Pasadena Water and Power
2018 Power Integrated Resource Plan

Supported by Northwest Economic Research LLC & Pace Global, A Siemens Industry Business & Pasadena Water and Power

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December 2018

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List of Acronyms

AAEE	Additional Achievable Energy Efficiency
ARB	Air Resources Board of the State of California; also CARB
BA	Balancing Area
B/C	Benefit/Cost ratio
BEV	Battery Electric Vehicle
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CalEPA	California Environmental Protection Agency
CAGR	Cumulative Annual Growth Rate
CAP	Climate Action Plan of the City of Pasadena
CCGT	Combined cycle combustion turbine
CDD	Cooling degree days
CEC	California Energy Commission
CES	CalEnviroScreen
CO2e	Carbon Dioxide Equivalent
COD	Commercial Operation Date
CPUC	California Public Utilities Commission
CRAT	Capacity Resource Accounting Table
CSC	Customer Service Center
CT	Combustion turbine
DAC	Disadvantaged Community
DCFC	Direct Current Fast Charge
DER	Distributed Energy Resource
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
DSM	Demand Side Management
EBT	Energy Balance Table
EC	Energy Charge
EE	Energy Efficiency
EEP	Energy Efficiency Partnering Program
EIA	Energy Information Administration
ELCC	Energy Load Carrying Capability
EO	Executive Order
EPC	Engineer-Procure-Construct
ESAP	Energy Savings Assistance Program
EV	Electric Vehicles
FiT	Feed-in Tariff
FOM	Fixed Operating and Maintenance costs
FY	Fiscal Year of the City of Pasadena

GDP	Gross Domestic Product
GEAT	GHG Emissions Accounting Table
GHG	Greenhouse Gases, as defined under California law
GPCM	Gas Pipeline Competition Model
GT-2	Generator-turbine #2 at the Glenarm plant in Pasadena
GWh	Gigawatt-hour; one thousand MWhs
HDD	Heating degree days
HIP	Home Improvement Program
HVAC	Heating-Ventilating-Air Conditioning
IOU	Investor-Owned Utility
IPA	Intermountain Power Agency
IPP	Intermountain Power Project, Delta, Utah
IRP	Integrated Resource Plan
kV	Kilovolt
L1, L2, L3	EV Charging Levels 1-3
LADWP	Los Angeles Department of Water and Power
LCR	Local Capacity Requirements
LED	Light-emitting diode
LMP	Locational Marginal Price of energy
LNG	Liquified Natural Gas
LSE	Load Serving Entity (within the CAISO)
LTCE	Long-Term Capacity Expansion
MSRC	Mobile Share Air Pollution Reduction Review Committee
MVA	Megavolt-Amp
MW	Megawatt, a measure of instantaneous production or consumption of energy
MWh	Megawatt-hour, a measure of the production or consumption of energy over time
MT	Metric tonnes
NEM	Net Energy Metering tariff
NPV	Net Present Value
OEHHA	Office of Environmental Health Hazard Assessment
PCC	Portfolio Content Category
PCT	Participant Cost Test
PEV	Plug-in Electric Vehicle
PHEV	Plug-in Hybrid Vehicle
PMC	Pasadena Municipal Code
POU	Publicly-Owned Utility, such as PWP
PPA	Power Purchase Agreement
PSA	Power Sales Agreement
PTO	Participating Transmission Owner (in the CAISO)
PUC	Public Utility Code of the state of California
PV	Photo-voltaic
PWP	Pasadena Water and Power, a department of the City of Pasadena
RA	Resource Adequacy, a capacity standard of the CAISO
REC	Renewable Energy Credit
RFP	Request for Proposals

RIM	Rate Impact Measure
RPS	Renewable Portfolio Standards of the State of California
RPT	RPS Procurement Table
SB 100	Senate Bill 100
SB 350	Senate Bill 350
SCAQMD	South Coast Air Quality Management District
SCC	Social Cost of Carbon
SCE	Southern California Edison
SCPPA	Southern California Public Power Authority, a joint powers agency of which the City of Pasadena is a member
SCT	Social Cost Test
SDG&E	San Diego Gas and Electric Company
SoCalGas	Southern California Gas Company
STAG	Stakeholder Group advising PWP
T&D	Transmission and distribution
TE	Transportation Electrification
TOU	Time-of-Use (Rates)
TRC	Total Resource Cost test
UCT	Utility Cost Test
VLCP	Voluntary Load Control Program
WECC	Western Electricity Coordinating Council
WeDIP	Water and Energy Direct Install Program
WSPP	Western Systems Power Pool

Acknowledgements

This 2018 Integrated Resource Plan benefited greatly from the advice and efforts of multiple individuals, including the Stakeholder Technical Advisory Group, City Management (Julie Gutierrez and Steve Mermell), PWP Management (Gurcharan Bawa - General Manager, Eric Klinkner - Deputy General Manager, Anthony D'Aquila - Acting Assistant General Manager Power Supply and Wholesale Operation Manager, Shari Thomas- Assistant General Manager, Finance and Marvin Moon - Assistant General Manager, Power Delivery), PWP Power Resources Staff (Mandip Samra, Ren Zhang and Mauricio Mejia), PWP Staff, and residents of the City of Pasadena.

I. Introduction and Background

A. Introduction

1. Pasadena Water and Power Department

Under its municipal charter, the City of Pasadena has operated a Water and Power Department (PWP and its predecessors) since the early 20th century. PWP delivers about 1.1 million megawatt-hours (MWh) of energy annually to 65,000 retail customers, with an historical peak load of about 320 MW. To serve these customers, over time PWP has assembled a portfolio of generating resources, including gas-fired, large and small hydro, coal, nuclear, solar, wind, geothermal, and landfill gas. PWP holds partial shares of many of these resources to benefit from economies of scale and to share risks. Some of these resources are owned by PWP (e.g., the local Glenarm gas-fired units and, through the Southern California Public Power Authority (SCPPA), a share of the Magnolia gas-fired unit in Burbank), but most are purchased under long-term contracts. In addition, PWP has ownership and contract rights on various transmission lines, which were turned over to the California Independent System Operator (CAISO) in 2004 when Pasadena became a Participating Transmission Owner (PTO) in the CAISO.

Decisions of the Pasadena City Council over the last ten years demonstrate a commitment by the City to shift the City's energy supply portfolio more quickly than required to low-carbon and renewable resources. Previous Integrated Resource Plans (IRPs) have led to Renewable Portfolio Standard (RPS) targets and greenhouse (GHG) reduction targets that exceed state mandates. Pasadena has also adopted a Climate Action Plan and has been a leader in promoting energy efficiency. With this IRP, Pasadena again moves beyond current regulations and adopts a strategy of compliance with SB 100, enacted in September 2018.

2. Statutory Mandate for Integrated Resource Plans

PWP has multiple obligations under state and federal law regarding the operation of its municipal electric utility. One of those obligations in California is the preparation of Integrated Resource Plans (IRPs) on a regular basis, to help guide future decisions and ensure compliance with state regulations requiring increases in the procurement of renewable energy (Renewable Portfolio Standards, or RPS) and reductions in GHG as part of the state's overall objective of addressing climate change.

In 2015, SB 350 established the requirement that certain utilities in California must develop and file IRPs. Pasadena is large enough, measured by total annual sales of energy, to fall under this requirement. The California Energy Commission (CEC) is charged with developing regulations that establish the required and recommended details of the IRPs. The CEC's regulations are subject to change over time; this IRP relies on CEC regulations as of early October 2018.[1] The first deadline under current law is the adoption of a conforming IRP by January 1, 2019, with all documentation filed at the CEC by April 30, 2019.

3. Objectives of the IRP

The objectives of the IRP are to optimize the PWP portfolio to achieve a sustainable balance of system reliability, fiscal responsibility, environmental stewardship and compliance with SB 350 and other applicable legislation and regulatory mandates. Components of each objective follow. Metrics and check-lists for these objectives are developed and implemented in this IRP. Scenarios for compliance with recently enacted SB 100 are also presented.

a. System Reliability

- Maintain a capacity planning reserve margin of at least 15%;
- Maintain CAISO Resource Adequacy requirements in compliance with the CAISO Tariff (including System Resource Adequacy, Local Capacity Resources, and Flexible Resource Adequacy Capacity requirements);
- Preserve, optimize, and enhance local generation to reduce risk of over-reliance on a single transmission tie at the TM Goodrich substation;
- Integrate remote and variable generation (wholly owned or joint project participation), demand side management and distributed generation.

b. Fiscal Responsibility

- Maintain stable, competitive and affordable rates;
- Minimize the impact of market and price volatility in fuel and other cost factors;
- Minimize generation-related direct costs, including costs of greenhouse gas (GHG) compliance;
- Provide transparency in expected power-related rates for the average ratepayer, both in terms of percentage and dollar impact.

c. Environmental Stewardship

- Minimize the environmental impact of meeting Pasadena's electric energy needs;
- Comply with all federal, state and local laws and regulations;
- Meet or exceed required standards for renewables (RPS percentage) and GHG emission reductions.

[1] Vidaver David, Melissa Jones, Paul Deaver, and Robert Kennedy (2018). *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines (Revised Second Edition)*, California Energy Commission, Publication Number: CEC-200-2018-004.

d. Compliance with SB 350

- Meet or exceed the mandates of SB 350 (such as, but not limited to, 50% RPS by 2030 and 40% reduction of GHGs by 2030, based on 1990 levels);
- Follow the CEC Publicly Owned Utility (POU) Integrated Resource Plan Submission and Review Guidelines, Publication CEC-200-2017-004-CMD2 (including the most recently approved CEC POU IRP Submission and Review Guideline, October 4, 2018).

4. Major Mandates: Renewable Portfolio Standard (RPS) Increases and Greenhouse Gas (GHG) Reductions

Two critical elements of any California IRP are compliance with state regulations on RPS and GHG. Under SB 350, California law requires that utilities such as Pasadena procure 33 percent of their retail sales by 2020, and 50 percent by 2030, from renewable energy resources, including solar, wind, geothermal, biomass, and small hydro.[2] Under SB 100, Pasadena's future renewable obligations will be higher. Currently, Pasadena procures almost 38 percent of its energy from renewable sources, under a voluntary municipal policy that exceeds SB 350 requirements for the present time period.[3] Thus, the IRP must identify likely paths to higher RPS compliance obligations between now and 2030 under SB 350 and SB 100. Missing an RPS obligation can lead to financial penalties to the City, although the City may petition for exemptions under certain circumstances.

California law and regulations also set out targets for GHG reductions by 2030. The state Air Resources Board (ARB) has established Pasadena's share of the target GHG reductions by 2030.[4] To achieve these targets, PWP's GHG emissions must fall to 226,000 metric tonnes (or less) by 2030. The ARB establishes "planning targets", not hard constraints, but the City expects to work toward achieving and exceeding its individual planning target. In addition, the California Public Utilities Commission (CPUC) has required Load Serving Entities (LSEs) in California to adopt either the entity-specific GHG Benchmark (tonnes/year by 2030) or the GHG Planning Price of $150/MWh (by 2030 in $2016[5]). PWP is not an LSE subject to the CPUC but expects that the CEC will move to adopt the same approach (Planning Price). Therefore, the modeling in this IRP examines scenarios that incorporate the CPUC's GHG Planning Price, applied to the dispatchable (discretionary) production of energy from existing gas- and coal-fired facilities.

Both RPS increases and GHG reductions are considered in the development and analysis of various generation portfolios that the City could assemble over the next 20 years, to help ensure compliance with these and other mandates.

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[2] Large hydroelectric resources including PWP's share of Hoover do not count as "renewable" under SB 350. The carbon-free nature of Hoover may be recognized with the implementation of SB 100.
[3] See Exhibit 8, PWP's 2017 Power Content Label.
[4] https://www.arb.ca.gov/cc/sb350/staffreport_sb350_irp.pdf.
[5] "$2016" means that the future dollar values have the real purchasing power that they had in 2016.

As stated earlier, PWP had developed voluntary GHG reduction and RPS targets, above and beyond state mandates. As a result of previous IRPs, the current GHG target is a 60% reduction by 2030 (higher than the 40% GHG reduction target introduced by the State and the California Air Resources Board, or CARB) and a 40% RPS by 2020 (7% higher than the state mandate of 33% RPS).

5. Additional Mandates (Storage, TE/EVs, EE, DR, DG, Reliability)

In addition to RPS and GHG, state regulations require that Pasadena consider the technical feasibility and cost-effectiveness of energy storage (ES), transportation electrification (TE), doubling of energy efficiency (EE), demand response programs (DR), and distributed generation (DG) or Distributed Energy Resources (DER). All of these have the potential to reduce reliance on fossil fuels, improve air quality, and reduce GHGs broadly.[6] As an operating utility within the CAISO and the Western Electricity Coordinating Council (WECC), PWP also must meet several reliability criteria, to help ensure uninterrupted service to retail loads in the City. This IRP provides information, analysis and guidance on all these aspects.

6. Major Planning Considerations

In addition to meeting broad state mandates, PWP faces specific decisions during the planning horizon of this IRP, including:

- Whether or not to continue participation in the coal-fired Intermountain Power Plant in Delta, Utah after the plant is converted to natural gas in 2025 and existing contractual obligations expire in 2027;
- Whether any modifications may be required at the Glenarm gas-fired power plant in Pasadena;
- Which types and amounts of specific renewable resources should be evaluated and acquired as part of portfolios that meet the state's RPS mandates;
- How to integrate new local distributed generation (e.g., roof-top solar) into the City's distribution system;
- How much energy storage capacity to acquire, inside and/or outside the City;
- Which programs will implement the state goal of doubling energy efficiency by 2030 in the most cost-effective manner;
- Which programs will expand electrification of consumption most cost-effectively (e.g., conversion of transportation from fossil to electric); and
- How to best engage PWP's customers and the public in these decisions.

One purpose of this IRP is to evaluate the consequences of alternatives under consideration for many of these major upcoming decisions.

[6] https://efiling.energy.ca.gov/GetDocument.aspx?tn=223449.

7. Request for Proposals and Contractors

To comply with state mandates, in November 2017 Pasadena issued a Request for Proposals (RFP) to assist the City in developing a detailed IRP covering a 21-year study period of 2019-2039. The City chose Northwest Economic Research LLC (NWER), a local Pasadena business and registered state micro-business, as prime contractor for the 2018 IRP. NWER in turn has subcontracted to Pace Global, a Siemens Industry business, for certain complex analytical tasks, which are critical to assessing the impacts of alternative portfolios on RPS and GHG compliance, reliability mandates, and the rates paid by PWP's customers. Pace Global retained ASWB Engineering (ASWB) and Applied Energy Group (AEG) as subcontractors for specific energy efficiency analyses. The PWP Project Team (Power Resource Planning Staff) and NWER (and its subcontractors) worked closely to develop the assumptions, data inputs and the modeling. In addition, the PWP Project Team and contractors conducted quality assurance on all datasets and outputs. The PWP Project Team also spearheaded the stakeholder process and community outreach efforts.

B. Previous Integrated Resource Plans

This IRP continues PWP's commitment to long-term planning as a tool to help guide several kinds of decisions, including contracts for new generation (long-term and short-term) as well as municipal policies that promote TE, EE, DR and DG. Prior IRPs can be found at https://ww5.cityofpasadena.net/water-and-power/powerirp/.

Previous IRPs were used as guidance documents for actual procurement of resources. PWP's progress toward the 2015 IRP goals are listed below in Exhibit 1. This 2018 IRP supplements the goals of previous IRPs, while also meeting (or exceeding) the SB 350 mandates and looking beyond to the mandates of SB 100.

Exhibit 1: Progress Toward the Recommendations in the 2015 IRP

Recommendation	IRP Goals	Status
Renewable Energy: RPS	40% RPS by 2020; Meet/exceed the mandated level. (state mandate is 33%, PWP's voluntary goal is 40% RPS)	On track; on target for 2018-2020 requirements of 35%, 37.5% and 40%. PWP has secured additional renewable contracts with CODs beginning 2020.
Renewable Energy: Local Solar	Launch Community Solar pilot project by end of 2016.	After a thorough analysis, the Program Development is on hold due to cost, locational issues and implementation hurdles. This will be reconsidered as part of future IRPs.
Renewable Energy: Feed-in-Tariff (qualifying renewable resources located inside the City)	Establish Feed-in Tariff by end of 2016, with 5 MW by 2020, 10 MW by 2027.	Similar to Renewable Community Solar, the Program Development is on hold due to cost and implementation hurdles. This will be reconsidered as part of future IRPs.
Coal Power Displacement	Eliminate coal-fired generation from the portfolio no later than 2027; preserve transmission rights and option to reduce or opt out in 2019.	The IPP renewal contracts provide for coal generation to stop and for a new natural gas power plant to go on-line in 2025. PWP has subscribed for 14 MW in the new gas plant, which will also provide a 1.667% share of transmission capacity in the Southern Transmission System, with an option to reduce subscription or out in late 2019. Considerable GHG reductions have been achieved through power generation decisions in the meantime.
Upgrades to Existing Generation	Evaluate feasibility of repairing GT-2	Feasibility study for GT-2 repairs is complete. Staff recommends repairing the unit.
New Local Gas-Fired Generation	Replace Broadway power plant with a comparably sized new combined cycle plant by 2015.	The GT-5 project achieved commercial operation in December 2016. The capacity for the unit is 71 MW gross and 68.8 MW net.
Energy Savings	Achieve energy savings equal to 1% of annual net energy load and 0.7% of peak.	Updated ten-year goals for FY 2018-2027 were adopted on 3/27/2017. PWP has met energy savings goals from FY 2008 to date.
GHG Emissions Reductions ***(1990 emission approx. 918,600 metric tonnes)***	Reduction of at least 60% from 1990 levels by 2030 (approx. 367,500 metric tonnes).	On track, with a 39% reduction in 2016 (554,628 MT).

Source: Pasadena Water and Power

C. Community Outreach

PWP worked closely with the community to develop the IRP. The Community Outreach efforts were quite extensive. PWP advertised the IRP through social media, billing inserts, local newspapers, and other media outlets. PWP also worked closely with the City Manager to develop the Stakeholder Technical Advisory Group (STAG), which is a group of diverse ratepayers who advised on the development of the 2018 IRP. PWP held three Community meetings and conducted an online survey to solicit community input. As with the development of past IRPs, PWP values the input of the Community and works closely with the Community to identify major concerns and issues. A more detailed analysis on Community Outreach is listed in Section IV.

D. Existing City Policies and Programs

1. Renewable Portfolio Standards

Under SB 350, PWP must acquire 33 percent of its energy for retail loads from renewable resources by 2020, and 50 percent by 2030. As stated above, PWPs more ambitious near-term target is 40% RPS by 2020. To further define the “RPS ramp", the CEC has established “compliance periods” with RPS percentages that step up over time. Exhibit 2 shows the status of currently defined compliance periods, with the RPS percentages for each.

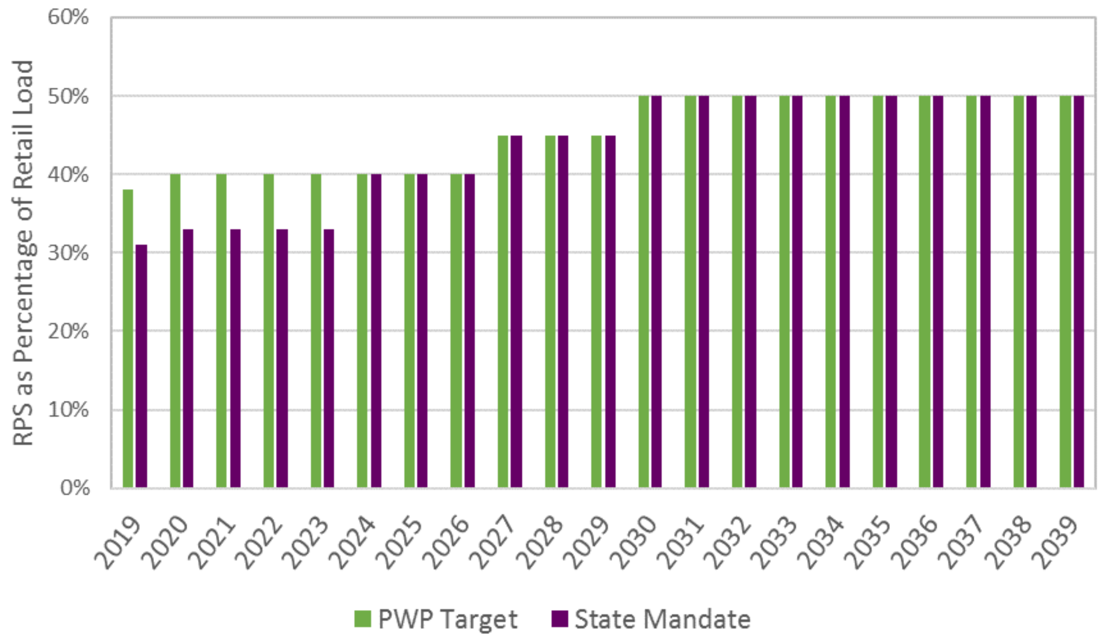
Exhibit 2: SB 350 Renewable Compliance Requirements

<table>
<tr><th colspan="7">RPS Procurement Requirements under SB 350</th></tr>
<tr><td rowspan="6">California RPS Mandatory Procurement Requirement (% of Net Retail Sales)</td><td colspan="2">Compliance Period 3</td><td>Compliance Period 4</td><td>Compliance Period 5</td><td>Compliance Period 6</td><td>Compliance Period 7+</td></tr>
<tr><td>Year</td><td>%</td><td rowspan="5">40% by 12/31/2024</td><td rowspan="5">45% by 12/31/2027</td><td rowspan="5">50% by 12/31/2030</td><td rowspan="5">50% by 12/31/2031+</td></tr>
<tr><td>2017</td><td>27%</td></tr>
<tr><td>2018</td><td>29%</td></tr>
<tr><td>2019</td><td>31%</td></tr>
<tr><td>2020</td><td>33%</td></tr>
</table>

Source: Pasadena Water & Power

In addition to state regulations, PWP has adopted more aggressive voluntary goals through 2020. Exhibit 3 compares PWP’s goals and state mandates through 2039 under SB 350.

Exhibit 3: RPS State Mandates under SB 350 and Pasadena's Voluntary Target



Source: Pasadena Water & Power

Within the overall mandates expressed as percentages, PWP must also comply with CEC regulations that define minimum and maximum RPS Portfolio Content Categories (PCCs). The CEC prescribes three PCCs: PCC1 is energy first delivered to a California Balancing Area (BA), PCC2 is energy that is "firmed and shaped" before delivery to a California BA, and PCC3 is unbundled Renewable Energy Credits (RECs) that are not associated with any energy delivered to California. Generally speaking, PCC 1 energy requirements grow over time, whereas PCC 3 requirements fall. Exhibit 4 shows the PCC requirements established by the CEC under SB 350. Attachments 3, 4 and 5 provide more detail on PCCs.

Exhibit 4: Current RPS PCC Requirements

Portfolio Content Category (PCC)	Description	Usage Limits (% of Renewable Energy)
PCC 1	First point of interconnection inside of California BA; Scheduled into a California BA without substituting electricity from another source; or dynamically transferred into a California BA	Minimum of 50% through 2013; 65% through 2016. 75% beginning in 2017
PCC 2	Firmed and shaped	Limited to anything left over after meeting the minimum PCC 1 and maximum PCC 3 limits
PCC 3	Unbundled renewable energy certificates	Maximum of 25% through 2013, 15% through 2016, 10% beginning in 2017

Source: California Energy Commission

For each Compliance Period, PWP must demonstrate to the CEC that it has achieved the required total energy, subdivided by PCC requirements, seek exemptions or waivers, or risk fines.

Given the enactment of SB 100 on September 10, 2018, it is reasonable to expect that the CEC will develop new Compliance Period obligations, both before and after 2030, through the CEC RPS guidance documents. Although the obligations for the interim targets are not fully developed for SB 100 compliance, this IRP does analyze a reasonable trajectory toward the SB 100 RPS goals in several scenarios. Finally, to meet the state's RPS mandates, PWP has developed an updated RPS Procurement Plan to implement the preferred portfolio and to meet the SB 100 RPS mandates. On January 29, 2018 the Pasadena City Council approved the RPS Procurement Plan and RPS Enforcement Program to comply with SB 350 requirement. Attachments 4 and 5 update and replace the January 29, 2018 documents (Procurement Plan and Enforcement Program).

2. Greenhouse Gas Emissions

California has set a target (not a mandate) that the state's GHG emissions will fall to 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 (Executive Order S-3-05). The CEC has allocated this state-wide reduction to individual utilities in the state to serve as a planning tool. Exhibit 5 shows PWP's state-allocated target GHG emissions from utility sources.[7]

Exhibit 5: PWP's Share of California GHG Emission Targets in 2030[8]

Emissions Range	PWP Range MT CO2e
Low End	128,000
High End	226,000
1990 Emissions	918,622

Source: Pasadena Water and Power and CARB

In addition, in March 2018 the City adopted a Climate Action Plan (CAP).[9] This plan sets forth a strategy that builds upon existing programs and policies that address climate change, identifies where these existing efforts can be expanded, and ultimately establishes a roadmap that not only enables the City to reach the State's reduction targets called forth under Executive Order S-3-05, Assembly Bill (AB) 32, and Senate Bill (SB) 32 but is also consistent with the State's climate strategy.

The CAP incorporates this IRP and programs of other departments in the City.[10] The CAP adopted the state-wide GHG emissions reductions targets, restated with 2009 as the benchmark, and added a target for 2035 (again with 2009 as the benchmark), as shown in Exhibit 6.

Exhibit 6: CAP Goals and Statewide GHG Emission Reduction Targets

Year	State-wide GHG Emissions Reduction Targets	CAP GHG Emissions Reduction Goals (relative to 2009 baseline and state-wide targets)
2020	1990 levels by 2020 per AB 32	27% below 2009 levels by 2020 (Equivalent to 14% below 1990 levels)
2030	40% below 1990 levels by 2030 per SB 32	49% below 2009 levels by 2030 (equivalent to 40% below 1990 levels)
2035	[The state does not have a 2035 target.]	59% below 2009 levels by 2030 (equivalent to 59% below 1990 levels)
2050	80% below 1990 levels by 2050 per EO S-3-05	83% below 2009 levels by 2050 (equivalent to 90% below 1990 levels)

Source: Pasadena Climate Action Plan March 2018, Figure 1.

With respect to this IRP, the CAP contemplates changes to both energy supply and energy consumption, including transportation electrification, energy efficiency, building codes, retrofit

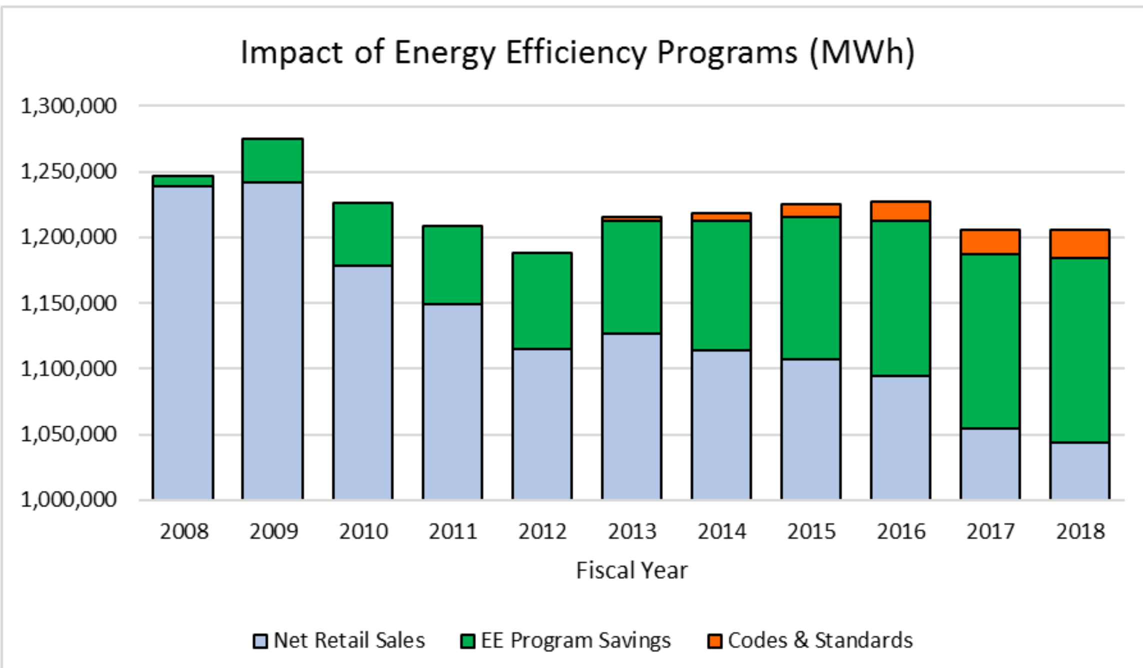
[7] This does not include emissions from sectors not directly under PWP's control, such as private transportation.
[8] https://www.arb.ca.gov/cc/sb350/staffreport_sb350_irp.pdf.
[9] See March 5, 2018 CAP Agenda Report, Attachment 7.
[10] For example, transportation, land use, water conservation, waste reduction and urban greening.

standards, and renewable energy supplies. In addition, PWP's RPS compliance actions will contribute significantly toward achieving the 2030 GHG target, as discussed further below.

3. Energy Efficiency and Demand Response

PWP offers a wide variety of programs designed to meet the energy efficiency goals adopted by the City Council while serving a broad cross-section of Pasadena customer groups. Programs include rebates, direct installation services, behavioral reports (water and energy usage), and educational materials to encourage efficient use of water and power. These programs have been aggressive and successful, resulting in a significant reduction in PWP's retail sales. As shown in Exhibit 7, PWP's net retail energy sales have steadily declined since fiscal year (FY) 2008. Over 11% of the reduction is attributed to the cumulative net effect of PWP's energy efficiency programs. Including savings attributed to statewide improvements in codes and standards since 2013, energy efficiency has reduced PWP's FY2018 retail sales by 13% from FY2008.

Exhibit 7: Impact of Energy Efficiency Programs



Source: Pasadena Water and Power

Historically, the Energy Efficiency Partnering Program (EEP) provided customized incentives on lighting and mechanical projects to encourage energy saving and load reduction projects for PWP's commercial customers. Beginning October 2018, PWP has replaced the EEP with the Customized Incentive Program that includes updated incentive levels and a streamlined application submittal process. In addition, PWP also launched a new Simple Business Rebates program, which offers incentives based on deemed savings for many common prescriptive measures.

PWP has continuously provided several residential rebates through our Home Energy Rebate program, which helps customers offset the cost of higher efficiency appliances and energy saving home improvements. Examples of incentivized measures include Energy Star refrigerators, ceiling insulation, HVAC tune-ups, smart thermostats and much more. In the past, PWP has also administered an online WebShop that enables residential customers to purchase LED light bulbs, smart thermostats and smart power strips at a lower-cost. PWP residential customers purchased or redeemed vouchers for approximately 1,600 products in 2017, with the majority being LED lightbulbs

PWP also administers behavioral programs for both water and power residential customers. The Home Energy Reports program is currently in its seventh year. Approximately four printed and four email reports are sent to approximately 40,000 customers, providing them with free efficiency tips and consumption comparison rankings to encourage reductions in their energy usage. Through the Living Wise program, PWP provides educational energy conservation materials for Pasadena public and private school student. The home energy efficiency “kits” and manuals teach the students the basics of energy conservation and allows them to install and experience energy efficient devices within their own homes.

PWP has begun shifting focus from rebates to direct install programs, in order to direct resources to customers who need the greatest support to complete efficiency improvements, including low and middle-income residential customers, seniors, and small businesses. Unlike traditional rebate programs, the free “Direct Install” programs do not require any upfront investment by the customer and deliver multiple efficiency measures, capturing additional conservation opportunities that might otherwise be out of reach. A key feature of PWP’s direct install programs is an on-site evaluation tailored to each residence or business. This customer-centric service allows PWP to become a trustworthy partner, providing services to customers that need them the most.

Currently, Pasadena has three existing no-cost direct install programs, each serving a specific customer segment. First, PWP launched a new free installation program called the Home Improvement Program (HIP). While this program is open to any residential electric customer, it specifically targets seniors and moderate-income households. Through this program, PWP provides a comprehensive home evaluation by a trained efficiency specialist and install free energy and water products services in customer’s homes. Next, PWP made enhancements to the existing Water and Energy Direct Install Program (WeDIP) that provides free measures and services for small and medium commercial customers. Qualified businesses are able to benefit from lighting, plumbing and refrigerator retrofits at no cost. Both the HIP and WeDIP programs provides customized tips on additional efficiency upgrades via a summary report after the on-site evaluation. Lastly, the city’s Under One Roof is a one-stop shop that consolidates all of the available offerings and services for residential low-income customers. Through the Under One Roof, PWP administers two programs related to energy efficiency. In particular, the utility has partnered with the Southern California Gas Company (SoCalGas) on the Energy Savings

Assistance Program (ESAP), which provides a complimentary on-site evaluation and free energy efficiency measures. Additionally, PWP also provides new Energy Star refrigerators at no cost through the Refrigerator Exchange program for low-income customers.

In terms of demand response, PWP relaunched the Voluntary Load Curtailment Program that encourages large customers to voluntarily reduce their energy usage when called upon by PWP, which alleviate stress on the grid during potential emergencies. Participants were provided with a free energy assessment to identify specific demand reduction opportunities. Through this partnership, PWP identified and secured more than 3 MW of "on call" voluntary load reduction capability from 20 of the City's largest customers.

4. Distributed Energy Resources

PWP does not currently offer any incentives for customers to install Distributed Energy Resources (DERs), but offers two applicable rate schedules to enable customer-owned DERs.[11] Each of these rate schedules incorporates Pasadena's Regulation 23 "Distributed Generation Facilities Interconnection Requirements" (which is comparable to Rule 21). Customers who have installed DERs on their premises can use the generation to offset all or a portion of their retail bills from PWP. Compensation to the customer for any energy delivered to PWP from the customers depends on whether the DER qualifies for the Net Energy Metering (NEM) schedule and the customer's choice of whether to net energy on each monthly or bi-monthly bill (as applicable), or to net annually. Currently, 1,303 customers have qualifying renewable DERs (solar) under PWP's NEM tariff, with an estimated net installed capacity of 10.4 MW and an estimated annual energy production of 16,600 MWh. Another nine customers have installed 17.5 MW of non-qualifying DERs (fuel cells, microturbines, and combined-cycle cogeneration) under PWP's Self-Generation rate. Additional information may be found at www.PWPweb.com/selfgeneration.

5. Transportation Electrification (Electric Vehicles)

PWP has offered incentives for the purchase of electric vehicles (EV) and in-home EV charger installation for many years. Current incentives include rebates for: (i) the purchase or lease of a new or used plug-in electric vehicle by residential customers; (ii) the installation of Level 2 (240V) or Level 3 DC-Fast Charging (DCFC) stations by commercial customers; and (iii) the installation of "Wi-Fi enabled" EV chargers for home use. These rebates are in addition to state and federal programs. Educational and incentive program information may be found at www.PWPweb.com/EV. Transportation electrification is discussed in more detail below.

[11] See Pasadena Municipal Code Section 13.04.177 (Net Energy Metering) and Section 13.04.078 (Self Generation Service).

6. Disadvantaged Communities

There are several city programs which target the Disadvantaged Community (DAC) in northwest Pasadena. Residents of the DAC (as well as elsewhere in the City) who meet certain income criteria can take advantage of bill assistance programs, as well as supplemental rebates for EV purchases or leases.

The Water & Energy Direct Install Program[12], was originally launched in 2013 to provide free water and energy installation services to small business customers that often operate on narrow profit margins and are unable to invest the time and financial resources to participate in PWP's commercial efficiency rebate programs. The program was expanded in 2018 to include additional services, eligibility for medium commercial customers, and actively recruit small business customers in the DAC census tract area. PWP obtained a $1.2 million grant from the California Department of Water Resources to expand the WeDIP program, and the grant requires that 85% of grant funding be spent on services in the DAC area. Since the expanded WeDIP program commenced in June 2018, more than 100 onsite audits and 53 installations have been completed, with over half of these in the DAC. Participants have included churches, nursing care facilities, residential care facilities, grocery stores, retail stores, drug stores, restaurants and laundry services.

PWP's Under One Roof program provides residents of the DAC (as well as elsewhere in the City) with all the available City programs and services for residents that meets certain income requirements. In the past year, PWP has re-designed marketing material to increase awareness of the Under One Roof services. Pasadena's Customer Service Center (CSC), available online, via smartphone app, or by phone at (626) 744-7311, has been designated as a single point of contact for the program. Aside from PWP's free installation of energy/water efficiency measures and the refrigerator exchange, income qualified residents of the DAC (as well as elsewhere in the City) can potentially qualify for no cost exterior home painting, turf replacement to drought tolerant landscape, greywater systems, double and home energy rebates. Additional free services include low/no-interest home rehab loans, solar energy systems, wheel chair ramp installations and broken window replacements.

Moving forward, PWP staff will collaborate with Pasadena Media, to develop short Public Service Announcements that will be aired on the public access channel to expand reach. PWP will also implement similar outreach techniques that were effective for our energy efficiency direct install programs, including door-to-door canvassing, outreach collaboration with Department of Housing and Human Services, and continue to have a strong presence at community events with eligible customers.

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[12] https://ww5.cityofpasadena.net/water-and-power/wedip/.

E. PWP's Existing Resources

1. 2017 Power Content Label

PWP's power supply portfolio is composed of a variety of technologies. These are summarized in PWP's annual filing of its "Power Content Label" at the CEC. Exhibit 8 shows the most recent Power Content Label, for calendar year 2017 filed in 2018.

Exhibit 8: 2017 Power Content Label, City of Pasadena[13]

Energy Resources	2017 PWP Power Mix	2017 CA Power Mix
Eligible Renewable	**38%**	**29%**
Biomass & Waste	15%	2%
Geothermal	1%	4%
Eligible Hydroelectric	4%	3%
Solar	9%	10%
Wind	9%	10%
Coal	**31%**	**4%**
Large Hydroelectric	**3%**	**15%**
Natural Gas	**11%**	**34%**
Nuclear	**6%**	**9%**
Other		<1%
Unspecified sources of power[14]	**11%**	**9%**
TOTAL	**100%**	**100%**

Note: this does not include PWP's green power program mix
Source: Pasadena Water & Power

PWP's existing resource portfolio consists of the specific generation assets described below. PWP has a total resource capacity of 423 MW, which consists of 197 MW of owned resources and 226 MW of contracted resources. It is important to note that PWP is long in capacity and in certain cases, long in energy, until the IPP contract terminates (in June 2017). Overall, PWP would have excess energy in most hours of the year if IPP was operated at its full economic capacity, without regard for GHG emissions and costs. However, during the summer peak, PWP is often short energy. This trend is expected to continue until the IPP contract terminates.

[13] https://ww5.cityofpasadena.net/water-and-power/pcl/
[14] "Unspecified sources of power" means electricity from transactions that are not traceable to specific generation sources.

a. Fossil-Fueled Resources

i. Intermountain Power Project (Utah: coal to be repowered to natural gas)

PWP has a long-term Power Sales Agreement (PSA) with the Intermountain Power Agency (IPA) for a capacity share of the coal-fired IPP of 108 MW. The IPP plant, located in Delta, Utah, has a total capacity of 1,800 MW and is operated by the Los Angeles Department of Water & Power (LADWP) as agent of IPA. For the purposes of the IRP, the coal plant has a minimum (must run) dispatch level for PWP and is economically dispatched above that, depending on market conditions. PWP's current Power Sales Agreement with IPA expires in June 2027.

ii. Glenarm Power Plant (Pasadena: natural gas)

Pasadena owns five Glenarm assets: a 65.8 MW combined cycle unit and four gas peakers totaling 131.6 MW. The Glenarm Power Plant units are assumed to be operational in all scenarios and portfolios. The assets are required for local reliability reasons whenever local hourly load is higher than 280 MW, which is the import limit at the Goodrich tie to the CAISO. Since PWP's Glenarm natural gas units (especially the peakers) can ramp up relatively quickly, PWP will likely have no need for new resources to meet current local RA and flexible RA requirements.[15]

iii. Magnolia Power Plant (Burbank: natural gas)

PWP's share of the natural gas-fired Magnolia Power Plant is 6.1307% of the base capacity of 242 MW. This comes out to approximately 14 MW of base capacity, of which 10 MW is take-or-pay by contract and is therefore modeled as must-run generation in all Cases. The remaining 4 MW are operated based on economic dispatch.[16]

b. Other Existing Contract Resources

PWP has executed contracts for energy from various large hydro, nuclear, coal, large gas-fired, solar, wind, geothermal, landfill gas generation, small hydro renewable resources and generic renewable resources. PWP holds rights to 20.2 MW of hydro power from the Hoover project, 9.9 MW of nuclear power from the Palo Verde station, 19.2 MW of energy from landfill gas, and 11 MW of contracted wind. Exhibit 9 and Exhibit 10 show the essential terms of the existing contract resources (costs are in 2017 dollars).

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[15] In the Social Cost of Carbon (SCC) cases, when the Glenarm units run for reliability, they are not subject to the Social Cost of Carbon; they are only subject to Social Cost of Carbon when turned on for economic reasons.

[16] The 4 MW of economic dispatch at Magnolia is subject to Social Cost of Carbon in the SCC cases, while the must-run portion is not.

Exhibit 9: Summary of PWP's Contracts

SI No.	Asset Name	PWP Capacity (MW)	Online Date	Contract Expiration	Estimated Energy Cost ($2017/MWh)
1	Antelope Big Sky Ranch Solar Project	6.5	8/19/2016	12/31/2041	66.15*
2	Summer Solar Project	6.5	7/25/2016	12/31/2041	66.15*
3	Columbia II Solar Project	2.6	12/10/2014	12/9/2034	69.98
4	Kingbird Solar Project	20.0	4/30/2016	12/31/2036	68.5
5	Windsor Reservoir Solar Project	0.6	5/31/2011	5/30/2031	104.49
6	Milford Wind Corridor Phase	5.0	11/15/2009	11/14/2029	70.47
7	High Winds Generation Facility	6.0	8/25/2003	12/31/2024	53.5
8	Hoover Uprating Hydroelectric Project	20.2	10/1/2016	9/30/2067	18.07
9	Puente Hills Landfill Gas	12.6	1/1/2017	12/31/2030	80
10	Chiquita Canyon Landfill Gas-to-Energy	8.3	11/23/2010	11/22/2030	65.25
11	Heber South Geothermal Project	2.1	6/18/2006	12/31/2031	71.2
12	Magnolia Power Plant	14.0	9/22/2005	N/A	26.92
13	SCPPA Palo Verde Nuclear Station	9.9	1/29/1986	N/A	40.08
14	Intermountain Power Project	108.0	7/1/1986	6/15/2027	63.27**

*Energy portion only (does not include the renewable energy credit price)
** Debt service includes
Source: Pasadena Water and Power

Exhibit 10: PWP's WSPP Contracts for Renewable Energy

Net Procurement Requirement	Quantity	Contract Year
PCC1 Bundled Renewable Energy & RECs	70,000 MWh annually	2020-2030
PCC2 Bundled Renewable Energy & RECs	5,000 MWh	2020
PCC2 Bundled Renewable Energy & RECs	15,000 MWh	2021
PCC2 Bundled Renewable Energy & RECs	40,000 MWh	2022
PCC3 RECs	316,000 MWh	2020-2027

Source: Pasadena Water and Power

F. Definitions for Analysis

1. Technical and Economic Feasibility

Because an IRP looks out two decades, uncertainty must be addressed both generally and in some detail. Technical and economic feasibility are metrics often employed to help screen out options and to help focus the analysis on realistic options. Technical feasibility refers to the proven or reasonably expected ability of a technology (*e.g.,* solar PV) or program (*e.g.,* energy efficiency measures) to achieve an objective (energy production or energy saved, respectively). Technical feasibility just asks the question "will this work or not?" For example, we know that photovoltaic solar can be used to produce electricity, and thus passes the test of technical feasibility, but the technology is expected to improve over time (and existing solar panels will degrade over time). Technical improvements are expected to lead to larger solar arrays, more efficient solar panels, more offsite assembly of engineered rooftop systems, and more efficient inverters. All of these will allow an increase in the capture and conversion of solar insolation potential to energy. Similarly, testing technical feasibility helps rule out generators that are not capable of meeting air emission standards in southern California, or energy efficiency programs that have proven ineffective at reducing consumption. Thus, the set of technically feasible options may be smaller for Pasadena, compared to utilities in other parts of California or the rest of the country.

Economic feasibility requires a more detailed examination of expected costs and benefits. In practice, many technologies are technically feasible, but a supply curve is defined by the cost per MWh of energy produced: while many technologies are technically feasible, the energy production cost associated with each technology varies. We want to identify a set of optimal portfolios for the City to consider. This metric applies to both supply-side and demand-side resources.

2. Cost-Benefit Analysis

One objective of this IRP is to provide a better indication of the relative benefits of different energy efficiency (EE) programs, because SB 350 also sets a target of "doubling EE" by 2030. In Section III, we show the results of five standard tests of the avoided costs (benefits) of EE vs. the costs of implementing EE measures. Ranking of benefit/cost ratios will ultimately help PWP determine which programs should be expanded, reduced or restructured, or added to the City's current EE portfolio. The value of ranking is that limited funds for energy efficiency programs will be spent on programs that maximize the level of consumption that is reduced.

One complication in any of these analyses is that only some customers will participate in EE programs. If consumption falls for some customers, other customers may face higher rates because fixed costs are spread across lower sales. However, from the perspective of the utility as a whole, total costs should fall if the avoided costs exceed the costs of implementing the program (e.g., energy audits or EV-charging incentives). This IRP provides data on both the total cost of meeting load and the rate impacts.

3. Scenarios and Portfolios

To systematically evaluate different paths for achieving mandates and targets, this IRP develops least-cost portfolios of generating resources within several "scenarios", and within reliability constraints. Broadly speaking, scenarios are states of the world outside of Pasadena, whereas portfolios are bundles of resource choices made by Pasadena to achieve the identified objectives. The scenarios evaluated in this IRP are shown in Exhibit 11.

Exhibit 11: IRP Scenarios

Scenario	Scenario Title
1	Base Case (BC)
2	Social Cost of Carbon (SCC)
3	BC + SB 100
4	SCC + SB 100
5	SCC + SB 100 + Leave IPP Energy in Utah
6	SCC + SB 100 + Diversification
7	SCC + SB 100 + Diversification + Biogas
8	SCC + SB 100 + Diversification + Biogas + Leave IPP Energy in Utah

Source: Pasadena Water and Power

a. Base Case

The Base Case is the least-cost portfolio of resources that meets all SB 350 state mandates and targets by 2030, based on the best available information existing as of this IRP regarding availability of technologies, future costs of renewable and non-renewable resources, energy storage, future costs of fuel and capital, and reliability requirements.

b. Social Cost of Carbon (SCC)

In the SCC scenario, the Base scenario forecast of carbon prices is replaced by a forecast of much higher carbon prices, intended to reflect the impact of fossil-fuel emissions on climate change. The SCC is applied to the dispatchable portions of PWP's fossil units: the incremental portion of the IPP, the incremental portion of Magnolia natural gas plant in Burbank, and the Glenarm units in Pasadena. Some minimum output at each of these plants is determined by contractual provisions that are not affected by the SCC. The SCC is a planning tool for the IRP and cannot be used by PWP in setting bids for its fossil-fueled units due to the CAISO's auction rules. Via the IRP, the SCC can, however, be used to guide future acquisition decisions regarding specific supply-side resources. This Case also complies with SB 350 regarding RPS obligations by 2030.

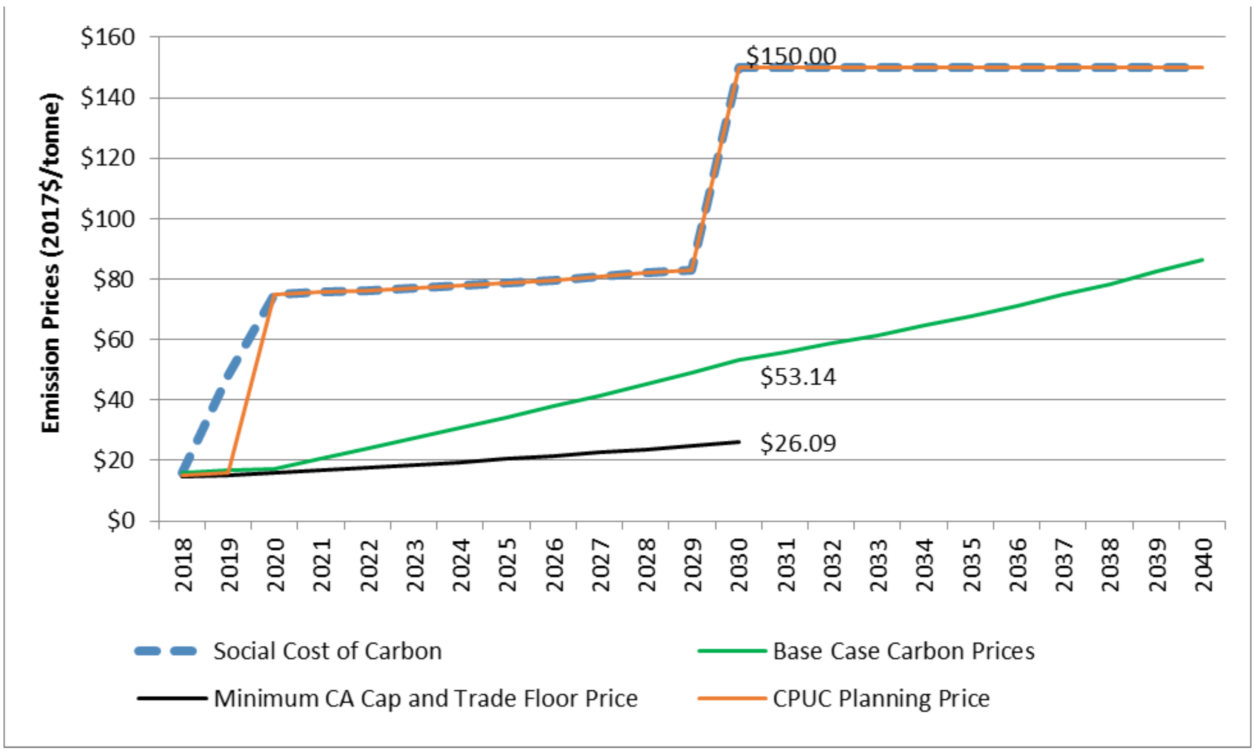
The SCC is approximated by the greater of

(a) $50/MT (metric tonnes of CO_2e, 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.

Exhibit 12: Cost of Carbon



Source: Pace Global

Exhibit 13: Cost of Carbon ($/tonne)

Year	CA Base Case	CPUC Planning Price	Minimum CA Cap and Trade Price	Social Cost of Carbon
2018	16.00	15.17	14.53	16.00
2019	17.00	16.05	15.26	48.31
2020	17.18	74.93	16.02	74.93
2021	20.47	75.65	16.82	75.65
2022	23.82	76.36	17.66	76.36
2023	27.22	77.08	18.54	77.08
2024	30.68	77.80	19.47	77.80
2025	34.21	78.52	20.45	78.52
2026	37.81	79.65	21.47	79.65
2027	41.50	80.78	22.54	80.78
2028	45.28	81.91	23.67	81.91
2029	49.16	83.05	24.85	83.05
2030	53.14	150.00	26.09	150.00
2031	55.80	150.00		150.00
2032	58.59	150.00		150.00
2033	61.52	150.00		150.00
2034	64.59	150.00		150.00
2035	67.82	150.00		150.00
2036	71.21	150.00		150.00
2037	74.77	150.00		150.00
2038	78.51	150.00		150.00
2039	82.44	150.00		150.00
2040	86.56	150.00		150.00

Source: Pace Global

c. Base Case + SB 100

In September 2018, SB 100 was signed into law. This law requires electricity sold to customers in the state to be sourced by emission-free sources by 2045, includes an interim target that accelerates the 50 percent RPS obligation from 2030 to 2026, and increases the 2030 RPS obligation to 60 percent by 2030. Although regulations implementing SB 100 have not been written, PWP decided to develop several scenarios that comply with SB 100 in broad terms. This scenario did not model the implications of SB 100 for the State of California as a whole but focused only on PWP meeting these requirements.

d. SCC + SB 100

This scenario is like the Base Case + SB 100 scenario but uses the cost of carbon from the SCC Case, shown above in Exhibit 12.

e. SCC + SB 100 + Leave IPP Energy in Utah

Starting with the SCC + SB 100 scenario, this scenario models the financial (not dispatch) consequences of selling PWP's share of the must-take energy generated by coal (until mid-2025) and natural gas (2025-27) at the Intermountain Power Plant in Utah. This scenario replaces the must-take IPP energy with the output of a geothermal plant in California starting in 2019, the first year of the study period. The fixed costs of IPP would still have to be paid and are reflected in the retail rate impact calculations, along with the new costs of the geothermal plant.

f. SCC + SB 100 + Diversification

The above scenarios (1-5) yielded least-cost portfolios that were heavily weighted toward new solar. PWP is concerned about the risks of a non-diversified portfolio, so decided to develop a "forced diversification" Case. Starting with the SCC + SB 100 scenario, this SCC + SB 100+ Diversification scenario forces certain amounts of renewable resources otherwise not considered economic by AURORA (the production cost model used for the IRP- which is discussed later in Section II.B.1) into the portfolio at specified dates. Exhibit 14 shows the specific resource assumptions.

Exhibit 14: Inputs for the Diversified Portfolio

Resource Name	PPA Price ($/MWh)	PPA Type	PPA Term (Years)	Capacity (MW)	First Year	Location	Capacity Factor (%)	Load Profile
Geothermal 1	20.00	Fixed	20	5	2023	Imperial Valley, CA	90	24*7
Geothermal 2	70.04	Variable	30	5	2033	Imperial Valley, CA	90	24*7
Geothermal 3	75.75	Fixed	25	5	2038	Mono County, CA	90	24*7
Biomass 1	95.00	Fixed	15	5	2026	Northern California	90	24*7
Wind	50.00	Fixed	15	10	2029	Riverside, CA	39	Milford Wind
Solar + Batteries 1	40.50	Fixed	10	15	2038	LA County/ Riverside	55	Battery Energy 6-8 am and pm
Solar + Batteries 2	40.50	Fixed	10	15	2031	LA County/ Riverside	55	Battery Energy 6-8 am and pm

Source: Pasadena Water and Power

g. SCC + SB 100 + Diversification + Biogas

In addition to the resources identified in the SCC + SB 100 + Diversification scenario, the SCC + SB 100 + Diversification + Biogas scenario assumes that the natural gas to be burned at

Magnolia and Glenarm is increasingly replaced by biogas at a premium price: $3.50/therm in 2030 increasing to $5.00/therm in 2039. The AURORA dispatch of the SCC + SB 100 + Diversification scenario was used, and the financial impact on retail rates of the higher biogas prices calculated.

h. SCC + SB 100 + Diversification + Biogas + Leave IPP Energy in Utah

In the final scenario, the SCC + SB 100 + Diversification + Biogas + Leave IPP Energy in Utah the assumptions were augmented by the requirement that the coal/gas-fired generation at IPP would not be imported into California, and the must-take energy replaced by the output of a California geothermal plant. Again, this used the AURORA dispatch from the SCC + SB 100 + Diversification scenario.

i. Rate Impacts

For each scenario, the total cost of generation was calculated for each year of the study period (in nominal and 2017 real dollars) and on a net present value (NPV) basis across the study period (2019-39). This allows the portfolios to be ranked in order of financial impact overall in the Scorecard. In addition, the total cost of each portfolio was divided by the energy load in the appropriate year, to allow the calculation of rate impacts, which are shown both in cents/kWh and in percentage changes from the Base Case (in 2019 dollars). The rate impacts and costs of these scenarios are discussed in detail in Section II.B.5.

G. Other Planning Considerations

1. Resources

a. Renewable Options

Wind and geothermal resources are included in the set of resources available to PWP in the future. For these resources, industry-standard sources were used to develop forecasts of capacity costs and performance characteristics (e.g., capacity factors and hourly output profiles).

Distributed renewable resources, focusing on solar technology, were not found to be cost competitive with utility scale solar for PWP's IRP. Lazard's *Levelized Cost of Energy Analysis* (November 2017) reported the current levelized costs of utility scale and distributed scale solar shown in Exhibit 15.

Exhibit 15: Levelized Cost of Solar Energy Technologies

Technology	Low LCOE ($/MWh)	High LCOE ($/MWh)
Solar PV – Rooftop Residential	179	308
Solar PV – Rooftop C&I	81	186
Solar PV – Community	72	143
Solar PV – Crystalline Utility Scale	44	50
Solar PV – Thin Film Utility Scale	41	46

Source: https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

Distributed scale solar is two to six times more expensive than grid-scale solar, and the cost estimates are much more variable depending on specific site parameters. Therefore, distributed solar is not considered further in this IRP. Distributed energy resources (DER) in general are expected to be addressed in PWP's upcoming Power Delivery Master Plan.

b. Fossil Fuel Technologies

PWP does not consider any additional conventional fossil fueled technologies for future portfolios. Coal and oil fueled technologies are not viable due to environmental and economic constraints. Although natural gas fueled technologies may be permitted, this IRP assumes that no new natural gas fired plants will be built within California, which is consistent with state policies requiring decarbonization of the electric energy sector over time. Although other conventional technologies, especially natural gas power plants, are expected to be built outside of California, PWP does not consider these resources because of uncertainty regarding their contribution to resource adequacy requirements.

c. Physical vs. Financial Transactions

Currently, PWP acquires renewable energy via (a) Power Purchase Agreements (PPAs) with the developer of a specific resource and (b) standardized energy acquisition contracts, such as the Western Systems Power Pool Agreement, for delivery into California of renewable energy at "index-plus" prices. The former are sometimes called "physical" and latter "financial". In a financial transaction, PWP buys the energy from the seller at a specified point in the CAISO and pays (a) the Locational Marginal Price (LMP) set by the CAISO for such deliveries at that point plus (b) a premium for the Renewable Energy Credits (RECs) used for regulatory compliance. PWP simultaneously sells that same energy at the same LMP, making the transaction "energy-neutral". The net cost to PWP is then the premium for the RECs. Both types of contracts are incorporated into this IRP.

d. Baseload Options to Replace IPP

As noted previously, PWP is considering the impact of replacing energy provided by the Intermountain Power Plant in Utah. Although this coal plant is planned to be converted to natural gas, scenarios 5 and 8 replace this fossil generation with energy from a geothermal plant beginning in 2019.

2. Preparation for Non-Market Uncertainties

a. Potential Legislative and Regulatory Changes

As noted previously, SB 100 was signed into law on September 10, 2018. As a result, many scenarios modeled in this IRP do not reflect the requirements of the new law. However, because SB 100 will be binding on future actions, PWP has analyzed several Cases that incorporate the higher RPS obligations of SB 100, compared with SB 350. Future IRPs will also need to consider the increased RPS and carbon-free supply requirements defined in SB 100 as regulations are developed.

b. Updated Power Delivery Master Plan

PWP last updated its Electric Distribution System Master Plan in January 2005. Due to market uncertainties such as the growth in distributed solar and behind the meter energy storage, PWP is planning to update the Electric Distribution System Master Plan in 2019. This study will focus on distribution impacts and review DER impacts to PWP that this IRP does not address.

3. Environmental Costs

Environmental mandates and planning targets are discussed throughout this IRP report, and are specifically included in scenarios that are modeled to comply with both SB 350 and SB 100.

4. Partnerships for Innovation and Compliance

PWP works closely with other agencies, when it can, to facilitate compliance with state and federal mandates and for information sharing.

PWP looks for opportunities for grant funding with federal, state and local agencies, such as the Department of Energy (DOE), California Energy Commission (CEC) and South Coast Air Quality Management District (SCAQMD). Recently, PWP was successful in obtaining a grant for transportation electrification efforts from SCAQMD, through the Mobile Share Air Pollution Reduction Review Committee (MSRC) Local Government Partnership Program. The MSRC grant is for a total of $183,670, to be used for electric charging infrastructure throughout the city.

PWP works closely with the Southern California Public Power Authority (SCPPA), to partner on renewable energy contracts and sharing knowledge on a variety of topics (resource planning, energy efficiency and renewable efforts, transmission and distribution efforts, transportation electrification, and energy storage). PWP also partners with SCPPA on a variety of request for proposals (RFPs) for generation resources, software, consulting services, and other purposes. SCPPA itself issues bonds for shared projects, which allows PWP to benefit from economies of scale and diversify its portfolio. The partnership with SCPPA enables PWP to save money and share expertise with other POU staff.

II. IRP Filing Contents Per CEC

A. Planning Horizon

1. Study Period

The minimum study period required by the CEC is through 2030. To assess the implications of longer-term decisions, PWP extended the analysis and modeling (as encouraged by CEC guidelines related to Public Utilities Code Sections 9621 and 9622), through December 2039.

2. RPS Obligations

Under SB 350, California's Renewable Portfolio Standard (RPS) requires POUs to procure eligible renewable energy resources equal to at least 50% of their total load by December 21, 2030. Scenarios 1 and 2 use the SB 350 RPS standard, and scenarios 3-8 incorporate the SB 100 RPS standard. It should be noted that scenarios 5-8 will show "excess procurement" of renewable energy, compared with RPS requirements, as the portfolio is increasingly "decarbonized". For each portfolio, the RPS target is modeled as a constraint to ensure compliance in every year, currently 33% by 2020, 40% by 2024, 45% by 2027, and 50% by 2030. In the period from 2031 to 2039 (the last year of the analysis conducted for the IRP), the minimum was kept at 50% in the SB 350 Cases. In the SB 100 Cases, the RPS target was increased throughout the study period, to reflect the new requirement of 60% by 2030. AURORA considers a wide range of technologies and determines the least cost combination of technologies (existing and new) to meet the RPS requirement (and other constraints) in any year.

3. GHG Target

The CPUC and CARB have agreed that 42 million metric tonne of carbon dioxide equivalent (MMT of CO2e) is the GHG planning target for the electricity sector, representing an 81% reduction from 1990 levels. PWP's share of this planning target ranges from 128,000 to 226,000 MMTCO2-e; for modeling purposes, this IRP uses a target of 178,288 MMTCO2-e. The AURORA production cost model embeds the California cap and trade program design and allows each load serving entity (LSE), modeled as a zone in AURORA, to choose between physically reducing carbon through the selection of resources or, if cost-effective, to purchase GHG allowances in the market to meet its individual carbon emission target.

B. Scenarios and Sensitivity Analysis

1. Production Cost Modeling Software: AURORA

AURORA was used as the primary tool for conducting the IRP analysis. AURORA is an industrial standard chronological unit commitment model, which simulates the economic dispatch of power plants within a competitive market framework. The model uses a state of the art, mixed integer linear programing approach to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operating limits, renewable energy availability and mandatory portfolio targets. It is widely used by electric utilities, consulting agencies, and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices, and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g., heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates, and capital costs. The model can assess the potential performance and capital costs of existing and prospective generation technologies and resources, and make resource addition and retirement decisions for economic, system reliability, and policy compliance reasons on a utility system, regional or nationwide scale as needed. Outputs of the model include plant generation, emissions, and a variety of other metrics as needed.

AURORA uses a dynamic simulation of additional (or retiring) economic capacity with optimization logic to forecast Long-Term Capacity Expansion resources and retirements. With this approach, AURORA performs an iterative future analysis where

(a) resources that have negative going-forward value (revenues minus costs) are retired;
(b) resources with positive values are added to the system on a gradual basis: a set of resources with the most positive net present value is selected from the set of new resource options and added to the study;
(c) AURORA then uses the new set of resources to compute all of the values again; and
(d) the process of adding and retiring resources is continually repeated (iterated) until the system price stabilizes, indicating that an optimal set of resources has been identified for the study.

Where net energy and capacity revenues together justify construction of a new unit based on forecasted value, a new unit is built. Sustained positive expected returns, generally pushed by falling reserve margins and rising prices, are expected to lead to capacity additions. The magnitude of the capacity expansion depends on the achieved Return on Investment specific to the type of generating plant, when the plant is run against market prices. This allows all market simulations to incorporate the reactive behavior observed in the market to periods of sustained margins. The economic measure used is real levelized value (revenues less cost) on a $/MW basis. Investment cost is included in the cost portion of the formula. The methodology assumes that potentially non-economic contracts will not influence market prices and that someone will capture the value of economic contracts. Therefore, contracts are not explicitly modeled in AURORA but can be evaluated in the Portfolio Analysis capability of AURORA.

AURORA also features a minimum cost logic that is designed to ensure that enough generation from designated resources is produced at a lowest cost solution. This creates constraints for meeting annual energy requirements such as RPS targets. Two constraint types can be combined. An hourly load objective is defined by a load distribution curve prior to a chronological solution. If the constraint is binding (i.e., load cannot be met), AURORA creates a shadow price and increases the output of the resource in the hourly dispatch. Conversely, a long-term energy minimum cost constraint type is only enforced in the long-term decisions. It ensures that enough capability from new and existing resources is online to meet the target and that if the capability is available, it will be used (e.g., low cost renewable resource).

2. Dynamic Gas Supply/Demand Modeling Software

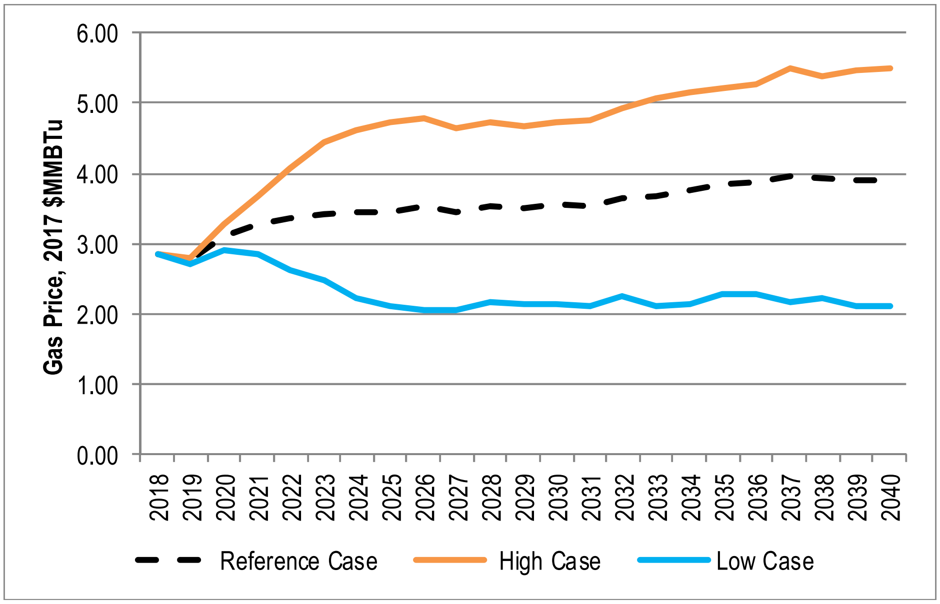
The Gas Pipeline Competition Model (GPCM) was used for developing natural gas prices. GPCM is a network model that can be diagrammed as a set of "nodes" and "arcs". Nodes represent production regions, pipeline zones, interconnections, storage facilities, delivery points, and customers or customer groups. The connections between these nodes are called arcs, which represent transactions and flows. Some of these are supplier deliveries to pipelines, transportation across zones and from one zone to another, transfers of gas from one pipeline to another, delivery of gas into storage, storage of gas from one period to another, withdrawal of gas from storage, and pipeline deliveries of gas to customers. GPCM dynamically solves for economic rents, allowing cheaper supplies to be used before more expensive supplies and enabling customers willing to pay more to be served before those willing to pay less. By including the entire system of North American gas production, transmission, storage, consumption, and imports/exports, GPCM optimizes gas flows to produce an economically efficient, market-clearing solution. GPCM contains more than 200 existing and proposed pipelines, 400 storage areas, 85 production areas, 15 liquefied natural gas (LNG) import/export terminals, and nearly 500 demand centers.

3. Key Inputs and Assumptions

a. Natural Gas Price

Pace Global developed the gas price assumptions using GPCM and a proprietary outlook for benchmarking Henry Hub and regional prices based on market fundamentals shown in Exhibit 16.

Exhibit 16: Natural Gas Price Forecasts



Source: Pace Global

The resulting Reference Case price forecast incorporates the latest views on North American supply, demand, and infrastructure assumptions. The High Case and Low Case forecasts are derived from a stochastic view that gas prices lie normally within +/-1 standard deviations from the Reference Case forecast. Recent market forward prices curves are used to benchmark (validate) the initial years of the natural gas forecast.

b. Capital Costs

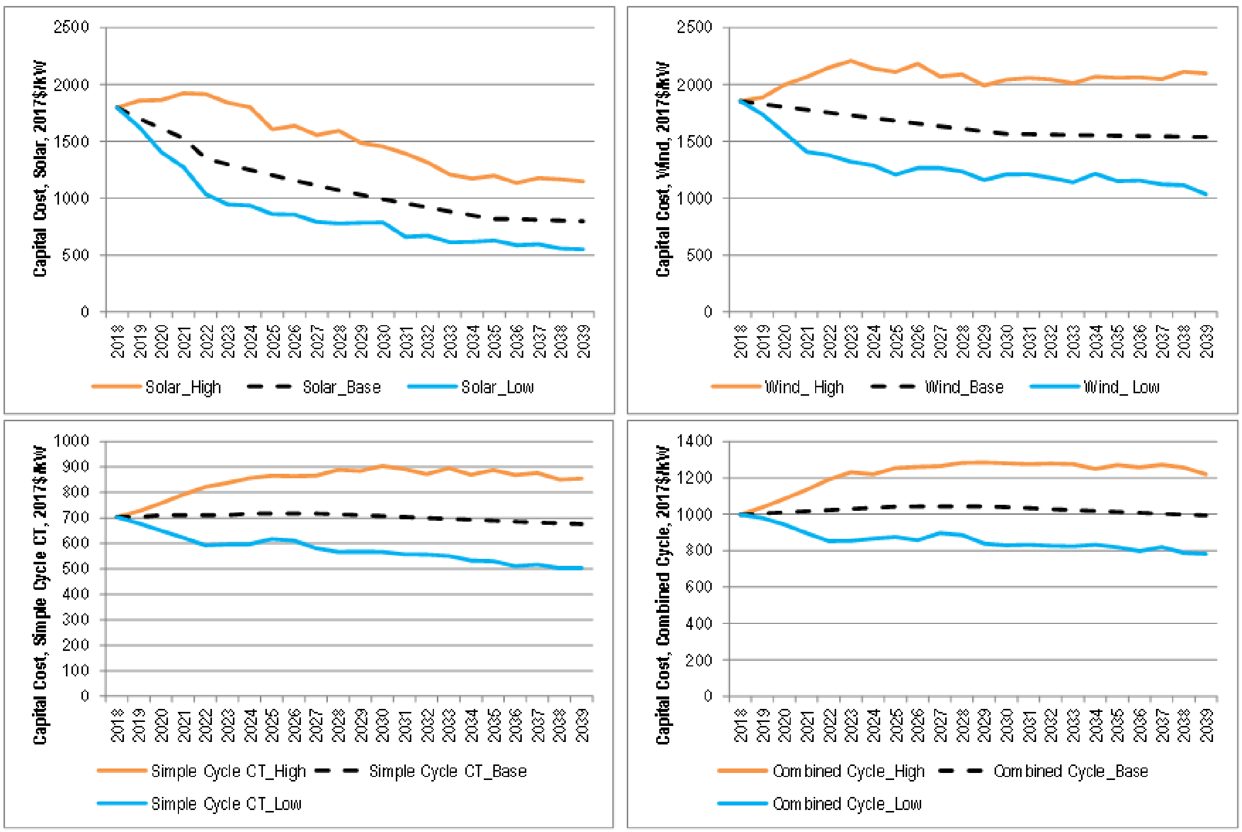
Pace Global developed capital cost assumptions using current estimates for overnight capital costs by technology. Pace Global then developed a long-term view of capital costs for each technology by reviewing public studies, other IRPs, other project work, and proprietary sources.

To forecast capital cost for solar power generation technology, Pace Global reviewed numerous public sources (including the National Renewable Energy Lab) regarding industry issues, trends, and predictions. Equipment, material, labor, and developer costs were considered to project the rate of cost change. This forecast was then compared with independent forecasts to ensure consistency (validation). Pace Global used a similar survey methodology for estimating simple cycle and combined cycle gas turbine capital costs.

A similar industry literature review was conducted for wind technology costs. In general, onshore wind-powered electrical generating technologies are becoming a mature technology. While wind project capital costs are expected to continue declining for several years as wind turbine pricing declines, the rate of decline is expected to slow. Turbine nameplate capacity, hub height, and rotor diameter have all increased significantly. Though increases in the average nameplate capacity, hub height, and rotor diameter of turbines have been notable, the growth in the swept area of the rotor has been particularly rapid. All else being equal, increased swept rotor area results in greater energy capture for each watt of rated turbine capacity, meaning that the generator is likely to run closer to or at its rated capacity and more often.

Exhibit 17 shows the Reference Case estimates for capital costs for each technology, together with a High Case estimate and a Low Case estimate of future capital costs.

Exhibit 17: Capital Cost Forecasts



Source: Pace Global

c. Base Case Assumptions

The required Base Case includes assumptions to meet the PUC section 9621 requirements for POUs: existing and new generation, grid operational efficiencies, energy storage, distributed energy resources, energy efficiency, and short-term/long-term products.

i. Existing and New Generation Resources

See the Introduction and Background section for a discussion of PWP's existing resource portfolio.

Pace Global conducted screening analyses to identify technically feasible and commercially viable generation resources that could be used as building blocks in constructing future generation portfolios. For this reason, the technology screening focuses on resource options that could meet PWP's new generation resource requirements, including:

- Size of the new generation resource, which is informed by factors including its load profile, existing resources retirement, and PPA expiration
- Resource type: base load, intermediate, intermittent, or peaking resources
- Characteristics: ramping rates, ability to provide voltage support
- Fuel type: fossil-fueled, renewable, and storage
- Local considerations: altitude, pressure, natural wind or solar resources

The technology selection considered a combination of dispatchable fossil-fueled generation resources, renewable technologies, and storage resources. Fossil-fueled resources include combustion turbines (CTs) and combined cycle gas turbines (CCGTs). Renewable resources include solar, wind, small hydro, landfill gas, biogas and geothermal resources. Performance and costs were estimated for several technologies that could become part of the Pasadena's future power generation portfolio. For each technology, capital costs were estimated to include engineer-procure-construct contract costs, owner's costs, and construction financing costs. A variety of gas and renewable technologies was sized to meet the Pasadena's potential demand. Performance (adjusted for local conditions) and current capital cost estimates for the technologies provided below were used as the basis for the construction of portfolios in the IRP.

ii. Grid Operational Efficiencies

Dispatch modeling was based on net energy for load (i.e., measured at the sum of the PWP Goodrich tie point and local generation inside the City), which omits transmission and distribution (T&D) losses. For the retail rate impact analyses, the costs of transmission losses (three percent) and distribution losses (4.6 percent) were added.

iii. Energy Storage

Energy storage is discussed in detail in Section II.F.5, below. Lithium ion batteries were included in AURORA when analyzing potential portfolios for each scenario.

iv. Distributed Energy Resources

As discussed in the Introduction and Background section, distributed energy resources (DER) were considered in initial IRP discussions; due to higher costs compared with grid-scale renewable resources, DERs were not modeled as a part of this IRP and are expected to be addressed in the upcoming Power Delivery Master Plan.

v. Energy Efficiency

For the AURORA modeling, load reductions (13,500 MWh/year) due to energy efficiency were included in the load forecast.

vi. Short-Term and Long-Term Products

Regarding new resources, we have estimated levelized cost recovery targets based on the economic life of resources. Existing PPA contract durations were included in the optimized modeling of each scenario.

vii. RPS Procurement

PWP plans to carry over and bank, or sell, future RECs associated with "excess RPS procurement". The methodology for calculating PCC purchases in AURORA is as follows:

- PWP will purchase the allowed maximum of PCC 3, because this is the lowest cost RPS compliance instrument. PCC 3 RECs (with no energy) will account for 10% of the total annual RPS compliance obligation.
- PWP will purchase the allowed minimum of PCC 1 energy, which is the most expensive resource. PCC 1 energy will account for 75% of the total RPS compliance obligation.
- PWP will procure the remaining RPS energy as PCC 2, which accounts for 15 percent of the total RPS compliance obligation.

The reported amounts of RECs for each scenario assume that any excess procurement that occurs yields RECs that can be either banked for future RPS compliance or sold if there is a significant excess of RECs in a given future year. In some Cases, excess procurement amounts are so large that the value of banking is not clear. However, RECs are reported in same manner for all scenarios. For all SB 100 scenarios, modeling constraints led to excess RPS procurement, resulting in either banking or selling of excess RECs to mitigate cost impacts to ratepayers. All SB 100 scenarios reached the 60% RPS by 2030, in part by banking excess RECs for future compliance periods.

viii. Off-System Sales Limit

PWP's primary concern is the delivery of safe, reliable power to residents at minimum cost. As a result, PWP has adopted a limit on off-system wholesale sales of ten percent of retail loads. This constraint is modeled using AURORA by *ex post* removal of some new resources, which the model had "built" because of off-system sales revenues. During the development of this IRP, most Cases incorporate a limit of ten percent of retail load on the annual volume of off-system (wholesale) energy that PWP can plan to make. This limit was increased to 30% in the resource diversification Case to control the risk of exposure to spot markets in southern California.

For each scenario, the least-cost portfolio was identified through production cost modeling using AURORA. In addition, PWP conducted post-AURORA calculations of costs not explicitly modeled in AURORA.

4. Overview of all Cases

Attachment 1, "Consultant and PWP Team Roles for IRP Analysis", provides a detailed analysis on the Consultant and PWP Team roles and responsibilities, as well as information on all of the Scenarios. Overall, the Consultant developed the model runs and constraints, while both the Consultant and the PWP Team ran quality assurance checks and added the cost of compliance with RA requirements, costs of renewable integration, costs of debt service obligations (for the IPP and Magnolia resources), analysis for RPS resource optimization, conversion of the dataset to $2019[17], development of the retail rate analysis, and development of the scorecard for selecting the recommended planning strategy.

5. Summary of All Scenarios, and Score Card, and the Recommended Strategy

PWP worked closely with the Consultants to develop Scenarios that aligned with Community input that was received. The STAG also provided input on the assumptions, IRP analysis and scenario options.

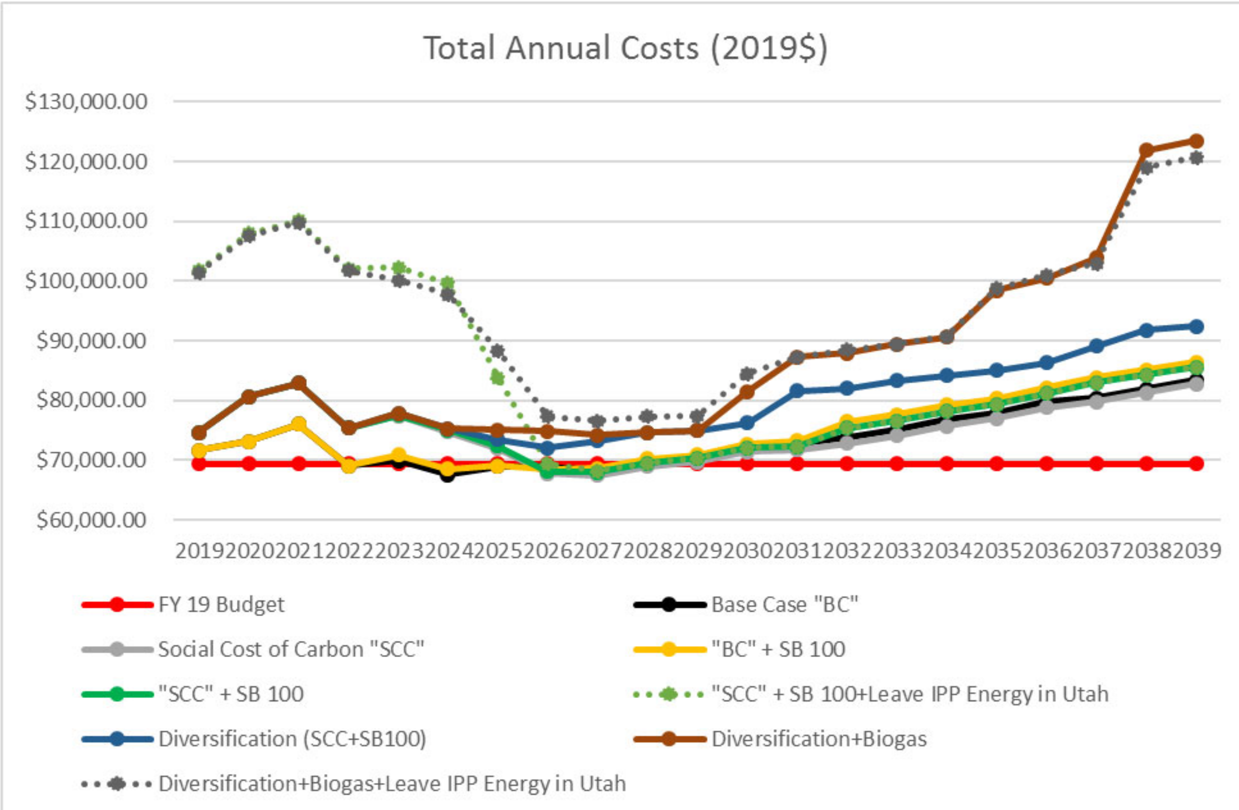
a. Summary of All Scenarios

All costs for the Scenarios were compared to the resource costs in the FY2019 Power Supply budget, in order to create a close comparison with current actual energy charge costs (which is the charge that is impacted by the IRP in $2019). In FY2019, the amount PWP budgeted for Power Supply is $69.4 million (note, details on the assumptions of this analysis is provided in Section II.I). The analysis of rate impacts was developed using the average energy charge, based on the 2019 Power Supply budget. For residential customers, the energy charge is 9.3¢/kWh, for FY 2019.

Exhibit 18 shows the Total Annual Cost for each scenario, as compared to the 2019 Power Supply budget. These costs <u>have not</u> been adjusted for credits from the Stranded Investment Fund and IPP fund credits, as Discussed in Section II.I. The Base Case is the least cost portfolio, while "Diversification + Biogas + Leave IPP Energy in Utah" is the highest cost scenario. Exhibit 19 shows the Annual Ratepayer Costs over the 20-year study period and the modeled Social Cost of Carbon. It is important to highlight that the Social Cost of Carbon is not included in payments by ratepayers for energy and is used as a dispatch penalty, increasing the incremental cost of fossil fueled resources, as described in Section I.F.3.b.

[17] "$2019" means that future dollars have been adjusted, by removing inflation, to their purchasing power in 2019.

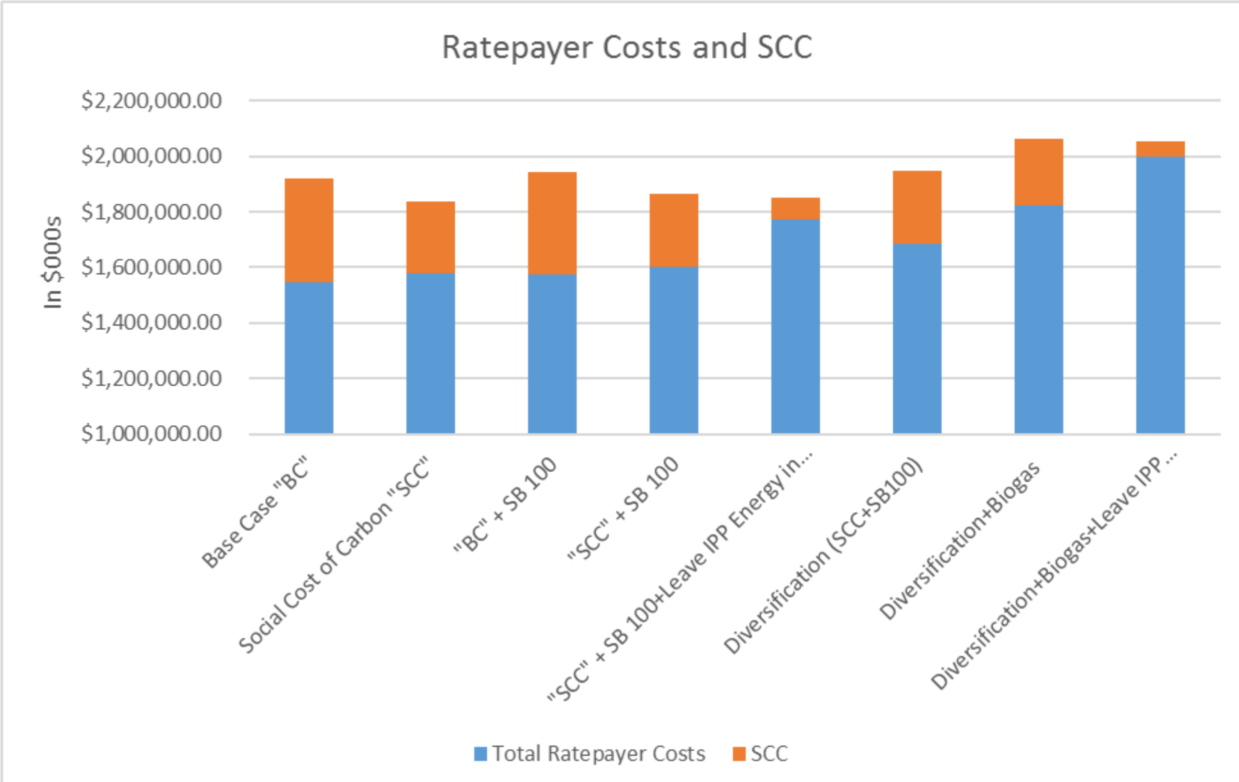
Exhibit 18: Annual Total Cost to Ratepayers ($2019)[18]



Source: Pasadena Water and Power

[18] Not adjusted for the Stranded Investment Reserve and IPP Fund Credit. FY 2019 budget adjusted, without fund credits, highlighted in Section II.I.

Exhibit 19: Total Costs to Ratepayers and Social Cost of Carbon 2019-39 ($2019)[19]

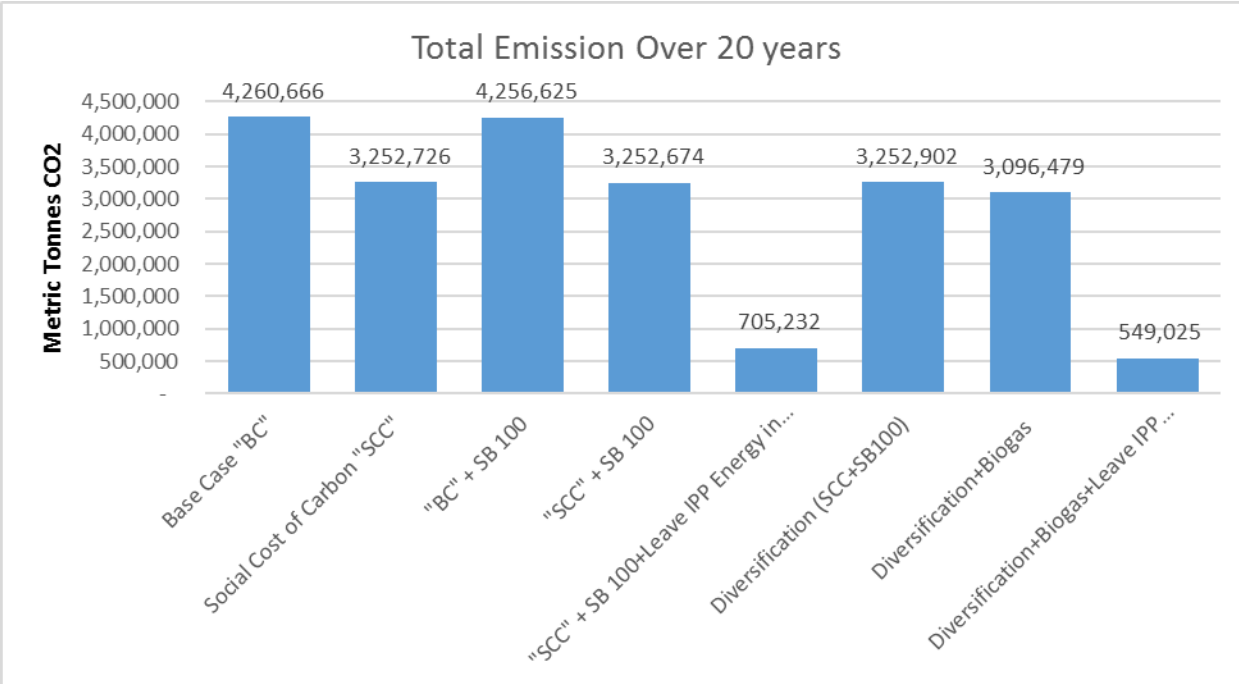


Source: Pasadena Water and Power

Exhibit 20 shows the Total Annual Emissions for each scenario. As can be seen, the "Diversification + Biogas + Leave IPP Energy in Utah" Scenario has the lowest GHG emissions.

[19] Not adjusted for the Stranded Investment Reserve and IPP Fund Credit

Exhibit 20: Total Annual Emissions (Metric Tonnes)



Source: Pasadena Water and Power

b. Scorecard

The Scorecard was developed using input from the Community IRP survey and a survey of STAG members. Exhibit 21 shows the final score for each Scenario. As seen below, the Scenario SCC+SB 100, which is the Recommended Planning Strategy, received the highest ranking.

Exhibit 21: Scorecard

Metric	Weight	Base Case	BC+ SCC	BC + SB 100	SCC + SB 100	SCC + SB 100+Sell IPP	Diversification	Diversification +Biogas	Diversification +Biogas+Sell IPP
Cost/Ratepayer Impacts	40%	40%	36%	37%	33%	11%	22%	4%	0%
Compliance	35%	18%	18%	35%	35%	35%	35%	35%	35%
Environmental Stewardship	20%	11%	13%	11%	13%	20%	13%	14%	20%
Diversity	5%	0%	0%	0%	3%	3%	5%	5%	5%
Total	100%	68%	67%	82%	84%	68%	75%	58%	60%
Rank		4	6	2	1	5	3	8	7

Source: Pasadena Water and Power

c. Recommended Planning Strategy

The results of the SCC + SB 100 scenario were ultimately selected as the Recommended Planning Strategy based on the Scorecard. Since SB 100 was signed into law on

September 10, 2018, PWP, in coordination with the STAG, chose a Recommended Planning Strategy based on examining several scenarios that met SB 100. This led to all Base Case Scenarios (those that only met SB 350 but not SB 100) being eliminated. Further, all three Base Case Scenarios did not optimize for RPS compliance over time and the model yielded significant over-procurement for RPS. PWP did not modify the RPS results for all the Base Case Scenarios, since SB 100 was signed, and these Scenarios were no longer under consideration. Though the Recommended Planning Strategy provides much greater GHG emissions reduction and RPS than SB 350, this analysis is based on rules and market conditions based on data available today and assists PWP in future procurement decisions.

d. Final Recommendations

The SCC+SB 100 Scenario, or the Recommended Planning Strategy, includes the following:

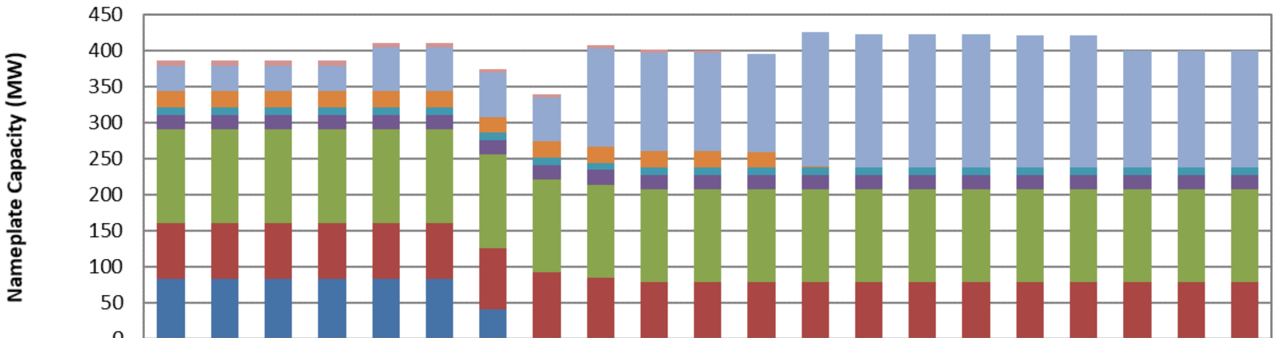
- Ensure that all new future long term energy generation contracts (i.e., excluded capacity contracts or payments to the CAISO to meet capacity obligations) be from renewable and or zero carbon emitting resources
    - This will enable PWP to comply with the SB 100 mandates and the GHG emissions reduction goals
- Eliminate fossil-fuel generation in Utah from the PWP power portfolio no later than 2027
    - The IPP contract expires in June 2027
- Decline to enter into the IPP Renewal that would facilitate a 50-year contract for repowering IPP with natural gas or and/or an alternative
    - This will enable PWP to meet the GHG emissions reduction goals
    - Pasadena City Council supported this objective at its October 29, 2018 City Council meeting
- Target GHG reductions of at least 75% from 1990 levels by 2030[20] (to approximately 226,000 metric tonnes) through the most cost-effective and expedient means available.
    - Opting out of the IPP Renewal and securing additional RPS will enable PWP to reach the GHG emissions reduction goals
- Meet (at least) a 60% RPS by 2030, per SB 100
- Continue to ensure reliability and flexibility to respond to electric industry changes
- Develop an update to this IRP, or a new IRP, within five years of the 2018 IRP

[20] https://www.arb.ca.gov/cc/sb350/staffreport_sb350_irp.pdf.

6. Base Case

To maintain the supply-demand balance and to meet RPS requirements across the study horizon, AURORA added six new solar units, each with a nameplate capacity of 25 MW, to the Pasadena resource portfolio.[21] Solar units were selected by the Long-Term Capacity Expansion (LTCE) as the most competitive resources because of their declining capital cost and zero fuel cost. Exhibit 22 through Exhibit 25 show the least-cost portfolio for the Base Case for the study period. As mentioned earlier, the RPS procurement in all Base Case Scenarios was not optimized for RPS compliance over time and showed significant over-procurement. The RPS analysis for the three Base Case Scenarios does not reflect all details of the current annual compliance strategy for the SB 350 RPS mandate.

Exhibit 22: Base Case - Capacity

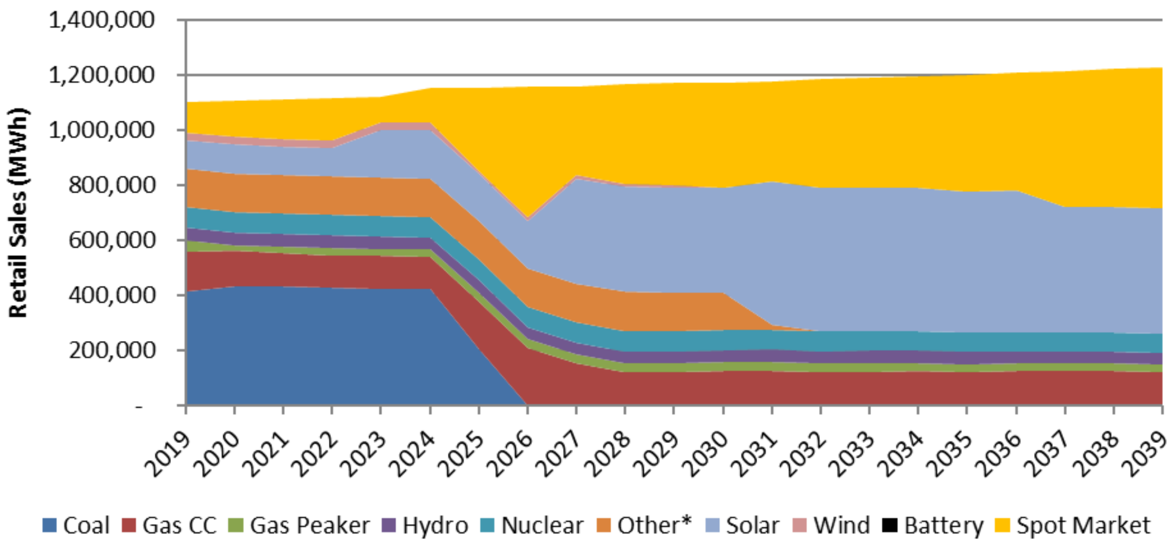


	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Battery																					
Wind	7	7	7	7	7	7	5	5	5	5	4	0	0	0	0	0	0	0	0	0	0
Solar	36	36	36	36	61	61	61	61	136	136	136	136	186	186	186	185	183	183	163	163	163
Other	23	23	23	23	23	23	23	23	23	23	23	22	2	0	0	0	0	0	0	0	0
Nuclear	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Hydro	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
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.

[21] AURORA adds resources in "standard" blocks of 25 MW, but that does not constrain PWP's future resource acquisitions, which may be in smaller shares of resources.

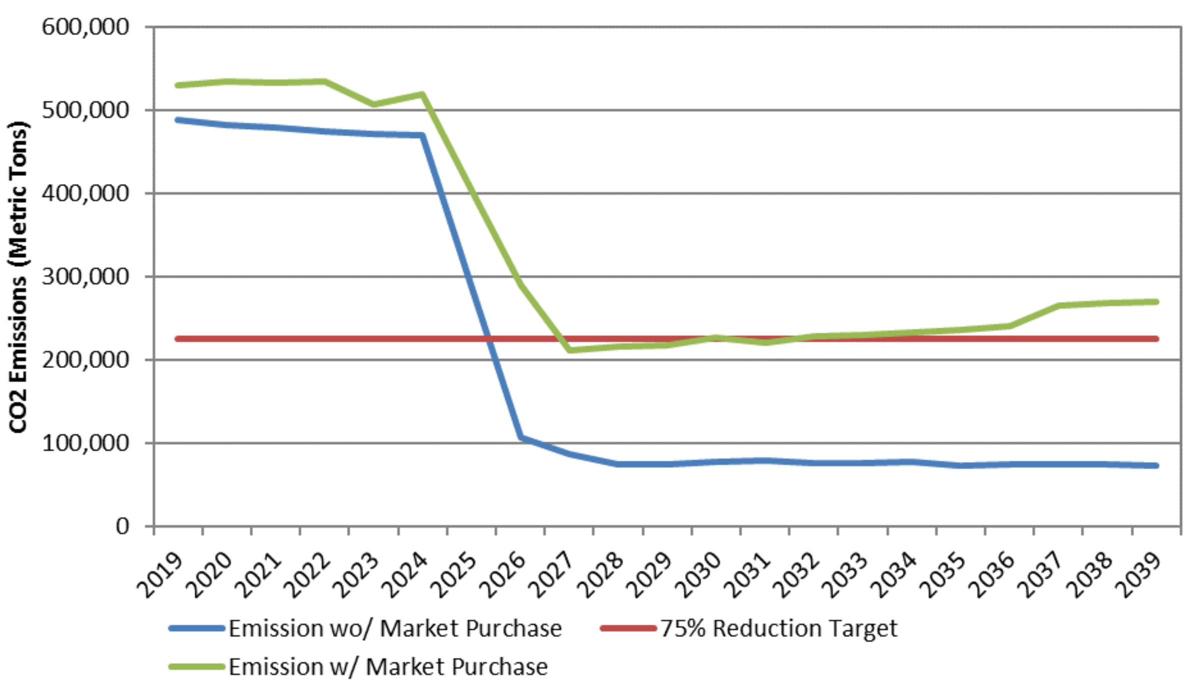
Exhibit 23: Base Case – Energy



Source: Pace Global

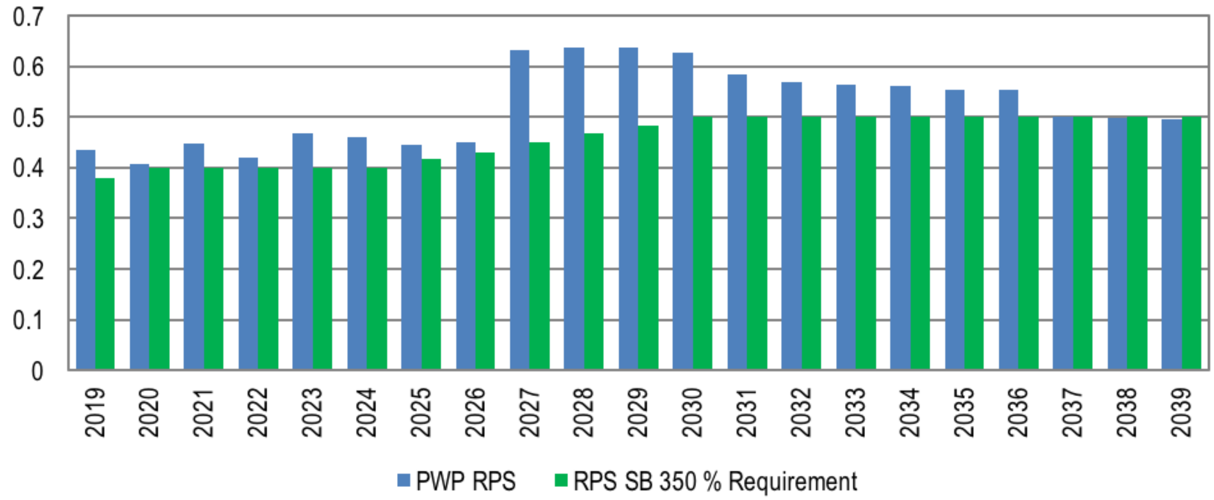
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 24: Base Case - Emissions



Source: Pace Global

Exhibit 25: Base Case – RPS Compliance



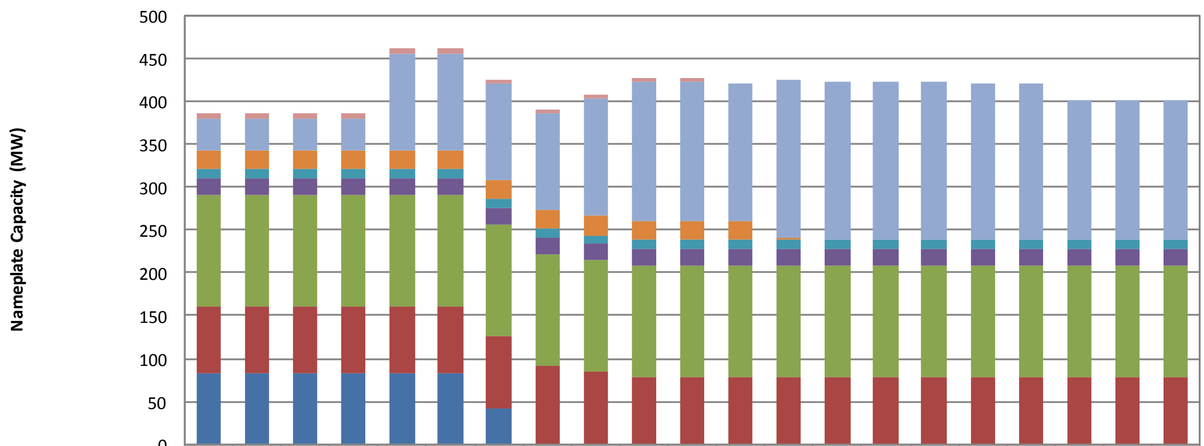
Source: Pace Global

7. Social Cost of Carbon (SCC)

Like the Base Case, six new solar units, for a total of 150 MW, were determined to be optimal for the SCC Case. Since the higher carbon prices displaced the total generation from the fossil units, LTCE elected to build the solar units earlier than in the Base Case to make up the energy short-fall in the midterm forecast.

Exhibit 26 through Exhibit 29 show the SCC least-cost portfolio throughout the study period. As mentioned earlier, the RPS output from AURORA for all Base Case Scenarios were not optimized for RPS compliance and showed over-procurement.

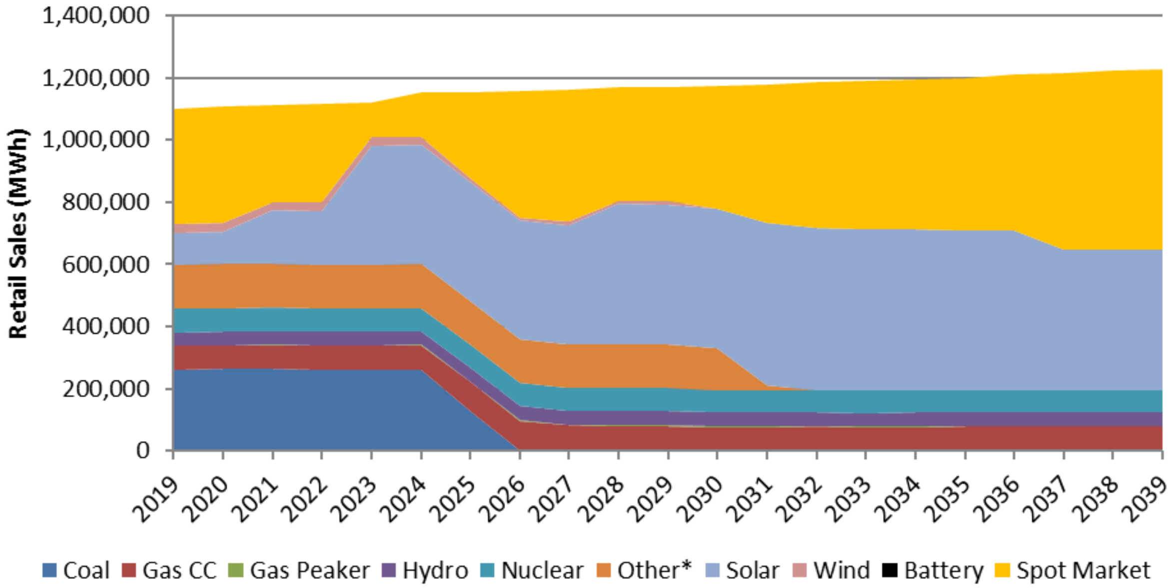
Exhibit 26: SCC - Capacity



	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	4.36	0	0	0	0	0	0	0	0	0	0
Solar	36	36	36	36	111	111	111	111	136	161	161	161	186	186	186	185	183	183	163	163	163
Other Renewable*	22.63	22.64	22.63	22.63	22.63	22.64	22.63	22.63	22.63	22.64	22.63	21.74	2.07	0	0	0	0	0	0	0	0
Nuclear	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Hydro	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	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	82.9	82.9	82.9	82.9	82.9	82.9	41.11	0	0	0	0	0	0	0	0	0	0	0	0	0	0

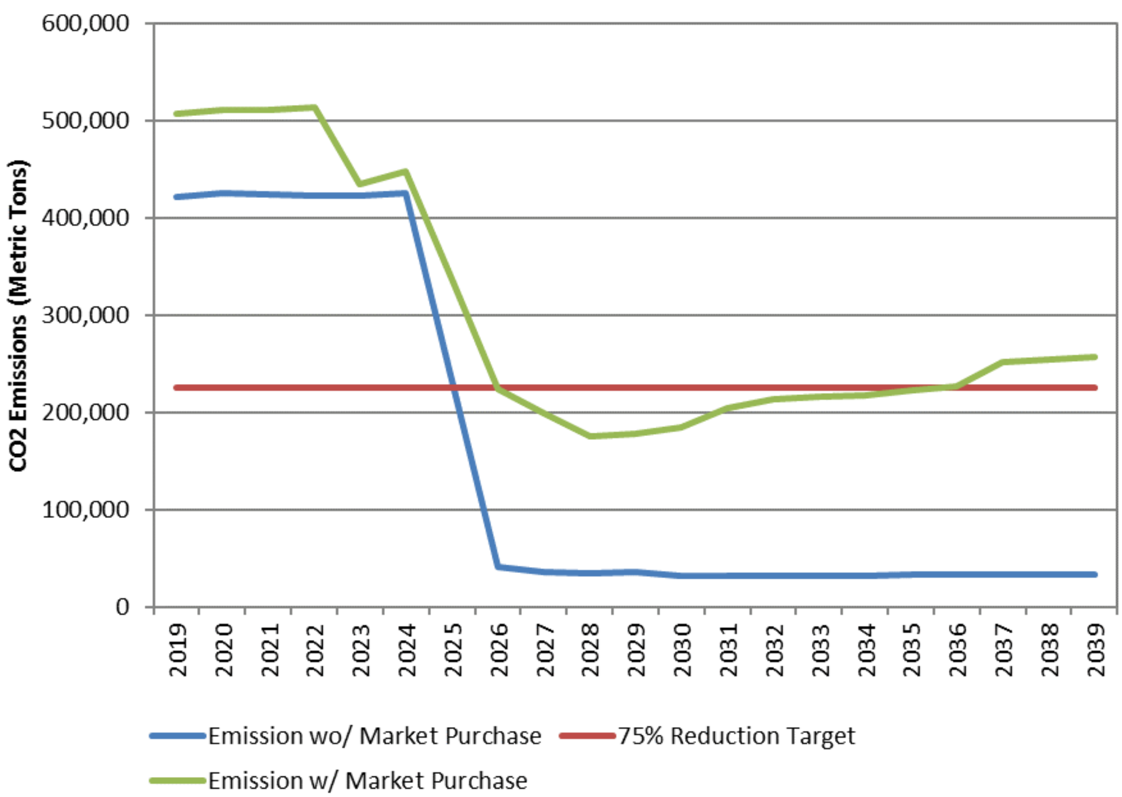
Source: Pace Global
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 27: SCC – Energy



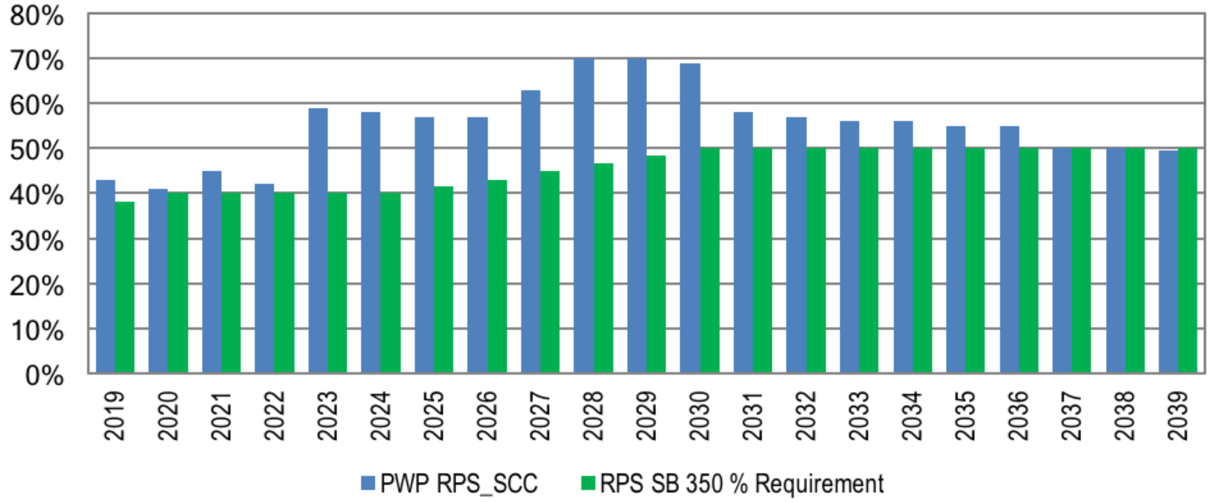
Source: Pace Global
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 28: SCC – Emissions



Source: Pace Global

Exhibit 29: SCC – RPS Compliance

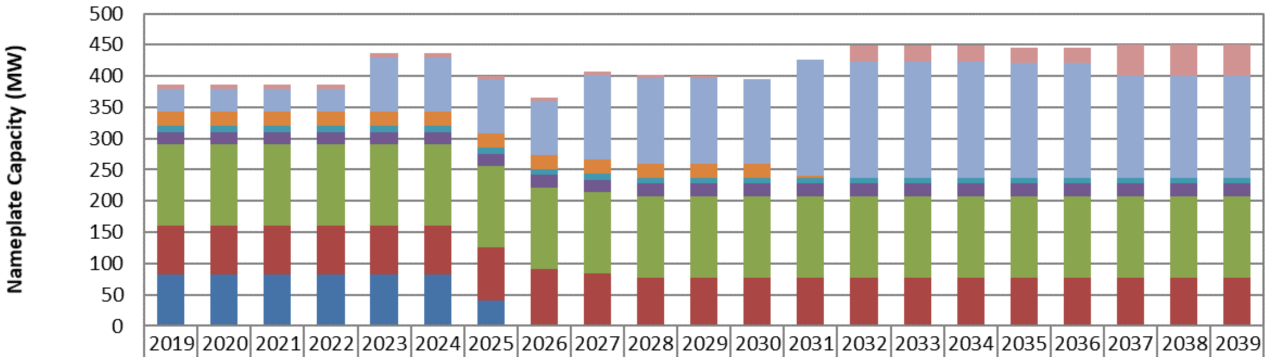


Source:Pace Global

8. Base Case + SB 100

This scenario modifies the RPS to meet the new statutory obligations related in SB 100. Due to the higher RPS standard, two additional wind resources, totaling 50 MW, were determined to be optimal for the SB 100 Case, and one solar unit was built earlier compared to the Base Case. Although the capital costs of the wind units are higher than the solar units during the study period, the wind units help meet internal demand at night when solar resources are not generating. In addition, wind resources become better options than the solar resources in the later years because they can help reduce the risk of exposure to nocturnal spot markets. Exhibit 30 through Exhibit 33 show the SB 100 Case optimal portfolio during the study period.

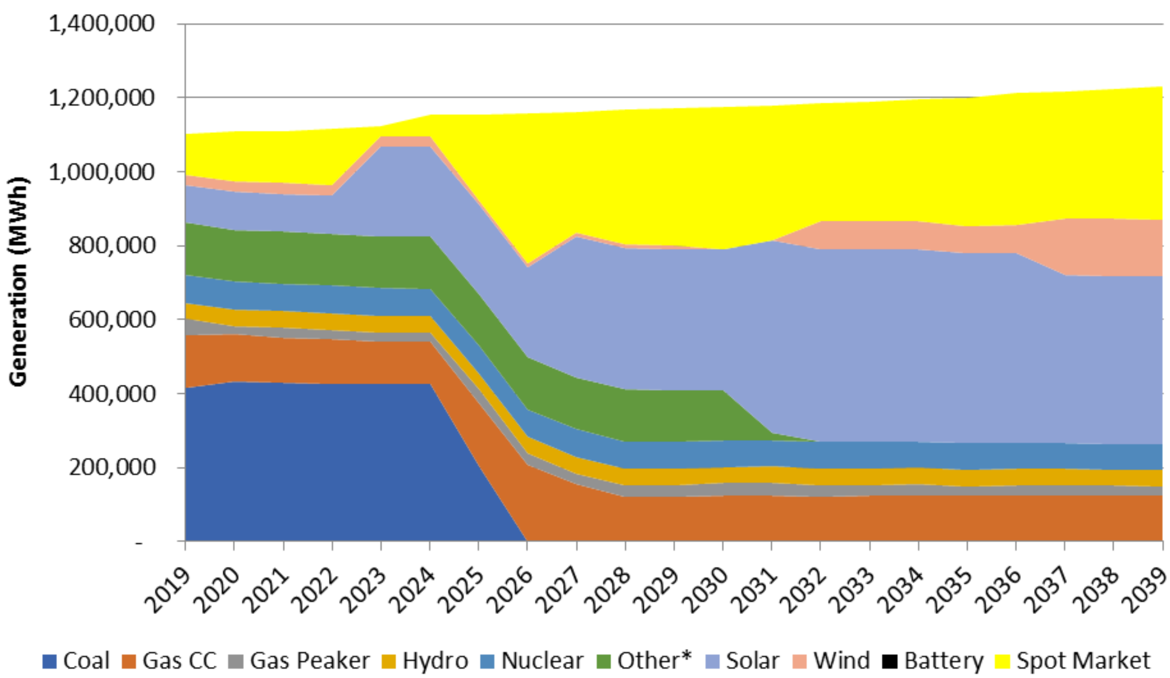
Exhibit 30: SB 100 - Capacity



	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	86	86	86	86	136	136	136	136	186	186	186	185	183	183	163	163	163
Other	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	10	10	10	10	10	10	10	10
Hydro	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20	20
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

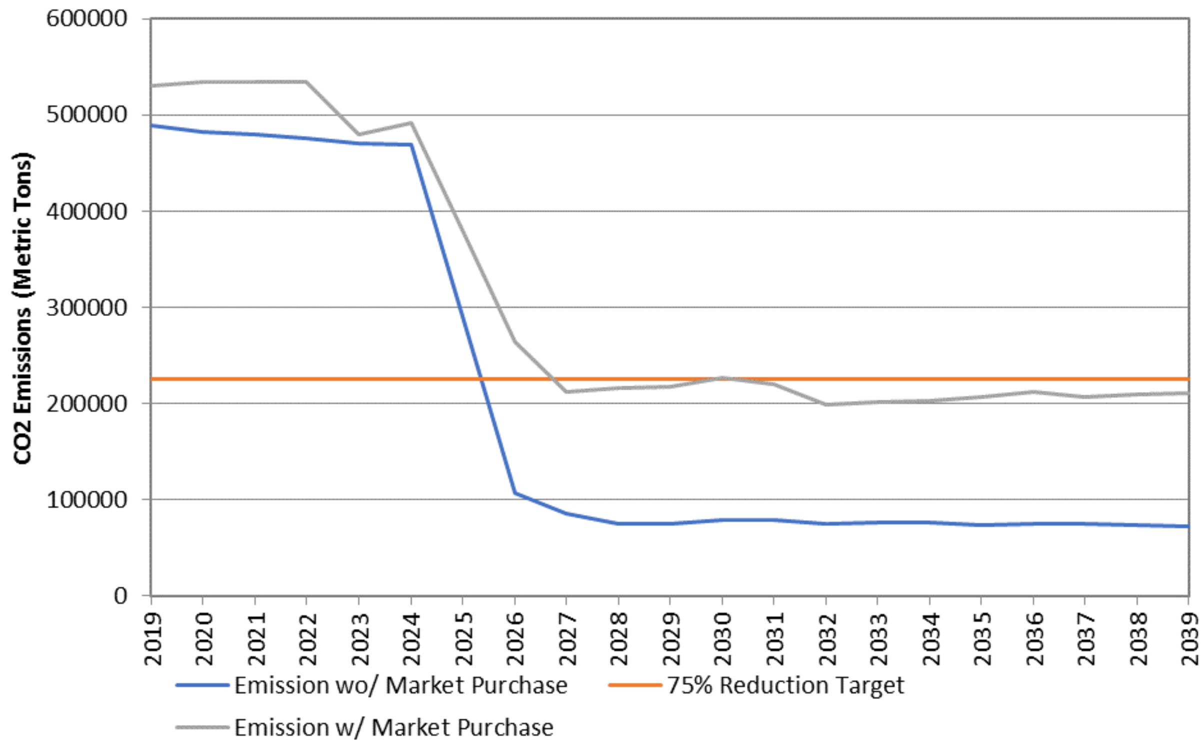
Source: Pace Global
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 31: SB 100 – Energy



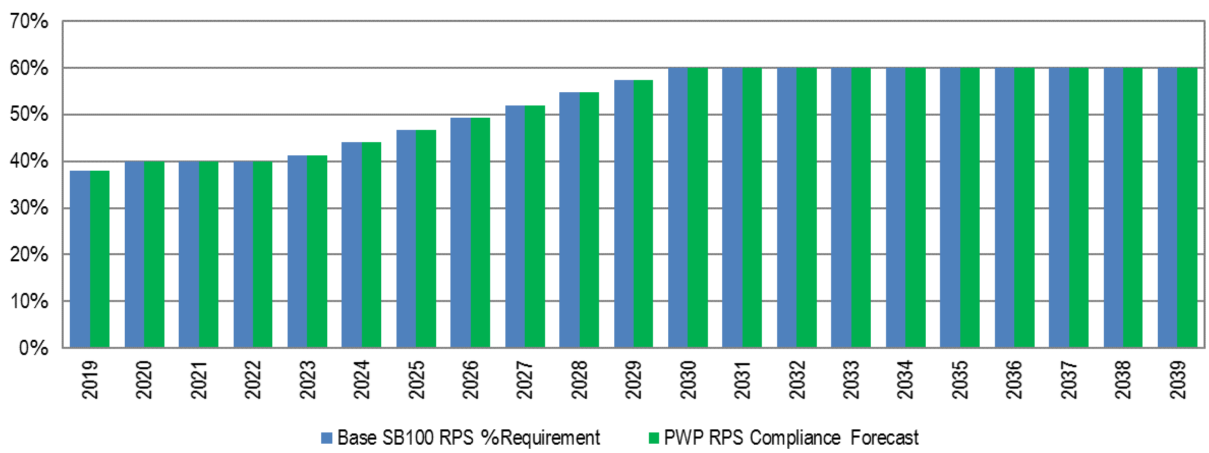
Source: Pace Global
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 32: SB 100 – Emissions



Source: Pace Global

Exhibit 33: SB 100 – RPS Compliance



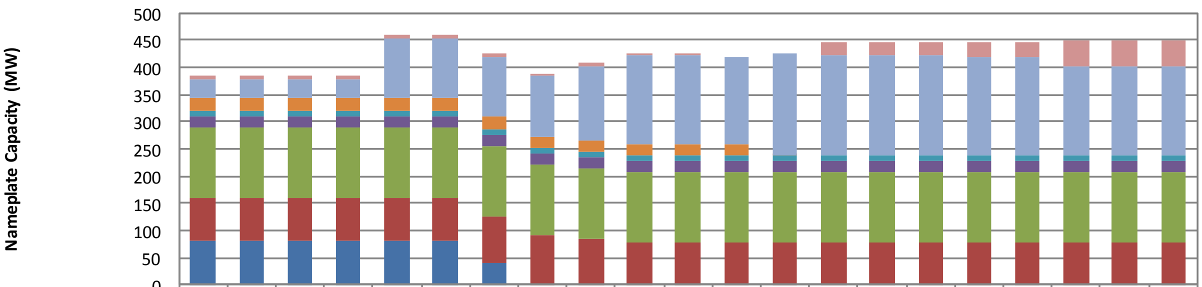
Source: Pace Global

9. SCC + SB 100

Like the SB 100 Case, 150 MW of solar units and 50 MW of wind units were determined to be optimal for the SCC + SB100 Case. Two solar resources were built earlier in the SCC + SB100 Case due to the reduced fossil generation resulting from the higher carbon prices. Exhibit 34 through

Exhibit 37 show the optimal portfolio for the SCC + SB100 Case for the study period. RPS procurement for all SB 100 Scenarios was maximized for compliance. This limits over-procurement of resources. As stated earlier, the SCC is a penalty on the dispatch of incremental fossil fuel resources, for modeling purpose. This scenario does enhance PWP's commitment to renewable resources, earlier than the SCC Case, which only complied with SB 350.

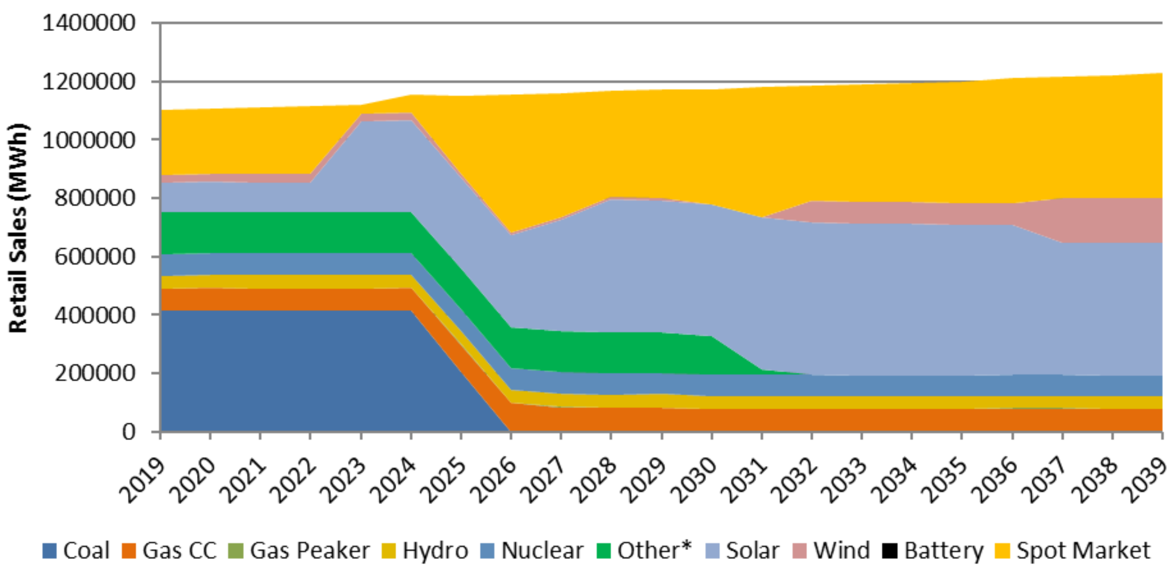
Exhibit 34: SCC + SB 100 - Capacity



	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.

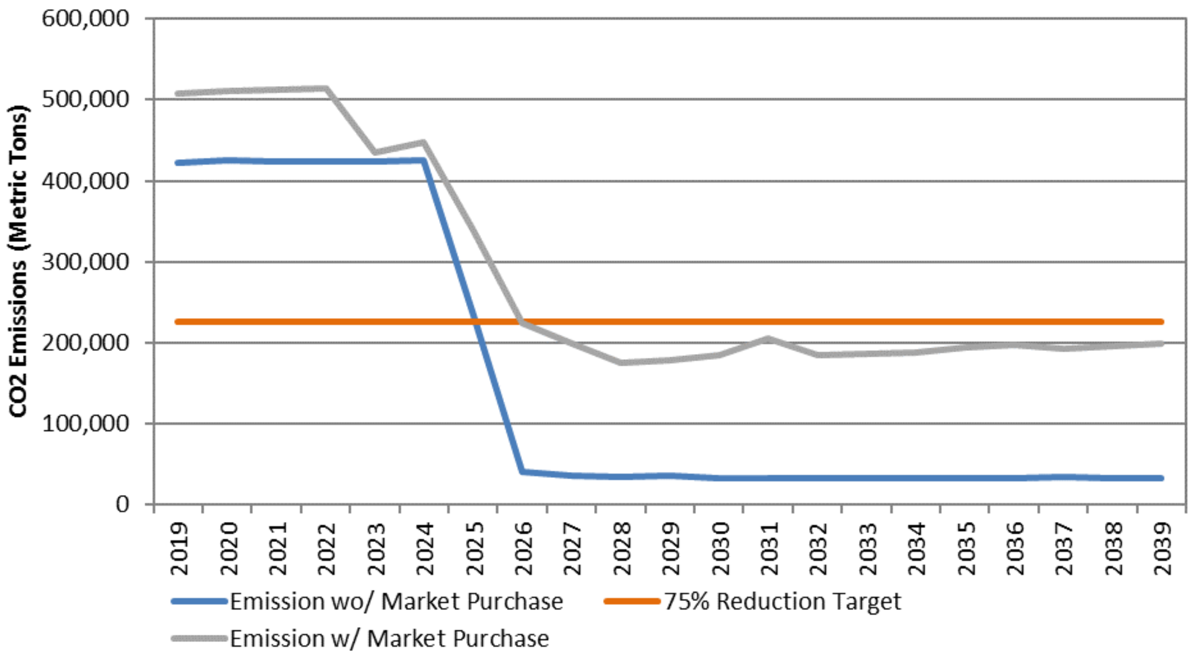
Exhibit 35: SCC + SB 100 - Energy



Source: Pace Global

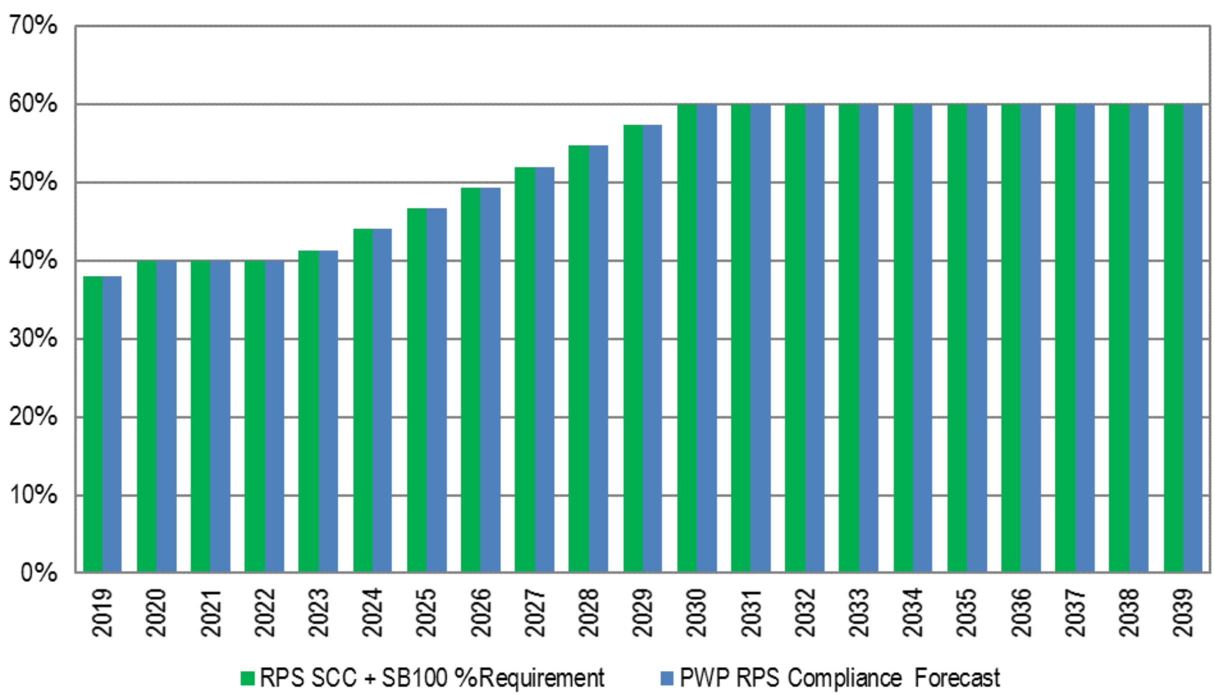
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 36: SCC + SB 100 – Emissions



Source: Pace Global

Exhibit 37: SCC + SB 100 – RPS Compliance

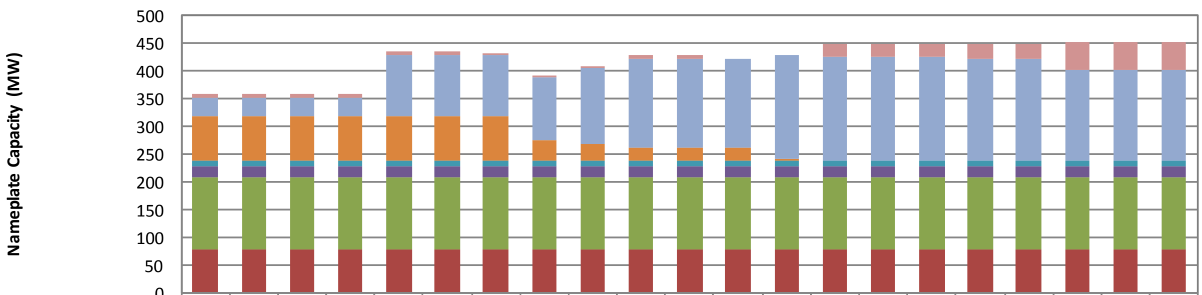


Source: Pace Global

10. SCC + SB 100 + "Leave IPP Energy in Utah"

In this scenario, a new assumption was added: PWP would find a contractually feasible way to *not* import coal-fired generation from Utah but would leave any required coal-fired energy outside of California. Significant financial and contractual obstacles would have to be overcome, including the fact that the bonds that financed IPP were issued by the Intermountain Power Authority, which is a tax-exempt Utah entity. Contracts and bond covenants would restrict the potential pool of buyers, although it might be possible to find a tax-exempt buyer if the price were low enough. Specifically, a geothermal unit of 55 MW (2019~2026) is added into the portfolio. PWP's share of IPP drops to 14 MW in 2025 and to 7 MW in 2026 when the coal-fired units are replaced with natural gas. Exhibit 38 through Exhibit 41 show the optimal portfolio for the "SCC + SB 100 + Leave IPP in Utah" Case for the study period. For this and all "Leave IPP Energy in Utah" Cases, it should be noted that leaving IPP output (coal- or gas-fired) outside the state, if feasible, does not mean that the emissions from IPP would necessarily fall, because the off-taker could decide to generate with coal or natural gas.

Exhibit 38: SCC + SB 100 + Leave IPP in Utah - Capacity

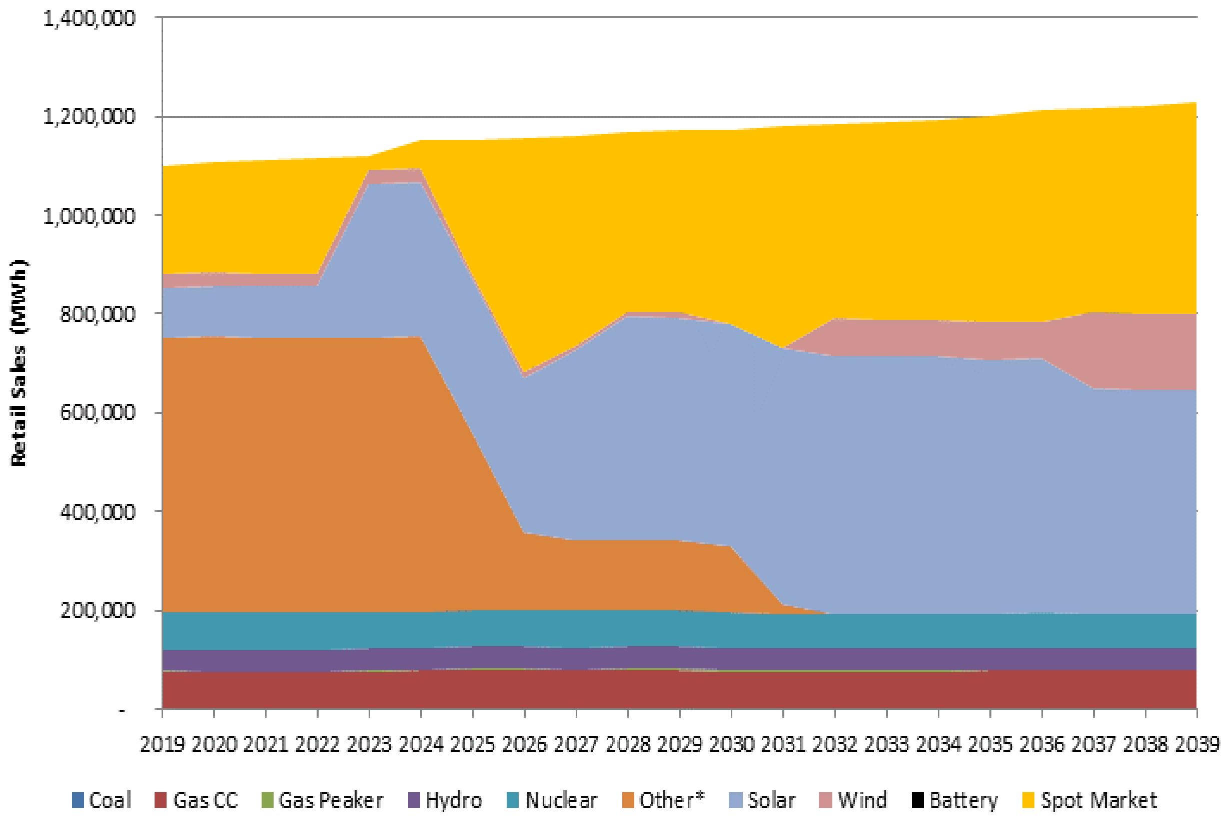


	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Battery																					
Wind	7	7	7	7	7	7	5	5	5	5	4	0	0	25	25	25	25	25	50	50	50
Solar	36	36	36	36	111	111	111	111	136	161	161	161	186	185.6	185.6	185.4	183	183	163	163	163
Other Renewable*	78	78	78	78	78	78	78	37	30	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	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Source: Pace Global

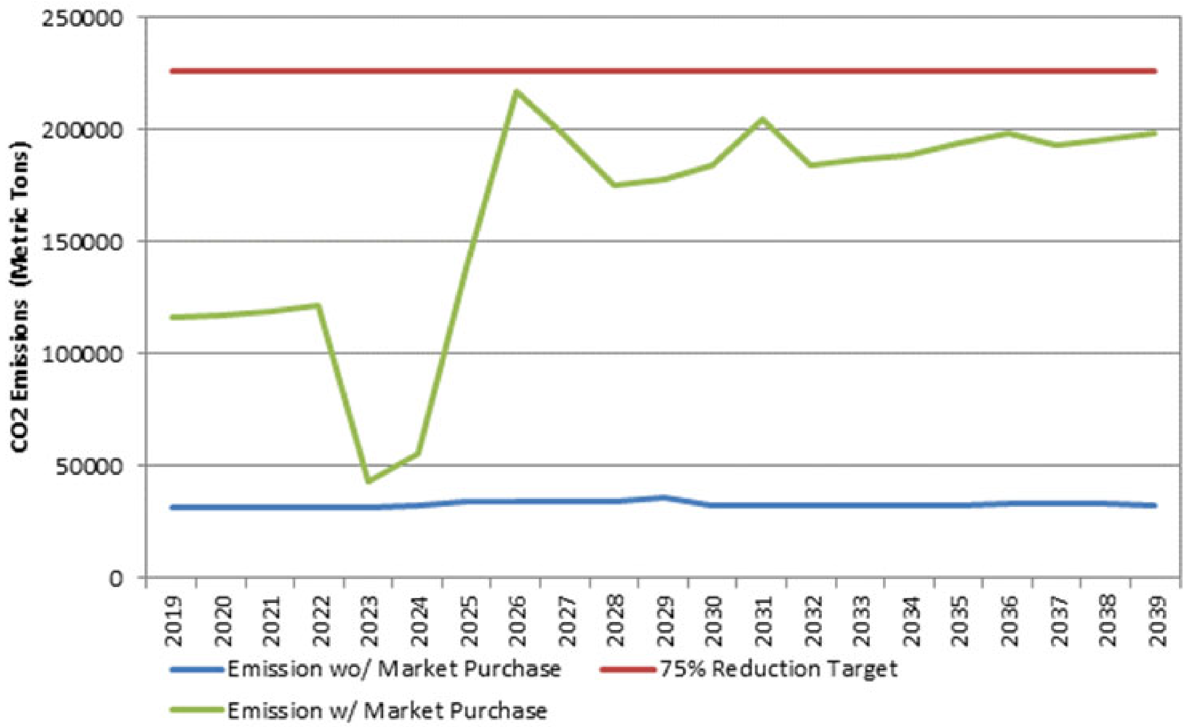
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 39: SCC + SB 100 + Leave IPP in Utah – Energy



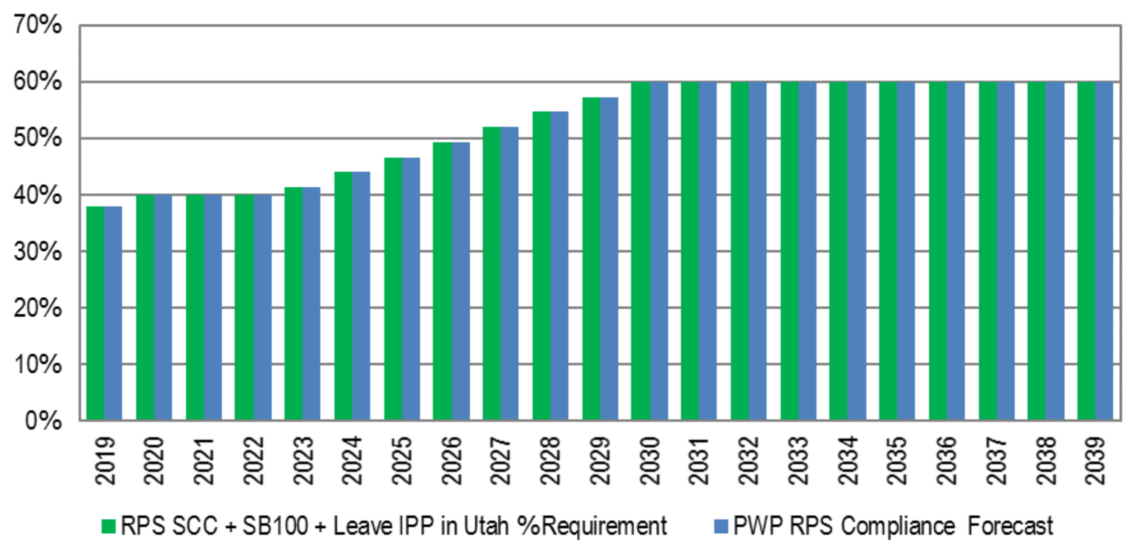
Source: Pace Global; *Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 40: SCC + SB 100 + Leave IPP in Utah – Emissions



Source: Pace Global

Exhibit 41: SCC + SB 100 + Leave IPP in Utah – RPS Compliance

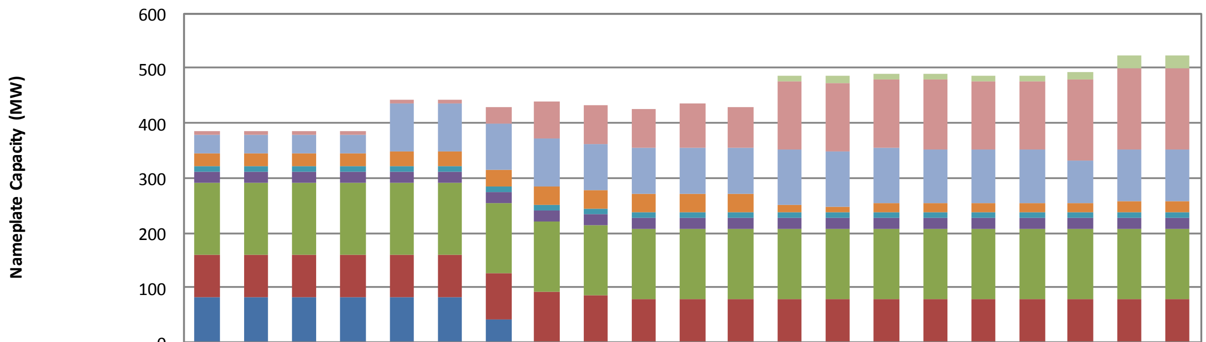


Source: Pace Global

11. SCC + SB 100 + Diversification

As discussed above, AURORA searches for the optimal portfolio that will meet load, even if that portfolio "builds" only one new technology (e.g., solar). PWP wanted to consider a portfolio that was deliberately diversified to include several renewable technologies. The results of the "forced diversification" are in Exhibit 42 through Exhibit 45.

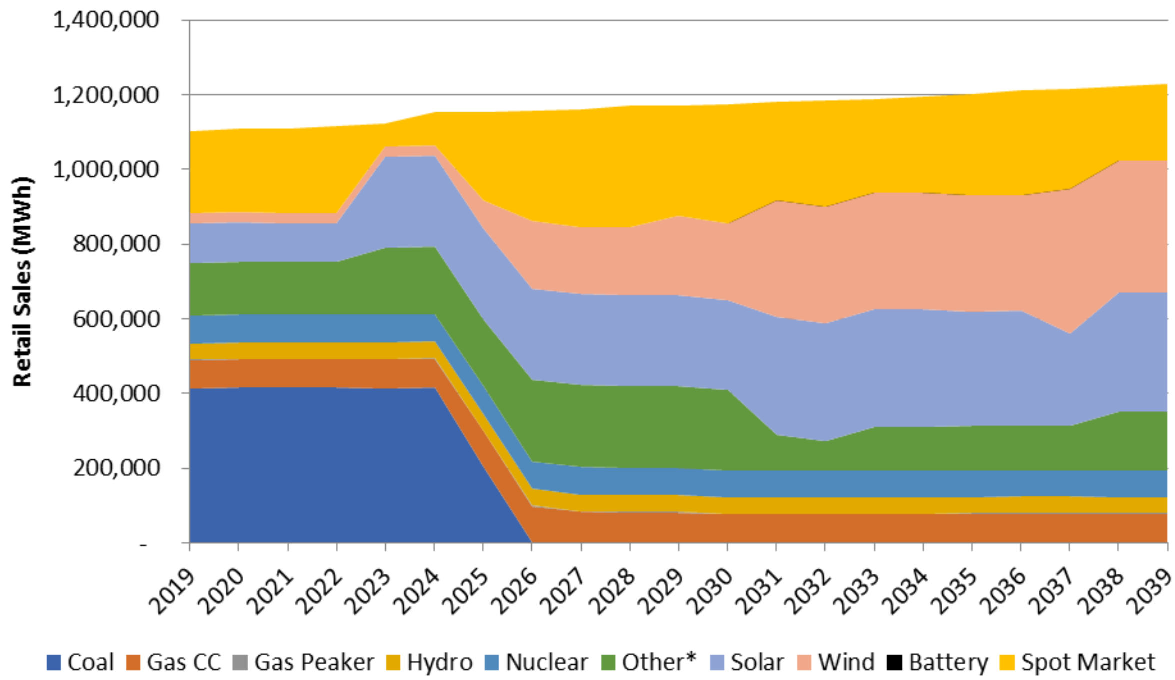
Exhibit 42: SCC + SB 100 + Diversification - Capacity



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Battery													11.7	11.7	11.7	11.7	11.7	11.7	11.7	23.4	23.4
Wind	7	7	7	7	7	7	30	70	70	70	79.36	75	125	125	125	125	125	125	150	150	150
Solar	36.13	36.13	36.13	36.13	86.13	86.13	86.13	86.13	86.13	86.13	86.13	86.13	100.8	100.6	100.6	100.4	98	98	78	93	93
Other Renewable*	22.63	22.64	22.63	22.63	27.63	27.64	27.63	32.63	32.63	32.64	32.63	31.74	12.07	10	15	15	15	15	15	20	20
Nuclear	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Hydro	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	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	82.9	82.9	82.9	82.9	82.9	82.9	41.11	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.

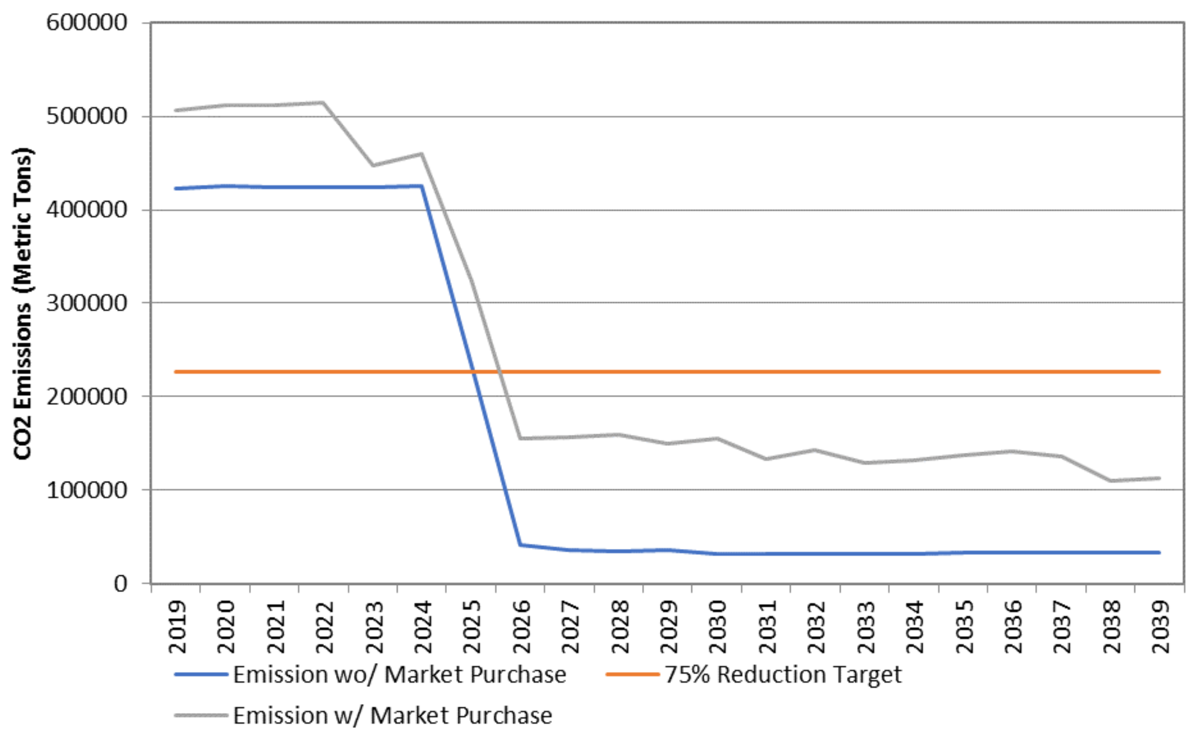
Exhibit 43: SCC + SB 100 + Diversification – Energy



Source: Pace Global

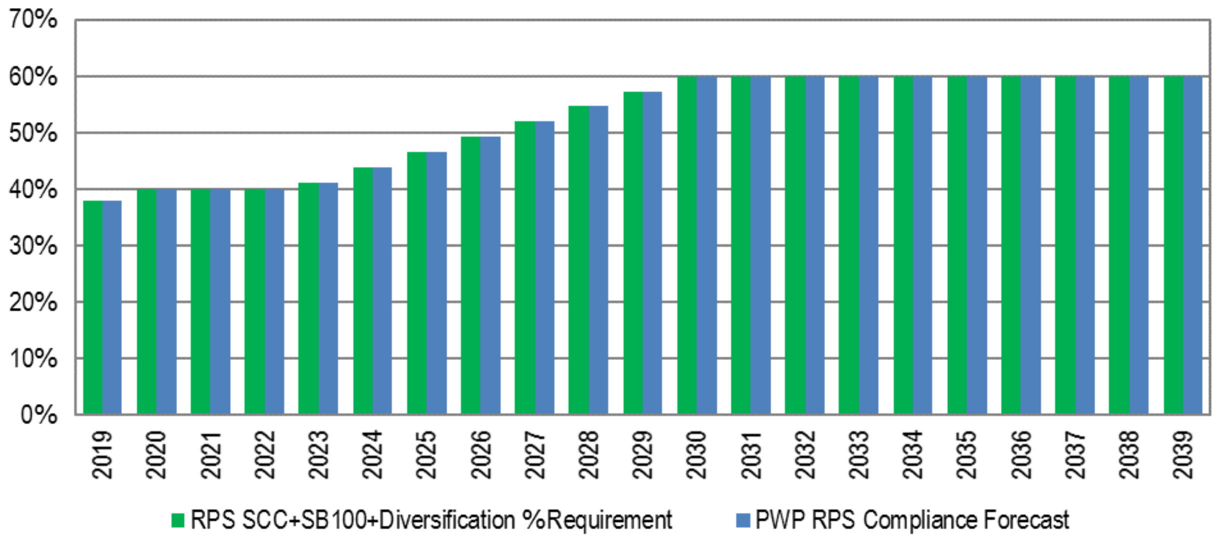
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 44: SCC + SB 100 + Diversification – Emissions



Source: Pace Global

Exhibit 45: SCC + SB 100 + Diversification – RPS Compliance

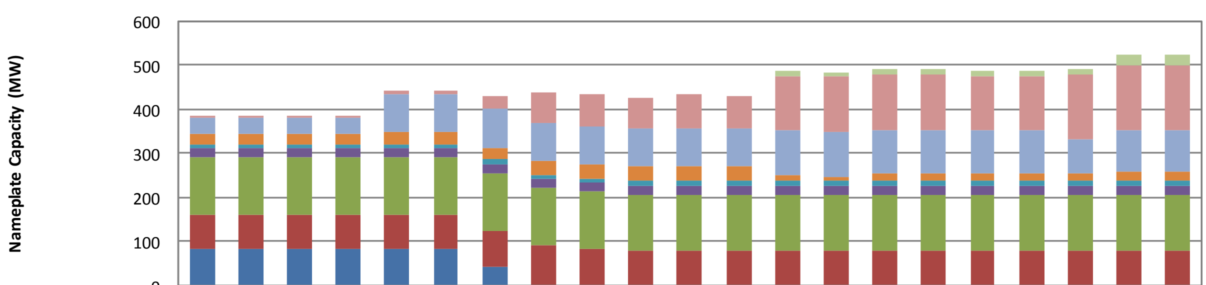


Source: Pace Global

12. SCC + SB 100 + Diversification + Biogas

This scenario does not add or subtract specific resources but assumes that the fossil natural gas that must be burned at Glenarm (for reliability) and at Magnolia (for contractual compliance) is replaced over time by biogas, so the capacity chart is the same as Scenario 6, replicated here. The results of this scenario are in Exhibit 46 through Exhibit 49. This assumes that these resources are at 25% biogas from 2030-2034, 50% biogas 2035-2037 and 100% biogas 2038-2039.

Exhibit 46: SCC + SB 100 + Diversification + Biogas – Capacity

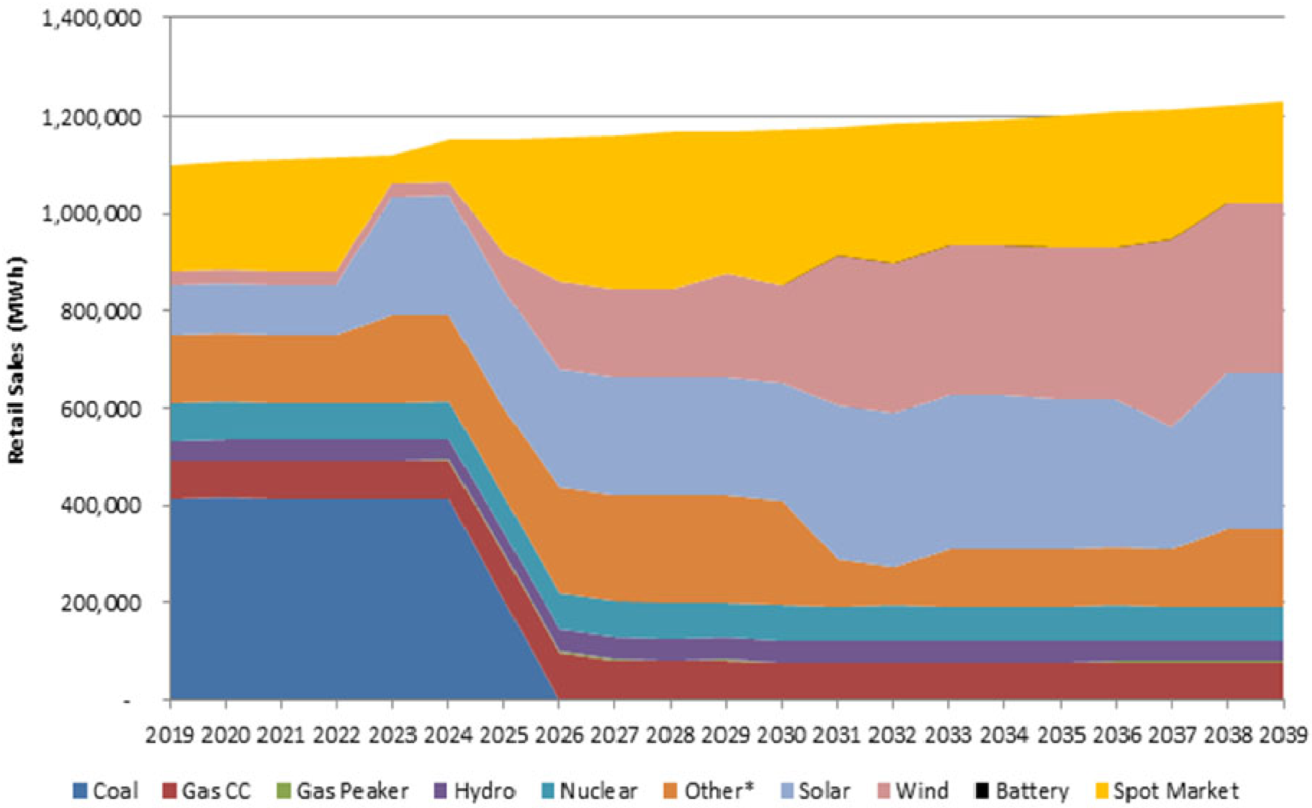


	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Battery													11.7	11.7	11.7	11.7	11.7	11.7	11.7	23.4	23.4
Wind	7	7	7	7	7	7	30	70	70	70	79.36	75	125	125	125	125	125	125	150	150	150
Solar	36.13	36.13	36.13	36.13	86.13	86.13	86.13	86.13	86.13	86.13	86.13	86.13	100.8	100.6	100.6	100.4	98	98	78	93	93
Other Renewable*	22.63	22.64	22.63	22.63	27.63	27.64	27.63	32.63	32.63	32.64	32.63	31.74	12.07	10	15	15	15	15	15	20	20
Nuclear	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Hydro	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	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	82.9	82.9	82.9	82.9	82.9	82.9	41.11	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.

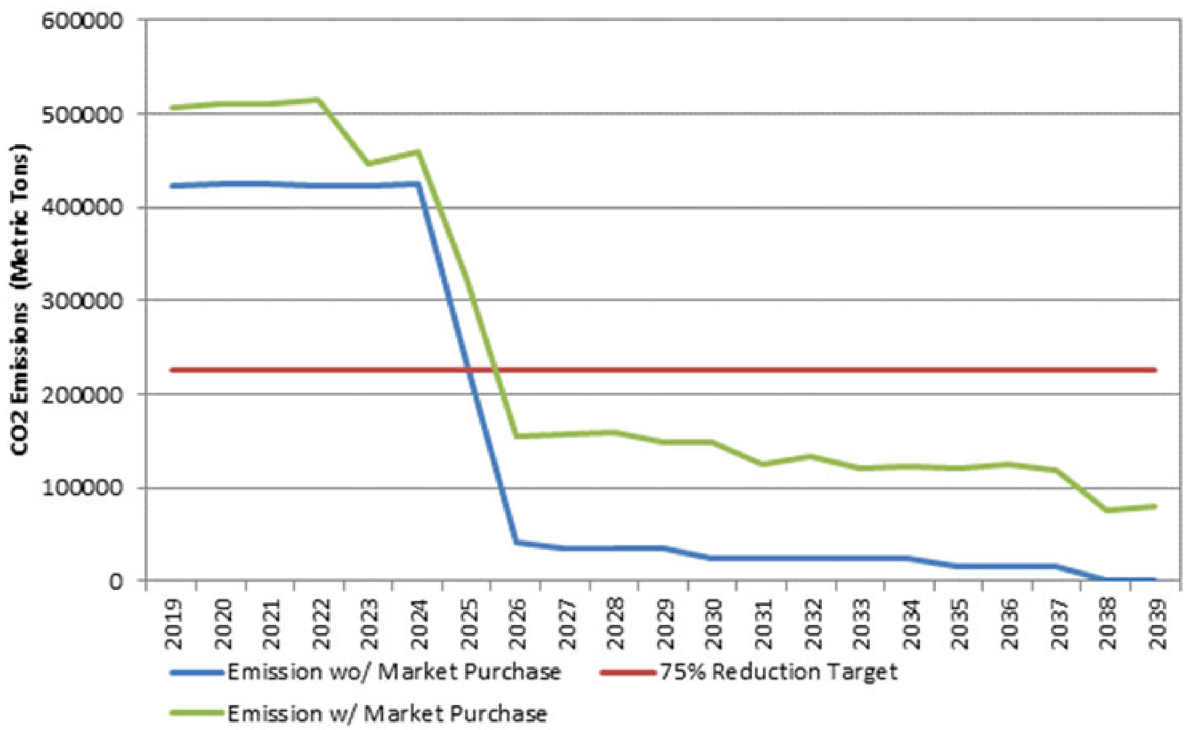
Exhibit 47: SCC + SB 100 + Diversification + Biogas – Energy



Source: Pace Global

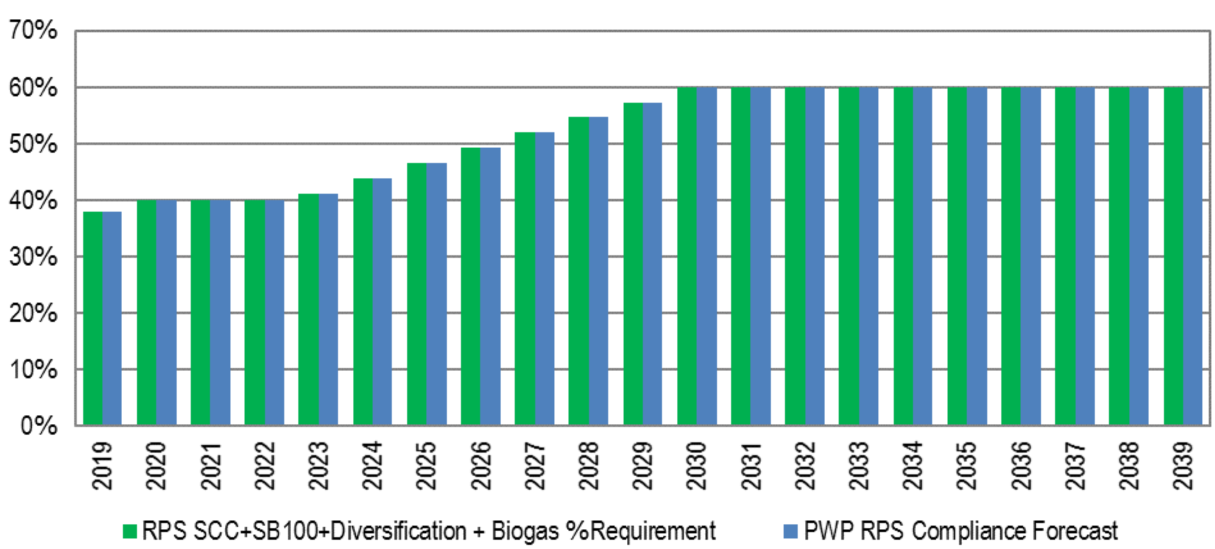
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 48: SCC + SB 100 + Diversification + Biogas – Emissions



Source: Pace Global

Exhibit 49: SCC + SB 100 + Diversification + Biogas – RPS Compliance



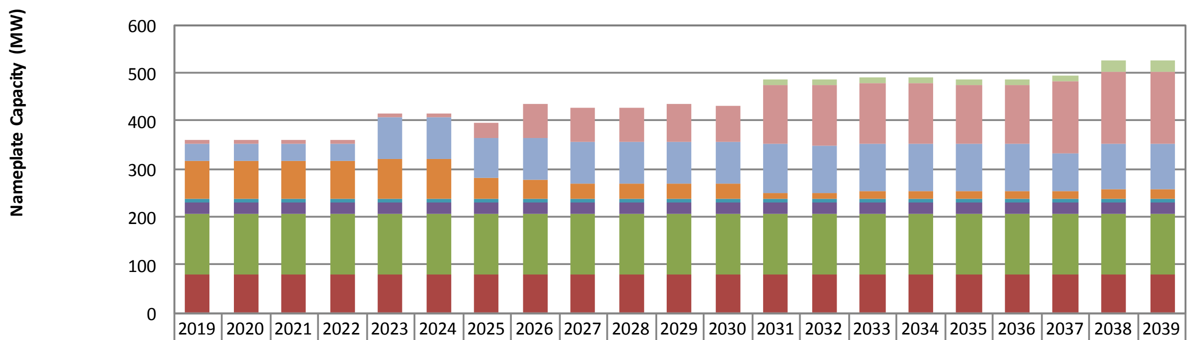
Source: Pace Global

13. SCC + SB 100 + Forced Diversification + Biogas + Leave IPP Energy in Utah

As in Scenario 5, a geothermal unit of 55 MW (added between 2019 and 2026) replaces the coal- and natural-gas fired energy at IPP. This is the incremental change from Scenario 7, "SCC + SB

100 + Diversification + Biogas." The results of this "forced diversification" scenario are shown in Exhibit 50 through Exhibit 53. Again, biogas would be combusted in the Gas Peaker and Gas CC units.

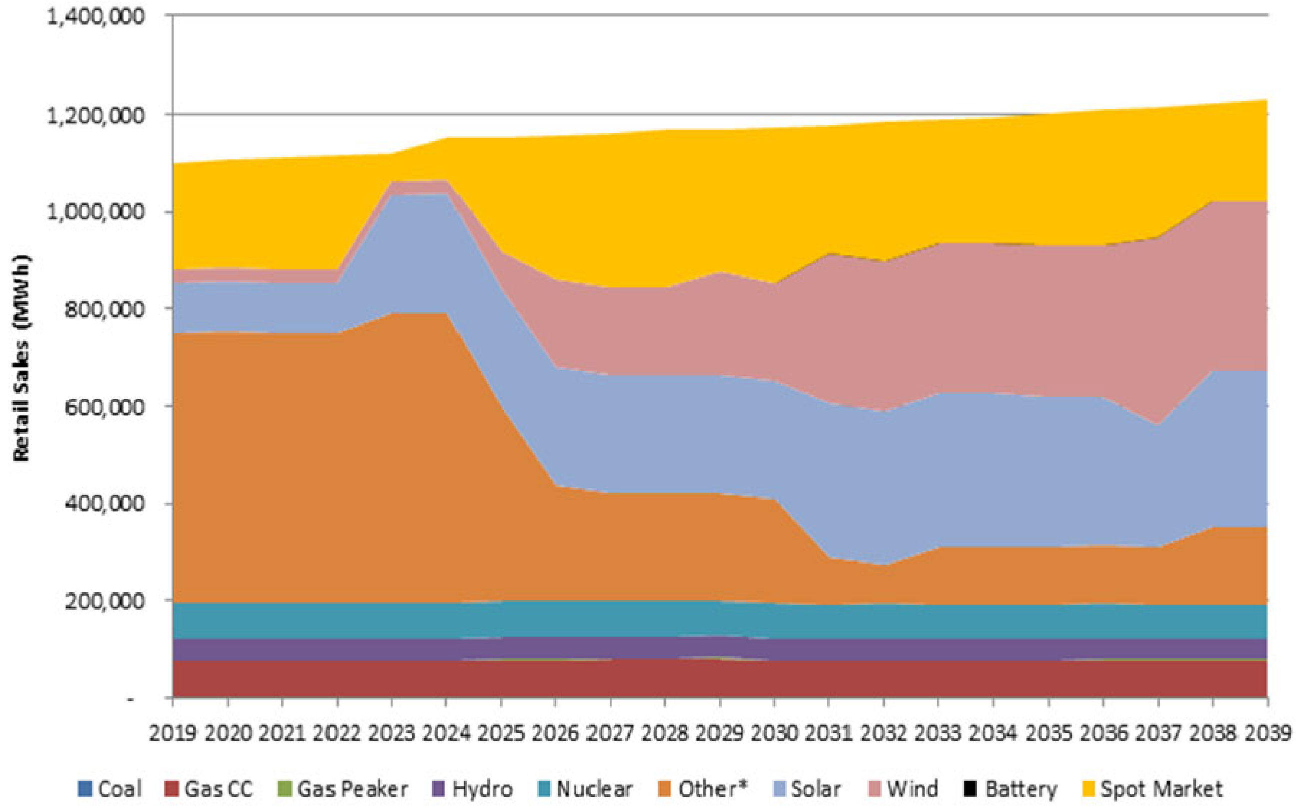
Exhibit 50: SCC + SB 100 + Diversification + Biogas + Leave IPP in Utah - Capacity



	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Battery													11.7	11.7	11.7	11.7	11.7	11.7	11.7	23.4	23.4
Wind	7	7	7	7	7	7	30	70	70	70	79.36	75	125	125	125	125	125	125	150	150	150
Solar	36.13	36.13	36.13	36.13	86.13	86.13	86.13	86.13	86.13	86.13	86.13	86.13	100.8	100.6	100.6	100.4	98	98	78	93	93
Other Renewable*	77.63	77.64	77.63	77.63	82.63	82.64	41.63	39.63	32.63	32.64	32.63	31.74	12.07	10	15	15	15	15	15	20	20
Nuclear	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Hydro	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	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	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

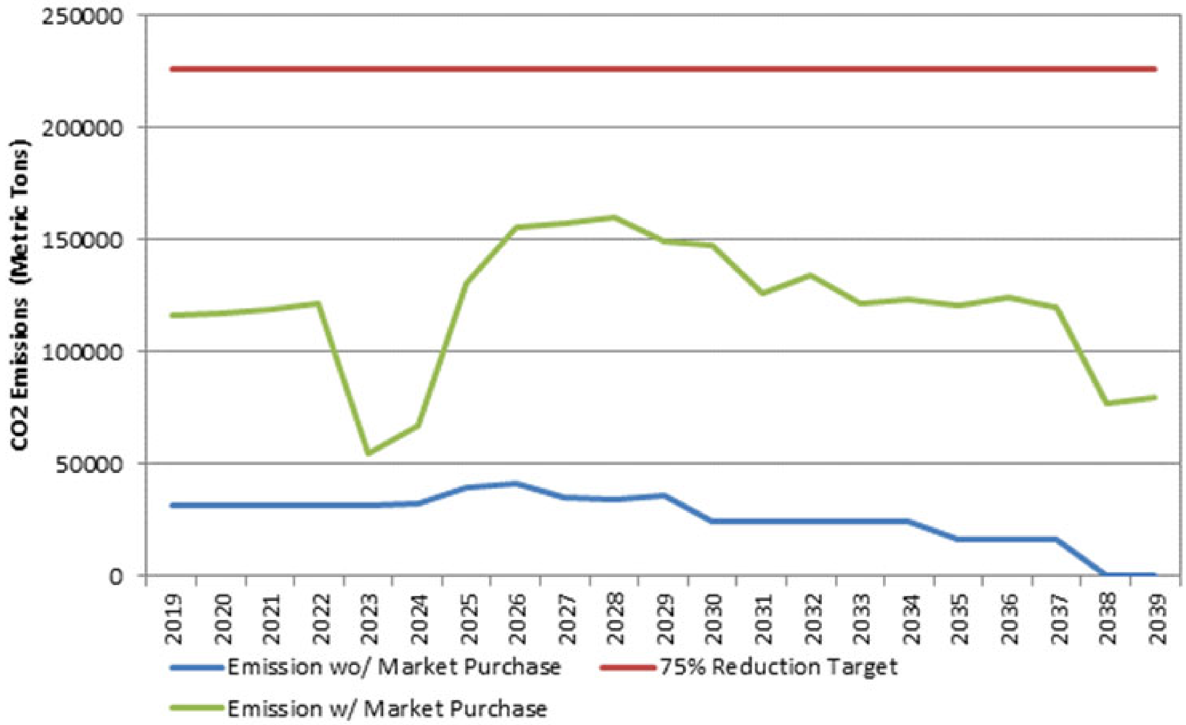
Source: Pace Global
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 51: SCC + SB 100 + Diversification + Biogas + Leave IPP in Utah – Energy



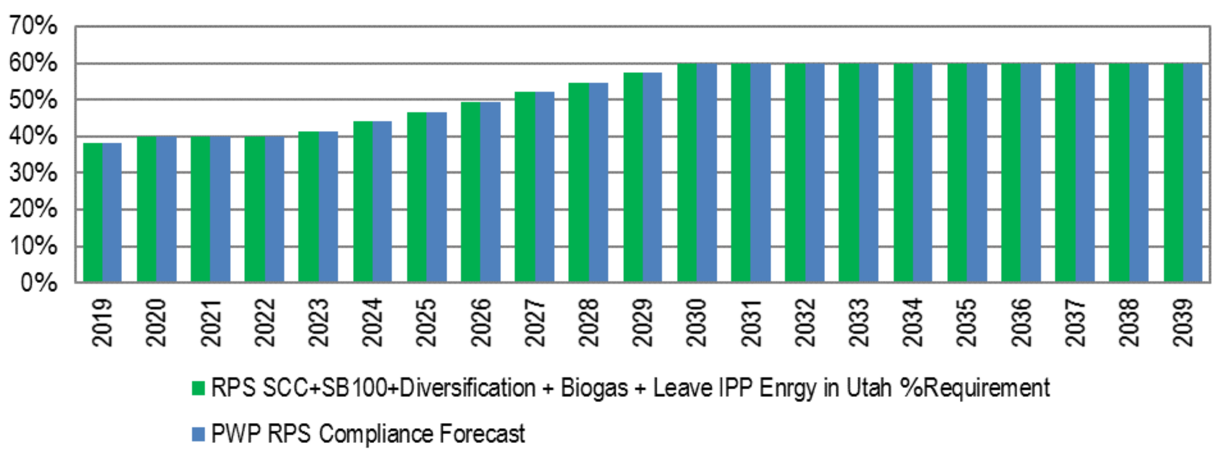
Source: Pace Global
*Other Renewables: Puente Hills, Chiquita Canyon Landfill, and Heber Geothermal.

Exhibit 52: SCC + SB 100 + Diversification + Biogas + Leave IPP in Utah – Emissions



Source: Pace Global

Exhibit 53: SCC + SB 100 + Diversification + Biogas + Leave IPP in Utah – RPS Compliance



Source: Pace Global

14. Dynamic RPS Compliance and Excess Procurement

Initially, every Scenario showed substantial over-procurement of renewable resources: acquisition of renewable resources and RECs in excess of annual regulatory obligations. As discussed in more detail below (under "RPS Planning Requirements"), excess procurement in any year can be part of a multi-year optimized compliance strategy, taking advantage of the ability to bank less expensive compliance instruments (RECs) in one year to avoid compliance instruments in a later year or years. However, some of the results above call into question the wisdom of relying on such a strategy to manage uncertainty and control costs, because the amounts of banked RECs might grow to be so large that the marginal value of a REC banked today for future compliance could fall dramatically. As a result, PWP staff re-ran all of the RPS compliance calculations for the SB 100 Scenarios to meet the RPS compliance mandates. The model selects RPS resources in 25 MW blocks. Sometimes PWP only needs 1 or 2 MW, and the 25 MW block minimum thus resulted in over-procurement. As a result, PWP staff adjusted the results to "cash out" any resulting excess RPS procurement in order to fairly compare the cost of various portfolios on an "equivalent RPS" compliance basis.

15. Emissions Summary

The emission reductions for each scenario's least-cost portfolio are reproduced for comparison in Exhibit 54. All portfolios exceed the target of 81% emissions reduction from 1990 levels by 2030, as set for this analysis in Section II.A.3. It should be noted that leaving IPP output (coal- or gas-fired) outside the state, if feasible, does not mean that the emissions from IPP will necessarily fall, because the off-taker could decide to generate with coal or natural gas.

Exhibit 54: GHG Emissions (Metric Tonnes)

Case	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Year	Base Case	Social Cost of Carbon (SCC)	Base Case + SB 100	SCC + SB 100	SCC + SB 100 + Leave IPP Energy in Utah	Diversification (SCC + SB100)	Diversification + Biogas	Diversification + Biogas + Leave IPP Energy in Utah
2019	488,453	422,397	488,453	422,397	31,773	422,397	422,397	31,773
2020	483,037	425,426	483,037	425,426	31,477	425,426	425,426	31,477
2021	479,126	423,989	479,126	423,989	31,498	423,989	423,989	31,498
2022	475,383	423,574	475,383	423,574	31,569	423,574	423,574	31,569
2023	471,169	423,444	469,793	423,444	31,727	423,447	423,447	31,729
2024	470,379	425,552	469,107	425,552	32,720	425,575	425,575	32,734
2025	290,644	233,387	290,429	233,387	39,563	233,459	233,459	39,635
2026	107,663	40,992	107,331	40,992	40,992	41,025	41,025	41,025
2027	86,466	35,311	86,370	35,311	35,311	35,438	35,438	35,438
2028	75,414	34,565	75,436	34,565	34,565	34,585	34,585	34,585
2029	74,744	35,671	74,981	35,671	35,671	35,837	35,837	35,837
2030	78,480	32,568	78,554	32,568	32,568	32,589	24,442	24,442
2031	79,487	32,602	79,687	32,602	32,602	32,584	24,438	24,438
2032	75,621	32,574	75,434	32,566	32,566	32,597	24,448	24,448
2033	76,443	32,383	75,954	32,360	32,360	32,390	24,292	24,292
2034	77,110	32,278	76,789	32,261	32,261	32,288	24,216	24,216
2035	73,435	32,786	73,742	32,790	32,790	32,754	16,377	16,377
2036	74,524	33,474	74,752	33,474	33,474	33,418	16,709	16,709
2037	75,200	33,655	74,928	33,664	33,664	33,612	16,806	16,806
2038	74,941	33,159	74,242	33,131	33,131	33,062	-	-
2039	72,948	32,938	73,097	32,950	32,950	32,857	-	-

Source: Pace Global

C. Standardized Tables

Although the Energy Commission only requires POUs to submit data for the scenario that is consistent with PUC Section 962.1 (the "Base Case" here, compliant with SB 350), this IRP contains data for the additional SB 100 scenario, in the format of the four standardized tables (provided separately in workbook "PWP – Compliance Tables"):

- Capacity Resource Accounting Table (CRAT): annual peak capacity demand in each year and the contribution of each resource (capacity) in the POU's portfolio to meet that demand.
- Energy Balance Table (EBT): annual total energy demand and annual estimates for energy supply from various resources.
- RPS Procurement Table (RPT): summary of the POU's resource plan to meet the RPS requirements.
- GHG Emissions Accounting Table (GEAT): annual GHG emissions associated with each resource in the POU's portfolio to demonstrate compliance with the GHG emissions reduction targets established by CARB.

D. Supporting Information

In addition to the standardized tables, PWP used assumptions in various aspects of the planning that have been discussed and sourced in the corresponding sections of this IRP. The data and supporting information are intended to support and expedite the California Energy Commission's review of the PWP IRP. The sources discussed throughout the report are included as footnotes with links to the necessary documents.

Please refer to the assumptions books (provided separately in workbook "PWP – Assumptions and Inputs") for data and supporting information modeled in AURORA. The data and supporting information are intended to support and expedite the California Energy Commission's review of the PWP IRP.

No sources were used that are older than 24 months old.

E. Demand Forecast

1. Reporting Requirements

PWP is reporting annual forecasted peak demand (in MWs) in the CRAT and annual forecasted retail sales, other loads, and net energy for load in the EBT. The demand forecast is a necessary input for determining the resource procurement needs of PWP. The method used for developing PWP's demand forecast is needed by the Energy Commission to support the review of the IRP and is discussed below.

2. Demand Forecast Methodology and Assumptions

Pace Global developed a deterministic reference Case load forecast for PWP's service territory, including residential and commercial segments. The load forecasting process takes into consideration the historical determinants of demand, such as weather and economic variables, as well as adjustments for customer additions, energy efficiency, Demand Side Management (DSM), and electric vehicle usage. The forecast followed a three-step process:

Step 1: Build an econometric model of the determinants of demand using historical weather, economic and seasonal dummy variables.

The relationships were built using multiple regression functions with historical monthly data for PWP's retail load for the period 2000-2017. Separate models were built for average monthly energy load and peak load. Pace Global used the Gross Domestic Product (GDP) data as an economic indicator for the Los Angeles metropolitan area, since it is available in the public domain.

Step 2: Build forecasts of the independent (exogenous) variables:

a. The most recent ten-year historical weather data produces a "normal" weather forecast
b. The most recent ten-year average growth rate extrapolates GDP for the forecast period

Step 3: Incorporate adjustments including:

a. Expected increase in Plug-in Electric Vehicles (PEVs) as discussed in the Transportation Electrification section
b. Energy Efficiency (EE) penetration levels and other DSM programs.
c. Known Load Changes.

a. Step 1 Details

Economic variables such as GDP and personal income normally are positively related to loads. Recently, however, in some markets this relationship seems to be changing (EIA and the Climate Institute).[22]

Pace Global now observes a generally negative relationship between GDP and demand. This can be attributed to several factors, such as disruptive technological advances in energy efficiency penetration, lighting standards, and increases in distributed generation such as roof-top solar installations. This relationship has not been observed in rural areas, less affluent parts of the country and in places with a strong industrial load (since industrial load tends to be positively correlated with the GDP). Pasadena's load is residential and commercial. As GDP increases, so does the possibility of increased energy efficiency, distributed generation and other attributes that may decrease loads.

b. Step 2 Details

For the average energy load in MWh, the following relationship was constructed:

Avg_Load_per_Customer = f (HDD, CDD, Humidity, GDP, EE_Program_MWh, Calendar Variables)

For the peak capacity load in MW, the following relationship was constructed:

Peak_Load_per_Customer = f (HDD, CDD, Humidity, GDP, EE_Program_MWh, Calendar Variables)

Using these functions, the forecast of average and peak load per customer is obtained for 2018 to 2039. Using the customer count forecast data, the MW per customer values are converted into the service area level average and peak load forecasts. As a last step, PEV additions are factored in to derive the final average and peak load forecasts.

c. Step 3 Details

Step 3 of the load forecasting methodology describes the adjustments in the load forecast after using historical metered load in combination with various independent variables. These adjustments account for energy efficiency programs, transportation electrification, and Pasadena's known load impacts (additions and subtractions) from specific customers in their territory. These assumptions are based on PWP internal analysis rather than public forecasts. In this IRP, Pasadena expects a constant 13,500 MWh of energy and 2 MW of capacity to be reduced by energy efficiency programs annually in the study period. As an offset, transportation electrification load is expected to increase at a compound annual growth rate (CAGR) of 11.26%

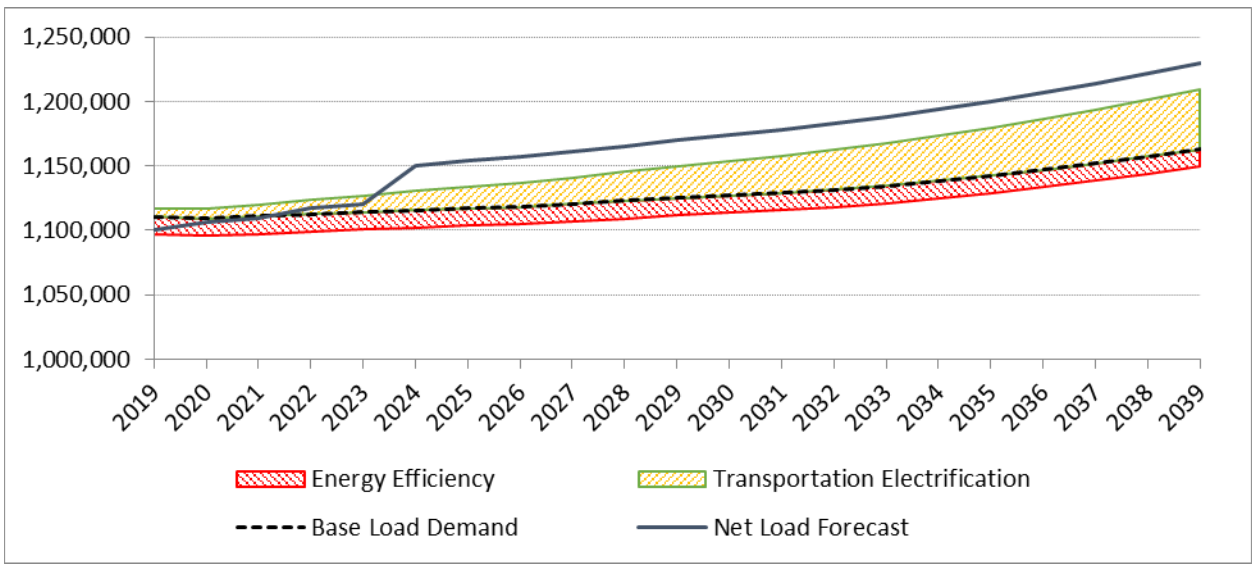
[22] https://www.eia.gov/todayinenergy/detail.php?id=33812; https://www.eia.gov/todayinenergy/detail.php?id=10491; https://thinkprogress.org/u-s-economic-growth-decouples-from-both-energy-and-electricity-use-16ae78732e59/.

during the study period, resulting in an additional 4 MW of capacity by 2039. Pasadena's known load changes result in a reduction through 2019 but then begin to increase the load forecast from 2020 through the duration of the study period. Distributed generation (DG) is captured in the historical net metered data but is not modeled as an additional reduction in load during the study period.

d. Assumptions

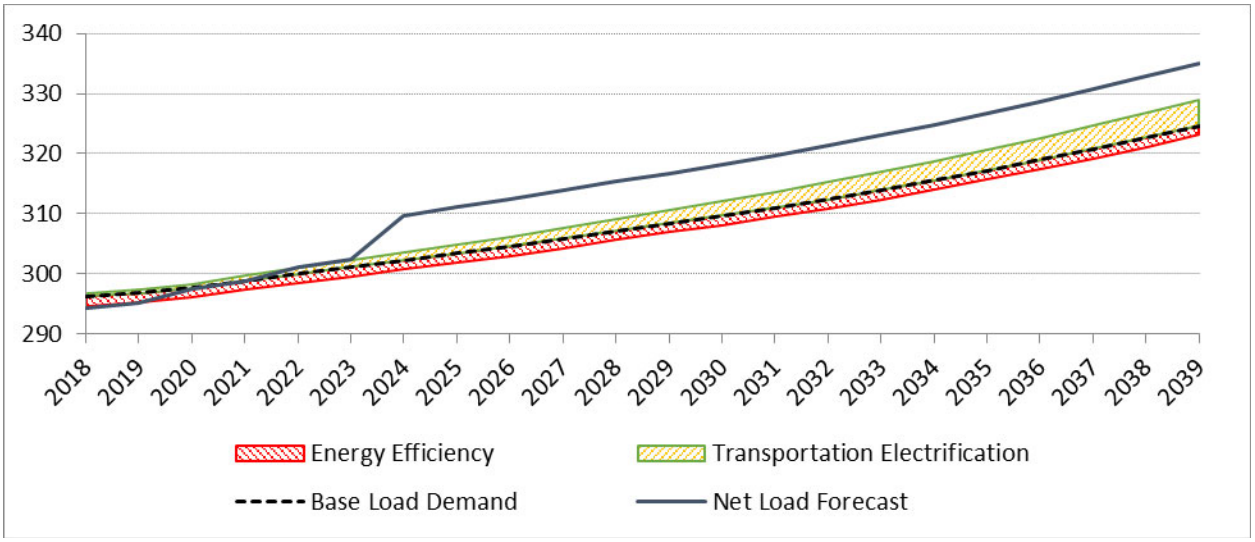
All load forecast data shown below are weather normalized projections. The load forecast data below shows "net load" amounts that include reductions for energy efficiency and additions for transportation electrification and PWP known load additions. Exhibit 55 and Exhibit 56 contains the resulting annual energy and peak load forecasts. Data for these forecasts can be found in workbook "PWP – Assumptions and Inputs".

Exhibit 55: Annual Energy Forecast, MWh



Source: Pasadena Water and Power; Pace Global

Exhibit 56: Annual Peak Capacity Forecast, MW



Source: Pasadena Water and Power; Pace Global

3. Demand Forecast – Other Regions

The demand forecast for other western U.S. regions is based on data received from the WECC.

a. Load Forecast Uncertainty

In California, policy is driving the state towards greater electrification and lower carbon emissions, but also toward greater energy efficiency. The balance of these forces is difficult to predict, especially because the policy climate is changing rapidly. Faster deployment of transportation and building electrification will contribute to larger load growth over time as well as a larger adoption of electric space cooling, which still has room for growth in California. On the other hand, growth of energy efficiency and demand response programs combined with stagnant economic growth could result in lower load growth over time.

Policies that hinder or enable gas-to-electric switching in space/water heating, specifically those involving customer rebate incentives, are major drivers that will determine the trajectory of load growth over time. Furthermore, market structures for energy storage, electric vehicle charging, and energy arbitrage (through load control of water heaters and air-conditioning) will result in different trajectories of load growth.

F. Resource Procurement Plan

1. Diversified Procurement Portfolio and RPS Planning Requirements

PWP plans to meet its future energy and capacity needs through a mix of short term, long term and variable energy resources. Currently, PWP is fully resourced for energy needs until 2025. Post-2025, per the Aurora production cost model, PWP will likely meet its future energy needs through wind and solar resources, as well as a mix of shorter-term renewable contracts. Though mostly wind and solar energy resources were selected as part of the scenario runs by the production cost model, in reality PWP reviews a myriad of resources to fulfill both its energy and RPS needs. In partnership with the Southern California Public Power Agency (SCPPA), PWP reviews various renewable resources (including wind, solar, geothermal, and landfill gas) to meet its energy and renewable resource needs, while maintaining stable rates. PWP will continue to evaluate every cost-effective energy source, when meeting its energy and renewable energy needs. The production cost model output simply provides one possible solution for PWP to meet those needs.

2. Required Tables

PWP's recommended strategy and portfolio requirements are shown in the EBT and RPS tables. See attached workbook "PWP – Compliance Tables".

a. Forecasted RPS Compliance (Point to and Discuss EBT and RPS Tables)

Tables EBT and RPS in the attached workbook "PWP – Compliance Tables" show forecasted RPS compliance by year under SB 350 and SB 100, respectively.

b. RPS Procurement Plan

The current RPS Procurement Plan is Attachment 3, and the proposed RPS Procurement Plan is Attachment 4

c. RPS Enforcement Plan

The proposed RPS Enforcement Program is Attachment 5

d. Metrics for Resource Diversity

Many resources and resource types were modeled in Aurora. Only economic resources (or forced-in resources, depending on the scenario) were selected by Aurora. Overall, the preferred strategy is a mix of short-term and long-term resources, including new wind and solar resources.

e. Recommended Information

PWP plans to meet the portfolio balance requirement (Attachment 3) and long-term contracting requirements (Attachment 4). Barriers to RPS compliance are set forth in Attachment 5.

3. Energy Efficiency and Demand Response Resources

a. Impacts of Energy Efficiency on Forecasted Load

For this IRP, PWP assumes that the annual savings from energy efficiency (EE) programs continue to yield approximately 13,500 MWh (or 2 MW) of savings every year of the study period. The expected measure life is factored in when determining the cumulative impact of these annual savings on net retail energy sales volumes. Due to ambiguity in existing regulations about the meaning of "doubling by 2030" in SB 350, this IRP assumes that PWP continues to implement its relatively aggressive historical approach for future EE efforts. In this IRP, PWP has undertaken an analysis of the benefits and costs of both existing and potential EE programs.

b. Existing Preferred Resources and Efficiencies During Peak Hours

The integration of more renewables requires a "smart grid", as variable renewable energy is both more uncertain and more variable than conventional generators.[23] Fortunately, a variety of technologies can assist in the deployment of renewable energy, such as smart inverters, demand response, storage, system awareness and dynamic line ratings.[24]

At this time, none of the portfolios identified in this IRP and analyzed with AURORA contains new demand-side programs or energy storage. Preferred resources to assist in the management of ramps were considered, but due to the infrastructure needed to implement demand response and the cost of storage, they were deemed infeasible and uneconomic for this IRP. Demand response may be examined in the Power Delivery Master Plan, which may lay out a plan to deploy Smart Meters, and required settlement, DR program structures and telecoms needed for effective DR. Future IRPs are expected to incorporate results from the Power Delivery Master Plan. Currently, PWP only offers a voluntary load curtailment program, as outlined below in Section III.C.

4. Energy Storage

Storage systems provide various benefits, such as deferring transmission and distribution investments, increasing renewable integration, and providing ancillary services. Despite the

[23] NREL (2015, May) *The Role of Smart Grid in Integrating Renewable Energy*, page 2 https://www.nrel.gov/docs/fy15osti/63919.pdf
[24] NREL (2015, May) *The Role of Smart Grid in Integrating Renewable Energy*, page10 https://www.nrel.gov/docs/fy15osti/63919.pdf

recent and expect fall in costs, batteries today are still a relatively expensive option for utility scale storage compared with pumped storage and other technologies. With more mandates to increase renewable generation and increased application of storage, however, battery costs may decline considerably due to innovation and economies of scale. If costs continue to fall and performance continues to improve, batteries could become an economic form of energy storage during the planning horizon. Storage was included in the list of potential resources but was not selected by AURORA in this IRP due to its higher relative cost; however, in diversification Cases, storage was "forced into" the resource portfolio.

a. Behind-the-Meter

As discussed in the Introduction and Background section, PWP last updated its Electric Distribution System Master Plan in January 2005. Due to market uncertainties such as the behind the meter energy storage, PWP is planning to update the Electric Distribution System Master Plan in 2019. The 2018 IRP does not evaluate distribution level impacts, including behind-the-meter storage.

b. Grid-Scale

Passed in 2013, California Assembly Bill 2514 (AB 2514) requires the state's utilities to procure 1,325 MW of storage, allocated among the state's three IOUs – Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric. AB 2868, passed in 2016, added another 500 MW of storage to the mandate. Those 1.8 GW energy storage units coming online by 2024 have already been embedded in AURORA to ensure state-level compliance but are assumed to be in the portfolios of the three IOUs and not available to PWP.

In addition, AB 2514 requires California Publicly Owned Utilities to evaluate the potential to procure cost-effective energy storage systems to facilitate reaching a target by December 31, 2021 as established by the City Council. In September 2017, PWP conducted an energy system evaluation and recommended a zero MW energy storage procurement target for 2021, because no cost-effective energy storage had been identified. Exhibit 57 lists PWP's estimated net benefits of energy storage projects in its AB 2514 report.[25]

[25] Pasadena Water & Power, "AB 2514 Energy Storage Systems Evaluation", September 12, 2017, page 10, Attachment 2 herein.

Exhibit 57: Energy Storage Net Benefit for Projects Scaled to 20 MW

Scenario #	Scenario Name	Details	Lead Acid	Advanced Lead Acid	Lithium Ion	Flywheel	Pumped Hydro	CAES Above Ground	CAES Below Ground
1	Energy Cost Optimization	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	-$ 304	-$ 128	-$ 1627	-$ 7505	-$ 0169	$ 0225	$ 0104
2	Capacity	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	$0 317	-$0 147	-$0 188	-$0 786	-$0 015	-$0 026	-$0.0071
3	Routine Grid Operation	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	$0 250	-$0 080	-$0.130	-$0 7256	-$0 0135	-$0.013	-$0 0056
4	Contingency Situations	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	$0 331	-$0 1606	-$0.1995	-$0.8947	-$0.0180	-$0 0290	-$0 0099

Source: Pasadena Water & Power, 2017 AB 2514 Energy Storage Systems Evaluation

Due to the progress in energy storage technologies and uncertainty in carbon reduction requirements, the potential of energy storage has been reassessed in the 2018 IRP. A screening analysis was performed starting with a wide array of storage options and, based on their characteristics and costs, limited the portfolio analysis to one or two most cost-effective options. With the one or two storage technology options incorporated as a building block for PWP portfolios, AURORA determined the economics of adding storage over the study horizon to meet reliability requirements, RPS obligations, and GHG targets in a cost-effective manner.

PWP evaluated storage in 2017 per AB 2514 to assess the potential to procure viable and cost-effective energy storage systems and set appropriate energy storage procurement targets by December 31, 2021. The technologies studied as part of the PWP 2017 Energy Storage Report included:

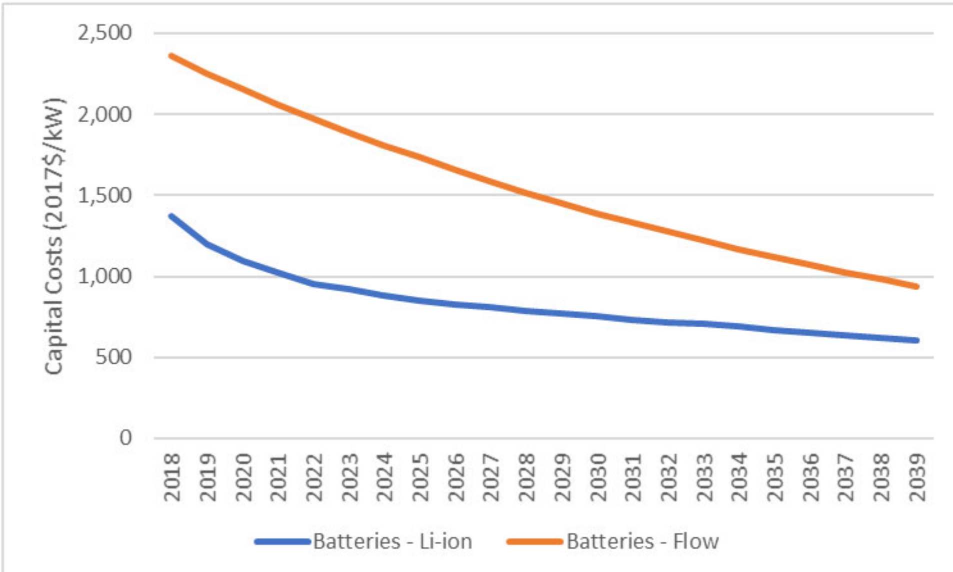
- Compressed air energy storage (CAES) above ground
- CAES below ground
- Pumped hydro storage
- Flywheels
- Advanced lead-acid batteries
- Lithium-ion batteries
- Flow batteries

In the 2017 Storage Report, PWP concluded that pumped hydro had the highest benefit to cost ratio, but still less than 1.00 (0.78). Lithium-ion batteries had the second highest benefit-to-cost ratio at 0.75. Exhibit 58 shows average capital cost and fixed operation and maintenance (FOM) costs through the forecasted period for lithium-ion batteries. Any benefit-cost ratio greater than one is determined to be cost effective with greater values denoting greater cost effectiveness.

Exhibit 58: Battery Storage Technology Assumptions

Technology	Block Size	Capex Site Rating	FOM
	MWh	*$2017/kW*	*$2017/kW*
Lithium Ion Batteries	4	830	10.50
Flow Batteries	16	1,544	15.19

Note: Battery costs include capital costs with Balance of Plant costs



Source: Pace Global

For this IRP, Pace Global considered lithium-ion batteries, which provide a high discharge rate, but require a long time to recharge. Pace Global also reviewed CPUC assumptions for pumped storage. The capital costs of candidate pumped storage resources are based on CPUC estimates derived from Lazard's *Levelized Cost of Storage 2.0* shown in Exhibit 59.

Exhibit 59: Fixed Cost Assumptions for Pumped Storage Resources

Cost Component	All Years
Capital Cost ($2017/kW)	$1,930
Fixed O&M Cost ($2017/kW-year)	$24.42

Source: Pace Global

Ultimately, energy storage did not make it into any of the portfolios except when it was forced in as a resource for the resource diversification Cases.

c. Analytical Requirements

The requirement to analyze storage has been met by including energy storage in the set of resources that could be chosen by AURORA for inclusion in least-cost portfolios that meet all constraints.

d. Multi-Hour Storage to Cover Over-Generation and Ramps

Resource adequacy requirements can take several forms, including the minimum firm capacity required to meet a certain minimum planning reserve margin target or requirement. Most jurisdictions in the United States have a target reserve margin in the 15-17 percent range. In California, resource adequacy requirements also include procuring or owning enough flexible resources to provide for intra-hour (flex) requirements. Meeting these requirements must be demonstrated in RA filings. Balancing authorities such as the CAISO have to hold flexibility reserves to address any discrepancy between the forecasted and actual net load within the hour. Flexibility resources provide the ramping capability needed to address changes in net load between the five minute and hourly intervals. Storage can be an effective resource to provide load following and ramping needs.

e. Potential Peak and Energy Roles of Storage

Peak Demand

Long duration energy storage systems can provide value to a system by dispatching during peak load conditions, reducing the amount of conventional generation capacity required to meet resource adequacy obligations. Since the ability of a storage resource to provide capacity during a potential shortage will depend on its state of charge prior to the event, the Electrical Load Carrying Capability (ELCC) method is sometimes used to approximate the capacity value of storage resources. In absence of a standard methodology, some jurisdictions have applied a minimum duration constraint for counting storage towards capacity requirements. In California, resources must be capable of running for four hours over three consecutive days to qualify for resource adequacy payments. As a result, SCE used a four-hour discharge duration as a proxy for this capability in its recent Local Capacity Requirements (LCR) Request for Offers.[26] The duration-based methodology is now being followed by a number of ISOs in the eastern part of the country in the incorporation of storage under FERC Order 841.

Energy

Energy storage resources provide time-shifting capabilities and help with energy arbitrage. Arbitrage opportunities are achieved by flattening the net load curve and monetizing the price spread between the hours solar is generating and the hours when solar is not available. In doing so, a storage unit can alleviate the impact of the "Duck Curve" by absorbing renewable generation during the high renewable output hours and then injecting the power back into the grid when the renewable output declines or disappears. Storage can also effectively follow changes in loads and address deviations between day-ahead and real-time market conditions (both loads and resources). Storage can also reduce curtailment of renewables. In the diversified Case, storage resources have been considered to improve the capacity factor of solar resources.

[26] www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=3089.

The battery storage unit discharges during the hours that the solar is not available, thus improving dispatch of a “hybrid system”.

f. Potential Costs and Savings

Forecasted costs of long duration battery storage are shown in Exhibit 58. The savings associated with storage mainly flow from the support of intermittent renewable resources with zero fuel costs. Savings from storage can also accrue from allowing fossil fired resources to operate at more efficient set points. With storage, a fossil fired unit can run at a baseload level while the storage picks up spinning reserve and regulation obligations. Finally, long duration storage can provide resource adequacy support, thus reducing the need to procure RA capacity.

g. Electric Vehicle Battery Potential

Energy storage potential will grow with increased adoption of electric vehicles in PWP’s territory. Based on the forecasted adoption rate of PEVs in PWP’s territory discussed in the Transportation Electrification section, the potential impacts of batteries in plug-in electric vehicles (PEVs) is discussed below. Exhibit 60 highlights battery characteristics of current plug-in hybrid electric vehicle (PHEV) and battery-only electric vehicle (BEV) models to evaluate the potential storage capacity of PEVs.

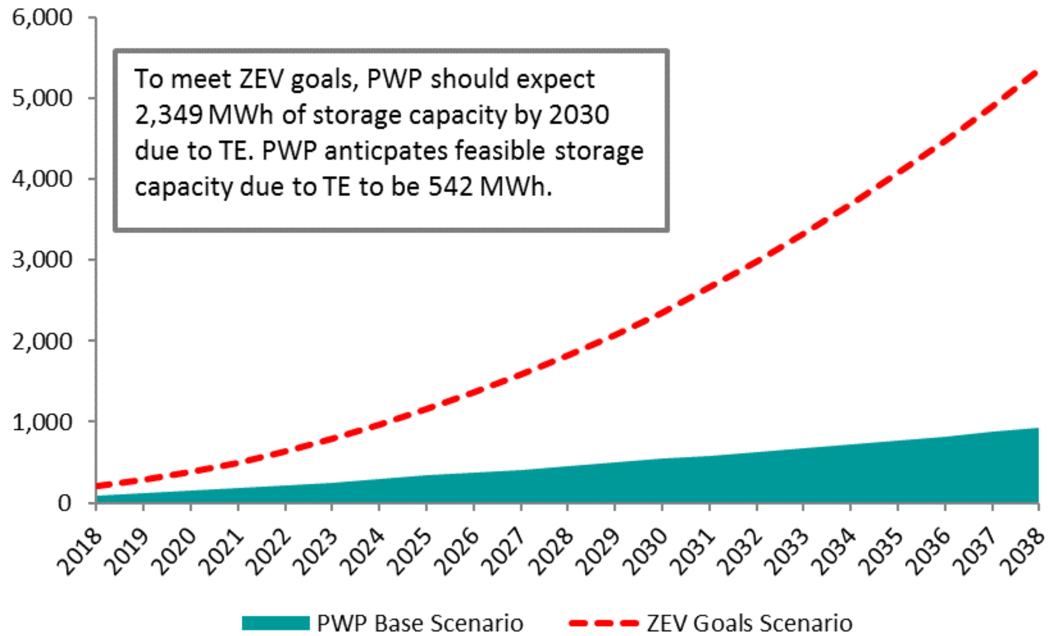
Exhibit 60: Battery Type, Range and Charging Time by PEV Model

Model	Battery	Charge Times
Toyota Prius PHEV	4.4kWh Li-ion, 18km (11 miles) all-electric range	3h at 115VAC 15A; 1.5h at 230VAC 15A
Chevy Volt PHEV	16kWh, Li-manganese/NMC, liquid cooled, 181kg (400 lb), all electric range 64km (40 miles)	10h at 115VAC, 15A; 4h at 230VAC, 15A
Mitsubishi iMiEV	16kWh; 88 cells, 4-cell modules; Li-ion; 109Wh/kg; 330V, range 128km (80 miles)	13h at 115VAC 15A; 7h at 230VAC 15A
Smart Fortwo ED	16.5kWh; 18650 Li-ion, driving range 136km (85 miles)	8h at 115VAC, 15A; 3.5h at 230VAC, 15A
BMW i3 Curb 1,200kg (2,645 lb)	22kWh (18.8kWh usable), LMO/NMC, large 60A prismatic cells, battery weighs 204kg (450 lb) driving range of 130–160km (80–100 miles)	~4h at 230VAC, 30A; 50kW Supercharger; 80% in 30 min
Nissan Leaf*	30kWh; Li-manganese, 192 cells; air cooled; 272kg (600 lb), driving range up to 250km (156 miles)	8h at 230VAC, 15A; 4h at 230VAC, 30A
Tesla S* Curb 2,100kg (4,630 lb)	70kWh and 90kWh, 18650 NCA cells of 3.4Ah; liquid cooled; 90kWh pack has 7,616 cells; battery weighs 540kg (1,200 lb); S 85 has up to 424km range (265 mi)	9h with 10kW charger; 120kW Supercharger, 80% charge in 30 min
Chevy Bolt Curb 1,616kg; battery 440kg	60kWh; 288 cells in 96s3p format, EPA driving rate 383km (238 miles); liquid cooled; 200hp electric motor (150kW)	40h at 115VAC, 15A; 10h at 230VAC, 30A 1h with 50kWh

Source: http://batteryuniversity.com/learn/article/electric_vehicle_ev

Assuming battery performance improves, and costs decline as forecasted, PWP uses the current largest battery capacities of EVs to forecast potential battery storage capacity from the PEV fleet in the City. The Chevy Volt PHEV has a battery storage capacity of 16 kWh, and the Tesla S BEV has a battery storage capacity of 90 kWh. Exhibit 61 shows the potential battery storage capacity from PHEVs and BEVs in PWP's service territory through 2038.

Exhibit 61: PWP PEV Battery Storage Capacity (MWh)



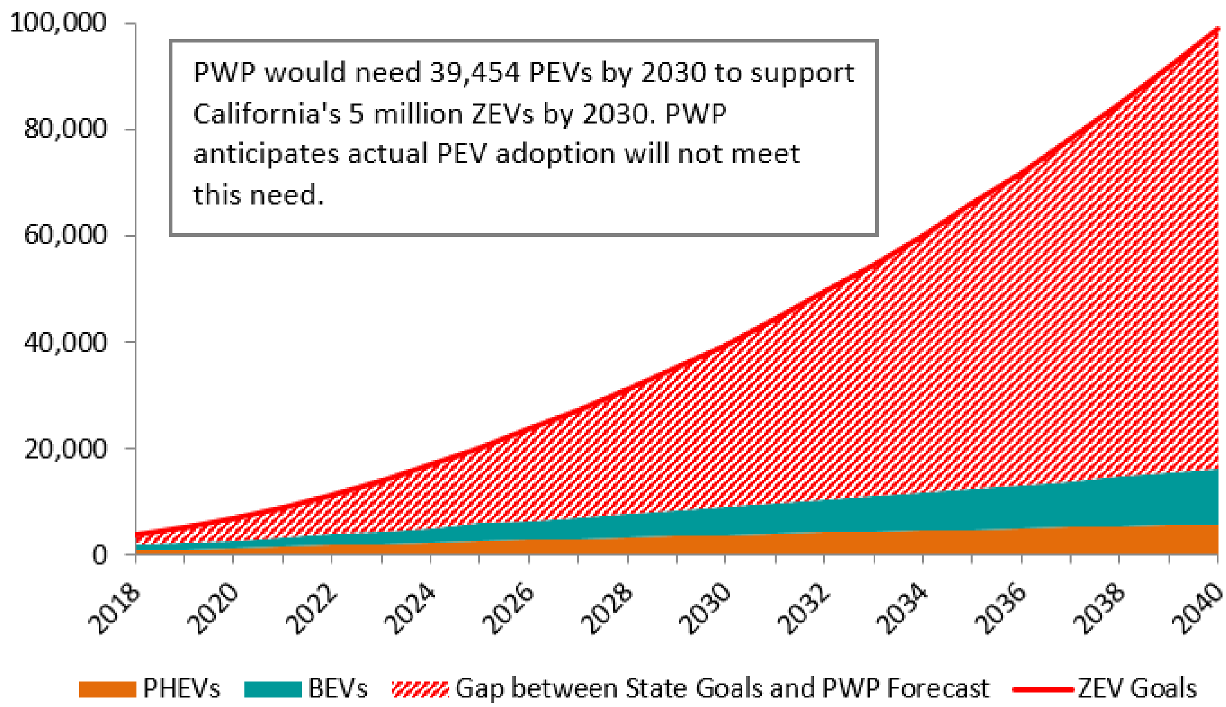
Source: Pace Global

5. Transportation Electrification

Executive Order B-48-18 (2018) targets five million Zero Emission Vehicles (ZEVs) by 2030 in California. PWP's share to meet this goal is shown in Exhibit 62. Vehicle registration data from 2015 shows approximately 0.79% of California's PEVs are within the PWP territory.[27] Currently, both PHEVs and BEVs share similar market share; however, PWP expects that the population of BEVs to grow at a faster rate than PHEVs due to improvements in battery performance and cost. Assuming EV technology does not gain traction past the current pilot stage and statewide ZEV targets with continued growth past 2030, it is estimated that PWP will have about 40,000 PEVs in 2030 and 85,000 PEVs in its service territory by 2038.[28] PWP has conducted its own review of the reasonableness of the CEC projections. Pasadena residents tend to turn over their automobiles about every seven years. PWP estimates that nearly all the new cars purchased between now and 2030 in Pasadena would have to be PEVs to meet its "share" of these state-wide targets, which is unrealistic. PWP anticipates a lower penetration level of 9,100 PEVs in its service territory by 2030 and 14,647 PEVs by 2038. Exhibit 62 shows PWP's forecasted adoption rate of PHEVs and BEVs in PWP's service territory through 2038 relative to PWP's share of the B-48-18 state-wide target.

[27] Estimated PEV percent is based on actual 2015 DMV PEV registrations by zip code vs PWP zip codes.
[28] A polynomial regression model was used to forecast PEV adoption growth rate extending past 2030.

Exhibit 62: PWP Light Duty PEV Adoption Forecasts



Source: Pace Global; CEC

The potential adoption scenarios shown in Exhibit 62 are used to forecast energy consumption by EVs, as shown in Exhibit 63. To convert PEV adoption rates to energy consumption, we use assumptions and forecasts of vehicle efficiency and miles traveled taken from:

- Electric vehicle efficiency: the CEC 2018-2019 Investment Plan Update for Alternative and Renewable Fuel and Vehicle Technology Program.[29]
- Annual vehicle miles traveled per vehicle: the Federal Highway Administration.[30]
- PHEV (hybrids) annual miles driven using electricity: the Alternative Fuels Data Center.[31]

In 2017, PEVs accounted for less than one percent of PWP's total energy load. PWP's PEV forecast shows TE energy consumption could become greater than four percent of PWP's total energy load by 2038.[32]

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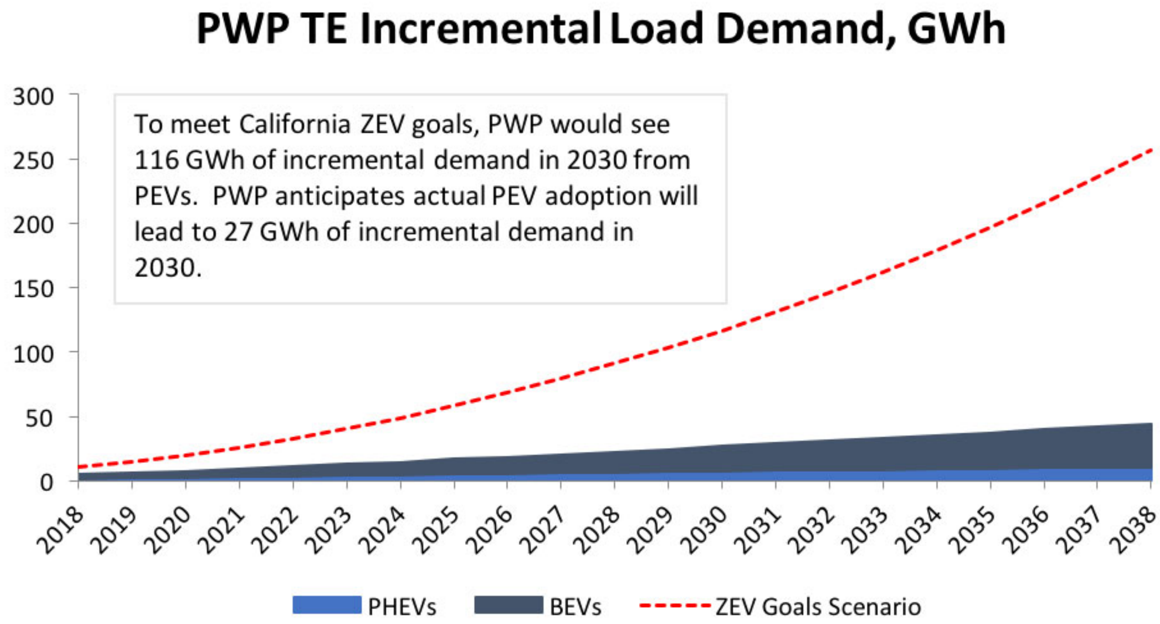
[29] Based on California Assumptions, Appendix C: All Vehicle-Level Assumptions of CEC 2018-2019 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program (17-ALT-01), released March 2018.
[30] Sourced from 2016 Federal Highway Administration, https://www.fhwa.dot.gov/ohim/onh00/onh2p11.htm.
[31] Sourced from the Alternate Fuels Data Center, https://www.afdc.energy.gov/vehicles/electric_emissions_sources.html.
[32] PWP's total demand is assumed to be 1,136 GWh based on the 2017 Load Demand estimate from CEC Form S-2: Energy Balance Table (issued 12/2016).

Exhibit 63: PWP Light Duty (LD) PEV Load Demand, GWh



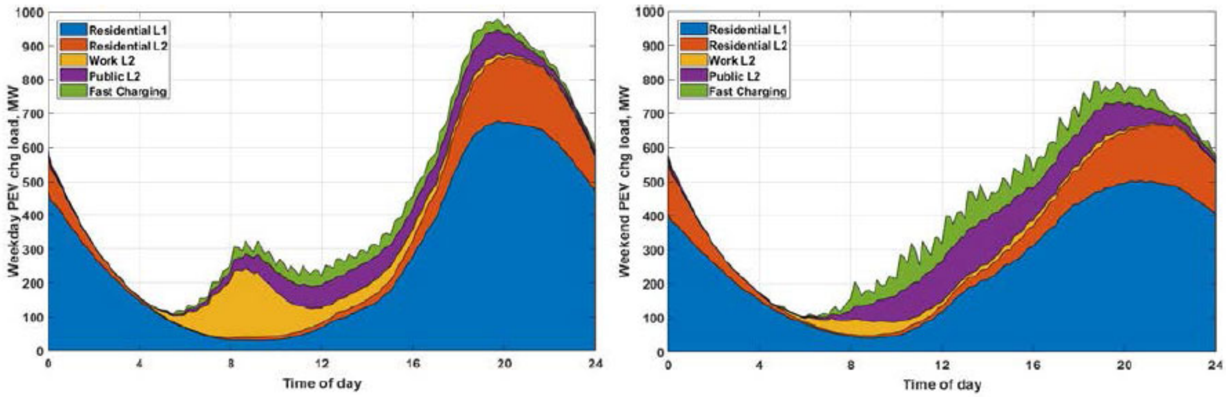
Sources: Pace Global; CEC; FHWA

If all of California meets the Executive Order B-48-18 (2018) goals through PEV adoption, PWP could see 116 GWh of new annual energy load in 2030. Assuming a compound annual growth rate (CAGR) of 10% after 2030, by 2038 TE load in PWP's service territory could reach 256 GWh.[33] Using PWP's lower expected PEV adoption rate, PWP expects TE energy load of 44 GWh by 2038.

Exhibit 64 illustrates potential PEV charging load profiles for weekdays and weekend in California in 2025. These charging profiles were included in PWP's hourly load profiles in AURORA.

[33] Compound Annual Growth Rate of 10% from 2018-2030 was assumed for growth projections past 2030.

Exhibit 64: PEV Charging Profiles in 2025



Source: CEC; NREL[34]

For weekdays, PWP should prepare for two charging peaks to account for vehicles arriving at work and returning home during the evening. The first peak will mainly come from workplace and public Level 2 (L2, 240v) chargers; whereas the second, significantly larger peak will mainly come from residential chargers (mostly expected to be L1, 120v). For weekends, PWP should prepare for one gradually increasing charging peak in the evening mainly met by residential chargers. Although the demand from Level 3 chargers (L3, DCFC) is not large in quantity, sub-hourly L3 rapid charging can cause volatility in load profiles. All types of charging loads should be integrated efficiently to prevent additional ramping generators and stress on distribution infrastructure.

[34]http://docketpublic.energy.ca.gov/PublicDocuments/17-ALT-01/TN222986_20180316T143039_Staff_Report__California_PlugIn_Electric_Vehicle_Infrastructure.pdf.

G. System and Local Reliability

According to California Public Utility Code section 9620, each local publicly owned electric utility serving end-use customers shall, at a minimum, meet the most recent minimum planning reserve and reliability criteria approved by the Board of Trustees of the WECC.[35]

WECC Standard BAL-STD-002-0 requires that each Balancing Authority shall maintain minimum Operating Reserve, which is the sum of regulating reserve, contingency reserve, additional reserve for interruptible imports, and additional reserve for on-demand obligations. BAL-STD-002-0 applies to the CAISO, which passes certain obligations on to PWP.

Under the state and federal mandates, PWP is required to hold sufficient generation capacity to ensure uninterrupted service to retail loads under a variety of conditions, and to meet reliability (resource adequacy) criteria of the CAISO. The CAISO has defined three types of RA: System, Local, and Flexible. On an annual basis, the CAISO provides specific RA obligations to PWP, and PWP must demonstrate to the CAISO that it can meet these RA obligations with existing owned or contracted resources, or PWP must purchase additional capacity rights from the CAISO as necessary to meet its RA obligations. This IRP projects PWP's ability to meet its future RA obligations with existing or new resources, and the financial consequences of any purchases of capacity to meet RA obligations.

1. Reliability Criteria

a. System Resource Adequacy

The System RA requirement is calculated by CAISO based on a one-in-two-year peak-load forecast plus a 15% reserve margin, adjusted for demand response if any. The System RA requirement is modeled as a reserve margin constraint in AURORA to select the least cost resource if there is any System RA shortage. In this IRP, AURORA calculated the capacity available from each PWP portfolio, and any shortfall was assumed to be purchased from the CAISO.

2. Local Reliability Area

a. Local Resource Adequacy

A resource that is (a) located within a Local Capacity Area (LCA) and (b) verified as deliverable under peak load conditions can qualify to meet local RA obligations. Local RA requirements are developed through the CAISO's annual Local Capacity Technical Analysis, which is based on a

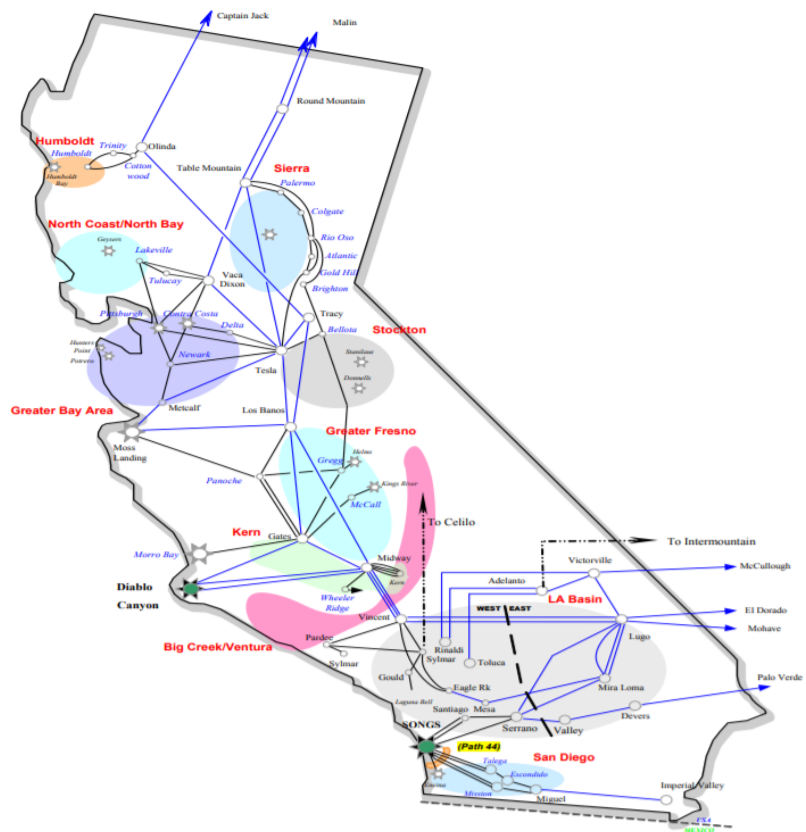
[35] California Public Utilities Code Division 4.9 - Restructuring of Publicly Owned Electric Utilities In Connection With The Restructuring Of The Electrical Services Industry, Section 9620.

one-in-ten-year peak-load forecast without a reserve margin. The results of the analysis are adopted in the CAISO's annual RA decisions and allocated to each Load Serving Entity (LSE) based on its August load ratio within each transmission access charge area.[36]

b. California Local Capacity Areas

The CAISO is responsible for establishing requirements for the California Local Capacity Areas (LCAs) shown in Exhibit 65. PWP is located in the LA Basin and Big Creek/Ventura area. The Local Capacity Requirement (LCR) for PWP was forecasted using the 2018 actual LCR, at 123.74 MW. This is an annual amount and needs to be met on a monthly basis.

Exhibit 65: California Local Capacity Areas

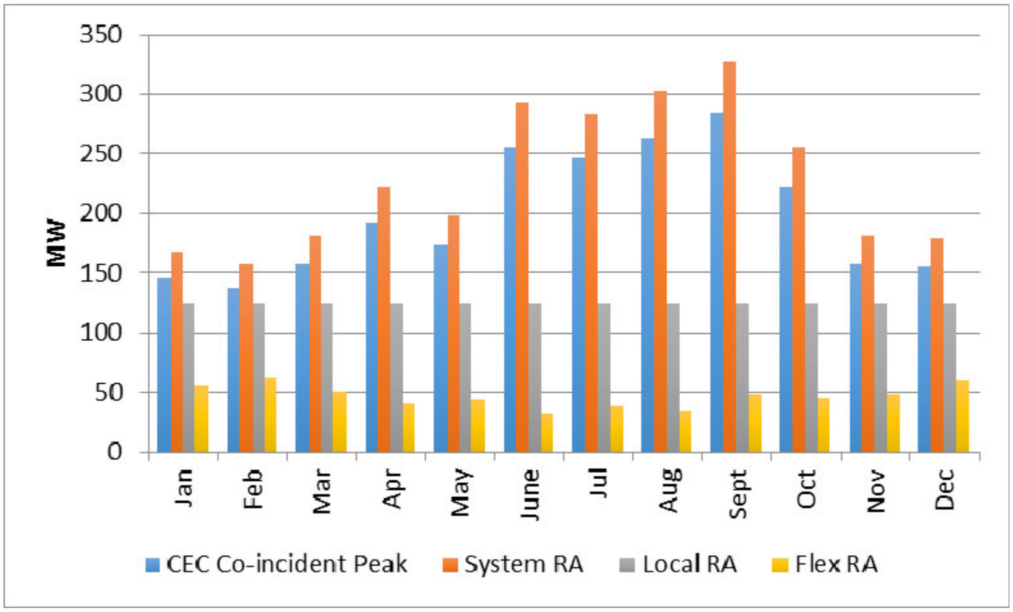


Source: California Independent System Operator (CAISO)

PWP has conducted an analysis of system RA requirement based on the CEC's published coincident peak[37] plus a 15% reserve margin for the year 2018. The local RA and flexible RA requirement are based on monthly calendar year (CY) 2018 values from the CAISO and are held constant for the study period. Exhibit 66 below shows PWP's forecast of all three RA requirements.

[36] See discussion of the T.M. Goodrich interconnection to the CAISO, *infra*.
[37] The sum of two or more utility system load peaks that occur at the same time.

Exhibit 66: PWP's Resource Adequacy Obligations in 2018



Source: Pasadena Water & Power, "PWP CAISO Requirements 2018.xlsx".

Since PWP's Glenarm natural gas units (with nameplate capacity of 196 MW) can provide quick ramping support, PWP will likely have no need for new resources to meet local RA and flexible RA requirements.[38]

3. Addressing Net Demand in Peak Hours

a. Flexible Resource Adequacy

As intermittent renewable generation resources continue to become an increasing proportion of CAISO generation and as once-through-cooling units are planned to be retired, the need for new flexible quick response generation resources has increased. Beginning with the 2015 compliance year, the CPUC adopted a flexible RA requirement for LSEs to manage grid reliability during the largest three-hour continuous ramp in each month. Resources are considered to provide flexible capacity if they can ramp up and sustain output for a minimum of three hours. The flexible RA requirement is subject to further refinement by both the CPUC and the CAISO and is reflected in this IRP. The Flexible RA requirements vary by month. The 2018 Flexible RA requirements, listed in Exhibit 67, were used for the IRP study period. Flexible RA is met through local internal generation (the Glenarm units).

[38] In this IRP, resource adequacy is analyzed using AURORA results to ensure that PWP's portfolios meet the RA requirements shown in Exhibit 6666.

Exhibit 67: 2018 Flexible RA Requirements for PWP

Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
54.56	61.73	50.44	40.36	43.12	30.73	38.53	34.06	47.80	44.34	48.37	59.29

Source: Pasadena Water and Power

H. Greenhouse Gas Emissions

1. California Targets

The California Air Resources Board scoping plan was initiated to help California on the path to reduce greenhouse gas emissions under Assembly Bill 32. To help reduce emissions, California launched the cap and trade program in 2013. Cap and trade systems are market-based mechanisms that allow companies to buy and sell a limited number of allowances for producing greenhouse gases, if needed beyond "free allowances" issued by the ARB to ease the transition to carbon pricing. The total volume of available allowances declines each year to reduce total emissions over time.

In July 2017, California passed legislation extending the cap and trade program to 2030. Executive Order B-30-15 and SB 32 extended the goals of AB 32 and set a 2030 goal of reducing emissions 40 percent from 2020 levels. As reflected in the 2017 Scoping Plan update, CARB proposed a range of 30 MMT CO_2e to 53 MMT CO_2e as the GHG planning target for the electricity sector.

2. PWP's Carbon Reduction Targets

Exhibit 68 shows CARB's state-wide emission reduction targets for 2030 and PWP's allocated share. Coordinating with CARB to establish the GHG planning targets, the California Public Utilities Commission (CPUC) recommended a GHG planning target of 42 MMT CO2e by 2030 for the electricity sector, because it "represented an increase in momentum relative to current policies and was not so burdensome as to discourage electrification of transportation and natural gas end uses that would benefit the state as a whole."[39] The CEC has proposed an allocation of the 42 MMT to individual utilities, including Pasadena.

[39] CARB, "Staff Report: Senate Bill 350 Integrated Resource Planning Electricity Sector Greenhouse Gas Planning Targets", July 2018, page 18.

Exhibit 68: PWP's Share of GHG Emission Reduction Targets by 2030

GHG Emissions in 2030	CA Available Allowances (million metric tonnes)	PWP's Share (million metric tonnes)
53 MMT CO_2-e	53,062,028	224,983
42 MMT CO_2-e	42,049,057	178,288
30 MMT CO_2-e	30,035,142	127,349

Source: Pasadena Water & Power, California Energy Commission, Pace Global

Exhibit 69: PWP's Share of California GHG Emission Targets in 2030[40]

Emissions Range	PWP Range MT CO2e
Low End	128,000
High End	226,000
1990 Emissions	918,622

Source: Pasadena Water and Power

AURORA embeds the California cap and trade program design and allows each load serving entity, modeled as a zone in AURORA, to choose between physically reducing carbon through the selection of resources or, if cost-effective, to purchase GHG allowances in the market to meet its individual carbon emission target.

3. Emissions Intensities

a. Report in GEAT CO2e/MWh for each resource in EBT

Tables in the attached workbook show the emission intensities from existing and planned resources for the Base Case and the SCC-SB100 Case, as well as total metric tonnes/year for each resource.

b. Assumptions for Existing and Planned Programs to Reduce GHG

The selected SB 100 compliance strategy provides for (a) PWP to execute long-term procurement contracts only for renewable resources, (b) PWP to not exercise the option to continue in the Intermountain Power Project in Utah, and (c) to minimize the output of existing fossil-fueled resources as constrained by reliability, contracts, and CAISO auction rules. The result is a reduction in GHG emissions that exceeds state targets by 2030.

[40] https://www.arb.ca.gov/cc/sb350/staffreport_sb350_irp.pdf.

4. Compliance

In order to meet California's GHG emission reductions targets, PWP plans to construct a resource portfolio that (a) eliminates coal-fired generation, (b) incorporates no new long-term supplies that use fossil fuels, (c) incorporates only new renewable resources, and (d) continues to rely on a Southern California spot energy market that will be increasingly composed of renewable resources.

I. Retail Rates (Energy Charge Cost Impacts)

PWP Power Resources Staff worked closely with PWP Finance Staff to develop the cost of service and retail rate impact analysis for the IRP. Model outputs provided by the Consultant, coupled with additional analysis by PWP staff, were used to develop the cost and rate analysis. The projected retail rate impact analysis is defined as the growth in the energy charge cost associated with the IRP, over the full retail rate. The energy charge is the portion of the retail electric rate, which addresses the power supply contracts and costs, associated with the IRP. As mentioned briefly in Section II.B.5, the retail rate impact analysis was determined using the FY 2019 power supply budget, which is $69.4 million. The $69.4 million represents the energy charge portion of the PWP bill, which incorporates the impacts the IRP. The $69.4 million includes, but is not limited to:

- Long term resources/contracts (Magnolia, IPP, Hoover, PV, etc.)
- Spot market purchases (CAISO purchases)
- Renewable contracts and RECs
- Gas costs, etc.
- This amount excludes offsets or credits (if included, the FY 2019 power supply budget would be closer to $65.96 million), such as:
    - An offset of $3 million as a result of the project stabilization fund credit (which is a fund with SCPPA, to prepay some long term power contracts, as set forth in SCPPA Resolution No. 1996-7) which will expire in FY 2021
    - An offset of $663,283 from the Northern Transmission System charges

The IRP retail rate impact analysis assumes similar considerations included in the FY 2019 power supply budget, including additional adjustments for

- $1 million a year, until 2024 from the IPP defeasance fund[41]
- $3 million a year in funds from the Reserves for Stranded Investment[42]
- Reflects the adjusted debt schedule for the planning period for all contractual obligations

[41] https://ww5.cityofpasadena.net/water-and-power/wp-content/uploads/sites/54/2018/03/PWP_2017_Annual_Report.pdf

[42] https://library.municode.com/ca/pasadena/codes/code_of_ordinances?nodeId=TIT13UTSE_CH13.04PORARE_13.04.176STINSU

Below are the steps conducted for the IRP rate impact analysis.

1. Steps for Retail Rate Impact Analysis in the IRP

- Step 1: PWP Staff took the AURORA model output and added:
    - Debt service for IPP and Magnolia
    - Renewable integration charges for all out-of-state renewables
    - Reliability payments to the CAISO (to meet reliability requirements)
    - Optimization of RPS compliance to limit cost exposure (bank as many renewable resources as possible and sell off any excess, to avoid over-procuring)
    - For any Scenario that leaves IPP in Utah (as defined in Section II.B), replace with an equivalent geothermal resource at $75/MWh
    - For any Scenario with biogas, include the cost of using biogas instead of fossil gas
- Step 2: Convert all data to $2019 using a 3.5% inflator to the AURORA costs, which are in $2017
- Step 3: Run the total annual cost data through the PWP rate analysis tool
    - Include fund adjustment from the IPP defeasance fund and Reserves for Stranded Investment (for the duration of these adjustments)
- Step 4: Compare the results to the FY 2019 budget for the energy charge (i.e., find the percentage increase in the IRP energy charge portion of the PWP rate compared to the FY 2019 budget)
- Step 5: Develop an analysis of potential costs for each customer class

2. Assumptions on Retail Rate Impact Analysis

As stated earlier, the retail rate impact analysis relies on a variety of assumptions. In the AURORA model and IRP analysis, the Consultant developed the assumptions document in May 2018. This was before the passage of SB 100 and before the record breaking summer heat wave in July 2018. There are many aspects of the assumptions that impact the portfolio cost, such as price of spot market energy, gas prices, renewable energy contract prices, etc. Assumptions are based on the data available at the time the assumptions are developed. Since the assumptions were developed, many things have changed. This includes the following:

- SB 100 signed into law, which may increase renewable contract prices in the future (with limited supply and high demand)

- The increase in the number of Community Choice Aggregators in California
    - May increases the demand for new renewable developments and limit the contracts available to retail electricity providers (like PWP)
- Weather patterns
    - Abnormally high summer temperatures have had an adverse impact on the demand for energy and spot market prices, by dramatically increasing both
- Capacity market pricing was developed using historical prices PWP staff has experienced for resource adequacy
    - If the CAISO or the CPUC changes the structure of capacity markets, the pricing could be adversely impacted.
        - During November 2018, there has been discussions at the regulatory level to enhance the capacity market to cover capacity needs for several years in advance, rather than the month ahead process in place today. This may adversely impact the pricing for capacity contracts.

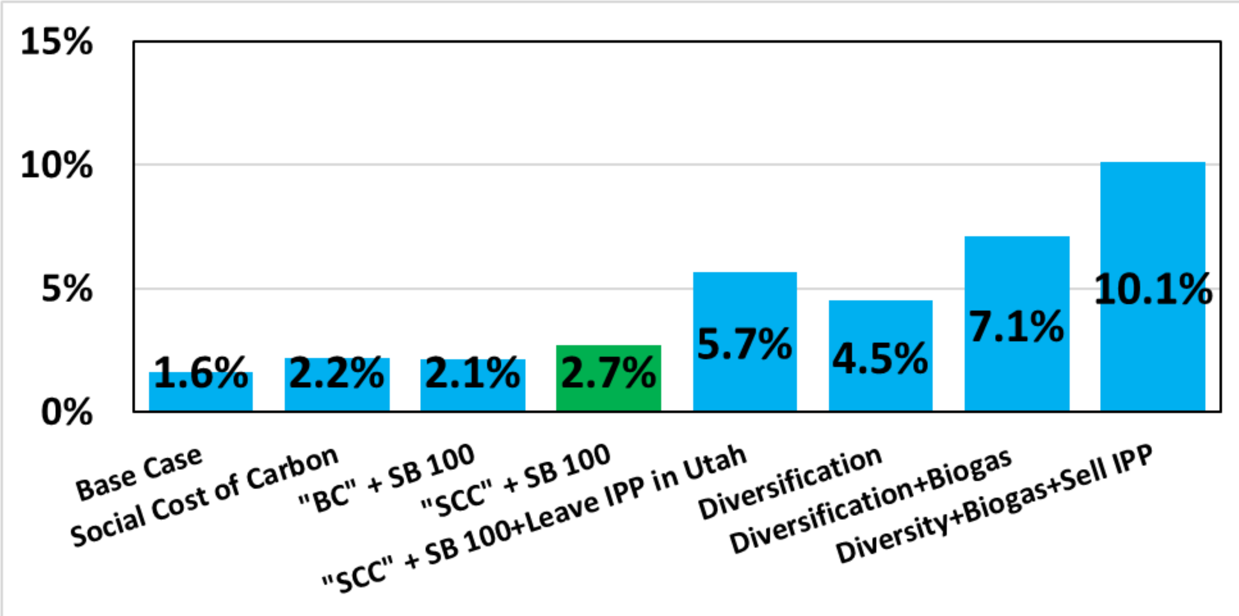
Any adjustment to these assumptions will occur in the next iteration of the IRP. The data presented in the IRP, including this cost and retail rate impact analysis, is dependent on the set of assumptions developed in May 2018.

3. Impacts of Scenarios and Portfolios

Exhibit 70 shows the potential retail rate impact analysis based on each scenario, over the study period. As mentioned earlier, this analysis is based on assumptions in place today and only reflects the impact to the IRP elements of the energy charge portion of the PWP retail electric bill. This does not include any rate adjustment due to other costs (such as transmission, distribution, customer service charge, etc.). It is important to note that PWP is in the midst of several major initiatives, including the power delivery master plan and the replacement of the customer information system, to name a few. These initiatives will have additional rate impacts to other charges on the retail electric bill. However, the impact is unknown at this time. Lastly, this analysis is not adjusted for inflation- so the potential impact will be higher, if adjusted annually for inflation. These assumptions are reflected in Exhibit 70, below.

The same assumptions for the cost and retail rate impact analysis were used in the analysis for all of the scenarios. Essentially, the Base Case has the least impact and the Diversify+Biogas+Sell IPP has the biggest impact and overall, the rankings of these impacts do not change.

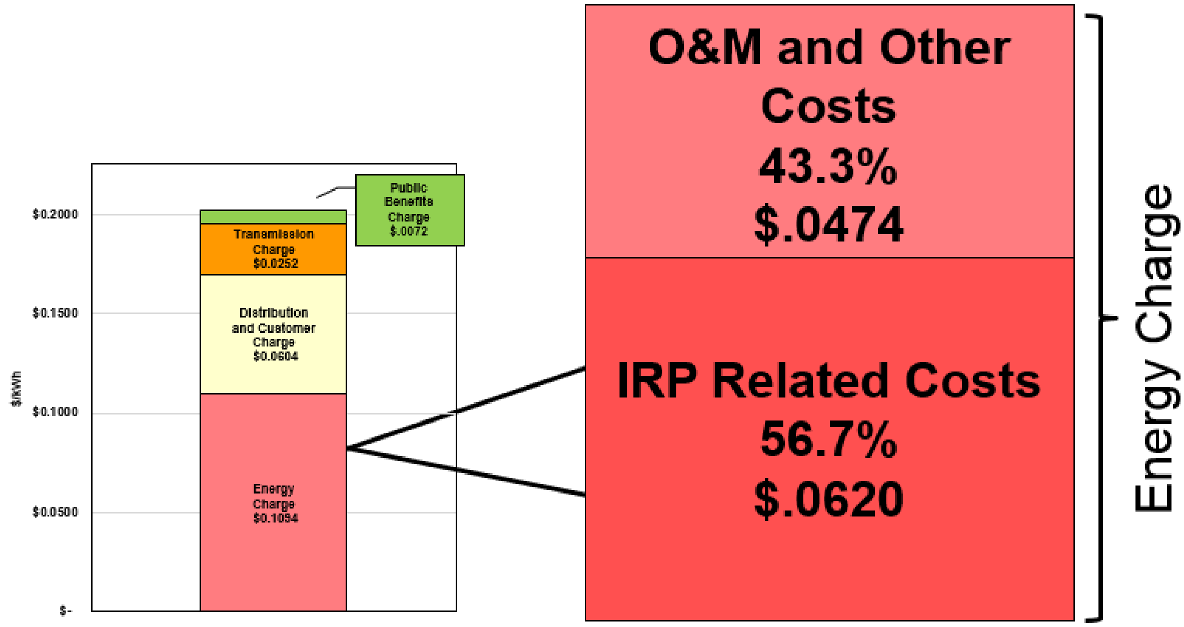
Exhibit 70: Potential Energy Charge Impacts from FY 2019 Over the Study Period[43]



Source: Pasadena Water and Power

As discussed above, the IRP only impacts a portion of the energy charge portion of PWPs retail electric bill. A breakdown of the PWP retail electric bill is provided in the figure below. This assumes an average of $.2022/Kwh charge for all electric services. Of that, the energy charge makes up 54.10%. The energy charge costs are then split up into IRP related costs and other costs, which include, but are not limited to, cost of financing and operating location power plant, operations and maintenance, etc.

[43] This analysis is based on a Residential Customer that consumes 500 KWh of energy, monthly. Impacts to other customer classes will change, slightly.



4. Retail Rate Design

The PWP website offers details on each rate classification and electric rates by season for PWP customers: summer rates are in effect June through September, and winter rates are in effect October through May. The summer rate analysis was used to estimate the rate impact for each Scenario. This is a deliberately conservative approach, as the summer energy charge rate (the portion of the bill that will be most affected by decisions pursuant to the IRP) is higher than the winter energy charge. The energy charge for all customer types are shown in Exhibit 71 for both Winter and Summer.

The energy charge portion of the bill covers PWP's costs for the purchase of electricity and natural gas, purchase of (and premiums for) renewable energy, debt service on power plants, GHG emissions costs, operation of local plants and other related costs for power supply. In addition, the energy charge includes the power cost adjustment (PCA). The PCA is a rate-stabilizing mechanism used to manage variability in energy costs over time and to pass-through additional energy costs and/or savings incurred by the electric utility to its customers.

The Light and Power Rate Ordinance provides for the PWP General Manager to implement applicable changes to the energy charge through the PCA, a formula-based rate adjustment mechanism, to pass-through changes in energy costs to electric customers. The PCA is added to or subtracted from the applicable Energy Services Charge rates set forth in the Light and Power Rate Ordinance for each kWh delivered to the customer. The PCA is monitored monthly and adjusted when deemed necessary.

The only component analyzed as part of the rate analysis in this IRP is the energy charge. There are other costs, not related to the energy charge, such as the customer charge, transmission charge and the distribution charge, to name a few, that are not considered in this analysis.

Exhibit 71: Energy Charges Effective 10/01/18

Customer Type	Details	Winter Rate (¢/kWh)	Summer Rate ¢/kWh)
Residential	Any size	8.38	9.30
Small S-1	< 30 kW	8.26	9.13
Medium Secondary M-1	30 kW to 299 kW	8.44	9.57
Medium Primary M-2	30 kW to 299 kW	8.35	9.34
Large Secondary L-1	>300 kW	8.81	12.62
Large Primary L-2	>300 kW	8.85	12.08

Source: Pasadena Water and Power

5. Rate-Setting Process

PWP's rate-setting process involves a great deal of community outreach and input. Historically, the following steps are taken when conducting a rate adjustment or setting new rates:

- Step 1: Conduct a cost of service analysis to see what, if any rate adjustment is needed.
- Step 2: Conduct a series of public hearing to receive input from the community. Conduct a community outreach campaign to explain the need for the rate adjustment.
- Step 3: Take the rate adjustment to the Municipal Services Committee for recommendation.
- Final Steps: Obtain City Council approval for the rate adjustment and implement the rate adjustments as approved.

6. Feed-In Tariff (FiT)

At this time, PWP does not have a FiT. PWP analyzed the implementation of a FiT in past IRPs and it was not economic at that time. FiT rates may be analyzed in future PWP IRPs.

7. Time of Use Rates (TOU)

PWP offers Time of Use (TOU) rates. TOU rates are mandatory for Large Commercial Customers with peak demands of 300 kW or more, and are optional for other customers. TOU customers are responsible for the cost of installing smart meters that are required to take advantage of the TOU rate. Details on the TOU are available under the rules and regulations for PWP rates.

J. Transmission and Distribution Systems

1. Bulk Transmission System

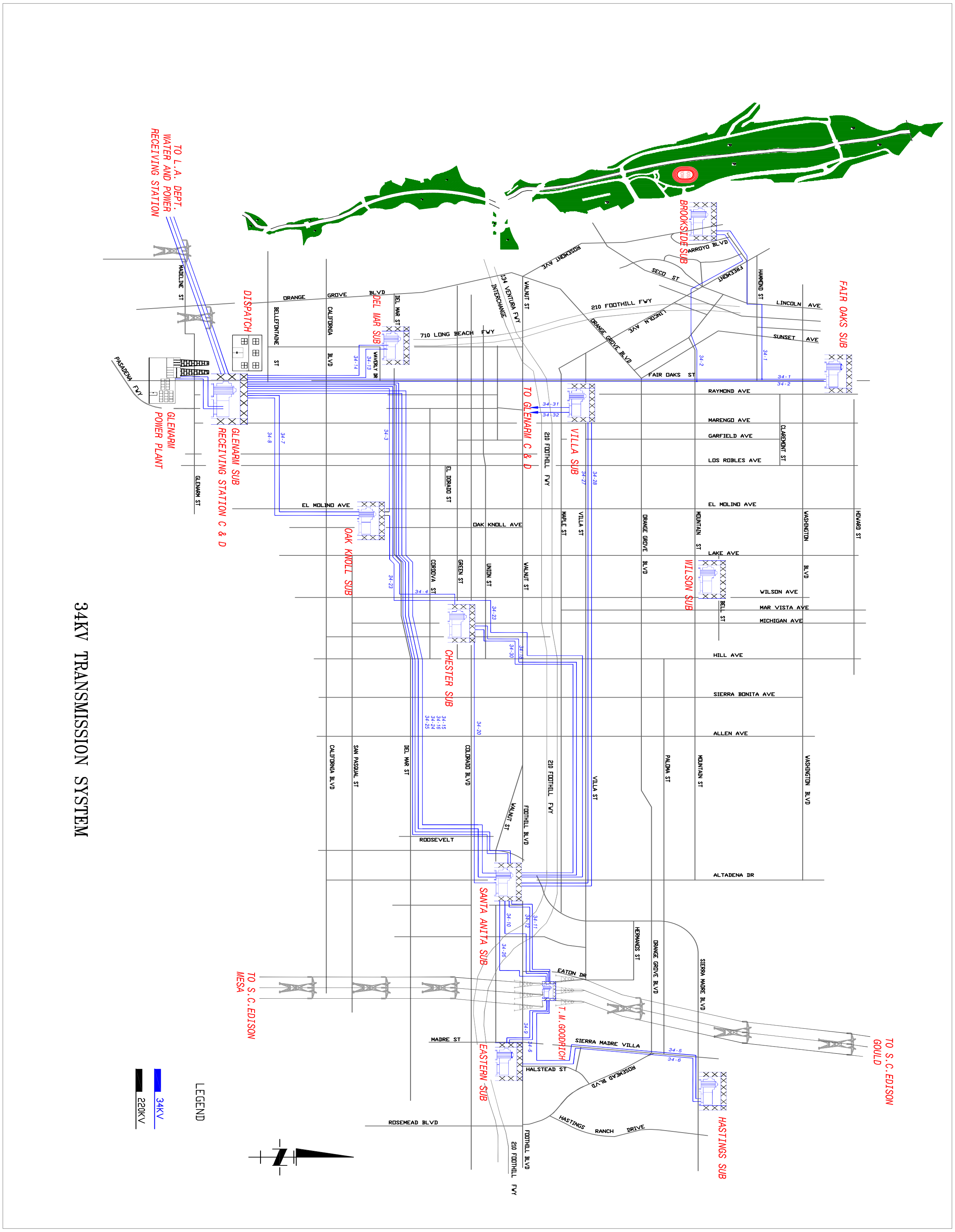
a. CAISO

The California Independent System Operator (CAISO) was created in the 1990s to manage portions of the regional transmission grid operated owned by the California Investor Owned Utilities. PWP's Goodrich receiving station, where PWP imports all its external power, is part of the CAISO grid. PWP is a CAISO-certified Scheduling Coordinator and Participating Transmission Owner (PTO), and PWP's transmission rights (owned and under contract) have been turned over to the CAISO for operation and planning.

Power imported from outside the PWP system is received at Goodrich Station. At Goodrich, power is received from the CAISO transmission grid via two 230-kV transmission lines: one is connected to the Laguna Bell 230-kV substation located southeast of Pasadena and the other to the Gould 230-kV substation located north of Pasadena. Most of the 230-kV equipment at Goodrich is owned by PWP but maintained and operated by SCE under the direction of the CAISO.

Power is delivered into the PWP distribution system from Goodrich across three transformers that step the voltage down from 230 kV to 34.5 kV. The connection at Goodrich consists of three 100-MVA, 230/34.5-kV transformers, providing a 200-MVA capacity. However, the import interconnection capacity is limited to 280 MW to address the N-1 contingency. Please refer to Exhibit 72 for an overview of PWP's distribution system.

Exhibit 72: Overview of the PWP Electric System



Source: Pasadena Power & Water

2. Bulk Transmission Planning

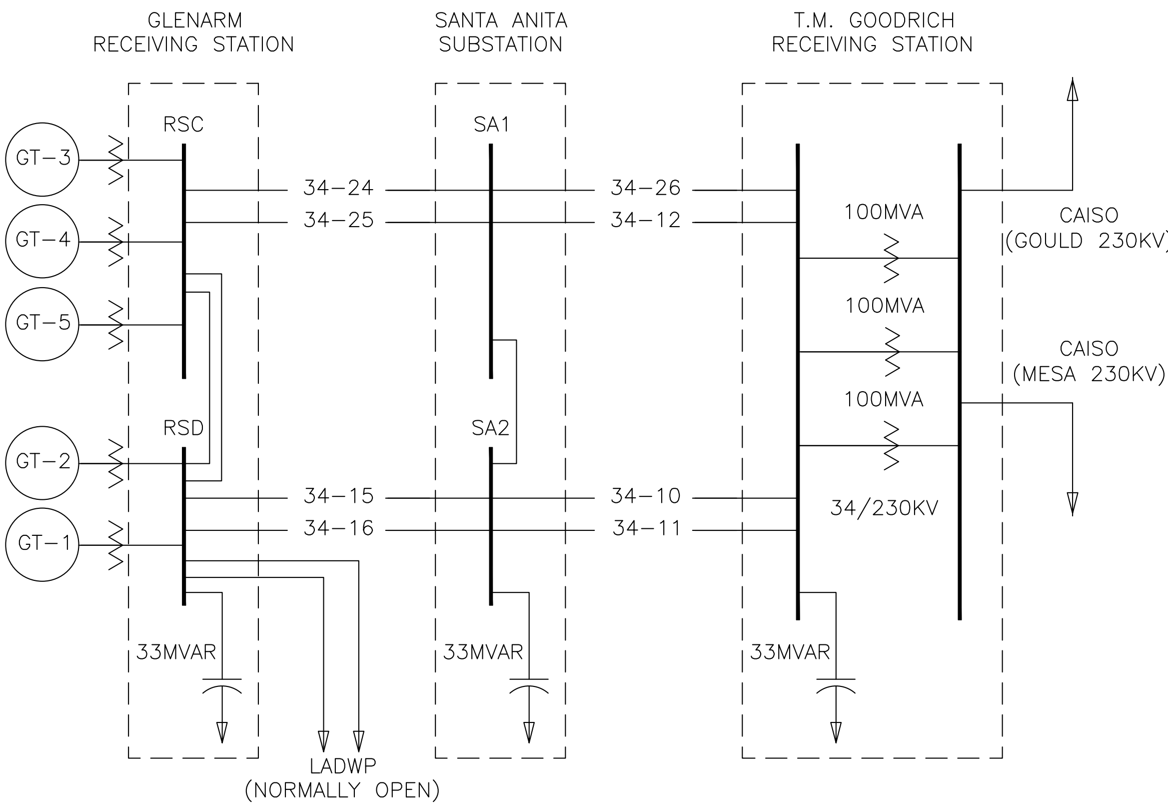
The CAISO's annual transmission plan evaluates grid reliability requirements, identifies upgrades needed to successfully meet California's policy goals, and explores projects that can bring economic benefits to consumers. The 2017-18 southern California bulk system assessment did not identify reliability concerns that require new corrective action plans to meet the NERC transmission system planning performance requirements.[44] As PWP does not operate the bulk transmission system, there are no identified transmission concerns for PWP that need to be addressed in this IRP.

3. Distribution System Planning

To distribute power from Goodrich and Glenarm, PWP has a network of underground sub-transmission cables with ten distribution substations. The single-line diagram of PWP's sub-transmission system is shown in Exhibit 73.

[44] "California ISO 2017-2018 Transmission Plan", page 172.

Exhibit 73: Simplified 34-kV System Single-Line Diagram



Source: Pasadena Power & Water

The 63 circuit miles of underground sub transmission network is comprised of 283 miles of 34-kV cable. The network includes seven 34-kV circuits that comprise the "cross-town" backbone of the sub transmission system. These circuits connect directly from Goodrich through the Santa Anita Substation to Glenarm, as shown above. PWP's 34-kV switchyards are double bus, double breaker design, which allows for a wide range of operating flexibility and provides a high level of reliability.

In FY 2018, underground substructures in San Rafael Avenue and in Nithsdale Road will be constructed. Additionally, the 17kV Paloma circuit and various 17kV circuits in San Rafael Avenue will be extended. Further analysis of the distribution system will be conducted in the Power Delivery Master Plan in 2019.

K. Localized Air Pollutants and Disadvantaged Communities

1. Reporting Requirements

California PUC Section 9261 requires publicly owned utilities (POUs) that address the goal of minimizing localized air pollutants and other GHG emissions, with a focus on disadvantaged communities (DACs). California Health and Safety Code Section 39711 requires the California Environmental Protection Agency (CalEPA) to identify DACs based on geographic, socioeconomic, public health, and environmental hazard criteria. This section identifies the existing DAC within PWP's service territory and discusses potential opportunities to target programs that will help minimize effects of localized air pollutants.

a. Current Programs and Policies Regarding Local Air Pollution

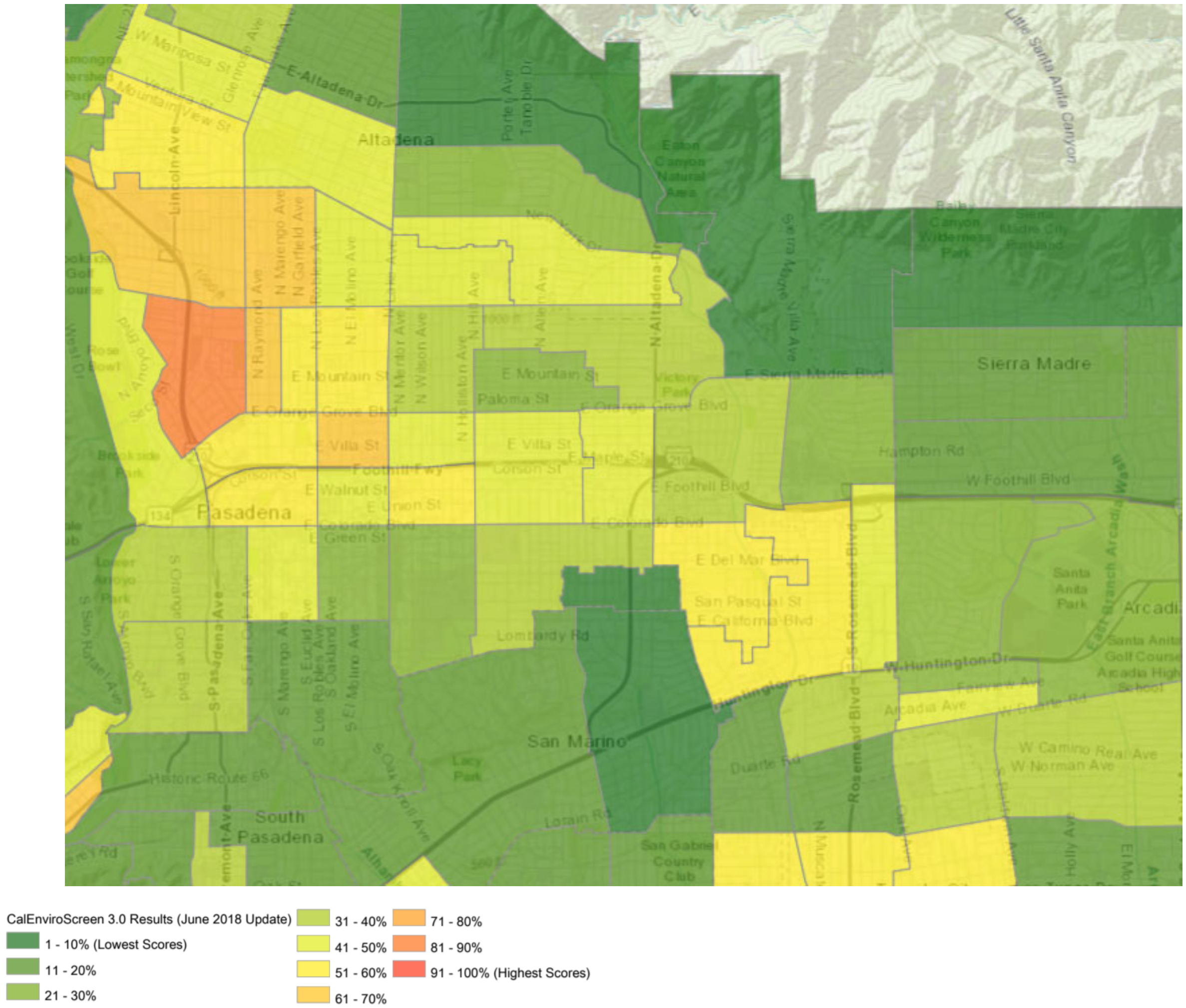
Senate Bill 535 (SB 535) provides that 25 percent of the proceeds from the Cap and trade auctions that are invested in reducing greenhouse gas (GHG) emissions must provide benefits directly to DACs. In addition, 40 percent of the DAC investments (10 percent of the total Cap and trade auction proceeds), must go to projects located within DACs. Assembly Bill 1550 (AB 1550, 2016) increased the percentage of total Cap and trade proceeds that must be directly invested in projects located within DACs to 25 percent. In addition, AB 1550 requires an additional minimum of 5 percent of the Cap and trade funds be invested in projects that benefit low-income households or communities statewide; and that an additional 5 percent be invested in projects that benefit low-income households or communities that are within 0.5 miles of a DAC.

i. DACs within PWP's Territory

In January 2017, the Office of Environmental Health Hazard Assessment (OEHHA), on behalf of the California Environmental Protection Agency (CalEPA), announced the availability of the California Communities Environmental Health Screening Tool, CalEnviroScreen 3.0 (CES 3.0).[45] This screen can be used to help identify California communities that are disproportionately burdened by pollution. Specifically, 22 metrics, focused on pollutants, socio-economic class, and health, are used to develop a census tract score for each zone. DACs are identified by census tract and have a score within the top 25th percentile. CalEPA used CES 3.0 to designate DACs pursuant to Senate Bill 535 in April 2017. There is one DAC in Pasadena, as shown in Exhibit 74.

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

Exhibit 74: DAC in PWP's Service Area



Source: Pace Global; OEHHA[46]

Under CES 3.0, the only DAC located within PWP's service area is located in zip code 91103 along Interstate 210 north of the intersection with the Ventura Freeway (State Route 134). This region received a census tract score of 43.20, which places it in the 80th percentile, above the DAC threshold. Although no other zones are DACs within PWP, the zones with the top five highest census tract scores in PWP are located within zip code 91103 near Interstate 210. PWP uses a broader DAC definition for certain efficiency and electrification programs.

The DAC within PWP's territory is in part defined by emissions scores. Exhibit 75 shows the emissions scores within the DAC.

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

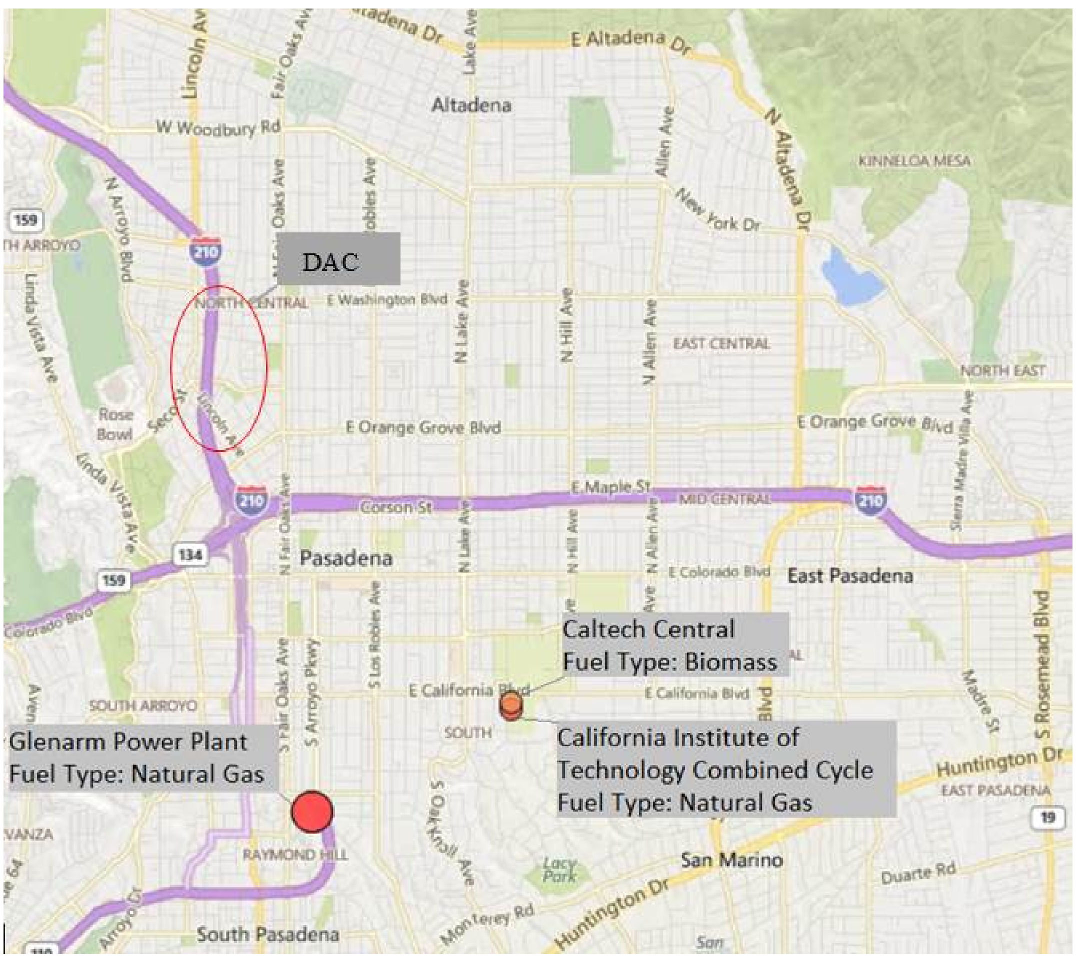
Exhibit 75: Emissions in the Pasadena DAC

Pollutant	Quality	Percentile
Ozone	0.051 Daily Maximum 8-hour Ozone Concentration	69th
PM2.5	10.79 Annual Mean Concentration	54th

Source: OEHHA

CO_2 is not used to identify DACs with CES 3.0, though it is typically a metric in programs implemented by POUs to reduce GHG emissions. Emissions in this DAC can be most correlated to the traffic on Interstate 210. Another metric used to identify a DAC is traffic density. This DAC has a 1,322.11 kilometer per hour per road length traffic density, which is in the 79th percentile. Emissions from electric generation within the service area are also considered to be a factor in identifying DACs. Exhibit 76 shows the generation facilities within PWP territory that could impact the DAC.

Exhibit 76: DAC and Existing Fossil Fuel Generation in Pasadena



Source: Pace Global; S&P Global

Of the three electric generation emissions emitting facilities in PWP territory, PWP only owns the Glenarm Power Plant. In 2017, Glenarm produced 26,154 tonnes of CO2 (118.8698 lb/MMBtu), 3,424 pounds of NOx (0.0078 lb/MMBtu), and 249 pounds of SOx (0.0006 lb/MMBtu).[47] The other two facilities are owned by the California Institute of Technology and are not operated by PWP. All three facilities are over two miles away from the DAC and are not believed to impact the DAC directly.

ii. Existing Programs Aimed at DACS

Currently, some of PWP's EE and EV programs help low-income customers, including those in the DAC. The WeDIP program and EV rebates specifically target the DACs. Please refer to Section I.D.6 for additional details on energy efficiency and home improvement program, targeted in the DAC. PWP offers additional incentives for installing EV chargers in DACs. The Commercial Charger Inventive Program provides double incentives (up to $6,000 per charger) for commercial charging stations in DAC territories.[48]

In addition to these DAC specific programs, PWP also provides many rebates to areas that include DACs but are not isolated to only DACs. A sample of programs is listed below.

- Energy Savings Assistance Program[49] offers no-cost, energy-saving home improvement services to income-qualified renters and homeowners though a partnership with Southern California Gas. Improvements include attic insulation, water heater blankets, door weather stripping, faucet aerators, caulking, minor repairs to exterior doors and windows, low-flow showerheads, evaporative cooler vent covers, furnace repair or replacement, and water heater repair or replacement.

- Home Energy Rebates[50] are available to all PWP customers, and low-income customers can receive double rebates. These rebates are for home appliances and fixtures, heating and cooling systems, insulation and building projects, and landscaping, irrigation and pools.

- Refrigerator Exchange provides a no-cost service where PWP exchanges old working refrigerator for a new energy efficient model.

- PWP also has the WeDIP, which provides eligible small business customers no-cost direct install water and energy saving equipment. Equipment installations include lighting upgrades, faucet aerators, pre-rinse spray valves, low-flow showerheads, efficient toilets, efficient urinals, refrigeration gaskets, strip curtains, LED refrigerated case lighting, electronically cumulated motors, auto door closers, evaporator fan controllers, and anti-sweat heaters. Eligible customers must use less than 30 kW electric

[47] Emissions data for Glenarm Power Plant is from S&P Global.
[48] https://ww5.cityofpasadena.net/water-and-power/commercialchargerrebate/.
[49] https://ww5.cityofpasadena.net/water-and-power/billassistance/.
[50] https://ww5.cityofpasadena.net/water-and-power/residentialprograms/.

capacity and at least one year remaining on lease term. This program can be applied to the DAC, but the program does not specifically target the DAC.

b. New and Existing Programs Aimed at Air Pollution in DACs

The California Air Resources Board (CARB) designed the California Cap and trade program to fund projects that reduce GHG emissions, strengthen the economy and improve public health and environment. Investments span all sectors: industrial, electricity, transportation, and natural and working lands. The 2018-19 Cap and trade Expenditure Plan[51] budgets $1.25 billion, some of which can be allocated to POU programs. The Expenditure Plan includes $255 million for reducing Air Toxic and Criteria Air Pollutants and $460 million for Low Carbon Transportation. Under Chapter 136, Statutes of 2017 (AB 617), this CARB funding will go towards grants for early incentive actions to reduce both stationary and mobile source emissions in communities heavily impacted by air pollution. PWP has an opportunity to apply for grant funding for targeted DAC programs.

Although PWP cannot control emissions from traffic on Interstate 210, there are other sources of emissions that affect the DAC, including municipal vehicles such as trucks and busses, and PWP programs could help mitigate the effects of such emissions. Other potential programs directed towards DACs include deployment of residential solar and community solar offerings.

PWP also can reduce GHG emissions in the DAC through transportation electrification programs and energy efficiency programs. Both the John Muir High School and Cleveland Elementary School are located adjacent to the DAC; however, their school busses travel through the DAC on routine schedules. Investing in electric school busses should help reduce emissions within the DAC. In addition, Pasadena Park Maintenance, PWP, and Pasadena Parks Natural Resources have buildings located within the DAC. Promoting electrification of the city vehicle fleets at these buildings can also reduce emissions within the DAC. Electrification of refuse collection vehicles also offers an opportunity to reduce the emissions within the DAC.

PWP is working with City Departments to establish a method to procure additional electric and hybrid fleet vehicles. Some of these vehicles will be housed in a DAC, located at the City yards at 311 West Mountain Street. This will reduce emissions from city vehicles. On a monthly basis, the PWP EV Program Manager leads an EV task force meeting, to facilitate the procurement of EV and hybrid fleet, citywide. This is one step, of many, that the City is taking to reduce its overall carbon footprint and to positively impact the surrounding area.

[51] http://www.ebudget.ca.gov/2018-19/pdf/BudgetSummary/ClimateChange.pdf.

III. Energy Efficiency Analysis

A. Energy Efficiency Doubling Goal

Senate Bill 350 (SB 350)[52] "requires the state to double statewide energy efficiency savings in electricity and natural gas end uses by 2030."[53] For regulatory implementation, SB 350 requires "the State Energy Resources Conservation and Development Commission [CEC] to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030."[54] SB 350 also requires "the PUC to establish efficiency targets for electrical and gas corporations consistent with this goal, and requir[es] local publicly owned electric utilities to establish annual targets for energy efficiency savings and demand reduction consistent with this goal."

SB 350 directs the CEC to extend existing 2025 projections for energy efficiency savings to 2030, and then to take that extended projection of 2030 expected energy efficiency savings as a "baseline." SB 350 then requires the state to achieve twice that baseline amount, "to the extent doing so is cost-effective, feasible, and will not adversely impact public health and safety."[55] The baseline is further defined as the sum of "the midcase estimate of additional achievable energy efficiency (AAEE) savings, as contained in the California Energy Demand Update Forecast, 2015-2025[56], and the targets set by local publicly owned electric utilities under Section 9505 of the Public Resources Code."[57]

The CEC currently interprets "cumulative" in SB 350 to mean the savings realized in the year 2030, not the sum of the cumulative energy efficiency savings realized in every year from 2015

52 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.
53 "Clean Energy & Pollution Reduction Act SB 350 Overview", California Energy Commission, https://www.energy.ca.gov/sb350/.
54 SB-350 Clean Energy and Pollution Reduction Act of 2015; http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.
55 Cal. PRC. Code § 25310(c)(1), 2016: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=25310.&lawCode=PRC.
56 SB 350 directs the CEC to use the mid-case estimate in the following document as the baseline: Kavalec, Chris, 2015. California Energy Demand Updated Forecast, 2015-2025. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2014-009-CMF. http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-CMF.pdf.
57 Cal. PRC. Code § 25310(c)(1), 2016, available here: https://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=25310.&lawCode=PRC.

through 2030.[58] Also, the baseline forecast for energy efficiency savings contains both (a) a forecast of *committed* energy efficiency savings—that is, forecast energy efficiency savings from initiatives already in place or approved—and (b) a forecast of additional future energy efficiency savings not included in the committed energy efficiency savings forecast, but *reasonably expected to occur*, referred to as additional achievable energy efficiency (AAEE) savings.

The CEC's overall interpretation is that the statute requires doubling only the AAEE amount of savings, not the projected energy efficiency savings due to programs and codes already in place or approved as of 2015.[59] The CEC's statewide total energy efficiency savings targets for electricity, along with the projected savings from utility and non-utility programs, are presented in Exhibit 77 below.[60] The SB 350 Doubling Goal (top line) is the arithmetic doubling of projected AAEE savings from 2015 to 2025, with the 2026-to-2030 projected savings extrapolated using a trend line defined by the 2015-2025 projected savings.[61] The AAEE baseline itself is not clearly displayed in Exhibit 77; that baseline would presumably exclude any "committed" energy efficiency savings, which include at least the light blue triangle for savings from "codes and standards." Still it is clear the CEC is taking SB 350 to require a total of about 83,000 GWh of electricity energy efficiency savings in 2030, an increase of about 20,000 GW from the overall baseline forecast.[62]

[58] Framework for Establishing the Senate Bill Energy Efficiency Savings Doubling Targets, Docket 17-IEPR-06, TN# 215437, California Energy Commission 1/18/17.

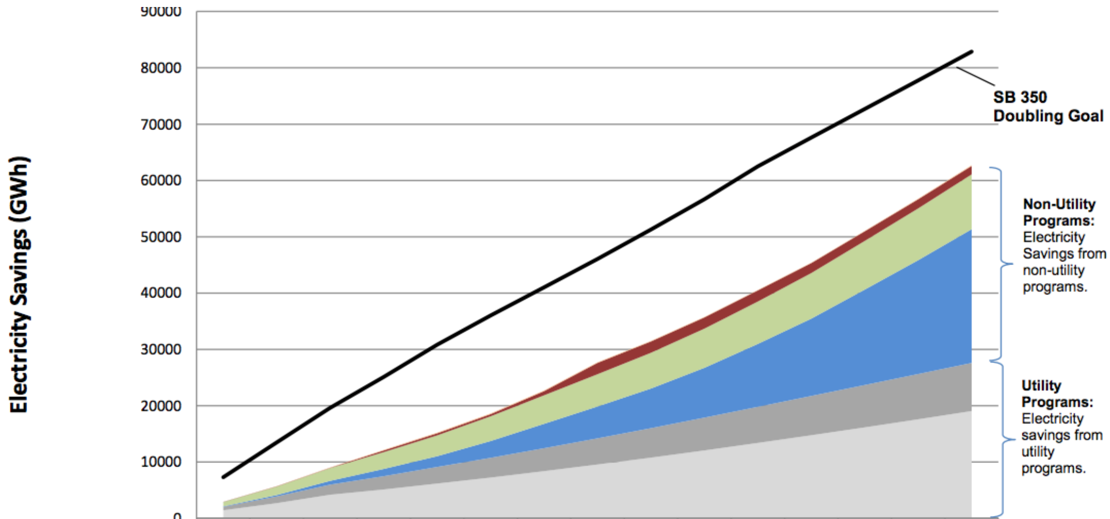
[59] *Senate Bill 350 Doubling Energy Efficiency Savings by 2030*, Docket 17-IEPR-06, Page 25, TN221631, California Energy Commission, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=221631.

[60] *Senate Bill 350 Doubling Energy Efficiency Savings by 2030*, Docket 17-IEPR-06, Page 25, TN221631, California Energy Commission, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=221631.

[61] The trendline appears to be a simple linear extension of the trend from 2015–2025. PWP is not aware of any CEC publication detailing the exact methodology for how they calculated the trendline displayed. The text of SB 350 provides that the CEC is to use the 2015 to 2025 report, "extended to 2030 using an average annual growth rate" so it seems reasonable to infer they have used an average annual growth rate in extrapolating from 2025 to 2030. Cal. PRC. Code § 25310(c)(1), 2016.

[62] This figure is from page 17 of *Senate Bill 350 Doubling Energy Efficiency Savings by 2030*, Docket 17-IEPR-06, TN221631, California Energy Commission, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=221631. The report has similar figures for natural gas savings and combined electricity and natural gas savings.

Exhibit 77: SB 350 Doubling Target (GWh)[63]



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Agriculture & Industry	2	33	58	95	118	121	116	109	94	83	76	75	82	99	127
Behavioral & Market Trans.	32	39	47	296	366	375	732	2002	1998	1986	1963	1762	1693	1617	1492
Financing	757	1513	2270	2994	3704	4401	5074	5736	6360	6967	7536	8099	8653	9202	9748
Codes & Standards	93	243	673	1280	1899	2980	4325	5655	7037	8841	11172	13729	16948	20215	23746
POU Programs	596	1190	1790	2360	2945	3501	4069	4645	5232	5822	6406	6977	7520	8042	8540
IOU Programs	1427	2685	4179	5112	6169	7230	8373	9550	10768	12052	13385	14748	16145	17580	19050
SB 350 Doubling Goal	7,286	13,46	19,60	25,10	30,81	36,01	41,03	46,04	51,28	56,66	62,51	67,60	72,69	77,78	82,87

Source: *California Energy Commission staff, Efficiency Division. Based on work in Appendix B by NORESCO. August 2017.*

The California Public Utilities code at Section 9505 requires POUs to report every four years to the CEC. Among other requirements, the report is to include:

> "(5) A comparison of the local publicly owned electric utility's annual targets established pursuant to subdivision (b) and the local publicly owned electric utility's reported electricity efficiency savings and demand reductions.
>
> (b) By March 15, 2013, and by March 15 of every fourth year thereafter, each local publicly owned electric utility shall identify all potentially achievable cost-effective electricity efficiency savings and shall establish annual targets for energy efficiency savings and demand reduction for the next 10-year period, consistent with the annual targets established by the Energy Commission pursuant to subdivision (c) of Section 25310 of the Public Resources Code. A local publicly owned electric utility's determination of potentially achievable cost-effective electricity efficiency savings shall be made without regard to previous minimum investments undertaken pursuant to Section 385. A local publicly owned electric utility shall treat investments made to

[63] Source: California Energy Commission staff, September 2017.

achieve energy efficiency savings and demand reduction targets as procurement investments."[64]

Multiple documents have been reviewed to establish annual targets for energy efficiency savings and demand reduction consistent with California's overall targets under SB 350.

First, "Senate Bill 350 Energy Efficiency Target Setting for Utility Programs", July 2017, describes POU targets for energy savings under SB 350. Exhibit 78 (Table C-5 in that document) sets out adjusted specific annual and cumulative targets for Pasadena.[65] Table C-5 resulted from CEC staff assessments and adjustments of data provided by the POUs and additional information from some POUs, the CMUA, and two webinars.[66] However the official description of the document is "Draft Staff Paper", so it seems that these numbers are not finalized.

Exhibit 78: Pasadena Energy Efficiency Adjusted Cumulative Targets (GWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Annual Cumulative Targets	17	32	45	58	71	84	97	110	123	135	146	157	167	176	184
Incremental Cumulative Targets	17	15	13	13	13	13	13	13	13	12	11	11	10	9	8

Second, "Senate Bill 350 Doubling Energy Efficiency Savings by 2030", October 2017, discusses adjustments that the CEC proposes making to each POU's energy efficiency savings projections shown in Exhibit 79 (Table A-11: POU Cumulative Electricity Savings Targets With Adjustments (GWh)). This table reports *proposed* annual targets for POUs, including Pasadena, for 2015 to 2029.[67] For Pasadena, Table A-11 in this later document shows cumulative end-of-year targets.[68]

Exhibit 79: Pasadena Annual Cumulative Electricity Savings Targets (GWh)

2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
12	31	51	64	77	91	106	121	136	149	161	173	184	194	203

[64] Cal. PUC. Code § 9505(5), 2016, available here:
http://leginfo.legislature.ca.gov/faces/codes_displaySection.xhtml?sectionNum=9505.&lawCode=PUC.

[65] *Senate Bill 350 Energy Efficiency Target Setting for Utility Programs,* California Energy Commission, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=220290-1 (TN220290-1, pages 44 and C-5) 7/21/2017.

[66] *Senate Bill 350 Energy Efficiency Target Setting for Utility Programs,* California Energy Commission, available at https://efiling.energy.ca.gov/getdocument.aspx?tn=220290-1 (TN220290-1, pages 44 and C-5) 7/21/2017.

[67] Senate Bill 350 Doubling Energy Efficiency Savings by 2030, California Energy Commission, https://efiling.energy.ca.gov/getdocument.aspx?tn=221631 (TN221631, at A-12 to A-22). October 2017.

[68] Senate Bill 350 Doubling Energy Efficiency Savings by 2030, California Energy Commission, https://efiling.energy.ca.gov/getdocument.aspx?tn=221631 (TN221631, at A-12 to A-22). October 2017.

The framework needed for utilities to adopt and plan to achieve EE doubling by 2030 under SB 350 has been flushed out by CEC but remains at the proposal stage, rather than finalized and controlling on PWP and other POUs.

Third, PWP also evaluated SB 100, which passed earlier this year and makes significant changes to California's clean energy goals.[69] On its face, it appears that the law does not alter the state-wide goal set by SB 350 for doubling the energy efficiency to be achieved by 2030. The law does not use the word "efficiency" or address policies to be taken to reduce energy demand; rather the law changes the dates and percentage figures for requirements that utilities obtain specified fractions of their total energy provided to their customers from renewable power sources.[70]

Also, SB 100 does not clearly change the baseline amount of energy efficiency to be doubled under SB 350. As of this report, it seems that the overall statewide target of energy efficiency to be doubled under SB 350 will not change, and it is reasonable to assume no changes in the existing doubling targets for POUs.

Because the CEC may update efficiency targets in light of SB 100, and because the SB 350 targets are "draft" or "proposed", PWP plans to remain in compliance with SB 350 for this IRP and postpone addressing the doubling issue until the next IRP, when more regulatory guidance from the CEC should be available. Thus, the forecasted annual load reductions due to EE programs are held flat at the SB 350 levels for the study period. In addition, PWP has undertaken an evaluation of the cost-effectiveness (benefit/cost ratios) of existing and potential EE programs in this IRP and plans further analyses in the near future that will help construct an EE program that meets state targets in a cost-effective manner by 2030.

[69] The law was passed as SB 100 and signed on September 10, 2018, and amends Sections 399.11, 399.15, and 399.30 of, and adds Section 454.53 to, the California Public Utilities Code. The law is available here: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

[70] The law was passed as SB 100 and signed on September 10, 2018, and amends Sections 399.11, 399.15, and 399.30 of, and adds Section 454.53 to, the California Public Utilities Code. The law is available here: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

B. Cost-Effectiveness and Benefit-Cost Analysis

The purpose of a benefit-cost test is to weigh the benefits (avoided costs) of an energy efficiency (EE) program against the costs of the program. That is, reductions in consumption create benefits in the form of avoiding costs that would have been incurred with higher consumption. However, those benefits and costs differ based on the economic accounting perspective. Economic account perspective refers to the entity that pays the costs and receives the benefits. To capture these varying interests, all of the tests above were run on PWP's current EE programs to determine if they are cost effective. Those tests were:

- Societal Cost Test (SCT)
- Total Resource Cost (TRC)
- Utility Cost Test (UCT)
- Ratepayer Impact Measure (RIM)
- Participant Cost Test (PCT)

At the broadest, the Societal Cost Test (SCT) counts benefits and costs that occur both within and outside the utility. At the narrowest, the Participant Cost Test (PCT) only looks at the individuals (homes and businesses) that engage in the EE program. Between these extremes lie the Utility Cost Test (UCT), the Ratepayer Impact Measure (RIM) and the Total Resource Cost (TRC) test. For example, a utility (UCT) may not be concerned about the full cost of an energy efficiency upgrade if it is rebating only a part of the purchase price. On the other side, a utility customer (PCT) will not normally take interest in the utility's avoided cost but, rather, the customer is normally concerned about the cost directly to install an EE measure and any resulting savings on the retail bill.

Each test takes on a different perspective and calculates whether the program's benefits outweigh the costs from that perspective. Specifically, each test results in a benefit-cost ratio that divides the benefits by the costs to evaluate whether the program is cost effective. Any benefit-cost ratio greater than one is determined to be cost effective with greater values denoting greater cost effectiveness. All five tests were calculated in according with the CPUC's benefit-cost analysis guidelines.[71]

[71] http://www.cpuc.ca.gov/General.aspx?id=5267.

1. Definitions

a. Avoided Cost of Energy

The avoided cost of energy captures the cost of energy at the utility's margin during the year. It is measured on a dollar per kWh basis and is used in the SCT, UCT, and TRC tests to capture the benefit of saving an additional kWh.

b. Avoided Cost of Capacity

The avoided cost of capacity captures the cost of capacity at the utility's system peak and is expressed in terms of dollars per kW. It is the cost the utility incurs to either generate or contract an additional kW to be provided during the system peak and is typically a multiple of the average cost of energy being provided when capacity is not plentiful. This value is used in the SCT, UCT, and TRC tests.

c. Avoided Cost of Carbon

The avoided cost of carbon is used to price the negative externality of energy production: namely the production of carbon dioxide and other greenhouse gases. Like energy, it is expressed in terms of a cost per kWh but is only used in the SCT test. In this analysis, PWP used the Social Cost of Carbon (SCC) that was incorporated into SCC scenarios of AURORA.

d. Line Losses

Line loss captures the amount of energy lost to the transmission and distribution system: the net difference between energy produced at the generator and energy received at the customer's meter. This value is expressed as a percentage and is used in the SCT, TRC, UCT, and RIM tests.

e. Measure Cost

The measure cost is the all-in cost of the measure when installed at the customer's point-of-service. It captures the additional cost incurred by either the customer or utility and is used across all tests as one of four components that are considered the cost of the measure.

f. Administrative Cost

The administrative cost captures the overhead the utility incurs to operate and administer a program. It accounts for additional employees required to administer the measure, costs to hire implementers to run the program, and final costs for evaluation of the program.

g. Incentive Cost

The incentive cost is the payment the utility gives to customers when not providing the full incremental cost of the measure. For the TRC test, incentive costs are considered a transfer payment that does not change the cost of the measure since either the utility or customer must end up payment for the full incremental cost at some point.

h. Revenue Loss

The revenue loss is used in the RIM test to capture the utility's lost revenue due to decreased energy consumption because of the measure and increases the cost to the utility. Since this cost is typically greater than the avoided cost of energy, this tends to drive the RIM test down when compared to other tests.

i. Net Present Value (NPV)

The NPV function is a financial formula used to discount future costs and benefits backwards to the current day for comparison. It primarily captures the utility's internal cost of capital and reflect that while the money is devoted to a measure it cannot be used for other potentially profitable investments in the utility. Formally, the NPV function is defined as:

$$NPV = \sum_{t=0}^{N} \frac{CashFlow_t}{(1 + DiscountRate)^t}$$

j. BenCost Tool

BenCost is Applied Energy Group's (AEG) cost effectiveness analysis tool, built in Excel. BenCost allows users to easily enter assumptions about energy costs, program costs, and other variables to quickly evaluate a given program's potential given across the five tests described below.

k. Five Tests of Cost-Effectiveness

i. Societal Cost Test (SCT)

The numerator of the societal cost test accounts for the energy and capacity costs avoided by reducing consumption, the positive externalities of reduced greenhouse gas (GHG) emissions of generating and delivering energy, and the line losses avoided when consumption is reduced. Avoided GHG costs can be measured in either the price of California carbon allowances or a SCC. This analysis, we used the SCC embodied in AURORA because of two goals:

(a) consistency in assumptions across different parts of the IRP analysis and

(b) policy direction from PWP that the SCC should be explicitly captured in the IRP.

The SCC is expressed in terms of dollars per metric tonne of CO2e ("carbon-dioxide equivalent", an index that combines various GHGs that contribute to climate change), which is multiplied by PWP's marginal carbon rate (in tonnes per MWh) to derive a $/MWh component of the numerator.

$$SCT = \frac{NPV(EnergyAvoidedCost + CapacityAvoidedCost + CarbonAvoidedCost) * (1 + LineLoss))}{NPV(MeasureCost + AdministrativeCost)}$$

The denominator is the sum of the costs of the specific EE measure plus the costs of running the utility's EE programs. The total cost of the measure may be covered from a variety of sources (the participant's own contributions plus federal-state-local tax and non-tax rebates). However, the SCT captures all these sources.

The SCT is similar to the TRC, but because the SCC is included in the numerator, the SCT will always show a higher BC ratio than the TRC test.

ii. Total Resource Cost (TRC)

The TRC test is the most commonly used cost effectiveness test.[72] The TRC is the same as the SCT except that the social cost of carbon is excluded.

$$TRC = \frac{NPV(EnergyAvoidedCost + CapacityAvoidedCost) * (1 + LineLoss))}{NPV(MeasureCost + AdministrativeCost)}$$

One goal of the TRC is to ensure that the measure itself is cost effective to all utility customers considered as a whole, compared with generating and delivering the energy.

iii. Utility Cost Test (UCT)

The utility cost test measures whether the utility would implement the program looking only at the utility's avoided costs compared with the costs of running the program:

$$UCT = \frac{NPV(EnergyAvoidedCost + CapacityAvoidedCost) * (1 + LineLoss))}{NPV(IncentiveCost + AdministrativeCost)}$$

As the incentive rate approaches 100%, the UCT approaches the TRC test. For any incentive less than 100% of the cost of the measure, the UCT will report a higher BC ratio than the TRC test.

iv. Ratepayer Impact Measure (RIM)

The RIM examines the benefit-cost ratio of the program from the perspective of all retail ratepayers. Specifically, it examines whether ratepayers will pay higher rates (to cover the utility's total costs) because of the EE program. Many, if not most, EE programs will reduce consumption, and thus revenues to the utility, during periods where avoided costs are lower than retail rates. That is, the EE program could reduce revenues more than avoided costs, thus raising

[72] https://www.epa.gov/sites/production/files/2017-06/documents/understanding_cost-effectiveness_of_energy_efficiency_programs_best_practices_technical_methods_and_emerging_issues_for_policy-makers.pdf.

rates. This is not unusual with traditional retail rate design, which recovers fixed costs through energy charges. Conversely, programs that reduce consumption when avoided costs are higher than retail rates (on summer peak days, for example) tend to have better results (higher benefit-cost ratios) under the RIM.

$$RIM = \frac{NPV(EnergyAvoidedCost + CapacityAvoidedCost) * (1 + LineLoss))}{NPV(RevenueLoss + MeasureCost + Incentives + AdministrativeCost)}$$

v. Participant Cost Test (PCT)

The PCT test examines the benefit-cost ratio of the program from the perspective of the customer participating in the program. The PCT is useful in the context of predicting participation if the program were offered, i.e., a program may make financial sense from the utility's perspective but if no one is willing to participate because the PCT less than 1.0, then the program would not be effective at all.

$$PCT = \frac{NPV(BillReduction + Incentive)}{NPV(MeasureCost)}$$

In the above equation, the bill reduction is the energy and demand savings multiplied by their respective retail rates ($/kWh and $/kW).

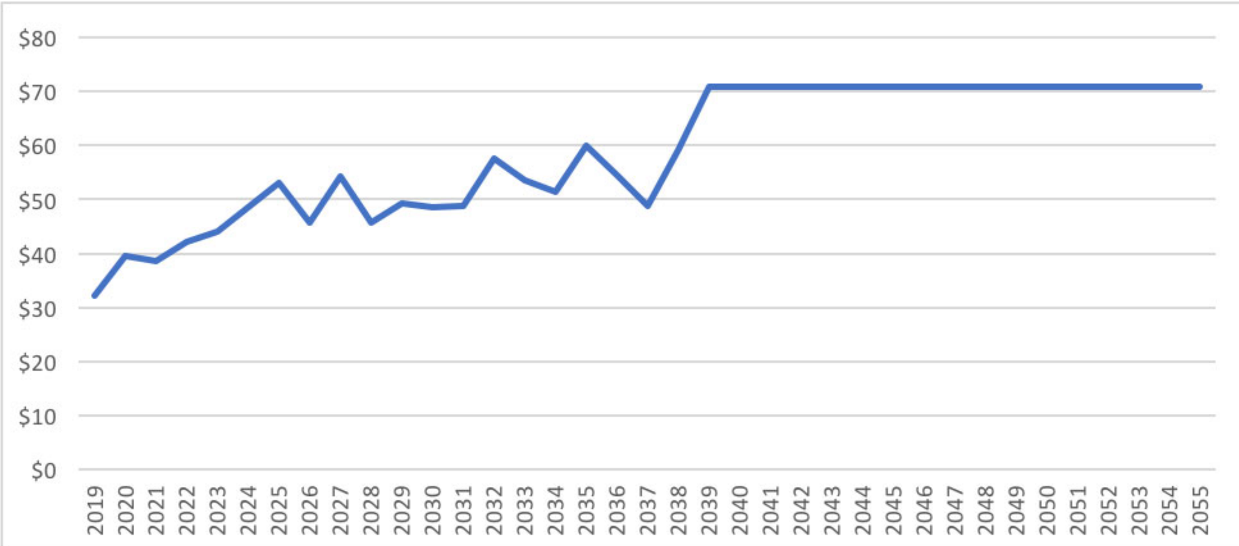
2. Assumptions

The analysis for existing programs encompassed all 12 energy efficiency programs that Pasadena Water & Power currently offers. Each program was evaluated in AEG's BenCost model using all five of the benefit-cost tests. To evaluate the tests, data was collected, and assumptions were made to provide the model with all the relevant data required to run each of the tests. All values are expressed in 2017 dollars, to be consistent with the AURORA modeling.

a. Utility Avoided Costs and Retail Rate Projections

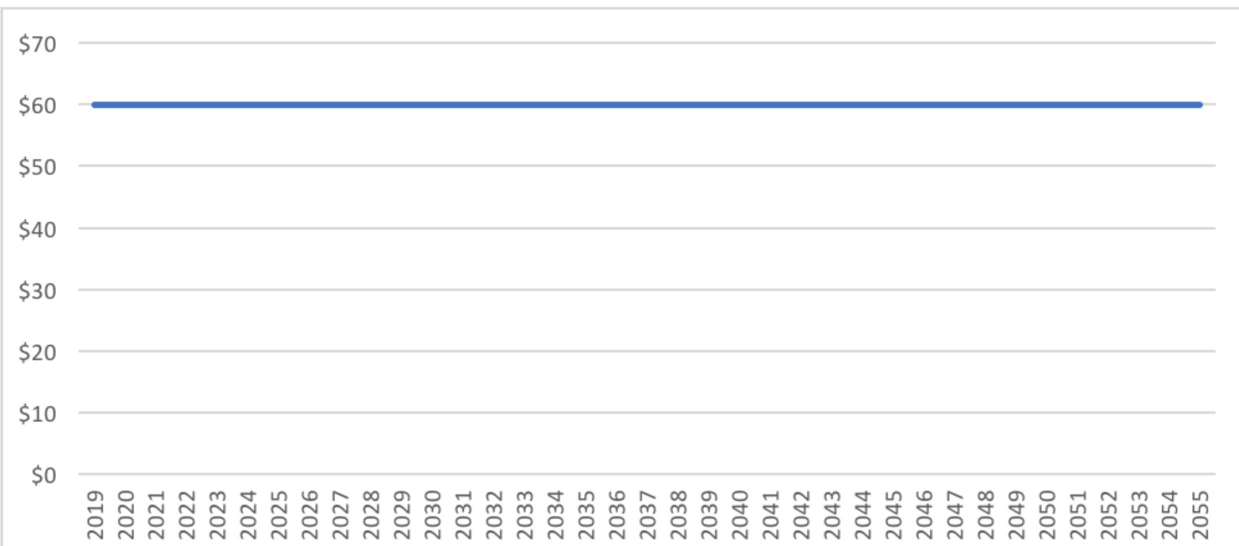
BenCost calculates utility and ratepayer benefits and costs using avoided costs for the utility side of programs and retail rates for the participant side of programs. PWP's avoided energy costs were provided by Siemens using the AURORA modeling software (Base Case results). PWP's avoided capacity costs assume that any RA shortfalls of PWP are covered by payments to the CAISO at $5/kW-month ($60/kW-yr) shown in Exhibit 81. The BenCost results provided encompassed the forecast period of 2019 through 2039. For years beyond 2039, which must be considered because of some extended program lives, avoided costs were held flat. Avoided energy costs increase from $32.08/MWh in 2019 to $70.93/MWh in 2039 shown in Exhibit 80. Avoided Cost of Carbon is shown in Exhibit 82. To be consistent with other parts of the report, all costs are in line with PWP's Base Case Scenario and are presented in real 2017 dollars. The carbon content shown in Exhibit 82 is associated with spot market energy purchases from the CAISO, because that is the variable supply on the margin available to PWP.

Exhibit 80: Avoided Energy Cost ($/MWh)



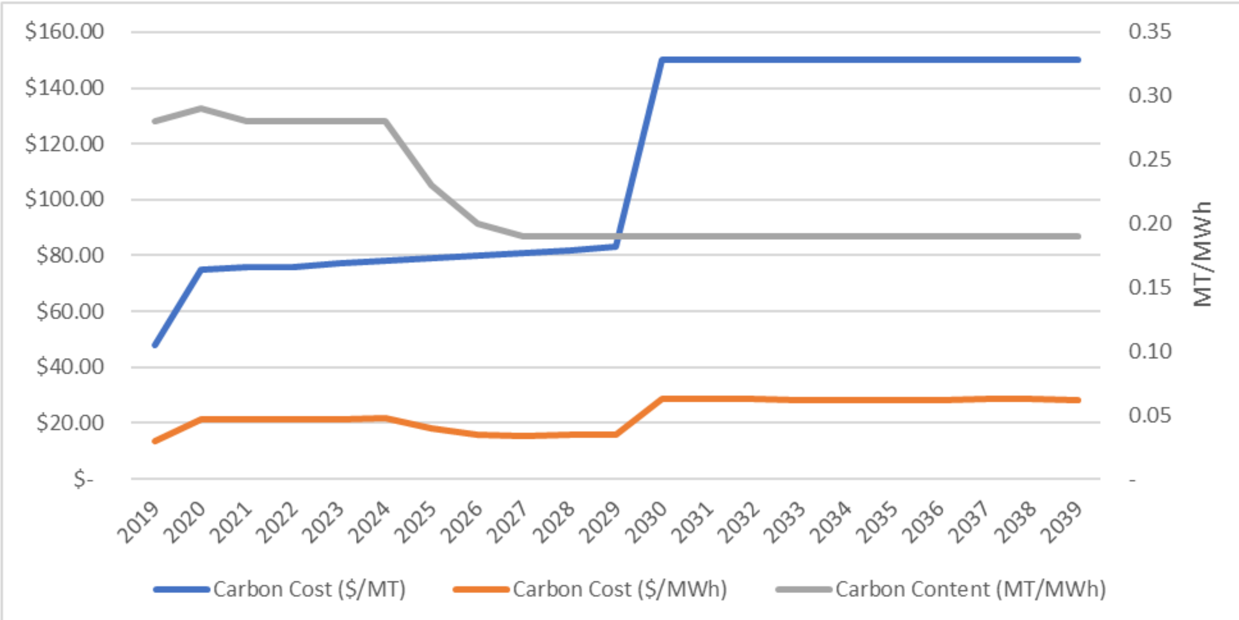
Source: Pace Global

Exhibit 81: Avoided Capacity Cost ($/kW-year)



Source: Pasadena Water and Power

Exhibit 82: Avoided Social Cost of Carbon



Source: Pace Global

The SCC shown here, and used in the SCT, is identical to the SCC used in AURORA. Avoided capacity costs were held flat at a rate of $60/kW-year for the entire duration of the study, per guidance from PWP on expected payments to the CAISO for RA shortfalls.

b. Real Discount Rate

To avoid layering on additional assumptions about long term inflation rates, the entire study was conducted using 2017 dollars. Therefore, the discount rate used in the BenCost model was the real discount rate as opposed to the nominal discount rate. For this study, a real discount rate of 2% was used when converting savings and costs from future years into 2017 dollars.

3. Existing Programs

For each program, details specific to that measure were entered into AEG's BenCost model. Where possible, data specific to the City of Pasadena was used. Savings, program costs, and participation were taken directly from annual filings by PWP in the 2017 POU EE Report. Lifetimes were calculated by dividing reported lifetime savings by annual savings. Net-to-Gross ratios were provided in Pasadena's Critical Activities Report and was used to adjust savings from a gross basis to a net basis. For programs considered that Pasadena Water & Power does not currently offer, data was taken from the CPUC's EE program database for the three major electric IOUs and adjusted to match Pasadena Water & Power's footprint.

a. Current Program Results

Once all the data was gathered and inputted into the model, cost tests were calculated in line with the CPUC's manual. Benefit-Cost test results for 2019 and 2039 are shown in Exhibit 83 and Exhibit 84, respectively. Due to the low avoided and capacity costs, many of the programs fail the TRC and SCT tests and none pass the RIM test due to the reasons discussed above.[73]

Exhibit 83: 2019 Benefit-Cost Results: Existing Programs

Sector	Measure	SCT	TRC	PCT	UCT	RIM
Residential	Residential Rebates	0.55	0.43	1.43	0.65	0.18
Residential	Home Energy Reports	0.56	0.39	n/a	0.39	0.18
Residential	Residential Recycling	0.75	0.54	2.01	0.66	0.18
Residential	Low Income Product Giveaways	2.79	2.00	6.07	2.00	0.28
Residential	Low Income Energy Savings Assistance	0.81	0.64	2.13	0.66	0.21
Residential	Low Income Refrigerator Exchange	0.33	0.24	1.25	0.34	0.11
Residential	Residential Audits	1.97	1.60	2.59	39.34	0.46
Residential	LED WebShop	1.79	1.28	4.88	0.79	0.22
Residential	LivingWise	0.11	0.07	n/a	0.07	0.06
Commercial	Commercial Direct Install WeDIP	0.73	0.54	2.24	0.72	0.17
Commercial	Commercial Rebates	0.73	0.53	1.78	4.25	0.19
Commercial	Upstream HVAC	0.89	0.68	2.28	1.39	0.21

Source: Pace Global; ASWB; AEG

[73] These results are based on data from FY16. Residential audits were discontinued after FY17. The LED webshop and upstream HVAC programs were discontinued after FY18. All results use available data, but market conditions are dynamic and these results may not be reasonable projections of future costs and benefits.

Exhibit 84: 2039 Benefit-Cost Results: Existing Programs

Sector	Measure	SCT	TRC	PCT	UCT	RIM
Residential	Residential Rebates	0.69	0.54	1.77	0.81	0.19
Residential	Home Energy Reports	0.82	0.58	n/a	0.58	0.22
Residential	Residential Recycling	1.17	0.87	2.97	1.06	0.22
Residential	Low Income Product Giveaways	3.55	2.59	7.86	2.59	0.29
Residential	Low Income Energy Savings Assistance	1.15	0.89	2.83	0.92	0.23
Residential	Low Income Refrigerator Exchange	0.50	0.37	1.63	0.53	0.14
Residential	Residential Audits	3.34	2.60	5.72	43.70	0.41
Residential	LED WebShop	2.28	1.67	6.04	1.03	0.24
Residential	LivingWise	0.15	0.11	n/a	0.11	0.08
Commercial	Commercial Direct Install WeDIP	1.11	0.83	3.35	1.12	0.19
Commercial	Commercial Rebates	0.91	0.67	2.36	5.41	0.20
Commercial	Upstream HVAC	1.06	0.81	2.93	1.63	0.21

Source: Pace Global; ASWB; AEG

Exhibit 85 shows the first year during the study period when each program passes each test (i.e., has a benefit/cost ratio greater than one). These results suggest that PWP's existing programs should be restructured.

Exhibit 85: First Year Existing Program Passes Test

Sector	Measure	SCT	TRC	PCT	UCT	RIM
Residential	Residential Rebates	Never	Never	2019	Never	Never
Residential	Home Energy Reports	Never	Never	2019	Never	Never
Residential	Residential Recycling	2032	Never	2019	2038	Never
Residential	Low Income Product Giveaways	2019	2019	2019	2019	Never
Residential	Low Income Energy Savings Assistance	2030	Never	2019	Never	Never
Residential	Low Income Refrigerator Exchange	Never	Never	2019	Never	Never
Residential	Residential Audits	2019	2019	2019	2019	Never
Residential	LED WebShop	2019	2019	2019	2031	Never
Residential	LivingWise	Never	Never	2019	Never	Never
Commercial	Commercial Direct Install WeDIP	2035	Never	2019	2036	Never
Commercial	Commercial Rebates	Never	Never	2019	2019	Never
Commercial	Upstream HVAC	2026	Never	2019	2019	Never

Source: Pace Global; ASWB; AEG

Each program was evaluated across the entire scope of the study (2019-39). The values in Exhibit 85 represent the first year the program becomes viable, which may not necessarily be the base year, and reflects the nature of changing avoided cost assumptions. Only three programs pass the TRC and SCT in the base year, though four pass the UCT and all pass the PCT.

4. Potential Future Measures

In addition to the 12 measures evaluated above, selected potential measures that Pasadena could implement were analyzed. Data was collected from the CPUC for nearby utilities (San Diego Gas & Electric and Southern California Edison) and adjusted to reflect the smaller size of Pasadena Water & Power's service territory, load, and number of customers. While the data did not provide every detail required for BenCost, assumptions were made to derive required values by recalculating some of the fields. For example, to derive measure costs, we took the total TRC cost and removed the general overhead cost, the net result of that being the measure cost. Each measure was then run through the same cost tests described above and the results are presented below.

a. Potential Measures

In collaboration with Pasadena Water & Power staff, several potential measures were selected for further analysis. These measures and the associated source utility are:

- Calculated Incentives – SDG&E
- Commercial Building Codes & Standards Advocacy – SDG&E
- Residential Building Codes & Standards Advocacy – SDG&E
- Multi Family Incentives and Rebates - SCE
- School Energy Efficiency Program - SCE
- Residential Direct Install Program - SCE
- Deemed Incentives – HVAC – SDG&E
- Healthcare Energy Efficiency Program - SCE
- Commercial Deemed Incentives - SCE
- Commercial Savings by Design - SCE
- Lodging Energy Efficiency Program - SCE
- Residential New Construction Program - SCE
- Energy Upgrade CA Home Upgrade - SCE

b. Potential Program Results

As with Pasadena Water & Power's current measures, the potential measures were entered into AEG's BenCost model and the five tests conducted. The results show, similarly, that most potential programs would pass most of the tests, except for RIM; see the following three Exhibits.

Exhibit 86: 2019 Benefit-Cost Results: Potential Programs

Sector	Measure	SCT	TRC	PCT	UCT	RIM
Commercial	Calculated Incentives	1.40	1.00	3.90	3.14	0.22
Commercial	Building Codes & Standards Advocacy	2.16	1.61	n/a	1.61	0.29
Residential	Building Codes & Standards Advocacy	1.70	1.25	n/a	1.25	0.32
Residential	Multi Family Incentives and Rebates	2.06	1.51	5.89	0.90	0.24
Commercial	School Energy Efficiency Program	0.95	0.71	3.29	0.61	0.17
Residential	Direct Install Program	1.36	1.05	3.55	0.74	0.26
Commercial	Deemed Incentives - HVAC	0.57	0.45	1.26	1.17	0.20
Commercial	Healthcare Energy Efficiency Program	2.06	1.51	5.22	3.79	0.24
Commercial	Deemed Incentives	1.05	0.76	3.01	1.84	0.20
Commercial	Savings by Design	2.79	2.10	7.10	3.45	0.28
Commercial	Lodging Energy Efficiency Program	0.77	0.54	2.20	1.63	0.18
Residential	New Construction Program	1.01	0.82	2.82	0.57	0.23

Sources: Pace Global; ASWB; AEG

Exhibit 87: 2039 Benefit-Cost Results: Potential Programs

Sector	Measure	SCT	TRC	PCT	UCT	RIM
Commercial	Calculated Incentives	1.70	1.24	5.19	3.56	0.23
Commercial	Building Codes & Standards Advocacy	2.09	1.56	n/a	1.56	0.26
Residential	Building Codes & Standards Advocacy	1.72	1.27	n/a	1.27	0.30
Residential	Multi Family Incentives and Rebates	3.04	2.22	8.35	1.33	0.26
Commercial	School Energy Efficiency Program	1.35	1.01	4.49	0.86	0.19
Residential	Direct Install Program	1.84	1.44	5.22	1.02	0.28
Commercial	Deemed Incentives - HVAC	0.82	0.65	2.02	1.69	0.21
Commercial	Healthcare Energy Efficiency Program	3.12	2.29	8.19	5.73	0.25
Commercial	Deemed Incentives	1.57	1.15	4.63	2.70	0.21
Commercial	Savings by Design	3.91	2.93	10.91	4.71	0.27
Commercial	Lodging Energy Efficiency Program	1.16	0.85	3.65	2.37	0.20
Residential	New Construction Program	1.21	0.96	3.42	0.67	0.23

Source: Pace Global; ASWB; AEG

Exhibit 88: First Year Potential Program Passes Test

Sector	Measure	SCT	TRC	PCT	UCT	RIM
Commercial	Calculated Incentives	2019	2019	2019	2019	Never
Commercial	Building Codes & Standards Advocacy	2019	2019	2019	2019	Never
Residential	Building Codes & Standards Advocacy	2019	2019	2019	2019	Never
Residential	Multi Family Incentives and Rebates	2019	2019	2019	2025	Never
Commercial	School Energy Efficiency Program	2021	2039	2019	Never	Never
Residential	Direct Install Program	2019	2019	2019	2038	Never
Commercial	Deemed Incentives - HVAC	Never	Never	2019	2019	Never
Commercial	Healthcare Energy Efficiency Program	2019	2019	2019	2019	Never
Commercial	Deemed Incentives	2019	2034	2019	2019	Never
Commercial	Savings by Design	2019	2019	2019	2019	Never
Commercial	Lodging Energy Efficiency Program	2034	Never	2019	2019	Never
Residential	New Construction Program	2019	2037	2019	Never	Never

Source: Pace Global; ASWB; AEG

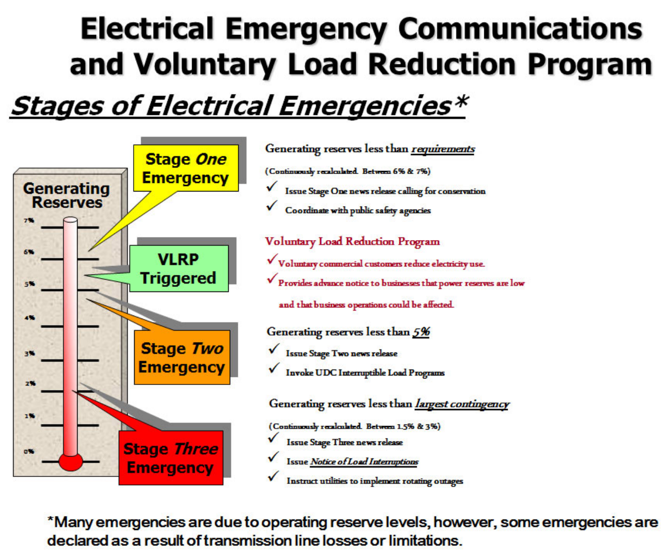
These potential programs are likely to pass most cost effectiveness tests and provide benefits to both ratepayers and participants. Before PWP decides to add programs, however, further analysis is necessary to check whether the new programs would have interaction effects that would be either synergistic (e.g., the net combined effect of two programs is greater than the sum of the individual programs) or cannibalistic (e.g., the net combined effect of two programs is less than the sum of the individual programs).

C. Demand Response

Demand response (DR) involves taking actions that lead to a reduction in electrical load, usually in real-time, due to operational problems. Demand response programs are designed to encourage a reduction in energy use during periods of loss of generating or transmission equipment, peak electricity demand forecast, or high temperatures and especially persistent heatwaves.[74]

PWP operates within the CAISO, which is responsible for ensuring reliability of its grid. Demand Response is called by the CAISO in Emergency Stages as shown in Exhibit 89 when generating reserves fall below requirements: reserve levels less than 7 percent trigger Stage 1 and reserves at 1.5-3 percent trigger Stage 3. Notices of load interruptions are issued, and utilities may be instructed to implement rotating outages to maintain grid reliability.

Exhibit 89: CAISO Emergency Communications and Voluntary Load Reduction[75]



Source: CAISO

1. Current DR Programs

PWP deployed a Voluntary Load Curtailment Program (VLCP) in 2016, which was designed to encourage customers to voluntarily reduce electricity use at PWP's request during periods of peak demand. The VLCP was initially developed to mitigate the threat of rolling blackouts in PWP service territory resulting from the Aliso Canyon storage problems but could also be called during Stage 3 Emergencies.

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[74] California ISO - System Alerts, Warnings and Emergencies. https://www.caiso.com/Documents/SystemAlertsWarningsandEmergenciesFactSheet.pdf.

[75] CAISO (2005, February 22), Outlook Summer 2005 and Beyond. https://seuc.senate.ca.gov/sites/seuc.senate.ca.gov/files/02-22-05iso.ppt.

The VLCP program targeted the top 50 Key Account customers, to inform them of the effort and to encourage their participation in the program. Customers were advised that although PWP was not offering financial incentives or the guarantee for uninterruptible services to participants, circuit protection during impending blackout procedures would be considered in exchange for the customer's voluntary commitment to reduce electricity use for 2-4 hours when called upon by PWP. In addition, PWP would take steps to acknowledge customers for their leadership in volunteering to participate in the VLCP to mitigate rolling blackouts in the community. The VLCP would extend weekdays from July 1, 2016 through October 31, 2016 during the peak demand period of noon to 7 p.m. The PWP VLCP has 2.7 MWs of load reduction available to assist in generation and transmission constraints.

It should be noted that no events were called during the summer of 2016. As a result, though PWP tested and verified load shedding capabilities at each site during the initiation of the program, the amount of consistent load reductions to support resource adequacy for future events is not confirmed.

2. Future DR Programs

California Code, PUC Section 9615 states that "[e]ach local publicly owned electric utility, in procuring energy to serve the load of its retail end-use customers, shall first acquire all available energy efficiency and demand response resources that are cost effective, reliable and feasible."[76]

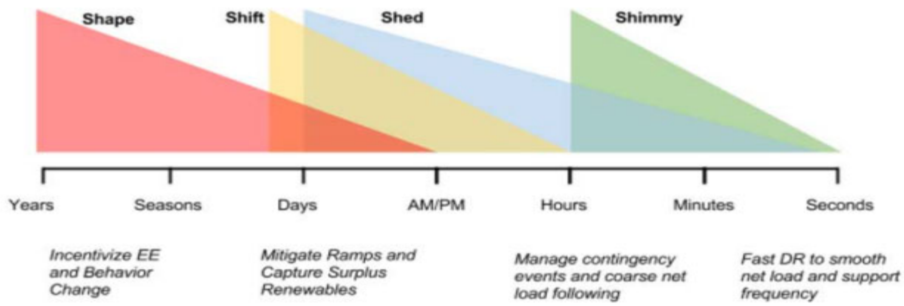
PWP currently does not have any DR resources that fit the criteria of Section 9615 aside from the efforts conducted in the VLCP. Reliable DR typically involves automated communications, tariffs and the creation of DR programs and settlement models and methods. At this time, the deployment of such a system for traditional DR in Pasadena is not technically feasible due to the lack of infrastructure.

As noted in the *2025 California Demand Response* study,[77] the value of DR is shifting from traditional DR (load reductions from HVAC, lighting and production) to four service types shown in Exhibit 90.

[76] AB 2021 Public Utilities: energy efficiency Sec.3. http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB2021.

[77] LBNL (2017, March 1) *2025 California Demand Response Potential Study,* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452698.

Exhibit 90: DR Service Types



Source: NREL

Some of these service types apply to PWP's service territory, but some fall within the purview of the CAISO, to be implemented by individual CAISO members (e.g., to help manage ramps with DR) and by the CAISO itself (e.g., frequency support).

It is PWP's intention to examine DR options in the Power Delivery Master Plan. To further extract value and reliability benefits from DR systems, future analysis is expected to consider a DR program that can leverage traditional DR, along with shape, shift and shimmy. Following the Power Delivery Master Plan, Pasadena plans to review DR options in the next IRP to examine if the technology and value of DR integration can reliably and economically offset the procurement of energy and manage reliability cost-effectively.

IV. Public Participation

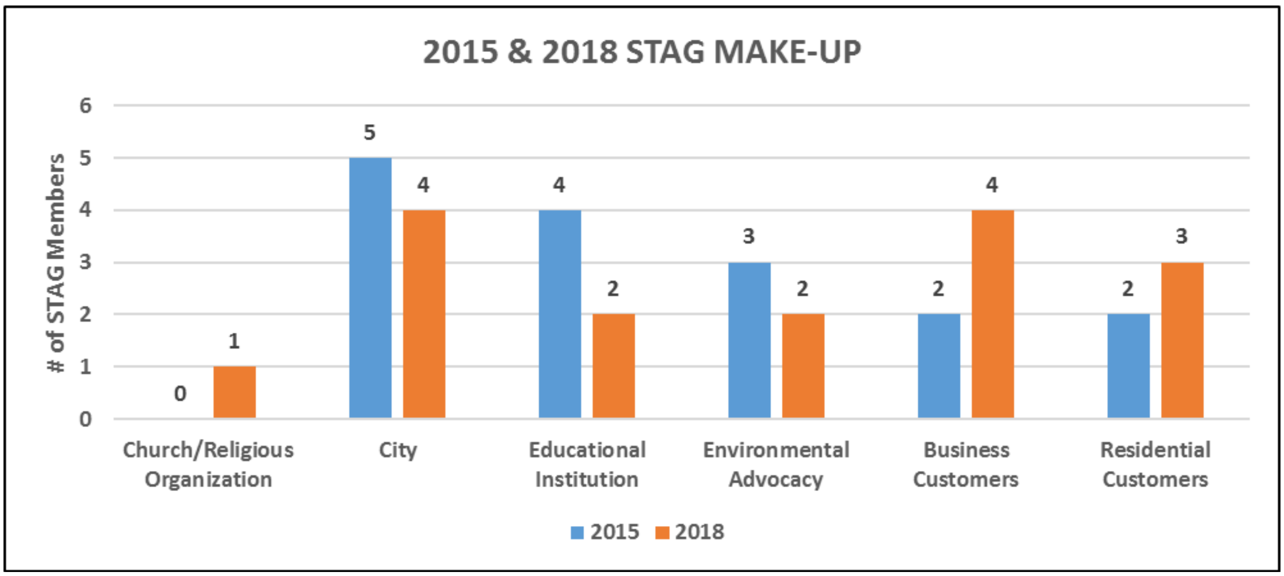
PWP develops each IRP with input from the public. Public participation is of optimal importance to PWP. Many of PWPs public outreach efforts are archived on the PWP website. PWP posts meeting notices, presentations and reports on this website.

A. Stakeholder Technical Advisory Group

1. Selection and Composition

In March 2018, the STAG was selected by the City of Pasadena, City Manager in close coordination with PWP Staff. The STAG represents a diverse group of ratepayers and city representatives, such as residential, small business, environmental advocated and educational institutions. Exhibit 91 shows the make-up of the 2015 STAG and the 2018 STAG. In order to limit paper printouts, PWP developed a ShareFile site to share all IRP documents, including agendas, reports, presentations, workbooks, assumptions, etc.

Exhibit 91: PWP's Stakeholder Advisory Group



Source: Pasadena Water and Power

2. STAG Mission and Vision

At the first STAG meeting on April 11, 2018, the STAG purpose, mission and vision was discussed. The STAG purpose is to represent the Pasadena and provide input on the IRP. The STAG mission is to assist in the development of the IRP, consistent with the mission of PWP and to serve in an advisory capacity. The STAG vision is to be a valued contributor to the development of the IRP and contribute to the quality of life in Pasadena.

3. Meeting Schedules

The STAG met a total of six times, from April to October 2018. Exhibit 92 is a list of meetings and topics.

Exhibit 92: Meeting Schedules

Meeting Type	Date	Topics
STAG Meeting #1	4/11/18	Discussion of IRP, Energy Market and Roles and Responsibilities of STAG, Staff and Consultant
STAG Meeting #2	5/31/18	Discussion of the modeling approach and data assumption
STAG Meeting #3	6/21/18	Discussion of the preliminary Base Case
STAG Meeting #4	9/13/18	Discussion of all Scenarios
STAG Meeting #5	9/20/18	Discussion of Scorecard and Results
STAG Meeting #6	10/8/18	Discussion Final IRP Recommendations and Next Steps

Source: Pasadena Water and Power

B. Public Participation

1. Community Meetings

PWP hosted three Community Meetings to discuss the IRP with the Community at large. Exhibit 93 is a list of the Community Meetings and topics discussed.

Exhibit 93: Community Meetings

Meeting Type	Date	Topic	Estimated Attendance
Community Meeting #1	7/18/18	Overview of the IRP process	70
Community Meeting #2	8/23/18	Discussion of IRP scenarios	100
Community Meeting #3	10/30/18	Discussion of final IRP recommendation	25

Source: Pasadena Water and Power

2. 2018 IRP Survey

PWP Resource Planning Staff worked closely with the Customer Relations Staff to develop an IRP survey. This non-scientific survey was posted online on May 31, 2018 and removed on August 30, 2018. During this time period, PWP received 296 responses.

Based on the survey, responders were only willing to pay additional 5-10% in their total electric bill, of which the IRP portion (i.e., the energy charge) is about half, which implies a willingness-to-pay of about 2.5-5% for the resources considered in this IRP. Responders ranked electric reliability and affordable electric rates as top priorities, with minimization of adverse environmental impacts very close behind. Over 36% of responders think that PWP should keep its RPS target to at least 50% by 2030; about 32% think it should increase to 75%; about 15% think it should increase to 60% and about 17% provided other responses (ranging from 0% RPS to 100% RPS). In terms of overall satisfaction with PWP, where 1 meant "very dissatisfied" and 5 meant "very satisfied," 75% ranked PWP at a 4 or higher.

Detailed responses to the survey are provided in Attachment 6.

C. Governing Bodies

The IRP must be approved by PWP's governing board, which is the City Council of the City of Pasadena. Exhibit 94 is the schedule of Commissions and Committees that must also review the IRP, the role of each agency and its schedule for review.

Exhibit 94: Schedule and Roles of Commissions and Committees Review

Who	Role	Date	Link to Agendas
Environmental Advisory Commission (EAC)	Advise the City Council and make policy recommendations to support the goals and objectives of the City's Environmental Charter and guide the Green City Action Plan. Representatives are community members.	11/13/18	https://ww5.cityofpasadena.net/commissions/environmental-advisory-commission/
Municipal Services Committee (MSC)	Review electric, water and sanitation services of the City. Representatives are City Council members.	11/27/18	https://ww5.cityofpasadena.net/commissions/city-council-municipal-services-committee/
City Council	The Council's goals are to maintain fiscal responsibility and stability; improve, maintain and enhance public facilities and infrastructure; increase conservation and sustainability; improve mobility and accessibility throughout the city; support and promote the quality of life and local economy; and ensure public safety.	12/3/18	http://ww2.cityofpasadena.net/councilagendas/council_agenda.asp

Source: Pasadena Water and Power

V. Regulatory Compliance

A. SB 350

SB 350, which was signed into law on October 7, 2015, requires that load serving entities with load greater than 700 GWh, such as PWP, develop an IRP by January 1, 2019, and requires updates to the IRP every five years. The SB 350 requirements are in addition to any internal Power IRP recommendations. SB 350 adds Section 454.52 and Section 9621 to the Public Utilities Code and mandates a RPS of 50% by 2030, GHG emissions reductions (of at least 40% by 2030) and recommends methods to analyze energy efficiency and demand response, energy storage options, transportation electrification, diversifying portfolio options, ensuring resource adequacy, system and local reliability options, while minimizing local air pollutants and other GHG emission with a priority on disadvantaged communities. In addition, it is recommended to discuss impacts on the transmission and distribution system and methods to enhance distributions and demand side management, all while serving customers with just and reasonable rates.[78]

B. CEC POU IRP Guidance

On September 5, 2017, the California Energy Commission approved the Publicly Owned Utility Power IRP Submission and Review Guidelines (Power IRP Guidelines). In addition, the CEC incorporated additional requirements into the Power IRP Guidelines and on October 4, 2018, implemented more requirements. This IRP meets the requirements of the October 4, 2018 Power IRP Guidelines.

C. SB 100

The initial scope of the 2018 IRP was to comply with the SB 350 requirements. However, on September 10, 2018, SB 100 was signed into law. SB 100 accelerates the RPS requirements to 60% by 2030 and develops a planning target of 100% zero carbon emitting resources by 2045. As a result of SB 100, the PWP 2018 IRP also includes compliance with SB 100, specifically for the new RPS requirement.

[78] http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

D. CARB Requirements

In July 2018, the California Air Resources Board issued direction on the GHG emissions targets for utilities, including Publicly Owned Utilities such as PWP. Though the California overall emissions reduction target is 40% reduction of 1990 levels by 2030, CARB took that further and recommended that the utility sector provide more of those reductions. Through various workshops and stakeholder meetings, PWP GHG reduction target was set at a minimum of 75% reduction from 1990 levels, as seen in Exhibit 95:

Exhibit 95: CARB Targets for PWP's GHG Reductions

Emissions Range	Range MT CO2e	% Reduction from 1990
Low End	128,000	86%
High End	226,000	75%
1990 Emissions	918,622	

Source: CARB

All the IRP scenarios met or exceeded these minimum GHG reduction targets.

VI. Process for Updating the IRP

PWP will update its IRP at least every five years. The current plan is to develop an update to the 2018 IRP in two to three years, with completion in 2022, or to develop a new IRP within five years, with completion in January 2024. PWP does not currently have the staff capability to run production cost models as were relied on in this IRP. Though acquisition of a production cost model license and training is budgeted, it is not guaranteed. PWP assumes that future IRPs will be developed through the assistance of consultants and with a continued emphasis on community input. Below are estimated schedules for developing an update to this IRP in 2022 and a new IRP in 2024.

A. Estimated Schedule for Adopting an IRP

Exhibit 96: Estimated Schedule for Adopting an IRP

IRP Option	Develop RFP	Hire Vendor	Develop Inputs and Assumptions	Stakeholder Process	Modeling and Analysis	Complete
Update 2022	December 2020	By April 2021	April - June 2021	To be determined (April – October 2021)	To be determined (June - October 2021)	January 2022
New 2024	March 2022	By October 2022	January 2023	To be determined (October 2023)	To be determined (March – October 2023)	January 2024

VII. Attachments

Attachment 1: Consultant and PWP Team Roles for IRP Analysis

Attachment 2: Pasadena Water & Power, "AB 2514 Energy Storage Systems Evaluation"

Attachment 3: Adopted RPS Procurement Plan

Attachment 4: Updated RPS Procurement Plan

Attachment 5: Updated RPS Enforcement Program

Attachment 6: 2018 IRP Survey Results

Attachment 7: Climate Action Plan Agenda Report

VIII. Electronic Materials

Compliance Tables workbook “PWP – Compliance Tables”

Assumptions and Inputs workbook “PWP – Assumptions and Inputs”

2018 PWP POWER IRP: ATTACHMENT 1
CONSULTANT AND PWP TEAM ROLES FOR IRP ANALYSIS

2018 PWP POWER IRP: ATTACHMENT 1
CONSULTANT AND PWP TEAM ROLES FOR IRP ANALYSIS

Details on the role of the Consultant and PWP Team are provided below.

- Prime contractor: Northwest Economic Research LLC (NWER), for overall oversight, management of client relationship, quality control, local knowledge and expertise, California regulatory compliance.

- Subcontractor to NWER: Pace Global, a unit of Siemens Inc., for complex analytical tasks involving production cost modeling using AURORA.

- Subcontractors to Pace Global: ASWB Engineering (ASWB) and Applied Energy Group (AEG) for energy efficiency analyses.

- PWP Project Team (Power Resource Planning Staff): data for production cost modeling and energy efficiency analysis, dynamic RPS compliance strategy and calculations, retail rate impacts, post-AURORA analyses of RPS compliance, management of the stakeholder process and community outreach efforts.

The following page provides more details on the role of the Consultant and PWP Team, for the IRP analysis and modeling efforts.

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
1	Base Case "BC"	1. All data in 2017$ 2. Minimum cost model run (procure what the utility needs, at least cost) 3. SB 350 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 50% by 2030+) 3. Tie Constraint of 280 MW	1. 10% limit on CAISO Sales	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%) 2. Add in Reliability needs (needs are purchased at $5/kW-month) 3. Debt Service for Magnolia and IPP 4. Renewable Integration Charge for Renewable outside CA (at $10 per MW per hour) 5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load)

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
2	Social Cost of Carbon "SCC"	1. Base Case Constraints 2. Dispatch Penalty on incremental IPP, Magnolia and Glenarm, priced at the higher of Siemens Carbon price forecast or CPUC forecast (in 2017$) 3. Higher carbon price forecast	1. 10% limit on CAISO Sales	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%) 2. Add in Reliability needs (needs are purchased at $5/kW-month) 3. Debt Service for Magnolia and IPP 4. Renewable Integration Charge for Renewable outside CA (at $10 per MW per hour) 5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load)

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
3	"BC" + SB 100	1. Base Case Constraints 2. SB 100 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 60% by 2030+, and updated interim targets post 2020)	1. 10% limit on CAISO Sales	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%) 2. Add in Reliability needs (needs are purchased at $5/kW-month) 3. Debt Service for Magnolia and IPP 4. Renewable Integration Charge for Renewable outside CA (at $10 per MW per hour) 5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load)

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
4	"SCC" + SB 100	1. SCC Constraints2. All data in 2017$3. Minimum cost model run (procure what the utility needs, at least cost)4. SB 100 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 60% by 2030+, and updated interim targets post 2020)5. Dispatch Penalty on incremental IPP, Magnolia and Glenarm, priced at the higher of Siemens Carbon price forecast or CPUC forecast (in 2017$)	1. 10% limit on CAISO Sales	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%)2. Add in Reliability needs (needs are purchased at $5/kW-month)3. Debt Service for Magnolia and IPP4. Renewable Integration Charge for Renewable outside CA (at $10 per MW per hour)5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load)

#	Scenario	Constraints in Model-Consultant	Constraints Outside Model-Consultant	Constraints Outside Model- PWP Staff
5	"SCC" + SB 100+Leave IPP Energy in Utah	1. SCC Constraints 2. All data in 2017$ 3. Minimum cost model run (procure what the utility needs, at least cost) 4. SB 100 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 60% by 2030+, and updated interim targets post 2020) 5. Dispatch Penalty on incremental IPP, Magnolia and Glenarm, priced at the higher of Siemens Carbon price forecast or CPUC forecast (in 2017$)	1. 10% limit on CAISO Sales	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%) 2. Add in Reliability needs (needs are purchased at $5/kW-month) 3. Debt Service for Magnolia and IPP 4. Renewable Integration Charge for Renewable outside CA (at $10/MW) 5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load) 6. Reduce IPP emissions to 0 7. Provide a 50% carbon credit (at the Aurora model base case carbon price, adjusted for 2019$) for IPP emissions 8. Sell IPP out of Utah and Replace IPP with a RPS geothermal baseload at $75/MWh (about 55 MW), for the same amount of MWh Annually. We are still liable for IPP costs and also new costs for additional Renewable resources. This is for the coal portion of IPP not the gas unit in 2025-2027.

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
6	Diversification (SCC+SB100)	1. SCC Constraints2. All data in 2017$3. Minimum cost model run (procure what the utility needs, at least cost)4. SB 100 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 60% by 2030+, and updated interim targets post 2020)5. Dispatch Penalty on incremental IPP, Magnolia and Glenarm, priced at the higher of Siemens Carbon price forecast or CPUC forecast (in 2017$)6. Force in Renewable Resources that vary in term, resource type and location (note, PWP provided guidance on these resources)	1. 10% limit on CAISO Sales2. 30% limit on CAISO Purchases	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%)2. Add in Reliability needs (needs are purchased at $5/kW-month)3. Debt Service for Magnolia and IPP4. Renewable Integration Charge for Renewable outside CA (at $10 per MW per hour)5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load)

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
7	Diversification +Biogas	1. SCC Constraints 2. All data in 2017$ 3. Minimum cost model run (procure what the utility needs, at least cost) 4. SB 100 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 60% by 2030+, and updated interim targets post 2020) 5. Dispatch Penalty on incremental IPP, Magnolia and Glenarm, priced at the higher of Siemens Carbon price forecast or CPUC forecast (in 2017$) 6. Force in Renewable Resources that vary in term, resource type and location (note, PWP provided guidance on these resources)	1. 10% limit on CAISO Sales 2. 30% limit on CAISO Purchases	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%) 2. Add in Reliability needs (needs are purchased at $5/kW-month) 3. Debt Service for Magnolia and IPP 4. Renewable Integration Charge for Renewable outside CA (at $10/MW) 5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load). RPS includes Magnolia and Glenarm biogas. 6. Reduce Magnolia and Glenarm emissions, when there is biogas 7. Force in biogas 25% biogas 2030-2034, 50% 2035-2037 and 100% (leading to 0 emissions) 2038-2039 units (at 1.5$term-3.5$ term in 2030).

#	Scenario	Constraints in Model- Consultant	Constraints Outside Model- Consultant	Constraints Outside Model- PWP Staff
8	Diversification +Biogas+Leave IPP Energy in Utah	1. SCC Constraints 2. All data in 2017$ 3. Minimum cost model run (procure what the utility needs, at least cost) 4. SB 100 RPS Requirements (leading to over procurement, due to limitations on resource size and using the system load as the denominator. RPS of 60% by 2030+, and updated interim targets post 2020) 5. Dispatch Penalty on incremental IPP, Magnolia and Glenarm, priced at the higher of Siemens Carbon price forecast or CPUC forecast (in 2017$) 6. Force in Renewable Resources that vary in term, resource type and location (note, PWP provided guidance on these resources)	1. 10% limit on CAISO Sales 2. 30% limit on CAISO Purchases	1. Adjust all data to 2019$ (model outcome in $2017 at 1.03%) 2. Add in Reliability needs (needs are purchased at $5/kW-month) 3. Debt Service for Magnolia and IPP 4. Renewable Integration Charge for Renewable outside CA (at $10 per MW per hour) 5. RPS Compliance Optimization (to match how PWP currently conducts business, we procure the minimum RPS required, annually, and either bank or sell excess. PWP also adjusts based on retail sales, not system load). RPS includes Magnolia and Glenarm biogas. 6. Reduce Magnolia and Glenarm emissions, when there is biogas 7. Force in biogas 25% biogas 2030-2034, 50% 2035-2037 and 100% (leading to 0 emissions) 2038-2039 8. Reduce IPP emissions to 0 9. Provide a 50% carbon credit (at the Aurora model base case carbon price, adjusted for 2019$) for IPP emissions 10. Sell IPP out of Utah and Replace IPP with a RPS geothermal baseload at $75/MWh (about 55 MW), for the same amount of MWh Annually. We are still liable for IPP costs and also new costs for additional Renewable resources. This is for the coal portion of IPP not the gas unit in 2025-2027.

2018 PWP POWER IRP: ATTACHMENT 2
PWP AB 2514 ENERGY STORAGE SYSTEMS EVALUATION

Agenda Report

September 18, 2017

TO: Honorable Mayor and City Council

THROUGH: Municipal Services Committee (September 12, 2017)

FROM: Water and Power Department

SUBJECT: **AB2514 ENERGY STORAGE SYSTEM PROCUREMENT TARGETS AND POLICIES**

RECOMMENDATION:

It is recommended that the City Council:

1. Find that the proposed action is not a project subject to the California Environmental Quality Act ("CEQA") as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines and, as such, no environmental document pursuant to CEQA is required for the project; and
2. Find that it is not appropriate at this time to establish procurement targets for energy storage systems to be procured by Pasadena Water and Power ("PWP") due to a lack of cost-effective, fully vetted, viable and feasible options.

MUNICIPAL SERVICES COMMITTEE RECOMMENDATION:

The Municipal Services Committee recommended that the City Council approve these recommendations at its September 12, 2017 meeting.

EXECUTIVE SUMMARY:

Assembly Bill 2514 (2010, Skinner) ("AB 2514") requires that publicly-owned utilities commence a process to determine appropriate targets, if any, for the procurement of viable and cost-effective energy storage by October 1, 2017, for energy storage systems to be procured by December 31, 2021. The City Council must reevaluate the policies and procurement targets, if any, at least once every three years. The City Council last approved AB 2514 Energy Storage System Procurement Targets and Policies established on October 6, 2014 (herein after referred to as the "2014 Report").

To date, PWP has not identified energy storage technologies that are cost-effective, fully vetted and tested. In addition, the environmental implications of some energy storage technologies (namely batteries) are unknown; therefore, it is recommended that the City Council not establish specific procurement targets for energy storage at this time. In other words, the recommendation is to set a 0 MW procurement target for energy storage, by December 31, 2021. However, due to the progress in energy storage technologies, PWP will reanalyze the potential for energy storage as part of the 2018 integrated resource plan ("IRP").

PWP will report energy storage system procurement targets and policies adopted by the City Council and PWP's compliance with such targets to the California Energy Commission ("CEC") as required by AB 2514. Any reports made by PWP to the CEC pursuant to AB 2514 will be made available to the public by the CEC and/or PWP on their respective websites.

BACKGROUND:

The term "energy storage system "is defined by AB 2514 as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy."

Evaluation Process

Since initiating the investigation into energy storage systems, PWP has reviewed research and documentation prepared by third parties, utilities and others and has been involved with the Southern California Public Power Authority ("SCPPA") in several efforts, including the SCPPA Energy Storage Working Group.

AB 2514 does not define "cost-effective". For purposes of this analysis, PWP used the following minimum criteria:

1. The product or service must fill an existing or anticipated unmet need;
2. Must have a benefit-to-cost ratio appropriately ≥ 1; and
3. The benefits must accrue proportionately to the parties that pay the costs.[1]

Lastly, PWP staff reviewed other relevant criteria, to accurately address the impact and practicality of energy storage referenced below:

1. Must be a proven, tested technology, and
2. Must be more cost effective than alternative resources.

Attachment 1, "PWP AB 2514 Energy Storage Systems Evaluation Report (2017)," provides a detailed analysis on the evaluation of energy storage systems.

Need for Energy Storage

PWP has no need for energy storage systems at this time. Benefits similar to energy storage (such as, ancillary services, regulation services, congestion relief, etc.) are available from existing generation (e.g., the Glenarm/Broadway power plants), as well

[1] For example, if it is determined that an energy storage system installed in Pasadena could provide hundreds of millions of dollars of net benefits to the CAISO system (of which PWP load is only about 1%), but there is no way for PWP customers to recover the remaining cost of the energy storage system from the other 99% of CAISO customers if PWP were to install it, then by this definition, it would not be cost effective for PWP, even if the benefit-to-cost ratio were >1 for the CAISO

as the California Independent System Operator ("CAISO") market, at a significantly lower cost. Some services provided by energy storage can also be achieved through conservation, demand-side management and rate design.

Cost Effectiveness

Similar to the experience in 2014, the SCPPA Energy Storage Working Group chose to license the Navigant SCPPA Energy Storage Tool ("ES Tool"). This is the same tool used for the 2014 Report, but with updated default values based on more recent data.

PWP considered the various technologies and functions that energy storage can provide, and narrowed the list to those options believed to have the highest potential viability and best fit for PWP by 2021. A detailed list of the modeled technologies is available in Attachment 1.

Results of ES Tool

As a result of the updated ES Tool, none of the energy storage technologies evaluated are considered cost effective at this time. Similar to the 2014 Report, the storage facility would need to be located within the city's limits in order to provide the highest value of services necessary to be cost effective. However, there may be future cost-effective opportunities to secure such resources outside of the city to help integrate PWP's portfolio of renewable resources. A more detailed analysis on opportunities inside and outside the City will be studied as part of the 2018 IRP.

Additionally, some of these energy storage technologies have not been fully tested and proven. For reference, please see Attachment 2: List of Comparable Energy Storage Projects in California. Attachment 2 provides additional details on the types of energy storage programs analyzed by PWP and its applicability in California. Attachment 2 relies on the DOE Global Energy Storage Database for analysis. Until there are additional applications and analysis on energy storage in California, the case for procurement of energy storage, based on economics alone, will not be strong.

COUNCIL POLICY CONSIDERATION:

The proposed action will help PWP achieve regulatory compliance and is consistent with the City Council's goal to maintain fiscal responsibility and stability by seeking cost-effective means to meet the City's conservation and sustainability goals and to provide a high level of public service.

ENVIRONMENTAL ANALYSIS:

The recommendation to set 0 MW of energy storage system procurement target is an administrative action that would not cause either a direct physical change in the environment or a reasonably foreseeable indirect physical change in the environment. The proposed action is for the City to comply with AB 2514. No physical construction is contemplated or would be authorized by the actions proposed in this staff report.

Therefore, the proposed action is not a "project" subject to CEQA, as defined in Section 21065 of CEQA and Section 15378 of the State CEQA Guidelines. Since the action is not a project subject to CEQA, no environmental document is required.

FISCAL IMPACT:

There is no fiscal impact as a result of this action, and it will not have any indirect or support cost requirements. The anticipated impact to other operational programs or capital projects as a result of this action will be none.

Respectfully submitted,

GURCHARAN S. BAWA
General Manager
Water and Power Department

Prepared by:

Mandip K. Samra
Power Resource Planning Manager
Water and Power Department

Approved by:

STEVE MERMELL
City Manager

Attachments (2):

Attachment 1- PWP AB 2514 Energy Storage Systems Evaluation Report (2017)
Attachment 2- List of Comparable Energy Storage Projects in California

AB 2514 Energy Storage Systems Evaluation

September 12, 2017

PASADENA
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Water&Power

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EXECUTIVE SUMMARY

This report is to re-evaluate and update Pasadena Water and Power's ("PWP") October 1, 2014 analysis ("2014 Report") on energy storage systems. This is required by California Assembly Bill 2514 ("AB2514").

AB2514 requires that California Publicly Owned Utilities ("POU"), by October 1, 2014 and October 1, 2017, evaluate the potential to procure viable and cost-effect energy storage systems and that their governing bodies (the Pasadena City Council, in the case of PWP) set appropriate procurement targets for energy storage systems to be procured by December 31, 2016 and December 31, 2021. The law further directs POUs to follow up with triennial re-evaluations of energy storage options.

For the 2014 Report, Staff at PWP with the concurrence of the City Council found that at that time the available energy storage technologies were still not cost effective nor did any fulfill an existing or anticipated unmet need as needed for PWP to comfortably plan for implementation by 2016 or 2021. The findings for 2017 are the same. Staff recommends a 0 MW procurement target for energy storage.

It is important to note that since PWP's initial report in 2014, changes and improvements in the various technologies for energy storage occurred. As well, changes in the makeup of electricity resources due to ratcheting RPS targets, new Greenhouse Gas ("GHG") targets, increasing energy efficiency, and declining electricity usage have occurred. Some southern California POUs, such as Glendale, LADWP and IID have moved forward with either installations or planned installations of pilot programs for energy storage systems. The pilot programs are to explore the possibility of incorporating energy storage within their systems, in the long run. It is important to note that both LADWP and IID are part of their own balancing authority ("BA") and energy storage systems can have more of an impact when POUs control their own BA. Additionally, Glendale is part of LADWP's BA. Since PWP is part of the California Independent System Operator ("CAISO") BA, it is less dependent on energy storage systems to shape load or assist in renewable integration. Further research on energy storage and an in depth analysis will be considered as part of the 2018 integrated resource plan (IRP).

The focus of this report ("2017 Report") is to provide the results of Staff's analysis of various energy storage technologies, as they have evolved since 2014.

ASSEMBLY BILL 2514

DEFINITION OF ENERGY STORAGE SYSTEM (REVIEW)

According to AB 2514, the term "energy storage system" means commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy.

An "energy storage system" may be either centralized or distributed. It may be either owned by a load-serving entity or local publicly owned electric utility, a customer of a load-serving entity or local publicly owned electric utility, a third party, or jointly owned by two or more of the above.

An "energy storage system" must be *cost effective* and:

- Reduce emissions of greenhouse gases,
- Reduce demand for peak electrical generation,
- Defer or substitute for an investment in generation, transmission, or distribution assets, or
- Improve the reliable operation of the electrical transmission or distribution grid.

An "energy storage system" must do one or more of the following:

- Use mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time.
- Store thermal energy for direct use for heating or cooling at a later time in a manner that avoids the need to use electricity at that later time.
- Use mechanical, chemical, or thermal processes to store energy generated from renewable resources for use at a later time.
- Use mechanical, chemical, or thermal processes to store energy generated from mechanical processes that would otherwise be wasted for delivery at a later time.

ENERGY STORAGE TECHNOLOGIES- WHAT'S NEW

The 2014 Report[1] to the Commission included comprehensive descriptions of the various energy storage technologies available or projected to be available soon. The technologies studied as part of the 2014 Report and 2017 Report are:

- Compressed Air Energy Storage ("CAES") Above Ground
- CAES Below Ground
- Pumped Hydro Storage
- Flywheels
- Advanced Lead-Acid Batteries
- Lithium-Ion Batteries
- Flow Batteries

Table 1 below, summarizes the information for these technologies.

1 http://www.energy.ca.gov/assessments/ab2514_reports/City_of_Pasadena/AB2514_energy_storage_systems_evaluation.pdf

Table 1
Summary of Technologies

Technology	Primary Application	Current Benefits	Current Challenges
Compressed Air Energy Storage (CAES)	• Energy management • Backup and seasonal reserves • Renewable integration	• Better ramp rates than gas turbine plants • Established technology in operation since the 1970's	• Geographically limited • Lower efficiency due to roundtrip conversion • Slower response time than flywheels or batteries • Environmental impact
Pumped Hydro	• Energy management • Backup and seasonal reserves • Regulation service also available through variable speed pumps	• Developed and mature technology • Very high ramp rate • Currently most cost effective form of storage	• Geographically limited • Plant site • Environmental impacts • High overall project cost • Large footprint
Fly wheels	• Load leveling • Frequency regulation • Peak shaving and off peak storage • Transient stability	• Modular technology • Proven growth potential to utility scale • Long cycle life • High peak power without overheating concerns • Rapid response • High round trip	• Rotor tensile strength limitations • Limited energy storage time due to high frictional losses
Advanced Lead-Acid Batteries	• Load leveling and regulation • Grid stabilization	• Mature battery technology • High recycled content • Good battery life	• No utility scale deployments • Low energy density • Large footprint • Electrode corrosion limits the useful life
Sodium-Sulfur Batteries (NaS)	• Power quality • Congestion relief • Renewable source integration	• High energy density • Long discharge cycles • Fast response • Good scaling potential	• Operating Temperature between 250° and 300° required • Liquid containment concerns (corrosion and brittle glass seals)
Lithium-ion Batteries (Li-ion)	• Power quality • Frequency regulation	• High energy density • Good cycle life • High charge/discharge efficiency	• High production cost • Extremely sensitive to high temperatures, overcharge and internal pressure buildup • Environmental impacts unknown
Flow Batteries	• Ramping • Peak shaving • Time shifting • Frequency regulation • Power quality	• Ability to perform a high number of discharge cycles • Lower charge/discharge efficiencies • Long life	• No utility scale deployments • Complicated design • Low energy density
Superconducting Magnetic Energy Storage (SMES)	• Power quality • Frequency regulation	• Highest round-trip efficiency from discharge energy density	• Low energy density • High material and manufacturing costs
Electrochemical Capacitors	• Power quality • Frequency regulation	• Very long life • Highly reversible and fast discharge	• High cost
Thermochemical Energy Storage (TES)	• Power quality • Frequency regulation	• Extremely high energy densities	• High cost

Since the 2014 Report was submitted, additional storage technologies have emerged showing promise to bring cost effective energy storage to the market. However, the energy storage resources listed above are the few with enough data to run an analysis. Overall, for the 2017 Report, the same technologies were modeled, with updates to their installation, maintenance and disposal costs.

TYPICAL ENERGY STORAGE APPLICATIONS/USES

As explained in detail in the 2014 Report, energy storage can have several benefits to any utility (assuming cost effectiveness requirements can be met):

- Electric Energy Time-Shift
- Electric Supply Capacity
- Ancillary Services
- Distribution Infrastructure Services
- Customer Energy Management Services
- Stacked Services—Use Case Combinations

Energy storage can be used for any of the services listed above, but it is rare for a single service to generate sufficient revenue to justify its investment. How these services are stacked or combined depends on the location of the system within the grid and the storage technology used. However, due to regulatory and operating constraints, stacking services is a process that requires careful planning and should be considered on a case-by-case basis. Table 2, below provides analysis on the applications for energy storage systems

Table 2
Navigant Summary of Technologies/Applications

	Economic								Reliability				Environmental		
	Market Revenue			Asset Utilization					Efficiency	Cost	Interruptions		Air		Water
Applications	Arbitrage Revenue	Capacity Revenue	Ancillary Service Revenue	Optimized Generator Operation	Reduced Congestion Cost	Deferred Generation Capacity Investments	Deferred Transmission Capacity Investments	Deferred Distribution Capacity Investments	Reduced Electricity Losses	Reduced Electricity Cost	Reduced Outages	Improved Power Quality	Reduced CO_2 Emissions	Reduced SO_x, Nox, and Particulate Emissions	Reduced Water Use
Electricity Cost Optimization															
Energy Arbitrage	X			X	X	X	X	X	X	X			X	X	X
Demand and PF Charge Management				X	X	X	X	X	X	X			X	X	X
Renewable Energy Shifting	X			X	X	X	X	X	X	X			X	X	X
Capacity															
Generation Resource Adequacy		X	X	X		X							X	X	X
T&D Infrastructure Adequacy				X	X	X	X	X	X	X			X	X	
Routine Grid Operations															
Frequency Regulation			X	X		X							X	X	X
Voltage/VAR Support												X			
Renewable Energy Ramping				X		X							X	X	X
Renewable Energy Smoothing				X									X	X	X
Contingency Situations															
Black Start			X			X									
Sustained Outages											X				
Momentary Outages												X			

PWP ANALYSIS

SCPPA ENERGY STORAGE WORKING GROUP

PWP continues to participate in the Southern California Public Power Authority ("SCPPA") Energy Storage Working Group. As well, PWP, through SCPPA's Request for Information ("RFI") process, continues to seek energy storage proposals, as stand-alone projects or part of intermittent renewable energy resource procurements. To date, such joint renewable/storage systems have pushed the cost of those projects' power to unjustifiably high levels and therefore result in PWP rejecting such projects.

CAISO AND ENERGY STORAGE

The CAISO continues to partner with parties to identify the best uses and implications for energy storage technologies. The CAISO's Stakeholder Process[2] includes analysis on energy storage and its implications to the CAISO grid. The Stakeholder Process started in 2012, with new updates as of June 2017. PWP will continue to monitor the CAISO activities to better understand the energy storage applications in the CAISO market, with particular attention to energy storage for reliability and renewable integration purposes.

ENERGY STORAGE MODELING TOOL

Through the SCPPA Energy Storage Working Group, PWP has chosen to use the Navigant SCPPA Energy Storage Tool, V.2.1b ("ES Tool"). Version 2.1b of the ES Tool provides a framework for evaluating potential energy storage costs and benefits depending on system characteristics (e.g., location on the grid, regulatory structure, and owner). The ES Tool is based on Microsoft Excel and takes advantage of Navigant's market price database, expertise in energy markets, and the latest in energy and storage costs.

Similar to 2014, the user enters the project location, owner, regulatory environment and technology type. Next, the user enters information such as installed cost, operation and maintenance costs, round trip efficiency, and cycle life. Default values are available for many of these inputs, depending on the selected technology. However, PWP replaces as many of these default values with values collected from PWP operations. After selecting which applications to analyze, the user is prompted to enter inputs to help calculate benefits, such as amount of energy storage dispatched by application, market prices and rate structures. It should be noted that "application" refers to the market application, such as load shifting, Ancillary Services, etc., and not to the technology types. Finally, the user has the option of selecting to run various scenarios. After inputting all the necessary information, the tool presents the net present costs and benefits of the project.

2
https://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResourcesPhase2.aspx

PWP considered the various technologies and functions that energy storage can provide, and narrowed the list to those that PWP believed would have the highest potential viability and best fit for PWP by 2021. The ES Tool is capable of modeling fifteen (15) different energy storage technologies, seven of which were selected by PWP as commercially viable for Pasadena's needs. In order to "level the playing field" between the different technologies, staff standardized all of the energy storage technologies to a 20 MW capacity model, and all costs, outputs, and revenues were scaled accordingly. The 20 MW size was chosen because it seemed to be an applicable energy storage size given the mix of PWP's contracted renewable technologies (for renewable integration), this is the maximum size that can be developed given the limited number of available locations/vacant lots for energy storage within city limits, for economies of scale (the installation costs are lower as the size increases), to alleviate some of PWP's monthly flexible resource adequacy capacity requirements, to maximize market opportunities for ancillary services sales, and to maximize opportunities with the current price differentials between off-peak and on-peak power. It is possible for PWP to consider larger or smaller projects. If PWP considers a larger storage project, it would take an appropriate share, similar to how PWP handles renewable projects through SCPPA. However, as mentioned earlier, larger projects would require financing and relying on equal cost share with partners.

Table 3 lists the technologies and costs that were modeled by PWP using the ES Tool, including Compressed Air Energy Storage (above and below ground), Pumped Hydro Storage, Flywheel Energy Storage, Advanced Lead Acid Batteries, Lead Batteries and Lithium Ion Batteries.

Table 3
Investigated Technology List for Projects Scaled to 20MW (ES Tool)

Inputs	Lead Acid	Advanced Lead Acid	Lithium Ion	Flywheel	Pumped Hydro	CAES Above Ground	CAES Below Ground
Nameplate Power Output (MW)	20	20	20	20	20	20	20
Nameplate Energy Storage Capacity (MWh)	40	40	46 67	5	186 67	200	200
Response Time (s)	001	001	001	001	60	60	60
Nameplate round-trip efficiency	88%	90%	94%	85%	81%	90%	90%
Nameplate calendar life (yrs.)	20	20	20	20	20	20	20
Expected lifetime (yrs.)	20	20	20	20	20	20	20
Total installed cost ($)	$75,427,200	$42,240,000	$46,989,333	$26,535,600	$26,540,000	$42,053,333	$13,146,667
Average O&M Costs not related to energy ($/yr.)	$730,600	$545,530	$606,867	$245,700	$112,000	$300,000	$300,000
Expected Decommissioning costs	$34,000,000	$4,060,800	$35,096,920	$14,393,333	$2,004,167	$2,349,756	$2,306,784
Installed Cost per kw ($/kW)	**$3,771**	**$2,112**	**$2,349**	**$1,327**	**$1,327**	**$2,103**	**$657**

PWP compared some of the ES Tool findings to another SCPPA vendor, Det Norske Veritas and Germanischer Lloyd ("DNV GL"). DNV GL provides advisory services for various energy market analyses, including energy storage. Table 4 shows DNV GL Study and analysis concerning Energy Storage costs as commissioned by SCPPA. Clearly, the ranges for installed costs ($/kW) vary, depending on energy storage size and type. Pumped Hydro was not included in their analysis. Overall, in both cases, the $/kW is quite high, especially compared to existing PWP generation resources.

Table 4
Investigated Technology List for Projects (SCPPA- DNV GL Study)[3]

Technology [1]	Lithium-Ion NCM	Lithium-Ion LFP	Lithium-Ion LTO	Vanadium Redox Flow Battery ("VRB")	Flywheel	CAES	TES
Size (kW)	20,000	20,000	20,000	20,000	20,000	100,000	50
Duration (Hour)	2	2	2	4	25	24	6
Total Installed Costs($)	$33,800,000	$35,800,000	$45,300,000	$78,750,000	$48,150,000	$136,000,000	$129,500
Installed costs ($/kW)	**$1,690**	**$1,790**	**$2,265**	**$3,938**	**$2,408**	**$1.360**	**$2,590**

The ES Tool can evaluate up to sixteen (16) applications for each energy storage technology. Applications which serve a common purpose were bundled into one of four scenarios to maximize the potential savings and/or revenues from each technology option. The applications and scenarios are summarized in Table 5 below. Analysis was focused on Scenarios 1 through 4, which evaluate transmission and generation level energy storage systems.

Table 5
Energy Storage Applications and Scenarios (ES Tool)

SCENARIOS	APPLICATIONS
Scenario 1 **Electricity Cost Optimization**	1. Energy Arbitrage 2. Renewable Energy Shifting
Scenario 2 **Capacity**	3. Operating Reserve Ancillary Service 4. Wholesale Capacity Market
Scenario 3 **Routine Grid Operation**	5. T&D Infrastructure Adequacy 6. Frequency Regulation
Scenario 4	7. Voltage/VAR Support 8. Renewable Energy Ramping 9. Renewable Energy Smoothing 10. Black Start

[3] Det Norske Veritas and Germanischer Lloyd (DNV GL), ES Study for NCPA and SCPPA, May 2017.

The results of the ES Tool modeling are summarized in Table 6 below.

Table 6
Energy Storage Net Benefit for Projects Scaled to 20 MW

Scenario #	Scenario Name	Details	Lead Acid	Advanced Lead Acid	Lithium Ion	Flywheel	Pumped Hydro	CAES Above Ground	CAES Below Ground
1	Energy Cost Optimization	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	-$ 304	-$ 128	-$ 1627	-$ 7505	-$ 0169	$ 0225	$ 0104
2	Capacity	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	$0 317	-$0 147	-$0 188	-$0 786	-$0 015	-$0 026	-$0.0071
3	Routine Grid Operation	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	$0 250	-$0 080	-$0.130	-$0 7256	-$0 0135	-$0.013	-$0 0056
4	Contingency Situations	Payback (yrs)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
		Net Benefit($/KWh)	$0 331	-$0 1606	-$0.1995	-$0.8947	-$0.0180	-$0 0290	-$0 0099

Adjusting for the appropriate uses for energy storage, as applied to PWP, no technology had a positive benefit-to-cost ratio. Generally, to be cost effective, the energy storage project must have a benefit-to-cost ratio ≥ 1, indicating that the net present value ("NPV") of the project benefit outweighs the NPV costs. However, a few technologies were close. Pumped Hydro had the highest benefit-to-cost ratio at .78, meaning that the expected benefits of Pumped Hydro are $.78 for each $1 of its cost. Simply put, PWP would not recoup its investment in Pumped Hydro projects, at this time. In addition, according to the Department of Energy Global Energy Storage Database ("DOE Database")[4] the existing Pumped Hydro facilities in California are older and much larger than the scale needed for PWP. For details on these Pumped Hydro facilities, please refer to Table 7, below.

Lithium-ion Batteries had the second highest benefit-to-cost ratio at .75, meaning that the expected benefits of Lithium-ion Batteries are $.75 for each $1 of its cost and PWP would not recoup its investment. Lithium-ion Batteries are becoming popular, but there is not enough history to analyze the success of those installations at the scale needed for PWP. In fact, according to the DOE Database, there have only been four installations of Lithium-ion batteries above 10 MW. These were all installed in 2016 or 2017. For details on these Lithium-ion Battery installations, please see Table 8, below. Though they are not cost-effective, an extensive analysis of Lithium-ion Batteries and Pumped Storage will be modeled as part of the 2018 IRP.

[4] https://www.energystorageexchange.org/

Table 7
DOE Database (Pumped Hydro Installed)[5]

Facility Name	City	Utility	Utility Type	MW	Commissioning Date (or planned)
Edward Hyatt(Oroville) Power Plant	Oroville, CA	Pacific Gas & Electric (PG&E)	Investor Owned Utility (IOU)	819	1/1/67
San Luis Pumped Hydro Power Plant	Gustine, CA	NA	NA	424	1/1/68
Thermalito Pumping Generating Plant	Oroville, CA	PG&E	IOU	120	1/1/69
Castaic Pumped-Storage Plant	Pyramid Lake, CA	Los Angeles Department of Water and Power (LADWP)	Publicly Owned Utility (POU)	1,247	1/1/73
O-Neill Pumped-Generating Plant	Los Banos, CA	NA	NA	25 2	1/1/73
Helms Pumped Hydro Plant	Fresno County, CA	PG&E	IOU	1,212	6/30/84
Big Creek Pumped Storage	Shaver Lake, CA	Southern California Edison (SCE)	IOU	199 8	1/1/87
Olivehain-Hodges Storage Project	Escondido, CA	San Diego Gas & Electric (SDG7E)	IOU	40	9/14/12
Eagle Mountain Pumped Storage Project	Desert Center, CA	NA	NA	1,300	Contracted
Lake Elsinore Advanced Pumped Storage	Lake Elsinore, CA	NA	NA	500	TBD
San Vicente Pumped Storage	San Vicente, CA	NA	NA	500	TBD

Table 8
DOE Database (Lithium-Ion Batteries Installed>10MW)[6]

Facility Name	City	Utility	Utility Type	MW	Commissioning Date
SCE LM6000 Hybrid EGT – Center	Norwalk, CA	Southern California Edison (SCE)	Investor Owned Utility (IOU)	10	3/30/17
SCE LM6000 Hybrid EGT – Grapeland	Rancho Cucamong a	SCE	IOU	10	4/3/17
Escondido Energy Storage	Escondido, CA	San Diego Gas & Electric (SDG&E)	IOU	30	3/24/16
Imperial Irrigation District BESS - GE	El Centro, CA	Imperial Irrigation District (IID)	Publicly Owned Utility (POU)	30	10/1/16

[5] https://www.energystorageexchange.org/
[6] https://www.energystorageexchange.org/

Overall, based on work completed to date, PWP has not identified any viable energy storage technologies that are cost-effective at a scale that is practical for PWP at this time. The energy storage industry is still evolving, and cost-effectiveness expected to improve rapidly over the coming years. PWP will continue to monitor the situation and continue to provide updates as conditions warrant. Additionally, energy storage will be modeled as part of the 2018 IRP process.

RECOMMENDATIONS

PROCUREMENT TARGETS

PWP recommends that the City Council establish a 0 MW energy storage system procurement target to be achieved by December 31, 2021. Even though energy storage technologies have improved over the past three years, they still do not provide the level of cost-effectiveness and guaranteed viability desired by PWP.

ONGOING EVALUATION

As storage technologies continue to evolve and improve and as the State's power mix transitions to a greater percentage of renewable resources, the need and ability to implement energy storage to maximize the benefits of those renewable resources will grow. Towards that end, PWP staff will continue to look for appropriate opportunities for energy storage systems as it executes its 2018 IRP and procures future renewable and conventional energy. PWP staff will continue to work with the SCPPA to evaluate various energy storage technologies through solicitation of proposals for energy storage systems as standalone offers as well as in conjunction with renewable and conventional energy projects.

PWP will reevaluate the issue of energy storage system procurement targets and policies with the City Council at least once every three years.

CEC REPORTING

PWP will report to the California Energy Commission ("CEC") regarding energy storage system procurement targets and policies adopted by the City Council.

If the City Council adopts any energy storage system procurement targets or policies to encourage the cost effective deployment of energy storage systems, then by January 1, 2022, PWP will submit a report to the CEC demonstrating that it has complied with the energy storage system procurement targets, if any, and policies adopted by the City Council. This report, with confidential information redacted, will be made available to the public by being published by the CEC and/or PWP on their respective websites.

REFERENCES

- Department of Energy, *Global Energy Storage Database,* website, http://www.energystorageexchange.org/
- California Public Utilities Commission ("CPUC") Order Instituting Rulemaking ("OIR") 10-12-007 Pursuant to Assembly Bill 2514 to Consider Adoption of Procurement Targets for Viable and Cost-Effective Targets for Energy Storage Systems, Decision 13-10-040, issued October 17, 2013
- Greentech Media, *Storage Costs Come Down Across Technologies and Applications According to Lazard Report*, website, https://www.greentechmedia.com/articles/read/energy-storage-costs-lcos-lazard-lithium-ion-flow-batteries, December 19, 2016.
- Det Norske Veritas and Germanischer Lloyd (DNV GL), ES Study for NCPA and SCPPA, May 2017.

Attachment 2- List of Comparable Energy Storage Projects in California

Attachment 2: List of Comparable Energy Storage Projects in California [DOE Database]

#	Project Name	Technology Type	Rated Power in kW	Duration	Status	City	Commissioning Date	ISO/RTO	Utility	Utility Type
1	Eagle Mountain Pumped Storage Project	Closed-loop Pumped Hydro Storage	1,300,000	n/a	Contracted	Desert Center		CAISO		
2	Castaic Pumped-Storage Plant	Open-loop Pumped Hydro Storage	1,247,000	10 0	Operational	Pyramid Lake	1/1/1973	N/A	Los Angeles Department of Water and Power	Public Owned
3	Helms Pumped Hydro Storage Project	Open-loop Pumped Hydro Storage	1,212,000	n/a	Operational	Fresno County	6/30/1984	CAISO	Pacific Gas & Electric (PG&E)	Investor Owned
4	Edward Hyatt (Oroville) Power Plant	Open-loop Pumped Hydro Storage	819,000	n/a	Operational	Oroville	1/1/1967	CAISO	Pacific Gas & Electric (PG&E)	Investor Owned
5	*Lake Elsinore Advanced Pumped Storage*	*Closed-loop Pumped Hydro Storage*	*500,000*	*12.0*	*Announced*	*Lake Elsinore*		*CAISO*		
6	*San Vicente Pumped Storage*	*Closed-loop Pumped Hydro*	*500,000*	*8 0*	*Announced*	*San Vicente*		*CAISO*		
7	San Luis (William R Gianelli) Pumped Storage Hydroelectric	Open-loop Pumped Hydro Storage	424,000	298.0	Operational	Gustine	1/1/1968	CAISO		
8	*PG&E Advanced Underground Compressed Air Energy*	*Compressed Air Storage*	*300,000*	*10*	*Announced*	*San Joaquin Co*	*01.01.2020*	*CAISO*	*Pacific Gas & Electric (PG&E)*	*Investor Owned*
9	Big Creek (John S. Eastwood) Pumped Storage	Open-loop Pumped Hydro Storage	199,800	17.67	Operational	Shaver Lake	1/1/1987	CAISO	Southern California Edison	Investor Owned
10	Thermalito Pumping - Generating Plant	Open-loop Pumped Hydro Storage	120,000	n/a	Offline/Under Repair	Oroville	01.01.1969	CAISO	Pacific Gas & Electric (PG&E)	Investor Owned
11	Olivenhain-Hodges Storage Project	Open-loop Pumped Hydro Storage	40,000	6 0	Operational	Escondido	9/14/2012	CAISO	San Diego Gas & Electric (SDG&E)	Investor Owned
12	*Escondido Energy Storage*	*Lithium-ion Battery*	*30,000*	*4 0*	*Operational*	*Escondido*	*3/24/2016*	*CAISO*	*San Diego Gas & Electric (SDG&E)*	*Investor Owned*
13	Imperial Irrigation District BESS - GE	Lithium-ion Battery	30,000	0.67	Operational	El Centro	10/1/2016	IID	Imperial Irrigation District	Public Owned
14	Modesto Irrigation District - Primus Power	Flow Battery	28,000	4 0	Offline/Under Repair	Modesto		BANC	Modesto Irrigation District	Public Owned
15	O'Neill Pump-Generating Plant	Open-loop Pumped Hydro Storage	25,200	n/a	Operational	Los Banos	1/1/1973	CAISO		
16	*20 MW / 80 MWh - Energy Nuevo - Amber Kinetics*	*Flywheel*	*20,000*	*4.0*	*Contracted*	*Fresno*	*01.05 2020*	*CAISO*	*Pacific Gas & Electric (PG&E)*	*Investor Owned*

2018 PWP POWER IRP: ATTACHMENT 3
ADOPTED RPS PROCUREMENT PLAN

PASADENA WATER AND POWER

City of Pasadena
Department of Water and Power
Renewable Portfolio Standard (“RPS”)
Procurement Plan

Pursuant to the RPS Enforcement Program
Adopted by the City Council on January 29, 2018

January 29, 2018

Table of Contents

City of Pasadena
Department of Water and Power
Renewable Portfolio Standard Procurement Plan[1]

Pursuant to the RPS Enforcement Program Adopted by City Council on January 29, 2018

EXECUTIVE SUMMARY

On July 20, 2015, the City Council approved PWP's 2015 Integrated Resource Plan ("IRP") Update, and reaffirmed the voluntary City of Pasadena ("City") 40% RPS goal first established in 2009. On October 7, 2015, Senate Bill 350 ("SB 350") (De León, Clean Energy and Pollution Reduction Act of 2015) was signed into law. SB 350 increases the state-wide RPS to 50%[2] by 2030. The main changes in this revised RPS Procurement Plan include:

1. Annual renewable energy targets will reflect reasonable progress in the intervening years between RPS milestones, and will be set at the greater of (i) the voluntary City of Pasadena RPS goal, or (ii) the State of California RPS goal;

2. Pursuant to SB 350 and the City of Pasadena RPS Enforcement Program (herein after also referred to as the "RPS Enforcement Program"), Pasadena Water and Power ("PWP") will incorporate the most recent RPS Procurement Plan into future iterations of the IRP;

3. Pursuant to SB 350, beginning January 1, 2021, at least 65 percent of the procurement PWP counts toward the California RPS in each compliance period will be from contracts of ten years or more in duration, or PWP ownership or ownership agreements, for eligible renewable energy resources;

4. Renewable energy resources under existing contracts are expected to supply at a minimum, 33% of projected Retail Sales in 2020

5. The following changes in Pasadena's contracted RPS resources are reflected in this RPS Procurement Plan:

[1] This RPS Procurement Plan describes the intended strategy of the Pasadena Water and Power department to comply with the Renewable Portfolio Standard requirements of California Senate Bill X1-2 ("SBX1-2"), Senate Bill 350, and the RPS Enforcement Program adopted by the Pasadena City Council on January 29, 2018. The RPS Enforcement Program and this RPS Procurement Plan incorporate the regulations established by the California Energy Commission (aka "CEC") regarding Public Utilities Code Section 399.30 (l), as such interpretations of the law are codified in the California Code of Regulations, Title 20, Division 2, Chapter 13, Sections 3200 through 3208, and in Title 20, Division 2, Chapter 2, Article 4, Section 1240. It is important to note that this RPS Procurement Plan addresses not only California's State-wide RPS requirements, but the City of Pasadena's own voluntary RPS goal, as affirmed in the 2015 Integrated Resource Plan Update.

[2] 50% of Retail Sales as explained below.

a. Deliveries under three Biomethane contracts have been terminated.
    - EDF: Contract terminated January 2, 2015 for failure to meet minimum deliveries. Pasadena has received no Biomethane under this contract since August 1, 2014.
    - Waste Management – Deliveries suspended April 4, 2016 by mutual agreement. Contract terminated on May 3, 2017.
    - Sequent – The contract was terminated October 14, 2016 by mutual agreement.

b. The contract with the Clearwater Solar project terminated on October 21, 2014 for non-performance. Due to circumstances unforeseen at the time of contracting and beyond the developer's reasonable control, the developer decided not to develop or construct the project. Pasadena had contracted for 3.4 MW (17.143%) of the 20 MW project through SCPPA[3].

c. The Columbia II Solar project achieved commercial operation on December 10, 2014, ahead of the guaranteed commercial operation date of December 31, 2014. Pasadena receives 2.6 MW (17.143%) of the 15 MW project through SCPPA.

d. The Kingbird Solar project achieved commercial operation on April 30, 2016, four months after the guaranteed commercial operation date of December 31, 2015. Pasadena receives 100% of the 20 MW project.

e. The Summer Solar project achieved commercial operation on July 25, 2016, almost one month after the guaranteed commercial operation date of June 30, 2016. Pasadena receives 6.5 MW (32.5%) of the 20 MW project through SCPPA.

f. The Antelope Big Sky Ranch project achieved commercial operation August 19, 2016, approximately two months after the guaranteed commercial operation date of June 30, 2016. Pasadena receives 6.5 MW (32.5%) of the 20 MW project through SCPPA.

g. The Puente Hills Landfill Gas project started in operation from January 1, 2017. It's a fourteen-year contract with Los Angeles County Sanitation District No. 2 through SCPPA. Pasadena receives 30.2326% of its output. The project proposed size is 43MW.

h. A new ten-year contract has been entered into with Falls Creek H.P., L.P. for the delivery of 35,000 to 69,000 PCC 3 Renewable Energy Credits ("RECs") annually, beginning in 2017. Supply will be from a group of existing

[3] The Southern California Public Power Authority

California Energy Commission ("CEC") RPS-certified low impact small hydroelectric facilities in Oregon and Idaho.

i. A new four-year contract has been entered into with Powerex for the delivery of 17,500 of PCC 1 RECs and 35,000 of PCC 2 RECs annually, beginning in 2017. Energy will be delivered to the California Independent System Operator ("CAISO"). Supply will be from a group of existing Powerex owned or contracted CEC RPS-certified facilities in Washington and British Columbia.

j. Given the number of variables and uncertainties related to actual resource performance and net retail load, it is very difficult to precisely match the amount of renewable energy procured for each year to the RPS requirements. PWP's RPS portfolio optimization strategy to achieve the target RPS at the lowest cost to Pasadena customers includes:

- To the extent available, maximizing the use of lower cost categories (e.g., PCC 2 and PCC 3), within resource balancing requirements, to meet the target RPS goals.

- Limiting the amount of renewable energy and RECs that are actually retired in each PCC each year to the targeted amount. Any surplus is carried over to the following year(s), as long as the RECs can be retired within 36 months of generation.

PORTFOLIO CONTENT CATEGORY ("PCC") REQUIREMENTS

The CEC has developed Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities, which specify rules and procedures for compliance with the provisions of the California Public Utilities Code as modified by SBX1-2 and SB 350. This Plan is consistent with the latest version of the CEC Enforcement Procedures[4] and the City of Pasadena RPS Enforcement Program.

The following categories of the renewable resources may be used to meet statutory RPS procurement targets. These categories are defined in the City of Pasadena RPS Enforcement Program and CEC Enforcement Procedures.

PCC 0

Resources procured prior to June 1, 2010. The Total RPS requirement, minus the grandfathered PCC 0 resources that count in full will result in a "Net" RPS requirement, against which the other PCC percentages apply ("Net Procurement Requirement").

[4] California Energy Commission: "Enforcement Procedures For The Renewables Portfolio Standard For Local Publicly Owned Electric Utilities," Amended Regulations, Title 20, Division 2, Chapter 13, Sections 3200 – 3208, Title 20, Division 2, Chapter 2, Article 4, Section 1240; Effective April 2016 - CEC-300-2016-002-CMF; and Pre-Rulemaking Amendments to the Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utility (Sections 3200 through 3208)

PCC 1
Eligible renewable energy resource electricity that meets the requirement of "in-state," or "out-of-state" resources scheduling power directly to a California balancing authority in accordance with Public Utilities Code section 399.16(b)(1);

PCC 2
Resources located outside of a California balancing authority that may be delivered at times or locations other than when the energy is actually produced, in accordance with Public Utilities Code Section 399.16(b)(2); and

PCC 3
Eligible renewable energy resource electricity products or any fraction of the electricity generated, including unbundled RECs that do not qualify under the criteria of PCC 1 or PCC 2, in accordance with Public Utilities Code Section 399.16(b)(3).

The "Net Procurement Requirement" is the total RPS requirement minus the grandfathered PCC 0 resources, which count in full. PWP assigns eligible renewable energy resource electricity products to the appropriate PCC consistent with Section A.3 of the City of Pasadena RPS Enforcement Program and the CEC Enforcement Procedures, Section 3203.

Under the CEC's Enforcement Procedures, all local publicly owned utilities ("POUs") must show an increasing annual renewable energy procurement to demonstrate reasonable progress towards reaching the mandated 33% RPS target by calendar year 2020 and with the enactment of SB 350, 50% by calendar year 2030. PWP must procure a minimum quantity of electricity products from eligible renewable energy resources, including RECs, as a specified percentage of Retail Sales. Retail Sales is defined in the RPS Enforcement Program as sales of electricity by a POU to end-use customers and their tenants, measured in MWh minus energy consumption by a POU, electricity used by a POU for water pumping, or electricity produced for onsite consumption (self-generation). Annually, PWP uses approximately 16 GWh[5] (or about 1.6% of total load) of electricity for water pumping. SB 350 further clarifies that Retail Sales may exclude sales to customers taking service under the optional Green Power Option or any shared renewable generation program to achieve the following targets.

Table 1 summarizes the renewable energy procurement requirements under the CEC Enforcement Procedures, Pasadena's own RPS Enforcement Program and SB 350.

[5] 1GWh = one GigaWatthour = one million KiloWatthours

Table 1 - Renewable Resource Categories and State RPS Requirements

Pasadena Water & Power California Energy Commission-Compliant RPS Procurement Plan Requirements by Calendar Year						
	Compliance Period 3		**Compliance Period 4**	**Compliance Period 5**	**Compliance Period 6**	**Compliance Period 7+**
California RPS Mandatory Procurement Requirement (% of Net Retail Sales)[1] [2]	**YEAR**	**%**	**40% by 12/31/2024**	**45% by 12/31/2027**	**50% by 12/31/2030**	**2031+ (3 year blocks) 50%**
	2017	**27.0%**				
	2018	**29.0%**				
	2019	**31.0%**				
	2020	**33.0%**				
PCC 1 Minimum:	≥75% of Net Procurement Requirement					
PCC 2 Maximum [3]:	≤25% of Net Procurement Requirement					
PCC 3 Maximum:	≤10% of Net Procurement Requirement					
Long-Term Contracts: (at least 10 years duration)	N/A		At least 65% of contracts must be long-term contracts (at least 10 years in duration)			

[1] As specified in the California Energy Commission Guidebook and California Energy Commission Enforcement Procedures.
[2] Net Retail Sales is defined as Total Retail Sales minus Department usage including Water Department pumping load.
[3] The PCC 2 constraint is not specified by law, but is derived logically as the maximum residual given the PCC 1 and PCC 3 constraints.

For a customer participating in the Green Power Option or any shared renewable generation project, the RECs associated with electricity credited to such customer under the program will not be used by PWP for compliance with state mandated RPS procurement requirements. The RECs will be retired on behalf of the participating customer, and may not be further sold, transferred, or otherwise monetized for any purpose. Under these programs, PWP will seek to procure generation from eligible renewable energy resources that are located in reasonable proximity to participants to the extent possible.[6]

Details of the above requirements can be found in the CEC's Enforcement Procedures for Local Publicly Owned Utilities and Pre-Rulemaking Amendments to the Enforcement Procedures.

RPS PROCUREMENT PLAN

SUPPLY VS. LOAD

This Plan is consistent with the renewable energy procurement guidelines recommended by the PWP 2015 IRP Update (note: as part of the 2018/2019 IRP, there might be additional changes, but that will be incorporated as part of the 2018/2019 IRP). The IRP Update was designed to strike a balance between environmental regulatory compliance and system reliability while maintaining stable and affordable retail electric rates. The 2015 IRP Update projects that PWP's Retail Sales will remain flat or decrease slightly due to the weak economy and increasing implementation of distributed generation, demand response and energy efficiency programs going into the future, as shown in Figure 1.

[6] PUC Section 399.30(c)(4)

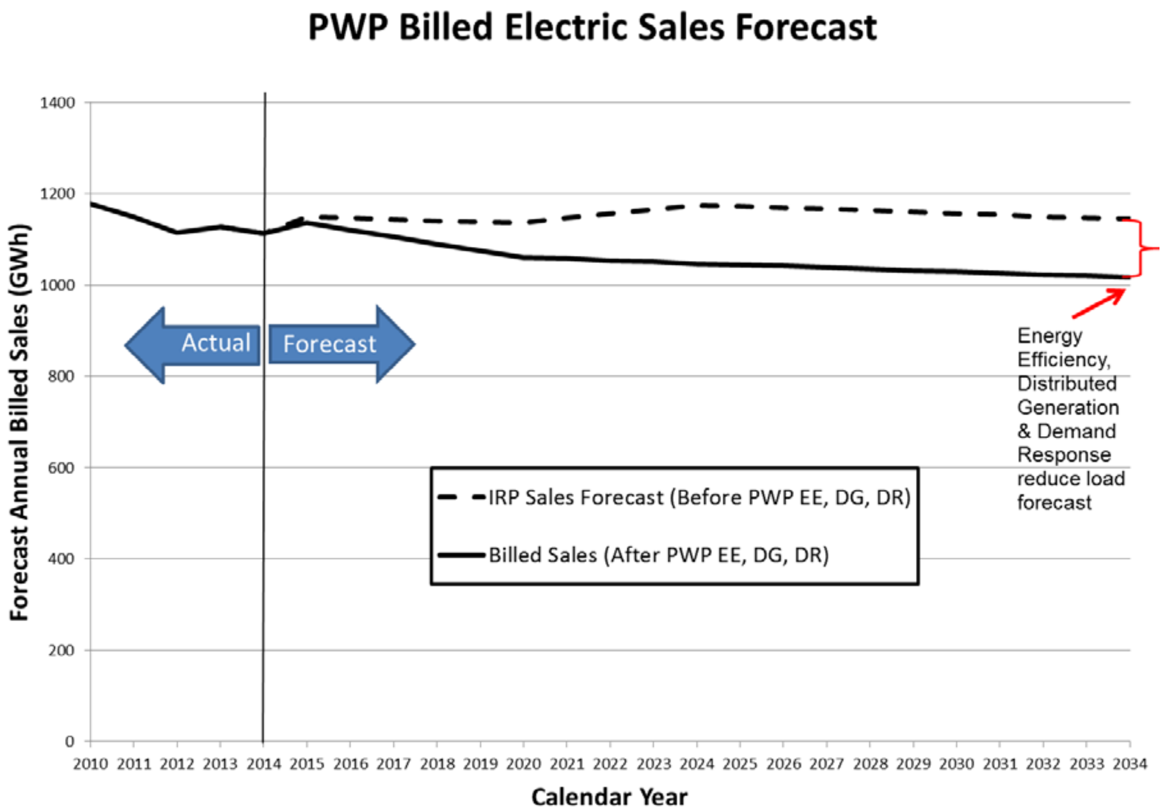


Figure* 1 – *2015 IRP Update Load Projection

PWP can generally be considered fully resourced as shown in Figure 2 from the 2015 IRP.

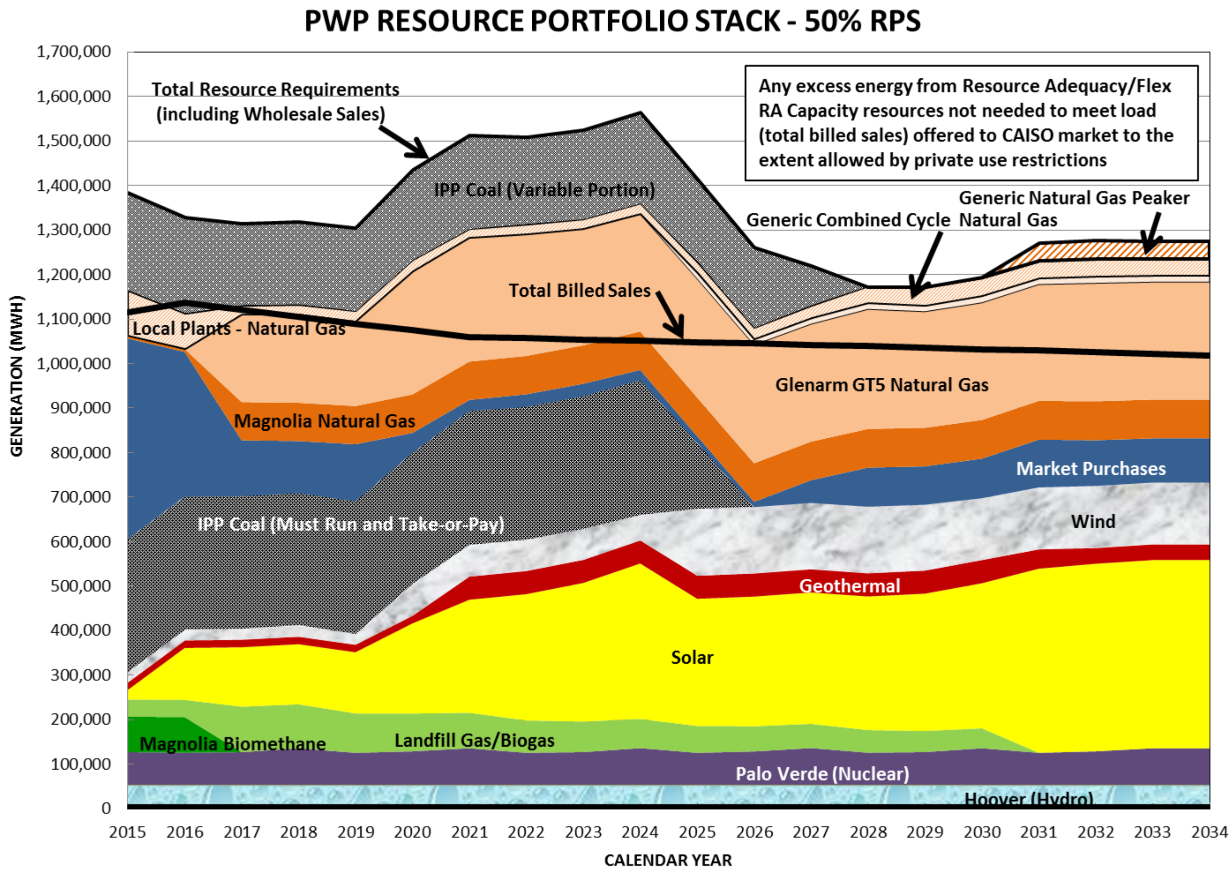


Figure 2 –2015 IRP Update Projected Portfolio of Long Term Contracts & Generation

Though the mandates of SB 350 require POU's to procure 50% of its retail needs through renewable power, by 2030, we must strike a balance of meeting this need, but being mindful of our reliability mandates and stranded investment. PWP has no need to procure more power and complying with the RPS causes over-generation and over-procurement. Although a sizeable portion of this additional renewable energy can be accommodated by curtailing the use of some long term resource contracts that have flexibility (energy above the take or pay obligation) and through reductions in short term energy purchases, some of the new renewable resources are still in excess of the City's needs.

Private use restrictions on generation projects financed with municipal bonds, and on the sale of power from the federally-owned and operated Hoover power project, generally require that these projects be dedicated to serving PWP load, and not resold to others. The Intermountain Power Project is expected to be repowered with a smaller natural gas-fired project of 1,200 MW or less in the year 2025. Much of the shortfall in capacity and energy after that date is planned to be fulfilled with renewable energy resources. Until such time, meeting all legal and regulatory requirements while managing the potential oversupply of energy in PWP's portfolio may be challenging. The use of RECs without associated energy to the maximum extent allowed helps reduce the potential oversupply. In addition, bundled RPS products with index-priced energy provide an important hedge by ensuring that PWP will pay and be paid the market price for the equivalent amount of any over-supplied energy it may have to sell if total resources exceed the amount necessary to serve load. To mitigate a variety of risks, PWP will seek to ensure an appropriate mix of various RPS and traditional generation products as part of a diversified power supply portfolio.

COMPLIANCE STRATEGY

PWP starts with a projected load forecast based on actual historical loads, assuming modest load growth offset by expected distributed generation, demand side management and projected energy efficiency savings. The PWP RPS Procurement Requirement is calculated by multiplying the load forecast for each year (in GWh[7]) by the required annual RPS percentage for that year to come up with the amount of renewable energy (in GWh) required by year (the annual "RPS Total Procurement Requirement").

Next PWP subtracts from the annual RPS Total Procurement Requirement the amount of energy that is expected to be delivered from the existing resources procured by PWP by PCC and Compliance Period. First are the existing, grandfathered contracts in PCC 0. The resulting number is the RPS "Net Procurement Requirement."

In addition to long term contracts, PWP purchases short-term RECs as allowed to meet the State's RPS requirements as well as the City's voluntary RPS goals.

BALANCED PORTFOLIO

After determining the amount of energy already procured in each year and in each PCC or, PWP must determine the amount of RPS Procurement still required in each PCC and year. This requires a calculation of the RPS procurement constraints reflected in Table 1: PCC 1 Minimums and PCC 3 Maximums (percentages multiplied by Net Procurement Requirement), and a comparison of annual energy procurement against these constraints to determine if future compliance targets (or obligations) will require additional purchases of PCC 1 resources, or will limit purchases of PCC 3 resources. The final calculation is the net short evaluation: If the sum of existing contracts is less than the total required RPS Net Procurement Requirement energy for the year, the difference is the amount that must be procured, and allocated to the Categories according to the constraints. Any surplus renewable energy and/or credits in a year may be carried over into the following year, and the RPS Net Procurement Requirement adjusted accordingly.

In addition to balancing between PCCs and Compliance Periods, PWP must consider the right mix of resources to fit PWP's portfolio and load as it evaluates RPS proposals. This means selecting some base-load projects, such as geothermal and landfill gas, and some

[7] 1GWh = one GigaWatthours = one million KiloWatthours (KWh)

variable/peaking projects such as wind and solar. It also means weighing the right mix of contract durations (long vs. short, within statutory limits) and counterparties to diversify and spread the risk of contract expiration and potential contract failure. SB 350 imposes a minimum percentage of long-term contracts. Starting with the 4th Compliance Period (2021-2024) and for all subsequent compliance periods, 65% of PWP's renewable resources must come from either owned resources or contracts that are at least 10 years in duration.

PWP'S VOLUNTARY IRP RPS STRATEGY

Above and beyond the mandatory RPS Procurement amount required under SBX1-2, PWP's target of 40% RPS by 2020, set by City Council, dictates the additional procurement of renewables. This incremental amount does not need to be in any particular PCC. Beginning in 2024, the state mandated targets under SB 350 exceed the voluntary RPS, and PWP's procurement will no longer be based on the voluntary targets. PWP looks for opportunities to procure incremental renewable resources that are economical, reliable, and a good fit for the portfolio of resources. Resources located within the State of California and CAISO SP15[8] typically score higher in PWP's resource evaluation due to lower transmission and congestion costs, the potential availability of local resource adequacy capacity and higher market value for the energy

PWP's RPS PROCUREMENT PROCESS

Because PWP is a relatively small municipal utility, it solicits most of its long-term renewable resources through open Requests for Proposals conducted by its joint powers authority, SCPPA[9] ("SCPPA RFP" – see sample SCPPA Request for Proposals for Renewable Energy Resources). This allows PWP (and other SCPPA members) to purchase the output of portions of multiple diverse projects and gain economies of scale, rather than limit the projects that they would be capable of participating in due to the comparatively small demand of most of the individual utilities. PWP anticipates dividing its outstanding RPS procurement between base-load and peaking renewable resources, and seeking some long-term and some mid-term contract lengths. In this case, PWP defines long-term as ten years or longer, and mid-term as five to ten years. PWP may procure some RECs and/or PCC 2 products with shorter tenures. PWP will also seek products with energy pricing tied to electricity market indices as well as fixed-priced.

The SCPPA RFPs are considered an open and "rolling" solicitation, generally issued in January, with responses accepted through December of each year. The SCPPA RFP solicits proposals for power purchase agreements with and without ownership options, and also invites energy storage and other innovative proposals. PWP initially screens prospective renewable resource proposals received through SCPPA and through direct

[8] SP15 is the California Independent System Operator's South of Path 15 zone, where resources that are deliverable to Pasadena load, with the least congestion and losses, and the highest probability of providing local area reliability capacity, are most likely to be located. Assuming price parity, such resources would be the most valuable to PWP.
[9] SCPPA = Southern California Public Power Authority, which includes the cities of Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Glendale, Los Angeles Dept. of Water & Power, Pasadena, Riverside, Vernon, and the Imperial Irrigation District.

contact with renewable project developers based on the levelized offer price ($/MWh) for resources with a project size and proposed delivery period that matches PWP's procurement targets. For larger projects, joint participation with other SCPPA members may be desirable to obtain the best project economics and contract terms.

QUANTITATIVE ANALYSIS

From the short-list of projects that pass the initial screening, PWP evaluates and compares proposals to identify the "least cost/best fit" opportunities. Best fit analysis considers PWP's projected needs in light of its existing portfolio of generating resources and contracts. Considerations include, for example: RPS targets and other regulatory requirements, grid and local area reliability needs, projected load and generation profiles, the estimated commercial operation or contract start date, and proposed contract term (duration). Variables can include:

- Generation cost and market value at the point of delivery;
- Time-of-delivery value;
- Capacity value (if any);
- Ancillary[10] service value (if any);
- Value of environmental attributes by PCC;
- Costs of integrating variable generation technologies; and
- Incremental transmission costs (if any), excluding current CAISO load-based transmission access and grid management charges.

QUALITATIVE ANALYSIS

In addition to the quantitative evaluation, PWP performs a qualitative evaluation, using a process similar to that employed by California investor-owned utilities to rate project viability. Project viability refers to:

- Project owner/development team experience developing, owning, operating and/or maintaining similar projects;
- Technical feasibility:
  - The proposed resource must be a commercialized technology in use at other operating facilities of similar or larger capacity;
  - Must meet the California Emission Performance Standard;
  - Must be pre-certified by the CEC as an eligible renewable resource;
  - The proposal must include high quality resource production profile estimates;
  - There should not be any known or anticipated manufacturing supply chain constraints;
  - Identified available water source and minimal water consumption;
- Development Milestones:
  - Site control;
  - Permitting;
  - Status of and ability to obtain financing;

[10] Ancillary Services are required to support the transmission of energy from generation resources to loads while maintaining reliable operation of the electric grid in accordance with regional reliability standards and good utility practice. Ancillary Services include Regulation, Spinning Reserve, Non-Spinning Reserve, Voltage Support and Black Start, each as defined in the CAISO Tariff.

  - Interconnection progress;
  - Transmission system and deliverability upgrade requirements/schedule; and
  - Reasonableness of proposed commercial operation or contract start date.

In addition to project viability, PWP’s qualitative evaluation also considers factors such as:

- Risk exposure diversification;
- Counterparty creditworthiness and willingness to post collateral;
- Resource flexibility and optionality;
- California’s Energy Action Plan preferred loading order;
- Preference for previously disturbed and brownfield sites, or locations in designated Renewable Energy Zones; and
- Local and certified small or micro business preference.

SUMMARY OF RPS PROCUREMENT PLAN

On the next page, is PWP's 2017 RPS Procurement Plan for meeting the RPS goals, with the appropriate PCC and RPS targets required under the CEC Enforcement Procedures. To optimize the portfolio and minimize costs, this plan assumes PWP retires only the amount of RECs required in each PCC in any particular year and carries over the remainder into future periods. The pending contracts listed below, refers to planned future contracts to meet compliance requirements. Some of these "planned contracts," are currently under negotiation while others are being planned for. The 2017 RPS Procurement Plan is an estimate only, to show PWP's intent to comply with SB 350.

When reviewing the 2017 RPS Procurement Plan, it is important to note the following:

- CP refers to "Compliance Period";
- CP 1 and CP 2 is shaded as the data is based on CEC compliance filings and is based on past data;
- CP 3, CP 4, CP 5 and CP 6 are based on PWP estimates;
- TBD is "To Be Determined" based on contract negotiations and the 2018/2019 Integrated Resource Plan; and
- "Planned" refers to projects that are under negotiation, or plan to be under negotiation in that CP.

PWP RENEWABLE RESOURCE PROCUREMENT PLAN											
22-Jan-18											
Compliance Period (CP)						CP1	CP2	CP3	CP4	CP5	CP6
Calendar Year (CY)						CY 2011-2013	CY 2014-2016	CY 2017-2020	CY 2021-2024	CY 2025-2027	CY 2028-2030
Estimated PWP Retail Sales (GWh)						3390.29	3248.34	4178.78	4161.55	3111.12	3110.07
Grandfathered Projects	**Resource Type**	**Location**	**Online Year**	**Contract Term (Years)**	**PCC**	**CP1 (GWh)**	**CP2 (GWh)**	**CP3 (GWh)**	**CP4 (GWh)**	**CP5 (GWh)**	**CP6 (GWh)**
Azusa Hydro	Small Hydro	CA	1933	Ownership	0	12.62	0.12	0.00	0.00	0.00	0.00
Chiquita Canyon LFG (Ameresco)	Landfill Gas	CA	2010	20	0	114.01	115.70	149.19	149.19	111.89	111.89
Heber South Geothermal (Ormat)	Geothermal	CA	2006	25	0	48.33	44.68	63.79	63.79	47.84	47.84
High Winds (Iberdrola)	Wind	CA	2003	20	0	44.08	36.76	51.88	38.91		
Minnesota Methane LFG	Landfill Gas	CA	2007	10	0	133.18	137.46				
Milford Wind	Wind	UT	2009	20	0	28.66	31.53	41.00	41.00	30.75	20.50
City of Glendale LFG (Grayson)	Landfill Gas	CA	2010	1	0	34.75					
Total Grandfathered Resources						415.63	366.24	305.86	292.89	190.49	180.24
Contracted Projects	**Resource Type**	**Location**	**Contract Year**	**Contract Term (Years)**	**PCC**	**CP1 (GWh)**	**CP2 (GWh)**	**CP3 (GWh)**	**CP4 (GWh)**	**CP5 (GWh)**	**CP6 (GWh)**
Antelope Big Sky Ranch	Solar	CA	2012	25	1	0.00	5.62	63.30	62.05	45.72	45.04
Columbia 2 Solar	Solar	CA	2013	20	1	0.00	15.30	30.52	29.87	22.03	21.69
EDF Biomethane (GWh equivalent)	Biogas	TX	2011	10	1	0.00	4.06	0.00	0.00	0.00	0.00
Kingbird A	Solar	CA	2013	20	1	0.00	46.80	235.03	230.27	169.58	166.90
Puente Hills LFG	Landfill Gas	CA	2014	14	1	0.00	0.00	282.64	188.12	96.08	67.76
Sequent Biomethane (GWh equivalent)	Biogas	TN	2011	10	1	80.21	70.62	0.00	0.00	0.00	0.00
Short Term WSPP (PCC1)	Various	WECC Region	2014	<1 year	1	0.00	37.75	0.00	0.00	0.00	0.00
Summer Solar	Solar	CA	2012	25	1	0.00	7.64	63.30	62.05	45.72	45.04
Short Term WSPP (PCC1)	Various	WECC Region	2014	<1 year	1	0.00	5.50	0.00	0.00	0.00	0.00
Waste Mgmt Biomethane (GWh equivalent)	Biogas	OH	2011	10	1	107.79	71.52	0.00	0.00	0.00	0.00
Short Term WSPP (PCC1)	Wind	CA	2016	<1 years	1	0.00	26.05	32.00	0.00	0.00	0.00
Windsor Reservoir Solar	Solar	CA	2010	20	1	1.31	2.38	3.48	3.48	2.61	2.61
Planned (PCC1) (TBD)	Various	WECC Region	2020	>=10 years	1	0.00	0.00	0.00	487.50	562.50	787.50
Short Term WSPP (PCC1)	Various	WECC Region	2017	<1 years	1	0.00	0.00	77.50	0.00	0.00	0.00
Short Term WSPP (PCC1)	Various	WECC Region	2017	<1 years	1	0.00	0.00	81.00	0.00	0.00	0.00
Short Term WSPP (PCC1)	Various	WECC Region	2011	<1 years	1	15.03	0.00	0.00	0.00	0.00	0.00
Short Term WSPP (PCC1)	Various	WECC Region	2012	<1 years	1	17.90	0.00	0.00	0.00	0.00	0.00
Short Term WSPP (PCC1)	Various	WECC Region	2012	<1 years	1	62.24	0.00	0.00	0.00	0.00	0.00
Short Term WSPP (PCC2)	Various	WECC Region	2014	<1 years	2	0.00	91.75	17.00	0.00	0.00	0.00
Short Term WSPP (PCC2)	Various	WECC Region	2017	<1 years	2	0.00	0.00	145.00	0.00	0.00	0.00
Planned (PCC 2) (TBD)				TBD					97.50	112.50	157.50
Unbundled RECs	N/A	WECC Region	2014	<1 years	3	0.00	146.25	0.00	0.00	0.00	0.00
Unbundled RECs	N/A	WECC Region	2013	<1 years	3	6.07	14.27	223.00	165.00	88.00	0.00
Unbundled RECs	N/A	WECC Region	2015	<1 years	3	0.00	76.75	0.00	0.00	0.00	0.00
Unbundled RECs	N/A	WECC Region	2011	<1 years	3	77.34	0.00	0.00	0.00	0.00	0.00
Unbundled RECs	N/A	WECC Region	2013	<1 years	3	20.10	0.00	0.00	0.00	0.00	0.00
Unbundled RECs	N/A	WECC Region	N/A	<1 years	3	55.00	0.00	0.00	0.00	0.00	0.00
Planned (PCC 3) (TBD)				TBD					65.00	75.00	105.00
Total Contracted Resources						443.01	622.24	1253.77	1390.83	1219.74	1399.04
Not Applied/Banked/Carried Over Procurement						92.23	49.02	TBD	TBD	TBD	TBD
California Energy Commission RPS TARGET						20%	25%	33%	40%	45%	50%
Achieved/Expected PWP RPS %						22.65%	27.00%	37.32%	40.46%	45.33%	50.78%

RPS PROCUREMENT PLAN LIMITATIONS AND RELIEF

Section E of the City's RPS Enforcement Program notes that PWP will use its best efforts to procure adequate supplies of renewable energy as set forth in this RPS Procurement Plan; however, PWP will at all times maintain system reliability and maintain average procurement costs for retail electric sales in accordance with the approved budget and retail electric rates approved by the City Council. California law recognizes that adverse situations beyond PWP's control may arise and prevent PWP from fulfilling the RPS Procurement Targets in a timely manner and consistent with such limitations.

In the event PWP discovers that such conditions, as specified in the City's RPS Enforcement Program, may potentially prevent PWP from meeting the RPS Procurement Targets set forth in the RPS Enforcement Program, PWP will notify the City Council of the adverse conditions and apply to the CEC for relief. If appropriate, PWP may submit a revised RPS Procurement Plan for discussion, approval and implementation.

The CEC may reduce a procurement requirement to the extent PWP demonstrates that it cannot comply because of conditions beyond its control[11]. However, the CEC may not, under any circumstance, reduce the procurement obligation of PCC 1 below 65 percent for any compliance period obligation after December 31, 2016.

PWP expects to fully comply with both the City's voluntary and the State of California's mandatory RPS requirements. PWP does not recommend taking advantage of this provision or other optional compliance measures detailed in the City's RPS Enforcement Program at this time.

VERSION HISTORY

- VERSION 1: Initially Adopted- July 22, 2013
    - New mandate to comply with SBX1 2
- VERSION 2: Amended- June 1, 2015
    - Include updates on contracts and other processes
- VERSION 3: Amended- January 29, 2018
    - Show compliance with SB 350
    - Include updates on contracts and other processes

[11] PUC Section 399.15(5)

2018 PWP POWER IRP: ATTACHMENT 4
UPDATED RPS PROCUREMENT PLAN

This document is included as Attachment 2 to the Agenda Report

2018 PWP POWER IRP: ATTACHMENT 5
UPDATED RPS ENFORCEMENT PROGRAM

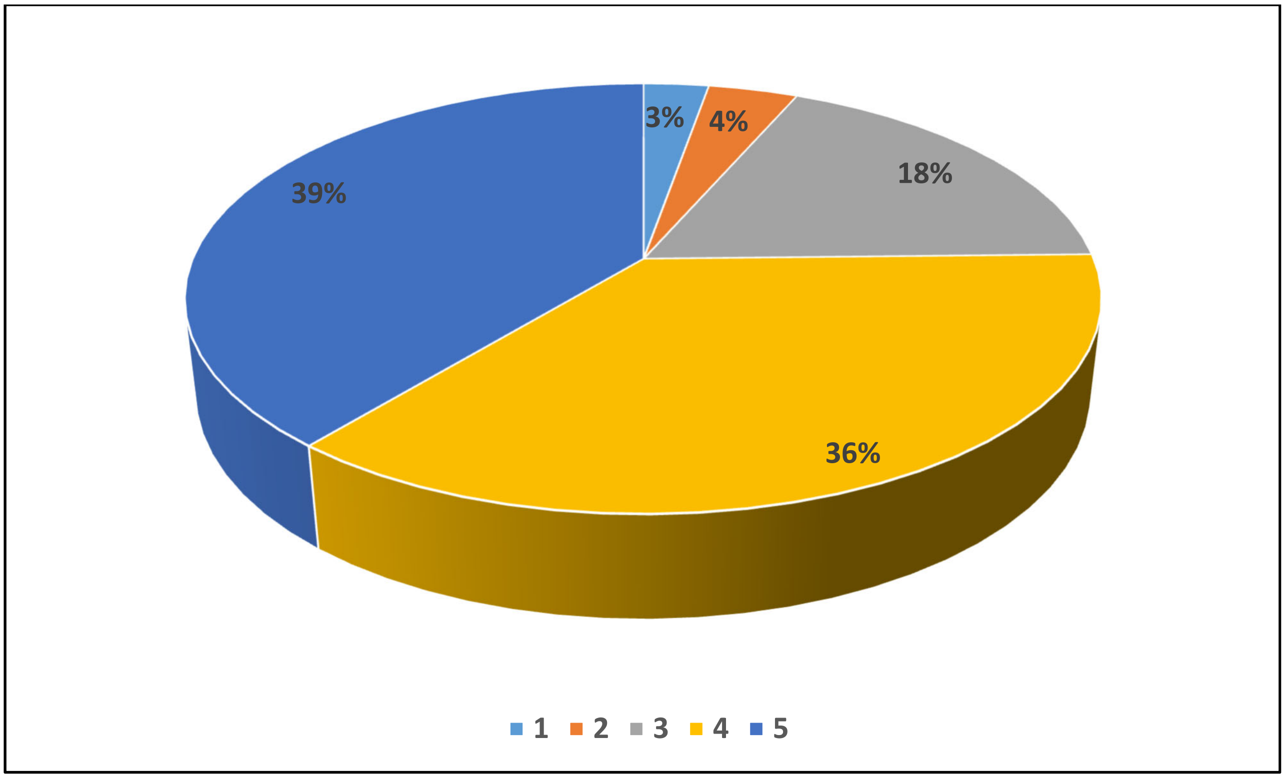
This document is included as Attachment 3 to the Agenda Report

2018 PWP POWER IRP: ATTACHMENT 6
SURVEY RESULTS

2018 PWP POWER IRP: ATTACHMENT 6
SURVEY RESULTS

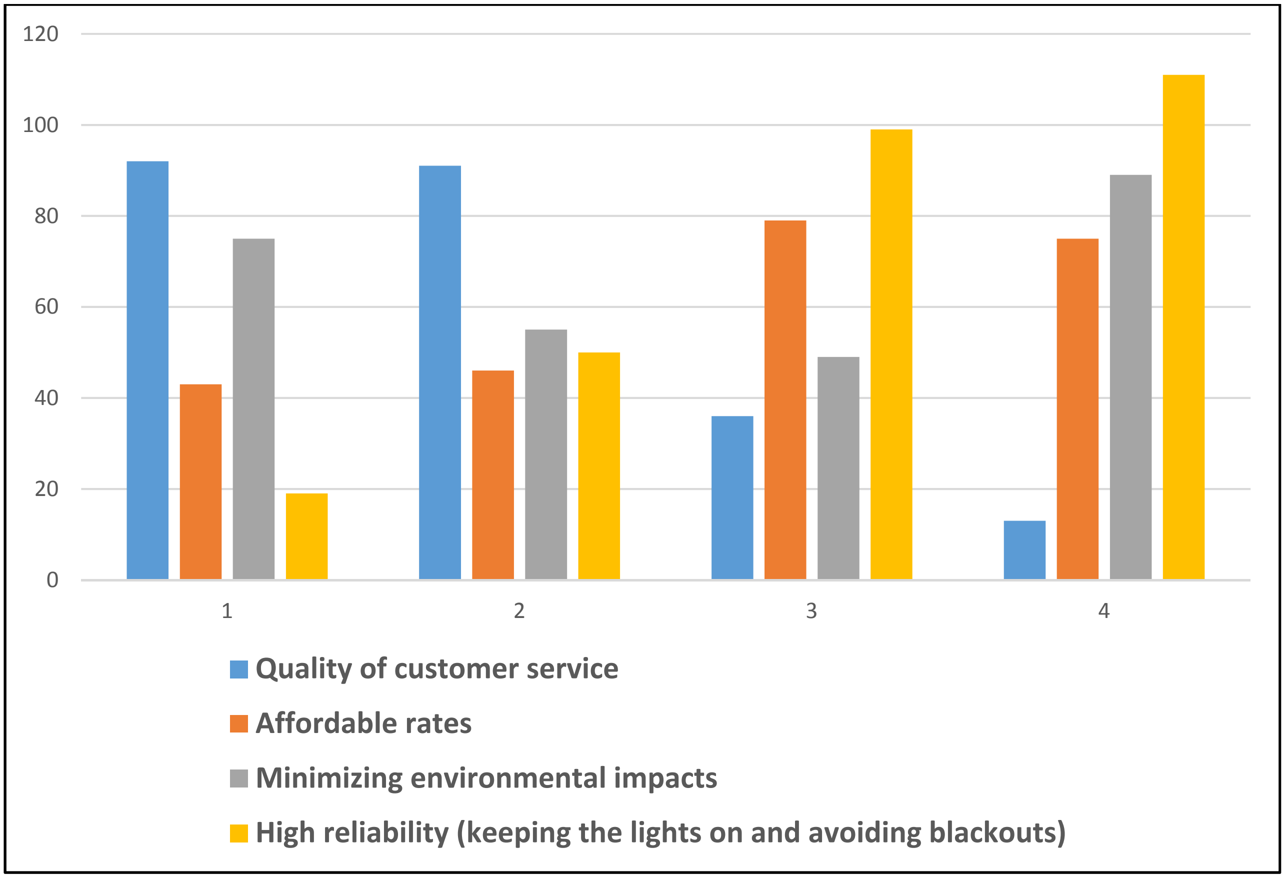
Question #1:

	Responses	#	%
How satisfied are you with the electric services offered by PWP (on a level of 1-5, with 1 being "very un-satisfied" and 5 being "very satisfied")?	1	8	3%
	2	11	4%
	3	53	18%
	4	106	36%
	5	114	39%
	Total	292	100%



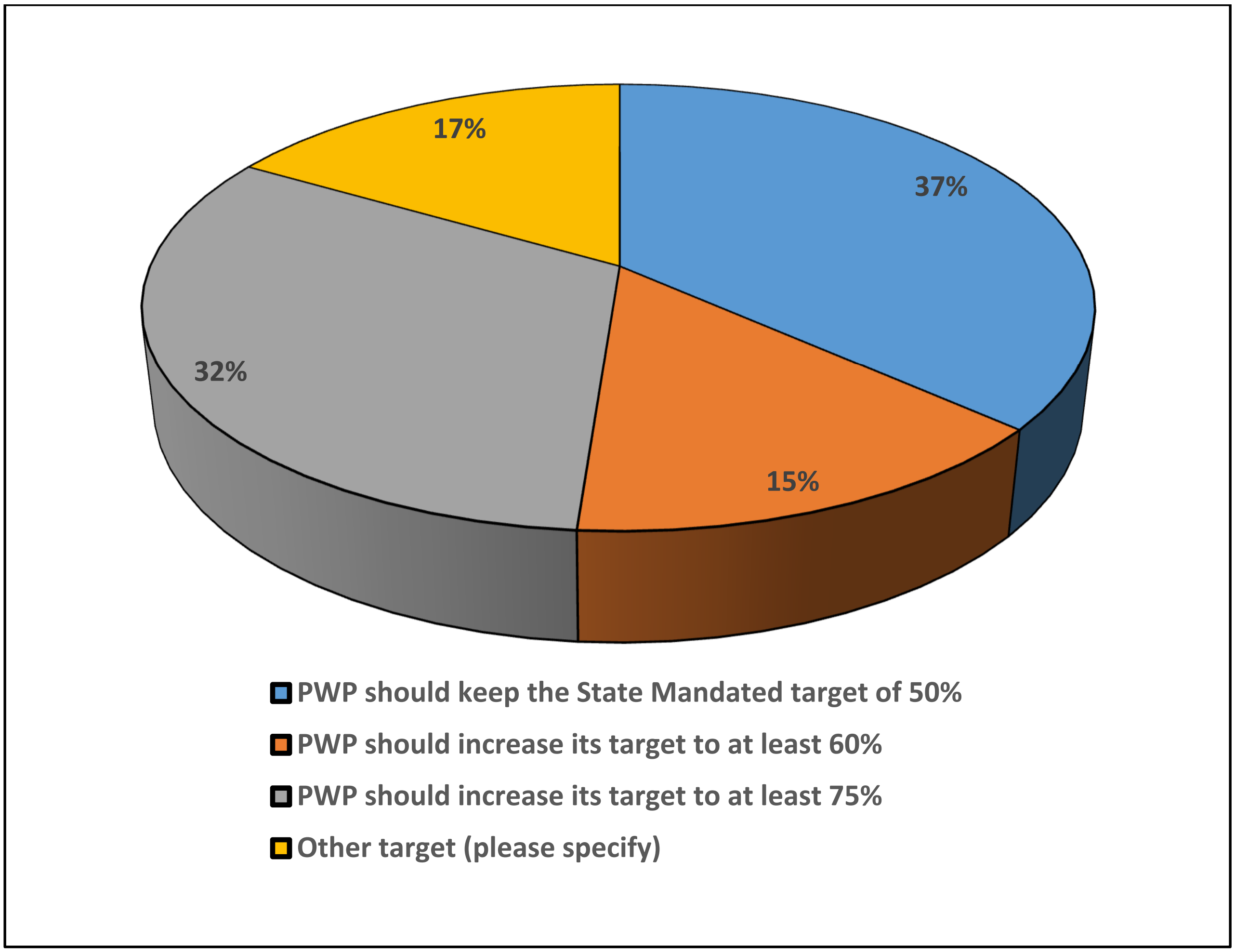
Question #2:

	Ranking	1	2	3	4	Total
Please rank the following electric service priorities in terms of importance, where "1" is the least important and "4" is the most important to you:	Quality of customer service	92	91	36	13	232
	Affordable rates	43	46	79	75	243
	Minimizing environmental impacts	75	55	49	89	268
	High reliability (keeping the lights on and avoiding blackouts)	19	50	99	111	279



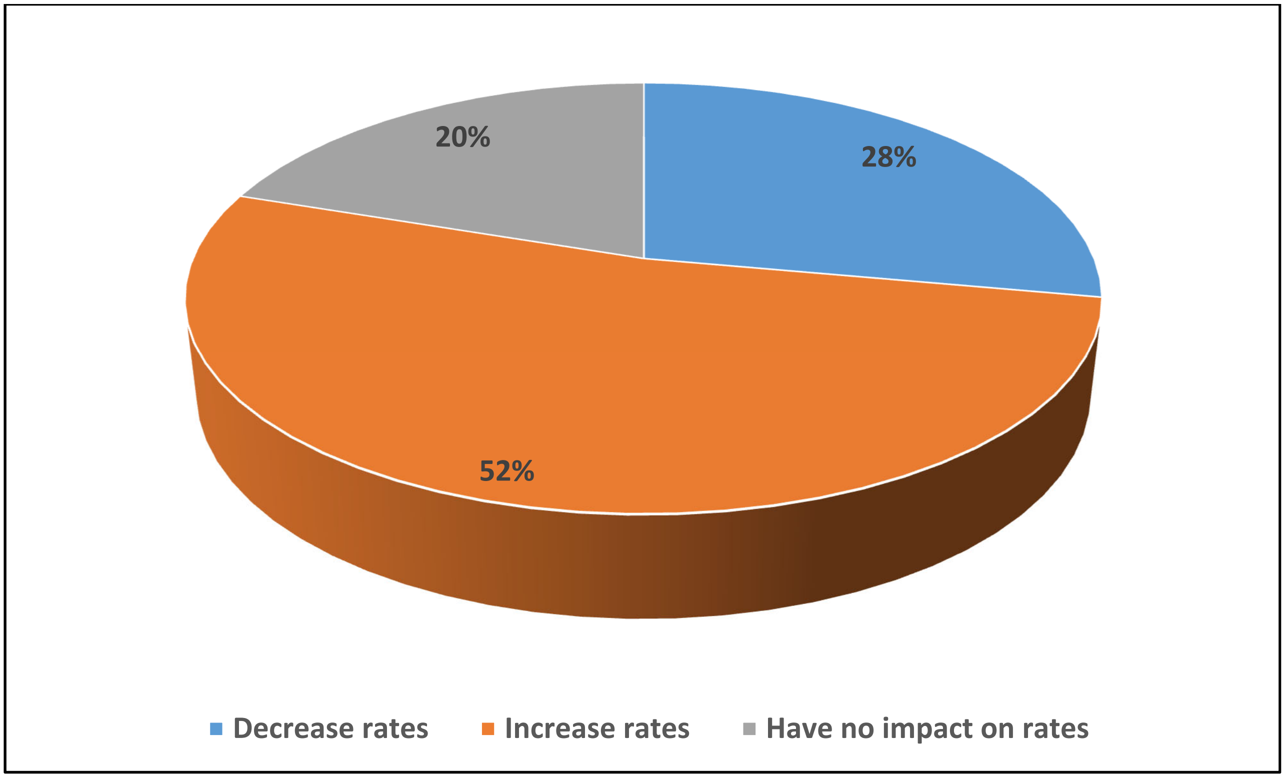
Question #3:

	Responses	#	%
State law requires utilities to achieve a 50% Renewable Portfolio Standard ("RPS") by 2030, which means that at least 50% of the electricity supplied to customers should come from resources like wind, landfill gas, bio-methane and solar. What do you think PWP's renewable resource target should be by 2030?	PWP should keep the State Mandated target of 50%	108	37%
	PWP should increase its target to at least 60%	43	15%
	PWP should increase its target to at least 75%	95	32%
	Other target (please specify)	49	17%
	Total	295	100%



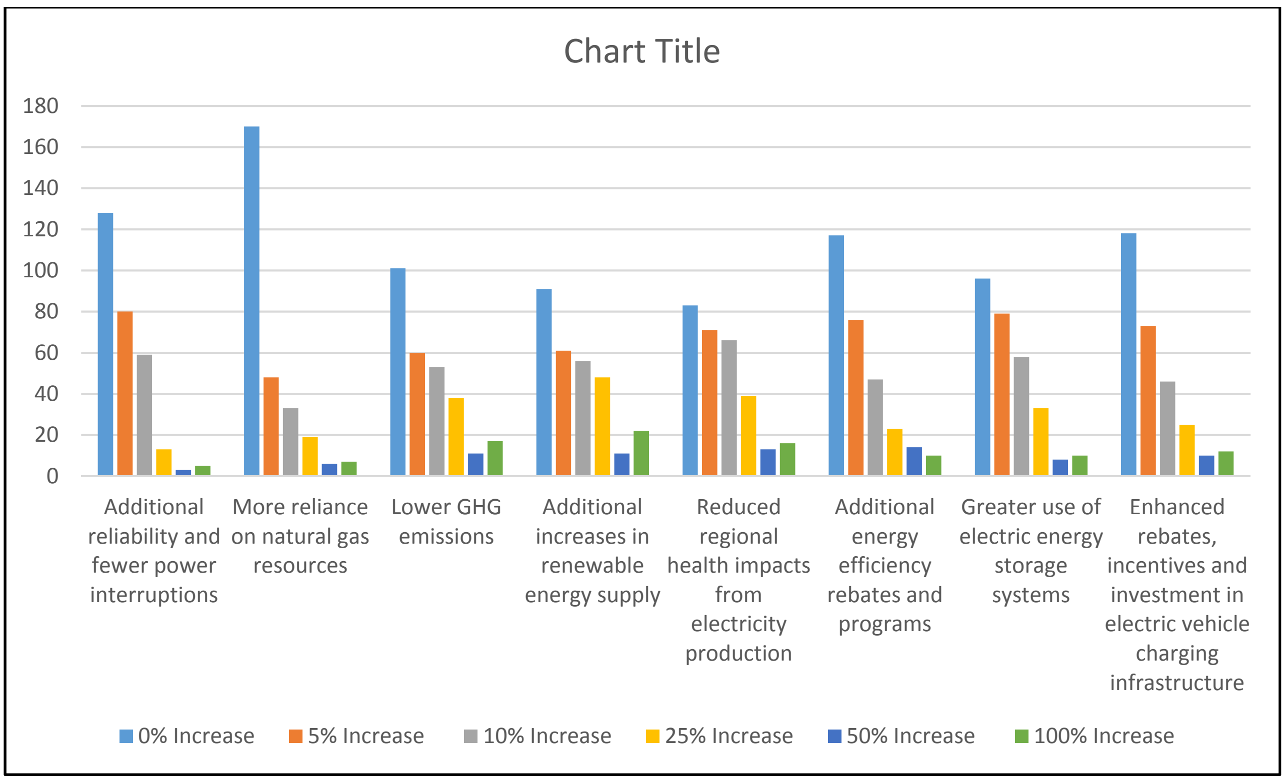
Question #4:

I believe adding additional renewable resources to PWP's energy supply will:	Decrease rates	80	28%
	Increase rates	150	52%
	Have no impact on rates	57	20%
	Total	287	100%



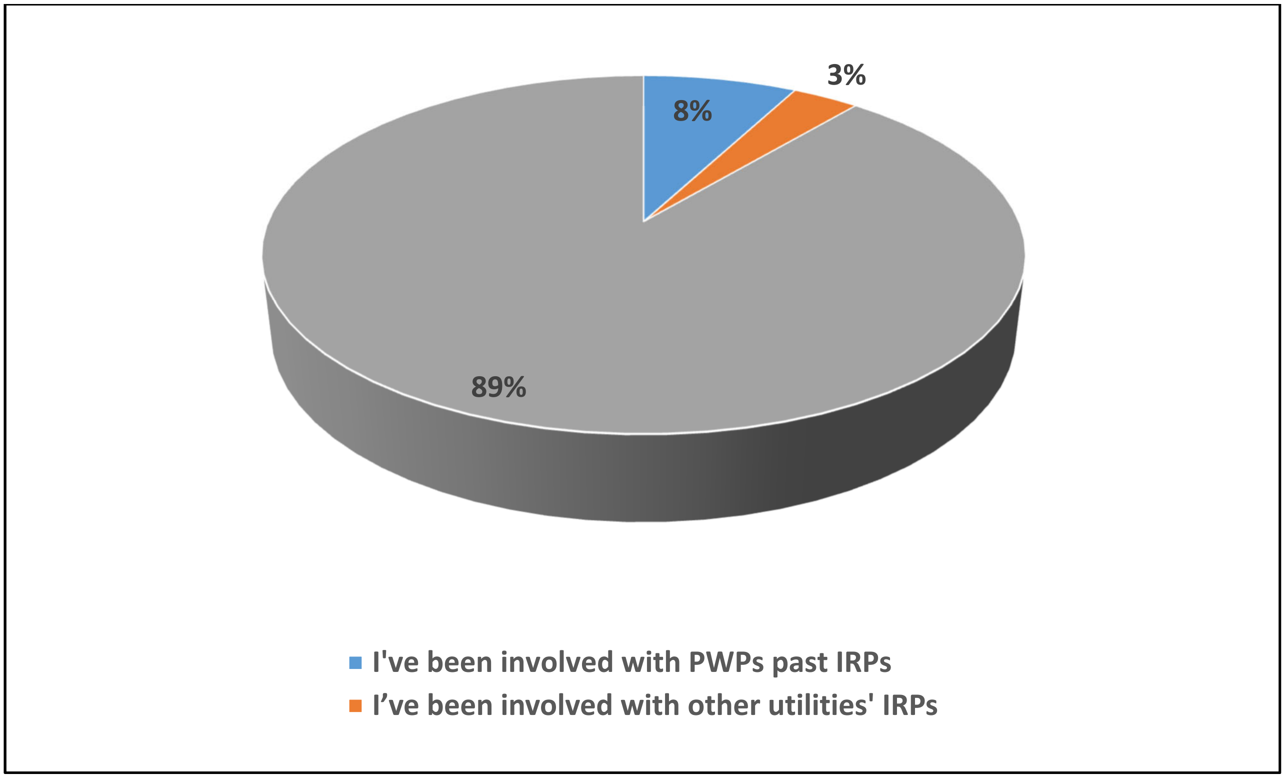
Question #5:

	Ranking	% Increase						
		0%	**5%**	**10%**	**25%**	**50%**	**100%**	**Total**
The Power IRP process will determine the lowest-cost portfolio mix to meet regulatory and reliability requirements. To what extent would you be willing to pay more on your electric bill to achieve:	Additional reliability and fewer power interruptions	128	80	59	13	3	5	288
	More reliance on natural gas resources	170	48	33	19	6	7	283
	Lower GHG emissions	101	60	53	38	11	17	280
	Additional increases in renewable energy supply	91	61	56	48	11	22	289
	Reduced regional health impacts from electricity production	83	71	66	39	13	16	288
	Additional energy efficiency rebates and programs	117	76	47	23	14	10	287
	Greater use of electric energy storage systems	96	79	58	33	8	10	284
	Enhanced rebates, incentives and investment in electric vehicle charging infrastructure	118	73	46	25	10	12	284



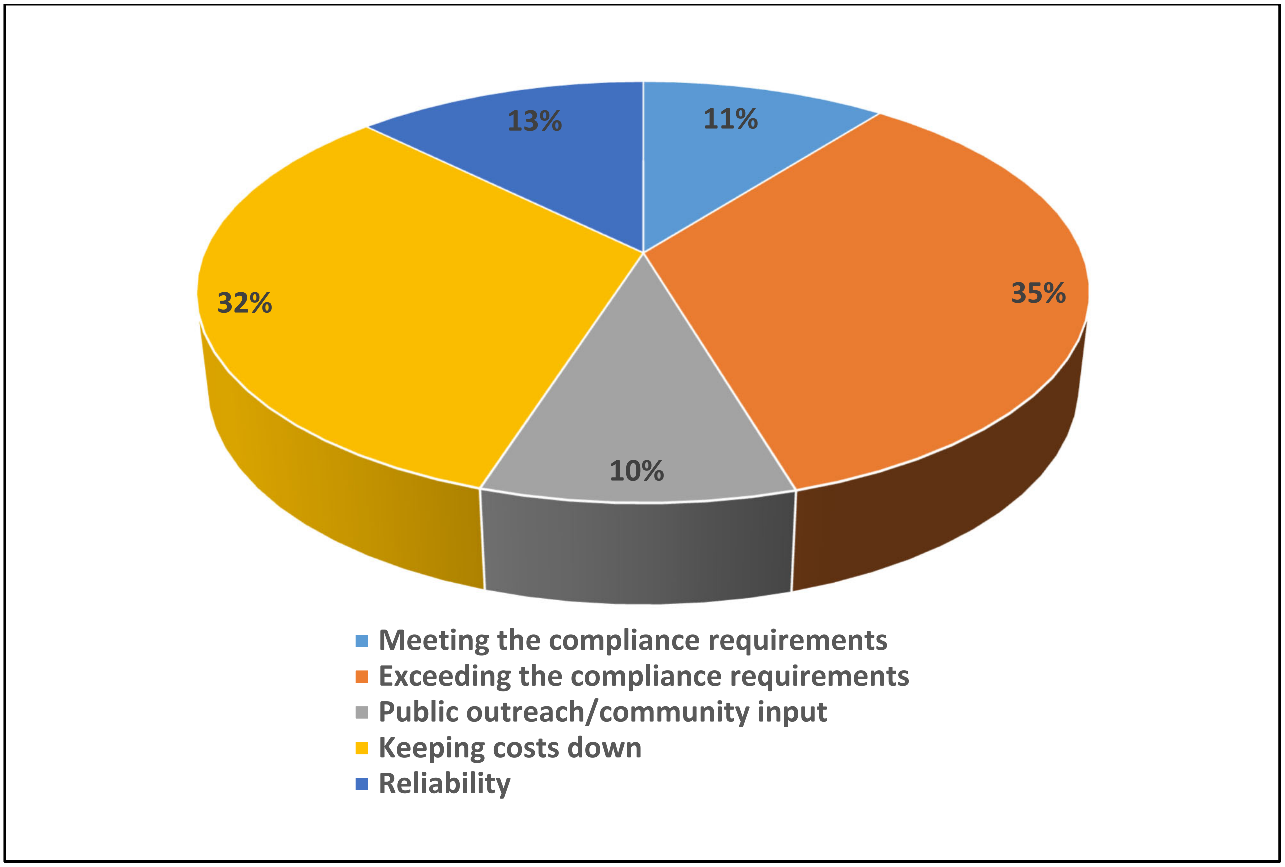
Question #6:

Have you been involved with the past IRP processes? Select all that apply:	Response	#	%
	I've been involved with PWPs past IRPs	23	8%
	I’ve been involved with other utilities' IRPs	10	3%
	No I have not been involved with any IRPs	263	89%
	Total	296	100%



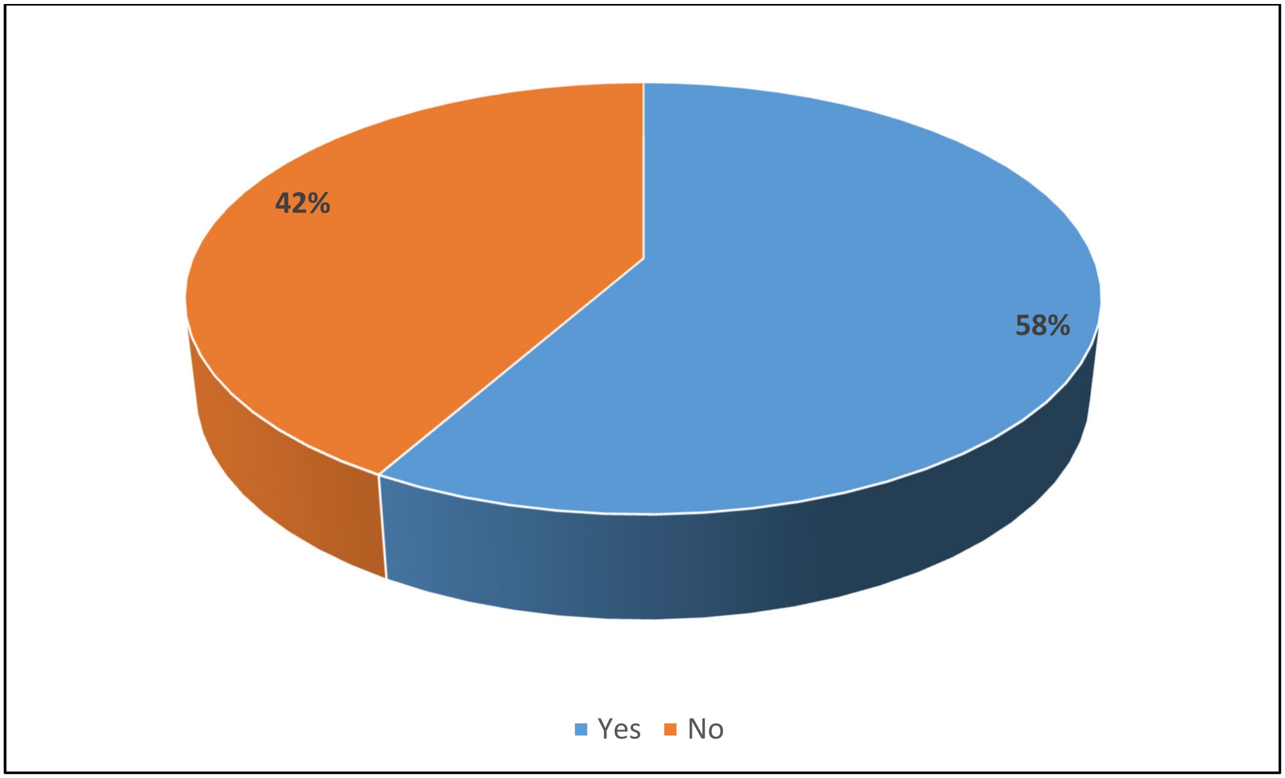
Question #7:

What do you think PWP should prioritize as it develops the Power IRP?	**Responses**	#	%
	Meeting the compliance requirements	31	11%
	Exceeding the compliance requirements	102	35%
	Public outreach/community input	28	10%
	Keeping costs down	95	32%
	Reliability	37	13%
	Total	293	100%



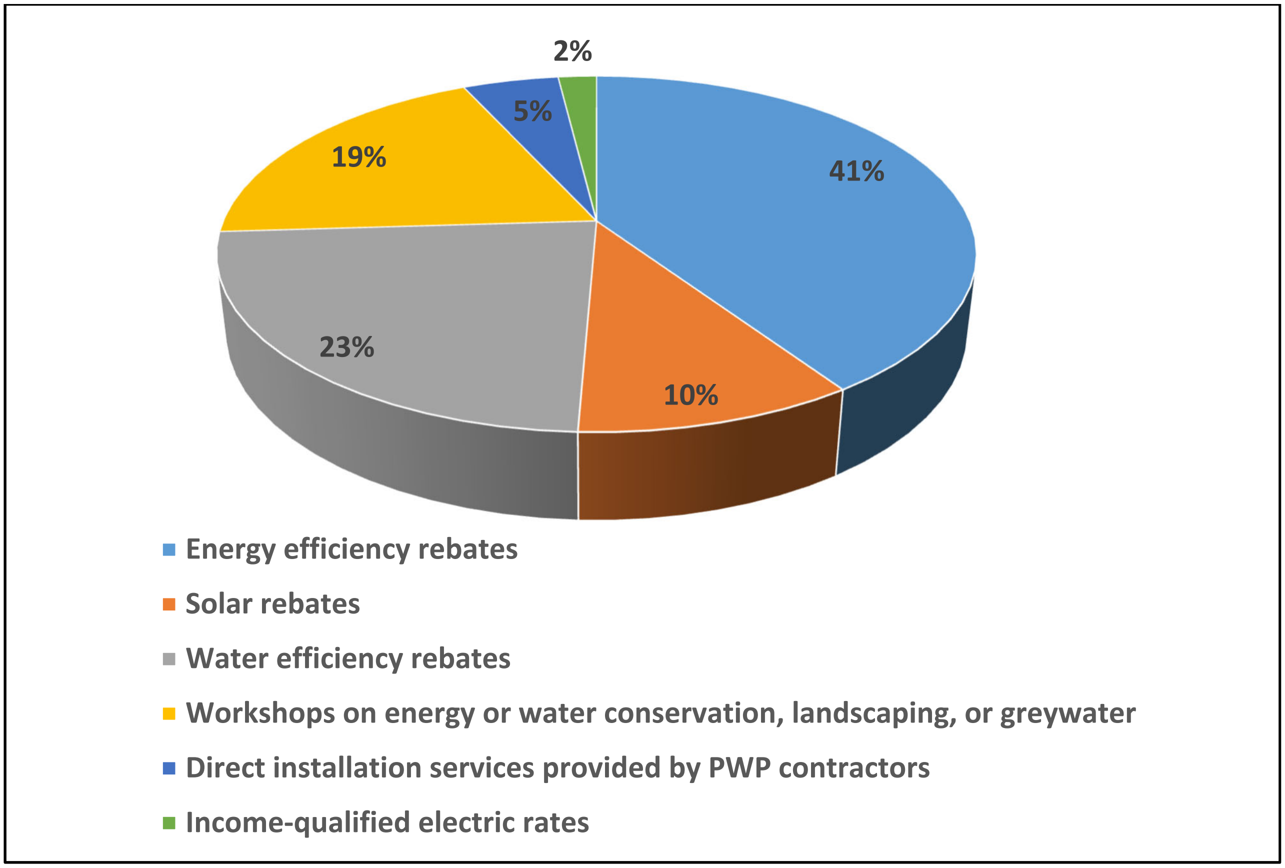
Question #8:

	Responses	#	%
Would you support an electric rate increase to implement the recommendations of the Power IRP?	Yes	167	58%
	No	120	42%
	Total	287	100%



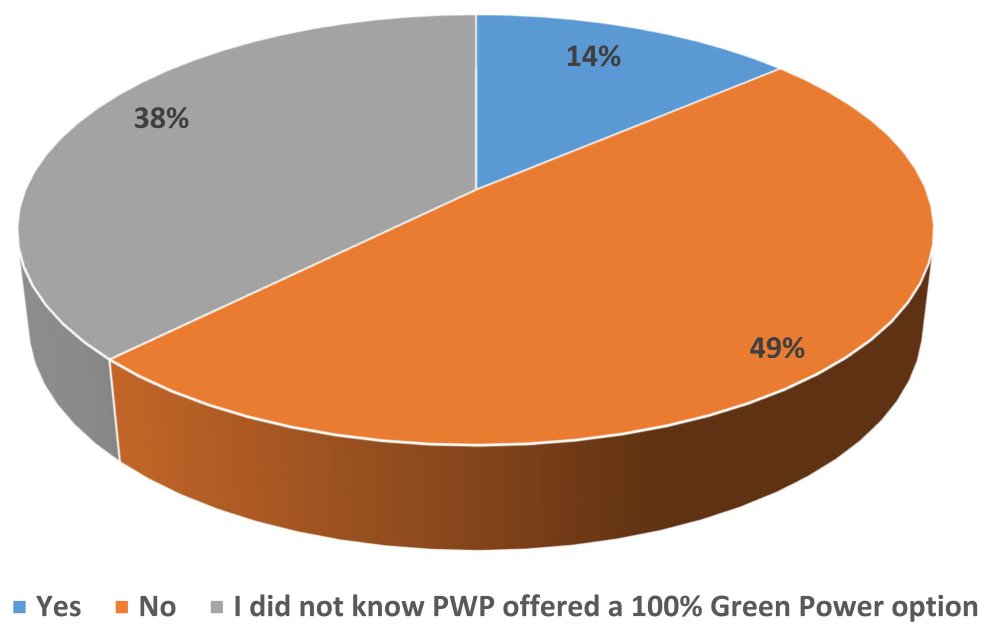
Question #9:

	Responses	#	%
Have you participated in any of the following programs offered by PWP? Select all that apply:	Energy efficiency rebates	125	41%
	Solar rebates	31	10%
	Water efficiency rebates	72	23%
	Workshops on energy or water conservation, landscaping, or greywater	59	19%
	Direct installation services provided by PWP contractors	15	5%
	Income-qualified electric rates	6	2%
	Total	308	100%



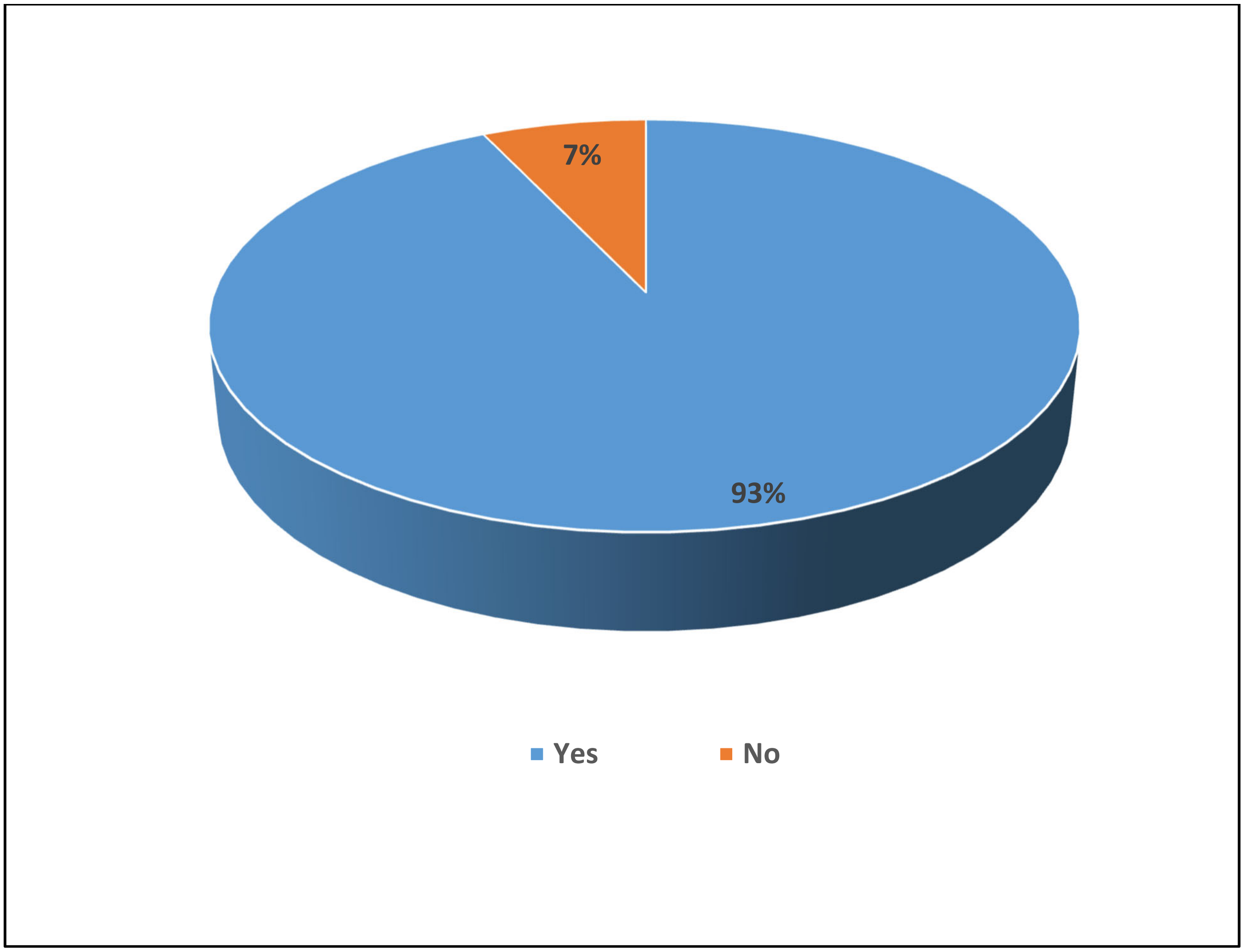
Question #10:

	Responses	#	%
Are you a Green Power Program customer (Do you pay additional money on your electric bill for Pasadena to purchase more renewable power)?	Yes	40	14%
	No	143	49%
	I did not know PWP offered a 100% Green Power option	110	38%
	Total	293	100%



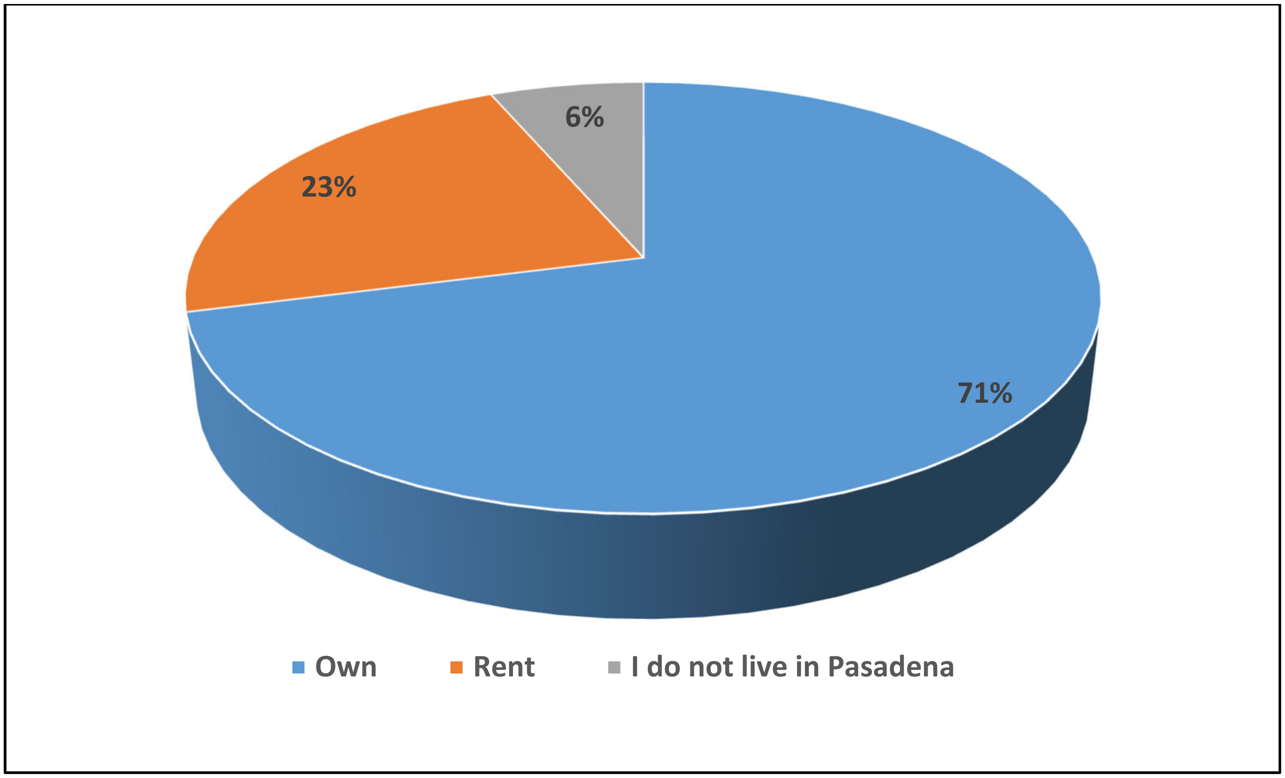
Question #11:

Do you live in Pasadena?	**Responses**	#	%
	Yes	275	93%
	No	21	7%
	Total	296	100%



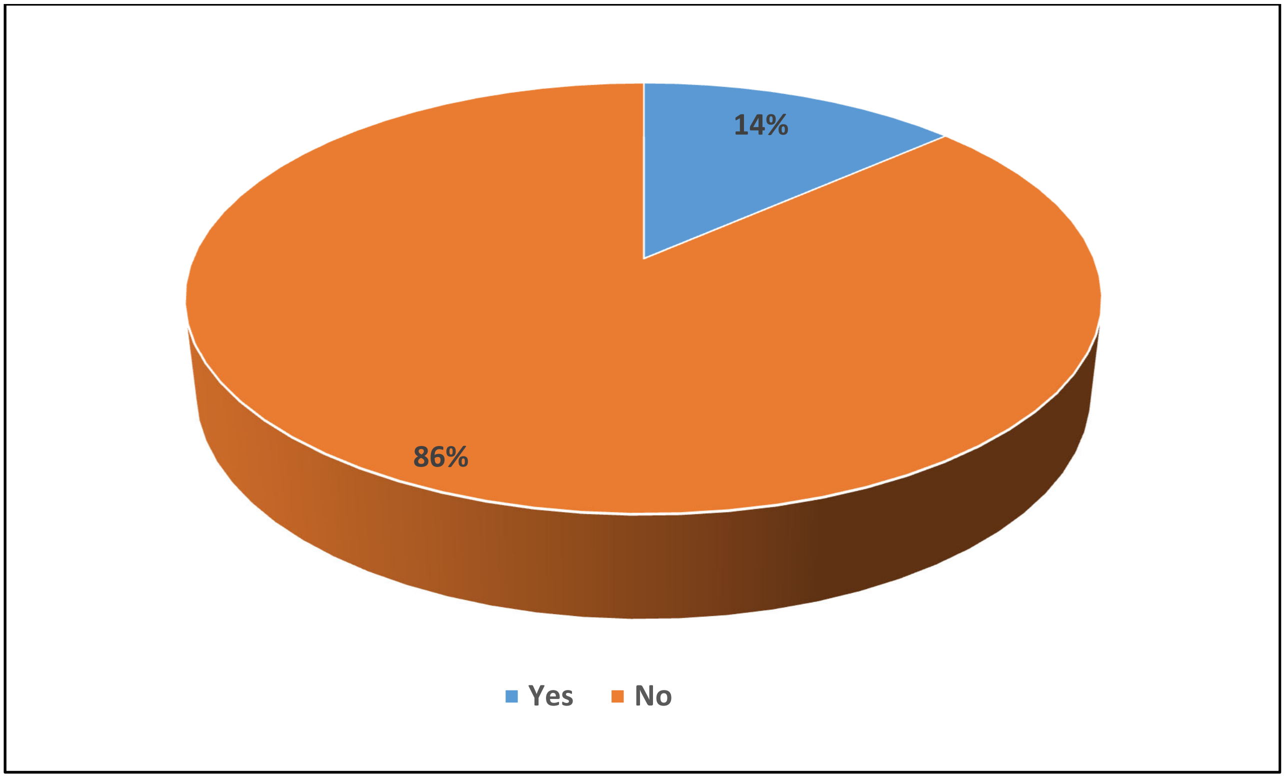
Question #12:

	Responses	#	%
If you live in Pasadena do you:	Own	208	71%
	Rent	66	23%
	I do not live in Pasadena	19	6%
	Total	293	100%



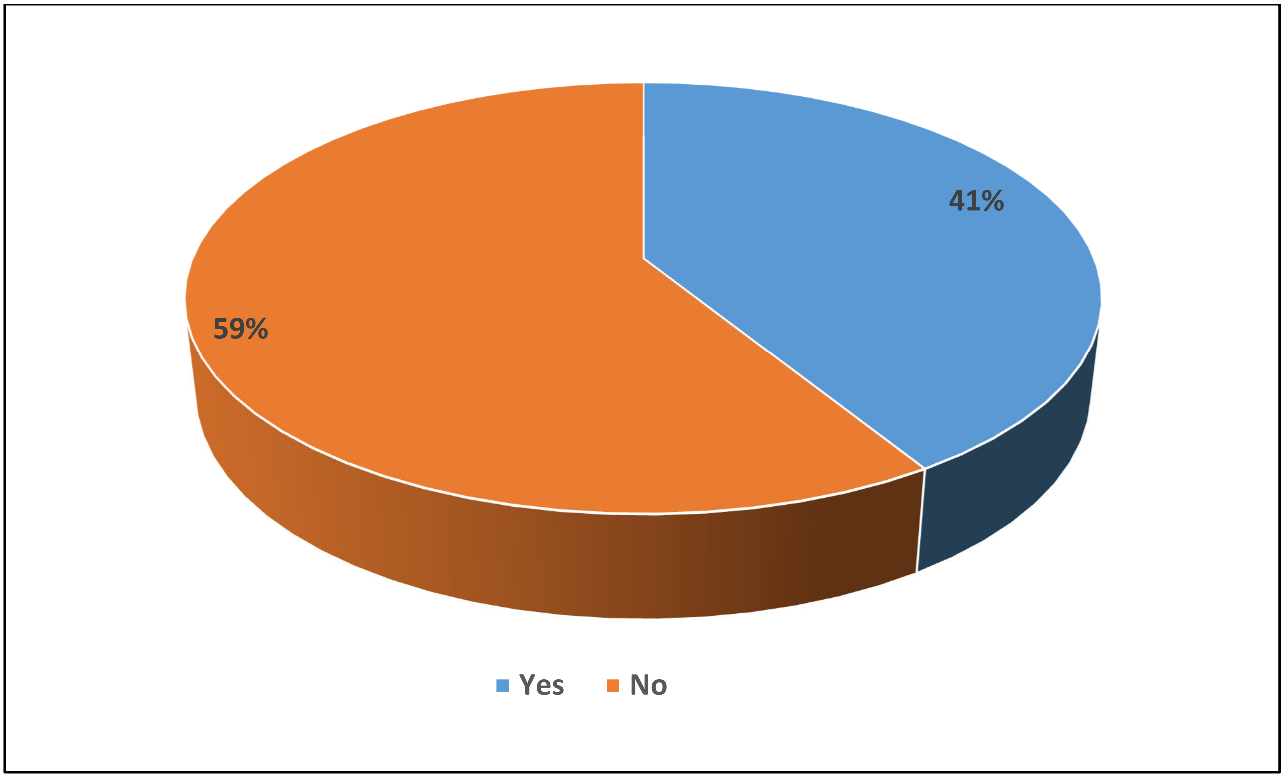
Question #13:

	Responses	#	%
Do you own or operate a business in Pasadena?	Yes	40	14%
	No	256	86%
	TOTAL	296	100%



Question 14:

Do you work in Pasadena?	**Responses**	#	%
	Yes	122	41%
	No	174	59%
	TOTAL	296	100%



2018 PWP POWER IRP: ATTACHMENT 7
CLIMATE ACTION PLAN AGENDA REPORT

Agenda Report

March 5, 2018

TO: Honorable Mayor and City Council

FROM: Planning & Community Development Department

SUBJECT: PASADENA CLIMATE ACTION PLAN (CAP)

RECOMMENDATION:

It is recommended that the City Council:

1. Adopt the Negative Declaration (Appendix E of Attachment A); and

2. Adopt the Pasadena Climate Action Plan (Attachment A) by resolution to implement Program B.3 of the Land Use Element of the General Plan; and

3. Direct the City Attorney to prepare amendments to Chapter 2.140 of the Pasadena Municipal Code to make the primary function of the Environmental Advisory Commission the monitoring of the implementation of the Climate Action Plan and establish that Commission meetings shall be quarterly.

MUNICIPAL SERVICES COMMITTEE RECOMMENDATION:

On January 23, 2018, the Municipal Services Committee (MSC) unanimously voted to recommend approval of the draft CAP and supported that the Environmental Advisory Commission have responsibility for monitoring and advising of the CAP.

ENVIRONMENTAL ADVISORY COMMISSION RECOMMENDATION:

On January 18, 2018, the Environmental Advisory Commission (EAC) unanimously voted to recommend that the City Council adopt by resolution the draft CAP with the suggestion to involve the Commission in monitoring and advising of the CAP in order to address concerns regarding the need for greater specificity within the draft CAP's stated actions and implementation.

EXECUTIVE SUMMARY:

Climate change presents Pasadena with both challenges and opportunities. During the past decade, Pasadena has pursued a variety of programs and policies that promote alternative modes of transportation, increase energy efficiency of new buildings, expand recycling, ban plastic bags and polystyrene products, and conserve natural resources to proactively reduce its carbon footprint and greenhouse gas (GHG) emissions. In the fall of 2015, the City embarked on a process to develop a climate action plan, a strategic framework for measuring, planning, and reducing the City's share of GHG emissions. The Pasadena Climate Action Plan (CAP) sets forth a strategy that builds upon existing programs and policies that address climate change, identifies where these existing efforts can be expanded, and ultimately establishes a roadmap that not only enables the City to reach the State's reduction targets called forth under Executive Order (EO) S-3-05, Assembly Bill (AB) 32, and Senate Bill (SB) 32 but is also consistent with the State's climate strategy. Overall, the CAP's strategies were developed based on three major factors: (1) consideration of the reductions needed to meet state-wide targets and local goals, (2) the sources and distribution of emissions revealed in the GHG inventory, and (3) the existing programs, policies and resources of Pasadena. The CAP is subject to future revisions as new technologies emerge and State legislation, such as CARB's 2017 Climate Change Scoping Plan, are adopted.

The CAP is divided into five strategies, 27 measures, and 142 actions that have the potential to reduce local GHG emissions from community-wide activities of residents, businesses, and municipal operations. The role of the CAP document is to:

- analyze the City's GHG emission levels and identifies major contributors;
- establish a baseline from which future GHG emissions will be compared;
- set local reduction goals and develop a strategy consistent with California's targets consistent with AB 32, SB 32, and EO S-3-05;
- identify existing and new programs to achieve reductions;
- monitor and evaluate progress;
- require new development projects subject to CEQA to reduce their share of emissions by demonstrating consistency with the CAP;
- serve as a qualified GHG emission reduction strategy consistent with the California Environmental Quality Act (CEQA) Guidelines Section 15183.5; and
- implement the Land Use Element of the General Plan.

BACKGROUND:

In response to the threat of climate change, different legislation, regulations, and executive orders have been enacted by the State to achieve robust GHG emissions reductions while addressing the impacts of a changing climate. In 2006, California passed the Global Warming Solutions Act, AB 32, becoming the first state in the U.S. to mandate state-wide reductions in GHG emissions as an effort to combat climate change. AB 32 established a state-wide target to reduce GHG emissions to 1990 levels by 2020. In 2016, the enactment of SB 32 extended this commitment by raising the emissions reduction target to 40 percent below 1990 levels by 2030, demonstrating California's commitment towards achieving the overall state-wide target of reducing emissions 80 percent below 1990 levels by 2050 (as established in EO S-3-05).

Local governments have a vital role in assisting the State's climate change initiatives. In 2006, the City adopted the Green City Action Plan and compiled a "green team" to oversee the plan's sustainability goals and develop a sustainability program. The sustainability program continues throughout several City departments and includes work programs such as Public Works' Zero Waste Strategic Plan, Pasadena Water and Power's Power Integrated Resources Plan, and Department of Transportation's Bicycle Transportation Action Plan.

The preparation of the CAP involved a comprehensive review of the City's existing efforts and analyzed which programs or policies could contribute to potential GHG reductions. The CAP demonstrates the City's commitment towards achieving the state-wide emissions reduction targets and serves as a qualified GHG reduction plan per the CEQA Guidelines Section 15183.5. The timeframe for the CAP extends from the date of adoption through the year 2035, consistent with the horizon year of the 2015 General Plan.

PROJECT DESCRIPTION:

Pasadena's GHG Emissions Reduction Goals

The CAP establishes the following GHG emissions reduction goals that are consistent with the state-wide targets called for in AB 32, SB 32, and EO S-3-05, as shown in Figure 1.

Figure 1 – CAP Goals and State-wide GHG Emissions Reduction Targets

Year	State-wide GHG Emissions Reduction Targets	CAP GHG Emissions Reduction Goals (relative to 2009 baseline and state-wide targets)
2020	1990 levels by 2020 per AB 32	27% below 2009 levels by 2020 (equivalent to 14% below 1990 levels)
2030	40% below 1990 levels by 2030 per SB 32	49% below 2009 levels by 2030 (equivalent to 40% below 1990 levels)
2035	The state does not have a 2035 target	59% below 2009 levels by 2035 (equivalent to 59% below 1990 levels)
2050	80% below 1990 levels by 2050 per EO S-3-05	83% below 2009 levels by 2050 (equivalent to 80% below 1990 levels)

Pasadena's GHG Emissions (2009 Baseline Inventory)

A community-wide inventory of GHG emissions was prepared for the year 2009 to establish a baseline, or a reference point, from which the City could set future emissions reduction goals and measure progress. The 2009 baseline inventory accounts for emissions in metric tons of carbon dioxide equivalent (MT CO_2e) resulting from four sectors: energy, transportation, water, and solid waste. In 2009, community-wide GHG emissions were approximately 2,044,921 MT CO_2e. As shown in Figure 2, the transportation sector accounted for the largest portion of emissions, contributing approximately 52 percent of the community-wide total. Energy use was the second largest producer of emissions, contributing approximately 47 percent of the community-wide total. *For more information on the 2009 baseline inventory refer to Chapter 2 of the CAP.*

Figure 2 – Community-wide Emissions (2009 Baseline)

Sector	Primary Sources of Emissions	2009 MT CO_2e (Baseline)
Energy	Electricity and natural gas consumption by residents and businesses	956,239
Transportation	Vehicle fuel consumption	1,054,901
Waste	Methane generation from the decomposition of solid waste sent to landfills	15,019
Water	Electricity used to transport, treat, and pump water consumed by residents and businesses	18,792
	TOTAL	**2,044,921**

Pasadena's GHG Emissions Forecast

An emissions forecast was also prepared for Pasadena to better understand how projected trends in energy use, driving habits, population growth, and employment expansion will affect future GHG emissions in the community. Based on Pasadena's adjusted forecast, which accounts for a number of state-level programs that have been enacted since 2013, community-wide emission is forecasted to be 1,671,934 $MTCO_2e$ by 2020 (approximately four percent below the state-wide target). It is forecasted that community-wide emissions will continue to decline over the next few decades and by 2050 emissions are forecasted to be 1,262,573 $MTCO_2e$. Despite the City's recent efforts to combat climate change, if no additional actions are taken, it will likely fall short of meeting the state-wide targets for the years 2030 and 2050 by approximately 365,153 MT CO_2e and up to 957,151 MT CO_2e, respectively, as shown in Figure 3. *For more information on the GHG emissions forecast refer to Chapter 2 of the CAP.*

Figure 3- Comparison of Pasadena's Adjusted Forecast and State-wide Targets

	2020 (MT CO_2e)	2030 (MT CO_2e)	2050 (MT CO_2e)
Adjusted Emissions Forecast	1,671,934	1,408,063	1,262,573 – 1,304,788
State-wide Targets	1,738,183 (15% below 2009 levels)	1,042,910 (49% below 2009 levels)	347,637 (83% below 2009 levels)
Reductions Needed to Achieve State-wide Targets	0	365,153	914,936 – 957,151

Pasadena's GHG Emissions Reduction Strategy

The CAP identifies five principle strategies to achieve the City's GHG reduction goals for the years 2020, 2030, and 2035: (1) Sustainable Mobility and Land Use, (2) Energy Efficiency and Conservation, (3) Water Conservation, (4) Waste Reduction, and (5) Urban Greening. It is important to note that although the CAP includes a reduction goal for the year 2050, no measures were developed due to a wide range of variables such as future state-level programs and new technologies or legislation that cannot be accounted for at this time. The following is a brief summary of each of the strategies that have been informed by community input and feedback from various City departments.

1) **Sustainable Mobility and Land Use** –focus on the reduction of GHG emissions from transportation fuel consumption by reducing vehicle miles traveled (VMT) and improvement of traffic flow. This strategy aims to create an interconnected transportation system and land use pattern that shifts travel from personal automobile to walking, biking, and public transit by improving pedestrian and bicycle infrastructure, enhancing carpooling and public transit services, supporting pedestrian and transit-oriented development, expanding the use of electric vehicles and related infrastructure, and improving the City's vehicle fleet.

2) **Energy Efficiency and Conservation** –focus on the reduction of GHG emissions by changing both energy demand and supply. The objective of this strategy is to minimize energy consumption, create high-performance buildings, and transition to clean, renewable energy sources by enhancing energy performance requirements for new construction and energy efficiency retrofits for

existing buildings, increasing the use of carbon-neutral and renewable energy, and improving community energy management.

3) **Water Conservation** – focus on the reduction of GHG emissions by conserving water. The purpose of this strategy is to promote water conservation and efficiency in both indoor and outdoor uses by increasing access to and use of recycled water and improving storm water infiltration.

4) **Waste Reduction** –focus on reducing GHG emissions associated with land filling, collection, and transportation of waste as well as the methane generation from the decomposition of solid waste sent to landfill and combustion facilities. Waste reduction measures aim to improve waste management and promote reuse, recycling, and composting.

5) **Urban Greening** – focus on the reduction of GHG emissions through the planting, care, and management of all vegetation in Pasadena including both developed natural areas such as street trees, landscaping, parks, and undeveloped natural areas and open space. Trees and other green space reduce GHG emissions by absorbing and capturing the GHG, carbon dioxide, from the atmosphere, also known as a process called carbon sequestration. Measures under this strategy seek to maintain a healthy urban forest by preserving greenspace and increasing the number of trees in Pasadena.

Each strategy includes a series of measures that define the direction the community and the City will take in order to accomplish state-wide targets and local reduction goals. The CAP contains 27 climate action measures that are regulatory, incentive-based, or voluntary. Overall, these measures were developed based on consideration of the reductions needed to meet state-wide targets and local goals, the sources and distribution of emissions revealed in the GHG inventory, and the existing priorities and resources of Pasadena. *Table 3.5 in Chapter 3 of the Proposed CAP outlines the CAP measures and potential GHG emissions reduction.*

Potential GHG Emissions Reductions from Implementing the CAP

In total, the strategies presented in the CAP have the potential to reduce emissions by approximately 181,197 MT CO_2e in 2020 and 458,181 MT CO_2e in 2035, creating the opportunity for Pasadena to achieve its GHG emissions reduction goals, as shown in Figure 4.

The transportation and energy sectors offer the most reduction potential. A significant proportion of Pasadena's residential buildings were built more than 30 years ago, prior to the adoption of California's energy efficiency standards. Considerable opportunities exist to reduce energy consumption, utilize energy more efficiently, and increase use of renewable energy within these structures. Pasadena also has a high potential to expand the availability and use of alternative fuel vehicles and fueling infrastructure to further reduce greenhouse gas emissions.

Figure 4- GHG Emissions Reduction Potential by Strategy (2020 and 2035)

	2020 (MT CO_2e)	% of total emission reductions in 2020	2035 (MT CO_2e)	% of total emission reductions in 2035
Sustainable Mobility and Land Use	66,288	37%	242,680	53%
Efficient Energy and Conservation	108,299	60%	199,044	43%
Water Conservation	1,867	1%	1,916	<1%
Waste Reduction	4,559	3%	14,197	3%
Urban Greening	184	<1%	344	<1%
Anticipated Reductions from CAP Implementation	**181,197**	--	**458,181**	-
Reductions Needed to Achieve Local CAP Goals	**179,141**	--	**437,710**	-

CAP Implementation and Monitoring

To achieve the GHG reduction goals established in the CAP, considerable changes within the community over the next few decades will be critical. To ensure this transformation is realized, each of the climate action measures is supported by a set of implementation actions intended to define the specific steps that both the City and the community will implement over time. The CAP contains 142 implementation actions that are ambitious, yet attainable and include a combination of ordinances, policies, programs, and incentives, as well as outreach and educational activities. Chapter 4 of the Proposed CAP provides an implementation chart for each climate action measure and details different action steps, the department(s) responsible for implementation, general timeline to achieve those actions, performance indicators, and estimated potential GHG reductions for the years 2020 and 2035. *Refer to Chapter 4 for additional information on the implementation actions.*

One of the benefits of adopting a local CAP is the ability to streamline the environmental review of projects. Per CEQA Guidelines Section 15183.5, the CAP is a qualified GHG reduction plan and allows the City to analyze the impacts associated with GHG emissions at a programmatic level so that project level environmental documents may tier from programmatic review. Since it is anticipated that GHG reductions will need to be achieved through better environmental and sustainable performance by new development projects, the CAP includes a consistency checklist that supports the achievement of individual measures at a project level. Not only is the checklist a tool for new development projects that are subject to CEQA to demonstrate consistency with the CAP, but it also supports the City in achieving its emissions reduction goals. *Refer to Appendix D of the CAP for more information on the checklist.*

To monitor and evaluate the CAP's progress towards meeting the emissions reduction goals, a GHG emissions inventory will be conducted for the year 2020 and approximately every five years thereafter. If the inventory reveals that the CAP is not making the anticipated progress towards meeting reduction goals, the effectiveness of the measures and/or actions will be evaluated and modified as necessary. Following the inventory, a report will be prepared to update the City Council, residents, and other interested stakeholders on the overall progress of the CAP. Along with the inventory, staff will track the progress of CAP measures and implementation actions, including the performance indicators, and provide an annual update to the EAC and City Council. If necessary, the report will provide recommendations for changes to the implementation strategy or the CAP itself.

Additionally, staff is recommending that the City Council formally designate, through an amendment to Title 2 of the Pasadena Municipal Code, the EAC as the advisory body that should monitor and make recommendations related to the implementation of CAP. The EAC has a broad charge related to promoting environmental stewardship and urban sustainability, as set forth in Chapter 2.140 of the Municipal Code, and as such it is the logical body to serve in the suggested capacity. Staff is also recommending that the City Council modify the frequency of Commission meetings from no less than monthly, to no more than quarterly. The Commission is staffed by the Planning and Community Development Department. Given current and anticipated future workloads supporting monthly meetings has placed a strain on limited staff resources which are desperately needed to attend to other projects within the Department. Further, staff believes that quarterly meetings should be sufficient to allow the Commission to fulfill its mission, including the proposed addition of the CAP.

Community Meetings

As part of the CAP development process, staff solicited public input at two community meetings, two public hearings with the EAC, meetings with community organizations, and resident surveys.

The first community meeting was held on May 31, 2016 at the Lincoln Avenue Baptist Church with approximately 60 attendees to introduce the project and gather initial feedback. In general, residents were supportive of the Climate Action Plan and offered several ideas on how the City can reduce its GHG emissions. These public comments along with input from various City departments helped to inform proposed strategies and measures that were presented in the second community workshop. The second meeting was held on March 23, 2017 at the Throop Unitarian Universalist Church with more than 80 participants. The City received a variety of comments such as the suggestion of using carbon neutral and renewable energy, providing incentives for electric vehicle charging infrastructure, installing additional bike lanes to reduce auto-dependency, and reducing the carbon footprint of hauling waste within Pasadena.

Public Hearings

On January 18, 2018, staff presented the draft CAP to the EAC and five individuals provided comments. Most of the comments pertained to the implementation and monitoring of the draft CAP. Additional comments included a recommendation to expand the City's mulch program, a request to present the draft CAP to the Transportation Advisory Commission (TAC) for its consideration on the transportation-related actions, a request for the City to review existing hauling and recycling programs, and a request that the City consider implementation of the draft CAP when reviewing long-term contracts.

Shortly after, staff presented the CAP to the MSC on January 23, 2018. Eight individuals commented on the draft document. Similar comments from EAC emerged at MSC regarding the implementation, enforceability, and monitoring of the draft CAP, as well as a request to present the draft CAP to the TAC for its consideration. Comments also included requests to diversify the City's energy portfolio to consist of multiple fuels and technologies, increase the City's goal for electric charging stations, upgrade City buses with electric powered vehicles, support transit-oriented development with unbundled parking for multi-family units, expand recycling services for multi-family apartments, separately reassess the performance indicators for new trees and consider a tree canopy inventory, create a connected east-west bicycle lane, compare the total length of roads in Pasadena with the CAP's proposed goal of 18 new miles of bike lanes, review potential partnerships with public organizations, and avoid long-term fossil-fuel contracts.

ENVIRONMENTAL DETERMINATION:

A Negative Declaration has been prepared in compliance with the California Environmental Quality Act (CEQA) provisions and City Guidelines (Attachment B - Initial Study and Negative Declaration). The Initial Study has determined that the proposed project would not have a significant effect on the environment and no mitigation is required.

The public review period for the Initial Study and Negative Declaration commenced on December 28, 2017 and concluded on February 10, 2018. Copies of the Draft Initial Study and Negative Declaration have been available to the public. No public comments were received.

FISCAL IMPACT:

There is no direct fiscal impact associated with the approval of the proposed CAP. While the City may be eligible for grant funded resources in the future to assist with CAP implementation, there will also be costs to various City departments associated with implementation of the CAP that remain unknown at this time.

Respectfully Submitted,

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Attachment: (1)

Attachment A - Draft Pasadena Climate Action Plan