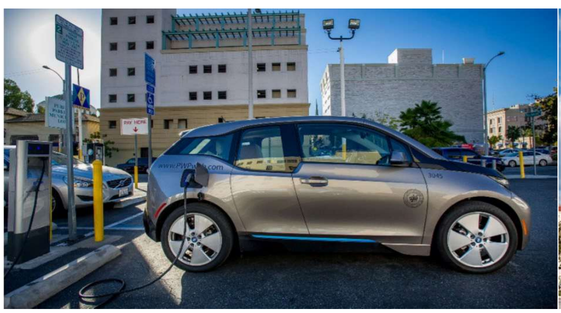
Pasadena Water & Power Integrated Resource Plan (Power) 2021 Update



Pasadena Water and Power, supported by Northwest Economic Research LLC and ACES Power Marketing LLC

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PASADENA Water&Power
SERVING THE COMMUNITY SINCE 1906

December 2021

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I. Executive Summary

Since the 2018 Integrated Resource Plan (IRP), energy market conditions and regulatory mandates impacting Pasadena Water & Power (PWP) have changed significantly.

The continued growth of renewable resources has required California to update its regulatory structure and strategic approach to meeting the state's ambitious greenhouse gas reduction goals. Accordingly, the California Independent System Operator (CAISO) is undergoing modification of its operating tariff, which will affect PWP's continued participation in the CAISO energy markets. Costs of renewable resources continue to fall, due to technology advancement and tax incentives.

PWP has updated previous projections of its power supply portfolio due to these external factors, and as a result, recommends approximately 260 Megawatts (MW) of new capacity supplies will be needed by 2030 to yield 120 MW of firm accredited capacity. This new capacity includes zero-carbon resources (wind, solar, storage and hybrids), modest demand response, and short-term purchases of capacity to meet residual obligations to the CAISO. This capacity will enable PWP to meet its strategic goals, including:

- meet forecasted peak and energy loads,
- achieve state Renewable Portfolio Standards (RPS),
- reduce carbon emissions to zero by the end of 2045, and
- meet new capacity planning standards and reliability criteria in California.

Figures 1 and 2 show projected zero carbon resource additions to the PWP portfolio, excluding short-term purchases of capacity to meet CAISO reliability standards.

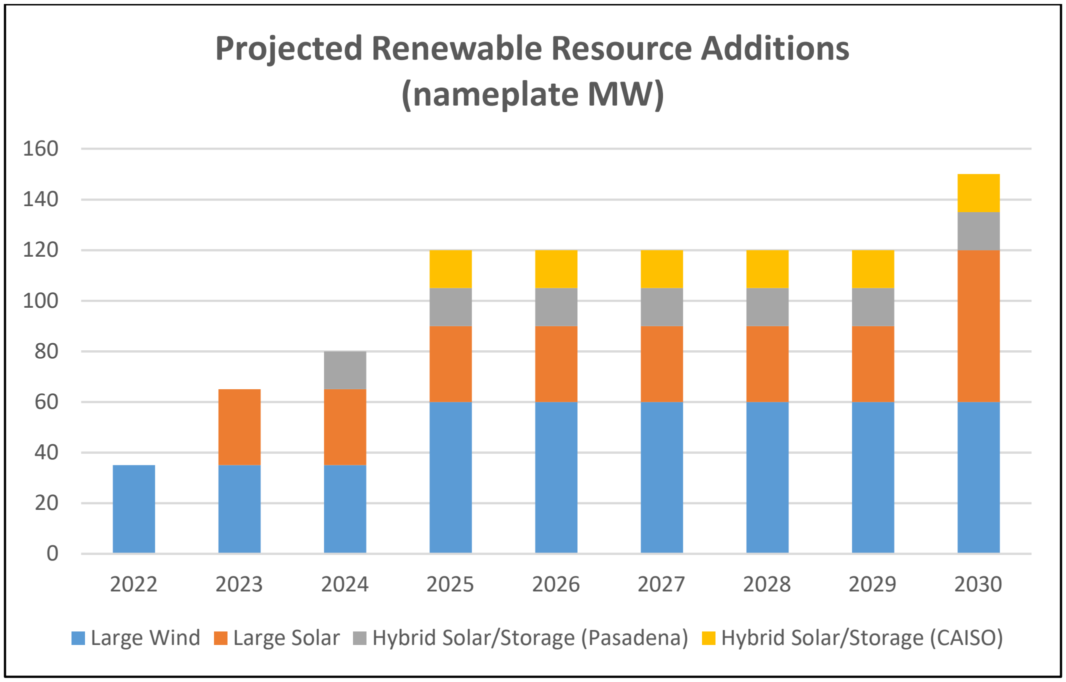


Figure 1: Projected Renewable Resource Additions

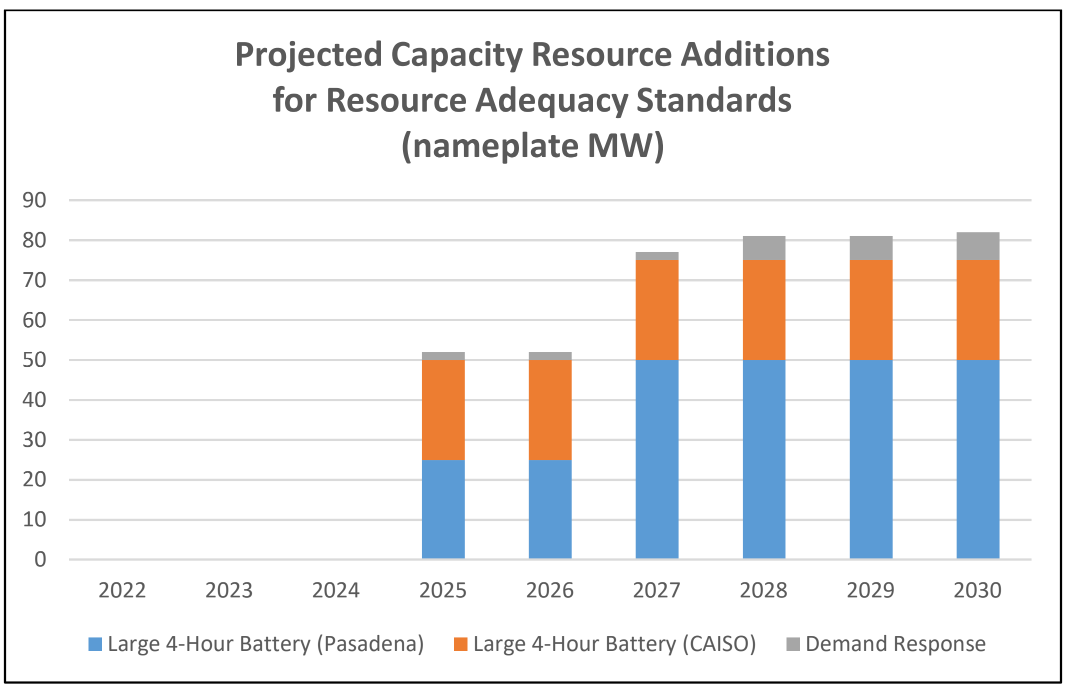


Figure 2: Projected Capacity Resource Additions for Resource Adequacy Standards

Upon reviewing the changes to the market and regulatory environment, the 2018 IRP Preferred Portfolio is no longer able to meet the new obligations identified during the 2021 IRP Update. The 2021 IRP Update recommends adding new zero carbon resources sooner than previously anticipated, potentially put upward pressure on retail rates. However, PWP expects to manage impact on retail rates by staggering procurement of zero carbon resources over time to optimize energy procurement.

Projected Power Supply Portfolio

The 2021 Update Portfolio (2021 Update) developed in this 2021 IRP Update recommends the following energy and capacity amounts to be installed in order to meet retail loads in the City of Pasadena (City), minimizing the cost of energy while meeting requirements for local reliability, RPS, and emission reductions.

PWP's strategic approach to procurement will be to purchase zero carbon resources while also considering the "firm capacity" value. The firm capacity of intermittent resources, such as solar and wind, may be only one-third of the "installed capacity" value due to the variabilities of when the sun shines or wind blows. Due to the increasing state-wide need for reliability, the firm capacity value will need to be carefully addressed in order to meet the reliability requirements.

Figures 3 and 4 show the expected energy supplies in 2030 and 2045.[1]

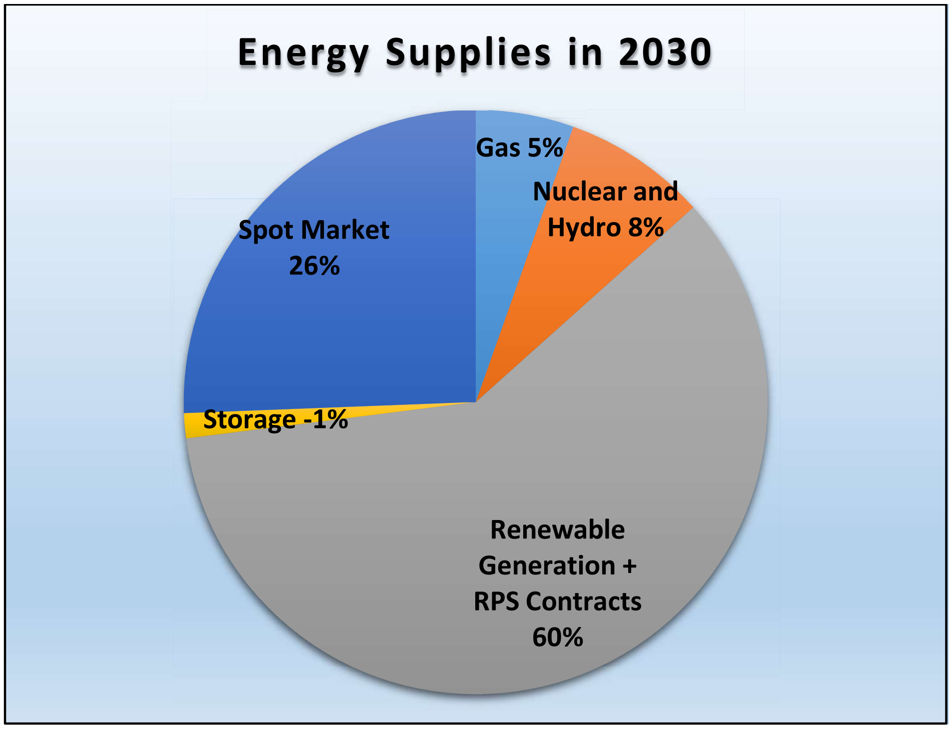


Figure 3: Energy Supplies in 2030

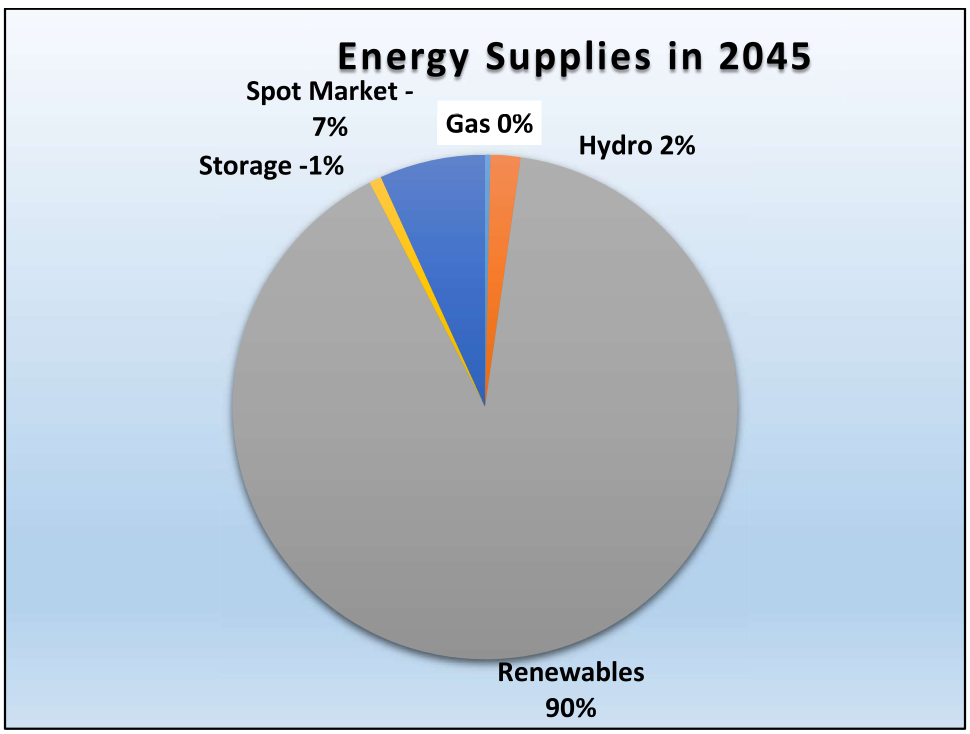


Figure 4: Energy Supplies in 2045

Figures 5 and 6 show the expected installed capacity in 2030 and 2045.

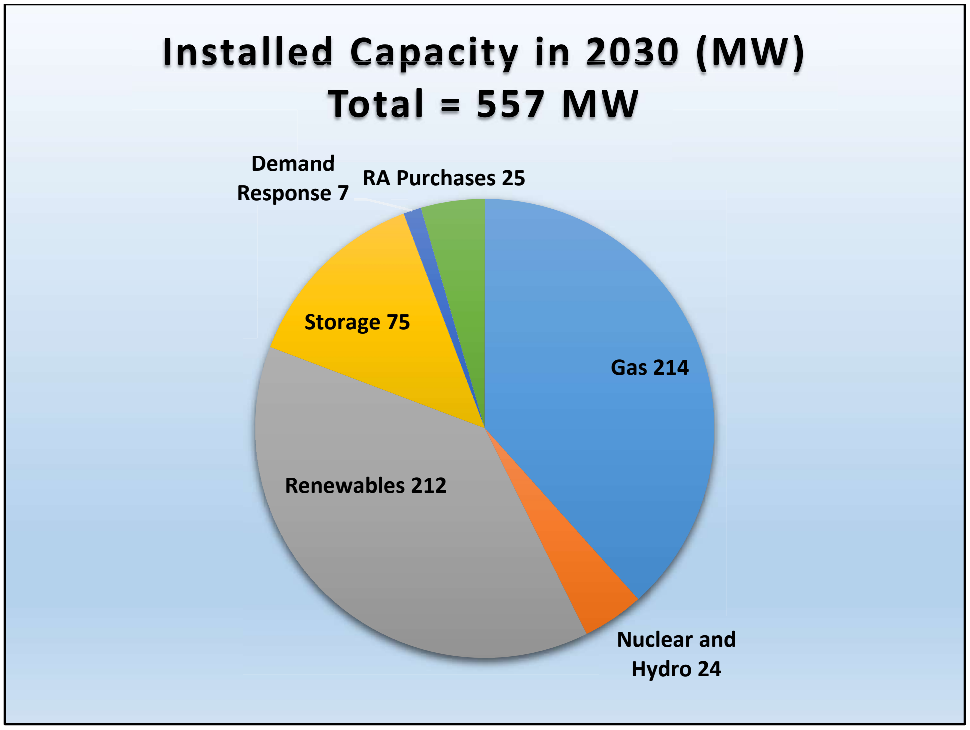


Figure 5: Installed Capacity in 2030 (MW)

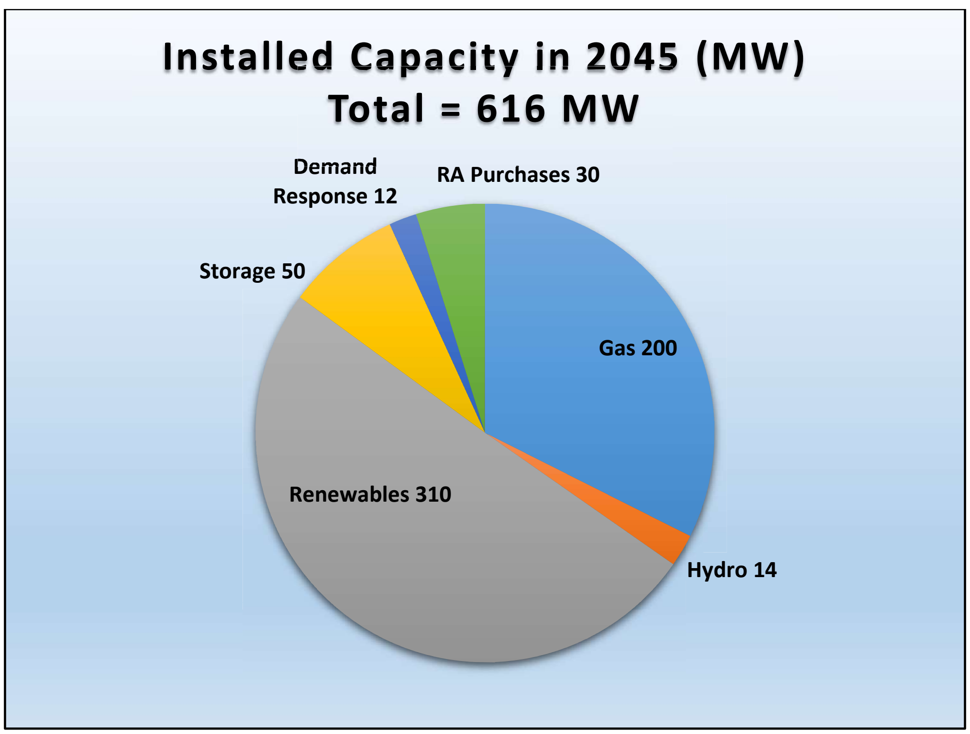


Figure 6: Installed Capacity in 2045 (MW)

Figures 7 and 8 show the expected firm capacity in 2030 and 2045.

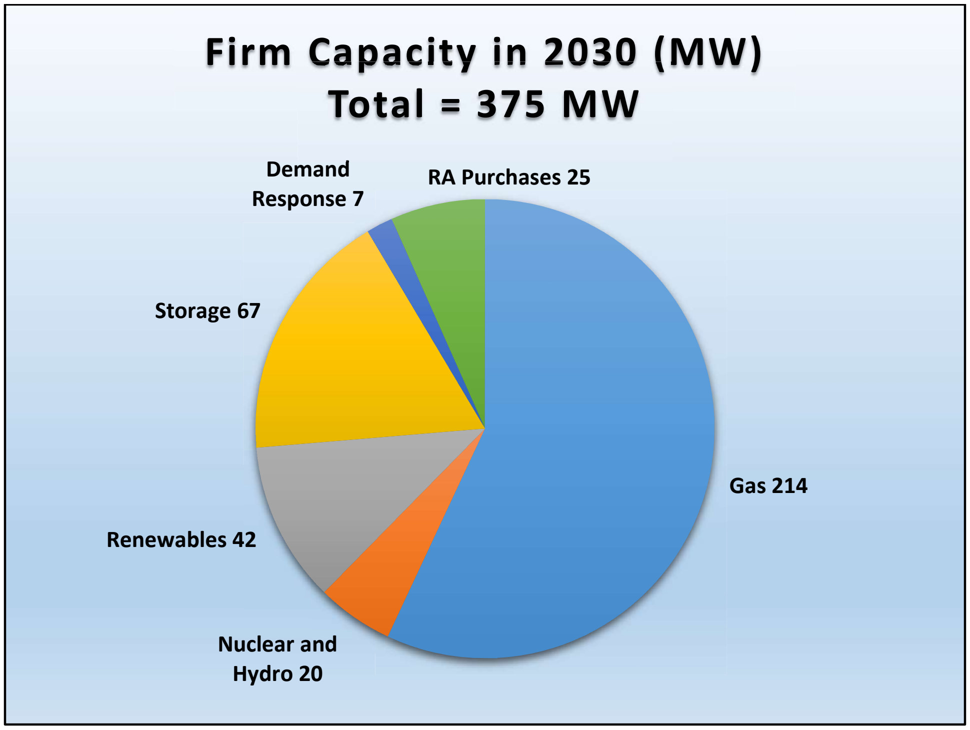


Figure 7: Firm Capacity in 2030 (MW)

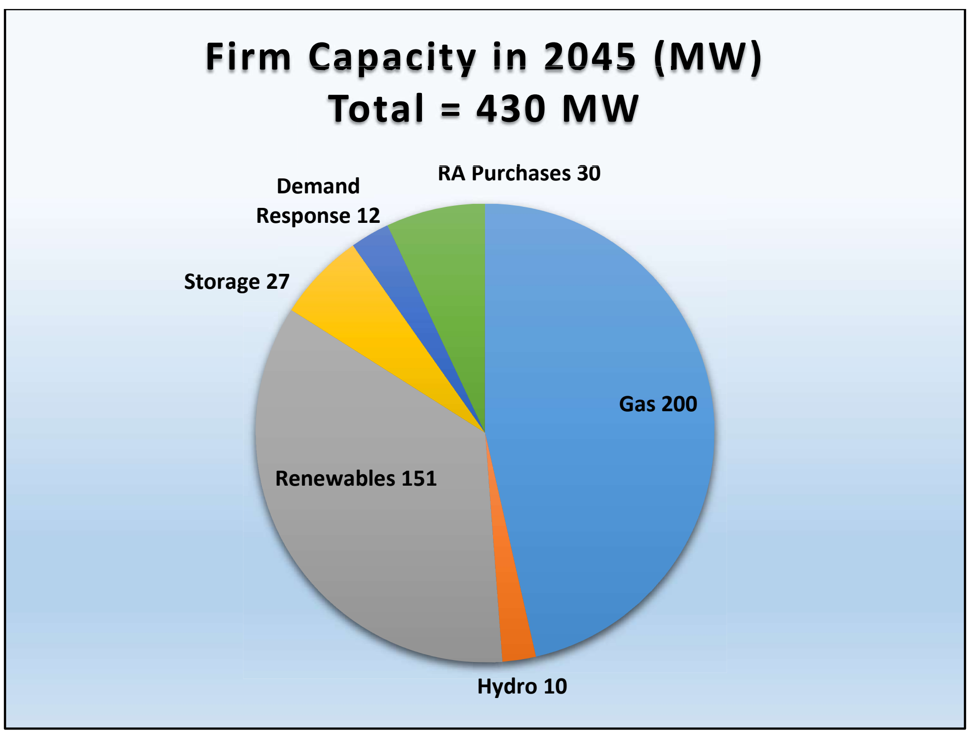


Figure 8: Firm Capacity in 2045 (MW)

2021 IRP Update

Recommendations

1. Review increasing near-term procurement recommendations, potentially including 70 MW of firm capacity *(about 120 MW nameplate capacity of wind, solar and hybrid resources, excluding storage)* by 2025 for reliability and Resource Adequacy (RA) requirements
2. Investigate energy storage options for capacity requirements and local reliability needs, because the Update identifies 50 MW (nameplate) of cost-effective storage by 2025
3. Continue efforts toward achieving 60% RPS by 2030 and net-zero carbon by 2045
4. Examine potential alternative fuel sources for local reliability resources (e.g., biogas and green hydrogen at Glenarm Power Plant)
5. Refine forecasted growth of Electric Vehicle (EV) charging in Pasadena

II. Background

In 2018, PWP developed its first state-mandated IRP for consumer-owned utilities.[2] The 2018 IRP was adopted by City Council on December 10, 2018; filed at the California Energy Commission (CEC) on December 18, 2018; and approved by the CEC on July 9, 2019. At the time, an update to the IRP was expected to be adopted by January 2022.[3] The 2021 IRP Update is not required by the state, but PWP has opted to review key assumptions and modeling inputs, and to incorporate the current economic and regulatory environment.[4]

III. Analytical Structure

a) Production Cost Model

This 2021 IRP Update used EnCompass, an industry standard modeling software for capacity expansion and production cost modeling that co-optimizes cost, environmental mandates, and reliability. This model imports annual and monthly data on multiple variables (e.g., Pasadena's forecasted monthly energy and peak loads, and the projected costs of solar and storage options, and hourly load and resource shapes), determines the optimal timing and amount of resource additions and retirements based on financial, regulatory, and environmental criteria, and dispatches the resulting power supply portfolio each year on an hourly basis to minimize the cost of energy to PWP's retail customers while also meeting other requirements and obligations, including RPS, carbon, and reliability.[5]

The production cost model (EnCompass) operates in a similar manner to the software utilized in the 2018 IRP (Aurora XMP):

- minimizing cost of serving PWP's retail load,
- using long-term and short-term energy supplies,
- meeting environmental, regulatory, and reliability constraints.[6]

See Figure 9 for an overview of the EnCompass Model Software.

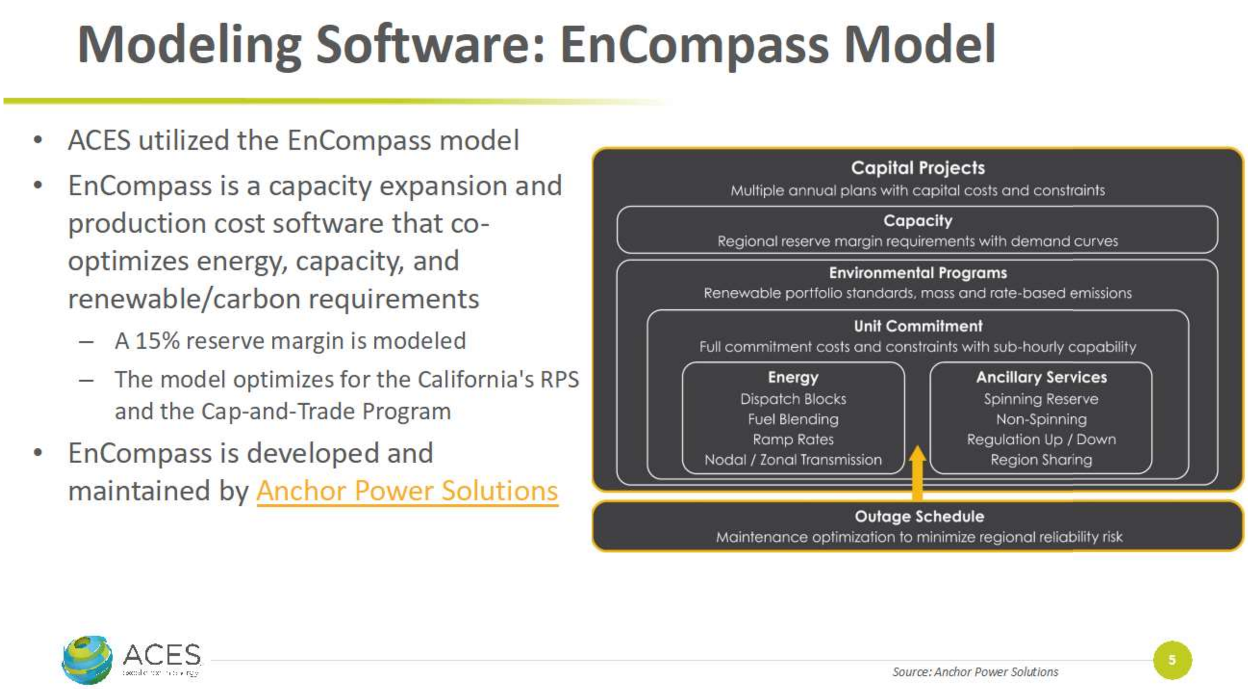


Figure 9: Modeling Software: EnCompass

The production cost model buys and sells energy in the spot energy markets of Southern California as necessary to meet all objectives, subject to municipal policies and physical limits. Figure 10 shows the topology used in the model. Resources are assigned to three zones: CAISO spot market, Pasadena's Remote Resources, and Pasadena's Local Resources. Connections between the zones are limited by municipal policies and existing infrastructure.

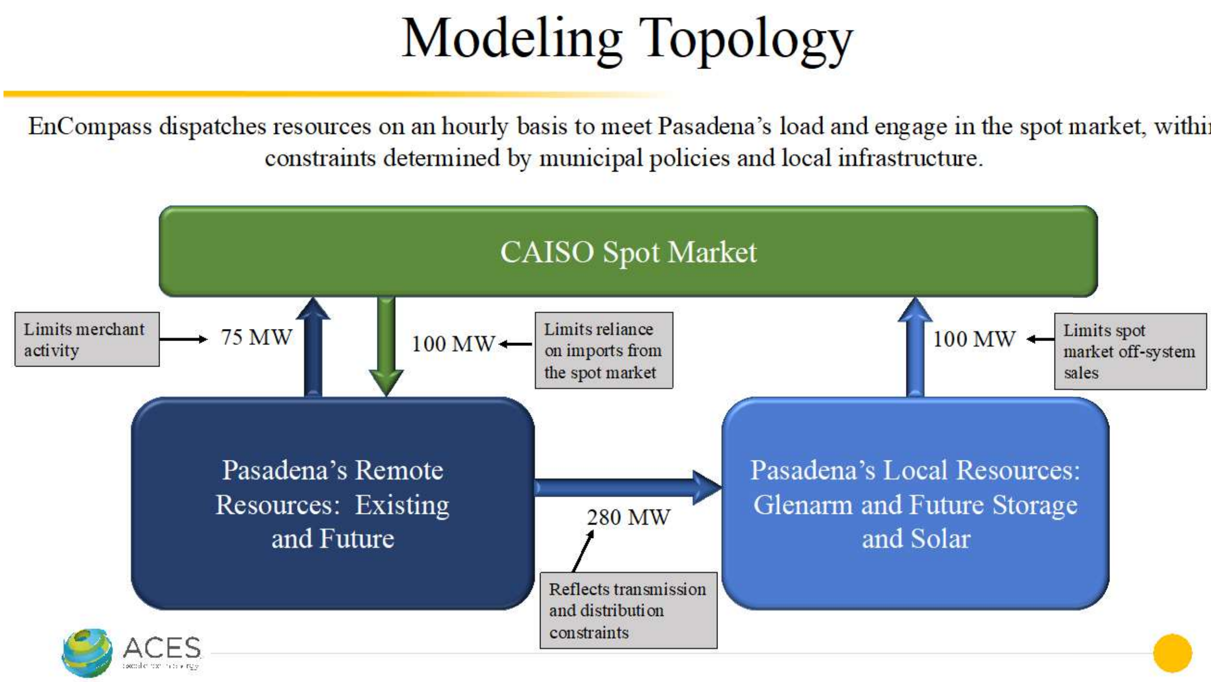


Figure 10: Modeling Topology

Sales by Pasadena's resources outside the City into the CAISO are limited to 75 MW/hour, so that the model does not add new resources to the PWP portfolio mainly or solely to earn revenues from sales to others. Imports of spot market energy from the CAISO are limited to 100 MW/hour and exports from Pasadena's local resources into the CAISO spot energy market are limited to 100 MW/hour, to manage the risk of short-term markets. Additionally, imports from all sources into Pasadena are limited to 280 MW/hour, to recognize the ability of the local distribution system to handle imports at the T.M. Goodrich interconnection.[7]

The modeling inputs restrict the potential new sources of energy to renewables and storage, as was assumed in the 2018 IRP. That is, the model does not have the option to add *any* new fossil-fuel generators to the PWP portfolio during the study period.[8] The existing Intermountain Power Project (IPP) contract expires in mid-2027, and the debt service and site license for Magnolia Power Plant (Magnolia) are assumed to end in mid-2036. The local Glenarm Power Plant units are assumed to continue operating through the study period in order to meet local reliability requirements, perhaps using non-fossil fuels such as biogas or hydrogen.

b) Portfolio Background Information

PWP modeled two portfolios of resources. The Preferred Portfolio selected from the 2018 IRP was re-modeled in EnCompass as the 2018 Refresh Portfolio (2018 Refresh), and the new 2021 Update was constructed.[9] Table 1 summarizes the main differences between the two portfolios.

Comparison of Portfolios Modeled in the 2021 Update	
2018 Refresh	**2021 Update**
Start with the results of the 2018 IRP	Do not constrain analysis by the 2018 IRP
Build only those new resources forecasted during 2019-39 from the 2018 IRP	Build least-cost mix of new resources to meet all requirements (RPS, GHG, reliability)
Magnolia shuts down in mid-2036; allow existing contracts to expire	Magnolia shuts down in mid-2036; allow existing contracts to expire[10]
Dispatch SCC+SB100 portfolio from 2018 IRP with updated inputs	Dispatch new portfolio with updated inputs
Pay penalties to CAISO for violations of new capacity requirements	Avoid most penalties imposed by CAISO for system RA obligations by building and acquiring new capacity
Study period: 2022-39	Study period: 2022-49

Table 1: Comparison of Portfolios Modeled in the 2021 Update

In the 2018 IRP, study period was only until 2039 and did not cover 2045, the deadline for net zero-carbon standard.[11] EnCompass achieves zero-carbon during the entire 2045 calendar year, with the assumption that Glenarm Power Plant is repowered to run after 2045 if necessary to meet local reliability requirements using biofuel or hydrogen.

c) Modeling Changes from 2018

Major updates to the model's inputs for both the 2018 Refresh and 2021 Update Portfolios include:

- ⇨ the social cost of carbon (SCC),
- ⇨ prices of natural gas and spot market energy in Southern California,
- ⇨ retail loads,
- ⇨ resource performance (capacity, energy, and hour output),
- ⇨ demand response (DR) as a capacity resource,
- ⇨ multiple local and remote storage options,
- ⇨ costs of new resources,
- ⇨ resource options,
- ⇨ capacity accreditation rules, and
- ⇨ carbon allowance prices.

Table 2 summarizes major differences between the 2018 IRP and this 2021 IRP Update.

Comparison of the 2018 IRP and 2021 IRP Update		
	2018 IRP	**2021 IRP Update**
Study Period	2019- 2039 (20 years)	2022-2049 (27 years)
Peak Load Forecast	Pace-Siemens using econometric analysis of historical loads	ACES using PWP's energy load forecast and historical hourly load shapes
Energy Load Forecast	Pace-Siemens using econometric analysis of historical loads	PWP using recent history
Model	Aurora XMP	EnCompass
Existing Resources	See Table A1 (appended)	Heber South geothermal contract terminated; Coso geothermal added
New Resources	Wind, biomass, geothermal, solar/storage hybrids; no distributed resources or distributed storage; no demand response (Exhibit 14)	Wind, utility-scale and distributed solar; geothermal options after 2023; storage options; solar/storage hybrids; demand response

Table 2: Comparison of 2018 IRP and 2021 IRP Update

IV. Projected Retail Loads

a) Retail End-Use Consumption

The annual peak and energy load forecasts for this 2021 IRP Update were prepared by PWP, combining the forecasts used in 2018 with recent actual peak and energy loads. PWP's actual loads have been lower than the projections made in the 2018 IRP. Energy loads are a function of multiple factors (see Table 3):

Major Determinants of Energy Consumption in Pasadena
Weather: heat storms drive up consumption
Economic conditions: occupancy rates of residential and commercial real estate fluctuate
Effects of the pandemic: commercial closures, shift to work-from-home, changes in work and commuting patterns
EV adoption rates: incentive programs and costs change over time
Consumer behavior: thermostat settings trends
Building retrofits: appliance replacements, new windows, new HVAC systems
Codes and standards: new buildings are more efficient than those torn down[12]
Energy efficiency programs: reduce consumption

Table 3: Major Determinants of Energy Consumption in Pasadena

ACES Power Marketing LLC (ACES) began with an energy forecast developed by PWP and added ACES' forecast of EV energy consumption. The monthly peak load forecast was prepared by ACES to include peak EV consumption and for dispatch based on an hourly load shape; the adjustment for hourly load shapes increased some monthly peak load amounts. PWP must meet the capacity planning standards of the CAISO: owned or acquired capacity resources sufficient to meet forecasted retail peak load at the time of the peak load in the entire CAISO (a.k.a., "coincident peak") plus a Planning Reserve Margin (PRM) of 15% of that coincident peak. Figure 11 shows the resulting annual peak load for planning (in MW).

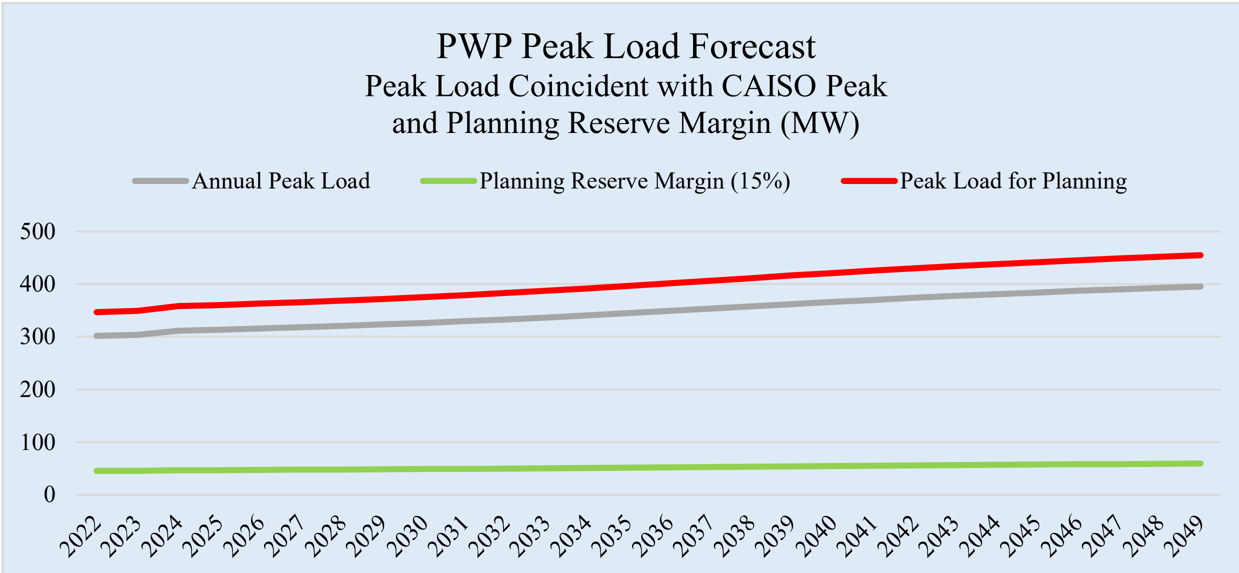


Figure 11: PWP Peak Load Forecast with PRM

For comparison, Figure 12 shows historical and forecasted peak loads, without the planning reserve margin (MW).

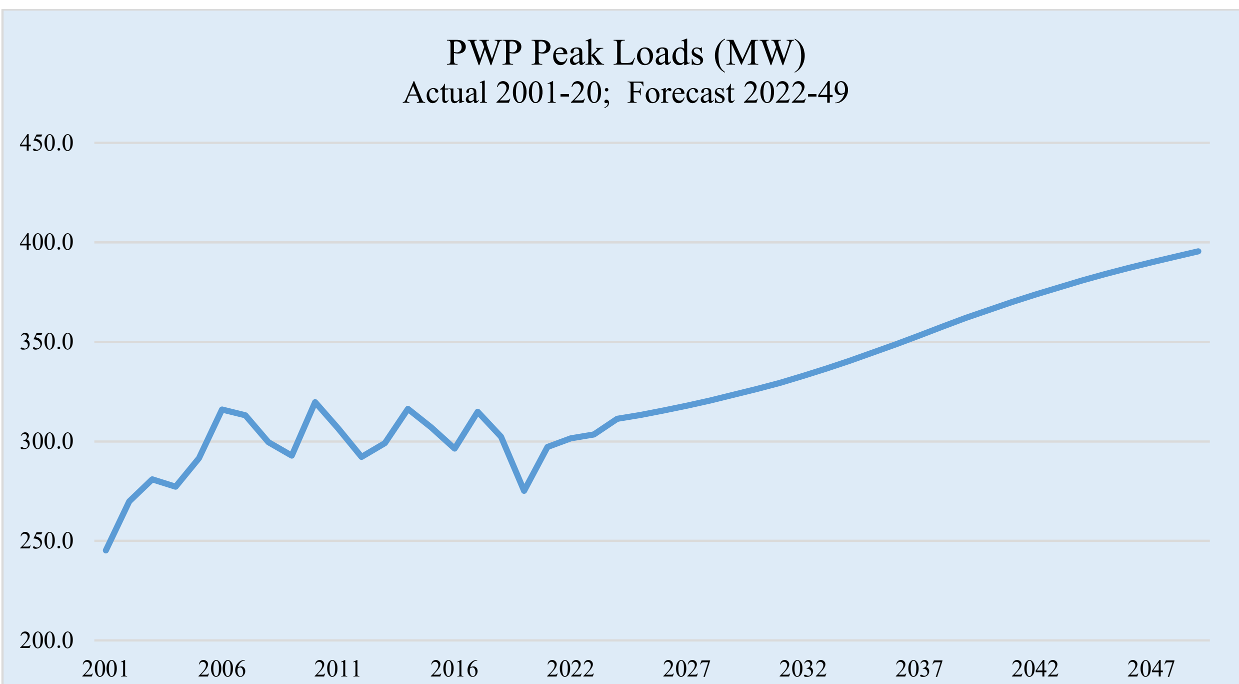


Figure 12: PWP Peak Loads, Actual and Forecast (MW)

Loads for planning purposes are measured at the point of interconnection between Pasadena and Southern California Edison (the T.M. Goodrich substation), to ensure that sufficient power is available locally to cover end-use loads and the energy lost when energy is distributed throughout the City. The sum of loads at retail meters and losses in the distribution system is Net Energy for Load (NEL) (or "System Load") used for planning. Figure 13 shows the forecasted energy loads in gigawatt hours (GWh) where a unit of energy represents one billion watt hours, with EV energy charging separately identified.

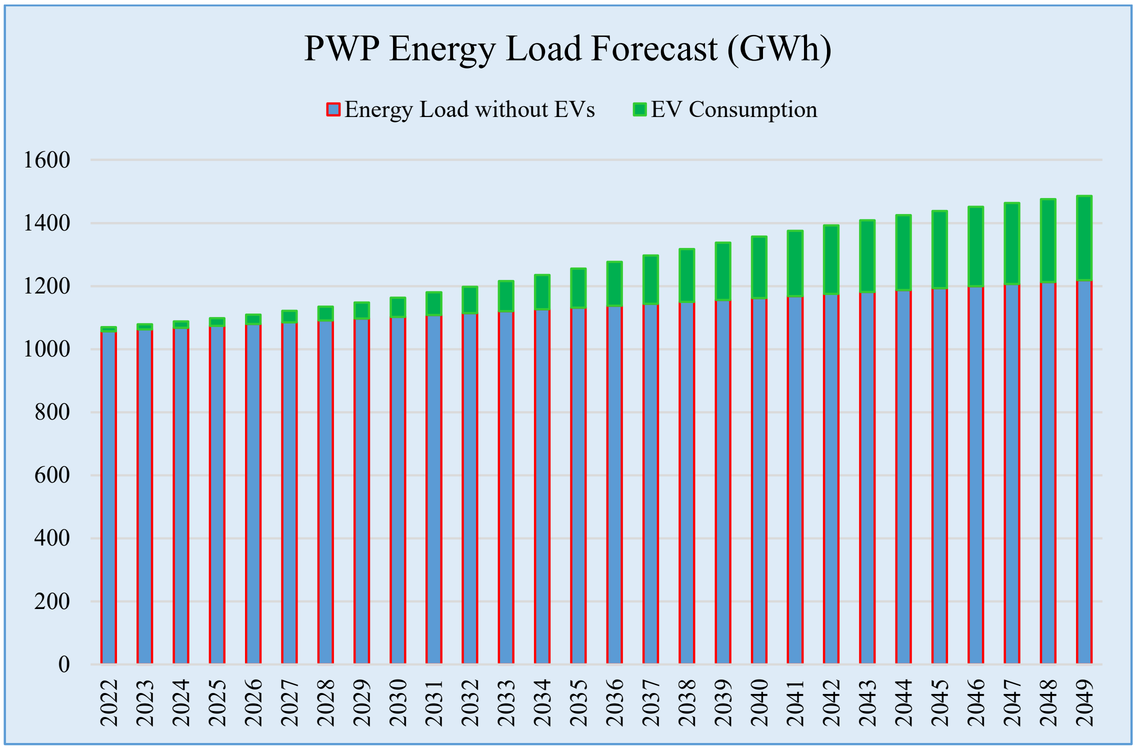


Figure 13: PWP Energy Load Forecast (GWh)

For comparison, Figure 14 shows historical and forecasted total energy loads, the latter with and without forecasted growth of EV charging. Energy loads have been declining for the last decade, but are forecasted to rise with the shift to EVs, a return to more-normal local economic activity, and efforts to promote electrification/decarbonization.[13]

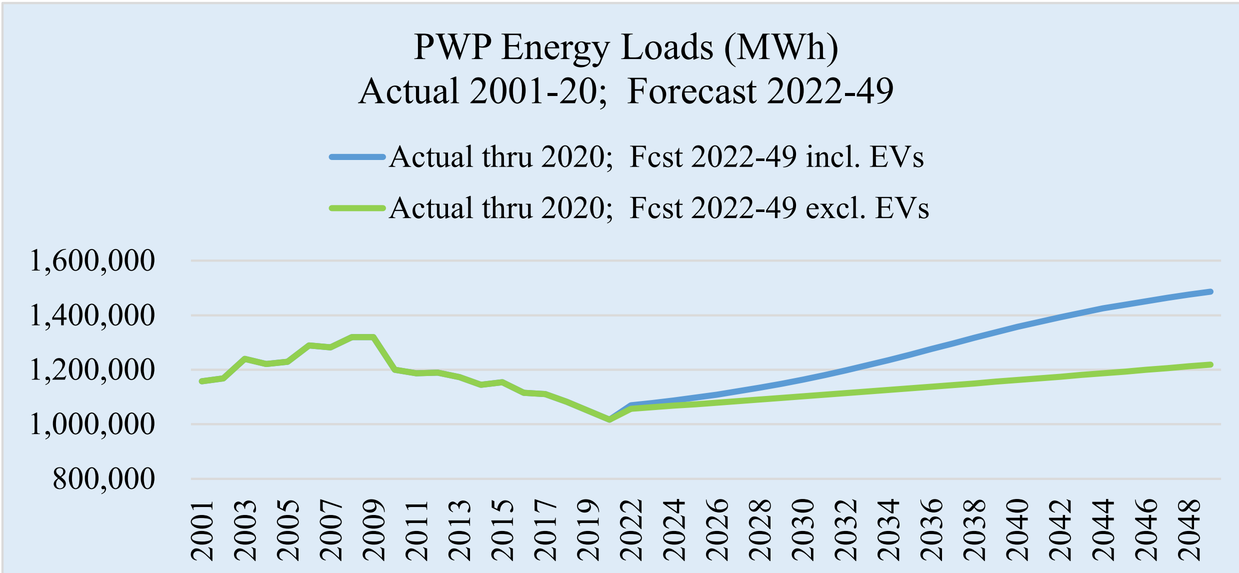


Figure 14: PWP Energy Loads, Actual and Forecast (MWh)

ACES used recent historical "hourly load shapes" (i.e., one value for each hour) to convert the monthly energy load forecasts into hourly loads for production cost modeling; projected hourly load shapes for the study period are shown in Figure 15. Growth in electric vehicle charging, electrification and active load management (demand response) are expected to change and probably flatten the hourly load shape.

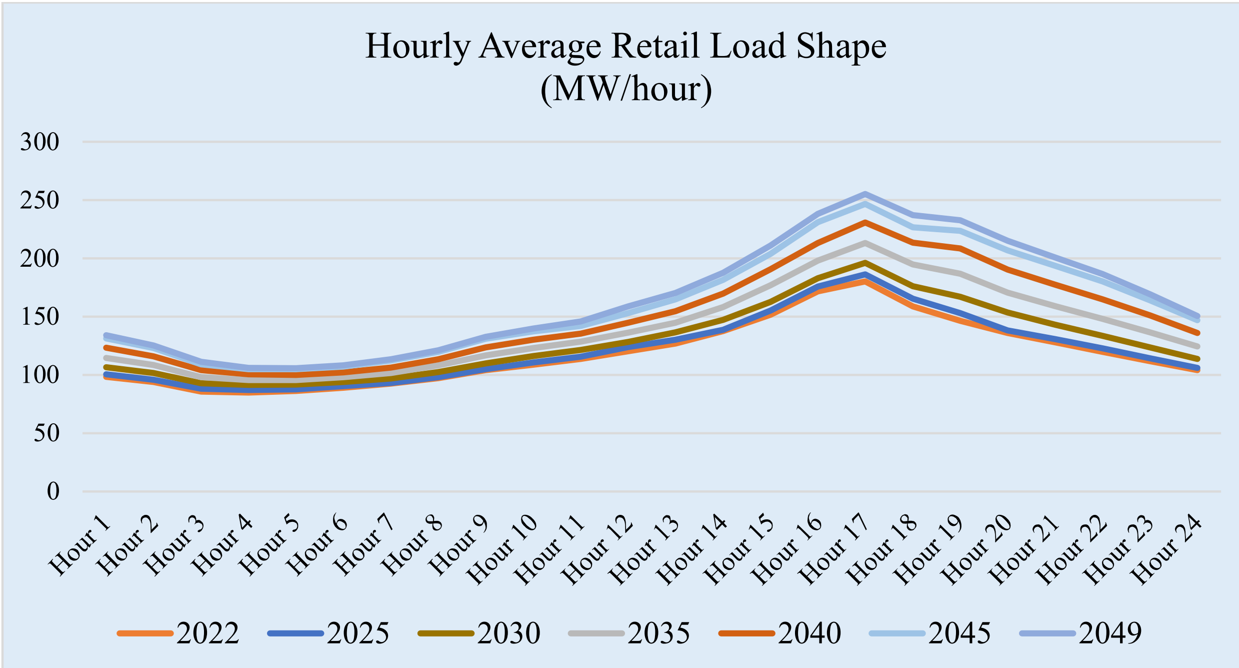


Figure 15: Retail Load Shape (MW/hour)

b) Energy Efficiency and Demand Response Programs

Pasadena has operated energy efficiency (EE) and demand-side management (DSM) programs for several years, with the goals of increasing the efficiency of energy consumption and reducing emissions associated with generating electricity. The goals for FY22-31, adopted in May 2021, are 11,720 Megawatt-hours (MWh)/year in energy savings and 1.8 MW/year in demand reduction, based on the application of analyses for California Municipal Utilities Association (CMUA). Figure 16 provides the projected energy savings from 2022 through 2031.[14] Codes and standards include local, state, and federal requirements for buildings, appliances, and devices that use energy.

Cumulative Ten-Year Net Market Potential Energy Savings

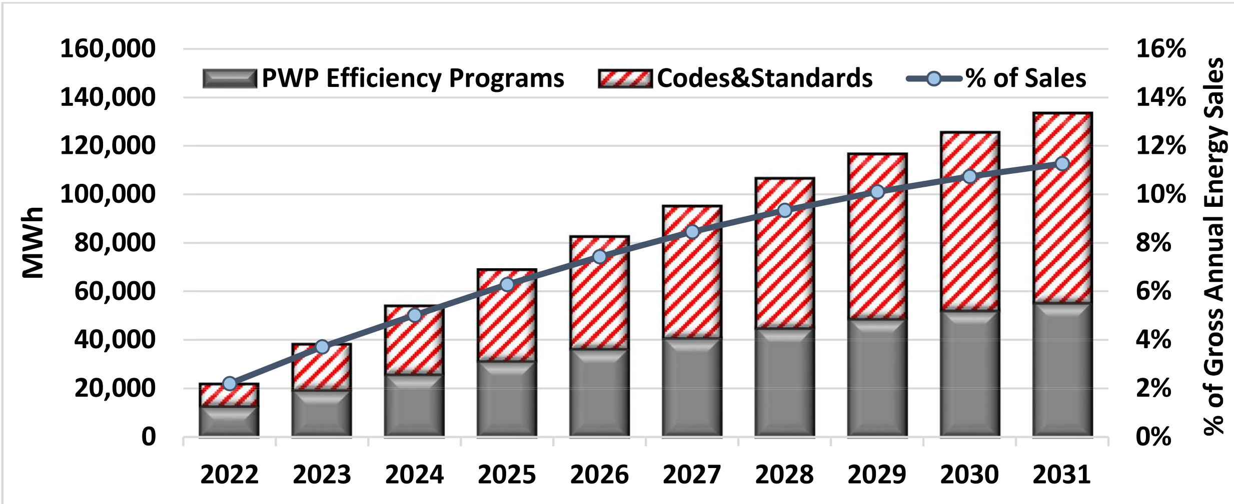


Figure 16: Cumulative Potential Energy Savings

EE and DSM are traditionally incorporated into IRPs by reducing the load forecast to recognize the expected savings. The 2022-23 IRP will consider modelling EE/DSM/DR and distributed resources simultaneously with supply-side resources, because paying for EE/DSM/DR programs may be less expensive than paying for energy. This combination of the demand- and supply-sides would also apply the same SCC to all programs and resources, using the federal standard for SCC rather than two different methods (CMUA for EE/DSM/DR and federal for the IRP). EnCompass models the firm capacity of demand-side programs as reductions in peak load and planning margin (both in MW). Table 4 provides an illustration of these effects.

Effect of DSM on Planning for System Peaks		Planning Reserve Margin (%)	Planning Reserve Margin (MW)	Forecasted Peak to Meet Planning Standards
Forecasted Peak Load	300 MW	15%	45 MW	345 MW
Demand Response	5 MW			
Peak Load Net of DR	295 MW		44.25 MW	339 MW

Table 4: Effect of DSM on Planning for System Peaks

V. Environmental Inputs and Mandates

a) Cap-and-Trade Compliance

PWP's resource portfolio must comply with state regulations governing greenhouse gas (GHG) emissions in Senate Bill 32 (SB 32). PWP must surrender or retire one carbon allowance for each metric tonne (MT) of CO_2e emitted at PWP's power generators. PWP receives "allocated carbon allowances" from the state and can buy and sell allowances in the carbon market.[15] PWP's retail consumers pay rates that cover the cost of purchased carbon allowances net of revenues from the sale of allowances. Carbon allowances, allocated and purchased, have an opportunity cost if surrendered for compliance in a given year, because they can also be sold and/or banked for future compliance. PWP has both bought and sold carbon allowances depending on its own operations and conditions in the carbon allowance market.

Any fossil-fuel energy sold into wholesale markets must receive prices high enough to cover PWP's variable costs of fuel and Operating and Maintenance (O&M), plus the cost of surrendering carbon allowances to the state; the cost of surrender takes into account the then-current price of such allowances as set in the regular allowance auctions and the secondary market for allowances. EnCompass modeling outputs indicate that actual PWP emissions will be significantly lower than allocated allowances throughout the planning horizon.[16]

For perspective, Figure 17 shows PWP's historical emissions for 1990 and 2013-20.[17] By 2020, PWP's emissions had fallen by over 50% from 1990 levels.

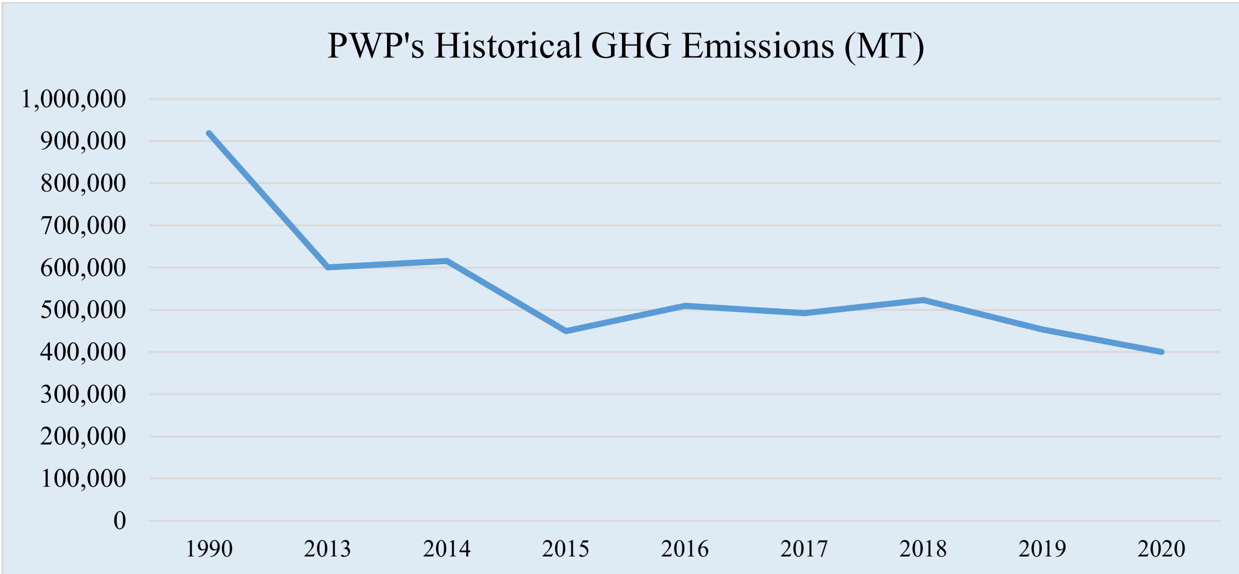


Figure 17: PWP's Historical GHG Emissions (MT)

In order to help manage the transition to zero carbon by the end of 2045, California allocates carbon allowances to entities such as PWP that have obligations to deliver energy to retail customers. The 2021 IRP Update uses California Air Resources Board's (CARB) current projection of reductions in allocated allowances to PWP as of 2020. PWP does not anticipate significant financial or operational impacts due to the reduction in allocated allowances. The IPP in Utah is scheduled for conversion from coal to natural gas in mid-2025, reducing PWP's emissions from fossil-fuel energy, and PWP's existing contract with IPP will terminate in mid-2027.[18] Allocated allowances are projected by CARB only through 2030, and then PWP assumed a straight-line trajectory of allocated allowances and emission reductions from 271,000 metric tonnes in 2030 to zero by the end of 2045 in order to meet the zero-carbon standard in SB 100. Figure 18 shows the forecast of allocated allowances.

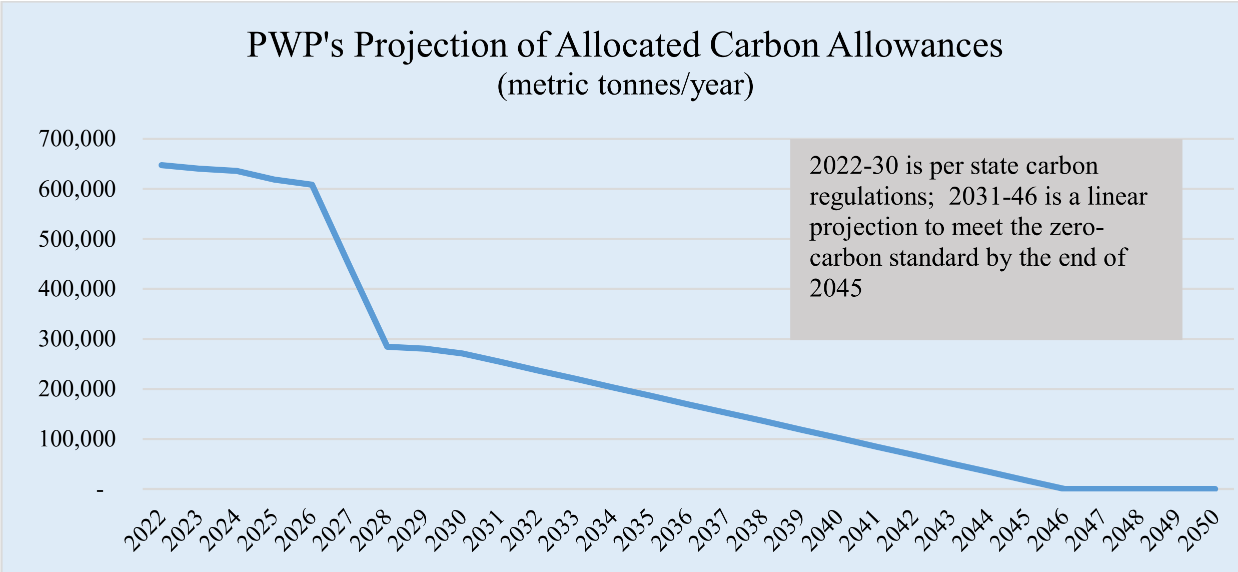


Figure 18: PWP's Projection of Allocated Carbon Allowances

b) Social Cost of Carbon: Policy and Planning Tool

PWP's municipal policies include directives to consider environmental impacts and reduce carbon emissions, and state policies mandate emission reductions in the electricity sector. This 2021 IRP Update constrains forecasted fossil-fuel emissions by imposing a Social Cost of Carbon (SCC) on hourly dispatch in the model. SCC is a measure not of the cost of compliance in California, but of the global cost of carbon emissions.[19] Table 5 summarizes the process for projecting the SCC.

Social Cost of Carbon	
Technique	Map global temperatures and physical effects of climate change into market and non-market damages
Damages	Include but are not limited to: declines in agricultural productivity, negative impacts on human health (e.g., increased mortality and morbidity), property damage (e.g., floods, fires), disruption of energy supplies, rising conflict and political destabilization, migration due to environmental change, lost value of ecosystem services, changes in trade and tourism, damage to transportation infrastructure, loss of biodiversity
Models	Integrated Assessment Models (IAMs), which project combined global climate processes and the global economy[20]

Scenarios	To address uncertainty, allow basic inputs to IAMs to vary: population growth, macro-economic conditions (GDP), GHG emissions growth rates, climate sensitivity (how fast and how far the climate changes due to GHG emissions), and interactions between climate and the economy
Metric	For each year, the present discounted value of the global cost of future emissions
Discount rates	2.5%, 3%, 5%; fixed/variable rates; lower discount rates value the future more than higher discount rates

Table 5: Social Cost of Carbon

Projections of global economic costs include both "market damages" and "non-market damages", and are based on the operation of IAM models that project environmental and economic impacts. Market damages include changes in agricultural productivity, energy use, property damage due to flooding, and reductions in water quality; non-market damages include the estimated lost value of services that natural ecosystems provide to society.[21]

Each year in the study period has its own SCC value; the SCC rises over time as the amount of long-lived carbon emissions in the atmosphere increases and causes more damage. Figure 19 shows three projections of the SCC by the federal government. In this 2021 IRP Update, PWP uses the highest projection: the 95th percentile of all values in each year, with a three percent discount rate.

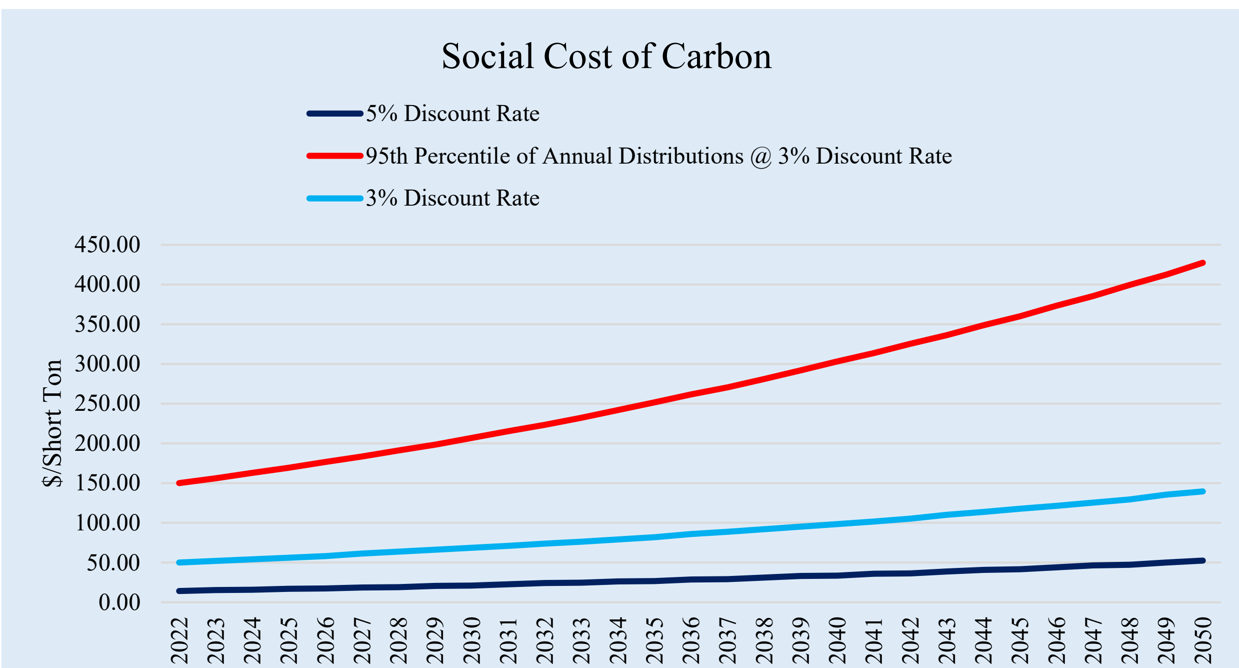


Figure 19: Social Cost of Carbon as of 2021

The model only dispatches fossil-fuel energy into the wholesale market if the price of energy exceeds the sum of the fuel cost, variable O&M cost, and the SCC. For example, in 2022 the forecasted spot market energy price must be high enough to cover all of IPP's fuel and variable O&M costs, plus $142/MWh for SCC, or IPP coal-fired generation will not be dispatched into spot wholesale markets. For planning purposes, the SCC is a "dispatch penalty" on PWP's fossil-fuel power plants, which results in a reduction of fossil-fuel generation for off-system sales.

Table 6 compares the cost of dispatch (in $/MWh) using (a) allocated California carbon allowances with an opportunity cost of $20/MT and (b) the SCC dispatch penalty at $150/MT. For example, coal-fired generation may be sold into the wholesale market if the price exceeds $40.91/MWh using the opportunity cost of a carbon allowance, but the SCC pushes that break-even threshold up to $163.84/MWh.

Cost of Dispatching PWP Fossil-Fuel Resources: SCC v. Cap/Trade				
Plant	**CO2e Emission Rate (MT/MWh)**	**Cost of Dispatch with Cap/Trade = $20/MT ($/MWh)**	**Dispatch Penalty with SCC = $150/MT ($/MWh)**	**Modeled Cost of Dispatch with SCC Penalty ($/MWh)**
IPP (coal)	0.95	$ 40.91	$ 141.84	$ 163.84
IPP (gas)	0.36	$ 27.75	$ 54.44	$ 74.94
Glenarm – 1	0.80	$ 65.99	$ 119.93	$ 169.93
Glenarm – 2	0.77	$ 69.79	$ 116.24	$ 170.53
Glenarm – 3	0.64	$ 54.90	$ 95.69	$ 137.83
Glenarm – 4	0.64	$ 55.34	$ 95.96	$ 138.51
Glenarm – 5	0.61	$ 50.45	$ 91.49	$ 129.75
Magnolia	0.41	$ 33.36	$ 61.53	$ 86.69

Table 6: Cost of Dispatching PWP Fossil-Fuel Resources: SCC v. Cap/Trade

In actual daily operations, PWP determines whether its owned and contracted generation that is not needed for retail loads can economically be sold into the wholesale market (a.k.a., "off-system sales") to generate revenues (net of variable costs) that reduce PWP's retail rates;

operationally, PWP compares spot market prices with the variable cost of production, including fuel, variable O&M costs, and carbon compliance costs. If carbon is emitted due to the wholesale sale, PWP must surrender the corresponding carbon allowances to the state, and retail customers must pay for those allowances, so the California carbon allowance price is used for actual dispatch.

For planning purposes, PWP assumes that the SCC, *instead of the California carbon allowance price*, must be "paid" from the revenues received from the wholesale markets. That is, the projected wholesale price must be high enough to cover all variable costs incurred in actual dispatch *plus* the SCC. The SCC penalty thus reduces off-system sales on a planning basis; if actually implemented, the SCC would reduce emissions and increase PWP's retail rates due to the loss of off-system, wholesale revenues. These impacts are discussed in the review of modeling results later in the report.

c) Renewable Portfolio Standards

In compliance with the state's RPS, PWP will generate an increasing share of its total retail consumption of electricity from zero-carbon resources, including wind, solar, eligible hydro, biofuel and geothermal sources. Figure 20 shows the combination of existing RPS requirements through 2030 and a projected ramp up to zero-carbon by the end of 2045. RPS regulations adopted in July 2021 by the CEC specify that 60 percent of the energy required to serve Net Retail Sales be certified renewable under California law in and after 2030.[22] For planning purposes, PWP assumes that additions of renewable resources to the power supply portfolio will rise after 2030 in a linear manner to reach the zero-carbon standard in 2045.

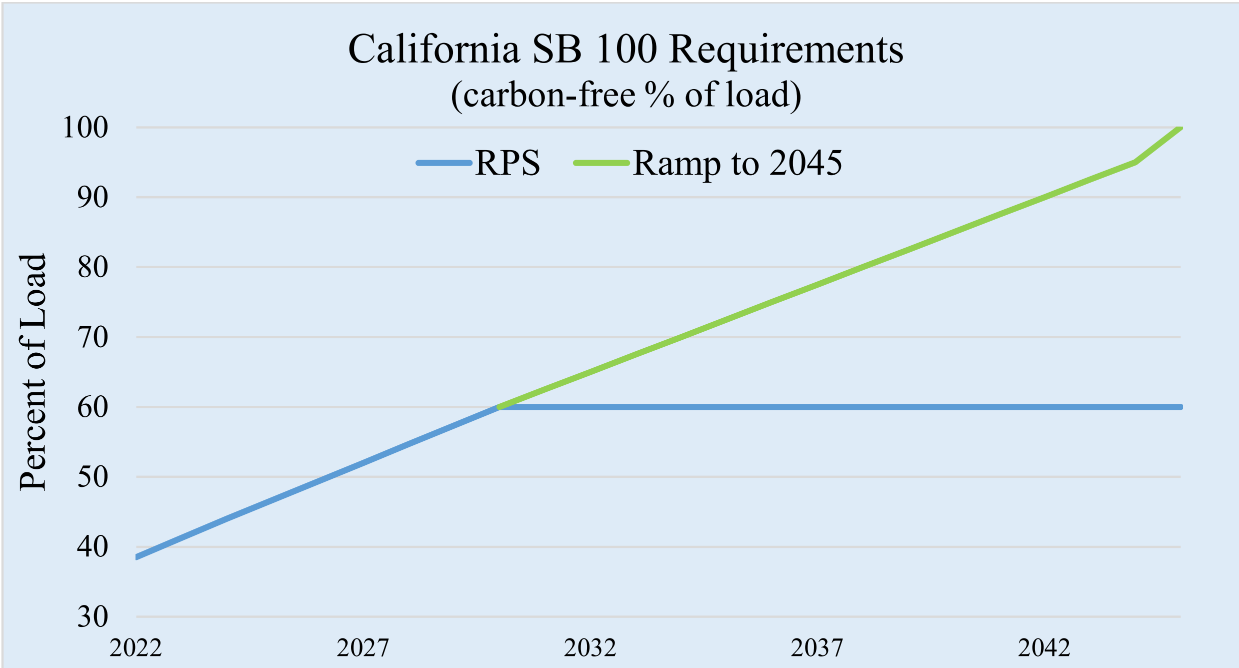


Figure 20: Requirements of SB 100

RPS requirements are met through eligible existing renewable energy contracts and incremental resources determined by the production cost model. Four categories of renewable resources and financial transactions are eligible for RPS compliance: Portfolio Content Categories (PCC) 0, 1, 2 and 3. During the study period, PWP relies on known, existing renewable resources, as well as a contract that delivers 70,000 PCC1 Renewable Energy Credits (RECs) annually through 2030 and 40,000 PCC2 RECs in 2022.[23] Table 7 defines the three PCCs. Renewable resources that pre-date state RPS requirements "count in full" as PCC0 (a.k.a., "grandfathered"). Table 8 shows the compliance obligations by PCC over time.

RPS Compliance Categories for Non-Grandfathered Renewable Resources		
PCC1	**PCC2**	**PCC3**
Resource is connected to the grid at a California balancing authority, or Out-of-state generation is scheduled to a California balancing authority Energy is delivered "as generated" Highest RPS value Example: Renewable project in California	Resource is connected to the grid outside a California balancing authority, and Seller delivers substitute energy to Buyer Energy is delivered but not "as generated" Medium RPS value Example: Washington wind project; energy is stored as potential hydropower, then delivered to a California utility; delivery occurs in an hour different from the hour of generation; a.k.a., "firmed and shaped"	Renewable Energy Credits (RECs) unbundled from renewable energy RECs are transferred to Buyer without any energy Energy is not delivered Lowest RPS value Example: Contract executed in June 2021 for RECs associated with renewable energy generated in 2020

Table 7: RPS Compliance Categories for Non-Grandfathered Renewable Resources

California RPS Mandatory Procurement Requirements, by Year and by PCC (% of Net Retail Sales)				
	Compliance Period 4	**Compliance Period 5**	**Compliance Period 6**	**Compliance Period 7+: 2031 and after**
	CY 2021-24	CY 2025-27	CY 2028-30	CY: 2031-33 (and following)
	44% by 12/31/24	52% by 12/31/27	60% by 12/31/30	60%

PCC 1 Minimum	75% or more of Procurement Requirement			
PCC 2 Maximum	25% or less of Procurement Requirement (capped at 15% to maximize PCC3)			
PCC 3 Maximum	10% or less of Procurement Requirement			
Long-Term Contract Requirement	Minimum 65% must be long-term contracts; at least 10 years or more			

Table 8: California RPS Mandatory Procurement Requirements, by Year and by PCC

Eligible new renewable resources include wind, solar, geothermal, and hybrid resources.[24] PCC3 RECs are not modeled in EnCompass because they are purely financial transactions. Operationally, PWP transacts in both PCC2 and PCC3 compliance instruments, subject to state regulations. The modeling in this 2021 IRP Update represents a conservative (high) cost of compliance because opportunities to use PCC2 and PCC3 are not modeled.

Over the 2022-49 study period for the 2021 Update, annual renewable energy credits (RECs) do not always exactly equal the percentages required under current regulations, but over that same period this portfolio shows projected overall compliance via banking, with a small REC surplus at the end of 2049. RPS compliance is also not an annual obligation, but is measured using a three-year compliance period. Banking means retaining unneeded allowances for future compliance, within limits defined by state regulations as to the PCC, the acquisition period, and the compliance period.

PWP's current RPS compliance plan incorporates banking.[25] EnCompass abstracts from many of the details of actual compliance, but is designed to ensure the addition of renewable resources sufficient over time to meet existing RPS and carbon requirements and targets. Actual compliance each year is a more detailed exercise performed by PWP staff and subject to review and attestation by PWP management.

VI. Other Assumptions, Inputs and Market Conditions

a) Forecasts of Natural Gas, Coal and Spot Market Energy Prices

Through mid-2025, PWP will import coal-fired electricity from the IPP in Utah, from mid-2025 to mid-2027, PWP will import gas-fired electricity from the new replacement power plant. Through mid-2036, PWP will generate with natural gas from its share of the Magnolia plant in Burbank and through the study period from the Glenarm units in Pasadena, with biofuel or hydrogen assumed to be burned at Glenarm after zero-carbon deadline of 2045, but not explicitly modeled given the lack of reliable data for those fuels.

PWP will also import energy from the Southern California spot market. EnCompass uses industry-standard forecasts of gas and spot market energy prices in Southern California through 2049 and PWP's forecast of the cost of coal and natural gas energy from IPP in Utah through mid-2027.[26]

b) Generic Solar/Wind/Geothermal/Storage Resources

The production cost model adds generic renewable resources to PWP's portfolio in order to meet several criteria, including RPS compliance, cost and reliability. In this 2021 IRP Update, the model can choose from an array of zero-carbon options: wind, solar, storage, hybrid plants (e.g., solar/storage), demand response, and geothermal.

Each resource type has expected cost and performance profiles.[27] All new resource options are assumed to be located in the CAISO. New solar, wind, hybrid resources, and geothermal contribute to meeting RPS requirements. Resources count towards system capacity at their accredited values. The following resource options are available to EnCompass.

Wind

- Installed capital costs and fixed O&M costs are taken from the National Renewable Energy Laboratory's (NREL) 2020 Annual Technology Baseline (ATB) Class 6 mid-range cost assumptions and IHS Markit for California.[28]
- Projected costs incorporate the Production Tax Credit (PTC), including the 40% safe harbor extension in 2024, the 60% safe harbor provision in 2025, and expiration in 2026.

- Wind is modeled in five MW blocks, to represent PWP participation in larger projects via the Southern California Public Power Authority (SCPPA).

Solar

- All solar
  - Installation and fixed O&M costs are taken from IHS Markit and NREL's ATB.[29] Investment Tax Credits (ITC) reduce installed cost.
  - For utility-scale and commercial solar, the ITC declines from 30% in 2022-2023 to 26% in 2024-2025 and then to a permanent 10%.
  - For residential solar, the ITC declines from 26% in 2022 to 22% in 2023 and then expires.
- Utility-scale solar
  - Located outside of Pasadena.
  - Modeled in five MW blocks to represent PWP participation in larger projects via SCPPA. Commercial and residential solar are modeled at two MW and one MW respectively, representing the aggregation of small distributed resources.
- Distributed solar
  - Located only within Pasadena's service territory.
  - Provides de-rated firm capacity and reduce the amount of required reserves.[30]
  - Costs are averages of data from IHS Markit and NREL's ATB.
  - Avoid five percent losses on the distribution system (not modeled).

Storage (4- and 8-hour lithium-ion batteries)

- The four-hour batteries use costs for five MW and 50 MW options from IHS Markit; the model can build five MW and 25 MW units. The eight-hour duration batteries are modeled as 25 MW projects.
- The fixed O&M cost of storage is 2.5% of initial capital costs.[31]
- All batteries have a five percent forced outage rate, an 88 percent roundtrip efficiency, and are limited to an average of one full daily discharge cycle per week to mimic existing contract provisions. The discharge assumption is the equivalent of a 15% capacity factor for the batteries (one full day of discharge/week is a discharge of energy equal to one-seventh of the capacity of the battery, or about 15%).
- Storage can be located anywhere in the CAISO.

Geothermal

- Six technologies are modeled using data from NREL's ATB. Installation costs and fixed O&M costs come from NREL's "moderate" assumptions.[32]
- Components have a forced outage rate of five percent.
- Geothermal is "must-run" and "must-take": these units operate as baseload power supplies that are not dispatchable, but yield high capacity factors and capacity accreditation.
- Flash and binary technologies have annual capacity factors of 90 percent and 80 percent, respectively.
- Geothermal technologies are only available outside Pasadena in the CAISO.
- Geothermal is modeled as 25 MW blocks, representing PWP participation in larger projects via SCPPA.

Solar/Storage Hybrid Projects

- Hybrid storage is modeled to charge from adjacent solar as necessary to earn tax credits, and then generic energy from the grid. Charging with "generic grid energy" may be an option, but could affect carbon compliance, depending on CARB regulations, the configuration of metering, partially jeopardize ITC funding, and the carbon content of grid energy.
- The fixed O&M cost of storage is reduced by 20 percent when combined with solar.[33]
- Hybrid resources can be located both inside and outside Pasadena's service territory.
- The hybrid project is a ten MW solar plant with a five MW battery.
- Storage should help "smooth out" the hourly generation profiles of wind and solar.[34]

Different technologies have different hourly generation profiles, as shown in Figure 21, which must be taken into account when projecting hourly dispatch of resources to meet retail loads. A comparison of Figures 15 and 21 shows that the hourly shapes of generation do not match the hourly shape of loads. The vertical axis in Figure 21 below is the modeled hourly generation shapes expressed as a percentage of installed capacity at the plant.

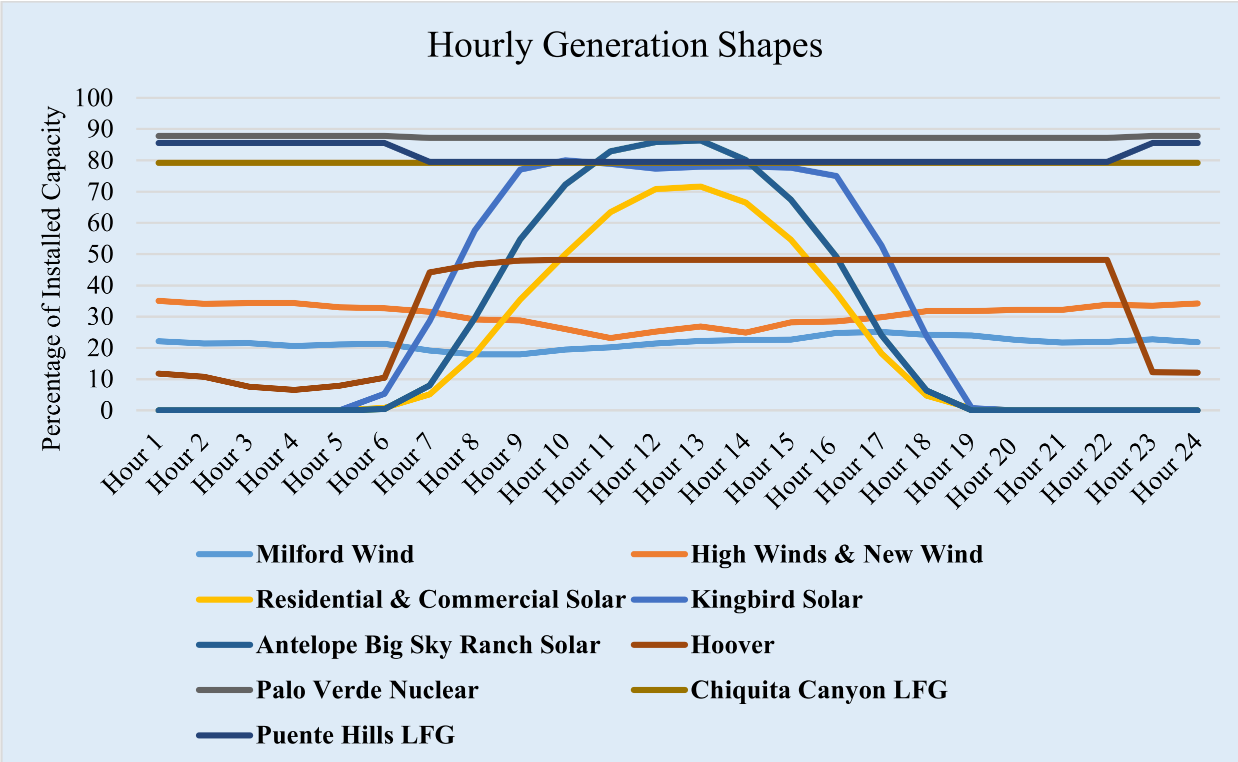


Figure 21: Hourly Generation Shapes

c) <u>Demand Response Programs</u>

PWP may develop Demand Response (DR) programs to purchase load reductions from its retail customers. These programs would pay customers to reduce or shift their consumption as controlled by PWP during heat storms or to help maintain frequency and voltage in the distribution system. Two types of DR resources are modeled as options that the model can pick if they are cost-effective: interruptible load and shifts in cooling loads.

Interruptible load means that certain retail customers have agreed that energy may not be delivered during certain high demand periods, and that they will be compensated for providing this service to PWP. Interruptible loads may include building energy management systems, control of individual loads, and breakers on specific circuits (e.g., refrigeration, heating, hot water, cooling, individual appliances, pool pumps, and EVs). In order to provide capacity value, it is likely that the interruptibility of retail loads will be fully automated and subject to control by PWP.[35]

Shifts in cooling load assumes that the same amount of energy is delivered, but that the timing of delivery shifts away from peak or super-peak periods. Load shifts are most likely changes in the timing of energy delivered for cooling.

ACES adapted the Los Angeles Department of Water & Power's (LADWP) 100% Renewable Energy Study ("LA100", March 2021) as follows.[36]

- DR resources are assumed to be available each year in Q3 (July-September) in one MW blocks, representing the aggregation of smaller resources.[37]
- Interruptible load and shifted load (commercial and residential cooling) are assumed to be aggregated into one MW blocks by 2025 to reflect the time and cost of systems necessary to develop such a program and because EnCompass builds and dispatches in whole megawatts.
- Customers are paid for reliable DR, and those payments (costs) must be recovered in retail rates. Costs are provided by PWP. Residential cooling, commercial cooling, and interruptible load are projected to cost $600/kW-year, $150/kW-year, and $300/kW-year in 2025, respectively, escalated annually at a projected inflation rate of two percent.
- Interruptible loads are limited to 48 hours per year, with no payback of energy.
- DR from residential and commercial cooling is assumed to shift energy usage daily.
- DR options have a five percent forced outage rate (i.e., a 95 percent availability factor) with one "start" or signal per day. Minimum "up time" is four hours.
- DR capacity is limited to reflect assumptions in the LADWP Study adapted to PWP's smaller scale.[38]

Table 9 shows the projected demand response capacity (in MWs) added in the 2021 Update.

Forecasted Peak Loads in Demand Response Programs

Year	Interruptible Load (MW)	Residential Cooling Load Shift (MW)	Commercial Cooling Load Shift (MW)
2025	4.9	10.7	2.3
2030	7.8	16.5	3.8
2035	7.7	20.1	5.3
2040	7.3	19.5	5.3
2045	7.3	17.2	5.3

2050	7.3	17.2	5.3

Table 9: PWP Peak Loads Projected for Demand Response Programs

d) Comparison of New Resources

Table 10 provides a comparison of selected new resources in 2025 which includes short-duration storage, hybrid solar/storage, and geothermal. This comparison shows that a variety of capacity factors, installed costs, and annual costs is forecasted to yield the least-cost portfolio. The Annual Energy Value in Table 10 indicates the market value of each resource, measured by the hourly prices at the point on the grid where the resource delivers energy. No one resource type is expected to meet all constraints while minimizing costs, and PWP expects to continue building a diverse portfolio of power supplies over time.[39]

Comparison of Selected New Resources in 2025			
Resource =>	**4-Hour Storage**	**Hybrid Solar/Storage (2:1)**	**Geothermal**
Installed Nameplate Capacity (MW)	25	Solar: 10 MW Storage: 5 MW	25
Annual Capacity Factor (%)	16%	41%	90%
Firm Accredited Capacity (%)	92%	35%	87%
Firm Accredited Capacity (MW)	23.0	5.3	21.8
Installed Cost ($/kW)	$1,036	$906	$5,005
Annual Fixed Cost of Capital ($/kW-year)	$167	$130	$476
Annual Fixed O&M Cost ($/kW-year)	$27	$150	$178
Total Annual Fixed Cost ($/kW-year)	$194	$280	$654

Annual Energy Value ($/kW-year)	($46)	($17)	($272)
Annual Revenue Requirement ($/kW-year)	$149	$263	$382

Table 10: Comparison of Selected New Resources in 2025

e) <u>Generic Financing Assumptions</u>

New power supplies may use private or public financing. For modeling, only debt is assumed to be used, and Power Purchase Agreements (PPA) with private developers are assumed for new resources, with the exception of demand response. Prices in PPAs are projected to cover the capital and operating costs of the plant using private financing, which includes the cost of debt (five percent), income taxes, insurance, property taxes, fixed O&M cost, net of investment tax credits (ITCs) and production tax credits (PTCs).

ITCs and PTCs are assumed to reduce the overnight capital cost that must be financed, and so are reflected in the PPA prices ($/kW-year). The annual cost of insurance is set at 0.5 percent of the overnight capital cost and property tax is 1.3 percent. New non-DR resources are 100% debt-financed at five percent with a book life for depreciation of 15 years. Payments for demand response are assumed to be expensed, not booked for amortization or funded with debt. Table 11 summarizes the financing assumptions used in EnCompass.

Financing Assumptions for Projects by Private Developers	
Capital structure	Debt only
Interest rate	5%
Tax credits	ITCs and PTCs under current law
Insurance	0.5% of overnight capital cost; incurred each year
Property tax	1.3% of overnight capital cost; incurred each year
Book life	15 years for all projects, for straight-line depreciation
Tax life	5 years for all projects, for accelerated depreciation
Fixed O&M (FOM)	Varies by technology
Composite tax rate	26.7%
Applicability	All resources except demand response
Annual cost to PWP	PPA price = debt service (on capital cost net of ITCs and PTCs) + taxes + insurance + FOM

Table 11: Financing Assumptions for Projects by Private Developers

Figure 22 shows the projected cost of implementation for demand response; these amounts are proxies for the complete cost of implementation, including payments to individual end-use consumers and the administrative costs associated with setting up and running demand response programs.

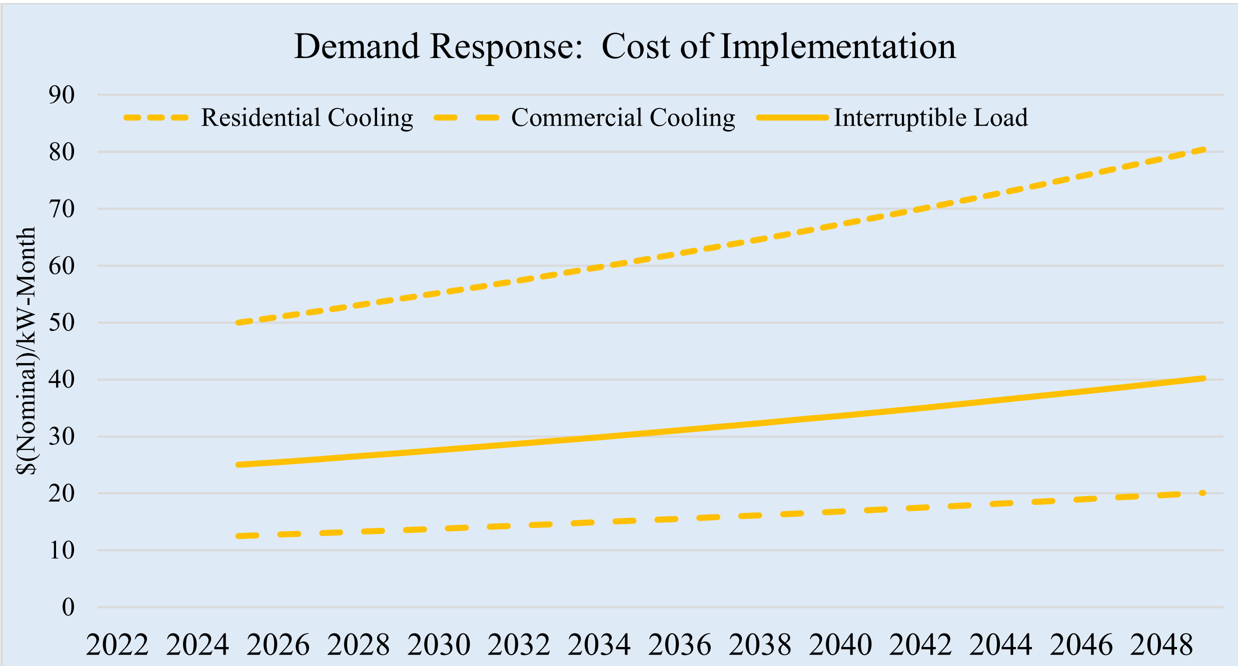


Figure 22: Demand Response – Cost of Implementation

f) <u>Changes in PWP's Renewable Power Supplies since the 2018 IRP</u>

Since the 2018 IRP, PWP has changed some of its long-term commitments to acquire renewable energy. First, the Ormat geothermal contract was terminated in May 2021, and final delivery of energy will occur on December 31, 2021, before this year's 2021 IRP Update study period begins. The Ormat contract was terminated by SCPPA using an "early out" provision for several reasons, including concerns about cost and performance relative to alternative supplies, and changes in congestion on the network in Southern California that altered the costs of delivering energy from the project.

Additionally, a long-term power purchase contract for the Coso geothermal project in Inyo County was secured, with PWP receiving baseload energy with all attributes starting in 2027. The Coso contract provides renewable energy as well as Resource Adequacy (RA) capacity required by the CAISO. Additional RA capacity will be required when the contracted coal-fired capacity in Utah is replaced by gas-fired capacity in 2025, and then terminates for PWP in mid-2027. The Coso geothermal plant meets the criteria for PCC1 energy delivered in California and provides System RA: reliable capacity for the entire CAISO. Coso geothermal will supply PWP about 10 MW of capacity from 2027 through 2036, and then about 19 MW of capacity through 2041.

g) <u>Fossil-Fuel Assumptions</u>

PWP's contract with the Intermountain Power Agency (IPA) for IPP energy will terminate in mid-2027. For this 2021 IRP Update, PWP provided cost projections to ACES for inclusion in the portfolio revenue requirements, including the cost of coal and natural gas. In mid-2025, PWP's capacity at the site will fall from about 100 MW to a 50 MW share of a new combined cycle combustion turbine. This 2021 IRP Update has no effect on PWP's previous decision to leave the IPP renewal project in mid-2027. No life-extension investments are included in this 2021 IRP Update for PWP's gas-fired plants in Burbank (Magnolia) and Pasadena (Glenarm).

h) <u>Southern Transmission System Rights after Mid-2027</u>

When PWP's contract rights to power and transmission in Utah expire in mid-2027, so will PWP's contract for access to the Southern Transmission System (STS), the HVDC transmission line that connects Delta, Utah with Adelanto, California. PWP's existing contract for wind power from the Milford project in Utah extends through November 2029, and new transmission rights will be necessary to bring that wind power into California for about 29 months.

LADWP is the Operating Agent for IPP on the STS, and has a posted tariff for transmission service on that path, including ancillary services. For planning purposes, PWP assumes that new transmission rights for 29 months will be acquired from LADWP, and will trigger mostly fixed-cost payments for transmission service and required ancillary services. This new fixed cost does not change dispatch, but will be recovered from PWP ratepayers. PWP does not expect to renew the Milford wind contract after November 2029 because of its cost, including delivery to California, compared with other alternatives such as solar/storage hybrid projects in California. The projected cost of Milford delivered to California will be included in the 2022-23 IRP.

VII. Resource Adequacy and CAISO Capacity Standards

From 2010 through 2020, renewable resources grew from about 13% to 33% of the total power supply in the state, calculated on an annual average basis and not counting imports.[40] Since the 2018 IRP, the concept of "firm capacity" has evolved to account for the renewable resource growth in the markets. Subsequently, the 2021 IRP Update provides for a path forward to meet Resource Adequacy (RA) standards.

State agencies and the CAISO are now redefining the capacity value of intermittent resources and requiring more non-intermittent and dispatchable power for RA requirements. In this 2021 IRP Update, increasing amounts of non-renewable and storage resources are necessary to meet operational and planning standards and ensure reliable service. RA from existing non-renewable resources will be phased out of California's power supply and replaced with remote and local storage, utility-scale and distributed storage, demand response programs, geothermal resources with high-capacity factors, and perhaps non-emitting fuels such as hydrogen.

The California Public Utilities Commission (CPUC) established an RA program in response to the California energy crisis 20 years ago. RA rules set by the CPUC apply to CPUC-jurisdictional entities, including many members of the CAISO. The CAISO applies the CPUC's RA rules to entities operating in the CAISO, including PWP, to determine each entity's System, Local and Flex RA compliance obligations.[41] RA standards have evolved over the years and are substantially different from 2018. (The oldest posted ELCC values are from 2019.[42]) Changes in RA standards are captured by "capacity accreditation" rules, implemented via the CAISO for PWP.

Accredited capacity is also known as Effective Load Carrying Capability (ELCC). Each new and existing MW of *installed capacity* must now be converted to *firm accredited capacity* in order to count toward RA obligations. Firm capacity is lower than nameplate capacity, changes over time, and varies by technology, by month, and by year of the study period. Both existing and new resources are subject to the accreditation or ELCC process, and each resource goes through a separate ELCC process, to take into account factors that affect performance, including location (e.g., for wind) and technology (e.g., for solar).

The general impact of the accreditation rules is illustrated in Figures 23 (annual) and 24 (monthly), which show the currently expected ELCC values (percentages of nameplate) by month, by year, and by technology, for both existing and new resources.

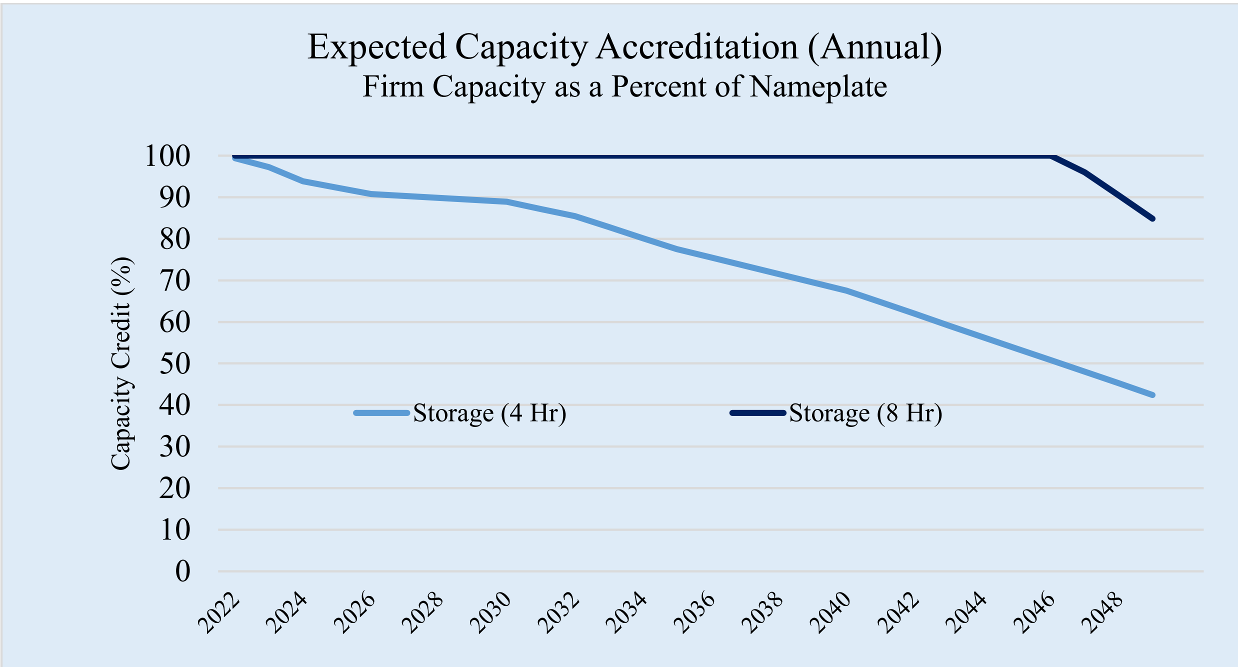


Figure 23: Expected Capacity Accreditation (Annual): Storage and Solar (%)

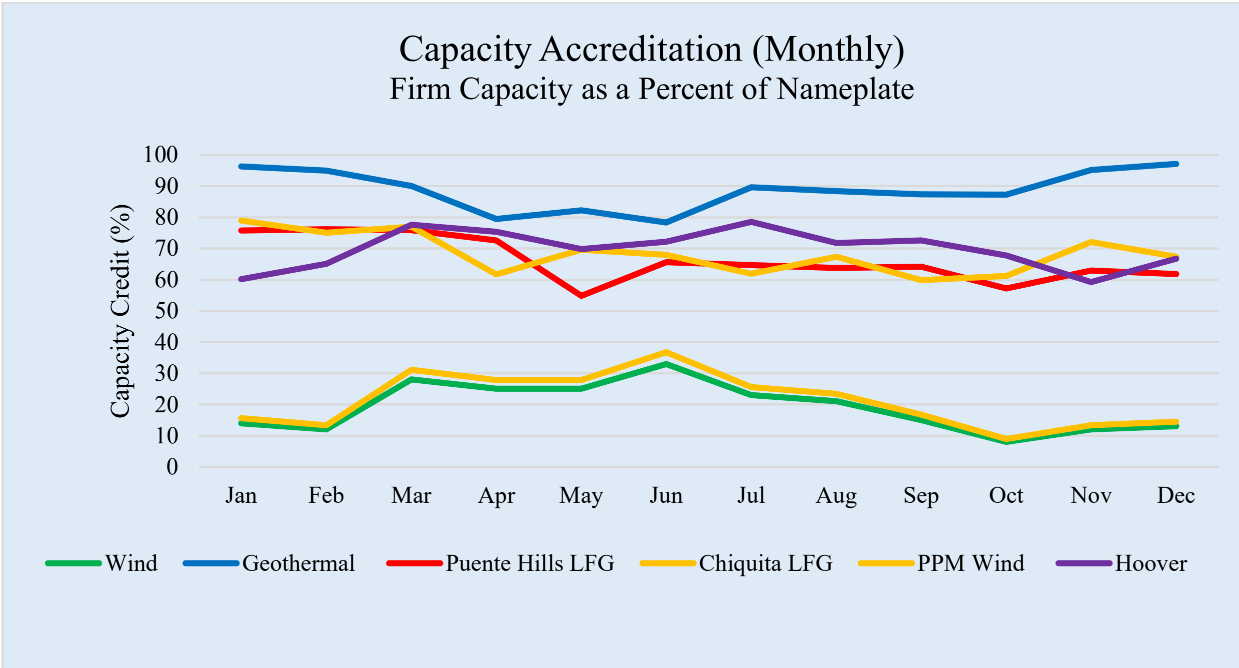


Figure 24: Capacity Accreditation (Monthly): Existing and New Resources (%)

The growth of wind and solar on the grid reduces the ability of those resources to meet forecasted reliability needs, and more intermittent generation increases the value of long-duration storage relative to short-duration storage. The IPP, the Glenarm units, Magnolia, and Palo Verde receive about 100 percent capacity accreditation. New demand response resources are assumed to have a 100 percent capacity accreditation, because they will be under the direct control of PWP.

Monthly capacity accreditation for Puente Hills, Chiquita Landfill, and PPM Wind come from CAISO documentation.[43] New and existing wind projects, new and existing geothermal plants, and Hoover are assigned the 2021 effective load carrying capacity (ELCC) as determined by the CPUC.[44] Annual average solar accreditation is obtained from a proprietary source (IHS Markit), and shaped to monthly values based on CPUC data.[45] According to the CPUC, accreditation of new solar is now less than 10 percent and is expected to fall over time.[46] Annual capacity accreditation of 4-hour storage resources is set at the average ELCC in 2020 and 2021 from the CPUC.[47] For a given year, eight-hour storage has twice the accredited capacity of 4-hour storage, measured in MWs, but no greater than the nameplate capacity of 8-hour storage.

As a result, accredited capacity for 8-hour storage equals 8-hour nameplate capacity until the mid-2040s, when the cumulative decline in firm capacity of 4-hour storage is large enough to force down the accredited capacity of 8-hour storage (see Figure 23). Capacity accreditation means that PWP must build or buy capacity above that defined by the nameplate capacity of new intermittent resources.

The production cost model incorporates two metrics for the projected cost to PWP of the new CAISO requirements: (1) the prices expected to be paid in advance in the forward RA market for capacity to meet PWP's system RA obligations to the CAISO; and (2) the penalty imposed by the CAISO if those RA obligations are *not* met in a given period. The RA price is used to calculate the cost of pure capacity purchased from third parties, unbundled from resources that PWP otherwise holds under contract or ownership.

The unmet RA penalty "pushes" the model to build or buy capacity, if building/buying is less expensive over time than paying the penalty.[48] ACES used forward price quotes from market sources to build the near-term price curve for system RA, then shifted to a projected "cost of new entry" (CONE) for the remainder of the study period.[49] This approach assumes that the market price for system RA will return to the long-run net cost of the marginal or incremental source of capacity: storage.[50]

Pasadena can meet its capacity requirements with existing resources, purchases of new resources, and purchases of System RA in the capacity market. In this 2021 IRP Update, the model allows up to 30 MW of capacity market purchases annually, or about ten percent of Pasadena's peak load. Forecasted System RA prices blend current broker market quotes into the cost of storage over time.[51] Penalties are imposed by the CAISO for "missing" an RA obligation. Figure 25 shows average projected monthly prices of System RA and penalties for unmet RA obligations.

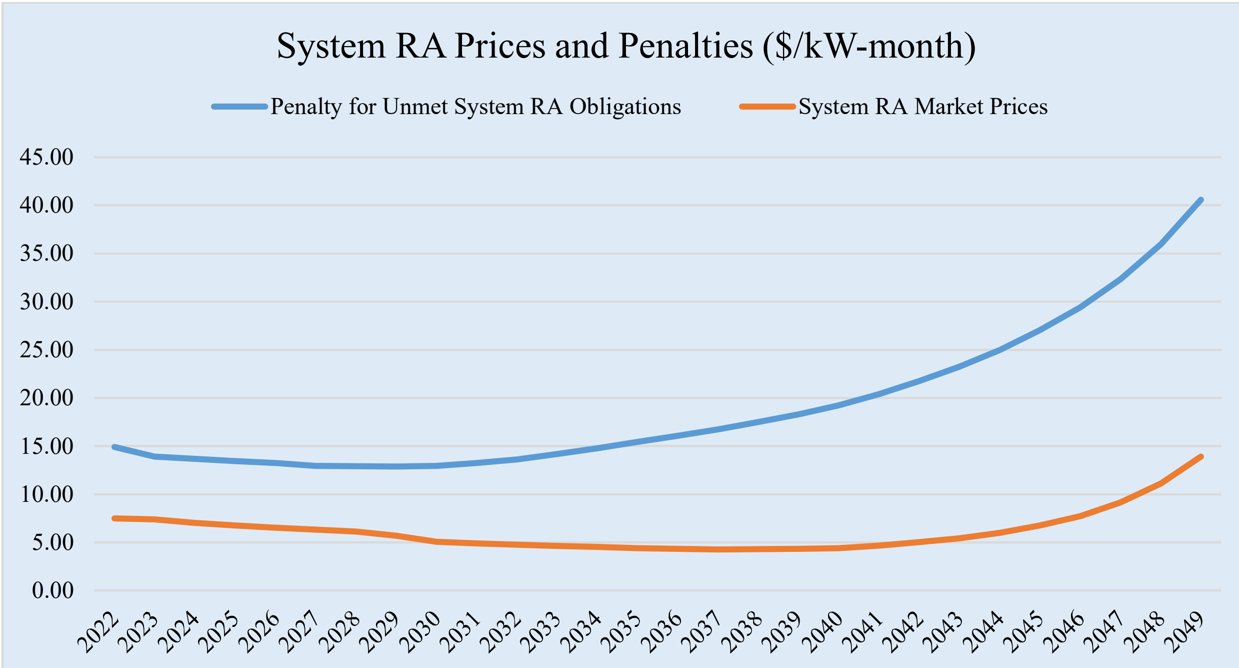


Figure 25: System RA Prices and Penalties ($/kW-month)

Pasadena is also required to supply local and flexible resource adequacy. As in the 2018 IRP, PWP expects that the Glenarm units will meet current and future local and flexible RA obligations.[52]

VIII. Energy Storage

Battery energy storage systems (BESS) provide highly flexible options for power system operations to maintain system reliability and integrate variable renewable resources. Technology advancements, cost declines, and state mandates have pushed battery storage into a firm position in planning exercises that integrate large amounts of renewables. While many forms of battery technologies exist, lithium-ion currently dominates the market for installed storage capacity in the U.S. and is expected to remain the market leader for storage deployed over the next decade. Figure 26 shows large-scale battery storage capacity by chemistry from 2003 through 2019, as reported to the Energy Information Administration. Lithium-ion installations make up over 90 percent of the reported projects. Given this information and the current commercial viability of other technologies, ACES modeled only lithium-ion based battery storage.

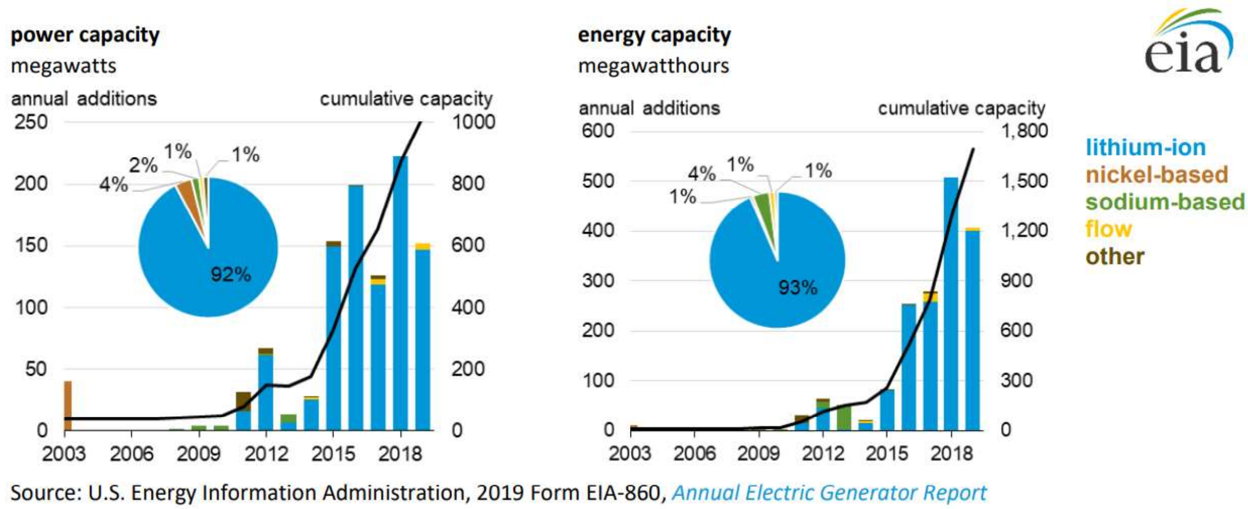


Figure 26: U.S. Installed Storage, 2003-18

Storage has the ability to respond rapidly to dispatch signals and operational commands.[53] These services include:

- Frequency regulation
- Spinning reserves
- Voltage or reactive power support
- Load following
- System peak shaving
- Load management
- Storage and discharge of excess wind and solar generation
- Backup power
- Transmission and distribution deferral
- Co-located generation firming

The values of storage vary by duration, location, scale, and ownership. Currently, 4-hour storage is the most common, but 8-, 10-, and 12-hour storage options are under development and provide greater value. Locations include:

- within the distribution system, e.g., at existing and new substations and switching stations but also in non-utility structures such as parking garages and EV battery swap stations;
- at major utility sites in the City such as Glenarm, perhaps co-located with solar; and

- outside the City, immediately adjacent to and metered with solar or wind, or at points in the grid where storage can help avoid grid-scale investments in new transmission capacity.[54]

If technology permits, EVs can act as mobile distributed storage devices. Ownership options include private developers and the City itself, perhaps through SCPPA. For the 2021 Update, the model focuses on utility-scale applications related to meeting system capacity and energy requirements, primarily system peak shaving, storage of excess wind and solar generation (using hourly market price curves), and co-located generation firming. An illustration of the potential for avoidable distribution costs is in Appendix A6. These options will be revisited in the 2022-23 IRP.

a) Cost Projections

Historical and projected cost reductions in utility-scale storage are well-publicized, reflecting the combination of manufacturing learning curves, storage mandates, and the growth of electric vehicles.[55] NREL produces an annual update of cost projections for storage systems, combining NREL and industry sources. Figure 27 shows the resulting projections for 2-, 4-, and 6-hour storage projects through 2050 (in \$2020), in \$/kilowatt-hours (kWh) and \$/kilowatts (kW).[56] Material cost reductions are expected to occur by 2030, after which the cost of storage is projected to increase less than the rate of inflation, resulting in continuing cost reductions in real dollars.

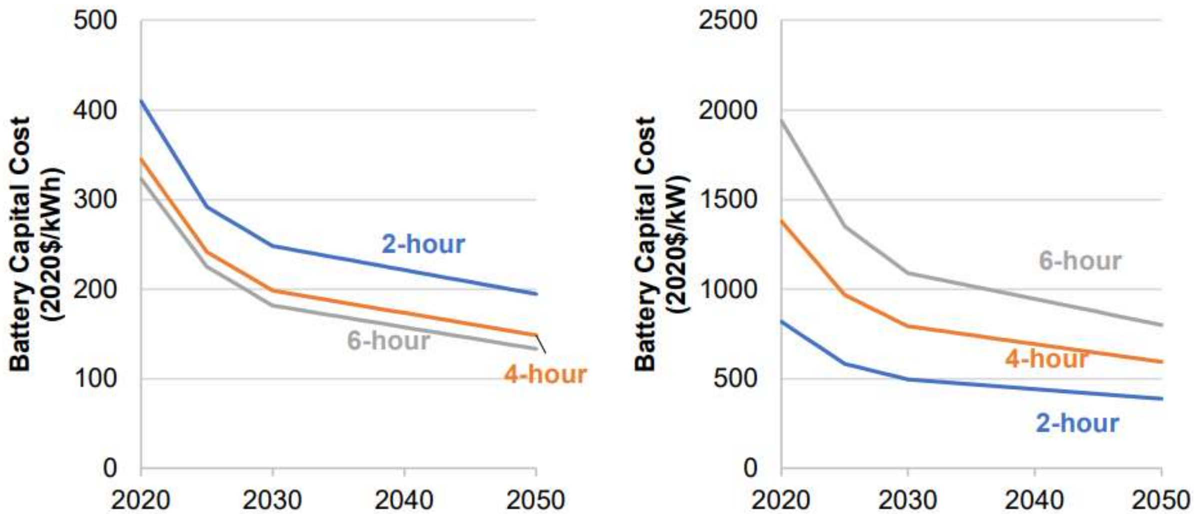


Figure 27: Battery Capital Costs, 2020-50

Currently, federal tax incentives exist for storage systems if the battery is charged by a paired solar system on-site. If a battery storage project is charged by at least 75 percent by a co-located solar system, the storage project can qualify for the federal Investment Tax Credit (ITC). Figure 28 shows tax incentives for battery storage, depending on ownership and relationship to solar capacity.[57]

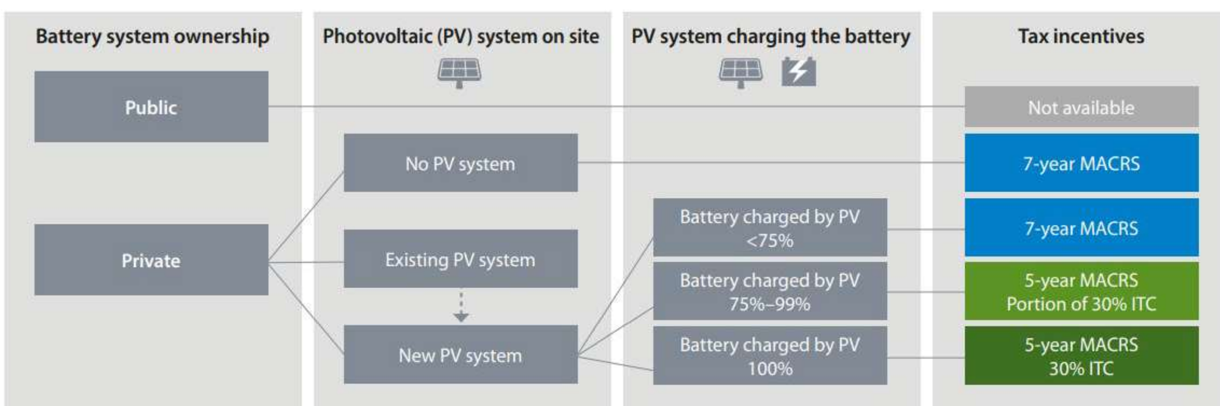


Figure 28: Federal Tax Incentives for Storage

Federal legislation could significantly improve the economics of storage. ITC eligibility for stand-alone battery storage projects would reduce the up-front capital cost net of tax credits, potentially resulting in a 25-30 percent cost decrease. Direct-pay of federal subsidies or incentives could avoid "tax equity" financing, in which taxable entities contribute equity (capital) to the project in exchange for receiving some of the avoided tax benefits.

b) Forecasted Costs and Technologies

The inputs to EnCompass include options for storage, with assumptions regarding the expected life of facilities, capacity accreditation/year (RA value in MW/year), cycling assumptions and limits, duration of storage (in hours), and minimum charge levels. These considerations will become more important as investments in storage become imminent.[58] In addition, forecasted degradation of storage due to cycling (storage/discharge) will be incorporated into the 2022-23 IRP, to get a more accurate prediction of changes in storage capacity over time.

c) Local Large-Scale Storage

PWP relies on gas-fired generation at Glenarm to maintain local reliability given the import constraint at T.M. Goodrich and the existing distribution infrastructure. With current state mandates, planning for retirement of local generation will be necessary in the 2030s. Options include hydrogen, biofuels (landfill gas, or LFG) and energy storage. Even assuming a price premium for biofuel over natural gas, the more fundamental problem may be reliability and adequacy of supply at any price.

The Glenarm site may be a good candidate for utility-scale long-duration storage (e.g., eight-ten hours of discharge). Utility scale helps reduce the cost per installed MW; long-duration may help maintain local service during multi-day heat storms, as long as the storage can be recharged, or a sufficient state of charge maintained, during off-peak hours. Over time, other sites may be identified (e.g., surface parking converted to parking structures with storage on the ground floor or below grade).

IX. Forecasted EV Loads

EVs remain a small portion of registered vehicles in the PWP service territory, making up only 2.3 percent of the vehicle count at the end of calendar year 2020, according to data collected by the CEC from the Department of Motor Vehicles (DMV).[59] As shown in Figure 29, in recent years no new Plug-In Hybrid EVs (PHEVs) have been registered in Pasadena, whereas EVs have continued to grow.

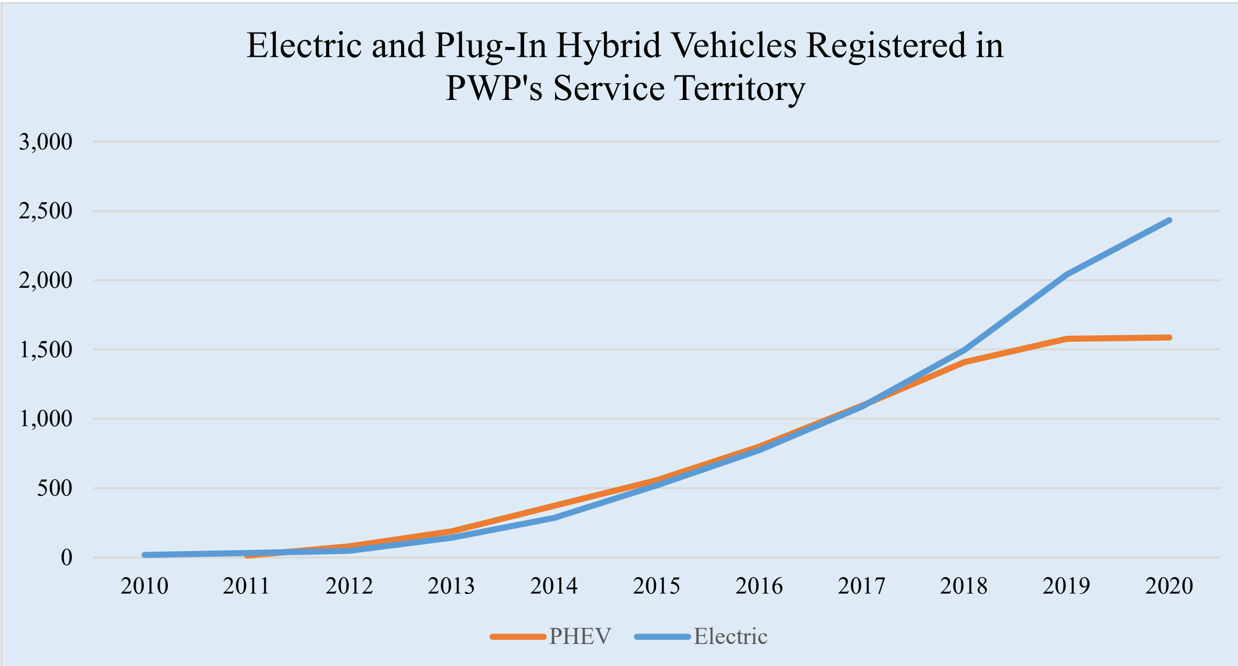


Figure 29: Electric and PHEV Hybrid Vehicles Registered in PWP's Service Territory

In September 2020, Governor Newsom signed an Executive Order adopting a target that all sales of new passenger cars and trucks in California will be zero emission by 2035.[60] The Governor's target may accelerate the growth of zero-emission vehicles in Pasadena, including EVs. This 2021 IRP Update includes a new forecast for the stock of EVs assumed to charge in Pasadena.

a) Methodology

The 2021 EV forecast establishes a baseline projection, and is subject to considerable uncertainty because the growth of EVs in Pasadena will depend not only on EVs registered in the City, but on inter-urban transportation (local trips, long-distance commuting, parking, buses, and trucks) and the growth of the charging infrastructure in the City.

Regular updates of any EV forecast may be needed to re-calibrate impacts on Pasadena's loads and infrastructure. The adoption of new consumer technologies often takes the form of an "S-curve": slow growth at the introduction of a technology, followed by a rapid increase in adoption, with an eventual leveling off as market penetration reaches saturation.[61]

b) Assumptions

The following assumptions for the forecast of EVs include:

- The maximum number of electric vehicles in the model is 90,000, approximately 90% of all passenger vehicles of all fuel types registered in Pasadena's service territory.
- The PHEV market share will fall as technology, economics, policies, and car manufacturers drive the market toward all-electric vehicles.
- The hourly charging profile will remain unchanged throughout the study period.

Charging profiles are based on NREL's EVI-Pro Lite Tool[62], a publicly available model that estimates the demand and infrastructure impacts of electric vehicles. This model is used by the CEC to estimate the impacts of electric vehicle growth. Figure 30 shows an example of the hourly EV load profile from the EVI-Pro Lite model.

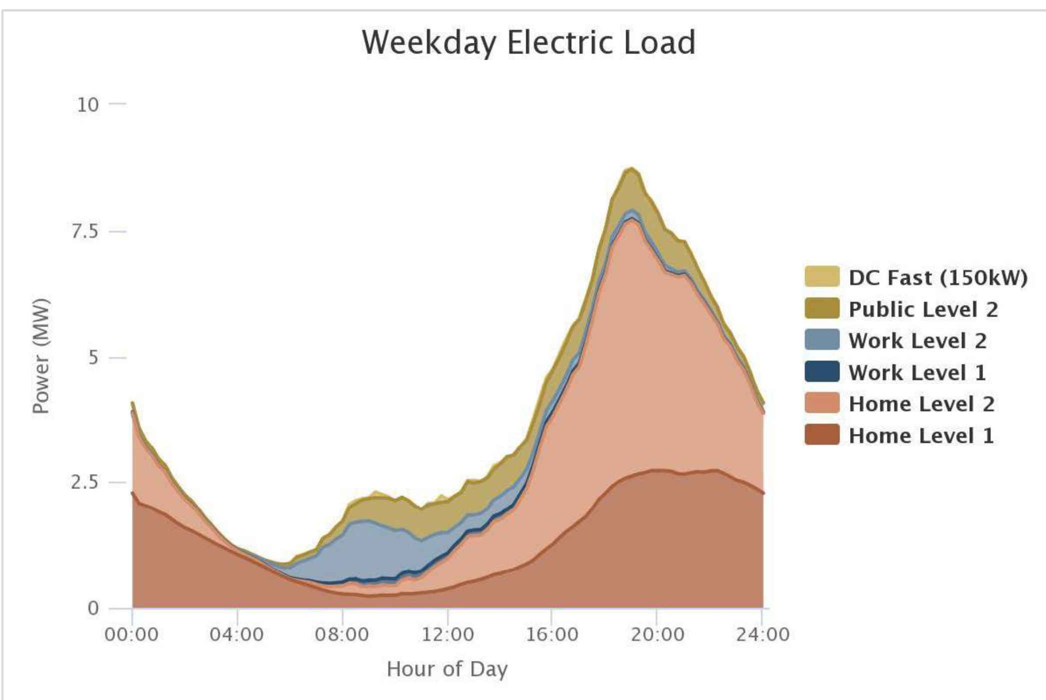


Figure 30: Typical Weekday Charging Profile

c) Results

Using DMV registrations of EVs through calendar year 2020 to calibrate diffusion models, ACES created an EV adoption curve that shows the growth of EVs charging in Pasadena during the study period.[63] Figure 31 shows actual registrations of new EVs (excluding PHEVs) through 2020 with ACES' projection through 2049. Based on the diffusion model, the count of electric vehicles registered and charging in Pasadena is forecasted to double by 2023 and reach 20,000 vehicles (about 20 percent of registered cars) in 2030-31.

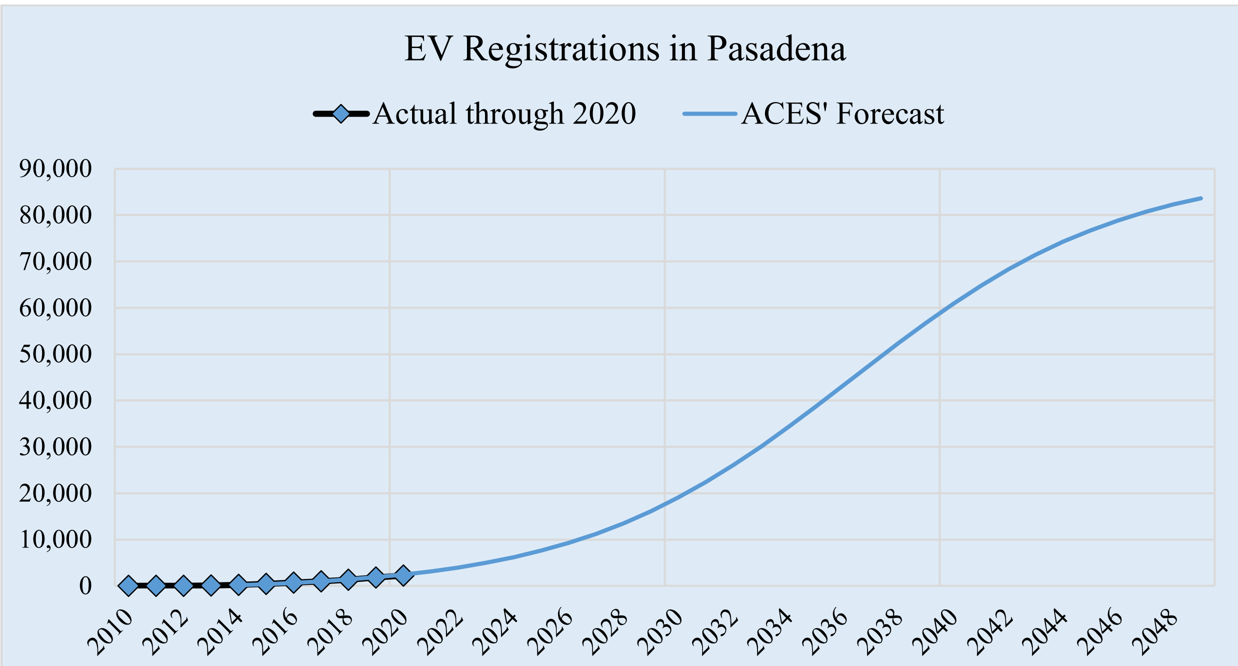


Figure 31: EV Registrations in Pasadena

d) Future EV Forecasts

As more EVs are purchased, forecasts of EV charging will need to be improved. Following are some topics for future forecasts.

- Dynamic charging profiles: The daily charging profile was assumed to be fixed over the study period. Future studies could allow charging profiles to change over time and across consumer segments as consumers manage charging, combined with time-of-use rates that help optimize charging profiles to match the economics of the grid. EVs could also be incorporated into the local grid via two-way communications when charging, allowing EV batteries to provide distributed frequency response. The shift to EVs will possibly change the hourly load shape.

- Cross-over from fossil-fuel to EVs: New information could improve the efficiency of estimated parameters in the diffusion model and help identify inflection points when adoption rates accelerate or slow down.
- Distribution-level mapping: More granular locational data (within zip codes, even down to addresses) for mapping EVs onto PWP's system could identify location-specific impacts on the distribution system, which could guide future investments in the distribution system.

X. Results: 2018 Refresh and 2021 Update Portfolios

Figures 32-41 compare the 2018 Refresh and 2021 Update in four dimensions: capacity, energy, RPS compliance, and GHG emissions. The capacity values reported here are "firm" or "accredited", not nameplate, which reflects current regulations.

a) 2018 Refresh

By replicating the 2018 Preferred Portfolio from the 2018 IRP, the 2018 Refresh demonstrates the impacts of changes in costs, technologies, and regulations since the 2018 IRP. Figures 32-36 show the model results for the 2018 Refresh, in which the model was not allowed to build resources beyond those added to the Preferred Portfolio in 2018, but was still required to meet all new regulatory obligations and the new load forecast. This 2018 Refresh tests the ability of the 2018 Preferred Portfolio to meet currently expected conditions during through 2039.

First, without new resources, PWP's total firm capacity falls over time due to the new capacity accreditation process and contract expirations, and is not adequate to meet planning standards. The cost of the 2018 Refresh includes penalties for missing capacity obligations.

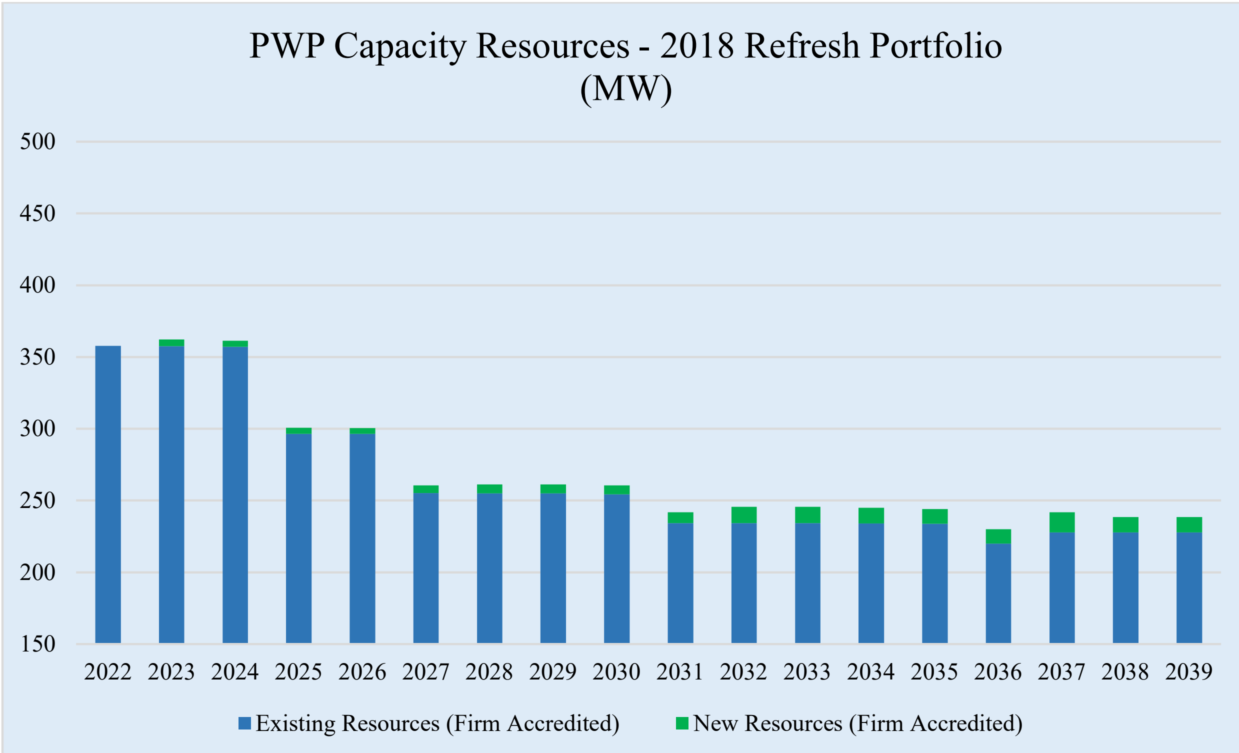


Figure 32: PWP Capacity Resources - 2018 Refresh Portfolio

Second, PWP's supply of energy increasingly relies on the spot market instead of new long-term commitments.

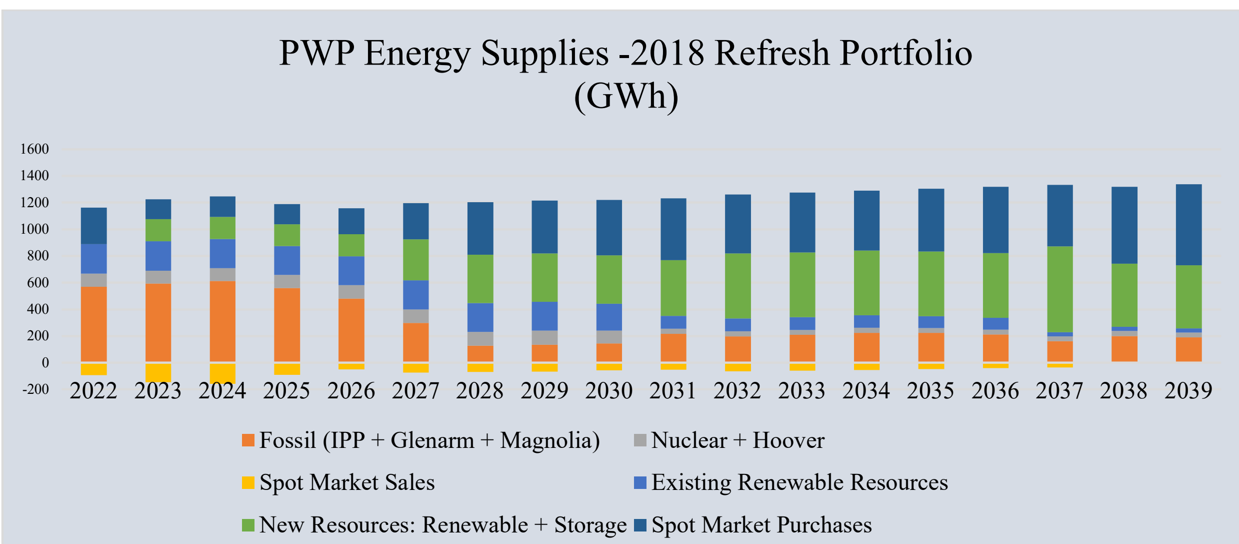


Figure 33: PWP Energy Supplies - 2018 Refresh Portfolio

Third, relying only on the 2018 Refresh, PWP will not be able to meet the zero-carbon standard of December 31, 2045.[64] As shown in Figure 34, the RECs required for RPS compliance increase steadily, but the supply of RECs from PWP's renewable resources is fairly flat, causing PWP to draw on its inventory of RECs accumulated in previous years. This is not a sustainable strategy.

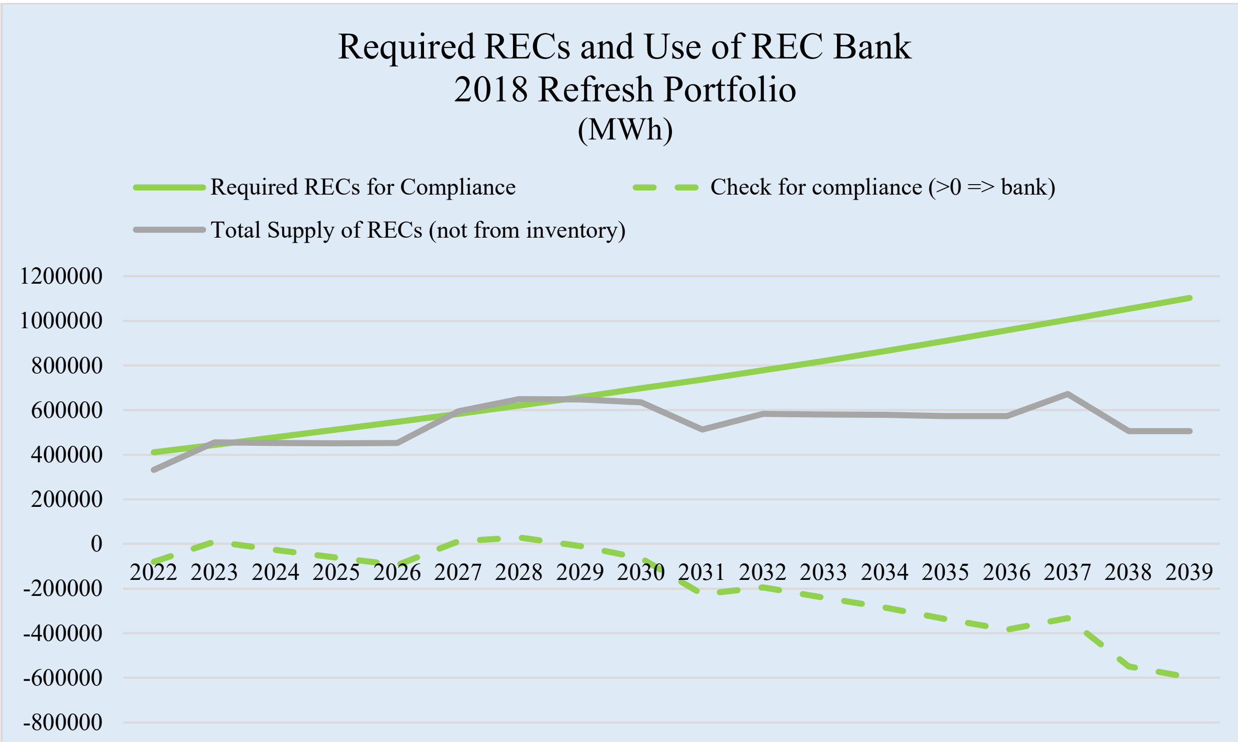


Figure 34: Required RECs and Use of REC Bank - 2018 Refresh Portfolio

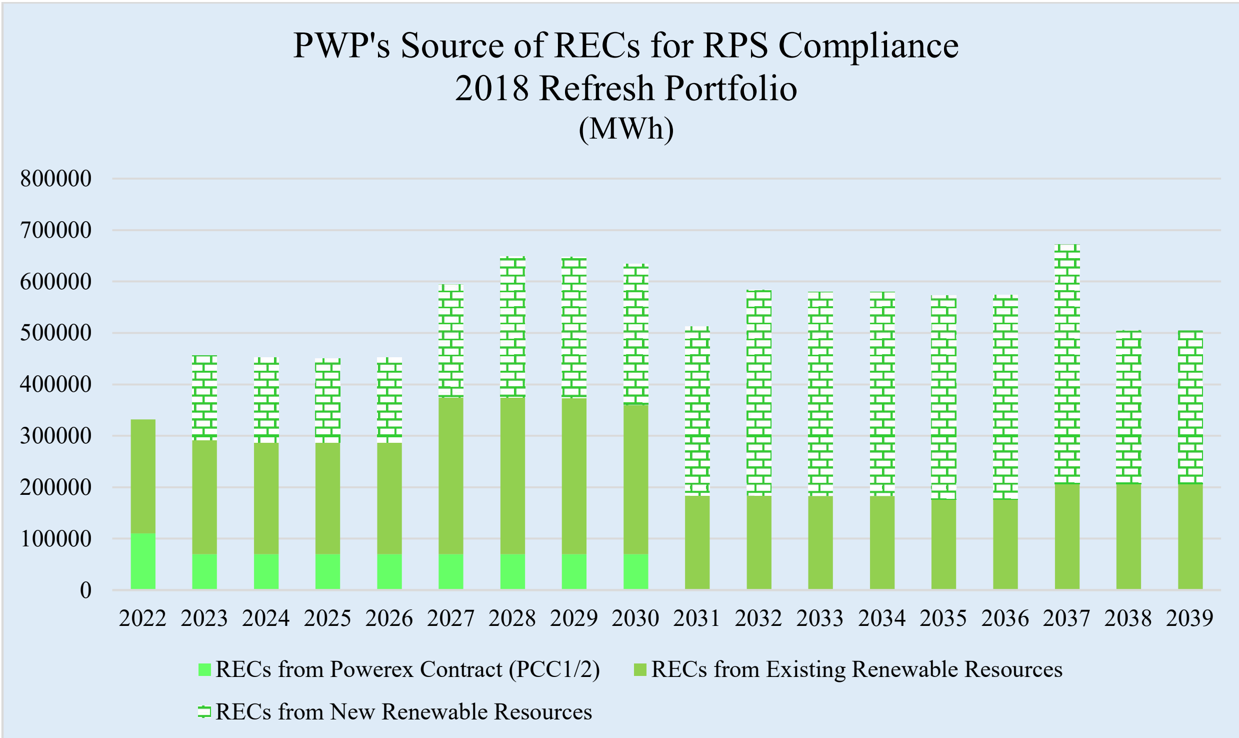


Figure 35: PWP's Source of RECs for RPS Compliance - 2018 Refresh Portfolio

Figure 35 excludes the purchase of RECs unbundled from renewable energy, but PWP's ability to rely on unbundled RECs is very limited under current regulations, and may be further limited by new regulations.

b) <u>2021 Update</u>

Figures 36-41 show the model results for the 2021 Update, in which the model was allowed to add more resources than in the 2018 Refresh. First, Figure 36 shows that the 2021 Update meets the capacity planning standard with new resources and limited purchases of system RA from the short-term market.

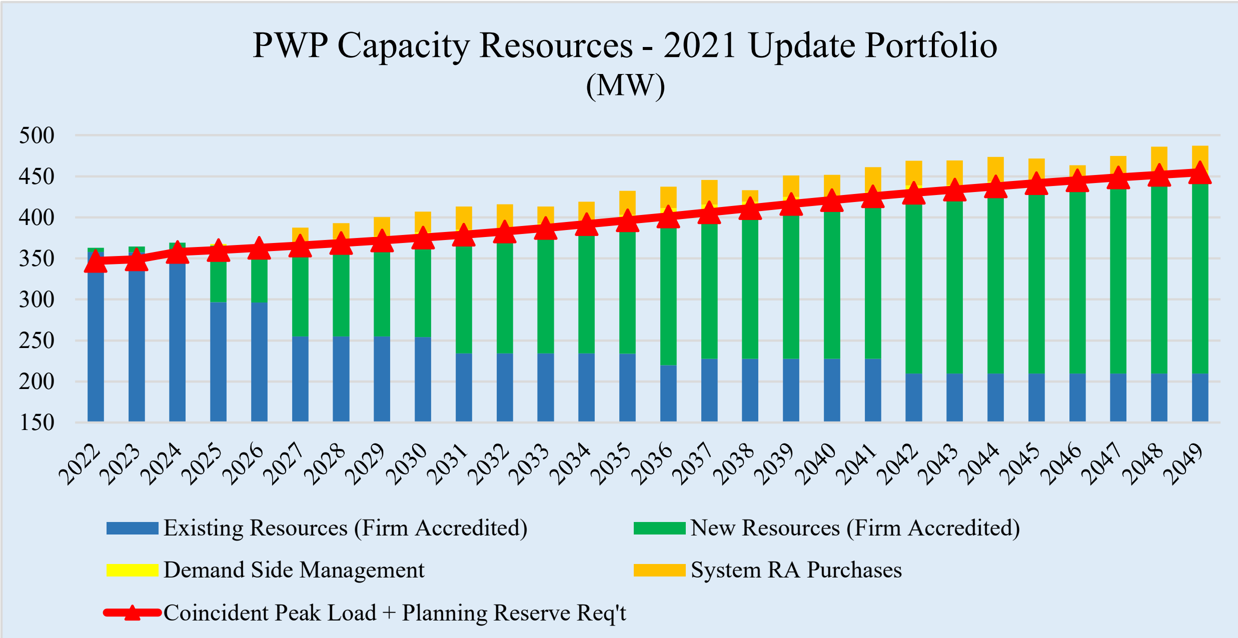


Figure 36: PWP Capacity Resources - 2021 Update Portfolio

Second, Figure 37 shows that the 2021 Update Portfolio meets PWP's energy obligations each year.

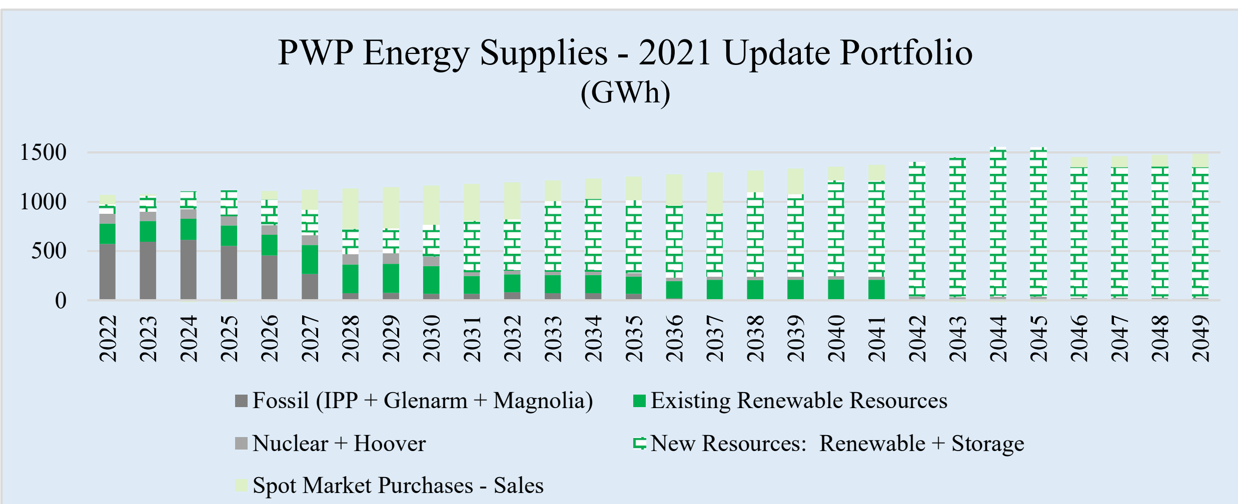


Figure 37: PWP Energy Supplies - 2021 Update Portfolio

From the late 2020s into the 2030s, PWP's reliance on the spot market for energy increases, which reflects the expectation that the spot market is the least-cost supply of energy during those daily and seasonal periods when PWP expects to rely on the spot market to meet peak loads, due to the growth of solar capacity, compared with signing new PPAs.

Third, Figures 39-40 show that new renewable resources replace retiring renewables and meet growing RPS obligations to support the zero-carbon standard. For compliance, PWP expects to use its ability to bank and withdraw excess RECs during three-year compliance periods.

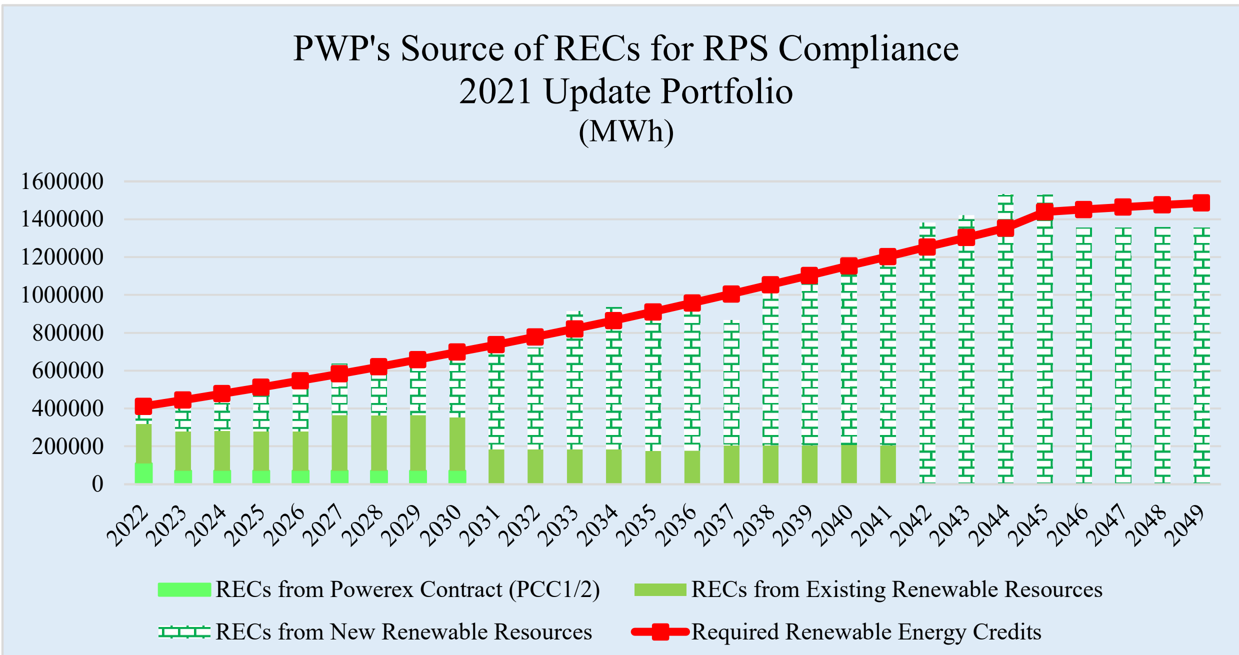


Figure 38: PWP's Source of RECs for RPS Compliance - 2021 Update Portfolio

Figure 39 shows that the 2021 Update is projected to yield enough RECs for long-term RPS compliance, with relatively small annual deposits and withdrawals from the bank of accumulated RECs. Positive amounts in "Use of REC Inventory" show excess RECs that are banked; negative amounts show withdrawals from the REC bank. The ability to use the REC bank, as with other aspects of RPS regulations, is subject to change by the CEC.

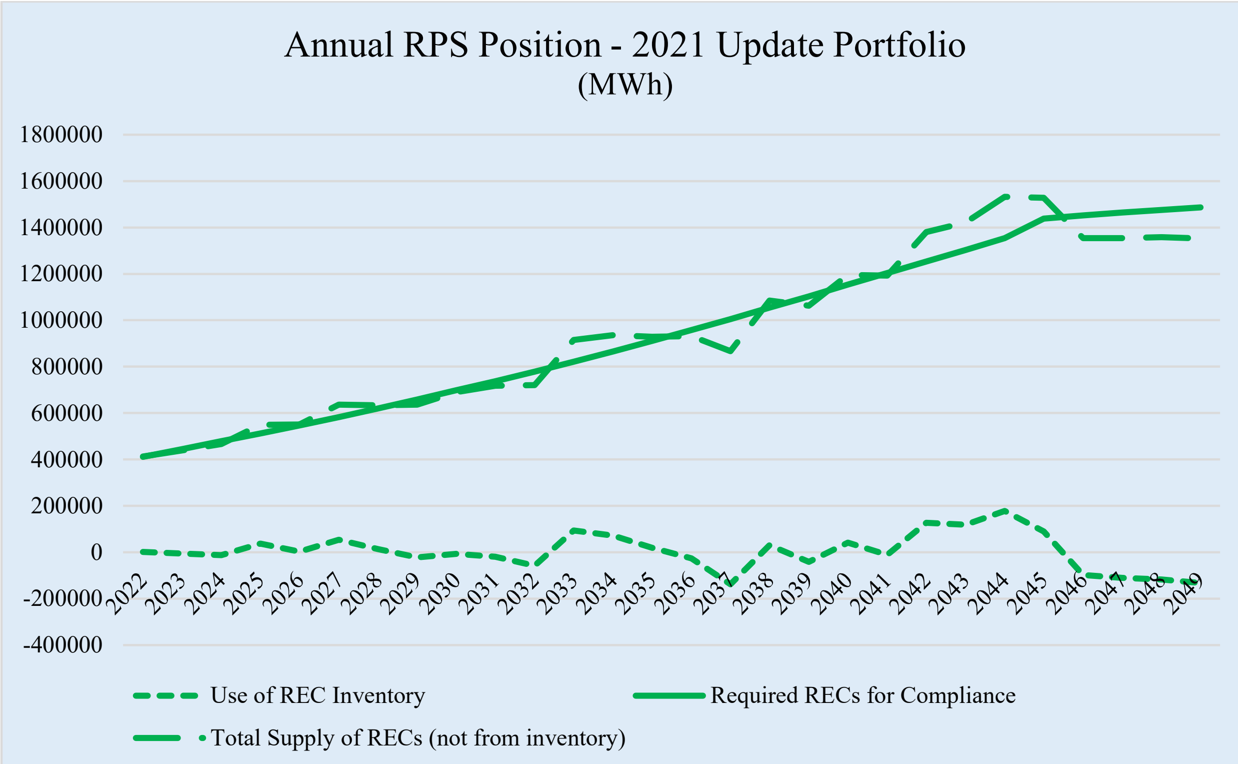


Figure 39: Annual RPS Position - 2021 Update Portfolio

Fourth, with the addition of new zero-carbon resources, the 2021 Update fully meets the zero-carbon standard by the end of 2045, as shown in Figure 40.

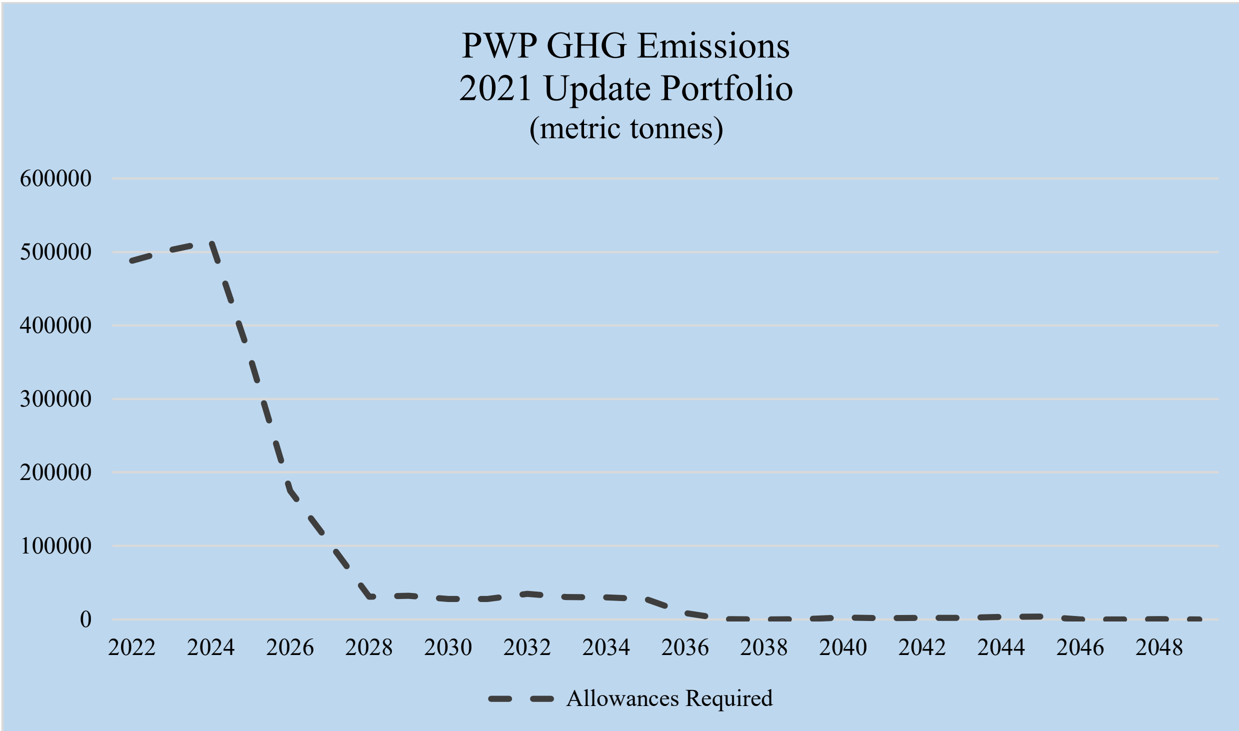


Figure 40: GHG Emissions - 2021 Update Portfolio

Allocated emission allowances during the study period are expected to exceed PWP's compliance obligation, allowing the accumulation of excess allocations. The ability to bank and withdraw allowances, and the annual amounts of allocated allowances, are subject to regulatory uncertainty.

c) <u>Annual Cost of Power Supply Modeled in the 2021 Update Portfolio</u>

The production cost model calculates an annual "revenue requirement" of a part of PWP's power supply portfolio, which is recovered through retail energy charges.[65] In the following discussion, the 2018 Refresh is truncated after 2039, the end of the study period in the 2018 IRP. In the 2018 Refresh, the model was not allowed to add new resources after 2039, causing substantial, rising and unrealistic capacity and energy shortages, which in turn triggered penalty payments.

Figure 42 reports those costs that were modeled in EnCompass; the projected cost of power supply (limited to those costs modeled in this 2021 IRP Update) is *lower* with the 2021 Update than with the 2018 Refresh through the mid-2030s.[66] Over the 2022-39 period, the 2018

Refresh and 2021 Update yield NPVs of $1.241 billion and $1.109 billion, respectively (nominal dollars), assuming a four percent discount rate. "Spikes" in individual years reflect decisions in the model to minimize the net present value of future costs over the remainder of the study period. In 2038, for example, the model estimates that it will be less expensive for the remainder of the study period to rely on short-term markets for a year and defer new long-term commitments.

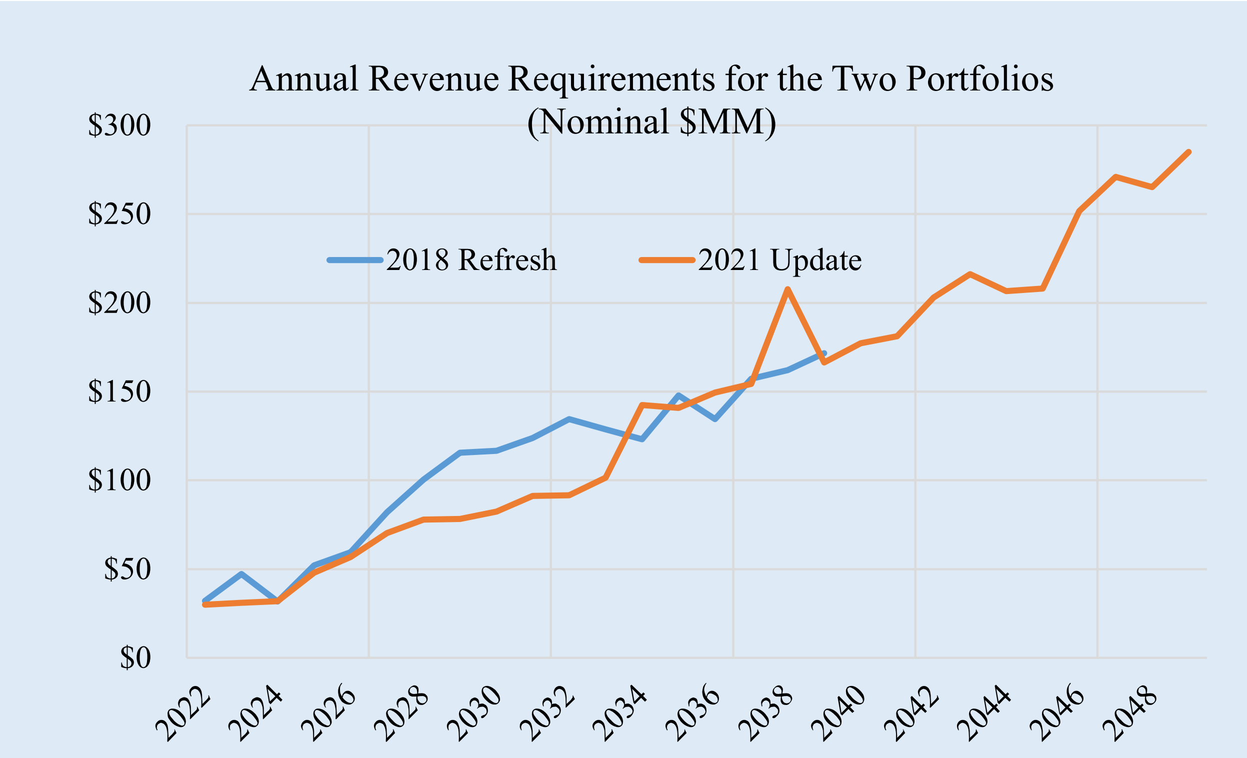


Figure 351: Annual Revenue Requirements for the Two Portfolios

Table 12 shows the annual data for Figure 41.

Modeled Power Supply Costs by Portfolio (nominal $MM)		
	2018 Refresh	**2021 Update**
2022	$32.2	$29.9
2023	$47.3	$31.0
2024	$31.8	$32.0
2025	$52.0	$47.9

2026	$59.5	$56.9
2027	$82.0	$70.3
2028	$100.3	$77.9
2029	$115.5	$78.3
2030	$116.7	$82.5
2031	$123.8	$91.2
2032	$134.4	$91.6
2033	$128.7	$101.6
2034	$123.1	$142.4
2035	$147.8	$140.8
2036	$134.5	$149.4
2037	$157.2	$154.3
2038	$162.1	$207.6
2039	$171.7	$166.4
2040		$177.3
2041		$181.2
2042		$202.9
2043		$216.0
2044		$206.5
2045		$208.0
2046		$251.6
2047		$270.9
2048		$265.1
2049		$284.9

Table 12: Modeled Power Supply Costs by Portfolio

Many factors account for the difference in costs between portfolios. The 2021 Update is not limited to the resources forecasted to be added to PWP's power supplies in 2018, and takes advantage of tax credits and reductions in resource costs since 2018 to build more and sooner than was forecasted in the 2018 IRP.

The 2021 Update has a higher cost of purchased power due to resource additions, but those new resources help meet System RA planning standards, avoiding substantial financial penalties in the 2018 Refresh. For example, by 2031, the penalty for missing the RA planning standard exceeds $21.8 million with the 2018 Refresh, which is avoided with the 2021 Update. The ability to add new resources beyond those identified in the 2018 IRP reduces the total expected cost of power supply.

Table 13 provides a comparison.

Causes for Differences in Portfolio Costs		
Factor	**2018 Refresh**	**2021 Update**
Timing of resource additions	Fixed by results in 2018 IRP	Allowed to change to minimize costs
Purchased power costs	Lower due to fewer additions	Higher due to sooner and more additions
Tax credits	Lower than 2018 IRP and 2021 Update	Higher than 2018 IRP and 2018 Refresh
System RA penalties	Substantial and rising	Minimal and relatively flat; penalties avoided by new resources
Capacity from resource additions	Fixed by results in 2018 IRP	Rising over time as resources are added

Table 13: Causes for Differences in Portfolio Costs

d) Effects of the SCC Dispatch Penalty

The SCC dispatch penalty is a planning tool that increases the cost of fossil-fuel resources that are dispatched into the wholesale spot market to reflect the global social cost of carbon. The SCC penalty is not actually paid by PWP ratepayers now. To estimate the impacts of the penalty, PWP re-ran the 2021 Update without the penalty, and with no other changes to the model. Certain costs did not change due to the removal of the penalty:

- Carbon compliance, because the model used allocated allowances;
- Renewable resource costs, because those contracts are still required for RPS compliance;
- Fixed costs, including interest, depreciation, fixed fuel transport, property taxes, insurance, and fixed O&M;
- Costs incurred due to purchases of System RA capacity, because capacity requirements did not change;

Some costs do change due to the removal of the dispatch penalty:

- Fossil fuel and variable O&M costs increase due to more wholesale or off-system sales; and

- Power purchases decrease, because the fossil units dispatched more to meet retail loads.

Wholesale revenues and emissions are greater *without* the SCC, because the fossil-fuel units produce more energy. The additional wholesale revenues yield financial credits that reduce the cost of the 2021 Update portfolio to PWP ratepayers by six percent (6%) in net present value over the period 2022-49. Total emissions are lower with the SCC dispatch penalty.

e) **Emission Reductions, RPS Compliance, and Reliability**

After the expiration of the IPP contract in mid-2027, PWP's emissions in the 2021 Update are forecasted to fall by 88 percent of 1990 levels by 2030 and even further after Magnolia leaves the portfolio in mid-2036. Further reductions in the 2040s will depend on decisions regarding the remaining gas-fired Glenarm units and California carbon regulations. The 2021 portfolio is forecasted to meet all RPS and reliability obligations.

XI. Stakeholder Involvement

On July 13, 2021, PWP provided status reports to the Municipal Services Committee (MSC) and the Environmental Advisory Commission (EAC), and answered questions. On MONTH-DAY, 2021, the initial draft report was presented to the MSC. The MSC recommended ______________. On MONTH-DAY, 2021, PWP presented an initial draft of this report to the EAC, received comments and answered questions. On MONTH-DAY 2022, a final revised report was presented to MSC, incorporating the recommendations of the MSC, along with comments from the EAC. On MONTH-DAY, 2022, the final report was presented to City Council for approval.

XII. Budget Impacts

Power supply costs are generally recovered from PWP's energy charges, which cover the fixed and variable costs of resources, labor and supplies, operations and maintenance, debt service and debt service coverage, transfers to the General Fund, and a portion of capital investments funded from rates (PayGo) rather than debt. The customer, distribution, and transmission charges in PWP's retail rates are not affected by decisions regarding power supply, given current rate design.

Table 14 shows major categories of PWP's annual operating expenses for the electric system. The 2021 IRP Update analyzes only a subset of Fuel & Gas and Purchased Power; energy, transmission, distribution and customer charges recover costs in other categories.[67]

Electric System Operating Expenses FY22		
Fuel & Gas - Retail	$	4,430,987
Fuel & Gas - Wholesale	$	3,107,495
Purchased Power	$	54,187,679
Public Benefit Charge	$	6,773,955
Climate Change Expense-Retail 8283 (PS/PP)	$	175,120
Climate Change Expense-Wholesale 8263	$	647,410
Purchased Power-Transmission 8223	$	12,084,121
Purchased Power-ISO System (TAC & GMC) 8294/8295	$	14,067,797
Direct Operating Expenses	$	42,067,919
General and Administrative Expenses	$	19,260,539
Interest Expense	$	9,060,095
Depreciation & Amortization	$	31,603,515
Total Operating Expenses	$	197,466,632

Table 14: Electric System Operating Expenses FY22

The IRP production cost model excludes many costs; those activities do not affect (a) the addition of new resources to the portfolio (because existing fixed costs must be paid irrespective of decisions to add resources) or (b) the hourly dispatch of resources in the portfolio (because dispatch only depends on variable costs, not fixed costs). Fixed costs are independent of both energy production by a resource and the level of retail energy sales, but some fixed costs are recovered through the volumetric energy charges (i.e., in cents/kWh).[68]

Figure 43 provides projections of energy costs from the production cost model (PCM) and other costs not modeled in the study period, including the projected costs of other resources;

the latter category generally declines over time because resources leave the portfolio (IPP, Magnolia and Palo Verde).

Figure 44 shows the projected cost of the entire electric system, assuming that costs other than energy supplies do not change over time. Figure 45 shows the projected cost of the entire electric system, assuming that costs other than energy supplies increase at three percent per year.

These cost projections lead to average annual increases in rates (i.e., all charges) between 3.5 and 4.0 percent per year over the study period Load growth would mitigate the impact of cost increases on retail rates, because the existing and new fixed costs would be spread across future higher loads in rate-making.

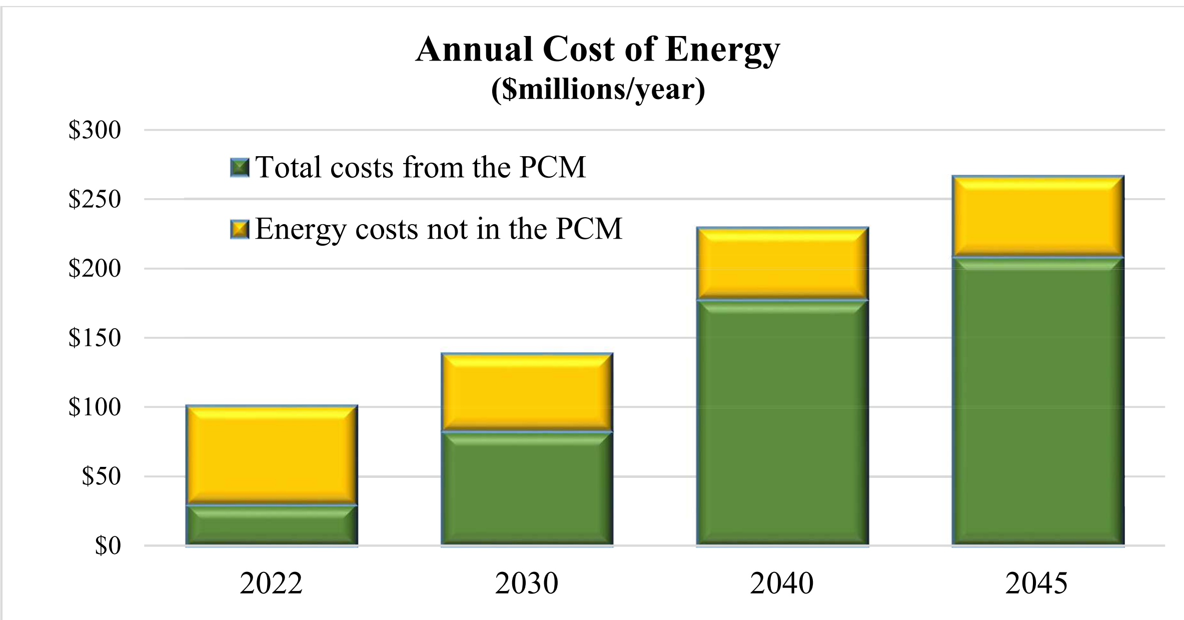


Figure 362: Annual Cost of Energy

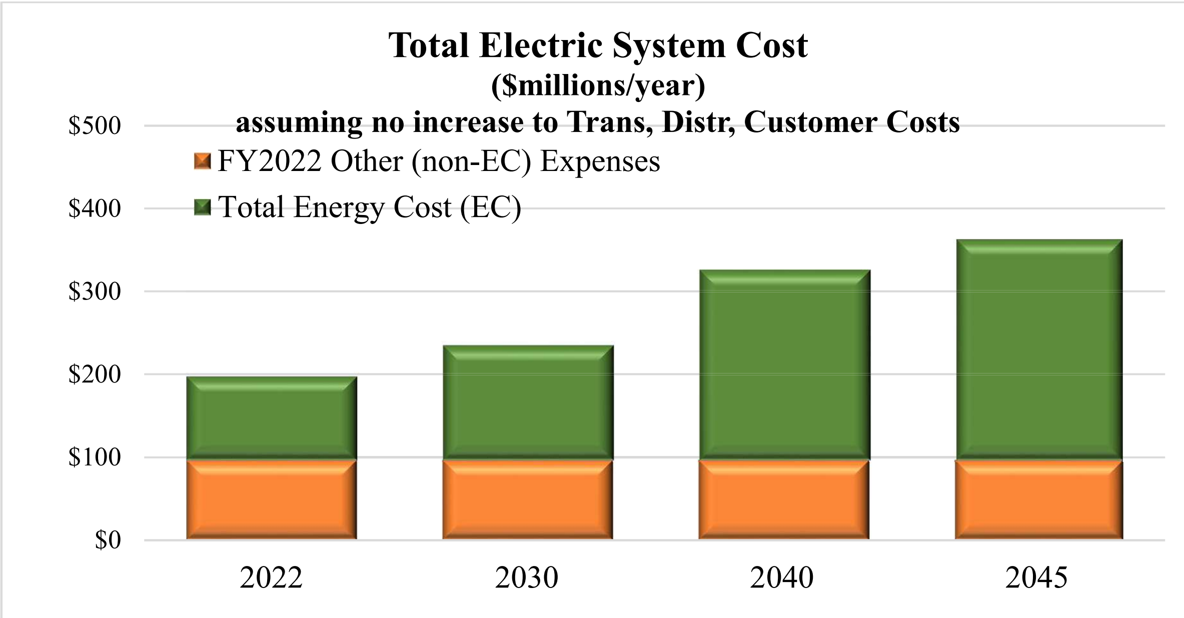


Figure 43: Total Electric System Cost (without escalation)

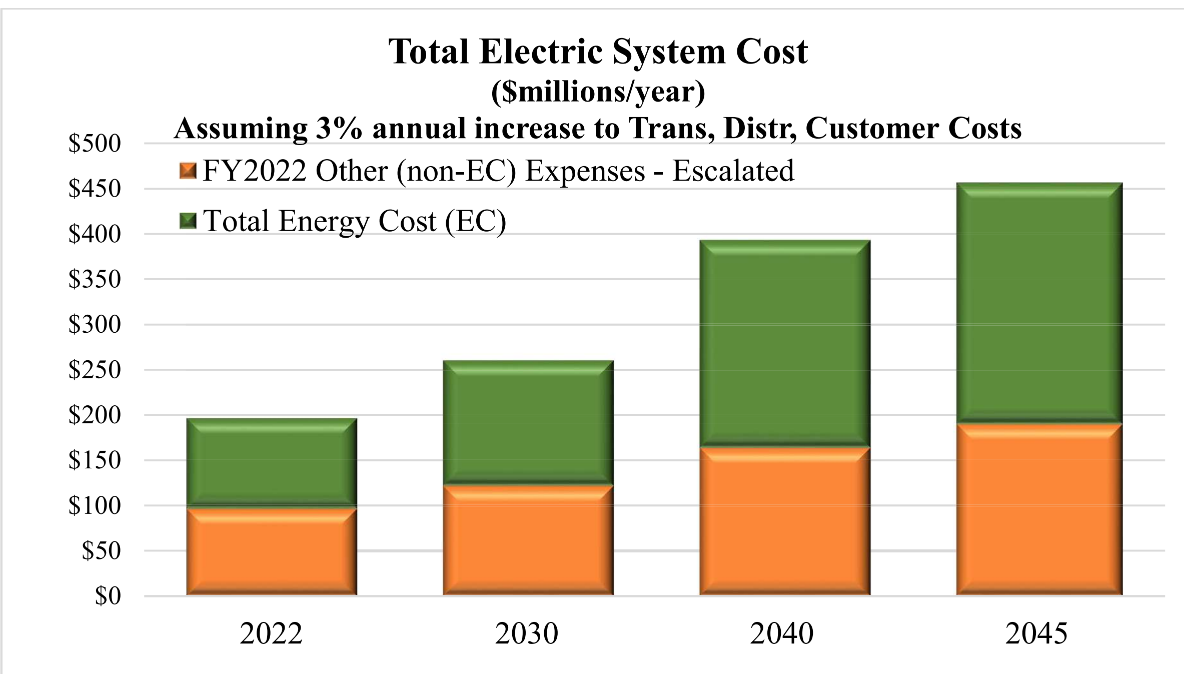


Figure 374: Total Electric System Cost (with escalation)

XIII. Conclusions

a) 2021 IRP Update

The 2021 IRP Update is the preferred strategy for procurement going forward. This 2021 IRP Update shows that conditions have changed materially since the 2018 IRP, and adjustments to procurement plans are needed to achieve the City's objectives: reduce carbon footprint and minimize cost of service to ratepayers. PWP is predicted to face a capacity shortfall by the mid-2020s, so should consider a competitive solicitation for all resource types to help meet that need, with a stated preference for low-carbon or zero-carbon supplies. The 2021 IRP Update points to the acquisition of solar, wind, geothermal and storage resources in different years, which also meets the goal of diversity across technologies and over time. Diversity of resources allows PWP to minimize overreliance on one or two technologies, and to take advantage of expected cost reductions for new technologies, especially energy storage.

The 2021 IRP Update allows for the Glenarm gas-fired units to continue to maintain local reliability services to the City, but may be replaced by non-fossil resources and/or repowered with zero carbon fuels in the 2030s and/or 2040s. As of this 2021 IRP Update, no significant near-term decisions regarding Glenarm are expected given the need to maintain local reliability. This 2021 IRP Update also assumes that PWP's share of the Magnolia gas-fired plant in Burbank leaves the portfolio in 2036.

b) Near-Term Implications

The 2021 Update forecasts the addition of 260 MW (nameplate) of resources in 2022-30: wind, solar, hybrids, storage, and demand response.[69] Figures 1 and 2 below *(included from executive summary)* display the projected resource additions in nameplate capacity and projected capacity additions for RA standards to 2030, excluding short-term purchases of RA capacity from unspecified resources.

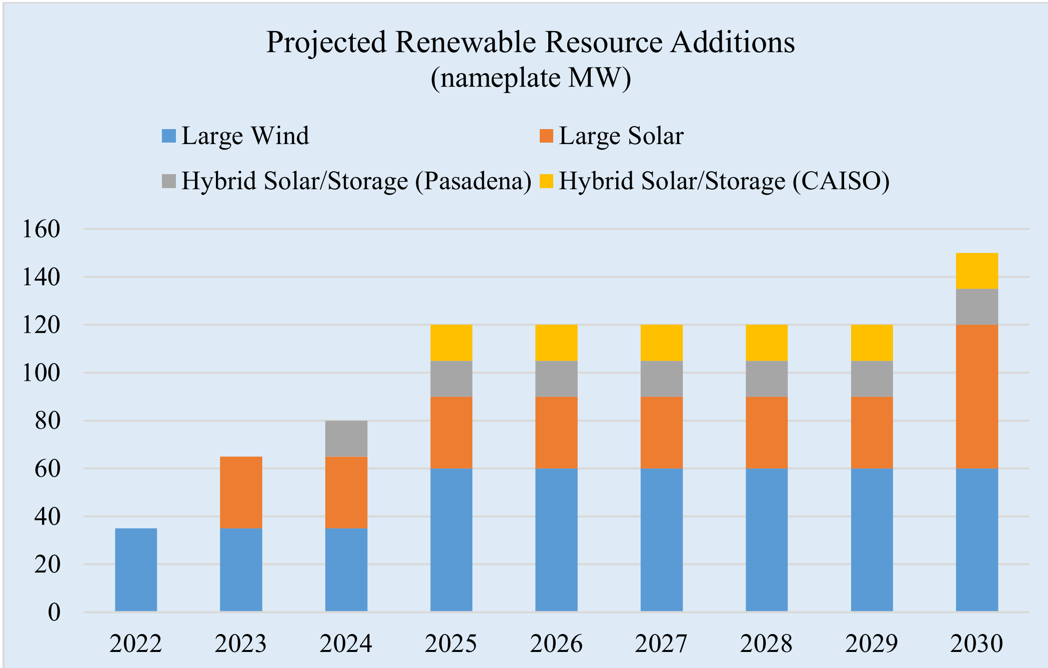


Figure 1: Projected Renewable Resource Additions

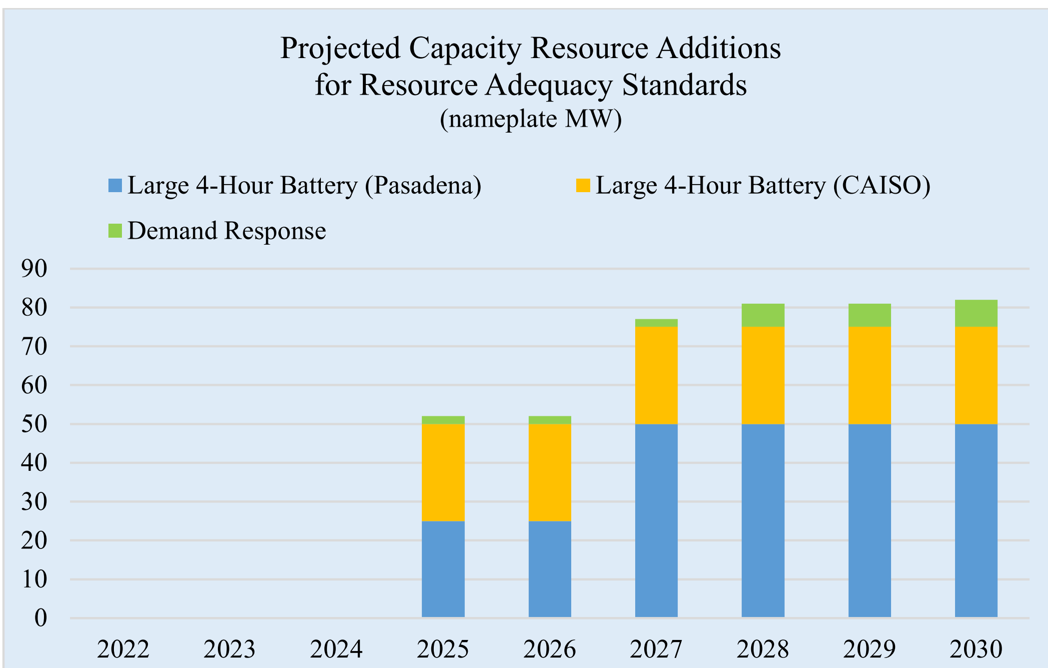


Figure 2: Projected Capacity Resource Additions for Resource Adequacy Standards

These resource additions are larger and sooner than expected in the 2018 IRP for several reasons.

Relatively Certain Near-Term Factors

- New capacity accreditation process: the "firm capacity" values of both existing and new non-dispatchable resources are being reduced by the state and CAISO. PWP may have to demonstrate higher System RA sooner.
- Lower costs of new wind, solar and storage resources: the costs of new renewables and storage continue to fall, making them more cost-effective.
- Scheduled changes in federal tax law: ITCs are on a schedule to be phased out, which will increase costs later.
- Near-term volatility in the market for System RA: System RA prices are subject to short-term market conditions, outages, derates, delays, and maybe illiquidity, increasing the insurance value of long-term contracts.

Less Certain Factors

- Near-term potential for a higher required Planning Reserve Margin (PRM): the state and CAISO may require even more System RA for a given peak load.
- Potential changes in RPS regulations to encourage PCC1 resources: PCC3 could be discontinued; allowed PCC2 could be ramped down; more long-term PCC1 could be required.
- Life-extension investments at Magnolia and Glenarm: questions may arise about future investments related to the zero-carbon standard.
- New storage technologies reach commercial viability: if costs fall and duration increases, regulations could shift to require more installed storage.
- New proposals by developers with new pricing and hybrid options: an unknown.
- Potential acceleration in EVs charging in Pasadena: another unknown, both for timing and impacts on load and local infrastructure

Relatively Certain Factors with Long Implementation Periods

- Potential for new programs to encourage electrification and decarbonization: saving energy may be merged with fuel-switching; program design, staffing, program evaluation, acceptance in the community and transition could all be affected.
- Transition in retail rate design toward higher fixed and lower volumetric charges: abrupt changes are normally avoided.

- Potential cost-effectiveness of Demand Response programs: new programs will take time to ramp up.
- Integration of Distribution Master Plan and Integrated Resource Plan: new programs will take time to ramp up.
- Preparing for climate change (e.g., longer and more intense heat storms, fires): this will also impact the Distribution Master Plan and future IRPs.

XIV. Preview of the 2022-23 IRP

a) CEC Requirements

PWP expects to develop a "full IRP" starting in the spring of 2022, seeking City Council approval in late 2023. This schedule meets the CEC guidelines for IRPs submitted by municipal utilities.

b) Expected Activities and Topics

PWP expects the following activities in the 2022-23 IRP:

1. Review the inputs to the 2021 preferred portfolio
   - 1.1. Update generic resource assumptions (cost, performance) and peak/energy load forecasts, including expected degradation of solar PV panels and energy storage
   - 1.2. Update the planning reserve margin per state regulations and CAISO requirements
   - 1.3. Update forecasted inputs (e.g., fuel prices, energy prices, carbon allowance prices, SCC)
   - 1.4. Add details on DR options and EV forecasts
2. Test scenarios that modify inputs, requiring additional model runs (e.g., higher carbon allowance prices, lower/higher forecasted load, lower/higher forecasted EV consumption)
3. For local storage, incorporate expected avoided distribution costs from the PWP Distribution Master Plan, new technologies, different operational modes, and expected ancillary service revenues
4. Integrate Demand Response and Energy Efficiency into the resource stack for both build and dispatch

5. Potentially integrate the Distribution Master Plan
    5.1. Identify deferrable/avoidable distribution investments
    5.2. Identify local storage options to defer/avoid distribution investments
    5.3. Incorporate details on distributed solar resources and end-use batteries (e.g., EVs)
6. Refine the analysis of budget and rate impacts, for example by disaggregating the total change in the cost of the preferred portfolio into components: load changes, RPS compliance, and cost of carbon.
7. Re-design retail rates (e.g., Time of Use rates, EV storage rates, EV discharge payments, higher fixed charges and lower variable charges)
8. Update RPS procurement plans and enforcement programs

c) <u>Expected Schedule</u>

1. Spring 2022
    1.1. Assemble internal team: power supply, finance (retail rates), distribution planning
    1.2. Define scope among internal stakeholders; establish leads and data requirements
    1.3. Develop detailed scopes of work for external consultants
    1.4. Solicit and evaluate external consultants; negotiate and award contract(s)
    1.5. Begin data exchange and set model specifications
2. Summer/fall 2022
    2.1. Start Stakeholder Group meetings
    2.2. Update EAC/MSC
    2.3. Begin modeling work
3. Early 2023
    3.1. Continue Stakeholder Group meetings
    3.2. Start public meetings
    3.3. Update EAC/MSC
    3.4. Get results from model and conduct Quality Assurance/Quality Control (QA/QC)
    3.5. Re-run model if necessary
4. Mid-late 2023
    4.1. Write report(s)

4.2. Finish public meetings

4.3. Update RPS compliance and procurement programs

4.4. Provide recommendations for distribution system and retail rate re-design

4.5. Complete EAC/MSC updates

4.6. Complete review and adoption by City Council

A1. PWP's Existing Resources

Table A1 PWP's Existing Resources		
Plant	Fuel	Capacity (MW)
Intermountain Coal (Fixed Fuel)	Coal	41.48
Intermountain Coal (Variable Fuel)	Coal	13.83
Intermountain Repower	Natural Gas	50.00
GT - 1	Natural Gas	15.9 – 22.07
GT - 2	Natural Gas	8 - 22.07
GT - 3	Natural Gas	15 - 44.83
GT - 4	Natural Gas	15 - 42.42
GT - 5	Natural Gas	18 - 68
Magnolia	Natural Gas	14.00
Palo Verde	Nuclear	10.00
Hoover	Hydro	14.00
Puente Hills	Landfill Gas	9.90
Chiquita	Landfill Gas	5.96
Ormat	Geothermal	5.96
PPM Wind (Avangrid)	Wind	2.10
Milford Wind	Wind	5.00
Windsor Reservoir Solar	Solar	0.60
Antelope Solar	Solar	6.55
Kingbird Solar	Solar	20.00
Columbia Two Solar	Solar	2.47
Summer Solar	Solar	6.55
Cal Tech	Fuel Cell	10.00
Coso	Geothermal	10-20

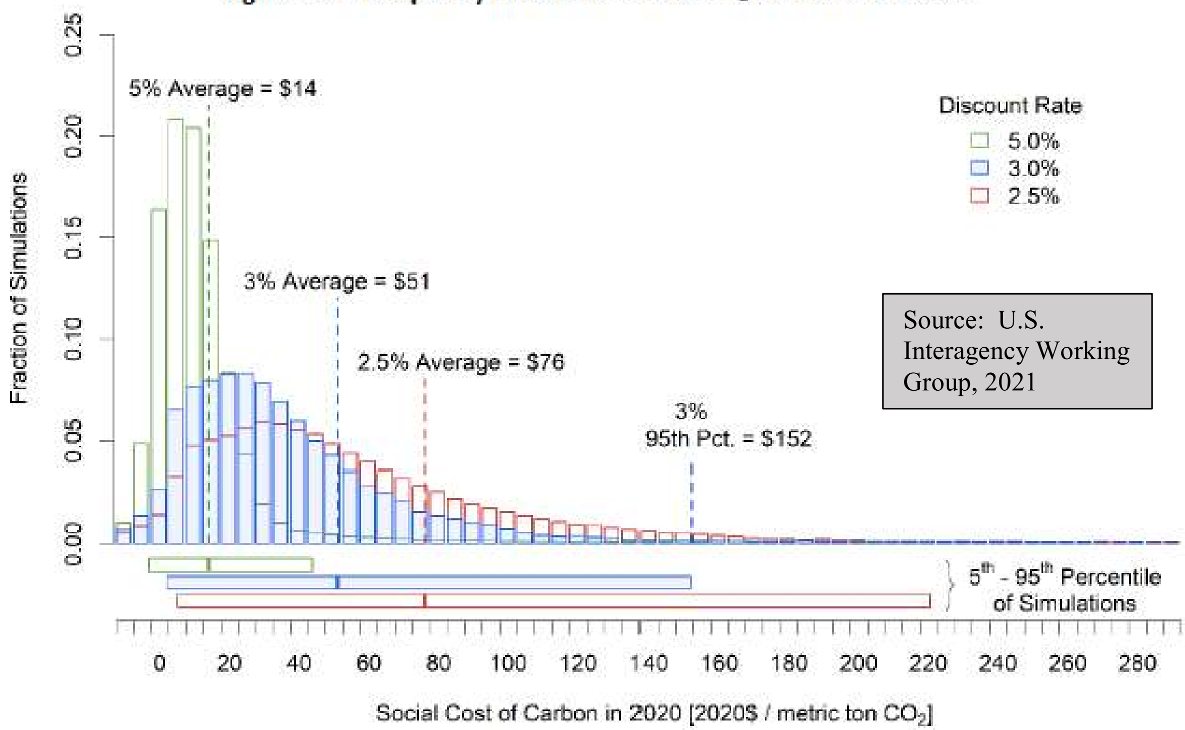
Source: 2021 PWP IRP Update Inputs, tab Existing Resources.

A2. Additional Background on the Social Cost of Carbon (SCC)

To determine the SCC in 2021, PWP used a recent federal report, which drew together the collective efforts of 14 federal Cabinet departments, agencies, councils, and offices, and applied a consistent methodology through 2049. (See U.S. Government, Interagency Working Group on Social Cost of Greenhouse Gases, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990", February

2021.) Figure ES-1 from the federal report shows three projected distributions of SCCs in one year (2020). (See "Technical Support Document", p. 7.) For each year in the study period, the report provides annual values of the SCC for three discount rates and for the 95th percentile of the 3% discount rate. (See "Technical Support Document", p. 10.) The three distributions in Figure ES-1 reflect three social discount rates applied to the projected annual values of SCC.

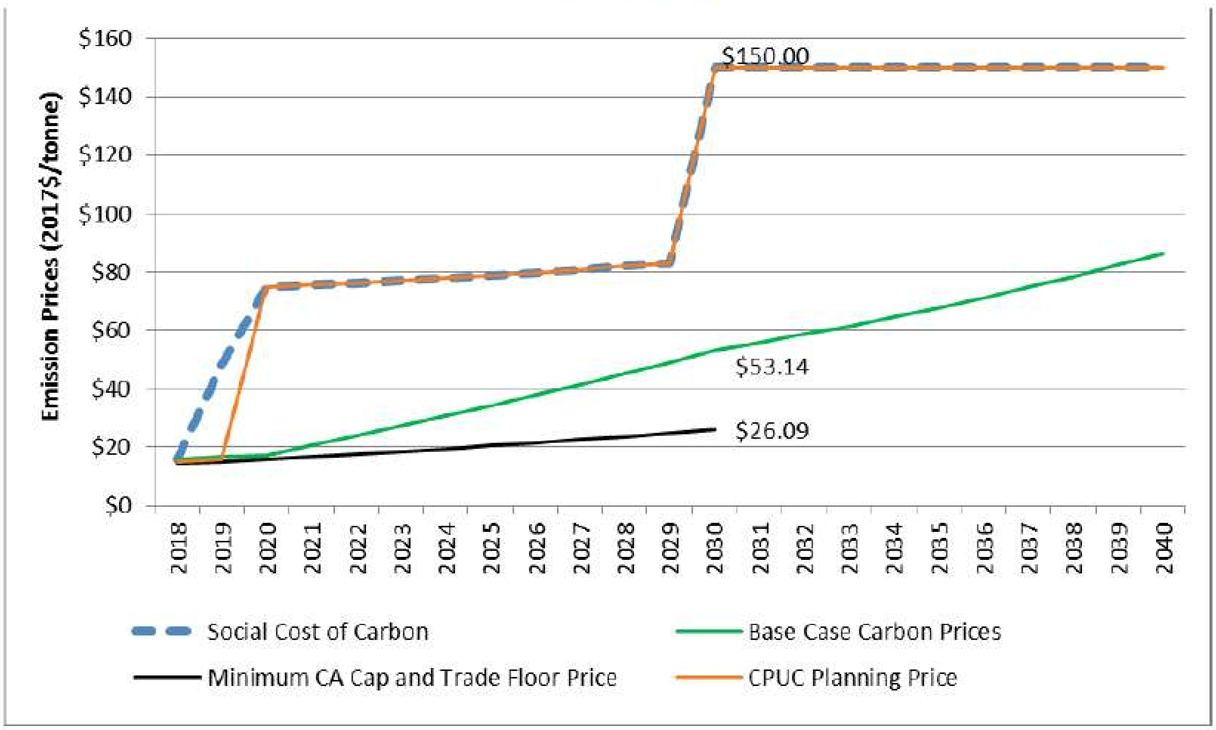
Figure ES-1: Frequency Distribution of $SC\text{-}CO_2$ Estimates for 2020[6]



Lower discount rates yield higher SCCs in each year; higher discount rates reduce the present value of future emission costs and yield lower SCCs in each year. The three percent social discount rate reflects the importance of long-term climate conditions, by discounting those long-term conditions less than would result from using a private discount rate. Private discount rates used by individuals and corporations can be two-to-three times as high as social discount rates (or even higher given uncertainty about the future), and would yield lower SCC projections. As shown in ES-1, the models yield distributions of annual values of the SCC for a given discount rate, driven by variations in the modeling assumptions (a.k.a., scenarios). In 2020, the distribution for a three percent social discount rate ranges from zero to over $260/MT (ES-1 is a snapshot of 2020). PWP picked the 95th percentile of each annual range (with the three percent social discount rate) to "insure" against all but the largest impacts of climate change further out in the tail of the distribution. The SCC measured at the 95th percentile includes all but the highest five percent of projected values from thousands of model runs for each year.

A3. Social Cost of Carbon in the 2018 IRP

Exhibit 12: Cost of Carbon



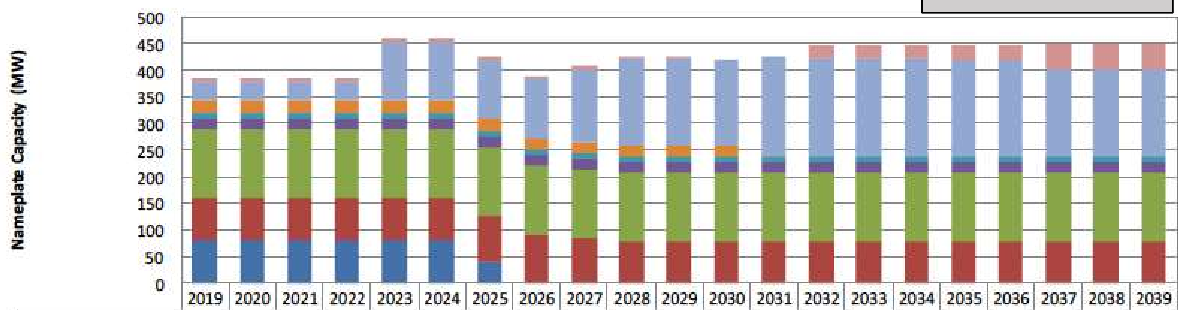
Source: Pace Global

A4. Results of the "SCC + SB 100" Scenario in the 2018 IRP

For comparison with the 2021 Update, following are the results of the 2018 IRP's preferred portfolio in four dimensions: capacity, energy, RPS compliance, and GHG emissions.

Exhibit 34: SCC + SB 100 - Capacity

Source: 2018 IRP.



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Battery																					
Wind	7	7	7	7	7	7	5	5	5	5	4	0	0	25	25	25	25	25	50	50	50
Solar	36	36	36	36	111	111	111	111	136	161	161	161	186	185.6	185.6	185.4	183	183	163	163	163
Other Renewable*	23	23	23	23	23	23	23	23	23	23	23	22	2	0	0	0	0	0	0	0	0
Nuclear	10	10	10	10	10	10	10	10	10	10	10	10	10	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Hydro	20	20	20	20	20	20	20	20	20	20	20	20	20	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Gas Peaker	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130
Gas CC	78	78	78	78	78	78	85	91	84	78	78	78	78	78	78	78	78	78	78	78	78
Coal	83	83	83	83	83	83	41	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Source: Pace Global; *Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 35: SCC + SB 100 - Energy

Source: 2018 IRP.

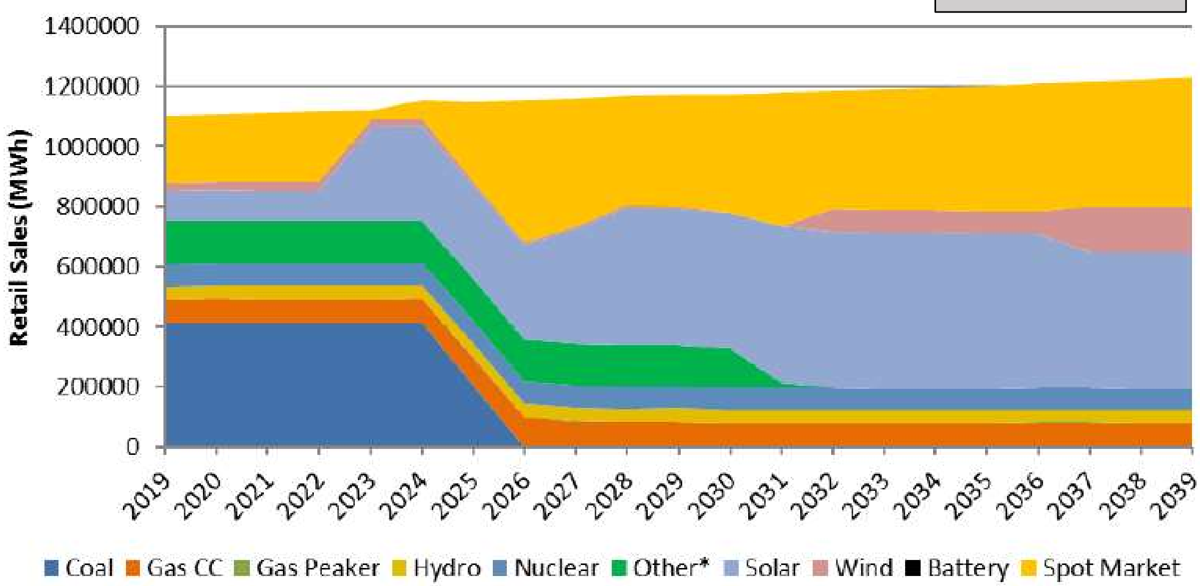
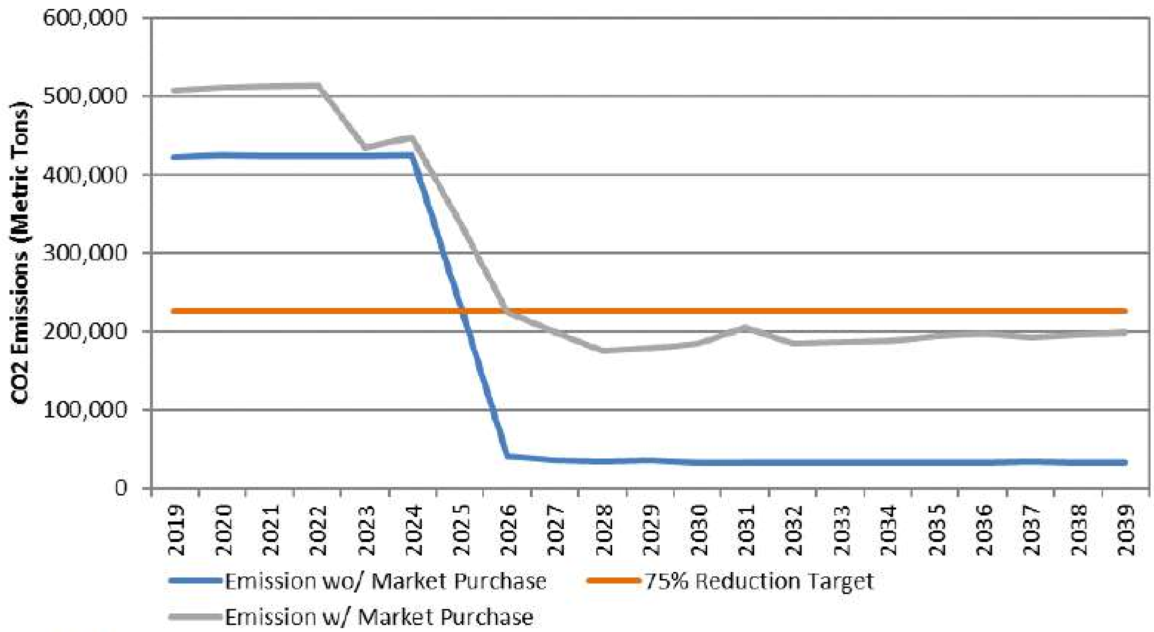


Exhibit 36: SCC + SB 100 – Emissions

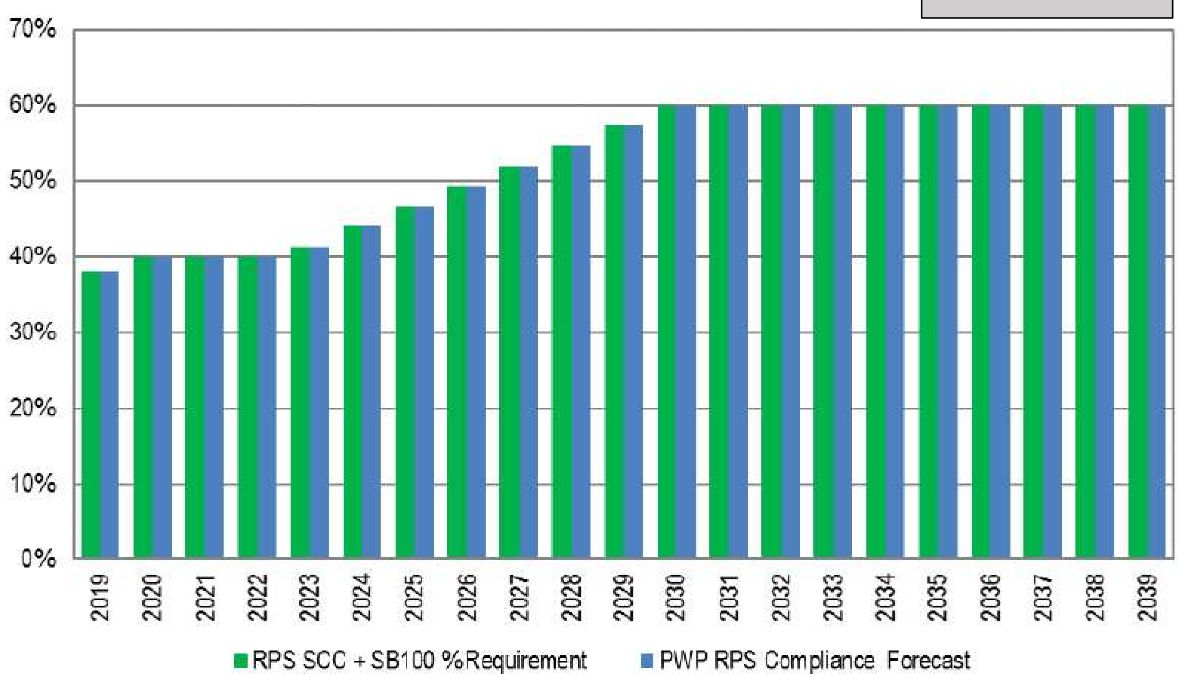
Source: 2018 IRP.



Source: Pace Global

Exhibit 37: SCC + SB 100 – RPS Compliance

Source: 2018 IRP.



Source: Pace Global

A5. Resource Adequacy

There are three types of Resource Adequacy (RA): System, Local, and Flex. The System RA requirement is set by the CAISO, and for this 2021 IRP Update is assumed to be PWP's projected peak load (coincident with the peak load of the entire CAISO), plus a 15 percent planning reserve margin (PRM). Local and Flex RA are provided by PWP's Glenarm units, supporting local reliability and the CAISO's need for generation that can ramp up and down relatively quickly in response to system conditions. The California Public Utilities Commission (CPUC) establishes RA obligations for some load-serving entities.[70] PWP is not subject to the jurisdiction of the CPUC, but PWP is a Participating Transmission Owner and operates within the CAISO.

In the event of a capacity shortage, CAISO requests bids for resource adequacy (capacity) under its Capacity Procurement Mechanism (CPM).[71] The CPM auction has a soft-offer cap of \$6.31/kW-month (\$75.66/kW-year), based on the cost of a combined cycle plant.[72] Currently, capacity shortages in CAISO can be charged that price. Prices resulting from the CPM can be lower than the transactions actually executed in the resource adequacy market, because some entities are subject to both CAISO and CPUC penalties. As a result, the prices of transactions in the resource adequacy market can exceed the CPM soft-offer cap.[73] Therefore, current CPM prices and current costs of new capacity resources are not the most reasonable prediction of future capacity prices.

A6. Avoided Distribution Costs for Evaluation of Local Storage

Earlier in 2021, PWP used the CPUC's Avoided Cost Calculator (ACC) for Southern California Edison (SCE), with PWP-specific modifications related to energy and emissions, for estimates of avoided costs used in determining PWP's energy efficiency goals. For this 2021 IRP Update, PWP used version 1b of the ACC (June 22, 2021).[74] For distributed energy resources, demand response programs, and energy storage, the ACC provides estimates of avoided costs, including generation capacity, energy, GHG emissions, and transmission/distribution (T&D) capacity.[75]

For storage, the ACC provides estimates of potential revenues from ancillary services that batteries can supply to the grid, which are ignored here. The ACC is used to determine avoided costs for California's investor-owned utilities, which implies financing assumptions (cost of equity capital, federal/state income taxes, and private discount rates) that do not apply to PWP, so the comparison here starts with overnight capital costs and uses simplified PWP-specific financing assumptions. Not all future distribution costs can be completely avoided by distributed storage or behind-the-meter resources; some would be deferred instead.[76] For SCE's distribution system, the ACC reports near-term marginal costs, unspecified deferred costs, and long-term marginal costs.[77] ACC Tables 24, 25 and 32 show a wide range of potentially avoidable or deferrable costs, both specified and unspecified, which reflects the variability in situation-specific, near-term and long-term projects (all in $/kW-year).

Table 24. Near-Term Distribution Marginal Costs

	PG&E	SCE	SDG&E
Circuits only		$12.24	
B-Bank Substations		$12.30	
A-Bank Substations		$3.07	
Subtransmission		$0.86	
Total Distribution Capacity ($/kW-yr)	$14.49 ($2019)	$28.47 ($2018)	$3.66 ($2019)

Table 25. Unspecified Distribution Deferral Costs by IOU

Line	Number of Overloads	PG&E	SCE-Substations (B-Bank)	SCE-Circuits	SDG&E	Notes:
1	Actual Overloads	224	35	226	11	[1]
2	Counterfactual Overloads	271	50	349	25	[2]
3	Number of Proposed Projects	180	N/A	N/A	10	[3]
4	Percentage of Overloads addressed by Load Transfers	20%	20%	20%	9%	[4] = 100% - ([3]/[1])
	Overload Capacity					
5	Actual Overloads (kW)	289,880	269,140	634,702	10,039	[5]
6	Counterfactual Overloads (kW)	349,018	286,660	643,360	25,320	[6]
7	Deferrable Counterfactual Overloads (kW)	280,461	229,328	514,688	23,018	[7] = [6] x (100% - [4])
	Project & Planned Investment Costs					
8	Total Cost of Planned Investments in DDOR Filing ($)	$390,416,858	$350,016,877	$288,412,287	$17,800,000	[8]
9	Capacity Deficiency that Planned Investments Mitigate (kW)	323,844	269,140	634,702	17,178	[9]
10	Unit Cost of Deferred Distribution Upgrades ($/kW)	$1,205.57	$1,300.50	$454.41	$1,036.21	[10]* = [8] / [9]
	System Level Avoided Distribution Costs					
11	Deferrable Capital Investment	$338,114,662	$298,241,326	$233,877,317	$23,851,370	[11] = [10] x [7]
12	5 Year Total forecasted DER (kW)	2,285,003	2,911,430	3,113,110	625,460	[12]
13	Distribution Deferral Value ($/kW)	$147.97	$102.44	$75.13	$38.13	[13] = [11] / [12]
14	IOU Specific RECC	9.79%	11.49%	11.45%	7.65%	[14]
15	Capacity Deferral Value ($/kW of DER installed-yr)	$14.49	$11.77	$8.60	$2.92	[15] = [13] * [14]
	O&M Distribution Costs					
16	O&M Deferral Value ($/kW-yr)	$0.00	$6.74	$21.98	$20.26	[16]
17	O&M Deferral Value ($/kW of DER installed -yr)	$0.00	$0.53	$3.63	$0.75	[17] = [16] * [7] / [12]
18	**Unspecified Marginal Cost ($/kW of DER installed-yr)**	**$14.49**	**$12.30**	**$12.24**	**$3.66**	[18] = [15] + [17]

Table 32. Long-term Distribution Marginal Capacity Costs for SCE ($2018)

	SCE Distribution Marginal Capacity Costs (2018$)
Subtransmission ($/kW-yr)	$40.00
Substation ($/kW-yr)	$25.00
Local Distribution ($/kW-yr)	$102.90
Total ($/kW-yr)	$167.90

A methodology that uses the long-run marginal cost of distribution capacity to parallel the expected lifetime of storage capacity, combined with the simple assumption that each MW of storage avoids one MW of investment somewhere in the distribution system, yields an avoided-cost range of about $30-$110/kW-year (in $2022, rounding from Table 32 and assuming 3% inflation from 2018 to 2022, the first year of the study period for this 2021 IRP Update).[78] These annual amounts are probably too high because they use IOU financing (debt and equity, with returns sufficient to pay income taxes) rather than municipal debt (tax-free), but might be too low if PWP's system is older or weaker than SCE's on average. The following table provides corresponding data for utility-scale storage options, using the inputs to EnCompass ($2022).[79]

Annual Fixed Cost of 50 MW of New Storage		
	4-hr	**8-hr**
Overnight capital ($/kW)	$ 1,000	$ 1,750
Service life = debt life	20	20
Debt service cost	3.5%	3.5%
Cost per kW-year	$ 70	$ 123
FOM per kW-year	$ 25	$ 50
Annual cost per kW-year	$ 95	$ 173

The range of storage costs is $95-$173/kW-year; the range of long-run avoided distribution costs is lower, at $25-$100/kW-year. In this very simple exercise, some optimally-placed, utility-scale storage inside the City might be partially justified by avoided costs (as well as revenues from ancillary services, which are not estimated here). These simple calculations are not a substitute for the detailed analyses required before deciding on specific investments, but provide some guidance for planning purposes. In addition, local, small-but-utility-scale storage may qualify for grants, and up-front costs may be reduced by avoided or deferred distribution costs.

A7. Workbooks for Figures and Tables

Figures 1-2: 2021 PWP IRP Update Results+SCC+Graphs, tab “2021 Update”.

Figures 3-8: 2021 PWP IRP Update Results 9.23.21 (5.30pm)

Figure 11: 2021 PWP IRP Update Results 9.23.21 (5.30pm), tab “2021 Update Portfolio”.

Figure 12: 2021 PWP IRP Update Results 9.23.21 (5.30pm), tabs “2021 Update Portfolio” and “Historical and Fcst Loads”.

Figure 13: 2021 PWP IRP Update Results 9.23.21 (5.30pm), tabs “2021 Update Portfolio” and “2021 Monthly Load, EV, DR Data”.

Figure 14: 2021 PWP IRP Update Results 9.23.21 (5.30pm), tabs “2021 Update Portfolio” and “Historical and Fcst Loads”.

Figure 15: Demand Shape.

Figure 17: PWP Emissions

Figure 18: 2021 PWP IRP Update Inputs, tab “Cap & Trade”.

Figure 19: 2021 PWP IRP Update Inputs, tab “SCC”.

Figure 20: 2021 PWP IRP Update Inputs, tab “RPS”.

Figure 21: Generation Profiles, using Horizons Energy North American Market Database https://www.horizons-energy.com/data/ and PWP’s own records for named resources.

Figure 22: 2021 PWP IRP Update Inputs, tab “PPA Math”.

Figure 23-24: 2021 PWP IRP Update Inputs, tab “Capacity Accreditation”.

Figure 25: 2021 PWP IRP Update Inputs, tab “Cost of Unserved Capacity”.

Figure 29: Vehicle Population.

Figure 31: Bass Diffusion.

Figures 32-41: 2021 PWP IRP Update Results 9.23.21 (5.30pm), tabs (a) 2018 Refresh Portfolio, (b) 2021 Update Portfolio, (c) Portfolio Figures (1) and (2); and (d) 2018 Refresh and 2021 Update Enviro & Cap.

Figure 42: 2021 PWP IRP Update Results 9.23.21 (5.30pm), tab Annual Revenue Requirement.

Figures 43-45: 2021 PWP IRP Update Budget 9.22.21, tab Avoided RSC Detail.

Table 6: 2021 PWP IRP Update Inputs, tab "Emission Rates".

Table 10: 2021 PWP IRP Update Inputs, tab "Demand Response".

Table 14: 2021 PWP IRP Update Budget 9.22.21, tab Power Fund FY22.

Endnotes

[1] The spot market is defined in these charts as purchases minus sales. The sum of the slices is not 100 percent due to rounding.

[2] The 2018 IRP can be found at https://ww5.cityofpasadena.net/water-and-power/powerirp/. PWP's IRPs prior to 2018 were developed before the state mandate in SB 350 (2015). IRPs are subject to regulation by the CEC.

[3] See the 2018 IRP, section VI, p. 130.

[4] To support the Update, PWP issued a task order to ACES Power Marketing LLC under an existing contract for modeling work using EnCompass, an updated Electric Vehicle (EV) load forecast, and a detailed look at energy storage options. PWP used an option in its 2018 contract with Northwest Economic Research LLC (NWER), for overall quality control, continuity of effort from 2018, coordination between ACES and PWP, review of ACES' modeling work, and assistance in the preparation of reports and briefing materials.

[5] Some input data used in EnCompass is proprietary and can be displayed only in figure form.

[6] In this Update, ancillary services are not modeled.

[7] In addition to MW constraints, "loss factors" on interconnections were imposed to reflect margins added to variable fuel and VOM costs to ensure that off-system sales created financial gains for rate-payers.

[8] PWP will leave the Intermountain Power Project in mid-2027, eliminating its use of coal and natural gas generation in Utah. Decisions will eventually be required regarding PWP's remaining gas-fired generation in Burbank and Pasadena.

[9] Exhibits 34-37 from 2018, showing major results, are attached to this report. Because of the constraints imposed in modeling, the 2018 Refresh portfolio shows large and unrealistic capacity/energy deficits and costs after 2039. Projections of the 2018 Refresh portfolio beyond 2039 are not provided.

[10] Decisions will be needed regarding life-extension investments in PWP's remaining fossil-fuel plants (Glenarm and Magnolia), but are not modeled in this Update.

[11] SB 100 identifies December 31, 2045 as the "zero-carbon deadline": "SEC. 5. Section 454.53 is added to the Public Utilities Code, to read: 454.53. (a) It is the policy of the state that eligible renewable energy resources and zero-carbon resources supply 100 percent of all retail sales of electricity to California end-use customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045." After 2045, the model assumes that (a) PWP can buy allowances to cover emissions up to the first 1% of actual GHG emitted in 2044/2045 at a price forecasted by IHS Markit, and above that 1%, PWP would pay a penalty equal to $2,000/MWh for fossil-fuel generation. Over time, PWP will monitor its operations and make decisions to ensure compliance with SB 100 on schedule.

[12] See https://www.dgs.ca.gov/bsc.

[13] Traditional load forecasting techniques may not be reasonable for the future.

[14] The table shows savings in Pasadena due to statewide adoption of new Codes and Standards, but PWP's goals are driven by its own programs, not statewide standards. Source: Agenda Report to City Council, May 17, 2021.

[15] Greenhouse gas (GHG) emissions are measured by "CO2e", which combines several emission types into a single "carbon dioxide equivalent" index. See https://ww2.arb.ca.gov/ghg-inventory-glossary#:~:text=Carbon%20Dioxide%20Equivalent%20(CO2,mass%20of%20another%20greenhouse%20gas.According to the California Air Resources Board, CO2e is "[a] metric used to compare emissions of various greenhouse gases. It is the mass of carbon dioxide that would produce the same estimated radiative forcing as a given mass of another greenhouse gas. Carbon dioxide equivalents are computed by multiplying the mass of the gas emitted by its global warming potential." Allocated allowances are sometimes called "free" or "no-cost", but have values set in the California carbon market; PWP has an incentive to reduce emissions and can both sell the "saved" allowances and "bank" them for future compliance.

[16] Purchases of allowances are limited in EnCompass to 1% of the compliance obligation. Based on CARB regulations, PWP's allocated allowances are expected to exceed its compliance obligations through 2030. Allowances are allocated, traded and priced in metric tonnes, but modeled in short tons.

[17] Source: IEPR S-2 data submitted by PWP to the CEC.

[18] See https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/allowance-allocation/edu-ngs and https://ww2.arb.ca.gov/sites/default/files/2021-02/ct_reg_unofficial.pdf.

[19] PWP uses a recent federal projection of SCC, measured in $/tonne/year (metric tonne = 2,200 pounds) for each year of the study period. See U.S. Government, Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990", February 2021, pp. 32-34, and embedded references. In 2018, the IWG was disbanded by Executive Order; the IWG was re-established in 2021 by Executive Order. The SCC is an estimate of the global consequences of a tonne of carbon emitted in a given year, for as long as that tonne remains in the atmosphere and causes environmental and economic damages. For example, the SCC in 2040 is the present discounted value of global economic costs, including environmental remediation, of one tonne of carbon emitted in 2040 over the lifetime of that tonne.

[20] Integrated Assessment Models (IAMs) are discussed in the IWG Technical Support Document, sections 1.1 and 1.2. IAMs project changes in global economic and environmental conditions due to GHG emissions, in contrast to EnCompass, which builds projected power supply portfolios for individual utilities such as PWP, including emissions from fossil-fuel plants.

[21] Attachment A3 shows the SCC used in 2018: "The SCC is approximated by the greater of (a) $50/MT (metric tonnes of CO2e, in $2017, escalated at five percent per year) and (b) the CPUC Carbon Planning Price, as shown in Exhibit 12. After 2030, the SCC is held constant. This is the price as determined by the CPUC Resolve Model (the model used to develop the IRP analysis for CPUC jurisdictional entities). By 2030, the SCC reaches the planning price of $150/tonne set by the CPUC, in Decision 16-02-007 of February 2018, and continues at this level for the remainder of the forecast, as shown in Exhibit 12 and Exhibit 13. These Exhibits also show the SCC compared with the cost of carbon used in other scenarios. The Minimum Cap and Trade floor price is the minimum that the Cap and Trade price for carbon allowances can be, as set out in the Cap and Trade regulations at the CARB." At the time, this function was determined to be reasonable by PWP and its Stakeholders. The function resulted in a noticeable increase in the projected SCC in 2030, as shown in Exhibit 12 from the 2018 IRP (page 21), which also shows the *floor prices* and expected (*Base Case*) prices in the California carbon allowance market.

[22] See CEC, "Amendments to Regulations Specifying Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities", 16-RPS-03, July 12, 2021, sections 3204(a)(6) and 3204(a)(7); available at https://efiling.energy.ca.gov/Lists/Docketlog.aspx?docketnumber=16-RPS-03.

[23] The energy delivered under the PCC1/PCC2 contract is not included in the model, but is liquidated (sold) into the CAISO spot market, with the RECs retained by PWP for RPS compliance.

[24] See https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/renewables-portfolio-standard-0. Geothermal resources are not available until 2024, under the assumption that current market conditions will limit availability to new projects with newly negotiated PPAs.

[25] Year-specific RPS obligations (in percent) are connected by linear functions to identify the annual constraints in the model for the renewable content of PWP's portfolio.

[26] Monthly on- and off-peak energy prices and greenhouse gas (GHG) prices are from IHS Markit, "North American Power Market Outlook data tables", November 2020. Hourly price shapes are from IHS Markit, "North American Power Market Hourly Prices Outlook data tables - nominal", November 2020. This data is proprietary.

[27] Sources: IHS Markit, "North America Solar PV Capital Cost and LCOE Outlook", December 2020; North America Wind Capital Cost and LCOE Outlook", December 2020; U.S. Battery Storage Capital and Levelized Cost Outlook", January 2021; North American Power Market Outlook", November 2020; North American Power

Market Hourly Prices Outlook", November 2020; Assessing the Capacity Value of Solar in US Power Markets", October 2020.
[28] Source: IHS Markit, "North America Wind Capital Cost and LCOE Outlook", December 2020".
29 Source: IHS Markit, "North America Solar PV Capital Cost and LCOE Outlook", December 2020. NREL data is provided in DC for commercial and residential solar, converted to AC using a 1.34 conversion ratio (i.e., each 1.34 kW of DC solar panels yields 1.0 kW of AC output). See https://atb-archive.nrel.gov/electricity/2020/data.php. Degradation of solar PV panels will be addressed in the 2022-23 IRP.
[30] See the discussion of demand response below.
[31] The 2.5% assumption is from https://atb.nrel.gov/electricity/2020/index.php?t=st.
[32] See https://atb.nrel.gov/electricity/2020/index.php?t=gt.
[33] Fixed O&M costs are from IHS Markit, "North America Solar PV Capital Cost and LCOE Outlook", December 2020.
[34] The generation profiles of both stand-alone batteries and hybrid renewable/storage power plants depend on contractual specifications for charging/discharging energy into/from storage that are unknown at this time.
[35] See LA100, Chapter 3, pages 209-10. Interruptible loads may also provide contingency reserves, which are not evaluated here.
[36] Illustrations of DR resources are in Figure 110 of the LA100 report. See "Chapter 3: Electricity Demand Projections", https://maps.nrel.gov/la100/report.
[37] See https://weatherspark.com/y/1718/Average-Weather-in-Pasadena-California-United-States-Year-Round.
[38] LA100, Table 48, calculates resource availability as a function of system peak demand.
[39] Annual energy value is the sum of the hourly generation output of the resource multiplied by the hourly nodal prices where the energy is delivered to the grid, expect for storage, where value is measured by arbitrage value: the difference between the lower price of energy when storing and the higher price when discharging.
[40] Source: eia.gov/electricity/data/browser.
[41] See the CPUC's "2021 Filing Guide for System, Local and Flexible Resource Adequacy (RA) Compliance Filings, R.19-11-009, April 23, 2021, at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials; http://www.caiso.com/Documents/RevisedStrawProposal-ResourceAdequacyEnhancements.pdf; and https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials.
[42] See http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=9A94E71F-5542-49E8-BFBF-B9E00A2EC11B.
[43] See CAISO, "NetQualifyingCapacityList-2021", 10.29.2020, http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx. Geothermal and hydro resources use the average of accreditation values for 2017-19 to avoid outlier values.
[44] See CAISO, "2021 Tech Factors" tab in "NetQualifyingCapacityList-2021". The CPUC uses ELCC for solar and wind and methodologies based on availability for the other non-dispatchable resources. See https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-compliance-materials/final-2021-ra-guide_20210423.pdf.
[45] IHS Markit, "Assessing the capacity value of solar in the US power markets", October 2020.
[46] CPUC, "Incremental ELCC Study for Mid-Term Reliability Procurement", August 31, 2021, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/20210831_irp_e3_astrape_incremental_elcc_study.pdf.
[47] See "2020 ACC Net Cone v1c (2)", https://willdan.app.box.com/v/2020CPUCAvoidedCosts/folder/136743423347, averaged with "2021 ACC Net Cone v1b", at https://willdan.app.box.com/v/2021CPUCAvoidedCosts/folder/136593940728, tab "Net CONE", row 8 ("ELCC Adjustment").
[48] Without a penalty, the model would assess a persistent and large short position to be acceptable.
[49] See "2021 ACC Net Cone v1b" at https://willdan.app.box.com/v/2021CPUCAvoidedCosts/folder/136593940728. The 2022 value is $14/kW-month, set by ACES to ensure that the System RA penalty exceeds the cost of the 4-hour, 5 MW battery. See "ELL Adjusted Nominal Fixed Costs" row in "Net Cone" tab.
[50] "Net cost" refers to the capital cost minus forecasted revenues from ancillary services provided to the grid, on the assumption that the buyer (e.g., PWP) will pay for the actual injection and scheduled withdrawal of energy from the hybrid renewable power supply, and that the developer will retain any revenues from other services provided to the grid. Other business models may emerge.

[51] See "Net CONE" row in "Net Cone" tab. ACES averaged 2020 data (forward market prices for System RA blended to storage in 2028) and 2021 data (forward market prices for System RA blended to storage in 2037). The RA penalty and the RA forward market prices involve blending and averaging from two datasets. The capacity penalty is based on CPUC data, and the System RA price is based on CPUC data and market quotes.
[52] See 2018 IRP, p. 83.
[53] See https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf
[54] See https://www.emp.lbl.govpublicationsare-coupled-renewable-battery-power
[55] See https://www.eia.gov/todayinenergy/detail.php?id=45596
[56] Two-hour and six-hour storage is not common. Conversion of capital costs to energy prices requires assumptions about the capacity factor of the batteries, which are limited by the specific storage technology and contractually defined by charging cycles to allow warranties regarding performance and longevity. For this study, the capacity factor for storage is set at 15 percent, defined as the weekly value of one full discharge per day (i.e., 100%/7).
[57] See https://www.nrel.gov/docs/fy18osti/70384.pdf. MACRS (Modified Accelerated Cost Recovery System) reduces federal taxes and thus the cost to a private developer.
[58] Preliminary analysis showed that some amount of local storage without the 25% and 50% discounts is cost-effective during the study period, and so the 2021 Update portfolio was re-run without those discounted options.
[59] See CEC, "Vehicle Population_Last updated 04-30-2021", ZEV and Infrastructure Stats Data. https://www.energy.ca.gov/files/zev-and-infrastructure-stats-data. The CEC uses vehicle registrations from the California DMV.
[60] See https://www.gov.ca.gov/2020/09/23/governor-newsom-announces-california-will-phase-out-gasoline-powered-cars-drastically-reduce-demand-for-fossil-fuel-in-californias-fight-against-climate-change/.
[61] See NREL, "Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States", 2018. https://www.nrel.gov/docs/fy18osti/71500.pdf. See Bass, F.M., "A New Product Growth Model for Consumer Durables", *Management Science*, 15(5), January 1969, 215-227.
[62] See https://afdc.energy.gov/evi-pro-lite
[63] Given the available data from the DMV, this report uses registration in a Pasadena zip code as the proxy for charging in PWP service territory. In reality, charging with energy supplied by PWP and registration in Pasadena are likely to differ, because EVs are "mobile load".
[64] In the 2018 IRP, the RPS standard was set at a constant level of 60 percent after 2030; in this Update, the RPS standard is assumed to continue to grow after 2030 to reach the zero-carbon standard by the end of 2045.
[65] Sunk costs are past investments that have no current market value; fixed costs are regularly incurred (such as interest on debt) and the level of such costs is unrelated to either the output of a generating resource, the use of a storage resource, or the amount of energy delivered to either retail or wholesale customers.
[66] This figure excludes fixed costs that were not modeled in either portfolio, because the decisions both to add/retire and to dispatch resources are independent of those fixed costs.
[67] The production cost model operates in calendar years, to model outputs have been adjusted to fiscal years to match PWP's budget. Fuel purchased for wholesale transactions is covered by off-system revenues, and not charged to PWP ratepayers.
[68] The recovery of fixed costs through energy charges is traditional, but inefficient and possibly unsustainable over the long run as the mix of fixed and variable costs changes and retail rate design shifts to encourage carbon-free electrification. PWP is engaged in a separate examination of retail rate design.
[69] Although resource additions are forecasted in 2022 in the 2021 Update portfolio, it is likely that the first new additions to the PWP portfolio will not occur before 2023.
[70] See https://www.cpuc.ca.gov/ra/
[71] Per §42A.2.3 of its Tariff, the CAISO may assign CPM capacity to a deficient load-serving entity pursuant to the Competitive Solicitation Process (CSP) outlined in §43A.4, subject to a $6.31/kw-month "soft offer" cap. Section 43A.4.1.1 of the Tariff allows for offers above the soft cap if the "Resource Owner of Eligible Capacity makes the required resource-specific cost filing with FERC pursuant to Section 43A.4.1.1.1."
[72] See http://www.caiso.com/Documents/Presentation-CapacityProcurementMechanismSoftOfferCap-Aug6-2019.pdf.
[73] The CPUC approved in 2022 a plan for entities to accumulate "penalty points" for deficiencies, with higher penalties in the summer. Penalty points yield penalty multipliers. Because entities may go to the System RA market to avoid these penalties, prices in the RA market can be higher than the CAISO's CPM. See Item #16, p. 80 of "Decision Adopting Local Capacity Obligations For 2022-2024, Flexible Capacity Obligations For 2022", and

"Refinements To The Resource Adequacy Program", https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M389/K603/389603561.PDF.

[74] See "2021 Distributed Energy Resources Avoided Cost Calculator Documentation", prepared for the California Public Utilities Commission, https://www.cpuc.ca.gov/general.aspx?id=5267, https://www.ethree.com/cpuc-acc-downloads-page, and https://willdan.box.com/v/2021CPUCAvoidedCosts.

[75] Electrification programs that increase loads could cause new costs to be incurred, e.g., reinforcement of the distribution system.

[76] The estimates here are limited to distribution-level assets, because transmission-level investments are driven by regional, not just local, considerations.

[77] A-Bank substations transform 220 kW to 66 kV; B-Bank substations transform 66 kV to lower voltages.

[78] Table 32 is explicitly a long-run analysis of avoidable distribution-level investments, and thus is most comparable to utility-scale energy storage. Table 24 is based on a methodology that compares levels of distributed energy resources driven by various policies, incentives and programs; utility-scale storage would be driven by other considerations. Table 25 is driven by an analysis of potentially over-loaded distribution lines, but is limited to deferrable investments, not replacement investments. See "2021 Distributed Energy Resources Avoided Cost Calculator Documentation", pp. 54-66.

[79] Overnight capital costs are rounded in nominal mid-2020s dollars, to emphasize that these are estimates and projections. Some components of costs and benefits of storage are left out.