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CITY OF RIVERSIDE

PUBLIC UTILITIES

2023

RIVERSIDE PUBLIC UTILITIES
INTEGRATED RESOURCE PLAN

RESOURCE OPERATIONS & STRATEGIC ANALYTICS DIVISION

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Riverside Public Utilities

Our Mission

The City of Riverside Public Utilities Department is committed to the highest quality water and electric services at the lowest possible rates to benefit the community.

Our Ten-Year Vision

Our customers will recognize Riverside Public Utilities as a unique community asset with a global reputation for innovation, sustainability and an enhanced quality of life.

Our Core Values

The City of Riverside Public Utilities Department values:

Safety

Honesty and Integrity

Teamwork

Professionalism

Quality Service

Creativity and Innovation

Inclusiveness and Mutual Respect

Community Involvement

Environmental Stewardship

2023 Integrated Resource Plan

January 31, 2024

Riverside Public Utilities

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Executive Summary

This *2023 Integrated Resource Plan* ("IRP") provides an impact analysis of Riverside's acquisition of new power resources, specifically towards meeting the state of California's aggressive carbon reduction goals; along with the effect these resources will have on Riverside Public Utilities' future projected power supply costs. Both current and proposed supply-side and demand-side resources are examined in detail, towards a goal of continuing to provide the highest quality electric services at the lowest possible rates to benefit our local community, while adhering to a diverse set of local, state, and regional legislative/regulatory mandates. Additionally, this 2023 IRP examines several related longer range planning activities, including battery energy storage (BES), transportation electrification (TE), distributed energy resources (DER), preliminary distribution system studies for accommodating increasing TE and DER penetration levels, and Riverside Public Utilities' (RPU) current and future planned engagement with disadvantaged communities.

In the most general sense, an IRP can be seen as a forward planning process for acquiring and delivering electrical services in a manner that meets multiple objectives for resource use. This 2023 IRP reviews and analyzes both intermediate term (5-year forward) and longer term (20-year forward) resource portfolio and energy market issues, along with the related longer range planning activities mentioned above. The goals of this IRP are multi-fold, but can be broadly summarized as follows:

- To provide an updated overview of RPU's (a) energy and peak demand forecasts, (b) current generation and transmission resources, and (c) existing electric system.

- To review and assess the impact of important legislative and regulatory mandates imposed by various state or regional agencies (California Energy Commission, California Air Resources Board, South Coast Air Quality Management District, etc.), along with the impact of important active or proposed California Independent System Operator (CAISO) stakeholder initiatives.

- To summarize and assess the utility's current set of Energy Efficiency (EE) and Demand Side Management (DSM) programs and assess the overall cost-effectiveness of these EE/DSM programs with respect to both the utility and all utility customers (i.e., both participating and non-participating customers).

- To review and quantify the most critical intermediate term power resource forecasts, specifically with respect to how RPU intends to meet its (a) projected energy, capacity, and resource adequacy requirements, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, and (d) power resource budgetary objectives.

- To examine and analyze certain critical longer term power resource procurement strategies and objectives, specifically those that will help RPU reach its 2030 and 2040 carbon reduction goals and quantify how such strategies and objectives might impact the utility's future power supply costs.

- To begin to assess how various emerging technologies may concurrently impact RPU's existing distribution system, to better define future actions that continue to support the utility's fundamental objective of providing reliable electrical services at competitive rates.

The entirety of this IRP document contains nineteen (19) Chapters and three (3) Appendices. The chapter organization and layout sequentially follows the general goals discussed above; i.e., background information (Chapters 2-4), mandates and initiatives (Chapter 5), EE and DSM programs (Chapters 6 and 14), forward market views and intermediate term portfolio forecasts (Chapters 7-8), longer term resource planning issues (Chapters 9-12), preliminary distribution studies on TE/DER impacts (Chapter 13), and related IRP topics (rate design, TE efforts, disadvantaged communities, and IRP topics requiring further research: Chapters 15-18). The interested reader can find brief descriptions of each chapter and appendix contained in this IRP document in the Introduction (Chapter 1). Likewise, succinct summaries of the most important staff findings can be found in the Conclusion (Chapter 19).

Table of Contents

1. Introduction

This *2023 Integrated Resource Plan* ("IRP") provides an impact analysis of Riverside's acquisition of new power resources, specifically towards meeting the state of California's aggressive carbon reduction goals, along with the effect these resources will have on Riverside Public Utilities future projected power supply costs. Both current and proposed supply-side and demand-side resources are examined in detail, towards a goal of continuing to provide the highest quality electric services at the lowest possible rates to benefit our local community, while adhering to a diverse set of local, state, and regional legislative/regulatory mandates. Additionally, this 2023 IRP examines several related longer range planning activities, including battery energy storage (BES), transportation electrification (TE), distributed energy resources (DER), preliminary distribution system studies for accommodating increasing TE and DER penetration levels, and Riverside Public Utilities' (RPU) current and future planned engagement with disadvantaged communities.

In the most general sense, an IRP can be seen as a forward planning process for acquiring and delivering electrical services in a manner that meets multiple objectives for resource use. However, the focus of an IRP can and will evolve over time, depending upon each utility's specific situation. This 2023 IRP reviews and analyzes both intermediate term (5-year forward) and longer term (20-year forward) resource portfolio and energy market issues, along with the related longer range planning activities mentioned above. The goals of this IRP are multi-fold, but can be broadly summarized as follows:

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❖ To begin to assess how various emerging technologies may concurrently impact RPU's existing distribution system, so that staff can better define future distribution system improvements that continue to support the utility's fundamental objective of providing reliable electrical services at competitive rates.

1.1 Resource Planning: Guiding Principles and Current Strategies

RPU's resource portfolio has evolved over time to address key issues such as CAISO market price volatility, various fuel and delivery risk tolerances, internal generation and distribution needs, and load and peak demand growth. Price stability, cost effectiveness, and technology diversification have represented the traditional guiding principles used by the utility when selecting generation assets or contracts. Consistent with the generation technologies of the 1980s and 1990s, RPU had historically relied upon coal and nuclear assets for much of its base-load energy needs, along with various energy exchange contracts and forward market purchases to meet its summer peaking needs. However, after the 2000-2001 California Energy Crisis, RPU embarked upon developing more natural gas power plants within its distribution system in order to better meet local reliability requirements and summer peaking needs in an economical and reliable manner.

Additionally, over the last twenty years, RPU's portfolio of generation assets has evolved to meet new regulatory mandates, particularly the need to achieve specific greenhouse gas (GHG) reduction targets and a commitment to incorporate an increasing percentage of renewable resources. The utility entered into its first significant contracts for renewable energy in 2002 and 2003, met a 20% RPS goal in 2010, exceeded the 33% RPS goal in 2020 and is currently expected to exceed the 60% by 2030 RPS mandate three years ahead of schedule. It is worth noting that over the last ten years, all new RPU portfolio resource additions have been exclusively renewable assets; i.e., wind, solar, and geothermal contracts.

To the extent possible, RPU assesses and applies a set of high-level guiding principles when examining the feasibility of adding a new generation asset or contract to its existing portfolio of resources. While no single contract or asset can ever be expected to represent an optimal choice with respect to all of these principles, the best contracts or assets ensure that most of these principles are satisfied. These guiding principles can best be expressed in the form of the following questions: "Does the new asset or contract…"

- Ensure wholesale and/or retail price stability?
- Maintain or improve the technology diversification within RPU's existing portfolio?
- Support or improve local and/or system reliability needs?
- Meet RPU's cost effectiveness criteria?
- Properly align with RPU's daily and/or seasonal load serving needs?
- Reduce RPU's carbon footprint and/or increase RPU's renewable energy supply?
- Support RPU's commitment to Environmental Stewardship?

Table 1.1.1 presents more detailed justifications and rationale for each guiding principle.

Table 1.1.1. Detailed justification and rationale for each guiding principle (for assessing the feasibility and desirability of new assets or contracts).

Guiding Principle	Justification / Rationale
Price Stability	At the most fundamental level, RPU procures assets or contracts to ensure energy price stability; i.e., to meet the City's load serving needs with a high degree of price certainty. Optimal assets/contracts will offer either a fixed price structure, or a price structure that can be effectively forward hedged.
Technology Diversification	A portfolio that relies too much on a single type of generation technology or fuel source is more vulnerable to catastrophic technology or fuel disruptions. In contrast, portfolios that contain a wide variety of technology and fuel sources are much more robust to such disruptions.
Local/System Reliability	As a Load Serving Entity (LSE), RPU must ensure that it can effectively meet its system peaking needs under all reasonable conditions. Assets or contracts that provide either system or local capacity attributes help PRU effectively meet these needs.
Cost Effectiveness	The development or contract cost for different technologies can vary significantly over time. However, at any point in time it is typically possible to evaluate the cost effectiveness of a particular asset, and/or perform cost comparisons and generation revenue studies, etc., to determine the overall competitiveness of a specific offer. Obviously, assets or contracts that are more cost effective are preferable.
Energy Alignment	Again, as an LSE, RPU's fundamental goal is to reliably and cost effectively meet its load serving needs at all times of the day, every day of the year. Thus, assets or contracts that can provide more fixed-price power to the distribution system when load serving needs are greatest helps RPU met this goal.
Carbon Footprint	As California moves forward with its AB32 GHG reduction mandates, it is becoming critically important to procure assets and/or contracts with zero or near-zero Carbon footprints. (Note: these GHG reduction mandates essentially determine and direct California RPS goals.)
Environmental Stewardship	Every asset has some degree of environmental impact, regardless of its technology base. Whenever possible, RPU should demonstrate good environmental stewardship by procuring assets and contracts with minimal environmental impacts, and/or by supporting local, state, and federal policies and regulations that support the cost effective development of such assets and contracts.

At this current point in time, RPU remains uniquely positioned with respect to its power resource portfolio. For the last twelve years RPU has embraced an active plan to significantly increase the percentage of renewable energy resources in its resource portfolio, and within the last ten years RPU has signed power purchase agreements (PPA's) for thirteen new or existing renewable energy projects. Due to these purchases, RPU is on track to potentially serve 68% of its retail electrical load with renewable energy by 2027.

Beyond 2027, RPU still faces some very important power supply decisions. The Intermountain Power Project (IPP) is scheduled to shut down its two 900 MW coal units by July 1, 2025, and replace these with a single 840 MW combined cycle natural gas (CCNG) unit. This IPP "repowering project" will scale back Riverside's share of generation energy from 136 MW to just 64 MW from July 2025 through June 2027, after which the IPP contract will terminate. RPU's recent signing of the new SunZia contract (starting in April 2026, see Chapter 3) is expected to deliver enough new wind energy to replace the 72 MW of 2025 derated IPP capacity. However, one or more additional contracts will need to be identified and secured to replace the final 64 MW of natural gas energy (ending after June 2027). Additionally, the utility will need to identify and implement an even more aggressive renewable (and/or carbon free) energy procurement strategy during the next decade, so that RPU can successfully achieve carbon neutrality by or before 2040.

Furthermore, the aggressive drive by the state of California towards distributed energy resources, energy storage technology and transportation electrification is fundamentally changing how the distribution grid is expected to operate. Rapid changes within the electric industry are forcing both publicly owned and investor owned utilities to develop new ways to integrate these various technologies in an efficient manner, and in some cases even challenging how utilities have traditionally planned for distribution grid improvement efforts. Thus, RPU must ensure that it adopts and incorporates the necessary strategies, tools, and technologies to adapt to these changes, in order to remain an integral, relevant, and sustainable part of the City of Riverside's broader infrastructure.

Perhaps most importantly, it should be emphasized that RPU is a pro-active participant in the CAISO MRTU wholesale energy market. The wholesale power markets in California are continuing to undergo unprecedented change, and many of these paradigm shifts have the potential to significantly alter the assumptions underlying this IRP. Hence, although this and future Integrated Resource Plans are intended to form the basis for formulating and executing supply-side and demand-side strategies, Power Resources Division staff must retain the flexibility to quickly adapt to changing market conditions and paradigms as circumstances develop. Therefore, like all previous IRP's, this latest IRP should continue to be viewed as a baseline roadmap to help guide our potential future long-term decision-making process, rather than as an absolute set of unmodifiable procurement recommendations.

1.2 Document Organization

The entirety of this IRP document contains nineteen (19) Chapters and three (3) Appendices. The chapter organization and layout sequentially follows the general goals discussed above; i.e., background information (Chapters 2-4), mandates and initiatives (Chapter 5), EE and DSM programs (Chapters 6 and 14), forward market views and intermediate term portfolio forecasts (Chapters 7-8), longer term resource planning issues (Chapters 9-12), preliminary distribution studies on TE/DER impacts (Chapter 13), and related IRP topics (rate design, TE efforts, disadvantaged communities, and

IRP topics requiring further research: Chapters 15-18). Additionally, Chapter 19 presents an overall summary of pertinent findings, Appendix A describes the Ascend production cost modeling software used to facilitate these IRP analyses, and Appendix B provides a reference to Ascend's CAISO Market Report (20-year forward forecasts). Finally, Appendix C presents the technical details associated with the avoided cost of energy calculations presented in Chapter 14, respectively.

Brief descriptions of each subsequent Chapter and Appendix contained in this IRP document are presented below.

Chapter 2. RPU System Load and Peak Demand Forecasts

Chapter 2 provides an overview of RPU's long-term energy and peak demand forecasting methodology. This overview includes a discussion of the econometric forecasting approach used by Power Resources Division staff, including the key input variables and assumptions and pertinent model statistics. This chapter also presents the baseline 2023-2045 system energy and peak demand forecasts used throughout this IRP.

Chapter 3. RPU Generation and Transmission Resources

Chapter 3 provides an overview of RPU's long term resource portfolio assets, including the utility's existing resources, future renewable resources (currently under contract), and recently expired contracts. Chapter 3 also describes RPU's transmission assets, as well as the utility's transmission control agreements with the CAISO.

Chapter 4. RPU Existing Electric System

Chapter 4 briefly reviews RPU's existing electric system and describes how it operates. RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities; it receives most of its system power through the regional bulk transmission system owned by SCE and operated by the CAISO. This chapter concludes with a discussion on the proposed Riverside Transmission Reliability Project (RTRP), which will provide a second point of interconnection to the bulk transmission system.

Chapter 5. Important Legislative and Regulatory Mandates and CAISO Initiatives

Chapter 5 outlines the current legislative, regulatory and stakeholder issues that will have significant impact to the California electric energy industry in the foreseeable future, specifically to the markets run by the CAISO. An assessment of each issue's current and potential future impact on RPU is also provided.

Chapter 6. Demand Side Management and Energy Efficiency

RPU is committed to making Riverside a greener place to live by supporting renewable energy, multiple EE and DSM programs, and sustainable living practices. Chapter 6 presents an overview of RPU's current EE and DSM programs and discusses the utility's projected EE/DSM energy saving targets and goals. This chapter also reviews the methodologies for determining the overall cost effectiveness of DSM and EE programs.

Chapter 7. Market Fundamentals

Chapter 7 presents an overview of the forward market data used by the Ascend Portfolio Modeling software platform. RPU obtains forward curve information for the Southern California electricity and natural gas markets from the Intercontinental Exchange (ICE); this forward ICE data has been used in conjunction with long term Ascend market price forecasts to calibrate all of the forward curve simulations for this IRP.

Chapter 8. Intermediate Term (Five-Year Forward) Power Resource Forecasts

Chapter 8 presents a detailed overview of RPU's most critical intermediate term power resource forecasts. These represent power supply forecasts and metrics that the Resource Planning & Analytics Unit routinely analyzes, monitors, and manages in order to optimize Riverside's position in the CAISO market and minimize the utility's associated load serving costs. These metrics include forecasted (a) renewable energy resources and projected renewable energy percentages, (b) primary resource portfolio statistics, (c) net revenue uncertainty metrics, (d) internal generation statistics, (e) hedging percentages and open energy positions, (f) GHG emission profiles and net carbon allocation positions, and (g) five-year forward Power Resource budget estimates.

Chapter 9. GHG Emission Targets and Forecasts

One of the primary purposes of the 2023 IRP process is to identify and assess the most cost-effective means for RPU to continue to reduce its GHG emissions, such that the utility can reach its specified 2030 emission and 2040 carbon neutrality targets. This chapter examines how much RPU's total GHG footprint must change (i.e., decrease) over time to meet CARB's August 2023 GHG Planning targets for Riverside. This issue is examined from the perspective of how much carbon-free energy RPU must have in its portfolio in order to meet these targets.

Chapter 10. Future Resource Adequacy Capacity Needs

Chapter 10 reviews RPU's future capacity needs for the 22-year time horizon from 2024 through 2045. Ultimately, these needs will be primarily influenced by Riverside's future load growth rate and the expiration of capacity resources. However, future capacity needs will also be significantly impacted by RPU's ability to obtain Maximum Import Capability (MIC) at various intertie points (where the utility has contracted resources that can supply RA). This chapter discusses these various capacity issues in detail, in addition to presenting Riverside's Net-Peak Demand analysis.

Chapter 11: Modeling Assumptions for Current and Future Generation Resources

Chapter 11 examines all of Riverside's existing resource contracts that are scheduled to end before December 2045. Some of these resources will definitely be retired, while the contracts for others are anticipated to be extended; this chapter identifies each of these resources and classifies them accordingly. This chapter also provides a narrative on RPU's rational and justification for extending the Palo Verde Nuclear contract from 2030 to 2045. Finally, Chapter 11 presents and defines the assumptions around a hypothetical set of new, renewable and/or carbon-free resources that will ensure that RPU can achieve carbon neutrality by 2040.

Chapter 12. Long Term (20 Year Forward) Portfolio Analyses

This chapter examines the projected budgetary impacts of the new renewable and carbon-free resources introduced in Chapter 11, specifically focusing on comparing two resource options in 2030. Additionally, this chapter examines the projected budgetary impacts of replacement options for the Springs and RERC generation facilities upon their assumed retirements. The budgetary assessments consider both the expected values and simulated standard deviations of RPU's resource portfolio cost over the 2024-to-2045-time horizon. Net value calculations for the proposed resources are also provided. These net value calculations will also facilitate a comparison to the energy efficiency programs discussed in Chapter 14.

Chapter 13. Distribution System Studies of Distributed Energy Resource Impacts

As part of the current Integrated Resource Plan, RPU has evaluated the distribution grid's sensitivity to continued customer adoption of DER technologies. This chapter presents a preliminary Integration Capacity Analysis (ICA) of each RPU distribution system feeder. The intent of this chapter's study is exploratory in nature and is not a formal forecast used for resource planning or capital investment planning purposes, since RPU does not currently have all the technology tools available to complete a formal forecast ICA. However, this study does identify the threshold levels of DER adoption that may trigger upgrades to distribution substation or feeder equipment, for various DER technologies.

Chapter 14: Evaluating the Impacts of Increasing Energy Efficiency Targets

Recall that Chapter 6 summarized RPU's adopted and forecast EE targets that are included in the power supply analysis. In contrast, Chapter 14 focusses on the costs and benefits of these programs and what the impact would be to RPU and its customers if higher targets are sought. Specifically, Chapter 14 examines the costs associated with three types of EE measures and compares them to the avoided costs of energy. Avoided cost analyses are differentiated between residential and commercial/industrial customer measures as well as whether the EE measure are for baseload, lighting, or air conditioning.

Chapter 15. Retail Rate Design

In 2022, staff began working on a new five-year rate plan. On September 19, 2023, the City Council adopted RPU's proposed new five-year (fiscal years 2023/24 through 2027/28) electric utility rate plan that will result in a five-year system average annual rate increase of 5.0% per year. Chapter 16 briefly reviews and summarizes the utility's new electric rate proposal, including its justification for why the new electric rate plan is fair and reasonable. This chapter also describes the new Self Generation tariff that the utility introduced and adopted in 2022, as well as new enhancements to the low-income and fixed-income assistance programs.

Chapter 16. Transportation Electrification

Chapter 16 presents an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. The discussion addresses the anticipated energy demand and reduced greenhouse gas (GHG) emissions that will result from the forecast transition of vehicles from using internal combustion engines (ICE) to electric motors. RPU is working closely with the City and is developing a plan to expand access to electric vehicle charging infrastructure as well as meet Citywide environmental and sustainability goals. This chapter reviews the policy and regulatory environment around transportation electrification, as well as the status of electrification in the RPU service territory. Finally, Chapter 16 also presents multiple forecasts for EVs and their associated loads and load profiles in the service territory, along with the corresponding calculations of the associated GHG emissions reductions.

Chapter 17. Minimizing Localized Air Pollutants and Greenhouse Gas Emissions in Disadvantaged Communities

RPU and the City of Riverside have long been committed to implementing the best existing and emerging sustainability practices, particularly in the areas of reducing air pollution and greenhouse gas emissions. Along these lines, Chapter 17 discusses disadvantaged and low-income communities in Riverside and then presents the utility's efforts to minimize local air pollutants and greenhouse gas emissions; focusing specifically on disadvantaged communities as required by Senate Bill 350. Additionally, RPU's efforts that specifically address the CEC Barriers Study report recommendations are also presented at the end of this chapter.

Chapter 18. Potential Future Studies

While staff believe that this 2023 IRP document has proposed a viable strategy for RPU's continuing efforts towards deep decarbonization, several of the planning issues examined in this document will most likely require further investigations and additional studies. Chapter 18 explores these issues in greater detail, specifically with respect to how future resource planning assessments might be strengthened, improved, and/or expanded. Topics that are briefly discussed in this chapter include (a) the role of future generation technologies (including hydrogen), (b) improved methodologies for performing more comprehensive distribution system ICA studies, (c) potential future DR and/or DSM efforts, and (d) the value and benefits of a more comprehensive and integrated future TE planning effort.

Chapter 19. Summary and Conclusions

Chapter 19 reviews and summarizes the core findings associated with the comprehensive Integrated Resource Planning activities addressed throughout this IRP document. A summary of where CEC staff can locate narratives and information on SB 350 IRP requirements is also presented in this concluding chapter.

Appendix A.

Appendix A presents a detailed description of the Ascend PowerSimm software package, which represents the production cost modeling software used to perform the vast majority of analyses presented in this IRP. The Ascend software platform can be used to value portfolios consisting of structured transactions, generation assets, load obligations, and hedges plus operating components of transmission, ancillary services, and conservation programs. The PowerSimm software is hierarchical and enables generation assets and market instruments to be valued individually or jointly as an element of the parent portfolio. The valuation of a utility portfolio or structured transaction follows from the application of analytic algorithms that optimize asset values and calculate hedge, load, and structured transaction values relative to an underlying simulated market.

Appendix B.

Appendix B provides a front-page reference to Ascend Analytics CAISO Market Report, Release 4.1. This report documents and describes all the CAISO forward market forecasts produced by Ascend and used by RPU staff during the development of this 2023 IRP document.[1]

Appendix C.

The Avoided Cost of Energy (ACOE) calculations for the various RPU Energy Efficiency measures discussed in Chapter 14 are presented in Appendix C, in Tables C.1 through C.6. These tables present the calculation details for each ACOE estimate presented in this chapter.

[1] The full Ascend Market Report, Release 4.1, will be submitted by RPU to the CEC concurrently with the submission of this 2023 IRP.

2. RPU System Load & Peak Demand Forecasts

This chapter provides an overview of RPU's long-term system load and peak demand forecasting methodology. This overview includes a discussion of the utility's econometric forecasting approach, key input variables and assumptions, and pertinent model statistics, along with the utility's 2023-2045 system load and peak demand forecasts.

2.1 RPU Load Profiles

As of December 2021, RPU provided electrical service to approximately 112,000 metered customers across the City of Riverside, CA. Riverside shares the climate characteristics of other cities in the inland region of Southern California, enjoying temperate winters along with warm, occasionally hot, summers. As such, the utility's loads and peaking power needs are highest in the warmest summer months and the focus of RPU's long term planning activities typically revolve around meeting these needs. Figure 2.1.1 below shows hourly load profiles for typical days in February and August 2021, respectively. In August, the utility expects to need about 60% more energy and 95% more capacity to meet the city's summer load serving requirements, as compared to February.

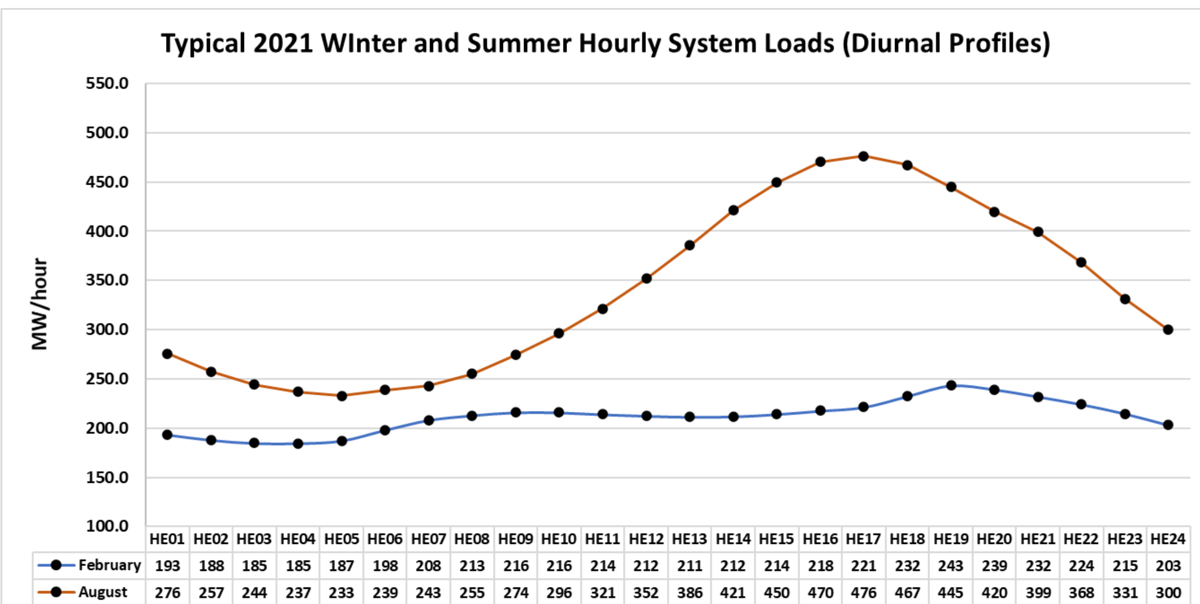


Figure 2.1.1. Hourly system load profiles for typical 2021 weekdays in February and August.

Figure 2.1.2, which shows the average 24-hour diurnal load patterns by month for 2021, illustrates another example of RPU's summer driven load serving needs. Significant increases in residential AC and commercial HVAC usage cause the utility's load serving needs to nearly double during the summer season (June through September). Figure 2.1.2 is typical of the types of diurnal load patterns that RPU has experienced for at least the last decade.

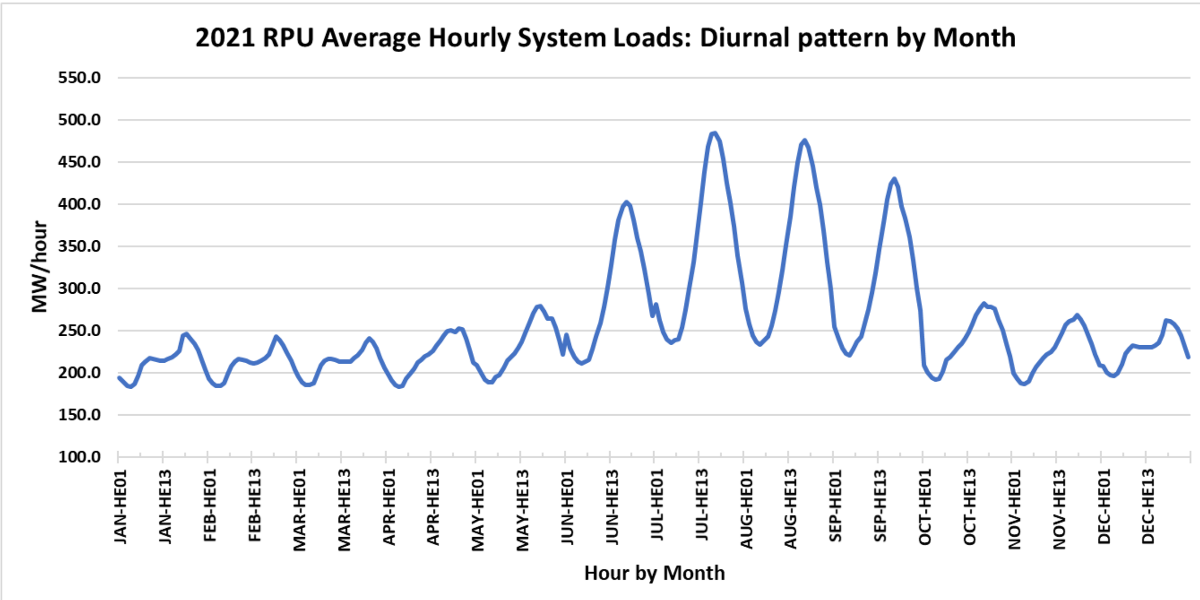


Figure 2.1.2. 24-hour diurnal by month average RPU system load levels during 2021.

RPU's customer base represents a diversified mix of Residential, Commercial and Industrial customers. Nearly all Residential customers are currently billed under a tiered-rate system. More than 90% of the utility's Commercial customers are billed on a flat-rate; the remaining medium-sized Commercial customers are billed under a commercial demand rate. All Industrial customers are billed under a time-of-use (TOU) rate. As of December 2021, RPU served approximately 99,450 Residential, 11,950 small and medium-sized Commercial and 600 Industrial customers, respectively. While residential households make up nearly 89% of RPU's customers, the total energy consumption by customer class is much more evenly distributed. Figure 2.1.3 shows how 2021 retail sales distributed across customer classes; it is worthwhile to note that the Industrial Customer class accounted for about 43% of total retail MWh sales. The Residential Customer class accounted for 36% of the utility's MWh sales, while Commercial customers accounted for another 20%. Miscellaneous (Other) accounts accounted for the remaining 1% of 2021 retail MWh sales. Once again, as shown in Figures 2.1.2 and 2.1.3, summer peaking needs are driven primarily by the summer AC (cooling) needs of the three customer classes, particularly the Residential customer class.

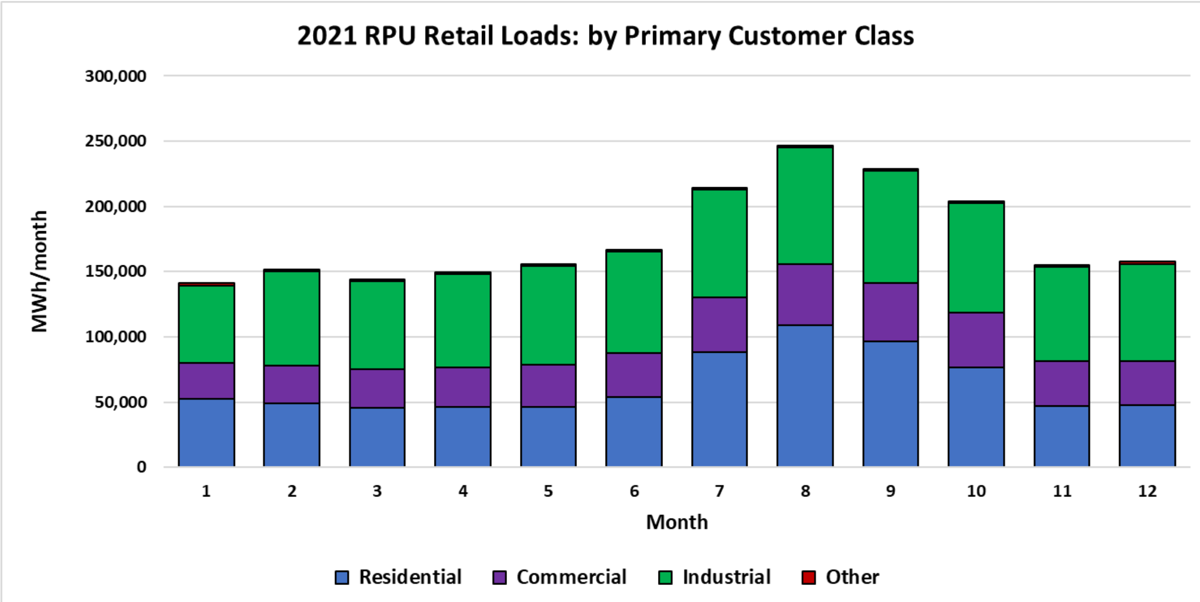


Figure 2.1.3. 2021 RPU retail sales by month and primary customer class.

2.2 Forecasting Approach/Overview

RPU uses regression based econometric models to forecast both its total expected GWh system load and system MW peak on a monthly basis. These models are calibrated to historical load and/or sales data extending back to January 2007. The following input variables are used in one or more of these econometric models: (a) various monthly weather summary statistics, (b) specific calendar effects, (c) unplanned for (but verified) expansion and contraction of industrial loads, (d) annual per capita personal income (PCPI) and monthly labor employment (Labor_Emp) econometric input variables for the Riverside – San Bernardino – Ontario metropolitan service area, (e) the cumulative load loss effects associated with retail customer solar PV installations and all of our measured energy efficiency (EE) programs, and (f) the expected net load gain due to increasing light-duty and medium/heavy-duty electric vehicle (EV) penetration levels and anticipated building electrification (fuel switching) within the RPU service territory. These models can be used to project RPU wholesale gross and peak monthly loads and monthly retail sales up to twenty-five years into the future.

Due to a lack of AMI and load research survey data, RPU does not currently produce forecasts of coincident or non-coincident peak loads associated with any specific customer class, or future electrical rates for any customer class and/or tier rate structure. However, our current wholesale and retail forecasting models explicitly capture and account for the effects of all active RPU EE programs at their current funding and implementation levels, along with the impacts of currently installed solar PV distributed generation and EV penetration within our service territory. This chapter describes our statistical methodology used to account for these EE, solar PV and EV effects in detail. The interested reader should also refer to our SB1037/AB2021 reports for more detailed information about RPU's various EE/rebate programs, and our prior SB1 reports for more general information about historical solar PV installation trends within the RPU service territory.

RPU does not currently administer any type of long-term, dispatchable Demand Response program in its service territory. In response to the 2012 SONGS closure, RPU continues to administer the Power Partners voluntary load curtailment program to call upon up to 10 MW of commercial and industrial load shedding capability during any CAISO Stage 3 Emergency situation. For large commercial customers, RPU uses commercial TOU rate structures to encourage and incentivize off-peak energy use. Finally, RPU has no Electric Service Providers (ESPs) as defined by Public Utilities Code Section 394 within our service territory and RPU does not anticipate either losing any existing load or gaining any new service territory over the next ten years.

2.2.1 General Modeling Methodology

The following load metrics are modeled and forecasted by the RPU Power Resources Division:

- Hourly system loads (MW),
- Total monthly system load (GWh),
- Maximum monthly system peak (MW),
- Total monthly retail loads for our Residential, Commercial, Industrial and Other customer classes (GWh).

All primary monthly forecasting equations are statistically developed and calibrated to ~15 years of historical monthly load data. The parameter estimates for each forecasting equation are normally updated every 12 months; if necessary, the functional form of each equation can also be updated or modified on an annual basis. Please note that this chapter only summarizes the methodology and statistical results for our monthly system load and peak forecasting equations (which are described in more detail in section 2.3).

2.2.2 Input Variables

The various weather, calendar, economic and structural input variables used in our monthly forecasting equations are defined in Table 2.2.1. All weather variables represent functions of the average daily temperature (ADT, °F) expressed as either daily cooling degrees (CD) or extended heating degrees (XHD), where these indices are in turn defined as

$$CD = \max\{ADT-65, 0\} \quad \text{[Eq. 2.2.1]}$$

$$XHD = \max\{55-ADT, 0\} \quad \text{[Eq. 2.2.2]}$$

Thus, two days with average temperatures of 73.3° and 51.5° would have corresponding CD indices of 8.3 and 0 and XHD indices of 0 and 3.5, respectively.

The "structural" variables shown in Table 2.2.1 represent calculated cumulative load and peak impacts associated with the following programs and mandates:

- An indicator variable for additional, new industrial load that relocated into the RPU service territory in the 2011-2012 time frame, in response to a two year, city-wide economic incentive program. (Note that this load later migrated out of our service territory in the 2014-2015 time frame; the impact of this load loss is also incorporated into this "EconTOU" structural variable.)
- Avoided energy use directly attributable to RPU energy efficiency programs and rebates.
- Avoided energy use directly attributable to customer installed solar PV systems within the RPU service territory.
- Additional expected load directly attributable to the increasing number of electric vehicles in RPU's service territory.
- Additional future expected load directly attributable to building electrification (fuel switching) in RPU's service territory.

The calculations associated with each of these load and peak impact variables are described in greater detail in subsequent sections. More specifically, section 2.2.4 describes the amount and timing of the new industrial load that relocated into our service territory in 2011 and 2012, and out of our service territory in 2014 and 2015. Additionally, sections 2.2.5, 2.2.6, 2.2.7 and 2.2.8 describe how we calculate the cumulative avoided load and peak energy usage associated with RPU energy efficiency programs and rebates, load loss due to customer installed solar PV systems, load gain due to vehicle electrification within the RPU service territory, and load gain due to anticipated future building electrification, respectively.

Low order Fourier frequencies are also used in the regression equations to help describe structured seasonal load (or peak) variations not already explained by other predictor variables. These Fourier frequencies are formally defined as

$$\text{Fs}(n) = \text{Sine}[\, n \times 2\pi \times [(m\text{-}0.5)/12\} \,], \qquad \text{[Eq. 2.2.3]}$$

$$\text{Fc}(n) = \text{Cosine}[\, n \times 2\pi \times [(m\text{-}0.5)/12\} \,], \qquad \text{[Eq. 2.2.4]}$$

where *m* represents the numerical month number (i.e., 1 = Jan, 2 = Feb, .., 12 = Dec). Note also that a second set of Fourier frequencies are also used in our system load and peak models to account for structural changes to our distribution system that occurred in 2014. These 2014 distribution system upgrades were expected to reduce our energy losses across all load conditions, but appear to have only reduced energy losses under low load conditions.

Table 2.2.1 Economic, calendar, weather, structural and miscellaneous input variables used in RPU monthly system load (SL) and system peak (SP) forecasting equations.

Effect	Variable	Definintion	Forecasting Eqns.	
			SL	**SP**
Economic	PCPI	Per Capita Personal Income ($1000 units)	X	X
	Emp_CC	Labor Employment Level (100,000 units)	X	X
Calendar	SumMF	# of Mon-Fri (weekdays) in month	X	
	SumSS	# of Saturdays and Sundays in month	X	
Weather	SumCD	Sum of monthly CD's	X	X
	SqCD	(SumCD/100) squared		X
	SumXHD	Sum of monthly XHD's	X	
	MaxHD1	Maximum 1-day XHD in month		X
	MaxCD3	Maximum concurrent 3-day CD sum in month		X
	Summer2020	SumCD's for 2020	X	
	Summer2021	SumCD's for 2021	X	
Structural (TOU,EE,PV,EV)	EconTOU	Expansion/contraction of New Industrial load	X	X
	Avoided_Load	Cumulative EE+PV-EV-BE load (GWh: calculated)	X	
	Avoided_Peak	Cumulative EE+PV-EV-BE peak (MW: calculated)		X
Fourier terms	Fs1	Fourier frequency (Sine: 12 month phase)	X	X
	Fc1	Fourier frequency (Cosine: 12 month phase)	X	X
	Fs2	Fourier frequency (Sine: 6 month phase)	X	X
	Fc2	Fourier frequency (Cosine: 6 month phase)	X	X
	Fs3	Fourier frequency (Sine: 4 month phase)		X
	Fc3	Fourier frequency (Cosine: 4 month phase)		X
	Fs2014a	Fourier frequency (on/after 2014 effects)	X	X
	Fc2014a	Fourier frequency (on/after 2014 effects)	X	X
	Fs2014b	Fourier frequency (on/after 2014 effects)	X	X
	Fc2014b	Fourier frequency (on/after 2014 effects)	X	X

2.2.3. Historical and Forecasted Inputs: Economic and Weather Effects

Annual PCPI data have been obtained from the US Bureau of Economic Analysis (http://www.bea.gov), while monthly employment (Labor_Emp) statistics have been obtained from the CA Department of Finance (http://www.labormarketinfo.edd.ca.gov). Forecasts of future PCPI levels reflect the 15-year recession-adjusted historical average for the region (i.e., approximately 3.25 % income growth per year); likewise, forecasts of future Labor_Emp levels reflect the current 10-year historical average for the region (e.g., 2.5% employment growth per year). As previously stated, these data correspond to the Riverside-Ontario-San Bernardino metropolitan service area.

All SumCD, SumXHD, MaxCD3 and MaxHD weather indices for the Riverside service area are calculated from historical average daily temperature levels recorded at the UC Riverside CIMIS weather station (http://wwwcimis.water.ca.gov/cimis). Forecasted average monthly weather indices are based on 25 year historical averages; these forecasted monthly indices are shown in Table 2.2.2 below. These average monthly values are used as weather inputs for all future time periods on/after January 2022.

Table 2.2. Expected average values (forecast values) for future monthly weather indices; see Table 2.1 for weather index definitions.

Month	SumCD	SumXHD	MaxCD3	MaxHD
JAN	2.5	72.6	1.8	9.5
FEB	6.0	60.0	3.5	7.7
MAR	14.4	29.1	8.3	6.5
APR	35.7	14.5	18.4	4.4
MAY	74.2	0.7	28.5	0.5
JUN	173.6	0.6	38.5	0.2
JUL	345.8	0.0	55.0	0.0
AUG	371.8	0.0	57.5	0.0
SEP	266.3	0.0	54.1	0.0
OCT	104.1	0.5	35.3	0.2
NOV	21.0	20.2	14.4	4.1
DEC	2.0	77.4	2.0	9.4

2.2.4 Temporary Load/Peak Impacts due to the 2011-2012 Economic Incentive Program

In January 2011, in response to the continuing recession within the Inland Empire, the City of Riverside launched an economic incentive program to attract new, large scale industrial business to relocate within the city boundaries. As part of this incentive program, RPU launched a parallel program for qualified relocating industries to receive a two year, discounted time-of-use (TOU) electric rate. In response to this program, approximately 10-12 new industrial businesses relocated to within the city's electric service boundaries over an 18 month period.

In prior iterations of our load forecasting models, staff attempted to directly calculate the approximate GWh energy and MW peak load amounts associated with this economic incentive program. However, since these numbers have proved to be very difficult to accurately determine, in the current forecasting equations staff has instead used indicator variables in the forecasting models that automatically calibrate to the observed load (or peak) gains and losses over the 2011-2014 period. Table 2.2.3 shows how the "econTOU" indicator variable is defined, and what the resulting parameter estimate corresponds to in each equation. By definition, this indicator value is set to 0 for all years before 2011 and after 2014.

Table 2.2.3 Values for econTOU indicator variable used to model RPU's 2011-2014 discounted TOU incentive program. Incentive program was closed in December 2012; nearly all early load gains disappeared by December 2014.

<table>
<tr><th>Year</th><th>Time Period</th><th>EconTOU value</th><td rowspan="7">Load parameter value represents incremental Monthly GWh</td><td rowspan="7">Peak parameter value represents incremental monthly MW peak</td></tr>
<tr><td>2011</td><td>January - June</td><td>0.33</td></tr>
<tr><td>2011</td><td>July-December</td><td>0.67</td></tr>
<tr><td>2012</td><td>All months</td><td>1.00</td></tr>
<tr><td>2013</td><td>All months</td><td>1.00</td></tr>
<tr><td>2014</td><td>January - June</td><td>0.67</td></tr>
<tr><td>2014</td><td>July - December</td><td>0.33</td></tr>
</table>

2.2.5 Cumulative Energy Efficiency Savings since 2005

RPU has been tracking and reporting SB-1037 annual projected EE savings since 2006. These reported values include projected net annual energy savings and net coincident peak savings for both residential and non-residential customers, for a broad number of CEC program sectors. Additionally, these sector specific net energy and peak savings can be classified into "Baseload", "Lighting" and "HVAC" program components, respectively.

In the fall of 2014, staff reviewed all EE saving projections going back to fiscal year 2005/06, in order to calculate the cumulative load and peak savings attributable to efficiency improvements and rebate programs. Since that time, staff have continued to track and accumulate this load and peak savings. The steps we perform in this analysis are as follows:

1. Staff first computed the sum totals of our projected net annual energy and coincident peak savings for the three program components (Baseload, Lighting, and HVAC) for each fiscal year, for both residential and non-residential customers.
2. Next, staff calculate the cumulative running totals for each component from July 2005 through the most recent EE 1037 filing by performing a linear interpolation on the cumulative fiscal year components.

3. Staff then convert these interpolated annual totals into monthly impacts by multiplying these annual values by the monthly load and peak scaling/shaping factors shown in Table 2.2.4. Note that the monthly HVAC factors reflect an engineering estimated, monthly interpolation of EE savings associated with heating and AC loads in the Riverside service territory.
4. Finally, staff sum these three projected monthly program components together to estimate the cumulative projected monthly load and peak reduction estimates, directly attributable to measured EE activities.

Staff continue to update these projections as new information becomes available. Also, as stated above, these represent interpolated engineering estimates of energy efficiency program impacts. Figure 2.2.2 shows a graph of the cumulative impact of the projected retail load savings due to EE impacts over time (along with projected load savings attributable to solar PV installations; see section 2.2.6). Likewise, Figure 2.2.3 shows a graph of the cumulative impact of the projected retail peak energy savings due to EE impacts over time.

In theory, if such estimates are unbiased and accurate, then when one introduces a regression variable containing these observations into an econometric forecasting model, the corresponding parameter estimate should be approximately equal to -1.05 (to reflect the anticipated load or peak energy reduction over time, after adjusting for 5% distribution system losses). In practice, this parameter estimate may differ from -1.05 in a statistically significant manner, due to inaccuracies in the various EE program sector savings projections.

Table 2.2.4. Monthly load scaling and peak shaping factors for converting interpolated SB 1037 cumulative annual net load and coincident peak EE program impacts into cumulative monthly impacts.

Month	Load Scaling Factors			Peak Shaping Factors		
	Baseload	Lighting	HVAC	Baseload	Lighting	HVAC
Jan	0.0833 for all months	0.0970	0.0788	1.0 for all months	1.164	0.411
Feb		0.0933	0.0541		1.119	0.283
Mar		0.0858	0.0367		1.030	0.192
Apr		0.0784	0.0256		0.940	0.134
May		0.0746	0.0486		0.896	0.253
Jun		0.0709	0.1122		0.851	0.586
Jul		0.0709	0.1802		0.851	0.940
Aug		0.0746	0.1916		0.896	1.000
Sep		0.0784	0.1289		0.940	0.673
Oct		0.0858	0.0513		1.030	0.268
Nov		0.0933	0.0294		1.119	0.154
Dec		0.0970	0.0626		1.164	0.327

Finally, with respect to the load and peak models discussed in section 3, the future impacts from EE savings are forecasted to incrementally offset approximately 1% annual load and peak growth, respectively. These estimates represent a continuation of the average EE savings trends observed over the last 10 years.

2.2.6 Cumulative Solar PV Installations since 2001

RPU has been tracking annual projected load and peak savings due to customer solar PV installations for the last 11 years. Historically, RPU had also been encouraging the installation of customer owned solar PV through its solar rebate program. Figure 2.2.1 shows the calculated total installed AC capacity of customer owned solar PV in the RPU service territory since 2002.

Staff estimate the projected net annual energy savings and net coincident peak savings for the RPU distribution system by calculating the cumulative load and peak savings attributable to customer installed PV systems within our service territory. These calculations are performed by converting the installed AC capacity data into monthly load and peak energy reduction impacts (by multiplying these capacity values by the monthly load and peak scaling/shaping factors shown in Table 2.2.5). These scaling and shaping factors are based on a typical south-facing roof-top solar PV installation with a 20% annual capacity factor and assume that our distribution peaks occur in HE19 from November through March, and HE17 in April through October. These projected monthly components are then summed together to estimate the cumulative projected monthly load and peak reduction estimates, directly attributable to solar PV distributed generation (DG).

As before, it should be noted that these represent interpolated engineering estimates of solar PV DG impacts. As previously discussed, Figure 2.2.2 shows a graph of the cumulative impact of the projected retail load savings due to both EE and solar PV-DG impacts over time. Likewise, Figure 2.2.3 shows a graph of the cumulative impact of the projected retail peak energy savings due to EE and PV-DG impacts over time. As before, if such estimates are unbiased and reasonably accurate, then when one introduces a regression variable containing these observations into an econometric forecasting model, the corresponding parameter estimate should be approximately equal to -1.05 (to reflect the anticipated load or peak energy reduction and distribution system losses over time, etc.). In practice, this parameter estimate may once again differ from -1.05 in a statistically significant manner, due to inaccuracies in the various solar PV-DG savings calculations.

Additionally, with respect to the load and peak models discussed in section 3, the future installed capacity levels associated with customer solar PV systems are forecasted to grow at 4.2 MW of capacity annually. This estimate coincides with the observed trend over the last four years.

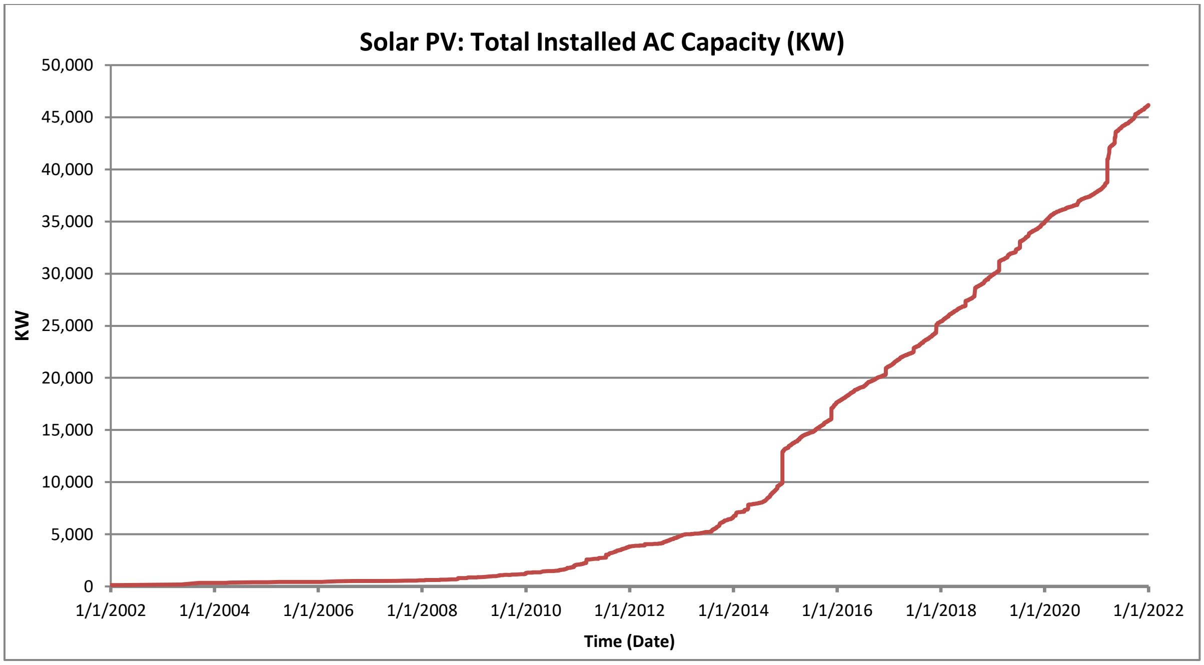


Figure 2.2.1. Total installed AC capacity of customer owned solar PV in the RPU service territory since 2002.

Table 2.2.5. Monthly load scaling and peak shaping factors for converting cumulative solar AC capacity into monthly net load and peak PV-DG impacts.

Month	Load Scaling Factors	Peak Shaping Factors
Jan	0.172	0
Feb	0.181	0
Mar	0.195	0
Apr	0.211	0.247
May	0.225	0.285
Jun	0.232	0.294
Jul	0.229	0.269
Aug	0.217	0.219
Sep	0.203	0.156
Oct	0.188	0.098
Nov	0.176	0
Dec	0.170	0

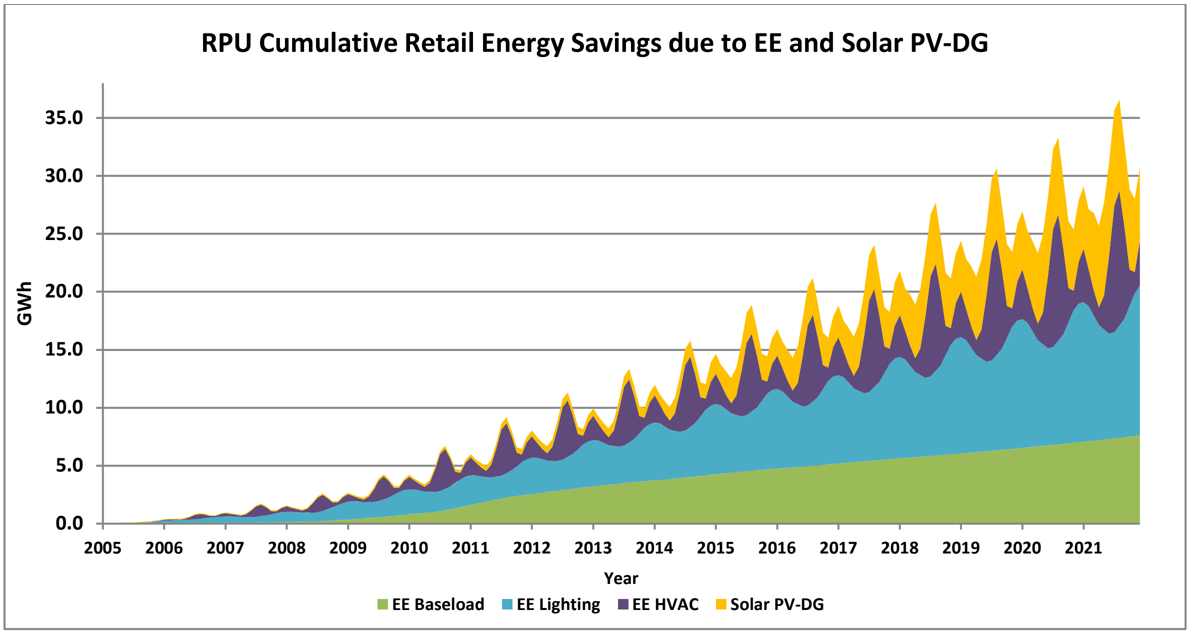


Figure 2.2.2. Calculated cumulative projected retail energy savings in the RPU service territory due to both EE program and solar PV distributed generation impacts over time.

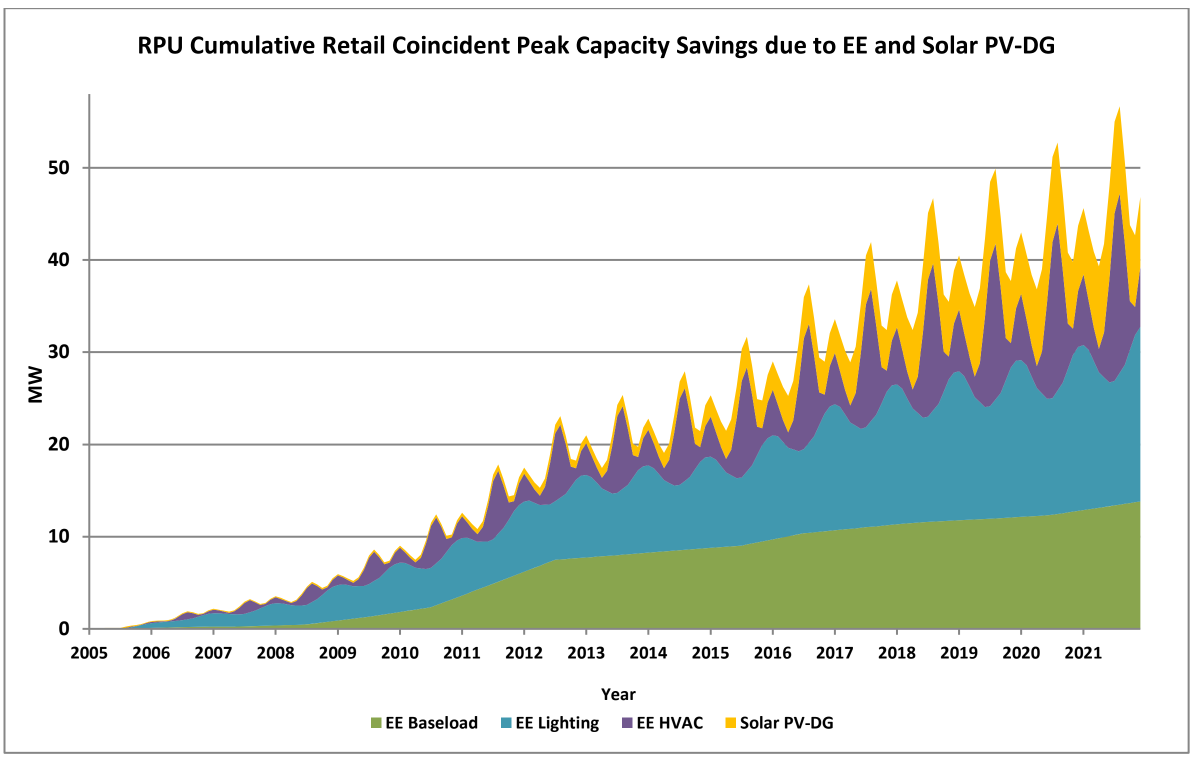


Figure 2.2.3. Calculated cumulative projected coincident peak capacity savings in the RPU service territory due to both EE program and solar PV distributed generation impacts over time.

2.2.7 Incremental Electric Vehicle Loads

In early 2017 the CEC released their Transportation Electrification Common Assumptions 3.0 model. Since that time, this model has been periodically updated. (RPU staff are currently using version 3.5-3). This model can be used by CA utilities to forecast EV growth in the utilities service territory through 2030, based on a limited number of objective input assumptions. This model can also be used to forecast several emission reduction metrics, in addition to the expected net load growth associated with the forecasted EV penetration level.

Riverside has elected to continue using this model in our 2022 load forecasting equations to estimate our expected net Light-duty EV load growth. For baseline load forecasting purposes, we assume that Riverside will meet its share of the governors 3,500,000 EV's by 2030 mandate, based on the default 0.61% Riverside estimate that defines our service area PEV population as a percent of the state total. This target has been selected because the forecasted increase in Light-duty EVs for 2020-2021 (2,177 vehicles) closely matches the registered DMV information for our service territory (2,171 vehicles). Note that we also assume 5% distribution losses within our service territory and that 10% of our customers EV charging load is self-supplied.

Currently, Riverside does not have an independent means to estimate Medium/Heavy-duty EV load growth in our service territory. For this metric, we instead have relied on published CEC projections for the SCE service territory. More specifically, we have rescaled the SCE projections published in the 2021 CEC IEPR hourly forecast scenario[1] using a factor of 0.022214 (which represents the ratio of RPU to SCE system loads) to deduce a suitable set of forecasts for RPU.

Based on these input assumptions, Figure 2.4 shows the projected additional utility electrical load from both new Light-duty and Medium/Heavy-duty EVs entering our service territory between 2015 through 2042.[2] Note that for forecasting purposes, these incremental EV loads (above the 2015 baseline level) are treated as net load additions that effectively offset some of our future EE and DG.PV (solar) load losses.

[1] Data obtained from the CED 2021 Hourly Forecast – SCE – Mid Baseline – AAEE Scenario 2 – AAFS Scenario 4 Excel workbook publication (TN241182).

[2] LD-EV forecasts beyond 2030 and MHD-EV forecasts beyond 2035 represent linear extrapolations.

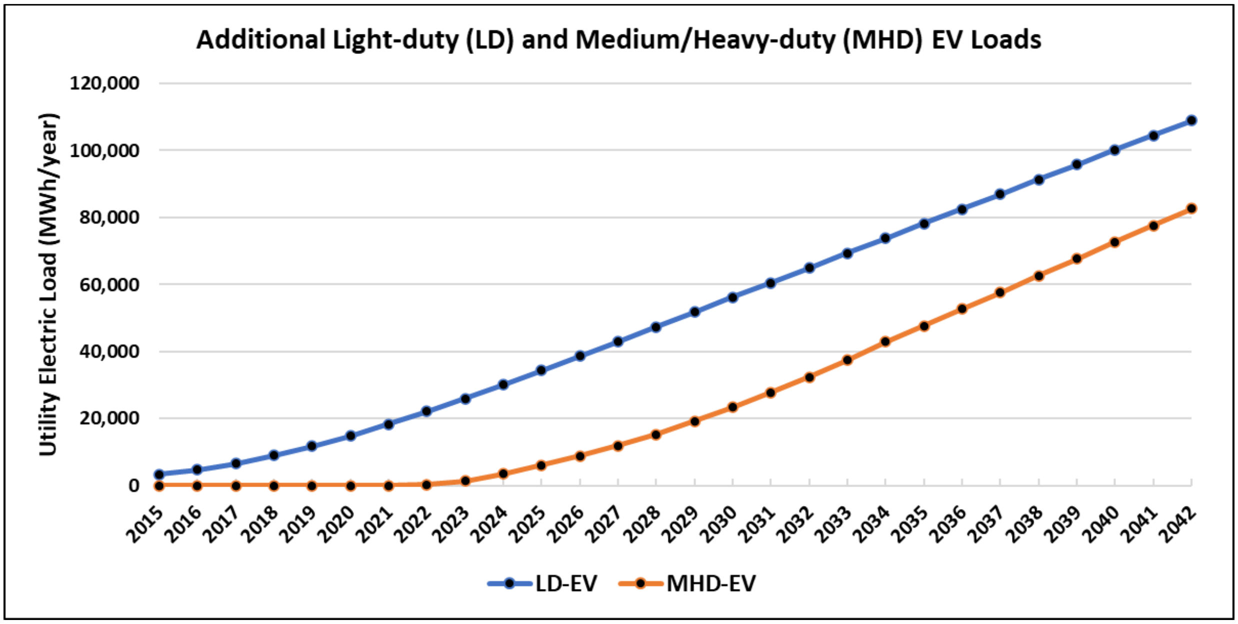


Figure 2.4. Projected 2015-2042 RPU electrical load from both Light-duty and Medium-/Heavy-duty EV penetration within our service territory.

2.2.8 Incremental Building Electrification (Fuel-Switching) Loads

Like Medium/Heavy-duty EVs, Riverside does not have an independent means to estimate future Building Electrification (BE) load growth in our service territory. For this last load modifier, staff once again have relied on published CEC projections for the SCE service territory. As before, staff have rescaled the SCE projections published in the 2021 CEC IEPR hourly forecast scenario using a factor of 0.022214 to deduce suitable BE forecasts for RPU.

Figure 2.2.5 shows the projected additional utility electrical load from building electrification entering our service territory, again from 2015 through 2042.[3] (Loads prior to 2021 are assumed to be 0.) Note that the bulk of the impacts of these anticipated load additions occur beyond 2030 and appear to be quite similar to the Medium/Heavy-duty EV load forecasts.

[3] BE forecasts beyond 2035 represent linear extrapolations.

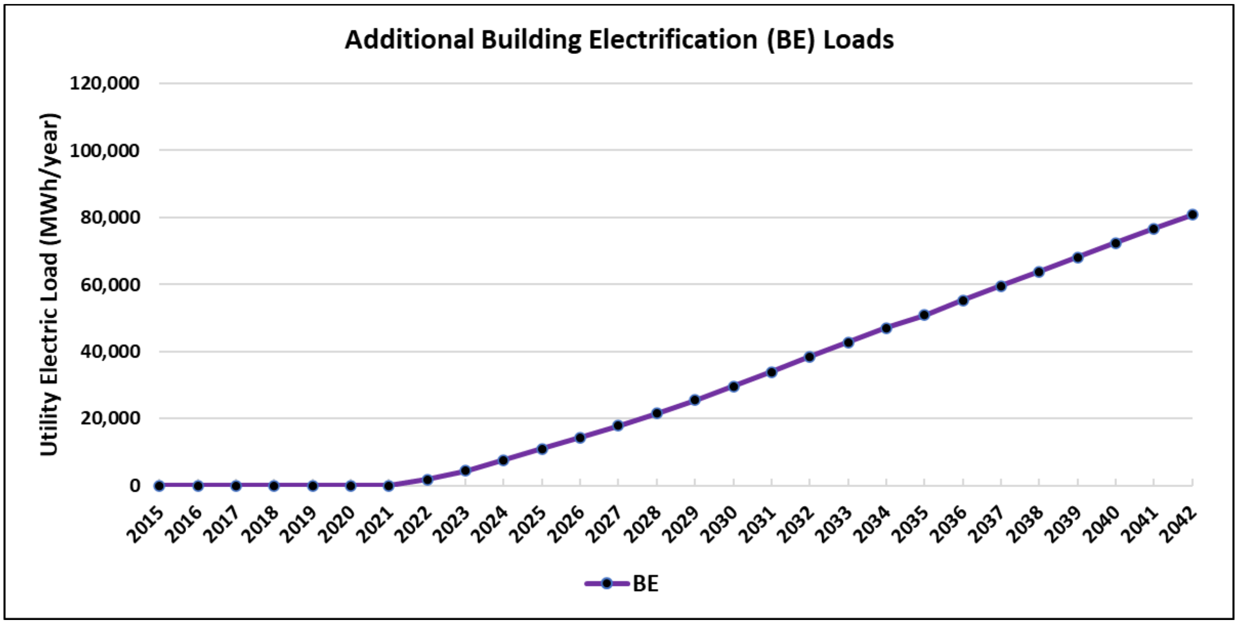


Figure 2.2.5. Projected 2015-2042 RPU electrical load from new building electrification (fuel-switching) activities our service territory.

2.3 System Load and Peak Forecast Models

2.3.1 Monthly System Load Model

The regression component of RPU's monthly total system load forecasting model is a function of two primary economic drivers (PCPI and Emp_CC), two calendar effects that quantify the number of weekdays (SumMF) and weekend days (SumSS) in the month, two weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD), two additional effects that allow the SumCD impact to be more pronounced in calendar years 2020 and 2021 (summer2020 and summer2021) due to the temporary impacts of more people working from home during the COVID pandemic, eight low order Fourier frequencies that quantify seasonal impacts both before and after our distribution system upgrades (Fs1, Fc1, Fs2, Fc2, Fs2014a, Fc2014a, Fs2014b, and Fc2014b), one unconstrained Industrial load indicator variable (econTOU), and one constrained effect that captures the combined impacts of (avoided) EE, PV and (incremental) EV, BE loads. Additionally, the heterogeneous residual variance (mean square prediction error) component is defined to be seasonally dependent; i.e., larger for the summer months (May through October) than the winter months (November through April). Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[PCPI_t] + \beta_2[Emp\_CC_t] + \beta_3[SumMF_t] + \beta_4[SumSS_t] + \beta_5[SumCD_t] + \beta_6[SumXHD_t] +$$

$$\beta_7[Fs1_t] + \beta_8[Fc1_t] + \beta_9[Fs2_t] + \beta_{10}[Fc2_t] + \beta_{11}[Fs2014a_t] + \beta_{12}[Fc2014a_t] +$$

$$\beta_{13}[Fs2014b_t] + \beta_{14}[Fc2014b_t] + \beta_{15}[econTOU_t] + \beta_{16}[summer2020_t] +$$

$$\beta_{17}[summer2021_t] + \theta_1[EE_t+PV_t-EV_t-BE_t] + \varepsilon_{jt} \qquad \text{[Eq. 2.3.1]}$$

where

$$\varepsilon_{jt \text{ for } j=1(\text{summer}),\ 2(\text{winter})} \sim N(0, \sigma_j^2). \qquad \text{[Eq. 2.3.2]}$$

In Eq. 2.3.1, y_t represents the RPU monthly total system load (GWh) for the calendar ordered monthly observations and forecasts (t=1 → January 2007) and the seasonally heterogeneous summer and winter residual errors are assumed to be Normally distributed and temporally uncorrelated. Eqs. 2.3.1 and 2.3.2 were initially optimized using restricted maximum likelihood (REML) estimation (SAS MIXED Procedure). These REML results yielded summer and winter variance component estimates of 13.3 and 6.6 GWh^2, suggesting that the variance ratio for the seasonal errors follows a 2:1 ratio. Based on these results, Eq. 2.3.1 was refit using weighted least squares (SAS REG Procedure).

All input observations that reference historical time periods are assumed to be fixed (i.e., measured without error) during the estimation process. For forecasting purposes, staff treated all forecasted economic indices and structural effects (PCPI, Emp_CC, econTOU, EE, PV, EV and BE) as fixed variables and the forecasted weather indices as random effects. Under such an assumption, the first-order Delta method estimate of the forecasting variance becomes

$$\mathrm{Var}(\hat{y}_t) = \sigma_m^2 + \mathrm{Var}\{\ \beta_5[\mathrm{SumCD}_t] + \beta_6[\mathrm{SumXHD}_t]\ \} \qquad \text{[Eq. 2.3.3]}$$

where σ_m^2 represents the model calculated mean square prediction variance and the second variance term captures the uncertainty in the average weather forecasts. Note that the second variance term can be approximated via an analysis of 25 years of historical weather data, once the parameters associated with the two weather effects have been estimated.

2.3.2 System Load Model Statistics and Forecasting Results

Table 2.3.1 shows the pertinent model fitting and summary statistics for the total system load forecasting equation, estimated using weighted least squares. The equation explains 99.0% of the observed variability associated with the monthly 2007-2021 system loads and nearly all input parameter estimates are statistically significant below the 0.01 significance level. Note that the summer and winter variance components were restricted to a 2:1 variance ratio during the weighted least squares analysis; likewise, the avoided load parameter was constrained to be equal to -1.05.

As shown in Table 2.3.1, the estimate for the winter seasonal variance component is 7.15 GWh^2; the corresponding summer component is 2 times this amount (14.30 GWh^2). An analysis of the variance adjusted model residuals suggests that the model errors are also Normally distributed, devoid of outliers and approximately temporally uncorrelated; implying that the modeling assumptions are reasonable. By definition, all of the engineering calculated avoided (and incremental) load effect is accounted for in this econometric model via use of the avoided load input variable.

The remaining regression parameter estimates shown in the middle of Table 2.3.1 indicate that monthly system load increases as either/both weather indices increase (SumCD and SumXHD) and the weekdays contribute slightly more to the monthly system load, as opposed to Saturdays and Sundays (i.e., the SumMF estimate is > than the SumSS estimate). Also, the RPU system load is expected to increase as either the area wide PCPI index or Emp_CC level grows over time (i.e., these economic parameter estimates are > 0). However, this load growth will grow more slowly if future EE and/or PV trends increase above their current forecasted levels, or more quickly if future EV or BE penetration levels increase above their baseline levels.

Figure 2.3.1 shows the observed (blue points) versus calibrated (green line) system loads for the 2007-2021 timeframe. Nearly all back-casts fall within the calculated 95% confidence envelope (thin black lines). Figure 2.3.2 shows the forecasted monthly system loads for 2022 through 2034, along with the corresponding 95% forecasting envelope. This forecasting envelope encompasses model uncertainty only, while treating both the weather and projected economic indices as fixed inputs.

Table 2.3.1. Model summary statistics for the monthly total system load forecasting equation.

Gross Monthly Demand Model (January 2007 - December 2021): GWh units

Forecasting Model: includes Weather & Economic Covariates, Fourier Effects, pseudo TOU (unconstrained), 2014 Dist.system Adj and Avoided Load (EE+PV-EV-BE). Assumes constrained Avoided load savings and a 2:1 seasonal variance structure.

Dependent Variable: GWhload Load (GWh)

Number of Observations Read	468
Number of Observations Used	180
Number of Observations with Missing Values	288

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	17	115374	6786.71147	949.22	<.0001
Error	162	1158.26787	7.14980		
Corrected Total	179	116532			

Root MSE	2.67391	R-Square	0.9901
Dependent Mean	179.97801	Adj R-Sq	0.9890
Coeff Var	1.48569		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	-114.64638	9.22313	-12.43	<.0001
PCPI	PCPI ($1,000)	1	0.28043	0.11202	2.50	0.0133
Emp_CC	Labor (100,000)	1	6.03616	0.37085	16.28	<.0001
SumMF		1	5.84761	0.29673	19.71	<.0001
SumSS		1	5.25615	0.35753	14.70	<.0001
SumCD		1	0.19787	0.00659	30.04	<.0001
SumXHD		1	0.04435	0.01024	4.33	<.0001
Fs1		1	-2.42618	0.83332	-2.91	0.0041
Fc1		1	-3.55067	1.09874	-3.23	0.0015
Fs2		1	1.48735	0.66624	2.23	0.0270
Fc2		1	1.95287	0.54811	3.56	0.0005
Fs2014a		1	-3.35594	0.73686	-4.55	<.0001
Fc2014a		1	-4.24944	0.76999	-5.52	<.0001
Fs2014b		1	3.49973	0.70004	5.00	<.0001
Fc2014b		1	2.09728	0.70474	2.98	0.0034
econTOU		1	6.56760	0.68069	9.65	<.0001
avoided_load	EE+PV-EV-BE	1	-1.05000	0	-Infty	<.0001
summer2020		1	0.01810	0.00641	2.82	0.0054
summer2021		1	0.03960	0.00716	5.53	<.0001

Durbin-Watson D	1.672
Number of Observations	180
1st Order Autocorrelation	0.160

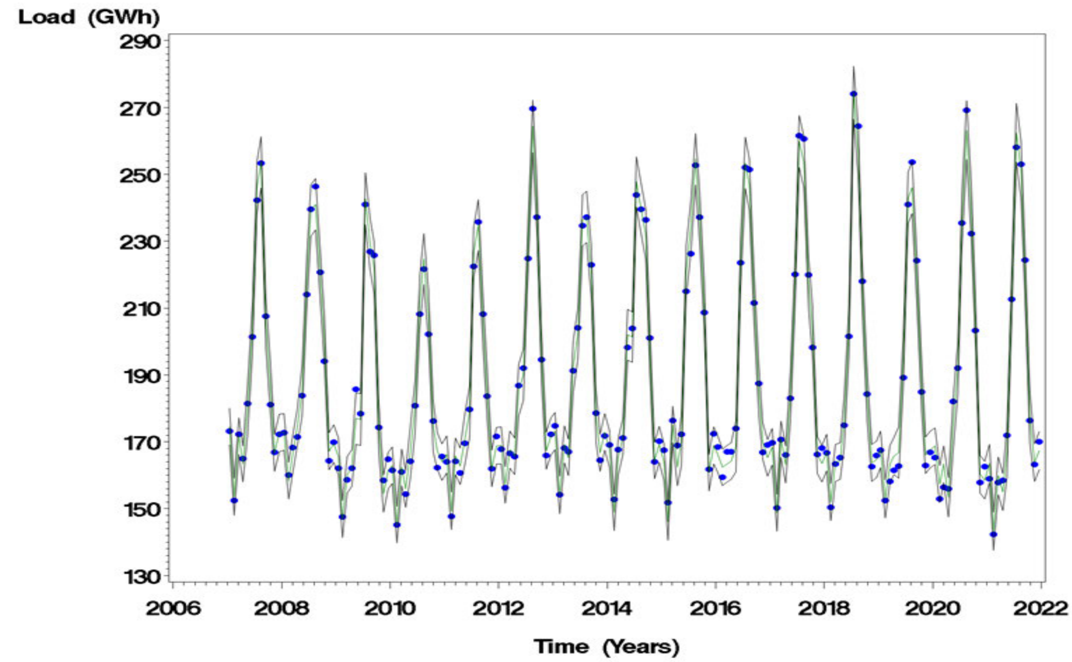


Figure 2.3.1. Observed and predicted total system load data (2007-2021), after adjusting for known weather conditions.

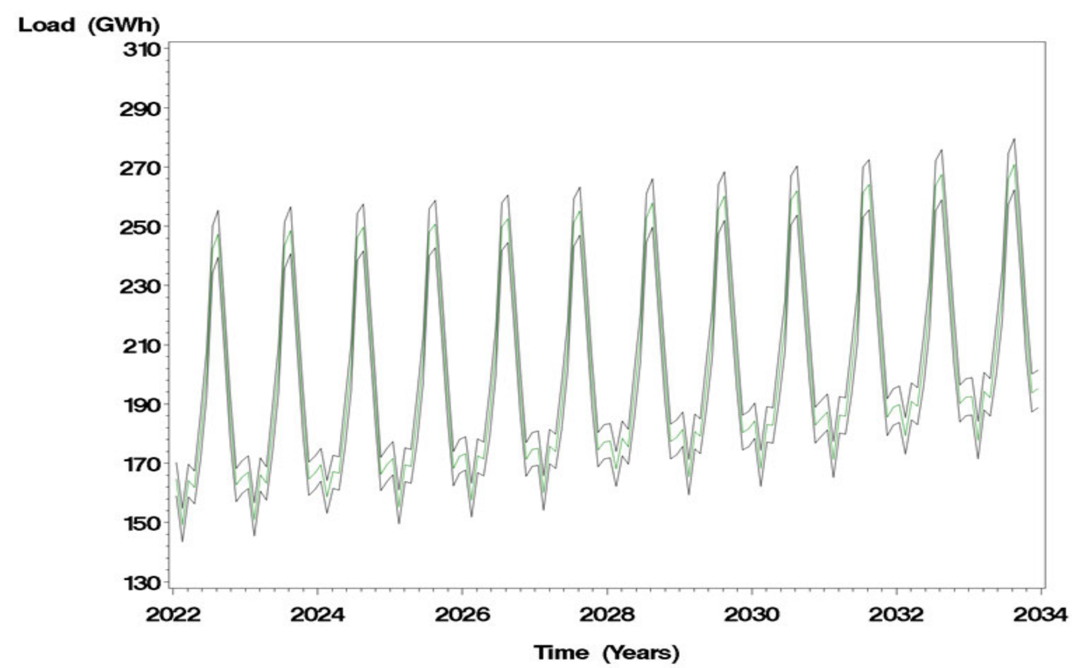


Figure 2.3.2. Forecasted monthly system loads for 2022-2034; 95% forecasting envelopes encompass model uncertainty only.

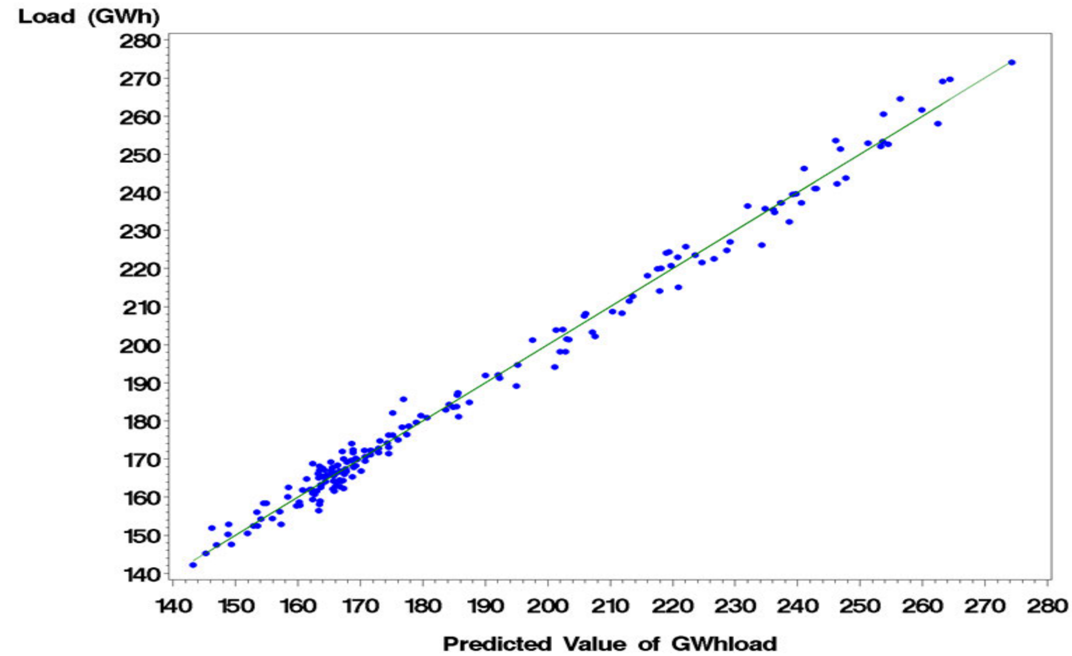


Figure 2.3.3. Strength of correlation between the observed versus prediction system loads shown in Figure 2.3.1.

Finally, Figure 2.3.3 shows the strength of correlation between the observed versus back-cast predicted system loads shown in Figure 2.3.1. Note that this observed versus calibrated load correlation exceeds 0.995.

It should be noted that these model forecasts assume that future PV-DG installation rates will continue at 4.2 MW of AC capacity per year, that future calculated EE savings rate will continue to be approximately equal to 1% of RPU's total annual system loads, and that all EV and BE load additions will materialize as discussed in sections 2.7 and 2.8. Given these assumptions, Table 2.3.2 shows the forecasted monthly RPU system loads for 2022, along with their forecasted standard deviations. In contrast to Figure 2.3.2, these standard deviations quantify both model and weather uncertainty. The 2022 forecasts project that RPU's annual system load should be 2239.8 GWh, assuming that the RPU service area experiences typical weather conditions throughout the year.

Table 2.3.2. 2022 monthly total system load forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Load (GWh)	Std.Dev (GWh)
JAN	164.60	3.20
FEB	149.16	3.57
MAR	164.22	4.39
APR	161.83	5.19
MAY	178.99	10.36
JUN	200.28	15.04
JUL	242.30	14.82
AUG	247.42	13.16
SEP	217.30	13.02
OCT	185.67	12.28
NOV	162.67	4.43
DEC	165.41	3.31
Annual TOTAL	2239.83	33.86

2.3.3 Monthly system peak model

The regression component of RPU's monthly system peak forecasting model is a function of two primary economic drivers (PCPI and Emp_CC), three weather effects that quantify the maximum three-day cooling requirements (i.e., 3-day heat waves), the monthly cooling degrees and the maximum single day heating requirement (MaxCD3, SumCD, SqCD and MaxHD, respectively), ten lower order Fourier frequencies that quantify seasonal impacts both before and after our distribution system upgrades (Fs1, Fc1, Fs2, Fc2, Fs3, Fc3, Fs2014a, Fc2014a, Fs2014b and Fc2014b), one unconstrained Industrial peak indicator variable (econTOU), and one constrained effect that captures the combined impacts of (avoided) EE, PV-DG and (incremental) EV peaks. However, unlike the load forecasting model, the residual variance (mean square prediction error) component was not found to be seasonally dependent. Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[PCPI_t] + \beta_2[Emp\_CC_t] + \beta_3[MaxCD3_t] + \beta_4[SumCD_t] + \beta_5[SqCD_t] + \beta_6[MaxHD_t] +$$

$$\beta_7[Fs(1)_t] + \beta_8[Fc(1)_t] + \beta_9[Fs(2)_t] + \beta_{10}[Fc(2)_t] + \beta_{11}[Fs(3)_t] + \beta_{12}[Fc(3)_t] +$$

$$+ \beta_{13}[Fs2014a_t] + \beta_{14}[Fc2014a_t] + \beta_{15}[Fs2014b_t] + \beta_{16}[Fc2014b_t] +$$

$$\beta_{17}[econTOU_t] + \theta_1[EE_t + PV.DG_t - EV_t] + \varepsilon_t \qquad \text{[Eq. 2.3.4]}$$

where

$$\varepsilon_t \sim N(0, \sigma^2). \qquad \text{[Eq. 2.3.5]}$$

In Eq. 2.3.4, y_t represents the RPU monthly system peaks (MW) for the calendar ordered monthly observations and forecasts (*t*=1 → January 2007) and the seasonally homogeneous residual errors are assumed to be Normally distributed and temporally uncorrelated. Eqs. 2.3.4 and 2.3.5 were again initially optimized using REML estimation (SAS MIXED Procedure). These REML results yielded summer and winter variance component estimates of 329.7 and 283.8 MW^2, confirming that the variance could be treated as homogeneous ($Pr > \chi2 = 0.566$). Based on these results, Eq. 2.3.4 was refit using ordinary least squares (SAS REG Procedure), where the θ_1 parameter estimate was constrained to be equal to -1.05.

As in the total system load equation, all input observations that reference historical time periods were assumed to be fixed. Likewise, staff again treated the forecasted economic indices as fixed variables and the forecasted weather indices as random effects. Under such an assumption, the first-order Delta method estimate of the forecasting variance becomes

$$Var(\hat{y}_t) = \sigma_m^2 + Var\{ \beta_3[MaxCD3_t] + \beta_4[SumCD_t] + \beta_5[SqCD_t] + \beta_6[MaxHD_t] \} \qquad \text{[Eq. 2.3.6]}$$

where σ_m^2 represents the model calculated mean square prediction variance and the second variance term captures the uncertainty in the average weather forecasts. As before, the second variance term was approximated via the analysis of historical weather data after the parameters associated with the weather effects were estimated.

2.3.4 System Peak Model Statistics and Forecasting Results

Table 2.3.3 shows the pertinent model fitting and summary statistics for the system peak forecasting equation. This equation explains approximately 97.9% of the observed variability associated with the monthly 2007-2021 system peaks. Note that the avoided peak parameter was constrained to be equal to -1.05 during the ordinary least squares analysis.

As shown in Table 2.3.3, the estimate for the variance component is 312.5 MW^2. An analysis of the model residuals suggests that the model errors are again Normally distributed, devoid of outliers and approximately temporally uncorrelated; implying that the modeling assumptions are reasonable. By definition, all of the engineering calculated avoided (and incremental) peak effect is accounted for in this econometric model via use of the avoided peak input variable.

The remaining regression parameter estimates shown in the middle of Table 2.3.3 imply that the monthly system peaks increases as each of the weather indices increase (in a linear manner with the MaxCD3 and MaxHD indices and in a curve-linear manner with the SumCD index). RPU system peaks are also expected to increase as either/both the PCPI and/or Emp_CC indices improve over time (e.g., both parameter estimates are > 0). Likewise, peak loads will grow more slowly if future EE and/or PV trends increase above their current forecasted levels, or more quickly if our EV and/or BE penetration levels increase. Additionally, not every individual Fourier frequency parameter estimate is statistically significant, although their combined effect significantly improves the forecasting accuracy of the model.

Figure 2.3.4 shows the observed (blue points) versus calibrated (green line) system peaks for the 2007-2021 timeframe. Nearly all the back-casts fall within the calculated 95% confidence envelope (thin black lines). Figure 2.3.5 shows the forecasted monthly system peaks for 2022 through 2034, along with the corresponding 95% forecasting envelope. This forecasting envelope again encompasses just the model uncertainty, while treating the weather variables and projected economic and structural indices as fixed inputs. Finally, Figure 2.3.6 shows the strength of correlation between the observed versus back-cast predicted system peaks shown in Figure 2.3.4. Note that this observed versus calibrated load correlation exceeds 0.985.

Table 2.3.4 shows the forecasted monthly RPU system peaks for 2022, along with their forecasted standard deviations. In contrast to Figure 2.3.5, these standard deviations quantify both model and weather uncertainty. The 2022 forecasts project that RPU's maximum monthly system peak should be about 594.5 MW and occur in August, assuming that the RPU service area experiences typical weather conditions that month. Note that this represents a 1-in-2 peak forecast, respectively.

Table 2.3.3. Model summary statistics for the monthly system peak forecasting equation.

Gross Monthly Peak Model (January 2007 - December 2021): MW units

Forecasting Model: includes Weather & Economic Covariates, Fourier Effects, pseudo TOU (unconstrained), 2014 Dist.system Adj, and Avoided Peak (PV+EE-EV-FS)
Assumes constrained Avoided peak savings.

Dependent Variable: Peak Peak (MW)

Number of Observations Read	468
Number of Observations Used	180
Number of Observations with Missing Values	288

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	17	2342965	137821	441.00	<.0001
Error	162	50628	312.51746		
Corrected Total	179	2393592			

Root MSE	17.67816	R-Square	0.9788
Dependent Mean	407.92494	Adj R-Sq	0.9766
Coeff Var	4.33368		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	151.93512	21.25969	7.15	<.0001
PCPI	PCPI ($1,000)	1	2.27332	0.51922	4.38	<.0001
Emp_CC	Labor (100,000)	1	4.28095	1.87436	2.28	0.0237
MxCD3		1	2.77469	0.20150	13.77	<.0001
SumCD		1	0.47412	0.08853	5.36	<.0001
SqCD		1	-5.55395	1.46659	-3.79	0.0002
MxHD		1	0.76295	0.68943	1.11	0.2701
Fs1		1	-8.64968	4.83337	-1.79	0.0754
Fc1		1	-12.35611	6.79653	-1.82	0.0709
Fs2		1	1.75616	3.79409	0.46	0.6441
Fc2		1	-0.38840	3.06797	-0.13	0.8994
Fs3		1	4.87650	2.21529	2.20	0.0291
Fc3		1	9.84449	2.00155	4.92	<.0001
Fs2014a		1	-8.84831	3.92285	-2.26	0.0254
Fc2014a		1	-26.22864	3.99416	-6.57	<.0001
Fs2014b		1	6.34514	3.87979	1.64	0.1039
Fc2014b		1	8.58756	3.91049	2.20	0.0295
econTOU		1	17.65800	3.91489	4.51	<.0001
avoided_peak	EE+PV-EV-BE	1	-1.05000	0	-Infty	<.0001

Durbin-Watson D	2.060
Number of Observations	180
1st Order Autocorrelation	-0.030

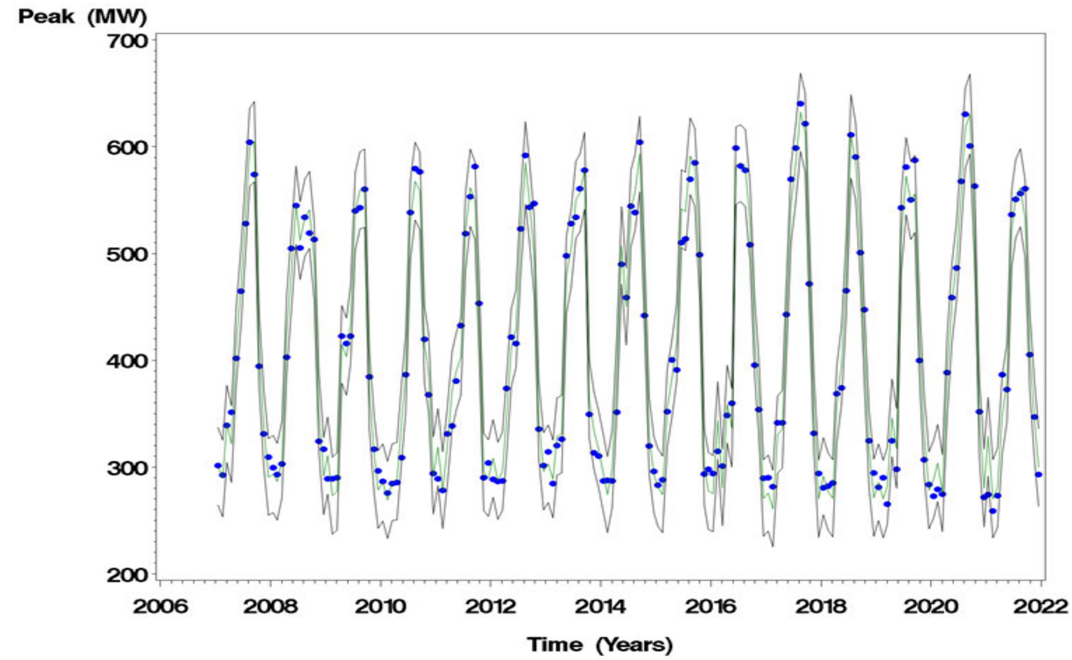


Figure 2.3.4. Observed and predicted system peak data (2007-2021), after adjusting for known weather conditions.

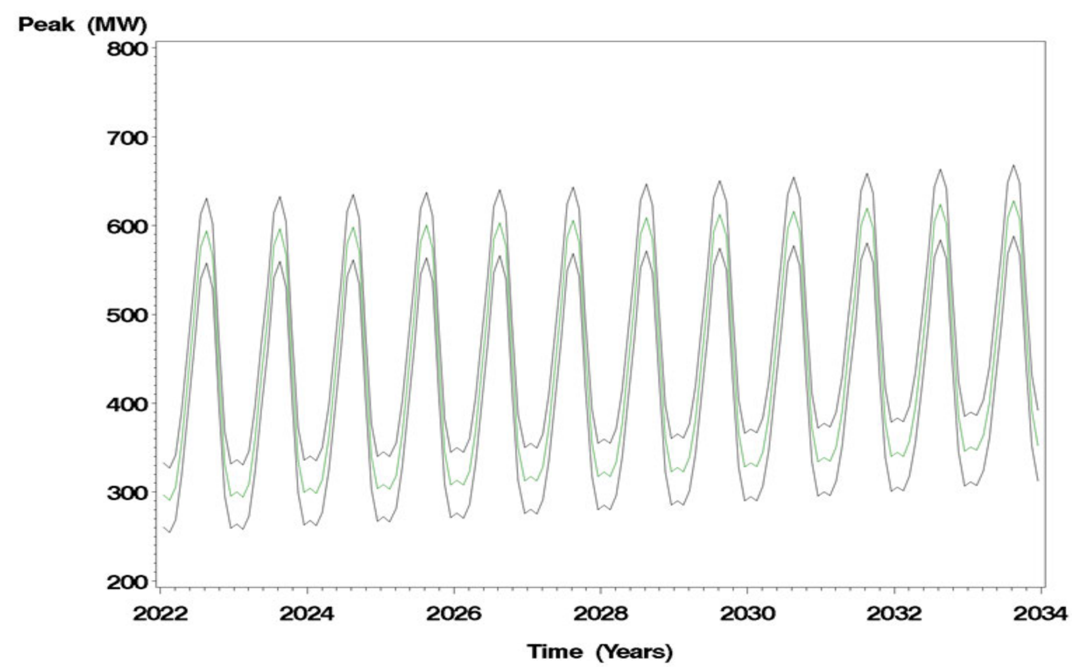


Figure 2.3.5. Forecasted monthly system peaks for 2022-2034; 95% forecasting envelopes encompass model uncertainty only.

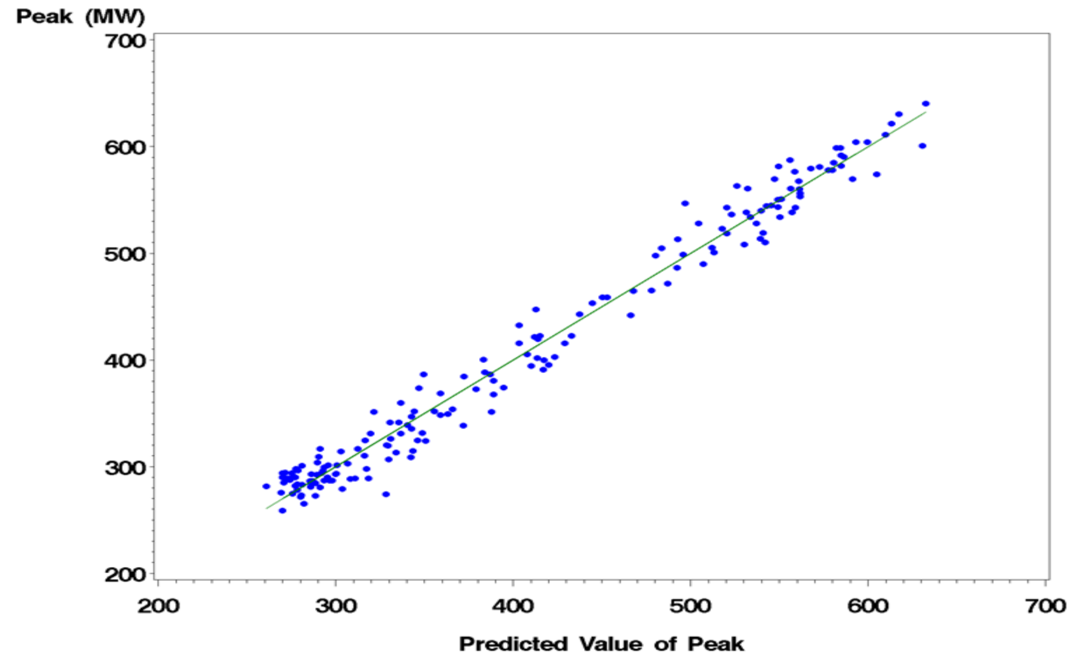


Figure 2.3.6. Strength of correlation between the observed versus prediction system peaks shown in Figure 2.3.4.

Table 2.3.4. 2022 monthly system peak forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Peak (MW)	Std.Dev (MW)
JAN	296.7	22.3
FEB	290.5	25.9
MAR	305.3	33.1
APR	356.2	43.9
MAY	425.2	56.9
JUN	494.4	57.7
JUL	576.1	30.5
AUG	594.5	30.6
SEP	565.5	39.3
OCT	438.8	54.2
NOV	331.7	38.8
DEC	295.4	23.6

2.3.5 Peak demand weather scenario forecasts

After calculating the monthly peak forecasts and their corresponding standard deviation estimates (that incorporate weather uncertainty), additional peak demand forecasts for more extreme weather scenarios can be produced. Under the assumption that these $\hat{y}_t$ forecasts can be probabilistically approximated using a Normal distribution, the following formulas can be used to calculate 1-in-5, 1-in-10, 1-in-20 and 1-in-40 forecast scenarios:

1-in-5 Peak: $\hat{y}_t + 0.842[\,\mathrm{Std}(\hat{y}_t)\,]$ [Eq. 2.3.7]

1-in-10 Peak: $\hat{y}_t + 1.282[\,\mathrm{Std}(\hat{y}_t)\,]$ [Eq. 2.3.8]

1-in-20 Peak: $\hat{y}_t + 1.645[\,\mathrm{Std}(\hat{y}_t)\,]$ [Eq. 2.3.9]

1-in-40 Peak: $\hat{y}_t + 1.960[\,\mathrm{Std}(\hat{y}_t)\,]$ [Eq. 2.3.10]

In equations 2.3.7 through 2.3.10, the scale multiplier terms applied to the standard deviation represent the upper 80% (1-in-5), 90% (1-in-10), 95% (1-in-20) and 97.5% (1-in-40) percentiles of the Standard Normal distribution, respectively.

In the RPU service area, the maximum weather scenario peaks are always forecasted to occur in the month of August. Thus, for 2022, RPU's forecasted, COVID-19 adjusted 1-in-5, 1-in-10, 1-in-20 and 1-in-40 peaks are 620.3, 633.7, 644.8 and 654.5 MW, respectively.

2.3.6 CEC Load and Peak Forecasts for RPU versus RPU Staff Forecasts

RPU staff are aware that the CEC produces their own set of system load and peak forecasts for the City of Riverside during each annual IEPR reporting process. Historically, these CEC forecasts have been presented on the California Energy Demand Managed Forecast tables for various Demand and AAEE scenarios. A recent set of tables were published by the CEC in February 2022 (e.g., California Energy Demand 2022-2035 Managed Forecasts).

Figure 2.3.7 compares RPU's staff annual system load forecasts (produced by the load model discussed in section 2.3.2) to the recent CEC Demand forecasts from the Mid-Demand - AAEE Scenario 2 – AAFS Scenario 4 workbook (CEC Publication TN241384). As shown in Figure 2.3.7, the two forecasts align quite closely up through 2030. After 2030, the RPU forecasts begin project more load growth within the City of Riverside; staff believe that these differences are most likely due to differences in assumptions about longer-term customer solar PV load growth within the RPU service territory.

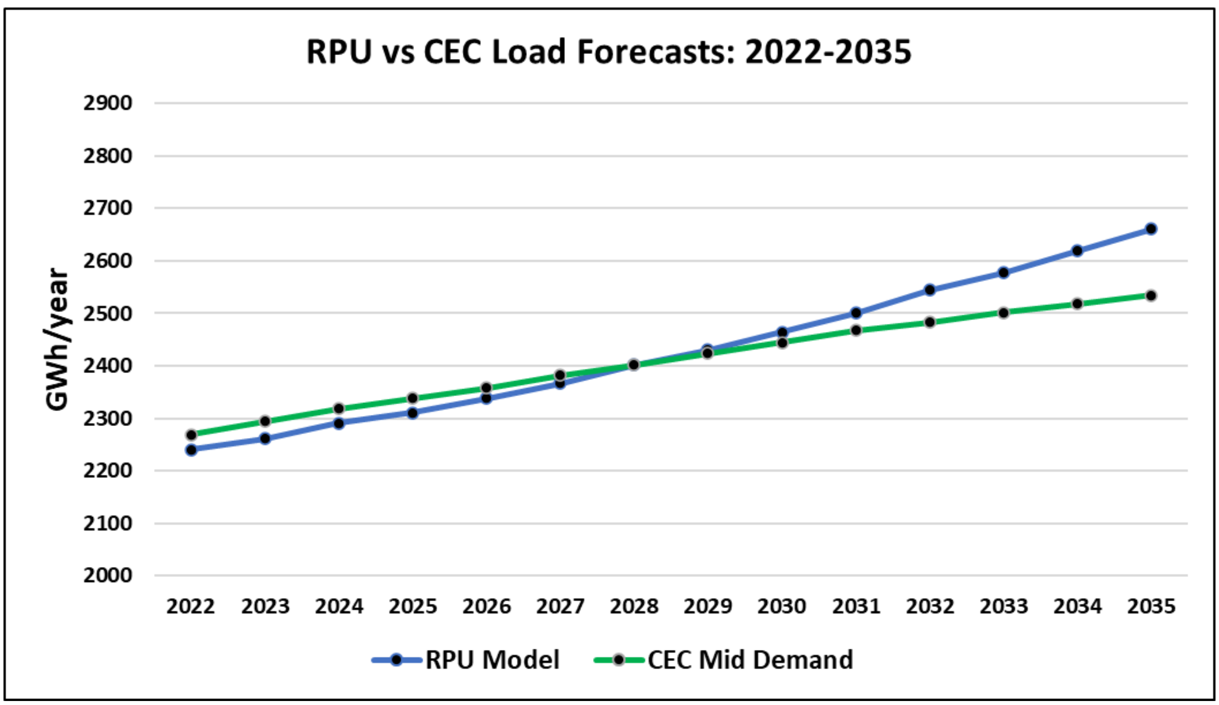


Figure 2.3.7. A comparison of RPU system load forecasts produced by RPU staff versus the recent CEC CEDU demand forecasts for the City of Riverside (2022 Mid-Demand - AAEE Scenario 2 – AAFS Scenario 4).

Likewise, Figure 2.3.8 compares RPU's staff annual 1-in-2 system peak forecasts (produced by the peak model discussed in section 2.3.3) to the recent CEC 1-in-2 Peak forecasts from the Mid-Demand - AAEE Scenario 2 – AAFS Scenario 4 workbook. It should be noted that the CEC peak forecasts for individual cities in past CEDU publications have historically represented coincident peak forecasts, but now appear to instead represent non-coincident peak forecasts. Assuming that this is indeed the case, these RPU versus CEC forecasts should be directly comparable.

As shown in Figure 2.3.8, both the growth rate and absolute levels for RPU's peak forecasts corresponds very closely to the CEC forecasts up through 2030. After 2030, the RPU forecasts tend to be 7-10 MW lower, but again exhibit similar growth rates. Therefore, staff believe that RPU peak forecasts exhibit close consistency with these CEC Mid-Demand - AAEE Scenario 2 – AAFS Scenario 4 peak forecasts.

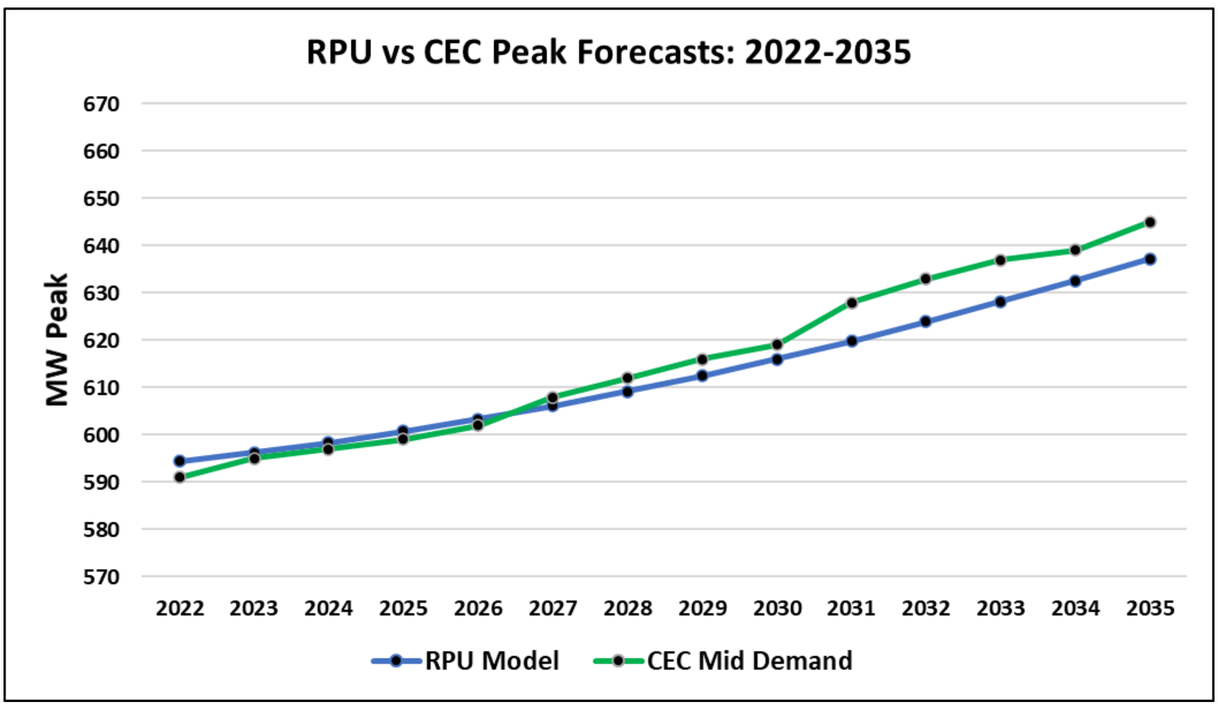


Figure 2.3.8. A comparison of RPU system 1-in-2 peak forecasts produced by RPU staff versus the recent CEC CEDU 1-in-2 peak forecasts for the City of Riverside (CEC Mid-Demand - AAEE Scenario 2 – AAFS Scenario 4).

2.4 2023-2045 System Load and Peak Forecasts

Based on the previous system load and peak forecasting equations, Table 2.4.1 shows the annual forecasted system loads and peaks for the 2023-2045 timeframe (columns 2 and 3). These forecasts represent future RPU load and peak estimates under this base case scenario. Recall that this base case scenario assumes historical average annual PCPI and labor growth rates, continued 1%/year energy efficiency efforts, continued customer solar PV (DER) installations, increasing adoption of electric vehicles, and future fuel switching efforts (see sections 2.2.5 through 2.2.8). RPU's expected annual load and peak growth rates under this scenario are 1.4% and 0.6%, respectively.

Table 2.4.1. Annual forecasted RPU system loads and peaks: base case scenario.

Year	System Load (GWh)	System Peak (MW)
2023	2,260.8	596.3
2024	2,290.7	598.4
2025	2,310.8	600.7
2026	2,337.9	603.3
2027	2,366.7	606.2
2028	2,401.6	609.2
2029	2,430.0	612.5
2030	2,464.2	616.0
2031	2,500.4	619.8
2032	2,543.7	623.9
2033	2,577.2	628.1
2034	2,618.5	632.6
2035	2,660.7	637.3
2036	2,710.1	642.3
2037	2,750.1	647.5
2038	2,797.0	652.9
2039	2,844.9	658.6
2040	2,900.3	664.6
2041	2,947.5	670.9
2042	3,001.1	677.5
2043	3,056.4	684.4
2044	3,118.2	691.5
2045	3,172.1	699.0
Load/Peak Growth: 2023 vs 2042	1.4%	0.6%

Conceptually, there are many factors that could alter these future system load and peak forecasts. Future economic conditions will tend to be the dominant driver; note that this base case scenario envisions an extended period of typical growth rates in local area per capita personal income and employment. Any extended period of suboptimal economic conditions will depress this load growth accordingly. Other factors that could also reduce the load growth more than currently forecasted include (a) a higher than expected penetration of solar PV installations, (b) significantly increased (and effective) energy efficiency activities, and (c) the need for an excessive increase in retail rates to compensate for either the cost of increasingly stringent regulatory mandates or unforeseen spikes in long term electricity prices. Likewise, accelerated electric vehicle adoption rates represent the primary factor that could significantly increase the utilities load growth (above these current forecasts). Later chapters in this IRP will examine the impacts associated with some of these DER input assumptions in greater detail.

3. RPU Generation and Transmission Resources

Chapter 3 provides an overview of RPU's portfolio of generation resources. Specifically, this chapter identifies and describes all the utility's existing resources under City of Riverside contracts, future resources under contract, and resources that have recently expired. Additionally, this chapter describes Riverside's transmission assets and the utility's role in the CAISO, as well as RPU's evolving resource procurement strategy.

3.1 Existing and Anticipated Generation Resources

RPU's resource portfolio has evolved over time to address key issues such as CAISO market price volatility, various fuel and delivery risk tolerances, internal generation and distribution needs, and load and peak demand growth. Additionally, the utility's portfolio continues to be shaped by new statutory and regulatory mandates, particularly the need to achieve specific greenhouse gas (GHG) reduction targets and a commitment to incorporate a systematically increasing percentage of renewable resources. Table 3.1.1 presents a high-level overview of RPU's current resource portfolio, with respect to both existing and anticipated resources. Additionally, Figure 3.1 shows the locations of all the currently existing resources referenced in Table 3.1.1, along with one short-term biomass resource (ARP Loyalton) that expired in 2023.

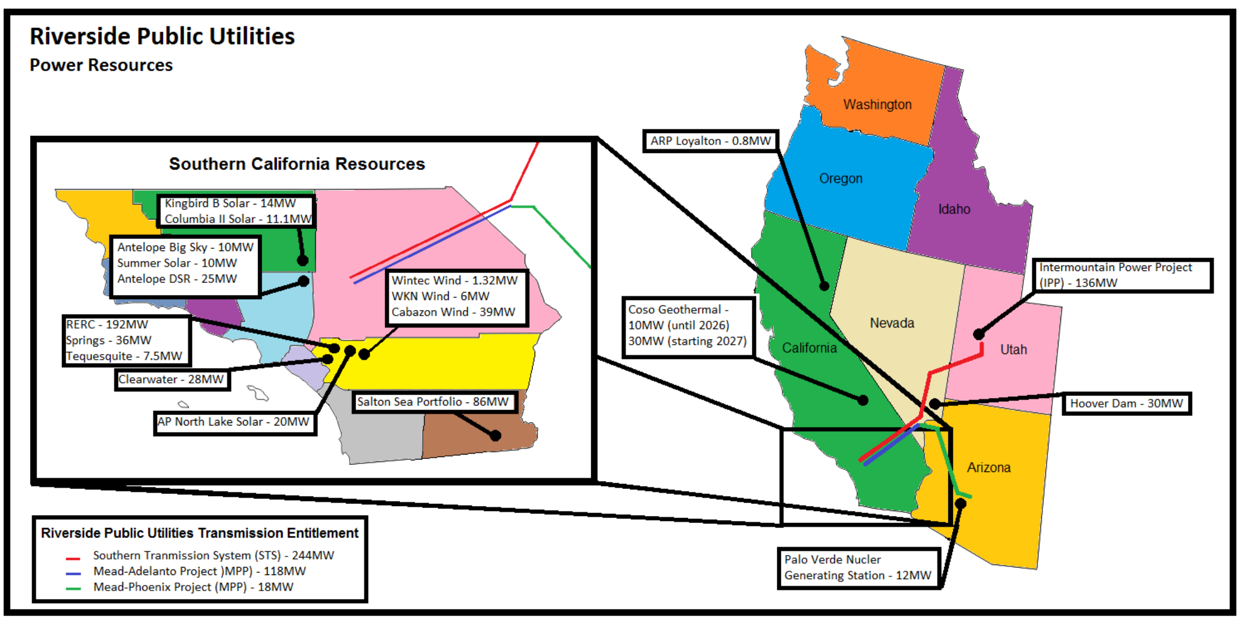


Figure 3.1. Physical locations of existing RPU long-term generation resources.

Table 3.1.1. Long-term generation resources in the RPU power portfolio.

Existing Resources	Technology	Nameplate Capacity (MW)	Contract End Date	Asset Type
Intermountain (IPP)	Coal, base-load	136	Jun-2025 **	Entitlement/PPA
IPP-CCNG Conversion	Nat.gas, combined-cycle	66	Jun-2027	Entitlement/PPA
Palo Verde	Nuclear, base-load	12	Dec-2030	PPA (SCPPA)
Hoover	Hydro, daily peaking	18-28	Sep-2067	PPA (SCPPA)
RERC 1-4	Nat.gas, daily peaking	194	n/a	Owned Asset
Springs	Nat.gas, daily peaking	36	n/a	Owned Asset
Clearwater	Nat.gas, base-load	28.5	n/a	Owned Asset
CalEnergy Portfolio	Geothermal, renewable (base-load)	86	Dec-2039	PPA
Coso	Geothermal, renewable (base-load)	10/30	Dec-2041	PPA
Wintec	Wind, renewable	1.3	Dec-2023	PPA
WKN	Wind, renewable	6	Dec-2032	PPA
AP North Lake	Solar PV, renewable	20	Aug-2040	PPA
Antelope Big Sky Ranch	Solar PV, renewable	10	Dec-2041	PPA (SCPPA)
Antelope DSR	Solar PV, renewable	25	Dec-2036	PPA (SCPPA)
Summer	Solar PV, renewable	10	Dec-2041	PPA (SCPPA)
Kingbird B	Solar PV, renewable	14	Dec-2036	PPA (SCPPA)
Columbia II	Solar PV, renewable	11	Dec-2034	PPA (SCPPA)
Tequesquite	Solar PV, renewable	7.3	Dec-2040	PPA w/PO
Cabazon	Wind, renewable	39	Dec 2024	PPA
Future Resources (under contract)	**Technology**	**Nameplate Capacity (MW)**	**Contract Start & End Dates**	**Asset Type**
Pattern/SunZia	Wind, renewable	125	Apr-2026 to Mar-2041	PPA
Recently Expired Contracts	**Technology**	**Nameplate Capacity (MW)**	**Termination Date**	**Asset Type**
Salton Sea 5	Geothermal, renewable (base-load)	46	May-2020	PPA
Expired Contracts with continuing Debt Service Payments	**Technology**	**Nameplate Capacity (MW)**	**Force Majeure Date**	**Asset Type**
SONGS	Nuclear (base-load)	39	Feb-2012 Force Majeure	Ownership Interest

** the IPP contract ends in June 2027, but the coal units will be retired by June 2025.

3.1.1 Existing Resources

Intermountain Power Project (IPP)

Riverside has contractual rights in the Intermountain Power Project (IPP) for base-load coal energy through mid-June 2027. In 2018, LADWP announced that they would shut down these coal plants by June 2025 and build a 875 MW Combined Cycle Natural Gas (CCNG) plant on the site. While the coal units are still functioning, RPU is entitled to receive 7.617% of the energy output from Units 1 & 2, or 68 MW per hour from each unit. In theory, RPU can receive a maximum of 1,048,400 MWh of base-load energy if both plants run at full-load 88% capacity factors. However, the plant's capacity factor has been steadily decreasing over the past five years due to the added dispatch cost of carbon, lower CAISO market pricing and more recently, fuel supply shortages and persistent fuel delivery disruptions. In CY 2021, the effective plant capacity for RPU's share of energy was just 49%.

In July 2025, RPU will have rights to 64 MW of CCNG output for the final two years of the IPP contract. After mid-June 2027, RPU will exit the IPP contract entirely, surrender its rights to any further energy deliveries and associated transmission assets, and be relieved of all further generation and transmission debt service payments.

Riverside is required to pay for its contractual share of debt service costs, fixed O&M costs, and take-or-pay coal supply costs whether or not the IPP units generate any electricity. In FY 20/21, this fixed cost component was $34,485,975, which translated to a fixed capacity cost of $21.13/kW-month and a 63.7% minimum take obligation. For all energy above the annual minimum take-or-pay obligation, RPU pays a flat $/MWh energy cost (incremental coal cost); as of June 2021, this variable fuel cost was approximately $22.07/MWh.

Palo Verde Nuclear Facility

Riverside has a long-term contract with SCPPA for ownership rights in the Palo Verde (PV) Nuclear facility. (SCPPA officially owns a share of the nuclear facility; RPU in turn has a contract with SCPPA to pay its share of the debt services, capital, O&M, and fuel costs.) Riverside's share of PV entitles RPU to 3.9 MW of base-load energy from each nuclear unit (PV-1, PV-2, and PV-3; 11.7 MW total) through December 2030. As of June 2021, Palo Verde energy cost $6.31/MWh. Additionally, RPU also pays approximately $3,600,000 annually in fixed capacity costs (or $36.73/MWh, based on an expected delivery of 98,000 MWh of annual energy).

Hoover

Riverside is a participant in the Hoover Uprating project. Hoover is owned and operated by the United States Bureau of Reclamation, and power from the project is marketed by the Western Area Power Administration. The City has a 31.9% (30 MW) entitlement interest in SCPPA's approximately 94 MW interest in the total capacity and allocated energy of Hoover.

For scheduling purposes, participants in the Hoover project receive a total MWh per month allocation of energy and a maximum hourly capacity limit (as determined by current lake levels). During

October 2021 – September 2022, RPU was entitled to approximately 26,720 MWh's of Hoover hydro energy, subject to the scheduling limits shown in Table 3.1.2. As of June 2022, Hoover energy cost $10.32/MWh. Additionally, RPU also pays approximately $550,000 annually in fixed capacity costs (or $20.37/MWh, based on an expected delivery of 27,000 MWh of annual energy).

Table 3.1.2. 2021-2022 MWh/month and MW/hour scheduling limits for Hoover Dam energy.

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
MWh/month	1731	1898	1561	1625	1872	2820	2957	2908	2705	2374	2268	2001
MW/hour	16	14	14	14	14	13	13	16	17	17	16	17

RERC Units 1-4

RPU owns and operates four LM-6000 peaking units; these units are collocated together at the RERC generation facility in the center of Riverside and connected directly to Riverside's local distribution system (69kV lines). RERC Units 1 and 2 became operational in 2006; RERC Units 3 and 4 came on-line in 2011. All four units have P_{max} heat rates of 9,600 (Btu/kWh), net P_{max} outputs of 48.4 MW/hour per unit and are certified to provide energy, RA, and some ancillary services to the CAISO.

The annual and/or monthly runtime limits on each unit are determined by air quality pollution control permit limits. For RERC Units 1 and 2, the primary limits are the 1200-hour maximum runtime constraints in any rolling 12-month window. For RERC Units 3 and 4, the primary constraints are 700 starts in any rolling 12-month window, and 60 starts-per-month. Theoretically, RERC's four units could generate up to a maximum of 290,000 MWh of energy per year. In practice, the RERC units typically produce 40,000 to 80,000 MWh a year (under economic dispatch). More recently, under the CAISO's Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO) paradigm, the RERC units have been dispatching more frequently under CAISO instruction for CAISO ramping needs. The costs Riverside incurs for these additional dispatches are recovered through the CAISO's bid cost recovery mechanism.

Springs (Units 1-4)

RPU also owns and operates four GE-10 peaking units; these units are collocated together at the Springs generation and distribution facility in the eastern part of Riverside. Springs Units 1-4 were brought on-line in 2002 (after the last energy crisis), to increase reliability and serve basic emergency power needs. All four units have P_{max} heat rates of approximately 14,000 (Btu/kWh) and net P_{max} outputs of 9 MW/hour per unit under typical summer temperature conditions.

Generation hours for these GE-10 units are primarily limited by the units' inefficient heat rates; e.g., these units typically produce just 1,000 to 4,000 MWh a year under economic dispatch. Currently, these units are used for occasional distribution system voltage support and more importantly, helping to meet local and system RA requirements.

Clearwater

RPU owns and operates one additional small combined-cycle (cogeneration) plant located in the city of Corona, CA. This facility is certified to provide energy and RA to the CAISO, but not ancillary services. Although Clearwater lies outside of the RPU service territory, the CAISO classifies all energy generated from this facility as internal RPU generation.

Clearwater has a combined-cycle P_{max} heat rate of 8,600 (Btu/kWh) and a net output of 28 MW/hour. RPU has sufficient AQMD permits to dispatch this unit on a 6 x 16 schedule year-around, but Clearwater is typically out-of-the-money during most heavy load hours outside of Q3. Clearwater typically generates 15,000 to 25,000 MWh of energy per year (under economic dispatch).

CalEnergy Generation Portfolio

In 2013, Riverside successfully concluded contract negotiations with CalEnergy LLC to significantly increase the amount of geothermal energy delivered from the CalEnergy Salton Sea geothermal portfolio. Under this new contract, Riverside increased its purchase of geothermal energy from 46 MW delivered from a single facility (Salton Sea 5) to 86 MW delivered from a portfolio of facilities. In February 2016, the utility began receiving an additional 20 MW of base-load geothermal energy from the portfolio, which increased to 40 MW in January 2019. Additionally, after the Salton Sea 5 contract terminated in May 2020, the utility simultaneously began receiving an additional 46 MW of energy from the geothermal portfolio (thus maintaining 86 MW of total CalEnergy geothermal capacity in RPU's resource portfolio). This 86 MW of geothermal capacity is expected to deliver approximately 618,000 MWh annually. The FY 21/22 price for this portfolio energy was $79.03/MWh and includes all RA attributes; note that this contract price is subject to a 1.5% annual escalation clause.

Coso Geothermal Project

In early 2021 the Public Utilities Board and the City Council approved a new 20-year long-term renewable energy power sales agreement (PSA) through SCPPA for the partial output of baseload geothermal energy from Coso Geothermal Power Holdings, LLC. Riverside began receiving about 10 MW of baseload energy from their China Lake, CA geothermal facility in January 2022; these energy deliveries are scheduled to increase to about 30 MW in January 2027. Overall, this contract is expected to deliver about 83,000 MWh of renewable energy annually beginning in 2022, increasing to 249,000 MWh annually on/after 2027. The price for this energy is $69.00/MWh flat for 20 years and includes all RA attributes.

Wintec Wind

In 2003, Riverside and Wintec-Pacific Solar, LLC entered into a fifteen-year PPA for 1.3 MW of wind energy generated from the Wintec project near Palm Springs, California. This take-and-pay renewable wind resource typically delivers around 4,500 MWh per year of intermittent renewable energy to the utility. As of June 2017, RPU paid $57.32/MWh for this energy. In February 2019, Riverside extended this PPA for five additional years at a new price of $35.77/MWh. This extension contract is scheduled to terminate in January 2024.

WKN Wind

In 2012, Riverside and WKN-Wagner, LLC entered into a twenty-year PPA for 6.0 MW of wind energy generated from the WKN project near Palm Springs, California. This take-and-pay renewable wind resource delivers about 17,000 MWh per year of intermittent renewable energy to the utility. As of FY 21/22, RPU paid $76.54/MWh for this energy; note that this contract price is subject to a 1.5% annual escalation clause.

North Lake Solar PV

In 2012, Riverside and SunEdison entered into a bilateral twenty-five year PPA for the 20.0 MW North Lake solar PV project in Hemet, California. This take-and-pay renewable solar resource became fully operational in August 2015 and typically delivers about 44,000 MWh per year of intermittent renewable energy to the utility. As of FY 21/22, RPU paid $86.15/MWh for this energy; note that this contract price is also subject to a 1.5% annual escalation clause.

Silverado Solar PV Projects

In 2013, Riverside also executed two agreements with the Southern California Public Power Authority (SCPPA) to participate in two twenty-five-year PPAs for two 20.0 MW (combined 40.0 MW) solar PV projects in Lancaster, California: Summer Solar and Antelope Big Sky Ranch. Riverside has a 50% share of the output from each project or 20.0 MW total. These take-and-pay renewable solar resources came online in July and August 2016 and typically deliver about 53,500 MWh per year of intermittent renewable energy to the utility. The price for this energy is $71.25/MWh flat for 25 years and includes all RA attributes.

Kingbird B Solar

In 2013, Riverside executed an agreement with SCPPA to participate in a twenty-year PPA for the 20.0 MW Kingbird B (First Solar) PV project in Rosamond, California. Riverside has a 70% share (14.0 MW) of the output from this facility. This take-and-pay renewable solar resource came online in April 2016 and typically delivers about 40,500 MWh per year of intermittent renewable energy to the utility. The price for this energy is $68.75/MWh flat for twenty years and includes all RA attributes.

Recurrent Columbia Two Solar

In 2013, Riverside executed an agreement with SCPPA to participate in a twenty-year PPA for the 15.0 MW Recurrent Columbia Two solar PV project in Mojave, California. Riverside has a 74.29% share (11.1 MW) of the output from this facility. This take-and-pay renewable solar resource came online in December 2014 and typically delivers about 31,000 MWh per year of intermittent renewable energy to the utility. The price for this energy is $69.98/MWh flat for twenty years and includes all RA attributes.

Tequesquite Solar

In March 2014 Riverside executed a twenty-five-year bilateral PPA with SunPower to develop a 7.3 MW solar PV facility on the Tequesquite landfill site in the city of Riverside, California. This take-and-pay, distributed generation solar resource became fully operational in September 2015 and normally delivers about 14,500 MWh per year of intermittent renewable energy to the utility. As of FY 21/22, RPU paid $88.25/MWh for this energy and corresponding RA attributes; note that this contract price is subject to a 1.5% annual escalation clause.

Cabazon Wind

In 2013, Riverside also entered into a bilateral ten-year PPA with Nextera for the 39.0 MW Cabazon Wind Energy project located near North Palm Springs, California. This existing take-and-pay renewable wind resource began delivering about 55,000 MWh of intermittent renewable energy annually to the utility in 2015. The price for this energy is $59.30/MWh flat for ten years and includes all RA attributes.

In 2019 Nextera sold this facility to Glidepath, which took over operation of the facility. In 2022 the facility was subject to multiple theft events and turbine failures that resulted in the Cabazon facility becoming a semi-distressed asset. Then in Q3-2023 Glidepath sold this facility to Salka Energy; Salka concurrently executed a three-year contract extension with Riverside and instituted a plan to repair the facility to its prior performance levels. Under this new contract amendment, Cabazon will continue to sell energy and RA attributes to Riverside for $59.30/MWh through December 2027.

Antelope DSR Solar

In 2015, Riverside executed an agreement with SCPPA to participate in a twenty-year PPA for the 50.0 MW sPower Antelope DSR Solar Project in Lancaster, California. Riverside has a 50% share (25.0 MW) of the output from the facility. This take-and-pay renewable solar resource became fully operational in December 2016 and typically delivers about 65,000 MWh of intermittent renewable energy to the utility. The price for this energy is $53.75/MWh flat for twenty years and includes all RA attributes.

Under this PPA, SCPPA has both a Purchase Option and a Storage Option. With the Purchase Option, SCPPA has the option to purchase the Antelope DSR Solar Project in years 10, 15 and 20 at the then fair market value. With the Storage Option, SCPPA has the option in the first 15 years of the contract to install up to 12.0 MW of energy storage at the project site.

3.1.2 Future Resources

Pattern/SunZia Wind

In the fall of 2023, Riverside entered into a bilateral fifteen-year PPA with Pattern Energy Limited for 125.0 MW of the (to be developed) 3,515 MW SunZia Wind Energy project located in the Lincoln, Torrance, and San Miguel counties in New Mexico. Once built, SunZia Wind will represent the largest wind energy facility in the United States. This take-and-pay renewable wind resource will be dynamically scheduled into the CAISO at the Palo Verde (PV West) intertie; RPU expects to receive approximately 369,250 MWh/year of intermittent renewable energy annually once the facility is fully developed. Deliveries are expected to begin in April 2026 and the price for this energy will be $59.50/MWh flat for fifteen years. This facility will also provide RPU with RA attributes, provided that the Utility obtains the necessary residual import capacity at PV West in the annual CAISO MIC Allocation process.

3.1.3 Recently Expired Contracts

Salton Sea 5

Riverside entered into a ten-year PPA in 2003 for 20 MW of base-load geothermal energy generated by the CalEnergy Salton Sea 5 facility located in Imperial County, California. In 2005, Riverside and CalEnergy amended this PPA to increase the amount of renewable energy from 20 MW to 46 MW effective June 1, 2009 through May 31, 2020 at a price of $61.00/MWh. On July 1, 2013 the contract energy price was increased to $69.66/MWh (with a 1.5% annual escalation rate) as part of the pre-pay agreement for the CalEnergy Portfolio contract.

Salton Sea 5 was a traditional take-and-pay PPA with a historic base-load, outage-adjusted capacity factor of about 87%. Traditionally, the Salton Sea 5 unit delivered about 325,000 MWh per year of renewable base-load energy to the utility. As noted above, this contract terminated on May 31, 2020.

ARP Loyalton Biomass Facility (short-term resource)

Riverside entered into a five-year term biomass project with American Renewable Power-Loyalton Cogen, LLC in January 2018 through Riverside's participation in the Southern California Public Power Authority (a.k.a. "ARP-Loyalton Biomass"). This project was procured to meet the requirements of Senate Bill 859, which required specific utilities to procure their proportionate share of potential biomass-fueled resources utilizing high hazard fuel sources. The ARP-Loyalton Biomass project achieved full commercial operation in April 2018 and this biomass project qualified as a PCC-1 renewable resource scheduled into a California balancing authority. Unfortunately, in January 2020 the Loyalton biomass facility declared bankruptcy and ceased producing energy. This plant remained off-line through April 2023, at which point the contract expired.

3.1.4 Expired Contracts with continuing Debt Service Payments

San Onofre Nuclear Generating Station (SONGS)

Riverside has a 1.79% undivided ownership interest in Units 2 and 3 of SONGS, located south of the City of San Clemente in northern San Diego County. RPU had received 39.5 MW of firm local capacity and approximately 290,000 MWhs per year from Units 2 and 3, respectively, before SONGS went off-line in early 2012 due to excessive steam-tube wear. SONGS is operated and maintained by SCE under an agreement with Riverside and SDG&E. In the summer of 2013, SCE elected to permanently shut down SONGS, due to the ongoing economic uncertainty surrounding the repair of the steam turbines (and the potential complication of relicensing of the nuclear generation facility).

Under the current participation agreement, Riverside is entitled to its proportionate share of benefits of and pays its proportionate share of costs and liabilities incurred by SCE for construction, operation and maintenance of the SONGS facility. As of June 2021, Riverside owed approximately $15.0 million dollars in outstanding bond debt related to SONGS costs and liabilities. Additionally, Riverside is also responsible for its share of expenses associated with all decommissioning activities. According to SCE’s decommissioning cost estimate document as of August 2021, total decommissioning costs for SONGs Units 2 and 3 are estimated at $5.243 billion in 2020 dollars of which Riverside’s share is $94 million. The City had deposited $62.5 million in its decommissioning trust funds as of June 2021. Additionally, as of June 2021, Riverside had paid $36.4 million in decommissioning obligations, and the decommissioning liability balance was $50.9 million.

Due to adequate funding of the liability, the utility no longer provides additional funding to the decommissioning trust account. However, since the decommissioning cost estimate is subject to several uncertainties including the cost of disposal of nuclear waste, site remediation costs, as well as a number of other assumptions and estimates, RPU continues to set aside approximately $2 million per year in an unrestricted designated decommissioning reserve account to cover potentially increased decommissioning expenses.

3.2 Status of Active Contracts

3.2.1 Existing Generation Resources with Contracts that Expire before December 2030

Table 3.2.1 presents an overview of the utility’s current generation resources with either contracts or expected lifetimes that expire by or before December 2030. In Table 3.2.1, each resource has been classified into one of three mutually exclusive groups defined as follows: (a) resources with contracts that will be terminated before 2030 (or reach their end-of-life before 2030), (b) resources with contracts that RPU plans on extending, and (c) resources with contracts whose extensions are currently uncertain. Note that the contracts associated with IPP, Palo Verde, Wintec, and Cabazon are all scheduled to be terminated by or before 2030. Additionally, the Springs generation facility will reach its 25-year end-of-life cycle in 2027, although it is currently not expected to be decommissioned by that date. The IPP Coal plants are currently scheduled to be retired in 2025 and replaced with a smaller CCNG facility (which will supply power to Riverside during the final two years of the IPP contract); this IPP contract will not be extended. However, the state of the remaining facilities is less certain, as discussed in further detail below.

Table 3.2.1. Long-term RPU generation resources with end-of-life dates or contracts that expire before 2030.

Resource	Technology	Capacity (MW)	Contract End Date	Assumption
Intermountain (IPP)	Coal, base-load	136	June-2027	Contract terminates
Palo Verde	Nuclear, base-load	12	Dec-2030	Contract to be extended
Springs	Nat.gas, daily peaking	36	n/a	Forecasted end-of-life: 2027
Wintec	Wind, renewable	1.3	Dec-2023	Contract likely terminates
Cabazon	Wind, renewable	39	Dec-2027	Status uncertain

Palo Verde Nuclear Facility

The City's current contract with Palo Verde is scheduled to terminate in December 2030. However, in 2011 the Nuclear Regulatory Commission extended the Palo Verde nuclear facility licenses for Units 1, 2 and 3 by 20 years each, thus extending the expected operational plant life at least through 2045. In turn, the Palo Verde facility has announced that it intends to offer contract extensions to all primary subscribers through this date; all SCPPA member participants currently in the Palo Verde project (including Riverside) plan on pursuing these contract extension offers. Given these developments, it is expected that carbon-free Palo Verde nuclear energy will continue to be delivered to Riverside at the same capacity allotment and CF% at least through 2045.

Springs Generation Facility

RPU owns and operates four GE-10 peaking units; these units are collocated together at the Springs generation and distribution facility in the eastern part of Riverside. Springs units 1-4 were brought on-line in 2002 (after the last energy crisis), to increase reliability and serve basic emergency power needs. Due to their relatively inefficient heat-rates, these units are now primarily used for occasional distribution system voltage support and meeting local and system RA requirements. These units are forecasted to reach their end of serviceable life by 2027. However, the CAISO market continues to be critically short of dispatchable capacity, and this Springs facility is currently providing RPU with $3.46M per year of local RA value.[1] Therefore, RPU anticipates working to extend this facility's serviceable life until 2030, assuming maintenance on these units remains feasible.

[1] Assuming an annual local RA contract price of $8.00/kW-month and 36 MW of local RA value.

Wintec PPA

In 2003, Riverside and Wintec-Pacific Solar, LLC entered into a 15-year PPA for 1.3 MW of wind energy generated from the Wintec project near Palm Springs, California. As of June 2017, RPU paid \$57.32/MWh for this energy. In February 2019, Riverside extended this PPA for five additional years at a new price of \$35.77/MWh. As previously discussed, this extension contract is scheduled to terminate in January 2024, but could be further extended (subject to new price negotiations), since these wind turbines have a forecasted 25-year life expectancy. However, for purposes of this IRP process, staff have assumed that this PPA will terminate as planned in January 2024.

Cabazon Wind

As stated previously, Cabazon came under new ownership in 2023. However, the 51 wind turbines associated with this facility had already been in operation for 20 years and have now exceeded their expected serviceable life. Thus, it remains to be determined if Salka Energy can fully repair this facility, due to the age of the turbines and a potential shortage of serviceable parts.

For these reasons, in the absence of a suitable repowering proposal, Riverside anticipates terminating this PPA in December 2027. However, if this facility can be repowered with new, modern turbines at a competitive PPA price, staff anticipate that RPU might be interested in entering into a new power purchase agreement with this repowered facility. Nonetheless, the likelihood of such repowering activities is currently unknown and therefore the status of this contract is highly uncertain.[2]

3.2.2 Contracts that Expire After 2030 but Before 2045

As previously shown in Table 3.1.1, nearly all of Riverside's contracts that extend beyond 2030 are scheduled to expire before 2045. It is currently uncertain how many of these contracts may be either extended or replaced with equivalent generation technologies. However, for planning purposes, it is reasonable to assume that if any of these contracts are not extended then the corresponding assets will be replaced with newer assets of the same basic technology, under equivalent (or improved) pricing structures.

Figure 3.1.1 shows the status of all current Riverside contracts over the 2023-2042 time-period. This figure also shows some of staff's baseline assumptions about contract extensions or replacements. Note that many of these assumptions are discussed in further detail in Chapter 12 of this IRP.

[2] For purposes of this IRP analysis, due to the age of the turbines and the uncertainty surrounding viable repowering options, staff have assumed that the current contract will terminate as planned on December 31, 2027.

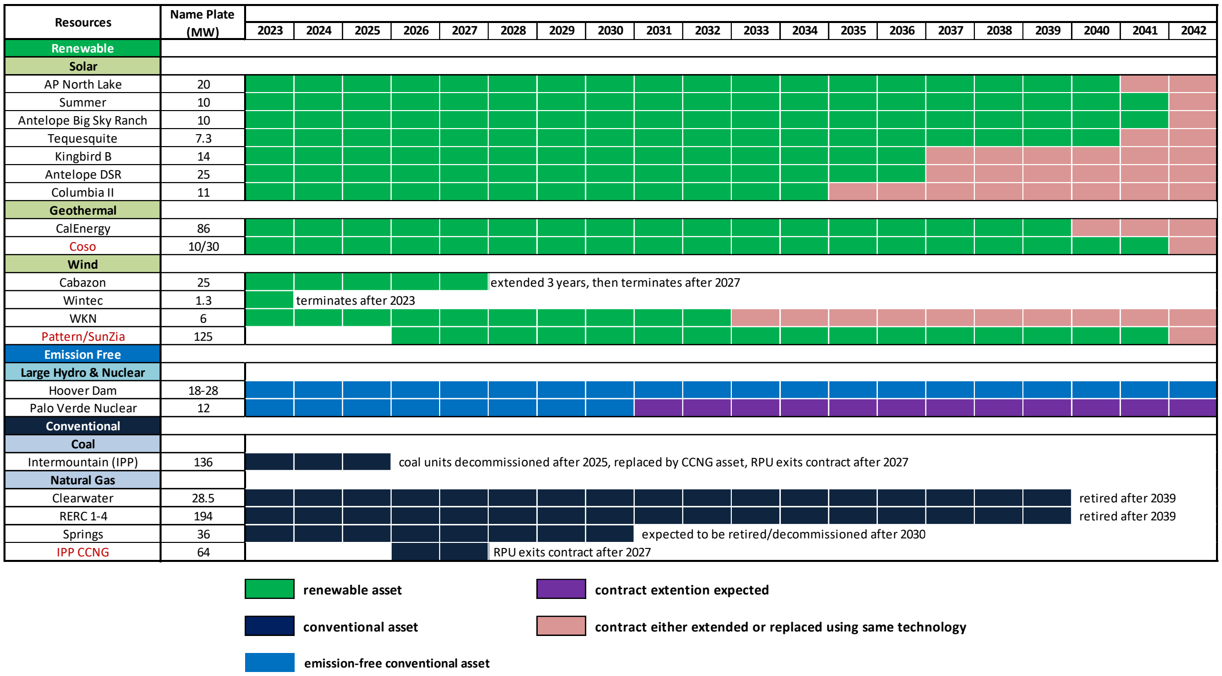


Figure 3.2.1. Delivery assumptions for all current RPU contracts over the 2023-2042 time-period.

3.3 Long-term, Capacity-only Contracts

Historically, RPU has met its annual Resource Adequacy (RA) deficits using short-term (1-2 year forward) RA contracts executed under standard WSPP Agreements. Note that these RA-WSPP Agreements are for capacity only; such agreements do not include the purchase, sale or transfer of any energy attributes.

Given Riverside's increasing reliance on variable renewable energy resources, there is now a need for RPU to procure stand-alone, long-term RA contracts to fully meet its CAISO RA obligations. Thus, RPU is currently in negotiations with Viridity Energy Solutions, Inc., a wholly owned subsidiary of Ormat Nevada, Inc., for a 15-year RA contract on a to-be-developed 80 MW / 320 MWh Battery Energy Storage System (BESS) located in Visalia, CA. RPU expects to have this RA Purchase Agreement (RAPA) executed in early 2024 and anticipates receiving RA benefits from this facility in late 2025.

3.4 Transmission Resources

Riverside has historical ownership rights to various transmission resources; these resources are described in more detail below.

Southern Transmission System

In connection with its entitlement to the IPP Generating Station, Riverside acquired a 10.2% (195 MW) entitlement in the transfer capability of the 500-kV DC bi-pole transmission line, known as the Southern Transmission System (STS). The STS provides for the transmission of energy from, among other resources, the IPP Generating Station to the California transmission grid. The STS provides approximately 2,400 MW of transfer capability. The City's total entitlement in the STS increased from 195 MW to 244 MW after the STS upgrade was completed in January 2011. However, as previously noted, Riverside's entire STS entitlement will end in mid-June of 2027 when the IPP contract terminates.

Mead-Phoenix Transmission Project

Originally in connection with its entitlement to PV nuclear generation station power, the City has acquired a 4.0% (12 MW) entitlement in SCPPA's share of the Mead-Phoenix Transmission Project, separate from the SCPPA interest acquired on behalf of the Western Area Power Administration. The Mead-Phoenix Transmission Project consists of a 256-mile, 500-kV AC transmission line that extends between a southern terminus at the existing Westwing Substation (in the vicinity of Phoenix, Arizona) and a northern terminus at Marketplace Substation. The Mead-Phoenix Transmission Project was upgraded in June 2009 as part of the East of River 9300 Project. Riverside received an additional 6 MW entitlement in the Mead-Phoenix Transmission Project from the upgrade.

Mead-Adelanto Transmission Project

In connection with the Mead-Phoenix Transmission Project, Riverside has acquired a 118 MW entitlement to SCPPA's share of the Mead-Adelanto Transmission Project. The Mead-Adelanto Transmission Project consists of a 202-mile, 500-kV AC transmission line that extends between a southwest terminus at the existing Adelanto Substation in southern California and a northeast terminus at Marketplace Substation. SCPPA currently owns 67.9% of this 500-kV transmission line; this line has a transfer capability of 1,286 MW.

Riverside Transmission Reliability Project

Riverside has historically relied upon a single point of electrical interconnection to California's bulk power transmission system, but the City is now pursuing the creation of a second point of interconnection to significantly enhance its system reliability and import capacity. This $521 million dollar project is known as the Riverside Transmission Reliability Project (RTRP) and will include a 230-69 kV transmission substation as a second point of interconnection to the California transmission grid. RTRP is discussed in greater detail in Chapter 4, Section 4.7.

3.5 California Independent System Operator

Riverside serves as its own Scheduling Coordinator with the CAISO and was the first California municipal utility to do so. In July 2002, the City notified the CAISO of its intent to become a Participating Transmission Owner (PTO), by turning over operational control of Riverside's transmission entitlements to the CAISO effective January 1, 2003. In November 2002, Riverside formally executed its Transmission Control Agreement with the CAISO.

On January 1, 2003, Riverside became a PTO with the CAISO, entitling the City to receive compensation for the use of its transmission entitlements committed to the CAISO's operational control. The compensation is based upon Riverside's annual Transmission Revenue Requirement (TRR) as approved by the FERC. Riverside now obtains all its transmission requirements from the CAISO. With the launch of the Market Redesign and Technology Upgrade (MRTU), the CAISO also implemented a Congestion Revenue Rights (CRR) allocation and auction process. Riverside participates in the CAISO CRR process to obtain the additional transmission congestion hedging rights necessary to hedge most of its load serving transmission requirements.

3.6 RPU's Evolving Resource Procurement Strategy

Fifteen years ago, RPU's resource portfolio was comprised of a blended amount of coal, nuclear, natural gas and geothermal generation resources, along with some strategic hydro and energy exchange contracts to help meet the City's summer peaking needs. However, this resource portfolio has undergone a significant transformation, specifically away from nuclear and coal and towards more renewable resources. With the (force majeure) loss of SONGS in February 2012, RPU has had both the need and opportunity to replace a nuclear resource that supplied 39 MW of firm, GHG-free base-load capacity (and approximately 290,000 MWh of annual energy) with a replacement base-load contract having equivalent characteristics. Thus, in 2013, Riverside entered into the long-term PPA with CalEnergy LLC to significantly expand the utility's base-load geothermal resources. In February 2016, RPU began receiving an additional 20 MW of base-load geothermal energy from the CalEnergy geothermal resource portfolio located in Imperial Valley, CA. This amount increased to 40 MW in January 2019 and then to 86 MW in June 2020 (immediately after the expiration of the 46 MW Salton Sea 5 contract).

In early 2021, Riverside executed a new 20-year long-term renewable energy PSA through SCPPA for the partial output of baseload geothermal energy from Coso Geothermal Power Holdings, LLC. Riverside begun receiving about 10 MW of baseload energy from their China Lake, CA geothermal facility in January 2022; these energy deliveries are scheduled to increase to about 30 MW in January 2027. Thus, Riverside currently has 96 MW of geothermal energy under contract and this amount is scheduled to increase to 116 MW by 2027.

In the fall of 2023, Riverside entered into a bilateral fifteen-year PPA with Pattern Energy Limited for 125.0 MW of the (to be developed) 3,515 MW SunZia Wind Energy project located in New

Mexico. This take-and-pay renewable wind resource will be dynamically scheduled into the CAISO at the Palo Verde (PV West) intertie beginning in 2026. RPU expects to receive approximately 369,250 MWh/year of intermittent renewable energy annually once this facility is fully developed.

Concurrently with the contracting of these new geothermal resources, RPU has executed multiple new solar PV and wind renewable PPA's. Combined, these seven solar PV and three wind resources have 142 MW of nameplate capacity and typically supply approximately 350,000 MWh of annual energy to the utility. Hence, Riverside's resource portfolio has been and continues to be evolving to incorporate over 700,000 MWh of new solar and wind resources, in addition to the aforementioned renewable geothermal resources.

Together, these new PPA's will contribute to a significant expansion of capacity and renewable energy to RPU's current resource portfolio. In 2022, Riverside served 45.4% of its retail load using renewable resources and RPU expects to significantly exceed its 60% by 2030 RPS mandate three years early (e.g., by 2027). The combined effects of these new renewable resources on RPU's portfolio are discussed further in Chapter 8, along with additional power resource metrics on the utility's forecasted net positions, internal generation, and GHG emissions during the 2024-2028 timeframe. Likewise, more in-depth discussions of RPU's long-term capacity and RPS energy needs are presented in Chapters 11 and 12, respectively.

4. RPU Existing Electric System

This chapter briefly reviews RPU's existing electric system and describes how it operates. RPU is a vertically integrated utility that operates electric generation, sub-transmission, and distribution facilities. Power is delivered to RPU through the regional bulk transmission system owned by Southern California Edison (SCE) and operated by the CAISO.

4.1 Energy Delivery Division

The Energy Delivery Division is responsible for managing and maintaining RPU's sub-transmission and distribution facilities. The Energy Delivery Division's main purpose is to effectively manage activities related to the transmission and delivery of electricity to RPU's customers. The three primary objectives of the Energy Delivery Division are to:

- Ensure electric service reliability,
- Operate and maintain the distribution system safely, efficiently, and in compliance with Federal and State regulatory requirements, and
- Supervise and control all activities related to energy distribution and delivery.

4.2 System Interconnections

RPU's electrical interconnection with the California transmission grid is established at the SCE's Vista Substation, northeast of the RPU system. RPU currently takes delivery of the electric supply at 69 kilovolts (kV) through two 280 megavolt-amperes (MVA) transformers. The transformers are connected to the RPU electric system by seven (7) 69 kV sub-transmission lines. The RPU electrical system is comprised of 14 separate substations linked by a sub-transmission network of 69 kV lines. Each substation steps down the power on the system from 69 kV to 12.47 kV and 4.16 kV for distribution to the RPU customers.

Figure 4.2.1 illustrates the existing RPU sub-transmission electrical system. Currently, RPU's system comprises of 98.6 circuit miles of sub-transmission lines. Operating in a closed network, the sub transmission system serves ten distribution substations, the RERC and Springs generation stations, and two high-voltage customer stations (Alumax and Kaiser).

4.3 Substations

RPU owns and operates 14 substations that fall into three categories: distribution, customer, and generation. The ten (10) distribution substations served at 69 kV include 12.47 kV distributions, with three (3) of these substations also including legacy 4.16 kV distribution. Table 4.3.1 lists RPU's substations, along with their types and ratings in alphabetical order.

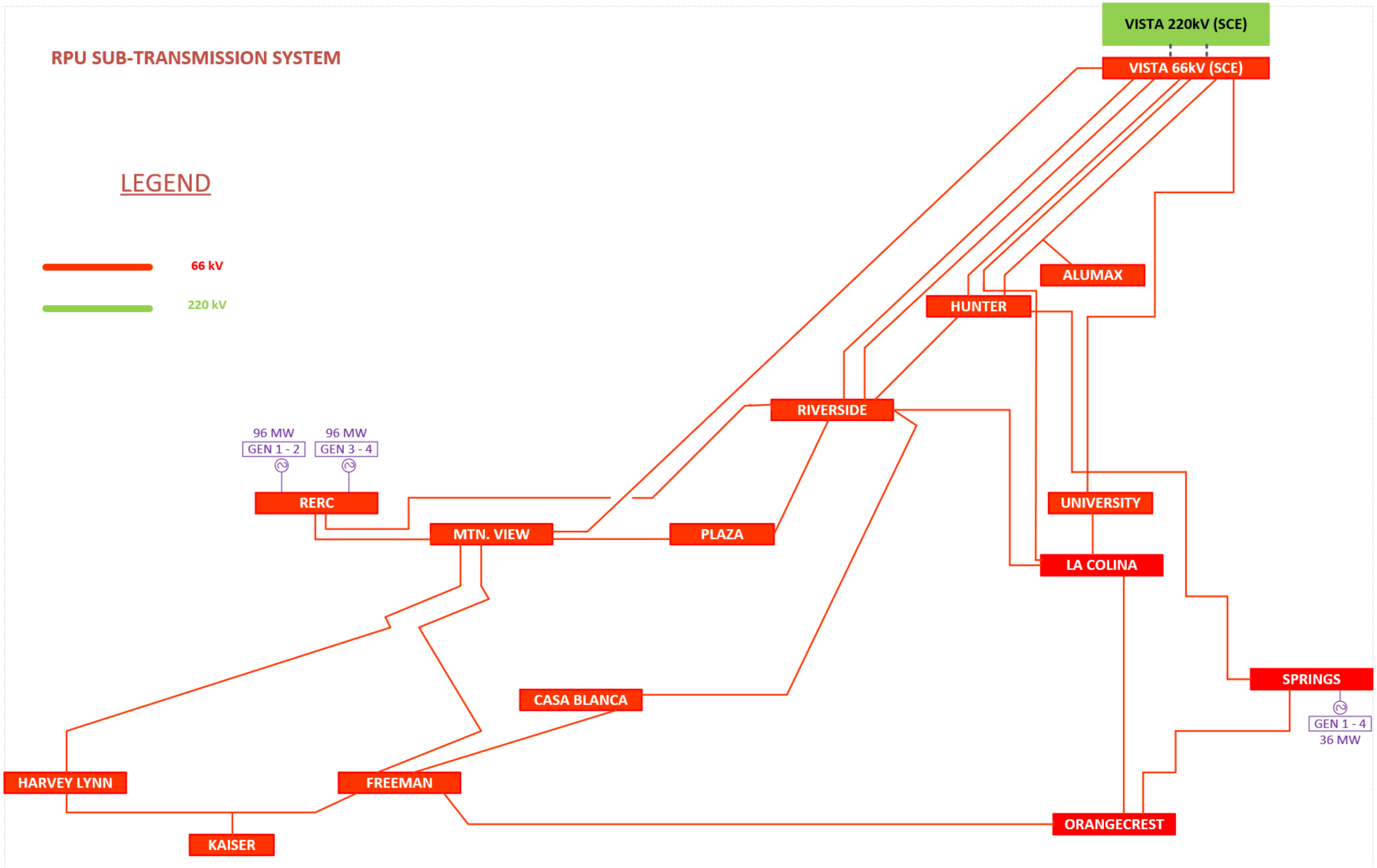


Figure 4.2.1. Existing RPU sub-transmission electrical system.

Table 4.3.1. RPU substations; type and rating definitions.

Substation	Type	Rating
Alumax	Customer	69-4.16 kV
Casa Blanca	Distribution	69-12.47 kV
Freeman	Distribution	69-12.47 kV
Harvey Lynn	Distribution	69-12.47 kV
Hunter	Distribution	69-12.47 kV & 69-4.16 kV
Kaiser	Customer	69-4.16 kV
La Colina	Distribution	69-12.47 kV
Mountain View	Distribution	69-12.47 kV & 69-4.16 kV
Orangecrest	Distribution	69-12.47 kV
Plaza	Distribution	69-12.47 kV & 69-4.16 kV
RERC	Generation	69 kV
Riverside	Distribution	69-12.47 kV
Springs	Generation and Distribution	69-12.47 kV
University	Distribution	69-12.47 kV

RPU substations connected to the 69 kV sub-transmission system are configured in four (4) typical electrical bus configurations: single bus, sectionalized bus, ring bus, and breaker-and-a-half. Table 4.3.2 lists the configurations currently in use at each substation.

Table 4.3.2. RPU substation configurations.

Single Bus	Sectionalized Bus	Ring Bus	Breaker-and-a-Half
Alumax	Hunter *	Casa Blanca	RERC
Kaiser	Mt. View *	Freeman *	Riverside
	Plaza *	Harvey Lynn *	
	University *	La Colina	
		Orangecrest	
		Springs	

* Multiple transformers in a single security node.

4.4 Protection and Control Systems

For most of the older 69 kV line protection schemes, primary protection is provided by high-speed pilot wire relays (HCB type made by ABB, Ltd.) while the current standard for line protection uses line current differential relays (SEL-387L, SEL-311L, and SEL-411L types made by Schweitzer Engineering Laboratories, Inc). Backup protection for the 69 kV lines is a mixture of directional overcurrent in the older relay schemes and distance protection in the newer schemes.

Supervisory control and data acquisition (SCADA) systems send supervisory control commands to remote equipment and acquire status and analog data from remote equipment and systems. The existing RPU SCADA system was installed in 2007, including SCADA software provided by Open systems International (OSI) packaged under the Monarch product name. This system is in the process of being upgraded to bring the various SCADA software and hardware components up to current operational technology specifications.

4.5 Distribution Circuits

RPU's distribution circuits originate at circuit breakers connected to the distribution substations in the system. The circuits are made up of main line conductors connected in an open loop arrangement to one or more adjacent circuits and branch line conductors that are connected to the main lines.

RPU's overhead distribution network contains 517 miles of distribution circuits (feeders) and operates both 4 kV and 12 kV with approximately 23,000 poles. The majority of RPU's load is served from the 12 kV system. About 10 percent of RPU's load continues to be served from the 4 kV system, which includes 90 miles of distribution circuits.

RPU's underground distribution network contains cable of various types, sizes, and ages. There are over 838 miles of underground 15 kV and 5 kV class cable in the RPU system, which is also comprised of approximately 3,900 vaults and substructures. These subsurface enclosures include vaults, manholes, commercial subsurface transformer enclosures, and pull-boxes.

In total, RPU's overhead and underground distribution network contains 122 distinct circuits that are used to serve customer loads.

4.6 Metering Systems

A variety of electric meters are deployed to support RPU's rate schedules and various service types, including flat rate, single-phase and three-phase demand, time-of-use, and net metering, among other service types. In 2019 RPU began implementing Advanced Meter Infrastructure (AMI) throughout its distribution system. The implemented AMI solution is an "ERT overlay," which means that the new AMI devices (collectors and meters) also collect and transmit data from all currently installed legacy meters. Pre-2019, > 99% of RPU customers had remote-reading radio frequency meters (ERT meters). As of December 2022, more than 25,000 customers have been upgraded to AMI meters (including all Commercial customers), and this AMI network is being used to concurrently collect and transmit data from all remaining legacy meters.

All meter reading data is radio transmitted through communication devices to an AMI head-end system, which in turn transfers this information to a Meter Data Management (MDM) system. The MDM system further distributes validated meter readings and calculated billing determinants to a Customer Information system for billing purposes. Information retained in the MDM includes meter reads, meter location, voltage quality and related notes of safety. The MDM also distributes both meter and voltage information to multiple Grid Management software platforms, to facilitate both near real-time monitoring of critical distribution system performance metrics and longer-term analytical load and voltage studies.

4.7 Riverside Transmission Reliability Project (RTRP)

RPU's mission statement includes a commitment to provide the highest quality electrical service to its customers. The Board of Public Utilities sets policy for RPU to fulfill its mission and has been concerned since the early 1990s about the capacity of the system to supply RPU customers, as well as the reliability of the existing single point of service within the regional transmission system. Since 2006, the City's electric demand has exceeded the capacity of the interconnection with the regional system.

In 2004, pursuant to SCE's FERC-approved Transmission Owner Tariff, RPU made a request to SCE to develop a means to provide additional transmission capacity to meet RPU projected load growth and to provide a second interconnection for system reliability. SCE determined that in order to meet RPU's request, SCE should expand its regional electrical system to provide RPU a second source of transmission capacity to import bulk electric power. This expansion would be accomplished by the:

- Creation of a new SCE 220 kV transmission interconnection,
- Construction of a new SCE substation,
- Construction of a new RPU substation, and
- Expansion of the RPU 69 kV system.

After a 10-year planning process, SCE and RPU jointly designed and proposed the development of the Riverside Transmission Reliability Project (RTRP). RTRP is designed to provide RPU with long-term system capacity for load growth, along with needed system reliability and flexibility. RTRP will provide Riverside Public Utilities (RPU) with a critical second connection to the state electric transmission grid by connecting to the existing 230kV SCE Mira Loma – Vista line.

RTRP has been designed to address long-term capacity and reliability needs of the City's electric utility system. The CPUC issued a Certificate of Public Convenience and Necessity for RTRP in March 2020 and preliminary work on the project began in early 2021. Once ultimately developed, the additional transmission capacity will become available through a new substation, named Wildlife Substation. Wildlife Substation will be a 220 kV substation owned and operated by SCE. This substation will be connected to the electric transmission grid by connecting to the existing Mira Loma to Vista #1 transmission line. The voltage of the electrical power will be transformed to 69 kV for integration into the RPU electrical system serving the City. This transformation of power from 220 kV to 69 kV will take place at a second new substation, named Wilderness Substation. Wilderness Substation will be a

220/69 kV substation owned and operated by RPU. The Wildlife and Wilderness Substations will be located within the City of Riverside, adjacent to each other on property that is presently owned by RPU.

After completion, RTRP will divide RPU's electric system in two sections – the East (Vista) and West (Mira Loma/Wildlife) subsystems. As shown in Figure 4.7.1, the East system will be served from the existing SCE Vista station and the West system will be served from the new SCE Wildlife Station. Both systems will have the ability to be operated in parallel under emergency conditions, if there is ever a loss of one of the SCE bulk transmission sources.

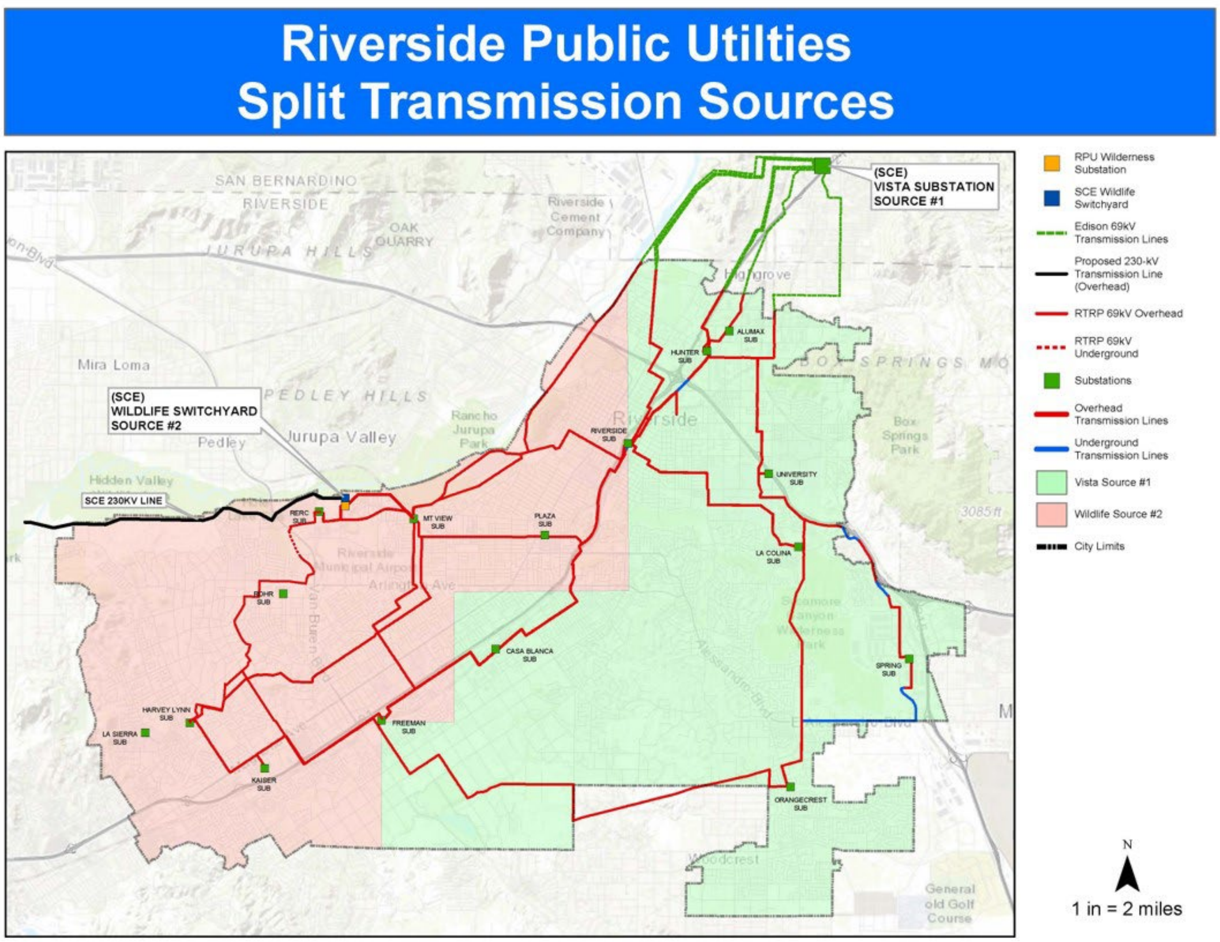


Figure 4.7.1. The new East and West RPU distribution systems created by the Riverside Transmission Reliability Project.

In total, RTRP includes construction of approximately nine (9) miles of double circuit 230kV transmission lines, installation of approximately 10 miles of 69kV sub-transmission lines within the City of Riverside, construction of two new substations – Wildlife (SCE) and Wilderness (RPU), improvements to five existing RPU 69kV substations, reconfiguration of the existing sub-transmission system and distribution lines, related substation improvements and installation of new telecommunication lines. RTRP consists of two major elements:

1) SCE's portion: the high voltage element constructed, owned, and operated by SCE (i.e., the 230 kV transmission line from Jurupa Valley to Riverside and the new Wildlife Substation), and

2) RPU's portion: the various 69 kV elements that will be constructed, owned, and operated by RPU (i.e., the new Wilderness Substation, upgrades to existing substations, 69 KV line improvements and the distribution system bifurcation to accommodate the new SCE transmission connection).

Some of the more critical RTRP sub-transmission system components and improvements within RPU's project scope are shown in Figure 4.7.2.

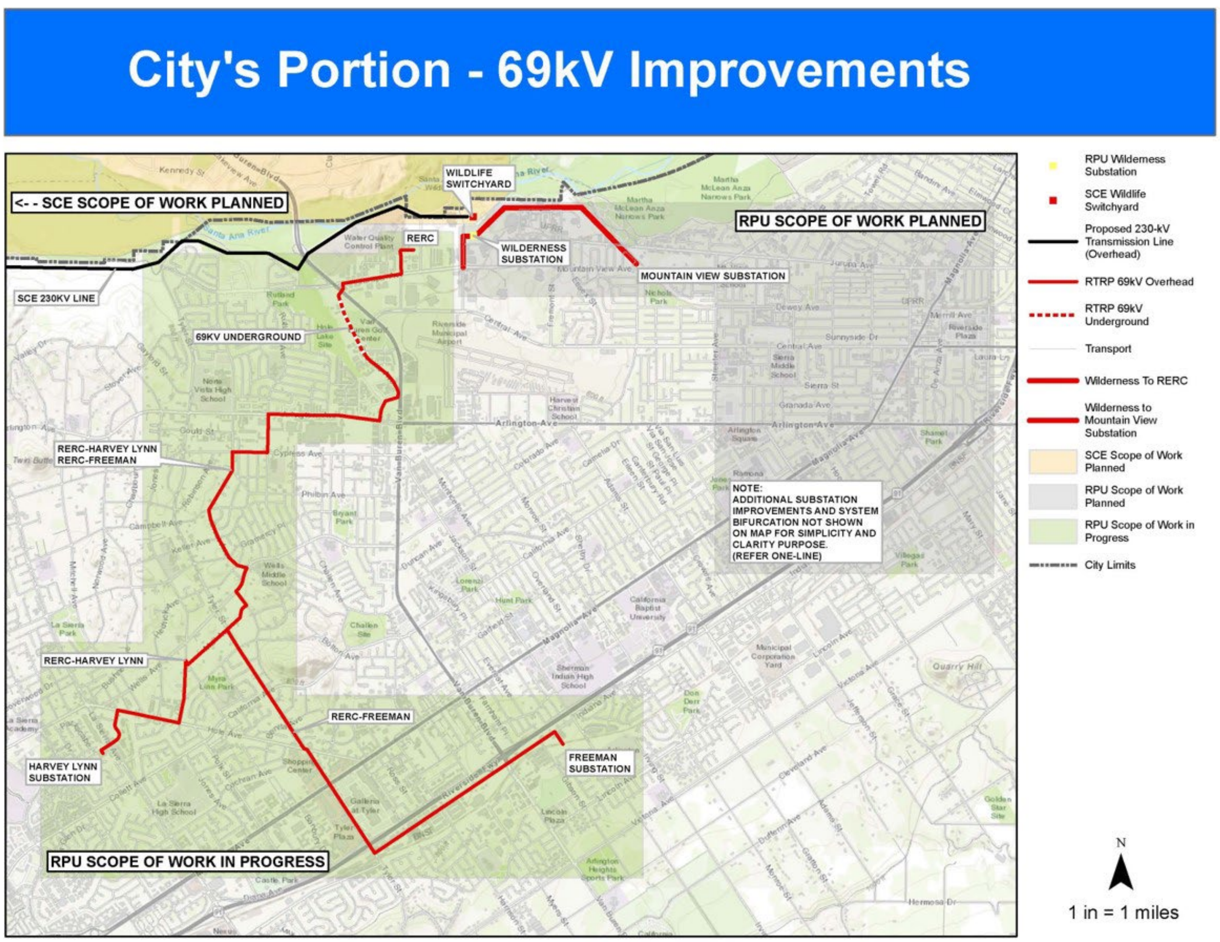


Figure 4.7.2. Critical RTRP sub-transmission system project components and improvements within RPU's project scope.

4.8 Impacts of Solar PV and Electric Vehicles

The existing distribution system was designed to operate in a radial manner, with power-flow in one direction from the substation source to the load. Due to economic viability, incentives, and renewable portfolio standards, photovoltaic (PV) systems have become more common. If the penetration level of PV becomes extremely high, reverse power-flow through the distribution system will occur during certain time periods. This can create unanticipated conditions and cause mis-operation of voltage control equipment.

Increasing numbers of electric vehicles (EVs) could also have a sizable impact on the demand for power. EVs represent a significant new source of electricity use for the electric distribution system. This use will affect total system requirements and will affect the distribution grid because of the relative concentration of EVs on specific circuits or at peak times. The impact of EVs on the system peak will be influenced by the number of EVs on the system and when they charge. For example, charging could be concentrated during the early hours of the day and after arriving home from work. This could in turn result in dual charging spikes impacting the distribution system.

In general, both Solar PV systems and EVs have the potential to significantly impact RPU's distribution system. Chapter 13 examines these potential distribution system impacts from PV systems and EVs in greater detail, on a circuit-by-circuit basis.

5. Important Legislative and Regulatory Mandates and CAISO Initiatives

This chapter presents a review of the relevant legislative, regulatory, and CAISO initiatives that have occurred since RPU's 2018 IRP assessment and have the potential to significantly impact both RPU and its customers. A review of the ongoing, new, and upcoming legislation that is driving the changes in regulations that impact grid reliability and resource selection is presented first. Some notable efforts to be discussed include SB 859 – the Biomass mandate; SB 350 – the Clean Energy and Pollution Reduction Act of 2015; AB 398 – the extension of the cap-and-trade program; SB 1028, SB 901, and AB 1054 – all related to wildfires, and SB 100 – the 100 Percent Clean Energy Act of 2018. Next, the second half of this chapter will highlight some of the more critical CAISO initiatives that are most likely to impact the stability and economics of the electric grid. A few examples of these are Congestion Revenue Rights Auction Efficiency, Day-Ahead Market Enhancements, Energy Storage, Resource Adequacy Enhancements, and Maximum Import Capability Enhancements. Finally, this chapter concludes with a brief discussion about Riverside's local Carbon Reduction ordinance which was adopted by our City Council in the Envision Riverside 2025 Strategic Plan.

5.1 Legislative and Regulatory Mandates

5.1.1 SB X1-2 – Renewable Portfolio Standard (RPS)

The California state legislature passed SB X1-2 RPS in 2011, which mandates that utilities, including publicly owned utilities (POUs), must procure a defined percentage of renewable resources to serve retail loads. The end goal of this bill was to achieve a 33% Renewable Portfolio Standard (RPS) by 2020. However, SB X1-2 also specified that all POU's had to meet the interim Compliance Period (CP) targets shown in Table 5.1.1.

Table 5.1.1. Interim Renewable Portfolio Standard (RPS) targets.

Compliance Period	Time Frame	Retail Load
CP1	Calendar years 2011-2013	An average of 20% of retail load for the 3-year period
CP2	Calendar years 2014-2016	No less than 25% of retail load by the end of calendar year 2016
CP3	Calendar years 2017-2020	No less than 33% of retail load by the end of calendar year 2020
Beyond 2020	Calendar year 2021 and beyond	No less than 33% of retail load each year

In addition, renewable resource procurement had to be predominantly from in-state renewable resources; e.g., starting in 2017, 75% of renewable resources within the target had to be located in-state and no more than 10% could be from tradable renewable energy credits (TRECs).

SB X1-2 also required POUs to adopt and implement a Renewable Energy Resource Procurement Plan that explains the RPS requirements and the utility mandate to procure the minimum quantity of electricity products from eligible renewable resources. RPU's RPS Procurement Plan was adopted in May 2013, then updated in 2018 and adopted by RPU's Board and City Council in September and October 2018, respectively.

In June 2017 and July 2019, Riverside received an official CEC Compliance Determination notice stating that it was deemed compliant in meeting the CP1 and CP2 RPS procurement targets. Riverside filed its CP3 report in August 2021 and expects to receive a similar notice for CP3. At the end of calendar year 2020, Riverside met 42.2% of its retail sales from renewable resources, exceeding the 33% by 2020 RPS mandate.

The renewable targets were further updated on October 7, 2015 when the Clean Energy and Pollution Reduction Act known as SB 350 was signed into law. SB 350 mandated that all CA utilities serve at least 50% of their retail sales with renewables by 2030, but no new compliance periods for the future years beyond CP3 were set. In 2018, SB 100 was signed into legislation, which further increased the RPS goals of SB X1-2 and SB 350, while maintaining the 33% RPS target by December 31, 2020. The future RPS percentage targets were increased to 44% by 2024, 52% by 2027, and 60% by 2030. The current end goal of SB 100 is to have 100% of the state's retail electricity supply generated from a mix of RPS-eligible and zero-carbon resources by December 31, 2045. SB 350 and SB 100 are both discussed further later in this section.

5.1.2 AB 32 – California Greenhouse Gas (GHG) Reduction Mandate

The state legislature passed AB 32 in 2006 which mandated the statewide reduction of greenhouse gas (GHG) emissions to 1990 levels by calendar year 2020. On September 8, 2016, the Governor of California expanded on this bill by approving Senate Bill 32 (SB 32), which requires the state board to ensure that statewide greenhouse gas emissions are reduced to 40% below the 1990 level by 2030.

AB 32 tasked the California Air Resources Board (CARB) to develop regulations for GHG which became effective January 1, 2012. Emission compliance obligations under the cap-and-trade regulation began on January 1, 2013. The Cap-and-Trade Program (Program) was implemented in phases with the first phase from January 1, 2013, to December 31, 2014. This phase placed an emission cap on electricity generators, importers, and large industrial sources emitting more than 25,000 metric tons of carbon dioxide-equivalent greenhouse gases per year. In 2015, the program expanded to cover emissions from transportation fuels, natural gas, propane, and other fossil fuels. Since the enactment of AB 32, RPU has actively participated with major investor-owned utilities and other POUs to affect the final rules and regulations with respect to AB 32 implementation.

As a generating facility, RPU is mandated to report emissions from its Clearwater generation plant and Riverside Energy Resource Center (RERC) generation plants. RPU's Springs generation is not required to be reported due to it emitting less than the applicability threshold of 25,000 metric tons or more of CO_2e per year. As an importer of electricity, RPU is also required to report emissions from any generation imported into the state of California. Purchases of electricity from within California, such as market purchases directly from the California ISO or purchases from in-state generation plants, are not covered emissions under the CARB Mandatory Greenhouse Gas Reporting Regulation (MRR) and therefore do not have to be reported. Thus, RPU's mandated reporting emissions under AB 32 are currently imports from the Intermountain Power Project, Hoover, and Palo Verde projects (both of which are carbon free), unspecified sources, and generation from Clearwater and RERC. More than 90% of Riverside's covered emissions are from imports from the Intermountain Power Project.

The Program requires electric utilities to have enough GHG allowances on an annual basis to offset their GHG emissions associated with generating electricity. As part of the GHG enforcement program, CARB provides a free allocation of GHG allowances to each electric utility to mitigate retail rate impacts. If a utility requires additional allowances, it must purchase them through the auction or on the secondary market to offset the corresponding GHG emissions. Each allowance can be used for compliance purposes in the current year or carried over for use in future year compliance. Riverside's free allocation of GHG allowances is expected to be sufficient to meet all the utility's direct GHG compliance obligations through 2030.

Any allowance not used for current year compliance or carried over for future use in compliance must be sold into the quarterly allowance auctions administered by CARB. Proceeds from the auctions must be used for the intended purposes as specified in AB 32 which include but are not limited to: procurement of renewable resources, energy efficiency and conservation programs, and measures that provide clear GHG reduction benefits. Riverside is segregating the proceeds from the sales of allowances in the auctions as a restricted asset.

In 2017, AB 398 was signed into law. This law extended the cap-and-trade program beyond 2020, but left the post-2020 consignment requirements subject to future CARB rulemaking processes.

5.1.3 SB 1368 – Emission Performance Standard

The state legislature passed SB 1368 in 2006, which mandates that electric utilities are prohibited from making long term financial commitments (commitments greater than five years in duration) for baseload generation resources with capacity factors greater than 60% that exceed a GHG emission factor of 1,100 lbs/MWh. SB 1368 essentially prohibits any long-term investments in coal-fired generation resources. Thus, SB 1368 initially disproportionally impacted Southern California POU's since these utilities had invested heavily in coal technology. However, additional legislation such as SBX1-2, SB 350, SB 100, and SB 32 have now led to a gradual decrease in the generation of existing coal resources to serve load.

As discussed in Chapter 3, Riverside has ownership entitlement rights to a small percentage of the Intermountain Power Plant (IPP). IPP has a GHG emission factor of approximately 2,000 lbs/MWh, hence under SB 1368, RPU is precluded from renewing its IPP Power Purchase Contract at the end of its current term in June 2027.

Going forward, SB 1368 related issues are expected to have minimal impact to the CAISO markets as the percentage of California load served by coal resources is small and diminishing. However, to the extent that significant numbers of coal plants throughout the Western US continue to retire in the next 5 to 15 years, it is certainly conceivable that there could be a tightening of supply throughout the Western US electricity market. In turn, this could lead to higher regional costs and potentially reduced system reliability.

5.1.4 SB 1037 – Energy Efficiency and Demand Side Management Programs and AB 2021 – 10-year Energy Efficiency Targets

SB 1037, enacted in 2005, requires all POUs to report on all investments in energy efficiency and demand reduction programs annually to the CEC. CMUA, NCPA, and SCPPA led a combined effort to prepare and compile this report on behalf of their member POUs. The report identifies the methodologies and assumptions used by the POUs to report energy savings from different measures and programs; investments in energy efficiency programs made by each entity; and the evaluation, measurement, and verification process utilized.

The report also includes an update on the 10-year energy savings target, which stems from AB 2021 that signed into law by the Governor on September 29, 2006. The purpose of this bill was to develop statewide energy efficiency potential estimates and savings targets. Each POU was directed to identify all potentially achievable cost-effective, reliable, and feasible electricity efficiency savings and establish 10-year energy efficiency targets every three years.

In 2012, per AB 2227, the frequency of this update was changed to every four (4) years to be in line with the IEPR timeline. The costs for these efforts are funded through a 2.85% energy sales charge that is applied to all retail customers in a POU's service territory. All POUs are required to report annually on their sources of funding, cost-effectiveness, and verified energy efficiency and demand reduction results from independent evaluations. RPU has been funding the required amount of EE and DSM programs via the sales charge since AB 2021 became law.

5.1.5 AB 2514 - Energy Storage

AB 2514 "Energy Storage Systems" was signed into law on September 29, 2010. The law directed the governing boards of publicly owned utilities (POUs) to consider setting 2016 and 2020 targets for energy storage procurement, but emphasized that any such targets must be consistent with technological viability and cost effectiveness. In 2012, AB 2227 amended the reporting timeline of the energy storage targets referenced in AB 2514.

Energy storage (ES) has been advocated as an effective means for addressing the growing operational problems of integrating intermittent renewable resources, as well as contributing to other applications on and off the grid. In general, ES is a set of technologies capable of storing previously generated electric energy and releasing that energy later. Currently, the commercially available ES technologies (or soon to be available technologies) consist of pumped hydro generation, compressed air systems, batteries (primarily lithium-ion), and thermal ES systems.

In the ten years since AB 2227 was passed, the demand for battery energy storage has increased exponentially. It is now exceedingly rare to see any type of new, utility-scale solar PV facility developed that does not also include a large, on-site battery energy storage (BES) system. Likewise, stand-alone BES systems are being deployed throughout the CAISO BA area and customer adoption of smaller residential and commercial BES systems is also increasing rapidly. Finally, both US and foreign auto manufacturers are investing heavily in new electric vehicles, further driving up demand. As such, there is no longer any need to “stimulate” the growth in this market through new legislation.

5.1.6 SB 380 – Moratorium on Natural Gas Storage – Aliso Canyon

On October 23, 2015, a significant gas leak was discovered at the Aliso Canyon natural gas storage facility, which makes up 63% of the total Southern California storage capacity and serves 17 gas fired power generation units. On May 10, 2016, the Governor of California signed SB 380 placing a moratorium on Aliso Canyon’s natural gas storage usage until rigorous tests were performed and completed on each injection well by the Division of Oil, Gas, and Geothermal Resources (DOGGR). Thus, beginning June 1, 2016, Southern California Gas Company (SoCalGas) implemented new Operational Flow Order (OFO) tariffs due to limitations surrounding Aliso Canyon storage injections and withdrawals. These tariff changes were put in place to reduce the probability of natural gas curtailments, which could disproportionally impact Southern California electric utilities due to the requirements to operate internal natural gas generation to maintain system reliability during the summer.

On July 19, 2017, DOGGR issued a press release in concurrence with the CPUC that Aliso Canyon was safe to resume injections up to 28% of the facility’s maximum capacity. On that same day, the CEC issued a separate press release with a recommendation urging closure of Aliso Canyon in the long-term. On July 31, 2017, SoCalGas resumed injections. Effective July 23, 2019, the CPUC approved new protocols that enable SoCalGas to withdraw from the Aliso Canyon natural gas storage facility when specific conditions are met related to Low Operational Flow Order (OFO) calculations, Southern California natural gas inventory levels, and/or emergency conditions.

Senate Bill 380 added Section 715 to the Public Utilities Code, which requires the CPUC to determine the range of Aliso inventory necessary to ensure safety, reliability, and just and reasonable rates. In the most recent 715 Report, the Energy Division recommended that the maximum allowable Aliso inventory increase from 24.6 to 34 billion cubic feet for summer 2018 and going forward, due to continuing pipeline outages on the SoCalGas system. RPU continued to fulfill its system reliability without any natural gas delivery issues during multiple heat waves from 2016 through 2022. RPU continues to monitor any developments (e.g. new legislation, regulations, and workshops) that impact the status of Aliso Canyon and its effect on the reliability of the utility’s service territory.

5.1.7 SB 859 – “Budget Trailer Bill” – Biomass Mandate

In the final two days of the 2015-2016 legislative session, a “budget trailer bill” on how to spend cap-and-trade funds was amended to include a biomass procurement mandate for local publicly owned utilities serving more than 100,000 customers. This amendment required these utilities to procure their pro-rata share of the statewide obligation of 125 MW based on the ratio of the utility’s peak demand to the total statewide peak demand from existing in-state bioenergy projects for at least a 5 year term. On September 14, 2016, the Governor of California signed SB 859 into law.

On October 13, 2016, the CPUC adopted Resolution E-4805, which established that the POUs be allocated 29 MW of the 125 MW statewide mandate. Staff determined that RPU's obligated share would be 1.3 MW to meet the mandate. It was expected that RPU's proportion of these facilities would be counted towards the utility's RPS goals.

In 2017, the affected POUs – consisting of the cities of Anaheim, Los Angeles, and Riverside, Imperial Irrigation District, Modesto Irrigation District, Sacramento Municipal Utility District, and Turlock Irrigation District – decided it would be beneficial to procure a contract together for economies of scale. Since four of the seven POUs affected are existing SCPPA members, all the affected POUs worked jointly through SCPPA to issue a Request for Proposals.

In January 2018, the Riverside Board of Public Utilities and City Council approved RPU's five-year Power Sales Agreement with SCPPA for 0.8 MW from the ARP-Loyalton biomass project. On April 20, 2018, the facility declared commercial operation. On February 24, 2020, and March 17, 2020, the Riverside Board of Public Utilities and City Council, respectively, approved a five-year Purchase Agreement with Roseburg Forest Products Co. for 0.5 MW of capacity to fulfill the remaining MW share of the mandate. On February 16, 2021, Roseburg declared commercial operation. To date, there have been no further legislative bills signed into law that mandate any extensions or additions to the SB 859 statewide obligation.

5.1.8 SB 350 – Clean Energy and Pollution Reduction Act of 2015

SB 350, enacted in 2015, consisted of a multitude of requirements to advance various clean energy goals. The primary components that affected RPU were a) the increased mandate of the California RPS to 50% by December 31, 2030, b) the doubling of statewide energy efficiency savings by January 1, 2030, and c) the transformation of the CAISO into a regional organization. In addition, there was a detailed Integrated Resource Planning (IRP) mandate embedded in the bill that applied to 16 POUs with 3-year average annual demands over 700 GWh, which included Riverside. This mandate required that an IRP should be completed at least once every five years and address specific topics such as energy efficiency and demand response resources, transportation electrification, GHG emissions, energy storage resources, enhanced distribution systems and demand-side management. Furthermore, this mandate required that all POU IRPs be submitted to the CEC for review, so that the CEC could check and verify that all statutory requirements had been met. On August 9, 2017, the CEC adopted the POU IRP Submission and Review Guidelines.

Shortly thereafter, on September 30, 2017, the Governor signed SB 338, which required that the governing board of local POUs consider as part of the IRP process the role of existing renewable generation, grid operational efficiencies, energy storage, energy efficiency, and distributed energy resources in meeting the energy and reliability needs of each utility during the hours of peak demand. On August 1, 2018, the CEC adopted a Second Edition of the POU IRP Submission and Review Guidelines to include the requirements of SB 338. On October 3, 2018, the CEC adopted an amendment to the second edition guidelines to include the CARB's GHG emission reduction planning targets for IRPs.

On November 26, 2018 and December 11, 2018, the Board of Public Utilities and City Council, respectively, adopted RPU's 2018 Integrated Resource Plan. The IRP and additional submittal requirements were submitted to the CEC on December 18, 2018. In April 2019, the CEC issued their Staff Paper Review of RPU's IRP, as well as the CEC Executive Director's Determination Letter finding RPU to be consistent with the requirements of SB 350. The adoption of this determination occurred at the CEC Business meeting on August 14, 2019.

5.1.9 AB 802 – Building Energy Use Benchmarking and Public Disclosure Program

On October 8, 2015, AB 802 was signed into law creating a new statewide building energy use benchmarking and public disclosure program for the State of California. The bill requires California utilities to maintain records of energy usage data for all large buildings (e.g., commercial and multifamily buildings over 50,000 square feet gross floor area) for at least the most recent 12 months. Beginning January 1, 2017, utilities are required to deliver or provide aggregated energy usage data for a covered building, as defined, to the owner, owner's agent, or operator upon written request.

Although the law states the availability of this information is to be effective January 1, 2017, the CEC did not adopt their regulation guidelines on it until October 11, 2017. Hence, the approved regulation action became effective on March 1, 2018. RPU does not have a direct reporting requirement under AB 802, but as stated, must provide the data to building owners required to report their building's energy use each year (the first reports were due in 2018). RPU has been providing owner requested consumption data for buildings meeting the legislative requirement since 2018.

5.1.10 AB 1110 – Greenhouse Gas Emissions Intensity Reporting

On September 26, 2016, AB 1110 was signed into law requiring GHG emissions intensity data and unbundled renewable energy credits (RECs) to be included as part of a retail supplier's power source disclosure (PSD) and power content label (PCL), which are provided to their customers. In 2017, the CEC began hosting workshops on the GHG emissions disclosure requirements and initiated the rulemaking process of updating their PSD regulations. A pre-rulemaking phase also began that included an implementation proposal on AB 1110. The legislation required the CEC to adopt guidelines by January 1, 2018.

In early 2018, the CEC provided an update to their 2017 pre-rulemaking activities and proposed changes to the regulations and reports, but additional workshops were needed. In March 2019, the last pre-rulemaking workshop was held by the CEC, but the formal rulemaking process did not get underway until September 2019. On December 11, 2019, the CEC adopted the updated PSD regulations, which required the GHG emissions intensity data to be included in the PCL starting in 2021 for calendar year 2020 data. The adoption of the updated PSD regulations was approved on May 4, 2020.

RPU began including this new GHG intensity information on the PCL began in 2021 for calendar year 2020 data. In addition to requiring that the PCL be posted on the city website, AB 1110 also reinstated the requirement that the PCL disclosures must be mailed to the customers (starting in 2017 for calendar year 2016 data), unless customers have opted for electronic notifications. Per this requirement, RPU also reinstated the inclusion of printed disclosures of the PCL with its September 2017 customer bills.

5.1.11 AB 398 – GHG Cap-and-Trade Program Extension

AB 398 was signed on July 25, 2017; this bill extended the GHG cap-and-trade program to December 31, 2030, as originally implemented under AB 32. AB 398 required the CARB to update their scoping plan no later than January 1, 2018. AB 398 also required all adopted GHG rules and regulations to be consistent with this plan. On July 27, 2017, the CARB approved the 2016 Cap-and-Trade Amendments, which includes the 2021-2030 allowance allocations that utilities will receive each year. RPU's allowance allocations should be sufficient to cover all the utility's 2021-2030 direct compliance obligations.

In June 2021, as part of the next iteration of the Scoping Plan Update, CARB began discussion workshops focused on four areas: 1) the electricity sector, 2) the transportation sector, 3) equity and environmental justice, and 4) natural and working lands. On June 8, 2021, CARB hosted a workshop series to commence development of the 2022 Scoping Plan Update to *Achieve Carbon Neutrality by 2045*. In July 2021, a series of technical workshops commenced, covering various topics and sectors within the Scoping Plan. The most notable impacts to RPU are the proposed scenarios for achieving carbon neutrality and how these scenarios can be accomplished. CARB also indicated that a reassessment of the 2021-2030 cap-and-trade allowance allocations will not be the focus of the Scoping Plan Update; potential regulatory changes (if any) can only occur after the Scoping Plan Update is completed. This issue is important because CARB had previously stated that the 2021-2030 allocations might need to be adjusted downwards to account for increased RPS target levels.

On December 15, 2022, the CARB Board approved the 2022 Scoping Plan Update. RPU will continue to monitor its implementation and any impacts it will pose to RPU's service territory and ratepayers.

5.1.12 AB 617 – Air Quality Monitoring

AB 617 was signed on July 26, 2017 and was part of a legislative bill package with AB 398 which authorized the extension of the Cap-and-Trade Program in the State. AB 617 addresses the disproportionate impacts of air pollution in areas impacted by a combination of economic, health, and environmental burdens. Both the CARB and local air districts are required to take specific actions to reduce air pollution and toxic air contaminants from commercial and industrial sources, including from electricity-generating facilities.

This bill requires the CARB, by October 1, 2018, to prepare a statewide monitoring plan regarding technologies and reasons for monitoring air quality, and based on that plan, identify the highest priority locations for the deployment of community level air monitoring systems. Local air districts are required to deploy the air monitoring systems in the specified communities by July 1, 2019. AB 617 also requires the CARB to develop uniform reporting standards for criteria air pollutants and toxic air contaminants for specific uses, including electricity-generating facilities. Air districts are to adopt an expedited schedule for implementing best available retrofit control technologies for the uses, while the CARB will identify these technologies.

This bill affects the City and RPU by imposing additional reporting requirements, particularly on power plants, and potentially adding or improving air monitoring systems in selected communities located within Riverside. For Riverside, the local air district is the Southern California Air Quality Management District ("SCAQMD"). CARB and SCAQMD have been holding community meetings to implement the required elements of AB 617. Preliminary discussions and proposals have already been conveyed by community members from the City as well as from the University of California, Riverside proposing areas for community air monitoring and planning. The City and RPU continues to monitor the progress of the community meetings and the two proposed areas for any impacts.

5.1.13 SB 100 – The 100 Percent Clean Energy Act of 2018

On September 10, 2018, the Governor signed into law the 100 Percent Clean Energy Act of 2018 (SB 100). This bill further increases the RPS goals of SBX1-2 and SB 350 by increasing the 33% RPS target by December 31, 2020, to be 44% by December 31, 2024, 52% by December 31, 2027, and 60% by December 31, 2030. The current end goal of SB 100 is to have 100% of the state's retail electricity supply generated from a mix of RPS-eligible and zero-carbon resources by December 31, 2045.

The CEC adopted updated RPS Enforcement Procedures for POUs on December 22, 2020, and they were approved by the Office of Administrative Law (OAL), effective July 12, 2021. New compliance periods were established with interim targets for each year as follows:

Table 5.1.2. Interim Renewable Portfolio Standard (RPS) targets.

Compliance Period	Time Frame	Interim POU Retail Load Target
CP4	2021	No less than 35.75% of retail sales
	2022	No less than 38.50% of retail sales
	2023	No less than 41.25% of retail sales
	2024	No less than 44.00% of retail sales
CP5	2025	No less than 46.00% of retail sales
	2026	No less than 50.00% of retail sales
	2027	No less than 52.00% of retail sales
CP6	2028	No less than 54.67% of retail sales
	2029	No less than 57.33% of retail sales
	2030	No less than 60.00% of retail sales
Beyond 2030	Calendar year 2031 and beyond	No less than 60.00% of retail load each year

Per the CEC's Amendments to Regulations Specifying Enforcement Procedures for the RPS for Local POUs, compliance periods beginning on and after January 1, 2031 shall be three years in length starting on January 1 and ending on December 31. For each compliance period beginning on or after January 1, 2031, a POU shall demonstrate it has procured electricity products within the compliance period sufficient to meet or exceed an average of 60.00% of the POU's retail sales over the three calendar years of the compliance period.

With respect to SB 100 and based on existing resources, RPU expects to remain above the minimum compliance levels through 2024. Since the last IRP update in 2018, RPU has procured one additional renewable energy resource that began delivering energy in 2022. RPU is continuing to actively plan and procure additional resources to meet the remaining years of compliance under SB 100. If needed, RPU also has the alternative compliance option to use excess renewable energy credits to meet the future RPS compliance period mandates. Based on the recent CP3 filing, it is estimated that RPU will have 1.48 million excess renewable energy credits that can be utilized for this purpose (if needed).

5.1.14 SB 1028, SB 901 and AB 1054 – Legislation Relating To Wildfires

On September 24, 2016, Governor Brown signed into law SB 1028, which requires each POU, IOU and electric cooperative to construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment. SB 901, which was passed at the end of the 2017-2018 biennium session of the California State Legislature and signed by the Governor on September 21, 2018, is meant to address the Governor's and legislative leaders' desire to address response, mitigation, and prevention of wildfires. The bill requires RPU to prepare, before January 1, 2020, and annually thereafter, a Wildfire Mitigation Plan (WMP) that includes specified information and elements. RPU must present its WMP in an appropriately noticed public meeting and accept comments on the plan from the public, other local and state agencies, and interested parties, and to verify that the plan complies with all applicable rules, regulations, and standards, as appropriate. In addition, RPU must contract with a qualified independent evaluator to review and assess the comprehensiveness of its plan. The report of the independent evaluator must be made available on the utility's website and presented at the local governing board's public meeting.

On July 12, 2019, the Governor signed into law AB 1054 and AB 111, which establishes the California Wildfire Safety Advisory Board (WSAB), adds an additional process requirement for review of wildfire mitigation plans, and establishes a wildfire fund. In addition to the utility presenting its WMP to its local governing board by January 1, 2020, RPU must now also submit it to the new advisory board by July 1, 2020 and provide annual updates each year thereafter. Additionally, RPU is required to submit a comprehensive WMP at least once every three years. RPU presented and brought forth its WMP for City Council adoption on December 17, 2019 and submitted it to the WSAB on May 6, 2020.

RPU presented the updated 2021 WMP to its Board in September 2021. The updated 2021 RPU WMP was approved at the September 27, 2021, Board of Public Utilities meeting and October 12, 2021, City Council meeting, respectively. The annual WMP update was filed on October 14, 2021.

For the wildfire fund, only voluntary participating IOUs are eligible for claims arising from a covered wildfire. The POUs are not required nor able to join due to concerns and issues over complications of funding as a public entity. The bills do not address existing legal doctrine relating to utilities' liability for wildfires. However, any future legislation that addresses California's inverse condemnation and strict liability issues for utilities in the context of wildfires could be significant for RPU. RPU will continue to monitor the outcome and impacts of any upcoming legislation and regulations on its service territory and ratepayers.

5.1.15 Executive Order B-55-18 - Carbon Neutrality by 2045

On September 10, 2018, Governor Brown signed Executive Order B-55-18 for a new statewide goal to achieve carbon neutrality by 2045. This goal is in addition to the existing statewide targets of reducing greenhouse gas emissions. Per the Executive Order, the CARB is required to work with relevant state agencies to develop a framework for implementation and accounting that tracks the progress toward this goal. CARB must also ensure future Scoping Plan updates identify and recommend measures to achieve the carbon neutrality goal. In addition, CARB and the relevant agencies must include sequestration targets in the Natural and Working Lands Climate Change Implementation Plan.

Various workshops, regulations, rulemakings, Executive Orders, and legislation have occurred since the signing of EO B-55-18 to provide statutory requirements, regulatory frameworks, and determine methods for reaching the carbon neutrality goal. A sampling of the activity that has occurred related to this goal is as follows:

1. Executive Order N-79-20 signed by Governor Newsom on September 23, 2020, orders that 100 percent of in-state sales of new passenger cars and trucks to be zero-emission by 2035 and for medium- and heavy-duty vehicles by 2045.
2. AB 1279, the California Climate Crisis Act, requires the state achieve net zero greenhouse gas emissions as soon as possible and to ensure that by 2045, statewide anthropogenic greenhouse gas emissions are reduced to at least 85% below the 1990 levels.
3. SB 1020, the Clean Energy, Jobs, and Affordability Act, amends AB 32 further to require that eligible renewable energy resources and zero-carbon resources supply 90% of all retail sales of electricity to California end-use customers by December 31, 2035, 95% of all retail sales of electricity to California end-use customers by December 31, 2040, 100% of all retail sales of electricity to California end-use customers by December 31, 2045, and 100% of electricity procured to serve all state agencies by December 31, 2035.
4. Scoping Plan Update for 2022 has begun and includes proposed scenarios for achieving carbon neutrality in multiple sectors by looking at the possibility and feasibility of accomplishing the goal either in 2035 or 2045.
5. SB 100 workshops with one of the modeling efforts to be focused on zero-carbon technologies.

Ongoing workshops are occurring simultaneously, ranging from the SB 100 Implementation, Scoping Plan Update, and Advanced Clean Fleets related topics that all have a subcomponent either in their modeling or proposed regulations that will contribute to meeting the carbon neutrality goal. The outcome of these workshops, reports, and regulations will impact Riverside's 2025 Strategic Plan that includes achieving carbon neutrality by 2040, which is ahead of the statewide goal. The medium/heavy duty vehicle provision (100% ZEV by 2045) in EO N-79-20 and CARB's forthcoming Advanced Clean Fleets regulation will have direct impacts on state or local government agency fleets, including publicly owned utility fleets. Through SCPPA, Riverside is taking part in the rulemaking for the Advanced Clean Fleets regulation. Depending on the final rules, Riverside may need to adjust its fleet procurement strategies, in addition to planning facility upgrades to accommodate charging of an expanded electric fleet. RPU will continue to monitor the outcome and impacts of these workshops along with any upcoming legislation and regulations.

5.2 CAISO Market Initiatives

Given the multitude of ongoing mandates that affect CAISO market operations, CAISO periodically proposes market changes to its current market structure through market initiatives. Each CAISO Initiative undergoes a stakeholder process from the early stages of development through the final implementation of an initiative, which ultimately results in CAISO Tariff and Business Practice Manual changes. The primary/overarching themes/issues in these market initiatives are as follows:

- Create efficient market paradigms to solve grid reliability issues,
- Appropriate cost allocation equitably and fairly, and
- Maintain regulatory jurisdiction in the decision-making process

RPU actively engages in the Initiative Stakeholder Process for numerous CAISO Initiatives through its participation in web conferences, in-person meetings, market simulations, as well as submitting written comments throughout the process. The most important CAISO market initiatives that have the potential to affect grid reliability, efficiency, and lead to cost impacts for Riverside's ratepayers are described in more detail below.

5.2.1 Commitment Costs Enhancements Phase 3 Initiative

This initiative developed a market-based methodology to optimally commit use-limited resources and provide more effective risk management tools while maintaining reliability. Use-limited resources have start and run limitations due to environmental or other operational restrictions that extend beyond a one-day period and therefore cannot be explicitly recognized in the CAISO market commitment decision. This initiative changed the definition of a use-limited resource to align it with resources that need an opportunity cost included in their commitment costs to be efficiently dispatched given limitations that extend beyond the market optimization horizon. Given this change, the initiative also clarified the registration process for use-limited resources and provided documentation to determine opportunity costs. By May 2019, this initiative was fully implemented with the CASIO activating system changes to calculate use-limited resource opportunity costs and create opportunity cost adders for bidding into the CAISO market.

The changes made through this initiative were crucial for RPU staff to understand because RPU owns and operates two use-limited natural gas power plants. RPU submits annual documentation to the CASIO that supports the classification of these two resources as use-limited. Per the initiative, RPU now includes opportunity cost adders when bidding these resources in the CAISO market.

5.2.2 Congestion Revenue Rights Auction Efficiency

This initiative addressed an efficiency flaw in the CRR Auction that persistently contributed to substantial revenue inadequacy, which load serving entities in the CAISO market had to pay. The revenue inadequacy was caused by the fact that congestion revenue rights (CRR) auction revenues collected by the CAISO were persistently less than the payments that the CAISO pays to auctioned CRR holders. As discussed in its 2015 Annual Report, the CAISO's Department of Market Monitoring found that since 2012, CRR auction revenues that were allocated to load serving entities were on average $130 million less than the congestion payments received by entities purchasing these CRRs. Moreover, most of these payments were paid to financial entities that purchased CRRs but were not engaged in serving any load or managing generation in the CAISO market. Thus, the Department of Market Monitoring recommended reassessing the CRR auction design to correct the revenue inadequacy issue.

At the start of this initiative in late 2017, the CAISO divided it into four tracks: Track 0, Track 1A, Track 1B, and Track 2. Track 0 addressed enhancements to the auction that did not require changes to the CAISO's tariff. Track 1A made two changes: (1) imposed a new annual outage reporting deadline that is aligned with the annual CRR allocation and auction process to improve the CRR model used in the annual process and (2) limited the CRR source and sink combinations that market participants can purchase in the auctions to generators and load aggregation points to better align the CRR product with the purpose of hedging congestion charges associated with supply delivery in the CAISO's locational marginal price-base day-ahead market. Track 1B made three changes: (1) reduced CRR payments on over-subscribed constraints to enforce system revenue adequacy, (2) distributed system day-ahead congestion rent surpluses, if any, to measured demand, and (3) reduced the amount of system capacity available in the annual CRR allocation and auction process. Track 2, which will consider whether further design changes to the CRR auction are needed in addition to the Track 0, 1A, and 1B changes, has yet to start as the CAISO and market participants wanted time to assess the effectiveness of the Track 0, 1A, and 1B changes, which were all implemented by January 2019.

As an active participant in the CRR auction process, RPU was largely supportive of this initiative. However, RPU was and still is concerned about the Track 1B change that reduces CRR payments after-the-fact if those CRRs contributed to a revenue shortfall on an over-subscribed constraint. This after-the-fact reduction can effectively eliminate RPU's ability to fully hedge its DA congestion cost. Additionally, determining the value of CRRs in the auction is more difficult because of the after-the-fact CRR payment reductions. These concerns aside, RPU has yet to experience any significant financial detriment on account of the implemented changes. While some of RPU's CRR revenues do get reduced, RPU receives offsetting revenues from the CAISO market's congestion rent surpluses that make up for some of the reductions. Most importantly, the changes appear to have alleviated the CAISO's revenue inadequacy issues surrounding the CRR auction, which is beneficial to the CAISO market.

5.2.3 Day-Ahead Market Enhancements

With the overarching goal to increase market efficiency and reliability, this market initiative introduces an imbalance reserves product to meet ramping and net load uncertainty needs between the day-ahead and real time markets. Imbalance reserves will ensure the day-ahead market has enough real-time dispatch capability scheduled to meet net load imbalances that materialize between the day-ahead and real-time markets. Under the proposed enhancements, an imbalance reserve reward will obligate generators dispatchable in the fifteen-minute market to provide economic energy bids in the real-time market. Additionally, the CAISO proposes to enhance the residual unit commitment process with new capacity products: Reliability Capacity Up/Down (RCU/RCD), Flexible Ramp Up/Down (FRU/FRD), and Imbalance Reserves Up/Down (IRU/IRD). RCU/RCD is 60-minute capacity to cover the difference between the day-ahead net demand forecast and non-variable energy resource physical supply schedules. FRU/FRD is 15-minute capacity to cover upward/downward uncertainty in the day-ahead net demand forecast. IRU/IRD is imbalance/flexible reserve capacity to meet additional uncertainty.

The latest proposed implementation of this initiative is Fall 2025, with FERC approval granted in late 2023.

5.2.4 Transmission Service and Market Scheduling Priorities

The CAISO manages schedules on its grid through the day-ahead and real-time markets and applies scheduling priorities to conduct curtailments of self-schedules in these markets. If there is sufficient generation and transmission capacity to support self-schedules, the CAISO will uphold them. If there is insufficient supply or binding transmission constraints, CAISO markets will curtail self-schedules to clear the market based on market penalty parameters that reflect respective scheduling priorities.

This initiative explores the development of a process for wheel-through transactions to obtain higher-priority scheduling rights across the CAISO system particularly during high load periods and stressed system conditions. Additionally, the initiative evaluates potential enhancements regarding the treatment of export transactions from non-resource adequacy generation. This initiative has two phases. Phase 1, which was implemented in Spring 2022, focused on near-term enhancements to the existing scheduling priorities framework. Phase 2, which is expected to be implemented in Summer 2024, focuses on developing a long-term holistic framework. RPU is concerned about some of the proposed Phase 2 changes and remains actively engaged in this initiative.

5.2.5 Resource Adequacy Enhancements (Phase 1 & Phase 2/2B)

The rapid transformation of the resource fleet to cleaner and more variable energy resources is exposing shortcomings in the current resource adequacy (RA) framework. In this initiative, the CAISO, in coordination with the CPUC and stakeholders, will explore reforms needed to the CAISO's RA rules, requirements, and processes to ensure the future reliability and operability of the grid. This initiative was split into three phases: Phase 1, Phase 2, and Phase 2B.

The Phase 1 changes, which were approved in March 2021, were able to be implemented quickly to provide greater assurance resources providing RA capacity are available when and where needed to meet system and local needs beginning summer 2021. The changes included the following:

- A minimum state or charge requirement for RA storage resources that will be in place on an interim basis while the CAISO and stakeholders consider market enhancements to better manage storage resources as key reliability resources;
- Enhancements to the existing planned outage process that will better ensure planned outages are fully replaced with substitute capacity; and
- Expansion of the local capacity procurement mechanism backstop authority to ensure sufficient energy in local capacity areas.

Riverside is supportive of the Phase 1 changes but continues to be concerned about the ability to count imports with a limited subset of hours as RA.

Phase 2 of this initiative is still in the policy development stage and originally had a proposed implementation timeframe of early 2023. Policy changes stemming from this initiative have been delayed into 2024 or later subject to a new working group process, the Resource Adequacy Modeling & Program Design Working Group, that began in late 2023. Phase 2 explores the following:

- Methodologies for calculating unforced capacity (UCAP) values for system, local, and flexible RA requirements
- Determining minimum System RA requirements
- System RA energy sufficiency testing
- Must offer obligations and bid insertion rules
- UCAP for Local Capacity Studies
- Backstop Capacity Procurement Mechanism (CPM) modifications and availability structure for Reliability Must Run (RMR)

Lastly, Phase 2B of this initiative will explore additional elements that require additional development and refinement before the CAISO brings them forward in a proposal. These elements include:

- Planned outage process improvements
- RA Import requirements
- System RA showings and sufficiency Testing Portfolio Assessment

- Flexible RA

Riverside currently supports the conceptual changes proposed in Phase 2 but does have the following areas of concern:

- Riverside's forecasted UCAP requirement and the UCAP values of its resources
- The ability to count imports with a limited subset of hours as RA
- Riverside's local RA requirements and the ability to meet its requirement with its internal generation
- Riverside's Flex RA requirement and the Effective Flexible Capacity (EFC) values of its internal generation and import resources
- No exceptions for certain Nature of Work (NOW) forced outages when assessing forced outage rates for UCAP

Riverside continues to be actively engaged in Phase 2 of this initiative to better understand the proposed changes and impacts to Riverside.

5.2.6 Transmission Access Charge Structure Enhancements

Formerly called Review Transmission Access Charge (TAC) Structure, this initiative proposes to change the CAISO's current TAC billing determinant – which recovers participating transmission owners' (PTO) costs of owning, operating, and maintaining transmission facilities that are under CAISO operational control – from purely volumetric to a hybrid approach that uses a combination of both a volumetric charge and a peak demand charge. This initiative's draft final proposal is complete and on hold pending policy development of the Extend Day-Ahead Markets to EIM Entities initiative to ensure the proposed policies have consistent treatment for transmission cost recovery.

Once approved, the CAISO proposes to phase-in the proposed hybrid TAC billing determinant over two years. Riverside supports this gradual phase-in as it allows time to assess the financial and settlement-related impacts of this change. Based on CAISO and its own internal estimates using historical load data, Riverside expects its TAC costs to increase about 1% under the new hybrid TAC structure.

5.2.7 Energy Storage and Distributed Energy Resources Phase 4

The focus of this initiative is on enhancing the ability of distributed energy resources (DER) – including rooftop solar, energy storage, plug-in electric vehicles, and demand response – to participate in the CAISO market. This initiative will also explore expanding the DER participation models to optimally capture their value, as well as leverage resource design attributes that support grid reliability and allow for multiple-use applications.

Currently, Riverside does not have any energy storage or DERs participating in the CAISO market. However, Riverside continues to explore new energy storage and DER opportunities and is interested in understanding how they can optimally participate in the CAISO market. Riverside is particularly interested in the proposed bidding rules for energy storage. The information provided in this initiative will enable Riverside to effectively evaluate potential future projects. This initiative was approved in Q4 2020 and fully implemented by October 2021.

5.2.8 Energy Storage Enhancements

This initiative addresses items brought up by stakeholders during previous energy storage related initiatives such as Energy Storage and Distributed Energy Resources and Hybrid Resources. These items include real-time enhancements for energy storage, marginal costs in energy bids, ensuring state of charge, variable charging rates, and exceptional dispatches.

Riverside is currently supportive of this initiative. Though not directly impacted, Riverside is still interested in understanding this initiative's changes as Riverside continues to explore and evaluate new energy storage opportunities. This initiative was approved in December 2022.

5.2.9 Maximum Import Capability Stabilization and Multi-Year Allocation

This initiative proposed short and long-term changes. In the short term, the initiative updated the methodology used in the calculation of the simultaneous Maximum Import Capability (MIC) to achieve a greater stability of MIC overall allocations. In the long-term, the initiative will update the annual nature of the MIC allocation process into a multi-year allocation process to accomplish numerous important objectives, the primary of which is the facilitation of long-term procurement of import resources and multi-year System Resource Adequacy requirements.

Riverside supports the proposal for multi-year allocation of MIC for long-term contracts and continuation of MIC allocation to load-serving entities only. This initiative was completed in 2020 and implemented in Q3 2021.

5.2.10 Maximum Import Capability Enhancements

In this initiative, the CAISO discussed stakeholder concerns raised during the Maximum Import Capability Stabilization and Multi-Year Allocation initiative that was completed in 2020, about potential improvements to the calculation of MIC and the process used to allocate and track it during the resource adequacy process. This initiative scope also included: 1) the development of a process that would permit wheel-through transactions to reserve import capability and transmission across the CAISO system and 2) the associated review of wheel-through priorities when accessing the CAISO system.

The ability to acquire through the allocation process is very important for Riverside given its existing import RA contracts. Thus, Riverside was very active in this initiative, advocating for changes to the current Step 13 allocation process. Specifically, Riverside recommended that load-serving entities with existing long-term RA contracts be given priority in the Step 13 MIC allocation. This proposed change can help provide more certainty to Riverside when requesting MIC in the Step 13 allocation. This initiative was approved in November 2021.

5.2.11 2022 Annual Policy Initiatives Roadmap

In March 2022, CAISO published its 2022 Final Policy Initiatives Roadmap, which establishes the framework of current and upcoming Initiatives that the CAISO will address over the next three years. The 2022 Roadmap proposes changes to CAISO's current Resource Adequacy Program, Day-Ahead Market Structure (along with its EIM interactions), and Energy Storage market participation paradigm. CAISO has stated that these proposed market changes within the next three years will likely result in numerous sub-initiatives. RPU will participate in the stakeholder process for the upcoming initiatives through its participation in web conferences, in-person meetings, market simulations, and submission of written comments throughout the process.

5.3 Envision Riverside 2025 Strategic Plan

The City's 2025 Strategic Plan, known as **Envision Riverside**, identifies a clear vision for the future of Riverside's Economy, Community and Environment. During 2020, several one-on-one interviews were held with the Mayor, Council Members, and key City staff and public meetings occurred to discuss the priorities and goals for the City organization for the next five-year period. Based on the information received from these discussions and the public, the Envision Riverside 2025 Strategic Plan was created and approved by City Council on October 20, 2020.

The Envision Riverside 2025 Strategic Plan sets forth the Strategic Priorities and Goals of the City Council to advance Riverside's potential and to frame the work efforts of staff through 2025. The Riverside City Council adopted six strategic priorities and associated indicators and goals for each priority. The priorities include: 1) Arts, Culture and Recreation, 2) Community Well-Being, 3) Economic Opportunity, 4) Environmental Stewardship, 5) High Performing Government, and 6) Infrastructure, Mobility & Connectivity. Within the Environmental Stewardship priority, the first foundational goal that was adopted was **Goal 4.1:** *Rapidly decrease Riverside's carbon footprint by acting urgently to reach a zero-carbon electric grid with the goal of reaching 100% zero-carbon electricity production by 2040 while continuing to ensure safe, reliable, and affordable energy for all residents.*

Consistent with this goal, the long-term IRP studies examined in Chapter 12 consider various scenarios designed to achieve a carbon-free electrical portfolio by 2040.

6. Demand Side Management: Energy Efficiency, Fuel Substitution, and Demand-Response Resources

This chapter presents an overview of RPU's demand side management (DSM) programs and resources, including energy efficiency (EE), fuel substitution (FS), and demand response (DR). RPU recognizes the important role that DSM plays in planning for resources and offers a variety of programs and education to customers about using energy efficiently and managing energy usage to reduce bills as well as meet Citywide environmental and sustainability goals. With the passage of Senate Bill (SB) 350 and the requirement to develop and submit an IRP to the California Energy Commission (CEC), RPU is also required to specifically address the procurement of these resources in the IRP. As such, this chapter reviews the methodologies for determining the cost effectiveness of DSM programs overall, as well as the officially adopted EE targets reflected in RPU's load and peak demand forecasts. A brief overview of fuel substitution is also discussed.

6.1 Background

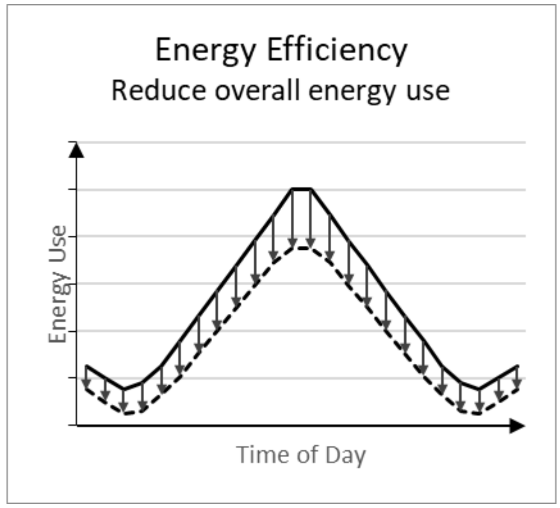
Demand side management (DSM) including energy efficiency (EE), fuel substitution (FS) and demand response (DR) resources are important considerations for the utility as it develops and refines the IRP. DSM programs and resources provide the utility and customers the ability to manage when they use electricity or reduce the overall amount of electricity they need. This concept is important in understanding the load that a utility serves, as well as the infrastructure needed to serve that load. These resources impact the amount of energy being demanded by customers and offer the potential to reduce peak energy demands by shifting energy demand from one time-period to another, thus reducing the need for additional generation and other utility infrastructure. FS programs may increase electricity demand but also reduce emissions of greenhouse gasses (GHG) as well as other harmful air emissions that result from the combustion of fossil fuels (both in buildings and transportation as well as from generation). RPU's future resource strategy incorporates cost effective and mandated DSM programs. Costs and benefits are measured for both the utility and the customer.

6.1.1 Defining Demand Side Management Programs

For the purposes of this IRP, DSM programs and systems are collectively programs that allow customers and the utility to manage the amount, time and type of energy used. DSM has historically been associated primarily with EE programs offered by a utility. However, the collective set of programs including EE, DR and FS all change how electricity is used in the city to meet infrastructure, affordability and sustainability goals. Each of these programs, described below, can affect the utility's overall energy demand and/or when during each day energy is used. All these programs also focus on changing energy use at the customer level. Additionally, these programs may not only be offered by a utility but can be the result of actions outside of the utility's control. For example, DSM impacts can also result from statewide programs or state and federal regulation having the same effect as a utility program.

Energy Efficiency

EE allows customers to use energy more efficiently – basically allowing the customer to reduce the amount of energy used for a given outcome (lighting a room, keeping a space at an optimal temperature and humidity, etc.). EE outcomes can include:



1. Reduce a customer's energy use, whether electricity or fossil fuel such as natural gas or gasoline. This is often the primary goal of EE programs. Reducing energy use can have the additional benefit of reducing a customer's overall electric bill. When this is the outcome, the EE program can also reduce costs for the utility by reducing the need to expand infrastructure and generation resources.

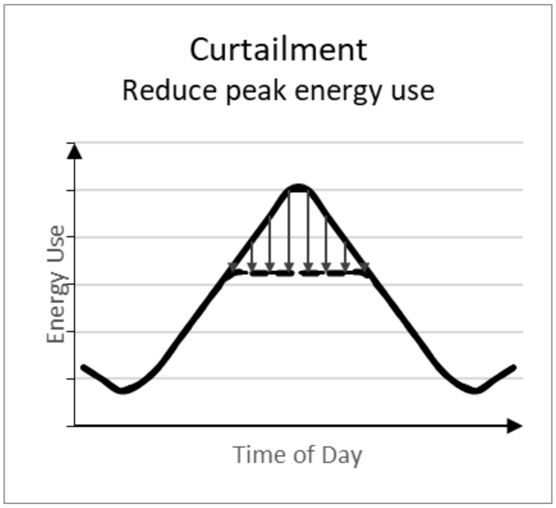
2. Provide the customer with the ability to improve the quality and results of their energy use. In this case, the customer may still use the same amount of energy while their bill remains the same but will realize and experience another benefit. For example, a customer may be able to run their more efficient air conditioner such that it uses the same amount of energy, but it provides a more comfortable indoor environment for the customer. The customer experiences the same cost but has now improved their indoor comfort with a consistent indoor temperature resulting in an improved quality of life. In these cases, the utility may not see reduced costs or any reduction in the need to expand infrastructure or generation resources because the same amount of energy is used.

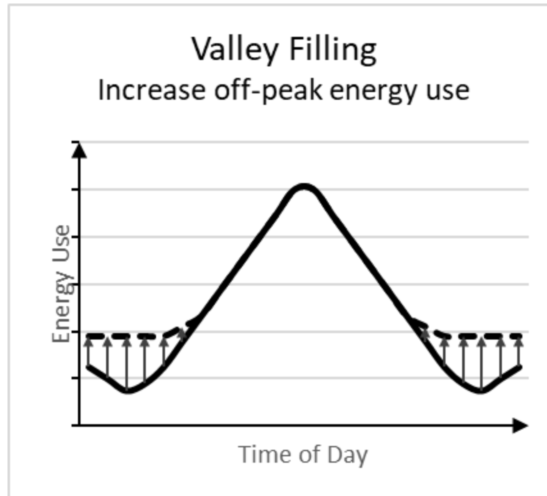
Energy efficiency programs from a utility are often in the form of rebate programs to support customers who choose to install appliances that are more efficient than the existing ones they have. These include rebates for common household or business appliances such as refrigerators, light bulbs, and HVAC systems, etc. Programs can also be expanded to include changes to the building envelop. For example, rebates can be used to offset the costs of replacing insulation and windows or adding insulation into spaces not previously insulated, such as an attic.

Energy efficiency also results from changes to building and appliance codes. Typically referred to as "codes and standards" energy efficiency, this type of energy efficiency results from the adoption of building codes that require new buildings or substantially remodeled buildings to be more energy efficient than those built in previous years. Similarly, codes and standards also change over time and affect the appliances that are allowed to be sold in the state. Appliance standards can require devices that use electricity to operate more efficiently. These standards have been implicitly built into the load forecast discussed in Chapter 2.

Demand Response

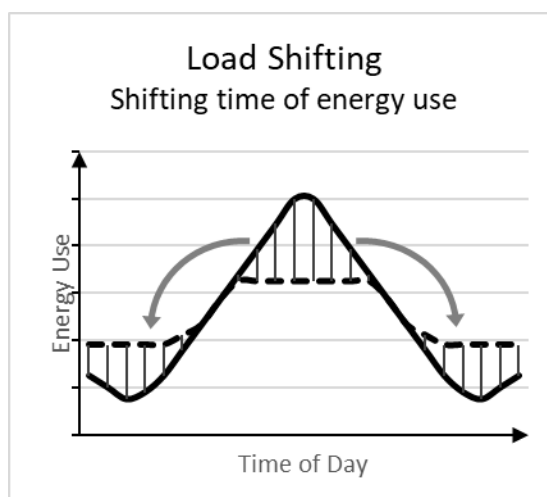
DR programs and resources allow customers to change their energy consumption to better match demand for energy with the supply and capacity available. DR programs have traditionally been seen as programs to support resiliency in the electricity grid system by providing the ability to reduce demand during peak energy use periods (e.g. when the region is experiencing an extreme heat event) or





reduce demand at any time when there is a loss of generation, distribution, or transmission that limits the supply and capacity of the system. They can also be used to increase demand if needed to support grid stability. These programs can be provided by the utility if needed or may be the result of statewide programs. Utility programs are generally targeted at minimizing utility costs as well as for responding to utility grid stability emergencies. Statewide programs are often implemented to address statewide grid stability, with one of the most recognizable programs being the statewide Flex Alert System. A Flex Alert may be called by the State when there is an anticipated lack of supply of electricity to serve load during specific hours due to extreme heat events or loss of significant regional transmission lines. Customers may voluntarily reduce their energy demand by switching appliances off and reducing electricity consumption.

DR programs can provide benefits to individual customers by allowing them to reduce costs by shifting their electricity usage to a different time of day if they pay for their electricity under a TOU rate. The shifted energy use benefits the overall electric grid by reducing the need to overexert distribution and transmission infrastructure. An example of this type of program would be one that rebates customer sited, behind-the-meter energy storage such as a battery system. The customer can charge the battery at a time of day when electricity



costs are low because there is a readily available electricity supply. The customer can then use that stored electricity during times when electricity costs more due to a limited supply. Essentially, the customer is shifting their energy consumption from the grid but is able to use their energy on their home appliances without impacting their day-to-day life. For the utility, when customers install battery energy storage systems, they often reduce their peak demand and increase their demand in off-peak times. This effectively reduces the overall capacity needs of the grid system and can increase the utilization of the existing infrastructure that may not have otherwise been used.

As discussed in Chapter 2, RPU does not currently administer any type of long-term, dispatchable Demand Response program in its service territory. However, RPU continues to support a Power Partners voluntary load curtailment program to call upon up to 10 MW of commercial and industrial load shedding capability during any CAISO Stage 2 or 3 Emergency situation. Additionally, large commercial customers are subject to commercial TOU rate structures to encourage and incentivize off-peak energy use. Finally, RPU also offers a residential TOU rate structure to encourage residential customers to shift loads to off-peak time periods.[1]

Fuel Switching

FS programs encourage customers to switch from using fossil fuel energy sources to another fuel for the purpose of reducing GHG emissions or other pollutant air emissions. When the FS program targets switching from a fossil fuel to electricity, the program may also be called electrification. FS programs can apply to any appliance, building or vehicle that traditionally has used natural gas, gasoline, diesel, or other fossil fuel. This chapter will focus on FS programs for buildings while Chapter 16 addresses FS for transportation systems.

FS has the primary goal of reducing the combustion of fossil fuels in order to reduce emissions of GHG and other air pollutants including volatile organic compounds and nitrous oxides. In buildings, this means transitioning to efficient electric appliances and technologies such as electric water heaters, furnaces, clothes dryers, and cooktops/ovens. When high efficiency electric appliances are installed, customers will experience a drop in their natural gas bill due to eliminating or minimizing natural gas usage. However, they will experience an increase in their electric bill due to the increased electricity usage. At a minimum, the goal of FS is to keep the overall energy expenditure the same but shift the resource from natural gas to electric. In some cases, such as transitioning to a heat pump for air conditioning and heating, the customer may experience a decrease in their overall annual bills, depending on how they utilize the appliance.

RPU does not currently have an independent means to estimate future FE load growth in its service territory. Instead, staff have relied on published CEC projections for the SCE service territory, where these SCE projections (published in the 2021 CEC IEPR hourly forecast scenario) have been

[1] This domestic residential TOU rate is optional for most residential customers, but mandatory for all residential customers who elect to interconnect customer-sided solar PV systems after November 1, 2022.

rescaled using a factor of 0.022214 to deduce suitable FS forecasts for use in the load forecast discussed in Chapter 2.

Summary

In summary, DSM programs can save customers money by reducing the total amount of energy purchased or by shifting usage to times of the day that are a lower cost to the customer. DR and EE programs tend to reduce overall utility costs by avoiding or reducing energy usage during peak hours or by reducing overall the amount of electricity that needs to be procured by the utility. In addition to these benefits, EE and DR programs also help RPU to:

- Defer the need to build new physical generation assets,
- Reduce Renewable Portfolio Standard (RPS) compliance costs,
- Satisfy various State and Federal regulatory mandates,
- Reduce the utility's environmental footprint by lowering GHG emissions, and
- Create a potential for local job creation opportunities.

For the electric utility, FS programs will increase customer electricity usage and the need for infrastructure investment. Therefore, to ensure that the transition is cost effective, it is important that FS is planned for and complemented by other efforts to reduce peak loads and optimize the use of existing infrastructure.

Finally, EE and DR programs can have a negative impact on utilities by imposing costs on a utility, specifically in the area of "unmet revenue streams." It is important to properly estimate these costs so that it is possible to accurately track overall program costs and benefits.

6.1.2 Regulatory Requirements Affecting RPU

RPU began offering EE programs over 20 years ago. These programs ramped up in 1997 after the electricity markets in California were restructured in response to Assembly Bill (AB) 1890. At that time, EE was recognized as an important component necessary to meet California's energy goals. AB 1890 required all utilities to establish the public benefits charge to fund specified programs. RPU's public benefits charge remains at 2.85% of customer usage charges and collects approximately 8 to 10 million dollars annually. These funds are mandated to be spent in the following four areas:

1. Cost-effective demand-side management services promoting energy efficiency and energy conservation;
2. New investment in renewable energy resources;
3. Research, development, and demonstration projects; and
4. Services provided for low-income electricity customers.

In response to the energy crisis in 2000 and 2001, the focus on managing and reducing energy use increased to control the size of and demands on the electric grid. Annual reporting of the energy efficiency savings attained by the programs began with reporting on the accomplishments of the programs in 2005 after the passage of SB 1037.

In the following year, AB 2021 was passed; this bill required RPU to identify all potentially achievable cost-effective, reliable, and feasible electricity energy savings and establish energy efficiency targets for 10-years. RPU's first EE savings target was adopted in 2008 and has subsequently been updated every 3 to 4 years as required by statute.

In recent years, California's goals to reduce GHG emissions have also led to a push to reduce energy consumption by using energy efficiently based on a belief that "the less energy used, the fewer the emissions."[2] Thus, when EE is cost-effective, it represents a cost-effective means to reduce emissions. However, state laws and recent regulations are gearing up to transition from fossil fuels to focus more on fuel substitution, which could mean the overall impact of EE will lessen over time as FS comes to fruition. Current state laws are beginning to include FS requirements – sometimes just to be electric ready or to specifically require that certain electric appliances be used in new and substantially upgraded structures. Cities like Riverside have also begun to adopt their own ordinances to require all-electric new construction. RPU is cognizant of the potential impact of this transition and is in the early stages of incorporating FS along with the EE changes into its load forecasts (see Chapter 2). With the passage of SB 350 in 2015, which added Public Utilities Code (PUC) §9621 requiring utilities to submit IRPs that demonstrate how each utility is working to achieve the GHG emissions reduction goals of the state, the state noted the importance of identifying how DSM and EE are used by each utility in their energy procurement plans and how they are evaluated. Specifically, the IRP must consider the procurement of EE and DR resources pursuant to PUC §9615 which states: "Each 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 reduction resources that are cost effective, reliable, and feasible."

In addition to requiring that EE be considered in the procurement plans developed by IRPs, SB 350 also required that utilities strive to meet an EE target extending through 2030 established by the CEC. The targets were mandated to double the cumulative energy efficiency savings by end uses by January 1, 2030, and reflect both utility and non-utility programs and actions. In adopting the statewide energy efficiency targets in November 2017, the CEC also adopted sub-targets for individual utilities and non-utility programs.

In 2018, SB 100 was adopted which increased the RPS goals referenced in SB 350 and created a requirement that 100% of the state's electricity supply be generated from a mix of RPS-eligible and zero-carbon resources by December 31, 2045. In support of this goal, the city adopted its own strategic plan that set a 100% zero-carbon goal by 2040, which is five years earlier than the state requirement, and adopted an ordinance requiring all new buildings three stories and less to be all electric beginning January 1, 2023 and all new buildings, regardless of height, to be all electric beginning January 1, 2026. The continual improvements and changes made to RPU's DSM programs represent one of many components of RPU's portfolio that has an impact in ensuring it meets the zero-carbon goals. RPU is

[2] National Action Plan for Energy Efficiency, *Energy Efficiency as a Low-Cost Resource for Achieving Carbon Emissions Reductions*. Prepared by William Prindle, ICF International, Inc. 2009. (www.epa.gov/eeactionplan)

exploring options for programming to support building electrification and is closely following programs offered by the state.

In developing its IRP, RPU relies on the data and information developed for the purposes of the above legislative requirements. Data reported and contained in the annual reports on the energy savings resulting from programs submitted to the CEC pursuant to the requirements of PUC §9505, the estimated future potential energy savings from programs required pursuant to PUB §9505(b), RPU's EE target of energy savings from utility programs adopted by the City of Riverside, as well as the sub-targets adopted by the CEC in 2017 are all utilized. Descriptions of each of these data sources are contained in the following section.

6.2 DR, EE and FS Programs, Potential Energy Savings, and Energy Reduction Targets

Energy savings or the shifting of energy use is considered EE or DR, respectively, when it is the result of a program or action undertaken by either the utility or another non-utility entity. Utility programs are programs provided by RPU to help customers to use less energy or manage their electricity load. These programs are funded primarily by public benefits funds but may also be funded through grants. Non-utility programs are actions taken by other agencies, primarily state and federal agencies that also result in lowering or shifting energy consumption patterns. The most common non-utility programs are the codes and standards set by federal and state agencies that affect the energy efficiencies of buildings and consumer appliances.

In recent years, however, federal and state agencies have begun to offer rebate programs to support decarbonization of buildings by fuel substitution. RPU has specific DR related programs tied to Time-of-Use (TOU) rates such as the Self-Generation Program and Feed-in-Tariff (FIT). Simultaneously, RPU is working towards implementing a virtual net energy metering (VNEM) program. Lastly, in 2022, the state began offering incentives to utilities and their customers for participating in its Demand Side Grid Support (DSGS) program in times of elevated emergencies to offset load, which normally occur during high heat waves or extreme circumstances impacting the grid. Another state program being implemented is the Distributed Electricity Backup Assets (DEBA) that is expected to go live in 2024.

6.2.1 RPU Customer Programs

There are several DSM programs offered by RPU. RPU also provides educational resources to its customers so that they can better manage their energy usage and lower their bills. Funding for the RPU programs is provided by the 2.85% public benefits charge (PBC) on all customer energy usage. In addition to RPU's in-house programming, partnerships have also been formed with Riverside County's Community Assistance Program and the Southern California Gas Company[3] to provide additional energy efficiency programs to low-income customers. However, the energy savings resulting from the actions

[3] Energy savings resulting from programs funded by the Southern California Gas Company are not reported in RPU's IRP.

of these agencies are not included in RPU's reported EE savings or in RPU's EE goals. The following section lists and describes each of RPU's EE customer programs.

Commercial Rebate Programs

- Air Conditioning Incentives – Rebates for replacement of energy inefficient AC units.
- Energy Star Appliances – Rebates for purchase of Energy Star-rated refrigerators, dishwashers, commercial clothes washers, solid door refrigerator/freezers, ceiling fans and televisions.
- Lighting Incentive – Rebates for kWh savings on installation of more energy efficient lighting and controls.
- Tree Power – Rebates for purchase and planting of up to 5 qualifying shade trees per year.
- Weatherization – Rebates for installation of insulation, window film and cool roofs.
- Performance Based Incentive – Rebates for customers who can demonstrate a kWh savings based on custom energy-efficiency measures.
- Key Account Energy Efficiency Program (KEEP) – Program targeting RPU's largest Time-of-Use Customers. This customer segment includes the top 300 RPU customers in terms of consumption. KEEP is intended to provide Key Account customers with a comprehensive energy efficiency plan including a priority list of recommended energy efficiency measures along with an estimated return on investment and applicable utility incentives. Customers are also offered additional technical and contracting assistance to bring large energy efficiency projects from concept to fruition.
- Custom Energy Technology Grants – Grants awarded for research, development, and demonstration of energy efficiency and renewable energy projects that are unique to the business or manufacturing process and can demonstrate energy savings, demand reduction or renewable power generation.
- Energy Innovation Grants – Grants available to public or private universities within RPU's service territory for the purpose of research, development, and demonstration of energy efficiency, renewable energy, energy storage, strategic energy research, and electric transportation.
- Energy Management Systems – Rebates for the purchase and installation of energy management systems for monitoring and controlling facility energy load.
- New Construction and LEED Construction Incentives – Rebates for energy savings exceeding Title 24 standards for pre-approved new construction projects.
- Pool and Spa Pumps Incentive – Rebates for purchase of qualifying multi-flow or variable speed high-efficiency pumps and motors.
- Premium Motor Incentives – Rebates for the purchase of premium high efficiency electric motors.

Commercial Direct Installation Programs

- Small Business Direct Installation (SBDI) Program – This program was recently updated to provide small and medium sized businesses with energy audits and direct installation of energy efficiency measures such as lighting upgrades and controls, HVAC tune-ups, exit and open/closed signs and weatherization measures.

Residential Rebate Programs

- Energy Star Appliances – Rebates for purchase of Energy Star-rated refrigerators, dishwashers, clothes washers, room air conditioners, ceiling fans, and televisions.
- Residential HVAC – Rebates for replacing Central Air Conditioners with a SEER rating of 15 or above.
- Tree Power – Rebates for purchasing and planting of up to five qualifying shade trees per year and one free qualifying shade tree coupon printed on the back of the March bill.
- Pool Saver – Rebates for purchase and installation of high efficiency, variable speed, or multi-flow pool pump motors.
- Weatherization – Rebates for installing attic insulation or wall insulation, standard rebates for duct replacement, duct testing/sealing, window film, solar and standard attic fans, whole house fans, and cool roofs.
- Appliance Recycling – Free recycling service for old inefficient refrigerators and freezers.

Residential Direct Installation Programs

- Multi-Family and Mobile Home Direct Installation – Program offering multi-family and mobile home residents direct installation measures including HVAC tune-ups, lighting efficiency upgrades, weatherization, and Tier 2 advanced power strips. Also addresses energy efficiency measures in common areas.
- Energy Savings Assistance Program (ESAP) – Direct installation program targeting low-income customers, offered in partnership and cooperation with Southern California Gas Company. Measures include lighting efficiency upgrades, HVAC tune-ups, smart power strips, and refrigerator recycling.

Figure 6.2.1 depicts a bar chart of RPU's achieved EE savings with respect to established annual targets for FY 12/13 through FY 21/22, respectively.

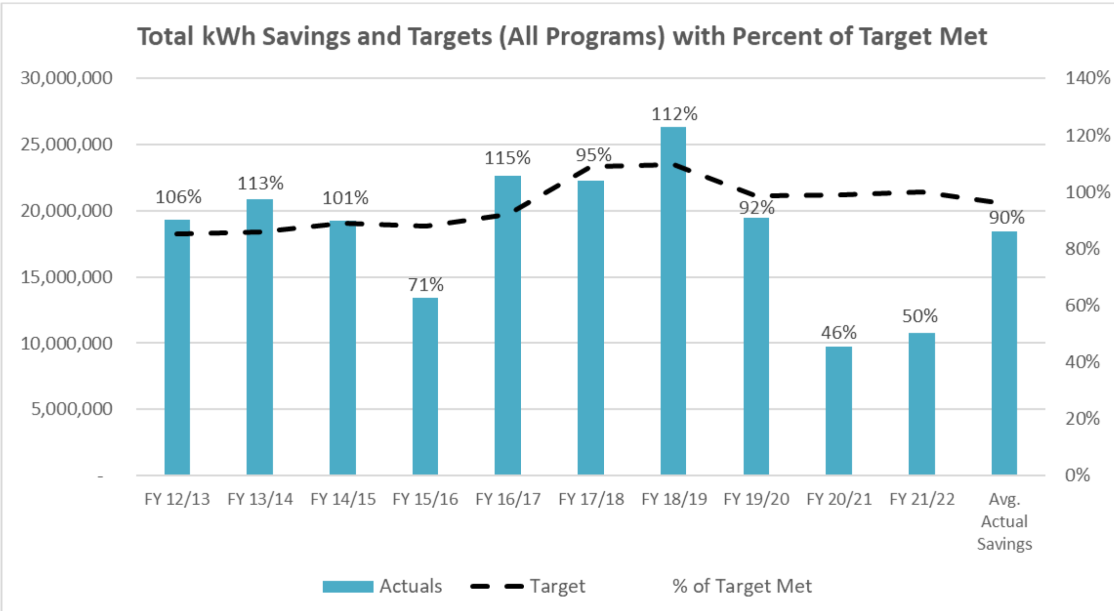


Figure 6.2.1. Reported EE savings for FY 12/13 through FY 21/22. FY 20/21 and FY 21/22 actuals are below target due to the global Covid-19 pandemic.

6.2.2. Energy Savings Potential and Targets for EE Programs

As noted previously, PUC §9505(b) requires that every four years POUs identify and evaluate all potentially achievable cost-effective, reliable, and feasible electricity efficiency savings. Additionally, these same utilities must establish 10-year energy efficiency targets for energy savings as well as peak demand reduction. In 2021, RPU, along with other members of the California Municipal Utilities Association (CMUA), engaged GDS Associates, Inc. to identify potential target goals for EE programs. Potential energy savings were developed for the years 2022 through 2031 as well as the expected savings from the currently adopted California building and appliance codes and standards. A full description of the model, the analysis completed, and the results can be found in CMUA's report prepared by GDS Associates, Inc., 2020 Energy Efficiency Potential Forecast Final Report, April 2021.[4] In conjunction with reporting on the potential savings identified in this report, RPU adopted EE savings targets in June 2021.

GDS's model, shown below, was used to develop utility specific estimates for technical, economic, and market potential energy savings. Based on the model information, the calculated energy savings potential (savings as percentage of total sales) is reflected in the following table.

[4] GDS Associates, Inc., *2020 Energy Efficiency Potential Forecast Final Report,* Prepared for California Municipal Utilities Association, April 2021.

Energy Savings Potential (Savings as a Percentage of Total Sales)	
Description	**Range**
Technical Potential	(3% to 26%)
Economic Potential	(3% to 23%)
Cumulative Market Potential	(1% to 5%)
Incremental Market Potential	(<0.11% to 0.97%)

As referenced previously, CMUA's report prepared by GDS Associates, Inc. describes the types of EE potentials and GDS' modeling assumptions within each as follows:

- Technical Potential. Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed, they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation is assumed to be resource constrained and that it is not possible to install all retrofit measures all at once. Rather, retrofit opportunities are assumed to be replaced incrementally until 100% of stock is converted to the efficient measure over a period of no more than 20 years.

- Economic Potential. Economic potential refers to the subset of the technical potential that is economically cost-effective. Both technical and economic potential ignore market barriers to ensuring actual implementation of EE. Technical and economic potential only consider the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration, program evaluation, etc.) that would be necessary to capture them. The GDS models calculate several financial tests for evaluating the measure of cost-effectiveness.

- Maximum Market Potential. Maximum market potential estimates achievable potential from aggressive adoption rates based on paying incentives equal to 100% of the measure's incremental costs and increased program awareness.

- Market Potential. Market potential is the amount of energy that can be realistically saved given likely future program offerings and various market barriers. Market potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and Evaluation, Measurement and Verification (EM&V)); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in the programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Market potential is estimated based on a relationship between incentive levels (as a percentage of incremental measure costs) and expected market adoption rates. In the base market potential scenario, assumed measure incentive levels are closely calibrated to historical levels.

Market potential energy savings estimates are conservative estimates of achievable energy efficiency from the suite of measures offered by a utility. Per the CMUA report prepared by GDA Associates, Inc., market potential also includes an estimate of non-incentive program costs to fully capture the overall expected utility costs relative to the lifetime benefits of EE improvements. Many utilities in California will opt to select the market potential savings estimate as their target for energy savings pursuant to their programs. However, RPU elected to continue to adopt a more aggressive energy savings target of 1% of forecast sales through 2031 based on gross energy savings from measures (consistent with the maximum market potential). In setting its EE savings target, RPU recognized that there is a substantial amount of energy savings considered to be economically feasible for the customer, as identified in the study. Therefore, it was determined reasonable and responsible to focus on education and program optimization in the coming years to ensure success in achieving more aggressive targets. RPU's adopted targets (as of June 2021) as well as the energy efficiency and demand goals and savings from the GDS analysis are shown in Tables 6.2.1 (a and b) and 6.2.2 (a and b), respectively.

6.2.3. Energy Savings Targets Adopted by RPU and the CEC

The CEC adopted both statewide energy efficiency targets as well as recommended sub-targets for each utility in November 2017.[5] The CEC recommended a conservative approach when establishing the utility specific sub-targets. The CEC's adjusted sub-targets for RPU are shown in Table 6.2.3. For POUs, including RPU, the CEC established the targets as the market potential (or net incremental energy savings) produced by the 2016 EE potential analysis completed by Navigant Consulting, Inc. in February 2017. Additionally, the CEC also extended the range of the sub-targets to reflect their mandated requirement to develop targets to be achieved for doubling of energy efficiency savings from 2015 levels by January 1, 2030. They also extended the net incremental EE savings from 2027 through the end of 2029. These same values were used in RPU's last IRP analysis.

However, the CEC sub-targets have not been updated since the publication date in 2017. Instead, the CEC is utilizing the latest available potential study prepared by GDS (referenced earlier in this chapter) in its studies or analysis, including in their Integrated Energy Policy Report (IEPR) filings. Additionally, for the purposes of this IRP, RPU is using its adopted EE targets of 1% of retail sales.

[5] Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. *Senate Bill 350: Doubling Energy Efficiency Savings by 2030. California Energy Commission.* Publication Number: CEC-400-2017-010-CMF. 2017.

Table 6.2.1a. Energy Goals and Savings from Energy Efficiency Programs (MWh) – 2022-2031

ALL Sectors (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	76,277	145,800	210,299	269,400	324,822	378,437	430,059	476,006	519,227	559,564
Economic Potential	68,176	130,369	189,274	243,636	294,661	344,194	391,782	434,040	473,465	510,358
Incremental Market Potential	21,383	18,523	16,569	15,551	14,120	13,117	11,694	9,340	8,584	8,394
Cumulative Market Potential	21,383	39,894	56,231	71,321	84,730	97,415	108,586	116,683	124,561	132,230
RPU Adopted Targets	21,789	21,105	21,380	21,569	21,828	22,100	22,436	22,697	23,017	23,358

Source: GDS Potential Study

Table 6.2.1b. Energy Goals and Savings from Energy Efficiency Programs (MWh) – 2032-2041

ALL Sectors (MWh)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Technical Potential	594,914	625,563	653,829	680,080	704,368	721,339	736,633	750,481	758,346	765,431
Economic Potential	542,655	570,689	596,255	619,862	641,420	656,273	669,310	680,839	687,572	693,468
Incremental Market Potential	8,222	6,952	6,713	6,499	6,383	5,276	5,134	4,937	3,659	3,406
Cumulative Market Potential	138,405	143,055	146,976	150,639	153,908	155,332	156,506	157,723	157,669	157,641
RPU Adopted Targets	23,771	24,090	24,480	24,876	25,336	25,719	26,162	26,618	27,141	27,580

Source: GDS Potential Study

Table 6.2.2a. Demand Goals and Savings from Energy Efficiency Programs (kW) – 2022-2031

ALL Sectors (kW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Technical Potential	22,040	41,830	59,886	75,985	89,702	101,883	112,807	122,210	130,412	137,889
Economic Potential	17,334	33,059	47,823	61,225	72,664	82,911	92,138	100,106	106,989	113,269
Incremental Market Potential	5,261	4,453	3,982	3,714	2,978	2,638	2,301	1,763	1,590	1,539
Cumulative Market Potential	5,261	9,708	13,674	17,359	20,259	22,676	24,755	26,269	27,629	28,998

Source: GDS Potential Study

Table 6.2.2b. Demand Goals and Savings from Energy Efficiency Programs (kW) – 2032-2041

ALL Sectors (kW)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Technical Potential	144,063	149,350	154,135	158,849	163,511	166,608	169,583	172,388	174,114	175,848
Economic Potential	118,965	123,857	128,235	132,496	136,628	139,286	141,742	143,973	145,331	146,680
Incremental Market Potential	1,556	1,384	1,401	1,446	1,499	1,306	1,276	1,283	1,065	1,054
Cumulative Market Potential	30,182	31,164	32,091	33,068	34,090	34,678	35,218	35,824	36,249	36,720

Source: GDS Potential Study

Table 6.2.3. CEC adjusted sub-targets for RPU (GWhs)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Net Incremental Savings	21	17	20	21	21	20	19	18	18	16	15	14	13	12	10
Cumulative Savings	12	25	42	58	74	91	109	127	145	162	179	195	209	221	231

Source: Tables A-10 and A-11 from Appendix A of Senate Bill 350: Doubling Energy Efficiency Savings by 2030. California Energy Commission

6.2.4 Non-Utility Programs and Impacts to Demand Forecast

In addition to the programs that RPU offers, RPU also recognizes that many state regulations, laws, and individual consumer preferences are influencing customer energy consumption. The United States, and particularly the State of California, have long had goals to reduce energy consumption in businesses and households, increase energy efficiency, and requirements for the installation of solar photovoltaic systems (solar PV). As the state continues its efforts to reduce GHG emissions, fuel substitution standards and mandates are beginning to be implemented, which will affect a utility's demand forecast.

More importantly, building codes, initially developed to ensure that basic construction standards were met for the safety of occupants, now also require new and remodeled buildings to comply with increasingly energy efficiency standards, installation of electrification-ready infrastructure, and requirements to install solar PV. Furthermore, many of the appliances and devices that are used in these buildings are also now subject to energy efficiency regulations through federal and state appliance standards with certain appliances now being banned in some locations. Appliance standards not only affect new development, but also existing buildings that replace appliances at end of life. These codes and standards result in new construction that has an energy use profile that is different than the past. Although the GDS potential study did not account for codes and standards savings, it is implied in RPU's forecasting and analysis.

Customers also have access to appliances and systems that give them more control over their energy consumption than ever before. New energy management technologies for homes and businesses, internet connected devices, and energy efficient appliance options are making it easier for customers to choose to use energy more efficiently. Adoption of these technologies is increasing as some customers voluntarily install such appliances while others (primarily commercial and industrial new construction as well as substantial retrofits of existing buildings) are mandated to install such systems.

Finally, RPU also recognizes several other state policies and programs with the intent of reducing energy consumption. As the various strategies are implemented, whether pursuant to legislation or regulation, the effect they have on energy consumption is noted by RPU. However, the exact impact of each of the programs on RPU is not currently known. As with energy management technologies, as data becomes available, RPU will incorporate it into its future IRP analyses. Notable legislation and programs affecting energy efficiency includes:

- <u>Zero-net-energy buildings:</u> AB 1103 and the IEPR Policy direct the CEC to develop building codes to require new residential construction to be zero-net energy by 2020 and new commercial and industrial construction to be zero-net energy by 2030.
- <u>Energy Efficiency in Existing Buildings:</u> AB 758 develops policy and strategies intended to vastly improve energy efficiency in existing buildings.
- <u>Energy Efficiency in Public Schools:</u> Proposition 39 and SB 73 provides funding and direction for improvement in energy efficiency at schools.

- Reporting Energy Use in Existing Buildings: AB 802 mandates non-residential and large multi-family building energy use reporting.
- Ongoing updates to the State's Building Codes and Appliance Energy Efficiency regulations.

6.3 CEC Additional Achievable Energy Efficiency and Fuel Substitution

In the CEC's IEPR program, the CEC includes demand modifiers that result from codes and standards. In the 2021 IEPR, the CEC included updates and improvements to the Additional Achievable Energy Efficiency (AAEE) scenarios and added FS scenarios known as Additional Achievable Fuel Substitution (AAFS) to the forecasts. The AAEE impacts represent energy savings that are incremental to the savings from the market potential savings from utility programs. AAEE energy savings are reasonably expected to occur due to customer choices (outside of energy efficiency programs), updated building and appliance codes and standards, and future energy efficiency programs not incorporated in the market potential forecast. As noted previously, RPU does account for some of the AAEE in its forecast due to the adopted energy efficiency target set at 1% of RPU's retail sales. However, codes and standards are not tracked separately, but rather are incorporated into the base demand forecast. RPU does monitor changes occurring in areas such as building energy codes and state energy efficiency plans and continually reviews and updates the programs offered to customers as they impact the electricity resource portfolio supply and demand. RPU recognizes that the CEC does not project as much savings from RPU's existing programs but is focused more on the impacts and expected savings from future building standards, appliance regulations and other fuel substitutions.

FS or building electrification is a new component being forecasted by the CEC. The CEC defines fuel substitution as the substitution of one end use fuel type for another, such as changing out gas end-use appliances in buildings for cleaner more efficient electric end uses.[6] New construction in RPU's service territory will increasingly incorporate all-electric building construction, not only because the state's building codes continue to transition construction to all-electric requirements for buildings, but because the City has also adopted an ordinance requiring all new construction to be all-electric. Riverside's ordinance, adopted in December 2022, requires all-electric buildings with no natural gas infrastructure for buildings 3 stories or less beginning January 1, 2023 and all buildings regardless of size beginning January 1, 2026. Fuel substitution in existing buildings will occur at a slower pace and will be reliant on building occupants to make changes to the buildings and to choose to utilize electric appliances. RPU will evaluate how the demand forecast will be affected by fuel substitution over the next several years using new information as it becomes available.

It should be noted that the CEC developed an AAFS forecast to address the current and anticipated future state and federal codes and standards for buildings and appliances for the 2021 IEPR.

[6] Javanbakht, Heidi, Cary Garcia, Ingrid Neumann, Anitha Rednam, Stephanie Bailey, and Quentin Gee. 2022. *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast*. California Energy Commission. Publication Number: CEC-100- 2021-001-V4.

Since Riverside does not currently have an independent means to estimate future Building Electrification load growth in its service territory, staff have relied on published CEC AAFS projections for the SCE service territory to produce suitable FS forecasts for use in this IRP. As mentioned earlier in section 6.1.1 and discussed in Chapter 2, section 2.2.8, staff have rescaled the SCE projections published in the 2021 CEC IEPR hourly forecast scenario using a Riverside specific factor to deduce and project suitable FS forecasts for the RPU service territory.

7 Market Fundamentals

This chapter presents an overview of the forward market data used by the Ascend Portfolio Modeling software platform, as well as projections of the CAISO's Transmission Access Charge (TAC) rate and Resource Adequacy (RA) prices. Note that RPU uses market analytics and forecasts for the Southern California electricity and natural gas markets provided by Ascend Analytics. Staff has found that the Ascend forecast meets or exceeds the capabilities of RPU internal forecasting, is research informed, and consistent with industry best practices. The details on these forecasts and reasoning thereof can be found in Ascend Analytics *CAISO Market Report 4.1*, a reference to which is included in Appendix B. The data provided by Ascend Analytics has been used to calibrate the forward curves for this IRP.

7.1 Ascend Analytics CAISO Market Forecast

For this IRP, RPU is using longer term electricity and natural gas forward price forecasts produced by Ascend Analytics. The electricity and natural gas forward price hubs that RPU uses for its resource portfolio modeling are shown in table 7.1.1. The Ascend forecasts for these price hubs start with published forwards from the Intercontinental Exchange (ICE). Ascend uses the ICE forwards for the first 36 months or "liquid" period of the forecast before blending and transitioning to its long-term forecast which extends through 2045. Ascend describes this approach further in its *CAISO Market Report 4.1*:

> Ascend forecasts begin with market forwards for fuel and power prices over the duration for which they are liquid. This ensures that Ascend models are calibrated to observed market conditions. Ascend then blends the end of the liquidity period with a long-run forecasting approach that explicitly accounts for the new market dynamics. (Ascend p.60)

The Ascend forward price forecasts seamlessly integrate with the Ascend Portfolio Modeling software platform for use in all studies performed for this IRP. More detailed information about the Ascend Portfolio Modeling software can be found in Appendix A.

Table 7.1.1. Ascend Forward market data.

Commodity	Hub	Source
Electricity	SP15 (Peak, Off-Peak)	ICE + Ascend
Natural gas	SoCal Citygate	ICE + Ascend

7.2 SoCal Citygate Forward Gas Prices

As discussed in section 7.1, Ascend blends the current ICE SoCal Citygate forwards with the Ascend long term forecast. The Ascend SoCal Citygate forward monthly price curve used to create all the forward price simulations considered in this IRP is shown in Figure 7.2.1.

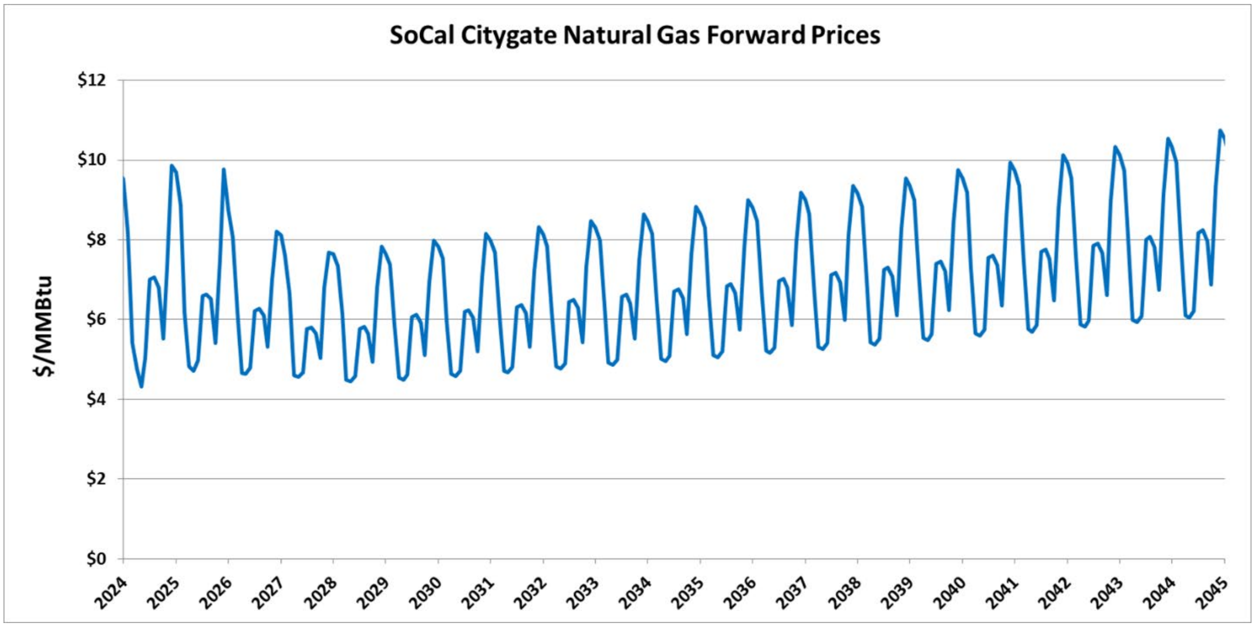


Figure 7.2.1. Ascend natural gas forward prices for the SoCal Citygate Hub.

7.2.1 Comparison of Natural Gas Price Forecasts

The CEC produces annual and monthly forecasts of natural gas prices to develop its Integrated Energy Policy Report (IEPR). For the 2023 IEPR report, the CEC developed three natural gas price reference cases – High Supply, Mid Supply, Low Supply – for major hubs in the Western Interconnect.[1] The hub the CEC modeled that is closest to the Ascend SoCal Citygate hub is the *California (SoCalGas) - SoCalGas Citygate* hub. A comparison of the CEC's forecast cases to the Ascend extended SoCal Citygate price forecast is shown in Figures 7.2.2 and 7.2.3; note that all natural gas forecasts are shown in nominal dollars.

[1] CEC 2023 IEPR Preliminary Electric Generation Price Model. Retrieved 5/24/2023. *https://www.energy.ca.gov/sites/default/files/2023-04/2023_IEPR_Preliminary_Electric_Generation_Price_Model_ada.xlsx*

As shown in Figure 7.2.4, the Ascend forward natural gas curve for the SoCal Citygate Hub differs from the CEC SoCal Gas Hub forecasts. The Ascend curve dips below the CEC forecast for the Low Demand reference case and then escalates at a greater rate in the 2030 through 2045 time-horizon, ending substantially above the CEC High Demand reference case. Nevertheless, RPU finds that the overall Ascend gas price trends reflect research-informed market assumptions. Ascend describes this approach in the *CAISO Market Report 4.1*:

> The natural gas price forecast uses the Pindyck approach,[2] which takes market forward data and then indexes by inflation after the liquidity period. Pindyck's analysis showed that using this method for natural gas forecasting is more reliable than a fundamentals-based approach, as price changes can drive a variety of unforeseen developments, including efficiency gains, alternative sources, and fuel switching. The Ascend forecast then calculates a carbon price adder, which is the product of the forecasted carbon price and the monthly carbon intensity forecast, which co-evolves with the implied heat rate forecast. (Ascend p.61)

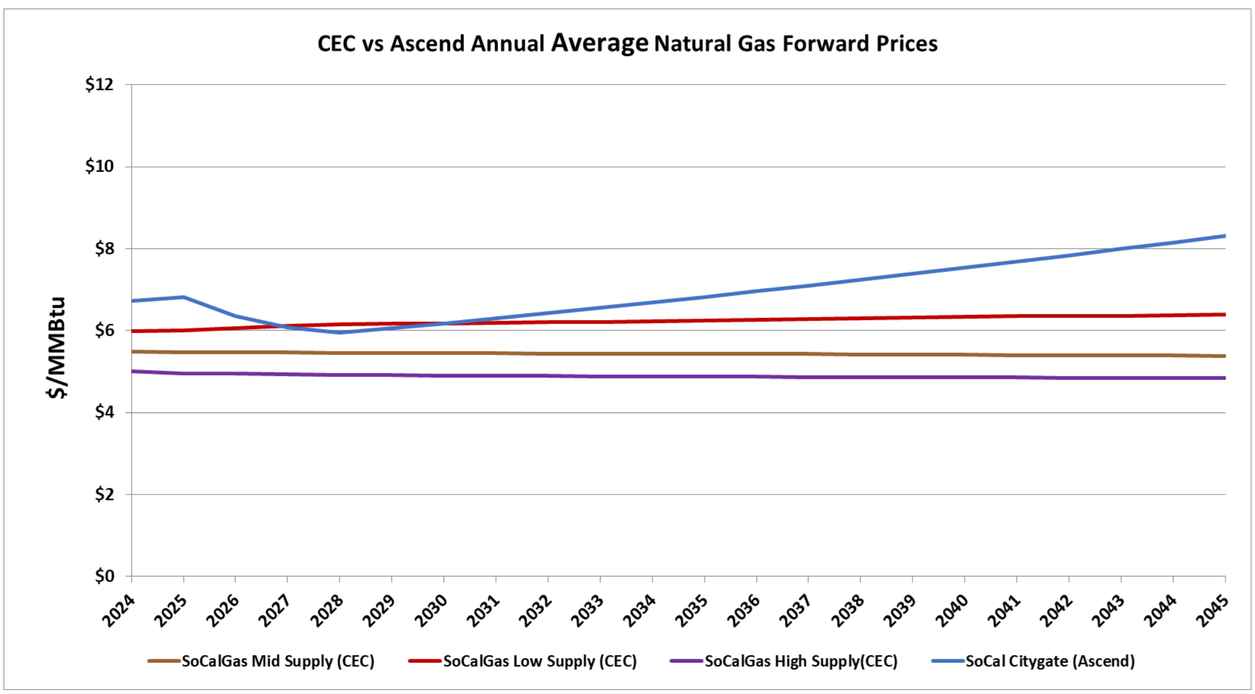


Figure 7.2.2. Annual Average of CEC and Ascend forward natural gas prices.

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

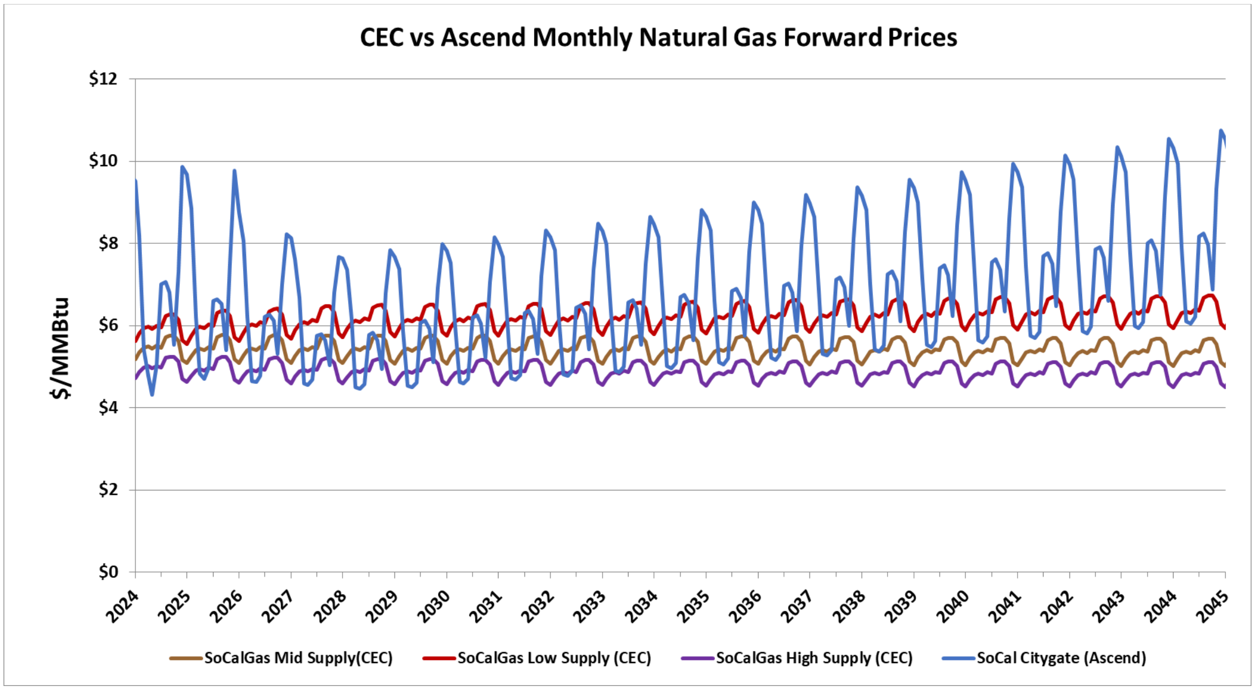


Figure 7.2.3. Ascend and CEC monthly forward natural gas prices.

7.3 Carbon Price Forecast

With the implementation of California's Cap and Trade program, a minimum price per metric ton (MT) of carbon was established. In California's Cap and Trade regulations, this minimum price is known as the Auction Reserve Price. When the program launched in 2012, the initial Auction Reserve Price was set at $10/MT. Each year thereafter, the Auction Reserve Price is to increase annually by 5% plus the rate of inflation as measured by the most recently available 12 months of the Consumer Price Index (CPI) for All Urban Consumers.

For the 2021 IEPR, the CEC Low carbon price forecast followed the Auction Reserve Price calculation discussed above. RPU staff has incorporated a similar approach as the CEC Low forecast to develop a carbon price forecast for use in simulation modeling. RPU staff seeded the forecast with the mean average of the three recent quarters of auction clearing prices. RPU staff then increased prices by 5% annually, in line with the Auction Reserve Price, and an additional 2% to account for inflation during the period. RPU's resulting carbon price forecast is shown in Table 7.3.1. For the 2021 IEPR, the CEC developed a Mid, and High carbon price forecast through 2050 as well. A comparison of these CEC forecasts through 2045 is shown in Figure 7.3.1. It is worth noting that RPU resources with emissions exposed to carbon pricing will be retired before 2040 in all the scenarios studied in this IRP. Therefore, the impact of any potential divergence in carbon price on RPU's resource portfolio will be negligible beyond 2040.

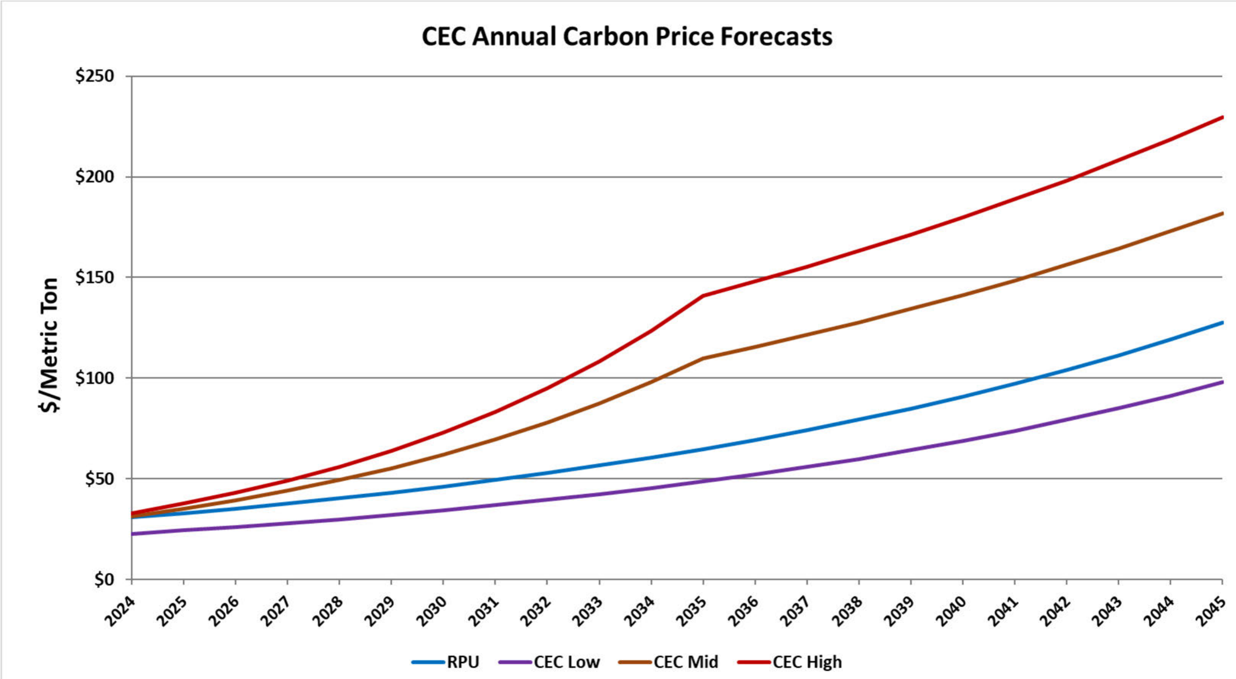


Figure 7.3.1. Comparison of CEC's 2021 IEPR and Ascend Annual Carbon Price Forecasts.

Table 7.3.1. RPU Carbon Price Forecast Used in Simulation Modeling.

Year	Price ($/MT)
2024	$30.80
2025	$32.95
2026	$35.26
2027	$37.73
2028	$40.37
2029	$43.20
2030	$46.22
2031	$49.45
2032	$52.92
2033	$56.62
2034	$60.58
2035	$64.82
2036	$69.36
2037	$74.22
2038	$79.41
2039	$84.97
2040	$90.92
2041	$97.28
2042	$104.09
2043	$111.38
2044	$119.18
2045	$127.52

7.4 Forward Power Prices

7.4.1 SP15 Forward Power Prices

As discussed in section 7.1, Ascend blends the current ICE SP15 on and off-peak forwards with the Ascend long term forecast. The resulting on and off peak SP15 monthly forward curves through 2045 are shown in Figures 7.4.1 and 7.4.2 below.

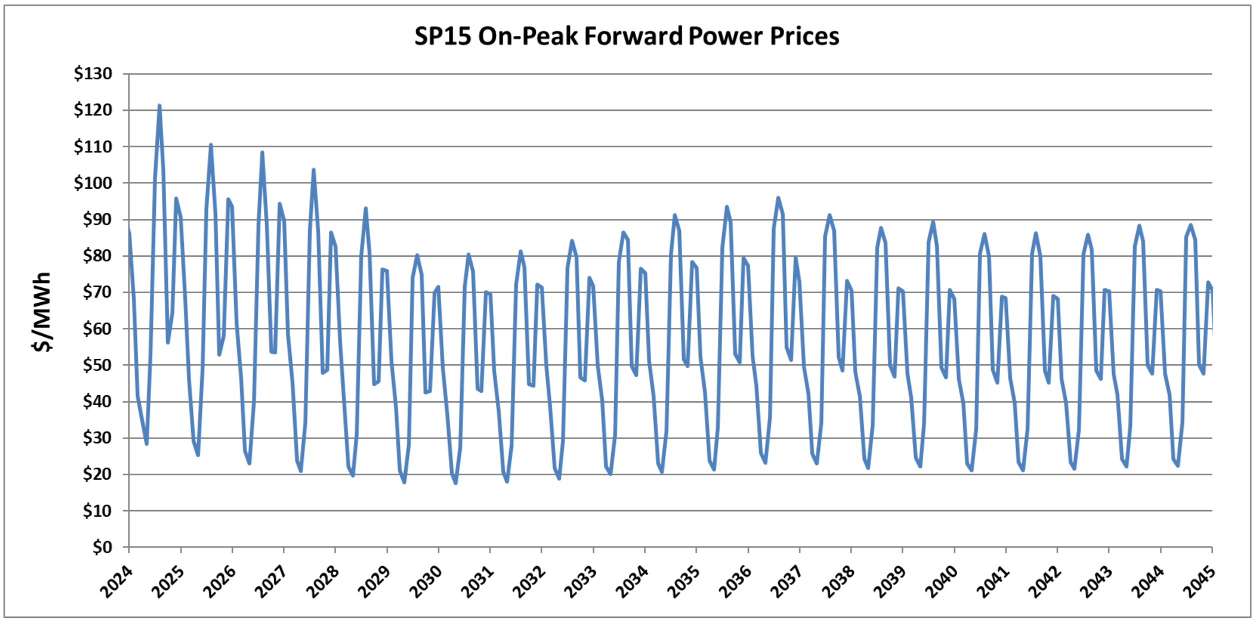


Figure 7.4.1. Ascend SP15 On Peak monthly forward price curve.

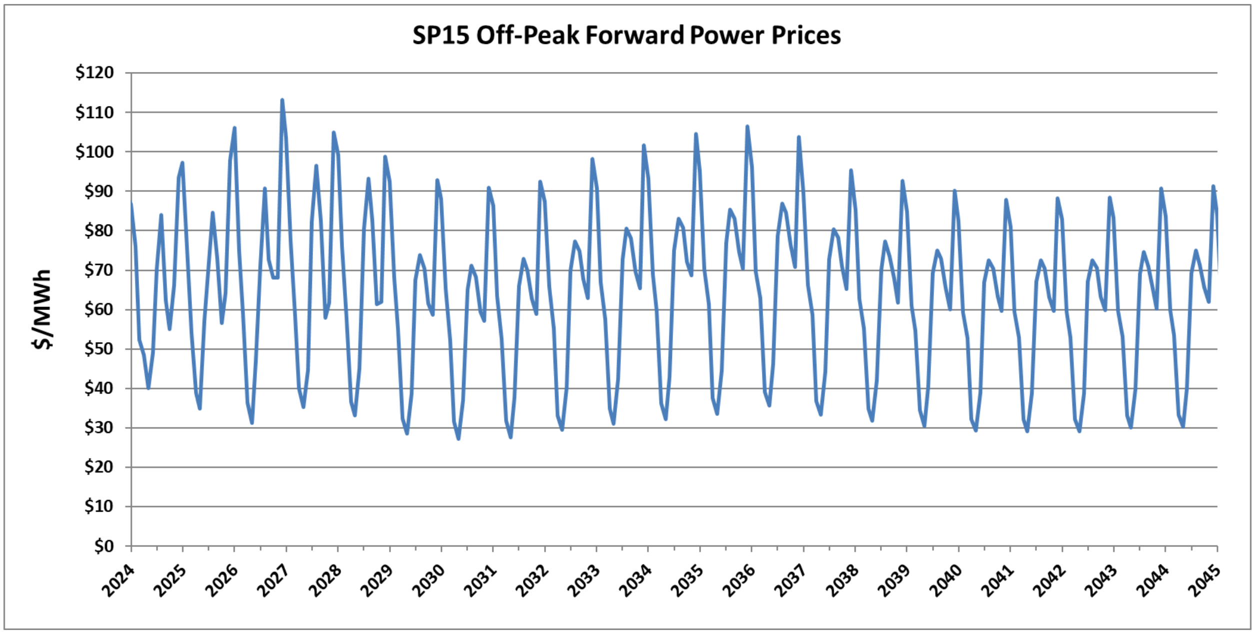


Figure 7.4.2. Ascend SP15 Off Peak monthly forward price curve.

7.5 CAISO Transmission Access Charge (TAC) Forecasts

The CAISO TAC is a function of two components: (1) the CAISO TAC rate, which is a $/MWh charge assessed to load serving entities (LSE) who require access to the CAISO grid, and (2) the LSE's gross MWh load served via the CAISO grid. As a CAISO member, RPU incurs this TAC charge on its total MWh of gross load. Thus, for any RPU load forecast, projecting RPU's TAC cost through the 2045 only requires a projection of the CAISO TAC rate. The CAISO has such a projection through 2036 in its 2021-2022 Transmission Access Charge Model [3], which is posted in the Transmission Planning Section on the CASIO website.

In the CAISO TAC Model, the TAC rate is derived by dividing the total revenue requirements to pay for high voltage transmission projects within the CAISO by the forecasted CAISO system gross load. Given projections of these parameters, the CAISO TAC Model shows TAC rates increasing between 2 to 5% annually through 2029 and then increasing about 0.3% annually between 2031 and 2036. For this IRP, RPU has elected to use the CAISO projected TAC rates through 2036, where they reach $21.94/MWh, and then hold that amount constant through the end of the 2045 study horizon. Table 7.5.1 and Figure 7.5.1 show the projected TAC rates used to calculate RPU's TAC costs associated with our system load growth forecast.

[3] http://www.caiso.com/Documents/2021-2022TransmissionAccessChargeForecastModelwithNewCapital.xlsx

Table 7.5.1. CAISO TAC rate projections through 2045; for use in computing RPU's TAC costs.

Year	TAC Rate ($/MWh)
2024	$17.80
2025	$18.47
2026	$18.91
2027	$19.79
2028	$20.70
2029	$21.23
2030	$21.54
2031	$21.59
2032	$21.65
2033	$21.72
2034	$21.79
2035	$21.86
2036-4045	$21.94

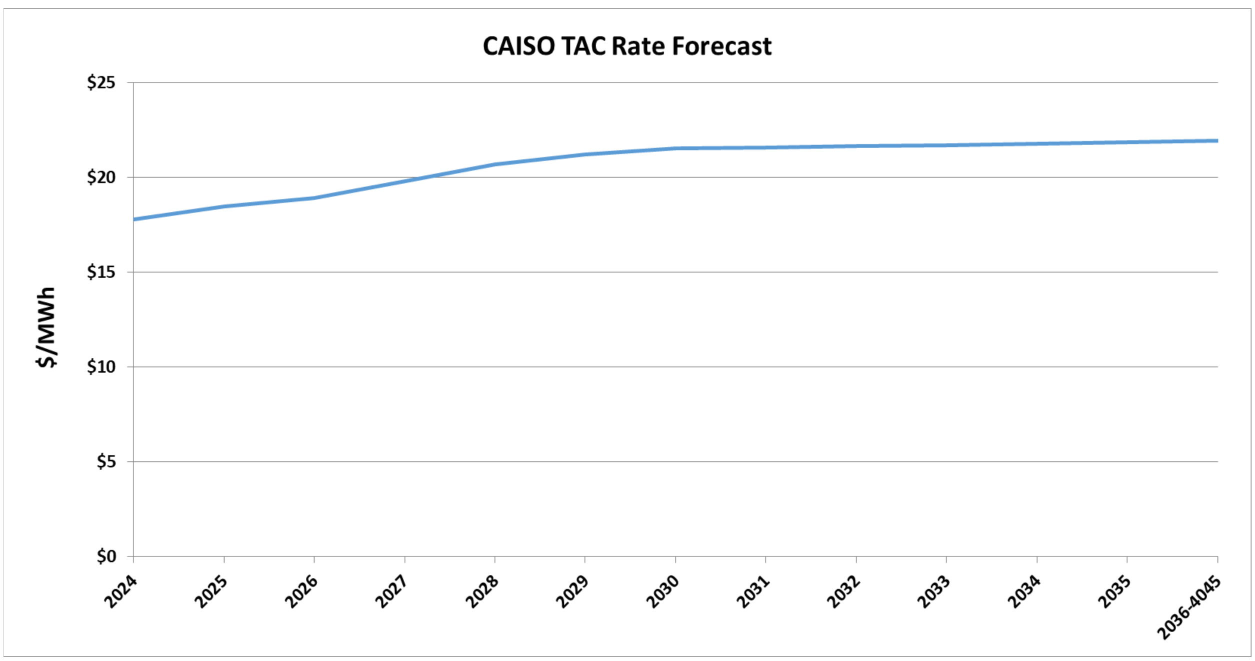


Figure 7.5.1. CAISO Transmission Access Charge rate forecast.

7.6 Resource Adequacy Price Forecasts

Under its current resource adequacy (RA) paradigm, the CAISO has requirements for System, Local, and Flexible RA, and each type of RA has its own price in the market. Unfortunately, future pricing for these RA types is very uncertain as they are dependent on CAISO rulemakings through ongoing stakeholder processes. The CAISO redefined the paradigm in 2015 through the Flexible Resource Adequacy Criteria Must Offer Obligation (FRAC-MOO) Phase 1 stakeholder initiative, which led to the introduction of the flexible RA requirement. Now, the CAISO has closed Phase 2 of the FRAC-MOO initiative and has not significantly redefined the flexible RA requirements introduced in Phase 1. Changes to flex RA were migrated to the Resource Adequacy Enhancements initiative in 2021 as discussed in Section 5.2.5.

Phase 1 of the Resource Adequacy Enhancements stakeholder initiative did not change flex RA requirements materially. Phase 2 was scheduled to begin in 2023, however it is unclear if any substantive changes will occur in the near term related to flexible RA. The straw proposal does suggest some limited changes to RA for storage, and the 3-hour ramping requirements, but it is unclear what form those may take in final rulemaking and whether they would have material impact to RPU's capacity, prices, and/or obligations for RA.

With the uncertainty surrounding the future requirements of CAISO's RA paradigm and future pricing for individual RA products, RPU has elected to use a projection of RA pricing based on recent bundled price quotes it has received for System and Local RA products through 2028 plus longer-run expectations of equilibrium RA pricing (through 2035). It should be noted that there are currently critical capacity shortages impacting the CAISO, which have in turn caused near term RA prices to more than double in cost. For example, Riverside was able to secure 2023 annual System+Local RA products for ~ $7.25/kW-mo, but now these same RA products in 2025 are selling for more than $15.00/kW-mo. Although it is impossible to know for sure how long such price contortions will continue, for planning purposes we have assumed that such pricing is not sustainable and thus must begin to drop back down after 2025.

Table 7.6.1 shows the annual RA price assumptions for System+Local RA from 2024 through 2045. (System+Local+Flex RA products are assumed to follow the same pattern, but with an additional $0.75/kW-mo price adder.) This pattern reflects the current distressed RA market conditions, along with the assumption that prices drift back down to a $9.00/kW-mo equilibrium mark by 2035 (and then escalate at ~ 2.5% per year thereafter). This same data is shown graphically in Figure 7.6.1.

Finally, Table 7.6.2 shows the assumed monthly ratio weights (multipliers) used to convert annual RA prices into corresponding monthly RA prices. Likewise, Figure 7.6.2 shows how the annual RA cost for 2024, 2025, and 2028 translates into monthly pricing. Note that monthly prices are used in Chapter 10 to determine the expected future costs associated with monthly RA shortfalls throughout the planning horizon.

Table 7.6.1. Annual average market RA price forecasts for a System+Local RA product.

Year	Bundled RA Price ($/kW-mo)
2024	$12.50
2025	$15.00
2026	$14.00
2027	$12.00
2028	$11.50
2029	$11.00
2030	$10.00
2031	$9.75
2032	$9.50
2033	$9.25
2034	$9.00
2035	$9.00
2036	$9.25
2037	$9.50
2038	$9.75
2039	$10.00
2040	$10.25
2041	$10.50
2042	$10.75
2043	$11.00
2044	$11.25
2045	$11.50

Table 7.6.2. Monthly ratio multipliers for converting annual RA pricing into monthly prices.

Month	Ratio Multiplier
Jan	0.1538
Feb	0.1538
Mar	0.1538
Apr	0.3077
May	0.6154
Jun	1.2308
Jul	2.4615
Aug	2.4615
Sep	2.4615
Oct	1.2308
Nov	0.6154
Dec	0.1538

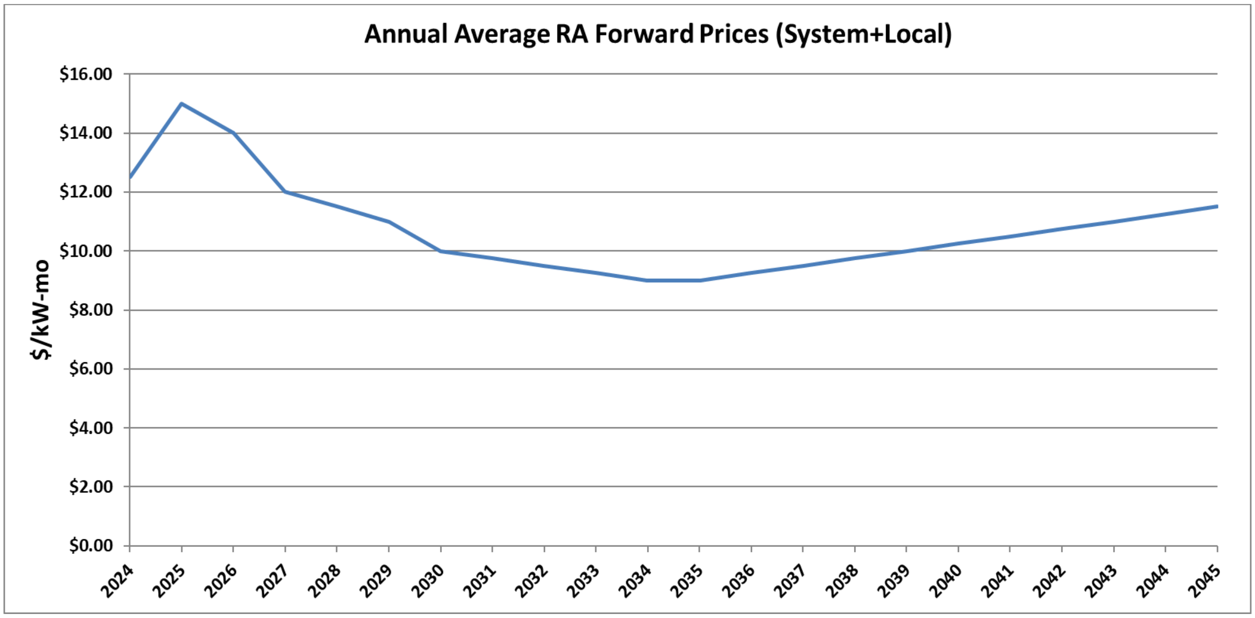


Figure 7.6.1. Annual average market RA Price forecast (System+Local): 2024-2045.

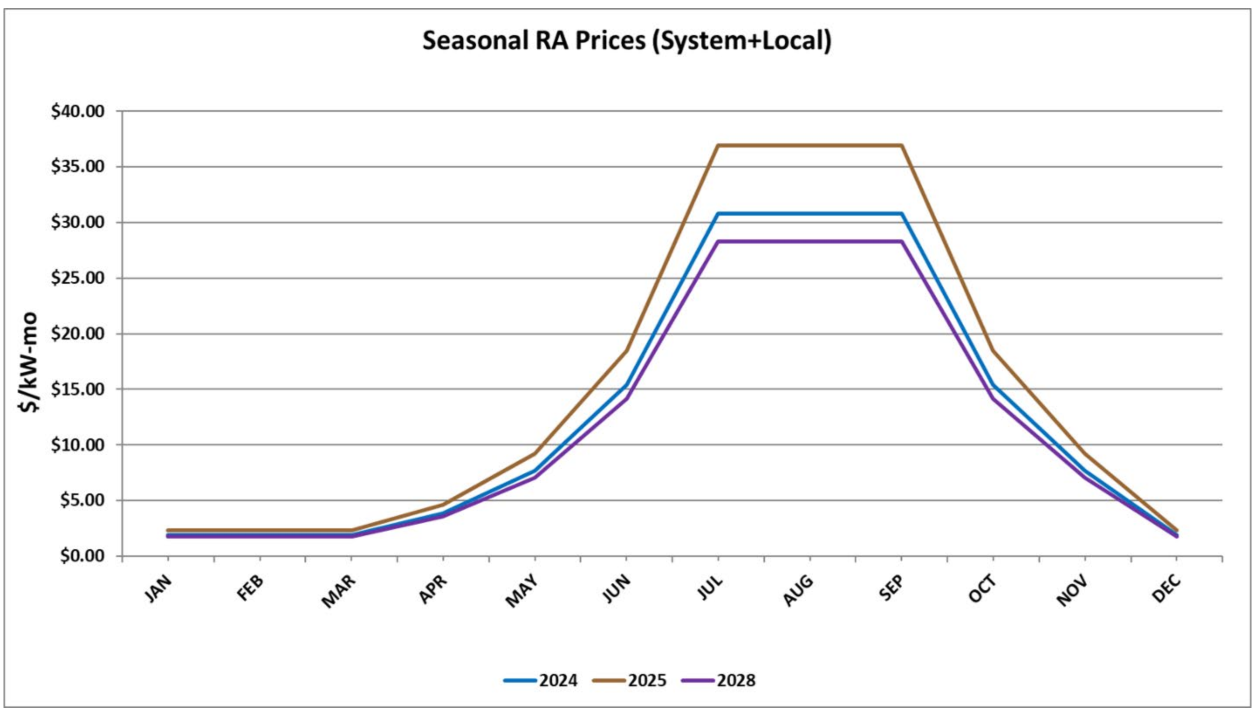


Figure 7.6.2. Monthly market RA Price forecasts (System+Local) for 2024, 2025, and 2028.

8. Intermediate Term (Five-Year Forward) Power Resource Forecasts

Chapter 8 presents a detailed overview of RPU's most critical intermediate term power resource forecasts. These forecasts quantify the metrics that the Planning Unit routinely analyzes, monitors, and manages in order to optimize RPU's position in the CAISO market and minimize the utility's associated load serving costs. The following metrics are discussed in detail in the indicated sections:

- Renewable energy resources and projected RPS %'s (8.1)
- Primary resource portfolio metrics (8.2)
- Net revenue uncertainty metrics (8.3)
- Internal generation forecasts (8.4)
- Forecasted hedging %'s and open energy positions (8.5)
- Forecasted GHG emission profiles and net carbon allocation positions (8.6)
- Five-year forward power resource budget forecasts (8.7)

All the analyses presented in this chapter have been performed using the Ascend Portfolio Modeling software platform. In practice, these forecasts can be (and are) updated on a weekly basis, to reflect the latest CAISO market conditions and associated forward energy price curves. The analyses presented in this chapter reflect late August 2023 CAISO market conditions.

8.1 Renewable Energy Resources and RPS Mandate

As discussed in Chapter 3 (Section 3.1), twelve renewable resources are currently delivering energy into the RPU portfolio. Furthermore, the Pattern/SunZia wind contract will begin delivering energy in 2026 and the Coso geothermal contract will step up to 30 MW/hour beginning in 2027. Figure 8.1.1 shows the utility's projected monthly RPS percentage levels for the 2024-2028 timeframe, before accounting for any excess REC sales that RPU may undertake to reduce budgetary pressure for rate increases. Since 2017, RPU has been significantly exceeding minimum California RPS mandates and this trend is expected to continue for at least the next five years. Additionally, it is worthwhile to note that all these renewable PPA's qualify as Portfolio Content Category 1 (PCC-1) products under the SB-2 and SB-100 paradigms and the above mentioned RPS percentages do not include any Category 3 Tradeable REC (TREC) products.

Table 8.1.1 quantifies some pertinent RPS statistics for the 2024-2028 timeframe, including the utility's expected versus mandated renewable percentages and associated GWh values. The expected excess RECs available to either sell or apply towards excess procurement are shown in the last column of Table 8.1.1, respectively. In 2022 RPU purchased 992.9 GWh of PCC-1 renewable energy, achieving an RPS of 45.4%. This RPS level is expected to remain approximately constant through 2025, before increasing significantly in 2026 and 2027. RPU expects to exceed its 60% by 2030 RPS mandate three years early (in 2027) and intends to apply all excess renewable energy that is not resold in the wholesale market towards excess procurement, to be used to meet future RPS compliance mandates.

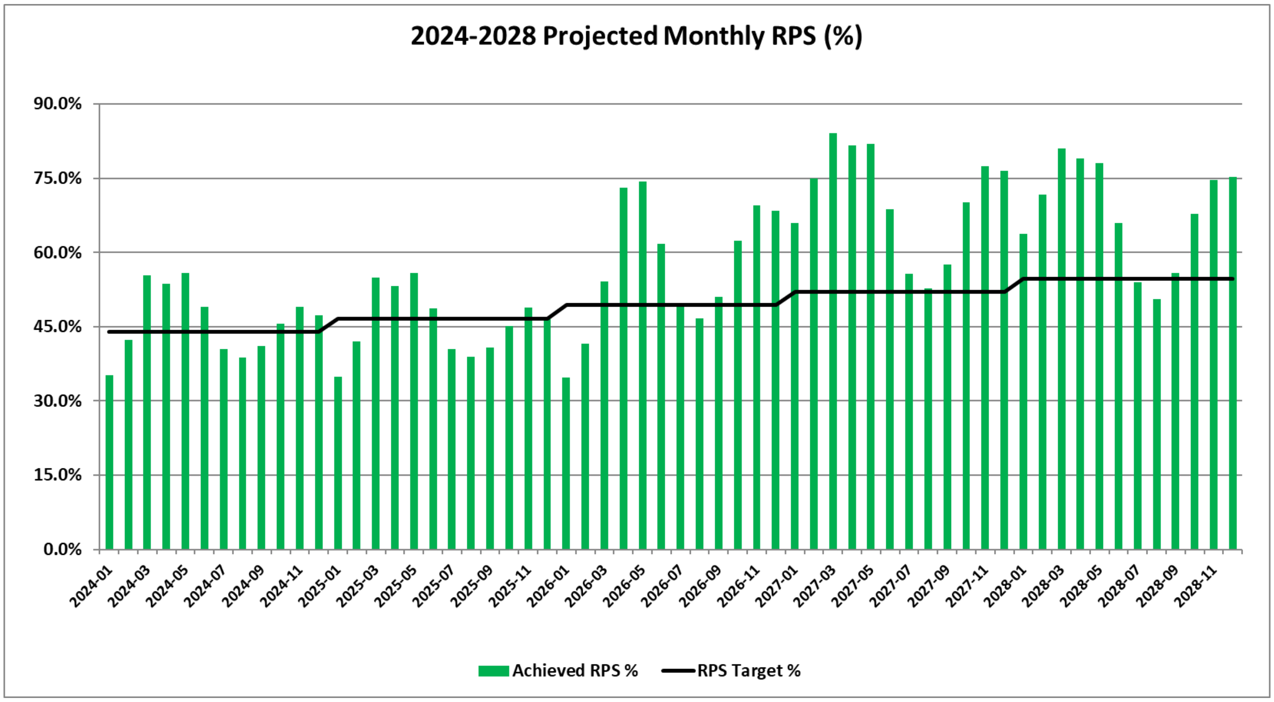


Figure 8.1.1. RPU five year forward renewable energy projections (2024-2028 timeframe).

Table 8.1.1. Pertinent RPU renewable energy statistics for the 2024-2028 timeframe.

Year	RPS Mandate (%)	Associated GWh Target	Expected RPS (%)	Expected GWh Amount	Expected Excess RECs (GWh)
2024	44.00%	953.49	45.66%	989.40	35.91
2025	46.67%	1,020.19	45.42%	992.82	(27.37)
2026	49.33%	1,091.00	56.82%	1,256.73	165.73
2027	52.00%	1,164.24	69.23%	1,549.95	385.71
2028	54.67%	1,242.06	66.83%	1,518.32	276.26
Total Excess Purchases over 5 Years (GWh):					836.24

8.2 Resource Portfolio: Primary Metrics

Figure 8.2.1 shows the utility's projected monthly resource stacks in conjunction with its expected system loads for the 2024-2028 timeframe. Over the next five years, 62% to 83% of the utility's expected system energy needs will be served using fixed-price contracts within the resource portfolio (including optional IPP natural gas energy), while another 4% to 5% will be served using internal generation assets (primarily during summer). The remaining 22% to 33% of energy needs will need to be acquired from the CAISO market, either via forward purchases or day-ahead market transactions.

In Figure 8.2.1 below, the "IPP NGCC-Decking" energy represents decremented IPP natural gas energy that is replaced with less expensive CAISO day-ahead market purchases. These market purchases quantify the amount of optional IPP energy that RPU can elect to not receive, under economic dispatch. For a few months in 2027, counting these excess IPP purchases creates (artificial) long energy positions. However, these "long" energy positions are typically less than the allowable amount of IPP-Decking energy and thus do not represent a long market position in the traditional sense. It should also be noted that in practice, the IPP resource can be "decked" in both the day-ahead and real-time CAISO markets. However, the Ascend software platform only simulates day-ahead energy prices, so these simulated energy volumes are constrained to only reflect day-ahead pricing conditions.

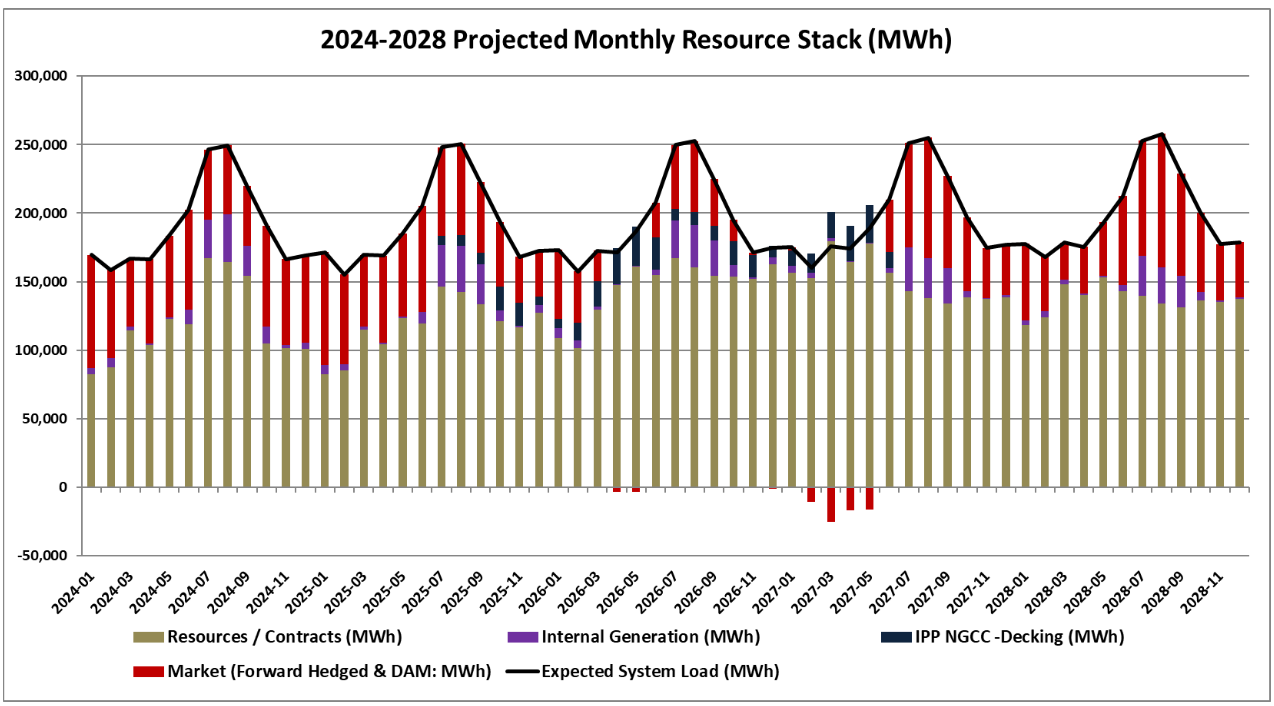


Figure 8.2.1. RPU five year forward resource stacks and system loads (2024-2028 timeframe).

Table 8.2.1 below quantifies the forecasted annual energy volumes attributable to the resource categories shown in Figure 8.2.1, along with RPU's expected system loads. These internal generation forecasts, optional IPP-decking energy calculations and net CAISO market purchase estimates will vary with the prevalent CAISO market conditions; the values shown in Table 8.2.1 are referenced to late August 2023 forward CAISO price forecasts. Note that the CAISO market purchases include both forward hedged energy contracts and net purchases in the day-ahead CAISO market. Additional details concerning the utility's forecasted internal generation are also presented in Section 8.4.

Table 8.2.1. 2018-2022 forecasted resource energy volumes and RPU system loads (GWh units).

Resource Stack	2024	2025	2026	2027	2028
Fixed resources/contracts	1423.35	1417.58	1753.88	1816.95	1641.37
Internal Generation	130.90	131.86	119.70	110.00	104.58
IPP NGCC-decking	0.00	63.69	186.58	109.51	0.00
Net Market purchases	736.49	697.62	277.72	330.26	655.67
RPU System Load	2290.73	2310.75	2337.89	2366.73	2401.62

8.3 Net Revenue Uncertainty Metrics

Both monthly and annual estimates of the net revenue uncertainty (NRU) associated with RPU's total power supply budget can be readily computed under the Ascend simulation modeling paradigm. These estimates are calculated by examining the financial results produced by all the production cost modeling simulation runs (typically N=100 runs per study). Note that these Ascend simulations reflect both weather induced load and market price volatility, in addition to the generator dispatch deviations likely to be seen in practice. Hence, these NRU estimates effectively quantify the uncertainty around RPU's power supply budget forecasts**.**

Figure 8.3.1 shows the 5th and 95th percentile estimates of the simulated monthly NRU for RPU's power supply budget. As shown in Figure 8.3.1, this revenue uncertainty is about ± 2 million dollars in 2024-2026, but more variable thereafter. In general, the NRU in any given month will be a function of the percentage of unhedged monthly energy combined with the potential for significant load deviations. Table 8.3.1 shows the corresponding annual NRU standard deviations; for the next five years these annual standard deviations are forecasted to increase from 6 M$ to 13 M$, respectively. Using the typical [1.65 x Std.Dev] rule, these estimates can be translated into expected 90% confidence intervals; these estimates are also shown in Table 8.3.1. These latter estimates suggest that RPU's forecasted net power supply budget costs could potentially either increase or decrease as much as 21.6 million dollars per year due to weather, load and/or market price volatility, respectively (in the absence of any further hedging activities).

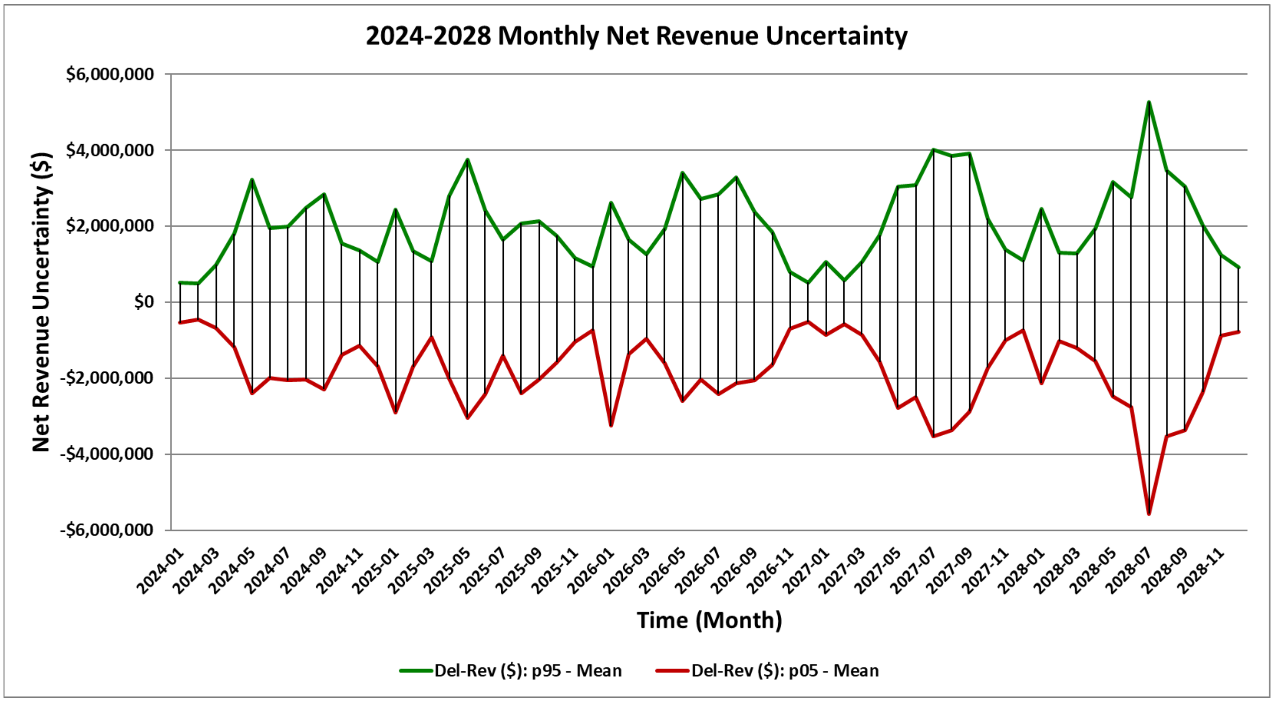


Figure 8.3.1. Monthly 5th and 95th percentile estimates of the net revenue uncertainty associated with RPU's power supply budget.

Table 8.3.1. 2024-2028 forecasted net revenue uncertainty standard deviations and corresponding 90% confidence intervals (units in millions of U.S. Dollars, nominal).

Metric/Statistic	2024	2025	2026	2027	2028
Annual NRU Std.Dev	5.97	8.67	9.78	10.56	13.10
Corresponding 90% CI	± 9.85	± 14.31	± 16.14	± 17.42	± 21.62

8.4 Internal Generation Forecasts

Figure 8.4.1 shows the utility's forecasted monthly internal generation amounts for the RERC, Springs and Clearwater cogeneration units for the 2024-2028 timeframe. Not surprisingly, about 80% of RPU's annual internal generation is expected to come from the four RERC units, and all these units mostly serve as summer (June-October) peaking resources. As discussed in Section 8.3, the Table 8.4.1 forecasted internal generation GWh volumes can move significantly in response to changing load, weather, and market prices.

Table 8.4.1 summarizes the expected generation levels, gas burns and net revenue estimates associated with these internal generation forecasts under traditional economic dispatch assumptions. The net energy revenue estimates account for the embedded carbon emission costs, but exclude all debt related financing costs (i.e., bond debt associated with the engineering, design, and construction costs). It should be noted that the current CAISO market is experiencing a deficiency in dispatchable generation and thus these dispatchable natural gas resources are forecasted to run more frequently than they have in the recent past for the next 2-3 years).

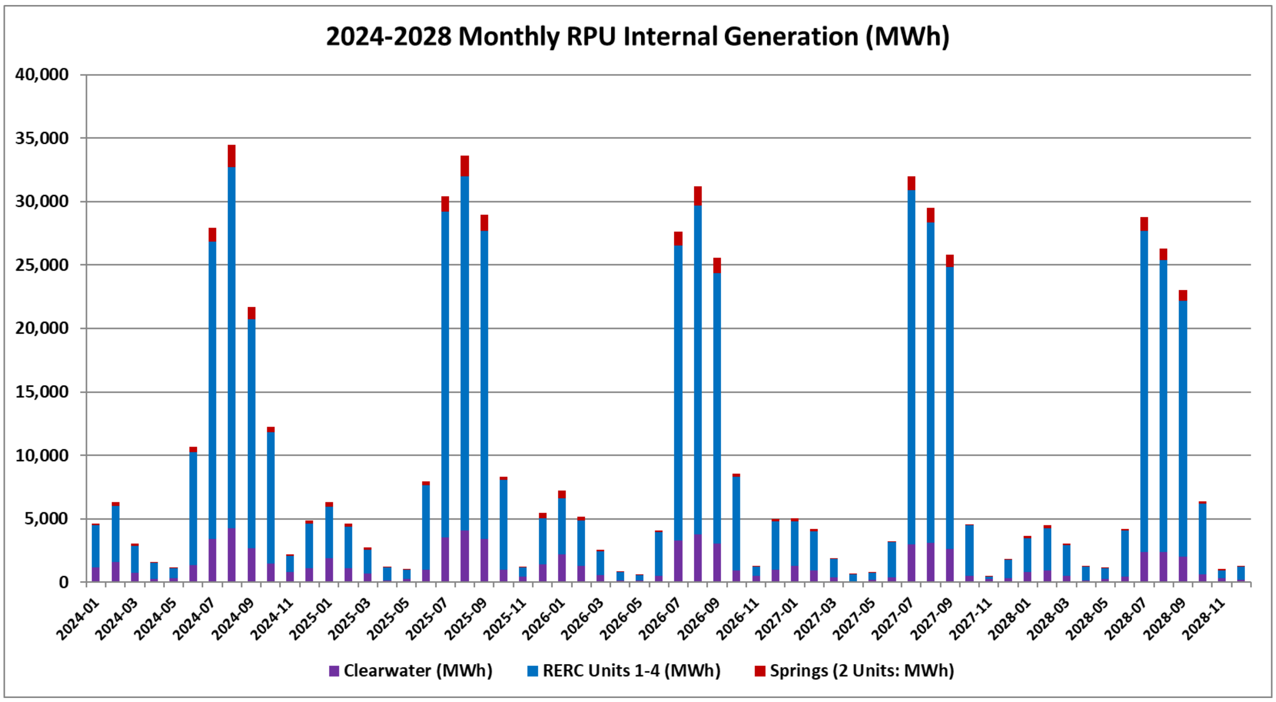


Figure 8.4.1. 2024-2028 forecasted monthly RPU internal generation amounts for RERC, Springs and Clearwater.

Table 8.4.1. 2024-2028 forecasted internal generation levels, gas burns and net revenue estimates.

Internal Generation	2024	2025	2026	2027	2028
Total generation (MWh)	130,897	131,857	119,704	110,005	104,584
Total gas burns (MMBtu)	1,274,148	1,284,002	1,165,668	1,068,562	1,017,657
Net revenue (nominal USD)	$13.22 M	$12.57 M	$11.36 M	$10.15 M	$9.75 M

8.5 Forecasted Hedging % and Open Energy Positions

RPU's current risk management strategy includes a conservative yet flexible hedging approach where fixed price natural gas and/or power purchases can be executed for delivery up to four years into the future. The primary goal of this hedging strategy is to preserve a reasonable degree of cash-flow (budget) certainty in the mist of potentially volatile forward natural gas and energy prices, by layering in fixed price purchases over time. RPU's Risk Management Committee (RMC) is responsible for establishing all acceptable energy and natural gas forward price limits and setting the annual and monthly hedging goals.

Currently, RPU quantifies its hedging needs using a volumetric measurement of the amount of fixed price energy in the portfolio, relative to its load serving needs. For any time period of interest (i.e., hour, day, month, etc.), staff define the Net Energy Position (NEP) to be the difference between the expected system load and all of the hedged energy resources. Formally, the NEP is calculated as follows:

NEP = Sys.Load – Total.Gen – Hedged.Power – (Hedged.NGas – Burned.NGas)/10 [Eq. 8.5.1]

In Eq. 8.5.1, all variables are expressed in either MWh or MMBtu units (for the appropriate time period) and defined as follows:

- Sys.Load = RPU's wholesale system load
- Total.Gen = all fixed-price energy produced by any resource, including any internal generation and all available IPP energy
- Hedged.Power = the total delivery amount of all fixed-price forward purchases + the expected amounts of any call options (defined as the strike probability x the strike volume) – the total delivery amount of all fixed-price forward sales – the expected amounts of any put options (again defined as the strike probability x the strike volume)
- Hedged.NGas = the total delivery amount of all fixed-price forward gas purchases + the expected amounts of any gas call options (defined as the strike probability x the strike volume)
- Burned.NGas = the total volume of NGas consumed by all internal generation units

Note that the factor of 10 for the NGas component is used to convert MMBtu natural gas amounts into approximate MWh energy amounts, using an assumed heat rate of 10 MMBtu/MWh. This adjustment is included in the NEP calculation in order to account for (i.e., adjust out) any economically dispatched, "un-hedged" internal generation. Additionally, the strike probabilities for all call and put options are determined under simulation. (For example, if an option is struck 15 times in 100 simulation runs then the strike probability would be calculated to be equal to 0.15. In turn, the expected energy delivery volume for this 10,000 MWh monthly call option would be 0.15 x 10,000 = 1,500 MWh, etc.)

In any given time period, the NEP can be positive or negative. Positive values indicate short energy positions, while negative values indicate long energy positions. (Since RPU tends to be short resources to serve its expected system load, during most months the NEP will generally be positive). Finally, the effective hedging percentage (H%) is a direct function of the NEP. Formally, it is calculated as

$H\% \; = \; 100 \times [\, Sys.Load - NEP] \,/\, Sys.Load$ [Eq. 8.5.2]

where the Sys.Load and NEP variables are defined as above. In any time interval when the NEP = 0, RPU is effectively 100% hedged for that time interval.

Figure 8.5.1 shows RPU's forecasted monthly hedging percentages for the 2024-2028 timeframe. The utility's risk management guidelines currently require that the H% for each prompt month must be within 85% to 115%; the Planning Unit coordinates with Market Operations to ensure that each prompt-month satisfies this constraint. As shown in Figure 8.5.1, 10 of the 12 forthcoming 2024 months already satisfy this constraint. However, in 2025 and beyond, a considerable amount of additional hedging still needs to be performed.

The RMC has also set the minimum annual H% targets shown in Table 8.5.1 for the 2024-2026 timeframe; RPU's current annual H% values are also shown in this table. These results show that RPU is not currently in compliance with respect to its annual targets in 2025; additional hedging activities need to be performed to bring this year into compliance.

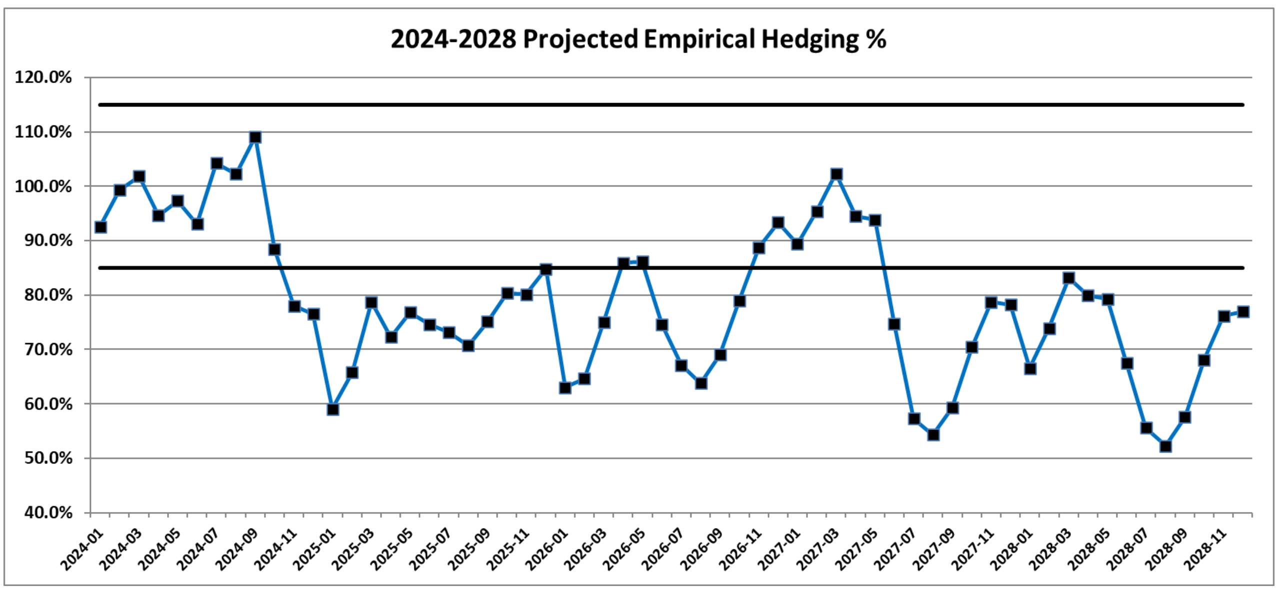


Figure 8.5.1. Forecasted monthly RPU hedging percentages for the 2024-2028 timeframe.

Table 8.5.1. RMC target versus current actual annual hedging percentages (H%); 2024-2028 timeframe.

Hedging Metric	2024	2025	2026	2027	2028
RMC Target Annual H%	90%	80%	70%	n/a	n/a
Current NEP (GWh)	101.25	594.21	580.87	546.63	757.43
Current Annual H%	95.6%	74.3%	75.2%	76.9%	68.5%

RPU has historically layered in its natural gas hedges over a two-to-three year forward window, while implementing its power hedges over a one-to-two year forward window. Part of this strategy has been driven by attractive Q3 market heat rates, along with the increased flexibility that natural gas hedges offer (e.g., the ability to trade out the gas for power under changing market heat rate conditions). RPU is currently still employing such a strategy, although it should be noted that the Utility relies almost entirely on forward power hedges to close open energy positions during non-Q3 months.

The NEP metric can be conveniently used to quantify open short or long energy positions on either a MWh or MW/h basis. Figure 8.5.2 shows the forecasted monthly open net energy positions on a MWh/month basis. Likewise, Figure 8.5.3 shows the corresponding monthly MW/h short (or if negative, long) LL and HL energy positions. In principle, if RPU were to buy LL and HL energy products that exactly match these positive net energy positions, the utility would achieve a 100% hedging percentage for each short month of the year. Likewise, if RPU were to "ramp down" its IPP energy to offset any long energy positions, the utility would again achieve a 100% hedging percentage for each long month of the year. Hence, these open net positions effectively define the deviations from the "ideal" hedging targets for the 2024-2028 timeframe.

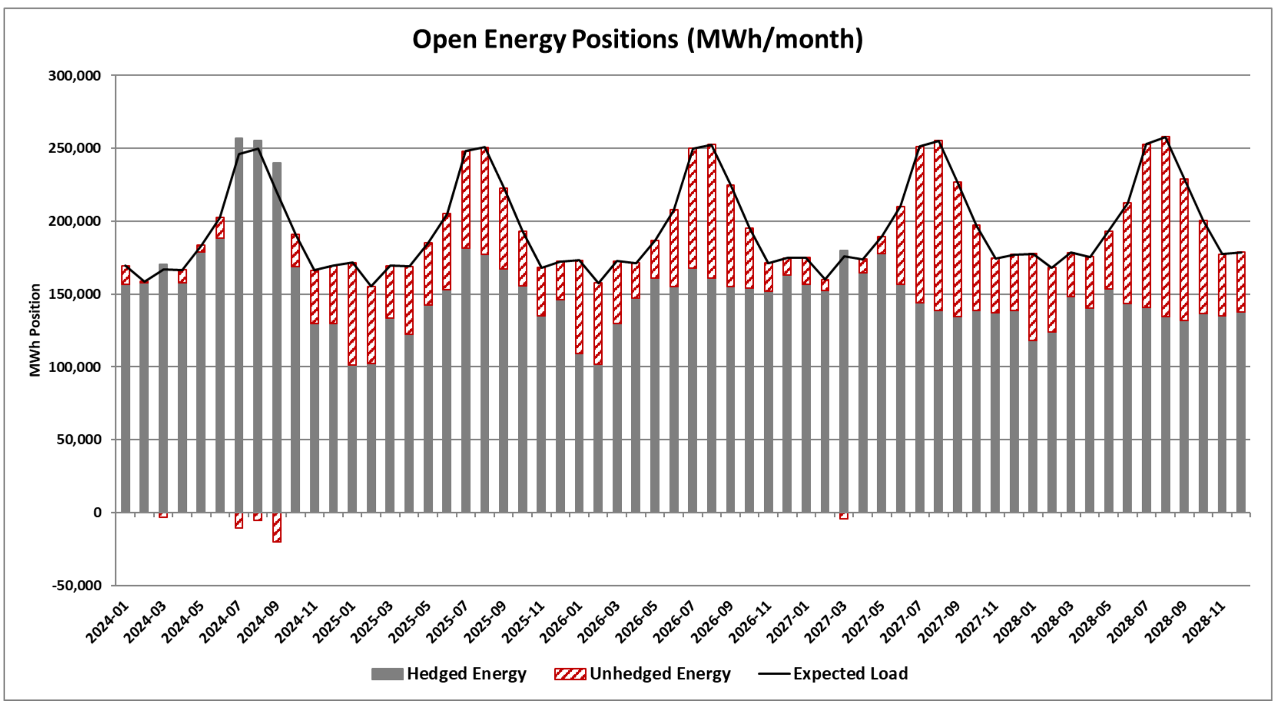


Figure 8.5.2. 2024-2028 forecasted monthly net energy positions (MWh/month).

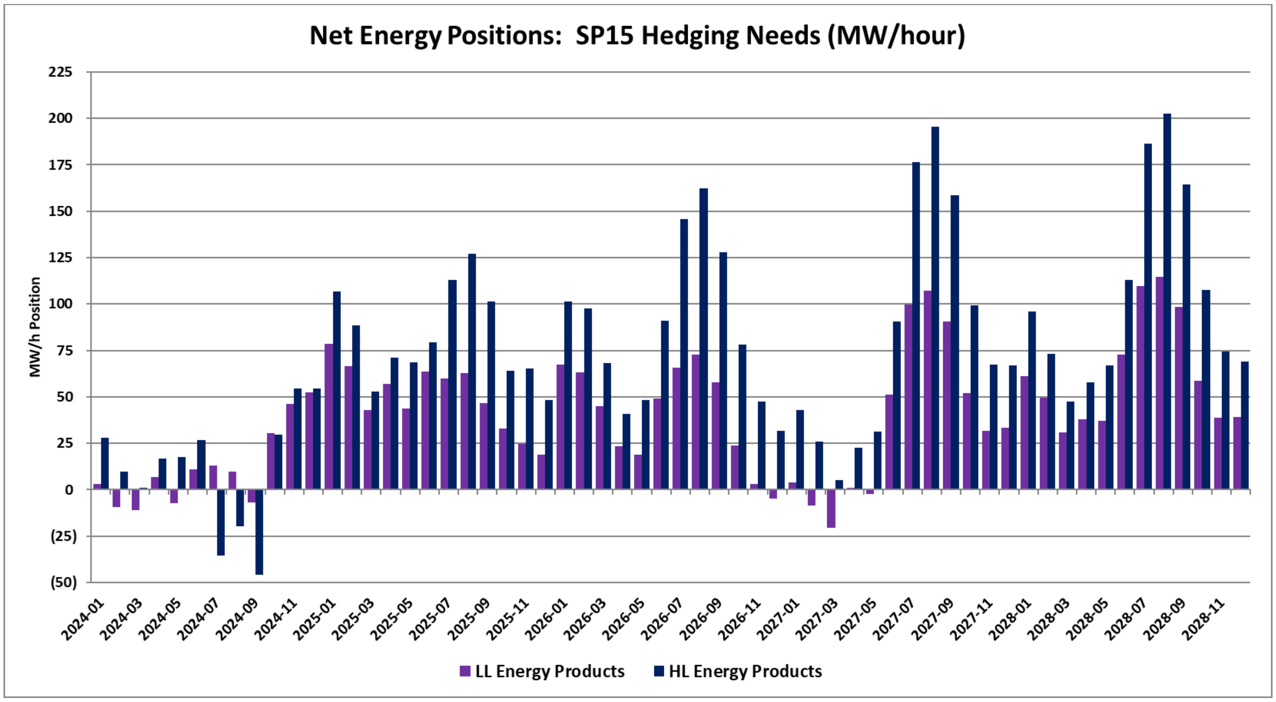


Figure 8.5.3. 2024-2028 NEP forecasted monthly open HL and LL energy positions (MW/hour).

As shown in Figures 8.5.2 and 8.5.3, RPU is reasonably well hedged for calendar year 2024. However, significant open energy positions are still present in 2025 and beyond, during both winter and summer months. Overall, this pattern of open energy positions represents the summed impact of the expiring IPP contract with the new energy from the SunZia/Pattern wind and Coso geothermal contracts. Additionally, the larger Q3 HL open positions reflect RPU's summer peaking energy needs, which cannot currently be met using any of the Utility's fixed priced contracts.

8.6 GHG Emissions, Allocations and Positions

The California Air Resources Board (CARB) is the lead regulatory agency implementing the AB 32 directives to reduce GHG emissions. CARB finalized its initial implementation of GHG regulations in early 2012, including the allocation of GHG allowances to all eligible California utilities for calendar years 2013 through 2020. In July 2017, AB 398 was passed by the state legislature and signed by the governor, extending the Cap and Trade program through 2030. Shortly thereafter, CARB approved the extension Cap-and-Trade Amendments, which included RPU's new 2021-2030 allowance allocations.

Table 8.6.1 shows RPU's annual allowance amounts for the 2024-2028 timeframe, along with RPU's annual forecasted 1st deliverer emission levels for this same period. Likewise, Figure 8.6.1 shows RPU's forecasted 1st deliverer carbon emission levels by resource, at a monthly granularity level. As can be seen in this figure, RPU's 1st deliverer emissions are expected to be substantially below its annual allowance amounts, due primarily to the fact that the Utility is transitioning out of the IPP coal to natural gas contract.

It should be noted that CARB is currently in the middle of a new rule-making process that includes a re-examination of the 2025-2030 allowance amounts for all CA load serving entities. Although the final outcomes of this new rule-making process remain to be determined, many CA utilities are concerned that a significant portion of their 2025-2030 allowances will be "clawed-back" by CARB. Table 8.6.2 provides a simplified, high-level assessment of such an impact; specifically, where it is assumed that 40% of RPU's 2025-2028 allowances are required to be forfeited to CARB and thus unavailable for monetizing in the auction. A comparison of the projected annual Auction Income amounts confirms that this 40% claw-back would substantially reduce the extra revenues RPU receives from the Cap-and-Trade program.

Table 8.6.1. RPU's annual carbon allocations, forecasted GHG emission profiles, allowance balances and projected auction income for the 2024-2028 timeframe.

	2024	2025	2026	2027	2028
CARB Allocations (mt)	1,015,558	1,000,815	991,145	799,554	609,032
RPU Emissions (mt)	352,185	224,346	199,194	109,610	54,104
Allowance Balance (mt)	663,373	776,469	791,951	689,944	554,928
Carbon Cost ($/mt)	$30.80	$32.95	$35.26	$37.73	$40.37
Auction Income ($000)	$20,431.8	$25,584.5	$27,924.1	$26,031.5	$22,402.4

Table 8.6.2. The 2024-2028 financial impacts from a hypothetical 40% reduction to RPU's annual carbon allocations (beginning in 2025).

	2024	2025	2026	2027	2028
CARB Allocations (mt)	1,015,558	600,489	594,687	479,732	365,419
RPU Emissions (mt)	352,185	224,346	199,194	109,610	54,104
Allowance Balance (mt)	663,373	376,143	395,493	370,122	311,315
Carbon Cost ($/mt)	$30.80	$32.95	$35.26	$37.73	$40.37
Auction Income ($000)	$20,431.8	$12,393.9	$13,945.1	$13,964.7	$12,567.8

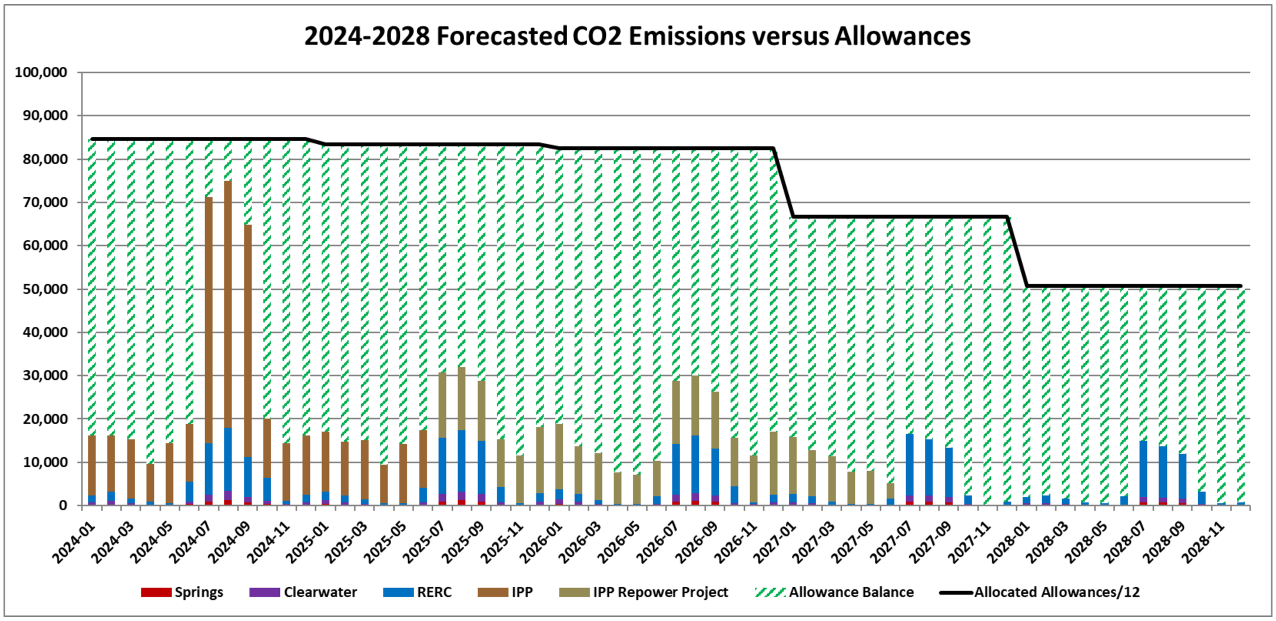


Figure 8.6.1. Forecasted monthly RPU carbon emission levels, by resource: 2024-2028 timeframe.

Regardless of the ultimate claw-back levels (if any), Tables 8.6.1 and 8.6.2 show that the surplus allowances monetized through the quarterly CARB Carbon auction process are expected to generate material amounts of additional revenue. Currently, it is anticipated that these Cap-and-Trade revenues will continue to be used to help offset costs associated with other legislatively imposed carbon reduction programs, such as the RPS program (e.g., to help offset RPU's incremental RPS costs associated with excess renewable energy purchases).

8.7 Five Year Budget Forecasts

All the previously discussed power resource components play an important role in determining RPU's overall power resource budget projections. Since a number of these forecasts are dependent on current CAISO market conditions, RPU has implemented a dynamically updated budget forecasting tool into the Ascend software platform. This forecasting tool produces updated Power Resources budget projections on a weekly basis, to better reflect the latest market price forecasts and generation stack conditions.

Table 8.7.1 presents a summary of RPU's FY 23/24 through FY 27/28 budget forecasts, as of August 18, 2023. As shown in Table 8.7.1, the utility's gross power supply costs are projected to be $254.2 M in FY 23/24, which represents a $27.1 M increase over the budget projections produced in October 2021. These cost forecasts increase further in FY 25/26 ($266.8 M) and FY 26/27 ($272.5 M), before decreasing somewhat in FY 27/28 ($259.7 M). Post-COVID supply chain issues, the Russia/Ukraine war, and the 2022 winter natural gas price blowouts have all caused forward market power costs to nearly double over the last two years, which has in turn driven up our power supply budget costs.

The lower portion of Table 8.7.1 also summarizes RPU's total expected budget costs and all primary category costs (Transmission, Energy, Capacity, and SONGS) on a $/MWh basis. Staff expects Transmission and Energy costs to continue to increase over the next four to five years, as the utility continues to decrease the GHG content of its portfolio. In contrast, Capacity costs are expected to decrease once RPU completely exits the IPP repowering contract.

Table 8.7.1. Five year forward power resource budget forecasts: fiscal years 23/24 through 27/28; all forecasts shown in $1000 units. October 2021 budget forecast for FY 23/24 also shown (gray column).

Summary	FY 23/24	FY 23/24	FY 24/25	FY 25/26	FY 26/27	FY 27/28
Gross Costs	$ 227,086	$ 254,241	$ 251,804	$ 266,826	$ 272,472	$ 259,739
Gross Revenue	$ (30,797)	$ (29,222)	$ (34,971)	$ (35,193)	$ (35,967)	$ (10,283)
Net Costs w/o CO2 Auction Revenue	$ 196,288	$ 225,019	$ 216,832	$ 231,633	$ 236,505	$ 249,456
Summary						
Transmission	$ 65,885	$ 66,340	$ 69,656	$ 72,952	$ 76,118	$ 53,768
Energy	$ 116,124	$ 136,966	$ 129,081	$ 145,103	$ 149,052	$ 165,550
Capacity	$ 35,436	$ 39,651	$ 41,896	$ 37,034	$ 36,626	$ 30,899
SONGS	$ 841	$ 841	$ 852	$ 862	$ 873	$ 884
Ice Bear	$ 141	$ 141	$ 143	$ 145	$ 147	$ 150
GHG Regulatory Fees	$ 182	$ 182	$ 191	$ 201	$ 211	$ 221
Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
Gas Burns + Net Hedge Cost or (Revenue)	$ 6,276	$ 7,920	$ 7,785	$ 8,328	$ 7,243	$ 6,067
Post 2030 Cap and Trade Cost	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL COST	$ 227,086	$ 254,241	$ 251,804	$ 266,826	$ 272,472	$ 259,739
CO2 Allowance Auction Revenue	$ (8,317)	$ (20,302)	$ (20,243)	$ (25,930)	$ (24,452)	$ (23,870)
TRR Revenue	$ (29,222)	$ (29,222)	$ (30,071)	$ (30,993)	$ (31,942)	$ (6,433)
PCC-1 RPS Sale	$ -	$ -	$ -	$ -	$ -	$ -
RA Capacity Sales Revenue	$ (1,575)	$ -	$ (4,900)	$ (4,200)	$ (4,025)	$ (3,850)
SUBTOTAL REVENUE	$ (39,114)	$ (49,525)	$ (55,215)	$ (61,122)	$ (60,419)	$ (34,153)
TOTAL NET COST w/o CO2 Auction Revenue	$ 196,288	$ 225,019	$ 216,832	$ 231,633	$ 236,505	$ 249,456
Summary (Cost/Gross Load)						
Adjusted Transmission	$ 15.52	$ 16.29	$ 17.22	$ 18.05	$ 18.78	$ 19.82
Energy	$ 49.16	$ 60.12	$ 56.16	$ 62.42	$ 63.35	$ 69.33
Capacity	$ 15.00	$ 17.40	$ 18.23	$ 15.93	$ 15.57	$ 12.94
SONGs	$ 0.36	$ 0.37	$ 0.37	$ 0.37	$ 0.37	$ 0.37
Total (all categories)	$ 83.09	$ 98.77	$ 94.34	$ 99.64	$ 100.53	$ 104.47

8.8 Summary of Results

Based on the forecast data presented in this Chapter, the following conclusions can be drawn concerning RPU's intermediate term resource positions.

- RPU continues to procure a significant amount of excess renewable energy, above and beyond the state's minimum mandated amounts. Since 2017, RPU has begun to accumulate excess renewable energy credits which can be used to meet future RPS compliance obligations, should any significant (and extended) future renewable resource outages occur. Currently, the utility expects to remain above a 44% RPS in 2024 and exceed the "60% by 2030" mandate three years early.

- Over the next five years, 62% to 83% of the utility's expected system energy needs will be served using fixed-price contracts within the resource portfolio (including optional IPP natural gas energy), while another 4% to 5% will be served using internal generation assets (primarily during summer). The remaining 22% to 33% of energy needs will need to be acquired from the CAISO market, either via forward purchases or day-ahead market transactions. These open energy positions will need to be forward hedged via longer term forward market purchases or through the contracting of additional resources. Currently, these unhedged positions can cause RPU's forecasted net power supply budget costs to potentially either increase or decrease as much as $21.6 M per year due to weather, load and/or market price volatility.

- RPU is expected to have more than enough carbon allowances to fully meet its direct emission compliance needs through 2028. Staff currently forecasts having an excess allowance balance of 550,000 to 800,000 credits annually; however, these excess allowance volumes might be substantially reduced under the CARB 2025 rulemaking process. Nonetheless, whatever excess credits remain are expected to be monetized through the CARB quarterly auction process, with a significant portion of the proceeds used to help offset RPU's excess renewable energy costs.

- As shown in Table 8.7.1, the utility's gross power supply costs are projected to be $254.2 M in FY 23/24, which represents a $27.1 M increase over the budget projections produced in October 2021. Unfortunately, these power supply cost forecasts are expected to remain elevated throughout the five-year planning horizon due to the impact of macro market conditions beyond the utility's control.

In summary, the utility is reasonably well positioned to meet its load serving needs over the next five years, but additional efforts will need to be undertaken to control RPU's power supply costs. With respect to energy needs, additional systematic forward hedging activities will be required to maintain cash flow stability. Additional resources may also need to be procured in the immediate term time horizon (i.e., in the next three to five years) to reduce the utility's net revenue uncertainty.

9 GHG Emission Targets and Forecasts

The fundamental purpose of the 2023 IRP process is to plan and assess the most cost-effective scenario for RPU to continue to reduce its GHG emissions, with the eventual goal being that the utility achieves a carbon-free (or near carbon-free) portfolio. Since 2018, CARB has specified and adopted Electricity Sector Greenhouse Gas Planning targets for 2030. Originally, the Electricity Sector's overall 2030 target was set to be at least 40% below the Sector's 1990 emission level, but more recently these targets have been increased significantly.

This chapter examines how much RPU's total GHG footprint is expected to change (i.e., decrease) over the next 7 years. This issue is examined from the perspective of how much renewable and carbon-free energy RPU expects to have in its portfolio through 2030 and if this supply will be enough to meet Riverside's CARB-assigned 2030 Planning Target.

9.1 Terms and Definitions

Before presenting any historical or forecasted RPU GHG emission levels, two terms need to be clearly defined. The following sections discuss both 1st Importer emissions and Total Portfolio emissions. 1st Importer emissions are precisely defined by CARB and subject to independent verification; these are the emissions that RPU (as a regulated entity) is required to report each year to CARB under their MRR reporting paradigm. Essentially, 1st Importer emissions are the emissions that RPU is legally responsible for and must surrender carbon allocation credits to offset.

In contrast, Total Portfolio emissions represent all the implied emissions associated with power that a utility uses to serve its native load. There is no consensus option over how to define this metric, but RPU interprets this to be the calculated GHG emissions associated with the physical power that is either generated within or scheduled into a CA balancing authority and used to serve load. More specifically, the utility's Total Portfolio emission levels can be calculated by assigning resource specific emission factors to all resources that have been (or will be) used to serve RPU load, then multiplying these factors by the annual amounts of energy received from each resource. Note that a default 0.428 emission factor is used for all unspecified system power (e.g., net CAISO market purchases) in these calculations. Additionally, the carbon emissions from all load-serving fossil-fuel resources are included in this calculation (whether they generate enough electricity to have a CARB MRR reporting obligation or not) and all PCC-1 renewable resources are assumed to be carbon-free.

9.2 1990 GHG Emissions Profile

For reference, RPU's 1990 1st Importer and Total Portfolio emission estimates are shown in Table 9.2.1. These emission levels have been calculated by multiplying the utility's financially reported FY-89/90 and FY-90/91 power supply data with the best available resource specific emission factor information available to the utility (see Table 9.2.1 notes for details). Under the original AB 32 legislation, the overall goal for each sector of the CA economy was to achieve at least a 40% reduction in their emissions over their 1990 levels. For the Electricity Sector, this goal entailed that the Sector reduce their overall emissions down from 108 MMT (1990 level) to at least 65 MMT. However, as of August 2023, CARB is now calling for the Electricity Sector to reduce its emissions down into a range of 30 to 38 MMT.

Table 9.2.1. Calculated RPU 1990 1st Importer and Total GHG emission levels.

Power Supply (MWh)				Emission Factor (MT CO2e)	Transmission Loss Multiplier	Calculated MT CO2e
Resource	1990/1991	1989/1990	Average	2014	Imports Only	1990
San Onofre	264,500	239,500	252,000	0.000	0.00	-
Intermountain Power	697,800	795,400	746,600	0.923	1.02	703,021.4
Palo Verde	84,700	27,800	56,250	0.000	1.02	-
Hoover	33,700	24,100	28,900	0.000	1.02	-
Firm contracts	358,300	314,000	336,150	0.999	1.02	342,535.8
Non firm contracts	79,000	77,600	78,300	0.428	1.02	34,182.6
Southern California Edison	36,000	47,200	41,600	0.428	1.00	17,804.8
Totals:	1,554,000	1,525,600	1,539,800			1,097,544.7

2014 ARB Emission Factors	
Bonanza Power Plant	1.030
Hunter Power Plant	0.968
Intermountain Power Project	0.923
Unspecified Imports	0.428

Emission Intensity Factor:	0.7128
1st Importer Intensity Factor:	0.7012
Total GHG Emissions:	**1,097,545**
1st Importer Emissions:	**1,079,740**

Notes: Firm contracts are assumed to be imports from Deseret.
Deseret has two generation units, Bonanza Power Plant and Hunter Power Plant.
Emission factor for Deseret is the average of that of Bonanza and Hunter.
Non firm contracts are assumed to be unspecified imports.
Southern California Edison assumed equal to unspecified imports (for total emission intensity calculations).
For 1st Importer emissions, SCE energy is treated like CAISO energy (i.e., no reporting requirement).

9.3 CEC POU-Specific GHG Emission Reduction Targets

As shown above, RPU had an estimated Total GHG emission level of 1,079,740 metric tons (MT) in 1990. However, the CARB-assigned 2030 Planning Target for Riverside now ranges from 349,000 MT (high target) down to 275,000 MT (low target). Thus, CARB is essentially directing RPU to reduce its carbon emissions by at least 65% below its 1990 levels, and if possible, by as much as 74%. Details concerning these latest CARB Planning Targets can be found in CARB's August 2023 GHG Planning Targets: Draft 2023 Update report.

In their report, CARB listed individual utility targets for the 16 largest POUs based on two different electricity sector targets: 30 and 38 MMT CO_2-e. CARB has endorsed this target range for the

POUs and proposes that each POU should choose one or more targets within this range for integrated resource planning purposes. Hence, for planning purposes RPU has elected to focus on these target levels.

Under the 38 MMT sector target, RPU's utility specific target is 349,000 MT CO_2-e. Likewise, under the 30 MMT sector target, RPU's utility specific target is 275,000 MT CO_2-e. RPU is electing to use the higher 349,000 MT target for official planning purposes. However, in this IRP process staff will examine the costs and implications of supply and demand expansion strategies for also reaching the lower target. Table 9.3.1 below summarizes these two GHG planning targets, respectively.

Table 9.3.1. The two RPU GHG planning targets analyzed in this IRP.

GHG Planning Target	Description	MT CO2-e Emission Value
38 MMT Sector Goal	Official RPU target	349,000
30 MMT Sector Goal	More aggressive GHG reduction scenario	275,000

9.4 Historic RPU Emissions: 2011-2022

RPU has been actively trying to incrementally reduce its GHG emissions since the enactment of AB 32. Table 9.4.1 lists the utility's 1st Importer emissions and Total Portfolio emissions from 2011 through 2022 (rounded to the nearest 100 MT); note that the 1st Importer values represent verified emissions. The general downward trends apparent in both profiles are a direct result of the decision in 2012 to begin economically dispatching incremental IPP energy subject to its embedded carbon costs, and RPU's commitment to procure significant amounts of new renewable resources to meet anticipated future load growth and replace the utility's lost SONGS energy.

It should be noted that these historic 1st Importer emissions are primarily a function of how much dispatch coal energy RPU received from IPP. In contrast, the Total Portfolio emissions tend to reflect the incremental increase in carbon-free renewable energy that has entered RPUs portfolio since 2012. It is also worthwhile to note that RPU's average Total Portfolio emission level from 2011-2015 (~1,090,300 MT) was almost identical to the utility's 1990 emission level, even though the 2011-2015 retail loads were nearly 50% higher. Furthermore, since 2015, both RPU's 1st Importer and Total Profile emissions have been steadily decreasing.

Table 9.4.1. RPU 1st Importer and Total Portfolio GHG emissions: 2011-2022.

Year	Total Portfolio Emissions ($MT\ CO_2$-e)	1st Importer Emissions ($MT\ CO_2$-e)
2011	1,060,800	947,800
2012	1,125,100	716,400
2013	1,052,200	705,700
2014	1,212,700	865,400
2015	1,000,600	604,100
2016	972,100	594,300
2017	949,600	665,600
2018	905,000	632,400
2019	821,600	557,000
2020	753,000	472,800
2021	766,500	548,800
2022	679,100	387,300

9.5 RPU GHG Emission Forecasts through 2030

The following steps were used to forecast future RPU GHG emissions through 2030. First, all 1st Importer emissions were calculated for the average hourly dispatch amounts of all thermal generation that currently exist in the utility's portfolio and then summed up to their annual values. Second, the future expected renewable energy amounts associated with the Coso geothermal and Pattern/SunZia wind facilities were then added into the portfolio, in line with their expected start dates (see Table 3.1.1). Third, the difference between the total annual generation level of this thermal + renewable resource stack and the forecasted retail load level was then assumed to be met using unspecified CAISO market purchases (having a default emission factor of 0.428 tons of carbon per MWh).

In addition to adopting the above-mentioned forecasting methodology, the following assumptions were also incorporated into the portfolio dispatch simulations:

- The IPP coal plant retires on June 30, 2025 and is replaced with a combined cycle natural gas (CCNG) plant exhibiting an emissions factor at least as low as 0.428. This replacement natural gas energy is then used to satisfy the final two years of IPP contract energy deliveries to RPU through 2027.
- RPU does not enter into any new tolling agreements with any other CCNG plants between now and 2030.
- As previously described in Chapter 3, all remaining generation assets in RPU's portfolio perform as expected through 2030 (or until the end of their contract periods).

Finally, as will be discussed in Chapter 11, a new renewable is assumed to be incorporated into RPU's portfolio beginning January 1, 2030. This resource will either be a 50 MW baseload geothermal asset with an 84% capacity factor (CF, or a 120 MW solar PV facility (35% CF) collocated with a 50 MW / 200 MWh BES system; in either case, this 2030 resource will add approximately 368,000 MWh more renewable energy into RPU's portfolio. However, for the sake of transparency, two projected 2030 carbon emission amounts have been computed in this analysis (e.g., both with and without either of these new assets in the portfolio).

Figure 9.5.1 summarizes both the historical to date and forecasted future RPU GHG emissions through 2030. The upper green line quantifies RPU's Total Portfolio emissions under the assumption that a new resource is brought online in 2030, while the lower purple line quantifies the utilities 1st Importer emission liabilities. Finally, note that the orange deviation off the green line shows the expected Total Portfolio emissions without a new 2030 resource.

As shown in Figure 9.5.1, RPU expects to get below its official GHG target of 349,000 MT whether the utility adds another renewable resource into its portfolio by 2030 or not. Furthermore, if a new renewable resource is added, RPU should easily get below the more aggressive 275,000 MT target. These forecasted reductions in carbon emissions are a direct result of the utility's commitment to replacing its coal and CCNG assets with increasing procurements of renewable energy resources.

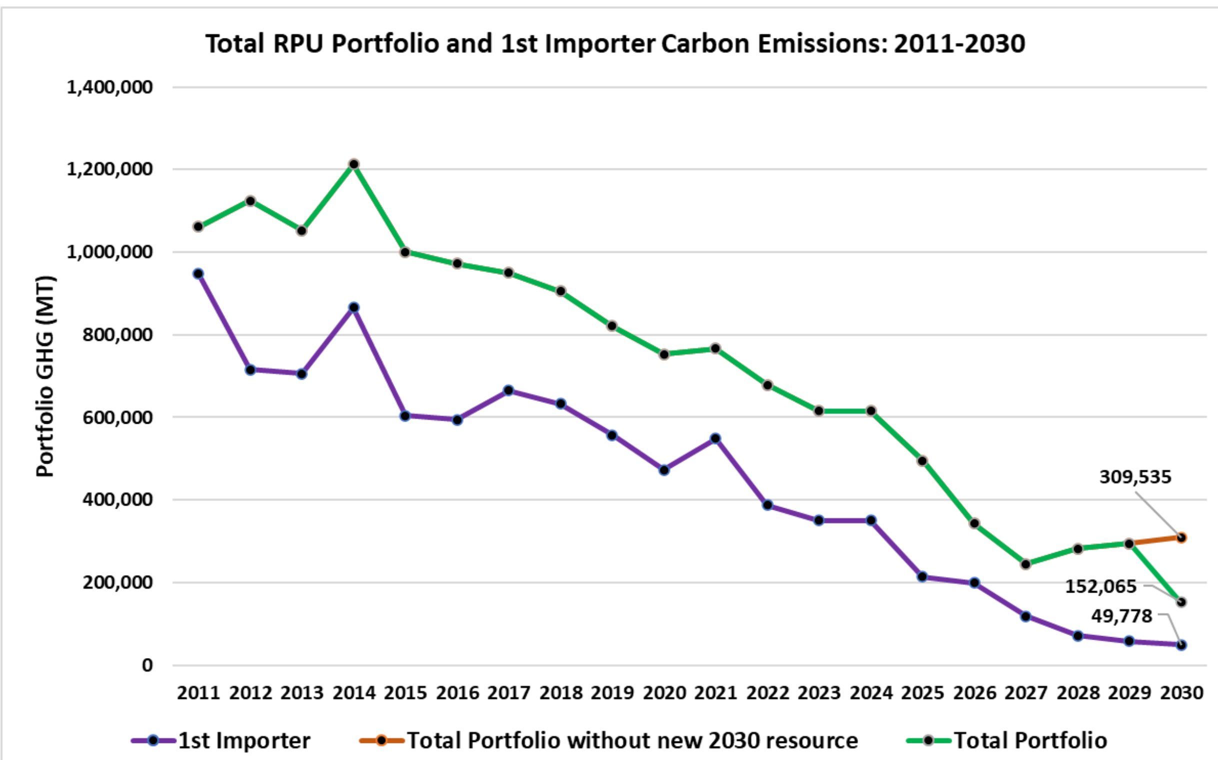


Figure 9.5.1. Historical and forecasted RPU 1st Importer and Total Portfolio GHG emission levels through 2030, both with and without the new 2030 renewable resource.

10. Future Resource Adequacy Capacity Needs

This chapter provides an overview of the CAISO's Resource Adequacy (RA) Paradigm, RPU's specific RA requirements, and RPU's existing RA capacity versus its forecasted planning reserve margin in the 2024 to 2045 timeframe. RPU's RA capacity needs increase over time, primarily driven by Riverside's forecasted peak load growth rate and the expiration of capacity resources. RPU will need to procure short-term RA products in the next 5 years and add new capacity resources to its portfolio longer term to meet its forecasted planning reserve margin.

10.1 Current CAISO Resource Adequacy Paradigm

Resource Adequacy (RA) is a planning and procurement process used to ensure that capacity exists and is under contract so load serving entities (LSE) can serve all their load and ensure that the CAISO can meet its operational needs and maintain reliability. Under the current CAISO RA paradigm, LSEs must secure enough capacity resources to meet their share of the peak load plus any applicable reserve margin, as well as local and flexible capacity requirements. The CAISO's current RA tariff provisions require each LSE to submit a year-ahead forward showing and month-ahead showings of resources to demonstrate that it has satisfied its capacity requirements. Capacity resources that LSEs can procure to satisfy these requirements are categorized as System capacity, Local capacity, and Flexible capacity. System capacity is capacity from any resource that is qualified for use in meeting system peak demand and planning reserve margin requirements. Local capacity can count as System capacity and come from any capacity resource that is located within an LSE's Local capacity area, as defined by the CAISO, and capable of contributing toward the amount of capacity required in that particular area. Flexible capacity is capacity from a system and/or local capacity resource that is operationally able to respond to dispatch instructions and manage variations in load and variable energy resource output. A brief discussion of each type of capacity requirement as well as RPU's specific requirements follows. However, the primary focus of this chapter will be on RPU's system RA capacity requirement.

10.1.1 System Capacity Requirement

The system RA requirement is based on coincident peak load and developed using a system coincident peak demand forecast study. The California Energy Commission (CEC) develops the forecast for the CAISO balancing authority area through its Integrated Energy Policy Report (IEPR) proceeding. Each year, LSEs within the CAISO submit load forecasts to the CEC, and the CEC adjusts the forecasts for system coincidence by month. LSEs must provide sufficient capacity to meet their coincidence adjusted monthly peak load forecast plus a planning reserve margin. The default planning reserve margin in the CAISO tariff is 15%. This is also RPU's officially adopted planning reserve margin, although since 2021 the utility has been voluntarily meeting a 16% to 17% planning reserve margin during summer months.

Figure 10.1.1 shows RPU's forecasted coincidence-adjusted[1] monthly system peaks and system RA requirement for 2024 through 2045. For this IRP, RPU's system RA requirement or planning reserve margin is assumed to be 115% of its monthly peak forecast in 2024; from 2025-2045, it is assumed to be 115% November-May and 117% June-October.

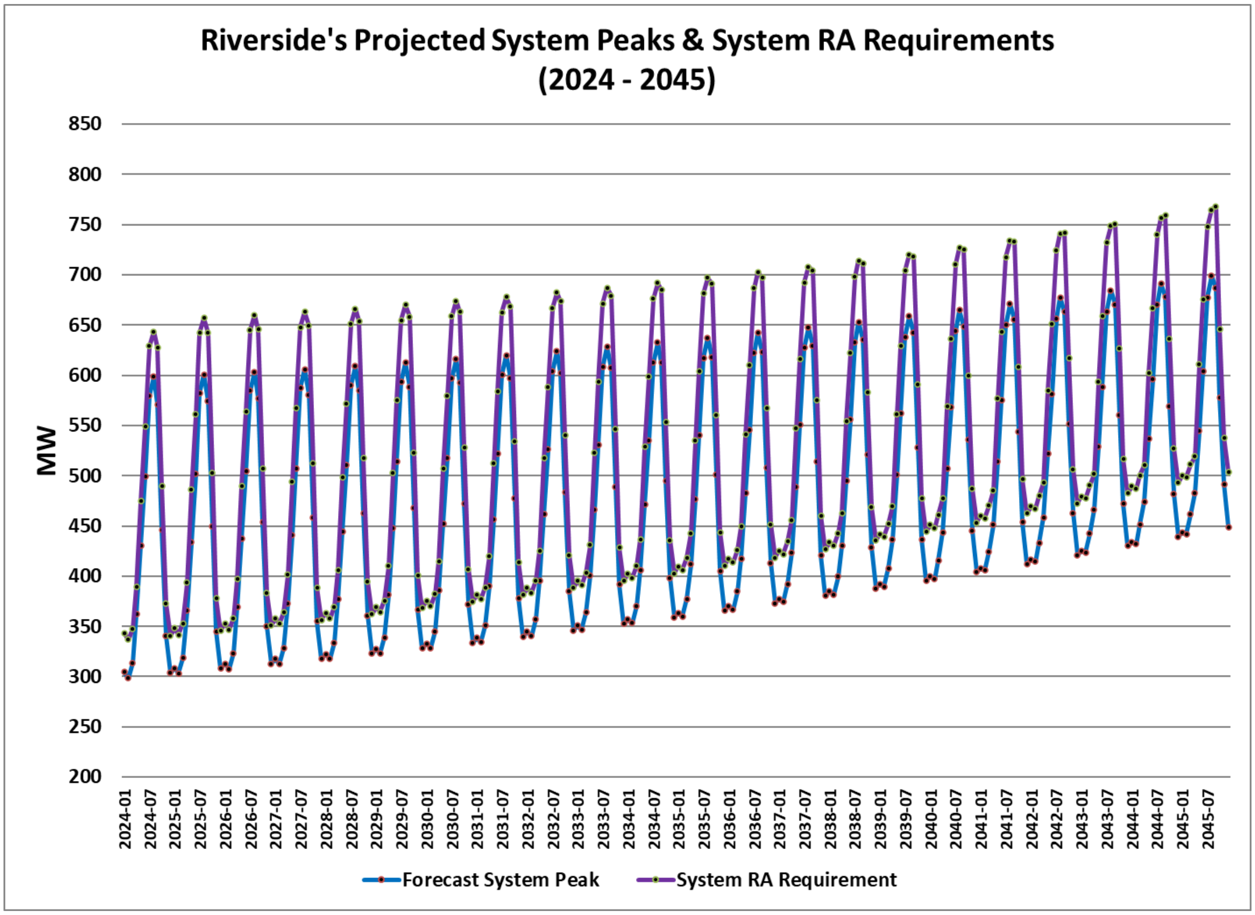


Figure 10.1.1. Riverside's forward system peaks and system RA requirement (2024-2045 timeframe).

[1] RPU's forecasted system peaks have been adjusted for CAISO's coincident peak using a 5-year average of RPU's CEC-determined monthly coincident peak factors.

10.1.2 Local Capacity Requirement

The RA local capacity requirement is a subset of system RA requirements and represents the minimum resource capacity that needs to be procured and made available to the CAISO in specific local areas, as determined in the CAISO's annual Local Capacity Technical Report,[2] to reliably operate the grid. In the technical study, the CAISO uses a "load pocket" concept, where load within a local area may exceed transmission capacity available to deliver resources into that local area. The CAISO determines the RA local capacity requirement annually and is the same MW amount for all months of the year. An LSE has a local requirement in each Transmission Access Charge (TAC) area in which it serves load.

RPU only serves load in one TAC area and therefore has only one local RA requirement. Riverside's local RA requirements for 2015 through 2024 are shown in Figure 10.1.2. Over this 10-year timeframe, Riverside's local RA requirement has trended downward. Moreover, as discussed in Chapter 3, Riverside owns 258 MW of local natural gas generation assets that counts as local RA. Given the downward trend of its local RA requirement and sufficient local capacity resources in its portfolio, RPU anticipates being able to satisfy its local RA requirements through the late 2030s. Therefore, RPU's future local RA requirements will not be explored further in this chapter.

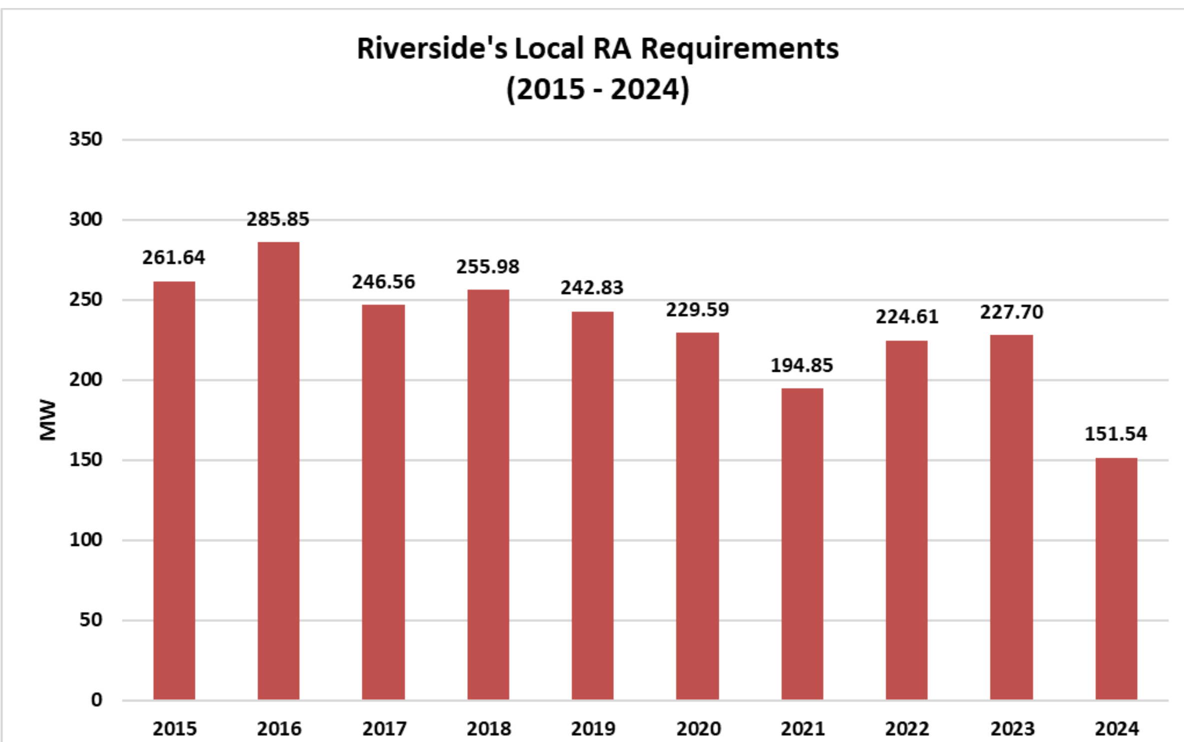


Figure 10.1.2. Riverside's local RA requirements for the past 10 years (2015-2024).

[2] http://www.caiso.com/Documents/Final2023LocalCapacityTechnicalReport.pdf

10.1.3 Flexible Capacity Requirement

The RA Flexible capacity requirement is also a subset of system RA requirements. The CAISO determines its flexible capacity need through an annual Flexible Capacity Needs Assessment[3]. The flexible capacity needs assessment is based on the largest three-hour net load (load minus wind and solar) ramp for the system in each month. Based on the system's operational needs, the CAISO divides its flexible capacity needs into three categories – Base Flexibility, Peak Flexibility, and Super-Peak Flexibility. These categories are based on the characteristics of the system's net load ramps and define the mix of resources that can be used to meet the system's flexible capacity needs. Certain use-limited resources, such as those with starts or emissions limitations, may not qualify to be counted under the base flexibility category and may only be counted under the peak flexibility or super-peak flexibility categories, depending on their characteristics. Although there is no limit to the amount of flexible capacity that can come from resources meeting the base flexibility criteria, there is a maximum amount of flexible capacity that can come from resources that only meet the criteria to be counted under the peak flexibility or super-peak flexibility categories. The CAISO allocates flexible RA capacity needs to LSEs based on their contribution to the net load ramp. LSEs end up with a MW requirement that varies by month. LSEs must annually demonstrate sufficient capacity to cover their share of the net load changes.

Figure 10.1.3 shows Riverside's average overall flexible RA requirement by month from 2015-2023. Note that this overall flexible RA requirement is the sum of the Base, Peak, and Super-Peak requirements as presented in the previous paragraph. Since 2015, Riverside's overall flexible RA requirement has been about 100 MW. With over 200 MW[4] of flexible RA resources, Riverside has comfortably met this requirement. Although Riverside's requirement will increase as it adds additional wind and solar (variable) resources to its portfolio, Riverside's excess flexible capacity along with newly contracted flexible capacity resources are expected to satisfy this requirement through the late 2030s. Moreover, the Flexible RA paradigm might be redesigned or retired in the next few years as part of the CAISO's Resource Adequacy Enhancements Phase 2 Initiative[5]. Therefore, given RPU's sufficient flexible capacity position and potential uncertainty surrounding the Flexible RA paradigm, RPU's future Flexible RA requirements will not be explored further in this chapter.

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[3] http://www.caiso.com/InitiativeDocuments/Final2023FlexibleCapacityNeedsAssessment.pdf

[4] Riverside's flexible RA resources – RERC and Clearwater – count for 194 MW and 8 MW of flexible RA, respectively.

[5] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Resource-adequacy-enhancements

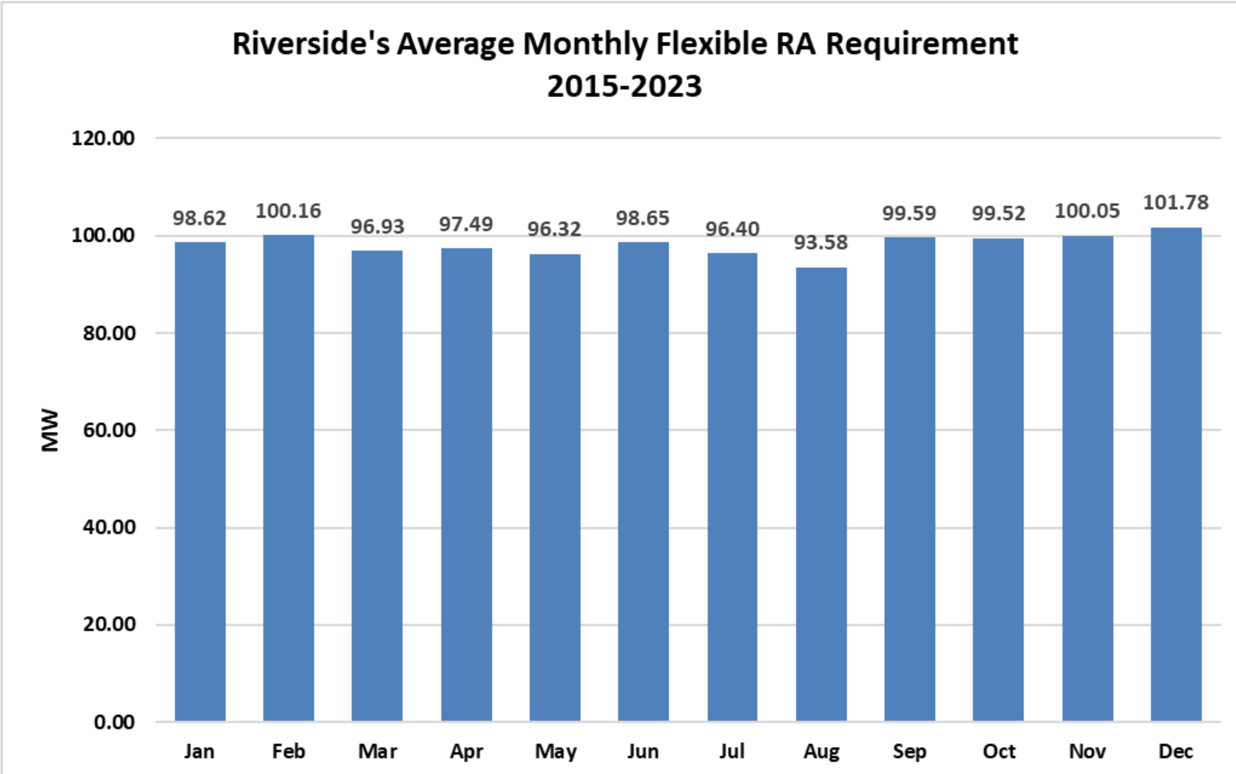


Figure 10.1.3. Riverside's average overall flexible RA requirement by month from 2015-2023.

10.1.4 CAISO Maximum Import Capability

An additional component of the CAISO's RA paradigm is Maximum Import Capability (MIC). MIC represents the maximum simultaneous deliverability of all imports used in the RA process and is required for LSEs to receive RA credit from imports. Each year, the CAISO assesses the deliverability of imports using the MIC calculation methodology and calculates MIC values for each intertie for a one-year term and allocated to LSEs using a 13-step process[6,7]. MIC allocations are not assigned directly to external resources; rather they are assigned to LSEs who choose the portfolio of imported resources they wish to elect for utilization of their MIC allocations to claim RA credit. An LSE's RA showings designating import MWs to meet RA obligations across interties are required to be used in conjunction with a MIC allocation and are considered a firm monthly commitment to deliver those MWs to the CAISO at the specified interconnection point with the CAISO system.

[6] CAISO Tariff section 40.4.6.2: http://www.caiso.com/Documents/Section40-ResourceAdequacyDemonstration-SCs-CAISOBAA-asof-Aug12-2019.pdf
[7] Reliability Requirements Business Practice Manual sections 6.1.3.5-9: https://bpmcm.caiso.com/BPM%20Document%20Library/Reliability%20Requirements/BPM%20for%20Reliability%20Requirements%20Version%2073.docx

Unfortunately, receiving a MIC allocation is subject to many conditions and is not guaranteed. One condition that has impacted RPU's ability to secure MIC allocations for new import resources is that an LSE's pre-existing, grandfathered MIC allocations cannot exceed its CAISO load share quantity. RPU is in this situation, having grandfathered MIC allocations for its legacy import resources, and consequently, is disallowed from nominating for additional MIC until the very end of the 13-step nomination process when remaining MIC allocations are either limited or no longer available. RPU expects this to remain the case until the grandfathered IPP contract expires in June 2027 at which point its grandfathered MIC allocations will have decreased enough that it should be eligible to receive additional MIC, particularly for its CalEnergy Portfolio resource and anticipated SunZia Wind resource. With the MIC allocation process however, there is still the risk that RPU receives insufficient MIC allocations to count a resource's eligible capacity for RA. In recent years however, RPU has had success bilaterally purchasing MIC from other CAISO participants, and RPU expects this to continue until sufficient MIC can be obtained via the MIC allocation.

Given the MIC allocation issues, for the capacity needs assessment presented in this IRP chapter, RPU makes the following assumptions with respect to its major import RA resources:

- RPU will receive between 11 MW and 24 MW of capacity credit from Hoover through the entire time horizon.
- RPU will receive 12 MW of capacity credit from Palo Verde through the entire time horizon.
- RPU's capacity credit from IPP will decrease to 64 MW in July 2025, when the IPP coal plant is retired, and a new IPP natural gas plant begins operation.
- RPU stops receiving the 64 MW capacity credit from the IPP natural gas plant in June 2027, when it exits the project.
- RPU will bilaterally purchase enough MIC to count the 86 MW of RA capacity credit from the CalEnergy Portfolio contract through December 2027 and assumes that sufficient MIC allocation will be obtained thereafter.
- RPU will purchase approximately 35 MW of MIC to count RA capacity credit from the new Sunzia Wind resource.

10.2 Riverside's System RA Requirements and RA Capacity

Figure 10.2.1 shows RPU's (1) expected monthly firm capacity amounts associated with its current resource portfolio, (2) forecasted 1-in-2 system peaks, and (3) system RA reserve margin requirements for the 2024-2045 timeframe. As shown in the figure, beyond 2024 (2024 RA has already been purchased), RPU will need to procure additional RA capacity to meet its forecasted 1-in-2 peak and reserve margin, especially in Q3. In the near term, RPU's capacity shortfalls are manageable, and RPU can fill them with year-ahead RA product purchases. In the longer term, RPU's capacity shortfalls become more significant as capacity resources retire, and contracts expire[8]. RPU will continue to need

[8] As discussed in Chapter 3, nearly all RPU's contracts that extend beyond 2030 are scheduled to expire before 2045.

short-term RA products but will also need to add additional resources to its portfolio that provide RA capacity.

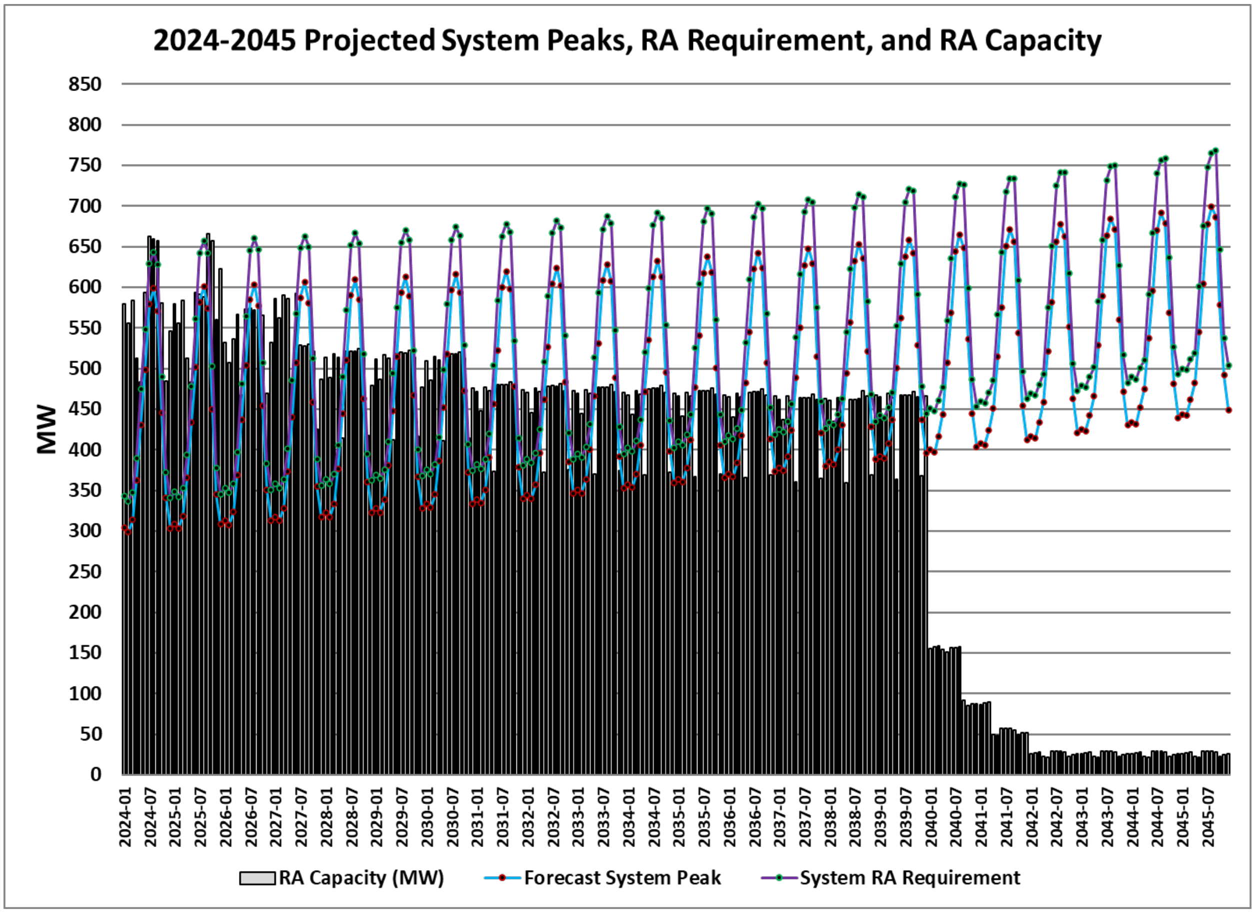


Figure 10.2.1. Riverside's forward capacity projections, system peaks and RA needs (2024-2045 timeframe).

The following sections split the discussion of RPU's capacity needs into three time-horizons: a five-year period from 2024 through 2028, a five-year period from 2029 through 2033, and a 12-year period from 2034 through 2045. The discussions highlight significant drivers of RPU's capacity needs during each period.

10.2.1 Capacity, System Peaks and Resource Adequacy Needs (2024–2028 time-horizon)

Figure 10.2.2 presents RPU's capacity needs during the 2024-2028 timeframe. A few notable changes in RPU's capacity stack occur in this timeframe. First, RPU expects a new 15-year capacity contract on an 80 MW / 320 MWh BESS to start providing 80 MW of capacity credit to RPU in late 2025. Second, RPU expects to begin receiving up to 35 MW of capacity credit from the new SunZia Wind Energy project in Q2 2026, provided that RPU obtains the necessary MIC. Third, the IPP coal plant will be retired by June 2025, and RPU will begin taking its 7.617% share in the project from a smaller 840 MW natural gas combined cycle (NGCC) plant. When this occurs, RPU's capacity credit from IPP will drop from 136 MW to 64 MW. Lastly, the IPP contract will expire after June 2027, at which point RPU will exit the IPP NGCC plant and lose the 64 MW of capacity credit from its portfolio.

With these expected changes in its capacity stack, as shown in Figure 10.2.2, RPU has enough capacity in its resource stack to meet its expected 1-in-2 system peaks and system RA requirements in most months outside of Q3. The exceptions are months such as May and November when some of RPU's capacity resources typically go offline for maintenance. To fill capacity shortfalls in this 5-year timeframe and fully meet its reserve requirement, RPU will need to forward purchase additional RA products. Table 10.2.1 shows the expected cost forecasts to fill short RA needs over the next five years. Note that RA for 2024 has already been purchased, and the expected cost shown for that year represents actual purchase costs. Over the next five years, RPU anticipates spending 95.335 million dollars[9] to satisfy its RA obligations. This amount also includes an estimated cost[10] to purchase the necessary MIC.

[9] Using assumed RA pricing discussed in Chapter 7.
[10] The assumed MIC pricing is $3/kW-month.

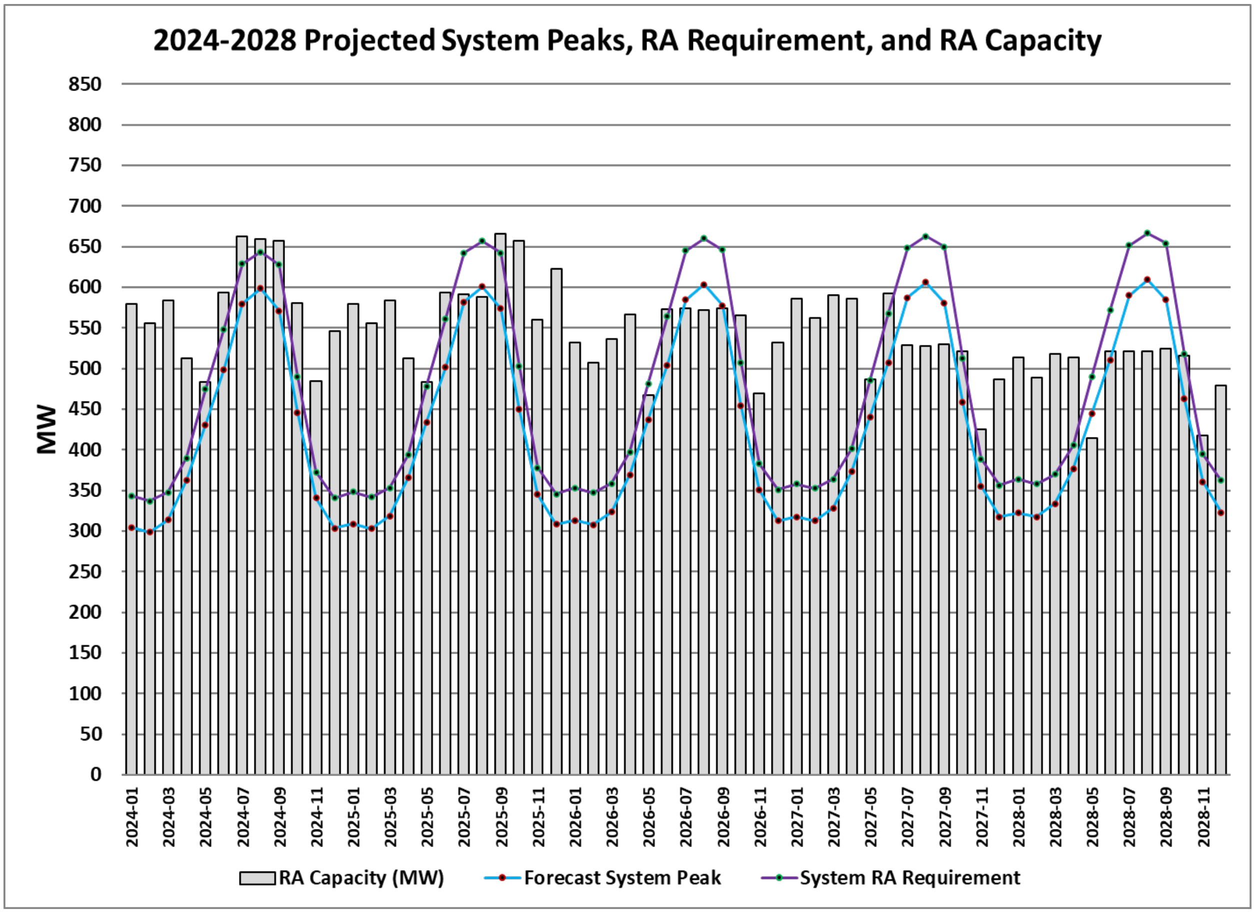


Figure 10.2.2. Riverside's 5-year forward system peaks and capacity projections (2024-2028 timeframe).

Table 10.2.1. 2024-2028 short RA positions and expected RA cost forecasts.

Year	Total RA Needs (MW)	Average Annual RA Cost ($/kW-month)	Expected Cost (million $)
2024	0	n/a	13.147
2025	120.22	$15.00	19.938
2026	244.93	$14.00	19.114
2027	374.90	$12.00	21.950
2028	532.97	$11.50	21.251
		Total 5-Year Cost Forecast ($):	95.400

10.2.2 Capacity, System Peaks and Resource Adequacy Needs (2029-2033 time horizon)

Figure 10.2.3 presents RPU's capacity needs during the 2029-2033 timeframe. The notable change to RPU's capacity stack during this timeframe is the anticipated retirement of the Springs Generation Facility after December 2030, a loss of 36 MW of capacity credit that will need to be replaced. RPU's RA capacity shortfalls each year are apparent between May and November. During Q3, monthly shortfalls are upwards of 210 MW by 2033. RPU will still need to procure RA products to fill some of the shortfalls in this timeframe. However, for the bulk of these shortfalls, RPU will need to add additional energy and capacity resources to its portfolio. Potential resource additions are explored in Chapter 11.

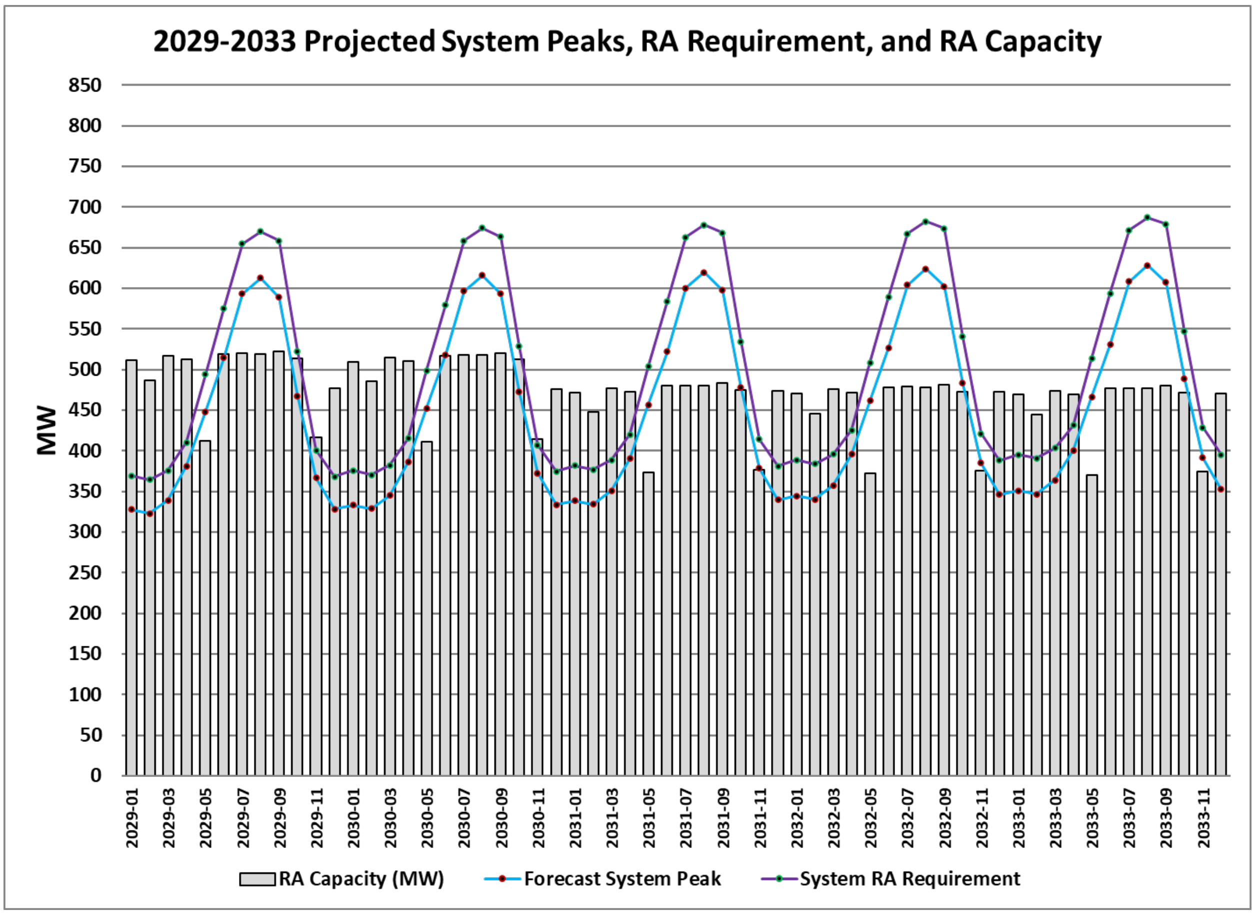


Figure 10.2.3. Riverside's forward capacity projections, system peaks and RA needs (2029-2033 timeframe).

10.2.3 Capacity, System Peaks and Resource Adequacy Needs (2034-2045 time horizon)

Figure 10.2.4 shows RPU's capacity needs for the final 12 years of this IRP's study horizon – 2034 through 2045. With anticipated retirements of RERC 1-4 after December 2039, combined with almost all RPU's contracted resources expiring, RPU's capacity needs are significant. RPU will be planning to add additional energy and capacity resources to fulfill these RA shortfalls during this period. Potential resource additions are explored in Chapter 11.

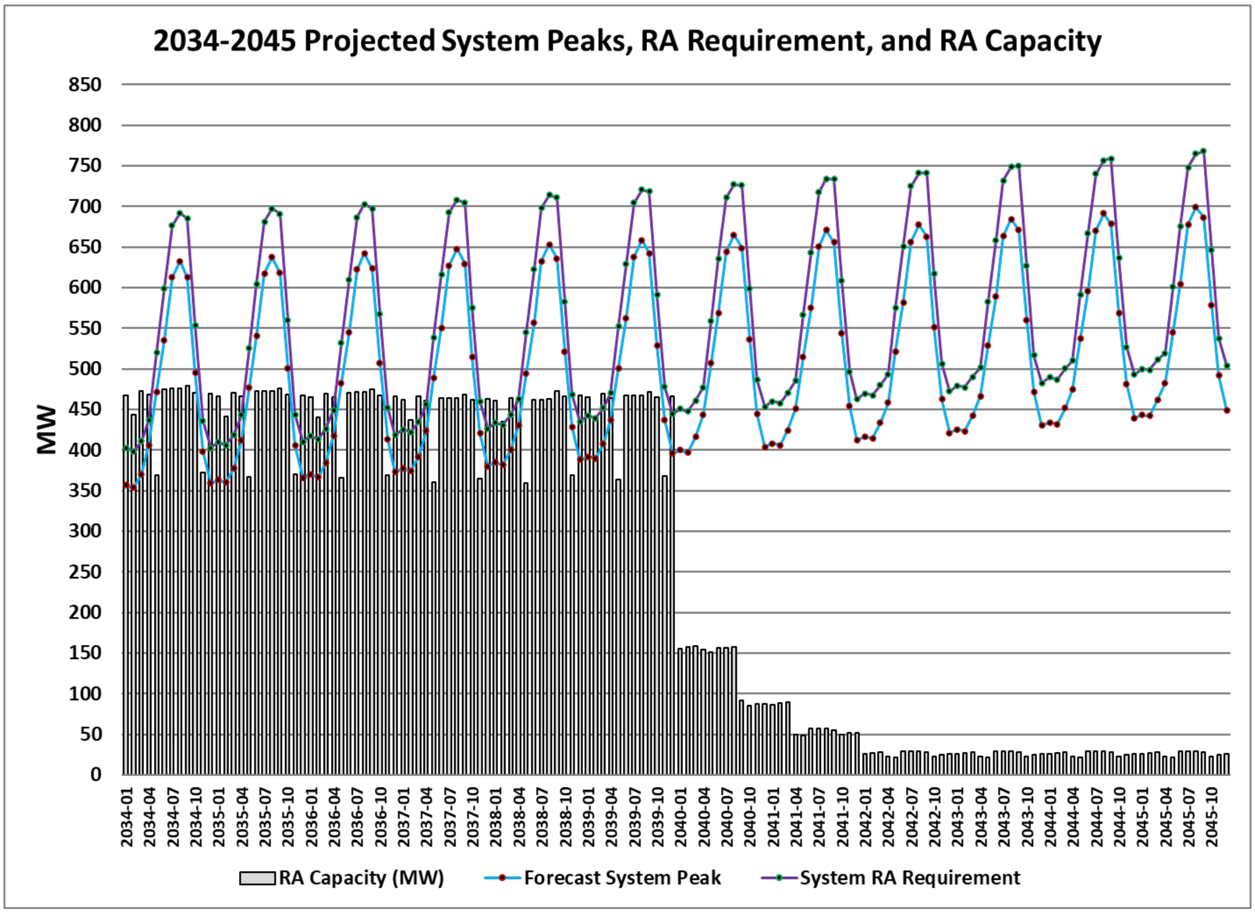


Figure 10.2.4. Riverside's forward capacity projections, system peaks and RA needs (2034-2045 timeframe).

10.3 Net-Peak Demand

The specific resources available to meet energy and reliability needs during the hour of net-peak demand is an important consideration required under PUC Section 9621. To assess RPU's position, staff has created net-load curves by subtracting RPU's hourly intermittent solar and wind generation from its hourly wholesale load, for a typical winter and summer day in 2022 and 2028. RPU's net load in 2022 reflects its current portfolio of intermittent renewable resources; its net load in 2028 reflects the addition of the new SunZia wind project that is expected to come online by Q2 2026.

RPU's wholesale and net load for a typical winter day in February 2022 and 2028 are shown in Figures 10.3.1 and 10.3.2. In the winter, RPU sees lower wholesale loads and a flatter diurnal wholesale load curve, with the wholesale peak load occurring in HE19. In contrast, RPU's net load curve clearly shows the impact of solar and wind generation, particularly when solar is producing energy between HE07 and HE17. However, the net-peak load coincides with the wholesale peak load at HE19, even when considering the additional wind expected by 2028.

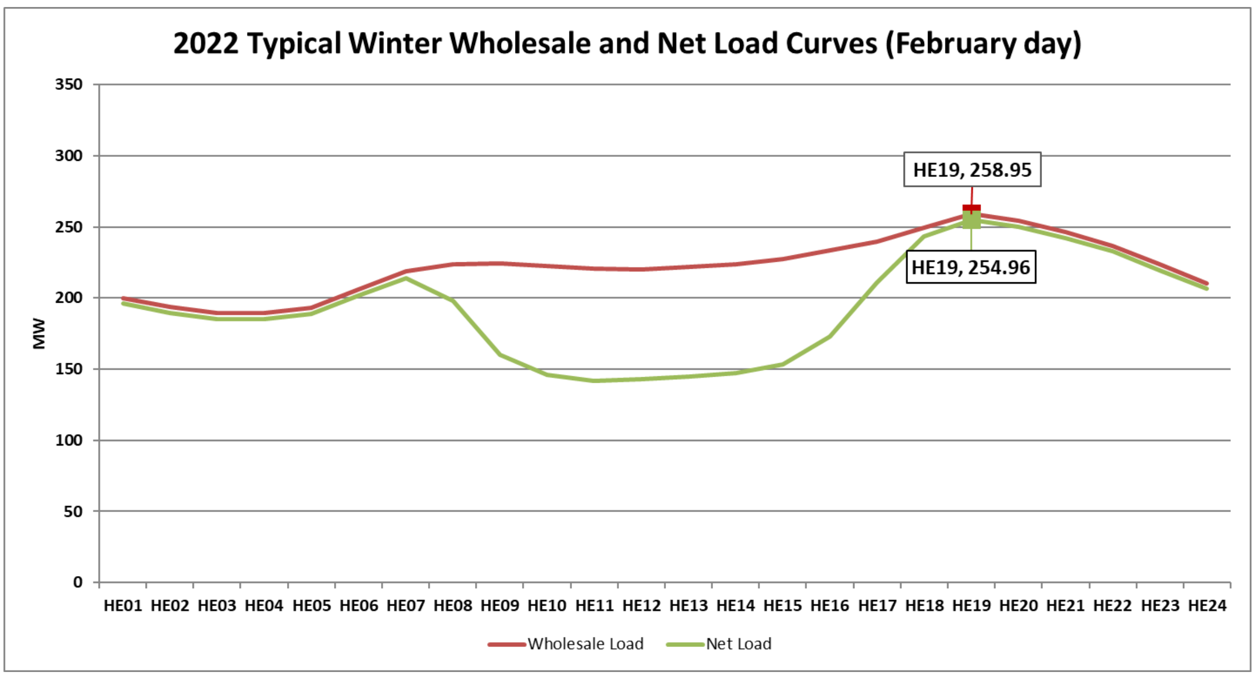


Figure 10.3.1. Riverside's diurnal wholesale and net load curves for a typical winter day in 2022.

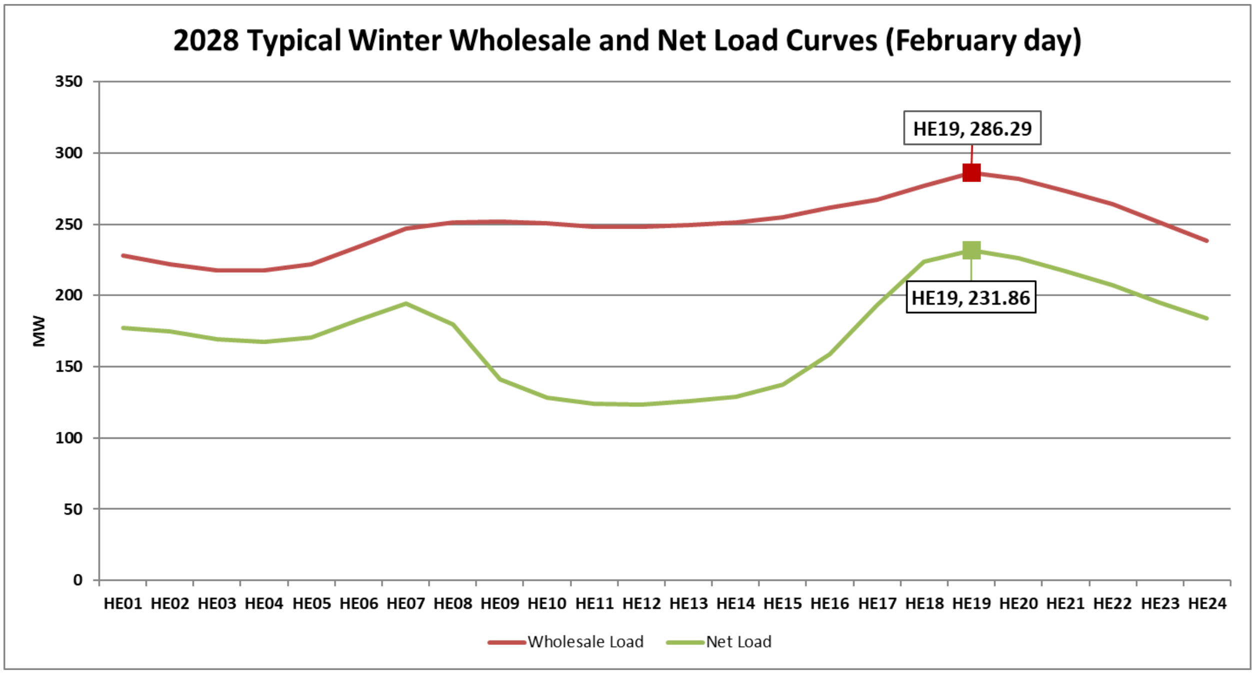


Figure 10.3.2. Riverside's diurnal wholesale and net load curves for a typical winter day in 2028.

RPU's wholesale load and net load for a typical summer day in August 2022 and 2028 are shown in Figures 10.3.3 and 10.3.4. RPU is a summer peaking utility, driven by high temperatures and air conditioning load, so in contrast to winter, its summer wholesale loads are higher with a well-defined peak in the late afternoon at HE17. Because of the higher loads, RPU's summer net load curve is an improvement from a reliability standpoint, as it is flatter and has a lower peak than the summer wholesale diurnal load curve. The net peak load occurs at HE18 in 2022 and HE19 in 2028.

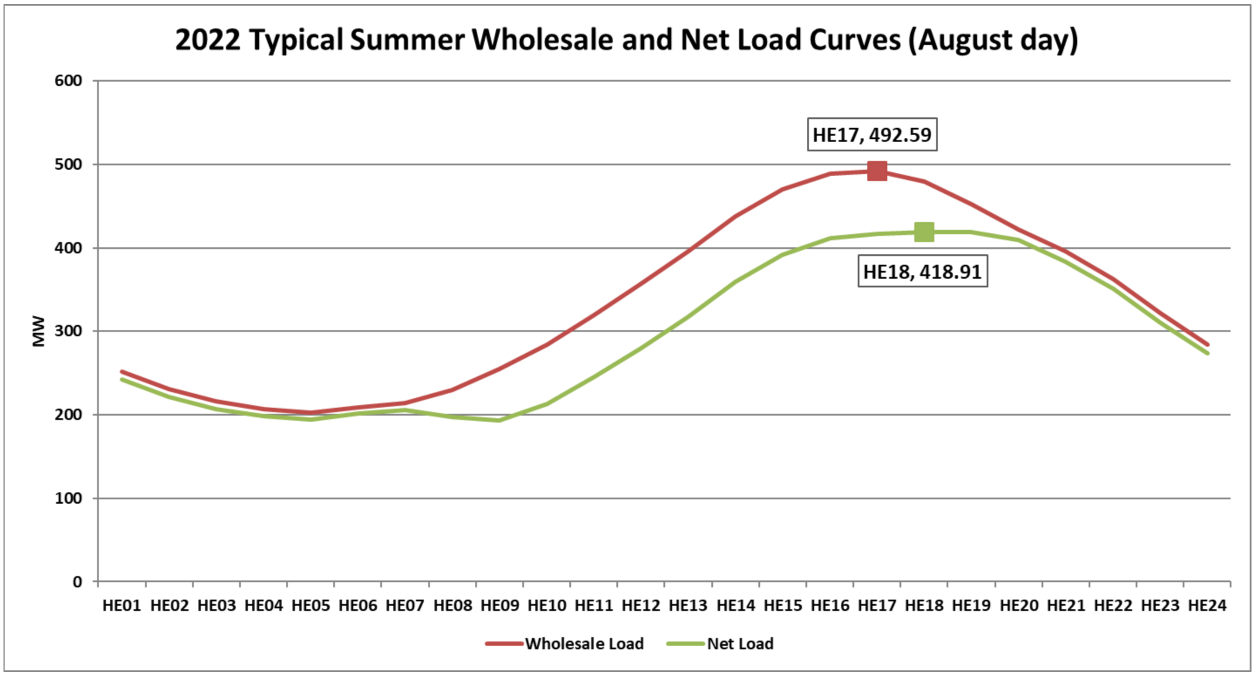


Figure 10.3.3. Riverside's diurnal wholesale and net load curves for a typical summer day in 2022.

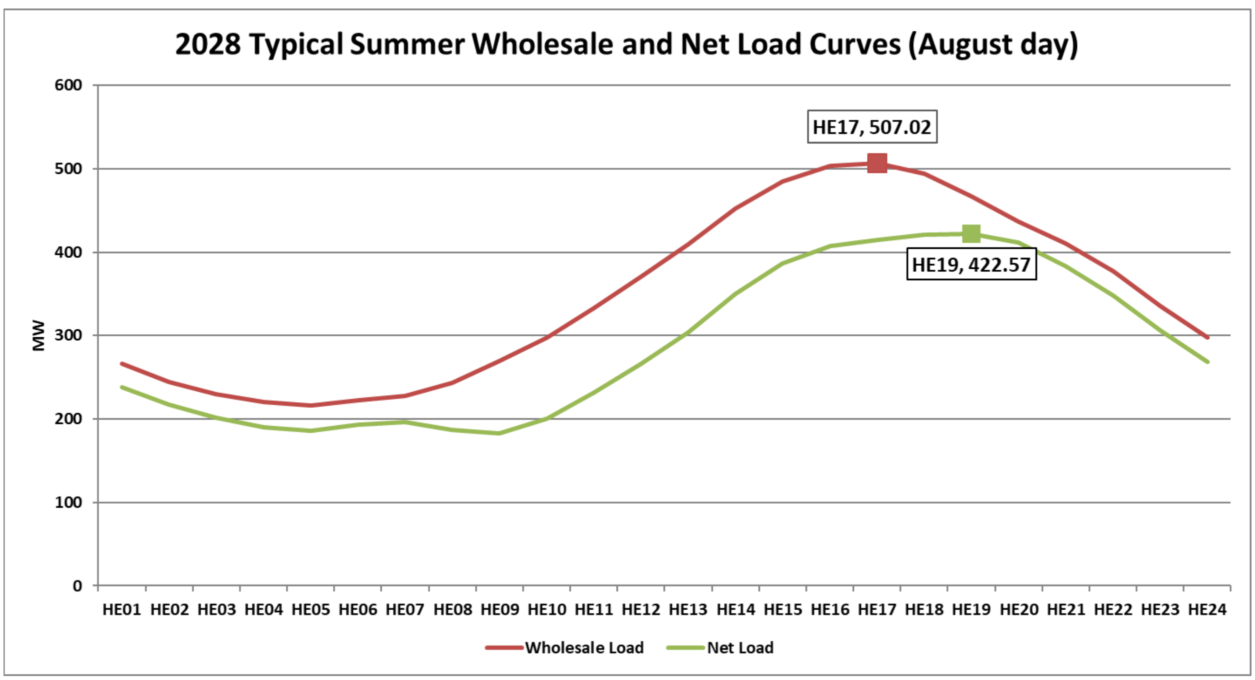


Figure 10.3.4. Riverside's diurnal wholesale and net load curves for a typical summer day in 2028.

While additional solar PV resources would continue to improve the summer net load curve (RPU is short capacity and energy in the summer), these resources exacerbate Riverside's risk exposure in the winter. RPU's must-take resources would often exceed its load, and it would be exposed to market price risk as it sells excess-to-load fixed price generation into the CAISO market, potentially at negative prices. To avoid this situation, RPU's procurement strategy historically has been to procure only renewable resources that can serve its load (i.e. best-fit). Figures 10.3.5 and 10.3.6 below show Riverside's typical diurnal net load curves for winter and summer overlaid with RPU's resource stack under typical operations. As shown in the figures, all of Riverside's must-take resource energy fits below its net load curves, and any gaps are filled with either dispatchable generation or market energy purchases, depending on the economics. The figures also highlight that baseload geothermal resources make up a notable portion of RPU's resource stack. RPU had 96 MW of baseload geothermal in its portfolio in 2022, and it will have 116 MW in 2028, which is significant because this baseload renewable resource contributes directly to meeting reliability needs during the hours of net-peak demand.

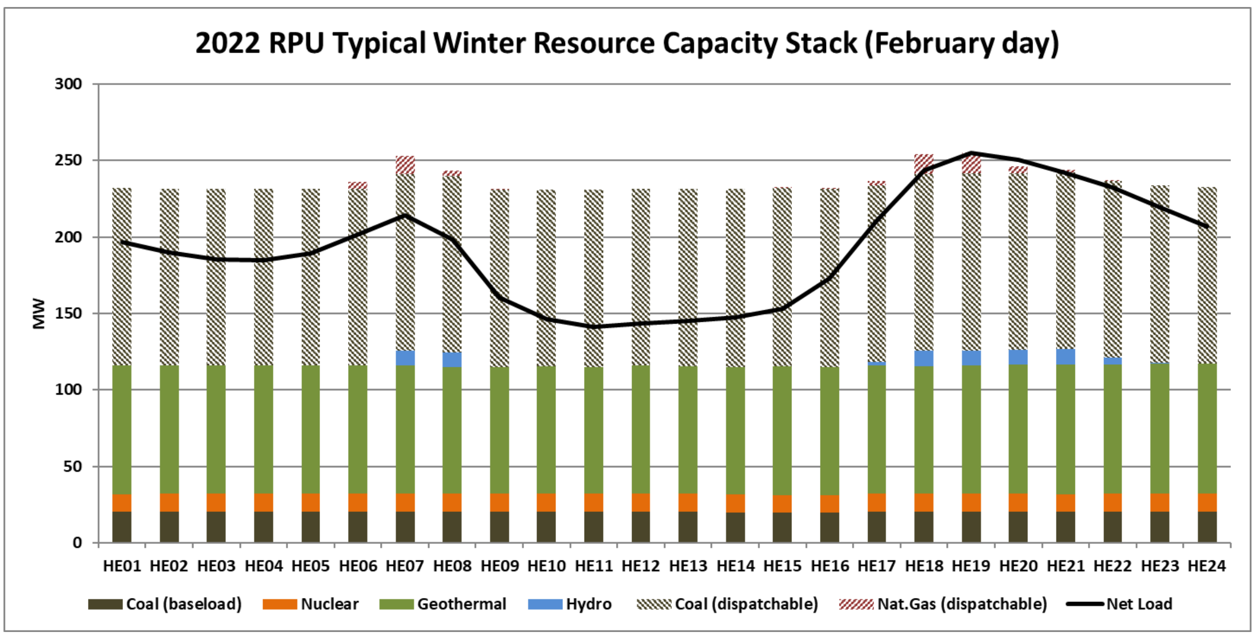


Figure 10.3.5. Riverside's diurnal net load curve and resource stack for a typical winter day in 2022.

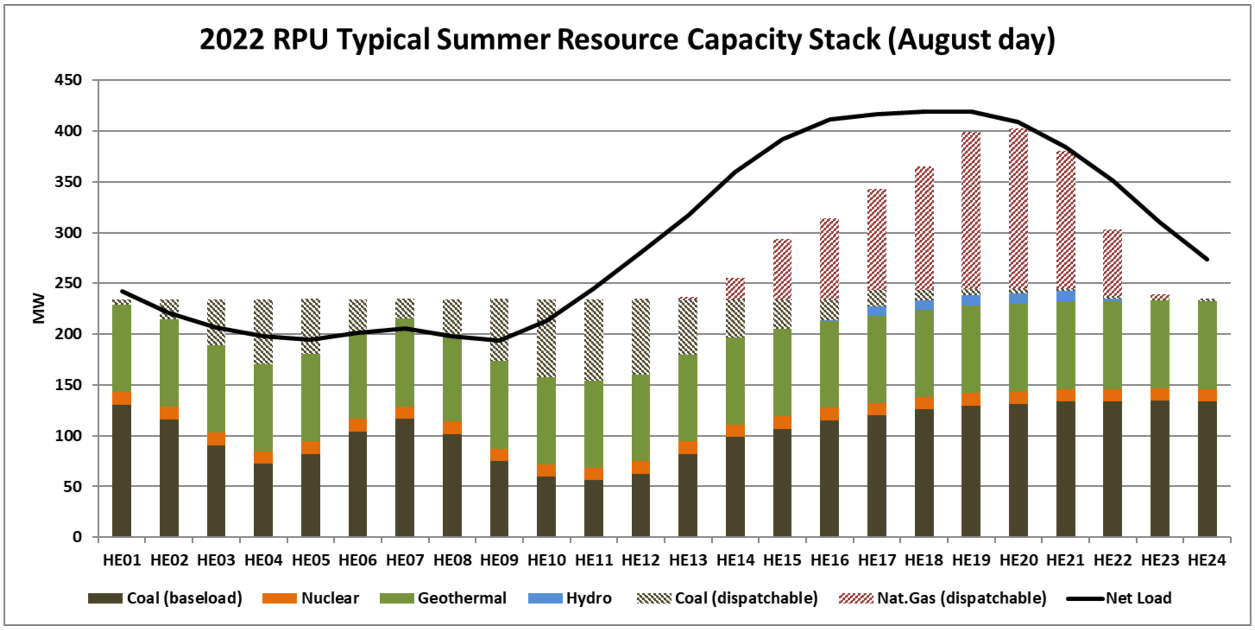


Figure 10.3.6. Riverside's diurnal net load curve and resource stack for a typical summer day in 2022.

As RPU's resource mix evolves over time, it is important to consider whether the resource stack continues to match the load pattern over the next five years. Figures 10.3.7 and 10.3.8 show what the load and resource stack would look like in 2028 should all current planned resource changes become effective. As seen in Figure 10.3.7, with an additional wind resource online, RPU's net load curve has shifted down compared to 2022. Additionally, RPU's resource stack no longer includes coal and is predominantly baseload geothermal. RPU's geothermal energy is projected to serve about 45% and 25% of the hour of net-peak demand in the winter and summer, respectively. However, the figures also show RPU will need additional renewable and/or carbon-free baseload resources to meet net peak hour load, particularly in the summer.

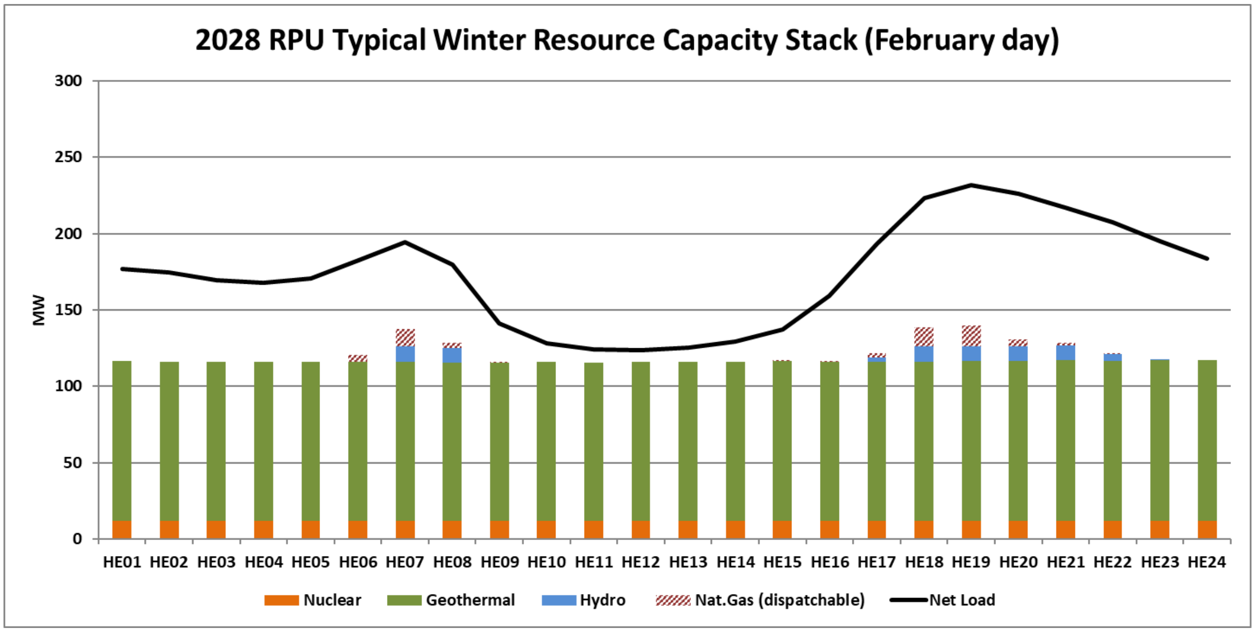


Figure 10.3.7. Riverside's projected diurnal net load curve and resource stack for a typical winter day in 2028.

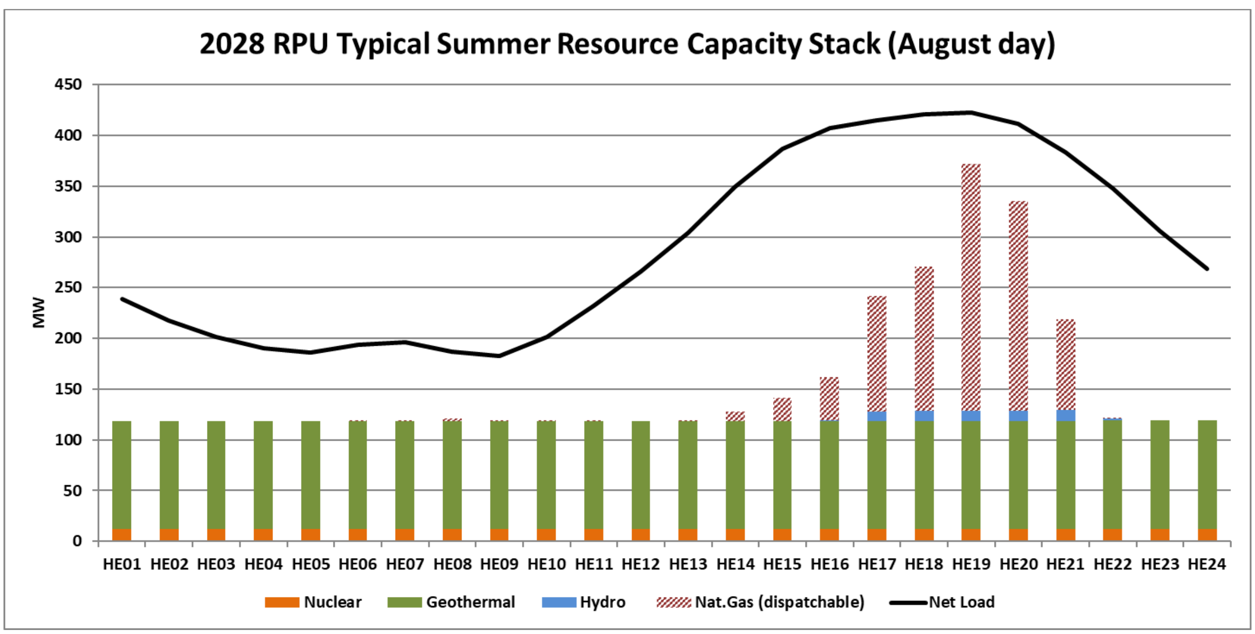


Figure 10.3.8. Riverside's projected diurnal net load curve and resource stack for a typical summer day in 2028.

As a further exploration of how renewable energy resources contribute toward RPU's energy and reliability needs during the hour of net-peak demand, staff performed an additional analysis using RPU's actual 2022 hourly load and renewable generation data. Figure 10.3.9 shows a bar chart of Riverside's monthly average and median peak window RPS levels for 2022. In this analysis, the peak "window" is defined to be the four-hour period containing the peak hour, one hour before the peak hour and two hours after the peak hour, respectively. As shown in Figure 10.3.9, Riverside does not experience a significant decline in its peak load window RPS level as compared to its monthly average RPS levels. This is because baseload geothermal resources supply about 75% of Riverside's renewable energy, and, as discussed previously, they can fully and directly contribute to meeting Riverside's peak load. Specifically, Riverside's RPS level during the peak window almost always remains near or above a 25% mark and is often at or above the 35% mark.

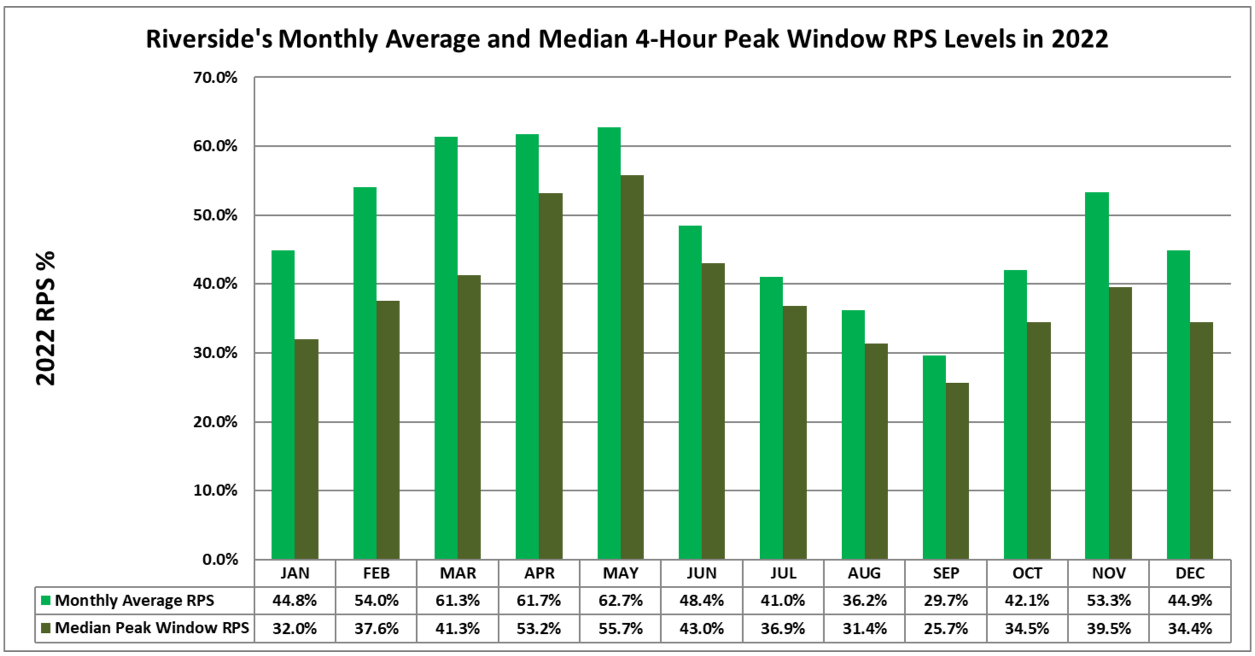


Figure 10.3.9. Riverside's actual monthly average and median peak window RPS levels in 2022.

11. Modeling Assumptions for Current and Future Generation Resources

Recall that Chapter 3 provided an overview of Riverside's portfolio of generation resources and presented staff assumptions about RPU's existing resource contracts that are scheduled to end by 2030. Building on those assumptions, this chapter defines assumptions about Riverside's resource contracts that are scheduled to expire in the 2030 to 2045 timeframe. A discussion concerning the Palo Verde nuclear contract, including RPU's rationale and justification for extending this contract beyond 2030 is also provided. More importantly, this chapter presents and describes a set of potential future portfolio resource additions during the 2030 to 2045 timeframe that are consistent with RPU's long-term carbon reduction goals. Battery energy storage resources are considered as replacements for RPU's gas-fired Springs and RERC Generation Facilities once they reach their anticipated end-of-life retirement dates. These proposed resources will allow RPU to meet its 2040 and 2045 carbon neutrality goals, and as such will form the basis for the long-term portfolio resource studies defined in this chapter and examined in Chapter 12.

11.1 Assumptions for Existing Resources Expiring between 2030 and 2045

As noted in Chapter 3, nearly all of Riverside's contracted and utility-owned resources that extend beyond 2030 are scheduled to expire or reach end-of-life before 2045, and it is currently uncertain how they may be either extended or replaced. However, to establish a baseline planning portfolio for long-term studies, RPU staff have made the following assumptions for Riverside's existing resources in the 2030 to 2045 timeframe:

- Palo Verde Nuclear contract will be extended through 2045.
- CalEnergy Geothermal Portfolio, Coso Geothermal, and SunZia Wind contracts are extended through 2045 under their respective pricing structures.
- All other existing contracts (1 wind and 7 solar) will expire as scheduled and be collectively replaced with new carbon free (renewable) resources discussed later in this chapter.
- RERC and Clearwater generation facilities will reach end-of-life and be retired after 2039. Likewise, the Springs facility will reach end-of-life and be retired after 2030.

11.1.1 Justification for Extending the Palo Verde Nuclear Contract

The City's current contract with Palo Verde is scheduled to terminate in December 2030. However, in 2011 the Nuclear Regulatory Commission (NRC) extended the Palo Verde nuclear facility licenses for Units 1, 2 and 3 by 20 years each, thus extending the expected operational plant life beyond 2045. In turn, the Palo Verde facility has announced that it intends to offer contract extensions to all primary subscribers through these new extension dates.

Staff firmly believe that the City should take advantage of this contract extension offer so that RPU can continue to receive power from Palo Verde. The rational for this recommendation is as follows:

1. The Palo Verde nuclear facility currently provides Riverside with about 95,000 MWh/year of clean, carbon-free baseload energy at a very reasonable cost (currently less than $48/MWh). Identifying a replacement baseload, carbon-free resource may be difficult – and finding a resource at this same price will be virtually impossible.
2. Under SB 100, all CA utilities will be allowed to continue to receive up to 40% of their annual resource energy mix after 2030 from non-renewable, carbon-free resources. Currently, nuclear and large hydro facilities are the only resources that can supply such power, yet there are no plans for developing any new nuclear or hydro facilities in the Southwest United States anytime in the near future. Thus, if RPU wishes to take advantage of such energy as the utility continues to decarbonize, then it must hold onto its legacy Palo Verde nuclear (and Hoover large hydro) contracts.
3. The Palo Verde nuclear facility has consistently achieved some of the highest safety ratings from the NRC since 2011 and is currently recognized as one of the safest commercial nuclear facilities in the United States.
4. Since the inception of this contract, Riverside has been paying its proportionate share of future Palo Verde decommissioning expenses into a designated reserve account and this reserve account is currently 100% fully funded, according to the latest PV Decommissioning Study report.[1]
5. Finally, exiting our PV contract in 2030 will not relieve Riverside of its proportionate share of future decommissioning liabilities, or recapture any decommission funds that have already been paid. Rather, an early exit will just deprive RPU and Riverside City residents from continuing to receive (and benefit from) this cost-effective, baseload, carbon-free energy.

For all the above reasons, staff intend to bring forward a Palo Verde contract extension proposal to the RPU Board of Public Utilities and Riverside City Council in 2024. Additionally, all SCPPA member participants currently in the Palo Verde project plan on pursuing and proposing such contract extension offers to their respective Boards and Councils.

Hence, for this Integrated Resource Planning process, it is expected that carbon-free Palo Verde nuclear energy will continue to be delivered to Riverside at the same capacity allotment, CF%, and under the same pricing structure at least through 2045. Therefore, all the long-term portfolio planning studies discussed in Chapter 12 include the energy from this nuclear resource throughout the 2030-2045 planning horizon.

[1] *2023 Decommissioning Cost Study for the Palo Verde Nuclear Generating Station*. Prepared for Arizona Public Service by TLG Services, LLC. Document A04-1815-001, Rev. 0. December 2023.

11.2 Assumptions for New Carbon-free (Renewable) Resources

Figure 11.2.1 shows RPU's forecasted renewable energy levels through 2030, based on the utility's current set of contracted renewable generation assets. From a planning perspective, RPU has sufficient renewable resources under contract to meet or exceed the utility's current SB 100 RPS requirements through 2030. Additionally, as already discussed in Chapter 9, RPU also expects to get below its official 2030 GHG target of 349,000 MMT but will need a new carbon-free resource in 2030 to get below the more aggressive 275,000 MMT target. Beyond 2030, RPU will need more carbon-free (renewable) resources to achieve carbon neutrality by 2040 per the Envision Riverside 2025 Strategic Plan[2] and 2045 per SB 100.

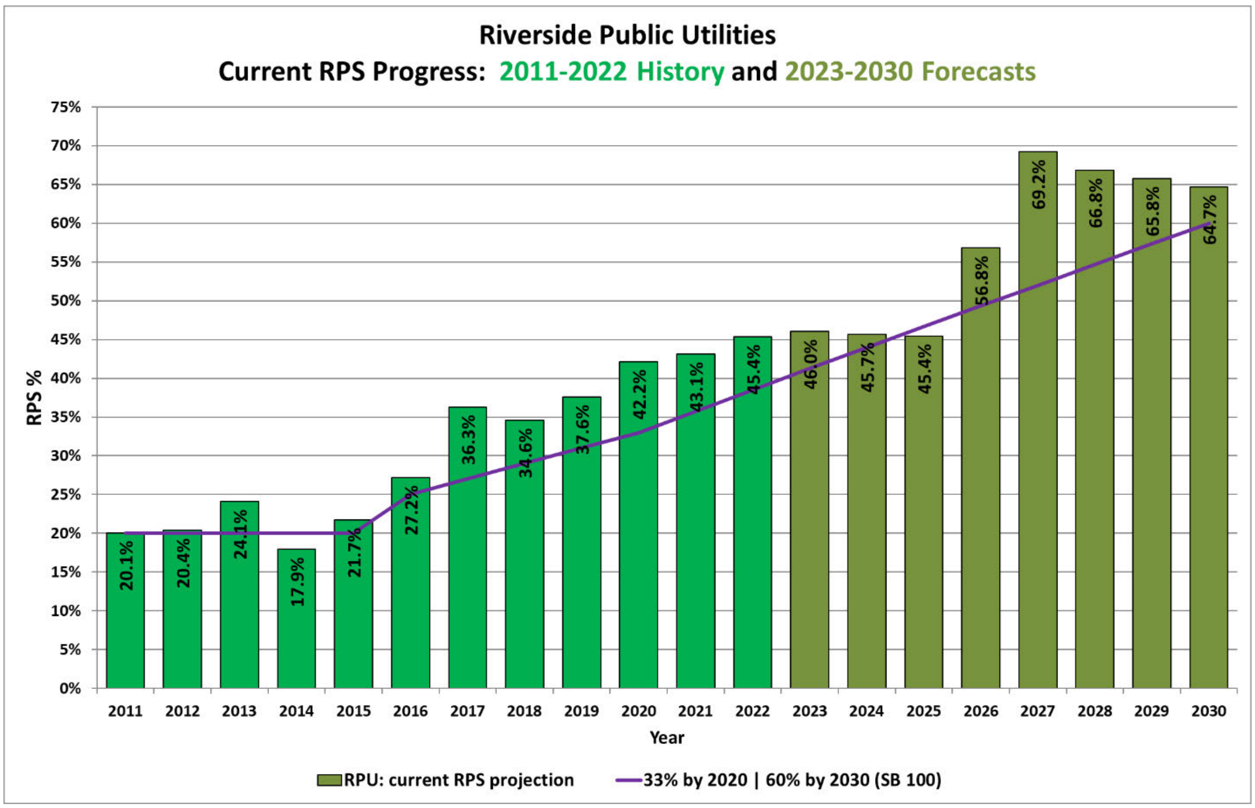


Figure 11.2.1. RPU's current forecasted RPS levels through 2030, as of October 2023.

Table 11.2.1 shows a hypothetical set of new carbon-free, renewable resources for the baseline portfolio that will ensure that RPU can achieve carbon neutrality by 2040. As introduced in Chapter 9, it is assumed that one of the proposed contract options to come online in 2030 will be incorporated into

[2] https://riversideca.gov/press/envision-riverside-2025

RPU's portfolio. Both proposed contracts will be studied to determine which one is the most cost-effective for RPU's portfolio. The post-2030 proposed contracts represent generic renewable assets that are yet to be identified but are being studied for planning purposes. The contract assumptions for each resource used in the long-term portfolio modeling are shown in Tables 11.2.2 through 11.2.5. All proposed contracts are assumed to run at least through 2045 – the end of the IRP study period.

Table 11.2.1. Proposed new renewable resource contracts for 2030-2045.

	New Resource	Resource Description	COD	Annual MWh
1a	Baseload Geothermal	50 MW baseload geothermal resource (84% CF)	2030	367,920
1b	Solar + Storage	120 MW Solar PV (35% CF) + 50 MW / 200 MWh BESS	2030	367,920
2	Baseload Resource (Renewable and/or Carbon-Free)	Baseload Resource Tranche (90% CF) (1) • 50 MW • 60 MW • 20 MW	 2034 2038 2043	 394,200 473,040 157,680
3	Solar PV-2037	75 MW Solar PV (35% CF)	2037	229,950
4	Solar PV-2041	75 MW Solar PV (35% CF)	2041	229,950

Note (1): The additional 60 MW and 20 MW may come from new assets or be incremental to the original 50 MW asset.

Table 11.2.2. Baseload Geothermal operating parameters and cost assumptions.

Operating Parameters	
COD	1/1/2030
Capacity (MW)	50
Capacity Factor (%)	84
Resource Pricing	
Power Cost ($/MWh)	90.00
Power Cost Escalator (%)	0.0

Table 11.2.3. Solar + Storage operating parameters and cost assumptions.

Operating Parameters	
COD	1/1/2030
Solar Capacity (MW)	120
Solar Capacity Factor (%)	35
Solar Degradation (%/year)	0.5
BESS Capacity (MW)	50
BESS Storage Duration (hours)	4
BESS (MWh)	200
BESS Losses (%)	15
Cycles per day	1
Resource Pricing	
Solar Power Cost ($/MWh)	40.00
Solar Power Cost Escalator (%)	0.0
BESS Cost ($/kW-month)	16.00
BESS Cost Escalator (%)	0.0

Table 11.2.4. Baseload Resource operating parameters and cost assumptions.

Operating Parameters			
COD	1/1/2034	1/1/2038	1/1/2043
Cumulative Capacity (MW)	50	110	130
Capacity Factor (%)	90	90	90
Resource Pricing			
Power Cost ($/MWh)	100.00	100.00	100.00
Power Cost Escalator (%)	0.0	0.0	0.0

Table 11.2.5. Solar PV operating parameters and cost assumptions.

Operating Parameters		
COD	1/1/2037	1/1/2041
Capacity (MW)	75	75
Capacity Factor (%)	35	35
Solar Degradation (%/year)	0.5	0.5
Resource Pricing		
Power Cost ($/MWh)	40.00	40.00
Power Cost Escalator (%)	0.0	0.0

11.3 Replacement Assumptions for the Springs Generation Facility

As previously discussed in Chapter 3, RPU anticipates that the 36 MW Springs Generation Facility will be retired after 2030. The baseline portfolio assumption is that Springs will not be replaced. However, in addition to the baseline, a BESS replacement scenario is studied in which 2 BESS resources (shown in Table 11.3.1) are staged in to replace Springs. Table 11.3.2 shows the BESS operating and cost assumptions used in the long-term portfolio modeling. These proposed BESS resources are assumed to run through at least 2045.

Table 11.3.1. Proposed Replacement resources for Springs

	New Resource	Resource Description	COD
1	Springs 4-hr BESS I	18 MW / 72 MWh BESS	2028
2	Springs 4-hr BESS II	18 MW / 72 MWh BESS	2030

Table 11.3.2. Springs BESS operating parameters and cost assumptions.

Operating Parameters		
COD	1/1/2028	1/1/2030
BESS Capacity (MW)	18	18
BESS Storage Duration (hours)	4	4
BESS (MWh)	72	72
BESS Losses (%)	15	15
Cycles per day	1	1
Resource Pricing		
BESS Cost - ($/kW-month)	16.00	16.00
BESS Cost Escalator (%)	0.0	0.0

11.4 Replacement Assumptions for RERC

The baseline portfolio assumption for RERC is that it will be retired after 2039 and will not need to be replaced assuming the RTRP is completed (giving Riverside a second point of interconnection to the CAISO grid). However, in addition to the baseline, two BESS replacement scenarios for RERC will be studied: (1) BESS resources deployed January 1, 2040, after RERC retires and (2) BESS resources deployed January 1, 2035, assuming RERC retires 5 years earlier. A scenario that explores RERC switching to run on biogas starting January 1, 2035, through its retirement on December 31, 2039 is also studied. Table 11.4.1 specifies the proposed BESS replacement resources for RERC, and Table 11.4.2

shows the BESS operating parameters and cost assumptions. Table 11.4.3 shows the operating parameters and cost assumptions for the biogas option. These proposed BESS resources are assumed to run at least through 2045.

Table 11.4.1. Proposed replacement resources/options for RERC.

	New Resource	Resource Description	COD
1	RERC 4-hr BESS	100 MW / 400 MWh BESS	2035 or 2040
2	RERC 6-hr BESS	100 MW / 600 MWh BESS	2035 or 2040

Table 11.4.2. RERC BESS operating parameters and cost assumptions.

Operating Parameters		
COD	1/1/2035 or 1/1/2040	
BESS Capacity (MW)	100	100
BESS Storage Duration (hours)	4	6
BESS (MWh)	400	600
BESS Losses (%)	15	15
Cycles per day	1	1
Resource Pricing		
BESS Cost - ($/kW-month)	16.00	24.00
BESS Cost Escalator (%)	0	0

Table 11.4.3. RERC Biogas Operating parameters and cost assumptions.

Operating Parameters	
Biogas Switch Date	1/1/2035
Resource Pricing	
Biogas Cost ($/MMBtu)	Index + 10.00
Biogas Cost Escalator (%)	0.0

11.5 Long-Term Study Portfolios

Following the discussion about future resources and assumptions laid out in the previous sections, Table 11.5.1 presents the long-term study portfolios and the proposed new resources that comprise each one. The Baseline A and B Portfolios are defined to meet GHG reduction targets and RPS mandates through the 2045 study horizon. The Baseline A and B portfolios are equivalent in terms of the amount of renewable/carbon-free energy being added. They are comprised of resources 2 – 4 presented in Table 11.2.1, plus the Baseload Geothermal (1a) in the case of Baseline A and the Solar + Storage (1b) in the case of Baseline B. In addition to the Baseline Portfolios, four additional resource planning scenarios are studied that specifically focus on replacement options for Springs and RERC. The results of these studies will be presented in detail in Chapter 12.

Table 11.5.1. Portfolios of new resources.

New Resource	Portfolio					
	Baseline A	Baseline B	Springs	RERC-2040	RERC-2035	RERC-2035 Biogas
Baseload Geothermal	X		X	X	X	X
Solar + Storage		X				
Baseload Renewable	X	X	X	X	X	X
Solar PV-2037	X	X	X	X	X	X
Solar PV-2041	X	X	X	X	X	X
Springs 4-hr BESS I			X			
Springs 4-hr BESS II			X			
RERC 4-hr BESS				X	X	X
RERC 6-hr BESS				X	X	X
RERC Biogas						X

11.5.1 Production Cost Modeling Assumptions

All the scenario studies for this IRP were performed using the Ascend Production Cost Modeling Software platform. One hundred (100) simulation runs were performed for each scenario. These simulations allowed staff to not only quantify the expected annual load serving costs associated with each portfolio scenario, but also the associated uncertainty (i.e., standard deviation) surrounding these cost estimates. Essentially, these standard deviations can be used to represent the “cost at risk” associated with each portfolio scenario. Conceptually, scenarios with lower expected load serving costs and associated standard deviations should be preferred, since the ultimate cost of any given future scenario can never be perfectly forecasted.

Each of the 100 Ascend simulation runs associated with each scenario were performed at the hourly granularity over the same January 1, 2024 through December 31, 2045 timeframe, using the same set of input forward price curves. (Note that the input forward price curves define the normalized mean of the simulated forward price data for each scenario, respectively). The corresponding total net portfolio costs (TNPC) were then summarized at the annual level for each simulation run and in turn used to compute the expected net portfolio costs and associated standard errors for each scenario. The TNPC variable is defined as

$$TNPC = TGC + TLC - TGGR - HP(MtM) \qquad \text{[Eq. 11.1]}$$

where the variables on the right hand side of this equation are defined as shown below.

- TGC: The total of all generation costs (other than CO_2 costs before 2030) associated with all of the generation assets in the portfolio.
- TLC: The total cost for purchasing RPU system load (from the CAISO SP15 day-ahead market).
- TGGR: The total gross revenue received from selling all of the generation energy in the RPU portfolio back into the SP15 market.
- HP(MtM): The total payoff amount associated with all forward hedging instruments, computed on a mark-to-market basis.

Once determined, the TNPC variable is useful when combined with other known portfolio costs explored later in this chapter to compute a complete total power resource portfolio cost that can be compared to RPU's current power resource budget.

11.6 Other Budgetary Costs and IRP Budget Assumptions

In addition to the calculation of the total net portfolio costs and other market-related costs discussed above, several other budgetary costs and revenues must be properly specified in order to calculate complete portfolio cost projections. The most important additional budget items are as follows:

- Resource Adequacy (RA) costs: The cost obligations associated with procuring market RA products to satisfy RPU's planning reserve margin.
- Transmission costs and Transmission Revenue Requirement (TRR): The cost obligations associated with the CAISO's TAC charge, RPU's transmission agreements and projects and RPU's TRR.
- SONGS: The cost obligations associated with winding down the SONGS contract and the ongoing SONGS decommissioning process.
- Carbon Allowances and Revenues: RPU's carbon allowances and the revenues associated with the sale of these allowances.
- CAISO Uplift fees and other Power Resource costs: The ongoing costs associated with CAISO energy and transmission uplift fees, CRR auction expenses, and internal generation facilities.

The input assumptions and methodologies used to forecast each of these additional cost components are described in more detail in the following sections.

11.6.1 Resource Adequacy Costs

As discussed in Chapter 10, RPU must procure enough capacity resources and/or RA products to satisfy its monthly planning reserve margin. For budget purposes, any projected capacity shortfalls are assumed to be satisfied with system RA purchases following the pricing shown in Section 7.6. These costs can vary across IRP scenarios depending on the resources included in each portfolio.

11.6.2 Transmission Costs and TRR

As a Participating Transmission Owner (PTO) in the CAISO, RPU's transmission entitlements generate both costs and revenues. The utility's costs consist of three primary components: (a) the CAISO Transmission Access charge (TAC) rate, as discussed in Chapter 7, (b) various transmission service agreements associated with certain long-term resources, and (c) the debt service and O&M costs incurred from transmission project entitlements that were financed through the Southern California Public Power Authority (SCPPA). These latter two cost categories make up the major components of RPU's annual Transmission Revenue Requirement (TRR). However, because RPU transferred operational control of these transmission entitlements to the CAISO when it became a PTO on January 1, 2003, RPU is entitled to compensation from the CAISO grid users for recovery of its associated transmission costs through RPU's TRR. While typically not an exact match in practice, the CAISO TRR compensation and RPU's transmission cost incurred from its SCPPA transmission project entitlements and other transmission service agreements are sufficiently close enough to be netted out for budget forecasting purposes. As such, staff has assumed that they directly offset one another in this IRP, leaving only the TAC cost flowing into the IRP's total budget cost calculation. (CAISO TAC rate projections through 2045 that were used to calculate RPU's TAC costs are presented in Chapter 7.)

11.6.3 SONGS Related Costs

Although the SONGS facility has been officially retired, decommissioning proceedings and activities are ongoing and related costs are expected to be present in RPU's budget through the 2045 time horizon studied in this IRP. These cost obligations are expected to be $0.9 million annually and common across all IRP scenarios.

11.6.4 Carbon Allowances & Revenues

The Cap and Trade Program in California is defined through 2030, and RPU is to receive the annual allocations of Carbon allowances shown in Table 11.6.1.[3] The allocations equate to metric tons (mt) of CO2. RPU can use most of these allowances for direct compliance purposes and monetize the remaining residual allowances in the quarterly Cap and Trade auctions at the prevailing clearing prices (see Chapter 8, section 8.6 for more discussion on this topic). However, these revenues are not included in the long-term budget forecast; staff assumes that this revenue stream will flow into a designated fund

[3] CARB is in the middle of a new rule-making process that includes a re-examination of the 2025-2030 allowance amounts for all CA load-serving entities and could result in a reduction in allowances.

(separate from the budget) to help offset costs associated with other legislatively imposed carbon reduction programs.

The California Cap and Trade allocation program is not defined by statute or regulation beyond 2030. Therefore, as a conservative assumption, staff has assumed that RPU receives no further Carbon allowance allocations beyond 2030. Thus, the entirety of RPU's post-2030 Carbon emission costs will be absorbed into its budget costs and recovered through future rates. Under this assumption, the post-2030 Carbon costs therefore directly impact the total budget cost calculation from 2031 through 2045 in each IRP scenario.

Table 11.6.1. RPU's Carbon allowances.

Year	Allowances
2024	1,015,558
2025	1,000,815
2026	991,145
2027	799,554
2028	609,032
2029	601,432
2030	583,388

11.6.5 CAISO Uplift Fees & other Power Resource Costs

In addition to the above-mentioned budgetary costs, in 2024 RPU expects to pay approximately $4 million for the following all-other power resource related costs. For the IRP analyses, staff escalates this cost at 3% annually, consistent with expected inflation, to produce future cost forecasts of these miscellaneous budgetary expenses. Note that these cost forecast amounts are common across all IRP scenarios.

11.7 Defining the Risk Integrated Portfolio Cost and Net Value Metrics

Staff has calculated the portfolio costs (PC) inclusive of the TNPC, defined in Eq 11.1, plus the sum of all the other portfolio costs discussed in sections 11.6.1 through 11.6.5. This PC metric includes system RA needs (RA), the CAISO Transmission Access Charge (TAC), Carbon Emissions costs beyond 2030 (GHG), SONGS decommissioning costs (SONGS), and CAISO uplift fees and other Power Resource costs (UFOC).

$$PC = TNPC + RA + TAC + GHG + SONGS + UFOC \qquad \text{[Eq. 11.2]}$$

As defined above, this PC value estimates the costs directly associated with and indirectly incurred as a result of the selected generation portfolio for the various IRP scenarios discussed in this chapter. To a significant degree, these PC estimates increase as the load metric increases. Hence, for planning purposes it is more useful to examine a "load normalized" PC metric, or PC_{LN}, since this essentially corresponds to the generation portfolio's larger contribution towards retail rates that RPU must charge to fully recover all of its expected costs. Staff has derived the Load-normalized Portfolio Cost (PC_{LN}) by dividing the annual total net portfolio cost variable, defined in Equation 11.2, by RPU's annual total retail load resulting in an easily comparable price per kilowatt hour basis. Note, to account for losses, the retail load is set equal to 0.946% of the utility's total system load forecasts, respectively.

$$PC_{LN} = \frac{PC}{Retail.Load} \qquad \text{[Eq. 11.3]}$$

It is important to recognize that these PC_{LN} estimates are primarily designed to facilitate an effective comparison between the different IRP scenarios. Additionally, it should also be noted that the calculated standard deviations for these PC_{LN} estimates only quantify the uncertainty associated with the TNPC variable. All other variables incorporated into the PC_{LN} estimate are treated as fixed variables (i.e., devoid of any uncertainty), regardless of whether the corresponding variable estimates are common or unique across the IRP scenarios. The Risk Integrated Portfolio Cost (RIPC) metric is inclusive of the expected load normalized portfolio costs and the standard deviation found across the TNPC variable in the Ascend software simulations and is defined in Eq. 11.4.

$$RIPC = PC_{LN} + Std[TNPC_{LN}] \qquad \text{[Eq. 11.4]}$$

Chapter 12 will focus on how these forecasted portfolio cost metrics change across the various scenarios shown in Table 11.5.1. The primary goal of these analyses will be to quantify both the absolute and relative portfolio costs and risk differences between these scenarios. Additionally, RPU staff have calculated the net revenue value inclusive of the capacity value, defined in Eq. 11.5, for proposed Resources 1a and 1b as well as all the BESS resources to facilitate direct comparisons across different portfolios. For Resources 1a and 1b, the net value is expressed as \$/kWh, as defined in Eq. 11.6, where the Net Value metric is divided by each resource's respective kWh of generation. For the BESS resources, the net value is expressed as \$/kW-month, as defined in Eq. 11.7, where the Net Value metric is divided by each BESS's kW of capacity multiplied by 12.

$$Net\ Value\ (\$) = Net\ Revenue\ CAISO + \ RA\ Capacity\ Value \qquad \text{[Eq. 11.5]}$$

$$Net\ Value\ \left(\frac{\$}{kWh}\right) = Net\ Value\ (\$)\ /\ Resource.Specific.Generation \qquad \text{[Eq. 11.6]}$$

$$Net\ Value\ (\frac{\$}{(kW-month)}) = Net\ Value\ (\$)\ /\ (BESS.Specific.Capacity * 12) \qquad \text{[Eq. 11.7]}$$

12. Long Term Portfolio Analyses

As introduced in Chapter 11, the Baseline Portfolio is defined to meet GHG reduction targets and RPS mandates through the 2045 study horizon. This chapter examines the projected budgetary impacts of the Baseline Portfolio, specifically focusing on comparing two resource options in 2030. Additionally, this chapter examines the projected budgetary impacts of battery energy storage replacement options for the Springs and RERC generation facilities upon their assumed retirements. The budgetary assessments consider both the expected values and simulated standard deviations of RPU's resource portfolio cost over the 2024-to-2045 time horizon. Net value calculations for the proposed resources are also provided.

With respect to the battery energy storage systems (BESS) analyzed in this chapter, it should be noted that such assets cannot currently qualify for new RA credit if they are deployed within RPU's distribution system. This is because RPU's single point of interconnection to the bulk electric transmission system is at the SCE Vista substation, and the CAISO currently considers Vista to be a "constrained tie-point". In turn, this means that no new generation or storage asset deployed within RPU's distribution system can qualify for full capacity deliverability status, which is a necessary pre-condition for qualifying for Resource Adequacy (RA) credit under the CAISO tariff. Unfortunately, the only way RPU can obtain RA for a new internally deployed BESS is by transferring existing RA from an existing internal RPU asset. Therefore, in the following analyses we have limited our internal BESS studies to just internal generation replacement scenarios, since these are the only scenarios that figure to be remotely cost effective.[1]

12.1 Baseline Portfolio

Two versions of the Baseline Portfolio were studied – Baseline A and Baseline B. The Baseline A and B portfolios are equivalent in terms of the amount of renewable/carbon-free energy being added.[2] They are comprised of Resources 2 – 4 presented in Table 11.2.1, plus the Baseload Geothermal (Resource 1a) in the case of Baseline A and the Solar + Storage (Resource 1b) in the case of Baseline B. Additional capacity and energy requirements not satisfied by these respective portfolios are met with short-term RA product purchases and CASIO energy market purchases, respectively.

The main goal of the Baseline A and B Portfolios is to compare the economics of Resources 1a and 1b to determine which would best fit into RPU's portfolio from a cost and risk perspective. As such, the discussion and analyses presented in sections 12.1.4 and 12.1.5 are primarily focused on these two proposed resources. RPU staff see either resource as a potentially viable option for RPU to add to its portfolio by or before 2030, and the analyses presented in these sections can help inform future procurement decisions pertaining to these types of resources. The remaining proposed resources

[1] RA credit currently represents over 50% of the implied value of a new 4-hour BESS. If RPU cannot obtain RA credit on the BESS, the deployment of such a system becomes cost prohibitive.

[2] Energy added is equivalent in 2030 but deviates thereafter as the solar resource is assumed to have a degradation rate of 0.5% per year.

(Resources 2 – 4) included in the Baseline Portfolio are considered to be prespecified. Furthermore, given that the lineup of resource technologies that will be commercially available in the middle of the next decade is currently unknown, the proposed Baseload Renewable (Resource 2) resource serves as a generic placeholder for resources that have yet to be identified. Specifically, this resource could represent a known renewable and/or carbon-free technology such as nuclear or solar/wind + long duration storage, or an emerging technology like green hydrogen. Nonetheless, a renewable and/or carbon free resource of some technology type will need to be added in the next decade for RPU to achieve its carbon neutrality goal.

Given the similarities of the Baseline A and Baseline B Portfolios, in this Chapter, they will be referred to as the Baseline Portfolio, unless otherwise specified.

12.1.1 Baseline Portfolio GHG Emissions

Figure 12.1.1 shows RPU's projected Total Portfolio and 1st Importer GHG emissions from 2024 through 2045 under the Baseline Portfolio. Note that CAISO market energy purchases are assumed to have a 0.428 MT/MWh emission factor throughout the study horizon. As shown in the graph, the Baseline Portfolio achieves an emission level of 152,065 metric tons of GHG in 2030, which is below RPU's more aggressive GHG reduction target of 275,000 metric tons. It is important to note that even if RPU does not bring on a new resource by 2030, RPU will have an emission level of 309,535 metric tons, which is below RPU's official target of 349,000 metric tons. By 2038, with the proposed renewable resources online, RPU will have enough renewable/carbon free energy to meet its retail load on an annual basis. By 2040, with all of its natural gas-fired generation retired, RPU achieves carbon neutrality, satisfying the carbon neutrality by 2040 goal set in the Envision Riverside 2025 Strategic Plan. RPU maintains carbon neutrality through 2045, satisfying the carbon neutrality by 2045 mandate set in SB 100.

12.1.2 Baseline Portfolio RPS

Figure 12.1.2 shows RPU's projected RPS percentage under the Baseline Portfolio. In 2030, the Baseline Portfolio achieves an 80.5% RPS with all PCC-1 renewable resources, exceeding the SB 100 RPS mandate of 60%. The Baseline Portfolio calls for a Baseload Renewable Resource (Resource 2) to begin delivering energy in 2034. This resource's contribution to RPU's RPS % is shown in the graph as orange-hatched bars. With this resource, RPU achieves a 105% RPS in 2038 and remains above 100% through the 2045 study horizon. However, this resource could potentially be a carbon free resource that does not count as renewable, in which case it would contribute toward RPU's carbon reduction goals but not its RPS percentage. If this resource is not renewable, RPU still maintains an RPS % above the 60% mandate through 2045, as required by SB 100 and shown by the green bars in the graph.

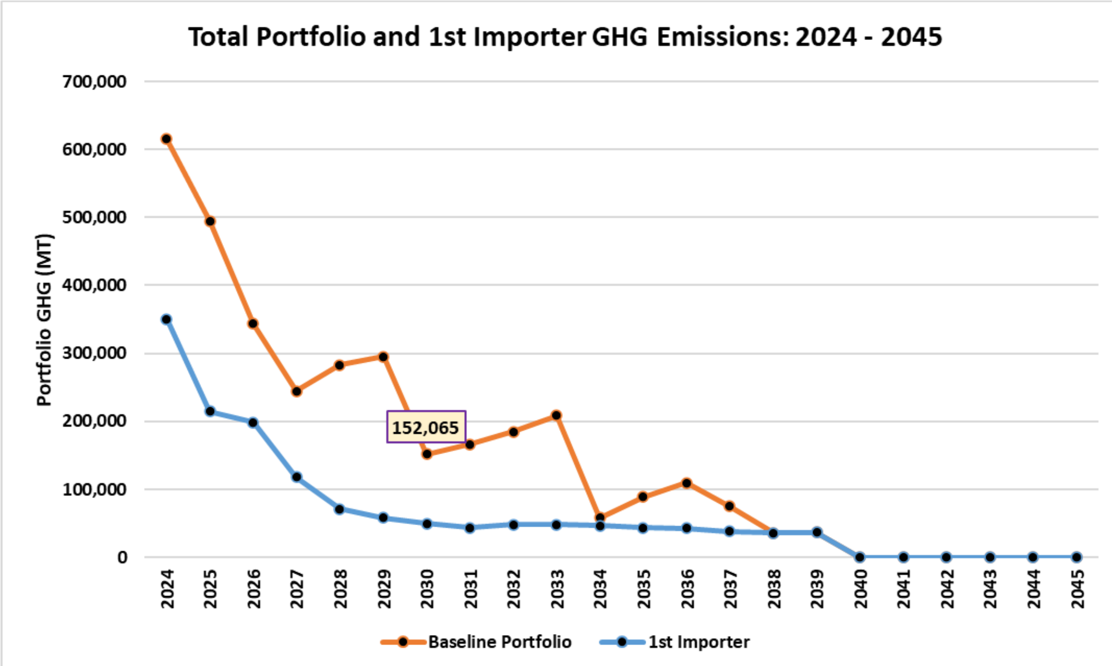


Figure 12.1.1. RPU's projected GHG emissions under the Baseline Portfolio.

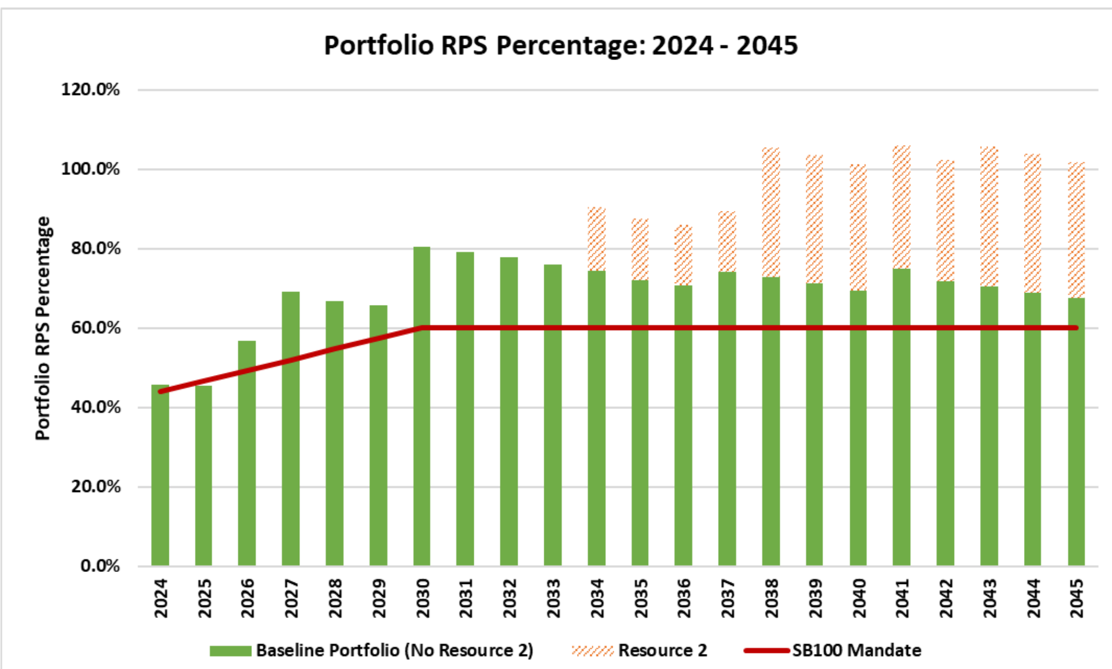


Figure 12.1.2. RPU's projected RPS percentage under the Baseline Portfolio, with the contribution of renewable Resource 2 identified separately.

12.1.3 Baseline Portfolio Capacity

Recall that RPU's existing RA capacity was presented in Chapter 10. Figure 12.1.3 shows how RPU's RA capacity changes under the Baseline Portfolio. New capacity from the Baseline A and B Portfolios is shown by the green and orange bars. The Baseline A and B Portfolios are shown as predominantly providing the same amount of RA capacity. However, the Baseline B Portfolio, with the co-located solar plus BESS, could offer some additional capacity from the solar resource. The orange bars show the potential additional amount of RA credit from the 120 MW solar resource based on the 2023 Effective Load Carrying Capability (ELCC) factors for solar PV. The ELCC for solar resources has been declining however, so the RA credit from solar might be immaterial by 2030 when this resource comes online.

Regardless of the solar RA issue, the Baseline A and B Portfolios add much needed RA capacity to RPU's portfolio. RPU will still need to rely on short-term RA purchases to meet RA requirements. However, these will be much more manageable once replacement options for Springs and RERC are added. Springs and RERC replacement options are discussed later in this chapter.

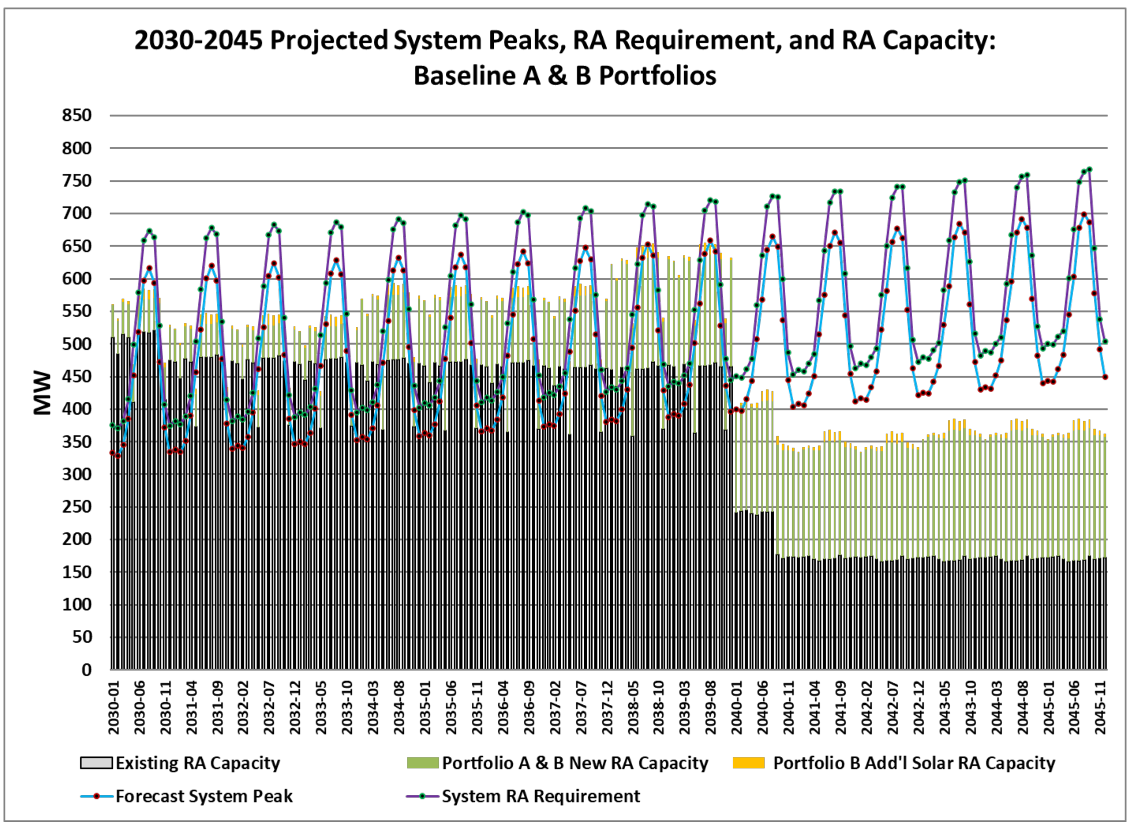


Figure 12.1.3. RPU's projected RA capacity under the Baseline A and B Portfolio.

12.1.4 Net Value of Proposed Resources 1a and 1b

Figures 12.1.4 and 12.1.5 show the net value of Resource 1a (Baseload Geothermal) versus Resource 1b (Solar PV + Storage) in the 2030-2045 timeframe. Figure 12.1.4 shows the combined net value of the Solar + Storage resource, while Figure 12.1.5 shows the individual net values for each PV and Storage component. Note that for comparison purposes, each resource is assumed to have 50 MW of RA capacity value.

With each resource having pricing consistent with similar resources in the market, Resource 1a has a negative average net value of $0.015/kWh while Resource 1b has a combined positive average net value of $0.002/kWh over the 2030 to 2045 timeframe. However, as Figure 12.1.5 clearly indicates, the combined positive value for Resource 1b is clearly resulting from the positive net value associated with the storage asset (in turn off-setting the negative net value of the Solar PV system). Hence, it is the battery storage asset that makes the Solar + Storage resource a potentially viable financial investment.

Overall, these net value results suggest that adding Resource 1a to RPU's portfolio would translate to portfolio cost increases while Resource 1b would not, for the assumed pricing marks discussed previously in Chapter 11. For Resource 1a to produce an average net value equivalent to Resource 1b, its price mark would need to be about 20% lower (e.g., a power cost of ~ $72/MWh). Alternatively, the combined positive average net value for this hypothetical Solar + Storage resource could be increased by increasing the BESS MW capacity level (e.g., to a level > 50 MW).

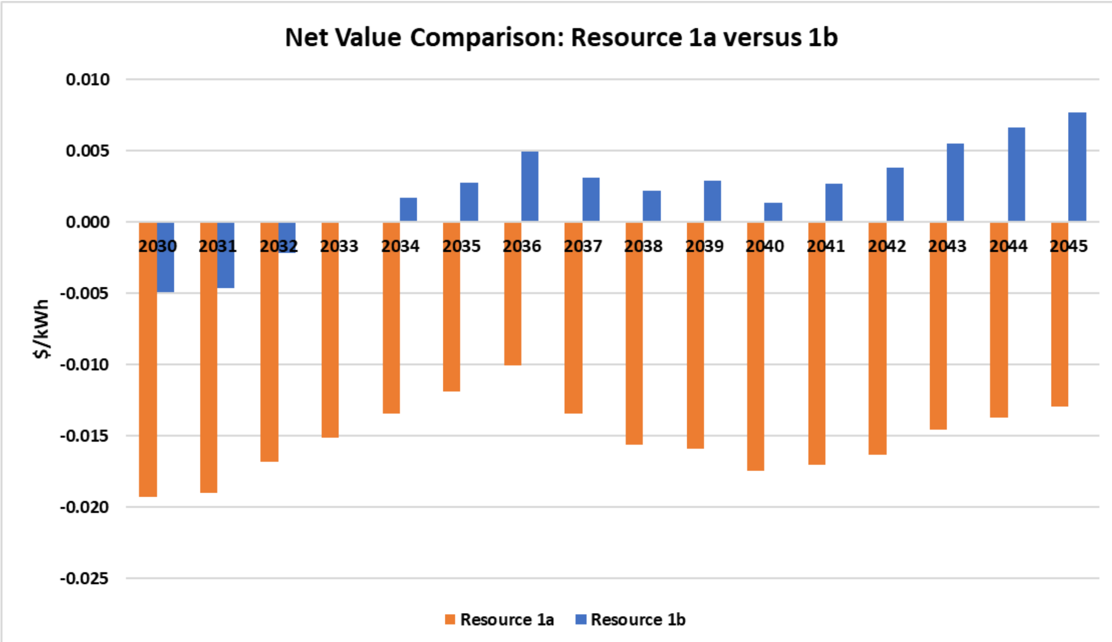


Figure 12.1.4. Net Value comparison for Resources 1a and 1b.

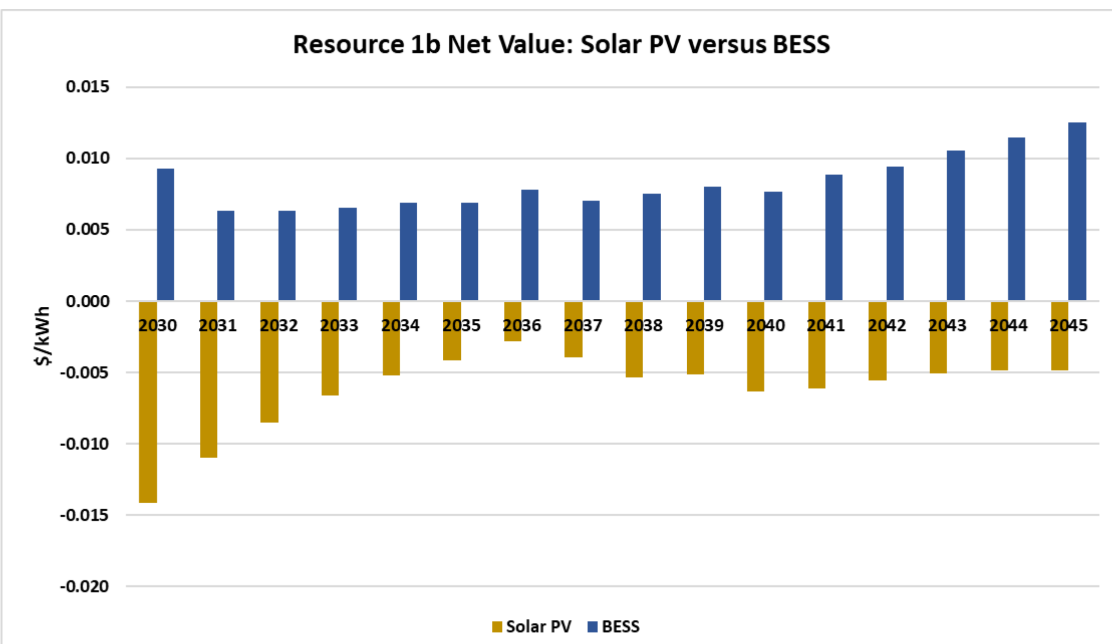


Figure 12.1.5. Net Value comparison for Solar PV and BESS assets comprising Resource 1b.

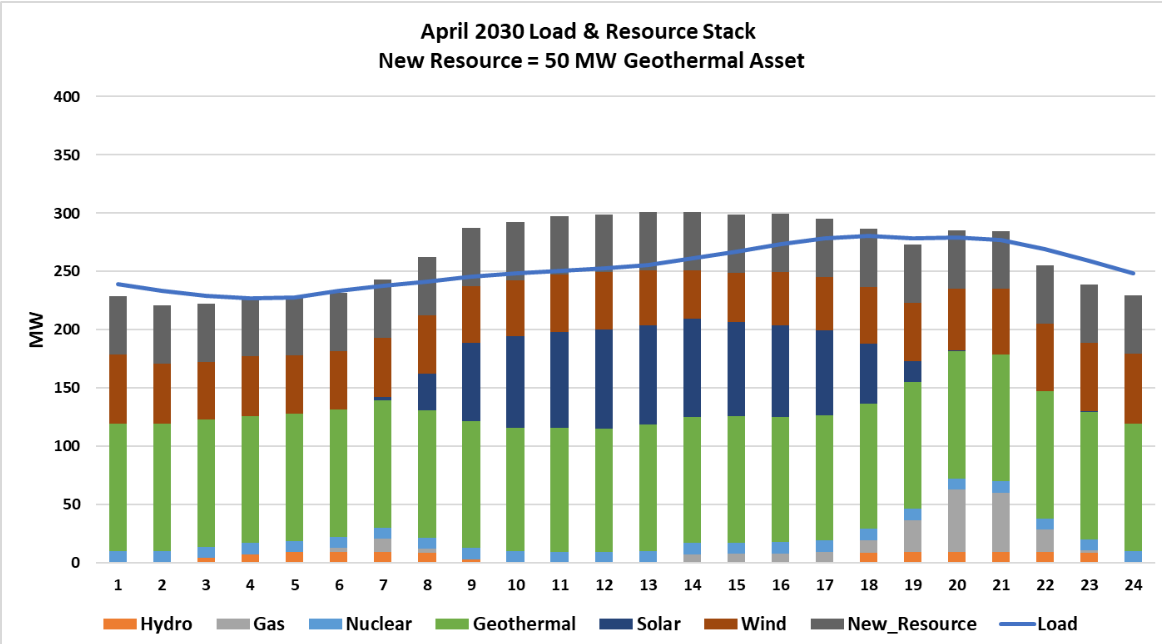
12.1.5 Baseline Portfolio Risk Integrated Portfolio Cost

Recall that the Risk Integrated Portfolio Cost (RIPC) metric is the sum of the expected load normalized portfolio costs with the standard deviation of the total net portfolio costs (Std[$TNPC_{LN}$]); see Equation 11.4). Adding in this standard deviation helps account for generation assets that introduce more uncertainty into our expected net portfolio cost. This increased uncertainty can occur due to the asset's highly variable nature of energy generation and/or if the generated energy pattern fails to align well with the utility's diurnal or seasonal load patterns.

The panel plots presented in Figure 12.1.6 show how the expected diurnal energy generation patterns for a 50 MW baseload geothermal resource and a 120 MW solar PV resource will fit into our forecasted energy generation portfolio in April 2030. It is clear from these plots that the generated energy pattern from the geothermal resource provides for a much better "match" to RPU's expected hourly load serving needs, as compared to the solar PV energy pattern. Indeed, unlike the geothermal energy profile, RPU would have to sell nearly all the solar PV energy back into the CAISO market as a Merchant generator (e.g., as generation energy not used to serve native load).

When a resource produces a generation profile that is poorly matched to a utility's load serving needs, these differences will result in a larger Std[$TNPC_{LN}$] estimate. The RIPC metric is designed to account for such differences by adjusting for the impacts of this increased uncertainty in the final cost comparisons. Figure 12.1.7 shows forecasted 2024, 2030, 2036, and 2042 RIPC metrics (expressed in ₵/kWh units) for the Baseline A and B Portfolios. The RIPC for these same years is also shown in Table 12.1.1.

The Baseline B Portfolio produces a lower RIPC than the Baseline A Portfolio, which is consistent with the (combined) net value results discussed in the previous section. In 2030, when each resource enters its respective portfolio, the Baseline B Portfolio's RIPC is 1.6% lower than the Baseline A Portfolio's. The individual risk component for the Baseline B Portfolio is somewhat greater than Baseline A, which makes sense given the inherent mismatch of the solar generation profile to RPU's load profile during specific Spring and Fall months. However, the 50 MW BESS can compensate for at least some of these impacts. Furthermore, as previously discussed, the cost difference between these two resources is the dominant factor impacting this analysis.



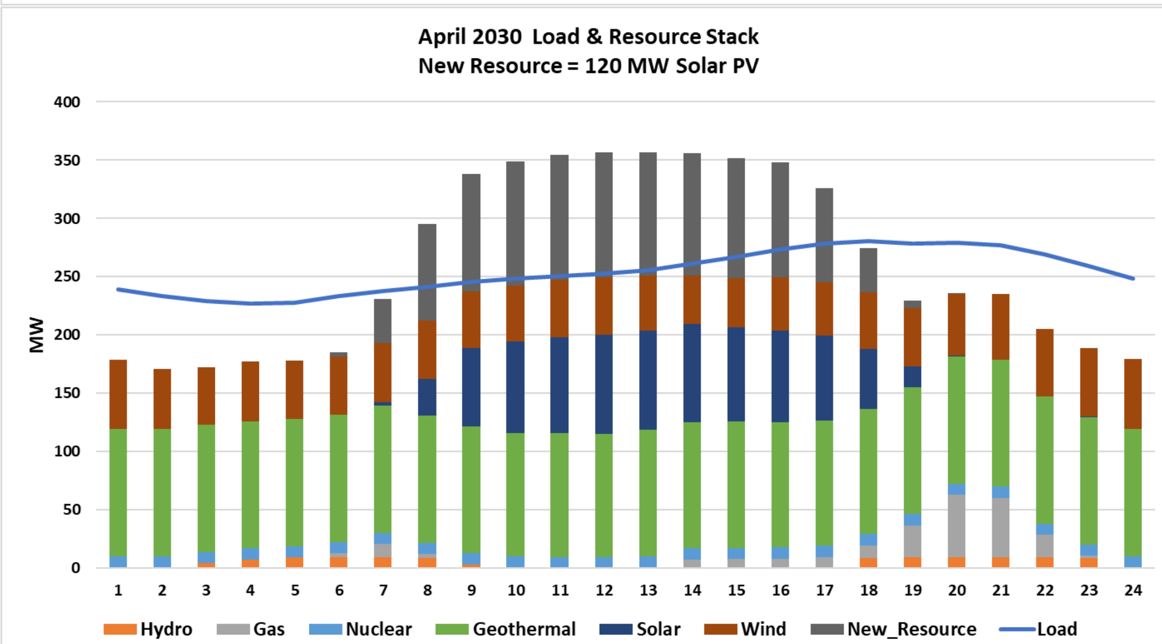


Figure 12.1.6. The expected diurnal energy generation patterns for a 50 MW baseload geothermal resource and a 120 MW solar PV resource, as compared to RPU's forecasted diurnal load and energy generation portfolio in April 2030.

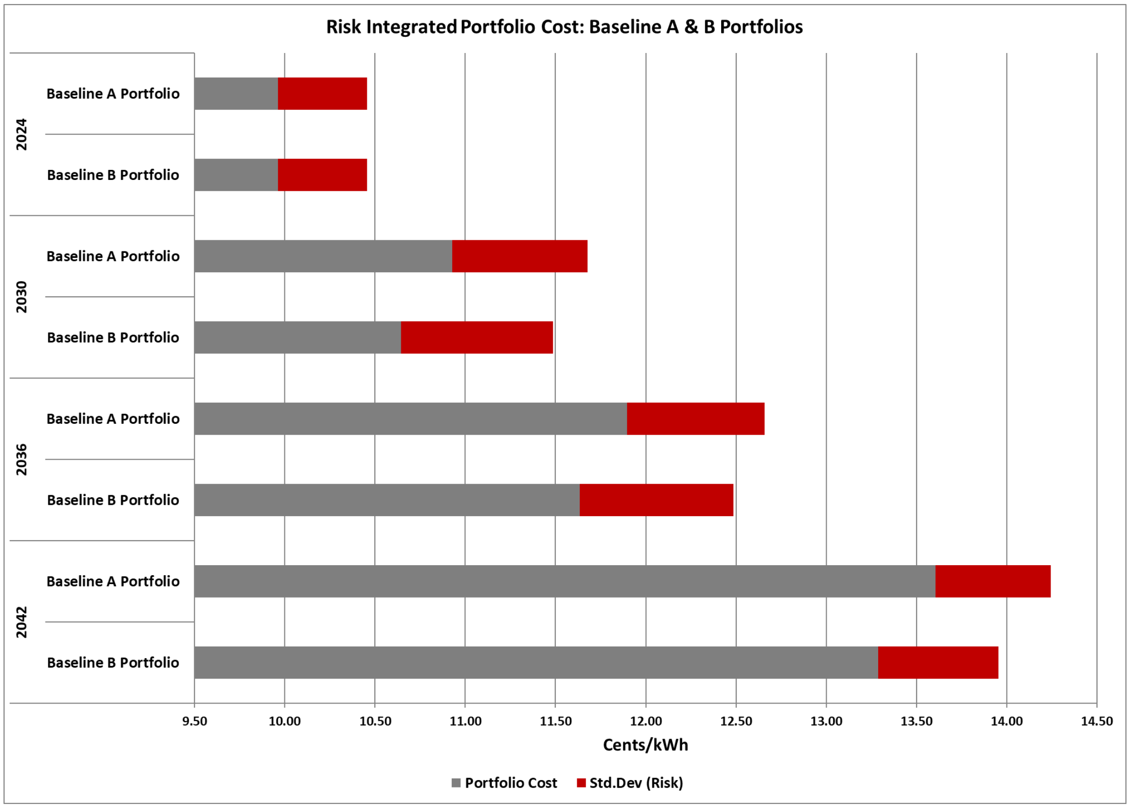


Figure 12.1.7. RPU's Risk Integrated Portfolio Cost under the Baseline A and B Portfolios.

Table 12.1.1. Figure 12.1.5 Risk Integrated Portfolio Cost estimates for years 2024, 2030, 2036 and 2042, along with relevant portfolio comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Portfolio	2024	2030	2036	2042	Annual GR
A. Baseline A Portfolio	10.455	11.678	12.657	14.243	2.0%
B. Baseline B Portfolio	10.455	11.488	12.484	13.952	1.9%
B vs A	0.0%	-1.6%	-1.4%	-2.0%	

12.2 Springs BESS Replacement

Under the Baseline Portfolio, Springs is retired at the end of 2030. This section presents an analysis of a staged-in approach to replacing the 36 MW Springs Facility, which would allow decommissioning to proceed before its assumed retirement at the end of 2030. In this analysis, two 18 MW 4-hour BESS (BESS I & BESS II) are staged-in as the replacement for Springs, with the BESS I deployed in 2028 and BESS II in 2030.

12.2.1 Baseline Portfolio Capacity with Springs BESS Replacement

Figure 12.2.1 shows RPU's RA capacity from 2028 to 2045 after including all new resources proposed in the Baseline A Portfolio plus the new Springs replacement BESS I and II. As each 18 MW 4-hour BESS is deployed in RPU's portfolio, 18 MW in RA credit is transferred from Springs to the BESS. The 36 MW of RA credit from the BESS is not considered additional to RPU until after Springs officially retires after 2030.

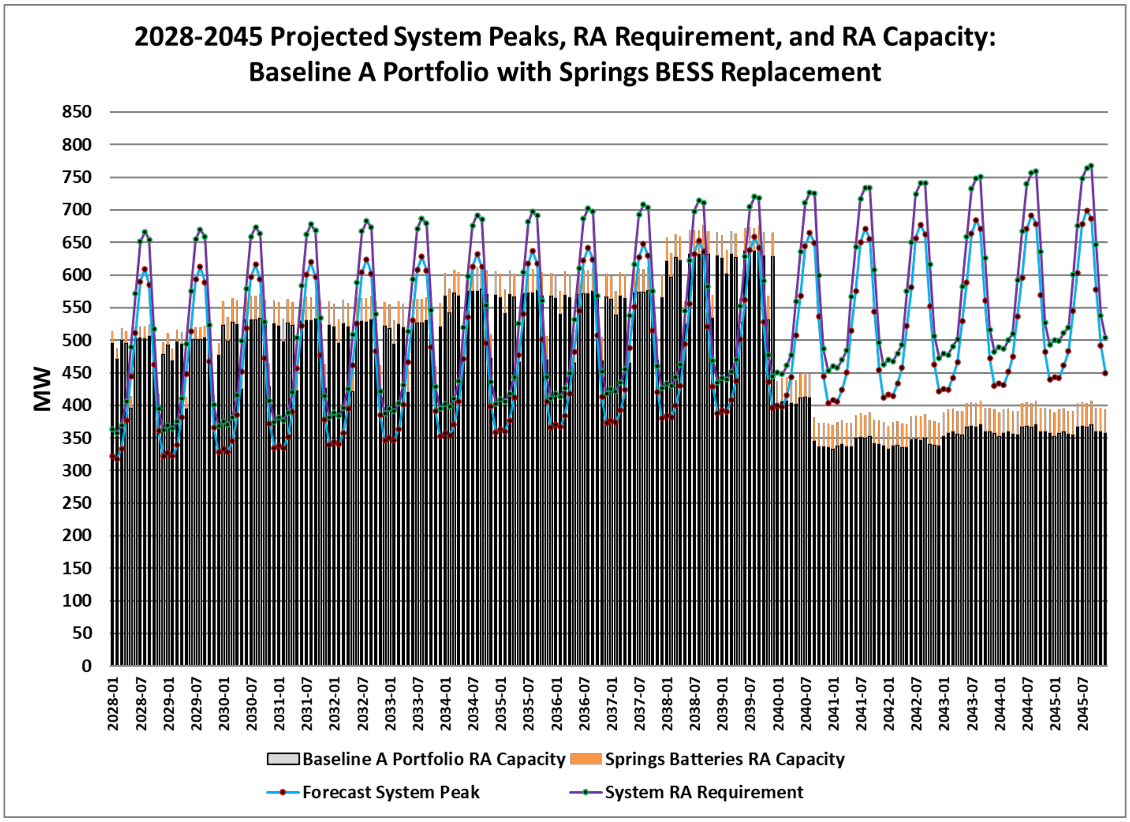


Figure 12.2.1. RPU's projected RA capacity under the Baseline A Portfolio with Springs replaced with BESS.

12.2.2 Springs BESS Net Value

The Springs BESS has a positive net value for the 2028 to 2045 timeframe, as shown in Figure 12.2.2. The average annual net value is $5.18/kW-month, which suggests that adding BESS I and II as a replacement for Springs should definitely not translate into any forecast portfolio cost increases (and perhaps actually help the Utility to reduce its future total portfolio costs). Note that the average annual net value estimate incorporates both the expected value of the replacement RA and the forecasted value of the shifted energy in the CAISO DA market.

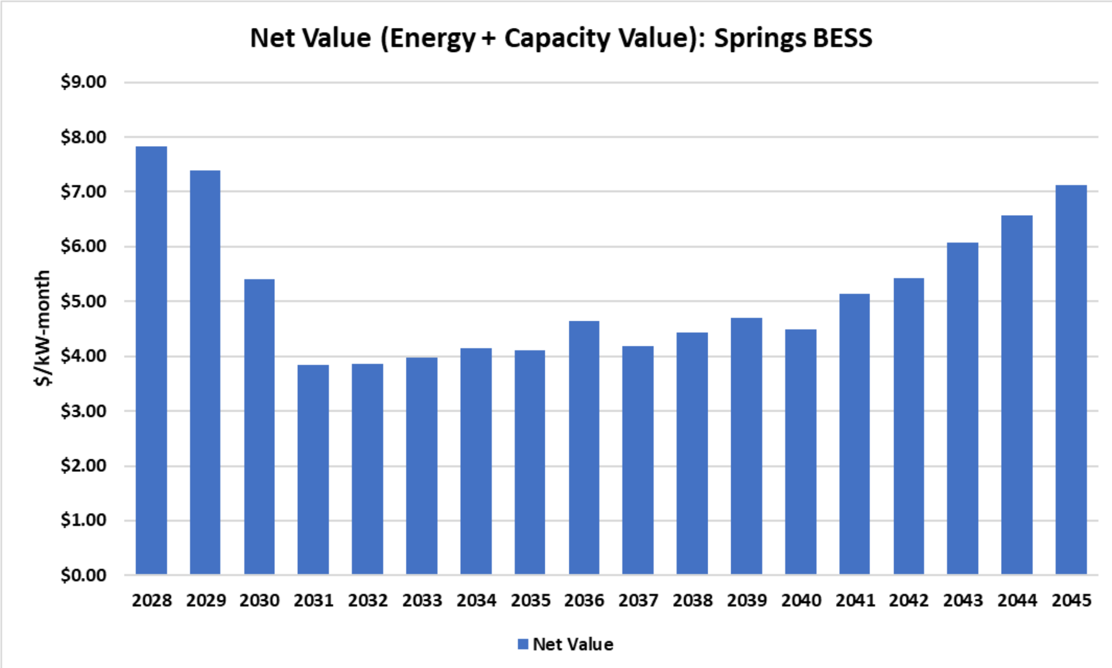


Figure 12.2.2. Springs BESS Net Value for the 2028 to 2045 timeframe.

12.2.3 Baseline A Portfolio with Springs BESS Risk Integrated Portfolio Cost

Figure 12.2.3 and Table 12.2.1 show the RIPC for the Baseline A Portfolio with the Springs BESS replacement included for 2024, 2028, 2030, 2036, and 2042. When Springs BESS I and II enter the portfolio in 2028 and 2030, there is essentially no impact to the RIPC compared to the Baseline A Portfolio. Beyond 2030, the BESS produces about a 1% decrease in the RIPC compared to the Baseline A Portfolio. The annual growth rate of the RIPC between the Baseline A and Baseline A w/Springs BESS Portfolios is essentially the same, suggesting that RPU could stage in these BESS resources to replace Springs with minimal to no cost impact.

The projected maintenance cost schedule for the gas-fired Springs Generation Facility calls for three million dollars of repairs and replacements for Springs Units 1 and 3 in FY2028/2029. With the BESS replacement analysis showing no significant cost increases, a BESS replacement for these units could be added during this timeframe in lieu of performing the projected maintenance thereby saving the maintenance cost. Given these results, a more detailed future analysis of battery replacement options for Springs is warranted.

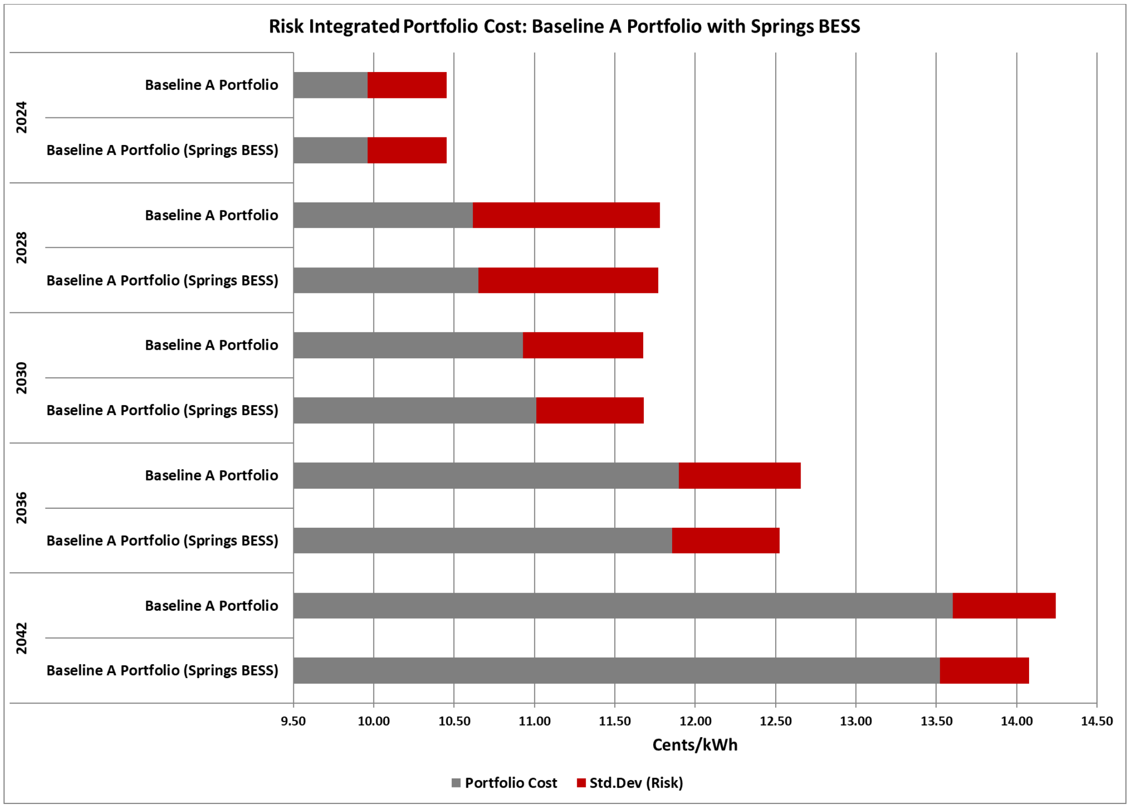


Figure 12.2.3. RPU's Risk Integrated Portfolio Cost under the Baseline A with Springs BESS Replacement.

Table 12.2.1. Figure 12.2.3 Risk Integrated Portfolio Cost estimates for years 2024, 2028, 2030, 2036 and 2042, along with relevant portfolio comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Portfolio	2024	2028	2030	2036	2042	Annual GR
A. Baseline A Portfolio	10.455	11.780	11.678	12.657	14.243	2.0%
B. Baseline A w/Springs BESS	10.455	11.771	11.680	12.524	14.078	1.9%
B vs A	0.0%	-0.1%	0.0%	-1.1%	-1.2%	

12.3 RERC Replacement Options

Under the Baseline Portfolio, RERC is retired after 2039 and not replaced. Note that this scenario assumes that the Riverside Transmission Reliability Project (RTRP) is built, giving Riverside a second point of interconnection to the electric transmission grid. Without RTRP, existing transmission constraints will necessitate repowering the RERC facility on at least a 1:1 basis when the current turbines reach the end of their useful life. Hence, this section presents analyses of the following alternative replacement scenarios:

1. Replacing RERC with a 100 MW 4-hour BESS and a 100 MW 6-hour BESS starting January 2040.
2. Scenario (1) plus the RERC units are switched to run on biogas starting in January 2035.
3. RERC shuts down five years early (e.g., after December 2034) and Scenario (1) starts in January 2035.

Note that Scenario (1) represents our default 2040 BESS replacement scenario, while Scenarios (2) and (3) represent two alternative scenarios for decarbonizing our internal generation assets by 2035 (e.g., five years ahead of schedule).

12.3.1 Baseline A Portfolio Capacity with RERC BESS Replacement

Figure 12.3.1 shows RPU's RA capacity from 2030 to 2045 after including all new resources proposed in the Baseline A Portfolio plus the Springs replacement BESS and the RERC 2040 BESS (shown in orange). The figure is representative of scenarios (1) and (2) defined above. Figure 12.3.2 is representative of scenario (3), where RERC is retired after 2034 and replaced with a 200 MW BESS. Replacing RERC with a 200 MW BESS partially fills the significant capacity need that arises once RERC retires. There are still capacity shortfalls to contend with, however. RPU will need to fill these with a combination of short-term RA products and yet-to-be-identified RA capacity contracts.

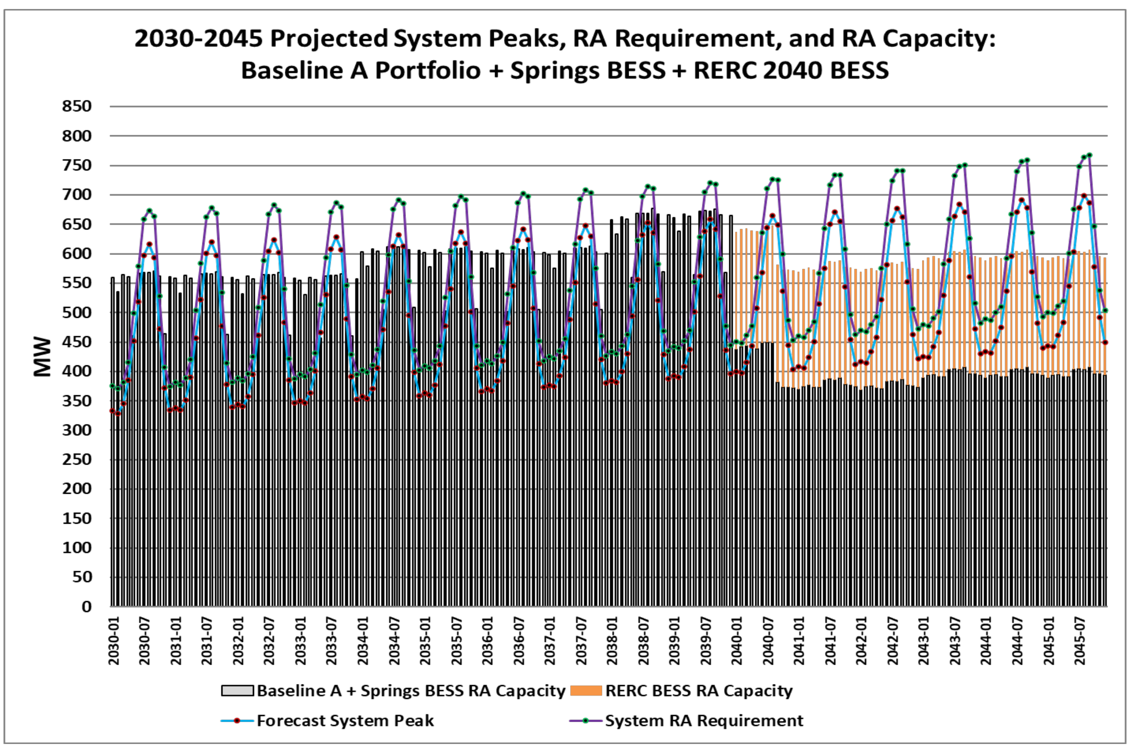


Figure 12.3.1. RPU's projected RA capacity under the Baseline A Portfolio (including a 36 MW Springs BESS) and RERC replaced with a 200 MW BESS after 2039.

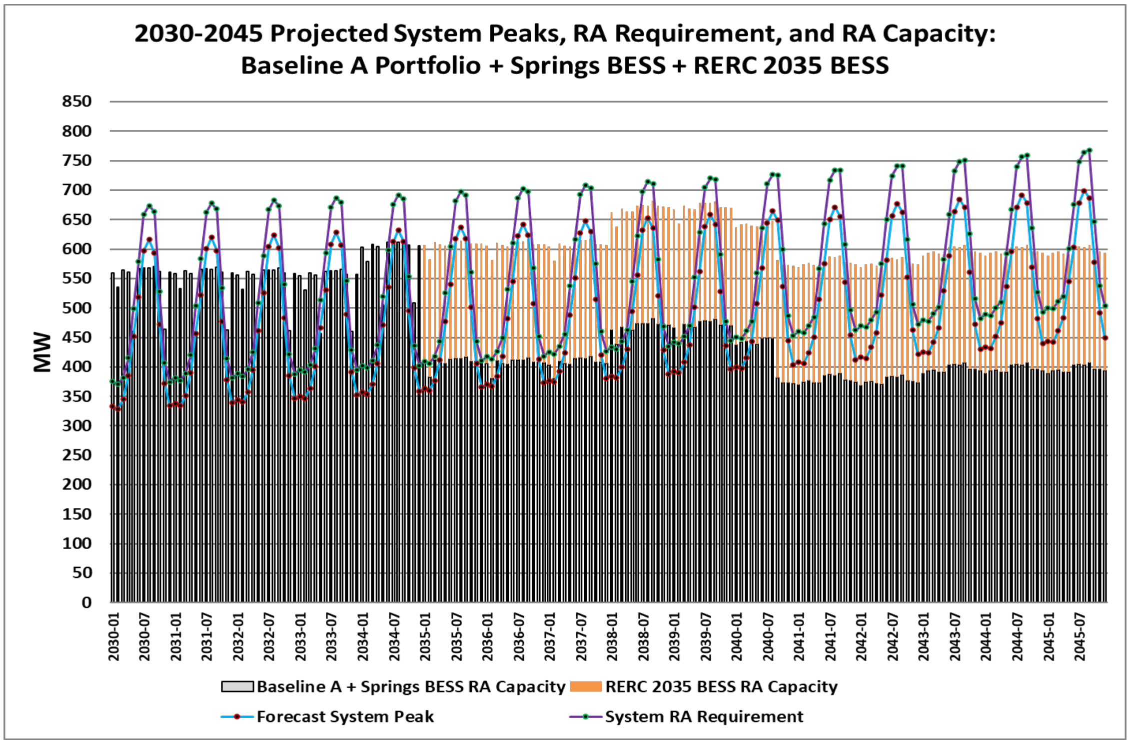


Figure 12.3.2. RPU's projected RA capacity under the Baseline A Portfolio (including a 36 MW Springs BESS) and RERC replaced with a 200 MW BESS after 2034.

12.3.2 RERC BESS Net Value

Figure 12.3.3 shows the net value for the proposed 100 MW 4-hour and 6-hour RERC replacement BESS. The 4-hour BESS has a positive net value through the 2035-2045 timeframe, with an average annual net value of $5.19/kW-month. For the 2040-2045 timeframe, the average annual net value is $5.80/kW-month. On the other hand, the 6-hour BESS has negative net values from 2035 through 2040 before they turn positive from 2041 through 2045. Overall, for the 2035-2045 timeframe, the 6-hour BESS does have a positive average annual net value of $0.36/kW-month; for the 2040-2045 timeframe, it increases to $1.02/kW-month. The difference in net values between the 4-hour and 6-nour BESS are predominantly driven by the assumed fixed $/kW-month cost of each BESS. In this analysis, the 6-hour BESS has a fixed cost 50% higher than the 4-hour BESS, which is consistent with current prices for comparable BESS in the market. The value proposition for the 6-hour BESS could change in the future if the CAISO RA rules change to require a longer-duration BESS for market participants to realize the full BESS nameplate capacity credit. In the current RA paradigm, a 4-hour and 6-hour BESS can provide the same RA value (100 MW in this analysis), so the additional cost of the 6-hour BESS does not translate to more RA value.

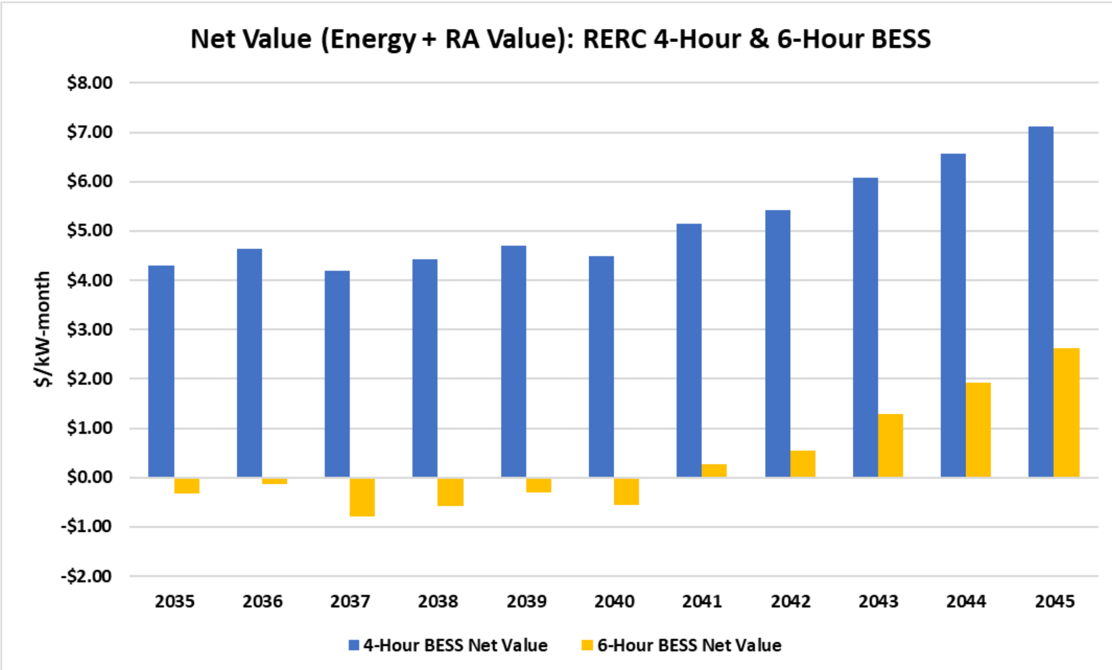


Figure 12.3.3. RERC 4-hour and 6-hour BESS Net Values for the 2035 to 2045 timeframe.

12.3.3 RERC Biogas

In Scenario (2), the RERC generation facility switches to run on biogas in the 2035 to 2039 timeframe. For this analysis, RERC's fuel cost is assumed to be the SoCal Citygate natural gas price index plus $10/MMBtu to mimic the premium for a biogas contract. Biogas is considered a renewable fuel, so RERC does not incur a carbon cost or have a carbon emissions obligation (emissions are assumed to be zero). Figure 12.3.4 shows the impact on RPU's Total Portfolio GHG emissions with RERC using biogas. Total Portfolio emissions decrease compared to the Baseline Portfolio since RERC no longer incurs a carbon obligation when running on biogas.[3]

Figure 12.3.5 compares the CAISO Day-Ahead Market Net Revenue for RERC running in its existing natural gas configuration versus a biogas configuration. As expected, the premium for biogas increases RERC's dispatch cost, reducing its dispatch and market net revenue. In the 2035-2039 timeframe, the market net revenue reduction is $20.2M or about $4M per year.

[3] The small residual amount of remaining GHG emissions in 2038 and 2039 are from the Clearwater cogeneration facility, which does not retire until January 1, 2040.

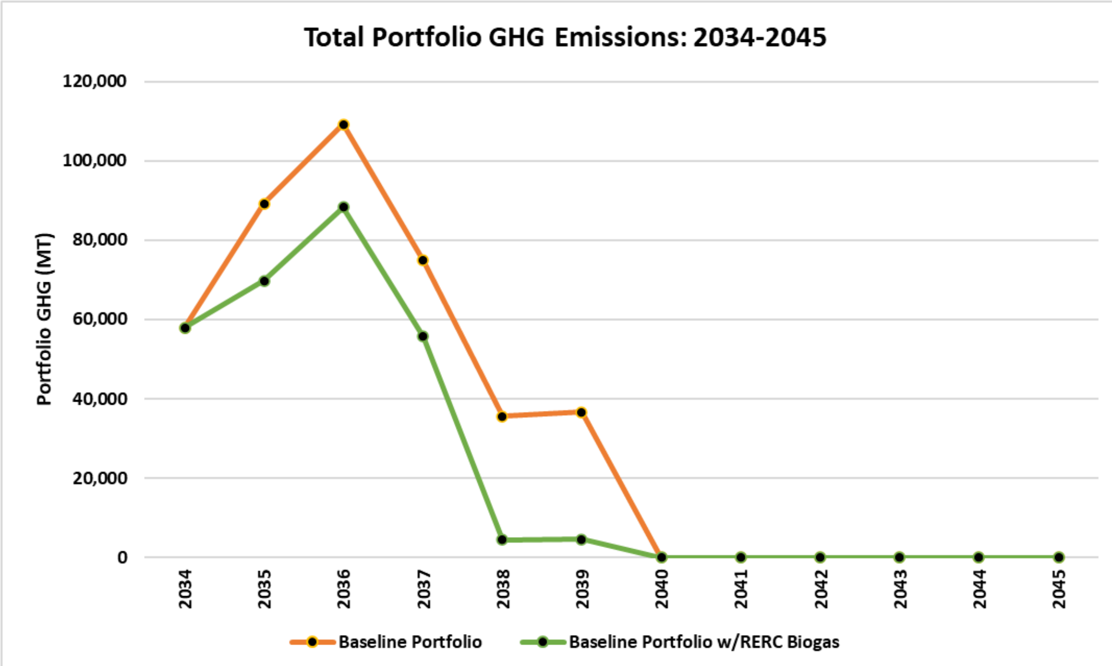


Figure 12.3.4. Total Portfolio Emissions with and without RERC converted to biogas for the 2035 to 2039 timeframe.

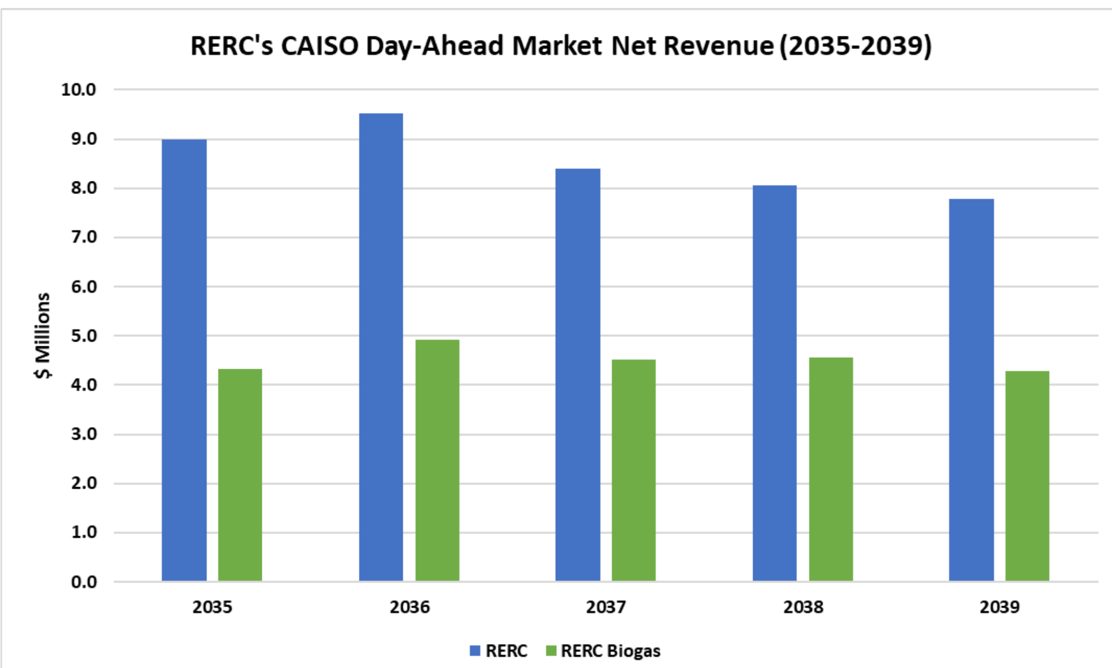


Figure 12.3.5. RERC versus RERC Biogas CAISO Day-Ahead Market Net Revenue for the 2035 to 2039 timeframe.

12.3.4 RERC Replacement Options Risk Integrated Portfolio Cost

Figure 12.3.6 and Table 12.3.1 show the RIPC impact of Scenario (1) compared to the Baseline A Portfolio. RIPC estimates are shown for 2039, 2042, and 2045. The RIPC estimates in 2039 are the same and shown for reference. The RIPC estimates for 2042 and 2045 clearly show cost and risk benefits of deploying the BESS to replace RERC when it retires. The RIPC estimates for 2042 and 2045 are about 3% and 6% lower, respectively, compared to the Baseline A Portfolio which does not include a RERC replacement. The average annual growth rate of the RIPC between 2039 and 2045 for the Baseline A Portfolio with RERC BESS replacement is half that of the Baseline A Portfolio where RERC is not replaced. The results make intuitive sense given the positive net value of the BESS, as discussed previously.

Figure 12.3.7 and Table 12.3.2 show the RIPC impact for Scenarios (2) and (3) compared to the Baseline A Portfolio, along with an additional Baseline A portfolio with RERC retired after 2034 and not replaced. RIPC estimates are shown for 2034, 2035, and 2037. The RIPC estimates in 2034 are the same and shown for reference. For scenario (2), RIPC estimates in 2035 and 2037 are about 1.6% higher than the Baseline A Portfolio. This reflects the reduced CAISO Day-Ahead Market Net Revenue generated by RERC when it is running on higher-cost biogas.

For scenario (3), the RIPC estimates in 2035 and 2037 are about 5.2% higher than the Baseline A Portfolio. The primary driver for this increase being the fixed cost for the BESS, which needs to be paid as part of the assumed contractual payment structure. RPU owns the RERC facility, and it was paid for with bond proceeds. Therefore, the fixed cost for RERC is assumed to be sunk and does not factor into this analysis. RPU realizes RERC’s RA capacity and energy benefits without the high fixed capacity costs a new BESS would require. RERC’s cost and risk benefits are highlighted in the case where RERC is retired after 2034 and not replaced. The RIPC for 2035 and 2037 is over 10% higher than the Baseline A Portfolio, which shows how important these generation assets are at mitigating RPU’s power supply costs. Additionally, the new 2035 BESS only offset about half of this cost increase, if/when the RERC units are retired five years ahead of schedule.

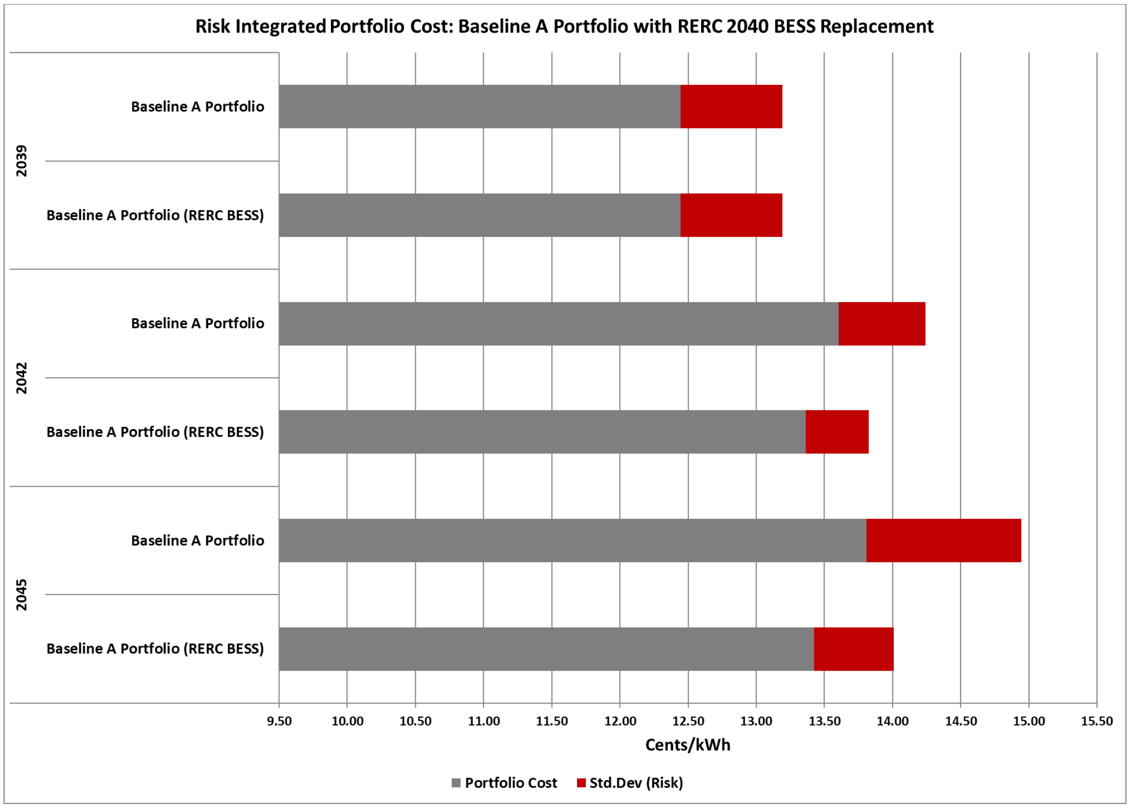


Figure 12.3.6. RPU's Risk Integrated Portfolio Cost under the Baseline A Portfolio with RERC BESS Replacement deployed in 2040.

Table 12.3.1. Figure 12.3.6 Risk Integrated Portfolio Cost estimates for years 2039, 2042, and 2045, along with relevant portfolio comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Portfolio	2039	2042	2045	Annual GR
A. Baseline A Portfolio	13.192	14.243	14.942	2.2%
B. Baseline A w/RERC 2040 BESS	13.192	13.824	14.009	1.0%
B vs A	0.0%	-2.9%	-6.2%	

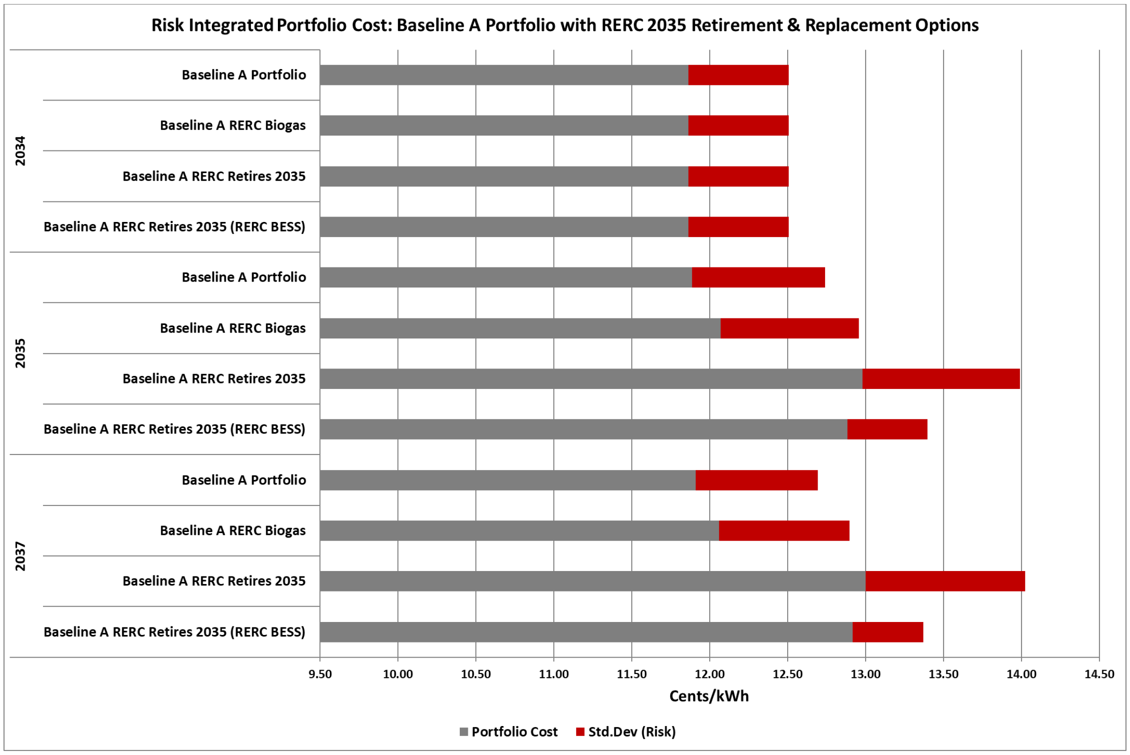


Figure 12.3.7. RPU's Risk Integrated Portfolio Cost under the Baseline A Portfolio and three RERC 2035 replacement/retirement options.

Table 12.3.2. Figure 12.3.7 Risk Integrated Portfolio Cost estimates for years 2034, 2035, and 2037 along with relevant portfolio comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Portfolio	**2034**	**2035**	**2037**	**Annual GR**
A. Baseline A Portfolio	12.508	12.740	12.695	0.5%
B. Baseline A w/RERC Biogas	12.508	12.957	12.896	1.0%
C. Baseline A RERC retires 2035	12.508	13.990	14.026	4.0%
D. Baseline A w/RERC BESS 2035	12.508	13.399	13.370	2.3%
B vs A	0.0%	1.7%	1.6%	
C vs A	0.0%	9.8%	10.5%	
D vs A	0.0%	5.2%	5.3%	

12.4 Impacts of Price Mark Assumptions for Resources 2, 3, and 4

The assumed price marks used for Resources 2-4 (see Tables 11.2.4 and 11.2.5) are considered normal and consistent with the current market. However, the market is uncertain, and the price marks could be significantly different by the time these proposed resources are slated to enter the RPU portfolio. Given the large energy volumes provided by these proposed resources, significant price mark changes will have an impact on the RIPC of the Baseline A Portfolio. To examine this impact, RPU staff have recalculated the RIPC with the price marks for Resources 2-4 raised and lowered by 30%.

Figure 12.4.1 and Table 12.4.1 show the RIPC of the Baseline A Portfolio compared to the RIPC with the adjusted price marks for Resources 2-4. As expected, the RIPC is very sensitive to the pricing of these resources. In 2036, Resource 2 is in the portfolio, and the 30% price mark adjustment translates to a 3.7% increase/decrease in the RIPC. In 2042, Resources 2-4 are in the portfolio, and the price mark adjustment translates to 7.8% increase/decrease. The average annual growth rate from 2024 to 2042 for the RIPC is 2.0% under the Baseline A Portfolio. With the Resource 2-4 price marks raised and lowered by 30%, the average annual growth rate is 2.6% and 1.4%, respectively. Maintaining a reasonable RIPC growth rate is very important from a portfolio budget cost and ultimately customer rate impact perspective. Hence, as this analysis suggests, securing cost-effective resource pricing will be essential for RPU to control its RIPC growth rate as it builds out its portfolio in the next decade to meet CA renewable and carbon neutrality goals.

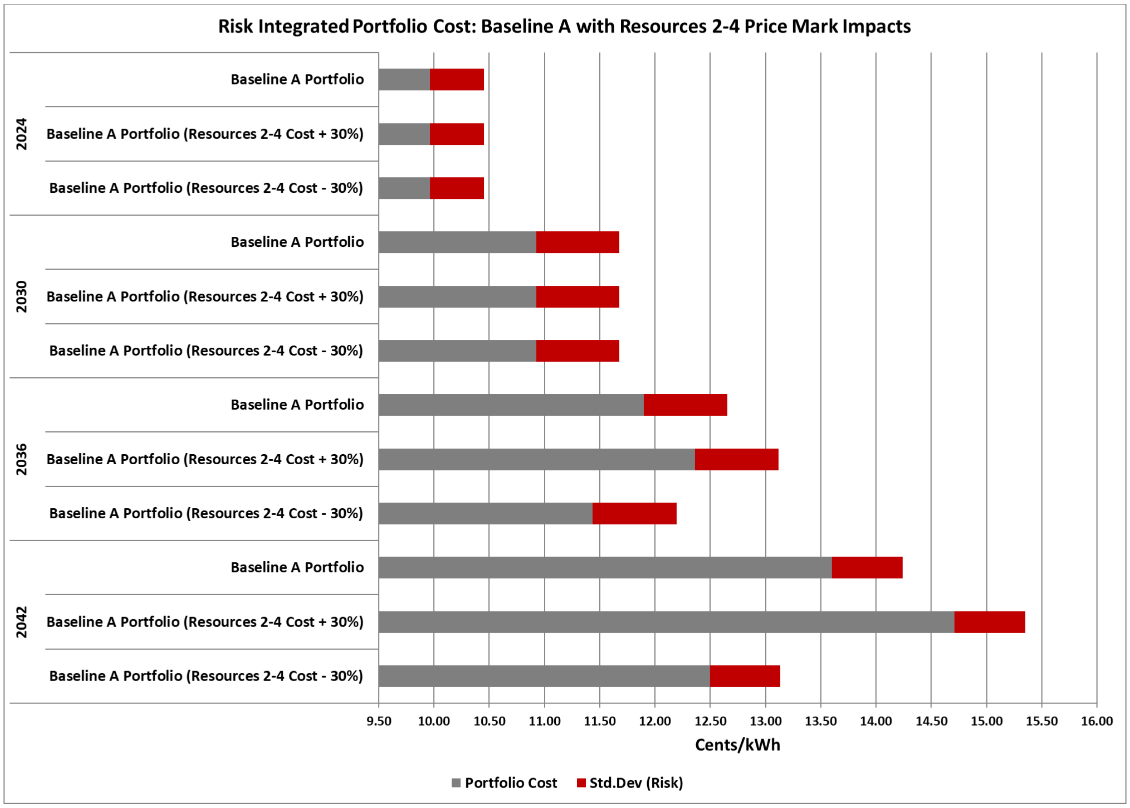


Figure 12.4.1. RPU's Risk Integrated Portfolio Cost under the Baseline A Portfolio with Resource 2-4 price marks raised and lower by 30%.

Table 12.4.1. Figure 12.4.1 Risk Integrated Portfolio Cost estimates for years 2024, 2030, 2036, and 2042, along with relevant portfolio comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Portfolio	2024	2030	2036	2042	Annual GR
A. Baseline A Portfolio	10.455	11.678	12.657	14.243	2.0%
B. A w/Resources 2-4 Cost +30%	10.455	11.678	13.119	15.351	2.6%
C. A w/Resources 2-4 Cost -30%	10.455	11.678	12.194	13.135	1.4%
B vs A	0.0%	0.0%	3.7%	7.8%	
C vs A	0.0%	0.0%	-3.7%	-7.8%	

12.5 Summary of Findings

Some of the more pertinent findings presented in this chapter are briefly summarized below.

1. The Baseline Portfolio satisfies all GHG reduction and RPS mandates through the 2045 timeframe. Under either the Baseline A or B portfolio, RPU achieves (a) a 2030 emission level of 152,065 metric tons, which is below its more aggressive reduction target of 275,000 metric tons, (b) a 2030 RPS of 80.5%, and (c) carbon neutrality by 2040.

2. Of the two renewable resources proposed for 2030, the Solar + Storage (Resource 1b) produces a 2030 RIPC that is 1.6% lower than the Baseload Geothermal (Resource 1a). This result is highly dependent on the assumed contract pricing for each resource, as well as the size of the storage asset. Nonetheless, it does suggest that under the assumed pricing structures and configurations, a Solar + Storage resource would be the more viable procurement option for RPU to pursue as its next resource (as opposed to another geothermal resource).

3. Between 2024 and 2042, these IRP studies suggest that RPU's power resource costs will grow at about 2.0% annually under the Baseline A Portfolio and 1.9% annually under the Baseline B Portfolio.

4. Deploying BESS as replacements for Springs in 2028 and 2030 resulted in essentially no impact to RPU's RIPC in those years. Beyond 2030, the BESS produces about a 1% decrease in the RIPC compared to the Baseline A Portfolio. These results suggest that a more detailed future analysis of battery replacement options for Springs is warranted.

5. Deploying BESS as a replacement for RERC after it retires in 2039 results in RIPC estimates for 2042 and 2045 that are about 3% and 6% lower, respectively, compared to the Baseline Portfolio which does not include a RERC replacement. These results show that it will be important to replace RERC with some type of energy storage technology after 2039, to continue mitigating the financial impacts of high price energy hours.

6. Running RERC on biogas starting in 2035 results in RIPC estimates in 2035 and 2037 that are about 1.6% higher than the Baseline A Portfolio. This reflects the reduced CAISO Day-Ahead Market Net Revenue generated by RERC when it is running on higher-cost biogas. Note that there could also be additional costs of converting RERC to run on biogas that are currently unknown. Hence, a more detailed analysis of such a conversion would need to be completed should RPU want to pursue this option.

7. In contrast to the biogas option, retiring RERC after 2034 and deploying BESS replacements results in RIPC estimates in 2035 and 2037 that are about 5.2% higher than the Baseline A Portfolio. The BESS does not produce equivalent market net revenue due to its fixed costs, which for RERC are considered sunk. Therefore, this represents a less financially appealing

alternative for decarbonizing our internal generation assets prior to 2040, as compared to the biogas alternative.

8. Finally, the price sensitivity studies presented in section 12.4 confirm that it will be very important for RPU to continue to secure cost-effective resources as the utility builds out its portfolio over the next 15 years. Securing cost-effective resource pricing will be essential for RPU to control its RIPC growth rate, which in turn will directly impact the magnitude of future rate increases.

13. Distribution System Studies of Distributed Energy Resource Impacts

As part of the current Integrated Resource Plan, RPU has evaluated the distribution grid's sensitivity to customer adoption of renewable and alternative technologies. In this chapter, we consider a capacity analysis study of each RPU distribution system feeder. The study results illustrate the ability to accommodate more generation from Distributed Energy Resources (DERs) like rooftop solar photovoltaic (PV) installations and loads from Building Electrification (Fuel Switching) or DERs like electric vehicle (EV) charging on each RPU distribution feeder. In industry literature this is sometimes called an Integration Capacity Analysis, or ICA[1].

The intent of this chapter's study is exploratory in nature and is not a formal forecast used for resource planning or capital investment planning purposes. While similar methods can be applied to create a forecast, RPU does not currently have all the technology tools available to complete a formal forecast ICA. With this study, staff primarily intend to show threshold levels of adoption that will require upgrades to distribution substation or feeder equipment. In the future, it is expected that these upgrades will become necessary to accommodate more renewables or alternative technologies. However, this study does not currently identify the costs of specific items that might require upgrading on RPU's distribution feeders and substations, nor does it identify specific years when such upgrades may need to occur.

RPU maintains independent processes to evaluate its resource plan and distribution grid capital investment plan. Consistent with industry practice, RPU has traditionally relied on single day peak load planning studies (representing the highest electrical loading during the hottest days of the year) to inform distribution capital investment plans.[2] For resource planning purposes at the system level, staff forecast the continued growth of DERs and include parameters for solar photovoltaic, energy efficiency, and electric vehicles in load forecasting methods.[3] In the future, these alternative technologies, including electric vehicles and solar photovoltaics, may require the development of updated capital investment planning approaches. However, RPU has not yet developed a comprehensive method to forecast on the distribution feeder or geospatial level when and/or where such DER adoption may occur.

For future IRPs, RPU will need to develop more studies and methodologies to disaggregate expected growth of these alternative technologies and/or develop organic growth models to geospatially forecast adoption.[4] Later studies may apply load growth assumptions or forecasts to this ICA, but the intent of this study is to consider a static scenario for determining the amount of additional electric vehicle load, fuel switching load, and solar photovoltaic generation that each existing RPU feeder can accommodate (under fairly generic assumptions). Finally, this study excludes all distribution

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[1] Per CPUC requirements, California's IOUs must publish their Integration Capacity Analysis 288 profiles on the DRP External Portal. See https://ltmdrpep.sce.com/drpep/.
[2] DERs on the RPU distribution grid appear to have de minimus impacts on current local electrical load peaks/times.
[3] As discussed in this IRP in Chapter 2.
[4] Future IRPs may assess projections of DER adoption in the RPU territory using NREL's dGen™ tool, a geospatial model that simulates the potential adoption of DERs for residential, commercial, and industrial entities.

feeder assets where existing locational constraints persist or where maintenance is currently in progress (since new equipment, capacity information, and load pattern data is either obsolete or not yet available at those locations).

13.1 Traditional System Study and Load Forecasting Considerations

RPU's distribution grid is made up of 126 radial[5] 12 kilovolt (kV) polyphase distribution feeders, which are the subject of this study.[6] Consistent with radial[7] feeder design, RPU's distribution feeders are operated on the principles of one-way power flow from electrical distribution substations to load customers. The design of RPU's radial feeders did not consider a future where distribution feeders would collect energy from generation resources and become net generators of electric power from time-to-time throughout the year, and traditionally these feeders have not done this. RPU's traditional utility system planning focuses on studying electric system peak loading to plan for system upgrades. As part of its distribution capital investment planning processes, RPU determines peak load serving capacity limits for all its distribution feeders. Currently RPU only has one feeder in its distribution system that is a net generator of electric power for certain periods of high photovoltaic output. However, substantial changes in load patterns in the coming years across the distribution grid due to rapid customer adoption of electric vehicles, solar photovoltaic, and other alternative technologies like energy storage are likely.

13.1.1 Feeder Loading: Air Conditioning versus Electric Vehicles, Fuel Switching, and Solar PV

Consider Figure 13.1.1, where the August peak for Feeder 1287 is highlighted in a 288-point summary of yearly demand data. Consistent with traditional radial feeder design, at no point in the year does the median load level on this feeder collect net generation or approach zero loading. In Southern California, air conditioning loads and use patterns have traditionally dominated overall electric grid loading. Weather (particularly temperature) correlation to system loading is strong and well documented[8]. A combination of continued customer adoption of air conditioning and repeatable customer behavior patterns, such as running the air conditioner in the late afternoon / early evening hours made forecasting local peaks relatively straight-forward.

In a traditional distribution system study, planners will identify capital upgrades to accommodate the expected peak load at critical nodes on the system. In many cases, a 1-in-2 or P50 (50th percentile) peak load forecast is used to identify "must-have" or "no regret" type upgrades. Planners also assign different contingencies for weather such as 1-in-10 hot weather contingency,

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[5] "The radial system gets its name from the fact that the primary feeders radiate from the distribution substations and branch into subfeeders and laterals which extend into all parts of the area served." John S Parsons & H. G. Barnett, Chapter 20: Distribution Systems II.1, in Electrical Transmission and Distribution Reference Book 667 (5 ed. 1997).

[6] As part of this ICA, RPU did not study several lower voltage distribution feeders scheduled for removal.

[7] Radial feeder design contrasts with networked feeders, such as transmission lines, which may receive and distribute electrical energy in any direction.

[8] Matthew Bartos et al., Impacts of rising air temperatures on electric transmission ampacity and peak electricity load in the United States, 11 Environmental Research Letters 114008 (2016).

and/or outages on critical equipment such as an N-1 study to plan contingency "good-to-have" capacity upgrades. Since the *time* of peak is consistently around 5 PM in summer, this allows utility distribution system planners to focus on economic growth (per capita income, tax receipts, permitted building starts, or some other econometric proxy) to develop meaningful peak forecasts without regard for computationally expensive time series data studies for non-peak times. While peak forecasts are still susceptible to weather and economic shocks, in many years, they perform quite well. Load patterns for alternative technologies, however, are unlikely to mirror the customer behavior patterns of the past.

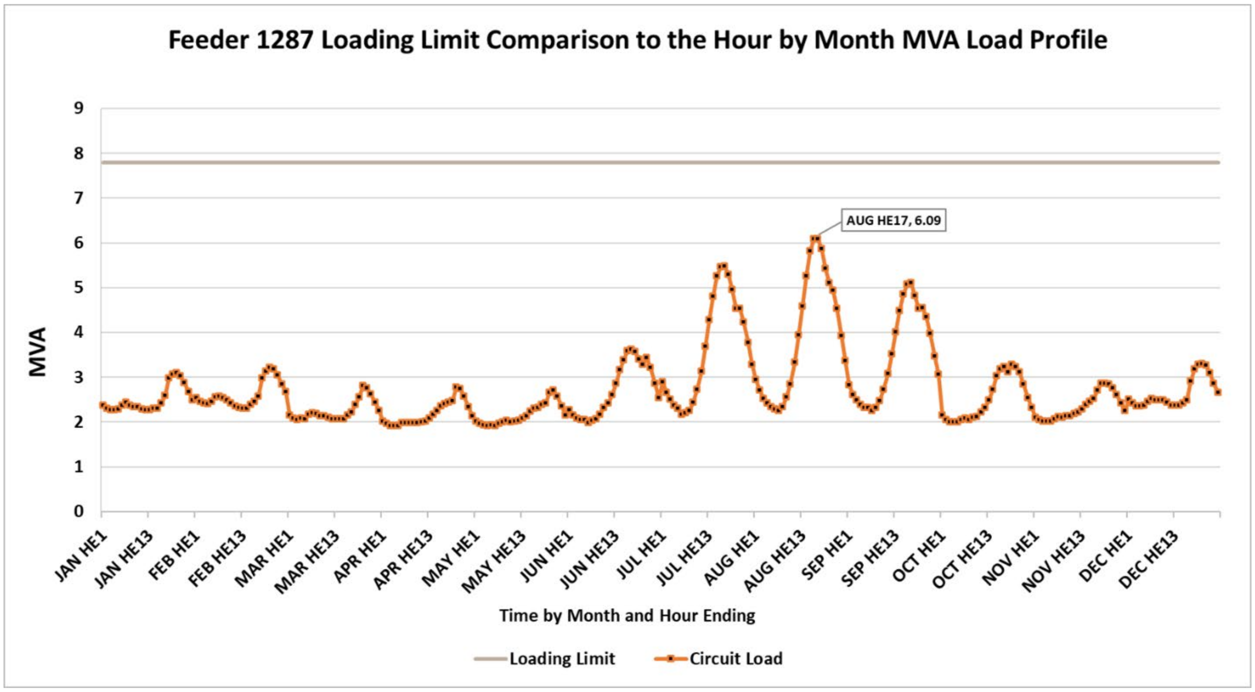

Figure 13.1.1. Feeder 1287 Loading Limit Comparison to the hour by Month MVA Load Profile.

Load patterns related to Electric Vehicles and Fuel Switching depend on economic factors like fuel prices and purchase prices, government regulation/incentives[9], supply chains, and other customer behaviors. Fortunately, research organizations are studying the changes and their impacts, and more information is becoming available from CEC, NREL, and even RPU's own internal study to produce meaningful load and generation patterns related to alternative technologies. The CEC has provided CA IOUs with forecasts of EV growth and Fuel Switching within their service territories. RPU has used a

[9] While additional federal incentives are becoming available, the primary incentive is the ZEV program is part of the California Air Resources Board's (CARB's) Advanced Clean Cars package of coordinated standards that controls smog-causing pollutants and GHG emissions of passenger vehicles in California. This program requires auto manufacturers to offer specific numbers of battery-electric, hydrogen fuel cell, and plug-in hybrid electric vehicles, calculated as a function of their total vehicle sales and vehicle types; the more electric driving range a vehicle has, the more credit it receives.

scaled version[10] of these CEC forecasted EV and Fuel Switching load shapes (see Figure 13.1.2 and 13.1.3 respectively) for SCE's service territory in this current study. In addition, due to net energy metering, tax incentives, and building standards updates,[11] customer adoption of solar Photo-Voltaic (PV), Electric Vehicles (EVs), and Fuel Switching (FS) will continue to grow in California.

The CEC forecasted EV load pattern[12] is not consistent with RPU's overall load shape (see Figure 13.1.1) which typically peaks at hour-ending (HE) 17. The load pattern illustrates some charging (at the workplace or shopping center) occurring throughout the daytime hours from HE 8 to HE 15. However, nighttime charging dominates the load pattern. The peak occurs when TOU rates are low and customers' vehicles are not in use from HE 21 to HE 2 the following day.

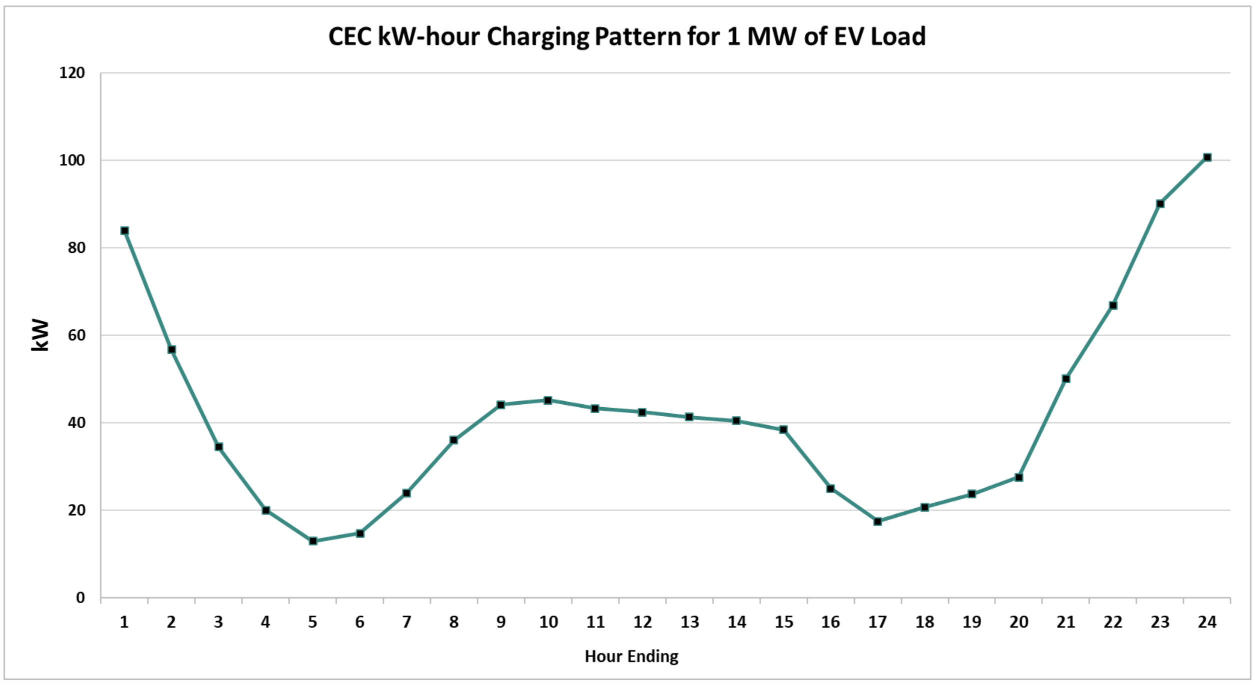

Figure 13.1.2. CEC Electric Vehicle (EV) kW-hour Load Pattern for 1 MWh/day of EV load within the SCE Service Territory.

[10] See Chapter 2 for a discussion on how RPU scales the SCE load shapes.
[11] Notwithstanding any local ordinances being considered, the CEC's Title 24 building energy efficiency standards are designed to reduce wasteful, uneconomic, inefficient or unnecessary consumption of energy and enhance outdoor and indoor environmental quality. These standards are updated every three years. The 2019 standards required that all new homes include solar PV systems. The upcoming 2022 standards additionally require EV charging readiness in all new homes. Future standards will likely reduce and end the use of natural gas appliances in new homes.
[12] While research and pilots continue in vehicle to grid or V2G, this nascent technology is not commercially available and therefore is not considered in this study. A forecast ICA may need to consider this technology adoption.

The CEC forecasted Fuel Switching (FS) load pattern is shown in Figure 13.1.3. This forecast illustrates a problematic characteristic with respect to FS as it contributes a more significant share to peak energy demand periods. Adding loads coincident at HE 17 is undesirable because it increases the maximum electrical peak loads on distribution system assets.

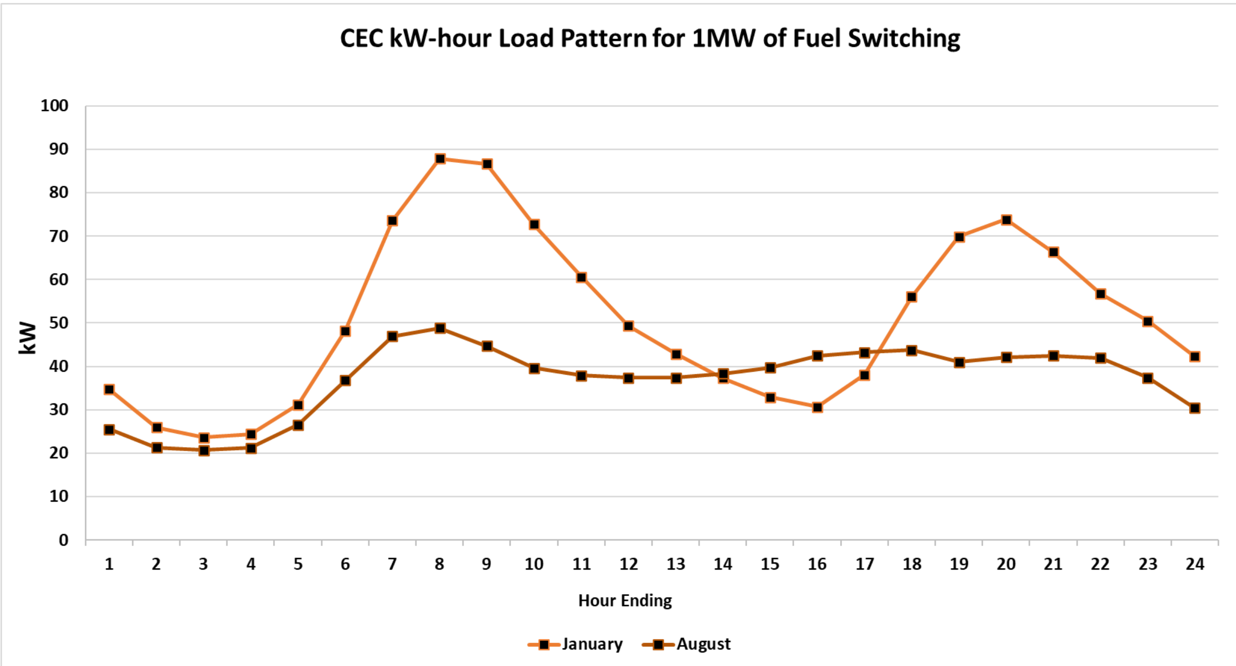

Figure 13.1.3. CEC Fuel Switching kW-hour Load Pattern for an annual average of 1 MWh/day of Fuel Switching load within the SCE Service Territory.

Finally, solar PV generation has seasonal and diurnal variabilities to consider (see Figure 13.1.4). The solar generation pattern varies due to the annual cycle of the sun, particularly for fixed mounted residential installations. The sun is more perpendicular to fixed panels in late spring and early summer, so the output of stationary PV in summer is greater than when the sun angle is low in winter months. Nonetheless, peak PV output occurs from HE 12 to HE 13 year-round. Note that RPU has incorporated its own system PV output profile results into this ICA, based on simulated generation profiles for our local area.

As discussed previously, RPU's feeder loads typically peak at HE 17 (see Figure 13.1.1), while solar PV generation peaks near HE 12. PV generation during HE 17 is minimal, as seen in Figure 13.1.4. EV loads peak at HE 24, as illustrated in Figure 13.1.2. FS peaks in the early morning hours around HE8 (Figure 13.1.3). Traditional peak planning will not capture the diverse behavior of these resources; therefore, a time-series analysis method is needed.

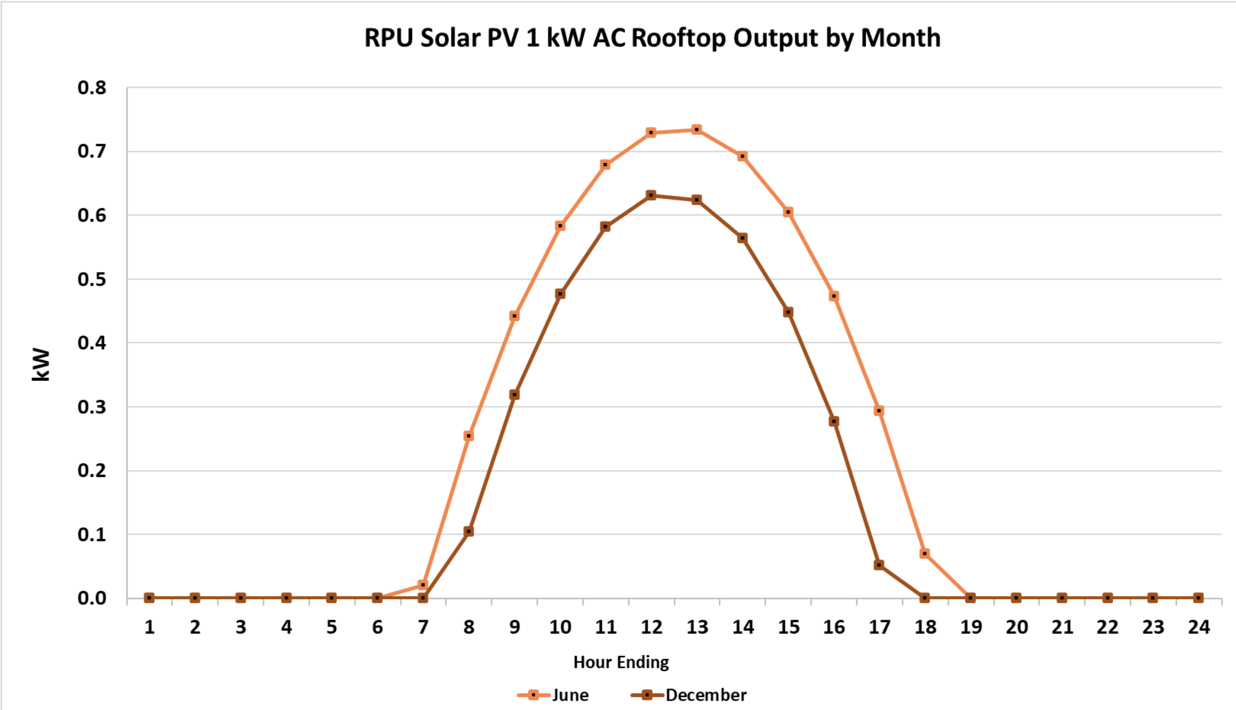

Figure 13.1.4. Expected Solar PV output for a 1 kW AC system during June and December in the RPU service territory.

13.1.2 Integration Capacity Analysis (ICA)

In this Integration Capacity Analysis (ICA), staff have used the CEC estimated diurnal patterns for EV and FS loads and RPU estimated local PV generation to study RPU's *current* electric system. The SCADA derived time-series analyses performed here calculate scalar quantities[13] that quantify how these expected EV, FS load shapes (and PV generation patterns) might impact the maximum (or minimum) capacity of each distribution feeder at any given hour. The resulting scalar quantities define the threshold levels of adoption that would begin to affect each distribution feeder as it exists today. More specifically, the EV and FS scalars can be used to derive peak power values of each resource that consume a feeder's entire capacity, while the PV scalar quantifies the maximum allowable daily PV generation that can occur before a reverse power flow condition would occur. Hence, these scalers conceptually identify the resulting sensitivity[14] to adoption of EV, PV, and FS. Note also that while the scalars of the typical EV, PV, and FS profile shapes do not correspond directly to a specific quantity of installations or locations, a range of plausible installation counts can be derived from these scalar quantities as well.

[13] The scalar quantities referenced here are used to derive the EV, FS and PV adoption ranges found later in Section 13.2.
[14] This sensitivity metric is the Capacity Utilization Factor, as defined in section 13.2.

This ICA study allows RPU to find the available capacity to integrate specific quantities of DER technologies and refresh this study on a regular basis. As the study results later show, RPU expects to have the ability to integrate material amounts of EV, FS, or PV on many of its distribution feeders before those loads become dominant factors in considering upgrades on the RPU distribution grid. This in turn should allow more time for fine tuning forecasts of demand and/or performing low level “bottom up” types of distribution grid studies.

13.2 Distribution System Statistics and Quantities

RPU planners typically compare the expected load to the power capacity limits in mega-volt-amperes or MVA[15] of available equipment on an annual basis. This ratio or percentage is expressed as a “Capacity Utilization Factor” value, which provides a planner with a sense of the congestion of the equipment and how *sensitive* that equipment would be to load growth. Consider the example of Feeder 1287 in Figure 13.1.1, where we can evaluate a capacity factor based on the given data. The Capacity Utilization Factor is defined as the ratio of the maximum demand on a feeder to its capacity:

$$\text{Capacity Utilization Factor} \; = \frac{\text{Maximum Load (Peak)}}{\text{Capability (Peak Capacity)}} \cong \frac{6.1\,MVA}{7.8\,MVA} \; = \mathbf{0.78}$$

The closer the Capacity Utilization Factor ratio is to one, the more sensitive it will be to additions of load in that peak hour. One can conclude that Feeder 1287 can accommodate limited amounts of added load, however substantial load increases may require upgrades as part of RPUs capital investment plan. One can summarize this information for RPU’s feeders as follows:

Table 13.2.1. Capacity Utilization Factor for Feeder 1287.

Feeder ID	Capacity Utilization Factor
1287	0.78

RPU desires to estimate these types of sensitivity statistics for different technologies, but because they do not share the same peak, this analysis becomes more complicated. RPU staff must quantify the diurnal patterns for each alternative technology studied, which are not necessarily related to the traditional summer peak. Since the peak times for EV, PV, and FS profiles are independent of

[15] In this Chapter’s analysis, RPU makes use of MVA as the preferred quantity for power capacity. Use of MVA as a quantity is beneficial as industry practice rates distribution transformers in MVA alone. While distribution feeder cable and components are rated in amperes, this ampere rating can be readily converted to MVA when the operating voltage is known.

traditional loads, a combined profile will no longer share the same shape or peak time. Once again, we find a more comprehensive time series analysis approach is needed.

13.2.1 288 Profile Diurnal Pattern Analysis Approach

Time series planning and forecasting for electric load or resource patterns in hourly intervals for hundreds of distribution assets can be computationally expensive as one year holds 8760 hourly points. Additionally, it is difficult to prepare useful illustrations with 8760 data as seen in Figure 13.2.1.

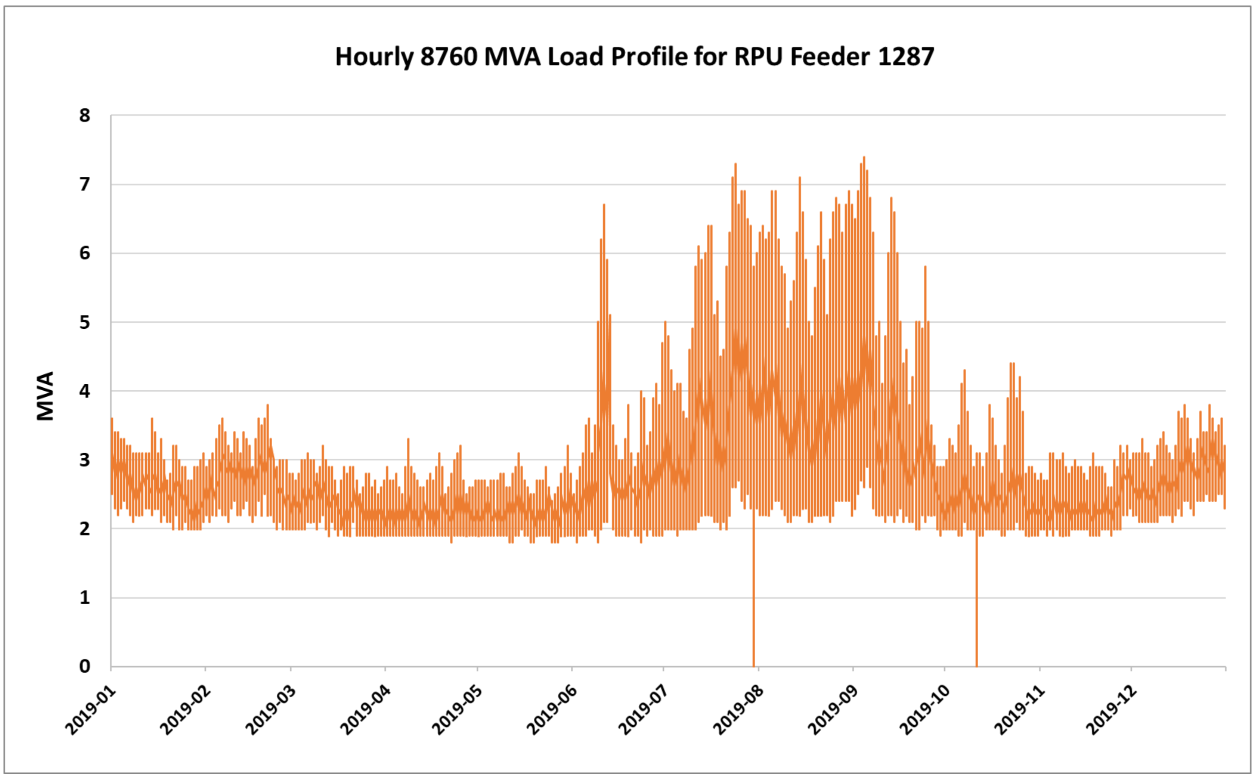

Figure 13.2.1. Hourly 8760 MVA load profile for RPU Feeder 1287.

Diurnal patterns on distribution feeders vary little day to day, but meaningful changes in the diurnal pattern occur across months. One method that can therefore be useful to study the distribution grid's available capacity is the study of the diurnal load shape across months. This can be done by constructing a "288" point profile that quantifies the average feeder load across all 24 hours by 12 months, or equivalently a 288-vector point summary of the substation and feeder loading. The "288 profile" is useful for visualizing scenario analysis of customer adoption of various technologies (self-generation like solar PV) and increasing loads (FS electrification of appliances, EV charging, etc.) which may have impacts at various times of the day other than the typical peak time. Planners do not typically study these changes in load shape behavior that encompass the peak during a peak planning process, but statute encourages the CEC to consider it in Integrated Resource Planning.[16]

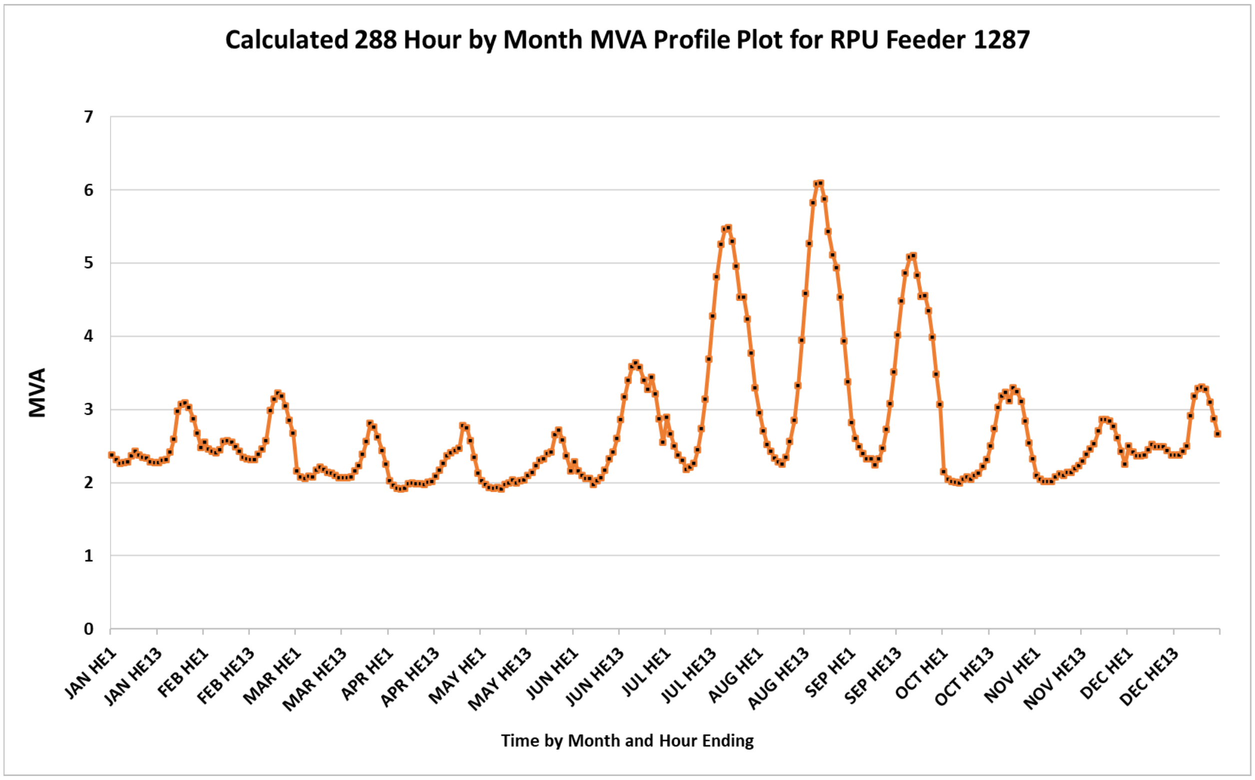

Figure 13.2.2. Calculated 288 Hour by Month MVA profile plot for RPU Feeder 1287.

The 288-profile in Figure 13.2.2 provides insights into electrical usage patterns. Usage on the example Feeder, 1287, is correlated to weather, peaking in hotter months of July and August. This pattern and load shape behavior is common throughout RPU's distribution grid.

13.2.2 Meaningful Statistics Related to Diurnal Patterns: 10th and 90th Percentile Profiles

As discussed earlier, a 288-profile can be instructive for better understanding the RPU distribution system's capacity for integrating alternative technologies. To construct 288-profiles for each RPU distribution grid feeder, RPU first collected hourly SCADA from 2017-2021. The 8760 data

[16] Public Utilities Code §454.54 "the commission [CEC] shall consider the role of existing renewable generation, grid operational efficiencies, energy storage, and distributed energy resources, including energy efficiency, in helping to ensure each load-serving entity meets energy needs and reliability needs in hours to encompass the hour of peak demand of electricity."

from this time period was then preprocessed with an Analysis of Covariance[17] method to eliminate as many outlier measurements in the SCADA as possible. After preprocessing, RPU staff performed a manual SCADA review to remove other difficult to detect anomalies in the data such as missing data periods, non-updating periods, de minimis load values, missing load data, anomalous static high load, sampling issues (static load), and anomalous time varying high load. Figure 13.2.3 illustrates the kinds of SCADA anomalies that were omitted from the analysis.

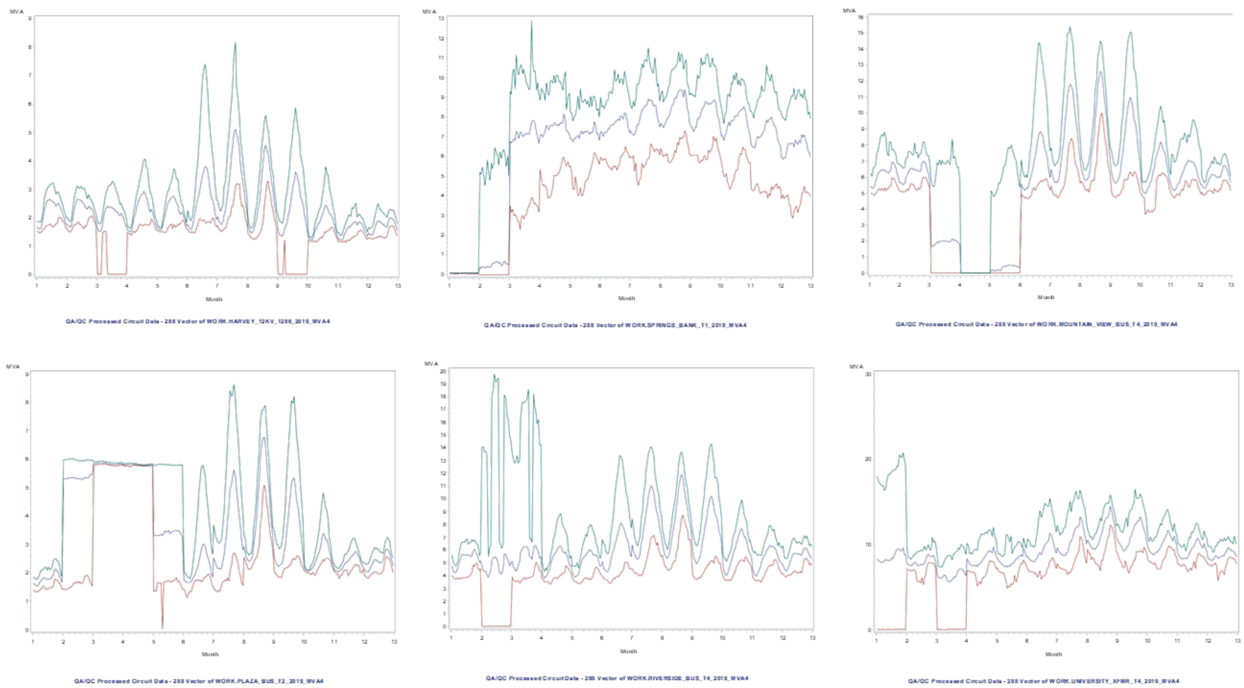

Figure 13.2.3. Multiple feeder charts illustrating various SCADA anomalies removed during the SCADA data QA/QC processing.

With anomalous SCADA data removed, RPU staff compiled the best available 8760 data from the original base time of 2017-2021 and prepared 288-point average, P10[18] and P90[19] data. RPU staff performed manual reviews of final data to verify quality of results. For example, consider the data

[17] Analysis of Covariance is a model that tests interaction between variables. In this case, the daily mean load and the corresponding load shape at 24 one-hour intervals. Outliers determined with this method are removed from the mean 288 processing since they are not congruent with the expected daily load shape for the feeder. While this method proved effective for data anomalies less than several hours in length, longer duration anomalies were more difficult to detect with this method and required more manual forms of evaluation.

[18] P10 – 10th percentile means that 10% of MVA data is less than this amount. P10 is useful as a light loading metric.

[19] P90 – 90th percentile means that 90% of MVA data is less than this amount. P90 is useful as a high loading metric.

shown in Figure 13.2.4 illustrating the mean average (blue), P10 (orange), and P90 (green) 288 curves for Feeder 1288 and 1297.

Harvey Lynn Circuit 1288 MVA | Harvey Lynn Circuit 1297 MVA

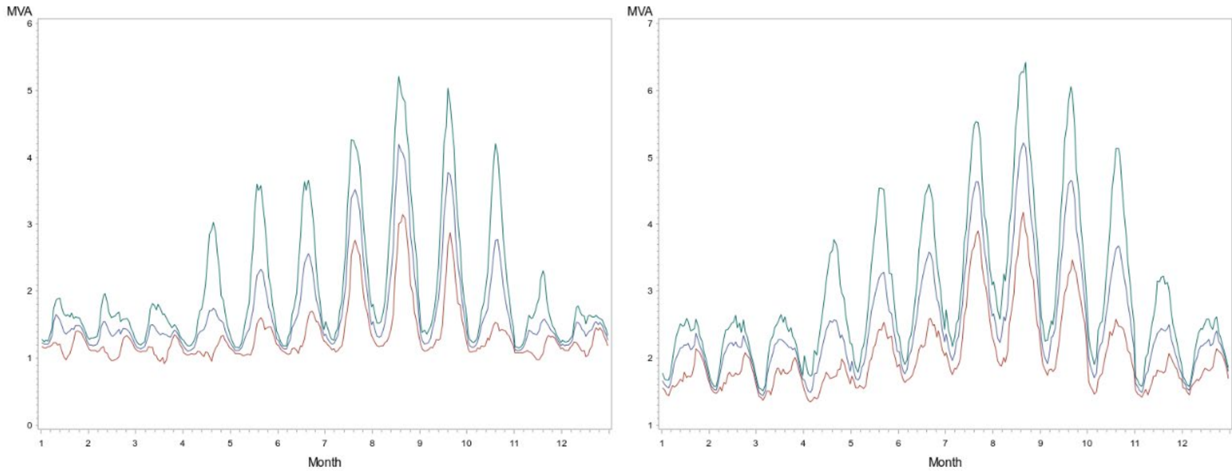

Figure 13.2.4. Calculated 288 Hour by Month average, P10, and P90 MVA profile plots Feeder 1288 and 1297.

Since Solar PV is a generation resource, its impacts to the distribution grid are most pronounced during periods of low usage or demand. Thus, staff calculated the PV analysis by scaling up the solar PV profile on each P10 light loading curve until all the demand of the distribution feeder was met in at least one P10 hour. This in turn was used to estimate the maximum allowable deployment of additional PV capacity on the existing feeder, both on an installed capacity and peak generated energy basis. Reverse power flows[20], or net generation, on RPU's distribution feeders are expected to require upgrades to accommodate since the engineering design of these feeders was intended to accommodate electrical loads only. Therefore, this analysis identifies the threshold amounts of additional PV capacity/energy that would result in the need for engineering studies for potential redesigns and/or upgrades of the substation and feeder equipment. Figure 13.2.5 graphically illustrates the results of this PV scaling analysis for Feeder 1287.

Likewise, staff chose to compare the EV demand profile against each feeder's heavy loading (P90) scenario. The results of this EV analysis found that while several feeders are constrained in the ability to serve EV load during peak hours, many feeders should be able to accommodate material future EV loads.

[20] "Reverse power flow" occurs when generation on a distribution feeder exceeds the amount of load on that feeder and causes power to flow into a distribution substation instead of towards customers as originally designed.

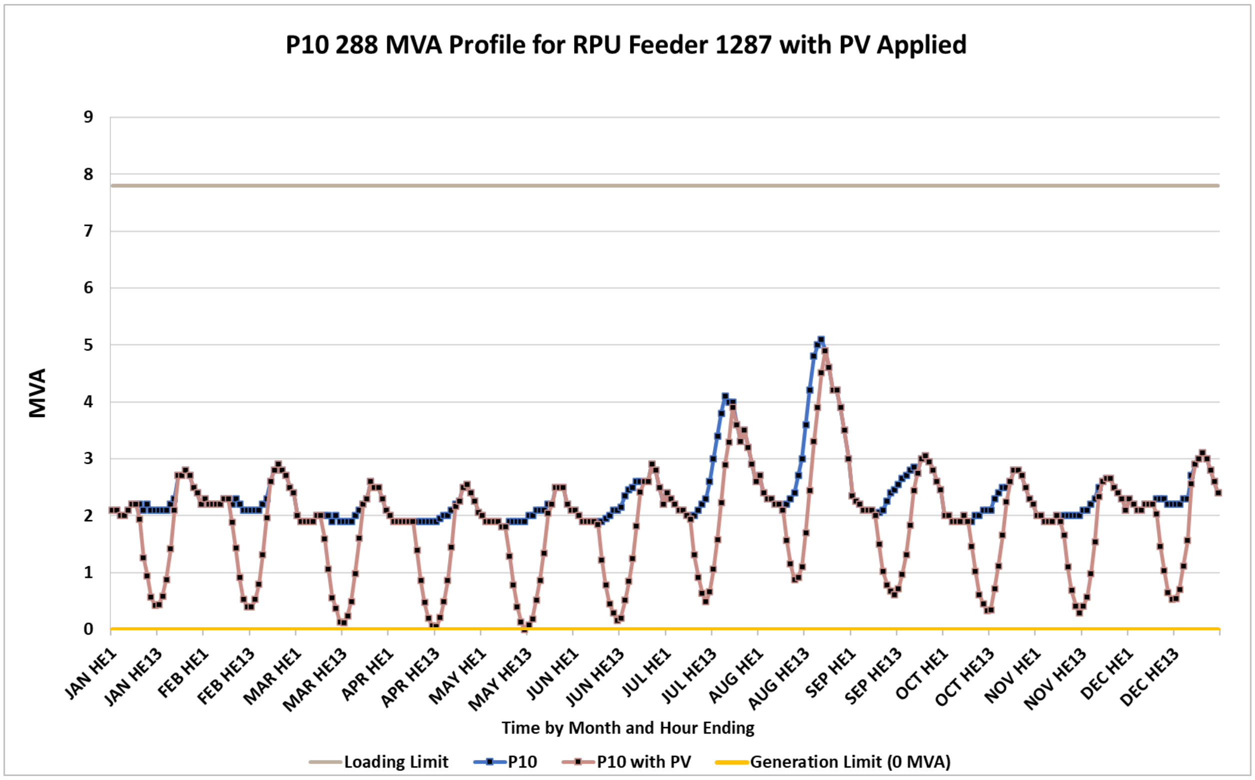

Figure 13.2.5. P10 288 MVA profile plot for RPU Feeder 1287 with the scaled PV profile applied to the P10 data.

Combining the 288 P10 and P90 data to the scaled EV and PV profiles, one can analyze in detail the behavior of a circuit at all hours in the year on a single chart. Consider Circuit 1287 shown in Figure 13.2.6 which has the following characteristics:

- 7.8 MVA Peak Capacity
- Radial feeder design, no generation back-feed capability
- Summer peaks in July, August, and September

The peak capacity of 7.8MVA is plotted in brown in Figure 13.2.6. For the purposes of this study, the generation limit is exactly zero MVA. The calculated 288 P10 vector is plotted in blue, and the 288 P90 vector is plotted in purple. By determining the maximum scalar quantity for the PV profile shown in Figure 13.1.4, the "PV10" impact profile can be constructed. This PV10 profile (e.g., expected light load profile with maximum PV additions added to the circuit) is plotted in auburn. Likewise, by determining the maximum scalar quantity for the EV profile shown in Figure 13.1.2, the "EV90" impact profile can be constructed. This EV10 profile (e.g., expected high load profile with maximum EV additions added to the circuit) is plotted in green. These analyses show that Feeder 1287 can in theory accommodate up to 1.95 MVA of peak PV generation and 2.62 MVA of peak EV loading before upgrades to the feeder will be necessary. (Similarly, a Fuel Switching profile, or FS90 was calculated but is not pictured for clarity).

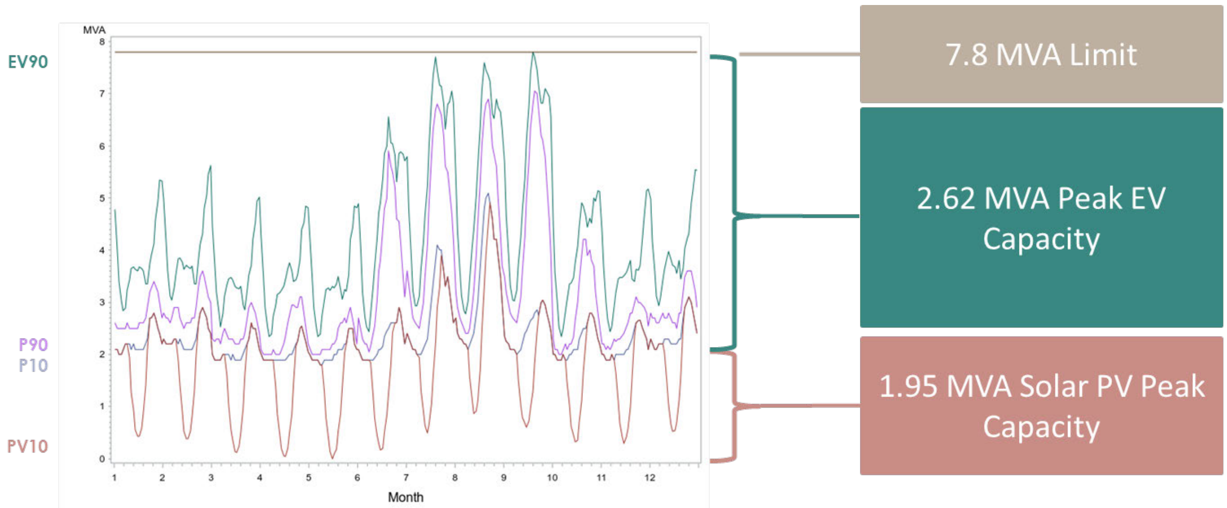

Figure 13.2.6. Graphical representation of peak EV and PV capacity analyses for RPU distribution Feeder 1287.

13.3 Distribution System PV, EV, and FS Capacity Factor Derivations and Results

To better understand the potential for future PV, EV, or FS adoption levels, RPU has developed its own PV, EV, and FS capacity utilization factors. Considering the chart above in Figure 13.2.6, RPU set about to identify useful metrics for the relationship of the peak PV, EV, and FS capacity to overall capacity. The intent of a capacity utilization factor is to define sensitivity of a given circuit to additional EV and FS load or PV generation by comparing load or generation at the forecasted peak hour to available capacity. To ensure the sensitivity metric is scaled appropriately, the basis for all metrics is the overall circuit capacity.

These utilization factors have been derived by multiplying the calculated minimum scalars (α-PV, α-EV, α-FS) with the forecasted peak hours in the CEC EV and FS load profiles and RPU local PV generation profile (see Figures 13.1.2, 13.1.3 and 13.1.4, respectively).[21] The relevant study metrics for Feeder 1287 are shown in Table 13.3.1.

[21] All capacity utilization factor calculations discussed in this chapter assume that the apparent power (MVA) is equal to the real power (MW).

Table 13.3.1. Relevant **s**tudy metrics for Feeder 1287.

Substation	**Bank**	**Circuit**	**Capacity MVA**	**α-EV MWh/day**	**α-PV MW-AC**	**α-FS MWh/day**	**Peak EV (MVA)**	**Peak PV (MVA)**	**Peak FS (MVA)**
Harvey Lynn	T-5	1287	7.8	26.02	2.66	17.55	2.62	1.95	1.54

It is worth noting that both the derived minimum scalars and corresponding peak factors represent interpretable metrics. For example, in Table 13.3.1 the α-PV scalar value of 2.66 represents the theoretical maximum additional amount of MW-AC solar PV capacity that can be installed on Feeder 1287 before the peak generation hour in May will offset all the calculated P10 load. And if this much additional solar PV capacity is installed, then the corresponding peak hour PV generation will be equal to 1.95 MVA (or MW). Likewise, the α-EV scalar value of 26.02 represents the theoretical additional amount of MWh/day of EV load that this feeder can accommodate before the peak EV load in September will cause the P90 load to exceed the 7.80 MVA limit. Similarly, this additional peak hour EV load will be equal to 2.62 MVA (or MW), assuming these hourly EV loads follow the pattern shown in Figure 13.1.2.

Following this logic, staff have defined the corresponding capacity utilization factor (CUF) for each metric to be equal to

$$\boldsymbol{Capacity\ Utilization\ Factor = 1 - \frac{Peak.Metric}{Feeder\ Capacity}}$$

For Feeder 1287, this definition yields the following results:

$$\text{PV CUF} = 1 - \frac{1.95\ MVA}{7.80\ MVA}$$
$$\text{PV CUF} = \mathbf{0.75}$$

$$\text{EV CUF} = 1 - \frac{2.62\ MVA}{7.80\ MVA}$$
$$\text{EV CUF} = \mathbf{0.66}$$

$$\text{FS CUF} = 1 - \frac{1.54\ MVA}{7.80\ MVA}$$
$$\text{FS CUF} = \mathbf{0.80}$$

Note that a CUF near 1.0 implies that the feeder in question has minimal remaining capacity to accommodate the corresponding DER technology.

13.3.1 Circuit Population Study Results and Analysis

While PV and EV have divergent load curves and peak patterns, the study results show that a large share of RPU's distribution feeders can tolerate additions of Solar PV, light duty EVs, and FS through appliance electrification. The sensitivities to EV, PV, and FS growth vary considerably by feeder. Table 13.3.2 presents the basic summary statistics for the 102 feeders analyzed in this study.

Table 13.3.2. Basic Utilization, PV, EV, and FS summary statistics for the 102 analyzed RPU feeders.

Variable	Mean	Std Dev	Minimum	Maximum	Sum
Capacity	7.00	1.61	2.58	11.37	713.86
P90-Peak	4.92	2.04	0.52	8.92	501.85
CUF	0.70	0.25	0.17	1.00	n.a.
Peak PV	1.40	0.80	0.14	4.10	142.51
Peak EV	3.67	2.15	0.00	9.17	374.31
Peak FS	3.39	2.44	0.00	9.97	345.37
PV CUF	0.80	0.11	0.49	0.98	n.a.
EV CUF	0.48	0.26	0.07	1.00	n.a.
FS CUF	0.53	0.30	0.05	1.00	n.a.

As shown in Table 13.3.2, the 102 examined feeders exhibited an average Capacity of 7.00 MVA and an average CUF of 0.70. This suggests that on average, 70% of a feeder's recommended capacity level is currently being used to meet peak load conditions. However, since this study examined 713.86 MVA of feeder capacity across 102 feeders, a wide range of CUF levels (0.17 to 1.00) was observed.

Interestingly, most feeders appear to be able to support more EV and FS loads than PV generation, as shown by the PV, EV, and FS CUF statistics. Our distribution feeders exhibit an average capacity utilization factor of 0.80 for PV technology. For EV, the population of feeders had an average of 0.48 capacity utilization, suggesting the RPU distribution grid can tolerate more EV growth in current configurations than PV growth. Additionally, there was a strong linear relationship between the EV and FS capacity factors, with FS being slightly higher. The FS capacity factor is 0.53 capacity utilization on average, suggesting that the sensitivity to those conversions is higher.

As shown in Table 13.3.2., the average peak integration capacity of RPU's distribution feeders was 3.67 MVA for EVs, 3.39 MVA for FS, and 1.40 MVA for PV systems. Likewise, there appears to be 374.31 MVA of capacity left across these 102 feeders to support EVs and 345.37 MVA left to support fuel switching, but just 142.51 MVA left to support additional solar PV growth. Of course, these values represent hypothetical perfect upper bounds, assuming that each feeder was optimized to its full potential, but no further. In reality, the actual upper bounds are most likely less than one half these values (before significant distribution upgrades would need to be performed).

Given the assumption that all capacity utilization factor calculations discussed in this chapter assume that the apparent power is equal to the real power (MVA = MW), these power totals can be easily converted into hypothetical estimates that quantify various potential PV, EV, and FS installation metrics. Table 13.3.3 presents some relevant PV (system capacity), EV (charging capacity), and FS (appliance demand levels) metrics of interest, which in turn allow for the calculation of the total number of additional units that can be supported by the existing distribution system capacity. For these calculations, both 100% and 50% of the MVA totals shown in Table 13.3.2 have been used to define the additional number of unit counts (the latter more likely represents a potentially realistic upper bound). With reference to the calculations at a 50% saturation level, these 102 feeders appear capable of supporting approximately 14,250 additional small customer solar PV systems, or 98,500 additional Level 1 EV chargers, or about 7,350 whole house electric conversions.

Table 13.3.3. Hypothetical number of additional PV, EV, FS units using the existing distribution system capacity associated with the 102 analyzed feeders.

PV, EV, FS Metric of Interest	kW AC	Sum.MW (100%)	Additional Units at 100% Saturation	Sum.MW (50%)	Additional Units at 50% Saturation
Small Res PV System	5.00	142.51	28,502	71.26	14,251
Large Res PV System	8.00	142.51	17,814	71.26	8,907
Comm PV System	100.00	142.51	1,425	71.26	713
Level 1 EV Charger	1.90	374.31	197,005	187.16	98,503
Level 2 EV Charger	11.50	374.31	32,549	187.16	16,274
Heat Pump	9.60	345.37	35,976	172.69	17,988
Oven	3.30	345.37	104,658	172.69	52,329
Dryer	6.10	345.37	56,618	172.69	28,309
Water Heater	4.50	345.37	76,749	172.69	38,374
Whole House	23.50	345.37	14,697	172.69	7,348

While these composite system numbers can be helpful in estimating how much additional PV, EV, and/or FS capacity is available in the existing distribution system, the calculation of equivalent metrics for individual feeders is also useful. Recall the example in Figure 13.2.6 for Feeder 1287. The peak EV capacity of 2.62 MVA suggests that this feeder can support an additional 228 Level 2 EV chargers or 1,379 Level 1 chargers at 100% saturation. Likewise, the peak PV capacity of 1.95 MVA suggests that this feeder can accommodate an additional 245 to 390 solar PV systems (from 5 to 8 kW AC in size). Finally, this same Feeder 1287 has 1.54 MVA of FS integration capacity, which translates to either 66 whole house electric conversions or the following numbers of electric appliances: 161 heat pumps, 462 ovens, 254 clothes dryers, or 343 electric water heaters.

In general, the individual feeder data indicates that RPU's distribution grid may be sensitive to complete fuel conversions, though there is tolerance to electrifying one appliance in the home. The data further indicates that that only 66 residences can complete conversion to all electric appliances on Circuit 1287 before consuming the remaining capacity (as opposed to 228 residences installing Level 2 EV chargers). Given the large upfront investments needed, it is uncertain that existing customers will choose to perform complete building electrifications. However, as economics improve and building code requirements evolve, the distribution grid impacts may quickly become acute. On average, RPU feeders can only tolerate 144 complete residential building electrifications before reaching their corresponding MVA limits.

Staff also examined the feeder distribution metrics to better understand if there were any concerning trends relative to integration capacity that might drive a capital influx in the future. Figure 13.3.1 illustrates the EV capacity utilization factors for the entire population of RPU's distribution feeders. The population of feeders is skewed left, implying that many feeders have substantial capability to integrate additional EV charging growth compared to current loads.

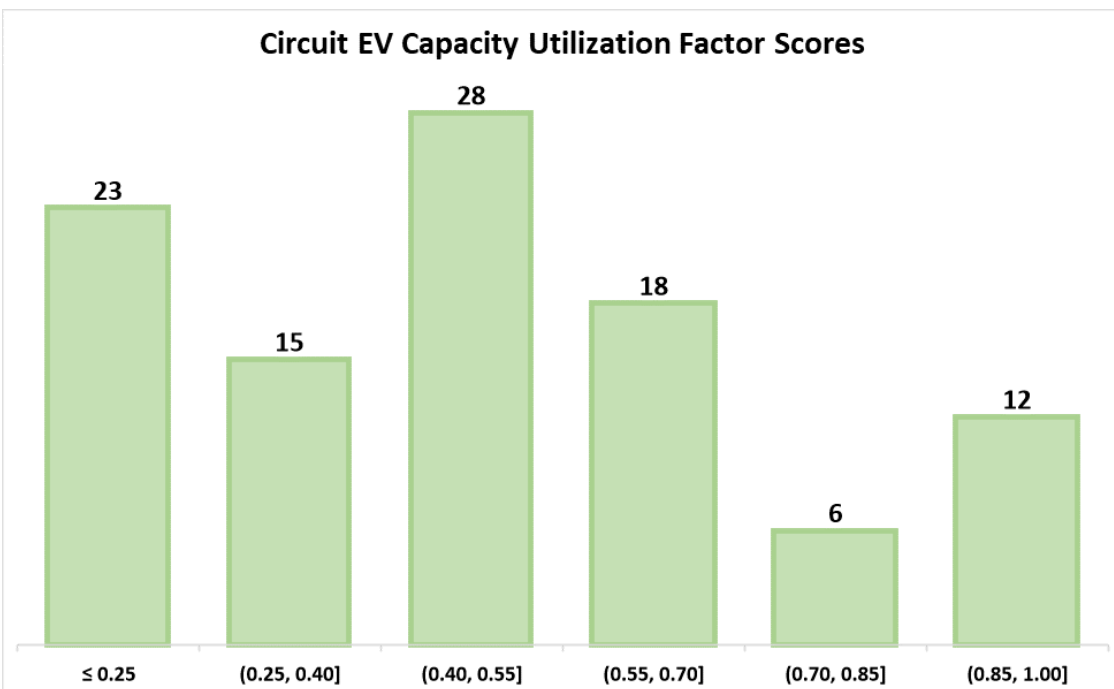

Figure 13.3.1. Distribution Analysis of EV Capacity Utilization Factor Scores for RPU Distribution Feeders.

Figure 13.3.2 illustrates the PV capacity utilization factors for the entire population of RPU's distribution feeders. This bar chart shows that the population of feeders is skewed right, implying that many feeders have diminished capability to integrate PV generation growth compared to current loads.

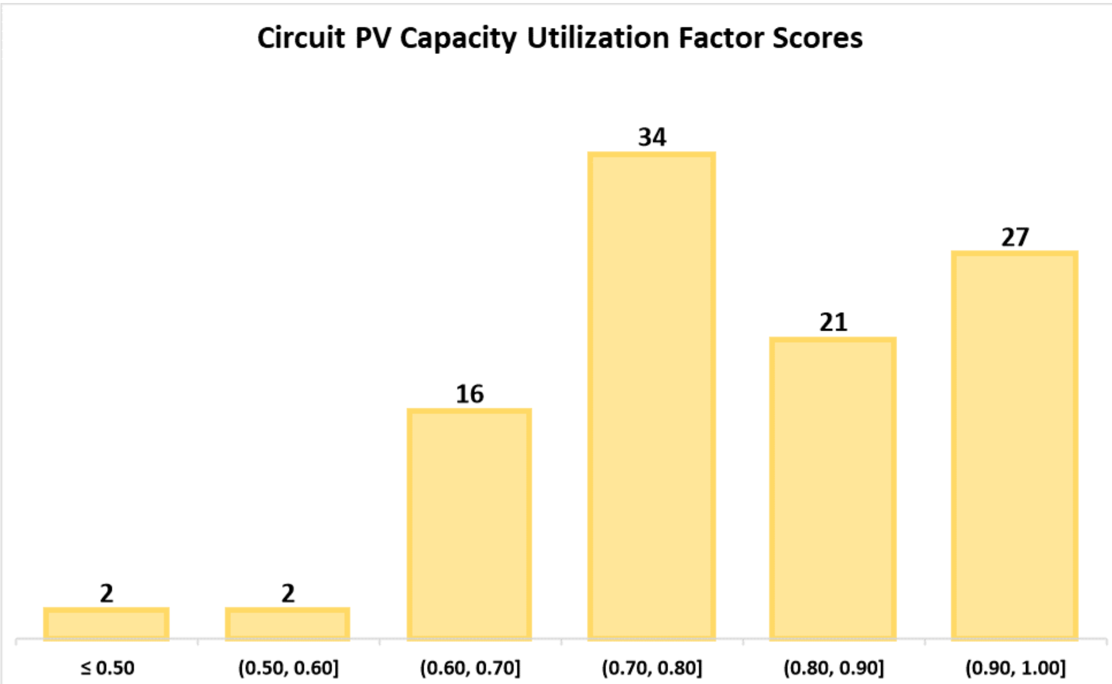

Figure 13.3.2. Distribution Analysis of PV Capacity Utilization Factor Scores for RPU Distribution Feeders.

Given the pattern in Figure 13.1.2, one might expect to see a diminished capacity to integrate Fuel Switching loads relative to other integration capacities studied in this chapter. However, the data does not neatly confirm this hypothesis. Figure 13.3.3 illustrates the distribution of capacity factors associated with fuel switching in the RPU distribution system. The distribution of capacity factors is relatively flat, meaning the number of distribution circuits containing low levels of integration capacity is roughly the same as those that have high levels of integration capacity.

While the capacity factors for incremental load from fuel switching do not reveal an obvious problem, roughly 20% of RPU's circuits are nearing capacity for fuel switching. The fuel switching load behavior is similar, but not identical, to EV loads in that it does not contribute heavily to loading during peak periods. However, the FS loads for all home appliances may be roughly double that of Level 2 EV chargers and thus similar EV and FS MVA levels may be somewhat misleading when comparing adoption numbers.

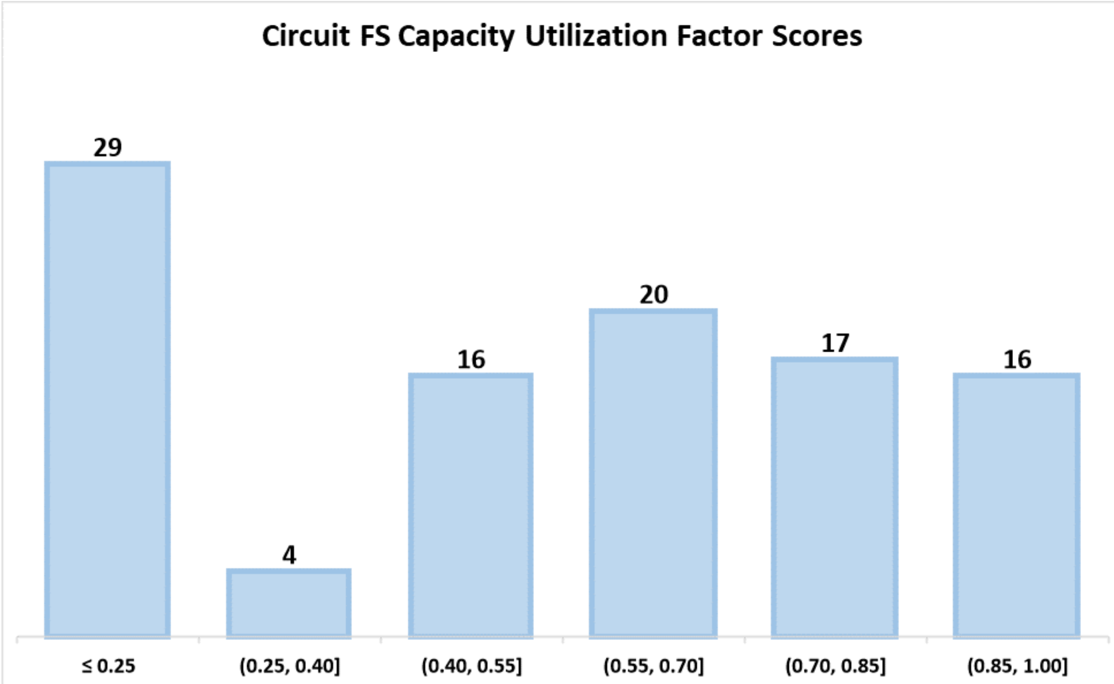

Figure 13.3.3. Fuel Switching Capacity Factor Scores for RPU's Distribution Grid.

Finally, Tables 13.3.4, 13.3.5, and 13.3.6 illustrate the top 10 capacity utilization factors for PV, EV, and FS. Recall that the higher the utilization factor, the more sensitive the feeder will be to additions of these kinds of resources (PV, EV, and FS respectively). These feeders will most likely need supplemental studies to assess what level (if any) of incremental additions in EV, PV, or FS can be supported. While capital upgrades to these circuits are not needed immediately, our engineering planners may soon need to consider methods to address these capacity constraints through restricting interconnections, system reconfigurations, capital upgrades, or a combination of these methods as tariffs and policy allow.

Table 13.3.4. Top 10 PV Capacity Utilization Factors of interest for various RPU Feeders.

Substation	Bank	Circuit	Capacity MVA	Peak PV (MVA)	PV Capacity Utilization Factor
Mt. View	T-6	1364	8.35	0.14	0.98
Plaza	T-1	445	6.18	0.21	0.97
Plaza	T-2	444	6.93	0.26	0.96
Mt. View	T-1	61	8.11	0.33	0.96
Plaza	T-2	450	5.86	0.24	0.96
Orangecrest	T-4	1540	8.57	0.44	0.95
Riverside	T-1	12	7.59	0.41	0.95
Hunter	T-2	26	8.31	0.45	0.95
Orangecrest	T-2	1532	7.57	0.45	0.94
Riverside	T-1	19	6.92	0.43	0.94

Table 13.3.5. Top 10 EV Capacity Utilization Factors of interest for various RPU Feeders.

Substation	Bank	Circuit	Capacity MVA	Peak EV (MVA)	EV Capacity Utilization Factor
Casa Blanca	T-1	1355	7.70	0.00	1.00
Harvey Lynn	T-5	1295	7.66	0.00	1.00
Harvey Lynn	T-5	1297	5.93	0.00	1.00
Hunter	T-4	1222	5.56	0.00	1.00
Harvey Lynn	T-5	1293	6.57	0.00	1.00
La Colina	T-1	1213	6.91	0.11	0.98
Harvey Lynn	T-4	1288	5.29	0.20	0.96
Harvey Lynn	T-2	1282	4.63	0.18	0.96
La Colina	T-4	1216	6.19	0.32	0.95
Riverside	T-5	1309	8.11	0.63	0.92

Table 13.3.6. Top 10 FS Capacity Utilization Factors of interest for various RPU Feeders.

Substation	Bank	Circuit	Capacity MVA	Peak FS (MVA)	FS Capacity Utilization Factor
Casa Blanca	T-1	1355	7.70	0.00	1.00
Harvey Lynn	T-5	1293	6.57	0.00	1.00
Harvey Lynn	T-5	1295	7.66	0.00	1.00
Harvey Lynn	T-5	1297	5.93	0.00	1.00
Hunter	T-4	1222	5.56	0.00	1.00
Riverside	T-5	1307	5.21	0.00	1.00
La Colina	T-1	1213	6.91	0.04	0.99
Harvey Lynn	T-2	1282	4.63	0.08	0.98
Harvey Lynn	T-4	1288	5.29	0.18	0.97
La Colina	T-4	1216	6.19	0.25	0.96

13.3.2 Geospatial Analysis of Study Results

Since the majority of the RPU distribution system is represented in this analysis, staff set out to determine if there were any geographic correlations of the distribution of circuits with respect to integration capacity results. RPU staff superimposed data of interest from this study on the Geographic Information System (GIS) database for RPU circuit mapping. Since this study is one of sensitivity, RPU staff binned the data into meaningful groupings based on the factors associated with each analysis as shown in Table 13.3.7. Those circuits found in the "Very High" bins are the most sensitive to additions, and therefore represent areas of greatest concern to utility planners. EV and FS share the same bin categories.

Table 13.3.7. Bin Groupings for EV, FS, and PV geospatial analyses.

EV/FS Capacity Factor Bins	
<0.40	Low
0.40-0.60	Moderate
0.60-0.80	High
>0.80	Very High

PV Capacity Factor Bins	
<0.60	Low
0.60-0.75	Moderate
0.75-0.90	High
>0.90	Very High

Figure 13.3.4 illustrates the EV Capacity Utilization Factors within the extents of the RPU Electric service territory. Considering Figure 13.3.5, note that the areas with limited available EV integration capacity are interspersed throughout RPU's territory. While results show there are pockets of limited integration capacity throughout RPU's service territory, this is a positive outcome. This likely means that these constraints might be mitigated using load rebalancing approaches on RPU's existing circuit assets, delaying more capital-intensive approaches.

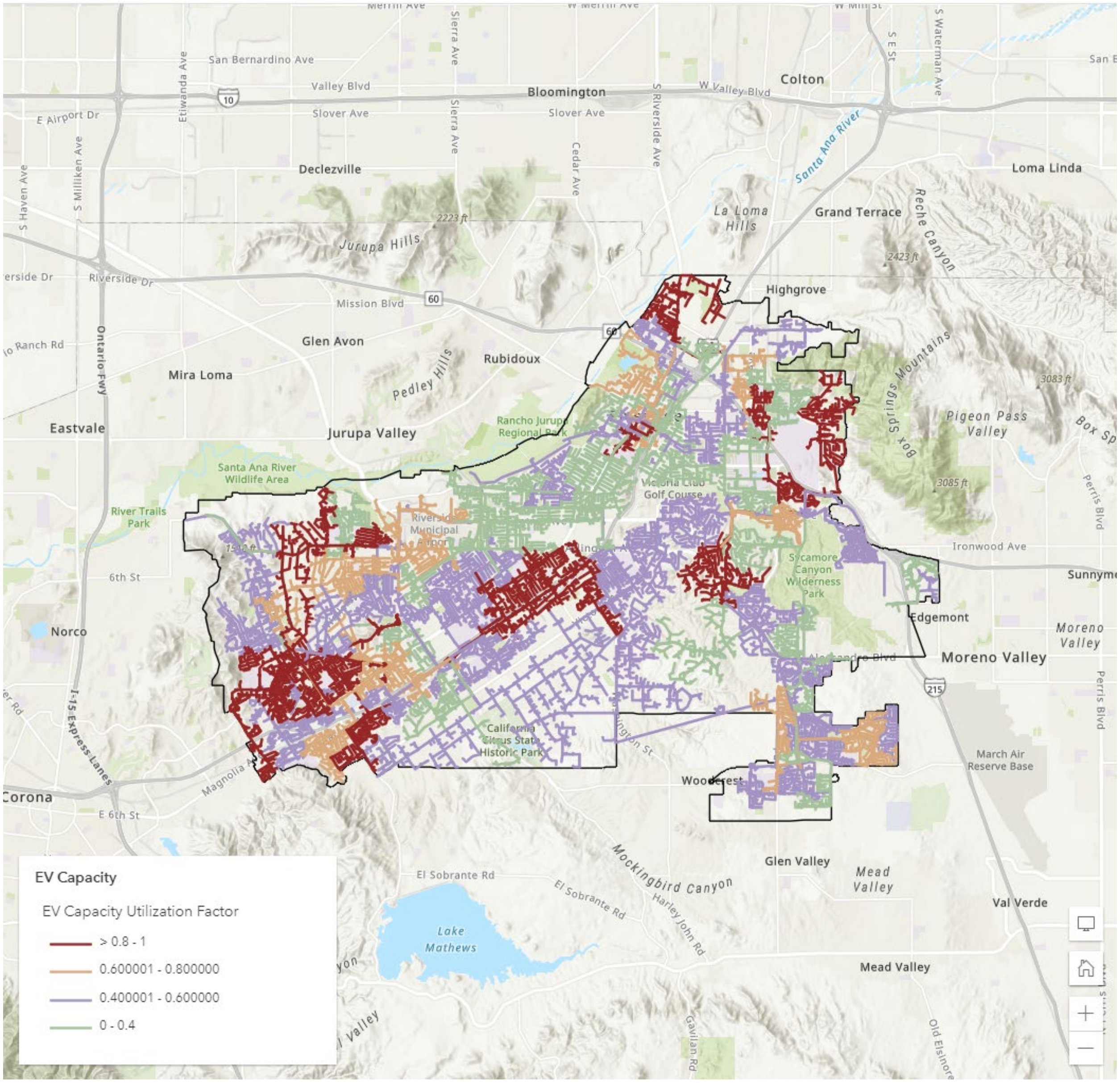

Figure 13.3.4. EV Capacity Utilization for RPU Feeders.

Additionally, RPU staff mapped the FS capacity factor distribution in Figure 13.3.5. With some exception, the clustering largely mirrors that found in the EV analysis. Note there is some additional congestion in the southeast segment of RPU's service territory.

RPU staff similarly analyzed the geographic distribution of PV adoption throughout RPU's service territory, as shown in Figure 13.3.6. Capacity for additional PV is limited in areas RPU expected, particularly the southeastern corner of the territory. However, the study identified other clustering geographically that was not expected, primarily in the north central segments of the city as well.

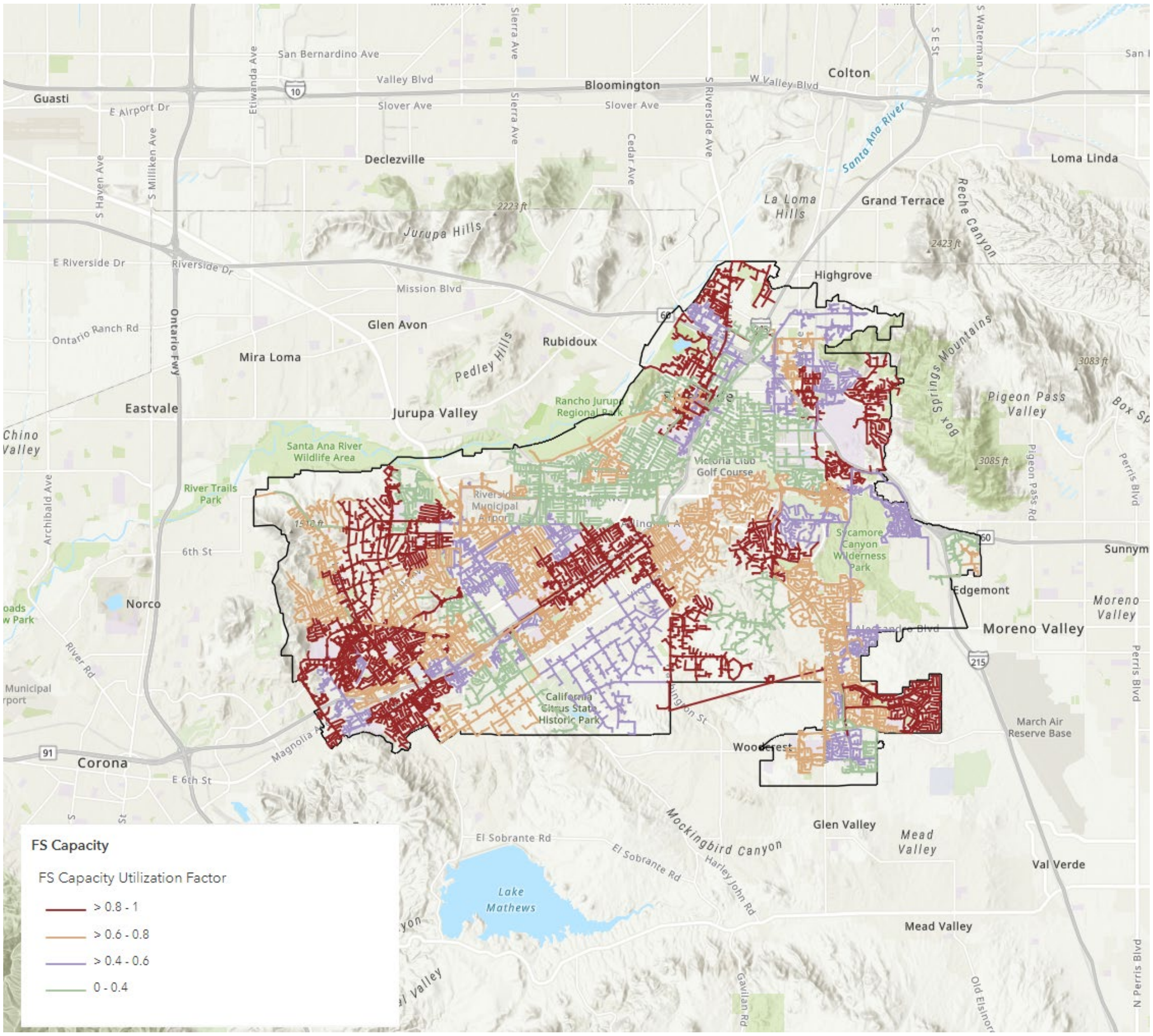

Figure 13.3.5. FS Capacity Utilization for RPU Feeders.

The clustering of PV capacity constraints on RPU's southeastern service territory comes as no surprise; RPU's interconnection data has indicated for several years that the city has high levels of PV adoption. This area additionally has limited capacity for additional fuel switching loads. Since this is at the fringes of the service territory this is the most concerning area with respect to capital upgrade needs. RPU has been extensively studying the circuit needs in this area and has seen concerning system events in these areas directly correlated to solar PV output. RPU has been focused on deploying AMI in these areas to precisely show the areas of concern and develop strategies to mitigate the adverse impacts of solar PV oversupply, such as Volt-Var Control[22] to manage transient over-voltages.

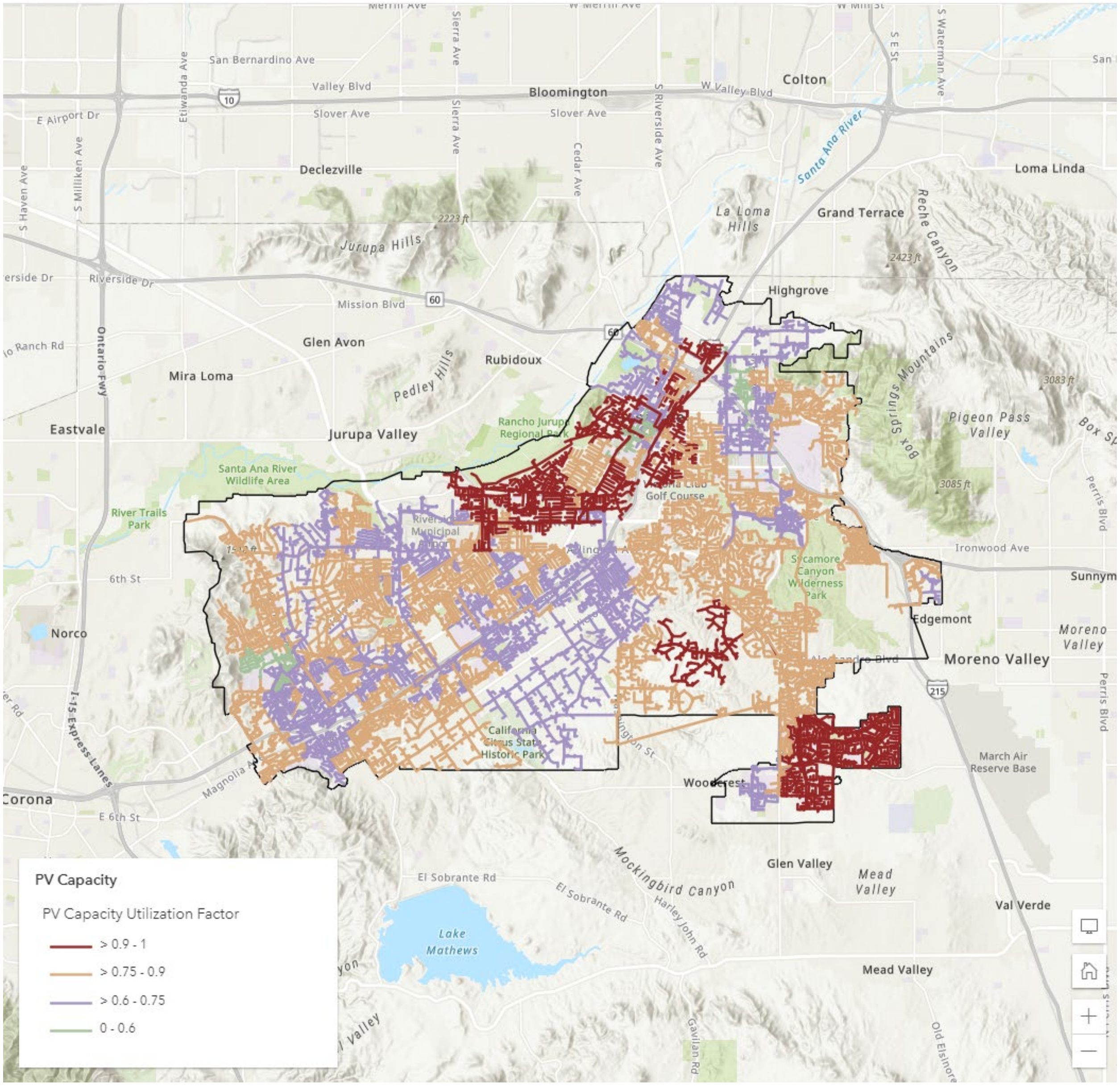

Figure 13.3.6. PV Capacity Utilization for RPU Feeders.

[22] Voltage and Voltage-Amps Reactive (Volt-VAR) Control (VVC) is a control method that maintains power quality on a circuit, e.g., mitigating voltage out of limits problems and power factor (reactive power) problems. Voltage out of limits can cause damage to customer and utility equipment over time. Power factor problems cause excessive power losses (inefficient power transfer) on circuits and contribute to voltage out of limits problems. Volt-VAR control seeks to eliminate these problems through automated control of substation and distribution equipment.

13.4 Future Distribution System Studies to Integrate DER Technology

As discussed above, studying a circuit's geographic distribution can be helpful in analyzing the effectiveness of policy and processes within the utility to influence and/or accommodate DER technology adoption. RPU is considering how to also use this information in screening processes for future DER interconnections. While EV adoption data is more limited than PV information, this type of analysis allows RPU to study circuits directly and is not limited by the quality or availability of PV interconnection or EV registration data. Fuel Switching activity is likely to be tied to new development. RPU will have the ability to study these interconnections through new development processes.

While the ICA performed in this chapter is based on a static grid concept (ceteris paribus), future planning will require integration of ICA type analyses into the preliminary stages of capital plan forecast development. As resources like solar PV and EVs proliferate on RPU's distribution grid and as builders install more electric appliances, the feeder populations shown in Figures 13.3.1, 13.3.2, and 13.3.3 will skew further towards saturation levels. However, as shown in this ICA, there currently remains sufficient capacity on many feeders to accommodate additional DER growth. Nonetheless, it is also becoming increasingly important to track and forecast DER growth at a more granular level across the distribution system, and this need is only expected to increase over time.

Currently, RPU's Energy Delivery Engineering (EDE) Division continues to review and approve all requests to interconnect distributed generation in accordance with Electric Rule 22.[23] Where power quality issues are identified on high penetration distribution circuits, a detailed investigation is performed and remedial action is taken. Remedial actions include adjusting distribution capacitor set points, substation capacitor switching and adjusting substation transformer load tap changer (LTC) settings. EDE has also investigated the use of in line secondary voltage regulators and secondary static VAR compensation for high penetration transformers. The analyses presented in this chapter should help further focus when and where these various remedial actions need to occur to help RPU continue to accommodate additional levels of DER penetration in the most cost-effective manner possible.

13.5 Upgrades to Distribution System Communications and Information Technology

Riverside Public Utilities formed and launched the Operational Technology Office (OTO) in 2015 in response to a business need to develop and support technologies focused on automating and improving electric and water utility operations. To better support the Operational Technology (OT) needs of the Utility, RPU consolidated existing functions and created new positions under the Operational Technology Office. The OTO was responsible for managing, consolidating, visualizing, and interpreting data from multiple systems to effectively operate electric and water systems and to make informed business decisions. This included existing and future OT systems, such as utility-wide

[23] Reference: https://riversideca.gov/utilities/pdf/rates/2011/B%20%20Electric%20Rule%2022%20(6-21-11%20CC)%20approved.pdf

Operational Data Management System (ODMS), Utility Work and Asset Management (UWAM) system, Advanced Metering Infrastructure (AMI), Geographic Information System (GIS), Supervisory Control and Data Acquisition (SCADA), Customer Information System (CIS), and field / monitoring devices.

In 2019 the OTO was reorganized into the Technology Integration (TI) Unit and moved into the Power Resources ROSA Division. During this reorganization process, this restructured TI Unit was tasked with focusing on the deployment and maintenance of three critical OT systems: (1) the ODMS, (2) the distribution wide rollout of AMI, and (3) the consolidation and restructuring of the GIS workflow process. Each of these OT systems had been previously identified as part of an integrated Operational Technology/Information Technology Master Plan strategy to improve RPU's organizational efficiency and to better optimize the deployment of DER technology. Currently, both the ODMS deployment and AMI rollout have been completed; the remainder of this section provides some more detailed information on the successful deployment of these two critical OT systems.

13.5.1 ODMS Deployment

One of the most critical and foundational projects outlined in the 2015 Strategic Technology Plan was the Operational Data Management System (ODMS). The ODMS is foundational for advancing the Strategic Technology Plan, as it serves as a "data hub" or central repository for collecting, analyzing, and visualizing operational data. An effective ODMS manages large amounts of data across multiple systems and workgroups and helps staff turn the data into actionable information to drive critical business decisions.

In April 2016, the Board of Public Utilities (Board) approved implementation of a five-year plan to implement and deploy the OSIsoft Pi System (Pi) to serve as RPU's ODMS. The Pi software can be used to integrate a wide range of disparate data and transform this data into meaningful information that can be displayed and consumed through visual tools such as dashboards and reports (as represented in Figure 13.5.1). In addition to providing readily available and easy-to-consume information, Pi provides an enhanced analytics platform that RPU can leverage to improve operational performance. During its five-year deployment process, over thirty separate software systems were integrated with the Pi System, including RPU's electric SCADA and Outage Data Management systems.

Utilizing Pi, RPU has been able to significantly improve operational efficiencies, reduce staff time and operating costs, and improve asset management and system reliability. Additionally, RPU has benefited in several other ways, including:

- Increased visibility into systems and assets.
- Improved ability to monitor and track performance to support operating decisions.
- Improved ability to analyze incidents to determine cause and effect for establishing corrective actions.
- Better enterprise-wide decision making, driven by real-time data.

- Automation of multiple manual workflow processes.
- Reduced risks and costs associated with potential equipment failure.
- Increased proactive (predictive) operations to optimize the cost of operating the distribution system.
- Improved analytics of historical data for better capital improvement and DER resources planning.

It is worthwhile noting that the Pi system was used in conjunction with SAS to produce all the ICA studies presented in this chapter.

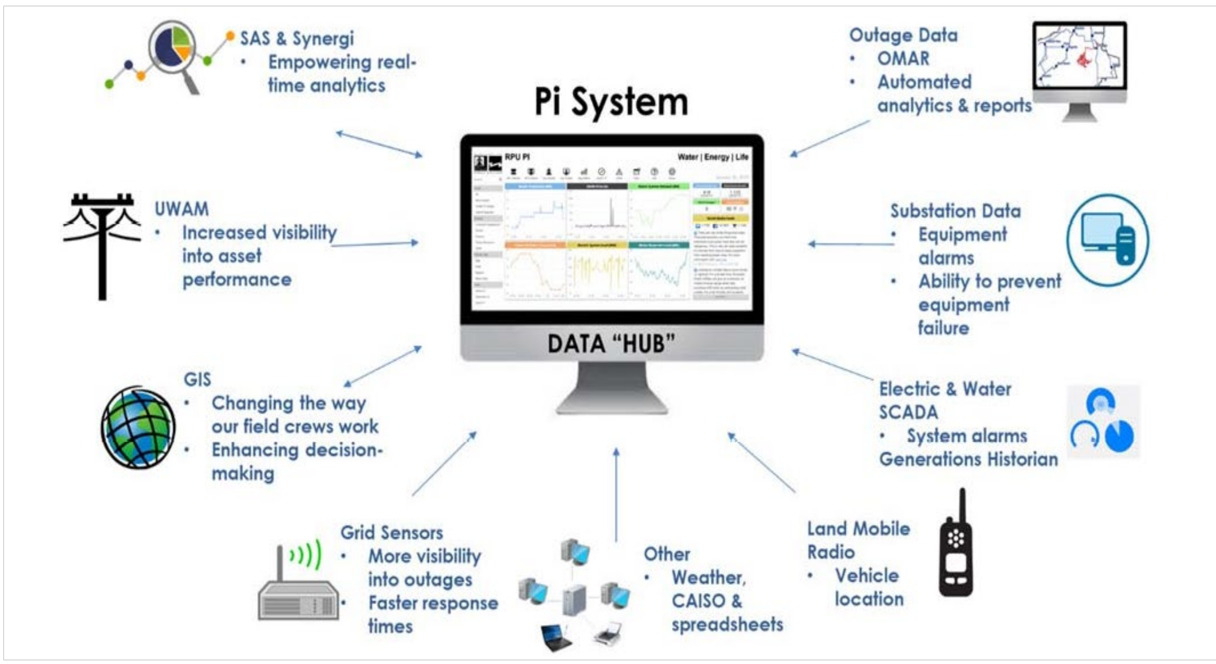

Figure 13.5.1. The ODMS Data Hub successfully facilitated by the OSI Pi system.

13.5.2 The 2019-2022 AMI Rollout

In January 2019, after several years of extensive industry research and gathering best practices from other successful electric AMI implementations, staff presented and obtained approval from the Board of Public Utilities to proceed with a four-year rollout of an Advanced Meter Program (Program). RPU's Program approach was designed to maximize the utility's current investment in residential Encoder Receiver Transmitter (ERT) meters, while introducing new AMI functionality across the entire service territory. The plan called for RPU to replace all commercial and industrial (C&I) meters (~12,000 C&I meters), along with about 1 out every 7 residential (R) electric meters (~13,000 R meters).

The AMI solution that was proposed for implementation was known as an "ERT overlay," which means that the new AMI devices (collectors and meters) would also be able to collect and transmit data from the legacy ERT meters. Hence, the initial AMI rollout only required the purchase of ~25,000 new AMI meters (~12,000 C&I meters and ~13,000 R meters) since these meters would be able to also collect data from the remaining 87,000 legacy ERT meters. (The remaining legacy residential ERT meters will be exchanged through the normal annual meter replacement cycle and when meters fail.) At the completion of this rollout, there would be no further manual electric meter reading activities conducted in the field, as all meter reads would be collected remotely through the communications network. Figure 13.5.2 shows a conceptual diagram of how this ERT overlay works in practice.

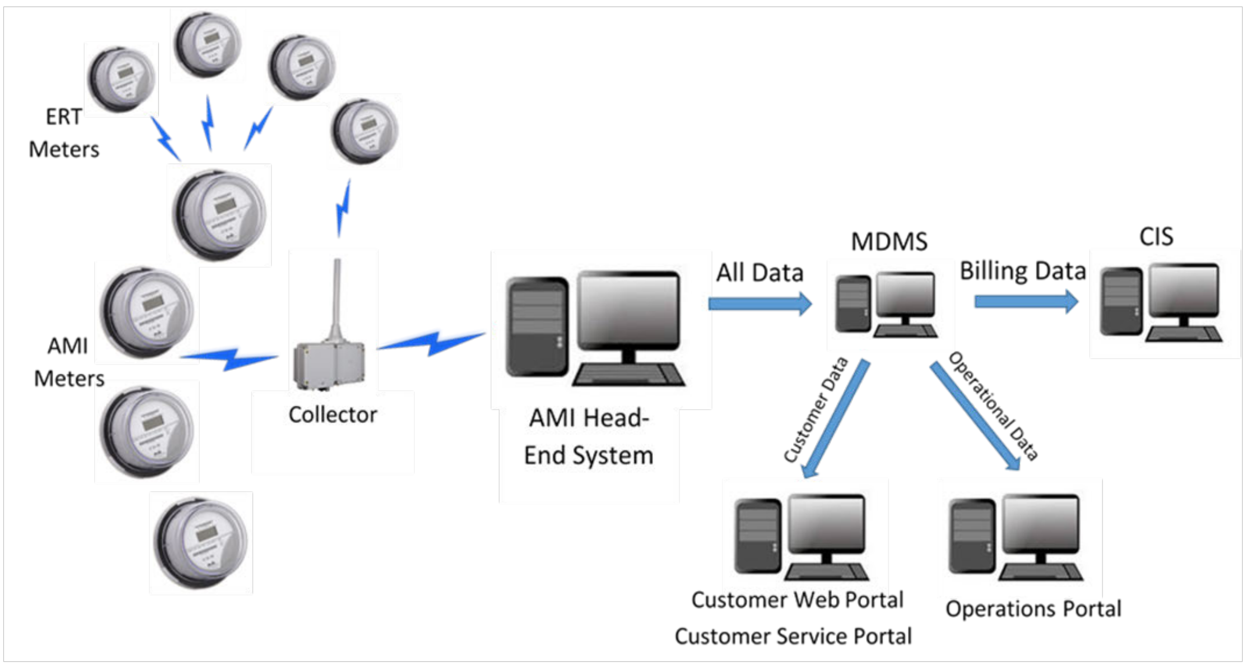

Figure 13.5.2. The AMI implementation design using an ERT overlay approach.

The AMI rollout was successfully completed in the summer of 2022, after 3.5 years of coordinated work between multiple RPU units. This implementation approach proved to be highly successful; the AMI Program was completed ahead of schedule and under budget, and the system is now fully operational. In addition to continued legacy meter replacements, staff are now focused on using this newly acquired AMI data to remotely measure electricity use, connect and disconnect service, detect tampering, identify and isolate outages, monitor distribution system voltage levels, improve power quality, and better analyze and optimize increasing levels of DER penetration.

14. Evaluating the Impact of Increasing Energy Efficiency Program Targets

This chapter presents a review of RPU's analysis of the costs to increase energy efficiency (EE) targets with respect to the value of the type of EE measure and the value that measure represents to the utility. Chapter 6 summarized RPU's adopted and forecasted EE targets that are included in the power supply analysis. This chapter will focus on the costs of these programs and what the impacts are to RPU and its customers if higher targets are sought.

As noted in Chapter 6, energy efficiency (EE) is an important topic for RPU and this IRP. EE has the potential to reduce demand and thus is an important consideration for RPU's future resource strategy. This chapter further examines the costs associated with the types of EE measures and compares them to the avoided costs of energy. Avoided cost analyses are differentiated between residential and commercial/industrial (CI) customer measures as well as whether the EE measure is for Baseload, Lighting, or Heating & Air Conditioning (HVAC).

14.1 Avoided Cost of Energy (ACOE) and Unmet Revenue Calculations for EE Measures

As discussed in Chapter 6, EE measures are typically evaluated using benefit-cost tests. The benefit-cost test most appropriate for this IRP is the Rate Impact Measure (RIM). This is because the RIM measures the cost effectiveness of EE measures considering how the cost of these measures impacts other customers not participating in EE measures (typically referred to as non-participating customers).

The RIM test looks at benefits and costs from both the perspective of the utility as well as the non-participating customers. Under this approach, benefits from the implementation of EE measures are the utility's avoided costs of energy (ACOE) that is not consumed by the participating customer. The costs are the utility's lost revenue. As a note for this analysis, RIM analysis usually includes the costs associated with the utility's expenses related to the EE measures (program overhead, incentive costs and installation costs). However, RPU does not include these costs in the analysis because they are paid for by the public benefits charge that all customers receive regardless of the EE measure; they are simply an unavoidable cost to all customers. Therefore, the program costs for EE measures would not result in a shift of costs from participating to non-participating customers.[1]

A calculation methodology is now presented for determining the appropriate ACOE estimates for various customer adopted EE measures. The approach presented here was originally adopted by the Utility in 2021 for valuing the ACOE associated with customer-sided solar PV systems under RPU's Self Generation tariff; note that it has been suitably modified here to assess various EE measures.[2]

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[1] Please note that EE program costs should be included in the cost effectiveness evaluations for determining the benefits and costs of individual programs within the context of determining how the public benefit charge is spent.

[2] See Chapter 15 for a discussion of RPU's Self Generation tariff, which represent the tariff that replaced the utility's prior NEM tariff.

Additionally, this approach is conceptually similar to the methodology in the 2017 CPUC Distributed Energy Resource avoided cost tool. The methodology for the various cost components discussed in that tool were adapted here to better reflect RPU's actual avoided costs and revenue losses associated with customer DSR and EE measures.

Finally, note that this specific discussion focuses on valuing the average avoided cost impact of multiple customer EE measures grouped into three broad EE measure categories: Baseload, Lighting, and HVAC categories. However, this methodology can also in principle be used to value any specific EE measure.

14.2 Conceptual Avoided Cost Components (Benefits Resulting from EE Measures)

The CPUC DER avoided cost tool originally proposed that the following avoided cost components could be recognized and valued when computing the implied value of DER/EE impacts:

- Generation energy
- Generation capacity
- Ancillary services
- Transmission costs
- Distribution costs
- Environmental/GHG costs
- Avoided RPS costs
- Avoided renewable integration costs
- System losses
- Avoided societal costs

As a publicly owned municipal utility, RPU should endeavor to accurately value as many of these avoided costs as reasonably possible, to compute a fair and equitable value for specific DER/EE measures. However, RPU must also recognize that not all these proposed avoided costs actually occur within our distribution system. With respect to the ten avoided cost categories listed above, reasonably objective methodologies can be proposed for appropriately valuing seven of these components (e.g., generation energy, generation capacity, ancillary services, transmission costs, environmental/GHG costs, avoided RPS costs and system losses). However, staff are currently unable to identify any avoided costs associated with renewable integration. Additionally, the avoided societal cost category is highly subjective (and beyond the scope of the utilities budget), and the calculation of reasonably accurate avoided distribution system costs (or benefits) tends to be very complicated and highly location specific. Further justification concerning the assessment of each of these avoided cost components is given below.

Avoided Generation Energy Costs

Every kWh of energy avoided by a customer adopted EE measure represents one less kWh of energy that RPU must purchase from the CAISO. Thus, the value of this energy should be recognized in any avoided cost calculation. For EE measures impacting future customer energy consumption, SP15 forward market energy price curves can be used as a reasonable proxy for RPU's expected wholesale energy costs.

Avoided Generation Capacity Costs

To the extent that an EE measure reduces energy consumption during peak energy needs, RPU can expect to achieve savings in its system RA costs. Additionally, RPU's local RA requirement should also decrease as its peak energy needs decrease. Both avoided costs should be recognized and quantified in the avoided cost calculation.

Ancillary Services

In theory, RPU should receive certain ancillary service benefits as more EE measures are adopted within our service territory. While RPU receives minimal ancillary service revenues from the CAISO for our internal generation assets and no ancillary revenues for our renewable assets, the utility does pay CAISO ancillary service uplift costs in proportion to its load share ratio. Thus, as EE measures reduce the utility's wholesale load serving needs, these uplift costs should decrease. Staff therefore recognizes that a calculated $/MWh cost reduction value should be assigned to this avoided cost component.

Avoided Transmission Costs

RPU pays a transmission access charge (TAC) to the CAISO for every MWh of energy used to serve our system load. Therefore, RPU receives avoided transmission cost benefits (due to reductions in our system load) in direct proportion to the CAISO TAC rate and hence staff recommends that this TAC rate value be assigned to this avoided cost component.

Avoided Distribution Costs

In theory, RPU could potentially avoid (or at least defer) specific distribution upgrade costs if the right type of EE measure is adopted by customers on a circuit at or near its maximum capacity. In contrast, the installation of EE measures on an underutilized circuit provides the Utility with no material financial benefit. Furthermore, EE measures adopted by customers on circuits that already have high customer DER penetration levels simply exacerbates the reverse energy flows occurring within our distribution system, in turn causing RPU to incur additional and unanticipated distribution upgrade costs.

More importantly, RPU does not currently possess the ability to accurately quantify these costs on anything other than a case-by-case basis. As such, although staff recognize that there could potentially be specific avoided or incurred costs associated with the adoption of specific EE measures, no value (either positive or negative) can currently be assigned to this cost component.

Avoided Environmental/GHG Costs

Under the Cap-and-Trade program, RPU must surrender Carbon emission credits to CARB to offset its greenhouse gas emissions. In principle, an argument can be made that since EE measures reduce RPU's need to purchase CAISO (non-zero emission) system energy, RPU's total Carbon footprint should be reduced. In turn, the value of these "avoided" Carbon emissions represents an additional avoided cost that can be directly attributed to the adopted EE measure.

Conceptually, this value can be readily quantified using the recent cost of CARB GHG emission credits as a proxy. However, the above argument assumes that RPU would have met the extra (EE avoided) load serving needs using generation assets having a Carbon emission factor at least as great as RPU's system average factor. This calculated avoided cost only represents a true (and accurate) avoided cost to the extent that this assumption holds true.

Avoided RPS Costs

Under the CA RPS legislative paradigm, RPU must acquire enough qualified renewable energy to meet specific percentages of its retail sales each year (for example, 33% in 2020). In principle, RPU will need to acquire proportionally less wholesale renewable energy as additional EE measures reduce its system load. Hence, the value of this "avoided" wholesale renewable energy represents another avoided cost that can be directly attributed to the adoption of extra EE.

To determine this avoided cost component, a suitable value for a renewable energy credit (REC) must be specified. Note that REC values essentially quantify the value of the "green energy attributes", in comparison to non-renewable market power. While there are multiple ways that such REC values might be determined, staff believe that this additional avoided cost should be recognized in our avoided cost calculation.

Avoided Renewable Integration Costs

Staff are currently unable to identify any avoided renewable integration costs associated with increasing adoption levels of EE measures. Therefore, staff recommends that a zero value be assigned to this avoided cost component.

System Losses

Nearly all the applicable cost components discussed above need to recognize the fact that customer adopted EE measures directly impact RPU's secondary distribution system, and thus are not subject to the various transmission and high voltage distribution system losses that affect its wholesale system energy imports. Hence, the values associated with these cost components need to be adjusted (i.e., scaled up) in the avoided cost calculation to account for such losses.

Avoided Societal Costs

This last cost component category is highly subjective and beyond the scope of the Utility's budget. Although various Public Utility Commissions have assigned specific $/kWh values to such costs, this category is generally recognized as a cross-class subsidy that is designed to further incentivize DER or EE programs within a utilities service area. Thus, staff does not recommend imposing this type of subsidy fee on RPU's non-DER customers, since it essentially violates cost-based rate setting principles.

14.3 Avoided Cost Calculation Methodology

Based on the above avoided cost components, a practical ACOE cost calculation methodology can be derived and used to estimate the $/kWh value of any individual EE measure or pooled set of EE programs. A few caveats concerning these calculations are worth expanding upon. First, it is necessary to specify certain additional assumptions about how the EE measures or programs perform in practice. For example, one must specify the annual capacity factor of each measure or program, the corresponding seasonal pattern of avoided energy, and the kW peak load reduction probabilities for each month of the year (for a measure or program that produces one kW per hour of EE savings for some seasonal pattern and annual capacity factor). After these assumptions have been determined, additional avoided cost values for the energy, capacity, ancillary services, transmission, carbon and RPS credits need to be quantified, along with the distribution loss adjustment factor. Table 14.3.1 discusses each of these avoided cost values in more detail. Once all this information has been quantified, ACOE estimates can be computed.

Table 14.3.2 shows the assumed seasonal avoided energy patterns for the three EE program categories (Baseload, Lighting, and HVAC), along with the corresponding 2024 monthly SP15 market energy prices used to value the avoided energy patterns.[3] Note that these estimates remain the same for the Residential (RES) and Commercial + Industrial (Comm/Indst) customer classes within each EE program category and that these estimates match the Load Scaling factors shown in Table 2.2.4. Likewise, Table 14.3.3 shows the monthly kW peak load reduction probabilities and annual capacity factors for each EE program category and customer class. Note that the Baseload and HVAC peak load reduction probabilities match the Peak Shaping factors shown in Table 2.2.4 and that some of the annual CF estimates change across customer classes within each EE program category, respectively.[4]

[3] Estimates derived from 10/03/2023 forward SP15 ICE price quotes.

[4] The Lighting peak load reduction probabilities are equal to the Lighting Peak Shaping factors divided by 1.164.

Table 14.3.1. Avoided cost components for use in the ACOE calculation methodology for Baseload, Lighting and HVAC EE programs.

Component (Avoided Costs)	Metrics (used in calculations)	Proposed Methodology (for deriving avoided cost estimate)
Energy	SP15 Forward electricity prices (i.e., either flat, LL (off-peak) or HL (on-peak) prices). Seasonal pattern of expected monthly kWh savings.	Use weighted average of SP15 ICE price forecasts. Multiply monthly price forecasts by monthly kWh forecasts, sum results to determine weighted average energy price.
Capacity (System RA)	kW $/month system RA costs. Peak hour reduction probability for corresponding EE program.	Estimate monthly system RA costs ($/kW-month), multiply each monthly cost by expected peak hour reduction probability; sum results to determine system RA credit.
Capacity (Local RA)	kW $/year local RA costs. Expected annual kWh savings for corresponding EE program.	Estimate annual local RA cost ($/kW-year), multiply cost by kW reduction / MWh production factor and annual kWh production forecast to determine local RA credit.
Ancillary Services	Current calculated CAISO AS uplift rate (as determined from CAISO settlement charges).	Divide the sum of the total annual AS uplift charges by the sum of the annual MWh system loads to determine the $/MWh avoided AS uplift costs.
Environmental (Carbon Credit)	ARB Carbon clearing prices (last four quarters). RPU system average emission factors (EF) from last two years of PSD filings.	Multiply the average carbon price by the average RPU system emission factor to determine the implied $/MWh carbon credit.
RPS Credit	Uses a PCC-1 REC value of $20/MWh, along with annual RPS target (proportion).	Multiply the REC value by the current years RPS target value to determine the $/MWh avoided REC costs.
Transmission	Current CAISO TAC rate.	TAC rate is already expressed in $/MWh units. Divide by 1000 for $/kWh rate.
System Losses	Average distribution loss factor (proportion).	Divide sum of $/kWh components (Energy, Capacity [system and local], Ancillary Services, Carbon, RPS credit, and Transmission) by 1 – loss factor.

Note: All metrics refer to the forecasted values for the year in question, unless otherwise noted in table. Most values can and typically will change annually. Additionally, all values can either be naturally expressed in (or converted into) $/kWh units.

Table 14.3.2. Assumed seasonal avoided energy patterns for Baseload, Lighting and HVAC EE programs and 2024 forward market energy costs ($/MWh).

Month	Seasonal avoided energy pattern			SP15 Flat, LL and HL market energy costs		
	Baseload	Lighting	HVAC	Flat	LL (off-peak)	HL (on-peak)
Jan	0.0833	0.0970	0.0788	$87.22	$84.00	$89.75
Feb	0.0833	0.0933	0.0541	$76.43	$77.00	$76.00
Mar	0.0833	0.0858	0.0367	$49.41	$53.75	$46.00
Apr	0.0833	0.0784	0.0256	$39.58	$45.85	$35.00
May	0.0833	0.0746	0.0486	$32.41	$37.55	$28.35
Jun	0.0833	0.0709	0.1122	$51.18	$47.35	$54.25
Jul	0.0833	0.0709	0.1802	$82.98	$68.55	$94.35
Aug	0.0833	0.0746	0.1916	$100.15	$82.35	$113.00
Sep	0.0833	0.0784	0.1289	$79.34	$59.95	$96.30
Oct	0.0833	0.0858	0.0513	$56.24	$55.40	$56.85
Nov	0.0833	0.0933	0.0294	$63.13	$63.05	$63.20
Dec	0.0833	0.0970	0.0626	$89.68	$88.15	$91.00

Table 14.3.3. Assumed monthly kW load reduction probabilities and annual capacity factors for Baseload, Lighting and HVAC EE programs.

Month	Residential customer class			Comm/Indst customer class		
	Baseload	Lighting	HVAC	Baseload	Lighting	HVAC
Jan	1.0	1.000	0.411	1.0	1.000	0.411
Feb	1.0	0.961	0.283	1.0	0.961	0.283
Mar	1.0	0.885	0.192	1.0	0.885	0.192
Apr	1.0	0.808	0.134	1.0	0.808	0.134
May	1.0	0.770	0.253	1.0	0.770	0.253
Jun	1.0	0.731	0.586	1.0	0.731	0.586
Jul	1.0	0.731	0.940	1.0	0.731	0.940
Aug	1.0	0.770	1.000	1.0	0.770	1.000
Sep	1.0	0.808	0.673	1.0	0.808	0.673
Oct	1.0	0.885	0.268	1.0	0.885	0.268
Nov	1.0	0.961	0.154	1.0	0.961	0.154
Dec	1.0	1.000	0.327	1.0	1.000	0.327
Annual CF	65%	35%	20%	75%	65%	30%

After quantifying all these assumptions and avoided cost estimates, ACOE estimates can be calculated for each EE program category and customer class. In these analyses, all Baseload EE ACOE calculations used SP15 Flat price forecasts, while all HVAC EE ACOE calculations used SP15 HL prices. Additionally, Comm/Indst EE ACOE calculations used SP15 Flat price forecasts while Residential EE ACOE calculations used SP15 LL prices. Additionally, all analyses assume a System RA price of $120/kW-year ($10/kW-month) and an adder of $30/kW-year ($2.50/kW-month) for Local RA attributes.[5] The remaining detailed calculations supporting each ACOE estimate are shown in Appendix C, Tables C.1 through C.6.

The six summary VOAE estimates are presented in Table 14.3.4. Note that these estimates quantify RPU's avoided costs (i.e., budgetary savings) for each EE program category by customer class, on a $/kWh basis, respectively.

Table 14.3.4. Final ACOE cost calculations for Baseload, Lighting, and HVAC EE programs, by customer class. (Detailed calculations presented in Appendix C, Tables C.1 through C.6.)

Customer Class	Baseload	Lighting	HVAC
Residential class	$0.1331/kWh	$0.1408/kWh	$0.1778/kWh
Comm/Indst class	$0.1302/kWh	$0.1292/kWh	$0.1610/kWh

14.4 Unmet Revenue Calculations for Energy Efficiency Programs

Like the ACOE calculations, a methodology is now presented for determining the unmet revenue impacts from customer adopted EE measures. The unmet revenue impacts represent the costs portion of the benefit-cost analysis. Unmet revenue means that any utility costs not avoided must be transferred to non-participating customers. The approach proposed here is high-level and relies on some straight-forward assumptions about when and how different EE measures reduce electricity usage within different customer classes. As before, this discussion focuses on valuing the average unmet revenue impact of multiple customer EE measures associated with the three broad EE program categories: Baseload, Lighting, and HVAC.

[5] As discussed in Chapter 7, section 7.6, the cost for 2024 System+Local RA is projected to be $12.50/kW-month.

14.4.1 RPU Rate Schedules

Tables 14.4.1 and 14.4.2 show the 2024 rate schedules for RPU's four primary customer classes: Domestic Residential (DOM), Commercial Flat (CF), Commercial Demand (CD), and Industrial TOU (TOU). Unmet energy revenue impacts can be estimated from these rate schedules, once certain assumptions are made about how the corresponding reduced electricity usage patterns are distributed across customers. However, due to the significant impacts of the COVID-19 pandemic on 2020-2022 electricity usage within the City of Riverside, the following analyses will rely on the electricity usage patterns derived during our last IRP cycle. Thus, unless otherwise noted, the energy usage patterns shown in the next section refer to the comprehensive 2015-2017 bill assessment study that staff performed for RPU's 2018 IRP.

Table 14.4.1. Current rate schedules for the Domestic Residential (DOM) and Commercial Flat (CF) rate classes.

Customer Class	Tariff Component	Details	Rate
Domestic Residential	Customer	all customers	$12.90
	NAC	Tier 1: < 12.0 kWh/day	$3.19
		Tier 2: 12.0 to 25.0 kWh/day	$7.44
		Tier 3: > 25.0 kWh/day	$15.32
	Reliability	0-100 Amp panel	$10.00
		101-200 Amp panel	$20.00
		201-400 Amp panel	$40.00
		> 400 Amp panel	$60.00
	Energy	Summer Tier 1: 0-750 kWh	$0.1179
		Summer Tier 2: 751-1500 kWh	$0.1880
		Summer Tier 3: > 1500 kWh	$0.2127
		Winter Tier 1: 0-350 kWh	$0.1179
		Winter Tier 2: 351-750 kWh	$0.1880
		Winter Tier 3: > 750 kWh	$0.2127
Commercial Flat	Customer	all customers	$21.12
	NAC	Tier 1: 0-500 kWh	$3.45
		Tier 2: 501-1500 kWh	$9.79
		Tier 3: 1501-3000 kWh	$17.40
		Tier 4: > 3000 kWh	$41.85
	Reliability	Tier 1: 0-500 kWh	$10.00
		Tier 2: 501-1500 kWh	$30.00
		Tier 3: > 1500 kWh	$60.00
	Energy	Tier 1: 0-15,000 kWh	$0.1531
		Tier 2: > 15,000 kWh	$0.2338

Table 14.4.2. Current rate schedules for the Commercial Demand (CD) and Industrial TOU (TOU) rate classes.

Customer Class	Tariff Component	Details	Rate
Commercial Demand	Customer	all customers	$22.10
	Reliability	all customers	$90.00
	NAC	$ per kW	$1.75
	Minimum Demand	first 15 kW or less	$160.95
	Excess Demand	all excess kW (> 15), $ per kW	$10.73
	Energy	Tier 1: 0-30,000 kWh	$0.1242
		Tier 2: > 30,000 kWh	$0.1360
Industrial TOU	Customer	all customers	$686.28
	Reliability (based on max Demand)	Tier 1: < 100 kW	$350.00
		Tier 2: 100-150 kW	$750.00
		Tier 3: 150-250 kW	$900.00
		Tier 4: 250-500 kW	$1100.00
		Tier 5: 500-750 kW	$1850.00
		Tier 6: > 750 kW	$2650.00
	NAC	$ per kW, max Demand	$3.87
	Demand	On-peak, per kW	$7.66
		Mid-peak, per kW	$3.83
		Off-peak, per kW	$1.92
	Energy	On-peak, per kWh	$0.1197
		Mid-peak, per kWh	$0.0981
		Off-peak, per kWh	$0.0838

It should also be noted that in 2019 RPU incorporated a Network Access Charge (NAC) into all customer bills. This NAC was designed to be an additional Demand charge that all customers need to pay for access to Riverside's distribution system. However, because the DOM and CF rate tariffs do not contain Demand charges, it was necessary to formulate this NAC into a tiered fixed charge that instead depend on a customer's monthly average energy usage levels.

14.4.2 Reduced Energy Usage Patterns

Table 14.4.3 shows the pertinent assumptions about the reduced electricity usage patterns for the DOM, CF, and CD customer classes, for all three EE categories. The usage patterns for the Baseload and Lighting have been derived from the 2015-2017 bill impact assessment within each customer class. In contrast, the HVAC usage pattern has been estimated for the DOM class by assuming that two-thirds of the customers whose highest average energy usage falls into tier 1 do not have (or rarely use) air conditioning. (In the commercial customer classes, it is simply assumed that the HVAC usage patterns are again uniformly distributed, since nearly all commercial entities maintain some degree of air conditioning.)

Table 14.4.3. Reduced electricity usage assumptions for the DOM, CF, and CD customer classes by EE measure category.

Customer Class	% of Customers in each energy Tier	Baseload & Lighting %	HVAC % (estimated)
Domestic Residential (DOM)	Tier 1 (annual average)	62.3%	35.5%
	Tier 2 (annual average)	26.5%	45.3%
	Tier 3 (annual average)	11.2%	19.2%
Commercial Flat (CF)	Tier 1: 0-15,000 kWh	98.0%	98.0%
	Tier 2: > 15,000 kWh	2.0%	2.0%
Commercial Demand (CD)	Tier 1: 0-30,000 kWh	88.0%	88.0%
	Tier 2: > 30,000 kWh	12.0%	12.0%

To develop similar reduced electricity usage patterns for the TOU customer class, it is necessary to first examine the TOU time periods and then consider how the EE programs might impact these time periods. The assumed weighting coefficients for each TOU EE category are shown in Table 14.4.4. For the Baseload category, the assumed weights simply correspond to the number of annual hours falling within each TOU time-period. In contrast, the weights for the Lighting category have been calculated assuming that there will be a 50% reduction in lost revenue during Off-peak hours. Finally, the weights for the HVAC category assume that all the lost revenues are distributed across just the On-peak and Mid-peak hours, following a 69% / 31% distribution for the On- and Mid-peak hours, respectively.

Table 14.4.4. Weighting coefficients for TOU EE measure categories.

TOU EE Measure Categories	Weighting % (estimated)		
	On-peak	**Mid-peak**	**Off-peak**
Industrial TOU (Baseload)	19.5%	37.5%	43.0%
Industrial TOU (Lighting)	24.8%	47.8%	27.4%
Industrial TOU (HVAC)	69.0%	31.0%	0.0%

Since nearly all EE measures reduce both energy consumption and energy demand, one would expect that there will be some lost NAC revenue across all customer classes (in addition to lost energy revenues). Likewise, in addition to lost revenue from avoided NAC and energy charges, the CD and TOU customer classes will also clearly show revenue losses from avoided demand charges. Thus, additional lost revenues from both NAC and Demand charge adjustments need to also be calculated, along with avoided energy charges.

Table 14.4.5 presents a high-level assessment for how and to what degree different EE measures would be expected to reduce NAC revenues within the Domestic Residential and Commercial Flat customer classes. The key working assumptions are as follows: (1) if a customer is going to move to a lower NAC tier due to some type of installed EE measure, this then would only be expected to happen at most 6 months out of the year, and (2) we would only expect to see a limited amount (%) of movement between tiers per installed kW of EE. The first assumption is reasonable because the NAC tiers in both the DOM and CF classes do not vary seasonally, while nearly all customer loads will (e.g., be higher in the summer and lower in the winter). Likewise, the second assumption is also reasonable because the tier ranges are quite large for both customer classes. Given these assumptions and based on the Table 14.4.5 computations, the forecasted lost NAC revenues in the DOM and CF customer classes are expected to be fairly minimal.

Table 14.4.5. Forecasted EE impacts on DOM and CF NAC revenues, due to movement between tiers.

Metric	**Domestic Residential**		**Commercial Flat**		
	Tier 2 to 1	**Tier 3 to 2**	**Tier 2 to 1**	**Tier 3 to 2**	**Tier 4 to 3**
Revenue Loss per Account (6 months)	$25.50	$47.28	$38.04	$45.66	$146.70
Annual kWh per installed kW:					
Baseload	5,694	5,694	6,570	6,570	6,570
Lighting	3,066	3,066	5,694	5,694	5,694
HVAC	1,752	1,752	2,628	2,628	2,628
$/kWh Adjustment:					
Baseload	$0.0045	$0.0083	$0.0058	$0.0069	$0.0223
Lighting	$0.0083	$0.0154	$0.0067	$0.0080	$0.0258
HVAC	$0.0146	$0.0270	$0.0145	$0.0174	$0.0558
Assumed % Movement per installed kW:					
Baseload	2.50%	2.50%	1.00%	2.00%	3.00%
Lighting	2.50%	2.50%	1.00%	2.00%	3.00%
HVAC	5.00%	15.00%	2.00%	6.00%	12.00%
Overall $/kWh Impacts:					
Baseload - per Tier	$0.00011	$0.00021	$0.00006	$0.00014	$0.00067
Lighting - per Tier	$0.00021	$0.00039	$0.00007	$0.00016	$0.00077
HVAC - per Tier	$0.00073	$0.00405	$0.00029	$0.00104	$0.00670
Baseload - Implied kWh adder	$0.0003		$0.0009		
Lighting - Implied kWh adder	$0.0006		$0.0010		
HVAC - Implied kWh adder	$0.0048		$0.0080		

Unlike the lost NAC revenue in the DOM and CF customer classes, the lost NAC revenue in the Commercial Demand and Industrial TOU classes will be more significant. This will be true because the NAC in these classes simply represents additional Demand rates that must respond to any reduction in demand. Table 14.4.6 presents the forecasted savings in Demand+NAC charges per kW of installed EE for the Commercial Demand and Industrial TOU customer classes. The analyses presented in this table are based on (1) first identifying the impacted monthly Demand + NAC rates for each EE measure in each customer class, (2) next multiplying this rate by the Annual Impact Factor (which represents the sum of the monthly kW load reduction probabilities shown in Table 14.3.3) to yield the annual demand savings estimate, and (3) then dividing this $/year estimate by the assumed CF to yield the implied kWh adder, which represents the $/kWh values of these avoided NAC and Demand charges.

Table 14.4.6. Estimated annual Commercial Demand and Industrial TOU Demand+NAC charges saved per kW by EE measure category.

Metric	Commercial Demand		
	Baseload	Lighting	HVAC
Demand + NAC $/kW	$12.48	$12.48	$12.48
Annual Impact Factor (Table 14.3.3)	12.000	10.309	5.221
Annual Demand Savings ($) per kW	$149.76	$128.66	$65.16
Annual kWh per installed kW	6,570	5,694	2,628
Implied kWh adder	0.0228	0.0226	0.0248
Metric	**Industrial TOU**		
	Baseload	**Lighting**	**HVAC (1)**
Demand + NAC $/kW	$17.28	$17.28	$15.36
Annual Impact Factor (Table 14.3.3)	12.000	10.309	5.221
Annual Demand Savings ($) per kW	$207.36	$178.14	$80.19
Annual kWh per installed kW	6,570	5,694	2,628
Implied kWh adder	0.0316	0.0313	0.0305

(1) Industrial TOU HVAC EE measures are assumed to only impact On-peak and Mid-peak Demand rates.

Finally, one can add the values shown in Tables 14.4.5 and 14.4.6 with the calculated avoided energy charges to yields the final, total $/kWh unmet revenue estimates for each of these four customer classes, respectively.

14.5 Calculated Net Unmet Revenue Impacts

Upon performing all the necessary avoided Energy, NAC and Demand calculations, the final gross $/kWh unmet revenue estimates for each customer class and EE category can be produced. After comparing the corresponding $/kWh ACOE calculations to these gross numbers, net unmet revenue estimates can be produced. A positive net unmet revenue estimate implies that there will be incremental costs that the utility must adsorb when implementing the associated EE measure, while a negative estimate suggests that the utility can actually save money by implementing the corresponding measure.

Table 14.5.1 shows these unmet revenue estimates, along with the previously derived ACOE estimates for the same customer class - EE measure category combinations. Figure 14.5.1 plots the associated net unmet revenue estimates by (grouped) customer class and (color coded) EE measure. This information quantifies estimates of either the net costs or net benefits passed onto our non-participating customers by each EE measure within a specific customer class, respectively.

The following are the key take-away points from Table 14.5.1 and Figure 14.5.1. First, most of the EE program categories exhibit positive net unmet revenue estimates and thus have benefit to cost ratios < 1. This should not be that surprising, since RPU's energy rates are designed to collect all the utility's fixed operating costs (i.e., infrastructure, personnel, and O&M), in addition to its variable power supply costs. However, four EE program categories do exhibit negative net unmet revenue estimates, with the Industrial TOU – HVAC category being the most pronounced (benefit to cost ratio = 1.12).

Table 14.5.1. 2024 unmet revenue estimates by customer category and EE measure category.

Customer Class	EE Measure	Gross Unmet Revenue ($/kWh)	ACOE Benefit ($/kWh)	Net Unmet Revenue ($/kWh)	Benefit to Cost Ratio
Residential	Baseload	$0.1474	$0.1331	$0.0143	0.90
	Lighting	$0.1477	$0.1408	$0.0069	0.95
	HVAC	$0.1726	$0.1778	($0.0052)	1.03
Comm Flat	Baseload	$0.1556	$0.1302	$0.0254	0.84
	Lighting	$0.1557	$0.1292	$0.0265	0.83
	HVAC	$0.1627	$0.1610	$0.0017	0.99
Comm Demand	Baseload	$0.1484	$0.1302	$0.0182	0.88
	Lighting	$0.1482	$0.1292	$0.0190	0.87
	HVAC	$0.1504	$0.1610	($0.0106)	1.07
Industrial TOU	Baseload	$0.1277	$0.1302	($0.0025)	1.02
	Lighting	$0.1308	$0.1292	$0.0016	0.99
	HVAC	$0.1435	$0.1610	($0.0175)	1.12

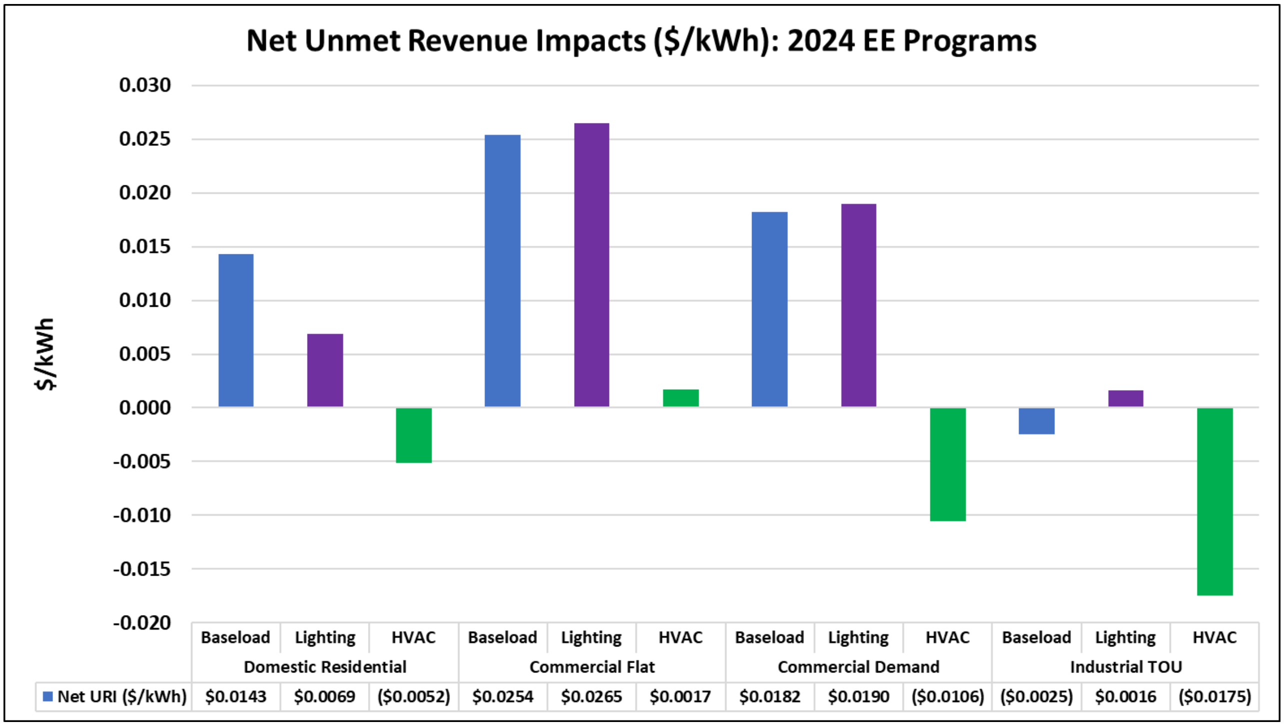

Figure 14.5.1. Net unmet revenue impacts by customer class and EE measure type ($/kWh).

Second, with respect to customer classes, the EE measures targeted towards the Industrial TOU customers would appear to be the most cost effective (from a utility perspective). Likewise, the HVAC EE programs would appear to be the most cost effective with respect to the type of EE measure being implemented. These results suggest that RPU might want to direct proportionally more of its 2024 EE efforts towards Industrial TOU customers and/or HVAC EE measures (across all customer classes).

Third, and perhaps more importantly, only two EE measures (CD – HVAC and TOU – HVAC) exhibit negative net unmet revenue estimates that are less than -$0.01/kWh and there are no EE measures with estimates less than -$0.02/kWh. These results imply that there are probably not a lot of opportunities for the utility to significantly increase the adoption of many EE measures in a cost-effective manner. Thus, RPU does not currently plan to significantly increase its EE investments to offset the need for some percentage of additional, future supply-side resources, unless the utility fails to identify any future supply-side resources with positive net value attributes.

15. Retail Rate Design

In 2022, staff began working on a new five-year rate plan. The previous five-year electric rate plan was adopted in 2018 and was effective January 1, 2019, through December 31, 2023. Unfortunately, this plan did not sufficiently account for the inflation of costs in the general economy and even greater inflationary market prices in power supplies and construction costs. On September 19, 2023, the City Council adopted RPU's proposed new five-year (fiscal years 2023/24 through 2027/28) electric utility rate plan that will result in a five-year system average annual rate increase of 5.0% per year. This rate plan reflects increased operational and capital costs, and includes additional funding to address declining reserve levels, pressures on financial metrics, and meeting fiscal policy requirements. The relevant rate documents and information about RPUs rate plans can be found online at: https://www.riversideca.gov/utilities/electric-proposed-rates.

15.1 Overview of the 2023 RPU Electric Rate Proposal

In August 2023, after 15 months of iterative work and development, RPU proposed a revised five-year (fiscal years 2023/24 through 2027/28) electric utility rate plan that would result in a five-year system average annual rate increase of 5% for typical electric customers. For an individual customer, the rate increase and associated bill impact varies by customer class and consumption levels. (For a typical residential customer using 600 kWh a month, the estimated annual electric rate increase in year 1 will be $7.97 per month.) This proposed rate increase is necessary for the following reasons:

- To help fund infrastructure investments, including upgrades to electric substation components and underground equipment;
- To meet increasingly aggressive State renewable energy regulatory requirements and GHG abatement legislation;
- To keep up with increasing operational costs including necessary improvements to the electric distribution system;
- To cover increased costs for natural gas and CAISO energy. Natural gas costs have doubled over the last two years due to increased liquid natural gas exports and restricted capacity on western interstate gas pipelines, which, along with supply-chain challenges delaying the development of new renewable resources, have in turn caused costs for California Independent System Operator (CAISO) market energy to increase 60% to 80%; and
- To maintain strong bond ratings and low debt costs.

RPU also retained most of the redesigned rates that were adopted in its prior five-year rate plan to continue aligning with its cost of serving customers and its revenue requirements. The prior electric rate restructuring was designed not only to fund the ten-year infrastructure program, but also to allow RPU to meet industry changes by providing better financial and revenue stability. An outline of the specific key changes to RPU's rate structure adopted in the prior FY18/19-22/23 rate plan is shown in Table 15.1.1, along with the few new tariff adjustments made in the latest proposed plan.

Table 15.1.1. Key proposed changes to RPU's electric rate tariffs.

Key Changes	Current Rates (FY18/19-22/23)	Proposed Rates (FY23/24-27/28)
Fixed Cost Recovery Concept	In FY17/18, the electric utility's fixed costs were approximately 54%, but the utility only collected 23% though fixed charges. By the fifth year of the rate plan, RPU will collect approximately 29% of our rate revenue through fixed charges. This adjustment helps RPU meet its objective of increased revenue stability and reflect how actual costs are incurred.	The proposed rates maintain billing components that should collect about 30% of our rate revenue through fixed charges.
Distribution System Cost Recovery (Network Access Charge)	Introduce a Network Access Charge (NAC) to ensure the adequate recovery of RPU's distribution infrastructure costs. This fixed charge contributes to the collection of fixed costs as noted above. The NAC will be applied to all customer classes.	The NAC will continue to be applied to all customer classes and escalated appropriately (along with monthly Customer charges) to ensure that 30% of our rate revenue is recovered through these fixed charges.
Industrial Time of Use (TOU) Reliability Charge	Restructure the Industrial TOU reliability charge to a tiered reliability charge to lessen the impact on lower demand use Industrial TOU customers and reflect their actual impact on the RPU electric system.	The proposed rates maintain this tiered TOU reliability charge.
Residential Class: Seasonal Rate Adjustment	The prior 3-month summer season was extended into a 4-month summer residential season (June 1 to September 30) to better reflect summer weather and usage patterns.	The proposed rates maintain this 4-month summer season.
Electric Vehicles (EV)	Introduced two new domestic time-of-use (DTOU) rates for residential EV customers (a whole-house TOU rate and a separately metered, EV-only TOU rate) to encourage EV adoption and off-peak charging.	The off-peak whole-house TOU rate will be collapsed down into a single tier and set equal to the (single tier) EV-only off-peak TOU rate.
Demand Charge Transition	Lowered the minimum demand charge on commercial demand customers to 15 kW within the customer class, thus reducing the impact of customers transitioning from the flat to demand class.	The proposed rates maintain this minimum 15 kW demand charge for commercial demand customers.
High Voltage (HV) Rate	Introduced a high voltage adjustment (discount) for customers that take service at the primary voltage level (4 kV to 69 kV).	The proposed rates maintain this high voltage discount.
Optional Renewable Energy Rate	Introduced an optional program that allows customers to purchase 100% green/renewable energy for an additional $/kWh fee.	The proposed rates maintain this 100% Renewable Energy Tariff (100% RET) program. Additionally, the $/kWh fee adder is being reduced.
NEM 1.0	The NEM 1.0 program remained open to new customers.	The NEM 1.0 tariff was officially closed on October 31, 2022, and replaced with a new Self Generation tariff (see section 15.3). The proposed rates reference this new Self Generation tariff.

15.2 Justification of Fair and Reasonable Rates

RPU has endeavored to keep the proposed rate increases as low as possible by maximizing the use of ongoing non-retail revenues such as transmission revenues from the use of electric transmission lines, scheduling coordinator services to other agencies, and leases of real property owned by RPU. Additionally, since 2019 the utility has reinvested approximately $36.4 million of GHG auction revenues back into the Electric Supply budget to offset costs for excess renewable power purposes. Finally, RPU has continued to strategically reduce operating costs using new technologies, including various upgrades to the utility's operational technology platforms and the use of a line of credit to partially fund electric reserves. This line of credit represents a low-cost way to reduce necessary cash levels and increase RPU's overall liquidity.

In addition, as part of the rate setting and budget development process, all RPU divisions have continued to review their budgets and reduce costs wherever possible. It should also be noted that even with these proposed rate increases, the monthly electric bill for a typical Riverside resident will remain considerably lower than the bills for similar residents in neighboring communities. Figure 15.2.1 shows a comparison of what the forecasted monthly electric bill for a 600 kWh/month typical Riverside resident would be, if they lived in the three IOU service territories or any of the nine similar Southern CA POU service territories.

Another important component of the current rate setting process has been customer outreach. Ten separate community outreach events were held from May to August 2023 to engage with the community on the proposed rate increases (see Table 15.2.1). The City Manager and RPU General Manager made presentations to community groups and residents, while providing opportunities for Q&A sessions during each event. Discussions about RPU's Power Resource Portfolio and Integrated Resource Planning process also occurred at many of these events, given that the utility's forecasted power supply costs represent one of the main components driving the need for additional rate increases.

Table 15.2.1. Community outreach events in support of the FY23/24-27/28 rate plan.

Event	Date
Greater Riverside Chamber of Commerce (GRCC)	May 25, 2023
Building Industry Association	June 7, 2023
Residents for Responsible Representation	June 14, 2023
Downtown Area Neighborhood Alliance	June 19, 2023
Neighbors Better Together	June 25, 2023
Mission Grove Neighborhood Association	July 10, 2023
Neighbors of the Wood Streets	July 13, 2023
City Sponsored – Orange Terrace Center	July 31, 2023
City Sponsored – La Sierra Senior Center	August 3, 2023
City Sponsored – Bobby Bonds / Cesar Chavez Community Center	August 8, 2023

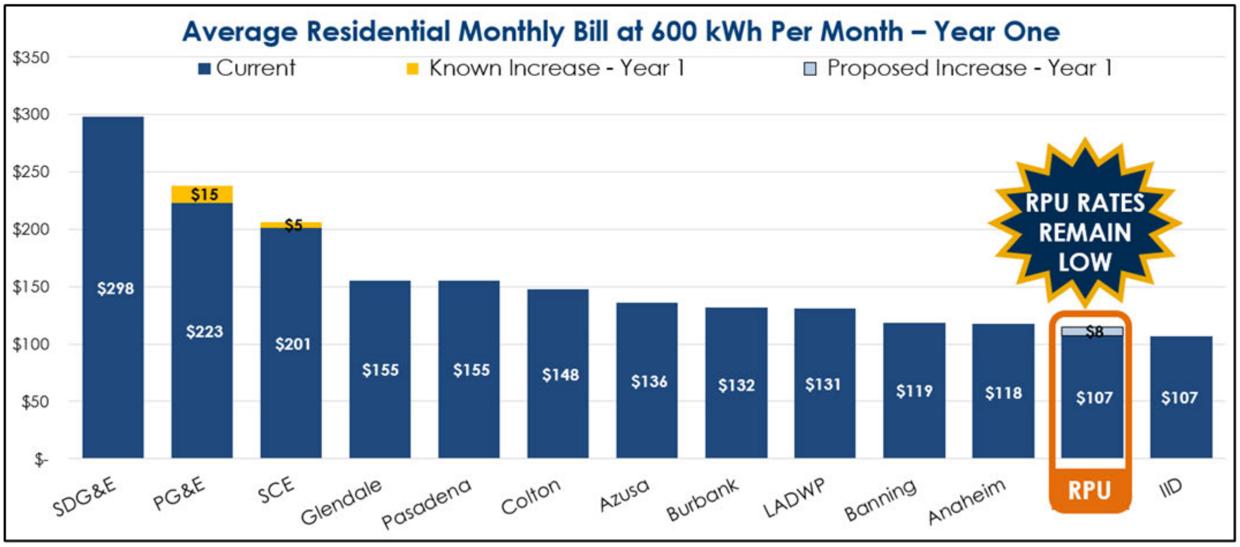

Figure 15.2.1. Forecasted monthly bills for a typical Riverside resident using 600 kWh a month, both within Riverside and across other IOU and POU service territories.

15.3 Important New Rate Tariffs

As shown in Table 15.1.1, RPU did not make many material changes to its existing rates in this latest 5-year rate proposal. However, in May 2022 the utility did introduce a new Self Generation tariff to replace its obsolete NEM 1.0 tariff, approximately one year after the generation capacity enrollment in the NEM 1.0 tariff exceeded 32 MW (which represented 5% of RPU's prior highest peak load).

Under the prior NEM 1.0 tariff, residential customers were allowed to net all their solar PV energy against energy purchased from RPU, while remaining on the default residential inclining block tariff. Unfortunately, this has created a material cost-shift between solar versus non-solar customers within this retail class, which was discussed in detail in RPU's 2018 IRP[1]. The new Self Generation tariff was designed and adopted to help reduce future cost-shift impacts by imposing two important tariff modifications for future solar PV customers. First, energy usage for all new solar customers is now monitored on an hourly basis and any energy exported into RPU's distribution system is compensated at the Utility's avoided cost of energy (currently about $0.08/kWh), rather than at the customers current retail rate. Second, all new residential solar customers must go onto the whole house Domestic Time-of-Use (DTOU) rate tariff. RPU has assigned this DTOU rate to be the default rate tariff for all residential customers who interconnect behind-the-meter DER systems on or after November 1, 2022.

This new Self Generation tariff has helped reduce the cost shift to customers without solar PV systems, while also helping support a more sustainable and equitable growth projection for customer

[1] RPU 2018 Integrated Resource Plan. Chapter 18: Long Term Impacts of Customer DER Penetration.

owned renewable self-generation. Additional administrative changes under this adopted tariff have also helped simplify the interconnection process for new customer-sided DER systems. While commenters expressed concerns about the potential impact on solar PV installation rates during the public hearings for the adoption of this new tariff, the installation of customer-sided solar PV systems has not slowed down since the tariff took effect. RPU customers continue to install approximately 4.0 MW of solar PV capacity per year within the utility's distribution system.

15.4 Enhanced Low-Income and Fixed-Income Assistance

At the September 2023 rate workshop, the City Council also approved further changes to RPU's low-Income and fixed income assistance programs to help off-set some of the new rate increase impacts on our lowest income customers. These programs include the Sharing Households Assist Riverside Energy (SHARE) Program and the Energy Savings Assistance Program (ESAP), along with the utility's associated outreach campaigns that support these program enrollment efforts. Some of the more important SHARE and ESAP program elements include:

- SHARE Program:
    - Eligibility is currently set at 250% of the Federal poverty level;
    - The current $16 monthly electric bill credit is set to increase to $20 per month in the first year of the new rate plan, and eventually $30 per month by year five;
    - The annual deposit assistance and emergency assistance was increased to $250 per year in March 2021;
    - RPU continues to work with its Community Action Partnership to create more convenient options for customers to sign up for program benefits.
- ESAP:
    - Suspended during COVID, but relaunched in 2022; program eligibility is aligned with SHARE and partner agency programs; and
    - Customers who qualify for the SHARE program are automatically signed-up into ESAP.

More details about these low-income assistance programs can be found online with the previously mentioned rate plan documents.

15.5 Projected Financial Impacts

Overall, the total additional revenue over the five-year period for this rate increase is projected to be $273 million for the electric utility, or approximately $54.6 million per year for each of the next five years. This revenue is essential to finance new and upgraded distribution system infrastructure, increased renewable energy procurement, and additional utility operation costs. Additionally, this increased revenue will help RPU maintain financial stability, strong bond ratings, and low debt costs. Note that the total planned debt issuances over this same five-year period are anticipated to be about $156 million for the electric utility to fully fund the above-mentioned infrastructure, operations, and power supply costs.

16. Transportation Electrification

This chapter presents an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. The discussion addresses the anticipated energy demand and reduced greenhouse gas (GHG) emissions that will result from the forecast transition of vehicles from using internal combustion engines (ICE) to electric motors supported by plug-in battery-electric vehicles (BEV or EV). RPU works closely with the City of Riverside and is working to expand access to electric vehicle charging infrastructure as well as meet Citywide environmental and sustainability goals.

This chapter also reviews the policy and regulatory environment around transportation electrification and the status of electrification in the RPU service territory. Additionally, multiple forecasts for EVs and their associated annual loads within the RPU service territory are examined, along with the forecasted GHG emissions reductions corresponding to these various EV penetration scenarios. These forecasts for EVs and their associated loads are derived from the CEC Transportation Electrification Common Assumptions 3.0 model, as well as the 2021 and 2022 Integrated Energy Policy Reports (IEPR) developed by the California Energy Commission (CEC) in consultation with the California Air Resources Board (CARB) and the California Public Utilities Commission (CPUC).[1] Overall, staff have elected to analyze multiple electric vehicle charging loads and their corresponding emissions reductions, given the high level of uncertainty around future EV adoption rates and charging patterns.

16.1 Overview of Transportation Electrification

Since the passage of Assembly Bill (AB) 32 in 2006, the State of California has continued the adoption of increasingly aggressive goals to transform the transportation sector to reduce GHG emissions. The transportation sector emits more GHG emissions than any other single sector, including electric generation. With about 40% of the GHG emissions tracked by the state[2] resulting from the combustion of fossil fuels used in transportation, State policies and regulations focus on their reduction. The primary strategy is to transition transportation fuel from higher GHG emitting fuels such as gasoline and diesel to those that emit fewer or have no GHG emissions such as electricity. While there are many alternative fuels, such as using hydrogen with fuel cells in vehicles, the State has focused on plug-in BEVs as the primary technology, particularly for light-duty vehicles. Hydrogen is anticipated to be used in medium- and heavy-duty (MHD) vehicles and other heavy transportation such as rail though the final mix of the technologies is currently unknown. Expanding electrification of the transportation sector, referred to as transportation electrification (TE), will have the additional benefit of decreasing leading

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[1] A comparison to the 2022 IEPR EV forecasts has been included here for reference purposes only, since these EV forecasts have not been incorporated into the demand forecast used for this IRP.

[2] California Air Resources Board, "California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators," October 26, 2022. https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf

criteria air pollutants in the south coast air basin[3] including nitrogen oxides (NO_x) and fine particulate matter (PM_{10} and $PM_{2.5}$) tailpipe emissions.

Because TE potentially represents a significant increase in the amount of electric demand, RPU is required to consider and address TE in its IRP. While RPU is not responsible for converting all vehicles to zero-emissions technology, RPU is required to prepare for and support its customers who have been and will be transitioning the vehicles and fleets. RPU must evaluate the expected electricity demand and ensure that the utility demonstrates it is preparing for the increasing number of electric vehicles (EVs). Additionally, RPU is required to evaluate the GHG emissions reductions resulting from EVs. This chapter addresses RPU's current planning efforts around various plausible future EV adoption / GHG emission reduction scenarios.

The growth in the number of light-duty EVs in California's statewide vehicle fleet is well underway and is expected to continue. As of April 2023, the State of California has surpassed its 1.5 million zero-emission vehicles (ZEVs) goal by 2025, two years ahead of schedule. This year 40% of ZEVs sold across the country were sold in California, and 21% of all cars sold in California in 2022 were ZEVs.[4] In Riverside as of mid-2023, there were almost 6,500 light-duty EVs owned by residents and businesses.

As the vehicle fleet transitions from ICE vehicles to BEVs, the electric grid will need to change to deal with the new load, including being able to accommodate the demand and timing of charging. An emerging consideration not evaluated in the chapter is the use of EV fleets as a type of mobile energy storage system that can be deployed in demand response, known as bidirectional charging.[5] EV charging represents a new type of load that has a unique profile and the potential for high electricity demand. In the future, as standards are developed, EVs may be able to be used as a type of virtual battery storage that dynamically supports the electric grid.

16.1.1 State Policy and Regulation Supporting Transportation Electrification

California has some of the most aggressive policies in the United States promoting the electrification of the transportation sector. RPU's role as the provider of electricity is to support, plan for, and ensure that the electric infrastructure and generation will be available to support the achievement of these goals.

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[3] The City of Riverside is part of the South Coast Air Basin which covers portions of Los Angeles, San Bernardino, and Riverside Counties and all of Orange County.

[4] Office of the Governor, Gavin Newsom, Press Release, "California Surpasses 1.5 Million ZEVs Goal Two Years Ahead of Schedule, April 21, 2023. https://www.gov.ca.gov/2023/04/21/california-surpasses-1-5-million-zevs-goal-two-years-ahead-of-schedule/

[5] U.S. Department of Energy, Federal Energy Management Program website, "Bidirectional Charging and Electric Vehicles for Mobile Storage, accessed at: https://www.energy.gov/femp/bidirectional-charging-and-electric-vehicles-mobile-storage

Transportation electrification is a priority action to help the State meet its near- and long-term climate change goals for reducing GHG emissions. These have included a broad set of activities from legislation and regulation through State level planning efforts and provision of funding programs to implement actions to achieve the State's goals. Over the past several years, executive orders have been issued by Governor Jerry Brown (Executive Orders B-16-2012, B-32-15 and B-48-18) and Governor Gavin Newsom (N-79-20) establishing goals for deployment of EVs, including requirements for fleet vehicles to transition to zero-emissions technology, and the deployment of charging infrastructure in the State:

- 1.5 million EVs on the road by 2025.[6]
- 5 million EVs on the road by 2030.[7]
- 250,000 public EV chargers, including 10,000 direct current fast chargers, in California by 2030.[8]
- 100 percent of new light-duty vehicle sales are ZEVs by 2035. 100 percent of operating drayage trucks, off-road vehicles, and off-road equipment are ZEVs by 2035, where feasible. 100 percent of operating trucks and buses are ZEVs by 2045, where feasible.[9]
  - California Air Resources Board (CARB) approved the Advanced Clean Fleets (ACF) rule on April 28, 2023, which requires a phased-in transition toward zero-emission medium- and heavy-duty vehicles to provide a path toward accomplishing the goals in Executive Order N-79-20.

Governor Newsom tasked the Governor's Office of Business and Economic Development (GO-Biz) to collaborate with multiple agencies and partners to shepherd the administration's ZEV Market Development Strategy (ZEV Strategy, see Figure 16.1.1). This document is the first part of the ongoing, purposefully evolving effort to turn California's 100 percent ZEV vision into reality. The ZEV Strategy is structured to break down silos and ensure cross-cutting work throughout the California state government to achieve the State's ZEV goals. The ZEV Market Development Strategy builds on the success and lessons of California's three ZEV Action Plans in 2013, 2016, and 2018.

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[6] California Executive Order No. B-16-2012, March 23, 2012, https://www.gov.ca.gov/2012/03/23/news17472/.

[7] California Executive Order No. B-32-15, July 17, 2015, https://www.gov.ca.gov/2015/07/17/news19046/.

[8] California Executive Order No. B-48-18, January 26, 2018, https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html#:~:text=Brown%20Jr.%2C%20Governor%20of%20the,on%20California%20roads%20by%202030.

[9] California Executive Order No. N-79-20, September 23, 2020, https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf

The ZEV Market Development Strategy identifies four pillars for the successful adoption of EVs by the community: Vehicles, Infrastructure, End Users, and Workforce.[10]

Figure 16.1.1: GoBIZ ZEV Market Development Strategy Diagram, 2021.

Four Pillar Definitions:

1. ***Vehicles:*** New and used plug-in electric and hydrogen fuel-cell electric vehicles, including light-, medium-, and heavy-duty vehicles and equipment used for transporting people and freight, as well as for construction, mining, materials handling, industrial operations, agriculture, recreation, and other industries.

2. ***Infrastructure:*** Fueling infrastructure needed to support all ZEVs, including electric vehicle charging stations, hydrogen fueling stations, catenary systems and the energy systems that supply them.

3. ***End Users:*** Consumers, riders, fleet operators, transportation network companies, car dealers, drivers, transportation planning agencies, program administrators, ports, regional and local governments and communities, trucking companies, fuel providers, and more.

4. ***Workforce:*** The human workforce, including supply chains, needed to design, manufacture, sell, construct, and install, service and maintain ZEVs, ZEV infrastructure, ZEV distribution systems, dealerships, energy systems, networks of charging and fueling stations, and other ZEV-related build-outs.

This ZEV Strategy focuses on the who, what, and how of building, maintaining, and balancing these four pillars and uses the construct to identify key market and implementation gaps. Each metric, objective, and collective problem-solving action in the ZEV Strategy maps directly back to at least one of these four pillars, the investments required to build them, and/or outcomes. Each action and decision are rooted in one or more of the following core principles.

[10] Governor's Office of Business and Economic Development, "California Zero-Emission Vehicle Market Development Strategy," February, 2021. https://static.business.ca.gov/wp-content/uploads/2021/02/ZEV_Strategy_Feb2021.pdf

Core Principles:

The following principles serve as the foundation for decision-making throughout the ZEV Market Development Strategy[11] and its subsequent implementation effort. They provide a framework of standards for RPU to achieve to help meet the State's aggressive ZEV goals:

1. ***Equity in every decision.*** Continual, meaningful engagement and capacity building within priority communities is key to ensuring that the ZEV market provides direct and assured benefits to those most impacted by poor air quality and lack of access to clean mobility and high-road jobs.

2. ***California embraces all zero-emission pathways.*** California is technology neutral and actively embraces and supports all viable pathways to zero emissions through policymaking, funding, and other state decisions/actions. This includes but is not limited to new and used battery-electric, hydrogen fuel-cell electric, and directly connected electric systems.

3. ***Collective problem-solving.*** Success depends on active engagement and collaboration between all levels of government, industry, non-governmental organizations (NGOs), communities, and other engaged stakeholders (e.g., end users).

4. ***Public actions drive greater private investment to scale investable markets.*** Public and private sector actors have unique, complementary roles to play in scaling the ZEV market. Public policies and actions should help limit market risk and ensure fair and equal access and activate market-based mechanisms; private actions drive scale and provide innovative solutions.

5. ***Design for resilience and adaptation.*** We are developing the ZEV system holistically, with resilience and adaptation front of mind. ZEVs enable opportunities to stabilize and support our energy system for the benefit of all, including increasing reliability, resilience, and renewable energy penetration.

These state-level policies and directives are being pursued by State agencies, including the CARB, CEC, CPUC, Department of Transportation, Office of Planning and Research, Strategic Growth Council, and local entities such as the metropolitan planning organizations and the South Coast Air Quality Management District. All agencies are developing and amending regulations, guidance, funding recommendations and internal actions in concert to implement and achieve the goals identified in the ZEV Strategy and executive orders.

Leading this change are a variety of regulations adopted by CARB: Advanced Clean Cars II, Advanced Clean Trucks, and Advanced Clean Fleets. These are complemented by funding that supports the rapid transition to EVs and the installation of EV charging infrastructure from a variety of agencies such as the CEC, CARB and even federal entities (such as funding from the Inflation Reduction Act of

[11] Ibid.

2022). As these and future regulations are implemented, it will be important that RPU continue to evaluate the increased load demand and infrastructure required to support the high-capacity charging of City and community-wide fleets. An initial evaluation of the capacity of RPU's distribution grid to support EV charging can be found in Chapter 13 of this IRP document.

16.1.2 Local Policy and Actions Supporting Transportation Electrification

Supporting TE is not solely the responsibility of RPU. Within the City of Riverside, cross-departmental efforts must be coordinated within the broader community. RPU works closely with various City departments and is developing a plan to expand access to electric vehicle charging infrastructure as well as meet Citywide environmental and sustainability goals of reaching carbon neutrality by 2040.

Envision Riverside 2025 Strategic Plan

The City adopted the Envision Riverside 2025 Strategic Plan in 2020. The Strategic Plan included five cross-cutting threads that must be incorporated into all actions across the City: community trust, equity, fiscal responsibility, innovation, and sustainability and resiliency. Two goals within the Strategic Plan are driving RPU and other city department's goals around TE:[12]

1. Strategic Priority No. 4: Environmental Stewardship – Goal No. 4.6. Implement the requisite measures to achieve citywide carbon neutrality no later than 2040.
2. Strategic Priority No. 6: Infrastructure, Mobility and Connectivity – Goal No. 6.3. Identify and pursue new and unique funding opportunities to develop, operate, maintain, and renew infrastructure and programs that meet the community's needs.

City Actions Supporting EV Adoption

Streamlined Permitting Process for EV Charging: Facilitating the installation of EV charging infrastructure is also a primary goal of the City and RPU. The City's permitting process supports increasing the number of EV charging locations with a streamlined permit process that is compliant with State's permit streamlining laws for EV chargers (AB 1236 and AB 970). A permitting checklist for the permitting process is available on the City's website for the installation of residential EV charging, non-residential buildings and facilities, as well as multi-family dwellings.

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[12] City of Riverside Strategic Plan, 2020 Edition, https://www.riversideca.gov/sites/default/files/COVID/City%20Strategic%20Plan_Spread%20Digital.pdf

Clean Fleets: CARB approved the Advanced Clean Fleet (ACF) regulation, which created a ZEV purchase requirement for new medium- and heavy-duty vehicles added to public fleets, where 50% of 2024-2026 model year vehicles would need to be ZEV, and 100% of 2027 and later model years would need to be ZEV.

The City of Riverside, which includes RPU, has already approached clean transportation by supporting a robust clean fleet program. About 70% of the City's light-, medium-, and heavy-duty fleets use alternative fuels, primarily compressed natural gas (CNG). Additionally, RPU supports efforts from non-residential customers to convert their fleets to cleaner technologies. RPU partners with customers to support grant applications for EV infrastructure and vehicles where appropriate.

Participation in the Low Carbon Fuel Standard Program

RPU and the City opted into the Low Carbon Fuel Standard Program (LCFS) in March 2018 to support the community's transition to EVs and to implement programs, education, and provide opportunities for charging infrastructure to be developed. RPU receives LCFS credits for residential EV charging within the City of Riverside. The number of credits that RPU receives is calculated by the California Air Resources Board and reflects the estimated emissions reductions resulting from residentially based EV charging in RPU's service territory. Each credit is the equivalent of a reduction of one metric ton of carbon dioxide equivalent (MT CO_2e). RPU sells these credits and uses the proceeds in a manner consistent with the LCFS regulation including in EV education and for EV related rebate programs.

EV Education and Awareness: RPU has a robust public education and marketing program that reaches customers through a variety of avenues. The utility continues to maintain information on its website[13] specifically addressing EVs and EV ownership. The site includes detailed information on the process to sign up under the Domestic EV-Only Rate (discussed later in this chapter) as well as information on the benefits of using an EV. This includes specific FAQs on how the vehicles work, differences between a battery electric vehicle (BEV) and a plug-in hybrid electric vehicle (PHEV), environmental benefits, locations of charging stations, financial benefits, maintenance requirements, and all EV rebates currently available. RPU has also organized and participated in EV related events such as Ride-and-Drive, to help customers become more familiar with EVs, and provided resources that will help customers install charging infrastructure and learn about our TOU rates.

RPU supports and attends numerous community events and provides EV education and information to attendees. More specifically, RPU has attended sustainability and community partnership fairs at our local universities to share available energy efficiency and EV rebates that RPU offers and highlight RPU's renewable energy and sustainability efforts. RPU staff provide presentations

[13] City of Riverside, Electrify Riverside Website, accessed November 8, 2023 from https://www.riversideca.gov/utilities/residents/rebates/electrify-riverside

to the community as well as at conferences and share learning events in the state to address topics covering EV and EV charging challenges, permitting, and infrastructure needs.

Rebate Programs: Using revenue from the LCFS program, Riverside launched the "Electrify Riverside" program[14] in 2022 to benefit current and future EV customers. The programs developed include hosting ride-and-drive events for plug-in electric vehicles, continuation of education programs, rebates for both residential and commercial charging equipment, and a rebate program for the purchase of a used electric vehicle. Low-income customers and commercial customers located in a disadvantaged community are also eligible for an increased rebate amount, as outlined below.

RESIDENTIAL USED EV REBATE PROGRAM	RESIDENTIAL HOME CHARGING EV CHARGER REBATE	NON-RESIDENTIAL & MULTIFAMILY EV CHARGER REBATE PROGRAM
• $500 rebate; additional $1000 for low-income customers	• $500 rebate for a Level 2 home charger • One-time $805 rebate for installation of TOU meter (if qualified)	• $3,500 per charging station; additional $1,000 for installation at a qualified affordable housing development

Electric Rates Supporting EV Charging: RPU's electric rates also support EV charging. Two electric rate schedules have been adopted by the City – one for single family residential charging and the other for non-residential EV charging. Both of these EV charging specific rates require meters that separate other electric load from the EV load but will support the unique requirements for EV charging. This section will provide an overview of both rates. RPU also offers time-of-use rates that will also support EV charging but are not described here because they are traditional utility rates.

EV Charging Rate for Single-Family Residential: RPU offers an EV-only time-of-use (TOU) rate schedule for home residential charging. Recognizing that EV charging is a new, additional, and substantial load that will be increasing over time, the EV-only TOU rate was developed as part of the 2018 RPU Rate Plan to encourage residents to shift their home EV charging to off-peak or, if necessary, mid-peak hours of the day (when overall demand on RPU's distribution grid is lower). This shift is intended to shift demand to lower demand hours, helping to mitigate impacts on daily peak demand.

[14] Information about the Electrify Riverside rebates available to customers can be found at: https://www.riversideca.gov/utilities/residents/rebates/electrify-riverside.

To qualify for the rate tariff, customers are required to have or to install a meter used only to measure EV charging. This separates the EV charging from the customer's household energy consumption. The energy consumption for EV charging will receive a flat customer charge with a per kilowatt hour (kWh) energy charge that varies by seasonally dependent off-, mid- or on-peak time periods. A typical customer should easily be able to use technology on their EV or EV charging equipment to manage when their vehicle charges. RPU offers a rebate of up to $805 to cover the cost of installation of the TOU meter.

The customer's household energy consumption will remain on the residential domestic rate tariff, which bases pricing on the amount of energy consumed. The energy price increases for additional kWhs used with seasonal adjustments. Since EV charging can result in substantial energy usage in each month, by separating the EV load from the household energy use, customers will ensure that the EV charging load will not drive household energy charges into higher price tiers. Figures 16.1.2 and 16.1.3 illustrate the pricing differences offered under the EV-only TOU rate schedule compared to the standard residential domestic rate tiers. Both figures show pricing effective as of January 1, 2024 for calendar year 2024.

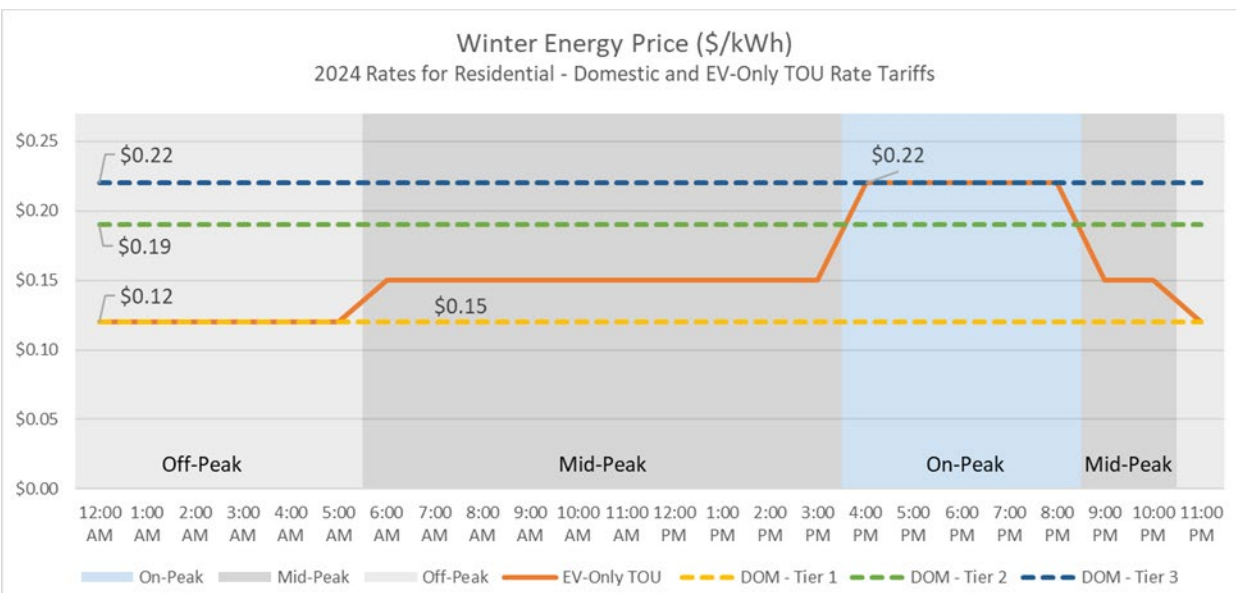


Figure 16.1.2. Illustration of the winter season EV-only TOU rate by hour, as compared to the tier prices of the residential domestic rate tariff.

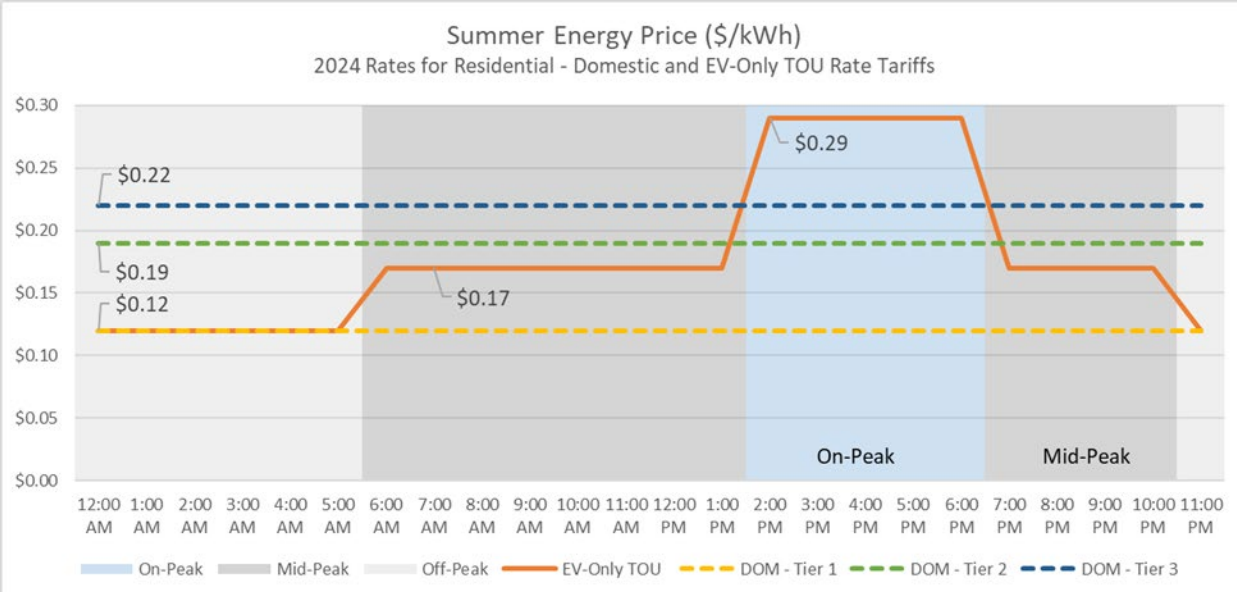


Figure 16.1.3. Illustration of the summer season EV-only TOU rate by hour, as compared to the tier prices of the residential domestic rate tariff.

EV Charging Rate for Multifamily and non-Residential Uses: In 2023, a new rate schedule was adopted by Riverside's City Council to support EV charging at multi-family and non-residential locations. This rate schedule, Separately Metered Electric Vehicle Charging (Non-Single Family), or Schedule SMEVC, provides a flat energy charge that incorporates the customer charge, reliability charge, network access charge and demand charges into a single rate applied based on the electricity used. The purpose of this rate is to simplify the electric rate and remove the risk that a customer with little EV charging would incur a high demand charge due solely from a limited number of EVs charging at their station. Providing cost certainty allows the customer to more easily evaluate the costs of EV charging at their locations. The Schedule SMEVC rate was adopted on September 19, 2023 and will be available and effective on January 1, 2024 through December 31, 2028. A single rate of $0.3291 / kWh used will apply for all years.

16.2 Electric Vehicle Loads & GHG Emissions

16.2.1 EV Population and Public Charging Locations

According to the CEC, there were 6,479 Plug-In Hybrid, BEV, and Fuel Cell (FCEV) light-duty vehicles registered in the City of Riverside at the end of 2022.[15] This represents 2.5% of total number of light-duty vehicles in the City as shown in Figure 16.2.1 below.

ZEV POPULATION

Total Light-Duty Vehicles end of 2022

6,479

Battery Electric (BEV)	Plug-in Hybrid (PHEV)	Fuel Cell (FCEV)
1.54%	0.90%	0.02%
4,053	2,370	56

NON-ZEV POPULATION

Total Light-Duty Vehicles end of 2022

256,247

Gasoline	Gasoline Hybrid	Diesel	Other
91.80%	3.67%	2.00%	0.07%
241,183	9,640	5,243	181

Figure 16.2.1. Light-Duty Vehicles Registered in the City of Riverside.[16]

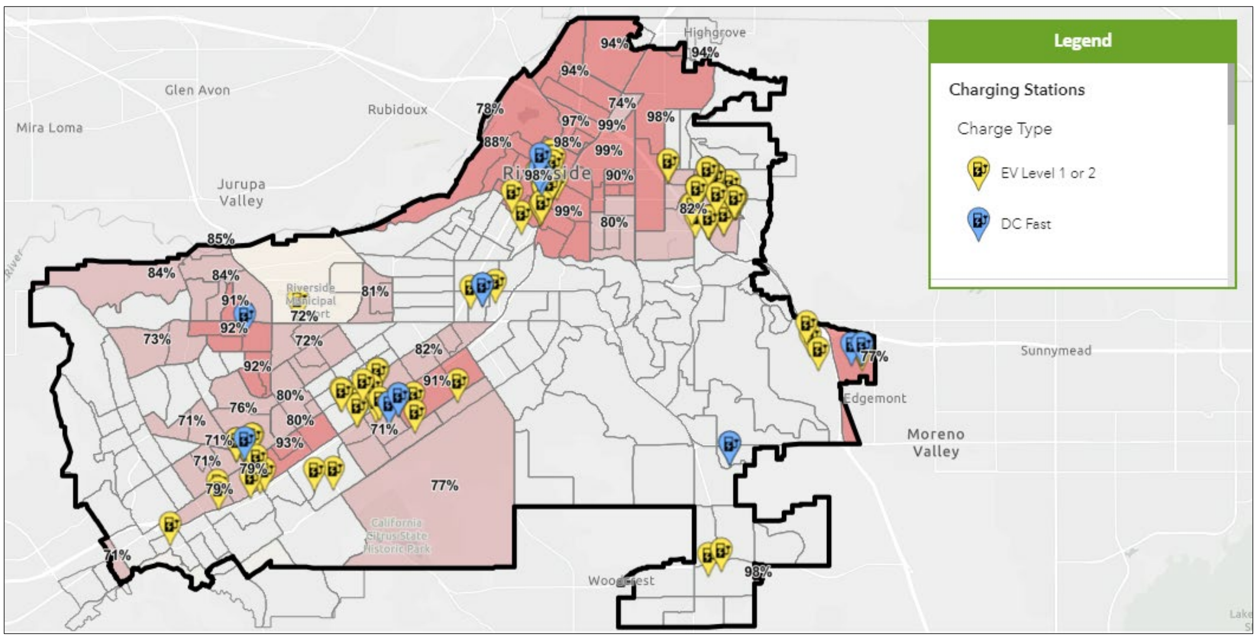
EV charging loads for light-duty EVs can be estimated based on registrations of the vehicles at the place of registration since the majority are residential vehicles. The California Energy Commission (CEC) developed a methodology for estimating EV charging loads for light-duty vehicles based on location of registration using data gathered statewide over the last several years, including anonymous data collected by the large investor-owned utilities. However, it is important to note that not all EVs charge at residences or at the residence to which they are registered. For example, students at universities may have an EV that is registered at a parent's residence as opposed to their residence when at school, or employees may charge their vehicles at their workplaces.

Vehicle registrations for medium- and heavy-duty (MHD) alternative fuel vehicles in 2023 were minimal statewide and are not detailed at the City level. It is important to note that the use of MHD vehicle registrations to determine or estimate their electric charging is difficult because these vehicles are often not registered within the city where they charge. They can even be registered out of state. ZEV technology for these vehicles is only now emerging, and patterns to develop how these vehicles are charged will be developed over the next several years. Regardless of this limitation, the CEC has developed a methodology for estimating the MHD EV charging anticipated based on CARB's recently adopted Advanced Clean Trucks and Advanced Clean Fleet regulations that will require fleet vehicles to transition to zero-emissions technologies.

[15] California Energy Commission. Light-Duty Vehicle Population in California. Data last updated April 28, 2023. Retrieved July 11, 2023 from https://www.energy.ca.gov/zevstats

[16] Ibid.

EV charging at non-residential locations will also contribute to EV charging load. While RPU does not currently measure the EV load from these charging locations, it does track where EV charging is installed. There are approximately 223 Level 2 public chargers, and 59 DC Fast Chargers (40 of which are Tesla) installed within the City.[17] Map 16.2.1 shows the locations of publicly available Level 2 and DC Fast charging stations. At this time, most public access chargers are located in destination areas of the City – downtown, at universities and shopping areas, and in the area of the City's auto center. Notably, almost all are also in Disadvantaged Communities (DACs).[18]



Map 16.2.1. Map of EV chargers and location of disadvantaged communities in Riverside, California.

City and RPU policies strongly support the deployment of EV charging infrastructure. RPU is developing a public access Level 2 Charger Program throughout the City with the City General Services Department, with the goal of increasing the availability of publicly accessible EV charging at locations such as libraries, community centers, public parking lots, and garages. A recent survey done by Boston Consulting Group found that in the U.S., 55% of charging was done at home, 18% was done at work, 15% was done at a destination (public charging, e.g., grocery store), and 12% was done en-route (public

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[17] U.S. Department of Energy (2023). Alternative Fuels Data Center. Retrieved [July 11, 2023] from https://afdc.energy.gov/fuels/electricity_locations.html#/analyze?location_mode=address&location=riverside%20ca&show_map=true

[18] California Office of Environmental Health Hazard Assessment (2023), CalEnviroScreen 4.0. SB 535 Disadvantaged Communities. Retrieved [April 6, 2023] from https://oehha.ca.gov/calenviroscreen/sb535

charging, e.g., highway rest area).[19] Although most EV charging is expected to occur at home, ensuring that access to EV charging is accessible to all, including those who do not have the ability to charge at home, will be important to support overall EV adoption.

16.2.2 Incremental Vehicle Loads Included in the Load Forecast

Since the development of the prior IRP in 2018, the methodology to forecast EV charging loads has changed substantially as the assumptions and methods have been validated against charging data. For the 2018 IRP, the CEC released their Transportation Electrification Common Assumptions 3.0 (TECA 3.0) model. RPU used this model to forecast EV growth in the utility service territory through 2030. That model was based on a limited number of objective input assumptions around adoption rates, vehicle types and charging habits. As new information became available in the last five years and as EV adoption has increased, the CEC has developed new methodologies to forecast EV charging across the state. However, these newer CEC forecasts are largely based on information gathered from the investor-owned utility territories.

Currently, Riverside does not have an independent means to estimate the light-duty and medium/heavy-duty EV load growth within the utility's service territory. To calculate the anticipated EV charging loads for this IRP, staff relied on two approaches: (1) staff relied on TECA 3.0 projections to forecast light-duty EV growth and (2) rescaled 2021 IEPR SCE projections to forecast medium/heavy-duty EV growth within the City of Riverside (see Chapter 2, section 2.2.7).

Based on these approaches, Table 16.2.1 and Figure 16.2.2 show the projected additional utility electrical load from both new light and medium/heavy-duty EVs entering RPU's service territory from 2015 through 2045. For light-duty EV loads, TECA 3.0 projections are used for years 2015 through 2030, while medium/heavy duty EV loads through year 2035 represent rescaled SCE projections. (All forecasts beyond these endpoints represent linear extrapolations.)

Since these forecasts were prepared based on modeling assumptions from the 2021 IEPR, they do not include the most recent assumptions based on regulations adopted by the state in 2022 and 2023. While this is a known limitation of the data, it reflects the best available data for the time it was prepared. Overall, these forecasts can be assumed to represent a conservative EV load within the RPU service territory which only increases RPU's overall annual load by about 2% in 2030.

While the data shown represents what was included in the IRP demand forecast, it is still important to describe new data that became available during the development of the IRP. In early 2023, the CEC released its 2022 IEPR – an interim year update to the IEPR that typically does not include significant updates to the modeling assumptions use for the energy forecast. However, to better

[19] Markus Hagenmaier, Christian Wagener, Julien Bert, Jennifer Carrasco, Nathan Niese, and Aman Wang (2023, January 17). What Electric Vehicle Owners Really Want from Charging Networks. https://www.bcg.com/publications/2023/what-ev-drivers-expect-from-charging-stations-for-electric-cars

prepare the state for the electric loads associated with recently adopted regulations, the CEC prepared new forecasts of electrical load for electrification of both buildings and transportation. The 2022 California Energy Demand Update (CEDU) included a streamlined forecast framework that eliminated some of the unused scenario forecasts from the 2021 IEPR and paired the remaining forecasts with assumptions for additional achievable energy efficiency (AAEE), additional achievable fuel switching (AAFS) and additional achievable transportation electrification (AATE).

Table 16.2.1. Forecast 2015-2045 RPU electrical load from Light-duty and Medium/Heavy-duty EV penetration within the service territory (MWh/year)

Year	Light-duty Forecast	Medium & Heavy-duty Forecast
2015	3,364	0
2016	4,801	0
2017	6,563	0
2018	8,936	0
2019	11,721	0
2020	14,881	0
2021	18,351	66
2022	22,084	245
2023	26,028	1,416
2024	30,127	3,581
2025	34,348	6,029
2026	38,647	8,880
2027	43,000	11,983
2028	47,380	15,328
2029	51,774	19,284
2030	56,171	23,338

Year	Light-duty Forecast	Medium & Heavy-duty Forecast
2031	60,571	27,798
2032	64,971	32,418
2033	69,371	37,411
2034	73,771	42,883
2035	78,171	47,599
2036	82,571	52,642
2037	86,971	57,649
2038	91,371	62,656
2039	95,771	67,662
2040	100,171	72,669
2041	104,571	77,676
2042	108,971	82,683
2043	113,371	87,689
2044	117,771	92,696
2045	122,171	97,703

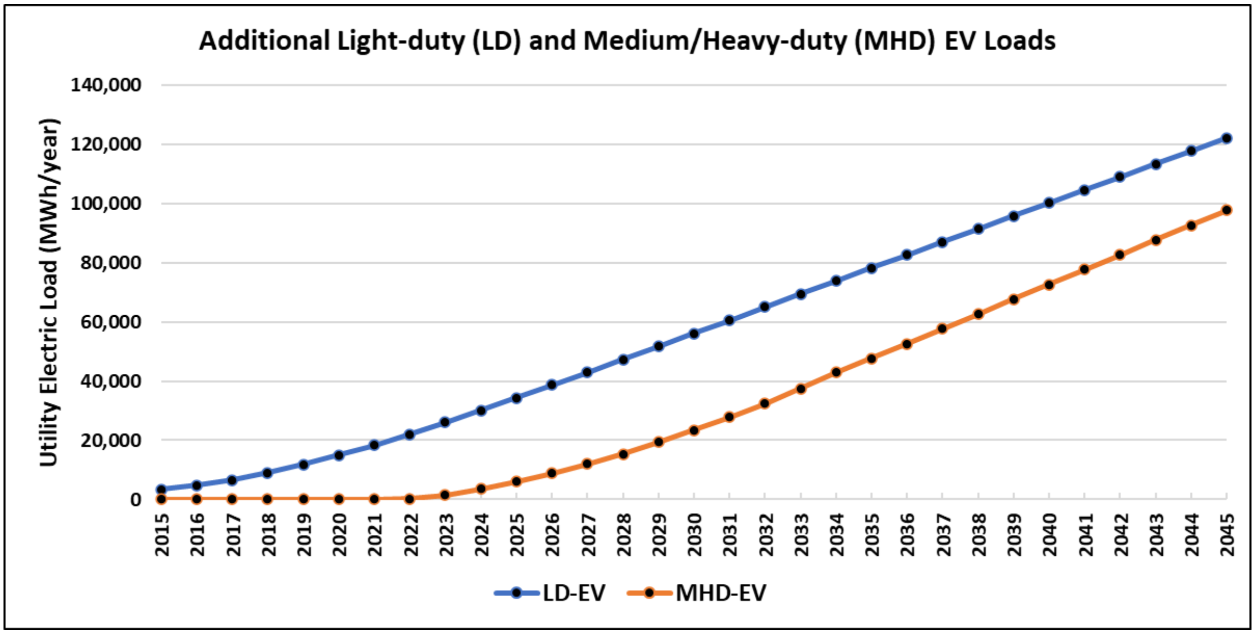

Figure 16.2.2. Forecast 2015-2045 RPU electrical load from Light-duty and Medium/Heavy-duty EV penetration within the service territory.

The new AATE framework accounts for the effects of State policy under a set of scenarios, each of which is reasonably expected to occur given market, policy, and programmatic conditions. The new AATE scenarios continue to assign load at the forecast climate zone level but also incorporate newly adopted mandatory regulations, such as CARB's Advanced Clean Fleets rule, and have incorporated reasonable assumptions to meet these state goals. These new CEDU and AATE forecasts for 2022, however, are statewide forecasts. This approach raises geographical questions involving load within forecast zones. TE represents a large source of new load, but the geographic distribution of such load is not well understood. Consequently, the AATE framework used by the CEC is expected to change and expand in future forecasts to align with other infrastructure needs.

RPU opted to not include the 2022 CEDU and AATE in this IRP's load forecast because RPU staff were not able to fully validate if the down sampled data from the IEPR processes was accurate for the City of Riverside. The data requires validation before RPU can fully incorporate it into its IRP analysis and planning efforts. However, despite these limitations, RPU recognizes the value of considering these loads and has included both the 2021 and 2022 IEPR data for comparison to better understand their potential impacts over the next several years. The CEC models are robust and include many factors that RPU should consider in future forecasting. Hence, it is worthwhile to examine the framework that the CEC used when developing the LD and MHD AATE Forecasts in more detail.

The AATE framework begins with a baseline forecast. In the baseline forecast, economic and demographic inputs, coupled with vehicle choice models and vehicle travel models, determine total vehicle stock and transportation energy demand for LD and MHD sectors. The AATE Scenario 3 – the Planning Scenario – represents compliance with all regulations, including CARB's Advanced Clean Fleets Regulation, with a post-process alignment of new vehicle sales with state light-duty regulations or proposed regulations for medium and heavy-duty vehicles. This is data that RPU does not have access to and thus must rely at this time on the assumptions that are part of the CEC process.

Tables 16.2.2 and 16.2.3 and Figures 16.2.3 and 16.2.4 show the 2022 IEPR Baseline load forecast and AATE forecasts for LD and MHD vehicles, respectively, compared to the forecast used in the IRP as previously described in this chapter. As shown, the 2022 IEPR forecasts for LD load reflect much more aggressive growth in the electric load due to rapid increases in electric vehicle adoption.

Table 16.2.2. Light Duty Electric Vehicle Load Forecast (MWh/year).

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2023	26,028	14,730	14,730
2024	30,127	28,896	28,896
2025	34,348	43,785	43,785
2026	38,647	57,823	61,120
2027	43,000	71,787	81,590
2028	47,380	86,665	105,263
2029	51,774	102,622	132,637
2030	56,171	120,061	163,906
2031	60,571	139,270	199,933
2032	64,971	159,123	237,839
2033	69,371	180,356	279,218
2034	73,771	202,663	323,539
2035	78,171	226,434	369,685
2036	82,571	250,205	415,831
2037	86,971	273,975	461,977
2038	91,371	297,746	508,123
2039	95,771	321,517	554,268
2040	100,171	345,288	600,414
2041	104,571	369,059	646,560
2042	108,971	392,830	692,706
2043	113,371	416,601	738,852
2044	117,771	440,372	784,998
2045	122,171	464,143	831,143

Table 16.2.3. Medium- and Heavy-Duty Electric Vehicle Load Forecast (MWh/year).

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2023	1,416	504	504
2024	3,581	880	880
2025	6,029	2,228	5,881
2026	8,880	3,858	9,613
2027	11,983	6,563	14,537
2028	15,328	10,111	20,444
2029	19,284	14,836	26,729
2030	23,338	19,376	33,240
2031	27,798	24,717	41,428
2032	32,418	29,341	49,610
2033	37,411	34,120	62,779
2034	42,883	38,743	74,870
2035	47,599	43,762	87,355
2036	52,642	48,781	99,840
2037	57,649	53,800	112,325
2038	62,656	58,819	124,811
2039	67,662	63,838	137,296
2040	72,669	68,857	149,781
2041	77,676	73,876	162,267
2042	82,683	78,896	174,752
2043	87,689	83,915	187,237
2044	92,696	88,934	199,722
2045	97,703	93,953	212,208

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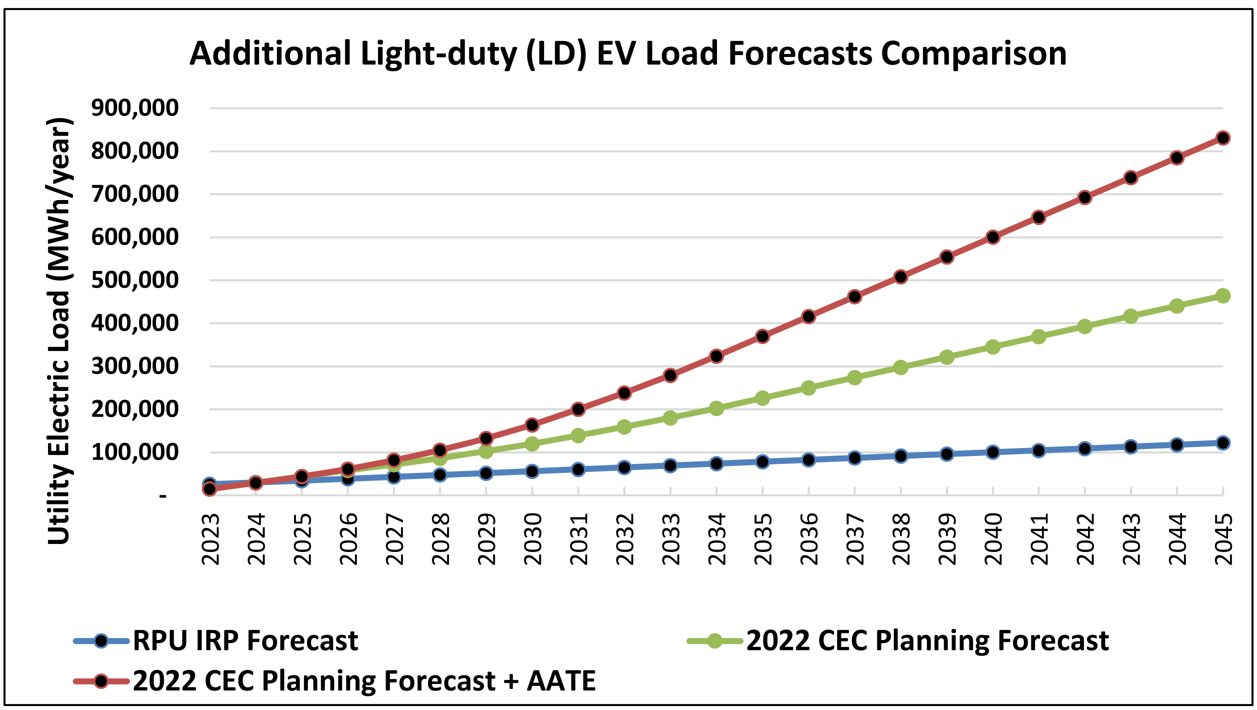

Figure 16.2.3. Additional Light-duty EV Load Forecasts Comparing IRP Forecast to Down Sampled 2022 CEC IEPR.

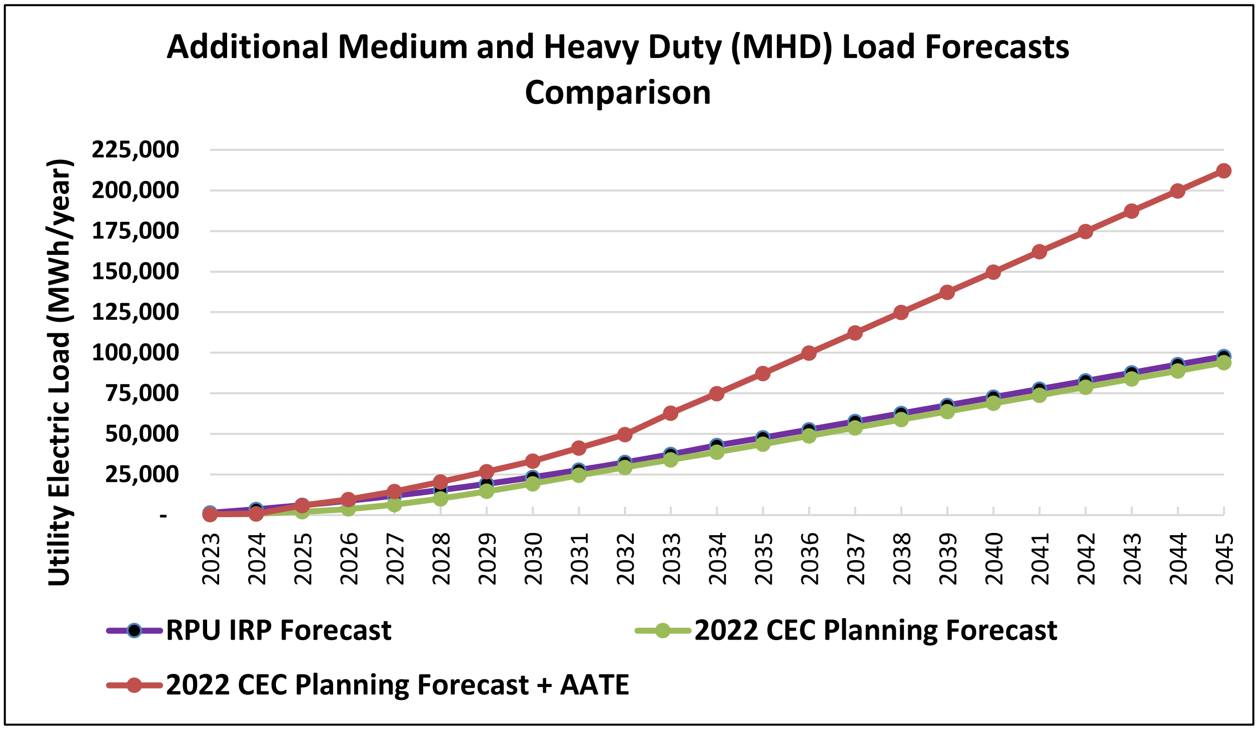

Figure 16.2.4. Additional Medium and Heavy-Duty Load Forecasts Comparing IRP Forecast to Down Sampled 2022 CEC IEPR.

The increases associated with the 2022 IEPR forecasts, particularly when including the AATE, are considerable. Should the load growth associated with these scenarios occur, it will require changes to RPU's planning for procuring new generation and the demands it will place on transmission and distribution infrastructure. In this IRP, RPU is planning for an additional load growth that will reach a very modest 219,874 MWh annually in 2045 for EV loads. However, the down sampled 2022 IEPR data identified that 2045 loads could reach over 558,000 MWhs per year under the 2022 CEC Planning Forecast or over 1 million MWh annually if the AATE forecast is reached. While energy efficiency may offset a large portion of this load, it would still represent a significant change. The uncertainty associated with these forecasts, particularly because they are down sampled forecasts from a regional dataset, however, means that they need to be better validated before costly investments in infrastructure and new generation are made.

16.3 Estimated Changes in Greenhouse Gas Emissions

For the IRP, RPU estimated the greenhouse gas (GHG) emissions and associated avoided GHG emissions for LD EV charging. Calculations for MHD were not included due to a number of factors discussed at the end of the section. To estimate the GHG emissions associated with the electricity used to charge the EV's, RPU assumed that the electricity used for EV charging included in the load forecast and the comparison forecasts from the 2022 IEPR was used in RPU's service territory. A two-step process was undertaken to first determine the GHG emissions associated with EV charging and a second process to evaluate the GHG emissions that are avoided had the vehicles used fossil fuels.

To determine the GHG emissions due to EV charging, RPU uses a straightforward calculation methodology of multiplying the electricity used (MWh) by the GHG emissions per MWh.

GHG Emissions from EV Charging = (Forecast EV MWh) * (EF)

Where

Forecast EV MWh = MWh of EV charging load associated with light duty EVs

EF = emissions factor expressed as MT CO_2e/MWh

The GHG emissions factor (EF) is calculated based on the protocols established by CARB under the mandatory reporting regulations and is derived from the GHG emissions associated with RPU's generation resources each year. GHG emissions are converted to metric tons of carbon dioxide equivalent (MT CO_2e). Dividing the total quantity of MT CO_2e by the total megawatt-hours of retail sales for the year results in an emissions factor (MT CO_2e / MWh) for the electricity. The emissions factors reflect the power supply forecast discussed in prior chapters that meets RPU's 2030 emissions target for the electricity sector and the City's goal to achieve 100% carbon-free electricity for retail sales by 2040. Emissions factors for each year are shown in Table 16.3.1. The emissions factor is then applied to the RPU IRP EV Load Forecast, the 2022 CEC IEPR Planning Scenario and the 2022 CEC IEPR Planning plus AATE Scenario to estimate the GHG emissions associated with EV charging.

The GHG emissions associated with the electricity for LD EV charging by year are shown in Table 16.3.2. Note that the RPU IRP Forecast electricity consumption is based on the LD vehicle population while the two IEPR based forecasts simply down sample energy use data from throughout the SCE territory. As noted previously, the two 2022 CEC IEPR forecasts appear to underestimate the energy demand in Riverside in year 2023 of the forecasts. Parity between all three forecasts occurs in 2024. As a result, these forecasts will also underestimate avoided GHG emissions overall in that year of the forecast. It is one of the known limitations in the data that needs to be addressed in future IRPs and analysis. Finally, GHG emissions in years 2040 to 2045 from EV charging are zero because the electricity associated with the EV charging is expected to have zero emissions.

Table 16.3.1. Annual emission factors for electricity used for EV charging.

Year	Emissions Factor (MT CO_2e / MWh)
2023	0.288
2024	0.284
2025	0.226
2026	0.155
2027	0.109
2028	0.124
2029	0.128
2030	0.065
2031	0.070
2032	0.077
2033	0.085
2034	0.023

Year	Emissions Factor (MT CO_2e / MWh)
2035	0.035
2036	0.043
2037	0.029
2038	0.013
2039	0.014
2040	0.000
2041	0.000
2042	0.000
2043	0.000
2044	0.000
2045	0.000

Table 16.3.2. Estimated GHG emissions from electricity used for LD EV charging (MT CO_2e).

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2023	7,496	4,242	4,242
2024	8,556	8,206	8,206
2025	7,763	9,896	9,896
2026	5,990	8,963	9,474
2027	4,687	7,825	8,893
2028	5,875	10,746	13,053
2029	6,627	13,136	16,978
2030	3,651	7,804	10,654
2031	4,240	9,749	13,995
2032	5,003	12,252	18,314
2033	5,897	15,330	23,734
2034	1,697	4,661	7,441

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2035	2,736	7,925	12,939
2036	3,551	10,759	17,881
2037	2,522	7,945	13,397
2038	1,188	3,871	6,606
2039	1,341	4,501	7,760
2040	-	-	-
2041	-	-	-
2042	-	-	-
2043	-	-	-
2044	-	-	-
2045	-	-	-

To determine the GHG emissions avoided due to electrification, the estimated emissions that would occur should the vehicles use internal combustion engines (ICE) was first determined. The resulting reduction of GHG emissions from transportation is the avoided GHG emissions, which are the emissions from LD EV minus the emissions associated with ICE vehicles.

The following formula and assumptions were used to estimate the emissions shown in Table 16.3.3, which represents the emissions for equivalent ICE vehicles:

GHG Emissions from ICE Vehicles = (Forecast EV kWh) * (Avg. Miles/kWh) * (Avg. MT CO_2/mile)

Where:

EV kWh = the forecast kWh of electricity load per scenario (MWh * 1000 = kWh)

Avg. Miles/kWh[20] = based on the national average of electric vehicles traveling 3 to 4 miles per kWh of charge. Estimate uses a conservative 3 miles per kWh.

Avg. MT CO2e/mile[21] = 400 grams of CO_2e per mile or 0.0004 MT CO_2e per mile.

Subtracting these results from the emissions shown in Table 16.3.2 yields the avoided emissions due to electrification. Table 16.3.4 and Figure 16.3.1 show the corresponding GHG emissions that would be avoided under the three scenarios discussed – the RPU IRP Forecast, the 2022 CEC IEPR Planning Scenario and the 2022 CEC IEPR Planning plus AATE Scenario, respectively.

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[20] U.S. Department of Energy, “The Cost to Charge an Electric Vehicle Explained” website accessed on November 13, 2023 by Tracy Sato. Found at: https://www.energy.gov/energysaver/cost-charge-electric-vehicle-explained#:~:text=Suppose%20you%20drive%20at%20the,cost%20nearly%20%2460%20per%20month.

[21] U.S. Environmental Protection Agency, Greenhouse Gas Emissions from a Typical Passenger Vehicle website accesses on November 13, 2023 accessed at: https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle#:~:text=including%20the%20calculations.-,How%20much%20tailpipe%20carbon%20dioxide%20(CO2)%20is%20emitted%20from,of%20CO2%20per%20mile.

Table 16.3.3. Estimated GHG emissions from equivalent LD ICE vehicles (MT CO_2e).

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2023	31,234	17,676	17,676
2024	36,152	34,675	34,675
2025	41,218	52,543	52,543
2026	46,376	69,388	73,344
2027	51,600	86,145	97,908
2028	56,856	103,998	126,315
2029	62,129	123,146	159,164
2030	67,405	144,073	196,687
2031	72,685	167,124	239,920
2032	77,965	190,948	285,407
2033	83,245	216,427	335,062
2034	88,525	243,195	388,247

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2035	93,805	271,720	443,622
2036	99,085	300,245	498,997
2037	104,365	328,771	554,372
2038	109,645	357,296	609,747
2039	114,925	385,821	665,122
2040	120,205	414,346	720,497
2041	125,485	442,871	775,872
2042	130,765	471,396	831,247
2043	136,045	499,921	886,622
2044	141,325	528,446	941,997
2045	146,605	556,971	997,372

Table 16.3.4. Estimated Potential Avoided GHG emissions resulting from LD vehicle electrification (MT CO2e).

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2023	(23,738)	(13,434)	(13,434)
2024	(27,596)	(26,469)	(26,469)
2025	(33,455)	(42,647)	(42,647)
2026	(40,386)	(60,425)	(63,871)
2027	(46,913)	(78,320)	(89,015)
2028	(50,981)	(93,251)	(113,263)
2029	(55,502)	(110,010)	(142,187)
2030	(63,754)	(136,269)	(186,033)
2031	(68,445)	(157,375)	(225,925)
2032	(72,962)	(178,695)	(267,093)
2033	(77,349)	(201,096)	(311,328)
2034	(86,828)	(238,534)	(380,806)

Year	RPU IRP Forecast	2022 CEC Planning Scenario	2022 CEC Planning Scenario + AATE
2035	(91,069)	(263,795)	(430,683)
2036	(95,535)	(289,487)	(481,116)
2037	(101,843)	(320,825)	(540,975)
2038	(108,457)	(353,425)	(603,142)
2039	(113,584)	(381,319)	(657,362)
2040	(120,205)	(414,346)	(720,497)
2041	(125,485)	(442,871)	(775,872)
2042	(130,765)	(471,396)	(831,247)
2043	(136,045)	(499,921)	(886,622)
2044	(141,325)	(528,446)	(941,997)
2045	(146,605)	(556,971)	(997,372)

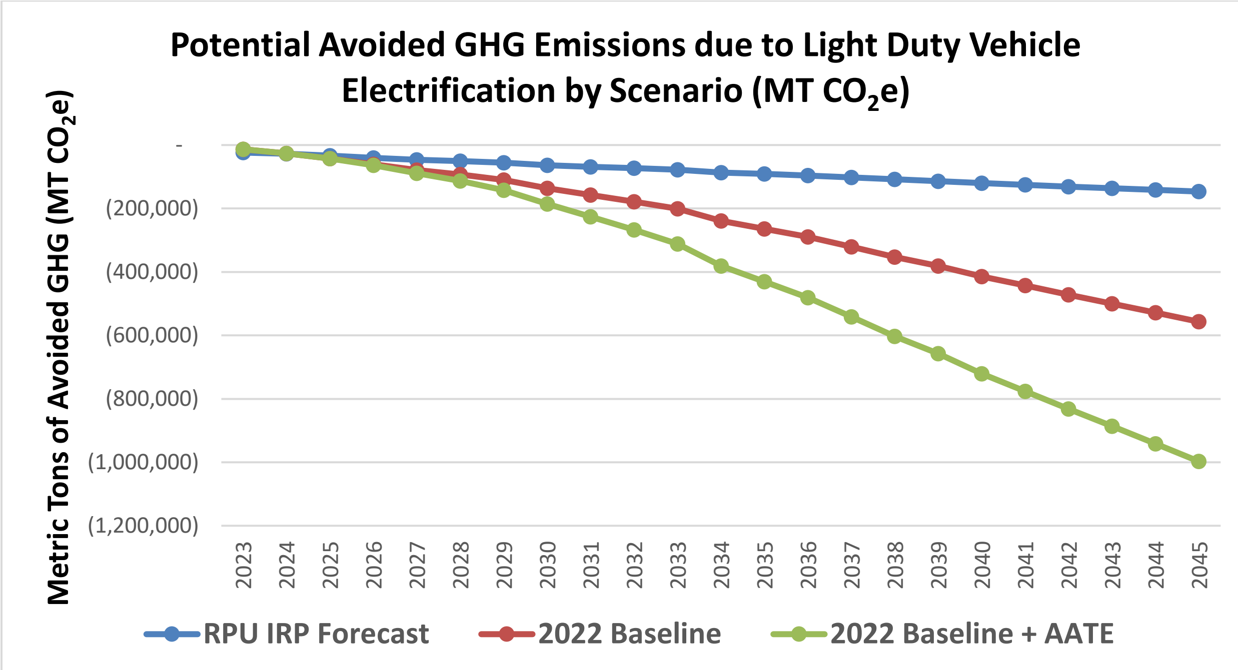


Figure 16.3.1. Estimated Potential Avoided GHG Emissions due to Light Duty Vehicle Electrification by Scenario.

In 2023, the avoided GHG emissions from light duty electric vehicle charging reflect the same limitations as the EV charging load forecast. The RPU Forecast scenario has emissions savings of almost 24,000 MT CO_2e while the two IEPR forecasts only show avoided emissions of about 13,000 MT CO_2e. In 2024, all scenarios show avoided emissions of about 27,000 MT CO_2e. All subsequent years show what the different policy scenarios achieve should EV adoption remain at a more business-as-usual level compared to a more aggressive adoption trajectory. In 2045, under the scenario included in the IRP, the adoption of EV's would achieve an estimated 146,605 MT CO_2e of avoided emissions – compared to 556,971 CO_2e in the 2022 IEPR Planning forecast and 997,372 MT CO_2e when the AATE policies are included. These avoided emissions scenarios can be considered to be bookends for emissions savings.

Calculations for the GHG emissions and GHG emissions avoided due to MHD EV charging are not included in this section due to the uncertainty of the methodology to use for RPU's service territory. Importantly, the vehicle mix that comprises the MHD vehicle population that may transition to EVs is not known. MHD vehicles comprise a wide variety of vehicles including vehicles ranging in size from large pickup trucks such as a Ford F350 size up to Class 8 semi-tractors as well as a number of specialty work vehicles, delivery trucks and buses. With the data RPU has available, it is not possible to simply assume an emissions factor for the fossil fuels they would use. These vehicles operate with a mix of gasoline, diesel, natural gas and propane fuels. Some of these fuels may also be biofuels that have non-traditional emissions factors applicable to them. Until better data and a deeper understanding of the vehicles charging in RPU's service territory is available, it would be too speculative to estimate the GHG emissions savings specific to RPU's service territory.

16.4 Summary of Findings about TE and Next Steps

The electrification of the transportation system has several benefits to RPU and its customers, but also presents several challenges. TE represents a significant new source of load and thus a new source of revenue that can provide benefits to all customers. It will also result in significant reductions in GHG emissions and other air pollutants. However, TE will also need to address the challenges that it brings to the distribution grid and overcome barriers to adoption. With regards to this IRP:

1. There is significant uncertainty in the accuracy of the forecasts and estimates discussed in this chapter. Numerous assumptions must be made about the number and type of EVs that will be used by customers. EV technology and the associated charging technology continues to change as technology is developed. Similar to the computer industry of years past, the rapid changes in technology are improving both EVs and chargers but are also becoming much more challenging to plan for. Despite increasing EV adoption rates, there remains minimal historical information available for utilities to use in forecasting. Therefore, the assumptions made now may not accurately represent what will occur in the future.

2. RPU staff have elected to utilize conservative forecasting for this IRP recognizing that the impacts of EVs on the electric system will need to be closely monitored. Planning for EVs and the charging infrastructure must remain flexible and ready to change as technology changes. Small shifts in the number of vehicles, charging assumptions, battery capacities, and other technologies can have significant impacts on the forecast results.

3. As the State's regulatory environment changes, electricity markets change due to increasing levels of renewables, and as the amount of rooftop PV increases, RPU's rate tariffs for TE will likely need to be further modified. More specifically, new or revised rate tariffs will need to be developed to encourage charging at times other than the current Off-peak period of each day, and/or to optimize resources on the distribution grid.

4. EVs can become a grid asset and be used as an energy storage device, or as a means of offsetting over-generation from rooftop PV. While this is not yet a reality, encouraging EV charging during the mid-day when current EV charging loads are low could help to offset or reduce the impacts of renewables on the distribution grid. EVs and the associated charging infrastructure can move into this realm, but only with more advanced grid system communications. Many of these communications systems are still being developed and tested. RPU will need to continue to monitor this technology and prepare for its deployment.

5. TE has the additional and significant benefit of reducing air pollutants and GHG emissions. While significant strides have been made to reduce emissions from gasoline and diesel over the last several decades, transitioning from those fuels to the use of electricity as a transportation fuel will reduce emissions overall. Even when the emissions from electricity generation are considered, moving from ICE vehicles to EVs reduces overall emissions. These efforts support both State and local goals and policies. Nonetheless, RPU's continued support in meeting these goals will require the careful planning activities identified above, specifically towards serving and balancing the expected increased loads on the distribution system.

17. Minimizing Localized Air Pollutants and Greenhouse Gas Emissions in Disadvantaged Communities

RPU and the City of Riverside have long been committed to implementing the best existing and emerging sustainability practices, particularly in the areas of reducing air pollution and greenhouse gas emissions. This chapter first discusses disadvantaged and low-income communities in Riverside and then presents RPU's efforts to minimize local air pollutants and greenhouse gas emissions, focusing specifically on disadvantaged communities as required by Senate Bill (SB) 350. Additionally, the California Energy Commission (CEC) encourages RPU to report how programs assist and prioritize disadvantaged communities and to address any implementation of relevant sections of the CEC's 2016 report *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities* (Barriers Study: Part A)[1] and the California Air Resource Board's (CARB) 2018 *Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents* (Barriers Study: Part B).[2] RPU's efforts that address these recommendations are discussed towards the end of this chapter.

17.1 Disadvantaged and Low-Income Communities in Riverside

It is important to understand how disadvantaged and low-income communities are defined and which areas of the City are identified as such. This section discusses three measures for identifying these customers.

Low-Income Customers

RPU has historically focused support for low-income residential customers that meet established income standards regardless of where they were located within the service territory. To qualify for assistance from the utility, customers must be at or below 250% of the Federal Poverty Level (250% FPL) as shown in Table 17.1.1. RPU changed the qualification requirements for the program in 2022 from 200% of the FPL to 250% of the FPL to align with Senate Bill 756 (2021) which expanded the definition of low-income for the purposes of the Energy Savings Assistance Program.

[1] Scavo, Jordan, Suzanne Korosec, Estaban Guerroro, Bill Pennington, and Pamela Doughman. *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities.* California Energy Commission, Publication Number: CEC-300-2016-009-CMF. December 2016.

[2] California Air Resources Board. *Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents*. February 21, 2018.

Table 17.1.1. Income Eligibility based on 250% of the 2023 FPL and Number of Persons in a Household.[3]

Household Size*	1	2	3	4	5	6	7	8
Annual Income	$36,450	$49,300	$62,150	$75,000	$87,850	$100,700	$113,550	$126,400

* More than 8: $126,400 plus $12,850 for each additional person.

Based on the 2021 American Community Survey 1-Year Estimates, the City of Riverside's population was estimated to be 317,257.[4] Of this population, income ratios to determine poverty status are calculated for approximately 299,549 people (see Table 17.1.2). About 39% had household incomes below 250% FPL.[5] The American Community Survey does not calculate the populations or households at 250% FPL. To calculate an estimate of the population and households that fall within 250% FPL, RPU took half of the 200% to 299% category and combined it with all lower percentage categories.

To compare the number of customers that may be eligible for RPU's assistance programs, family and non-family households were also evaluated. Riverside has approximately 66,568 family households of which 33% were estimated to have incomes below 250% FPL.[6] For non-family households, which are typically single person households or households comprised of unrelated people (includes group quarters, such as dormitories), it is estimated that about 39% of the 24,542 of these households have household incomes below 250% FPL[7] (see Table 17.1.2).

[3] The Federal Poverty Guidelines are issued each year by the U.S. Department of Health and Human Services (HHS); determination of the 250% level means that the income levels identified by the HHS are multiplied by 2.5 for purposes of determining customer eligibility for RPU low-income assistance programs. See: Department of Health and Human Services, "Annual Update of the HHS Poverty Guidelines", 88 FR 3424, January 19, 2023.
[4] U.S. Census Bureau; American Community Survey, 2021 American Community Survey 1-Year Estimates, Table DP05; generated by Tracy Sato; using the Data Census tool; <http://data.census.gov>; (September 18, 2023).
[5] U.S. Census Bureau; American Community Survey, 2021 American Community Survey 1-Year Estimates, Table B17002; generated by Tracy Sato; using the Data Census tool; <http://data.census.gov>; (September 18, 2023)..
[6] U.S. Census Bureau; American Community Survey, 2021 American Community Survey 1-Year Estimates, Table B17026; generated by Trisha Stull; using the Data Census tool; <http://data.census. gov>; (March 23, 2023).
[7] U.S. Census Bureau; American Community Survey, 2021 American Community Survey 1-Year Estimates, Table B19201; generated by Trisha Stull; using the Data Census tool; <http://data.census.gov>; (March 23, 2023).

Table 17.1.2. Summary of Population and Households by family and non-family with income below 250% of the Federal Poverty Level.[8]

	Total	Below 250% Federal Poverty Level**	Percent Below 250% Federal Poverty Level**
Population for whom poverty is determined	299,549	118,001	39%
Households*	91,110	31,710	35%
Family Households	66,568	22,036	33%
Non-Family Households	24,542	9,674	39%

* The population for whom poverty is determined excludes persons living in dormitories and those who are institutionalized. Households are defined by the U.S. Census Bureau as the people living together in a housing unit. Family households are comprised of people who are related by birth, marriage, or adoption and residing together. Non-family households are typically single person but also include groups of unrelated people living together, such as in group homes.
** The American Community Survey does not calculate the populations or households at 250% FPL. To calculate an estimate of the population and households that fall within 250% FPL, RPU took half of the 200% to 299% category and combined it with all lower percentage categories.

CalEnviroScreen Disadvantaged Communities

With the enactment of Senate Bill 535 (de Leon) in 2012, the California Environmental Protection Agency (CalEPA) was directed to identify DACs for the purpose of identifying locations in which to prioritize or target funding that the State receives from the Cap-and-Trade program (discussed in prior chapters of this IRP). The requirements to define a DAC expand on income as the sole or primary factor in determining if a community is disadvantaged. Section 39711 of the Health and Safety Code states that a disadvantaged community shall be identified by CalEPA based on geographic, socioeconomic, public health, and environmental hazard criteria that may include, but is not limited to either of the following:

(1) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation.
(2) Areas with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment.

To meet this requirement, CalEPA utilized and updated its environmental health screening tool, CalEnviroScreen to score and map DACs throughout the State based on adopted evaluation criteria.[9] In

[8] U.S. Census Bureau; American Community Survey, 2021 American Community Survey 1-Year Estimates, Tables B17002, B17026, and B19201; generated by Trisha Stull; using the Data Census tool; <http://data.census.gov>; (March 23, 2023).
[9] California Environmental Protection Agency, CalEnviroScreen 4.0, https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-40, accessed April 10, 2023.

order to identify a community as disadvantaged, CalEPA bases their analysis on the smallest geographic area for which data are available – the United States Census Tract geography.

The evaluation criteria shown in Figure 17.1.1 are measured and scored within each geography. Scoring is based on a basic ranking of the level of the impact. The more impacted the area is, the higher the area is in the ranking which then receives a higher community impact score. The scores are weighted and combined to determine one final score and ranking for each Census Tract. An area is identified as a DAC if the Census Tract ranks as one of the top 25% most impacted in the State. Therefore, Census Tracts that receive a score of 76% or higher are defined as DACs. It is important to note that for a tract to be identified as disadvantaged, it will be impacted by multiple pollution burden and population characteristic criteria – no single criteria determines if an area is disadvantaged or not. Map 17.1.1 on the following page identifies the locations in Riverside that are identified as DACs. An analysis of our customer accounts is summarized in Table 17.1.3 and shows that approximately 43% of the City's customer accounts are located within an identified DAC.

Pollution Burden

Exposures

- Ozone Concentrations
- PM 2.5 Concentrations
- Diesel PM Emissions
- Drinking Water Contaminants
- Children's Lead Risk from Housing
- Pesticide Use
- Toxic Releases from Facilities
- Traffic Density

Environmental Effects

- Cleanup Sites
- Groundwater Threats
- Hazardous Waste
- Impaired Water Bodies
- Solid Waste Sites and Facilities

Population Characteristics

Sensitive Populations

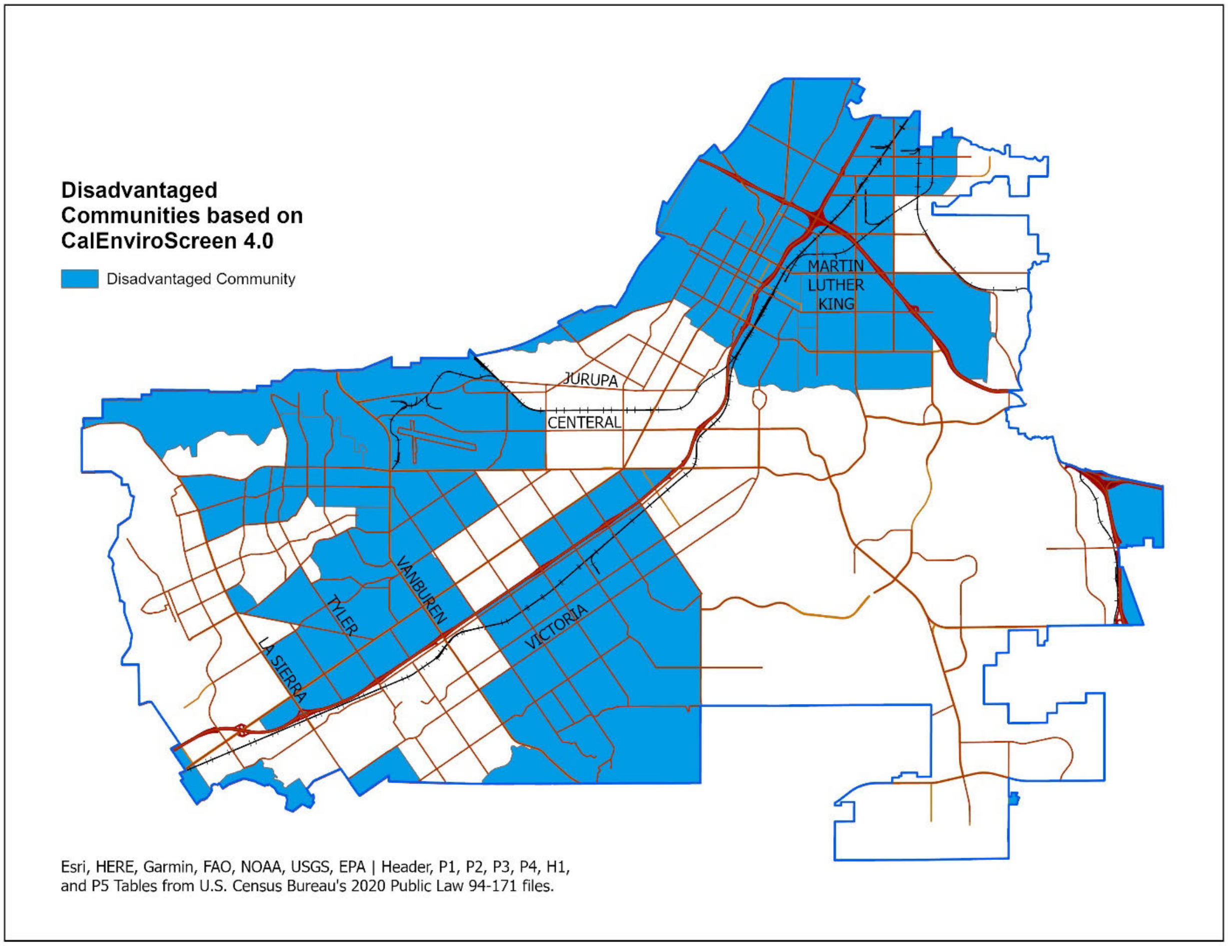
- Asthma Emergency Department Visits
- Cardiovascular Disease (Emergency Department Visits for Heart Attacks)
- Low Birth Weight Infants

Socioeconomic Factors

- Educational Attainment
- Housing-Burdened Low-Income Households
- Linguistic Isolation
- Poverty
- Unemployment

Figure 17.1.1. Indicator Criteria identifying Disadvantaged Communities.[10]

[10] August, Laura, Komal Bangia, Laurel Plummer, Shankar Prasad, Kelsey Ranjbar, Andrew Slocombe, and Walker Wieland. *CalEnviroScreen 4.0*. California Office of Environmental Health Hazard Assessment. October 2021.



Map 17.1.1. CalEnviroScreen 4.0 Disadvantaged Communities in Riverside.

Table 17.1.3. Summary of customer accounts within CalEnviroScreen 4.0 Disadvantaged Communities by customer type.

Customer Type	Total Number of Customer Accounts	Number of Customer Accounts in CalEnviroScreen DACs	Percent of Customer Accounts in CalEnviroScreen DACs
Commercial/Industrial	12,500	7,185	57.5%
Residential*	100,809	41,977	41.6%
All other (institutional, agricultural, etc.)	44	27	61.4%
Total	113,353	49,189	43.4%

* Residential customer type only includes residents that have residential accounts. That the total population resides in a variety of housing is not always captured by our residential account class. This includes locations where housing units are covered under a consolidated single commercial account such as in group homes and care facilities, mobile home parks, student housing and some apartment housing.

According to CalEnviroScreen, the majority of Riverside experiences high levels of pollution burden due primarily to poor regional air quality – including exposure to ozone and particulate matter 2.5 microns in size and smaller. Additionally, areas that border along the freeways also experience high diesel particulate matter and are impacted by heavy traffic. Socioeconomic and health impacts are located in more limited areas of the City and were often the determining factors for whether a Census Tract was considered disadvantaged or not.

Additionally, an evaluation of the potential association between race/ethnicity and CalEnviroScreen 4.0 scores within Riverside shows a disparity with respect to the racial makeup of the communities with the highest pollution burdens and vulnerabilities. People of color disproportionately reside in highly impacted communities within Riverside. This is consistent with the findings of the *Analysis of Race/Ethnicity and CalEnviroScreens 4.0 Scores*[11] report released by the Office of Environmental Health Hazard Assessment (OEHHA) and CalEPA, though Figure 17.1.2 shows that the disparity within Riverside is not as large as that seen within California as a whole.

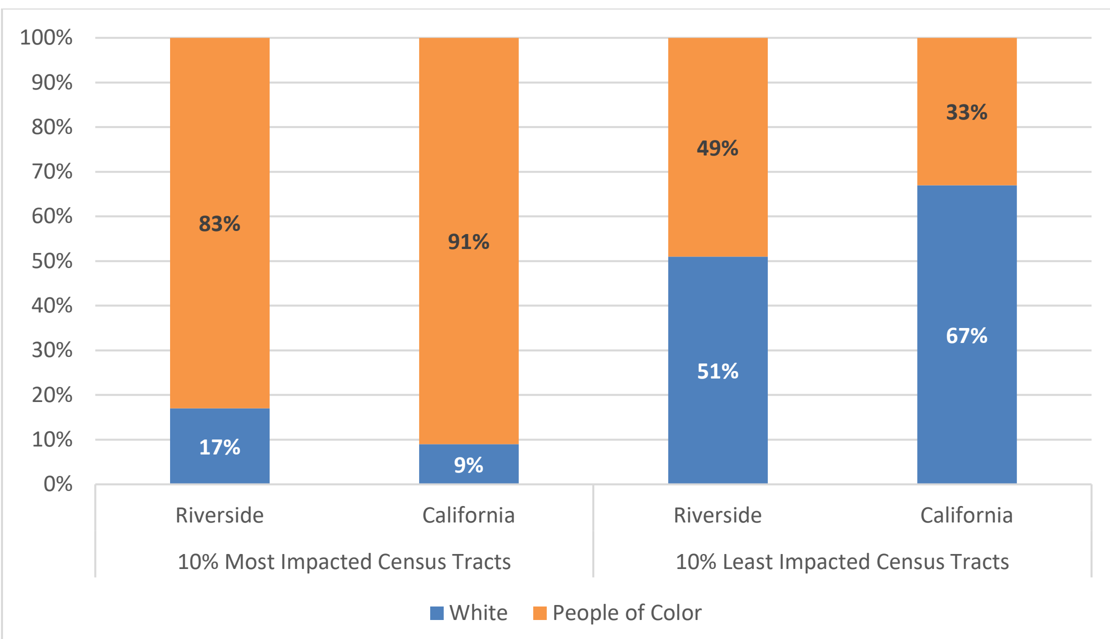


Figure 17.1.2. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores in Riverside versus California.

[11] California Office of Environmental Health Hazard Assessment and California Environmental Protection Agency. *Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores.* https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf. October 2021.

Justice40 Disadvantaged Communities

In January 2021, the President signed Executive Order 14008. As part of this Executive Order, the Justice40 Initiative was implemented which set a federal government goal that 40 percent of the overall benefits of certain Federal investments flow to disadvantaged communities that are marginalized, underserved, and overburdened by pollution. These investments include climate change, clean energy and energy efficiency, pollution reduction, and more. For the Justice40 Initiative, communities are considered disadvantaged if:

(1) They are in census tracts that meet the threshold for at least one of the categories of burden, or
(2) They are on land within the boundaries of Federally Recognized Tribes.

To help public agencies identify Justice40 disadvantaged communities, the White House Council on Environmental Quality developed and launched the Climate and Economic Justice Screening Tool (CEJST). The CEJST scores and maps DACs across all 50 states, the District of Columbia, and the U.S. territories based on adopted evaluation criteria.[12] The tool bases its analysis on the smallest geographic area for which data are available – the United States Census Tract geography.

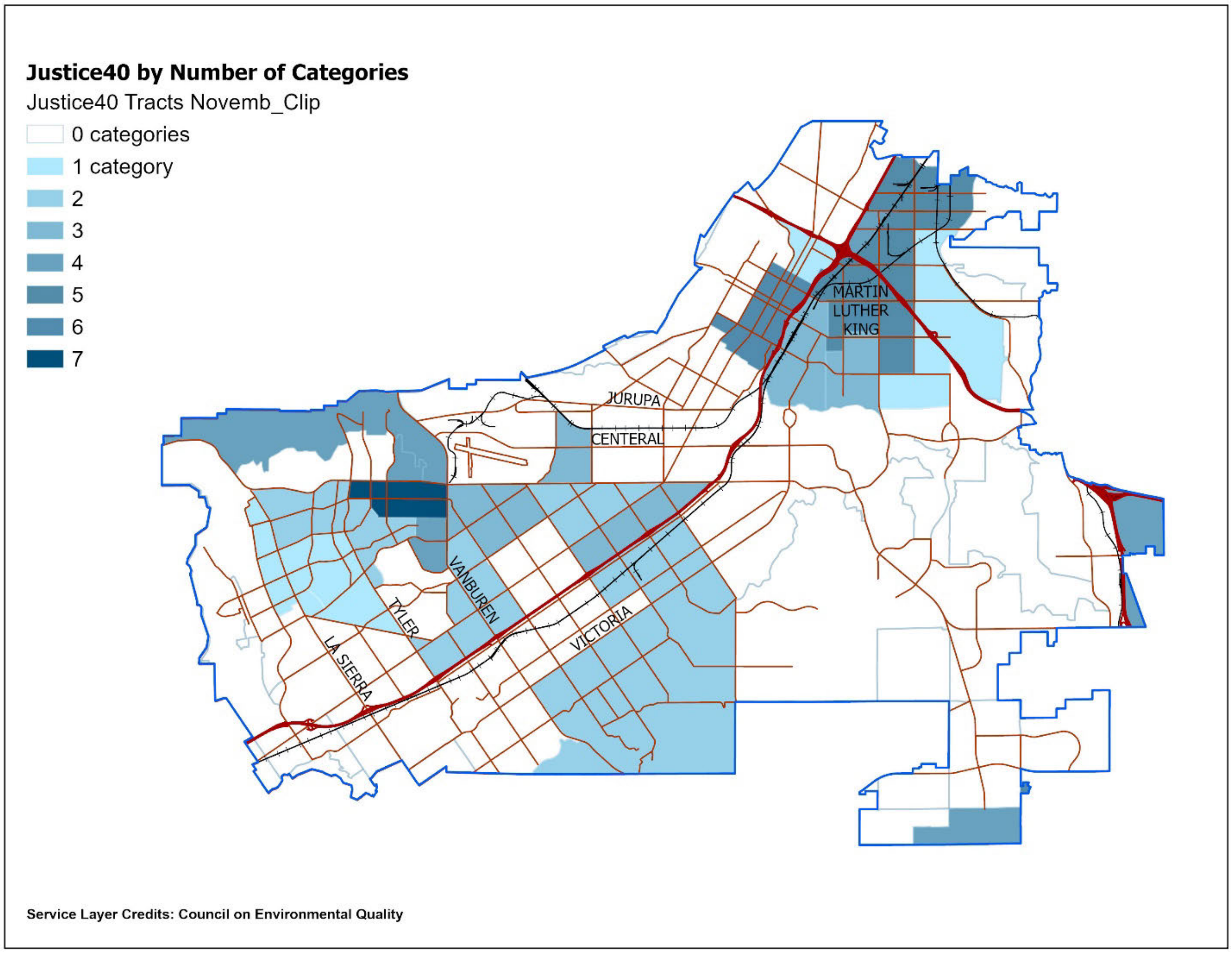
The evaluation criteria shown in Figure 17.1.3 are measured and scored within each geography. Communities are identified as disadvantaged if they are in a census tract that is at or above the listed thresholds for one or more of the categories listed. Map 17.1.2 shows the census tracts in Riverside that are considered DACs by the Justice40 Initiative and the number of categories of burdens they exceed. Using the Justice40 data and customer account meter locations, RPU staff have determined that about 34% of customer accounts are located within a Justice40 DAC, as shown in Table 17.1.4.

[12] Council on Environmental Quality, Climate and Economic Justice Screening Tool, https://screeningtool.geoplatform.gov/en/#6.05/44.722/-111.536, Accessed April 12, 2023.

Categories of Burdens

Climate change *Communities are identified as disadvantaged if they are in census tracts that:* **ARE** at or above the 90th percentile for expected agriculture loss rate OR expected building loss rate OR expected population loss rate OR projected flood risk OR projected wildfire risk **AND** are at or above the 65th percentile for low income	**Energy** *Communities are identified as disadvantaged if they are in census tracts that:* **ARE** at or above the 90th percentile for energy cost OR PM2.5 in the air **AND** are at or above the 65th percentile for low income
Health *Communities are identified as disadvantaged if they are in census tracts that:* **ARE** at or above the 90th percentile for asthma OR diabetes OR heart disease OR low life expectancy **AND** are at or above the 65th percentile for low income	**Housing** *Communities are identified as disadvantaged if they are in census tracts that:* Experienced historic underinvestment OR are at or above the 90th percentile for housing cost OR lack of green space OR lack of indoor plumbing OR lead paint **AND** are at or above the 65th percentile for low income
Legacy Pollution *Communities are identified as disadvantaged if they are in census tracts that:* Have at least one abandoned mine land OR Formerly Used Defense Site OR are at or above the 90th percentile for proximity to hazardous waste facilities OR proximity to Superfund sites (National Priorities List (NPL)) OR proximity to Risk Management Plan (RMP) facilities **AND** are at or above the 65th percentile for low income	**Transportation** *Communities are identified as disadvantaged if they are in census tracts that:* **ARE** at or above the 90th percentile for diesel particulate matter exposure OR transportation barriers OR traffic proximity and volume **AND** are at or above the 65th percentile for low income
Water and wastewater *Communities are identified as disadvantaged if they are in census tracts that:* **ARE** at or above the 90th percentile for underground storage tanks and releases OR wastewater discharge **AND** are at or above the 65th percentile for low income	**Workforce development** *Communities are identified as disadvantaged if they are in census tracts that:* **ARE** at or above the 90th percentile for linguistic isolation OR low median income OR poverty OR unemployment **AND** less than 10% of people ages 25 or higher have a high school education (i.e., graduated with a high school diploma)

Figure 17.1.3. Categories of Burdens identifying Disadvantaged Communities.



Map 17.1.2. Justice40 Disadvantaged Communities in Riverside by number of Categories of Burdens.

Table 17.1.4. Summary of customer accounts within Justice40 Disadvantaged Communities by customer type.

Customer Type	Total Number of Customer Accounts	Number of Customer Accounts in Justice40 DACs	Percent of Customer Accounts in Justice40 DACs
Commercial/Industrial	12,500	5,362	42.9%
Residential*	100,809	33,488	33.2%
All other (institutional, agricultural, etc.)	44	25	56.8%
Total	113,353	38,875	34.3%

* Residential customer type only includes residents that have residential accounts. That the total population resides in a variety of housing is not always captured by our residential account class. This includes locations where housing units are covered under a consolidated single commercial account such as in group homes and care facilities, mobile home parks, student housing and some apartment housing.

17.2 RPU Sustainability Efforts

The City of Riverside has long been committed to implementing the best existing and emerging sustainability practices including leading by example. Since 2000, actions by RPU and the City have resulted in reduced air pollution and a reduction in community wide GHG emissions. The City's environmental stewardship is highlighted through actions beginning in 2001 when the City began the conversion of its traffic signals to LED lights to reduce energy consumption. Over the years, the City and RPU have installed rooftop solar photovoltaic (PV) systems on several utility and community facilities. City and RPU policies and actions have supported the installation of electric vehicle charging infrastructure, the conversion of about 70% of the City's light-duty, medium-duty, and heavy-duty fleets to alternative fuels, and continued installation of solar PV systems throughout the City.

The City has been recognized for its sustainability efforts by various organizations. In 2014, Riverside was named "California's Coolest City" by the CARB. In 2015, the City was awarded a 3-STAR ranking for its sustainable programs and practices through the Sustainability Tools for Assessing and Rating Communities (STAR). Also in 2015, the City was the first in the State to join the Audubon Society's prestigious Sustainable Communities Program. The City has also been recognized numerous times through the NAFA Green Fleet Awards, most recently coming in first place in 2022.

Envision Riverside 2025 Strategic Plan

In 2020, the City adopted the Envision Riverside 2025 Strategic Plan (Strategic Plan) which set forth the priorities and policies for the next five years such as reaching 100% renewable energy and citywide carbon neutrality by 2040. The Strategic Plan includes goals and actions to improve air quality through multiple sectors including electricity, transportation, and urban forestry. There are also many actions to address equity to ensure staff are trained and responsive to Diversity, Equity & Inclusion (DEI) issues in the community, facilitate meaningful conversations around equity, and provide funding and research to support equity organizations and disadvantaged businesses within the City.[13] Table 17.2.1 below lists some of the goals and actions relevant to this discussion. Additionally, in 2021 the City adopted the PACT Plan which included an Active Transportation Plan that set goals around vehicle miles traveled (VMT) and other active transportation activities.[14]

[13] City of Riverside, "Envision Riverside 2025 Strategic Plan", January 2023. The full document can be found at: https://riversideca.gov/citymanager/envision-riverside-strategic-plan.
[14] City of Riverside, "PACT Plan", June 2021. The full document can be found at: https://riversideca.gov/pact.

Table 17.2.1. Envision Riverside 2025 Strategic Plan equity and air quality Action Items.

Action Item	Description
Action 2.4.1	Collaborate with community organizations to identify strategies to confront racism locally and regionally, and host community meetings with experts to learn about successful practices to confront racism
Action 2.4.2	Using trained City employees, engage community members, especially those historically marginalized, in a timely, accessible, and respectful manner on topics they prioritize.
Action 2.4.5	Establish an initiative that elevates inclusion, diversity, and equity and produce a comprehensive guide/toolkit.
Action 2.4.6	Establish a small grant program to support organizations that focus on issues of racism.
Action 3.2.1	Work with Diversity, Equity & Inclusion (DEI) Officer, once position is filled, to identify local workforce strengths and weaknesses/barriers, with a special focus on people of color and historically marginalized communities and create a city workforce development roadmap.
Action 3.4.5	Develop and implement programs that support microenterprise and small businesses and encourage entrepreneurship with a focus on minority-owned, women-owned and disadvantaged business.
Action 3.4.6	Research and identify a feasible method to collect reliable data that identifies the number of woman-owned, minority-owned, and disadvantaged businesses in the City.
Action 4.1.2	Procure adequate power supplies to provide renewable and GHG emissions free electricity to comply with, and where possible, exceed, state laws and regulations and reduce GHG emissions by dates specified to meet the State of California goals of GHG emissions free electricity for electric utility customers by 2045.
Action 4.1.3	Study opportunities to integrate solar generation, energy efficiency, fuel switching, energy storage and other advanced technology to support reduction of GHG emissions and integration of all renewable energy resources at public and private facilities, including parking structure, parking lots, and buildings.
Action 4.1.6	Identify best practices and sustainable methods to address energy affordability.
Action 4.3.1	Develop and implement new actions and strategies that will reduce transportation induced emissions…
Action 4.3.2	Develop a plan for clean air centers, similar to cooling centers, where residents can get reprieve from poor air quality during large fires or smog alerts.
Action 4.3.4	Research and identify air monitoring equipment for installation throughout the City, for better local air quality data.
Action 4.6.1	Expand the use of zero and low-emission vehicles as part of the City's fleet, including electric, hybrid, and hydrogen vehicles, and develop the charging/fueling infrastructure to support to meet state mandates and timelines.
Action 4.6.2	Update urban forestry policies to select tree species that maximize carbon sequestration and building energy reduction potential.
Action 4.6.6	Evaluate options for RPU to achieve carbon neutrality by 2040 for the electricity and water served to customers.
Action 4.6.7	Develop a transportation electrification strategy for the City to ensure effective infrastructure that will support widespread adoption of electric vehicles.
Action 5.2.5	Assess the geographic understanding of equity across the City to contribute to decision-making pertaining to public service demands and resource allocation needs.
Action 5.3.4	Lead and engage in meaningful conversations with the community, about inclusion, diversity and equity to eliminate barriers and work in a holistic manner that breaks down silos…
Action 5.3.5	Involve local groups and leadership of diverse backgrounds and provide equitable access to decision-making process that affect health and environment benefits/burdens, thereby raising awareness and making effort to ensure that environmental justice is considered and incorporated into Triple Bottom Line analysis of City projects.

Climate Action and Adaptation Planning

The City of Riverside will be developing a new Climate Action and Adaptation Plan (CAAP) with work beginning in early 2024. The CAAP will be a wholesale update to the City's previous climate action planning efforts and will be a complement to the City's General Plan being updated at the same time. As a department of the City, RPU's power generation will be considered and potentially be addressed by measures in the CAAP once completed.

These two documents will incorporate and embody equity and social justice as key policy areas along with addressing climate and the traditional elements of a planning document. Importantly, the new CAAP will reflect the policies and programs carried out by RPU because they work hand-in-hand with other City programs that support communities in Riverside. The new CAAP will replace the two existing climate policy documents in the City, the Green Action Plan adopted in 2009 and the Riverside Restorative Growthprint and Climate Action Plan adopted in 2016.

The Strategic Plan and the CAAP (when completed) guides RPU, as well as the City, when making decisions for energy procurement, efficiency and low-income program development, and even operations of RPU's fleets and power plants. As the sustainability goals of these plans are met, the benefits are realized by all RPU customers – particularly in the areas of green energy, transformation of fleet vehicles, and energy efficiency. For purposes of this chapter, the following goals and measures have been highlighted as particularly relevant to the IRP process:

Priority 4. Environmental Stewardship. Champion proactive and equitable climate solutions based in science to ensure clean air, safe water, a vibrant natural world and a resilient green new economy for current and future generations;

> **Goal 4.1.** Rapidly decrease Riverside's carbon footprint by acting urgently to reach a zero-carbon electric grid with the goal of reaching 100% zero-carbon electricity production by 2040 while continuing to ensure safe, reliable and affordable energy for all residents; and
>
> **Goal 4.6.** Implement the requisite measures to achieve citywide carbon neutrality no later than 2040.

In addition to supporting the City to meet these specific goals, RPU plays an important role in meeting or supporting all the goals in the Strategic Plan that cover environmental and community stewardship in the areas of waste management, urban design, urban nature and parks, water, and community health. The remaining sections discuss RPU's specific actions that have reduced air pollution and greenhouse gas emissions.

17.2.1 RPU Reduction in GHG Emissions in Power Generation

Since power generation is one of the largest emitters of GHG emissions, reducing such emissions in the overall generation portfolio provides a benefit that is realized by all customers. As discussed throughout this IRP, in 2022, 45.4% of RPU's electricity came from renewable resources that included geothermal, solar, and wind. Another 5.9% of RPU's generation resources were made up with GHG-free resources (large hydropower and nuclear). RPU is on track to have a 2030 portfolio of resources that exceed the 60% renewable portfolio standard with close to 70% of its resources being non-greenhouse gas emitting generation.

Additionally, Riverside has nearly 69.5 MW of installed solar PV capacity. About 58.1 MW of this capacity represents behind the meter customer installed PV systems, while the remaining capacity is either under contract with the City or the University of California, Riverside campus.

17.2.2 Reducing Localized Air Contaminants from Power Plants

RPU owns and operates nine gas turbine generators permitted and approved to operate under the strict guidance of the South Coast Air Quality Management District, California Air Resource Board and Environmental Protection Agency. As environmental stewards, RPU focused on strategies and programs for the electrical generators, which successfully lowered emissions beyond those required by regulators. The generators are in three power plant locations: four gas turbines are at Riverside Energy Resource Center (RERC), four gas turbines are at Springs Generating Station (Springs), and one gas turbine is at Clearwater Power Plant (Clearwater). Two of these facilities, RERC and Springs are in industrial areas of the City of Riverside while Clearwater is located in an industrial area of the City of Corona. RERC and Clearwater are in areas identified as DACs.

RPU's most important electric generation station, RERC was built to be used during critical local and California summer peak periods, City emergencies for essential public services, and to assist California as additional renewable energy sources supply our electric grid. The RERC electric generators were built with the best available emissions control technologies available in the industry. As leaders in the industry, staff have further reduced harmful pollutants by 30% beyond those required by regulators and supplied by the equipment manufacturers. General Electric (original equipment supplier), the Combined Cycle Journal, and Combined Cycle Users Group recognized RPU for their innovative emissions reductions programs, leading the industry with pioneering ideas.

RPU also depends on RERC during summer months to supplement the electricity brought into the service territory through the Vista Substation, RPU's one point of interconnection. The amount of electricity that can be brought into Riverside at the Vista Substation is limited to 540 MW while RPU's highest peak demand reached 648 MWs in 2022. RPU relies on RERC to support customer electricity demands reliably within the service territory when electricity demand exceeds the capacity at the Vista Substation. Additionally, all of RPU's power plants are relied upon during statewide high demand hours.

Despite the important role these facilities play today in ensuring reliable electricity for the City, RPU is actively working towards closure of these facilities as they reach end-of-life. Residents near to each of these power plants, as well as the region as a whole will experience reduced air contaminants such as nitrogen oxides (NOx) once these facilities retire. For these facilities to close, a second transmission interconnection to the statewide grid must be developed to address the capacity limitations at the Vista substation and enable replacement generation to be imported to RPU's service territory. Currently, RPU has approval of a second interconnection to the statewide grid (the Riverside Transmission Reliability Project; see Chapter 4, section 4.7). Chapters 11 and 12 discuss the details surrounding the decommissioning of all three power generation facilities; but in summary, the Springs Generating Station is expected to retire by 2030 and both RERC and Clearwater will retire by 2040.

17.2.3 Clean Fleet Vehicles

RPU has been supporting the transition of its internal combustion engine fleet vehicles to cleaner alternatives for many years. While Transportation Electrification overall is discussed in detail in Chapter 16, this short section highlights how RPU and the City have been transitioning its own fleet vehicles to alternative fuels and helping to reduce air emissions throughout the City and region.

RPU's fleet is part of the overall City fleet that is managed by the Fleet Management Division of the General Services Department. The City's fleet management has already completed projects to reduce emissions, including, but not limited to, installing a second compressed natural gas (CNG) fueling station at the Water Quality Control Plant, installing electric vehicle charging stations at various City facilities, and purchasing 642 clean fleet vehicles to replace older ICE vehicles over the past several years.

About 80% of the current light duty fleet of City vehicles utilize forms of fuel/energy other than conventional gasoline and diesel fuel (CNG, propane, electric, etc.). Hence, the City's Fleet Operations have significantly reduced GHG emissions and other pollutants when compared to a "business as usual" scenario, in a manner consistent with state and local regulations while exceeding them where possible.

Examples of other specific measures that have further contributed to a higher level of sustainability are as follows:

- A purchasing policy that requires the replacement of all non-emergency diesel vehicles with alternative fuel vehicles when available and the replacement of light duty vehicles with flex fuel, hybrid, plug-in hybrid, electric, CNG and propane vehicles whenever possible.
- A long-range planning/coordination policy that requires inter-departmental collaboration when replacing and purchasing new vehicles consistent with goals to maintain a "green" fleet of City vehicles.

- A proactive vehicle monitoring and replacement program to determine appropriate timing for vehicle replacement and the class of vehicle needed for replacement (with maximum energy efficiencies in mind).
- A "right sizing" program to ensure proper utilization of all City fleet vehicles.
- A vehicle/equipment anti-idling policy for all non-emergency vehicles to reduce GHG emissions, ambient noise, and unnecessary fuel use.
- The future use of GPS technology to track vehicle location, fuel usage and confirm mileage.
- Route planning practices are utilized by refuse services, street sweeping, etc. to maximize efficiencies and reduce fuel consumption.
- Multiple sites for fleet vehicle storage and checkout near primary City government facilities, reducing VMT and the number of vehicles needed for fleet services.
- Participation and investment in local green programs such as Clean Cities Coalition.
- Expansive staff training in the benefits of and properly maintaining green fleet vehicles.

Finally, due to the Advanced Clean Fleets regulation, beginning January 1, 2024, fifty percent (50%) or more of all medium- and heavy-duty (GVWR 8,500 or greater) new vehicle purchases will be zero-emission vehicles. Likewise, beginning January 1, 2028, one hundred percent (100%) of all medium- and heavy-duty new vehicle purchases will be zero-emission vehicles.

17.2.4 RPU Low-Income Assistance Programs

As identified in the CEC's Barriers Study: Part A, offering options for financing energy efficiency is an important action for increasing access in low-income communities. RPU offers several assistance programs that support low-income customers. The Sharing Households Assist Riverside Energy (SHARE) program provides financial assistance to qualified customers, while the Energy Savings Assistance Program (ESAP) is a direct-install program that provides no-cost energy efficiency upgrades to qualified customers.

The SHARE program has been in place since 1989 and enhanced several times over the last few years. Changes have been reflected in the assistance amounts offered as well as an extension of the income qualification criteria and include the following:

- In July 2020, a revision was made to the SHARE program guidelines to allow for an urgent notice to qualify customers for the $150 emergency assistance; an increase was made to the SHARE electric monthly credit, taking it from $14.50 to $15.00, and to the SHARE water monthly credit, taking it from $2.50 to $2.75.
- In March 2021, the SHARE emergency/deposit credit was increased from $150 to $250.
- In August 2021, a change was made to increase the SHARE electric monthly credit to $15.50 and increase the SHARE water monthly credit to $3.00.

- In May 2022, the income eligibility criteria for the program were expanded from 200% of the Federal Poverty Guidelines to 250% and the SHARE electric monthly credit was increased to $16.00, and the SHARE water monthly credit was increased to $3.25.
- Future increases are anticipated to align with changes to rates.

RPU's ESAP program was paused during COVID and reestablished in 2022. The program provides no-cost energy efficiency home improvements based on income and household size. Households may be eligible for the program based on participation in certain public assistance programs, such as RPU's Sharing Households Assist Riverside's Energy (SHARE) program, which assists income-qualified, residential customers with their electric utility bills, deposits, and urgent notices.

Finally, RPU offers a wide range of energy efficiency rebates that are available to all customers. These programs are regularly reviewed to ensure that all customers can access ways to reduce their energy consumption. Details on all programs are discussed in Chapter 6 of this IRP.

17.2.5 RPU Low-Income Clean Transportation Assistance

The CARB's Barriers Study: Part B analyzes barriers to accessing clean transportation in low-income communities and offers recommendations and actions to address these barriers. One of the priorities listed in the report was identifying and expanding funding as a way to address the barrier of accessibility for low-income and disadvantaged communities. Specifically, CARB recommended using revenue from the Low Carbon Fuel Standard (LCFS) program to develop EV rebates for low-income residents and disadvantaged communities.

RPU currently offers rebates to customers for the purchase of used electric vehicles and the installation of EV chargers. The rebate program is funded by LCFS revenue and was started in 2022. The latest program revisions were approved by the City Council on December 6, 2022, and went into effect January 1, 2023. Through the updated program, low-income customers enrolled in RPU's low-income assistance program called SHARE are eligible to receive a used EV rebate of up to $2,500. Customers are also able to receive an EV Level 2 charger rebate of up to $500 as well as a rebate of up to $805 to cover the cost of installing an EV meter adapter so they can use a time-of-use EV rate when charging their electric vehicle. As of April 1, 2023, six (6) SHARE customers had applied for and received a Used EV Rebate. Details of these programs are discussed in Chapter 16 of this IRP.

17.2.6 New and Upcoming Decarbonization Incentive Programs

In addition to the variety of low-income assistance programs RPU currently offers, there are several programs being developed or newly in effect at the state and federal level to assist households, particularly of low-income, with building decarbonization improvements. Once these programs are fully established, RPU may be able to participate or direct its customers to these assistance programs.

One incentive is the updated Energy Efficient Home Improvement Credit. This allows homeowners to receive a federal tax credit of up to $3,200 for qualified energy-efficient home improvements annually from 2023 to 2033.

Another program is the Home Energy Rebate Program, which was funded by the Inflation Reduction Act in August 2022. States will receive formula funding for two rebate programs. The first program is the Homeowner Managing Energy Savings (HOMES) rebate. California is expected to receive approximately $292 million to provide performance-based rebates for whole-house energy efficiency upgrades for single-family homes and multifamily buildings. Up to $8,000 for single-family homeowners and up to $400,000 for multifamily buildings will be available depending on energy savings and household income. The second program is the High-Efficiency Electric Home Rebate Program (HEEHRA). California is expected to receive approximately $290 million to provide point-of-sale rebates for the purchase and installation of qualified Energy Star appliances such as electric heat pumps for space heating and cooling. Households below 150% of area median income are eligible to participate and may receive up to $14,000 depending on their qualifying purchases.

At the state level, the CEC is currently working to develop the Equitable Building Decarbonization Program which will consist of a Statewide Direct Install Program and a Statewide Incentive Program. The Statewide Direct Install Program will offer low- or no-cost retrofits for low- and moderate-income households throughout the state. The Statewide Incentive Program will offer incentive to promote low-carbon technologies in homes and reduce GHG emissions with at least fifty percent of the funds required to benefit under-resourced communities. This program is anticipated to begin its initial rollout in 2024 or 2025.

The CEC also offers technical assistance and financial incentives to builders and developers. The Building Initiative for Low-Emissions Development (BUILD) program authorized by SB 1477 provides $60 million for new, all-electric homes for low-income residents. Up to 300 hours of free building electrification technical assistance and $2 million in incentives is available for each eligible developer. The California Electric Homes Program (CalEHP), named in statute as the Building Initiative for Low-Emissions Development Program Phase 2 by AB 137, provides $58 million for new, market-rate homes with all-electric appliances and equipment. In 2023, incentives start at $1,750 per residential unit for multifamily dwellings and $3,500 per residential unit for single-family dwellings on a first-come, first-served basis with additional incentives available based on location and above-code measures.

RPU will continue to monitor these new and upcoming decarbonization incentives to verify that the Utility's efforts are complementary to state and federal programs. Additionally, RPU will continue to actively inform customers about the variety of incentives available to them.

18. Potential Future Studies

While staff believe that this 2023 IRP document has proposed a viable strategy for RPU's continuing efforts towards deep decarbonization, several of the planning issues examined in this document will most likely require further investigations and additional studies. In this chapter we explore some of these issues in greater detail, specifically with respect to the results presented in chapters 10-14 and 16. The discussions presented here are primarily focused on how future resource planning assessments on these chapter topics might be strengthened, improved, and/or expanded. Topics that are briefly discussed in this chapter include (a) the role of future generation technologies in RPU's resource planning efforts, (b) improved methodologies for performing more comprehensive distribution system ICA studies, (c) potential future DR and/or EE/DSM efforts, and (d) the value and benefits of a more comprehensive and integrated future TE planning effort.

18.1 Future Generation Technologies

As discussed in detail in Chapters 11 and 12, staff have proposed a set of new renewable / carbon-free resource contracts for the 2030 to 2045 time frame that will ensure that RPU achieves a zero-carbon portfolio by 2040 (see Table 11.2.1). Central to this modeling assumption is a "Baseload Resource Tranche" of unspecified generation assets that begin delivering carbon-free energy in 2034. As stated in Chapter 12, the lineup of resource technologies that will be commercially available in the middle of the next decade is currently unknown. Therefore, this resource tranche could represent a known renewable and/or carbon-free technology such as nuclear or solar/wind + long duration storage, or an emerging technology like green hydrogen.

From a high-level, preliminary planning perspective, this assumption works fine; the proposed Baseload Resource Tranche (Resource 2) serves as a generic placeholder for resources that have yet to be identified. However, ultimately these resources will need to be identified and studied in greater detail, similar to how the baseload geothermal (Resource 1a) versus solar + storage (Resource 1b) assets were examined in Chapter 12. Likewise, a robust analysis of future technology options should include the most promising emerging technologies, such as long duration battery energy storage applications, proposed offshore wind developments, 2nd generation nuclear facilities, and/or green hydrogen thermal applications, etc.

While RPU is aware that such an analysis will need to be undertaken in the future, staff currently do not possess the necessary subject matter expertise to adequately specify the various cost components associated with most of these emerging technology options. Furthermore, since a significant amount of research may be required to even begin to develop and specify such cost components, it might make more sense to outsource this type of future study to a qualified 3rd party entity. Such an entity would most likely need to be either a qualified commercial energy consulting firm or suitable governmental research agency. Regardless, RPU may wish to seriously consider this option in support of such future resource planning efforts.[1]

18.2 Distribution System ICA Studies

As part of the current Integrated Resource Plan, RPU has evaluated the distribution grid's sensitivity to customer adoption of distributed energy resource (DER) technologies. Specifically, Chapter 13 presented a capacity analysis study of each RPU distribution system feeder. Recall that in industry literature this is sometimes referred to as an Integration Capacity Analysis, or ICA.

The intent of this chapter's study is exploratory in nature, rather than a formal forecast used for resource planning or capital investment planning purposes. As stated in Chapter 13, while similar methods can be applied to create a forecast, RPU does not currently have all the technology tools available to complete a formal forecast ICA. RPU has not yet developed a comprehensive method to forecast on the distribution feeder or geospatial level when and/or where such DER adoption may occur. Therefore, this study does not currently identify the costs of specific items that might require upgrading on RPU's distribution feeders and substations, nor does it identify specific years when such upgrades may need to occur.

For future IRPs, RPU will need to pursue more refined studies and methodologies to disaggregate the expected growth of these alternative DER technologies to develop organic growth models and forecast geospatial adoption rates.[2] However, such studies can be developed at various spatial resolutions. For example, future studies might apply load growth assumptions or DER forecasts to circuit level data, like the data analyzed in this ICA. In principle, RPU staff should be able to develop and perform such analyses internally, subject to certain simplifying assumptions about how future DER assets are distributed across the circuits.

Unfortunately, while simpler to implement, this approach will only yield a "low level spatial resolution" understanding of how RPU's distribution system might be expected to be impacted. In contrast, a more intensive effort could be made to model DER forecasts down to either a 2nd stage transformer level or even the individual customer meter level. This latter approach would yield a "high level spatial resolution" view of distribution system impacts and perhaps prove to be far more flexible for simulating various DER adoption scenarios. Of course, while this latter approach seems far more appealing, it will also require far more work and staffing resources.

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[1] This last point is especially relevant should there be a desire to explore any hydrogen-based internal generation technology options for future reliability needs. RPU Resource Planning staff are currently unable to assess or study such a scenario, due to a lack of sufficient subject matter expertise in the emerging field of green hydrogen generation applications.

[2] Future IRPs may assess projections of DER adoption in the RPU territory using NREL's dGen™ tool, a geospatial model that simulates the potential adoption of DERs for residential, commercial, and industrial entities.

Which of these approaches RPU should pursue in future studies remains an open question. Developing high resolution IDP models would represent a paradigm shift away from how RPU staff currently develop distribution capital investment plans – and perhaps require the support of 3rd party consultants or research organizations. Nonetheless, the answer to this question may ultimately depend in part on how important it becomes for RPU to produce comprehensive Integrated Distribution Planning (IDP) studies in support of future IRP activities.

18.3 Future EE, DSM and/or DR Programs

RPU is committed to making Riverside a greener place to live by supporting renewable energy, responsible purchasing and design, and sustainable living practices. An important portion of RPU's future resource strategy is to cost effectively support both Energy Efficiency (EE) and Demand Side Management (DSM) programs. Chapter 6 presents an overview of RPU's EE and DSM programs. RPU offers a variety of EE and DSM programs that both reduce customer bills and help support Citywide environmental and sustainability goals.

Following up on Chapter 6, Chapter 14 presents a review of RPU's analysis of the costs to increase energy efficiency (EE) targets with respect to various EE measures and the value that these measures provide to the utility. While Chapter 6 summarizes RPU's adopted and forecasted EE targets that are included in the power supply analysis, Chapter 14 focuses on the costs of these programs and what the impacts would be to RPU and its customers if higher targets are sought. More specifically, Chapter 14 examines the costs associated with the three broad types of RPU EE measures across four customer classes and compares them to the avoided costs of energy to determine their overall cost effectiveness.

As discussed in Chapter 14 (see Table 14.5.1 and Figure 14.5.1), eight out of twelve EE program categories exhibit positive net unmet revenue estimates and thus have benefit to cost ratios < 1. This is not that surprising, since RPU's energy rates are designed to collect all the utility's fixed operating costs (i.e., infrastructure, personnel, and O&M), in addition to its variable power supply costs. However, these results also indicate that the HVAC EE programs appear to be the most cost effective with respect to the type of EE measure being implemented. (HVAC EE programs exhibit relatively small but negative net unmet revenue estimates in three of RPU's four customer classes.) This suggests that RPU might want to consider directing proportionally more of its EE efforts towards these HVAC EE measures.

Historically, RPU has found most EE and nearly all Demand Response (DR) programs to not be cost effective, especially when compared to many supply-side resource options. However, given the current market prices for new capacity, it may be worthwhile to reexamine the avoided cost calculations for certain EE and DR programs in greater detail, specifically for those programs that have the potential to materially reduce RPU's future peak load serving needs. RA prices have nearly tripled over the last four years and it appears unlikely that RA cost pressures will abate anytime soon. Thus, implementing additional DR and/or EE programs that are specifically targeted towards reducing peak load levels might now make financial sense, even if these same programs were found to not be cost effective in the past.

Hence, RPU may want to seriously consider examining and implementing new DR and/or EE/DSM programs that are specifically targeted towards reducing summer peak load levels. Furthermore, given current CAISO market capacity prices, the utility may wish to consider implementing at least some of these programs on an expedited schedule.

18.4 More Comprehensive TE Planning Efforts

Chapter 16 presents an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. Included in this overview is a discussion addressing the anticipated energy demand and reduced greenhouse gas (GHG) emissions that will result from the forecast transition of vehicles from using internal combustion engines (ICE) to electric motors supported by plug-in battery-electric vehicles (BEV or EV). Chapter 16 also reviews the policy and regulatory environment around transportation electrification and the status of electrification in the RPU service territory. Additionally, multiple forecasts for EVs and their associated annual loads within the RPU service territory are examined, along with the forecasted GHG emissions reductions corresponding to these various EV penetration scenarios.

RPU coordinates closely with the City of Riverside and is working to expand access to electric vehicle charging infrastructure as well as meet Citywide environmental and sustainability goals. RPU and the City of Riverside have taken several actions to support increasing EV adoption rates, including:

- Streamlining the permitting process for installing EV charging infrastructure at residential, commercial, and multi-family buildings.
- Supporting a robust, city-wide Clean Fleet program.
- Supporting a robust public EV Education and Awareness campaign.
- Implementing various EV rebates using revenue from CARB's Low Carbon Fuel Standard (LCFS) program, including rebates for purchasing used EVs and rebates for residential and multi-family Level 2 chargers.
- Implementing whole-house and EV-only TOU rates that residential customers can optionally opt into.

Finally, RPU is also developing a public access Level 2 Charger Program throughout the City with the City General Services Department, with the goal of increasing the availability of publicly accessible EV charging at locations such as libraries, community centers, public parking lots, and garages.

These all represent important actions taken by the utility within the last five years to help make EV ownership a more convenient and cost effect option for RPU customers. However, with that said, RPU has not yet developed a long-range, comprehensive EV transportation plan that incorporates and integrates with its current Integrated Distribution and/or Resource Planning efforts (see the discussion in Section 18.2). In the absence of such a plan, it becomes more difficult to develop investment strategies to support expanded charging infrastructure or mitigation strategies to minimize distribution system impacts. Additionally, it also makes planning efforts for other types of transportation electrification more challenging, such as developing longer range plans for accommodating medium- and heavy-duty vehicle electrification or public transit electrification.

Currently, staff anticipate needing outside assistance to help develop a robust and comprehensive EV transportation plan for the City of Riverside. While this could remain a utility led effort, RPU staff do not currently possess enough overall transportation related subject matter expertise to undertake this effort in isolation. Alternatively, and like the future resource technology issue, it might make more sense to outsource this type of future study to a qualified 3rd party commercial energy consulting firm or suitable governmental research agency.

For now, it remains an open question as to how to best go about developing a long-range, comprehensive EV transportation plan. Nonetheless, it seems fairly obvious that the utility needs to develop such a plan, ideally before the 2028 IRP process gets underway.

19. Conclusion

As stated in the Introduction, this *2023 Integrated Resource Plan* ("IRP") has provided an impact analysis of Riverside's acquisition of new power resources, specifically towards meeting the state of California's aggressive carbon reduction goals; along with the effect these resources will have on Riverside Public Utilities future projected power supply costs. The six primary goals of this IRP were broadly summarized as follows:

- To provide an updated overview of RPU's (a) energy and peak demand forecasts, (b) current generation and transmission resources, and (c) existing electric system.

- To review and assess the impact of important legislative and regulatory mandates imposed by various state or regional agencies (California Energy Commission, California Air Resources Board, South Coast Air Quality Management District, etc.), along with the impact of important active or proposed California Independent System Operator (CAISO) stakeholder initiatives on RPU's power system and supplies.

- To summarize and assess the utility's current set of Energy Efficiency (EE) and Demand Side Management (DSM) programs and assess the overall cost-effectiveness of these EE/DSM programs with respect to both the utility and all utility customers (i.e., both participating and non-participating customers).

- To review and quantify the most critical intermediate term power resource forecasts, specifically with respect to how RPU intends to meet its (a) projected energy, capacity, and resource adequacy requirements, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, and (d) power resource budgetary objectives.

- To examine and analyze certain critical longer term power resource procurement strategies and objectives, specifically those that will help RPU reach its 2030 and 2040 carbon reduction goals and quantify how such strategies and objectives might impact the utility's future power supply costs.

- To begin to assess how various emerging technologies may concurrently impact RPU's existing distribution system, so that staff can better define future distribution system improvements that continue to support the utility's fundamental objective of providing reliable electrical services at competitive rates.

The chapter organization and layout has sequentially followed the general goals discussed above; i.e., background information has been presented in Chapters 2-4, legislative and regulatory mandates and initiatives were discussed in Chapter 5, EE and DSM programs were reviewed in Chapter 6 and assessed for their cost-effectiveness in Chapter 14, forward market views were discussed in Chapter 7 and RPU's intermediate term portfolio forecasts were discussed in detail in Chapter 8, longer term resource planning and issues and carbon reduction strategies have been analyzed in detail in Chapters 9-

12, and a preliminary assessment of the impacts of emerging DSM technologies on RPU's existing distribution system was presented in Chapter 13. Additionally, RPU's most recent electric rate plan has been reviewed in Chapter 15, an overview of RPU's efforts to support increasing levels of TE was presented in Chapter 16, and the utility's commitment to serving its disadvantaged community members has been discussed in Chapter 17. Finally, Chapter 18 presents a broad review of the key resource planning issues that require further investigations and additional studies. Overall, staff has attempted to compile and present information in these chapters that address these six primary IRP goals in a comprehensive and analytical manner.

This final chapter provides a high-level review of each of these primary goals, specifically with respect to the data and analyses presented in this IRP. Succinct summaries of the most important staff findings are presented below.

19.1 RPU Background Information

An overview of RPU's long-term energy and peak demand forecasting methodology was presented in Chapter 2. This overview included a discussion of staff's econometric forecasting approach, key input variables and assumptions, and pertinent model statistics. Chapter 3 provided an overview of RPU's long term resource portfolio assets, including the utility's existing resources, future renewable resources (currently under contract), and recently expired contracts. This chapter also reviewed RPU's transmission resources, along with the utility's transmission control agreements with the CAISO. Finally, a brief review of RPU's existing electric distribution system was given in Chapter 4, along with a description of its operational constraints and planned enhancements. The key highlights from these background chapters are as follows:

- ✓ Econometric forecasting models were used to produce RPU's baseline 2023-2045 output energy and peak demand forecasts. These forecasts call for system loads to grow at about 1.4% annually and peak demand to grow at approximately 0.6% annually over the next 20+ years.
- ✓ RPU currently either owns or has contracts for nineteen (19) different generation resources that are based on multiple types of thermal or renewable technologies. Altogether, this current resource portfolio provides RPU with about 665 MW of nameplate capacity; by 2027 this number should increase to about 675 MW of capacity, after the Pattern wind resource replaces RPU's retired IPP coal contract and the last component of the Coso geothermal portfolio comes online.
- ✓ RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities. The Utility receives over 90% of its system power through the regional bulk transmission system operated by the CAISO. Undoubtedly, the Riverside Transmission Reliability Project (RTRP) represents the most important anticipated change to the distribution system. If built, this project will provide Riverside with a second source of transmission capacity to import bulk electric power. In turn, this could significantly alter the utility's long-term

internal resource procurement needs to ensure that RPU has sufficient electricity to cover summer peak loads while simultaneously working towards meeting State and City renewable and zero-carbon electricity mandates.

19.2 Important Legislative and Regulatory Mandates

Chapter 5 provided an overview and discussion of relevant legislative, regulatory and stakeholder issues that will significantly impact the California electric energy industry in the foreseeable future, specifically the markets run by the CAISO. Not surprisingly, there are several legislative, regulatory, and CAISO mandates and initiatives that are expected to significantly impact RPU.

With respect to CA legislation, the most important Assembly bills (AB) and Senate bills (SB) effecting RPU include AB 32 (California greenhouse gas reduction mandate), SB 1368 (baseload generation emission performance standards), SB 1037 and AB 2021 (EE/DSM programs and 10-year targets), AB 398 (greenhouse gas Cap-and-Trade program extension), SB 350 (clean energy and pollution reduction act of 2015), SB 100 (the 100% clean energy act of 2018), SB 1020 (clean energy targets for 2035, 2040, and 2045) and SB 1028, SB 901, and AB 1054 (legislation relating to wildfires). Additionally, Executive Order B-55-18 mandates the achievement of state-wide carbon neutrality by 2045 and Executive Order N-79-20 mandates that 100% of in-state sales of new passenger vehicles to be zero-emission by 2035.

Concurrent with these legislative activities, the CAISO has been and continues to promote market enhancements and initiatives that are designed to both improve system reliability and better accommodate the increasing levels of renewable energy generation assets. Some of the most important CAISO initiatives include the launching of the Energy Imbalance Market (EIM), the proposed Extended Day-Ahead Market (EDAM) and corresponding EDAM enhancements, the Resource Adequacy, Energy Storage, and Maximum Import Capacity enhancements, and the recently completed initiatives that focused on improving the efficiency of the Congestion Revenue Rights Auction and Transmission Service and Scheduling protocols.

Finally, it is critically important to note that the Envision Riverside 2025 Strategic Plan was created and approved by the Riverside City Council on October 20, 2020. This Strategic Plan sets forth the Strategic Priorities and Goals of the City Council to advance Riverside's potential and to frame the work efforts of staff through 2025. The Riverside City Council adopted six strategic priorities and associated goals for each priority. One of these adopted priorities was the Environmental Stewardship priority. Under the Environmental Stewardship priority, the first foundational goal adopted by the City Council was **Goal 4.1:** *Rapidly decrease Riverside's carbon footprint by acting urgently to reach a zero-carbon electric grid with the goal of reaching 100% zero-carbon electricity production by 2040 while continuing to ensure safe, reliable, and affordable energy for all residents.* This City Council goal has in turn served as the fundamental driving guideline for the goals and strategies proposed in this 2023 IRP.

19.3 EE/DSM Programs

RPU is committed to making Riverside a greener place to live by supporting renewable energy, responsible purchasing and design, and sustainable living practices. An important portion of RPU's future resource strategy is to cost effectively support both Energy Efficiency (EE) and Demand Side Management (DSM) programs.

Chapter 6 presented an overview of RPU's EE and DSM programs. RPU recognizes the important role that DSM and EE play in planning for resources. RPU offers a variety of programs and education to customers about efficiently using energy and managing energy usage to reduce bills and meet Citywide environmental and sustainability goals. With the passage of Senate Bill 350 and the requirement to develop and submit an IRP to the California Energy Commission (CEC), RPU is also required to specifically address the procurement of energy efficiency in this IRP. As such, Chapter 6 reviewed the methodologies for determining the cost effectiveness of DSM and EE programs overall, as well as the officially adopted EE targets reflected in RPU's demand and peak demand forecasts.

Following up on Chapter 6, Chapter 14 presented a review of RPU's analysis of the costs to increase energy efficiency (EE) targets with respect to various EE measures and the value that these measures provide to the utility. While Chapter 6 summarized RPU's adopted and forecasted EE targets that were included in the power supply analysis, Chapter 14 focused on the costs of these programs and what the impacts would be to RPU and its customers if higher targets were sought. More specifically, Chapter 14 examined the costs associated with the three broad types of RPU EE measures and compared them to the avoided costs of energy. Avoided cost analyses were differentiated between residential and commercial/industrial (CI) customer measures as well as whether the EE measure was for Baseload, Lighting, or Air Conditioning (HVAC).

As discussed in Chapter 14 (see Table 14.5.1 and Figure 14.5.1), most of the EE program categories exhibit positive net unmet revenue estimates and thus have benefit to cost ratios < 1. This should not be that surprising, since RPU's energy rates are designed to collect all the utility's fixed operating costs (i.e., infrastructure, personnel, and O&M), in addition to its variable power supply costs. While four EE program categories do exhibit marginally negative net unmet revenue estimates, only two EE measures (CD – HVAC and TOU – HVAC) exhibit negative net unmet revenue estimates that are less than -$0.01/kWh, and there are no EE measures with estimates less than -$0.02/kWh. These results imply that there are probably not a lot of current opportunities for the utility to significantly increase the adoption of many EE measures in a cost-effective manner. However, as discussed further in Chapter 18, it may be worthwhile to reexamine the avoided cost calculations for these EE programs in greater detail, specifically for programs (like HVAC) that have the potential to materially reduce RPU's future peak load serving needs.

19.4 Intermediate Term Power Resource Forecasts

Chapter 8 presented a detailed overview of RPU's most critical intermediate term power resource forecasts. These forecasts quantified the metrics that the Planning Unit routinely analyzes, monitors, and manages in order to optimize RPU's position in the CAISO market and minimize the utility's associated load serving costs. The following metrics were discussed in detail:

- Renewable energy resources and projected RPS %'s
- Primary Resource Portfolio metrics
- Net Revenue Uncertainty metrics
- Internal Generation forecasts
- Forecasted Hedging %'s and Open Energy positions
- Forecasted GHG Emission profiles and net Carbon allocation positions
- Five-year Forward Power Resource Budget forecasts

All the analyses presented in this chapter were performed using the Ascend Portfolio Modeling software platform and referenced late August 2023 CAISO market conditions.

Based on the forecast data presented in this Chapter, the following conclusions can be drawn concerning RPU's intermediate term resource positions.

- ✓ RPU continues to procure a significant amount of excess renewable energy, above and beyond the state's minimum mandated amounts. Since 2017, RPU has begun to accumulate excess renewable energy credits which can be used to meet future RPS compliance obligations, should any significant (and extended) future renewable resource outages occur. Currently, the utility expects to remain above a 44% RPS in 2024 and exceed the "60% by 2030" mandate three years early.

- ✓ Over the next five years, 62% to 83% of the utility's expected system energy needs will be served using fixed-price contracts within the resource portfolio (including optional IPP natural gas energy), while another 4% to 5% will be served using internal generation assets (primarily during summer). The remaining 22% to 33% of energy needs will need to be acquired from the CAISO market, either via forward purchases or day-ahead market transactions. These open energy positions will need to be forward hedged via longer term forward market purchases or through the contracting of additional resources. Currently, these unhedged positions can cause RPU's forecasted net power supply budget costs to potentially either increase or decrease as much as $21.6 million per year due to weather, load and/or market price volatility.

- ✓ RPU is expected to have more than enough carbon allowances to fully meet its direct emission compliance needs through 2028. Staff currently forecasts having an excess allowance balance of 550,000 to 800,000 credits annually; however, these excess allowance volumes might be substantially reduced under the CARB 2025 rulemaking process. Nonetheless, whatever excess credits remain are expected to be monetized through the CARB quarterly auction process, with a significant portion of the proceeds used to help offset RPU's excess renewable energy costs.

- ✓ The utility's gross power supply costs are projected to be $254.2 million in FY 23/24, which represents a $27.1 million cost increase over the budget projections produced in October 2021. Unfortunately, these power supply cost forecasts are expected to remain elevated throughout the five-year planning horizon due to the impact of macro market conditions beyond the utility's control.

In summary, the utility is reasonably well positioned to meet its load serving needs over the next five years, but additional efforts will need to be undertaken to control RPU's power supply costs. With respect to energy needs, additional systematic forward hedging activities will be required to maintain cash flow stability. Additional resources may also need to be procured in the immediate term time horizon (i.e., in the next three to five years) to reduce the utility's net revenue uncertainty.

19.5 Critical Longer Term Power Resource Issues

The fundamental purpose of the 2023 IRP process is to identify and assess the most cost-effective means for RPU to continue to reduce its GHG emissions, such that the utility can meet or exceed its specified 2030 emission target. As such, Chapters 9 through 12 examined the critical longer term power resource planning issues surrounding this goal.

This discussion was initiated in Chapter 9 by first reviewing the utility's latest 2030 GHG emission targets, as specified in CARB's August 2023 GHG Planning Targets: Draft 2023 Update report. In their report, CARB listed individual utility targets for the 16 largest POUs based on two different electricity sector targets: 30 and 38 MMT CO_2-e. CARB has endorsed this target range for the POUs and proposes that each POU should choose one or more targets within this range for integrated resource planning purposes. Hence, for planning purposes RPU has elected to focus on these target levels.

Under the 38 MMT sector target, RPU's utility specific target is 349,000 MT CO_2-e. Likewise, under the 30 MMT sector target, RPU's utility specific target is 275,000 MT CO_2-e. RPU is electing to use the higher 349,000 MT target for official planning purposes, but the results presented in Chapter 9 show that the lower target could also be easily reached if RPU contracts for one additional medium sized renewable energy asset by or before 2030. Table 19.5.1 summarizes these two GHG planning targets, respectively.

Table 19.5.1. The two RPU GHG planning targets analyzed in this IRP.

GHG Planning Target	Description	MT CO2-e Emission Value
38 MMT Sector Goal	Official RPU target	349,000
30 MMT Sector Goal	More aggressive GHG reduction scenario	275,000

Next, in Chapter 10 staff reviewed RPU's future capacity needs for the 22-year time horizon from 2024 through 2045. Ultimately, these needs will be primarily influenced by Riverside's future load growth rate and the potential expiration of various capacity resources currently under contract. Additionally, staff also analyzed and discussed RPU's "Net-Peak" demand forecasts for 2022 and 2028 in this chapter as well.

Having thoroughly reviewed RPU's future capacity expansion needs, in Chapter 11 staff examined all the utility's current resource contracts that are scheduled to end before December 2045; the goal being to identify resources with contracts that are likely to be extended versus replaced (at least for integrated resource planning purposes). Battery energy storage resources were considered as replacements for RPU's gas-fired Springs and RERC Generation Facilities once they reach their anticipated end-of-life retirement dates. More importantly, a set of five potential future portfolio resource additions were presented in this chapter that are consistent with RPU's long-term carbon reduction goals. Four of these proposed resource additions represented specified carbon-free renewable resources, while the fifth was defined to be an unspecified, carbon-free baseload resource tranche. As originally shown in Table 11.2.1 and reproduced here as Table 20.5.2, the acquisition of these proposed resources (1a or 1b plus 2, 3, and 4) will allow RPU to successfully exceed the utility's lower (30 MMT Sector) 2030 emission target and achieve full carbon neutrality by 2040.

Table 20.5.2. Proposed new renewable resource contracts for 2030-2045.

	New Resource	Resource Description	COD	Annual MWh
1a	Baseload Geothermal	50 MW baseload geothermal resource (84% CF)	2030	367,920
1b	Solar + Storage	120 MW Solar PV (35% CF) + 50 MW / 200 MWh BESS	2030	367,920
2	Baseload Resource (Renewable and/or Carbon-Free)	Baseload Resource Tranche (90% CF) (1) • 50 MW • 60 MW • 20 MW	 2034 2038 2043	 394,200 473,040 157,680
3	Solar PV-2037	75 MW Solar PV (35% CF)	2037	229,950
4	Solar PV-2041	75 MW Solar PV (35% CF)	2041	229,950

Note (1): The additional 60 MW and 20 MW may come from new assets or be incremental to the original 50 MW asset.

Finally, Chapter 12 examined the projected budgetary impacts of the Baseline Portfolio, specifically focusing on comparing two resource options in 2030. Additionally, this chapter examined the projected budgetary impacts of battery energy storage replacement options for the Springs and RERC generation facilities upon their assumed retirements, as well as the impacts of ±30% deviations in the price marks for resources 2, 3, and 4. The budgetary assessments considered both the expected values and simulated standard deviations of RPU's resource portfolio cost over the 2024-to-2045 time horizon. Hence, both Net Value calculations and Risk Integrated Portfolio Costs (RIPC) for the proposed resources across the various scenarios were also provided. A few of the more pertinent findings presented in Chapter 12 can be briefly summarized as follows.

- ✓ The Baseline Portfolio satisfies all GHG reduction and RPS mandates through the 2045 timeframe. Under either the Baseline A or B portfolio, RPU achieves (a) a 2030 emission level of 152,065 metric tons, which is below its more aggressive reduction target of 275,000 metric tons, (b) a 2030 RPS of 80.5%, and (c) carbon neutrality by 2040.

- ✓ Between 2024 and 2042, these IRP studies suggest that RPU's power resource costs will grow at about 1.9% to 2.0% annually under the two proposed Baseline Portfolios.

- ✓ Deploying BESS as replacements for Springs in 2028 and 2030 resulted in essentially no impact to RPU's RIPC in those years. Beyond 2030, the BESS produces about a 1% decrease in the RIPC compared to the Baseline A Portfolio. These results suggest that a more detailed future analysis of battery replacement options for Springs is warranted.

- ✓ Deploying BESS as a replacement for RERC after it retires in 2039 results in RIPC estimates for 2042 and 2045 that are about 3% and 6% lower, respectively, compared to the Baseline Portfolio which does not include a RERC replacement. These results show that it will be important to replace RERC with some type of energy storage technology after 2039, to continue mitigating the financial impacts of high price energy hours.

- ✓ Most importantly, the price sensitivity studies presented in section 12.4 confirm that it will be very important for RPU to continue to secure cost-effective resources as the utility builds out its portfolio over the next 15 years. Securing cost-effective resource pricing will be essential for RPU to control its RIPC growth rate, which in turn will directly impact the magnitude of future rate increases.

19.6 Preliminary Distribution System DER Impact Studies

As part of this 2023 Integrated Resource Plan, RPU staff evaluated the distribution grid's sensitivity to customer adoption of renewable and alternative technologies. Accordingly, Chapter 13 presented a preliminary Integration Capacity Analysis study of each RPU distribution system feeder. The intent of this chapter's study was exploratory in nature and was not a formal forecast used for resource planning or capital investment planning purposes. While similar methods can be applied to create a forecast, RPU does not currently have all the technology tools available to complete a formal forecast ICA. With this study, staff primarily intended to show threshold levels of adoption that will require upgrades to distribution substation or feeder equipment.

The study results illustrated the ability for RPU's distribution system to accommodate more generation from Distributed Energy Resources (DERs) like rooftop solar photovoltaic (PV) installations and loads from Fuel Switching (FS) or DERs like electric vehicle (EV) charging across most RPU distribution feeders. For each feeder, Capacity Utilization Factors (CUF's) were developed by comparing the SCADA data to engineering estimated PV, FS, and EV generation or charging patterns, which in turn defined the amount of additional PV, FS, and/or EV penetration that the circuit could theoretically accommodate. These CUF's were then analyzed and summarized both statistically and spatially, to begin to develop a better understanding of the potential timing and location of various future distribution system upgrades.

Finally, section 13.5 discusses three critical OT platforms and technology efforts that RPU is relying on to better optimize the deployment of DER technology. These platforms and efforts include: (1) the successful deployment of the OSI Pi platform, which serves as RPU's Operational Data Management System, (2) the distribution wide rollout of AMI technology, and (3) the consolidation and restructuring of the GIS workflow process. Each of these OT systems had been previously identified as part of an integrated Operational Technology/Information Technology Master Plan strategy to improve RPU's organizational efficiency and to better manage, integrate, and optimize DER assets within RPU's distribution system.

19.7 Additional Important Topics Covered in Chapters 15 Through 18

The latter part of this IRP reviewed some additional specific topics directly related to RPU's Integrated Resource Planning efforts. These topics include Retail Rate Design (Chapter 15), Transportation Electrification (Chapter 16), Disadvantaged and Low-income Communities (Chapter 17) and Potential Future IRP Studies (Chapter 18).

Chapter 15 briefly reviewed and summarized the utility's latest electric rate proposal, including its justification for why the new electric rate plan is fair and reasonable. The Riverside City Council adopted RPU's proposed new five-year (fiscal years 2023/24 through 2027/28) electric utility rate plan in September 2023 and the relevant rate increase documents and information about this new rate plan can be found online at: https://www.riversideca.gov/utilities/electric-proposed-rates. This chapter also described the new Self Generation rate tariff that the utility introduced in 2022, as well as new enhancements to RPU's low-income and fixed-income assistance programs.

Chapter 16 presented an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. The discussion addressed the anticipated energy demand and reduced greenhouse gas (GHG) emissions that will result from the forecast transition of vehicles from using internal combustion engines (ICE) to electric motors supported by plug-in battery-electric vehicles (BEV or EV). RPU works closely with the City of Riverside and is working to expand access to electric vehicle charging infrastructure as well as meet Citywide environmental and sustainability goals. Chapter 16 also reviewed the policy and regulatory environment around transportation electrification and the status of electrification in the RPU service territory. Additionally, multiple forecasts for EVs and their associated annual loads within the RPU service territory were examined, along with the forecasted GHG emissions reductions corresponding to these various EV penetration scenarios. These forecasts for EVs and their associated loads were derived from the CEC Transportation Electrification Common Assumptions 3.0 model, as well as the 2021 and 2022 Integrated Energy Policy Reports (IEPR) developed by the California Energy Commission (CEC).

RPU and the City of Riverside have long been committed to implementing the best existing and emerging sustainability practices, particularly in the areas of reducing air pollution and greenhouse gas emissions. Along these lines, Chapter 17 discussed disadvantaged and low-income communities in Riverside and then presented the utility's efforts to minimize local air pollutants and greenhouse gas emissions; focusing specifically on disadvantaged communities as required by Senate Bill 350. Additionally, RPU's efforts that specifically address the CEC 2016 Barriers Study report recommendations were also presented at the end of this chapter.

Finally, while staff believe that this 2023 IRP document has proposed a viable strategy for RPU's continuing efforts towards deep decarbonization, several of the planning issues examined in this document will most likely require further investigations and additional studies. Therefore, Chapter 18 explored some of these issues in greater detail, specifically with respect to the results presented in chapters 10-14 and 16. These discussions primarily focused on how future resource planning assessments on these chapter topics might be strengthened, improved, and/or expanded. Topics that were briefly discussed in this chapter include (a) the role of future generation technologies (including hydrogen), (b) improved methodologies for performing more comprehensive distribution system ICA studies, (c) potential future DR and/or DSM efforts, and (d) the value and benefits of a more comprehensive and integrated future TE planning effort.

In summary, a significant number of diverse resource planning issues have been discussed and analyzed in detail this 2023 Integrated Resource Plan. More detailed discussions of key results have been presented throughout the various chapters, along with staff recommendations for further analyses and studies that should be undertaken. Additionally, staff has also proposed certain strategies that RPU can implement now to continue to provide the highest quality electric services at the lowest possible rates to benefit the Riverside community. The analyses, findings and recommendations presented in this 2023 Integrated Resource Plan can and should help RPU to continue to achieve this goal in a proactive, intelligent, and cost-effective manner.

19.8 An Index of SB 350 IRP Requirements for CEC Staff

This last section identifies where specific narratives and information pertaining to Senate Bill 350 IRP requirements can be found throughout this document. Please note that this information has been included for the benefit of CEC staff and these order of index requirements follow the CEC's POU IRP Checklist. Additionally, the following RPU 2023 worksheet datasets are being submitted to the CEC concurrently with this IRP and are referenced in some of the checklist items below.

- Capacity Resource Accounting Table (CRAT)
- Energy Balance Table (EBT)
- GHG Emissions Accounting Table (GEAT)
- Resource Procurement Table (RPT)

GHG Reduction Targets

[PUC code 9621(b)(1), 9621(2)(B)]

Chapter 9 discusses RPU's GHG emission targets and forecasts through 2030 in detail. RPU already expects to get below its official 2030 GHG target of 349,000 MT CO2e using its current portfolio of resources. Additional reductions will occur if the Utility contracts for and receives any further new renewable resource energy before 2030 (see section 9.5 and Chapter 11, section 11.2). Longer term GHG emission forecasts (through 2045) are discussed in Chapter 12, section 12.1. Mid-term 1st importer emissions (through 2028) are also discussed in Chapter 8, section 8.6. Finally, all CEC requested GHG emissions information for RPU has also been provided in our concurrently submitted GEAT workbook.

60% RPS Targets by 2030

[PUC code 9621(b)(2), 399.11 (50% RPS mandate), SB 100 (60% RPS mandate)]

Mid-term RPS forecasts (through 2028) are discussed in Chapter 8, section 8.1. Longer term renewable energy procurement plans are discussed in detail in Chapter 11 and the resulting RPS forecasts through 2045 are presented in Chapter 12, section 12.1. Additionally, all CEC requested RPS forecast information for RPU has also been provided in our concurrently submitted RPT workbook.

It should be noted that Riverside has met all CEC RPS compliance obligations for Compliance Periods 1, 2, and 3 (CP1, CP2, CP3). Furthermore, the Utility expects to meet/exceed all CP4, CP5, and CP6 obligations using generation resources that are already under contract. RPU does not currently use or claim any category 2 or 3 RECs and almost all our existing renewable resource contracts qualify as long-term contracts.

Just and Reasonable Rates / Minimize Impact on Ratepayer Bills

[PUC code 9621(b)(3), 454.52(a)(1)(C), 454.52(a)(1)(D)]

Detailed information on RPU's current five-year retail rate plan is presented in Chapter 15 (see also Chapter 14, section 14.4 for current customer class rate schedules). RPU uses a robust public rate setting process and a formal cost-of-service analysis when proposing or revising its retail rates. Chapter 15 includes information on rate comparisons with other utilities, public participation and outreach efforts, and enhanced low-income and fixed-income assistance programs. As a Publicly Owned Utility, RPU seeks to minimize rate increases to the greatest extent possible and only proposes the minimum amount of rate increases needed to cover its operating expenses and target reserve levels.

Ensure System and Local Reliability

[PUC code 9621(b)(3), 454.52(a)(1)(E)]

RPU's forecasted monthly system energy and peak load levels are derived and described in Chapter 2. Based on these forecasts, detailed assessments of future Resource Adequacy capacity needs are presented and discussed in Chapter 10 (sections 10.1 and 10.2). Topics covered in Chapter 10 include RPU's expected system, local, and flexible capacity requirements, maximum import capacity needs, and RA requirements through 2045. Additionally, sections 8.2 and 8.4 of Chapter 8 discuss RPU's system energy needs and expected internal generation levels through 2028, while the incremental capacity impacts from longer-term future proposed resources are examined in detail in Chapter 12. Finally, all the CEC requested capacity information for RPU has also been provided in our concurrently submitted CRAT workbook. It should be reiterated that RPU is part of the CAISO BAA and thus relies on the CAISO for operating reserves.

Strengthen the Diversity, Resiliency, and Sustainability of Transmission, Distribution, and Local Communities

[PUC code 9621(b)(3), 454.52(a)(1)(F)]

RPU does not manage or operate any bulk transmission assets. As discussed in Chapter 3 (sections 3.4 and 3.5) the City of Riverside is a PTO in the CAISO and has turned over the operational control of RPU's transmission entitlements to the CAISO. RPU does manage, maintain, and control its own distribution system. This system is described in detail in Chapter 4. This chapter also includes an extended discussion on the Riverside Transmission Reliability Project (RTRP), which is designed to provide Riverside with a second point of interconnection to the SCE/CAISO bulk transmission system.

Additionally, an Integrated Capacity Analysis (ICA) study of RPU's distribution system is presented in Chapter 13. This ICA study provided a high-level assessment of the ability of each RPU distribution system feeder (circuit) to support the installation of additional DERs (specifically, new customer solar PV systems, electric vehicles, and fuel switching applications). This study represents the first step towards determining how to better optimize future distributed generation assets, and/or identify feeders that might develop future reliability concerns due to excessive DER saturation levels.

Distribution System and Demand-Side Energy Management

[PUC code 9621(b)(3), 454.52(a)(1)(G)]

As noted above, a preliminary but comprehensive ICA study of RPU's distribution system is presented in Chapter 13. Furthermore, section 13.4 provides a narrative discussion on how this current and/or future ICA studies might be used to better integrate and accommodate future DER growth. Likewise, section 13.5 describes RPU's recent efforts to upgrade our distribution system communication and operational technology assets.

Localized Air Pollutants with Early Priority on DACs

[PUC code 9621(b)(3), 454.52(a)(1)(H)]

Chapter 17 discusses disadvantaged and low-income communities in Riverside and describes RPU's efforts to minimize local air pollutants and greenhouse gas emissions; focusing specifically on disadvantaged communities as required by Senate Bill (SB) 350. The topics covered in this chapter include the identification of *CalEnviroScreen* and *Justice40* disadvantaged communities within the City of Riverside (section 17.1), followed by a detailed review of RPU's comprehensive citywide sustainability efforts (section 17.2). Additionally, Chapters 11 and 12 describe RPU's planning efforts and strategies for decommissioning its GHG emitting internal generation assets by or before 2040.

Energy Efficiency and Demand Response Resources

[PUC code 9621(c)(1)(A)]

Chapter 6 presents an overview of RPU's EE and DSM programs. This chapter reviews the methodologies for determining the overall cost effectiveness of DSM and EE programs, as well as the officially adopted EE targets reflected in RPU's baseline load and peak demand forecasts. (See Chapter 2, section 2.2.5 for how historical EE savings information is factored into RPU's load and peak demand forecasting models.) Following up on Chapter 6, Chapter 14 presents a review of RPU's analysis of the costs to increase energy efficiency (EE) targets with respect to various EE measures and the value that these measures provide to the utility. More specifically, this chapter examines the costs associated with the three broad types of RPU EE measures and compares them to the avoided costs of energy. Avoided cost analyses are differentiated between residential and commercial/industrial (CI) customer measures as well as whether the EE measure is for Baseload, Lighting, or Air Conditioning (HVAC).

Energy Storage

[PUC code 9621(c)(1)(B)]

The suitability and cost-effectiveness of multi-hour storage assets as a viable resource to address reliability is examined in detail in Chapters 11 and 12. More specifically, Chapters 11 and 12 describe RPU's planning efforts and strategies for decommissioning its GHG emitting internal generation units by or before 2040 and replacing these natural gas assets with multi-hour storage assets. Additionally, RPU intends to actively pursue one or more long-term RA contracts with 3rd-party multi-hour storage assets to meet some of its future RA needs, as discussed in Chapter 3, section 3.3.

Transportation Electrification

[PUC code 9621(c)(1)(C)]

Chapter 16 presents an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. The discussion addresses the anticipated energy demand and reduced greenhouse gas (GHG) emissions that will result from the forecast transition of vehicles from using internal combustion engines (ICE) to electric motors supported by plug-in battery-electric vehicles (BEV or EV). Multiple forecasts for EVs and their associated annual loads within the RPU service territory are examined, along with the forecasted GHG emissions reductions corresponding to these various EV penetration scenarios. Additionally, the ICA study presented in Chapter 13 provides a high-level assessment of the ability of each RPU distribution system feeder to support additional electric vehicles. Finally, the relevant TE data information from these various studies has also been included in our concurrently submitted CRAT and EBT workbooks.

Address Procurement of a Diversified Procurement Portfolio

[PUC code 9621(c)(1)(D)]

Chapter 3 provides a comprehensive overview of RPU's diverse portfolio of thermal and renewable generation resources. As stated in Chapter 1, section 1.1, technology diversification has always represented one of the traditional guiding principles used by the utility when selecting new generation assets or contracts. Discussions concerning RPU's future resource procurement strategies can be found in Chapters 1 (section 1.1), 3 (section 3.6), 11, 12, and 18 (section 18.1). Likewise, the expected energy and capacity supplied by RPU's current and proposed future resources has also been included in our concurrently submitted CRAT, EBT, and RPT workbooks.

Address Procurement of Resource Adequacy Requirements

[PUC code 9621(c)(1)(E)]

As previously mentioned, detailed assessments of future Resource Adequacy capacity needs are presented and discussed in Chapter 10 (sections 10.1 and 10.2). Topics covered in Chapter 10 include RPU's expected system, local, and flexible capacity requirements, maximum import capacity needs, and RA requirements through 2045. Additionally, the incremental capacity impacts from longer-term future proposed resources are examined in detail in Chapter 12. Again, all the CEC requested capacity information for RPU has also been provided in our concurrently submitted CRAT workbook (including RPU's planning reserve margin).

Historically, RPU has used utility-owned generation, power purchase agreements with assets that include CAISO certified RA attributes, and short-term resource adequacy contracts to meet its RA needs. RPU intends to continue using these types of assets and contracts in the future, in addition to new long-term RA (or full toll) contracts with battery energy storage assets.

SB 338: Net Peak Demand

[PUC code 9621(c)]

RPU's net peak demand analysis is presented in Chapter 10, section 10.3. As previously stated, detailed assessments of future Resource Adequacy capacity needs are also presented and discussed in Chapter 10 (sections 10.1 and 10.2), while future preferred resources and their associated capacity additions are discussed in Chapters 11 and 12. It is worthwhile reiterating that RPU's renewable resource mix includes a substantial amount of baseload geothermal generation and this generation contributes directly to meeting reliability needs during the hours of net peak demand.

Demand Forecast

[not specifically address in PUC code, but required to determine consistency with SB 350 requirements]

Chapter 2 provides a complete overview of RPU's long-term system load and peak demand forecasting methodology. This overview includes a discussion of the utility's econometric forecasting approach, key input variables and assumptions, and pertinent model statistics, along with the utility's 2023-2045 system load and peak demand forecasts that were produced in March 2022. In addition to being shown in Table 2.4.1, RPU annual system load and peak demand forecast values can be found in our concurrently submitted CRAT and EBT workbooks.

RPU uses regression based econometric models to forecast both its total expected GWh system loads and system MW peaks on a monthly basis. These models are calibrated to 15+ years of historical load data. The following input variables are used in these econometric models: (a) various monthly weather summary statistics, (b) specific calendar effects, (c) unplanned for (but verified) expansion and contraction of industrial loads, (d) annual per capita personal income (PCPI) and monthly labor employment (Labor_Emp) econometric input variables for the Riverside – San Bernardino – Ontario metropolitan service area, (e) the cumulative load loss effects associated with retail customer solar PV installations and all of RPU's measured energy efficiency (EE) programs, and (f) the expected net load gain due to increasing light-duty and medium/heavy-duty electric vehicle (EV) penetration levels and anticipated building electrification (fuel switching) within the RPU service territory. These models are used to project RPU wholesale gross monthly loads and peaks up to twenty-five years into the future.

Although RPU produces its own load and peak forecasts, staff do compare these forecasts for consistency with similar CEC IEPR demand forecasts for Riverside. Section 2.3.6 in Chapter 2 discusses such a comparison and shows that the RPU forecasts used throughout this IRP document track very closely with the February 2022 California Energy Demand 2022-2035 Managed Forecasts (Mid-Demand – AAEE Scenario 2 – AAFS Scenario 4 workbook, CEC publication TN241384).

APPENDIX A

A.1 Ascend PowerSimm Simulation Framework

The Ascend solution values portfolios consisting of structured transactions, generation assets, load obligations, and hedges plus operating components of transmission, ancillary services, and conservation programs. The hierarchical portfolio structure of PowerSimm enables portfolio components to be valued individually or jointly as an element of the parent portfolio. The valuation of a utility portfolio or structured transaction follows from the application of analytic algorithms that optimize asset values and calculate hedge, load, and structured transaction values relative to underlying Monte Carlo simulations. Recognizing the importance of meaningful Monte Carlo simulations to valuations of portfolios and structured transactions, we present an overview of Ascend's simulation methodology below.

The simulation framework of PowerSimm addresses uncertainty as viewed through today's market expectations (forward prices) and the future realized delivery conditions for load, spot prices, and generation. PowerSimm supports the ability to modify inputs, model impacts, and evaluate key sources of uncertainty. The framework to simulate physical and financial uncertainty follows the process flow of Figure A.1.1. The simulation of volumetric and market prices further extends the correlated simulation of forward prices to model structural relationships during delivery. Examples of such relationships include weather on load, load on market prices, and gas and load on electric prices. Additionally, relationships with very limited historical information can be modeled by specifying statistical distributions on values such as CO_2 or REC prices. PowerSimm also performs fundamental modeling of demand and supply conditions to forecast market prices beyond the liquid portion of the forward curve.

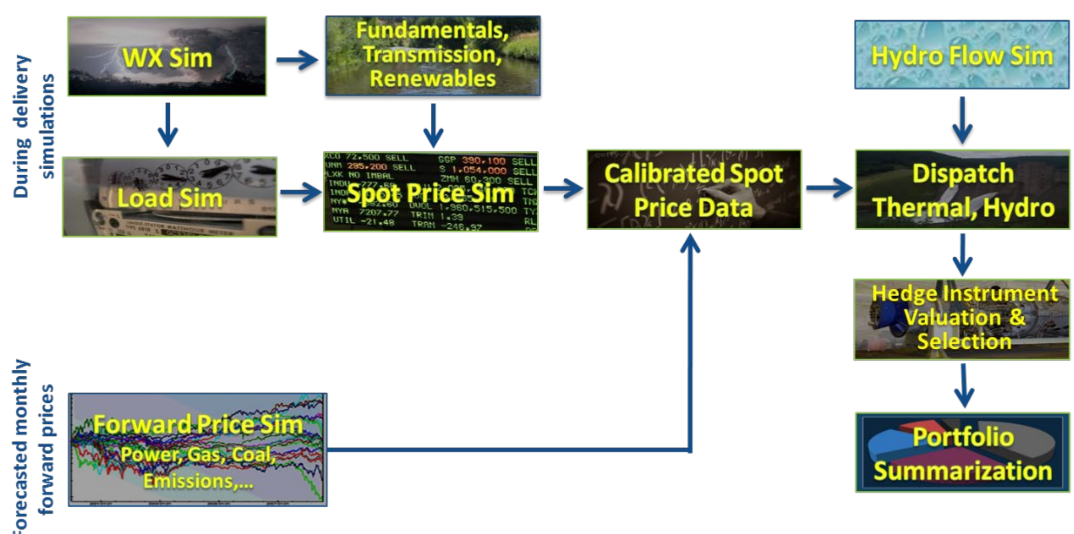


Figure A.1.1. PowerSimm simulation framework.

Simulation of electric system and customer loads follow from a common analytical structure that seeks to preserve the fundamental relationship between demand and price. The simulation process is divided into two separate components: 1) prior to delivery and 2) during delivery. The prior-to-delivery simulation of forward prices evolves current expectations through time from the start date to the end of the simulation horizon. The simulations during delivery capture the relationship of physical system conditions (i.e., weather, load, wind, run-of-river hydro, unit outages, and transmission) on market prices. The inter-relationship between 'prior-to-delivery' and 'during-delivery' simulations is central to linking expectations to realized observations that are either simulated or actual. Figure A.1.2 presents a graphical representation of this process.

For forward contracts representing prior-to-delivery simulations, monthly prices are evolved into the future from the current market prices to expiration for each contract. This process of evolving forward contracts into the future utilizes the current forward strip (market expectations of future prices) and the observed behavior of forward contract uncertainty and covariate relationships to create future price projections. For each simulation, the final evolved forward price becomes equal to market expectations. The average of the forward price simulations for each monthly contract will equal the final evolved spot price. During the prior-to-delivery simulations, monthly forward contracts are correlated with each other and across commodities. Seasonal hydro conditions are also correlated with the simulated forward prices.

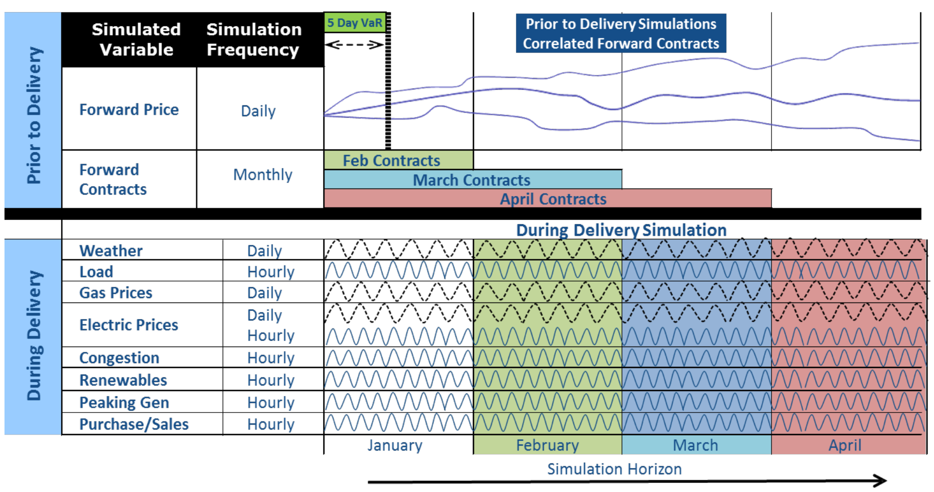


Figure A.1.2. Simulation framework of forward and spot prices.

The during-delivery simulation process begins with simulation of weather. PowerSimm simulates up to approximately 30 different weather variables (e.g., daily min/max temperatures) for user-specified weather stations using a cascading Vector Auto-Regression (VAR) approach. This approach maintains both the temporal and spatial correlations of weather patterns for the region with a 3-step process. Ascend applies a cascading VAR approach to maintain inter-month temperature correlations consistent with the historical data. For example, if a hot July is likely to be followed by a hot August, the cascading VAR does a superior job of capturing this effect. The application of weather simulations supports the analysis of uncertainty through hundreds of weather scenarios without the limitation of the pure historical record where extreme weather events beyond observed conditions may occur (but obviously with a low probability). The second step of the process combines these weather simulations for input into the load simulation process. PowerSimm offers the capability to weight weather stations together. Typically this is done via energy or population weighting.

PowerSimm incorporates external demand factors, scaling and shaping the simulated loads to match forecasted monthly demand and peak demand values. The simulations of electric load use a state-space modeling framework to estimate seasonal patterns, daily and hourly time series patterns, and the impact of weather. The state-space framework of PowerSimm produces unparalleled benchmark results that reflect the explained effects of weather and time-series patterns and the unexplained components of uncertainty. State-space modeling uses the regression equations to explain the variability in price as it relates to demand.

The during-delivery simulation of prices addresses the more intuitive simulations of system conditions and spot prices. System conditions of unit outages, supply stack composition, system imports and exports, and transmission outages are modeled and simulated independently of weather, but also serve as determinants to the spot price of electricity.

PowerSimm dispatch models forced outages (off-line and derates). The stochastic component of forced outage modeling captures the uncertainty in outage duration. Users can specify the maintenance schedule or elect to have PowerSimm optimize the maintenance schedule with reserve requirements observed.

Finally, PowerSimm enables users to readily perform sensitivity runs by supplying percent scaling factors to the “base” level key components of uncertainty. These sensitivity runs can be input and run in batch mode.

A.2 Simulation Engine: Overview

The analytic processes to PowerSimm reside in the SimEngine. The heart of the Simulation Engine is a Monte Carlo simulation of physical elements and market prices. The SimEngine produces Monte Carlo simulations of weather, load, market prices, and wind and solar generation. This section discusses the analytic methodology of the SimEngine and the specific model structure to simulate the following elements:

1. Weather
2. Load
3. Forward Market Prices
4. Spot Electric Prices

5. Spot Gas Prices
6. Wind and Solar Generation

A.2.1 State Space Modeling

State-space modeling in its simplest form is regression analysis with uncertainty. The uncertainty associated with regression analysis can be used to explain how weather relates to load or how yesterday's forward price relates to today's forward price. Simple regression analysis seeks to maximize the predictive capabilities of the explanatory variables on the dependent variable. An example of a simple linear regression equation is shown below and in Figure A.2.1.

$$Y = intercept + \beta X + \varepsilon$$

The regression line provides the best fit between the individual x values and maximizes the predictive value of each x observation and the dependent y variable. There exists several components of uncertainty in this equation including: i) uncertainty in the coefficient estimate β, ii) uncertainty in the residual error term ε, and iii) the covariate relationship between the uncertainty in β and the residual error. State-space modeling captures these elements of uncertainty.

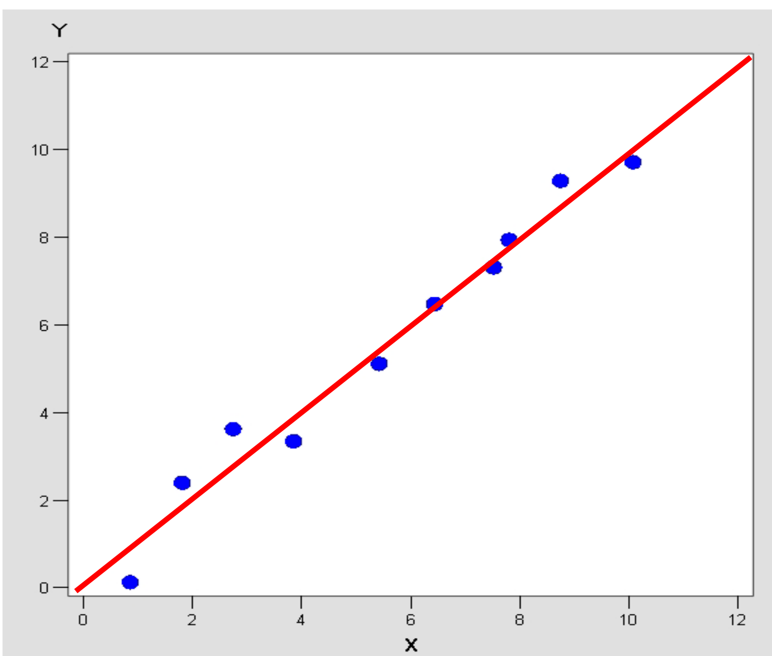


Figure A.2.1. Example of a traditional regression analysis.

For example, ten Monte Carlo simulations are shown in Figure A.2.2. The regression line is no longer completely straight because the state-space Monte Carlo simulations capture the uncertainty in the slope and add an element of random noise (i.e., residual error). The simulations also capture the covariate relationship between the uncertainty in the coefficient estimates and the residual error. By preserving the covariate relationships between the coefficients and the residual error we are able to maintain the relationship of the original data structure as we propagate results through time.

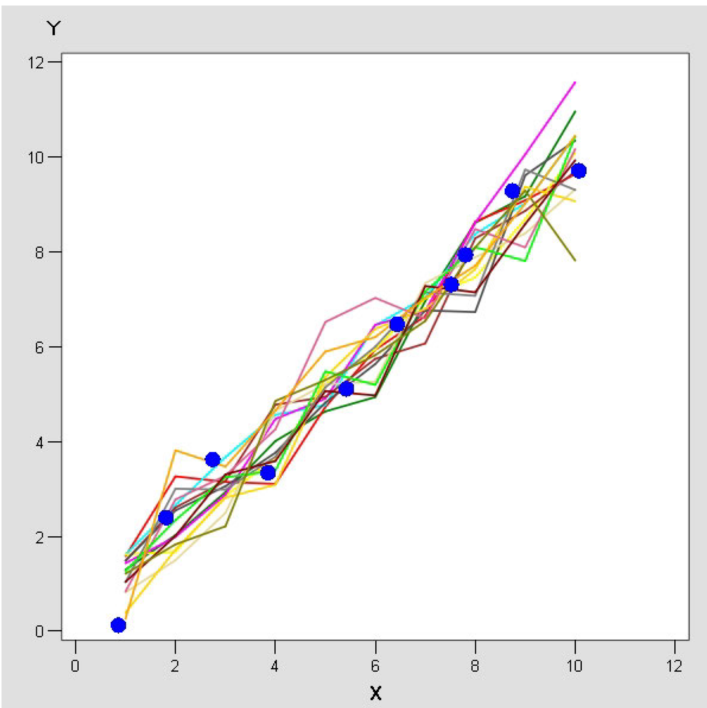


Figure A.2.2. Monte Carlo simulations.

The simulation results shown above are for a single equation, which could correspond to a utility load or a nodal price. The simulation estimates capture the effect of uncertainty in the individual parameter estimates, as well as the residual error and the covariate relationship between the uncertainty distribution in the coefficient estimates and residual error. For a system of equations, correlation effects between equations are captured through the residual error term.

In this report, state-space modeling serves as the cornerstone of uncertainty analysis. The logic of the linked physical and market relationships needs to be supported with solid benchmark results, which demonstrate the statistical match of the input values to the simulated data.

Parameter Estimation

The complexities of time series data can best be captured through the estimation of the state-space coefficients and conditional uncertainty estimates with full information maximum likelihood estimation (FIMLE). The FIMLE procedure allows for both the model estimation and the simulation of load based on perturbations of the parameter estimates that account for uncertainty of coefficient estimates and equation errors. FIMLE also accounts for the effects caused by temporal autocorrelation. For example, to accurately reproduce the distribution of load, we need to have more than weather as a stochastic variable. By introducing additional variance through the coefficients and residuals of the regression, we can more effectively simulate the realized outcome and pattern of electricity demand.

The first step is to combine the historical parameters needed for the model estimation, which include all of the variables needed for the parameters described above. Then, based on the input data, the model equation is then constructed and fit in with the parameter estimates and equation errors being stored. These estimates are then fed into a series of statements that simulate load for the next two years based on both weather simulations that are previously generated, perturbations of the parameter estimations, and equation errors. Normally, this is done in a symmetric manner where i load simulations are run on i weather simulations for a total of $2i$ simulations.

Weighting of Data

PowerSimm applies a weighting system to the input data that enables end users to adjust the emphasis of different historic events or time periods in the parameter estimation process. Each simulation module comes with a default weighting system. The default weighting system can be replaced by user-defined weights enabled through the PowerSimm user interface.

A.2.2 Weather Simulation

Understanding variability in climate data is important for accurate characterization of electricity load and price volatility. Climate dynamics are too chaotic for individual daily events to be accurately forecast. Therefore, it is often best to quantify a climate data variable on a monthly time step. Since the specific daily weather events of the upcoming months cannot be accurately anticipated, they are relegated to random phenomena within monthly probability distributions based on historical and forecasted climate data.

Though regarded as 'random' phenomena, daily weather events are correlated both in time and space. In other words, weather events observed today can influence weather events tomorrow and weather events observed in one location can be correlated with weather events in other locations. A straightforward way to represent the statistics of daily weather variations is the class of spatial-temporal models for surface weather data known as weather generators.

The purpose of a weather simulation is to provide a set of outcomes for simulated daily and hourly weather variables (e.g., daily min and max dry bulb temp) across 20 or more weather stations in the target region (e.g., Southern California). The simulation would maintain the appropriate correlation of observations among the weather stations.

In the modeling framework, weather forecasts are used as inputs to the short-term weather simulation model, but they can also be used as inputs to the long-term weather simulation model. Seasonal weather forecasts adjust the simulated mean and variance from long-run expectations to coincide with the forecast expectations. The long-run expectations are developed from historic values realized over the last 20 years. These forecasts provide a consistent set of weather realizations through Monte Carlo simulations, and are then fed into the overall simulation engine.

Analytical Scope

Weather simulation focuses on providing all weather explanatory variables used in the simulation of load. The model automatically works with the historic time series data specific to each weather station and determines the relationship between neighboring weather stations. This allows for consistent simulation of weather.

Analytical Applicability

Both Customer and System load are driven from simulated weather. Therefore, the use of weather simulation as a primary driving factor would enable a PowerSimm routine to preserve the appropriate relationship between customer load and spot prices. PowerSimm utilizes a Monte Carlo simulation whereby a specified number of equally likely events (realizations) influence a set of outcomes. These outcomes are comprised of realized weather values to capture weather for each station and the relationship to other stations in California (or the Western US).

Input Data

The core of a weather simulation engine runs on a dataset containing the requested covariates to be simulated. The data is presented in columns and sorted by date on a daily time step. This allows the engine to estimate the simultaneous and lagged correlations between all of the covariates.

Historic weather data is input into WeatherSimm through the Oracle database. (National Climate Data Center (NCDC) has been Ascend's preferred data source for historic data) Uploaded historic weather data should be consistent with the frequency of population of load data.

For long term (2+ years) simulations, trends in the historical data can be determined along with long-term weather forecast predictions made by groups such as the Climate Prediction Center (CPC) of the U.S. National Centers for Environmental Prediction, (NCEP) and the International Research Institute (IRI) for Climate Prediction.

Output Data

As described above, the core engine runs on a dataset where the covariates are represented by columns in a single dataset. The core engine generates an identical simulation output dataset with an additional variable that identifies the simulation number. This dataset can be restructured into any format required.

A.2.3 Load Simulation

Developing accurate electricity load simulations is critical for determining the cost of service, risks, and hedging strategies. In addition, load simulation has significant bearing on electricity prices because of the strong non-linear relationship between electricity load and prices. Traditional mathematical statistics may not be able to represent full distributions of load. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with simulated weather parameters. The combination of weather and load simulations provides a unified simulation process that can be used to estimate the potential long-term load.

Input Data

All load simulations are based on historical actual hourly load values. Projected economic/load growth input variables can also be applied, when available. For utility or large customer load, a minimum of one year of historic data is required. External load forecasts can be applied to create the expected value of load forecasts. External forecasts can be in the form of either monthly demand or a specified 8760 load stream. These forecasted values become the expected value of the simulated load.

Output Data

The output data is identical to the hourly historic input load dataset except that it includes the requested number of load simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

Model Specification

The simulation of electric load captures the uncertainty in electricity demand through the PowerSimm module LoadSimm. Variation in electricity load can be broken down into three structural components:

- Calendar aspects of ‘load shapes’ both on an hourly and daily basis,
- Weather parameters that influence load,
- Temporal autocorrelation within load.

The structural components of load include hour of day (HOD) and day of week (DOW) load shapes, and interaction between HOD and DOW. Holidays, seasonal trends, and long-term growth predictions are also important components, but the main explanatory factor for load is weather. An example of this simulated relationship is shown in Figure A.2.3. The current model structure simulates system and utility load.

Temporal autocorrelation within load allows for temporally correlated errors to be modeled with more detail. This takes into account the temporal correlation in the model estimation.

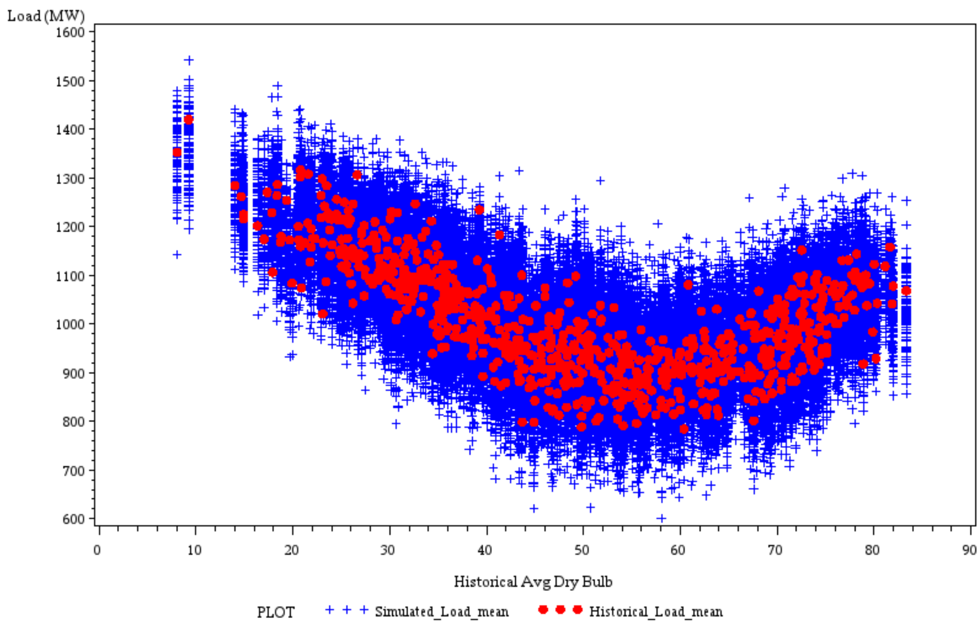


Figure A.2.3. Simulated and historical load and weather data.

A.2.4 Forward Prices

PowerSimm simultaneously simulates multiple strips of forward curves into the future where parameters for the stochastic processes and the covariate factors are estimated from historic data. PowerSimm builds a system of simultaneous equations that captures the stochastic component of each individual forward contract and the covariate relationship between neighboring contract months, other commodities, and other factors (such as interest rates and exchange rates). The state-space modeling framework satisfies the criteria for developing a “Cash Flow at Risk” solution by producing simulations of prices that are realistic, benchmark well to historic data, and produce a payoff of cash flows consistent with market option quotes at multiple strike prices. The consistency of simulated prices with market expectations remains the principal benchmark criteria for forward market simulations.

Input Data

PowerSimm requires a history of forward price quotes for each delivery month to simulate market prices into the future.

Output Data

PowerSimm outputs simulations of forward quotes to expiration for each contract. The simulations can be run on either a daily time step or a single time step until expiration. The simulation of forward prices produces a large number of simulated values. The reporting of these values is presented in terms of summary statistics that can be viewed in the standard output reports, which focus on the mean, 5th, and 95th percentile of simulation results.

Model Specification

The simulation of forward prices follows a state-space modeling framework. The correlation structure between each contract is preserved through a covariance matrix that maintains the covariate movements in uncertainty for different contracts and between different commodities. As a base simulation assumption, PowerSimm creates convergence between the initial forward price and the final forward price. PowerSimm also has the ability to weight the historic data used in the parameter estimation process to give more weight to more recent events and to reduce the leverage factor associated with outlier events.

A.2.5 Spot Electric Prices

Relationships between fundamental variables and electricity prices are measured from historic data. The simulated variables of load, hydro generation, imports/exports, reserve margins, supply stack, and gas prices are then used as explanatory variables for electricity prices through a structural state space model.

Within SimEngine, the process culminates in the simulation of spot electricity prices. Spot electricity prices preserve the weather, load, and price relationships that govern electric market price formation. The simulation inputs consist of the following modules:

- WeatherSimm
- LoadSimm
- HydroSimm
- TransSimm/Imports/Exports
- Gas Price Simulation Engine

These modules produce explanatory variables for electric spot market prices. Each simulation trajectory for heavy load (HL) and light load (LL) spot electric prices for each month are scaled to the final evolved forward price for electricity. The simulated daily HL and LL values are then further decomposed into hourly values with a state-space time series model.

The hourly-simulated values of load, price, and congestion flows are then input into economic dispatch and hedge payoff processes. The final simulated values are then written to the Results Database.

Input Data

The input data consists of the following (with the optional explanatory variables notes in parentheses following the data element):

- Historic hourly load data
- Historic hourly or daily hydro generation
- Daily gas prices
- Transmission imports and exports (optional)
- Daily reserve margins (optional)
- Supply stack characteristics (optional)

Output Data

SimEngine produces simulation of daily HL and LL electric prices and hourly spot electric prices. Summary statistics can be viewed in the standard output reports, which focus on the mean, 5th, and 95th percentile simulation results.

Methodology and Model Specification

The application of the fundamental drivers of electricity has influence on the daily and hourly formation of prices over both the intermediate and long-term prices. Over the intermediate term, daily HL and LL electricity prices are simulated so that the mean distribution of daily prices converges with the final evolved forward price.

Regional electricity prices are primarily a function of daily gas prices and daily reserve margins. Each variable explains about 50% of the variability in prices and jointly they explain about 90% of the variability

The simulation of electricity prices follows the simulation of the exogenous variables that jointly explain electricity prices. These variables include gas prices and load and may also include unit outages, capacity, supply stack characteristics, hydro generation, imports, and exports. The variables load, unit outages, capacity, imports, and exports are factored directly into the calculation of daily reserve margins.

The simulated values for price are conditional upon the path-dependent weather and load simulations. The mean or median of the realized daily HL and LL spot prices are bucketed into monthly time steps and scaled to be centered around the monthly forward price.

A.2.6 Spot Gas Prices

Developing accurate spot gas price simulations is critical for determining the cost of service, risks, and hedging strategies. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with exogenous system shocks such as extreme weather events. The combination of market electric prices and spot gas prices is critical to accurately capturing the cost of generation and driving dispatch of generation assets.

Input Data

Estimation of the parameters to simulated spot gas prices utilizes input of historical gas spot prices, weather, and daily HL and LL electric prices. The simulated weather is input into the model on a simulation basis.

Output Data

The output data is identical to the daily historic input dataset except that it includes the requested number of spot price simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

SimEngine produces daily spot gas price simulations over the forecast horizon. The summary statistics can be viewed in the standard output reports, which focus on the mean, 5^{th}, and 95^{th} percentile simulation results.

A.2.7 Wind and Solar Generation

Developing accurate wind and/or solar generation simulations is critical for determining cost of service, risks, hedging strategies, and for estimating the relationship between the explanatory variables and price. Traditional mathematical statistics may not be able to represent full distributions of such generation. A simulation approach is advantageous where a specified number of likely events (realizations) can be used in conjunction with simulated weather parameters. The combination of weather and wind/solar generation simulations provides a unified simulation process that can be used to estimate the relationship between wind/solar production, electricity demand, and market prices.

Input Data

WindSimm requires input of historical hourly wind or solar generation. For new assets, the estimated hourly data is used for input values.

Output Data

The output data is identical to the hourly historic input wind/solar generation dataset except that it includes the requested number of simulations for the requested simulation length. This dataset also includes the simulation date and time update along with a link table to describe the parameters used to run the simulation.

WindSimm produces simulations of hourly wind/solar generation over the forecast horizon. WindSimm summary statistics can be viewed in the standard output reports, which focus on the mean, 5^{th}, and 95^{th} percentile simulation results.

Methodology and Model Specification

Variation in wind/solar generation can be broken down into three structural components:

- Calendar aspects of 'generation shapes' both on an hourly and daily basis
- Weather parameters that influence generation
- Temporal autocorrelation within the generation data

The structural components of wind/solar generation include hour of day (HOD) and seasonal trends. The relationship between generation and electric load is maintained by using temperature as an explanatory factor.

Integration of these components into a modeling framework requires that the significant interactions among the components be taken into account. Weather parameters impact hourly and daily generation profiles depending on the HOD. There are also differences in the temporal autocorrelation contingent on seasonality. The combination of these main effects and their significant interactions can be used to accurately simulate generation.

WindSimm has three main components that influence changes in wind/solar generation. The first is the structural components that develop the 'production shapes' both on hourly and daily basis marked with bold fonts. The second is the weather variables that influence generation. The third is the temporal autocorrelation observed in the generation data. Beyond these main effects, there are significant interactions between these components that are incorporated for model accuracy.

A.3 Generation Dispatch

In PowerSimm, units are dispatched against multiple simulation sets of price, load and emissions, allowing for a distribution of outcomes. The core dispatch routine is based on a deterministic dynamic program-type model with backward and forward passes.

The setup configuration for Dispatch can be modified to maximize granularity and realism of unit operation or to maximize processing speed. Dispatch can also run autonomously from PowerSimm for short-term and high-granularity dispatch simulations. Greater speed can be achieved through simplifying unit characteristics and/or increasing the size of the simulation time step (e.g., from hourly to 4-hourly time step size).

Generation units are economically dispatched by finding the sequence of states for the unit hour-by-hour that maximizes the Total Net Revenue (Total Gross Revenue – Total Production Costs). Even when a collection of units is being dispatched to serve native load, it is treated as being dispatched economically, subject to a constraint condition: the overall portfolio of units should minimize the cost of production while maximizing revenue (if any) and subject to the condition that native load is serviced.

In addition to serving native load, units may also be constrained by a maximum number of starts in a month or how much of a specific emission they can generate. To enforce these constraints, penalties are added to the Net Revenue equation. These "economic" penalties and incentives do not show up in the final report on Costs and Net Revenue; they are simply used to satisfy the constraints. This modified Net Revenue equation represents the new objective function. The mathematical problem of dispatch is to maximize the cumulative total value expressed by this function.

Peak-period and seasonal unit characteristic changes are handled by identifying a unit. When unit characteristics change radically between seasons, the dispatch may be split into separate blocks; effectively modeling the different blocks as separate units and then splicing their results.

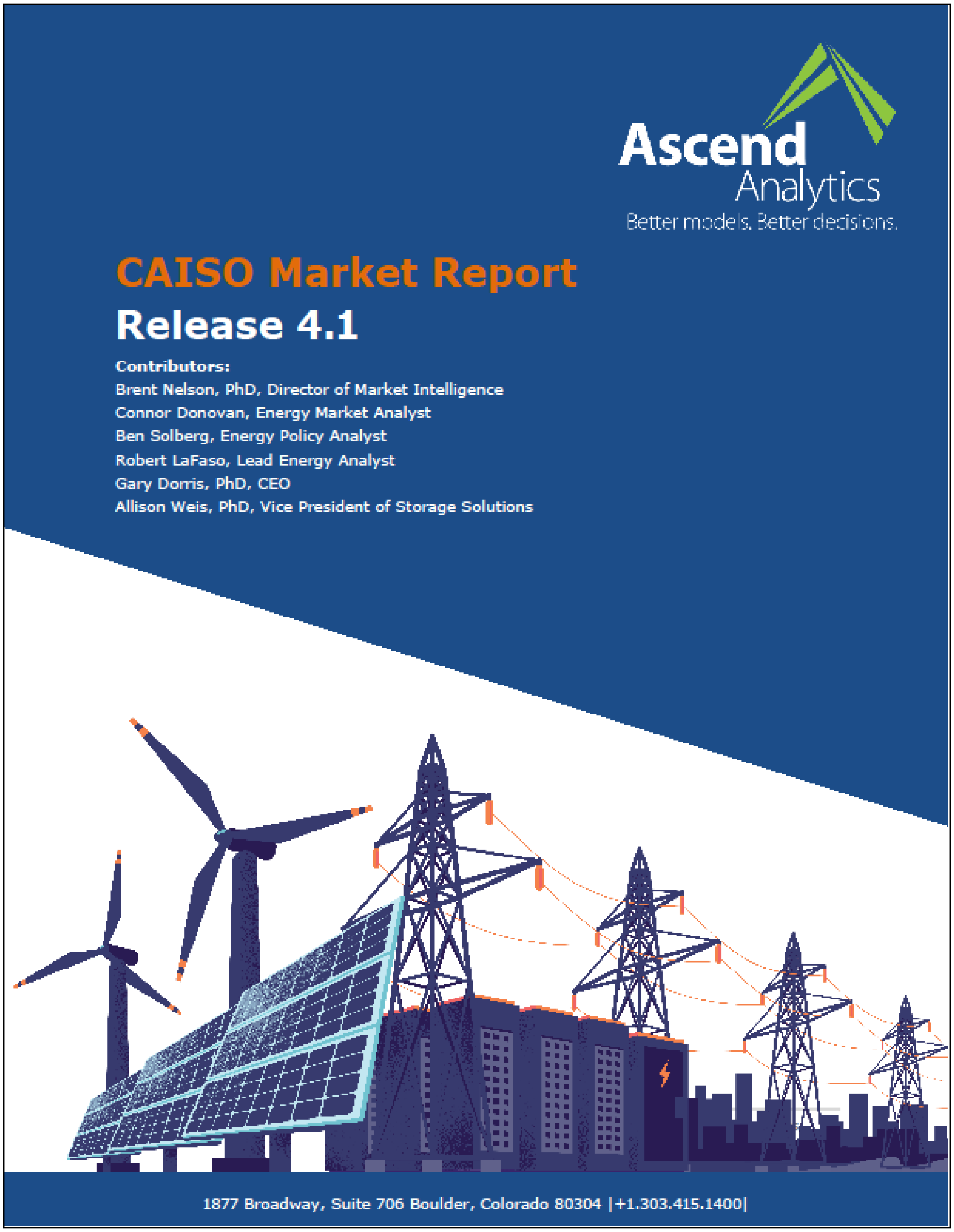
Planned outages are represented by assigning large negative objective function values to all "ON" states for the outage period. Partial Planned Outages act in the same manner, but are restricted to generation levels beyond the specified threshold. Unplanned or Forced outages are deemed to take the unit operator "by surprise". Unplanned outages are generated via random simulation.

Certain operational constraints (such as total generation limits, maximum starts, and emissions) involve iterative dispatch simulations using different adjustments to the objective function. The iterative dispatch loop seeks to obtain the minimum objective function adjustments that result in a dispatch result that obeys the conditions of the constraint. Startup/shutdown time, minimum run time, minimum down time and fuel switching constraints are all handled directly through the state-to-state mapping tables rather than through the objective function.

Finally, the PowerSimm dispatch engine can be configured to produce portfolio asset and dispatch simulations at the hourly granularity for one month to twenty-five (25) years into the future. The end-user can specify the number of simulations, the time step granularity, the generation asset portfolio, multiple portfolio constraints and stress test scenarios, and the degree of detail in the output data tables. All output data is delivered via the OLAP cube into Excel pivot-tables; these tables can then be further customized and modified by the end-user, to meet specific reporting and/or computational applications.

APPENDIX B

Ascend Analytics CAISO Market Report Release 4.1



APPENDIX C

Chapter 14: Avoided Cost of Energy (ACOE) Worksheets

ACOE Worksheet (for avoided energy due to EE savings)

kW/h:	1.0
Calendar Year:	2024
EE Type:	Baseload (Residential)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly kW Peak reduction Prob:	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Seasonal weighting of avoided kWh:	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833
Assumed annual hours of operation:	5,694.0											
Annual kWh Output:	5,694.0	CF:	65.0%									
Energy Credit												
SP15 Flat Power Price - 2024 ($/MWh)	$87.22	$76.43	$49.41	$39.58	$32.41	$51.18	$82.98	$100.15	$79.34	$56.24	$63.13	$89.68
$/kWh-month credit:	$41.37	$36.25	$23.44	$18.77	$15.37	$24.28	$39.36	$47.50	$37.63	$26.68	$29.94	$42.54
Annual kWh credit:	$383.12											
kWh value:	$0.0673											
System Capacity Credit												
Monthly RA ratios:	0.150	0.150	0.200	0.300	0.500	1.200	2.600	2.800	2.600	1.100	0.250	0.150
$/kW-month value:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
$/kW-month credit:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
Annual kW credit:	$120.00											
kWh value:	$0.0211										RA cost ($/kW-year):	$120.00

Additional Local Capacity Credit

$/kW-year value:	$30.00 (annual additional cost for Local RA benefits)
kW reduction /MWh production factor:	0.0925
Annual kW credit:	$15.80
kWh value:	$0.0028

Ancillary Services Credit

			CY 2021	CY 2022
Annual kWh credit:	$5.32	Total AS uplift costs ($):	$1,701,734	$2,559,936
kWh value:	$0.0009	Wholesale System Load (MWh):	2,246,814	2,317,573
		Implied $/MWh credit:	$0.93	

Environmental (Carbon) Credit

			Nov-22	Feb-23	May-23	Aug-23
Annual kWh credit:	$60.72	Carbon Clearing Price (last 4 ARB Auctions):	$26.80	$27.85	$30.33	$35.20
kWh value:	$0.0107	RPU - PSD emission factors:	2021 EF:	0.3670	2022 EF:	0.3429
		Implied $/MWh credit:	$10.66			

RPS Credit

Annual kWh credit:	$50.11	$/MWh RPS Credit (PCC-1):	$20.00
kWh value:	0.0088	2024 Target RPS:	44.00%
		Implied $/MWh credit:	$8.80

Transmission Credit (ISO TAC Rate)

Annual kWh credit:	$82.08	2022 TAC Rate ($/MWh)
kWh value:	0.0144	$14.4157

Sum of Credits ($/kWh):	$0.1259
Annual $ Value per installed kW:	$717.15
Distribution Loss Factor Adjustment	5.40%
Loss Component (kWh value):	$0.0072
Loss Adjusted kWh value:	$0.1331
Loss Adjusted Annual $ Value:	$758.09
$/kWh Value of EE:	**$0.1331** ← implied value to RPU for avoided load from EE
Annual $ Value per installed kW EE:	**$758.09**

ACOE Worksheet (for avoided energy due to EE savings)

kW/h: 1.0
Calendar Year: 2024
EE Type: Lighting (Residential)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly kW Peak reduction Prob:	1.000	0.961	0.885	0.808	0.770	0.731	0.731	0.770	0.808	0.885	0.961	1.000
Seasonal weighting of avoided kWh:	0.0970	0.0933	0.0858	0.0784	0.0746	0.0709	0.0709	0.0746	0.0784	0.0858	0.0933	0.0970
Assumed annual hours of operation:	3,066.0											
Annual kWh Output:	3,066.0	**CF:**	35.0%									
Energy Credit												
SP15 LL Power Price - 2024 ($/MWh)	$84.00	$77.00	$53.75	$45.85	$37.55	$47.35	$68.55	$82.35	$59.95	$55.40	$63.05	$88.15
$/kWh-month credit:	$24.98	$22.03	$14.14	$11.02	$8.59	$10.29	$14.90	$18.84	$14.41	$14.57	$18.04	$26.22
Annual kWh credit:	$198.02											
kWh value:	$0.0646											
System Capacity Credit												
Monthly RA ratios:	0.150	0.150	0.200	0.300	0.500	1.200	2.600	2.800	2.600	1.100	0.250	0.150
$/kW-month value:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
$/kW-month credit:	$1.50	$1.44	$1.77	$2.42	$3.85	$8.77	$19.01	$21.56	$21.01	$9.74	$2.40	$1.50
Annual kW credit:	$94.97											
kWh value:	$0.0310										**RA cost ($/kW-year):**	$120.00
Additional Local Capacity Credit												
$/kW-year value:	$30.00	(annual additional cost for Local RA benefits)										
kW reduction /MWh production factor:	0.0925											
Annual kW credit:	$8.51											
kWh value:	$0.0028					**CY 2021**	**CY 2022**					
Ancillary Services Credit					**Total AS uplift costs ($):**	$1,701,734	$2,559,936					
Annual kWh credit:	$2.86				**Wholesale System Load (MWh):**	2,246,814	2,317,573					
kWh value:	$0.0009				**Implied $/MWh credit:**	$0.93						
						Nov-22	**Feb-23**	**May-23**	**Aug-23**			
Environmental (Carbon) Credit					**Carbon Clearing Price (last 4 ARB Auctions):**	$26.80	$27.85	$30.33	$35.20			
Annual kWh credit:	$32.70				**RPU - PSD emission factors:**	**2021 EF:**	0.3670	**2022 EF:**	0.3429			
kWh value:	$0.0107				**Implied $/MWh credit:**	$10.66						
RPS Credit					**$/MWh RPS Credit (PCC-1):**	$20.00						
Annual kWh credit:	$26.98				**2024 Target RPS:**	44.00%						
kWh value:	0.0088				**Implied $/MWh credit:**	$8.80						
Transmission Credit (ISO TAC Rate)												
Annual kWh credit:	$44.20					**2022 TAC Rate ($/MWh)**						
kWh value:	0.0144					$14.4157						
Sum of Credits ($/kWh):	$0.1331											
Annual $ Value per installed kW:	$408.24											
Distribution Loss Factor Adjustment	5.40%											
Loss Component (kWh value):	$0.0076											
Loss Adjusted kWh value:	$0.1408											
Loss Adjusted Annual $ Value:	$431.54											
$/kWh Value of EE:	**$0.1408**		**← implied value to RPU for avoided load from EE**									
Annual $ Value per installed kW EE:	**$431.54**											

ACOE Worksheet (for avoided energy due to EE savings)

kW/h:	1.0
Calendar Year:	2024
EE Type:	HVAC (Residential)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly kW Peak reduction Prob:	0.411	0.283	0.192	0.134	0.253	0.586	0.940	1.000	0.673	0.268	0.154	0.327
Seasonal weighting of avoided kWh:	0.0788	0.0541	0.0367	0.0256	0.0486	0.1122	0.1802	0.1916	0.1289	0.0513	0.0294	0.0626
Assumed annual hours of operation:	1,752.0											
Annual kWh Output:	1,752.0	CF:	20.0%									
Energy Credit												
SP15 HL Power Price - 2024 ($/MWh)	$89.75	$76.00	$46.00	$35.00	$28.35	$54.25	$94.35	$113.00	$96.30	$56.85	$63.20	$91.00
$/kWh-month credit:	$12.39	$7.20	$2.96	$1.57	$2.41	$10.66	$29.79	$37.93	$21.75	$5.11	$3.26	$9.98
Annual kWh credit:	$145.01											
kWh value:	$0.0828											
System Capacity Credit												
Monthly RA ratios:	0.150	0.150	0.200	0.300	0.500	1.200	2.600	2.800	2.600	1.100	0.250	0.150
$/kW-month value:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
$/kW-month credit:	$0.62	$0.42	$0.38	$0.40	$1.27	$7.03	$24.44	$28.00	$17.50	$2.95	$0.39	$0.49
Annual kW credit:	$83.89											
kWh value:	$0.0479										RA cost ($/kW-year):	$120.00

Additional Local Capacity Credit

$/kW-year value:	$30.00 (annual additional cost for Local RA benefits)
kW reduction /MWh production factor:	0.0925
Annual kW credit:	$4.86
kWh value:	$0.0028

Ancillary Services Credit

			CY 2021	CY 2022
Annual kWh credit:	$1.64	Total AS uplift costs ($):	$1,701,734	$2,559,936
kWh value:	$0.0009	Wholesale System Load (MWh):	2,246,814	2,317,573
		Implied $/MWh credit:	$0.93	

Environmental (Carbon) Credit

			Nov-22	Feb-23	May-23	Aug-23
		Carbon Clearing Price (last 4 ARB Auctions):	$26.80	$27.85	$30.33	$35.20
Annual kWh credit:	$18.68	RPU - PSD emission factors:	2021 EF:	0.3670	2022 EF:	0.3429
kWh value:	$0.0107	Implied $/MWh credit:	$10.66			

RPS Credit

		$/MWh RPS Credit (PCC-1):	$20.00
Annual kWh credit:	$15.42	2024 Target RPS:	44.00%
kWh value:	0.0088	Implied $/MWh credit:	$8.80

Transmission Credit (ISO TAC Rate)

Annual kWh credit:	$25.26	2022 TAC Rate ($/MWh)
kWh value:	0.0144	$14.4157

Sum of Credits ($/kWh):	$0.1682
Annual $ Value per installed kW:	$294.75
Distribution Loss Factor Adjustment	5.40%
Loss Component (kWh value):	$0.0096
Loss Adjusted kWh value:	$0.1778
Loss Adjusted Annual $ Value:	$311.58

$/kWh Value of EE:	**$0.1778**	← implied value to RPU for avoided load from EE
Annual $ Value per installed kW EE:	**$311.58**	

ACOE Worksheet (for avoided energy due to EE savings)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
kW/h:	1.0											
Calendar Year:	2024											
EE Type:	Baseload (Comm/Indst)											
Monthly kW Peak reduction Prob:	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Seasonal weighting of avoided kWh:	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833
Assumed annual hours of operation:	6,570.0											
Annual kWh Output:	6,570.0	CF:	75.0%									
Energy Credit												
SP15 Flat Power Price - 2024 ($/MWh)	$87.22	$76.43	$49.41	$39.58	$32.41	$51.18	$82.98	$100.15	$79.34	$56.24	$63.13	$89.68
$/kWh-month credit:	$47.73	$41.83	$27.04	$21.66	$17.74	$28.01	$45.41	$54.81	$43.42	$30.78	$34.55	$49.08
Annual kWh credit:	$442.07											
kWh value:	$0.0673											
System Capacity Credit												
Monthly RA ratios:	0.150	0.150	0.200	0.300	0.500	1.200	2.600	2.800	2.600	1.100	0.250	0.150
$/kW-month value:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
$/kW-month credit:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
Annual kW credit:	$120.00											
kWh value:	$0.0183										RA cost ($/kW-year):	$120.00
Additional Local Capacity Credit												
$/kW-year value:	$30.00	(annual additional cost for Local RA benefits)										
kW reduction /MWh production factor:	0.0925											
Annual kW credit:	$18.23											
kWh value:	$0.0028											
						CY 2021	CY 2022					
Ancillary Services Credit					Total AS uplift costs ($):	$1,701,734	$2,559,936					
Annual kWh credit:	$6.13				Wholesale System Load (MWh):	2,246,814	2,317,573					
kWh value:	$0.0009				Implied $/MWh credit:	$0.93						
						Nov-22	Feb-23	May-23	Aug-23			
Environmental (Carbon) Credit					Carbon Clearing Price (last 4 ARB Auctions):	$26.80	$27.85	$30.33	$35.20			
Annual kWh credit:	$70.07				RPU - PSD emission factors:	2021 EF:	0.3670	2022 EF:	0.3429			
kWh value:	$0.0107				Implied $/MWh credit:	$10.66						
RPS Credit					$/MWh RPS Credit (PCC-1):	$20.00						
Annual kWh credit:	$57.82				2024 Target RPS:	44.00%						
kWh value:	0.0088				Implied $/MWh credit:	$8.80						
Transmission Credit (ISO TAC Rate)												
Annual kWh credit:	$94.71					2022 TAC Rate ($/MWh)						
kWh value:	0.0144					$14.4157						
Sum of Credits ($/kWh):	$0.1231											
Annual $ Value per installed kW:	$809.02											
Distribution Loss Factor Adjustment	5.40%											
Loss Component (kWh value):	$0.0070											
Loss Adjusted kWh value:	$0.1302											
Loss Adjusted Annual $ Value:	$855.20											
$/kWh Value of EE:	**$0.1302**		← implied value to RPU for avoided load from EE									
Annual $ Value per installed kW EE:	**$855.20**											

ACOE Worksheet (for avoided energy due to EE savings)

kW/h:	1.0
Calendar Year:	2024
EE Type:	Lighting (Comm/Indst)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly kW Peak reduction Prob:	1.000	0.961	0.885	0.808	0.770	0.731	0.731	0.770	0.808	0.885	0.961	1.000
Seasonal weighting of avoided kWh:	0.0970	0.0933	0.0858	0.0784	0.0746	0.0709	0.0709	0.0746	0.0784	0.0858	0.0933	0.0970

Assumed annual hours of operation:	5,694.0		
Annual kWh Output:	5,694.0	**CF:**	65.0%

Energy Credit

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
SP15 Flat Power Price - 2024 ($/MWh)	$87.22	$76.43	$49.41	$39.58	$32.41	$51.18	$82.98	$100.15	$79.34	$56.24	$63.13	$89.68
$/kWh-month credit:	$48.17	$40.60	$24.14	$17.67	$13.77	$20.66	$33.50	$42.54	$35.42	$27.48	$33.54	$49.53
Annual kWh credit:	$387.02											
kWh value:	$0.0680											

System Capacity Credit

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly RA ratios:	0.150	0.150	0.200	0.300	0.500	1.200	2.600	2.800	2.600	1.100	0.250	0.150
$/kW-month value:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
$/kW-month credit:	$1.50	$1.44	$1.77	$2.42	$3.85	$8.77	$19.01	$21.56	$21.01	$9.74	$2.40	$1.50
Annual kW credit:	$94.97											
kWh value:	$0.0167										**RA cost ($/kW-year):**	$120.00

Additional Local Capacity Credit

$/kW-year value:	$30.00 (annual additional cost for Local RA benefits)
kW reduction /MWh production factor:	0.0925
Annual kW credit:	$15.80
kWh value:	$0.0028

Ancillary Services Credit

			CY 2021	CY 2022
Annual kWh credit:	$5.32	**Total AS uplift costs ($):**	$1,701,734	$2,559,936
kWh value:	$0.0009	**Wholesale System Load (MWh):**	2,246,814	2,317,573
		Implied $/MWh credit:	$0.93	

Environmental (Carbon) Credit

			Nov-22	Feb-23	May-23	Aug-23
		Carbon Clearing Price (last 4 ARB Auctions):	$26.80	$27.85	$30.33	$35.20
Annual kWh credit:	$60.72	**RPU - PSD emission factors:**	**2021 EF:**	0.3670	**2022 EF:**	0.3429
kWh value:	$0.0107	**Implied $/MWh credit:**	$10.66			

RPS Credit

		$/MWh RPS Credit (PCC-1):	$20.00
Annual kWh credit:	$50.11	**2024 Target RPS:**	44.00%
kWh value:	0.0088	**Implied $/MWh credit:**	$8.80

Transmission Credit (ISO TAC Rate)

Annual kWh credit:	$82.08	**2022 TAC Rate ($/MWh)**
kWh value:	0.0144	$14.4157

Sum of Credits ($/kWh):	$0.1222
Annual $ Value per installed kW:	$696.01
Distribution Loss Factor Adjustment	5.40%
Loss Component (kWh value):	$0.0070
Loss Adjusted kWh value:	$0.1292
Loss Adjusted Annual $ Value:	$735.74

$/kWh Value of EE:	**$0.1292**	**← implied value to RPU for avoided load from EE**
Annual $ Value per installed kW EE:	**$735.74**	

ACOE Worksheet (for avoided energy due to EE savings)

kW/h:	1.0
Calendar Year:	2024
EE Type:	HVAC (Comm/Indst)

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly kW Peak reduction Prob:	0.411	0.283	0.192	0.134	0.253	0.586	0.940	1.000	0.673	0.268	0.154	0.327
Seasonal weighting of avoided kWh:	0.0788	0.0541	0.0367	0.0256	0.0486	0.1122	0.1802	0.1916	0.1289	0.0513	0.0294	0.0626
Assumed annual hours of operation:	2,628.0											
Annual kWh Output:	2,628.0	CF:	30.0%									
Energy Credit												
SP15 HL Power Price - 2024 ($/MWh)	$89.75	$76.00	$46.00	$35.00	$28.35	$54.25	$94.35	$113.00	$96.30	$56.85	$63.20	$91.00
$/kWh-month credit:	$18.59	$10.81	$4.44	$2.35	$3.62	$16.00	$44.68	$56.90	$32.62	$7.66	$4.88	$14.97
Annual kWh credit:	$217.52											
kWh value:	$0.0828											
System Capacity Credit												
Monthly RA ratios:	0.150	0.150	0.200	0.300	0.500	1.200	2.600	2.800	2.600	1.100	0.250	0.150
$/kW-month value:	$1.50	$1.50	$2.00	$3.00	$5.00	$12.00	$26.00	$28.00	$26.00	$11.00	$2.50	$1.50
$/kW-month credit:	$0.62	$0.42	$0.38	$0.40	$1.27	$7.03	$24.44	$28.00	$17.50	$2.95	$0.39	$0.49
Annual kW credit:	$83.89											
kWh value:	$0.0319										RA cost ($/kW-year):	$120.00

Additional Local Capacity Credit

$/kW-year value:	$30.00 (annual additional cost for Local RA benefits)
kW reduction /MWh production factor:	0.0925
Annual kW credit:	$7.29
kWh value:	$0.0028

Ancillary Services Credit

Annual kWh credit:	$2.45
kWh value:	$0.0009

	CY 2021	CY 2022
Total AS uplift costs ($):	$1,701,734	$2,559,936
Wholesale System Load (MWh):	2,246,814	2,317,573
Implied $/MWh credit:	$0.93	

Environmental (Carbon) Credit

Annual kWh credit:	$28.03
kWh value:	$0.0107

	Nov-22	Feb-23	May-23	Aug-23
Carbon Clearing Price (last 4 ARB Auctions):	$26.80	$27.85	$30.33	$35.20
RPU - PSD emission factors:	2021 EF:	0.3670	2022 EF:	0.3429
Implied $/MWh credit:	$10.66			

RPS Credit

Annual kWh credit:	$23.13
kWh value:	0.0088

$/MWh RPS Credit (PCC-1):	$20.00
2024 Target RPS:	44.00%
Implied $/MWh credit:	$8.80

Transmission Credit (ISO TAC Rate)

Annual kWh credit:	$37.88
kWh value:	0.0144

2022 TAC Rate ($/MWh)
$14.4157

Sum of Credits ($/kWh):	$0.1523
Annual $ Value per installed kW:	$400.19
Distribution Loss Factor Adjustment	5.40%
Loss Component (kWh value):	$0.0087
Loss Adjusted kWh value:	$0.1610
Loss Adjusted Annual $ Value:	$423.03
$/kWh Value of EE:	**$0.1610** ← implied value to RPU for avoided load from EE
Annual $ Value per installed kW EE:	**$423.03**