350 also contained provisions for establishing RPS targets (page 3-4), increasing energy efficiency (page 3-9), promoting transportation electrification (page 3-22), and taking steps to implement a regionalization strategy in the Western Interconnection (page 3-24).

Senate Bill 32: California Global Warming Solutions Act of 2006 – 2030 Emissions Limit. In 2016, SB 32 expanded the GHG emission reduction provisions implemented in AB 32 by codifying the levels set in SB 350: reducing GHG emissions to 40 percent below 1990 levels by

2030 and by 80 percent by 2050. CARB is responsible for ensuring that California meets this goal.

Since the passage of SB 32, VPU has been reducing its reliance on the gas-fired generation that produces GHG emissions in several ways: by transitioning to more renewable resources, increasing energy efficiency, promoting local rooftop solar installations, and transitioning to transportation and building electrification.

Assembly Bill 197: California Global Warming Solutions Act of 2006 – Direct Emissions. AB 197 required CARB to adopt regulations to achieve the maximum amount of GHG emission reductions in a cost-effective manner and to prioritize direct emission reductions from large, stationary, and mobile sources.

To comply with AB 197, VPU has reduced overall GHG emissions through several transportation electrification (see "Transportation Electrification Impacts" on page 4-13) and energy efficiency initiatives.

Assembly Bill 1279: The California Climate Crisis Act of 2022. AB 1279 established a statewide goal for achieving carbon neutrality within the next two decades. The bill furthered GHG emission reduction goals by requiring an 85 percent reduction of 1990 levels no later than 2045 and to continue that reduction into the future.

AB 1279 also contained a provision for an update to the RPS requirement (see page 3-5).

Senate Bill 12 of 2023. Introduced in late 2022 and still being debated, the bill sought to decrease GHG emissions by changing the current goal of "40 percent reduction from 1990 by 2030" and replacing it with an aggressive target rate reduction of 55 percent.

Renewable Portfolio Standard and Zero-Carbon Resources

California RPS Statutes

Five legislative statutes set various targets for replacing carbon-fueled generation with renewable and zero-carbon resources by establishing RPS targets starting in 2013 and culminating in 2045, with a crucial target in 2030.

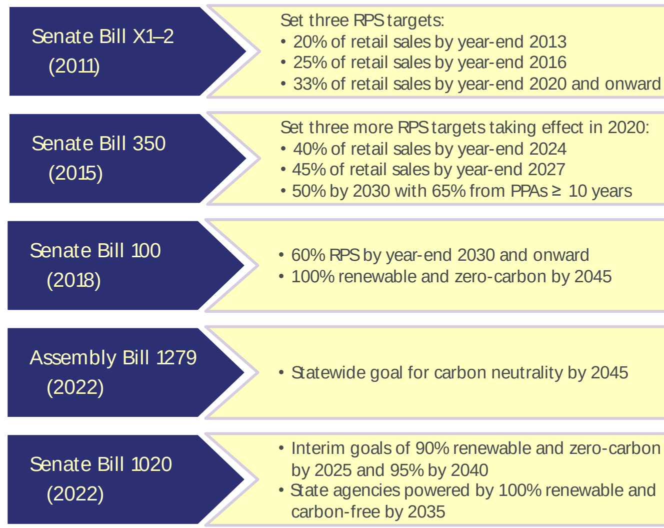


Figure 15. RPS and Zero-Carbon Target Legislation

Senate Bill X1–2: California Renewable Energy Resources Act of 2011. This bill fundamentally modified California's RPS by setting three new goals that apply to all retail electric providers in the state, including POUs, IOUs, ESPs, and CCAs. The bill defines compliant resources, establishes goals and minimum increases over time for a specific percentage of retail sales, and specifies the location and delivery point for renewable resources.

The RPS targets are:

- 20 percent of retail sales by year-end 2013.
- 25 percent of retail sales by year-end 2016.
- 33 percent of retail sales by year-end 2020 and thereafter.

VPU's governing board, the City Council, must implement these requirements with the CEC, with CARB having the specific enforcement authority.

Senate Bill 350: Clean Energy and Pollution Reduction Act of 2015. SB 350 called for a new set of objectives to improve air quality and public health, reduce GHG emissions to address the impacts of climate change, and expand other clean energy policies.

The bill was signed into law in 2015 and took effect in 2020. The bill established the California's renewable energy procurement goal of 33 percent by 2020 and 50 percent by 2030; with the 50 percent target that must be maintained into the future. The bill includes an interim goal of 40 percent RPS by 2024 and 45 percent RPS by 2027. Starting in 2021, at least 65 percent of RPS procurement must be derived from long-term contracts of 10 years or more.

The bill defined the renewable energy and zero-carbon sources that support the RPS goals. Renewable energy includes generation from solar, wind, geothermal, small hydroelectric, municipal solid waste, biofuels (biodiesel, biomass, and biomethane), fuel cells using renewable fuel, and hydrokinetic energy (ocean thermal energy conversion [OTEC], ocean wave, and tidal current). Zero-carbon generation that does not emit climate-altering greenhouse gases include large hydroelectric and nuclear technologies.

Senate Bill 100: The 100 Percent Clean Energy Act of 2018. Passed in 2018, SB 100 accelerated the state's RPS set in SB 350 to ensure that, by 2030, at least 60 percent of California's electricity is renewable. This percentage of renewable generation must be maintained at or above 60 percent from 2030 onward. In addition, SB 100 requires that renewable energy generation and zero-carbon resources power 100 percent of retail electricity sold in California by the year 2045.

While not specified in SB 100, combustion resources fueled by biofuels or hydrogen derived from renewable energy resources are defined as zero-carbon resources. In addition, while all retail electricity sales in California must come from renewable and zero-carbon resources by 2045, the transmission and distribution line power losses (due to heat) can still be served by fossil fuel-powered generation.

Finally, SB 100 required the CEC, the CPUC, and CARB to employ programs under existing laws to achieve 100 percent clean electricity and issue a joint policy report on SB 100 by 2021 and every four years thereafter.

Assembly Bill 1279: The California Climate Crisis Act of 2022. AB 1279 established a statewide goal for achieving carbon neutrality no later than 2045 and thereafter.

Senate Bill 1020: The Clean Energy, Jobs, and Affordability Act of 2022. In September 2022, SB 1020 added interim goals and the clean energy mandates established in SB 100. SB 1020 requires that eligible renewable energy and zero-carbon resources supply 90 percent of all retail electricity sales to California end-use customers by December 31, 2035, and supply 95 percent of all retail electricity sales by December 31, 2040. In addition, all electricity delivered to California state agencies must be supplied by renewable and zero-carbon energy resources by the end of 2035.

California RPS Goals

Under current legislation, all California retail electric providers that serve electric load, including IOUs, CCAs, ESPs, and POUs, must participate in the RPS program and comply with numerous deadlines to meet RPS goals.

Table 2 summarizes the compliance periods (CPs) and RPS targets, along with the corresponding legislations. Thus far, the CPUC has designated six CPs for reporting.

CP	%	Compliance Year	Bill	Bill Year	Notes
1	20%	2013	SB X1-2	2006	SB 1078 initially set a 20% RPS target for 2017
2	25%	2016	SB X1-2	2006	
3	33%	2020	SB 350	2015	Maintained in subsequent years
4	40%	2024	SB 350	2015	—
5	45%	2027	SB 350	2015	—
6	60%	2030	SB 100	2018	SB 350 initially set a 50% target for 2030
–	90%	2035	SB 1020	2022	From eligible renewable & zero-carbon resources
–	95%	2040	SB 1020	2022	From eligible renewable & zero-carbon resources
–	100%	2045	SB 100	2018	From eligible renewable & zero-carbon resources

Table 2. Renewable Portfolio Standard Percent Goals and Target Years

Starting in CP 3, the portfolio mix of all retail electric providers that serve electric load in California must be made up of 75 percent or more, from two portfolio contents categories (PCCs), PCC-0 and PCC-1 resources, 15 percent or less of PCC-2, and 10 percent or less of PCC-3 resources[2]. In addition, starting with CP 4 (2021–2024), the RPS procurement requires 65 percent or more of owned or PPA contracts that extend 10 years or more. Both requirements must be maintained starting in CP 4 and beyond. The annual RPS compliance report is due to the CPUC on July 1.

[2] PCC-0 designates a renewable resource located within the state of California or, a renewable resource that is directly delivered to California without energy substitution from another resource that was signed or went online before June 1, 2010. PCC-1 designates these resources that went online after June 1, 2010. PCC-3 designates a tradable or unbundled REC from a resource, delivered without the energy component.

Figure 16 depicts the RPS percent procurement requirements by CP, breaking the CPs into interim goals by year.

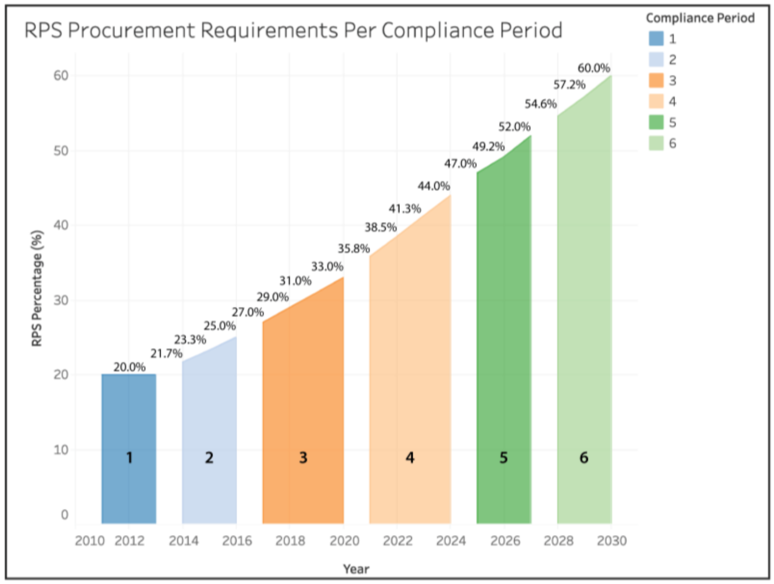


Figure 16. RPS Percent Procurement Requirements by Compliance Periods[3]

The CPUC has developed a formula for determining the procurement quantity requirements for CP 4, CP 5, and CP 6. The three formulas follow a pattern based on the following: the average procurement quantity of the electricity product over each related CP must be greater than or equal to the retail sales (RS) as calculated in each formula. Table 3 shows these formulas.

CP4 Procurement Quantity ≥			
	35.750%	*	2021 RS
+	38.500%	*	2022 RS
+	41.125%	*	2023 RS
+	44.000%	*	2024 RS

CP5 Procurement Quantity ≥			
	47.000%	*	2025 RS
+	49.2.000%	*	2026 RS
+	52.000%	*	2027 RS

CP6 Procurement Quantity ≥			
	54.600%	*	2028 RS
+	57.200%	*	2029 RS
+	60.000%	*	2030 RS

Table 3. RPS Compliance Period Procurement Quantity Formulas

The California Code of Regulations, Title 20, Section 3201, defines both electricity product and retail sales as follows:

- "Electricity product" means either (1) electricity and the associated RECs generated by an eligible renewable energy resource or (2) an unbundled REC.
- "Retail sales" means electricity sales by a POU to end-use customers and their tenants, measured in MWh. This does not include energy consumption by a POU, electricity used by a POU for its water pumping, or electricity produced for onsite consumption (self-generation).[4]

In 2018, VPU's resource portfolio was comprised of 31 percent renewable generation and 10 percent zero-carbon generation. Since then, VPU's share of the Astoria II Solar facility has risen to 30 MW. In addition, VPU has attained a PPA for 60 MW from the Daggett Solar

[3] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/60-percent-rps-procurement-rules

[4] https://casetext.com/regulation/california-code-of-regulations/title-20-public-utilities-and-energy/division-2-state-energy-resources-conservation-and-development-commission/chapter-13-enforcement-procedures-for-the-renewables-portfolio-standard-for-local-publicly-owned-electric-utilities/section-3201-definitions

facility, plus 30 MW of BESS and 39 MW from the Sapphire Solar facility, plus 19.67 MW of BESS. The COD for Daggett Solar is December 20, 2023; the COD for Sapphire Solar is December 31, 2026. The addition of these PPAs increases the renewable generation portion of VPU's entire resource portfolio.

Subsidies for Customer Rooftop Solar

Senate Bill 1: Subsidies for Customer Solar. SB 1 was enacted in 2006 to increase the number of rooftop solar PV systems, thus offsetting carbon resources and reducing GHG emissions. Potential systems include microturbines, fuel cells, solar, and solar plus battery storage installations. The bill raises the net energy metering (NEM) cap from 0.5 percent to 2.5 percent of VPU's aggregate customer peak demand.

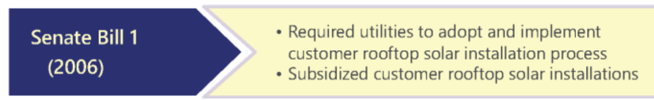


Figure 17. Customer Rooftop Solar Installation Legislation

Among related provisions, the legislation requires utilities to offer financial incentives for a limited time to encourage customer rooftop solar PV installations. A portion of those incentives must encourage optimal solar production during peak demand periods and energy efficiency improvements. Since its inception, VPU has met the requirements of the bill's provisions by offering incentives for solar installations during a 10-year period from 2008-2017. In addition, the utility continues to offer NEM and plans to develop a successor tariff in the near future.

Cap-and-Trade Program and Market

Assembly Bill 32: California Global Warming Solutions Act of 2006. AB 32 established a cap-and-trade market for carbon emissions requiring CARB to create two types of newly tradable commodities known as a California Compliance Instrument (CCI) Allowance and CCI Offset. Allowances are essentially permits created and issued by CARB that allows the holder to legally emit one metric ton (MT) of GHG measured in carbon dioxide equivalents (CO_2-e).

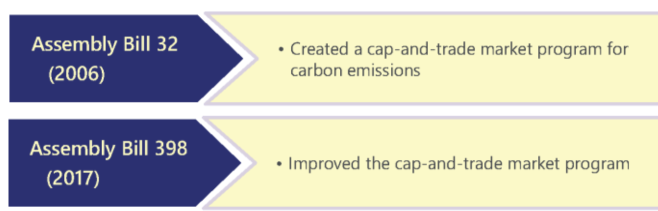


Figure 18. Cap-and-Trade Program Legislation

A CCI Offset is created when an approved project results in a GHG reduction or removal. These projects must be accurate, quantifiable, permanent, verifiable, and enforceable reductions or removals of GHG in the environment. An independent third-party verifier must periodically inspect these projects to ensure compliance with protocols created or adopted by

CARB. To comply with AB 32, a CCI Allowance and a CCI Offset must equally offset each other to allow for the legal emission of one MT of GHG, measured in CO_2-e.

Assembly Bill 398: Cap-and-Trade Extension. AB 398 extended and improved the cap-and-trade program established in AB 32. The extension enables California to meet the 2030 GHG emission reduction goals in a cost-effective manner, and also generates billions of dollars in auction proceeds to invest in statewide communities.

Energy Efficiency and Demand-Side Management

Assembly Bill 2021: 10-Year Energy Efficiency Targets. AB 2021 required POUs to establish specific annual energy efficiency goals as a percentage of total annual retail electric consumption and establish 10-year targets every three years, starting 2007. Before investing in new carbon-based resources, utilities must exhaust savings from all available energy efficiency and demand reduction resources that are cost-effective, reliable, and feasible. The cost of implementing this program was funded through a 2.85 percent surcharge on customer bills. The statute also required the CEC to quantify all achievable energy efficiency savings to establish realistic attainment levels.

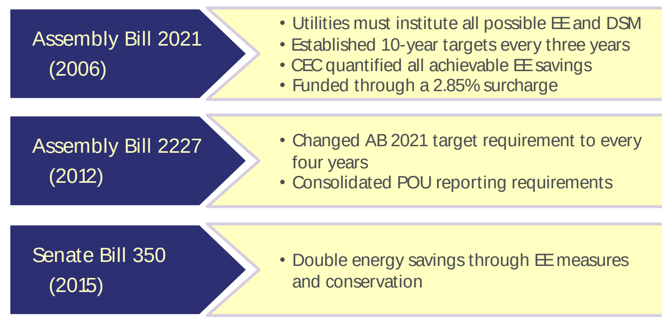


Figure 19. Energy Efficiency and Demand-Side Management Legislation

Assembly Bill 2227: 10-Year Energy Efficiency Targets (Amendment). AB 2227, passed in 2012, replaced the three-year requirement to establish 10-year energy efficiency goals to every four years. In addition, AB 2227 also consolidated all of the POU reporting requirements into a minimum number of sections in the Public Utilities Code (PUC).

Senate Bill 350: The Clean Energy and Pollution Reduction Act of 2015. Among the various provisions set forth by SB 350, a key requirement directed state agencies to double the energy savings in electricity and natural gas end uses through energy efficiency and conservation by 2030.

Transportation Electrification

Senate Bill 350: Clean Energy and Pollution Reduction Act of 2015. SB 350 required utilities to propose multiyear programs and investments to accelerate widespread transportation electrification that reduce dependence on petroleum, meet air quality standards, achieve EV charging station goals, and reduce GHG emissions. The CPUC, in consultation with CARB and the CEC, approves these programs and their investments.

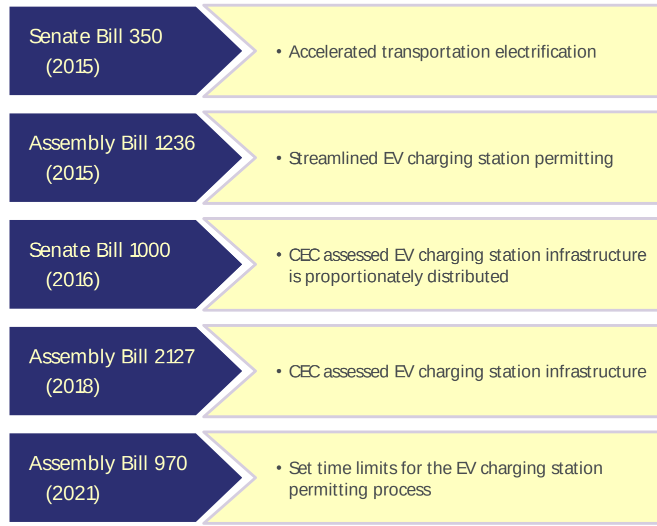


Figure 20. Electric Vehicle Charging Legislation

Assembly Bill 1236 (2015): Local Ordinances Electric Vehicle Charging Stations. AB 1236 required cities and counties to adopt an ordinance that creates an expedited, streamlined permitting process for EV charging stations based on criteria listed in the Permitting Electric Vehicle Charging Stations Scorecard.

Senate Bill 1000 (2016): Land Use Safety and Environmental Justice. SB 1000 required the CEC to assess whether EV charging infrastructure, especially DCFC stations, is disproportionately deployed by population density, geographical area, or by low-, middle-, and high-income levels and whether access to these charging stations is disproportionately available.

Assembly Bill 2127 (2018): Electric Vehicle Charging Infrastructure Assessment. AB 2127 required the CEC to assess all EV charging infrastructures to determine how well they meet the state’s goal of adding at least five million ZEVs by 2030 and reducing GHG emissions to 40 percent below 1990 levels by 2030.

Assembly Bill 970 (2021): Electric Vehicle Charging Stations Permit Application. AB 970 provides additional details set forth in AB 1236 by clarifying the EV charging station permitting process and setting deadlines for application acceptance.

The City of Vernon is subject to the regulations outlined in AB 1236 and AB 970, as it requires all California cities and counties with populations fewer than 200,000 residents to expedite and streamline permitting process for EV charging stations starting January 1, 2023. See “Electric Vehicle Charging Infrastructure” on page 5-11 for more detail about how VPU complies with all EV charging station statutes.

Energy Storage Resources

In early 2018, the Federal Energy Regulatory Commission (FERC) passed Order 841. The rule requires all Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to remove barriers by revising its tariff so electric storage resources can participate in the markets they operate. Order 841 enhances competition, promotes greater efficiency, and supports resiliency of the bulk power system.

The participation model ensures that an electric storage resource is eligible to provide all capacity, wholesale energy, ancillary services, and dispatch capability. Energy storage resources, whether on the transmission system, distribution system, or behind the meter, are able to participate and respond to wholesale market pricing signals.

Order 841 eliminates a major barrier for energy storage resources by ensuring more opportunities to provide grid benefits with fair compensation for those services. It enhances the ability to add increasing amounts of renewable generation to the power grid.

STATEWIDE PLANNING CONSIDERATIONS

Several external factors drive the planning of the IRP.

California Air Resources Board Scoping Plan

The 2022 CARB Scoping Plan for Achieving Carbon Neutrality lays out a sector-by-sector roadmap for California to achieve carbon neutrality by 2045 or earlier through the reduction of anthropogenic GHG emissions by 85 percent below 1990 levels, using cost-effective technology.

Two previous scoping plans focused on GHG reduction targets for industry, energy, and transportation, with the first scoping plan designed to meet 1990 levels by 2020, followed by the second scoping designed to achieve at least 40% below 1990 levels by 2030. The 2022 scoping plan extends the previous goals to comply with current legislation. This scoping plan seeks to eliminate the disproportionate burden of air pollution and ensure equity for underserved and disadvantaged communities.

The actions and outcomes in the scoping plan will achieve:

- A significant reduction in fossil fuel combustion by deploying clean technologies and fuels.
- A further reduction in short-lived climate pollutants.
- Support for sustainable development.

- Increased action on natural and agricultural lands to reduce GHG emissions, including CCS technology.

The 2022 Scoping Plan assumes:

- Thirty-eight million metric tons (MMT) GHG carbon dioxide (CO_2) emission reduction target by 2030.
- Sixty percent RPS by 2030.
- Vehicle miles travelled per capita reduced to 4 percent of 2019 levels by 2045. (Per-capita vehicle miles travelled increased from 2017 to 2019; assuming even a marginal decrease, without additional action, risks achieving 2030 emission reduction goals.)

Under this Scoping Plan, the role of electricity in powering the economy will grow in almost every sector. A clean, affordable, and reliable electricity grid will serve as a backbone to support decarbonization efforts across California's economy. Energy efficiency and the replacement of fossil-fueled generation with renewable and zero-carbon resources are two important components to decarbonizing the electric sector.

The Scoping Plan incorporates the goal of doubling energy efficiency, as set forth in SB 350, and aligns with:

- The CPUC's IRP 2030 GHG target and latest GHG emissions benchmarks through 2035.
- The Governor's 20 gigawatt (GW) offshore wind and no new natural gas generation goals.
- SB 100's 2030 RPS and 2045 zero-carbon retail sales targets.

The goal is to reduce dependence on fossil fuels in the electricity sector by transitioning substantial energy demand to renewable and zero carbon resources. Achieving the goals established in SB 100 require 6 GW of new solar, wind, and battery resources over the next 25 years. This requires tripling the existing amount of solar and wind installations at an eight-fold acceleration in conjunction with BESS to achieve the 2030 and 2045 targets.

A significant element of this transition is through transportation electrification, which involves replacing fossil fuel vehicles with ZEVs. CARB's Advanced Clean Fleet regulation helps accelerate the timeline of electrifying heavy-duty vehicles. The Advanced Clean Cars II (ACC II) rule also requires all car sales in California to be 100 percent zero emission by 2035. To this extent, VPU has made progress in electrifying a portion of its municipal fleet. (See "Transportation Electrification Impacts" on page 4-13.)

Transportation and building electrification both require substantially increasing clean energy production and expanding the distribution infrastructure to achieve decarbonization. The electric power grid must evolve and grow exponentially over the next two decades to ensure reliable, affordable, and resilient energy delivery.

This plan also calls for increasing renewable hydrogen for hard-to-electrify end uses. Upon its full implementation, this Scoping Plan would reduce the demand for petroleum by 94 percent below 2022 levels by 2045.

CEC Integrated Energy Policy Report Demand Forecasts

The CEC prepares the Integrated Energy Policy Report (IEPR) every two years, updated every other year. The IEPR outlines a cohesive approach to best manage California's energy transition from oil and natural gas to renewable energy resources and alternatively fueled vehicles. The report assesses and forecasts energy-related trends and, using that information, develops "energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state's economy, and protect public health and safety."[5]

The IEPR includes the California Energy Demand Update (CEDU) for 2022. The CEDU includes updates to historical data, economic and demographic projections, electricity rates, and hourly forecasts, as well as incorporates a new assessment approach for the transportation sector, given the rapid advancements in electrification.

The CEC revised forecasting framework includes a baseline forecast, a planning forecast, and a local reliability scenario. To better evaluate electricity forecasts, the planning forecast contains sensitivity scenarios for additional achievable energy efficiency (AAEE), additional achievable fuel substitution (AAFS), and additional achievable transportation electrification (AATE).

The Final 2022 IEPR Update[6] (filed February 28, 2023) assesses several trends: economic and demographic, climate, behind-the-meter solar photovoltaic (PV) and storage, and transportation as well as state policies and goals. Using these trends, the IEPR includes forecasts for the 2023–2035 timeframe for:

- Annual electricity consumption
- Electricity sales
- Managed sales, including AAEE, AAFS, and AATE electricity impacts
- Peak demand (load)

These IEPR forecasts provided a necessary framework for the development of the VPU IRP and its energy and peak demand forecasts.

[5] Pub. Res. Code § 25301(a)

[6] *Final 2022 Integrated Energy Policy Report Update with Errata*, California Energy Commission; Docket Number 22-IEPR-01, TN # 248998, February 28, 2023

CAISO Transmission Planning Process

The CAISO 2021–2022 Transmission Plan (published March 17, 2022) articulated an accelerated pace for developing new transmission facilities based on an average of 2.7 GW of new resources per year over the next decade.

On May 23, 2023, the CAISO Board of Governors approved its 2022–2023 Transmission Plan. That plan updated its needed capacity projections to more than 40 GW of new resources over the next decade; a sensitivity study projected the need for up to 70 GW over the same period. CAISO expects that next year's Transmission Plan will be based on this 70 GW projection, which is expected to grow to 120 GW to better align with the goal of a carbon-free power system by 2045. These projections consider the imminent retirement of over 7 GW of natural gas-powered and nuclear-powered generation.

Several factors drive this accelerated pace:

- The urgency of decarbonizing the electricity grid because of emerging climate change impacts.
- Higher electricity forecasts due to the expected electrification of transportation, building and construction, and other carbon-emitting industries.
- Reduced access to opportunity imports with the decarbonization of neighboring systems.
- Greater than anticipated impacts of peak demand shifting to evening hours when solar resources are unavailable.
- Maintaining system reliability when the Diablo Canyon Nuclear Power Plant and quantities of gas-fired generation that relied on coastal waters for once-through cooling (OTC) retirement.

Decarbonizing the power grid requires increased generation from solar PV, onshore and offshore wind, geothermal, out-of-state renewables, along with nuclear and hydrokinetic resources. Battery storage also plays a role in decarbonizing the power grid. In conjunction, the transmission system must be expanded, upgraded, and reinforced to integrate these resources to accommodate the expected increase in electricity consumption as transportation and other industries electrify.[7]

Several factors drove the new transmission plan. CAISO has received many interconnection requests from "areas that regulators and load-serving entities have not considered optimal for additional transmission development." In addition, CAISO has received "an excessive volume of interconnection requests" in optimal areas. This resulted in much longer wait times for resource developers to receive the results of their construction requests and more uncertainty around load-serving entities (LSEs) procuring additional resources.

[7] *California ISO 2021–2022 Transmission Plan*, CAISO, March 17, 2022; p. 1.

CAISO has created the new transmission plan in collaboration with the CPUC and the CEC and with input from hundreds of stakeholders that takes advantage of transmission and interconnection capacity under development. The interconnection process has also been optimized for transmission upgrades to accommodate longer-term resource development, such as out-of-state and offshore wind.[8]

The transmission plan focuses on ensuring that renewable resources can reliably connect and be delivered; it does not ensure that congestion would preclude achieving state policy goals.[9] The plan outlines potential transmission system solutions, which CAISO can initiate, as well as non-transmission solutions (such as energy efficiency, demand response (DR), renewable generating resources, and energy storage programs) that require regulatory approval.[10]

The 2022–2023 Transmission Plan "tightens the linkages between resource and transmission planning activities, interconnection processes and resource procurement so California is better equipped to meet its reliability needs and clean-energy policy objectives required by Senate Bill 100."[11] The plan outlines the need for a total of 46 transmission projects primarily built in California. The transmission projects range in projected costs from $4 million to $2.3 Billion, for a total infrastructure investment of an estimated $9.3 Billion.[12]

Using resource planning information provided by the CPUC, CAISO plans to develop a final transmission plan, initiate transmission projects, and communicate to LSEs the specific geographic zones being targeted for such projects. The CPUC, in turn, will direct LSEs to procure energy from those zones whose interconnection requests will be given priority.

8 http://www.caiso.com/about/Pages/Blog/Posts/A-better-way-to-address-interconnections.aspx

9 CAISO 2022, *op. cit.*; p. 2.

10 *Ibid.*

11 *California ISO Draft 2022–23 Transmission Plan*, CAISO, April 3, 2023; p. 1.

12 *Ibid.*; p. 3.

In concert with CPUC-provided resource planning information, the transmission plan identifies specific geographic zones targeted for transmission projects. Figure 21 depicts these geographic zones.

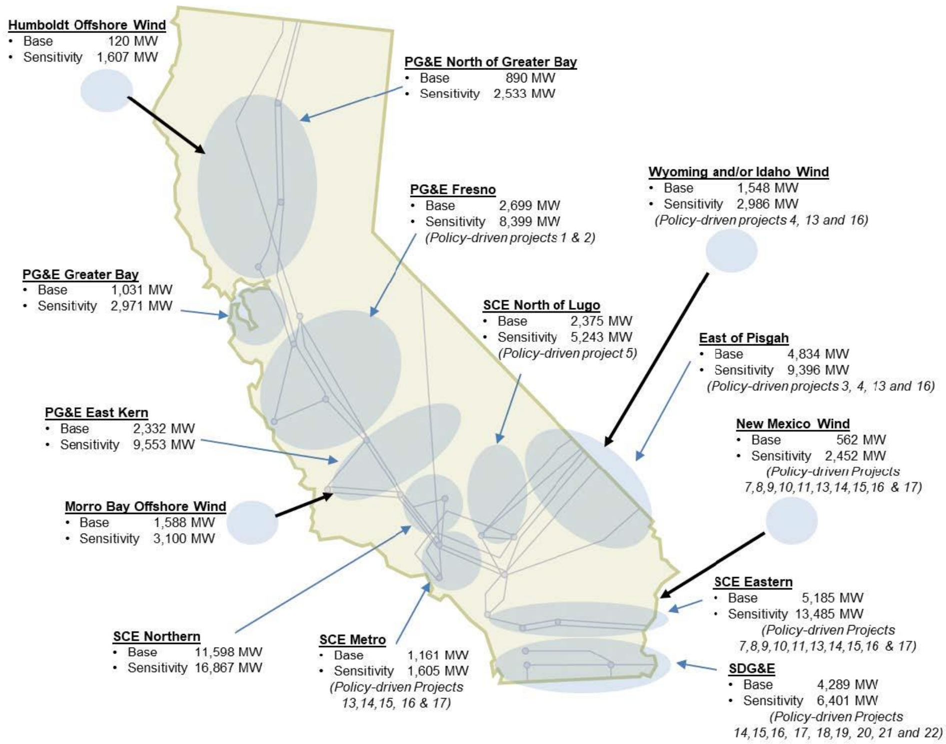


Figure 21. CAISO Transmission Planning Zones and Capacities[13]

Southern California Edison is reconductoring the existing Laguna Bell-Mesa #1 230 kV line and upgrading the corresponding substation's terminal equipment because the line has experienced thermal overloads. This transmission upgrade directly affects VPU. (For details, refer to "Laguna Bell Corridor Line Upgrades" on page 7-2.)

13 *Ibid.*; p. 4.

Resource Adequacy Methodology

In 2004, the CPUC established its RA Program with two goals: (1) to ensure safe and reliable electric service by providing sufficient resources to CAISO and (2) to create incentives for siting and constructing new resources.

Resources are counted based on their capacity contribution, as well as on assigned 24-hour profiles for wind and solar, dispatchable and non-dispatchable resources, dispatchable hydroelectric, energy storage, hybrid and co-located resources, imported resources, and demand response. The RA program also adopted monthly effective load carrying capability (ELCC) values for solar and wind resources beginning in 2023.

RA resources must be available during five-consecutive peak hours as designated by CAISO. LSEs within CAISO must demonstrate three distinct requirements of RA, System RA, Local RA, and Flexible RA, and file annual and monthly reports for each requirement.

System RA. This requirement maintains electricity during peak demand periods during the day, generally early morning and early evening. Capacity is determined by forecasting peak demand and adding a minimum 15 percent planning reserve margin (PRM).

LSEs must own, control, or contract rights to its RA resources, which must demonstrate sufficient CAISO-verified net qualifying capacity (NQC) to meet monthly coincident peak demand plus a PRM. VPU’s seasonal load profile is unique; it has a very high load factor of above 70 percent during summer and winter months.

VPU determined the capacity needed to maintain reliability for each year in the short-term planning period (2023 through 2031). Results demonstrate that VPU meets the short-term RA requirements through existing local and contracted resources.

Local RA. This requirement maintains electricity during grid contingencies where bulk transmission limitations or other conditions may constrain the electrical supply available to serve load. These include transmission line failures or a power plant tripping offline.

CAISO has identified ten transmission constrained areas in its jurisdiction area. VPU resides in the Los Angeles Basin and meets the 70 MW local RA obligation through the Vernon-owned and operated MGS and H. Gonzales power plants. This local generation insulates VPU from an N-2 contingency involving two transmission lines.

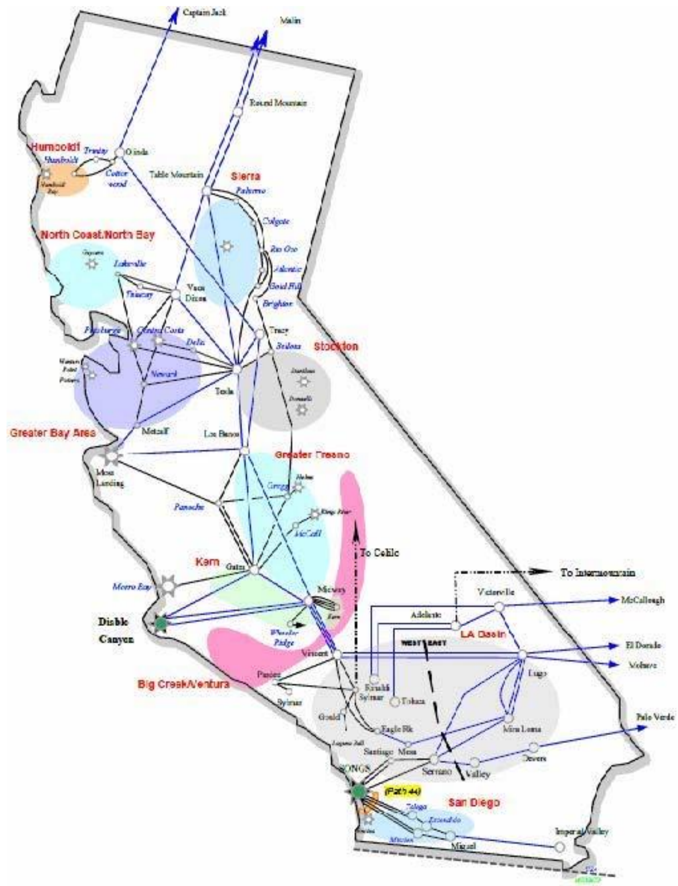


Figure 22. CAISO Local Capacity Area Map

Flexible RA. This requirement maintains electricity during evening peak demand when solar generation is diminishing and ensures enough flexible capacity to meet expected demand.

Increasing amounts of variable renewable generation present a challenge for meeting daytime demand. Sufficient capacity must be flexible and dispatchable enough to meet daily changing demand profiles, especially the ramping requirements for meeting peak evening demand.

The so-called duck curve (Figure 23) demonstrates the balancing act necessary to meet this challenge.

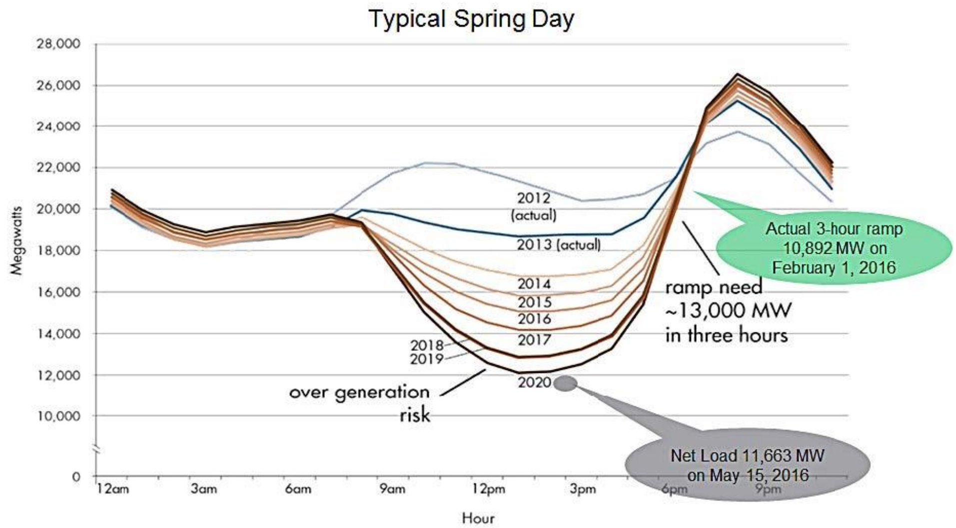


Figure 23. The Variable Renewable Generation Duck Curve

Every year, CAISO identifies the largest forecasted three-hour net load ramps plus 3.5 percent to determine the RA requirements for each LSE. The target RA can react quickly enough to meet net demand without over-generating. Solar generation requires capacity to ramp down in the morning when solar generation begins, followed by ramping up in the evening when solar generation wanes.

Flexible RA resources fall into three categories, each with increasingly stringent operating characteristics: Base Ramping, Peak Ramping, and Super-Peak Ramping. A Base Ramping resource also qualifies as a Peak Ramping resource, and both resources qualify as a Super-Peak Ramping resource.

Table 4 outlines the primary characteristics of each Flexible RA category.

Category	Available Days	Available Hours	Minimum Hours at Full Effective Flexible Capacity	Minimum Startups
Base Ramping	Every day	17 hours per day, 5:00 to 22:00	6 hours	2 per day; 60 per month
Peak Ramping	Every day	5 hours per day hours vary by season	3 hours	1 per day
Super-Peak Ramping	Non-holiday weekdays	5 hours per day, hours vary by season	3 hours	1 per day; 5 CAISO dispatches per month

Table 4. Flexible Resource Adequacy Categories

CAISO dictates the Flexible RA requirements for VPU (Table 5). VPU deploys MGS with its 105 MW of eligible flexible capacity and H Gonzales with its 23 MW for eligible flexible capacity to meet VPU's Flexible RA requirements. Both MGS and H Gonzalez are locally-sited and are used to meet VPU's flexible capacity needs.

Month	Base %	Base Ramping (MW)	Peak Ramping (MW)	Super-Peak Ramping (MW)	Total (MW)
January	40%	16.09	31.30	2.49	49.88
February	40%	20.98	40.80	3.25	65.03
March	40%	21.06	40.97	3.26	65.29
April	40%	20.03	38.95	3.10	62.08
May	50%	27.60	29.75	3.02	60.37
June	50%	27.78	29.93	3.04	60.75
July	50%	26.93	29.02	2.94	58.90
August	50%	27.47	29.61	3.00	60.08
September	50%	28.16	30.35	3.08	61.59
October	40%	20.69	40.24	3.21	64.13
November	40%	18.79	36.55	2.91	58.26
December	40%	16.28	31.67	2.52	50.47

Table 5. Flexible Resource Adequacy Capacity Requirements: 2023

Increased penetration of solar resources causes an increase in Flexible RA requirements. VPU's 2023 Flexible RA requirement increased by slightly more than 58 percent compared to the requirements stated in VPU's 2018 IRP. For 2023, VPU assumed that each addition of 60 MW of solar would result in an approximate increase in 60 MW for Flexible RA capacity. Ongoing increases in Flexible RA requirements, together with their associated costs, were factored into the modeling and analysis of this IRP's optimal resource portfolio.

Table 6 lists VPU's RA capacity for each committed resource compared to its total RA requirements.

Committed Unit	System RA (MW)	Local RA (MW)	Flexible RA (MW)
Malburg Combined Cycle	139.0	139.0	105.0
H Gonzales 1 & 2 Combustion Turbines	11.5	11.5	11.5
Palo Verde Nuclear	11.0	0.0	0.0
Hoover Dam Hydroelectric	15.0	0.0	0.0
Puente Hills Landfill Gas	4.0	0.0	0.0
Antelope DSR Solar PV	3.0	0.0	0.0
Astoria Solar PV	4.0	0.0	0.0
2023 RA Capacity	187.5	150.5	116.5
2023 RA Requirement	183.0	70.0	66.0
Long (Short)	4.5	80.5	50.5

Table 6. Resource Adequacy Capacity: 2023

Building Electrification Impacts

The CEC Building Energy Efficiency Standards, also known as Title 24 or the Energy Code, is an integral part of the state's efforts to reduce carbon emissions and address the ongoing issues related to climate change. The latest updates to the 2022 Energy Code reinforces the concept of building electrification, which not only encourages the adoption of efficient all-electric technologies by reducing emissions from newly constructed buildings but also increases electric load flexibility to support grid reliability and enable increased opportunities for on-site renewable energy generation through solar. Along the same lines, the 2022 Strategy for the State Implementation Plan (SIP) adopted by CARB is also aims to reduce building emissions in the form of nitrous oxide (NOx) due to natural gas combustion.

For VPU's customer base, which is mainly comprised of large commercial and industrial companies, this means newly constructed buildings must utilize electricity as the primary fuel for its core functions. This approach deviates from traditional fuel sources that includes on-site combustion of natural gas, oil, propane, or other fossil fuels. While each entity has its own unique operation, a few overarching concepts for building electrification can include adopting heat pumps to decarbonize space and water heating for buildings, coupled with all-electric boilers and furnaces for operations that require high industrial heat demand.

Opportunities for battery storage systems to respond to an increasingly intermittent grid and electric vehicle charging infrastructure to support the shift to an all-electric fleet also play vital roles. Solar PV and heat pump technologies have evolved significantly in various instances and can provide cost-competitive solutions to making the switch, especially in a new construction setting.

For industrial operations, adopting all-electric equipment can reduce maintenance costs, together with improved efficiency and less challenges with meeting air quality standards. Ultimately, the impacts of building electrification still heavily depend on the difference between the ongoing costs of energy to run all-electric equipment compared to the conventional fuel type.

VPU recognizes the need for customers and site owners to assess their potential to electrify, allowing for better decision-making when it comes to investing in all-electric equipment. As a result, VPU plans to develop robust customer programs that provide technical support and incentives to streamline the transition toward building electrification. At the same time, VPU continues to implement existing programs that encourage the efficient use of energy for existing and newly constructed buildings.

Transportation Electrification Analysis

Electrification of the transportation sector is vital to reducing California's GHG emissions.

In 2012, Governor Brown issued Executive Order B-16-2012 to electrify the transportation sector, calling on the CEC and other state agencies to achieve 1.5 million ZEVs by 2025. In 2018, Governor Brown issued Executive Order B-48-18 that increased that goal to 5 million ZEVs by 2030.

In August 2022, CARB established an annualized roadmap to phase out the sale of internal combustion passenger vehicles by issuing its ACC II rule which supports Governor Newsom's Executive Order N-79-20. ACC II aims to rapidly scale down light-duty passenger car, pickup truck, and SUV emissions starting with the 2026 model year through 2035.

Figure 24 shows the annual requirements for complying with ACC II, which requires all new passenger vehicles sold in California to be zero emission by 2035.

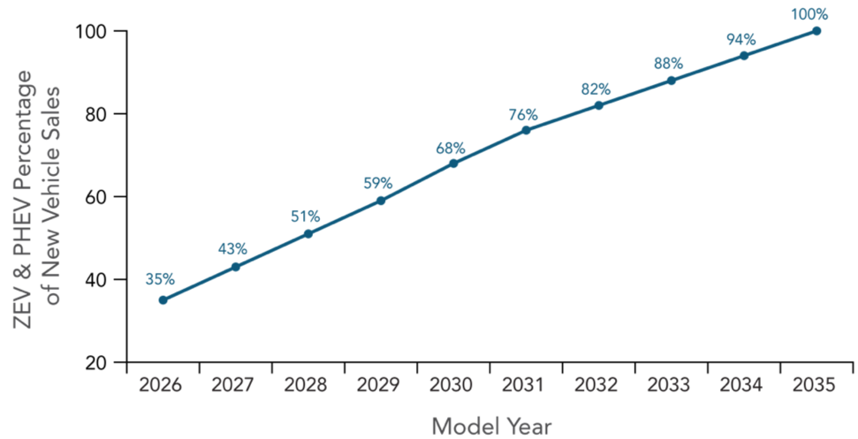


Figure 24. Zero-Emission Vehicles Sales Compliance with ACC II[14]

Transportation currently accounts for more than 50 percent of California's GHG emissions. By 2037, the rule will reduce pollution from light-duty vehicles by 25 percent to meet federal air quality standards. In 2040, GHG emissions from cars, pickups, and sport utility vehicles (SUVs) will decrease by 50 percent from today's levels. By 2040, the regulation will cut climate warming pollution from those vehicles a cumulative total of 395 MMT.

The rule delivers multiple benefits that continue to grow year after year. By 2030, 2.9 million fewer new gasoline-powered vehicles will be sold in California, rising to 9.5 million fewer gasoline-powered vehicles by 2035.

[14] https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035

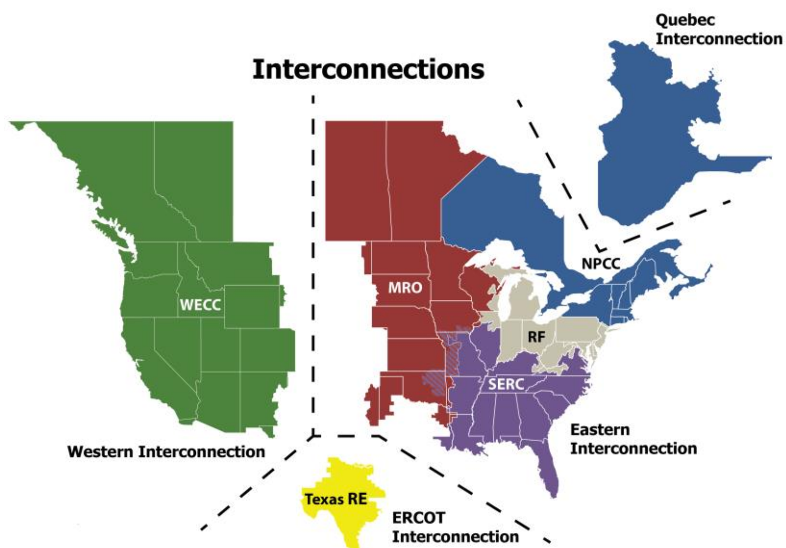
REGIONALIZATION CONSIDERATIONS AND RISKS

SB 350 took an essential step toward creating an integrated Western Interconnection system to consolidate control over electric grid operations, paving the way for easier integration and continued growth of renewable energy resources. The bill required CAISO to prepare proposed governance modifications to facilitate its transformation into a regional organization. The bill started a process for allowing CAISO to expand its wholesale electricity market programs to include out-of-state transmission owners.

The reorganization of the Western Interconnection is synonymous with grid regionalization.

The Western Interconnection and WECC

The United States power grid, which includes most of Canada, is separated into interconnection regions. The North American Electric Reliability Corporation (NERC) develops and enforces reliability standards among the interconnections. Figure 25 depicts a map of the NERC interconnection regions in North America.



MRO	Midwest Reliability Organization	NPCC	Northeast Power Coordinating Council
RF	Reliability First	SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity	WECC	Western Electricity Coordinating Council

Figure 25. North American NERC Interconnections and Governing Organizations[15]

These interconnections help maintain reliability by enabling generators to supply power to many load centers through a network of transmission routes.

Three main United States interconnections operate primarily as independent areas from each other with limited transfers of power between them. The network structure among the

15 https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx

interconnections helps maintain the reliability of the power system by providing multiple routes for power to flow and allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service.

Balancing authorities (BAs) manage this power system to finely balance demand and supply in real time. There are seven RTOs (or ISOs) that act as BAs for the three interconnections (as depicted in Figure 26).

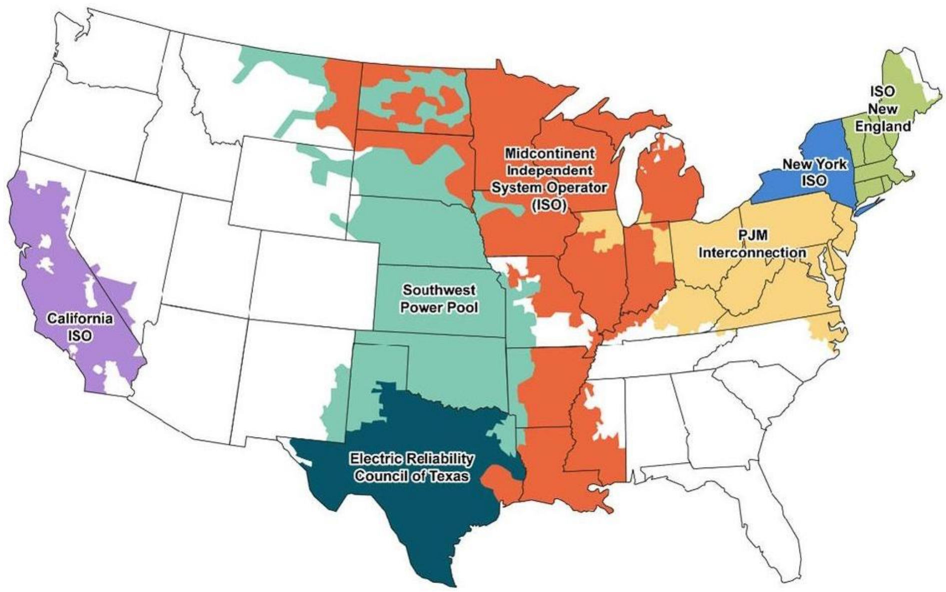


Figure 26. Map of Nationwide RTOs[16]

Five RTOs and a few large ISOs manage most of the Eastern Interconnection. The Electric Reliability Council of Texas (ERCOT) Interconnection manages itself. The Western Interconnection, however, is the most widely managed Interconnection in the country.

In 2007, NERC delegated authority to the Western Electricity Coordinating Council (WECC) as the regional entity to enforce its compliance standards throughout the Western Interconnection. Its two core missions are to coordinate reliability and transmission access to the bulk electric system (BES). WECC is responsible for over 300 member organizations, each operating within one of the 38 BAs in the Western Interconnection. Of those BAs, 37 are independent utilities; only CAISO is an ISO.

Over the years, CAISO has accomplished much to move the Western Interconnection closer to a renewable and clean energy future. While effective for several years, this structure is beginning to create problems for California as it pursues its climate change and clean energy objectives.

[16] https://www.eia.gov/todayinenergy/detail.php?id=790

CAISO as a Regional Transmission Operator

The Western Interconnection power grid can improve access to renewable energy, strengthen grid reliability, and unify transmission system planning, thereby reducing costs and GHG emissions.

CAISO has faced severe challenges in recent years due to several factors. Summer months have resulted in high demands and energy shortages, coupled with delayed renewable and clean energy projects. As a result, CAISO had to implement drastic steps to maintain natural gas plants and diesel backup generators. The option of joining other western states to create a regional grid operator might be the optimal solution for the transition to an all-clean energy market with improved grid reliability at lower costs.

In 2018, California legislators proposed AB 813, which would have enabled CAISO to become an RTO. The bill, however, did not pass. Since then, the struggle of electric utilities in California to meet state goals has led to a surge in clean energy and transmission expansion needs and an increase in consumer electric rates. Several mandates exacerbated the need for renewable and zero-carbon energy:

- Sixty percent renewable energy by 2030
- One hundred percent carbon-free by 2045
- Transportation electrification
- Building electrification to meet the GHG emission reduction targets.

Transmission planning under the current system would be suboptimal compared to regional transmission planning that alleviates regional issues that would result in significant savings on transmission expansion to move clean energy in the region.

A regional RTO would result in more efficient markets for clean energy through resource diversity and transmission connectivity between supply and demand regions throughout the western states.

Western Energy Imbalance Market

CAISO established the Western Energy Imbalance Market (WEIM) in 2014 as a real-time energy market. WEIM's advanced market system automatically finds low-cost energy to serve consumer demand across the West. Currently, 22 utilities, irrigation districts, and BAs across 11 states participate in WEIM.[17]

WEIM covers 79 percent of the load in the Western Interconnection. WEIM allows participants to buy and sell power close to the time electricity is consumed and gives system operators real-time visibility across neighboring grids. The result improves balancing supply and demand at a lower cost. The WEIM platform balances fluctuations in supply and demand by automatically finding lower-cost resources to meet real-time power needs. WEIM manages congestion on transmission lines to maintain grid reliability and supports integrating renewable resources. In addition, the market makes excess renewable energy available to participating utilities at low cost rather than turning the generating units off.

More specifically, regional coordination in generating and delivering energy produces significant benefits in four main areas:

- Reduced costs for participants by lowering the amount of costly spinning reserves utilities need to carry.
- Improved efficiency of the regional transmission system.
- Reduced carbon emission and more efficient use and integration of renewable energy. For instance, when one utility area has excess hydroelectric, solar, or wind power, CAISO can deliver it to customers in California or to another participant. Likewise, when CAISO has excess solar energy, it can help meet demand outside of California that otherwise would be met by more expensive, and less clean, energy resources. Since its inception, WEIM has reduced renewable energy curtailment by more than 1.8 million MWh and reduced CO_2 emissions by 800,000 MT.
- Enhanced reliability by increasing operational visibility across electricity grids and improving the ability to manage transmission line congestion across the region's high-voltage transmission system.

Extended Day-Ahead Market

The Extended Day-Ahead Market (EDAM) is a voluntary day-ahead electricity market designed to deliver significant economic, environmental, and reliability benefits to balancing areas and utilities throughout the Western Interconnection. Jointly approved by CAISO's

[17] WEIM participants are Arizona Public Service, Avangrid, Avista, Balancing Authority of Northern California (BANC), Bonneville Power Administration, CAISO, El Paso Electric, Idaho Power Company, Los Angeles Department of Water & Power, NorthWestern Energy, NV Energy, PacifiCorp, Portland General Electric, Powerex, Public Service Company of New Mexico, Puget Sound, Salt River Project, Seattle City Light, Tacoma Power, Tucson Electric Power, Turlock Irrigation District, and the Western Area Power Administration (WAPA) Desert Southwest Region.

Board of Governors and WEIM Governing Body in February 2023, the EDAM initiative leveraged existing features of the CAISO day-ahead market, features found in similar markets across the country, and used stakeholder feedback to further improve the market design.

The day-ahead market efficiently positions supply to meet forecasted demand across the EDAM footprint. It identifies economic transfers between participating areas, providing economic, reliability, and environmental benefits for participating BAs and their utilities.

Economic Benefits. Operational benefits result from reduced production expenses and providing the least-cost resources to meet demand. Since demand peaks vary for individual BAs across the year, the day-ahead market seeks to efficiently commit supply to meet peak needs of the entire footprint.

Reliability Benefits. A regional day-ahead market positions a comprehensive set of resources to cost-effectively meet the next day's conditions by improving visibility and awareness of conditions across the footprint, including supply availability. A diverse and broad supply pool allows the market to effectively position supply the day ahead and respond to changes in conditions while reducing operational risk, and the frequency and magnitude of emergency conditions.

Environmental Benefits. When excess renewable production occurs in one BA in the regional day-ahead market, the energy meets demand elsewhere, reducing the need for curtailing clean energy resources.

A 2022 study quantified the potential savings. EDAM would:

- Decrease power production and operational expenses across WECC states by 4.5 percent, saving up to $543 million annually. California's expenses would decrease by 6.2 percent, saving $214 million annually.
- Reduce GHG emission by 1.5 percent or 2.92 MMT annually.
- Avoid specific capacity resources through an RA program, saving WECC states up to $557 million, and California $95 million, in avoided investments.
- Save WECC states as much as $1.2 Billion annually, with California realizing $309 million annually.

EDAM is scheduled to be fully implemented in 2025.

Western Resource Adequacy Program

Replacing retiring thermal generation with variable energy resources has led to questions about whether the region will continue to have an adequate supply of electricity during critical hours. Numerous studies have shown RA to be an urgent and immediate challenge. Simultaneously, customers are consuming more energy. In addition, public policies, such as transportation and building electrification, are contributing to increasing loads.

The Western Resource Adequacy Program (WRAP) started at the request of the Western Power Pool (WPP) and by many in the industry concerned about the issue of RA in the West. WRAP is the first regional reliability planning and compliance program.

WRAP aims to enhance reliability by delivering a region-wide approach for assessing and addressing RA. Through the collaboration of participants, WRAP can paint a more accurate, regional picture of resource needs and supply, address resource adequacy, and ensure reliability by taking advantage of operating efficiencies, diversity, and sharing pooled resources. WRAP can also maintain existing responsibilities for reliable operations and observe existing frameworks for planning, purchasing, and delivering energy.

In February 2023, FERC approved the tariff for WRAP, clearing the way for its full implementation. Twenty-two utilities have already committed to participate in WRAP.[18]

Later in 2023, all participants are expected to join WRAP's forward showing and demonstrate they have secured their share of the region's energy needs. The operational component, initiated in winter 2023 and summer 2024, is when utilities with a deficit can tap into the pool of shared resources as needed.

Ultimately, WRAP expects to maintain reliable service using fewer overall resources, ensure adequate resources during extreme weather events, and help enable the transition to clean energy.

Grid Regionalization: Opportunities and Challenges

The concept behind creating a western RTO would be to improve grid reliability, energy market efficiency, and regional transmission planning, all of which could potentially hasten the transition to clean energy and lower energy costs for ratepayers. Creating a western RTO presents many opportunities for California and the region. Its implementation, however, presents challenges to all participating entities including VPU.

[18] As of April 6, 2023, participants included Arizona Public Service, Avista, Bonneville Power Administration, Calpine, Chelan County Public Utility District (PUD), Clatskanie PUD, Eugene Water & Electric Board, Grant PUD, Idaho Power, Northwestern Energy, NV Energy, PacifiCorp, Portland General Electric, Powerex, Puget Sound Energy, Public Service Company of New Mexico, Salt River Project, Seattle City Light, Shell Energy, Snohomish County Public Utility District, Tacoma Power, and The Energy Authority.

While regionalizing the western wholesale electricity market presents many benefits, several questions cannot be fully answered about this effort, specifically:

- How does regionalization affect California's efforts to expand energy efficiency, DR, and distributed generation if the wholesale market operator projects and determines that electricity, reliability, or other services shall be fulfilled through transmission and generation projects?
- How are other BAs operating in California affected to having equal access and interactions between participants and non-participants in the new market?
- How are transmission costs allocated to ensure that California ratepayers do not bear a disproportionate burden?
- How are California's GHG emission reduction goals affected?

Here are several issues to consider in response to these questions and to other challenges.

A Western RTO Governance Structure. California must pass legislation for CAISO to expand its operations into the rest of the Western Interconnection and become the region's RTO. This would allow other utilities in the Western Interconnect to join the RTO.

CAISO would need to create an independent governance structure, which could present a problem for California. The current CAISO Board of Governors is appointed by California's governor and confirmed by the state senate. While the CAISO board operates independently, these appointees can largely influence policy. The creation of a western RTO operated by CAISO means that California would make this process moot as a new Board of Governors would be created with regional input and FERC involvement. This newly formed regional board would ostensibly operate with the entire region in mind, not just for California. This presents a potential problem for California's transition to clean energy as recent history with other RTOs have demonstrated a negative impact to a clean energy transition.

The composition of governing boards and their decision-making process varies widely across existing RTOs. To streamline decisions, a group of western state electricity regulators, including two CPUC commissioners, created a set of governance principles to protect customers and support state policy mandates in the western electricity grid. These principles include having a committee to represent state interests, an independent and diverse board, along with a meaningful and open stakeholder engagement.[19] California would benefit if these types of governance principles were rooted in the creation of a western RTO.

Attaining California's Clean Energy Goals. By coordinating with neighboring BAs, regionalization might avert power outages with increased supplies during emergencies (such as severe heat waves). Regionalization might alter the way California achieves its RPS goals. The

[19] State Electricity Regulators. 2022 Letter to Organizations Building Regional Electricity System Optimization, April 18. https://www.westernenergyboard.org/wp-content/uploads/Multistate- Governance-Principles-4-25-22.pdf

law requires delivery of renewable energy to a California BA. An RTO would make out-of-state renewable power eligible under the current rules. Regionalization might also reduce the need for fossil fuel generation due to an increased supply base.

More States with Clean Energy Goals. Twenty-two states (plus the District of Columbia and Puerto Rico) currently have 100 percent clean energy goals, as opposed to only one in 2018. Besides California, other nearby states include Colorado, Nevada, New Mexico, Oregon, and Washington, which represents about 80 percent of the western state population. A western RTO would be dominated by participants working toward similar clean energy goals. This shared goal would maximize, but certainly not ensure, the opportunity for policies that would better enable California's transition to clean energy.

Power Market Competition. In 2018, CAISO's WEIM covered approximately 80 percent of load in the Western Interconnection. Since 2021, however, the Southwest Power Pool's (SPP) Western Energy Imbalance Service (WEIS) has competed directly with the CAISO WEIM. While CAISO is creating its EDAM to build on WEIM's success, SPP is responding by developing its day-ahead Markets+ service to compete directly with EDAM. Eight[20] of the 22 organizations participating in WEIM have executed agreements to participate in the development of Markets+, which jeopardizes their future participation in WEIM and EDAM.

[20] Arizona Public Service Company, Bonneville Power Administration, NV Energy, Powerex Corporation, Puget Sound Energy, Salt River Project, Tacoma Power, and Tucson Electric Power Company.

Figure 27 compares the CAISO WEIM participants with the eight WEIM members who have also signed agreements to participate in phase one of SPP's Markets+ development.

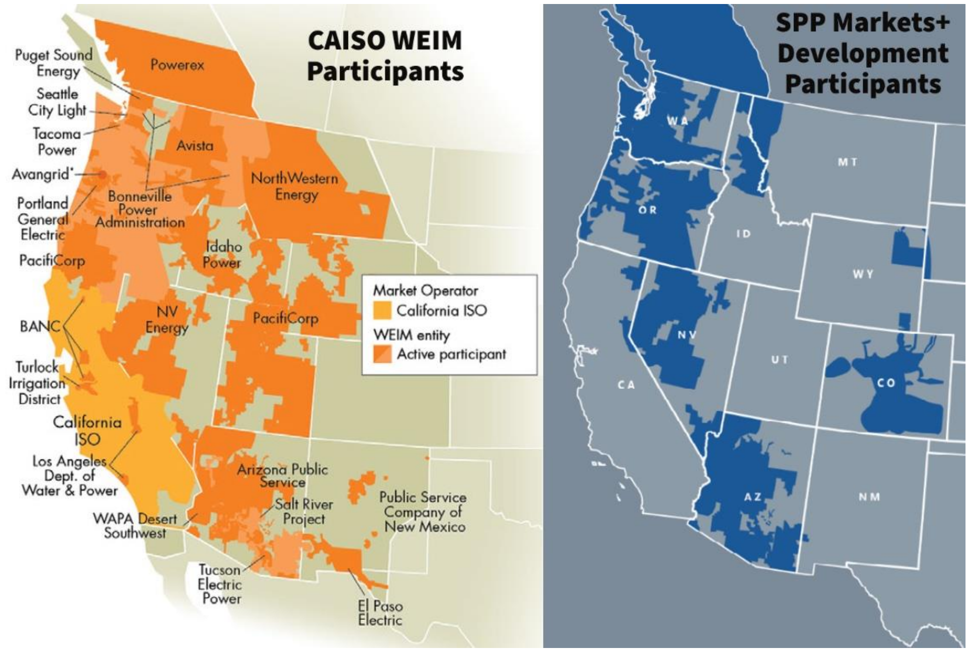


Figure 27. CAISO WEIM Participants[21] and SPP Markets+ Development Participants[22]

Thus, there is a risk that states might organize within the SPP and its Markets+ initiative and leave California behind to fend for itself.

Improved Resource Sharing. A western RTO would assume the role of the sole BA in the region. There are currently 38 BAs in the Western Interconnection. BAs plan RA, ensuring enough resources are available to maintain grid reliability. Grid regionalization accesses a more extensive and diverse generation pool. It would enable a BA to better meet differences in peak demand times especially when they occur at different times of the year in different geographical areas.

In-State Renewable Generation. Current legislation requires that at least 75 percent of generation necessary to meet California's RPS requirement be generated within the state. How a western RTO would affect this requirement is unclear as the potential to import increasing amounts of RPS-eligible generation would increase, thus affecting the siting of such generation in California.

Grid Reliability Challenges. Extreme weather events and other circumstances in the past few years have clearly demonstrated California's power grid fragility. Grid regionalization could reduce the overall amount of capacity needed to maintain grid reliability as the larger grid could better enable shared resources with every utility in the RTO.

21 https://www.westerneim.com/Pages/About/default.aspx

22 https://blog.ucsusa.org/mark-specht/western-grid-regionalization-is-back-on-the-drawing-board-why-now/

Efficient Transmission Access. All BAs in the Western Interconnection must coordinate transmission planning with other BAs. A western RTO, with access to the entire transmission infrastructure, would be better equipped to manage transmission constraints and could coordinate responses to extreme weather conditions from multiple resources. In addition, a western RTO could better manage transmission growth across states.

Coal Power Plant Retirements. A concern in 2018 was that grid regionalization would create a larger market for coal generation, especially when many coal plants are base loaded (operating without regard to cost). Today, however, many coal plants have planned retirement dates within the next decade. Indeed, the Inflation Reduction Act of 2022 only served to accelerate that trend. A western RTO could reverse this trend although it would take new legislation.

Organizing a Western RTO Has Already Begun. SPP has already made inroads into the Western Interconnection in addition to other erosions. State laws may compound this effect. Both Colorado and Nevada mandate certain utilities join an RTO by 2030. If SPP is the region's sole RTO, those utilities will only have one choice. The WPP has already organized WRAP to effectively share resources and ensure grid reliability across a range of western states.[23]

As time passes, other initiatives and collaborations might come to fruition, further limiting California's participation, design, and governance of these power structures.

COST OF SERVICE AND RATE IMPACTS

Maintaining competitive and stable electric rates remains an essential goal at VPU and was fundamental in developing the 2023 IRP. VPU customers consistently place affordable rates as a priority along with reliability.

The modeling and analysis implemented to arrive at the preferred portfolio employed a comprehensive production cost model to better ensure that the cost of generation to meet customer demand resulted in competitive and stable rates. Moreover, the 2023 electric cost of service and rate design study included key components (load forecast and power supply expenses) in the 2023 IRP. Two factors drive the production cost model: expected cost and market exposure. The total cost for generating necessary energy is the expected cost; the

[23] Sources include: https://blog.ucsusa.org/mark-specht/western-grid-regionalization-is-back-on-the-drawing-board-why-now/; https://blog.ucsusa.org/vivian-yang/what-does-western-grid-regionalization-mean-for-california/; https://www.newsdata.com/clearing_up/opinion_and_perspectives/regionalization-of-caiso-draws-much-comment-on-the-implications/article_df18e672-b9f1-11ed-85ab-33e4c6d21331.html; and https://www.ucsusa.org/resources/transforming-western-power-grid

amount of energy purchased from the wholesale market and its ability to effectively handle price volatility is the market exposure.

The preferred portfolio selected through modeling and analysis balances the increases in renewable generation and zero-carbon generation with providing reliable service and affordable rates as well as meeting all statutory requirements. VPU's goal is to strive for competitive and stable rates and industry best reliability throughout the entire planning period of 2023 through 2045.

4. Energy and Demand Forecasts

Energy and peak demand forecasts are foundational in developing the VPU IRP. The growth of retail energy sales is one of the main drivers for VPU's decisions on which resources to acquire and their associated costs. These forecasts identify the energy needed to serve customers every hour of every day throughout the year, offset by energy efficiency measures and DERs. The energy and peak demand forecasts dictate the timing of capacity expansion to meet impending demand plus a planning reserve margin, which in turn, ensures reliable energy.

In addition, the IRP process considered price forecasts and the impacts of transportation electrification.

LONG-TERM ENERGY FORECAST METHODOLOGY

Forecasting for this IRP involved several components, among them:

- Energy and peak demand forecasts prepared for VPU's service territory for both the short-term and the long-term planning periods.
- CEC statewide demand and energy forecasts.
- Demographic data and demand projections for the Southern California region and Los Angeles basin.
- Hourly electric system loads and the historical penetration of DERs.

Reliability is a critical factor in each of these components.

VPU contracted with NewGen Strategies & Solutions to create the short-term and long-term forecast of electric demand used in the development of the IRP.

Random Forest Regression

NewGen employed a random forest regression model that produced an hourly system to forecast demand from 2023 through 2045. The load forecast model relied on VPU historical hourly load data from 2014, energy efficiency and demand response program performance, the quantity of rooftop solar installed, and information regarding known loads added to or removed from the system.

Many predictive models use the forest regression model. It takes historical trends and utilizes them to create a forecast that would match the predictor variables. Random forests utilize decision trees, which are binary decisions that the model makes to determine data classification. The random forest model takes the predictor variables and produces several forecasts for the most likely value, in this case the kilowatts consumed in a specific hour, given those predictors.

These forecasts can all differ slightly as each decision tree can go down a different path based on the input variables. For instance, one tree could decide that all the predictors resemble the data point from a specific timestamp, still another tree might decide that the predictors most resemble data from a different timestamp. The model then forecasts usage as such. The demand at these two times is likely very similar; the model makes several slightly different decisions to achieve different results. As a result of these variations, the idea behind decision forests is to obtain the average prediction from many decision trees to determine the best possible prediction value for the set of predictor variables that are input into the model.

The model ran 500 iterations of hourly forecast simulations based on a normal distributions of each predicted hour's standard deviation to account for peak-causing deviations. Monthly and annual peaks were then obtained from the 500 simulations. The median peak for each month in the simulation and the tenth percentile peak (fiftieth highest) are then reported in the results.

Historic Forecasting Predictors

The first step in forecasting VPU's future load was to explore historical patterns and determine which items would be important in helping to predict future load.

Historic Annual Demand and Energy

Since the year 2000, VPU's peak demand and energy load has remained relatively flat with fluctuations due to changes in the economy, customer migration, new customer additions, weather and distributed energy resources such as energy efficiency measures and solar PV on customer sites.

Table 7 shows VPU's actual peak demand and load since 2014, which NewGen used in its historical modeling.

Year	Peak Demand (MW)	Load (GWh)	Load Factor
2014	191.00	1,184.0	71.0%
2015	197.00	1,164.0	68.0%
2016	194.00	1,154.0	67.0%
2017	184.00	1,129.0	70.0%
2018	182.83	1,125.7	70.3%
2019	180.35	1,122.7	71.1%
2020	191.37	1,168.3	69.5%
2021	194.31	1,220.3	71.7%
2022	189.49	1,150.6	72.3%

Table 7. Historic Annual Peak Demand and Load

Average Daily Profile by Month

The daily load profile changes each month throughout the year (Figure 28). From May through October, a peak occurs around noon with a slight increase in usage around the later evening hours ending at 9:00 PM. In the other months, the period from the hour ending at 10:00 AM to the hour ending at 2:00 PM is relatively flat, then ramps smoothly into the evening hours. The annual peak for VPU happens in August while the lowest peak for the year occurs in December. Given the differing characteristics of monthly load, the modeling process used individual monthly profiles to predict load values.

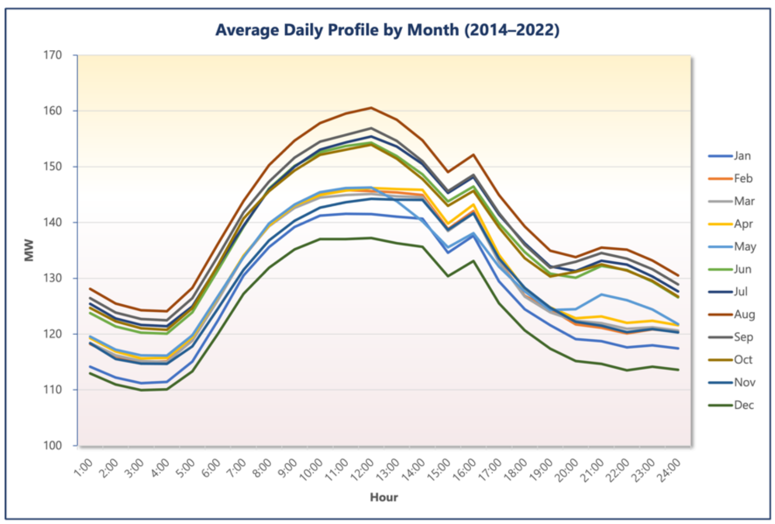


Figure 28. Average Daily Profile by Month

Average Daily Profile by Weekday

Analyzing average usage by weekday shows that:

- Sunday has a generally flat profile and is the lowest usage day of the week.
- Monday has a ramping up period in the morning that is lower than other weekdays.
- Tuesday through Thursday periods have similar load shapes and are the highest energy usage weekdays.
- Friday has a ramping down period in the afternoon and evening.
- Saturday shows significantly less usage than weekdays but does have a distinct ramping down shape.

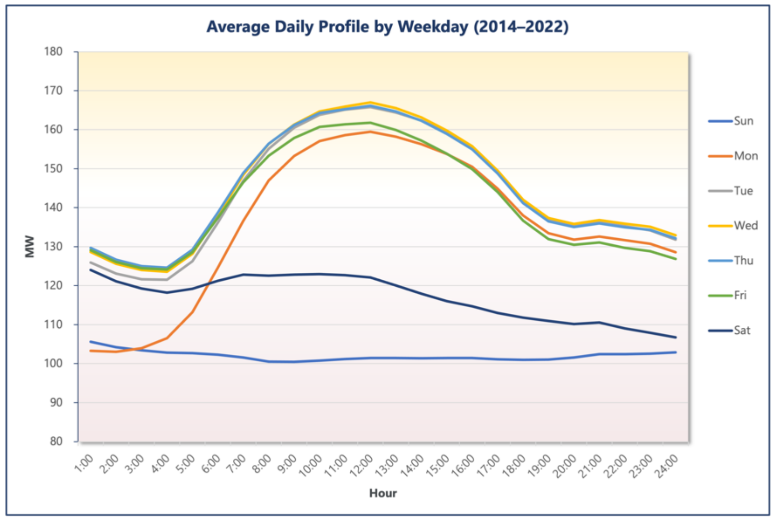


Figure 29. Average Daily Profile by Day

Given these distinct shapes (depicted in Figure 29), the modeling and analysis process used weekday average daily profiles as input in its forecasting.

Average Daily Profile by Holidays

Holidays generally appear to have load shapes similar to an average Sunday profile (Figure 30). The holidays with the most significant change in load included New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving, and Christmas. The IRP process reviewed various holidays on their actual dates versus the observed dates, with their observed dates showing the most significant load shape.

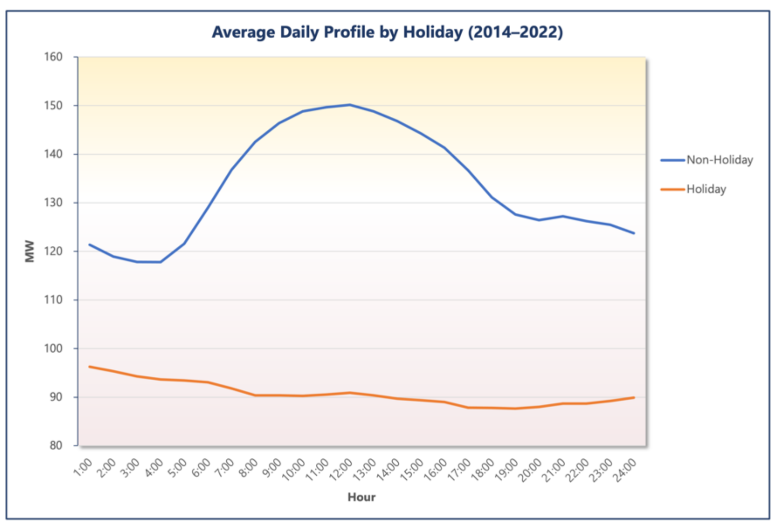


Figure 30. Average Daily Profile by Holiday

Average Daily Profile Changes Over Time

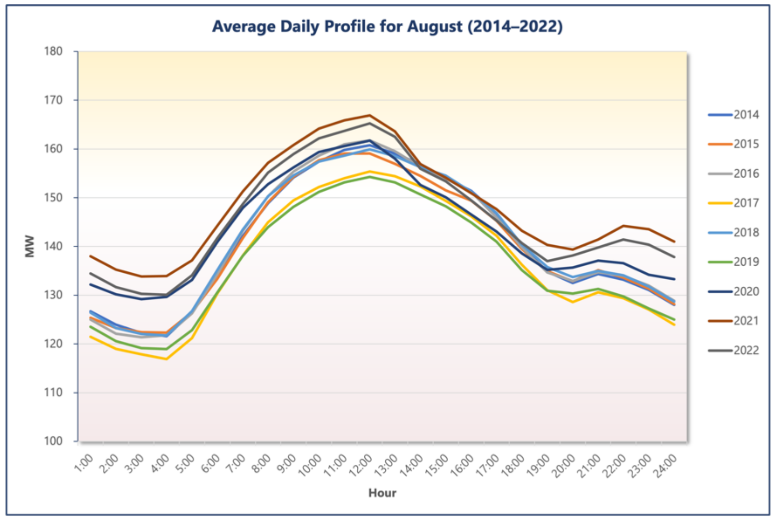


Figure 31. Average August Daily Profile

The monthly and yearly average load shapes have demonstrated significant off-peak usage in recent years, mainly because a significant off-peak load was added to the VPU electric system in the summer of 2020 (Figure 31). The year 2021 demonstrated the highest average daily profile for August; 2017 demonstrated the lowest. The modeling and analysis process used a classifying variable to indicate whether a particular period was before or after June 2020.

Historical Weather and 48-Hour Trailing Weather Predictors

Weather plays a significant role in electric load. In hot weather conditions, more energy is needed to cool homes, businesses, and manufacturing equipment; and in cool weather conditions, more energy is needed to warm those homes and businesses.

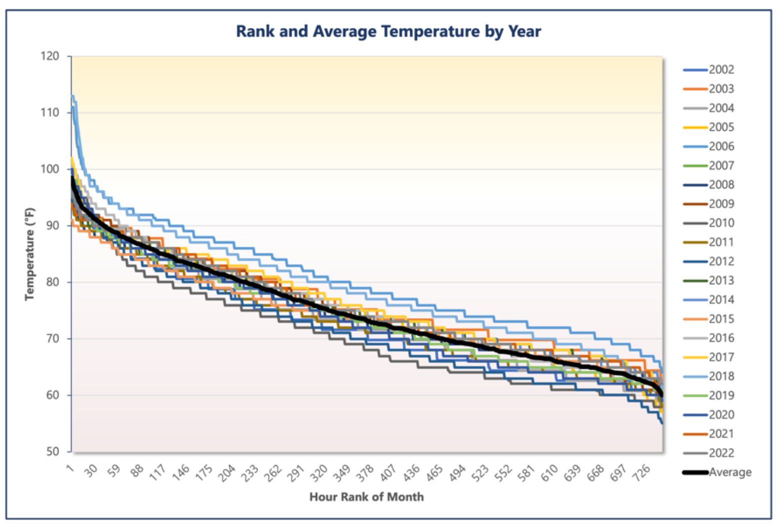


Figure 32. Example Rank and Average Weather Profiles

The IRP process used historical hourly weather data from the National Centers for Environmental Information to obtain the hourly weather for the last 20 years in the Vernon region. Next, a weather normalization analysis was performed by first applying the Rank and Average method for determining normal weather using the historical 20-year weather data. This approach involves ranking each hour of a given year by temperature, then taking an average over the first hottest hours, the second hottest hours, and so on. This results in a dataset ranging from the average hottest temperatures to the average coldest temperatures. These average temperatures are then applied to the year of interest, aligning the average hottest temperature with the hottest temperature of the year (depicted in Figure 32).

ANNUAL ENERGY AND DEMAND FORECASTS

The modeling and analysis employed to develop this IRP was based upon an hourly peak demand and energy forecast for the entire planning period. The model contains a base forecast created from the random forest model and from individual load modifiers. The combination of these two items creates the total projected loads.

The cumulative effect of several modifiers adjusts both the peak demand and energy forecasts. These modifiers include the forecasted impact of solar PV, DERs, load loss, data centers, hydrogen fuel, public and private electric vehicle charging stations, and energy efficiency projects. See Appendix D. Annual Energy Forecast Data for the annual adjustments for these load modifiers.

Annual Peak Demand Forecast

Table 8 lists the median peak demand forecast and the tenth percentile peak demand for the entire planning period. It was calculated from a base peak demand forecast, then modified by several load factors. The median peak demand forecasts an 18.7 percent increase over the entire planning period.

Year	Median Peak Demand (MW)			10th Percentile Peak Demand (MW)		
	Base Peak	Load Modifiers	Total Peak	Base 10th % Peak	Load Modifiers	Total 10th % Peak
2023	190.2	(13.1)	177.1	192.8	(13.6)	179.2
2024	190.5	(6.5)	184.0	193.1	(2.8)	190.3
2025	190.2	3.7	193.9	192.8	3.9	196.7
2026	190.4	3.3	193.7	192.6	3.6	196.2
2027	190.3	3.8	194.1	192.2	5.4	197.6
2028	190.2	4.5	194.7	192.9	4.2	197.1
2029	190.4	5.2	195.7	193.1	6.5	199.6
2030	190.4	6.8	197.2	192.8	6.2	199.1
2031	190.1	7.0	197.1	192.8	7.2	200.0
2032	190.2	7.7	197.9	192.7	7.8	200.5
2033	190.2	8.4	198.6	192.8	8.7	201.5
2034	190.3	9.4	199.7	192.9	9.6	202.6
2035	190.3	10.3	200.6	193.0	10.7	203.6
2036	190.1	11.1	201.2	192.5	12.2	204.7
2037	190.0	11.6	201.6	192.9	12.2	205.1
2038	190.3	12.8	203.1	192.8	14.0	206.8
2039	190.1	13.8	203.9	192.8	15.1	207.9
2040	190.2	14.7	204.9	192.8	16.1	208.9
2041	190.0	16.0	206.0	192.7	17.3	210.0
2042	190.3	16.8	207.2	193.0	18.1	211.1
2043	190.2	18.0	208.2	192.7	19.4	212.1
2044	190.3	18.6	208.9	192.8	20.4	213.2
2045	190.3	20.0	210.2	192.6	21.6	214.2

Table 8. Annual Peak Demand Forecast (MW)

Annual Energy Forecast

Table 9 lists the energy forecast for the entire planning period. It is similar to the peak demand forecast, whereas the energy forecast calculates the base energy forecast then modified. The energy forecasts a 21.22 percent increase over the entire planning period.

Energy Forecast (MWh)			
Year	**Base Energy Forecast**	**Load Modifiers**	**Total Energy Forecast**
2023	1,206,173	(66,664)	1,139,509
2024	1,209,911	(29,620)	1,180,292
2025	1,206,671	62,717	1,269,388
2026	1,206,554	95,294	1,301,848
2027	1,206,331	99,282	1,305,613
2028	1,209,919	103,575	1,313,494
2029	1,206,551	107,085	1,313,636
2030	1,206,194	110,958	1,317,152
2031	1,206,671	113,425	1,320,096
2032	1,209,992	118,081	1,328,073
2033	1,206,671	122,181	1,328,852
2034	1,206,671	126,557	1,333,228
2035	1,206,671	130,932	1,337,603
2036	1,209,992	135,633	1,345,625
2037	1,206,671	139,684	1,346,355
2038	1,206,671	144,059	1,350,730
2039	1,206,671	148,435	1,355,106
2040	1,209,992	153,186	1,363,178
2041	1,206,671	157,186	1,363,857
2042	1,206,671	161,561	1,368,233
2043	1,206,671	165,937	1,372,608
2044	1,209,992	170,739	1,380,731
2045	1,206,671	174,688	1,381,359

Table 9. Annual Energy Forecast (MWh)

ROOFTOP SOLAR PV INSTALLATIONS

From 2008–2017, VPU implemented a solar incentive program that encouraged commercial and industrial businesses to install behind-the-meter solar PV systems. VPU serves customers who participate in the program according to the terms and conditions of the City's Net Metering Service Schedule Number NM.

VPU currently has about 5 MW of existing distributed solar PV on the system. VPU is currently working with customers on approximately 4 MW of added solar load, of which 3 MW is currently under Building & Safety approval process. Stakeholder surveys indicate that customers are interested in VPU expanding its current program to include community solar, customer-sited solar installation, and customer-sited solar system maintenance services.

Table 10 shows the historical and forecast values for distributed solar PV installations. Since behind-the-meter solar power offsets some of VPU's system load, the solar PV forecast was applied to VPU peak demand and energy forecasts.

Year	Installed Solar PV Capacity (MW)	Installed Solar PV Energy (MWh)
2017	2.481	5.02
2018	3.289	6.66
2019	3.379	6.84
2020	3.628	7.36
2021	4.007	8.11
2022	4.303	8.71
2023	5.000	10.12
2024	5.000	10.14
2025	5.000	10.12
2026	5.000	10.12
2027	5.000	10.12
2028	5.000	10.14
2029	5.000	10.12
2030	5.000	10.12

Table 10. Rooftop Solar PV Historical and Forecast Installation Capacity and Energy Forecast

The PV Watts software was used to model the impact of additional solar installations. This tool, provided by National Oceanic and Atmospheric Administration, uses the angle and intensity of sunlight during each hour of the year in any city to generate an hourly load profile for energy offset by VPU's solar generators. Figure 33 depicts the behind-the-meter solar PV energy forecast for the short-term planning period.

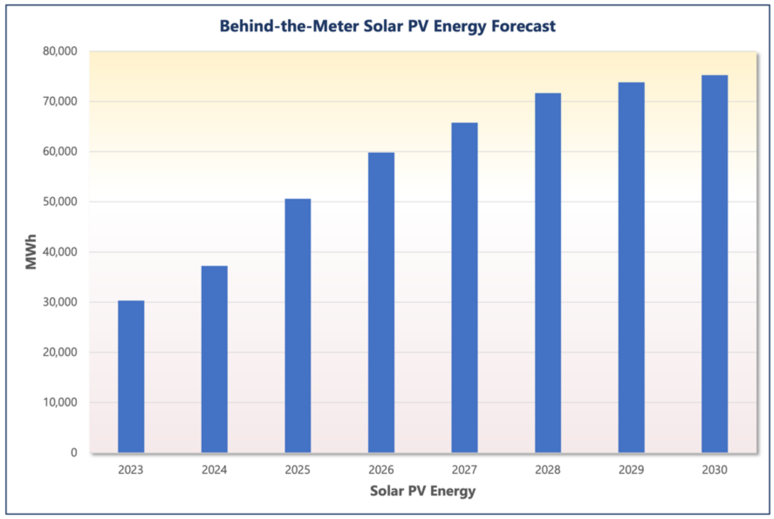


Figure 33. Behind-the-Meter Solar PV Energy Forecast

ENERGY EFFICIENCY IMPACTS

VPU has implemented various customer programs to promote the efficient use of energy with a specific focus on key areas such as lighting, refrigeration, and air conditioning. In total, these programs have generated approximately 3,479 MWh in annual energy savings for fiscal year 2022, and a cumulative net energy savings of 40,485 MWh from fiscal years 2014–2022.

A series of energy efficiency regulations apply to VPU (discussed in Chapter 5. Resource and Program Review), including SB 1037, AB 2227, and SB 350. The City's existing and future building codes also include the state's green building requirements outlined in Title 24 and CalGreen, which contains specific regulations for energy efficiency.

In 2021, the California Municipal Utilities Association (CMUA) hired GDS Associates, Inc (GDS) to analyze and quantify the potential impact of energy efficiency in VPU's electric service territory.[24] The CMUA study serves as the foundation for VPU's energy efficiency targets for fiscal years 2022 through 2031, which is to achieve 2,567 MWh per year in energy savings and 337 kW per year in demand reduction. The energy savings and demand reduction figures were derived from the 10-year average of the forecasted figures developed by GDS and VPU.

VPU remains committed to developing and implementing cost-effective energy efficiency programs. Because VPU's customer base is predominantly businesses that operate during

[24] https://www.cmua.org/files/CMUA%202020%20EE%20Potential%20Forecast.pdf

daytime hours, future programs will be focused on round-the-clock refrigeration initiatives as well as lighting and air conditioning impacts from 7:00 AM to 5:00 PM. The modeling for energy efficiency programs included flat profiles for the times indicated for refrigeration and lighting, and temperature weighted loads for air conditioning.

PRICE FORECASTS

California currently mandates a 100 percent shift to zero-carbon energy resources by 2045. As such, the shift in supply forecasts continued growth leading to increasing curtailment probability, lower average power prices, and increasing price volatility. The heavy solar generation during the day in California is forecasted to push on-peak power prices in CAISO below off-peak power prices in the near-term.

Power Price Forecast

The shift toward low to zero variable cost resources is forecasted to result in power prices remaining flat over the long term, even as natural gas prices and carbon costs increase.

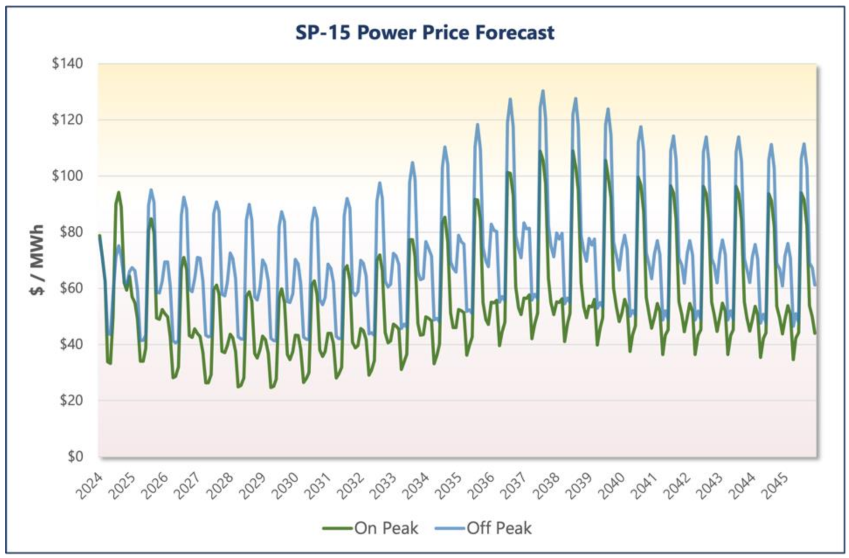


Figure 34. CAISO SP-15 Power Price Forecast

Natural Gas Prices

As more resources with little to zero variable cost come online, implied heat rates will drop, resulting in natural gas plants having a harder time clearing in the market. Natural gas prices are expected to rise over time while power prices are expected to fall in the near-term and remain flat in the long-term.

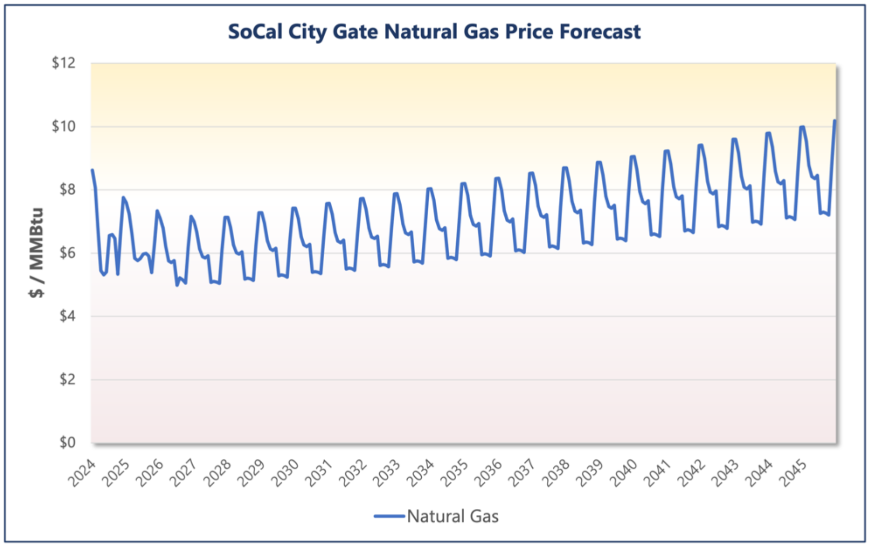


Figure 35. SoCal City Gate Natural Gas Price Forecast

Carbon Prices

Adding to the pressure on natural gas resources, the cost of carbon emissions is expected to continue to rise and accelerate over time. Over the course of the entire planning period, the carbon emission costs are forecast to quintuple.

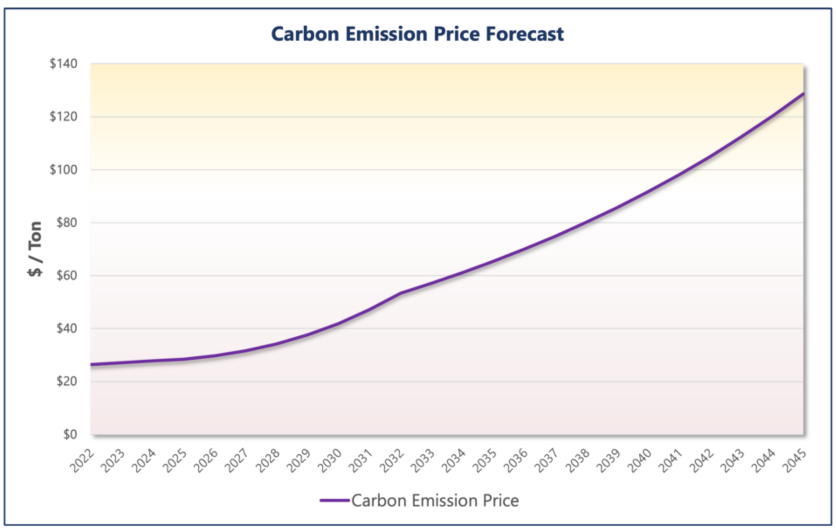


Figure 36. Carbon Emission Price Forecast

TRANSPORTATION ELECTRIFICATION IMPACTS

The transition to transportation electrification has been spurred by SB 350 and three CARB measures: the ACC II, Advanced Clean Trucks (ACT), and Advanced Clean Fleets (ACF) rules.

Zero-Emission Vehicle Adoption and Energy Impacts

The CEC's IEPR, through an additional achievable transportation electrification (AATE) framework, forecasts the adoption rate and energy impacts from three ZEV sectors (light-duty, medium-duty, and heavy-duty) by modeling three scenarios:

Baseline Scenario: Economic and demographic inputs; vehicle attributes such as price, range, refueling time, acceleration, and model availability; federal tax credits, state rebates and rewards, and high-occupancy vehicle access incentives; incentives resulting from the 2022 Inflation Reduction Act; consumer model preference; and CARB's Innovative Clean Transmit regulation.

Scenario 2: Direct, post-process alignment of light-duty ZEV sales that capture delayed compliance or some exemptions with CARB's policies, in particular the ACC II rule; lower prices for medium-duty battery-electric trucks to capture increased electrification.

Scenario 3: Full compliance with all regulations (including the Advanced Clean Fleets rule) with a postprocess alignment of new vehicle sales with state light-duty and proposed medium- and heavy-duty regulations.

Figure 37 shows the forecast for medium-duty and heavy-duty ZEVs a few years beyond the short-term planning period. Scenario 3, which accounts for complying with the Advanced Clean Fleet rule, shows a population of approximately 200,000 ZEVs by 2031.

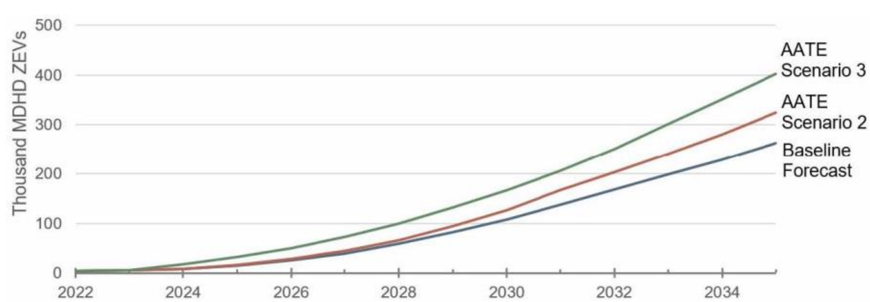


Figure 37. Medium- and Heavy-Duty Electric Vehicle Population Forecast

Increases in electricity energy consumption complement the increasing ZEV adoption forecast. The AATE framework used a managed forecast, which is an energy demand scenario that adjusts a baseline forecast to reflect either or all the following:

- The impacts of policies and programs that cannot be included within the basic architecture of the forecasting model.
- Significant uncertainties about existing programs, funding, or implementation features.
- Uncertainties regarding new policies and programs motivated by state or federal goals.

Figure 38 depicts the corresponding increase in energy growth over the same adoption rate period. An increase of approximately 35,000 GWh is forecast for 2031.

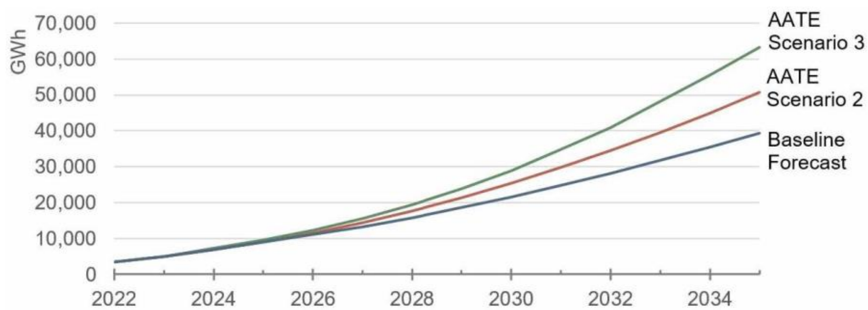


Figure 38. Transportation Electrification Demand Forecast

Technological advances have increased the efficiency of ZEVs. Improved fuel economy, vehicle travel model improvements, and consumption improvements for PHEVs have slightly lowered the energy consumption of ZEVs.

Electric Vehicle Impact

While its residential population is low, the City of Vernon sees an influx of almost 50,000 vehicles every day. Because of the ACC II rule, an increasing number of these vehicles will be ZEVs, and thus increase energy demand and the need for plug-in electric vehicle (PEV) charging stations.

As of 2022, the City of Vernon had over 120 electric-based, light-duty vehicles registered across one zip code, which is approximately three percent of all light-duty vehicles in Vernon's service territory.[25] In addition, VPU expects that several commercial and industrial fleets will transition to ZEVs, including the City of Vernon's municipal fleet.

By 2026, over 30 percent of light-duty vehicles in VPU's territory are expected to be zero-emissions to meet the ACC II mandate. Based on this knowledge, VPU's 2023 IRP considered the increased energy demands of transportation electrification and incorporated various state mandates in effect.

[25] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/light-duty-vehicle

To forecast EV penetration over the short-term planning period, the IRP process used two EV load profiles: one for public daytime charging and one for non-business hour charging (mostly for fleets).

The load profiles include an area to scale the amount of anticipated energy for both types of charging, which was then added to the hourly forecasts. The model assumed fleets grew based on the City of Vernon's vehicle electrification plan. The model assumed that approximately 2,500 passenger EVs were added each year, which represents an estimated five percent of the 50,000 vehicles estimated to enter Vernon daily. Finally, the model assumed that 35 percent of these EVs were charged in Vernon, each averaging 5,000 kilowatt hours (kWh) of total charging consumption annually.

VPU estimated the increase in PEV adoption compared to the overall adoption rate for the entire state. Table 11 lists the California and VPU forecast for PEV adoption levels; light-duty, medium-duty, and heavy-duty ZEV penetration, both for the next decade; together with the small amount of corresponding addition to peak demand and energy consumption for the VPU PEV population.

Year	California PEVs	VPU PEVs	Light-Duty ZEVs	Medium & Heavy Duty ZEVs	Vernon ZEVs	Peak Demand (MW)	Energy (GWh)
2023	1,394,050	836	1,478,300	5,705	2,500	0.8	4.2
2024	1,625,912	976	1,980,449	7,564	5,000	0.9	4.9
2025	1,866,987	1,120	2,522,018	15,293	7,500	1.1	5.5
2026	2,114,946	1,269	3,024,620	25,066	10,000	1.2	6.2
2027	2,367,753	1,421	3,550,516	39,570	12,500	1.3	6.9
2028	2,623,702	1,574	4,123,937	58,534	15,000	1.4	7.5
2029	2,881,494	1,729	4,743,520	82,450	17,500	1.6	8.2
2030	3,140,242	1,884	5,437,522	108,278	20,000	1.7	8.9
2031*	3,378,183	2,027	6,179,620	137,783	22,500	1.8	9.5
2032*	3,628,471	2,177	6,976,097	168,022	25,000	2.0	10.2
2033*	3,878,759	2,327	7,831,051	198,792	27,500	2.1	10.9
2034*	4,129,047	2,477	8,749,727	229,097	30,000	2.2	11.5
2035*	4,379,335	2,628	9,762,085	262,568	32,500	2.3	12.2

* Amounts in these rows highlighted in blue are extrapolated from 2023–2030 data

Table 11. Plug-In Electric Vehicle Adoption Forecast and Load Impacts

In 2023, the capacity (in MW) required for charging PEVs in the City of Vernon represented only 0.45 percent of peak demand. By 2035, that amount rises to 1.17% of peak demand, an increase of almost 260 percent. Similarly, the energy (in GWh) required for charging PEVs in the City represented only 0.38 percent. By 2035, that amount rises to 0.94 percent, an increase of almost 250 percent.

Scenario 2 from the CEC's IEPR forecasts an increase of approximately 1,000 percent by 2035, from approximately 5,000 GWh to approximately 50,000 GWh (see Figure 38).

Table 12 lists the changes in EV coincident peak demand, energy load, GHG emission due to increasing ZEV penetration, and the increasing number of EV in the City of Vernon contrasted with the equivalent emissions from the gas-powered vehicles they replace.

Year	EV Coincident Peak (MW)	EV Energy Load (GWh)	GHG Emissions (MT)	Number of EVs	Equivalent Emissions from Gas Vehicles (MT)
2024	0.26	4.79	2,340	5,000	5,406
2025	2.26	9.40	4,592	7,500	10,608
2026	3.00	14.01	6,843	10,000	15,810
2027	4.53	18.62	9,095	12,500	21,013
2028	5.60	23.19	11,327	15,000	26,170
2029	6.90	27.67	13,516	17,500	31,226
2030	7.48	32.04	15,650	20,000	36,157
2031	8.38	36.42	17,790	22,500	41,100
2032	9.11	45.30	22,127	25,000	51,121
2033	10.01	49.55	24,203	27,500	55,918
2034	10.90	53.92	26,338	30,000	60,849
2035	11.79	58.30	28,477	32,500	65,792
2036	13.16	62.85	30,700	35,000	70,927
2037	13.54	67.05	32,751	37,500	75,666
2038	14.49	71.43	34,891	40,000	80,609
2039	15.39	75.80	37,025	42,500	85,541
2040	16.32	80.41	39,277	45,000	90,743
2041	17.17	84.55	41,299	47,500	95,415
2042	18.06	88.93	43,439	50,000	100,358
2043	18.95	93.30	45,573	52,500	105,290
2044	19.90	97.96	47,849	55,000	110,549
2045	20.77	102.05	49,847	57,500	115,164

Table 12. Peak Demand, Energy, and GHG Emission Impacts of ZEV Penetration

5. Resource and Program Review

As required by SB 350, the CEC established annual targets that will achieve a cumulative doubling of statewide energy efficiency savings as well as demand reductions in electricity and natural gas end uses by 2030. In addition, Executive Orders N-79-20 and B-32-15 established targets for ZEV sales and expansion of EV charging infrastructure. AB 617 directed CARB and all local air districts to take measures to protect disadvantaged communities (DACs) from adverse impacts of air pollution.

VPU offers several incentives and programs to support energy efficiency, demand response, and EV adoption to align with the state's climate and transportation electrification goals. VPU is also actively investing in expanding EV charging infrastructure for the public and for the City of Vernon's EV fleet.

ENERGY EFFICIENCY TARGETS

PUC Section 9621 requires the CEC to address energy efficiency and DSM programs, energy storage, RA, and transportation electrification. SB 350 established annual targets for statewide AAEE savings and demand reduction that will produce a cumulative doubling of statewide energy efficiency savings for end-use retail customers by 2030. Utility and non-utility programs for both gas and electricity can contribute toward that goal.

Table 13 contains VPU's annual and cumulative energy efficiency saving targets with CEC adjustments.

VPU	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Annual	6	2	4	3	3	3	4	4	3	3	3	3	3	2	2
Cumulative	6	8	12	15	18	21	25	29	32	35	38	41	44	46	48

Table 13. Annual Electricity Savings Targets with Adjustments (GWh)[26]

[26] *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*. California Energy Commission. Publication Number: CEC-400-2017-010-CMF; Table A-10.

Adjustments to these targets generally involve shifting savings to avoid double counting, and to extrapolate savings for 2027 through 2029. VPU continues to utilize all available resources to achieve the energy efficiency targets, including continued implementation of its long-standing customer programs and identifying future challenges that can drive the development of new offerings and services.

ENERGY EFFICIENCY PROGRAMS

To comply with AB 1890, VPU must charge 2.85 percent of electric revenues to implement the following Public Benefit program categories:

- Cost-effective energy efficiency programs and services
- Development and implementation of existing and emerging renewable resource technologies
- Research, development, and demonstration programs and projects
- Income-qualified bill assistance

Since 2011, VPU has offered cost effective energy efficiency and DSM programs to achieve its annual savings targets and assist customers in managing their energy bills. These programs include incentives to explore and implement energy efficiency technologies. The current VPU program provides incentives to customers for energy savings that are obtained by retrofitting to LED lighting technology and installing energy efficient equipment. In addition, VPU also offers free comprehensive energy audits to all electric customers, which provide a starting point for organizations interested in developing a broader energy management strategy. Through this service, customers receive a detailed analysis of their energy consumption, coupled with suggested energy efficiency improvements, to realize cost savings.

To comply with SB 350, VPU has established annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of energy efficiency savings from retail customers by January 1, 2030. Through its comprehensive energy audit services and overall customer education, VPU has encouraged its commercial and industrial customers to remain steadfast in evaluating ongoing potential energy savings realized by replacing inefficient compressors or use of heat conversion and refrigeration controls technology to save energy. VPU has also sought energy efficiency savings through water and gas infrastructure upgrades, distribution system equipment and conductor upgrades, and retrofitting City facilities.

The increases in energy efficiency savings are reflected in the VPU peak demand and energy forecasts.

Demand Response Programs

Based on its commercial and industrial customer base, VPU has limited capabilities for demand response (DR) programs since most business processes cannot be readily interrupted to avoid economic losses from a lapse in customer production processes. Since VPU customers did not indicate a strong interest in traditional DR programs, DR resources are not included as candidate resource options in the modeling for a preferred portfolio. Nevertheless, VPU continues to identify strategic partnerships to advance energy storage on customer premises as a form of DR.

VPU implements a few reliability-driven programs and services that differ from traditional DR offerings. For example, VPU offers a voluntary load reduction program in the form of discounted rates to customers who can reduce their load in the event of an energy emergency.

Demand-Side Management Programs

VPU offers several energy efficiency and DSM programs for its commercial and industrial customers.

Customer-Directed Programs. VPU funds customized projects demonstrating energy efficiency and cost savings. Customers must fund at least 25 percent of the total project cost. Projects are only eligible if they do not qualify for the other programs.

Energy Audit Program. This program provides free on-site audits for commercial and industrial customers, and includes a comprehensive audit that analyzes a customer's energy usage and costs, identifies potential energy conservation measures, and recommends efficiency improvements.

Time-of-Use Rate Programs. Any customer with an electrical load that exceeds 100 kW is eligible for time-of-use rates. By shifting energy usage to times of the day when electric rates are lower, customers can achieve cost savings. In addition, energy consumption by customers during off-peak hours also lowers VPU's peak demand, which potentially defers the need to add more resource capacity. Most of VPU's large commercial and industrial customers use the TOU rate schedule.

Customer Incentive Program. This program funds the retrofit and implementation of energy efficiency technologies and equipment, such as LED lighting, variable speed drives, air compressors, motors, refrigeration, and air conditioning upgrades. The City of Vernon, also a VPU electric customer, successfully utilized this program to retrofit city facilities with LED lighting to reduce energy consumption in municipal operations.

Net Energy Metering. Since January 2010, VPU has offered a NEM program for customers that install qualifying solar PV systems on their premises.

ENERGY EFFICIENCY PROGRAM IMPACTS

The impacts from VPU's energy efficiency and DSM programs are quantified in Table 14, which contains the annual net savings in MWh from fiscal years 2014–2022.

Description	Installation Year and MWh Savings								
	2014	2015	2016	2017	2018	2019	2020	2021	2022
Cumulative Net	2,299	8,123	10,253	12,349	17,733	25,387	33,967	37,006	40,485
First Year Net	2,299	5,824	2,130	2,096	5,384	7,654	8,580	3,039	3,479
Lifecycle Net	25,943	17,689	12,615	17,826	66,720	92,782	108,940	38,250	46,866

Table 14. Cumulative Historical Energy Efficiency Savings: Fiscal Years 2014–2022

Energy Efficiency Incentive Program

Improvements in lighting technology have resulted in efficient LED solutions that use less energy and create a longer, useful life. The VPU Customer Incentive Program provides rebates on above code kWh savings from LED lighting retrofits. The non-lighting incentive portion of the VPU program includes variable speed drives, air compressors, motors, refrigeration, chiller replacement, air conditioner replacement, and building envelope upgrades. The program also includes rebates for the above-code savings generated via energy management systems or other load-controlling devices.

Table 15 lists the energy savings for the Customer Incentive Program from fiscal years 2018 through 2022.

Program Savings	FY 2018		FY 2019		FY 2020		FY2021		FY2022	
	MWh	MW	MWh	MW	MWh	MW	MWh	MW	MWh	MW
Lighting	4,528	0.95	7,209	1.67	6,585	0.98	2,687	0.43	2,934	0.65
Non-Lighting	856	0.00	445	0.00	1,995	0.02	352	0.13	545	0.04
Total	5,384	0.95	7,654	1.67	8,580	1.00	3,039	0.56	3,479	0.69

Table 15. Historical Lighting Incentive Program Savings: Fiscal Years 2018–2022

ENERGY EFFICIENCY POTENTIAL FORECASTS

To comply with AB 2021, POUs like VPU must identify 10-year energy efficiency and demand reduction forecasts every three years. AB 2227 changed the adoption timeline from every three years to every four years, starting in 2013. VPU's current ten year forecast runs from 2022–2031, with a four-year adoption timeline from fiscal year 2022 through fiscal year 2025.

VPU's annual energy efficiency and demand reduction targets are 2,567 MWh and 337 kW. The targets were derived based on the ten-year average market potential.

Energy Efficiency Potential Forecasting Study

VPU contracted with GDS to conduct the 2020 California Municipal Utilities Association (CMUA) Energy Efficiency Potential Forecasting Study. The study results are specific to VPU's service territory and account for unique characteristics, customer base, climate zone, economic conditions, and other relevant factors. The study forecasted potential energy efficiency savings for 2022 through 2031. VPU plans to conduct the next study during fiscal year 2025 to forecast potential savings for 2026 through 2035.

The study provides a roadmap for VPU as it develops strategies and programs for energy efficiency. The development of market potential estimates for a range of feasible measures is useful for program planning and modification purposes.

Summary of Market Potential

VPU's cumulative energy efficiency potential forecast from fiscal year 2022 through fiscal year 2031 is pre-set at 25,665 MWh. This results in an average annual gross savings target of 0.22 percent of forecasted retail energy sales. Table 16 contains the specific annual demand reduction impacts by sector. These data were used to create Figure 39: Net Incremental Market Potential by Sector (MWh) and Percent of Sales.

10-Year Demand Goals (Incremental kW)										
All Sectors	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Market Potential	749	765	694	604	356	103	40	16	17	18
Residential Market Potential	0	0	0	0	0	0	0	0	0	0
Non-Residential Market Potential	749	765	694	604	356	103	40	16	17	18

Table 16. Net Incremental Market Demand Potential By Sector

Table 17 contains the specific annual energy impacts by sector. These data were also used to create Figure 39: Net Incremental Market Potential by Sector (MWh) and Percent of Sales.

10-Year Energy Goals (Incremental Net MWh)										
All Sectors	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Total Market Potential	5,247	5,504	5,069	4,489	2,575	876	564	446	445	449
Residential Market Potential	0	0	0	0	0	0	0	0	0	0
Non-Residential Market Potential	5,247	5,504	5,069	4,489	2,575	876	564	446	445	449
Total Potential as a % of Total Sales	0.45%	0.47%	0.44%	0.39%	0.22%	0.08%	0.05%	0.04%	0.04%	0.04%
Residential Potential as a % of Residential Sales	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Non-Residential Potential as a % of Non-Residential Sales	0.45%	0.47%	0.44%	0.39%	0.22%	0.08%	0.05%	0.04%	0.04%	0.04%

Table 17. Net Incremental Market Energy Potential By Sector

The energy impacts are a percentage of forecasted sector-level and total sales. Incremental annual savings range from 2,622 MWh to 9,912 MWh, which corresponds to 0.04 percent to 0.47 percent of forecasting sales.

Figure 39 depicts the market potential for the residential and non-residential sectors, as well as the total incremental potential as a percentage of total sales for the 10-year period of 2022 to 2031.

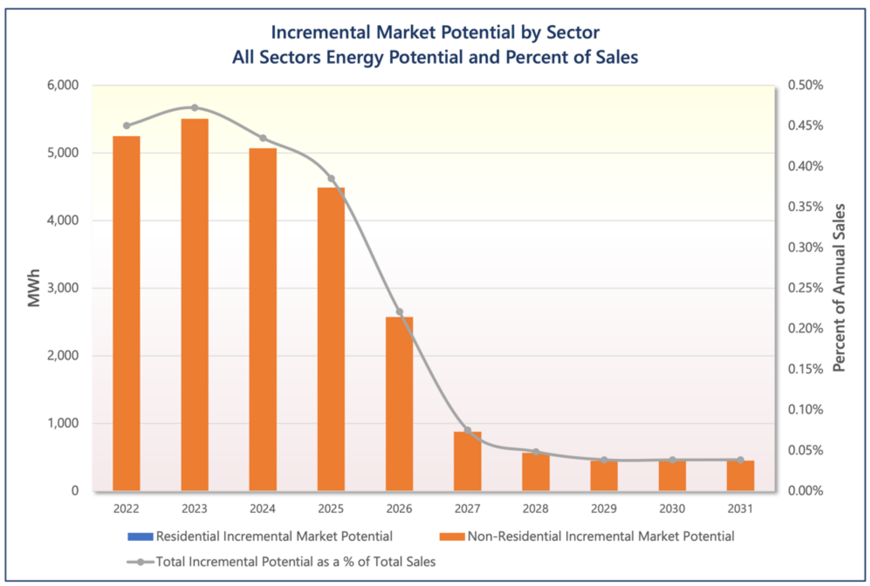


Figure 39. Net Incremental Market Potential by Sector (MWh) and Percent of Sales

At a glance, the City of Vernon's results include:

- A 2022–2031 average annual gross savings target of 0.22 percent of forecasted retail sales.
- A 2022–2031 average annual net savings target of 0.22 percent of forecasted retail sales.

The results also include separate estimates of the future energy savings impact from Codes and Standards advocacy.

Codes and Standards

The summary of potential energy efficiency savings represents the base case results. GDS also produced estimates of savings claims for Codes and Standards advocacy. Table 18 lists the base market potential and an estimate of Codes and Standards advocacy savings. The Codes and Standards estimates are considered as secondary to the base market potential.

10 Year Energy Goals (Incremental Net MWh)										
All Sectors	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Base Market Potential	5,247	5,504	5,069	4,489	2,575	876	564	446	445	449
Codes & Standards Advocacy	4,209	4,118	3,790	3,699	3,547	3,390	3,153	2,766	2,450	2,138

Table 18. Net Incremental Market Potential – Base And Codes and Standards

Potential Net Market Energy Efficiency Savings

Figure 40 depicts the *incremental* net market potential energy efficiency energy savings (in MWh) until 2031. The impact of energy savings through Codes and Standards savings are also included. The residential impact is minimal due to the small number of residential accounts in VPU's territory.

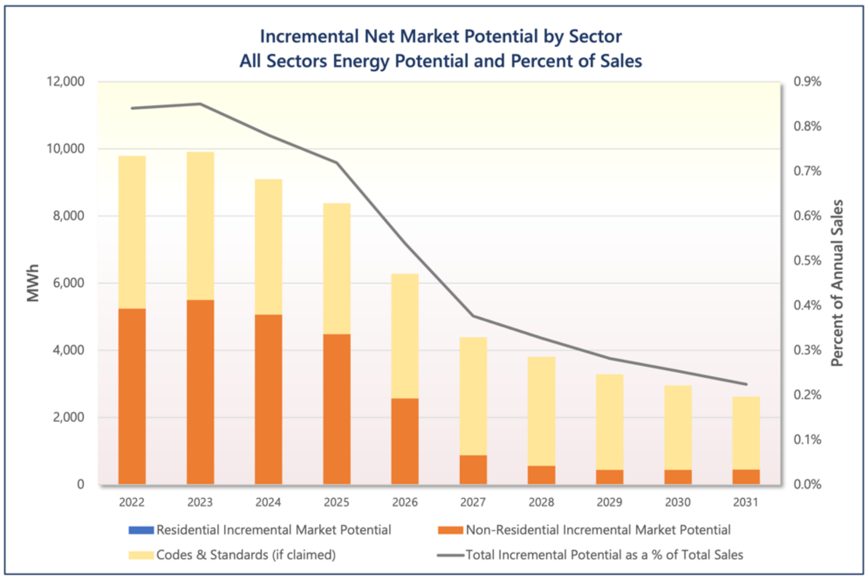


Figure 40. Incremental Net Market Energy Efficiency Potential by Sector

Figure 41 depicts the *cumulative* net market potential energy efficiency energy savings (in MWh) until 2031. The impact of energy savings through Codes and Standards savings are also included. The residential impact is minimal due to the small number of residential accounts in VPU's territory.

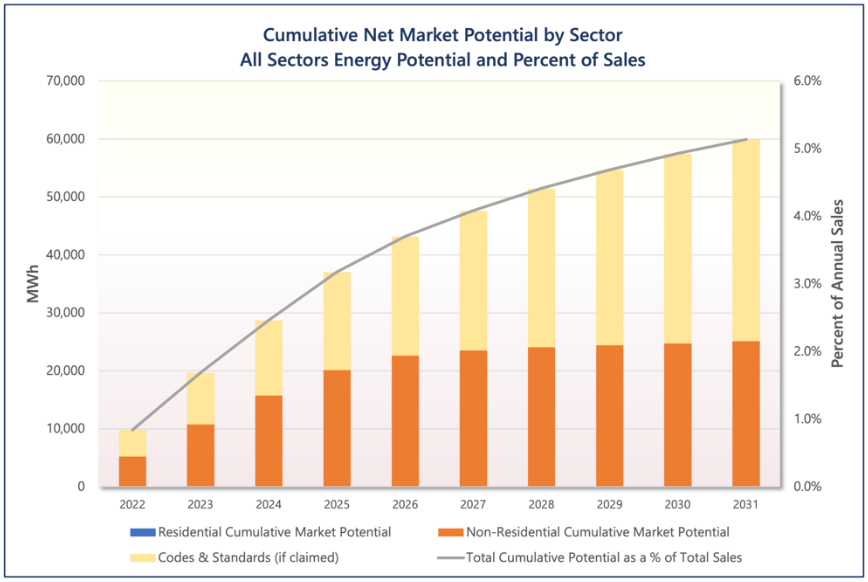


Figure 41. Cumulative Net Market Energy Efficiency Potential by Sector

TRANSPORTATION ELECTRIFICATION

Emissions from the transportation sector constitute California's largest source of GHGs, representing more than double the GHG emissions associated with the electricity sector.[27] Transportation electrification helps reduce GHG emissions while meeting California's aggressive climate goals. Executive Order B-48-18 signed by Governor Brown in 2018 set a target for five million zero-emission vehicles and 250,000 public EV charging stations by 2030. In 2020, Governor Newsom set a goal under Executive Order N-79-20 for all in-state sales of new passenger to be zero-emissions by 2035 and all new medium and heavy-duty vehicles to be zero-emission by 2045.[28]

VPU is committed to supporting the transportation electrification goals set by California and align with the state's GHG emissions reduction targets.

27 https://ww2.arb.ca.gov/ghg-inventory-data

28 https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification

Transportation Electrification Programs

To help support the growth of transportation electrification, VPU has several incentive programs designed to encourage the adoption of EVs and expand EV charging infrastructure.

VPU Commercial EV Charger Incentive Program. This program is designed to offset the upfront costs of purchasing and installing qualifying EV chargers for your business, fleet, or employees. All commercial VPU electric customers can receive a $3,000 rebate per port for the installation of a qualifying smart L2 EV charger. Additional bonus incentives are available for VPU customers that install L3 DCFCs or install qualifying smart L2 EV chargers at affordable housing structures serving 80 percent or more income-qualified individuals (defined as persons and families at or below 50 percent of Los Angeles County median income, adjusted for family size and revised on an annual basis).

VPU Commercial Electric Forklift Incentive Program. This program is designed for commercial and industrial customers looking to electrify their forklift fleet. VPU offers a $3,000 rebate toward the lease or purchase of an electric forklift. VPU recognizes the importance of reducing GHG emissions through electrifying the movement of goods and off-road vehicles.

VPU Residential EV Rebate Program. This program provides eligible residential electric customers with $2,500 for purchasing or leasing an EV and $2,500 for installing a qualifying EV charger.

VPU continues to explore additional opportunities to provide incentives for the electrification of medium- and heavy-duty vehicles and rail.

Customer Education and Outreach

VPU cross-promotes several external resources available for customers who are looking to make the switch to electric vehicles or considering installing EV charging infrastructure.

The "Electric For All" platform, available through Veloz, contains a wealth of resources designed to inform utility customers on everything related to EVs. This includes a tool to search for various consumer electric vehicle and charger incentives. The platform also contains a home charging advisor who can estimate the cost of equipment, installation, and operation of EV chargers.

The "Replace Your Ride" program from the South Coast Air Quality Management District (SCAQMD) offers up to $9,500 to replace gasoline vehicles 2007 or older with EVs for qualifying customers.

The CA Clean Vehicle Rebate Program offered by CARB provides up to $7,500 in rebates for qualifying customers to buy or lease an eligible EV.

To increase community awareness and engagement, VPU has developed a custom branding called "Electrify Vernon" placed on all of the publicly available DCFCs owned by the City of Vernon. VPU promotes its public EV charging depots on the City's social media accounts along with content in its newsletters. VPU is working closely with its customers to better understand the different transportation electrification roadmaps for each organization and how VPU can provide support through this transition, either with infrastructure adjustments or financial incentives. VPU continues to consider additional customer education and outreach to support transportation electrification.

Electric Vehicle Charging Rates

VPU offers qualifying commercial electric customers a time-of-use rate plan (TOU-V)[29]. The TOU-V electric rate schedule includes the following monthly charges:

- Customer and automated meter reading (AMR) charges that remains the same year-round.
- Energy charge for on-peak, mid-peak, and off-peak energy charges for the summer and winter seasons.
- Demand charge for on-peak and mid-peak charges for summer and winter seasons. Off-peak is not charged, but customers are subject to minimum demand charges.

The summer season runs from May 1 through October 31 each year; the winter season runs from November 1 through April 30. On-peak hours are 1 PM to 7 PM on summer weekdays except holidays. Mid-peak hours are 9 AM to 1 PM and 7 PM to 11 PM on summer weekdays except holidays, and 8 AM to 5 PM on winter weekdays except holidays. All other hours are off-peak.

In the near term, VPU plans to review electric rate design options for electric vehicles.

Municipal Fleet

The City of Vernon's municipal fleet consists of nearly 200 vehicles, including approximately a dozen light-duty EVs that are currently in operation. The City is planning to add ten more EVs. Out of these ten, three EVs have been ordered and will be delivered in the near future; the remaining seven EVs will be integrated into the city fleet as existing ICE vehicles are replaced and taken out of operation. Both VPU and the City will continue to evaluate opportunities to convert older and higher polluting fleet vehicles to EVs as more options become available from vehicle manufacturers.

[29] https://www.cityofvernon.org/government/public-utilities/rates-fees/-folder-49

Electric Vehicle Charging Infrastructure

VPU continues to expand its EV charging infrastructure for the public, City employees, and the municipal fleet while utilizing its incentive programs to encourage the installation of EV chargers on private properties.

VPU is also proactively transforming its power distribution systems to accommodate the growth of EV charging. In particular, the utility's 2020 CIP included funding to replace aging substation transformers, upgrading them with a reliability investment for a voltage conversion that added capacity. These distribution upgrades formed the structural underpinnings necessary to expand future EV charging infrastructure. The upgrades enabled VPU to engage various commercial and industrial customers who are interested in increasing their existing capacity to electrify their fleet.

EV Charging Station Installations

Starting with the City of Vernon, VPU has installed L2 EV chargers at several city sites, with plans to continue and expand the availability of EV charging to support current and future needs of employees and the municipal fleet. To promote adoption of EVs among city employees and provide EV charging to the existing city fleet, VPU installed over 40 L2 EV chargers at Vernon City Hall. In addition, VPU also installed four L2 EV Chargers at MGS to support fleet and employee charging. VPU plans to continue to offer utility and City employees with access to EV charging infrastructure located in employee and fleet parking facilities.

VPU has expanded its public EV charging infrastructure with several new capital projects, including two future sites that are anticipated to be completed in 2024. In July 2023, VPU partnered with Tesla to launch its first public DCFC site. The Soto EV Charging Depot features ten ChargePoint DCFCs that deliver up to 62.5 kW of energy and eight Tesla V3 Superchargers. VPU plans to partner with Tesla to open its second site called the Alameda EV Charging Depot, which will also be equipped with a mixture of ChargePoint DCFCs and Tesla V3 Superchargers. VPU is currently developing its third, public DCFC site that will offer between 10 to 14 L3 EV chargers.

Future EV Charging Station Projects

The City of Vernon is anticipating the launch of its first commercial fleet charging depot soon. The EV charging depot will be equipped with a mixture of L2 and L3 fast chargers. VPU is working to provide temporary electricity service so the depot can be operational by the end of the calendar year.

VPU expects the electric load to be approximately 3 MW once the depot becomes fully operational. VPU is actively working to connect Vernon businesses that are interested in a dedicated site for commercial EV fleet charging. The City's end goal is to meet the growing needs and goals of transportation electrification for local companies.

UNDERSERVED AND DISADVANTAGED COMMUNITY INITIATIVES

VPU is committed to ensuring that potential impacts on income-qualified customers and DACs are a primary consideration when designing EV programs and expanding EV charging infrastructure.

EV Chargers in DACs

Based on the California Office of Environmental Health Hazard Assessment (OEHHA), VPU's entire electric service territory (zip code 90058) is located in a DAC. VPU is actively addressing the lack of EV charging infrastructure in the DAC by launching its first publicly available L3 DCFC depot in July 2023. A second proposed site is scheduled to be completed by the end of 2023, with a third proposed site scheduled for completion in 2024. All three of the public DCFC depots are located close to several major interstate and intrastate highways. Vernon's public EV charging depots provides the infrastructure necessary to support battery electric vehicles in the "Gateway Cities" region in Southern California and help encourage the adoption of zero emission electric vehicles in underserved communities.

As noted under the "Transportation Electrification Programs" section, EV charging infrastructure serving affordable housing qualifies for additional "bonus" incentives of up to $12,000 per eligible EV charger. VPU residential customers can also receive up to $5,000 with the purchase of a qualifying EV and installation of an eligible EV charger. VPU will continue to offer rebates and work closely with its customers to remove EV adoption barriers across its service territory.

Environmental Sustainability

AB 617 directed CARB and all local air districts, including the South Coast Air Quality Management District (SCAQMD), to take measures to protect communities disproportionally impacted by air pollution. The bill promoted the development of a new community-focused program to effectively reduce exposure to air pollution and preserve public health. Among the highest priority communities are East Los Angeles, Boyle Heights, and West Commerce; southeast Los Angeles; and south Los Angeles, all areas that are in close proximity to the City of Vernon.

Vernon is developing an Environmental Sustainability Action Plan to comply with AB 617. The City has solicited a survey to gather the top concerns of residents and city employees. The Sustainability Action Plan is expected to be finalized later this year. In the meantime, the City has already undertaken a number of initiatives toward this issue.

Vernon Public Works developed of an Urban Tree Canopy assessment in partnership with Gateway Cities Council of Governments (GCCOG), Loyola Marymount University Center for Urban Resilience (LMU CURes), and TreePeople. The assessment found that up to 51 percent of the City's surface area could accommodate tree plantings; it also identified highly suitable locations for prioritizing plantings. The Urban Tree Canopy anticipates communitywide benefits from tree plantings that include greener spaces and beautification, shading, mitigation from heat, improvements to local air quality, and improvements to pedestrian pathways. The City of Vernon is recognized as a Tree City by the Arbor Day Foundation.

As the City's electric utility, VPU:

- Has reduced generation from its local natural gas power plant, MGS, over the last year by approximately 23 percent by favoring lower cost renewables during peak production of renewables. This reduction has also reduced GHG emissions in the area.
- Continues to provide free comprehensive energy audits for industrial businesses that are uniquely tailored to their needs. Recommendations include efficient lighting, cold storage refrigeration, and energy efficient machinery.
- Offers two rebate programs that help reduce GHG emissions: a rebate of up to $5,000 for EV purchases for residential electric customers and a broader GHG reduction rebate for gas customers. Using the gas utility's GHG reduction rebate, VPU has funded Vernon business customers' unique GHG reduction programs including the purchase of lower emission machinery, electric forklifts, and natural gas truck fueling stations.
- Provides net metering rates for customers who install behind-the-meter renewable generation.

The City of Vernon and VPU continue to explore, and implement, when possible, initiatives that support GHG emission reductions that directly affect DACs.

6. Transmission and Distribution

BULK TRANSMISSION SYSTEM

Bulk Transmission System

VPU is a POU whose load is under CAISO's jurisdiction. Most of VPU's load and generation capacity is within the CAISO BA. As such, VPU accesses the CAISO transmission grid for delivery of its market energy purchases and regional PPA generation to its energy needs.

VPU customers, through their electric rates, pay a transmission access charge (TAC) and a grid management charge (GMC), through a Transmission Control Agreement (TCA), to CAISO for transmission access. VPU was one of many Participating Transmission Owners (PTOs) in CAISO. Capital costs for transmission system upgrades and expansions within CAISO's transmission network are included in the TAC and GMC and recovered through CAISO's TCA.

Transmission Service Agreements

The City of Vernon had executed CAISO's TCA in 2001 and was a PTO, only by virtue of its three Existing Transmission Contracts (ETCs), which were turned over to CAISO's Operational Control as Transmission Entitlements.

VPU relied on transmission contracts with Los Angeles Department of Water and Power (LADWP) and Southern California Edison (SCE) to transmit its out-of-state power resources to its electric system load.

These contracts entitled VPU to:

- Victorville-Lugo Midpoint 500 kV line that interconnects the LADWP Victorville substation to the SCE Lugo substation.
- Lugo Midpoint-Laguna Bell 500 kV line that interconnects the SCE Lugo substation to the Vernon Laguna Bell substation. These rights included transmitting the capacity from the Palo Verde Nuclear Generating Station in Arizona.

- Mead-Laguna Bell 230 kV line that interconnects the SCE Mead substation to the Vernon Laguna Bell substation. These rights included transmitting the capacity from the Hoover Dam Hydroelectric Power Plant in Nevada.

On October 7, 2022, VPU terminated all three of its transmission contracts with SCE and LADWP after determining that the existing ETCs were no longer economically beneficial for its ratepayers. As a result, VPU no longer participates in the CAISO market as a PTO. VPU continues to participate in the CAISO market as a metered subsystem (MSS) under an MSS Agreement with CAISO. CAISO concurred with the termination of these three ETCs and Entitlements, and VPU's withdrawal from the TCA. VPU then filed for FERC approval to terminate its Transmission Owner (TO) Tariff and received approval in 2023.

Laguna Bell Corridor Line Upgrades

In 2020, CAISO approved a major upgrade to the Laguna Bell transmission corridor. An assessment of the SCE metro area identified thermal overloads on the transmission line.

The Laguna Bell-Mesa #1 230 kV line overloaded for a common-mode P7 outage as well as for P3 and P6 contingencies. The Laguna Bell-Mesa #1 230 kV line overload mitigation identified in the policy-driven needs assessment eliminated the overloads.

SCE submitted a proposal to reconductor the existing Laguna Bell-Mesa #1 230 kV line with Aluminum Conductor Composite Core (ACCC) conductors to increase the line rating. The project could address the portfolio resource deliverability issue identified in the policy-driven transmission analysis and provide reliability and economic benefits. The length of the line to be rewired is approximately five miles. The targeted in-service date is the fourth quarter of 2023.

The initial conceptual estimated cost for the project is $15 million. After further evaluation, SCE adjusted the cost to $17.3 million, which includes necessary upgrades of the Laguna Bell Substation terminal equipment that were not part of the original estimate.

The project increases the line rating by approximately 42 percent, to 3250/4760 amps SN/SE. When completed, the line upgrade will mitigate P3 (generator outage followed by loss of another element), P6 (loss of two non-simultaneous elements), and P7 (loss of two circuits on a common tower) contingencies.

Table 19 lists the four upgrades that are being implemented on the Laguna Bell-Mesa #1 230 kV transmission line.

Year	Item	Existing Emergency Rating*	Contingency	Category	Post Contingency Loading	Proposed Emergency Rating*	Contingency Loading with Proposed Upgrade
2023	1	3341/1331	Lighthipe-Mesa & Laguna Bell-Mesa #2 230 kV lines	P7	103%	4760/1896	≤100%
2026	2	3341/1331	Lighthipe-Mesa & Laguna Bell-Mesa #2 230 kV lines	P7	104%	4760/1896	≤100%
2031	3	3341/1331	Lighthipe-Mesa 230 kV line & Huntington Beach Repower	P3	104%	4760/1896	≤100%
2031	4	3341/1331	Lighthipe-Mesa & Laguna Bell-Mesa #2 230 kV lines	P7	112%	4760/1896	≤100%

* Ratings are amperes/mega volt-ampere (MVA)

Table 19. Laguna Bell-Mesa #1 230 kV Line Rating Increase Summary

Transmission deliverability into the Los Angeles Basin and the local capacity requirement (LCR) will also benefit from these line upgrades.

DISTRIBUTION SYSTEM

VPU has maintained a highly reliable electric system as evidenced by its Diamond Level RP3 designation over the last nine years from the APPA (see "Award Winning Grid Reliability and Service" on page 2-10).

VPU's distribution system is located entirely within the CAISO BA. It is connected to CAISO transmission and distribution system through the SCE 220-66 kV Laguna Bell Substation. Five 66 kV source lines that exit the SCE Laguna Bell 220-66 kV Substation supply and support the Vernon load. Due to the presence of local MGS generation, VPU's electric system is able to withstand a double contingency (N-2) situation when two 66 kV transmission lines are out of service.

VPU's service territory includes approximately 145 miles of transmission and distribution lines and includes three voltage levels: 7 kV, 16 kV, and 66 kV. Approximately 80 percent of the distribution system conductors and lines are overhead. The VPU electric system has nine substations. Four (Leonis, McCormick, Vernon, and Ybarra) are system-wide distribution substations. The remaining five are customer-dedicated substations: Owill, Beejay, Kinetic, Trigas, and Maisano.

Large industrial and commercial loads create abnormal challenges for operating and protecting VPU's electric system. The small geographical service area and dense loading results in shorter than average distribution circuits with multiple circuits on the same pole.

Distributed Generation Evaluation and Recommendations

In 2015, VPU completed a comprehensive Distributed Generation Impact Study to address the impacts of environmental, physical, and efficiency aspects of its distribution system through the addition of increasing amounts of solar PV DERs. The study assessed the impact of interconnecting solar, wind, diesel, and natural gas fueled facilities as well as the current mandatory requirement of a conditional use permit (CUP) for all distributed generation. Vernon's engineering staff currently uses the ETAP system model for distribution load flow, short circuit, transient flicker, and motor-starting analysis.

The study reviewed current electric rates, evaluated the potential rate impact associated with integrating increasing amounts of DERs, and outlined the optimal level of DERs without causing significant impacts by recommending a restructuring of electric rates for long-term financial security and stability.

Using this study as a starting point, the IRP analyzed the condition of VPU's existing interconnection and distribution system to identify safety, reliability, rate impacts, and operation issues and to determine the capabilities of VPU's current system. The analysis assessed the impacts of DERs and reviewed the existing rules and guidelines for the DER interconnection. This analysis served as a foundation for considering new improvements and measures to be undertaken to enhance the distribution system.

The results of the Distributed Generation Impact Study indicate that:

- The existing distribution system can support up to a full peak load 190 MW of DERs, but cannot be connected to any of Leonis Substation 7 kV distribution circuits until the feeder circuit breaker is replaced with a higher interrupting current rating.
- DERs of up to 5 percent of peak loads (non-coincident peak load of each class of customers) can be added, as required by net metering law and AB 327.
- Solar PV projects up to 1.0 MW can be exempted from the CUP requirements without significant environmental impacts. The CUP requirement should be maintained for the other types of DERs evaluated in the study and solar PV projects above 1.0 MW.
- Existing regulations provide adequate safety protection related to hazardous materials that are associated with solar PV, fuel cells, and fossil-fuel DER projects. Electric safety hazards can be managed by adopting prudent operating and maintenance procedures, interconnections agreement requirements, and guidelines and requirements that comply with DER and industry standards (such as IEEE Std.1547 and UA 1741).

The study recommended the following:

- Permit solar PV DERs of up to 1.0 MW without CUP process and continue CUP process for all other types of DERs, both renewable and non-renewable. Modify and update CUP language regarding diesel engines strictly used as back-up and stand-by generators, to clarify that those are exempt from the CUP.
- Replace all 7 kV circuit breakers at the Leonis substation with higher interrupting current rating to allow for DER connection on 7 kV circuits.
- Continue upgrading the VPU distribution infrastructure to maintain system reliability (accomplished through an approximate $5 million annual capital budget).
- Upgrade line conductors, transformers, and other aging infrastructure as part of its Capital Improvement Plan.

Distribution System Capital Improvement Project

VPU has developed a program to invest in its infrastructure. Over the past decade, this program has resulted in VPU successfully completing several major capital improvements projects to its distribution system.

Over the past three years alone, VPU has successfully completed over $25 million in system enhancements, including replacing over 100 distribution poles and two circuit miles of underground cable upgrades, converting the voltage in load growth areas, and completely rebuilding a major substation that is responsible for over one third of the City's electrical load.

In addition, VPU has recently completed substation upgrade projects on all of its major substations. Included in these upgrades is a four-year project at Leonis substation, which saw the replacement of all five transformer banks which had been in service since the 1950s. The transformers, responsible for over 30 percent the City's electrical load, were upgraded to add an additional 100 MW of capacity to the Vernon electric distribution system. The project also replaced circuit breakers, capacitor banks, and protective relays, essentially creating a new substation to provide reliable electric service to residential and business customers in the center, south, and east ends of the City for the next several decades.

Through the program, VPU successfully reduced the frequency and duration of distribution outages, maintained system reliability, improved safety, system efficiency, and operating flexibility. As the power system becomes more decentralized, the VPU distribution system needs to evolve, modernize, and incorporate emerging technology to support higher penetration levels of DERs.

While not subject to CPUC jurisdiction, VPU follows CPUC General Orders (GO) as a best practice. VPU performs inspections that adhere to with GO 165 and GO 174. Accordingly, VPU replaces deteriorating equipment that is identified as deficient under GO standards including wood power poles, oil-filled substation circuit breakers, aging underground substation getaway cables, and numerous electromechanical relays with solid state relays. VPU has also performed voltage conversion on limited segments of its distribution system, installed a comprehensive geographic information system (GIS), and performed many additional upgrades and replacements of capital infrastructure.

Vernon has assessed its distribution system to ascertain the condition of the existing system. The study has identified a number of distribution improvements that are needed to maintain system reliability, improve safety, system efficiency, and operating flexibility.

For the past three years, from 2020 through 2023, VPU has been working on a distribution Capital Improvement Plan (CIP) focused on strengthening infrastructure to better prevent outages, grid resiliency to sustain robust reliability, and maintain high service quality.

The result is VPU's Five-Year CIP. The plan focuses on infrastructure upgrades to help achieve a strategic vision that addresses its five-square-mile service territory and unique industrial characteristics that make up the City. The plan defined strategies that involved in-depth evaluation of the condition of the electric system; performed detailed engineering analysis of distribution system capability and performance; and listed construction and upgrade projects to help transform the system into an intelligent, increasingly automated, and technologically advanced electric system.

The CIP addresses the key areas and construction required for replacements or upgrades. The success of this project will be measured in the improved electric system reliability provided to the City of Vernon residential and business customers and, in turn, the benefits provided to the surrounding communities. The plan also aims reduce the carbon footprint of VPU by removing greenhouse gas emissions from the system. The plan includes replacing switches and circuit breakers that use sulfur hexafluoride (SF_6) for insulation and leverages new technologies for replacing and upgrading these units. The plan's goal is to increase system reliability for the local electric grid and environmental improvements for a sustainable future for the community.

Specific projects include replacing five aging substation transformers and upgrading to an additional 100 MW each of capacity; performing $5 million worth of reliability investment by upgrading 7 kV circuits to 16 kV; and replacing over 100 deteriorated wooden poles, 10,000 feet of underground primary cable, and all high-pressure sodium streetlight fixtures with new more efficient LED lights.

Actions that are part of the CIP include the following:

- Continue to replace and upgrade Vernon distribution aging infrastructure to maintain system reliability.
- Implement new distribution system automation by installing intelligent line switches and automatic reclosers for improvement of VPU's smart grid.

- Upgrade line conductors, transformers, and complete voltage conversions at electric substations.
- Perform system undergrounding in conjunction with development projects and City projects for improved system reliability.

These efforts provide VPU the opportunity to engage various commercial and industrial customers who are interested in increasing their existing capacity to meet expanding demand, electrify their fleet, and install EV charging infrastructure.

The Plan focuses on three target areas for improvement of the electric distribution system:

- Deteriorated wood pole replacements
- Reconductoring
- Sulfur hexafluoride (SF_6) gas removal

The purpose of each of the areas of improvement is outage prevention, hardening against natural disasters and extreme weather due to climate change, enabling quick recovery of the grid from disruptions, and decarbonization of the electric system.

The $25 million five-year CIP is summarized into three main distribution categories as outlined in Table 20.

Five-Year Capital Improvement Plan Budget ($ Thousands)						
Project	**2024**	**2025**	**2026**	**2027**	**2028**	**Total**
Deteriorated Wood Pole Replacement	$3,000	$3,000	$3,000	$3,000	$3,000	$15,000
Reconductoring	$500	$2,550	$350	$500	$600	$4,500
Sulfur Hexafluoride (SF_6) Gas Removal	$500	$900	$1,100	$1,500	$1,500	$5,500
Total	$4,000	$6,450	$4,450	$5,000	$5,100	$25,000

Table 20. Five-Year Capital Improvement Plan Budget

VPU will also continue with other capital improvements including the replacement of all SF_6 circuit breakers with vacuum circuit breakers, replacement of all underground SF_6 distribution switches with solid dielectric switches, adding new distribution circuit extensions, replacing substation getaways, and further upgrading substations.

SYSTEM RELIABILITY

VPU places significant emphasis on operational reliability indices as a cornerstone of its strategic vision. These indices serve as vital metrics to assess and enhance the resilience and dependability of VPU's services. By meticulously tracking and analyzing key reliability indicators, VPU proactively identifies areas for improvement, allocates resources effectively, and implements targeted strategies to maintain an unwavering commitment to providing consistent and uninterrupted power supply to its valued customers. This dedicated focus on reliability indices underscores VPU's dedication to delivering excellence in service while ensuring the utmost satisfaction and trust among its stakeholders.

Three Reliability Indicators

VPU tracks three reliability indicators that the electric utility industry uses to assess and improve the performance of power distribution systems.

- System Average Interruption Frequency Index (SAIFI): Quantifies the frequency of power outages per customer within a year.
- System Average Interruption Duration Index (SAIDI): Measures the duration of power outages experienced by the average customer over a year.
- Customer Average Interruption Duration Index (CAIDI): Provides the average time it takes to restore power after an outage, calculated by dividing SAIDI by SAIFI.

These indices collectively play a pivotal role in guiding VPU's efforts to enhance service quality, minimize downtime, and ensure a resilient and dependable power supply to consumers.

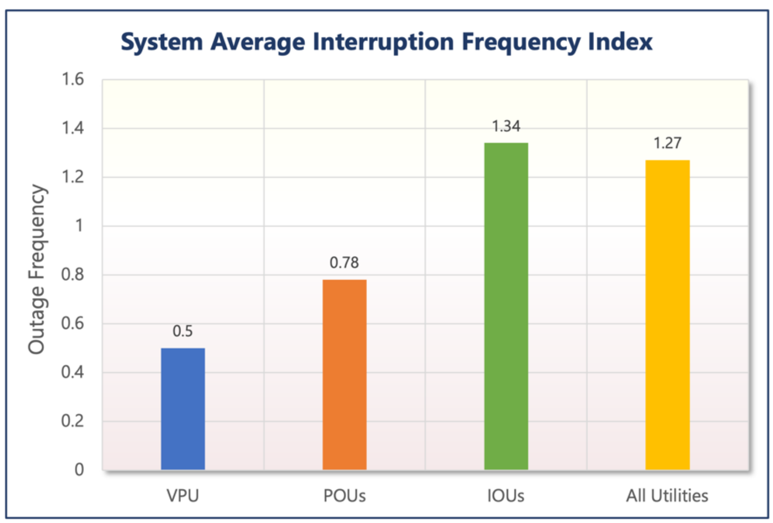


Figure 42. SAIFI Outage Frequency Comparison

VPU utilizes data from the U.S. Energy Information Administration (EIA), which annually calculates a nationwide electric utility reliability benchmark. This benchmark enables VPU to evaluate and compare its operational performance against industry standards and best practices. This process involves measuring various reliability indices, outage data, and service quality metrics, and then comparing these results to those of other utilities. From these results, VPU gains valuable insights into its strengths, weaknesses, and areas for improvement, fostering a culture of continuous enhancement.

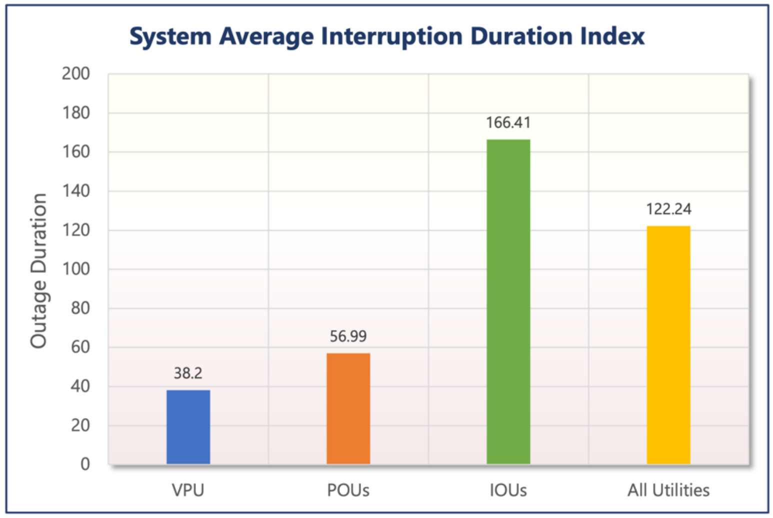


Figure 43. SAIDI Outage Duration Comparison

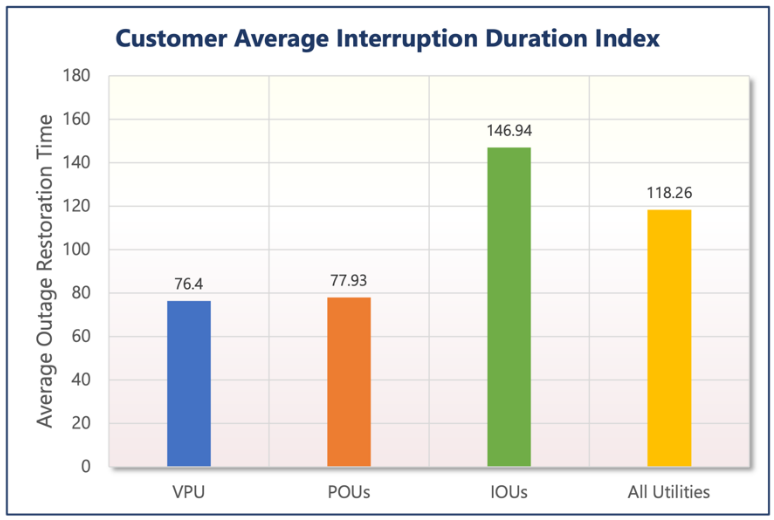


Figure 44. CAIDI Average Outage Restoration Time Comparison

Figure 42 shows that VPU's SAIFI outage frequency is 64 percent of all other POUs, 37 percent of statewide IOUs, and 39 percent of all utilities nationwide. Figure 43 shows that VPU's SAIDI outage duration is 67 percent of all other POUs, 23 percent of statewide IOUs, and 31 percent of all utilities nationwide. Figure 44 shows that VPU's CAIDI average outage restoration time is approximately the same as all other POUs, 52 percent of statewide IOUs, and 65 percent of all utilities nationwide. (All figures are from 2021.)

For 2021, VPU was ranked among the top 25 percent of the electric industry in reliability. Being in the top quartile of the benchmarking is significant for a utility for several reasons:

Customer Satisfaction. Utilities in the top quartile provide more reliable and consistent service, resulting in higher customer satisfaction. Fewer outages and quicker restoration times contribute to improved customer experiences and loyalty.

Economic Impact. A reliable utility with minimal service disruptions positively impacts the local economy. Businesses can operate without interruptions, productivity remains steady, and economic growth is sustained.

Operational Efficiency. Utilities in the top quartile often exhibit efficient operations and well-maintained infrastructure, leading to reduced downtime and operational costs.

Regulatory Compliance. Many regulatory authorities set reliability and safety standards that utilities must adhere to. Achieving top-quartile performance demonstrates compliance to the standards, avoiding potential penalties and demonstrating a commitment to compliance.

Resilience and Preparedness. Being in the top quartile signifies a utility's ability to effectively respond to and recover from unforeseen events such as storms, ensuring minimal disruption to the lives of its customers.

Stakeholder Confidence. High reliability levels demonstrate a utility's stability and competence, attracting stakeholder confidence and potentially leading to better access to funding for infrastructure improvements and expansion.

Customer Reputation. A utility's reputation for reliability and top-tier performance can positively influence public perception, attracting new customers and fostering positive community relationships.

Environmental Impact. A reliable utility may reduce the need for backup power sources or emergency generators, leading to lower emissions and a smaller carbon footprint.

In essence, being in the top quartile of electric utility reliability benchmarking signifies a commitment to excellence, ensuring that a utility consistently delivers dependable service, promotes customer satisfaction, and contributes positively to the overall well-being of the community it serves. These are all benefits that VPU enjoys as a result of its exemplary reliability and service to customers.

Cause of Outages

Virtually all outages in the City of Vernon are from accidental causes that are beyond VPU's control. Figure 45 depicts the various causes of the outages that VPU experienced in 2021. Contact with metallic balloons are the primary causes of outages (indicated as "foreign object" in Figure 45). The Other category includes single instances of storm damage, direct strike, and equipment damage.

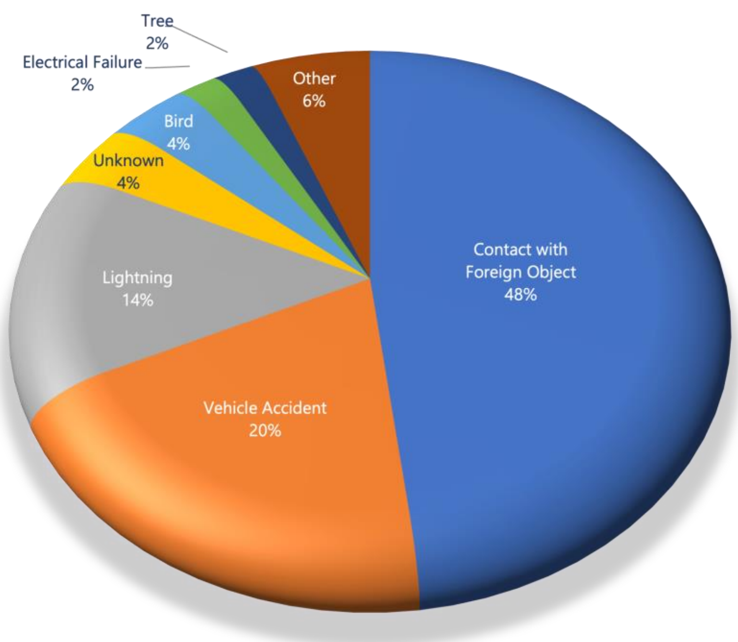


Figure 45. Causes of Outages

7. Resource Portfolio

VPU's load is served by a combined-cycle (CC) and two simple cycle (SC) natural gas plants, both locally owned and locally sited, two zero-carbon resource PPAs, a landfill gas RPS-eligible resource PPA, three solar PV RPS-eligible PPAs, and short-term market power purchases. In addition, VPU has recently signed two solar PV plus BESS RPS-eligible PPAs, which are scheduled to come online in the near-future.

RESOURCE PORTFOLIO OVERVIEW

Table 21 summarizes VPU's current and near-term generation portfolio mix.

Unit	Owner	Nameplate (MW)	VPU Share (MW)	VPU Energy (MWh)	RPS Status	End/ Retire
Malburg Generating Station	VPU	139.0	139.0	426,500	None	2036
H Gonzales Generating Station Units 1 & 2	VPU	11.5	11.5	383	None	—
Palo Verde Nuclear Station	SCPPA	3,937.0	11.0	92,427	Zero Carbon	2045
Hoover Dam Hydroelectric	WAPA	2,080.0	22.0	18,809	Zero Carbon	2067
Puente Hills Landfill Gas	LA Sanitation District	46.0	10.0	37,863	RPS Eligible	2030
Astoria II Solar PV	Recurrent Energy	100.0	30.0	92,900	RPS Eligible	2036
Antelope DSR 1 Solar PV	sPower	50.0	25.0	64,113	RPS Eligible	2036
Desert Harvest REC Solar PV	EDF Renewables	70.0	12.0	32,908	RECs	2045
Daggett Solar PV & BESS*	Clearway Energy Group	65.0 33.0	60.0 30.0	154662	RPS Eligible	2044
Sapphire Solar PV & BESS‡	EDF Renewables	117.0 59.0	39.0 19.7	124,007	RPS Eligible	2046
Total Generation Total BESS	—	6,610.5 92.0	354.5 49.7	1,044,572	—	—

* Daggett COD: December 20, 2023
‡ Sapphire COD: December 1, 2026

Table 21. Current VPU Owned and Contracted Generation Resources

Energy output is based on calendar year 2022.

The Daggett Solar PV energy is based on a first year PV generation projection of 208,499 MWh minus a round-trip efficiency loss of 15 percent (40,953 MWh) for the BESS. Since the Sapphire BESS has not received a Large Generator Interconnection Agreement (LGIA) from CAISO, its energy is based solely on a first year PV generation projection for VPU's share without an adjustment for round-trip efficiency.

Figure 46 graphs the current and near-term generation mix. The five light green slices represent current and near-term renewable generation, the two dark green slices represent zero-carbon resources, and the two dark gold represent its natural gas resources. By 2030, the renewable portion of VPU's portfolio will increase to 60 percent of total generation to comply with the state's RPS requirement.

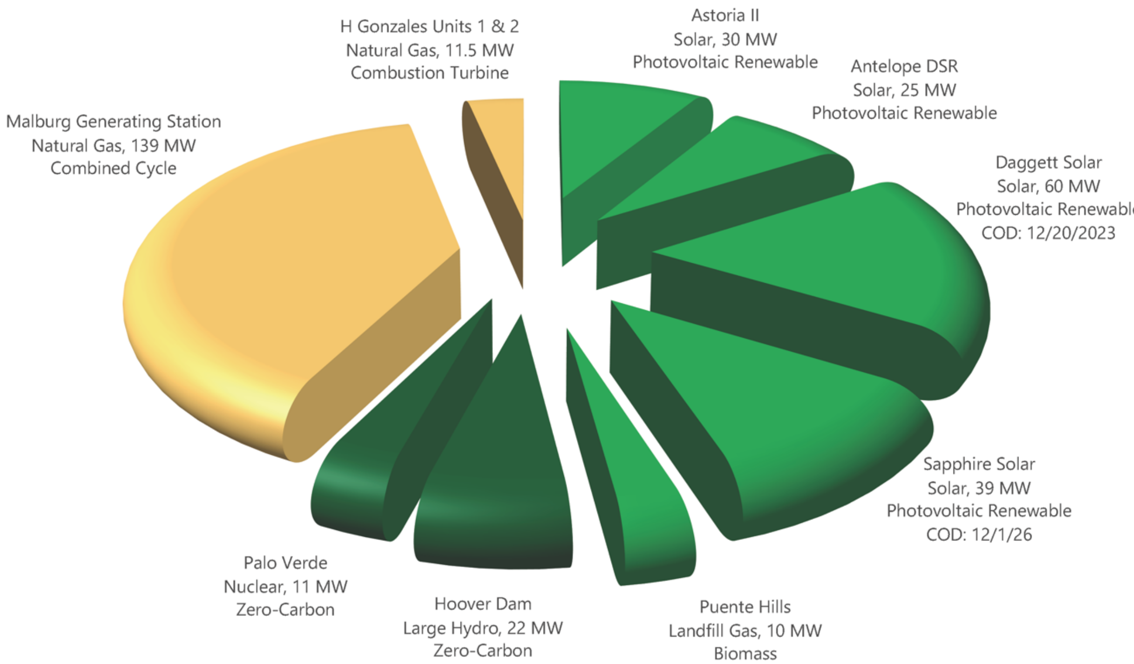


Figure 46. Current and Near-Term Generation Mix

CURRENT RESOURCE PORTFOLIO

The VPU portfolio consists of natural gas plants, nuclear, large hydroelectric, landfill gas, and solar PV facilities.

Natural Gas Resources

Malburg Generating Station

MGS is a 139 MW combined-cycle (CC) plant located in the City of Vernon. MGS includes two Siemens (formerly Alstom) GTXI00 natural gas-fired combustion turbine generators (CTGs) and a steam turbine generator (STG). MGS has duct burners and evaporative inlet air coolers and filters that enable the units to achieve higher levels of power output in selected modes of operation. MGS was originally built by the City of Vernon, later sold to Bicent Power LLC, then purchased back from Bicent in late 2021.

Figure 47. Malburg Generating Station

H. Gonzales Generating Station Units 1 & 2

The H. Gonzales Generating Station Unit 1 and Unit 2, located within the City of Vernon, is a natural gas-fueled facility powered by two Allison 571-KA combustion turbines (CTs), each rated at 5.75 MW that operate solely as peaking units. Both CT units began commercial operation in 1988. Each unit is restricted by air quality regulators to run on natural gas for no more than six hours per day.

Figure 48. H Gonzales CT1 and CT2

Zero-Emission Resources

Palo Verde Nuclear Station

The Palo Verde Nuclear Generating Station (PVNGS)[30] is located in Tonopah, Arizona, approximately 55 miles west of Phoenix. Palo Verde generates the largest capacity of electricity in the United States, with the second largest rated capacity. The Palo Verde plant consists of three nuclear electric generating units. Unit 1 is rated at 1,311 MW, Unit 2 at 1,314 MW, and Unit 3 at 1,312 MW.

Figure 49. Palo Verde Nuclear Station

In 1981, VPU signed a "take or pay" contract with SCPPA for 11 MW of power from Palo Verde. Under the PPA, VPU must pay for its proportionate share of power generated as well as operating and maintenance expenses, regardless of the amount of power taken. The PPA also requires VPU to pay its proportionate share of debt service on any bonds or debt, regardless of whether the project or any part of the project or its output is suspended, reduced, or terminated.

Hoover Dam Hydroelectric Power Plant

The Hoover Dam Hydroelectric Power Plant is located on the Arizona-Nevada border approximately 25 miles southeast of Las Vegas. This hydro power plant is part of the larger Hoover Dam facility, which was completed in 1935 and controls the flow of the Colorado River. The Hoover Dam facility consists of 17 generating units and two service generating units with a total installed capacity of 2,080 MW.

Figure 50. Hoover Dam Hydroelectric Power Plant

In 1987, Vernon entered into a PPA to purchase 22 MW of firm capacity from the

[30] Palo Verde is jointly owned by Arizona Public Service (29.1%), Salt River Project (20.2%), El Paso Electric (15.8%), Southern California Edison (15.8%), PNM Resources (7.5%), Southern California Public Power Authority (5.9%), and Los Angeles Department of Water and Power (5.7%).

Western Area Power Administration (WAPA). SCPPA and other contractor allocations of Hoover power and energy has been extended for 50 years beyond the PPA's original expiration in 2017, which now expires in 2067.

Renewable Energy Resources

Puente Hills Landfill Gas Plant


Figure 51. Puente Hills Landfill Gas Plant

The Puente Hills Landfill Gas-to-Energy facility is a 46 MW conventional Rankine Cycle Steam Power Plant that uses landfill gas as fuel to generate electricity. Landfill gas is fired in the plant's boilers producing superheated steam. The superheated steam is used to drive the steam turbine to generate electric power. The Puente Hills Landfill Gas-to-Energy facility was constructed by the Los Angeles County Sanitation District (LACSD) and began full commercial operation in January 1987; it has remained online 95 percent of the time since then.

On behalf of its members, SCPPA entered into a PPA with LACSD for 43 MW of generating capacity from the Puente Hills Landfill Gas-to-Energy facility. VPU, through SCPPA, is entitled to 10 MW of renewable capacity from the facility. The PPA expires on December 31, 2030.

Astoria II Solar Photovoltaic Facility


Figure 52. Astoria II Solar Photovoltaic Facility

The Astoria II Solar PV facility is sited on approximately 840 acres between Los Angeles and Kern Counties, and interconnects with the CAISO system at the SCE Whirlwind Substation.

The City of Vernon, in conjunction with five other SCPPA municipal utilities, participated in a PPA with Recurrent Energy to purchase the output from the Astoria II Solar facility for 20 years. The PPA entitled Vernon to 20 MW of capacity from January 2017 to December 2021. Starting in January 2022 and extending until the PPA's expiration in December 2036, VPU is entitled to 30 MW of power.

Antelope DSR 1 Solar PV Facility

The Antelope DSR 1 Solar PV facility is located in the City of Lancaster, Los Angeles County. It was developed by the Sustainable Power Group (sPower) and came online in December 2016.

Figure 53. Antelope DSR 1 Solar PV Facility

Through SCPPA, VPU owns a PPA with Antelope DSR 1 LLC (a subsidiary of sPower) for 25 MW of output, 50 percent of the facility's 50 MW capacity, through December 31, 2036.

In conjunction with the solar facility, the cities of Riverside and Vernon negotiated an energy storage option in the PPA, which provides for potential to design, build, and operate an energy storage facility at the site when economically feasible.

Desert Harvest 2 REC Solar PV Project

Figure 54. Desert Harvest 2 REC Solar PV Project

On December 17, 2020, SCPPA initiated a PPA with EDF Renewables for 70 MW of solar PV capacity from the Desert Harvest 2 Solar PV project. The project is a fixed-tilt PV system that interconnects at the Marketplace substation and is located on 1,200 acres of Bureau of Land Management (BLM) land in Desert Center, California. The REC + Index agreement serves the cities of Anaheim, Burbank, and Vernon.

VPU is entitled to 17.14 percent of the Project's output, or about 12 MW. This PPA, which expires at the end of 2045, provides RECs only.

Daggett Solar PV and BESS Project

The Daggett Solar plus BESS project is a single-axis tracker 65 MW solar with a 33 MW (132 MWh) 4-hour Lithium-Ion BESS. The COD is December 20, 2023. The project, located in City of Daggett in San Bernardino County, is a portion of an approximately 482 MW solar PV facility. The project is being developed by Clearway Energy Group and is owned by Daggett Solar Power 2 LLC.

Figure 55. Daggett Solar PV and BESS Project

On June 24, 2022, SCPPA executed a PPA for 65 MW for the cities of Vernon and Cerritos. The PPA entitles VPU to 60 MW of solar PV output and 30 MW of energy storage. The PPA expires at the end of 2044.

The contract will provide VPU with 60 MW of solar and 30 MW of Storage. City of Cerritos is entitled to 5 MW of solar and 3 MW of the storage in this project. This contract will expire on December 31, 2044.

Sapphire Solar and BESS Project

The Sapphire Solar project is a solar PV and BESS facility being developed by EDF Renewables. Located on 1,140 acres of private land in Riverside County, the project will generate 117 MW of solar power paired with a 59 MW 4-hour Lithium-Ion BESS with a total capacity of 236 MWh.

The project will interconnect on an existing Desert Harvest transmission line and deliver to the CAISO System. The bundled energy products include renewable energy, RECs, RA, and other energy attributes. The COD is December 31, 2026. VPU has acquired a PPA for 39 MW of solar output combined with 19.67 MW of BESS. The PPA expires on December 1, 2046.

WHOLESALE MARKET POWER PURCHASES

VPU participates in the CAISO market under a metered subsystem agreement (MSSA). The agreement allows Vernon to balance its load and resources within its city limits. As CAISO serves as VPU's Balancing Authority, VPU bids its resources and load into the CAISO market. Based on market pricing, CAISO determines the amount of energy supplied by VPU's resources into the market. If the local generation cost is above the market price, then CAISO meets VPU's load with market resources.

8. Renewable Energy and RPS Compliance

As with many other utilities in the state, VPU faces the task of meeting its RPS and zero-carbon requirements cost effectively while balancing that with its existing resources. These requirements must be achieved while retaining its award-winning level of reliability and high customer satisfaction.

Ascend took a broad approach when considering, modeling, and analyzing how VPU would meet state mandates over the next two decades. In this process, Ascend reviewed the following for the City: its current RPS compliance status for 2023 through 2045, its current RPS-eligible and zero-carbon contracts, its planned projects through 2045, and its plans beyond 2023. From this analysis, Ascend calculated the "net short" position or the difference between VPU's RPS requirement and its existing resources and planned PPAs. Using this information, Ascend modeled three different portfolios to determine the optimum, most cost-effective, mix of resources that meet the RPS and clean energy goals. In addition, the modeled portfolios had to maintain reliability and maximize benefits to the City. For these portfolios, Ascend considered a number of resource options with mature technologies. From this process, one portfolio emerged as most advantageous.

RENEWABLE GENERATION

VPU already has executed several solar PPAs as well as a couple of storage plus solar resources to add to its renewable portfolio. Any positions not met with its current renewable portfolio are covered by short-term REC purchases to comply the RPS requirements.

As California moves toward a carbon-free grid, VPU must consider how to replace MGS. One focus of this IRP is to consider replacing MGS, if implemented, with renewable and clean alternatives while maintaining reliable service and competitive and stable rates.

RPS COMPLIANCE

In 2022, VPU received 227,784 MWh of RECs from its contracted renewable resources (outside of market purchases). Table 22 lists the resources in VPU's portfolio that generate RECs used to comply with the SB 1020 RPS targets.

Resource	RECs in 2022 (MWh)
Antelope DSR Solar	64,113
Astoria II Solar	92,900
Puente Hills Landfill Gas	37,863
Desert Harvest Solar (RECs only)	32,908
Market Purchases	170,631
Total RECs	398,415

Table 22. REC Generation by Resource in 2022

Most recently, VPU has contracted with two new solar energy plus storage projects: Daggett Solar PV in 2024 and Sapphire Solar PV in 2026. Both projects include a BESS. This gives VPU the ability to shift a portion of the solar generation to hours that provide higher value. Generation from Daggett and Sapphire is expected to add 310,000 MWh per year, pushing VPU's RPS position to 46 percent by 2027. SB 100 requires VPU to cover 52 percent of its retail load (less municipal usage) with renewable energy in 2027. Thus, VPU must procure additional sources of renewable energy or purchase more short-term RECs to meet the RPS requirements.

Aside from the RPS targets for renewable energy, VPU must plan to meet SB 100's requirements that stipulate the following percentages of its retail sales (less municipal load) of electricity must be served with renewable energy and zero-carbon resources by specific years: 90 percent by 2035, 95 percent by 2040, and 100 percent by 2045. Zero-carbon resources, such as large hydroelectric and nuclear generation, are considered clean energy.

Figure 56 shows the RPS position by year for Vernon through 2035. Resources include all current and recently contracted PPAs, which is mostly from solar PV plus BESS. The blue hatched area depicts the calculated "net short" that VPU must fill with RPS eligible resources to meet state requirements.

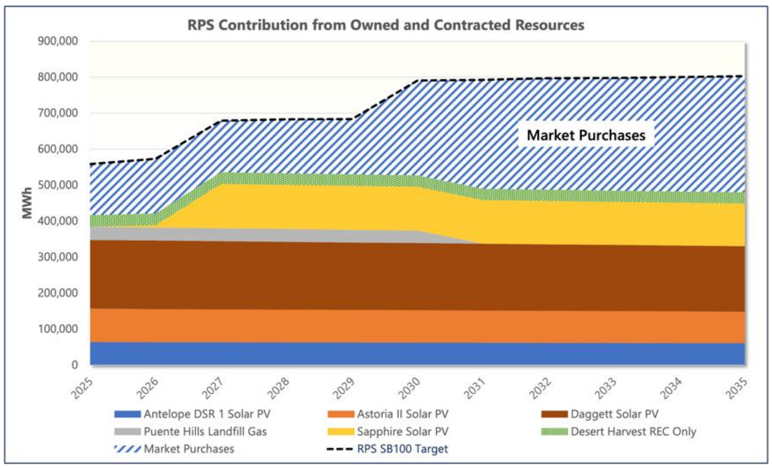


Figure 56. Market Purchases and Clean Energy Position until 2035

RPS and Clean Energy Portfolio 1

The first portfolio modeled for the IRP includes solar, wind, biomass, and storage resources to meet RPS requirements. Existing nuclear and large hydro resources count toward zero-carbon requirements.

Figure 57 depicts how eligible RPS resources modeled are selected for Portfolio 1 to meet the state mandated RPS requirements over a short-term planning period of 2024 through 2034.

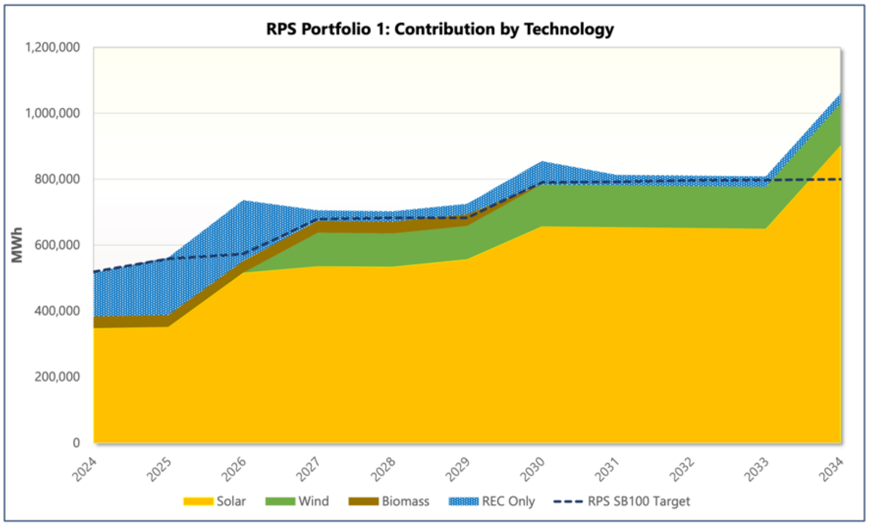


Figure 57. RPS Position for Portfolio 1

Figure 58 depicts how both the eligible RPS and zero-carbon resources modeled in Portfolio 1 meet the clean energy requirements over a long-term planning period of 2035 through 2045.

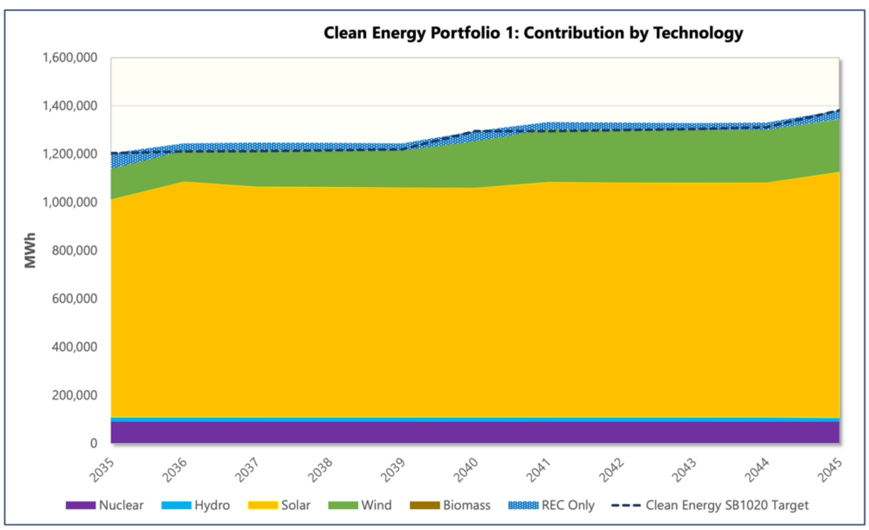


Figure 58. RPS and Clean Energy Position for Portfolio 1

RPS and Clean Energy Portfolio 2

The second portfolio modeled for the IRP includes solar, wind, biomass, and geothermal resources to meet RPS requirements. Existing nuclear and large hydro resources count toward zero-carbon requirements.

Figure 59 depicts how eligible RPS resources modeled in Portfolio 2 would meet the state mandated RPS requirements over a short-term planning period of 2024 through 2034.

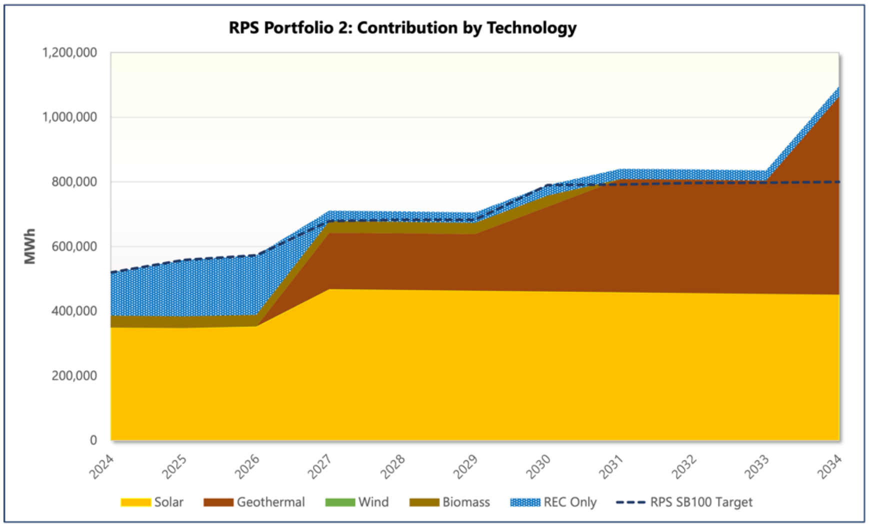


Figure 59. RPS Position for Portfolio 2

Figure 60 depicts how both the eligible RPS and zero-carbon resources modeled in Portfolio 2 meet the clean energy requirements over a long-term planning period of 2035 through 2045.

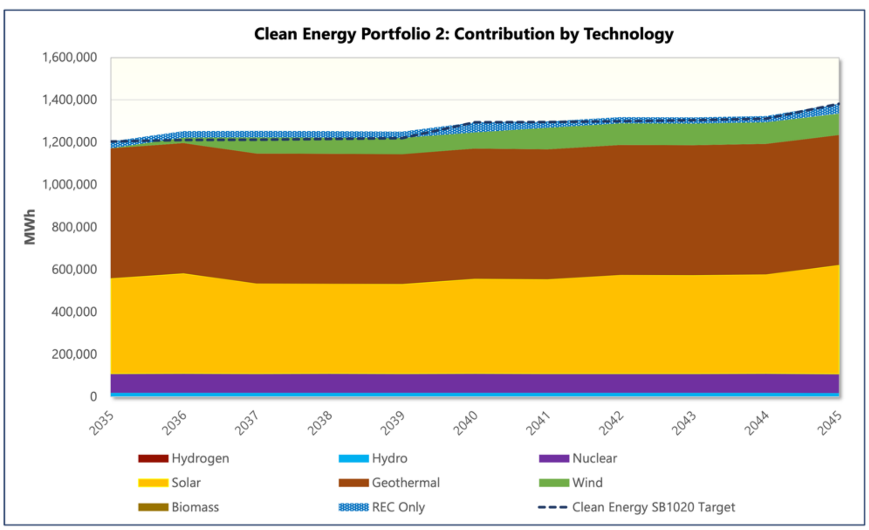


Figure 60. RPS and Clean Energy Position for Portfolio 2

RPS and Clean Energy Portfolio 3

The third portfolio modeled for the IRP includes the same resources as in the first portfolio: solar, wind, and biomass resources to meet RPS requirements. As in the second portfolio, Existing nuclear and large hydro resources count toward zero-carbon requirements.

Figure 61 depicts how eligible RPS resources modeled in Portfolio 3 meet the state mandated RPS requirements over a short-term planning period of 2024 through 2034.

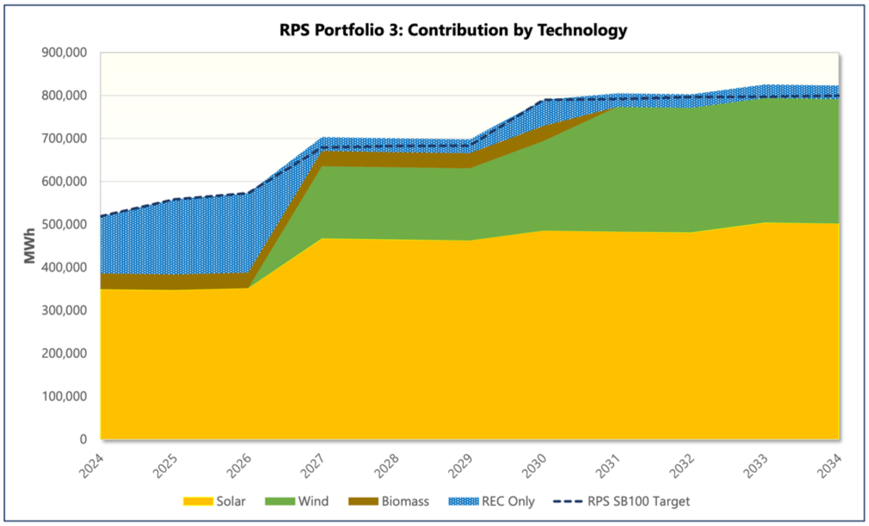


Figure 61. RPS Position for Portfolio 3

Figure 62 depicts how both the eligible RPS and zero-carbon resources modeled in Portfolio 3 meet the clean energy requirements over a long-term planning period of 2035 through 2045.

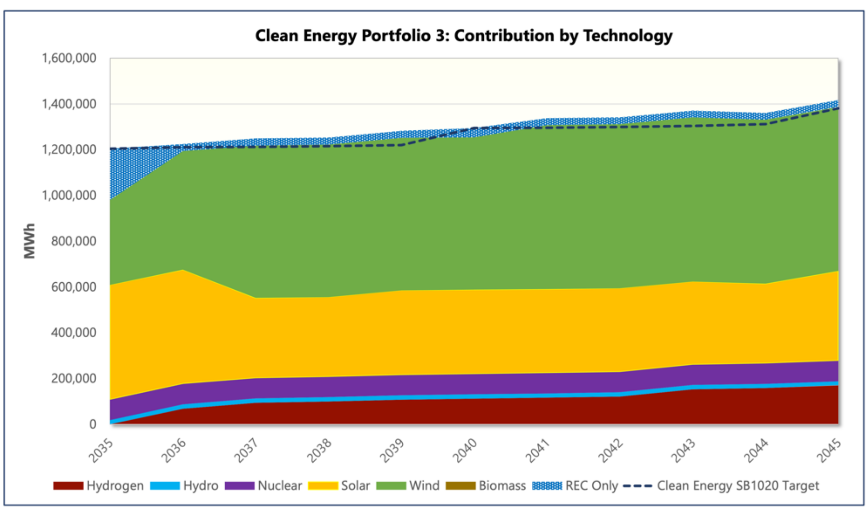


Figure 62. RPS and Clean Energy Position for Portfolio 3

PORTFOLIO COMPLIANCE

In addition to RPS requirements, there are additional requirements. SB 350 established a long-term procurement requirement for new generation. All resources must be from one of three PCCs.

PCC-1 generation must be at least 75 percent of total procured generation. PCC-1 generation must comply with one of the following stipulations:

- Have a first point of interconnection with a California balancing authority.
- Have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area.
- Scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source.
- Beginning in 2021, at least 65 percent of this 75 percent of new renewable generation must be from PPAs or in ownership agreements that are at least ten years in duration.
- Have an agreement to dynamically transfer electricity to a California balancing authority.[31]

A maximum of 15 percent of new procurement can come from PCC-2 generation, which is "firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority."[32]

Finally, a maximum of 10 percent of new procurement can be PCC-3 generation: "eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled RECs"[33], that does not qualify as a PCC-1 nor PCC-2 resource.

VPU currently purchases RECs to comply the RPS requirements. These requirements can also be met with PCC-1, PCC-2, and PCC-3 resources.

[31] California Legislative Information, SB-350 Clean Energy and Pollution Reduction Act of 2015; https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

[32] *Ibid.*

[33] *Ibid.*

9. Market Resource Portfolios

The fundamental purpose of integrated resource planning is to ensure adequate capacity to generate energy for current and forecasted demand while maintaining reliability and competitive and stable rates as well as meeting state regulatory requirements.

THE FOUNDATION OF THIS IRP

To address these issues, Ascend considered a series of fundamental market portfolio scenarios to test various resource mixes, assess their viability, and plan a timeline for this capacity expansion. These scenarios addressed key market and industry-side trends and conditions, supply and demand possibilities, and energy price forecasts. The market scenarios addressed several factors, including peak demand and energy forecasts, GHG emission reductions, renewable and clean energy integration, energy efficiency measures, energy storage, EV penetration, and building electrification. The scenarios are based on a wide-ranging set of assumptions and risk factors that might evolve over the long-term planning period of 2023 through 2045.

As a result of this planning, Ascend modeled three future market-based scenarios to identify a preferred portfolio of generation resources that meet all VPU goals and state regulatory requirements. Each portfolio consisted of a different mixture of resource options and other factors. Ascend ran capacity expansion and production cost models in its analysis software, PowerSIMM, to assist VPU in planning its resource mix over the entire extent of the long-term 2023–2045 planning period.

Vernon and Ascend worked together on portfolio scenarios that provided realistic representations of potential future paths for VPU. The portfolios shared a number of input assumptions, a key assumption being the reduction in MGS capacity in 2030 and its status in 2035.

A key goal of the scenario planning process is to provide City management with a robust quantitative assessment of how its business planning projections could be affected by key risk variables. Implementing the selected preferred portfolio will assist the City in identifying additional detailed analyses needed to further quantify operational and financial requirements while examining business planning risks and potential outcomes.

MODELING AND ANALYSIS FRAMEWORK

IRP modeling is a multi-step process to create capacity expansion plans and calculate their associated cost to serve Vernon's load. These costs include the production cost of VPU's generation assets as well as the costs and revenues associated with energy transactions in the CAISO markets. The objective is to find the optimum balance among cost, resource adequacy, environmental requirements, and policy objectives.

The process starts by defining the objectives, assumptions, and inputs into the capacity expansion models. Primary inputs include the physical and financial parameters of VPU's current resources, VPU's load forecast, the candidate resource options, price forecasts (power, natural gas, and carbon), and model constraints such as capacity needs, energy needs, and resource build limitations. Figure 63 outlines the optimal supply portfolio.

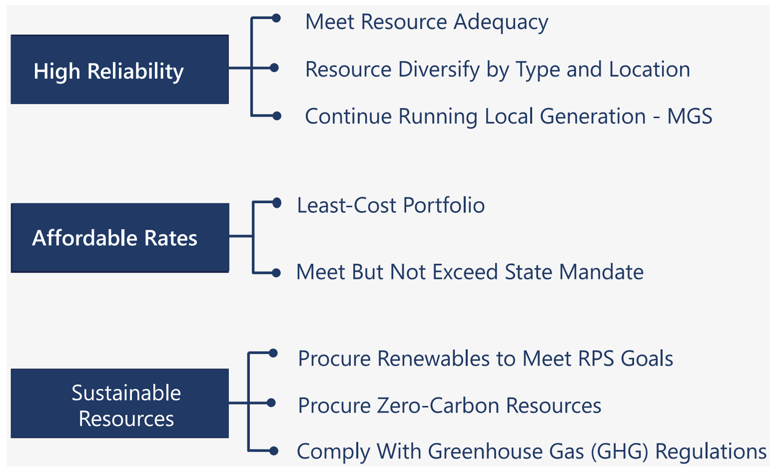


Figure 63. Optimal Supply Portfolio

Ascend worked with VPU staff to create a model of its existing system. Staff gathered data on VPU's supply resources and load, including historical data along with future plans and projections for resource updates and expected changes in customer load.

Capacity expansion models provide a least-cost set of resources that meet the constraints defined in the model. Portfolio outputs from the capacity expansion models are analyzed for resource adequacy. If a portfolio cannot adequately serve load, additional resources are added. Finally, portfolios are analyzed in a production cost model to determine production costs, emissions, market interactions, among other outputs.

Once all the input assumptions are defined, the VPU modeling team developed an initial list of scenarios and sensitivities. Scenarios are core frameworks for possible future portfolios, and sensitivities are variations on the scenarios to test how changing assumptions affect the resource selection and production costs.

Scenario development provides an opportunity to consider different future paths. In this case, the scenarios consider alternative replacement options for MGS. Modeling VPU's system with different scenarios gives important feedback on total system costs, reliability, emissions, and resource operations. VPU relied on this resource modeling to chart a path toward a clean, reliable system with competitive and stable rates.

INPUT ASSUMPTIONS AND PORTFOLIO MODELING

VPU licensed PowerSIMM, developed by Ascend Analytics, for the modeling work in this analysis. PowerSIMM provides capacity expansion, resource adequacy, and production cost modeling. The modeling in this IRP relied on stochastic models for capacity expansion and production cost. The modeling team configured PowerSIMM to capture variability and uncertainty in load, renewables, and prices while maintaining structural parameters among the variables.

PowerSIMM simulations combine future expectations for load, markets, and renewables, with historical data to create realistic future simulations of the power system. Simulations are scaled to future expectations based on monthly forecasts for renewable generation, load, and prices including price volatility and daily price shapes. The result is a set of simulations covering a useful and accurate range of potential future paths.

Automated Resource Selection (ARS) is the capacity expansion module in PowerSIMM. ARS selects the least-cost resource procurements or retirements that satisfy the model constraints. The models begin with a dispatch of existing and candidate resources to determine variable costs, energy generation, carbon emissions, and renewable generation over the long-term planning period. The modeling employed four constraints.

Planning Reserve Margin. Requires portfolio to meet projected annual peak demand plus a 15 percent PRM. Current discussions are considering increasing the PRM to 17 percent.

Emissions. Disallows new fossil fuel resource additions and reduce reliance on existing natural gas assets to ensure the resultant portfolio complies with SB 1020 requirements.

RPS Level. Requires adequate renewable generation to ensure the resultant portfolio complies with the RPS mandates of SB 350, SB 100, and SB 1020.

Energy Generation. Requires VPU to have adequate resources to meet at least 80 percent of their load which reduces their reliance on market purchases.

Outputs from ARS provide the timing and quantity of resources to procure over the long-term planning period that satisfies these four constraints at the lowest cost. The model considers full resource costs including capital costs, fixed costs, and variable costs such as start-up costs, fuel, and variable operation and maintenance (VOM) costs. Market sales revenue is treated as a negative cost in the model.

Candidate Resources

In addition to VPU's existing resource portfolio, the IRP considered several candidate resources to potentially add to a new resource portfolio. These resources included both renewable generation (geothermal, solar PV, BESS, and wind) and clean energy generation (hydrogen and CCS (Figure 64).

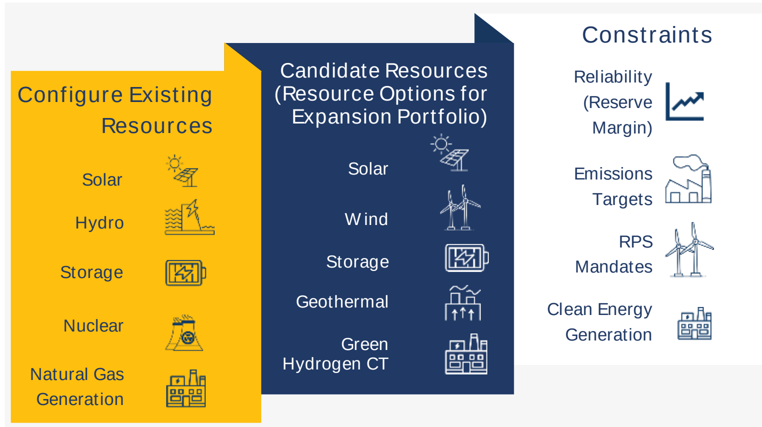


Figure 64. Resource Capacity Modeling Elements

These resources were included in the modeling of all three portfolios. The list of candidate resources was established to consider a range of new resource technology types that VPU could realistically procure. The following provides a brief overview of the candidate resources.

Solar. New candidate solar PV resources are assumed to be single-axis tracking with capacity factors of approximately 32 percent. VPU is expected to have abundant opportunity to contract for more solar in their portfolio over the next few years.

Wind. As a low risk and mature technology, wind provides carbon free energy that can also be counted in fulfilling the RPS requirements. VPU currently has no wind in its portfolio, but the resource is available in Southern California. New candidate wind resources are assumed to have capacity factors approximately 30 percent.

Storage. BESS storage durations of 4-, 8-, and 10-hour durations were considered. VPU will have an ideal location for energy storage at the MGS site. The model assumes that space and transmission capacity is adequate to install a battery in Vernon at the same site where MGS is currently located. The BESS candidate resource costs are based on lithium-ion chemistry, daily BESS cycling (up to 365 cycle per year), and capacity augmentation throughout the resource lifecycle. Battery technology will likely evolve over the next twenty years with iron-air and flow batteries showing promise for the next generation of energy storage. In future IRPs, VPU will consider such emerging technologies. For this IRP, however, VPU relied solely on mature storage technologies that are commercially available.

Geothermal. Geothermal provides reliable clean power around the clock. Generation from geothermal sourced power is firm and dependable since it does not rely on weather. California is the national leader in geothermal energy with more than 5 percent of total generation coming from geothermal resources. Due to high demand for renewable power around the clock, geothermal prices have increased lately. VPU will consider geothermal as an option for future supply acquisitions.

Green Hydrogen CT. Hydrogen can power a simple cycle CT with the fuel piped to the resource location. The model used a projected price forecast for hydrogen fuel with heat rates close to a new natural gas CT (10 MMBtu/MWh). A hydrogen powered generator was modeled within VPU's territory as a potential replacement for MGS.

Natural Gas CC+CCS. A natural gas combined-cycle unit with carbon capture and sequestration was included in the model with an assumption that it would replace MGS.

Potential Portfolio Options Procurement Plan

The IRP considered several options to increase VPU's renewable share to meet its RPS requirements. Starting in 2027, the portfolios analyzed and modeled by Ascend added wind or solar to VPU's resource mix to meet RPS requirements in the near term. The analysis for the long-term planning considers replacement options for MGS in 2035 to meet the 90 percent clean energy target. The long-term considerations for MGS are Li-Ion energy storage, hydrogen generation, and geothermal generation. Replacement resources are sized to provide the same RA as the capacity lost from MGS.

The IRP modeling process selected a set of options for clean energy, which included wind, solar, energy storage (4-hour and 8-hour duration), geothermal, hydrogen, and CCS. Wind and solar provide energy and RECs with low capacity value to meet RA requirements. Energy storage provides no energy or RECs, but can support variable resources like wind and solar to provide needed capacity value for RA. Energy storage has over 90 percent capacity value. Geothermal provides both energy and capacity value at a higher cost compared to wind and solar. Finally, hydrogen and CCS provide dispatchable capacity to supply clean energy around the clock at a higher cost than geothermal.

Three potential resource portfolios were modeled for the IRP. The added resources in each portfolio set VPU on a path to comply with future renewable and clean energy requirements.

The cost assumptions are but one factor when evaluating the portfolios, include the levelized cost of energy (LCOE), financial assumptions, tax credits, depreciation, and the cost of capital.

Table 23 summarizes the average cost of potential RPS-compliant resources, clean energy resources, and energy storage for the capacity expansion models to consider when selecting the preferred resource portfolio (for 2025 through 2045). The analysis shows that the lowest cost resources are southern California solar, Pacific northwest wind, and the 4-hour Li-Ion BESS. The lowest cost zero-carbon resource is nuclear small modular reactors followed closely by new geothermal.

Technology	Resource	Price Units	Average Cost
Geothermal	California Geothermal (new build)	$/MWh	$157.00
Hydrogen	Hydrogen Combustion Turbine	$/kW	$2,156.20
CCS	Carbon Capture and Sequestration	$/kW	$3,537.44
Solar	Southern California Solar	$/MWh	$48.66
	Northern California Solar	$/MWh	$54.67
Energy Storage	4-hour Li-Ion BESS	$/kW-Month	$15.02
	8-hour Li-Ion BESS	$/kW-Month	$25.70
	10-hour Flow BESS	$/kW-Month	$28.93
Wind	Pacific Northwest Wind	$/MWh	$46.32
	New Mexico Wind	$/MWh	$56.21
	Southern California Wind	$/MWh	$63.95
	Northern California Wind	$/MWh	$68.57
	Wyoming Wind	$/MWh	$70.59
	California Offshore Wind	$/MWh	$114.72
Nuclear	Nuclear Small Modular Reactor	$/MWh	$154.36

Table 23. Average Cost of RPS-Compliant, Clean Energy, and Storage Resource Portfolio Options

Resource Cost Estimates

Ascend prepared cost estimates for candidate resources, which were based on multiple sources of information. One source is the Annual Technology Baseline (ATB) report published by the National Renewable Energy Laboratory (NREL). It provides projections of resource costs for various technologies through 2050. Ascend augmented information from the ATB with data gathered through the administration of utility Request for Proposals (RFPs) to procure new resources throughout California. If, for example, Ascend received an indication that southern California solar prices are higher than the projected ATB values, Ascend adjusted the projections to attain more accurate prices for the southern California region. All price projections include the effects expected from the Inflation Reduction Act (IRA) on power purchase agreement costs from renewable resources.

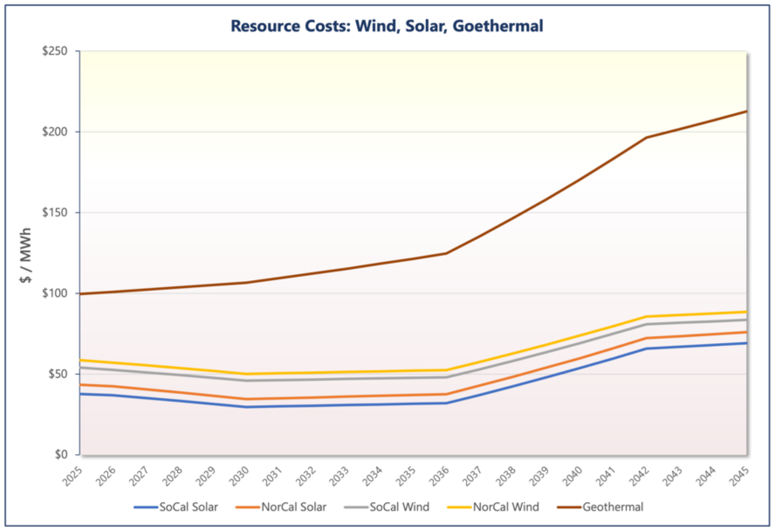


Figure 65. Resource Costs: Wind, Solar, Geothermal

Figure 65 depicts the forecast of solar PV and wind costs, in dollars per MWh, sited in southern and northern California together with geothermal costs. In general, the cost for geothermal generation is double that of wind and solar. That doubling cost gap is forecast to increase over time.

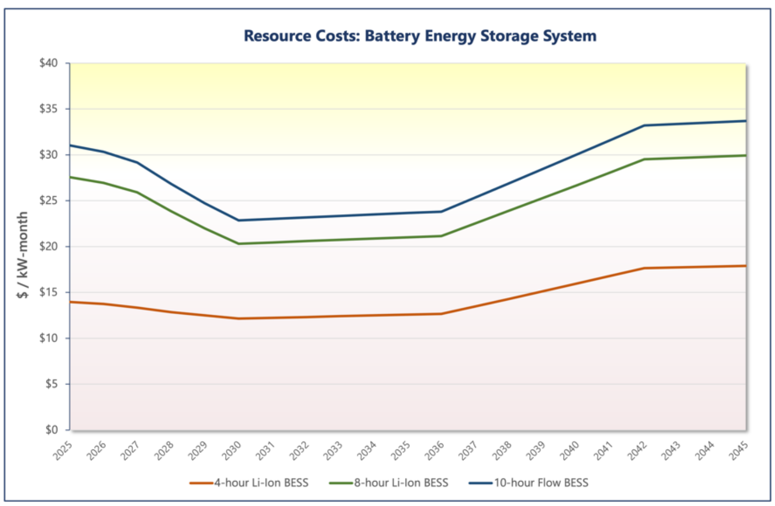


Figure 66. Resource Costs: Battery Energy Storage System

Figure 66 depicts the cost forecast for 4-hour, 8-hour, and 10-hour BESS in dollars per kW month (the kW consumed in an average month). In general, the cost for 4-hour BESS is half that of 8-hour and 10-hour BESS.

Figure 67 depicts the cost forecast for a hydrogen-fueled CT and for the implementation of CCS on the generation unit in dollars per kW. These cost forecasts are multiples of that of other mature generation technologies.

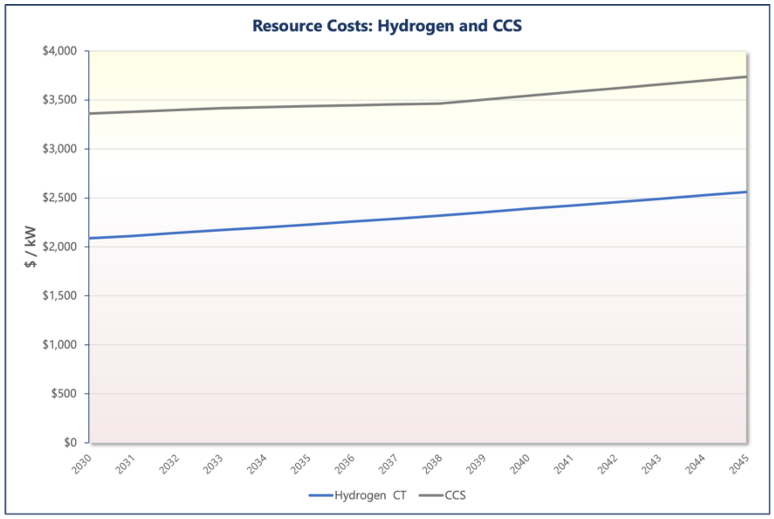


Figure 67. Resource Costs: Hydrogen with Carbon Capture and Sequestration

Risk Analysis

The future can only be predicted through research and forecasts. Modeling, based on numerous assumptions, and its incumbent analysis, comes with risk. Every effort is made to minimize risk, nonetheless, risk must be considered when devising and implementing any plan.

Risks inherent in resource planning include:

- Higher than expected environmental compliance costs
- Higher than expected carbon prices
- Higher than expected resource generation costs
- Higher than expected transmission and distribution costs
- Direct and indirect environmental costs
- Transportation costs

Additional risks include increased demand and energy requirements, regulatory energy policy changes, and financial liquidity risks. Resource planning attempts to mitigate these risks as much as possible so that resultant actions remain viable for the foreseeable future.

ANALYZING VPU'S CURRENT RESOURCE PORTFOLIO

VPU's resource portfolio consists of a balanced mix of energy generation consisting of natural gas, nuclear, hydroelectric, landfill gas, and solar. The largest generator, MGS, provides 139 MW of accredited capacity toward VPU's RA requirement. As a local resource in the city of Vernon, MGS can be counted on to reliably serve load even in the face of transmission outages and line congestion. Due to this advantage, VPU plans to continue to run MGS as long as possible to maintain low-cost, reliable service for the residents of Vernon. By 2030, however, the GHG emissions emitted by MGS must be reduced in a manner that will satisfy more stringent emission regulations.

The core scenarios revolve around the status of MGS. Modeling shows that VPU must reduce MGS emissions by 2030. The most favorable option for accomplishing this emission reduction is to stop operating one of MGS's CTs and run the unit less frequently outside the summer months. Thus, the models assume that, starting in 2030, MGS will operate in a 1x1 configuration (one CT and one ST) with limited dispatch in the off-peak months. Changing to a 1x1 configuration will likely cut MGS GHG emissions by two-thirds in 2030 compared to today.

In 2035, the model assumes that MGS will stop generating after 30 years of operation, which helps VPU meet the renewable and clean energy requirements of SB 32, SB 100, and SB 1020. In 2035, VPU is expected to meet 90 percent of its load with carbon-free resources.

The GHG Emissions Accounting Table (GEAT) projects annual GHG emissions attributed to MGS generation, VPU's only eligible GHG emitting resource, for all modeled portfolio scenarios. Figure 68 shows VPU's annual emission for its current 2x1 configuration, then GHG emissions, first through 2029 with MGS running in its current 2x1 configuration, then through 2035 when MGS converts to a 1x1 configuration. After 2035, the IRP assumes MGS stops operating and is replaced with zero-carbon energy that can meet RA requirements.

Figure 68 demonstrates that the IRP complies with the GHG emission requirements set forth in SB 32 and SB 350.

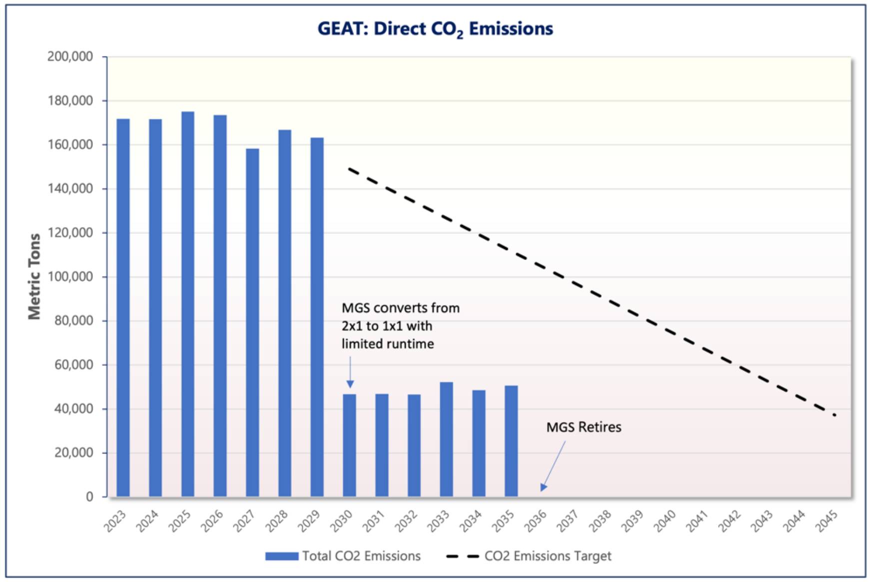


Figure 68. Greenhouse Gas Emissions Accounting Table (GEAT) for All Portfolios

The CO_2 emissions limit shown is based on the California carbon allowances provided to utilities.

When MGS stops operating, VPU's emissions will drop to nearly zero. This will not only make VPU a leader among utilities in clean energy procurement, but also reduce local GHG emissions from the natural gas combustion at MGS.

THREE PORTFOLIO SCENARIOS

For the IRP, in conjunction with VPU staff, Ascend modeled and analyzed three portfolio scenarios. Figure 69 summarizes these portfolios. The three portfolios contain several similarities.

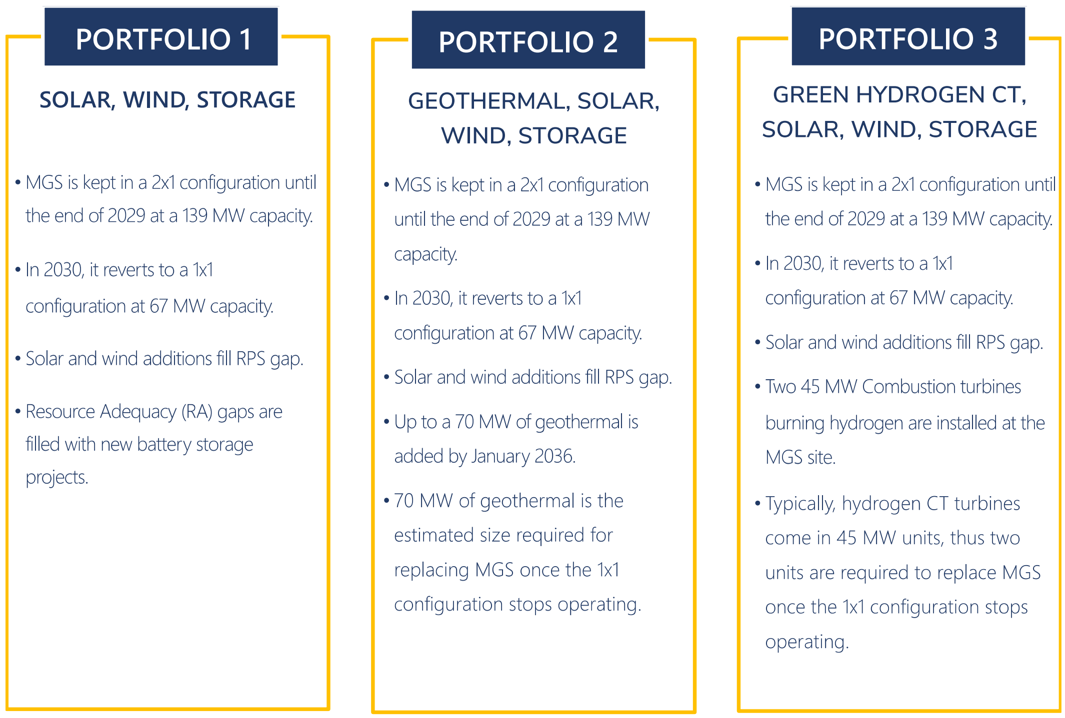


Figure 69. Summary of Modeled Portfolio Scenarios

Portfolio 1: Solar, Wind, Storage

A first portfolio, titled Portfolio 1, includes solar PV, wind, and BESS with the following assumptions:

- MGS is kept running at its current 139 MW capacity in a 2x1 configuration until the end of 2029. Beginning in 2030, MGS reverts to 67 MW capacity in a 1x1 configuration. Due to GHG emission reduction requirements, the model assumes no MGS generation beyond 2035.
- Solar PV resources from southern and northern California are chosen to diversify VPU's RPS generation portfolio.
- The ARS model selects the most cost-effective wind resources from southern California.
- The ARS model selects the most cost effective a 4-hour BESS capacity resource based on costs provided in the new resource cost slide.

Portfolio 2: Geothermal, Solar, Wind, Storage

A second portfolio, titled Portfolio 2, includes geothermal, solar PV, wind, and BESS with the following assumptions:

- MGS is kept running at its current 139 MW capacity in a 2x1 configuration until the end of 2029. Beginning in 2030, MGS reverts to 67 MW capacity in a 1x1 configuration. Due to GHG emission reduction requirements, the model does not account for MGS generation beyond 2035.
- Up to 70 MW of a geothermal resource is added by January 2035.
- Solar PV resources from southern and northern California are chosen to diversify VPU's RPS generation portfolio.
- The ARS model selects the most cost-effective wind resources from southern California.
- The ARS model selects the most cost effective a 4-hour BESS capacity resource based on costs provided in the new resource cost slide.

Portfolio 3: Green Hydrogen CT, Solar, Wind, Storage

A third portfolio, titled Portfolio 3, includes green hydrogen CTs, solar PV, wind, and BESS with the following assumptions:

- MGS is kept running at its current 139 MW capacity in a 2x1 configuration until the end of 2029. Beginning in 2030, MGS reverts to 67 MW capacity in a 1x1 configuration. Due to GHG emission reduction requirements, the model does not account for MGS generation beyond 2035.
- In January 2036, two 45 MW CTs burning green hydrogen are installed at MGS to replace the existing gas-fired CTs.
- Solar PV resources from southern and northern California are chosen to diversify VPU's RPS generation portfolio.
- The ARS model selects the most cost-effective wind resources from southern California.
- The ARS model selects the most cost effective a 4-hour BESS capacity resource based on costs provided in the new resource cost slide.

CAPACITY EXPANSION RESULTS

Ascend utilized their capacity expansion model to determine the most cost-effective portfolio that will provide adequacy capacity to replace MGS and serve VPU's anticipated load growth over the span of the long-term planning period.

Preferred Portfolio Selection

The production cost model selected Portfolio 1, a combination of wind, solar, and energy storage. Solar and wind provide renewable diversity to the portfolio, while 4-hour energy storage provides capacity. Results align with cost projections for future resources: wind, solar and a 4-hour BESS are the least cost options. (See Figure 65, Figure 66, and Figure 67 for projected cost comparisons of the various resource options.)

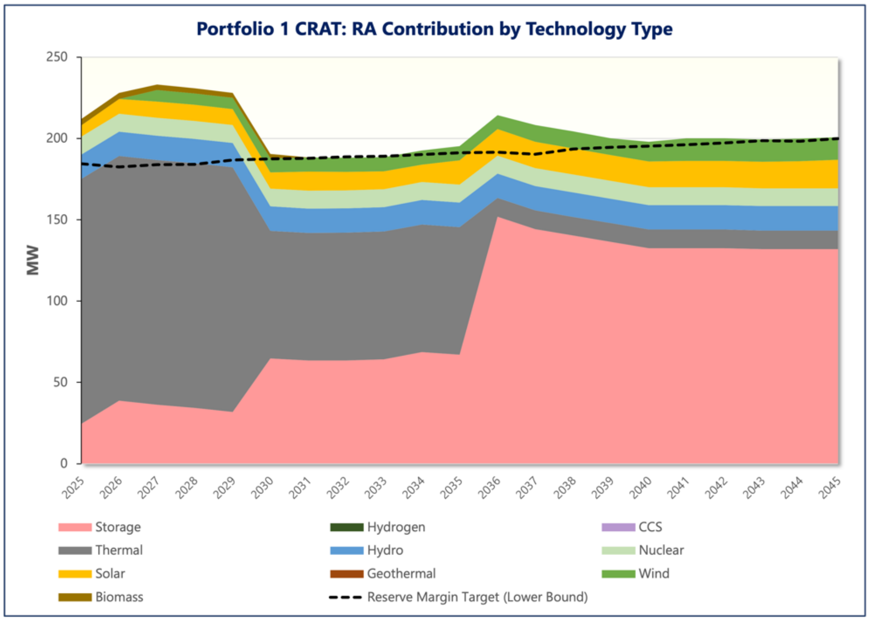


Figure 70. Capacity Resource Accounting Table (CRAT): Portfolio 1

The capacity and energy balance charts for Portfolio 1 are depicted in the following four figures.

Figure 70 shows the Capacity Resource Accounting Table (CRAT) for Portfolio 1. It depicts the annual peak capacity requirements (in MW) and contributions of existing and future resources to meet them. The CRAT depicts MGS transitioning to a 1x1 configuration in 2030 and no natural gas generation in 2035. H. Gonzales 1 and 2 will continue to provide minimal natural gas generation during peak hours.

Figure 71 shows the Energy Balance Table (EBT) for Portfolio 1. It depicts the annual energy needs (in GWh) and the amount procured from each resource in the portfolio. The capacity expansion model selects new energy storage to come online in 2030 to cover the capacity drop from the MGS transition from a 2x1 operation to a 1x1 operation and again in 2035 when MGS stops operating in the model. H. Gonzales 1 and 2 will continue to provide minimal natural gas generation during peak hours.

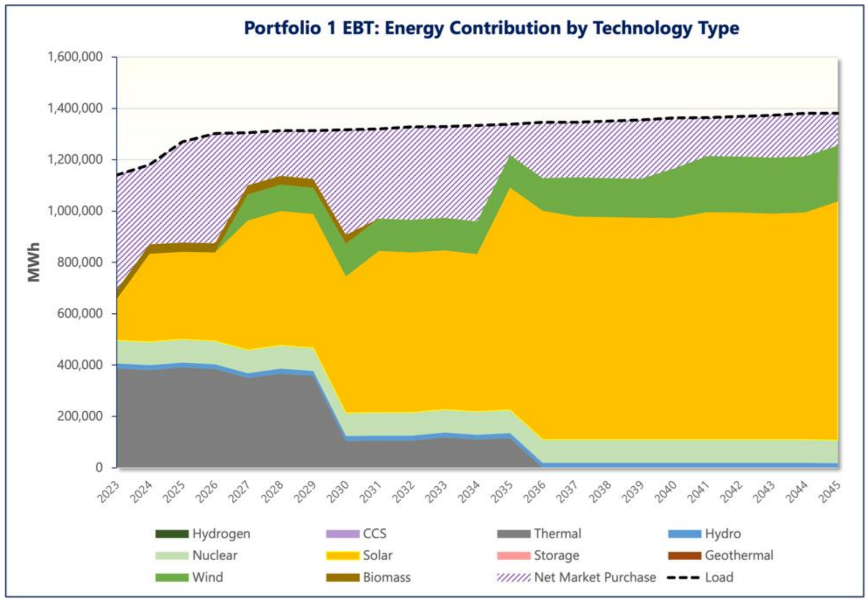


Figure 71. Energy Balance Table (EBT): Portfolio 1

Chapter 6 addressed the renewable procurement by portfolio, but it is worth noting that once MGS stops operating, VPU's portfolio will essentially be carbon free. The only carbon emitting resources in VPU's portfolio after 2035 will be H. Gonzales 1 and 2 which run very little due to strict operational limits (which is depicted in Figure 72 showing the renewable energy contribution and Figure 73 showing the clean energy contributions.)

Figure 72 shows the RPS Procurement Table (RPT) for Portfolio 1, which depicts the renewable energy contribution of the portfolio. It depicts how this portfolio meets the SB 350 and SB 100 requirement of a 60 percent RPS by 2030.

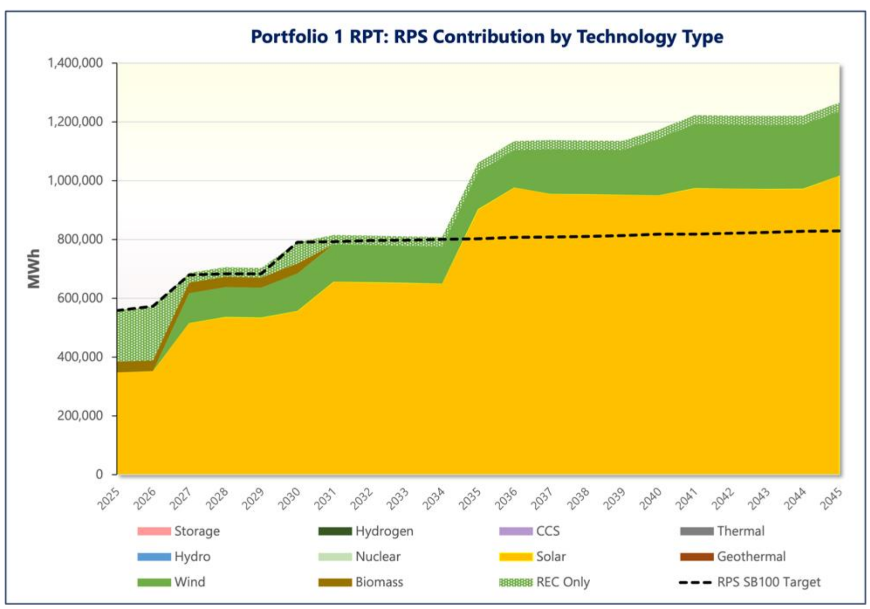


Figure 72. Renewable Procurement Table (RPT): Portfolio 1

Portfolio 1 fully meets the RPS requirement with contracted resources starting in 2027, after Sapphire is online. In Portfolio 1, VPU would contract for more solar generation before 2030 to maintain RPS compliance without the need to purchase additional RECs. After 2035, the model selects additional solar significantly surpassing the SB 1020 RPS minimum.

Figure 73 shows that this is driven by the clean energy requirement in SB 1020 starting in 2035.

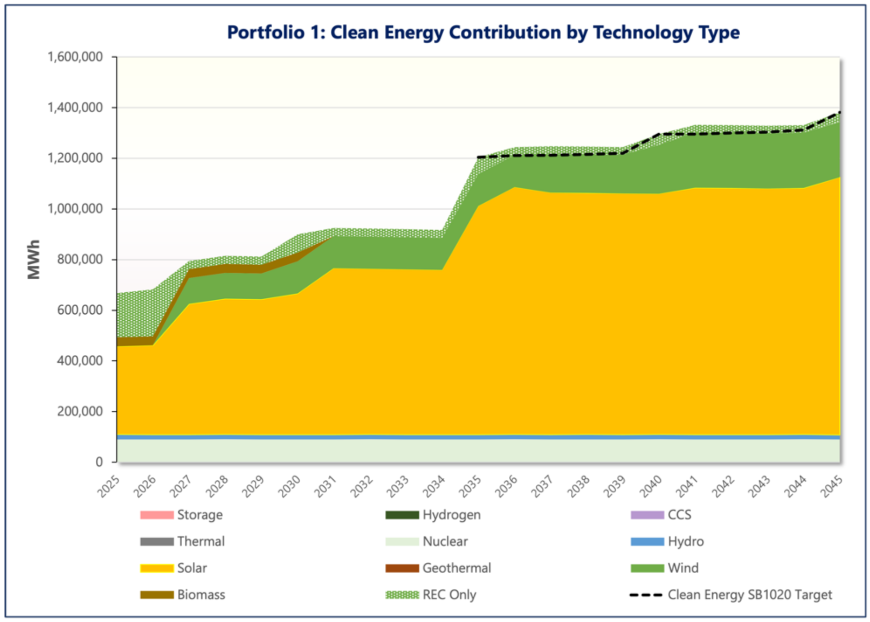


Figure 73. Clean Energy Contribution: Portfolio 1

Alternative Portfolio 2

The capacity expansion model was utilized to select resources to procure to replace diminishing capacity from MGS. The second portfolio scenario, Portfolio 2, assumed MGS would be replaced by a geothermal plant that grew in capacity over the long-term planning period. Portfolio 2 also included a diverse mix of solar PV, wind and 4-hour energy storage. Portfolio 2 meets the CAISO RA requirements and provides nearly 100 percent clean energy after MGS stops operating.

The capacity and energy for Portfolio 2 are depicted in the following three figures.

Figure 74 shows the Capacity Resource Accounting Table (CRAT) for Portfolio 2, depicting the annual peak capacity requirements (in MW) and contributions of existing and future resources. The CRAT for Portfolio 2 depicts MGS transitioning to a 1x1 configuration in 2030. H. Gonzales 1 and 2 continue to provide minimal natural gas generation during peak hours.

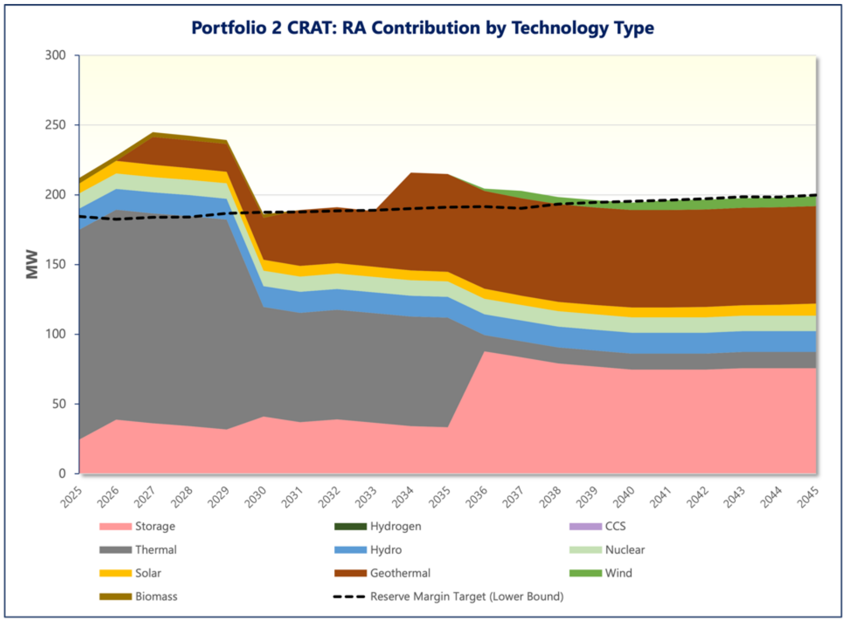


Figure 74. Capacity Resource Accounting Table (CRAT): Portfolio 2

Figure 75 shows the Energy Balance Table (EBT) for Portfolio 2. It depicts the annual energy needs (in GWh) and the amount procured from each resource in the portfolio.

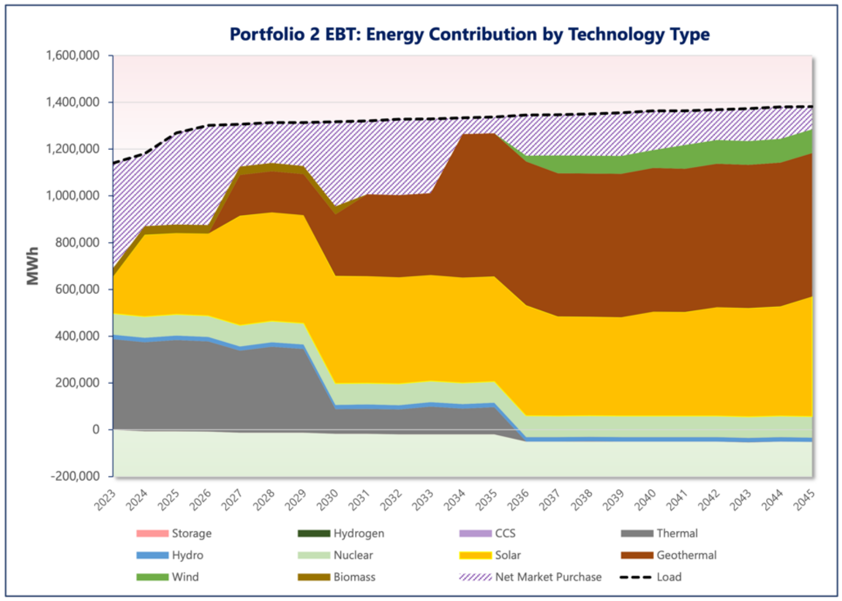


Figure 75. Energy Balance Table (EBT): Portfolio 2

Figure 76 shows the RPS Procurement Table (RPT) for Portfolio 2, which depicts the renewable energy contribution of the portfolio. It depicts how this portfolio meets the SB 350 and SB 100 requirement of a 60 percent RPS by 2030.

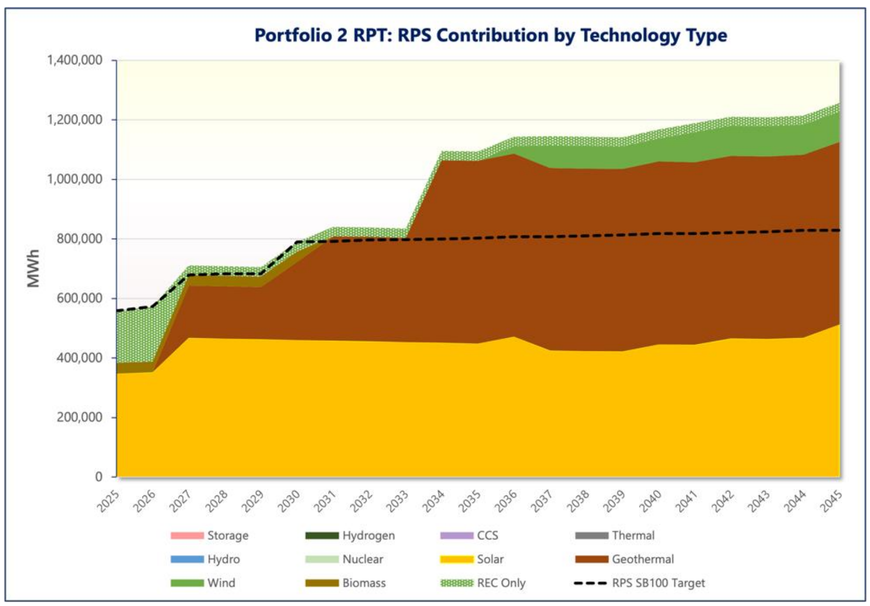


Figure 76. Renewable Procurement Table (RPT): Portfolio 2

Alternative Portfolio 3

The capacity expansion model was utilized to select resources for portfolio 3 to replace the diminishing capacity from MGS. Portfolio 3 assumed MGS would be retrofitted with two CTs fueled by green hydrogen. As in the other two portfolios under consideration, Portfolio 3 included a diverse mix of solar PV, wind and 4-hour energy storage. Portfolio 3 meets the CAISO RA requirements and provides nearly 100 percent clean energy after MGS stops operating.

The capacity and energy for Portfolio 3 are depicted in the following three figures.

Figure 77 shows the Capacity Resource Accounting Table (CRAT) for Portfolio 3, depicting the annual peak capacity requirements (in MW) and contributions of existing and future resources. The CRAT for Portfolio 3 depicts MGS transitioning to a 1x1 configuration in 2030. H. Gonzales 1 and 2 continue to provide minimal natural gas generation during peak hours.

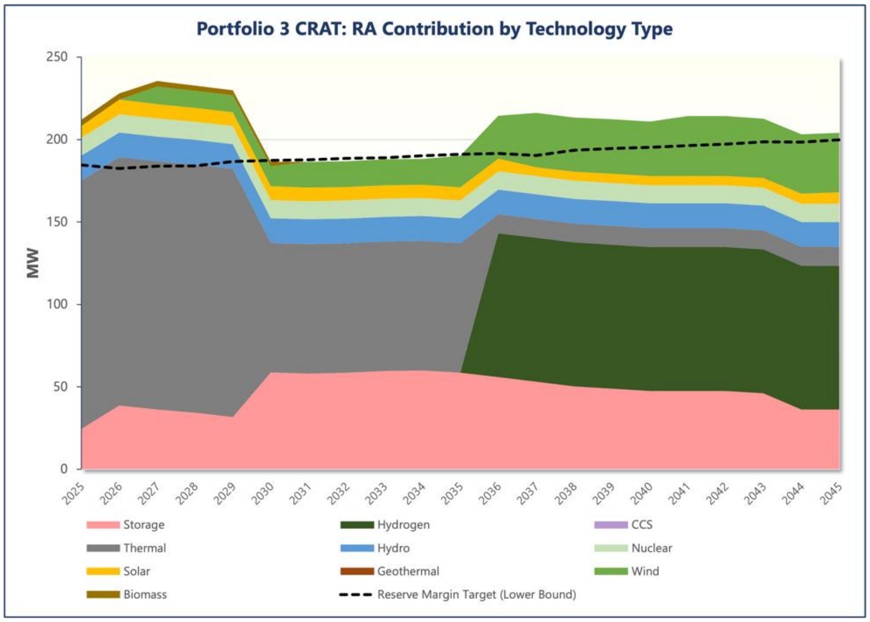


Figure 77. Capacity Resource Accounting Table (CRAT): Portfolio 3

Figure 78 shows the Energy Balance Table (EBT) for Portfolio 3. It depicts the annual energy needs (in GWh) and the amount procured from each resource in the portfolio.

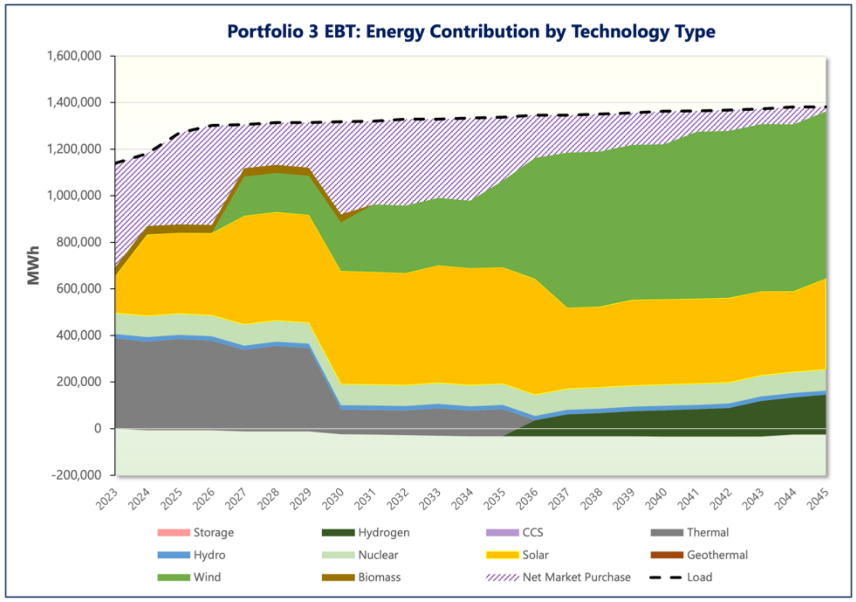


Figure 78. Energy Balance Table (EBT): Portfolio 3

Figure 79 shows the RPS Procurement Table (RPT) for Portfolio 3, which depicts the renewable energy contribution of the portfolio. It depicts how this portfolio meets the SB 350 and SB 100 requirement of a 60 percent RPS by 2030.

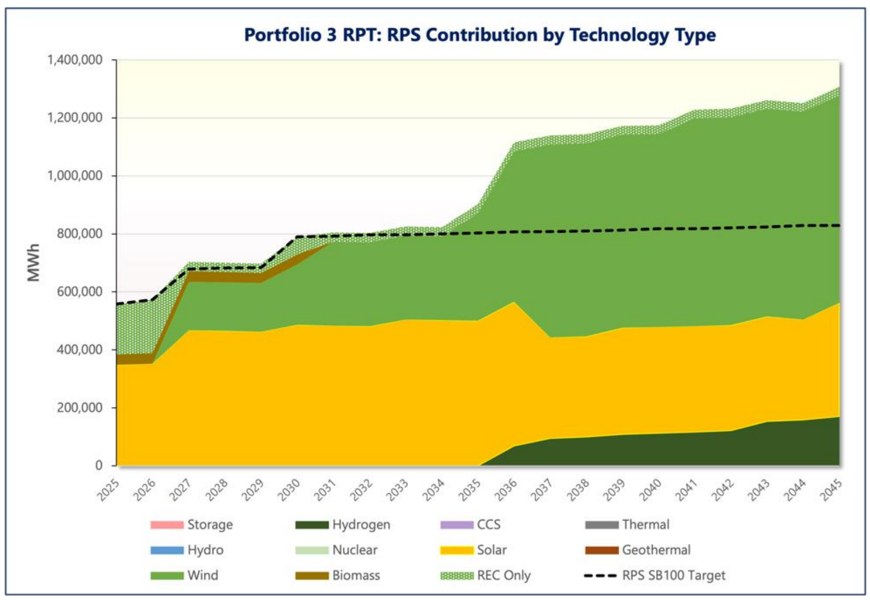


Figure 79. Renewable Procurement Table (RPT): Portfolio 3

Modeled Portfolios and RA Requirements

VPU meets the RA requirement through the entire long-term planning period for all portfolios under consideration. Satisfying the RA requirements will result in reliable service to VPU customers. The actual capacity values for all resources are determined by CAISO in its annual study. Therefore, the RA values shown in the CRATs for the three portfolios (Figure 70 on page 9-13, Figure 74 on page 9-16, and Figure 77 on page 9-18) are based on capacity accreditation projections from Ascend that may be different than the values experienced over time.

Geothermal and hydrogen generation are assumed to be much more expensive than 4-hour storage and solar in the future. As a result, total supply costs for Portfolio 2 and Portfolio 3 are higher than the total supply cost for Portfolio 1. These costs are a function of the expected resource costs ten to fifteen years from now, which include a significant amount of uncertainty and risk.

Capacity Expansion Resource Mix

Figure 80 and Figure 81 compare VPU resource capacity in 2030 to 2045. While the percentage of solar PV and wind has remained nearly constant between 2030 and 2045, the percent of thermal generation is minimal while the percent of energy storage has doubled.

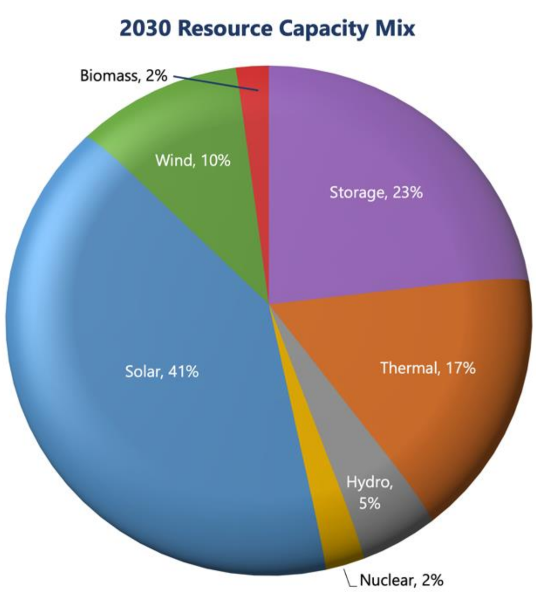


Figure 80. 2030 Resource Capacity Mix

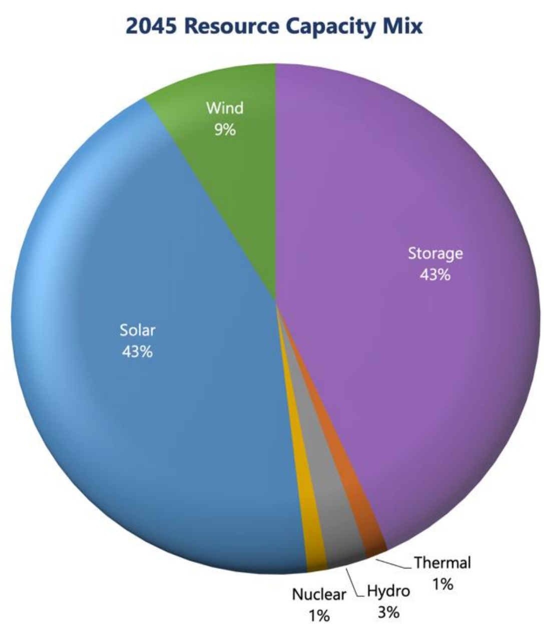


Figure 81. 2045 Resource Capacity Mix

Portfolio Cost Comparison

The preferred portfolio identifies the lowest cost resource portfolio. The IRP is based upon nominal cost estimates and forecasts, which represent current year costs not adjusted for inflation. Many factors contribute to the overall cost; generation costs represent only one factor. These overall costs also include bond payments, reserve requirements, electric system capital improvement costs, operating and maintenance cost, and administrative and general expenses, among others.

The financial cost of money is also factored into overall costs. These costs include the cost of capital, financial assumptions, tax credits, depreciation, and the LCOE. While all these costs directly affect electric rates, they are only an estimate of, and not a direct impact on, their effect on customer rates.

Figure 82 estimates the twenty-year net present value (NPV) cost (per MWh) of the three modeled portfolio scenarios compared with the current total portfolio cost.

Figure 82 indicates that replacing MGS with wind, solar PV, and energy storage through Portfolio 1, the preferred portfolio, only result in a modest increase in estimated supply costs. The cost of the geothermal and green hydrogen in the other two portfolios likely results in much higher costs.

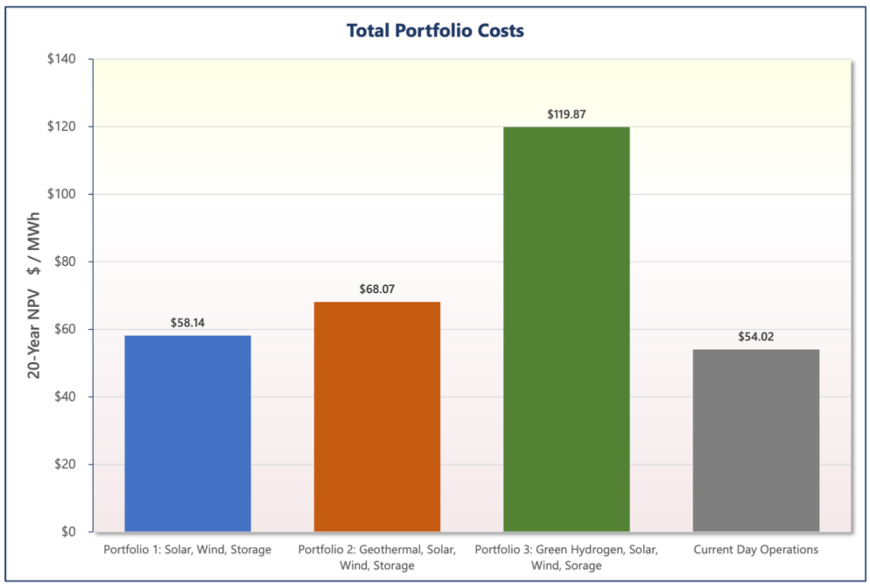


Figure 82. Total Net Present Value Cost of Load for Each Portfolio

VPU's near-term action plan will focus on procuring additional RPS sources, most likely from solar PV but also from wind and energy storage. VPU will continue to monitor the economics and viability of solar, wind, and energy storage versus geothermal and hydrogen generation to assess its viability in future IRPs.

The Preferred Plan and Disadvantaged Communities

The planned reduction in generation from MGS combined with increases in renewable and zero-carbon generation will contribute to significant reductions in local GHG emissions. This cleaner air will benefit all businesses, customers, and residents across varying socio-economic demographics. VPU's transition to a clean energy resource portfolio will improve the quality of life in the City of Vernon and its local and neighboring DACs.

Successfully implementing this clean energy transition requires the collaboration of VPU and its customers.

10. Action Plans

VPU looks to strengthen reliability, reduce cost, advance environmental stewardship, and improve the lives of its customers during its transition to clean energy. This IRP outlines the actions necessary to complete the transition to comply with state and RPS requirements for renewable generation by 2030 and zero-carbon energy by 2045, while maintaining reliability and keeping competitive and stable rates. The steps outlined in this action plan identify investment strategies and the most prudent approach to meet forecasted load.

VPU's action plan incorporates its commitment to educate its customers on energy efficiency measures, develop new incentive structures, transition to electric vehicles, and electrify their buildings.

Some action plan steps are already being implemented, while others are planned for the immediate future, and still others are planned for the longer term. It is important to note that this action plan was developed from both known and anticipated information.

Through VPU's stakeholder outreach efforts, customers have made it clear that reliable service and affordable rates are paramount. Complementing stakeholder mandates will need to be in tandem with state requirements for reduced GHG emissions, increased RPS compliant generation, and a zero-carbon grid.

As the future unfolds, VPU will adjust these action plan steps as necessary when circumstances that alter the underlying assumptions impact the basis of the 2023 IRP. Ultimately, implementing this IRP will be based on a sound operating and business principles that considers technical, regulatory, and financial aspects to best balance reliability, environmental stewardship, and rates.

INITIAL STEPS

The preferred portfolio in this plan proposes adding wind and solar starting in 2027, and energy storage in 2030. This timeline is based on current costs for supply resources, expected future supply costs, and power market trends. VPU will continue to monitor markets and technology and adapt as new information emerges. For example, hydrogen generation could emerge as a cost-effective replacement for MGS. If that occurs, VPU will adjust its current plan which relies on energy storage to firm new wind and solar.

VPU has already begun adding renewable resources to its portfolio. The first step in VPU's action plan is to ensure that Daggett comes online in late 2023 and Sapphire comes online in 2026, as expected. These new resources are an important step in VPU's carbon reduction strategy and will keep VPU on track to meet its future RPS requirements.

Beyond Daggett Solar PV and Sapphire Solar PV, VPU must procure additional RPS-eligible resources. The preferred portfolio selected wind and solar to increase VPU's RPS position before the 60% requirements in 2030. To accomplish this, VPU plans to issue a request for proposal (RFP) in the next year for resources to satisfy the RPS requirements.

Aside from the RPS mandates, VPU needs resources to cover RA requirements in CAISO. Currently, MGS provides 139 MW of RA accredited capacity (76 percent of VPU's RA requirement). Starting in 2030, VPU must adjust its use of MGS to meet carbon emissions limits. To accomplish this, VPU intends to convert MGS from a 2x1 facility to a 1x1 facility, thus retiring one combustion turbine but also reducing the RA value of MGS from 139 MW to 67 MW. In addition, the 1x1 facility will run less frequently outside of summer months to maintain a low number of unit starts.

Converting MGS to a 1x1 facility means VPU must procure replacement RA capacity by 2030. VPU also expects to stop operating MGS by 2035, creating another gap in RA that must be filled with new resources.

BULK POWER SYSTEM ACTION PLAN

This action plan's first priority is to ensure that the Daggett Solar PV and the Sapphire Solar PV PPAs meet their respective CODs. The action plan's next step is to replace 72 MW of MGS generation with renewable resources by 2030 and the remaining 67 MW by 2035 when MGS is planned to stop operating. During those years, the PPAs for Puente Hills Landfill Gas (10 MW), Astoria II Solar PV (30 MW), and Antelope DSR 1 Solar PV (25 MW) are scheduled to expire.

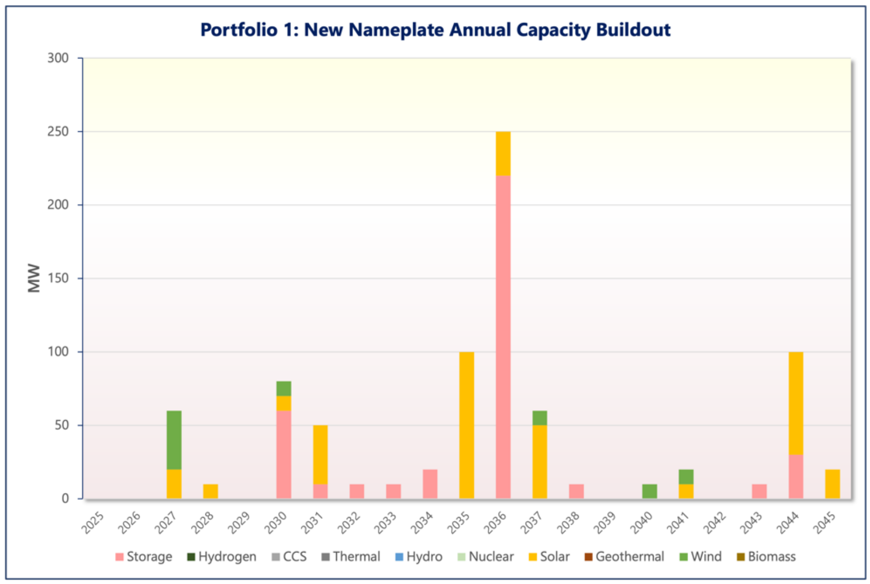


Figure 83. New Nameplate Annual Capacity Expansion for Portfolio 1

Figure 83 shows the required capacity additions of solar PV, wind, and storage to the VPU portfolio in the preferred scenario. VPU's preferred portfolio consists of adding, in the aggregate, a combination of 360 MW of solar PV, 80 MW of wind, and 380 MW of energy storage over the long-term planning period. VPU will monitor technology improvements and markets prices with the reduced operation of MGS. VPU plans to be flexible in selecting future resources based on updated information gathered in the future.

Table 24 lists the capacity amounts to be added to the portfolio in 2035 to meet the state's RPS and clean energy requirements. Capacity additions include 110 MW of energy storage, 180 MW of solar PV, and 50 MW of wind.

Capacity Expansion Action Plan (MW)									
Resource	2027	2028	2029	2030	2031	2032	2033	2034	2035
Storage	0	0	0	60	10	10	10	20	0
Solar	20	10	0	10	40	0	0	0	100
Wind	40	0	0	10	0	0	0	0	0

Table 24. Capacity Expansion Action Plan until 2035

Table 25 lists the capacity amounts to be added to the VPU portfolio in 2035 until 2045 to meet the state's RPS and clean energy requirements. Capacity additions include 270 MW of energy storage, 180 MW of solar PV, and 30 MW of wind.

Capacity Expansion Action Plan (MW)										
Resource	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Storage	220	0	10	0	0	0	0	10	30	0
Solar	30	50	0	0	0	10	0	0	70	20
Wind	0	10	0	0	10	10	0	0	0	0

Table 25. Capacity Expansion Action Plan from 2035 until 2045

Successfully implementing these actions begins with VPU staff starting the process to procure utility scale solar, wind and storage.

Utility-Scale Resource Procurement

The preferred plan adds utility-scale wind and solar renewable resources coupled with battery storage to provide resource adequacy. As a result, VPU plans to issue a renewable resource RFP to evaluate utility-scale solar and solar plus storage PPAs for delivery between 2025 and 2027. VPU plans to work with SCPPA to identify solar, wind, and storage projects for potential acquisition.

While VPU monitors potential procurement projects, VPU will also continue to reevaluate projects in its system via production cost modeling. As part of the evaluation, VPU will follow developments in CAISO's RA construct to determine how new resources will provide RA benefits to VPU customers.

Malburg Generating Station

In conjunction with added renewables and storage, VPU plans to change MGS operation by 2030 to meet carbon emission targets. The current plan is to convert MGS from a 2x1 combined cycle plant to a 1x1 plant. However, VPU will continue to evaluate reduced generation levels and options to reconfigure MGS to allow for more operational flexibility. VPU will also continue to evaluate alternative resource options to replace MGS. Given the 2030 target, VPU will work to ensure MGS or an alternative firm generation resource is in place by 2029 to maintain reliable operations while meeting state renewable targets.

DISTRIBUTED ENERGY RESOURCES ACTION PLAN

Pursuant to SB 656,[34] VPU's original NEM tariff has been available to eligible customers on a first-come, first-served basis with the passage of City Resolution 9472. VPU is evaluating the details of a new NEM tariff that will incorporate wholesale rates based on excess energy generated by behind-the-meter solar PV systems.

VPU also plans to continue and evaluate the installation of cost-effective solar-PV systems at city-owned facilities where appropriate.

ENERGY EFFICIENCY ACTION PLAN

The 2020 CMUA Energy Efficiency Potential Forecast currently serves as the blueprint for VPU's current and future energy efficiency action plans. The study analyzes VPU's service territory to account for the unique characteristics of its customer base, climate zone, economic conditions, and other relevant factors to develop annual and cumulative savings.

VPU's 10-year cumulative energy efficiency market potential from 2022 to 2031 (Table 26) is set at 25,665 MWh, which translates to an average annual savings target of approximately 2,566 MWh.

Year	Annual Market Potential (MWh)	Annual Demand Reduction Potential (Incremental kW)
2022	5,247	749
2023	5,504	765
2024	5,069	694
2025	4,489	604
2026	2,575	356
2027	876	103
2028	564	40
2029	447	16
2030	445	17
2031	449	18

Table 26. Energy Efficiency Potential Forecast

VPU achieved approximately 3,480 MWh of net annual savings through its energy efficiency programs in fiscal year 2022, which exceeds the forecasted market potential set by the CMUA study. Based on a five-year period from fiscal year 2018 through fiscal year 2022, VPU has

[34] http://www.leginfo.ca.gov/pub/95-96/bill/sen/sb_0651-0700/sb_656_bill_950804_chaptered.pdf

achieved a cumulative net energy savings of 28.13 GWh and is well positioned to continue to meet or exceed future energy efficiency targets through the implementation of various customer-facing programs and services.

VPU plans to build upon its longstanding energy efficiency programs and introduce new offerings to meet the evolving needs of the customer base through the following initiatives:

- Educate customers on the benefits of "deep energy retrofits" and identify those opportunities through VPU's complimentary on-site energy audit services. The process requires a shift from focusing on individual technologies in isolation to combining certain energy efficiency measures to leverage the interactive effects to achieve additional savings.
- Increase customer awareness on the energy efficiency opportunities associated with the implementation of energy-management hardware or software that can be combined with traditional technologies, such as LED lighting or individual smart devices.
- Develop new incentive structures and new customer programs to incorporate building decarbonization components that better align with the state's climate goals.

On the city level, VPU will continue to provide incentives and collaborate with other City departments to implement cost-effective energy efficiency measures throughout municipal facilities as various equipment reaches its end of useful life.

TRANSPORTATION ELECTRIFICATION ACTION PLAN

VPU's 2030 forecast has a target of approximately 2,000 EVs in its service territory with a load impact of an estimated 9 GWh and a peak demand of about 2 MW. As a result, VPU is actively doing its part to expand EV charging infrastructure to support the future growth of transportation electrification through the following efforts:

- VPU officially opened its first, public EV charging depot in the summer of 2023, with two additional public DCFC sites currently under development and scheduled to open by late 2024.
- VPU is proactively in discussions with numerous commercial and industrial customers to create incentives for deploying EV charging stations on private property to support fleet and workplace charging. As part of this effort, VPU plans to welcome the first commercial EV fleet charging depot in its service territory by the start of 2024. The site is anticipated to host several Level 3 DCFCs and over 30 Level 2 EV chargers to support an electrified medium- and heavy-duty fleet.

As for customer-facing incentive programs that will help accelerate the transition of transportation electrification, VPU will:

- Continue to implement its existing transportation electrification programs that include the Commercial EV Charger Incentive Program, Commercial Electric Forklift Incentive Program, and the Residential EV Charger Rebate Program.
- Continue to promote the various incentives offered by local air quality, state, and federal agencies.
- Consider creative solutions to be able to support its customers with large scale fleet electrification efforts. This includes possibly offering pilot incentive programs to help offset the upfront costs of infrastructure upgrades that must take place before EV charging stations can be installed.

VPU has continued to collaborate with other City departments to increase the number of EVs in operation within the municipal fleet. In particular, the City of Vernon currently has nine EVs in its fleet, with plans for approximately 10 additional EVs. Out of these 10 estimated EVs, three are scheduled to be delivered in the near future; the remaining seven will be incorporated gradually as existing ICE vehicles are taken out of operation.

CUSTOMER ENGAGEMENT ACTION PLAN

Action plans for customer engagement include collecting and prioritizing customer feedback on the IRP, increasing the frequency of customer outreach and educational events, and offering more utility products and services to customers.

DISTRIBUTION SYSTEM ACTION PLAN

The Five-Year CIP includes actions for continuing to replace and upgrade VPU's aging distribution infrastructure to maintain system reliability. While replacing equipment, VPU plans to upgrade line conductors and transformers to complete voltage conversions at electric substations where necessary. In addition, VPU will continue positioning part of the VPU distribution system underground as part of the City's development projects to enhance system reliability. Moving the distribution system underground during City development projects provides a cost-effective method to relocate distribution infrastructure.

Increasing levels of DERs are challenging VPU's distribution systems. To allow more DER interconnection, VPU intends to replace all 7 kW circuit breakers at the Leonis substation with higher interrupting current rating. This will allow for DER connection on 7 kV circuits and allow higher levels of DER resources.

VPU also anticipates implementing new distribution system automation with intelligent line switches and automatic reclosers to improve VPU's smart grid. These improvements will allow VPU's system to quickly recover from line outages or other problems. VPU will capitalize on advances in smart grid technology to continue reliable operations for the foreseeable future.

Table 27 details the action items for the distribution system action plan.

Action Item	2024	2025	2026	2027	2028
Atlantic Bridge	√				
Frontage improvements	√				
SCADA upgrades	√				
Data Center Substations	√		√	√	√
66 kV line extensions and upgrades for future data centers	√		√	√	√
Customer related projects for improved system reliability	√	√	√	√	√
Deteriorated wood pole replacements	√	√	√	√	√
Reconductoring (includes 7 kV to 16 kV conversion)	√	√	√	√	√
SF6 removal; breaker and switch replacements	√	√	√	√	√
Dumont 16 kV circuit - Leonis, Alcoa OH		√			
Yauk 16 kV circuit - OH and UG routes		√			
Vernon Substation #2 bank removal and reconfiguration		√			
Ybarra Substation 27 kV indoor vacuum breakers		√			
Smart Grid automation		√	√	√	√
System reliability improvements		√	√	√	√
System undergrounding		√	√	√	√
Relay replacement project		√	√	√	√
Leonis Substation additional 16 kV positions		√	√		
Vernon Substation #2 bank removal and reconfiguration			√		
New circuit extensions			√	√	√
McCormick Substation upgrade			√	√	√

Table 27. Distribution System Action Plan Items

11. Appendices

The IRP contains several appendices:

A. IRP Guidelines Cross-Reference

In August 2022, the CEC published its *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines, Revised Third Edition*, as draft Commission Guidelines. Chapter Two of these guidelines dictate the contents of all IRPs submitted to the CEC. This appendix contains a cross-reference between the numerous sections specified in Chapter Two and the relevant sections of the VPU 2023 IRP.

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Table 28. IRP Guidelines Cross-Reference

B. Glossary and Definitions

AAEE
Additional Achievable Energy Efficiency:
Defined by the CEC as incremental savings from the future market potential identified in utility potential studies not included in the baseline demand forecast, but reasonably expected to occur, including future updates of building codes, appliance regulations, and new or expanded investor-owned utility or publicly owned utility efficiency programs.

AAFS
Additional Achievable Fuel Substitution:
Defined by the CEC as a load modifier to the baseline demand forecast achieved by substituting an end-use fuel type with another, such as changing out gas appliances in buildings for cleaner more efficient electric end uses.

AATE
Additional Achievable Transportation Electrification:
Defined by the CEC as the estimated incremental transition to electric vehicles over the baseline transportation electrification forecasts.

AB
Assembly Bill:
Legislation that originates or is modified by the entire California State Assembly.

ACC II
Advanced Clean Cars II:
The rule that requires all car sales in California to be 100 percent zero emission by 2035

ACCC
Aluminum Conductor Composite Core:
High capacity transmission wire capable of carrying approximately twice the current of traditional transmission wire.

ACF
Advanced Clean Fleets:
The requirement for medium- and heavy-duty fleets to purchase an increasing percentage of zero-emission trucks.

ACT
Advanced Clean Trucks:
The regulation requiring manufacturers to sell ZEV trucks and school buses.

APPA
American Public Power Association:
National service organization representing the nation’s more than 2,000 publicly owned electric utilities.

ARS
Automated Resource Selection:
A component of Ascend’s PowerSIMM modeling software that chooses resources for a least-cost portfolio expansion plan.

ATB
Annual Technology Baseline:
A database that provides a publicly available source of the forward curves for capital costs and operations and maintenance expenses for several different power generation technologies; published by the National Renewable Energy Laboratory.

BA
Balancing Authority:
The responsible entity that integrates resource plans ahead of time, balances supply with demand, and supports interconnection frequency in real-time.

BES
Bulk Electric System:
All transmission elements operating at 100 kV or higher and the real power and reactive power resources connected at 100 kV or higher. The Western Interconnection is one of four bulk electric systems in the United States.

BESS
Battery Energy Storage System:
Rechargeable batteries that store energy that can be discharged when needed. Types include lithium-ion, lead-acid, and flow batteries, and flywheels. Common capacities include 4-hour, 8-hour, and 10-hour batteries, designating the length of time the battery can discharge energy.

BTM
Behind the Meter:
Refers to the amount of generation captured in customer meters that impacts demand.

CAISO
California Independent System Operator:
A nonprofit independent system operator that oversees the operation of bulk electric power system, transmission lines, and electricity market generated and transmitted by its participants. CAISO is the largest balancing authority in California.

CARB
California Air Resources Board:
Responsible for promoting and protecting public health, welfare, and ecological resources through the effective and efficient reduction of air pollutants while recognizing and considering the effects on California's economy.

Carbon-Free Percent
Similar to the RPS calculation, attained by dividing the total non-carbon emitting resources (including the non-RPS eligible resources nuclear and large hydroelectric) by the total retail sales.

CC
Combined Cycle:
A combination of combustion turbines (CTs) and one steam turbine (ST). The CT exhaust is passed through a heat recovery waste heat boiler which produces steam to drive the ST. Possible configurations include three CTs (3x1), two CTs (2x1), and one CT (1x1) paired with one ST.

CCA
Community Choice Aggregator:
Communities formerly served by the IOUs that have formed a separate organization to aggregate the buying power to procure energy.

CCI
California Compliance Instrument:
A permit created and issued by CARB that allows the holder to legally emit one metric ton of GHG measured in carbon dioxide equivalents.

CCS
Carbon Capture and Sequestration:
A process that captures, separates, and treats CO_2 emissions from a power plant, then transports it for long-term storage so that it doesn't enter the atmosphere.

CEC
California Energy Commission:
California's primary energy policy and energy planning agency. Responsible for ensuring publicly owned utilities' compliance with the state's Renewables Portfolio Standard and Title 20 data reporting requirements.

CEDU
California Energy Demand Update:
The biennial update to various statewide energy-related forecasts, included in the CEC IEPR.

CF
Capacity Factor:
The percentage a time a resource generates electricity compared to its maximum generation output.

CIP
Capital Improvement Plan:
A plan that described the future infrastructure investments and estimated costs for Vernon Public Utilities.

CMUA
California Municipal Utilities Association:
An association incorporated in 1933 to represent the interests of California's publicly owned electric utilities before the California Legislature and other regulatory bodies.

CO_2
Carbon Dioxide:
A colorless, odorless gas found in the atmosphere that is associated with global warming. It is released into the atmosphere through the burning of fossil fuels such as coal, oil, and natural gas.

CO_2-e
Carbon Dioxide Equivalent:
The standard measurement that expresses the impact of different greenhouse gases as an equivalent of the amount of CO_2 that would create the same amount of warming.

COD
Commercial Operation Date:
The date when a capacity resource begins to generate power that can be sold.

Coincidence Factor
The peak of a system divided by the sum of peak demand of its individual components. It tells how likely the individual components are peaking at the same time. The highest possible coincidence factor is 1.00, when all the individual components are simultaneously peaking.

COS
Cost of Service:
A study performed by utilities to forecast the cost to provide services to retail customers.

CP
Compliance Period:
There are six compliance periods for attaining Renewables Portfolio Standard goals as defined in Public Utilities Code section 399.30 (c):

- Compliance Period 1:
  January 1, 2011 to December 31, 2013.
- Compliance Period 2:
  January 1, 2014 to December 31, 2016.
- Compliance Period 3:
  January 1, 2017 to December 31, 2020.
- Compliance Period 4:
  January 1, 2021 to December 31, 2024.
- Compliance Period 5:
  January 1, 2025 to December 31, 2027.
- Compliance Period 6:
  January 1, 2028 to December 31, 2030.

CPUC
California Public Utilities Commission:
Regulates California's investor-owned electric utilities, telecommunications, natural gas, water, and passenger transportation companies, in addition to household goods movers and the safety of rail transit.

CRAT
Capacity Resource Accounting Table:
Defined by the CEC as the annual peak capacity demand in each year and the contribution of each energy resource (capacity) in a POU's portfolio to meet that demand.

CT
Combustion Turbine:
Any of several types of high-speed generators using principles and designs of jet engines to produce low cost, high efficiency power; also commonly referred to as a gas turbine (GT).

CTG
Combustion Turbine Generator:
An electric generator, commonly powered by a natural gas burning turbine, producing hot combustion gases that pass directly through the turbine, spinning the blades of the turbine to generate electricity.

CUP
Conditional Use Permit:
A zoning exception that allows the permit holder to use the property in a way that doesn't conform with the zoning requirements.

DAC
Disadvantaged Community:
Disadvantaged communities are designated by CalEPA pursuant to Senate Bill 535 using the California Communities Environmental Health Screening Tool; identified by census tract, they score at or above the 75th percentile.

DCFC
Direct Current Fast Charger:
Fastest available EV chargers, designed to fill a battery to 80 percent in 20–40 minutes, and 100 percent in 60–90 minutes.

Demand
The rate at which electricity is used at any one given time (or averaged over any designated interval of time). Demand differs from energy use, which reflects the total amount of electricity consumed over a period of time. Demand is measured in kilowatts (kW) or megawatts (MW). Load is considered synonymous with demand. (See also Load on page A-8.)

DER
Distributed Energy Resource:
Any resource (such as solar and wind power, energy efficiency, demand response, fuel cells, energy storage, electric vehicles, and building electrification) on the distribution system that produces electricity.

DR
Demand Response:
An electricity tariff or program established to motivate changes in electric use by end-use customers, designed to induce lower electricity use typically at times of high market prices or when grid reliability is jeopardized.

DSM
Demand-Side Management:
The planning, implementing, and monitoring programs that encourage consumers to manage their electricity usage patterns to shift or reduce demand.

EBT
Energy Balance Table:
Defined by the CEC as the annual total energy demand and annual estimates for energy supply from various resources.

EDAM
Extended Day Ahead Market:
A voluntary day-ahead electricity market designed to deliver significant economic, environmental, and reliability benefits to balancing areas and utilities throughout the West.

EE
Energy Efficiency:
Practices or programs designed to reduce the amount of energy required to provide the same level and quality of output.

ELCC
Effective Load Carrying Capacity:
The ability to effectively increase the generating capacity available to a utility without increasing the utility's loss of load risk, quantified as the amount of new load that can be added to a system after capacity is added by a generator without increasing the loss of load probability or expectation.

Energy
The amount of electricity a generation resource produces, or an end user consumes, in any given period of time, measured in kWh, MWh, or GWh. Energy is computed as capacity or demand multiplied by time (hours). A one MW power plant running at full output for one hour produces one megawatt-hour (1 MWh) of electrical energy.

ERCOT
Electric Reliability Council of Texas:
One of the main North American electricity interconnections.

ESP
Electric Service Provider:
A non-utility entity that offers electric service to customers within the service territory of an electric utility.

EV
Electric Vehicle:
A vehicle that uses one or more electric motors for propulsion.

EVSE
Electric Vehicle Supply (Service) Equipment:
Equipment that provides electric power to the vehicle and uses that to recharge the vehicle's batteries.

FERC
Federal Energy Regulatory Commission:
An independent regulatory agency within the Department of Energy that regulates the transmission and sale of natural gas, regulates the transmission of oil, regulates the transmission and wholesale sale of electricity, as well as many other energy-related commercial activities.

GEAT
GHG Emissions Accounting Table:
Defined by the CEC as the annual GHG emissions associated with each resource in a POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by the CARB.

GHG
Greenhouse Gas:
A gas that contributes to the greenhouse effect by absorbing infrared radiation, including carbon dioxide, methane, and fluorocarbons.

GIS
Geographic Information System:
A system consisting of integrated computer hardware and software that stores, manages, analyzes, edits, outputs, and visualizes geographic data.

GMC
Grid Management Charge:
A tariff that reimburses CAISO for the cost of operating its electric power grid.

GO
General Order:
Rules established by CPUC for operations within its areas of authority.

GW
Gigawatt:
A unit of power, capacity, or demand equal to one billion watts, one million kilowatts, or one thousand megawatts.

GWh
Gigawatt-Hour:
A unit of electric energy equal to one billion watt-hours, one million kilowatt-hours, or one thousand megawatt-hours.

Heavy-Duty Vehicle
A vehicle with a gross weight greater than five tons, including the vehicle, fuel, occupants, and cargo (such as large transit buses, common tractor-trailer trucks, and refuse trucks).

IEPR
Integrated Energy Policy Report:
A report adopted by the California Energy Commission and transmitted to the Governor and Legislature every two years. It includes trends and issues concerning electricity and natural gas, transportation, energy efficiency, renewables, and public interest energy research.

IOU
Investor-Owned Utility:
A for-profit utility owned by either public or private shareholders that serve 72 percent of United States electricity customers.

IRA
Inflation Reduction Act of 2022:
Offers funding, programs, and incentives to accelerate the transition to a clean energy economy, among many other provisions.

IRP
Integrated Resource Plan:
A long-term comprehensive plan that balances the mix of demand and supply resources over a long-term planning horizon to meet specified policy goals.

ISO
Independent System Operator:
An agency created to operate, control, and ensure the integrity of the integrated transmission grid independent of any generation, wholesale, or retail market.

kW
Kilowatt:
A unit of power, capacity, or demand equal to one thousand watts. The demand of an individual electric customer or the capacity of a distributed generator is often expressed in kilowatts.

kWh
Kilowatt-hour:
A unit of electric energy equal to one thousand watt-hours. The standard billing unit for electric energy sold to retail consumers is the kilowatt-hour.

L1
Level 1:
A private, residential EV battery charger, taking approximately 24 hours to fully charge an empty battery.

L2
Level 2:
A public EV battery charger designed to fully charge an empty battery in eight hours or less.

L3
Level 3:
A public EV battery charger (also known as a DCFC), the fastest EV charger available, uses a 480-volt direct current capable of producing a 100-mile charge per hour.

LADPW
Los Angeles Department of Power and Water:
A publicly owned utility that supplies electric and water to residents and businesses in Los Angeles and surrounding communities.

LCFS Credit
Low Carbon Fuel Standard credit:
A CARB program that aims to reduce emissions in the transportation sector by providing incentives to install EV charging equipment.

LCOE
Levelized Cost of Energy:
The price per kilowatt-hour for an energy project to break even; it does not include risk or return on investment.

LCR
Local Capacity Requirement:
The minimum resource capacity required by CAISO in each local area to meet established reliability criteria. CAISO performs annual studies to identify the local capacity requirement for the following calendar year.

Light-Duty Vehicle
A vehicle with a gross weight less than five tons including the vehicle, fuel, occupants, and cargo (such as passenger cars and light- and medium-sized pickup trucks).

Load
The moment-to-moment measurement of power that an end-use device or an end-use customer consumes. The total of this consumption plus planning margins and operating reserves is the entire system load. Load is often used synonymously with demand. (See also Demand on page A-4.)

LSE
Load-Serving Entity:
An energy-related company that serves end users and has been granted authority by California to sell electric energy to the same.

Medium-Duty Vehicle
A vehicle with a gross weight greater than five tons, including the vehicle, fuel, occupants, and cargo (such as moving trucks, large step vans, and some heavy-duty pickups).

MGS
Malburg Generating Station:
VPU's largest local natural gas fired combined-cycle generator.

MMBtu
One Million British Thermal Units:
One million of the units of energy equal to about 1,055 joules that describes the energy content of fuels.

MMT
Million Metric Tons:
A weight measurement used to determine the quantity of greenhouse gases emitted into the atmosphere.

MSS
Meter Subsystem:
A geographically contiguous single zone that has been acting as an electric utility before the formation of the CAISO.

MSSA
Metered Subsystem Agreement:
The terms and conditions under which VPU operates its generating units, submits bids, and self-schedules into the CAISO BA and markets.

MT
Metric Tons:
A weight measurement used to determine the quantity of greenhouse gases emitted into the atmosphere.

MW
Megawatt:
A unit of power, capacity, or demand equal to one million watts or one thousand kilowatts. Generating capacities of power plants and system demand are typically expressed in megawatts.

MWh
Megawatt-Hour:
A unit of electric energy equal to one million watt-hours or one thousand kilowatt-hours, used to specify the amount of energy consumed by customers over time.

N-1 Contingency
The unexpected loss of a single system component (such as a generator, transmission line, circuit breaker, switch, or other electrical element).

N-1-1 Contingency
An initial unexpected loss of a single system component (such as a generator, transmission line, circuit breaker, switch, or other electrical element), followed by system adjustments, followed by the loss of another single system component.

N-2 Contingency
The unexpected simultaneous loss of two major system components (such as a generator or a transmission line).

NEM
Net Energy Metering:
A billing arrangement that credits a customer with an eligible renewable distributed generator (mostly for solar photovoltaic rooftop systems) for electricity added to the grid. The customer only pays for the net amount of electricity taken from the grid.

NERC
North American Electric Reliability Corporation:
An international not-for-profit regulatory authority with a statutory responsibility to ensure the reliability and security of the North American electric grid by regulating bulk power system users, owners, and operators through the adoption and enforcement of standards for fair, ethical, and efficient practices.

Net Load
The remaining load after non-dispatchable resources (such as renewable energy) have been accounted for.

NOx
Nitrogen Oxide:
A pollutant and strong greenhouse gas emitted by combusting fuels.

NPV
Net Present Value:
The difference between the present value of all future benefits, less the present value of all future costs.

NQC
Net Qualifying Capacity:
The capacity that is available to meet the peak demand per CAISO.

NREL
National Renewable Energy Laboratory:
The Federal laboratory dedicated to researching, developing, commercializing, and using renewable energy and energy efficiency technologies relied on by utilities across the country for integrated resource planning.

O&M

Operations and Maintenance:
The recurring costs of operating, supporting, and maintaining authorized programs, including costs for labor, fuel, materials, supplies, and other current expenses.

OTC

Once-Through Cooling:
The process of pulling in water from a body of water to run through a cooling loop in a generator and discharging it back to the source.

OTEC

Ocean Thermal Energy Conversion:
A process that produces electricity by using the temperature difference between deep cold ocean water and warm tropical surface waters.

PCC

Portfolio Content Category:
A category of electricity products procured from an eligible renewable energy resource (as specified by the CEC) for meeting RPS requirements.

PCC-0: A renewable resource that meets the criteria of PCC-1 but was signed or went online before June 1, 2010.

PCC-1: A renewable resource located within the state of California or, a renewable resource that is directly delivered to California without energy substitution from another resource.

PCC-2: A renewable resource that is out-of-state and delivering to California, where the RECs are paired with a substitute energy resource imported into the state.

PCC-3: A tradable or unbundled REC from a resource, delivered without the energy component.

PCL

Power Content Label:
Regulatory reporting requirements to the CEC regarding percentages of energy sources sold by resource type.

PEV

Plug-in Electric Vehicle:
A vehicle that operates using a battery recharged by plugging into an external source of electric power.

PG&E

Pacific Gas & Electric:
An investor-owned utility that provides natural gas and electric services to northern and central California.

PHES

Pumped Hydroelectric Energy Storage:
Uses off-peak electricity to pump water from a lower reservoir into one at a higher elevation storing potential energy to be released to pass through hydraulic turbines to generate electricity. A modern pumped-storage facility can provide a number of ancillary services, such as frequency regulation, voltage support (dynamic reactive power), spinning and non-spinning reserve, load following, and black start as well as energy services such as peak shaving and energy arbitrage.

PHEV

Plug-In Hybrid Electric Vehicle:
A vehicle that operates using a battery recharged by plugging it into an external source of electric power or by using an on-board gas engine.

POU
Publicly-Owned Utility:
Not-for-profit utilities owned by customers and subject to local public control and regulation.

PPA
Power Purchase Agreement:
A contract to purchase energy and or capacity from a commercial source at a predetermined price or on pre-determined pricing formulas.

PRM
Planning Reserve Margin:
A percent of total capacity above projected annual peak load to meet expected demand and maintain adequacy of supply.

PSD
Power Source Disclosure:
Regulatory reporting requirements to the CEC regarding products and energy sources.

PTO
Participating Transmission Owner:
A utility eligible to receive generation through the CAISO transmission network.

PUC
Public Utilities Code:
A directive issues by the CPUC.

PV
Photovoltaic:
The technology that converts light into electricity using semiconducting materials that exhibit the photovoltaic effect by absorbing photons and then emitting electrons.

PVNGS
Palo Verde Nuclear Generating Station:
Nuclear power plant in Arizona that provides 11 MW of power to VPU's portfolio mix.

RA
Resource Adequacy:
The CAISO requirements that ensures sufficient capacity exists for grid-wide reliability, including system, local, and flexible capacity requirements.

REC
Renewable Energy Credit:
Tradable commodities that represent proof that 1 MWh of electricity was generated from an eligible renewable source.

RFP
Request for Proposal:
A competitive solicitation for suppliers to submit a proposal on a specific commodity or service, often through a bidding process.

RP3
Reliable Public Power Provider:
A designation that lasts three years and recognizes utilities that demonstrate high proficiency in reliability, safety, work force development, and system improvement.

RPS
Renewable Portfolio Standard:
The program that, by law, requires all California-sanctioned electric utilities to increase the production and procurement of energy from renewable energy resources.

RPT
RPS Procurement Table:
Defined by the CEC as a detailed summary of a POU's resource plan to meet the RPS requirements.

RTO
Regional Transmission Organization:
An independent, member-based, nonprofit organization that coordinates, controls, and monitors the electric grid over multiple states while promoting economic efficiency, reliability, and non-discriminatory practices. An RTO is essentially similar to an ISO, albeit with greater responsibility for the transmission network.

SAIDI
System Average Interruption Duration Index:
Electric reliability indicator that measures how long the average customer is interrupted.

SAIFI
System Average Interruption Frequency Index:
Electric reliability indicator that measures the average number of interruptions that a utility customer experience.

SB
Senate Bill:
Legislation that is either proposed or modified in the California State Senate.

SCAQMD
South Coast Air Quality Management District:
A control agency responsible for regulating sources of air pollution covering Orange County and the urban portions of Los Angeles, Riverside, and San Bernardino County.

SCE
Southern California Edison:
The largest investor-owned electric utilities serving Central and Southern California.

SCPPA
Southern California Public Power Authority:
A joint powers agency comprised of eleven publicly owned utilities and one irrigation district located in Southern California.

SF_6
Sulfur Hexafluoride (also SF 6):
A synthetic fluorinated compound with an extremely stable molecular structure that utilities rely on for voltage electrical insulation, current interruption, and arc quenching in the transmission and distribution of electricity.

SIP
State Implementation Plan:
A CARB document that governs the implementation of building electrification initiatives.

SMR
Small Modular Reactor:
Advanced nuclear fission reactors capable of generating up to 300 MW that can be built in one location, then shipped, commissioned, and operated at a separate site.

Spinning Reserves
Available generating capacity that is synchronously connected to the electric grid and capable of automatically responding to frequency deviations on the system.

SPP
Southwest Power Pool:
An RTO that ensures reliable supplies of power, adequate transmission infrastructure, and competitive wholesale electricity prices for the central United States electric grid

ST
Steam Turbine:
A turbine that extracts thermal energy from pressurized steam and uses it to rotate an output shaft.

STG
Steam Turbine Generator:
A generator attached to a steam turbine that generates power when activated.

Substation
Electric system equipment that contains switches, transformers, and other equipment that steps down voltages for customer use, monitors transmission and distribution circuits, and performs other service functions.

TAC
Transmission Access Charge:
The cost recovery mechanism issued by the CAISO to recover transmission system investments.

TCA
Transmission Control Agreement:
A set of rules agreed to by a utility that govern its participation in the CAISO transmission network.

TOU
Time-of-Use:
A rate structure for on-peak, off-peak, and mid-day times designed to encourage customers to shift energy use to lower rate periods.

VOM
Variable Operation & Maintenance:
A function of the hours of operation of a power plant, and include yearly maintenance and overhaul, repairs, consumables, water supply, and environmental costs.

WAPA
Western Area Power Administration:
One of four power marketing administration, it markets wholesale hydropower generated at 57 hydroelectric federal dams operated by the Bureau of Reclamation, United States Army Corps of Engineers, and the International Boundary and Water Commission.

WECC
Western Electric Coordination Council:
Ensures bulk electric system reliability for the entire Western Interconnection.

WEIM
Western Energy Imbalance Market:
An energy market that automatically finds low-cost energy to serve demand close to the time the electricity is consumed, improving the balance of supply and demand.

WEIS
Western Energy Imbalance Service:
A market that will balance actual generation with demand and in real-time for participants in the Western Interconnection when fully implemented.

WPP
Western Power Pool:
A group of ISOs and utilities dedicated to ensuring adequate supply and reliability throughout the Western Interconnection.

WRAP
Western Resource Adequacy Program:
A program that better addresses resource adequacy needs supplied through variable renewable generation by taking advantage of operating efficiencies, diversity, and sharing pooled resources.

ZEV
Zero-Emission Vehicle:
A vehicle that emits no exhaust gas from its source of power, such as plug-in electric vehicles and hydrogen electric vehicles.

C. PowerSIMM Planner

POWERSIMM OVERVIEW

PowerSIMM is a software program used for simulating the performance of an electric power system with high spatial and temporal granularity. This section provides an overview of the key features and capabilities of this simulation software. In the IRP analysis, PowerSIMM was used for the following applications:

- **Production Cost Modeling:** Simulates power system operations, inclusive of transmission constraints, on an hourly or sub-hourly timestep for use in decision making for portfolio management or resource planning.
- **Capacity Expansion Optimization:** Provides a roadmap of future resource procurements to meet policy or reliability needs at the lowest cost.
- **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 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 consist of 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 min and max temperatures and renewable generation. PowerSIMM constructs a model for each renewable item using inputs that include daily min and max 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 min and max 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 (that is, forward prices and option quotes for volatility in prices) by scaling simulations such that the average price exactly meets the forward curves for monthly average prices for natural gas, on-peak power, off-peak power, and carbon. The stochastic price ranges hold to future expectations of price volatility, correlations across time and commodities, and daily price shapes.

Additional details on the model simulations can be found in "Simulation Details" (page B-7).

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 (VOM) costs, fixed O&M costs, fuel costs and 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 max generation, economic min 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. This section describes the types of models used for the plan.

Production Cost Modeling

The most common application of PowerSIMM in resource planning is as a production cost model, 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 84 shows hourly dispatch outputs over a three-day period from a production cost model plotted against load. 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.

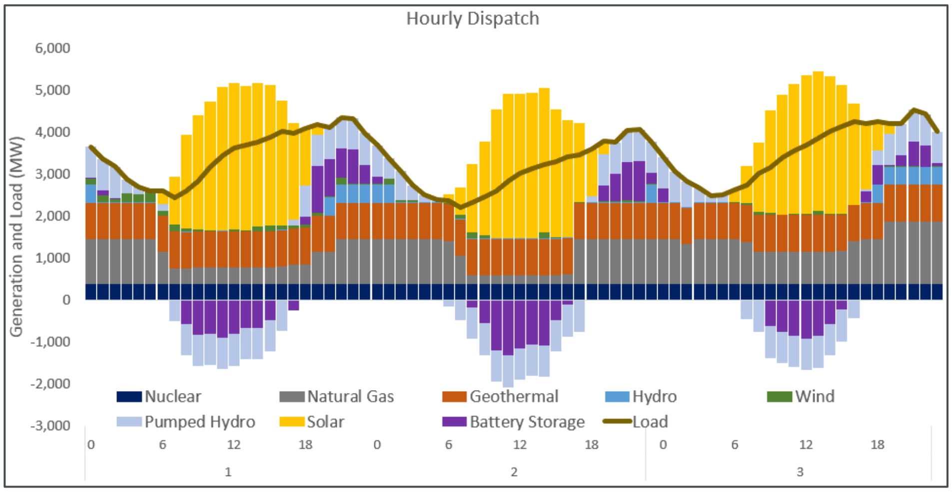

Figure 84. Three-Day Dispatch Outputs Plotted against Load

Key inputs for production cost models include the simulated system conditions[35] 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 application of PowerSIMM in resource planning is for 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 Automatic Resource Selection (ARS) module contains the PowerSIMM 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 (for example, carbon emissions). Based on the 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.

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

Figure 85 illustrates an ARS model that adds candidate resources to a portfolio to serve load at the lowest cost. 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.

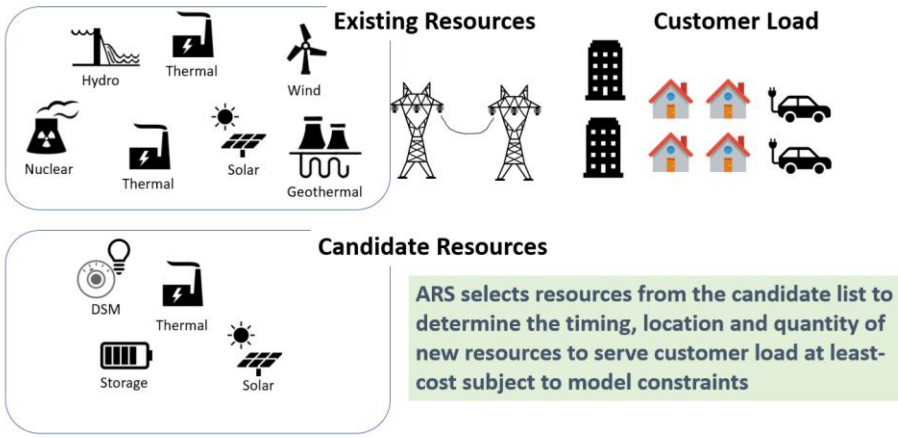

Figure 85. ARS Schematic of Candidate Resource Expansion

The input data requirements for ARS are generally the same as for production cost modeling except for additional project cost information (for example, new candidate resources), accredited capacity (for example, 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 is for resource adequacy analysis, which is used to assess 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 86, 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.

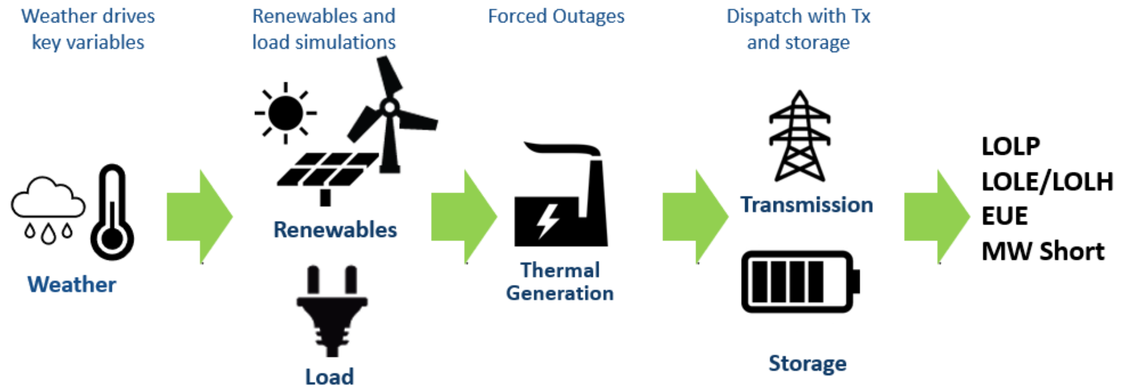

Figure 86. PowerSIMM Simulation Engine

The PowerSIMM resource adequacy model considers weather variability as a key driver to renewable and load simulation. These simulations are coupled with stochastically imposed forced outage in the dispatch module to measure common metrics, including LOLP, loss-of-load expectations (LOLE), or loss-of-load hours (LOLH), EUE, and capacity deficit (MW Short).

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 (that is, 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. In addition, resource adequacy models provide a useful means of determining the capacity contribution of a specific resource, known as the ELCC. The standard approach for an ELCC analysis involves three model runs. The reliability contribution of the ELCC resource is 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 for 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 select weather stations to create weather zones for use in their 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 to reflect predictions of a changing climate.

The resulting simulations should reasonably match historical data. Figure 87 shows an example of daily maximum dry bulb temperature simulations across a single year.

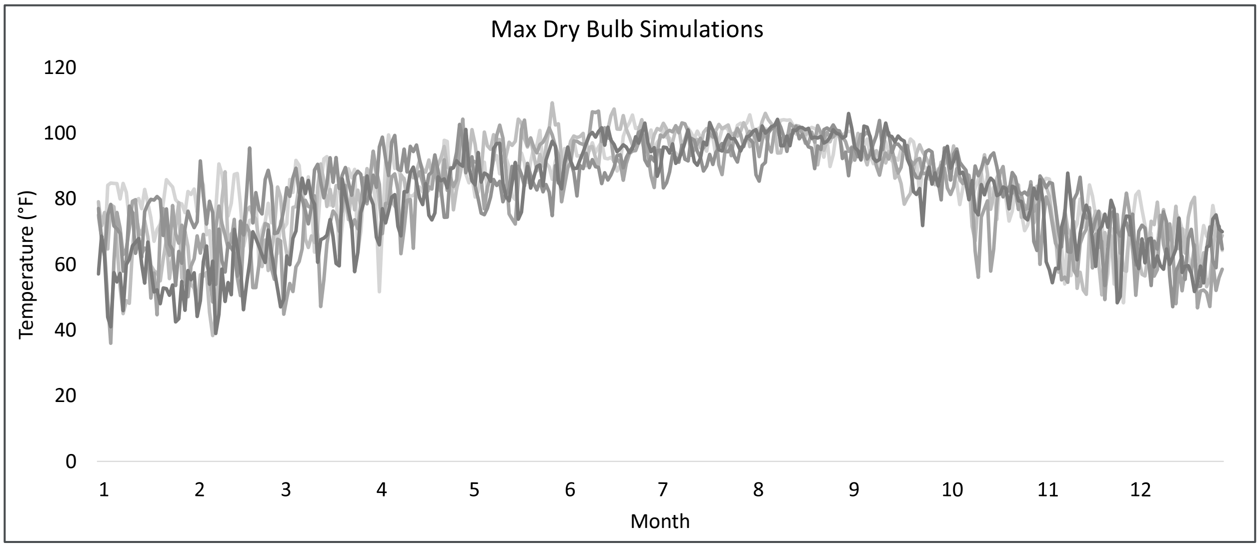

Figure 87. Multiple Simulations of Daily Maximum Dry Bulb Temperatures

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.

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 representation 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 88 shows a time series of multiple load simulations.

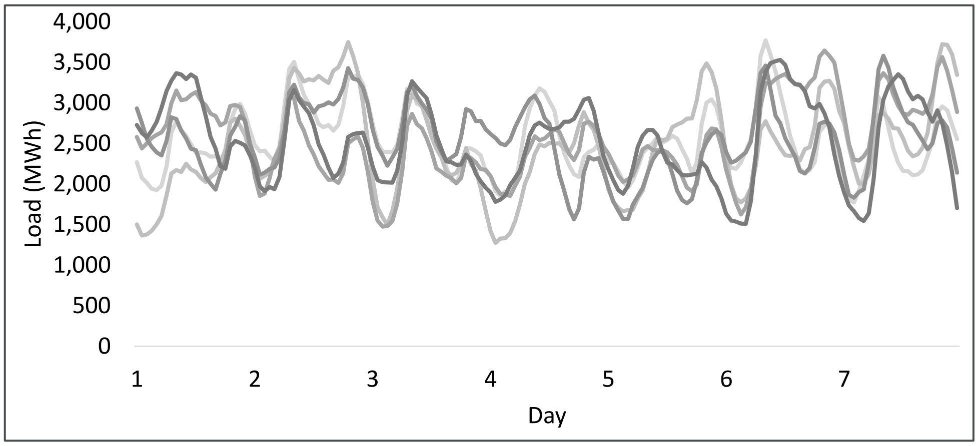

Figure 88. Multiple Simulations of Load Over a Single Week

Figure 89 shows the load versus temperature relationship maintained in the load simulations—when temperatures are at their highest load is at its highest, driven by the need to cool.

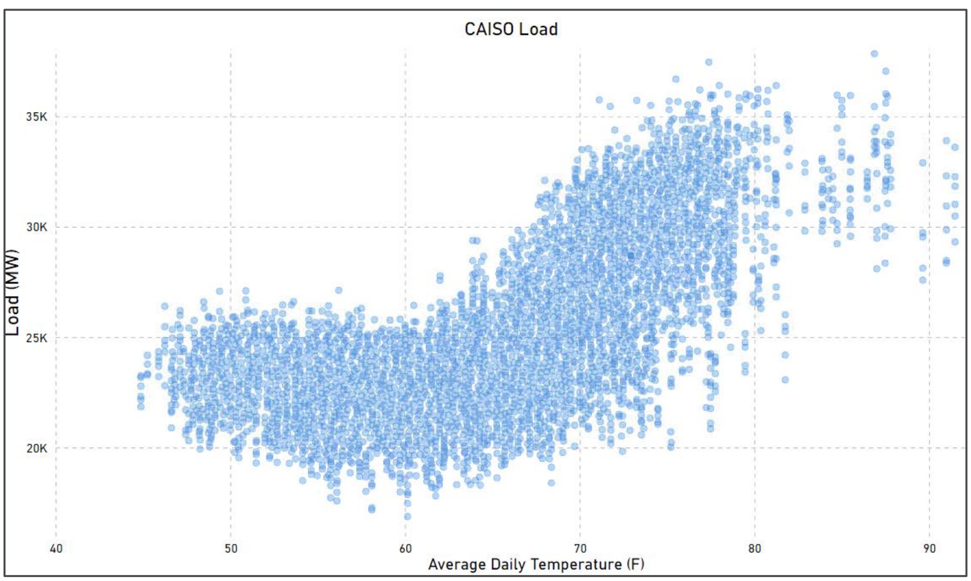

Figure 89. Load versus Temperature Relationships

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. 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 90 provides an example of solar simulations over a week.

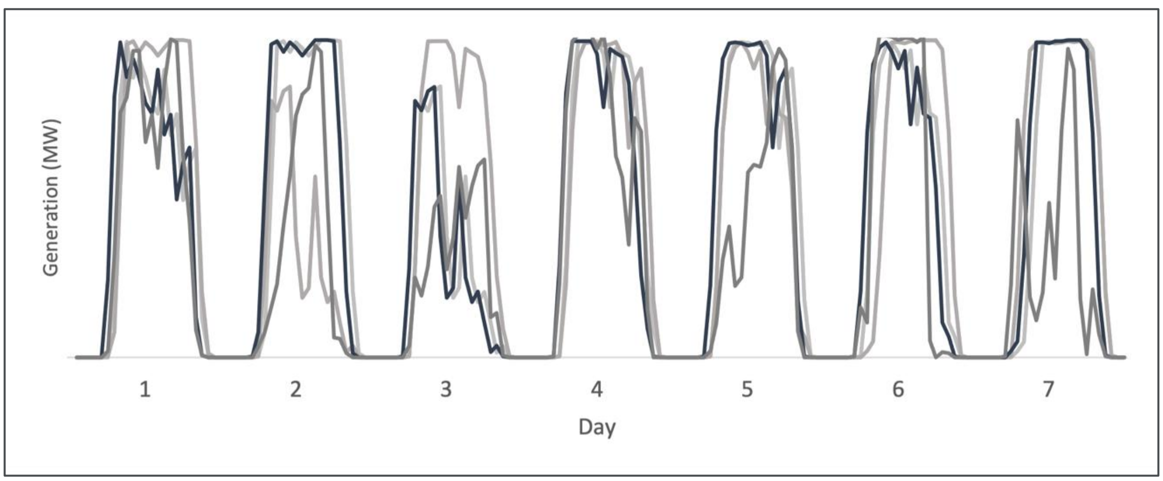

Figure 90. Multiple Simulations of Solar Generation Over a Single Week

Figure 91 provides an example of wind simulations over a week.

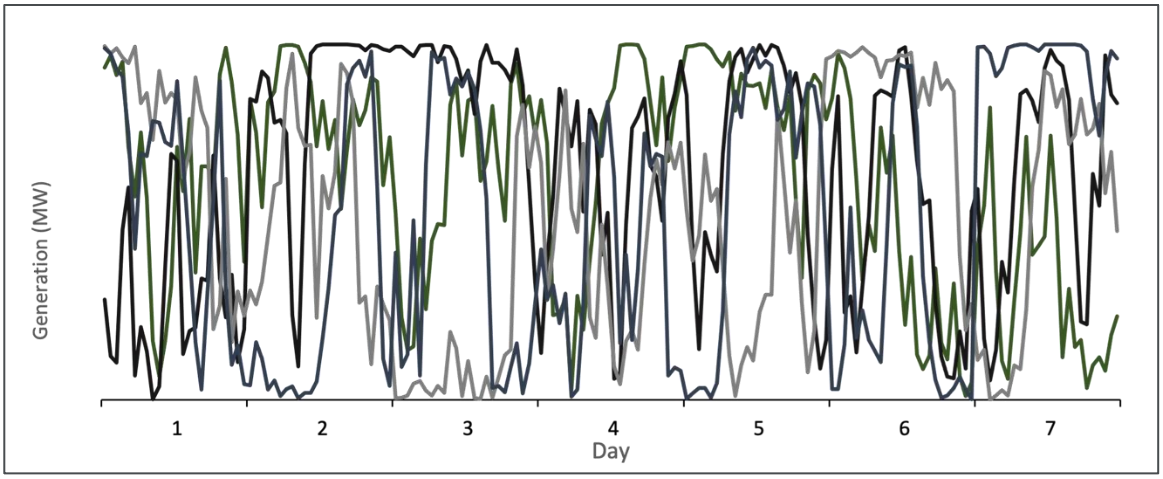

Figure 91. Multiple Simulations of Wind Generation Over a Single Week

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. Like 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 92 shows hydro simulations over a one-week period.

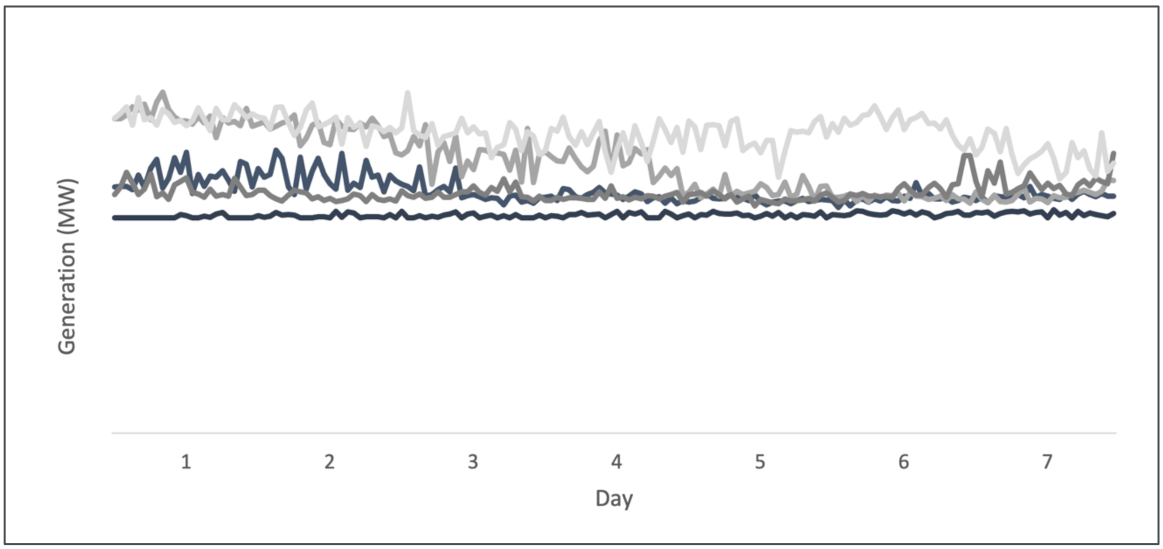

Figure 92. Multiple Simulations of Hydro Generation Over a Single Week

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, or 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 1. An AR coefficient less than 1 is equivalent to a Geometric Brownian Motion (GBM) model with mean reversion. Thus, the forward prices tend to do a random walk with a constant pull back to the monthly mean values.

Figure 93 shows multiple simulations of forward prices. The mean across all simulations equals to the input forecast.

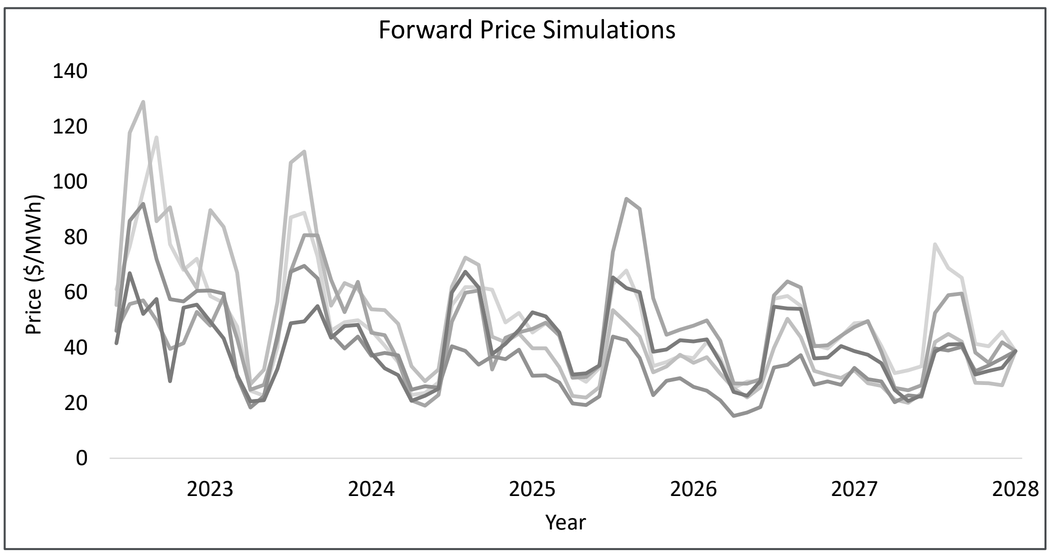

Figure 93. Multiple Simulations of Forward Prices

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 are shown in Figure 94 over the course of a week.

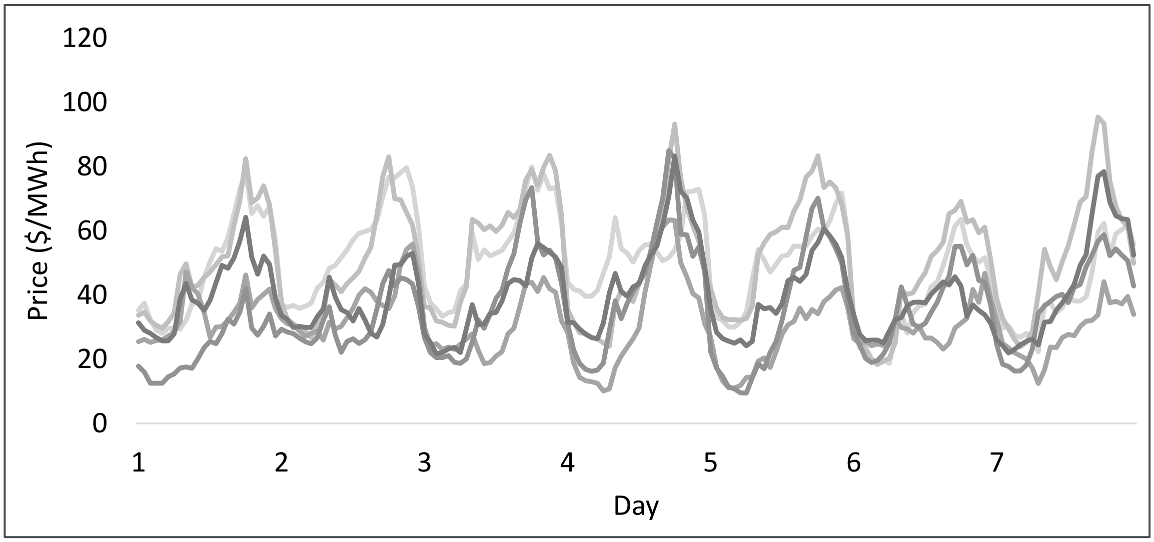

Figure 94. Simulations for Spot Prices Over a Single Week

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.

D. Annual Energy Forecast Data

Table 29 lists the energy forecasts (in MWh) for the entire planning period, including all the individual factors that modifying the base energy forecast. The energy modifiers include the solar impact, load loss impact, two data centers, hydrogen fuel, public and fleet electric vehicle impacts, and energy efficiency impacts.

Year	Base Energy Forecast	Solar Impact	Load Loss Impact	Data Center 1	Data Center 2	Hydrogen	Electric Vehicles-Public	Electric Vehicles-Fleet	Energy Efficiency	Total Energy Forecast
2023	1,206,173	(217)	(65,741)	—	—	—	4,376	414	(5,496)	1,139,509
2024	1,209,911	(703)	(104,712)	61,506	—	15,460	8,769	652	(10,592)	1,180,292
2025	1,206,671	(1,191)	(106,928)	67,015	43,664	61,217	13,125	886	(15,071)	1,269,388
2026	1,206,554	(1,410)	(106,959)	67,009	74,453	61,217	17,496	1,122	(17,635)	1,301,848
2027	1,206,331	(1,410)	(106,791)	67,008	74,461	61,320	21,877	1,318	(18,500)	1,305,613
2028	1,209,919	(1,410)	(106,997)	67,198	74,664	61,457	26,341	1,421	(19,097)	1,313,494
2029	1,206,551	(1,410)	(106,728)	67,015	74,463	61,217	30,613	1,416	(19,500)	1,313,636
2030	1,206,194	(1,410)	(106,782)	67,016	74,463	61,217	34,994	1,416	(19,955)	1,317,152
2031	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	39,375	1,416	(20,430)	1,320,096
2032	1,209,992	(1,411)	(107,923)	67,199	74,664	60,732	43,882	1,419	(20,482)	1,328,073
2033	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	48,131	1,416	(20,430)	1,328,852
2034	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	52,507	1,416	(20,430)	1,333,228
2035	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	56,883	1,416	(20,430)	1,337,603
2036	1,209,992	(1,411)	(107,923)	67,199	74,664	60,732	61,434	1,419	(20,482)	1,345,625
2037	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	65,634	1,416	(20,430)	1,346,355
2038	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	70,009	1,416	(20,430)	1,350,730

Year	Base Energy Forecast	Solar Impact	Load Loss Impact	Data Center 1	Data Center 2	Hydrogen	Electric Vehicles-Public	Electric Vehicles-Fleet	Energy Efficiency	Total Energy Forecast
2039	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	74,385	1,416	(20,430)	1,355,106
2040	1,209,992	(1,411)	(107,923)	67,199	74,664	60,732	78,987	1,419	(20,482)	1,363,178
2041	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	83,136	1,416	(20,430)	1,363,857
2042	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	87,512	1,416	(20,430)	1,368,233
2043	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	91,887	1,416	(20,430)	1,372,608
2044	1,209,992	(1,411)	(107,923)	67,199	74,664	60,732	96,540	1,419	(20,482)	1,380,731
2045	1,206,671	(1,410)	(107,600)	67,016	74,462	60,596	100,639	1,416	(20,430)	1,381,359

Table 29. Annual Energy Forecast with Modifiers (MWh)

E. Stakeholder Outreach

VPU held three in-person meetings to inform its stakeholders about the IRP process and conducted a 12-question survey to gather their input. The purpose of VPU's stakeholder outreach was to inform its stakeholders about the IRP process and the inherent issues necessary to be addressed in the IRP development, and to garner input as to their preferences and ideas. Discussions from the three meetings and responses to the survey enabled VPU to better understand and appreciate diverse viewpoints. This information was incorporated into the development of the IRP.

STAKEHOLDER MEETINGS

To engage its stakeholders directly, VPU held three in-person stakeholder meetings in the Council Chambers in Vernon City Hall. The Green Vernon Commission, Business and Industry Commission, and community members attended these meetings. At each meeting, attendees were afforded the opportunity to comment and impart their thoughts on the IRP process. VPU incorporated their feedback into the IRP analysis and employed their insights into selecting the preferred capacity expansion portfolio.

First Stakeholder Meeting, March 15, 2023. Attendees were appraised of the overall IRP process. This overview described the content of the IRP, the requirements proscribed by Public Utilities Code (PUC) 9621, how VPU selected Ascend Analytics, Ascend's task for creating the IRP, purpose of the IRP, and concluded that VPU is engaging its stakeholders for their guidance and input of the IRP goals and direction.

VPU gave a presentation that discussed the purpose of the IRP; the California Public Utilities Code requirements; IRP policy and regulation compliance focusing on SB 350, SB 100, and SB 1020; VPU's current resource mix; renewable requirements and resources; information about the City of Vernon, and the IRP timeline. The presentation asked for input from attendees and promoted the online stakeholder survey, encouraging attendees to take it.

Second Stakeholder Meeting, May 11, 2023. Attendees were appraised of the same information as with the first stakeholder meeting and that the results of the survey would be presented.

VPU gave a presentation that mainly focused on the survey results. The presentation began by updating attendees on the progress of the IRP and giving an overview of VPU's diverse stakeholders, then presented the results of several survey questions and summarized the key insights gained from the survey responses. VPU representatives described the various resource categories in its current and future portfolio (solar, wind, geothermal, battery, CCS, and MGS) and the resources that are being used to meet the state's renewable energy and zero-emission goals. The presentation concluded with an updated IRP timeline.

Third Stakeholder Meeting, June 21, 2023. VPU and Ascend gave an in-depth presentation about the IRP. The presentation began by laying a foundation of the IRP's progress and repeated the key insights from the survey. It continued by describing the IRP's goals and objectives, the long-term resource sustainability strategy, and the planned GHG footprint (especially concerning MGS) for complying with state regulations.

The presentation then focused on the modeling process used for developing a preferred portfolio for meeting VPU obligations. First was a series of slides discussing the optimal supply portfolio (encompassing high reliability and affordable rates, key stakeholder preferences, and the sustainable resources necessary to meet those targets), an overview of the capacities of the modeled resources, the estimated costs of each modeled resource, and the current VPU generation portfolio.

Next was three sets of slides about each of the three potential portfolios that were modeled and analyzed:

- Portfolio 1: solar, wind, and storage
- Portfolio 2: geothermal, solar, wind, and storage
- Portfolio 3: green hydrogen combustion turbine, solar, wind, and storage

Each set of slides first described the generation technology types of each portfolio: their energy contribution (in MWh), their RA contribution (in MW), their RPS contribution (in MWh), and zero-carbon clean energy contribution (in MWh); and concluded with the annualized net present value (NPV) cost of load and the current average cost by MWh. A concluding slide compared the annualized NPV costs of each portfolio with the cost of current day operations.

A final slide updated the IRP timeline.

STAKEHOLDER SURVEY AND RESULTS

VPU conducted a 12 question survey to better understand its customers' thoughts regarding their priorities about reliable power, affordable rates, renewable generation, EV charging, DERs, and MGS. The survey was available from March 16, 2023 through May 4, 2023.

VPU made a significant effort to encourage stakeholders to complete the survey. VPU publicized the survey in myriad ways:

- Discussing it and passing out survey flyers at stakeholder meetings, community and city events, Business Breakfasts, and joint commission meeting.
- Advertising it through various social media channels, the City of Vernon's website, the City of Vernon's newsletter, and VPU's newsletter.
- Mailing survey flyers to every residential and commercial customer.
- Emailing all residential and commercial customers whose email addresses are in its database.
- Phoning commercial customers.
- Partnering with the Business and Industry Commission and the Green Vernon Commission to spread the word about the survey.
- Distributing flyers at numerous community events, especially the city's Spring Egg-stravaganza on March 23, 2023; the Vernon Job Fair on June 23, 2023; the Business Breakfast on May 3, and the Wellness Equity Alliance Health event.
- Posting and leaving surveys at every public counter and at the entrance to City Hall.
- Distributing surveys through the Chamber of Commerce to notify current and prospective property and business owners, realtors, and developers.

Figure 95 is an exact replica of the survey flyer.

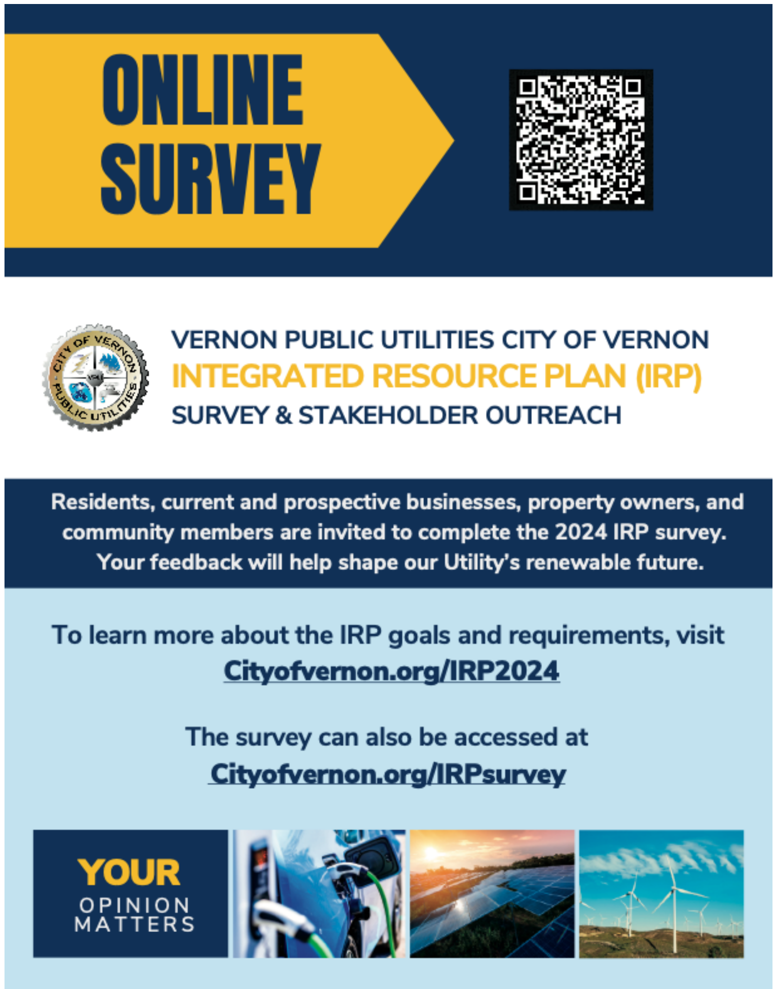

Figure 95. Stakeholder Survey Flyer with QR Code

Survey Results

The 12-question survey touched on issues about VPU's service, reliability, and rates as well as stakeholder preferences and knowledge regarding key issues facing VPU today and over the next two decades. Here is a summary of each survey question and its results.

Question 1: Stakeholder Demographics

The first question identified who responded to the survey. This information enabled VPU to better apply the remaining survey responses.

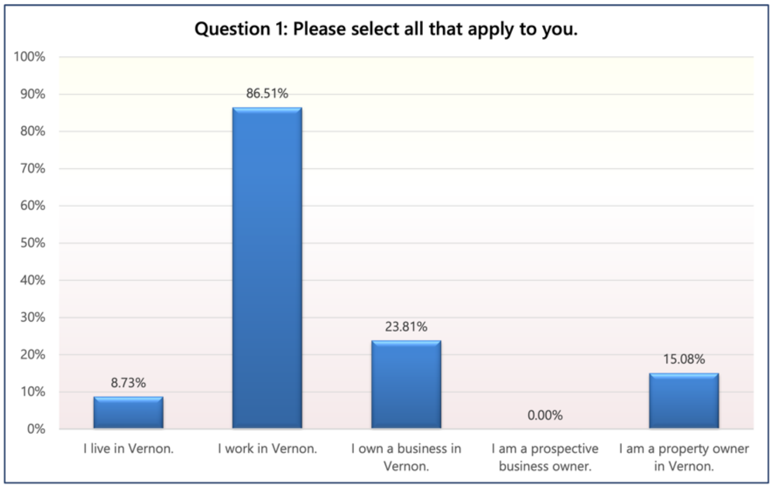

Figure 96. Question 1: Stakeholder Demographic Responses

The predominant survey taker was employed in Vernon, followed by business and property owners.

Question 2: Electric Services Satisfaction

VPU focuses on customer satisfaction. The second question considered how customers thought about VPU's service. Almost 82 percent were very satisfied or satisfied, with less than 5 percent being dissatisfied.

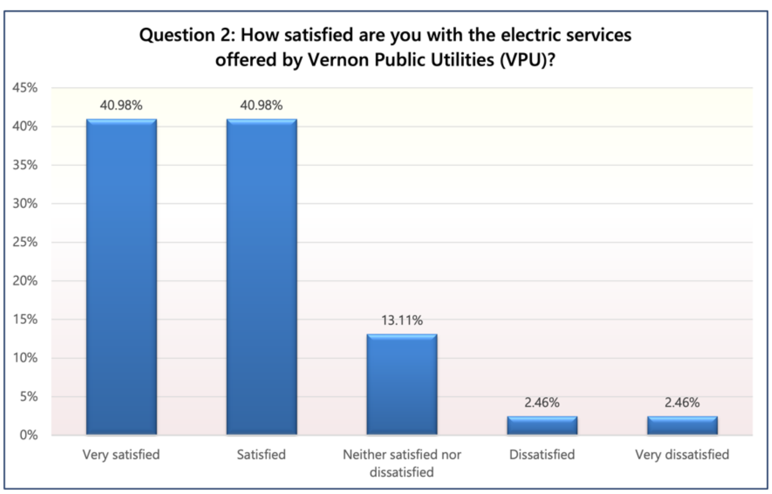

Figure 97. Question 2: Electric Services Satisfaction Responses

While VPU is proud of the results to this question, there remains work to be done. Customer satisfaction is an area that VPU continues to pursue.

Question 3: Electric Service Ranking

Understanding how stakeholders feel about a variety of VPU's services goes to the core of customer satisfaction. The third question sought information about how respondents ranked reliability, affordable rates, general customer service topics, and the environmental impact of VPU's generation portfolio.

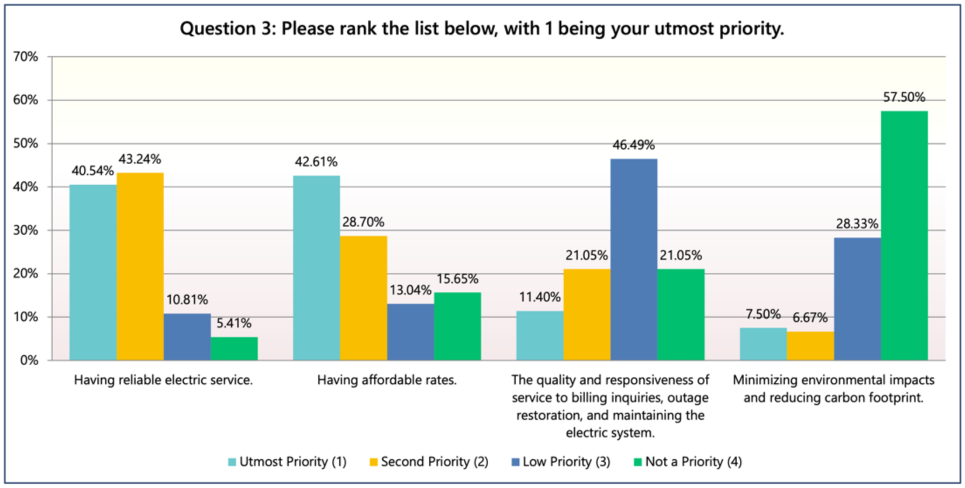

Figure 98. Question 3: Electric Service Ranking Responses

As has been the case in the past, affordable rates and reliability remains a core focus, far greater than considerations for the quality and responsiveness VPU's related services and environmental stewardship.

Question 4: Rates or Reliability Priority

When pitted head to head, respondents chose reliability over affordable rates.

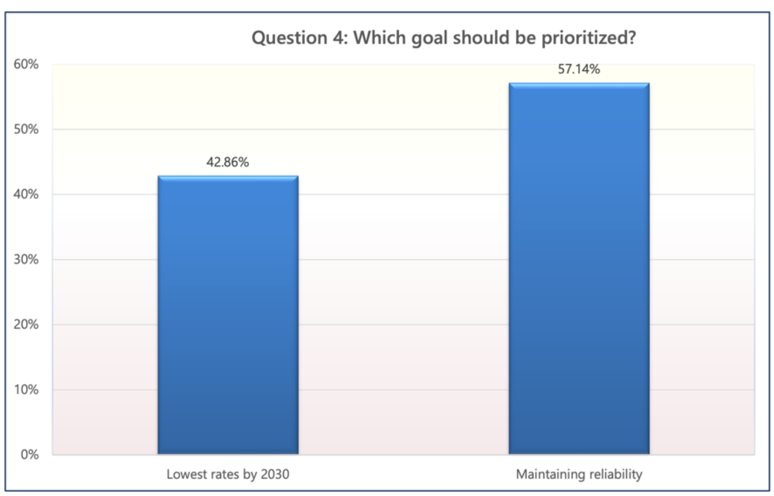

Figure 99. Question 4: Rates or Reliability Priority Responses

While these findings are the reverse of responses to question 3, VPU plans to give dual priority to rates and reliability.

Question 5: RPS Compliance

VPU must meet the mandated target of 60 percent of its generation portfolio to come from renewable generation. By an overwhelming margin, respondents expect VPU to attain, and not exceed, that target.

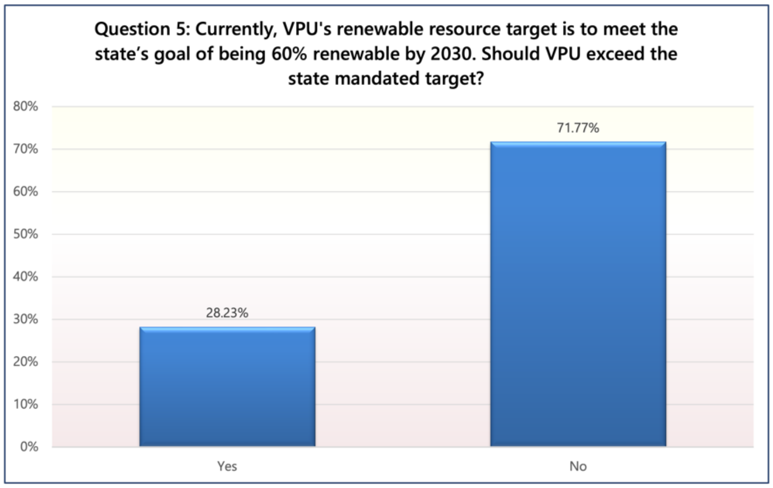

Figure 100. Question 5: RPS Compliance Responses

These responses directly inform the process of creating a preferred portfolio mix for 2030.

Question 6: RPS Increase Rate Impact

The sixth question informs the responses to the previous question. Two out of every three respondents think that increased renewable generation penetration causes a corresponding increase in rates, a factor that respondents want minimized.

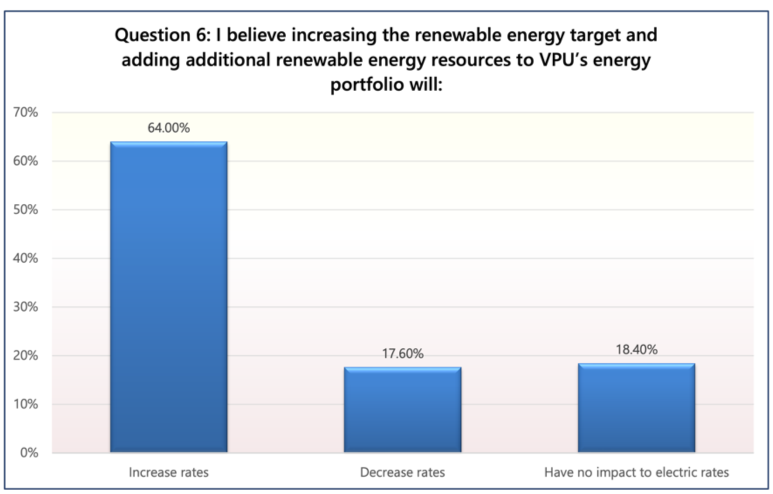

Figure 101. Question 6: RPS Increase Rate Impact Responses

As a result, VPU plans to focus on adding renewable generation at the lowest possible cost.

Question 7: Green Efforts Ranking

About 45 percent of respondents are very interested or interested in having more public EV charging stations installed in the City of Vernon. That percentage increases to 65 percent when incentives are offered. Installing DERs and energy storage are also important to respondents.

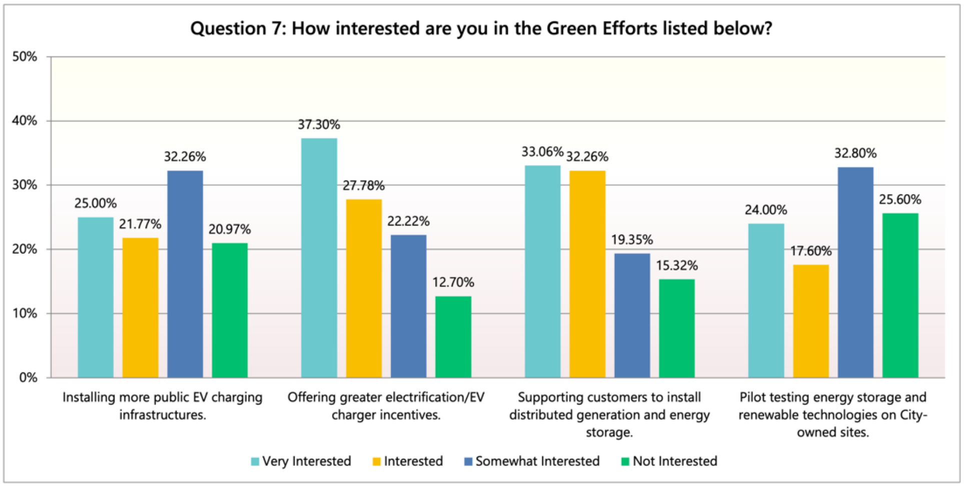

Figure 102. Question 7: Green Efforts Ranking Responses

VPU already has installed a number of EV charging stations in the city and intends to install more. To comply with state statutes, VPU is also easing the permitting process for EV charging station installations.

Question 8: DER Penetration Impacts

Responses to increases in DER penetration show that their impact is largely unknown. For example, the perception that DERs cause rates to increase, drop, or remain the same is about equally divided, as is the perception that DER penetration affects reliability.

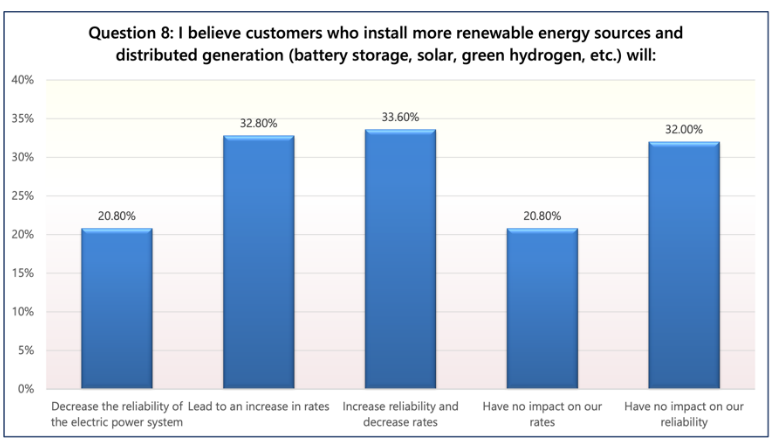

Figure 103. Question 8: DER Penetration Impacts Responses

As has been its focus, VPU ensures that increases in DERs have little to no effect on rates or reliability.

Question 9: MGS Energy Supply

Two-thirds of respondents didn't understand the impact that MGS has on reliability nor on meeting the CPUC's RA requirements.

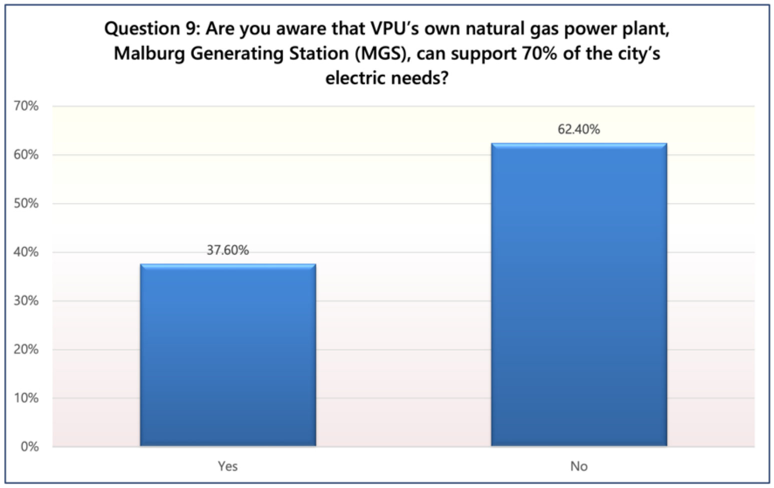

Figure 104. Question 9: MGS Energy Supply Responses

VPU fully understands and appreciates the impact that MGS supply has on reliable service, dispatchable generation, and state mandated compliance, and is fully considering the impact of transitioning to a zero-carbon resource portfolio.

Question 10: MGS Investment Ranking

How to handle MGS's future is an important transition topic at VPU. The tenth question was an effort to understand how stakeholders felt about various transition paths. Of note, 44 percent of respondents feel that VPU should be independent from the state's power grid.

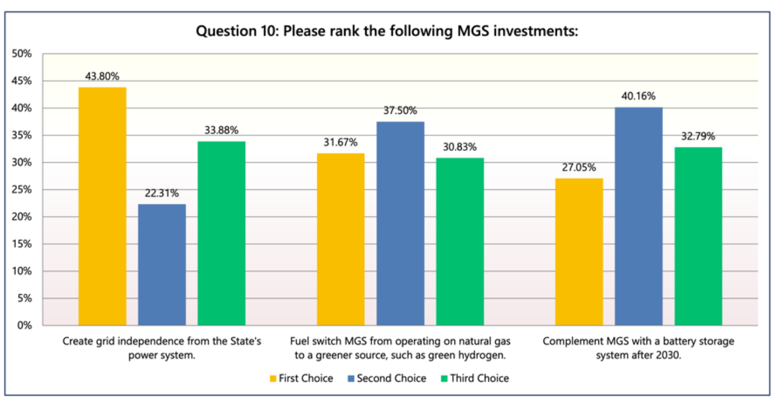

Figure 105. Question 10: MGS Investment Ranking Responses

Switching from burning natural gas to hydrogen is currently an expensive option. Complementing MGS with battery storage has the potential to minimize its thermal impact. Over time, other options will undoubtedly present themselves. MGS's generation currently is about 39 percent of VPU's entire generation, so the short-term impact to MGS portends to be minimal. Replacing MGS's baseload generation is a planning priority. This long-term picture could present a thorny issue, one that VPU will carefully consider as state mandates approach.

Question 11: MGS Investment Rate Impact

The eleventh question goes to the rate increases that stakeholders will accept when investments in MGS are made. Clearly, this response affects how VPU plans for the future of MGS.

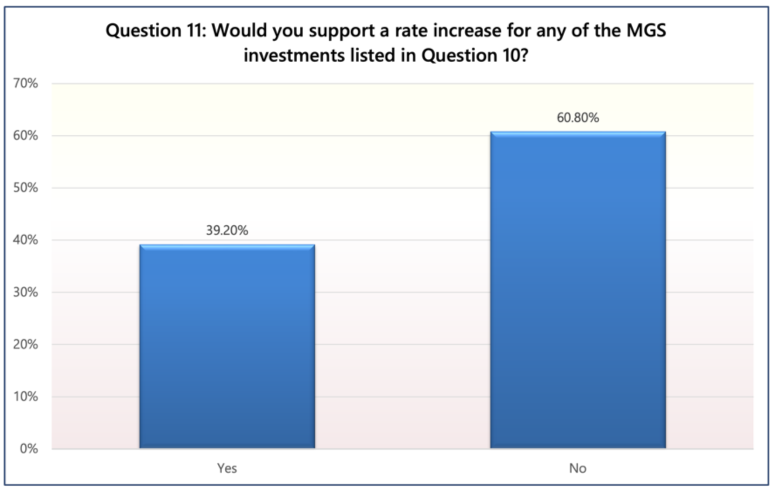

Figure 106. Question 11: MGS Investment Rate Impact Responses

Question 12: Comments Solicited

The survey results contained 14 comments in response a solicitation for comments. Each comment is listed here. Most comments pertained to reliability, rates, and investments in renewable generation.

Small edits were made to correct spelling, capitalization, grammatical, and punctation inconsistencies; words in parentheses were added for clarity. The original intent of the comments has not been altered.

- If a rate increase went through to fund an [MGS] investment, would rates drop after the project was completed? We support projects that keep power reliable. What good is low rates and unreliable service; what am I paying for? That said, don't take advantage and say all rate increases are for [MGS] or for reliability.
- I love Vernon.
- No more rate increases.
- Rate increase should explain (which) MGS investment (is made) or what the increase would be used for and why.
- We need stable rates.
- Need more incentive programs for installing the green energy equipment.
- Decrease rates and get back to being the lowest price(d) power provider in California.
- As a business owner in the community, the electricity isn't broken, why attempt to "fix it" and increase the cost when the cost of living has significantly increased within these 2 past years. Get a grant or a loan the way that we do to run our businesses. Sincerely, Business owner who pays their own bills.
- Nuclear power plants, as well as not banning or shutting down current energy production methods, but instead a gradual transition.
- The earlier investment is made into renewable infrastructure. As it stands today, the lower the cost of investment to enter the market.
- The extra charges recently have been out of line and outrageous. It questions why we are in Vernon.
- We are manufacturing bags and compete with Chinese manufacturers. In China, they use fossil fuel more than green resources to produce electricity. In order (to) survive in business, the price of our electricity should stay competitive with its price in China.
- Need good incentive program to install solar panel and battery at our location.
- Grid reliability is the upmost important to our business. Manufacturing downtime & loss of perishable stored product outweigh additional utility cost increases.

Key Insights

VPU gained several key insights from the survey responses. Among them are the following:

- Over 80 percent are either satisfied or very satisfied with the services VPU provides.
- Over 80 percent ranked reliability and low rates as their top two priorities; 57 percent selected reliability as their top priority.
- Over 70 percent do not believe VPU should exceed state mandated RPS targets.
- Over three-quarters are very interested in more EV charging station, electrification incentives, DERs, and energy storage; over 37 percent are very interested in greater electrification.
- Over 60 percent were not aware of Malburg Generating Station's capability.

VPU presented these findings during the second stakeholder meeting.