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CITY OF RIVERSIDE
PUBLIC UTILITIES

2018 INTEGRATED RESOURCE PLAN

RESOURCE OPERATIONS &
STRATEGIC ANALYTICS DIVISION

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City of Riverside

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

2018 Integrated Resource Plan

September 26, 2018

Riverside Public Utilities

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Executive Summary

This *2018 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 cost of service. Both current and proposed supply-side and demand-side resources are examined in detail over a 20 year time horizon, along with strategies for adhering to a diverse set of state and regional legislative/regulatory mandates. Additionally, this 2018 IRP examines a number of related longer range planning activities, including energy storage, rate design, transportation electrification, distributed energy resources, and Riverside Public Utilities (RPU) current and future planned engagement with disadvantaged communities.

More specifically, this IRP addresses six primary goals, which can be broadly summarized as follows.

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

2. 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.

3. 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).

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

5. To examine and analyze certain critical longer term power resource procurement strategies and objectives, specifically those that could help RPU reach its 2030 carbon reduction goals, and quantify how such strategies and objectives impact the utility's future cost-of-service.

6. To begin to assess how various emerging technologies may concurrently impact RPU carbon reduction goals and future cost-of-service metrics, in order 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 twenty (20) Chapters and five (5) 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 9-13), and related longer term planning activities on emerging technologies (Chapters 15-18). Additionally, Appendix A describes the production cost modeling software used to facilitate these IRP analyses, Chapter 19 describes RPU's engagement activities towards the City's disadvantaged communities, and Chapter 20 presents an overall summary of pertinent findings. The remaining Appendices describe secondary technical details associated with specific chapter analyses, respectively.

The interested reader can find brief descriptions of each chapter and appendix contained in this IRP document in the Introduction (Chapter 1). As mentioned above, succinct summaries of the most important staff findings can be found in the Conclusion (Chapter 20).

1. Introduction

1.1 The Purpose of Riverside's Integrated Resource Plan

This *2018 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 cost of service. 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 state and regional legislative/regulatory mandates. Additionally, this 2018 IRP examines a number of related longer range planning activities, including energy storage, rate design, transportation electrification, distributed energy resources, 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 process of planning to acquire and deliver 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 2018 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 overview of RPU (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 capacity and resource adequacy requirements, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives, and (e) cash-flow at risk metrics.

- ❖ To examine and analyze certain critical longer term power resource procurement strategies and objectives, specifically those that could help RPU reach its 2030 carbon reduction goals, and quantify how such strategies and objectives impact the utility's future cost-of-service.

- To begin to assess how various emerging technologies may concurrently impact RPU carbon reduction goals and future cost-of-service metrics, in order to better define future actions that continue to support the utility's fundamental objective of providing reliable electrical services at competitive rates.

1.2 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 fifteen 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, and has exceeded the 33% RPS by 2020 mandate three years ahead of schedule. It is worth noting that over the last five 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 1.2.1 presents more detailed justifications and rational for each guiding principle.

Table 1.2.1. 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 contract, 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 the most 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 meet 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 minimal Carbon footprints. (Note: these GHG reduction mandates essentially determine and direct California RPS goals.)
Environmental Stewardship	Every asset has some degree of environmental impact, no matter what 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 eight years RPU has embraced an active plan to significantly increase the percentage of renewable energy resources in its resource portfolio, and within the last six years RPU has signed power purchase agreements (PPA's) for ten new or existing renewable energy projects. Due to these purchases, RPU is on track to potentially serve 44% or its retail electrical load with renewable energy in 2020. Additionally, these purchases have left RPU almost "fully" resourced, at least for the intermediate term. Thus, right now the utility is primary focused on monitoring, incorporating and managing these new renewable energy resources, along with optimally positioning RPU within the broader CAISO market.

Longer term, RPU still faces some very important power supply decisions. Notably, the utility must identify and implement a more aggressive renewable (and/or carbon free) energy procurement strategy during the next decade, such that RPU can successfully reduce its carbon footprint to within the state mandated 2030 target range. Additionally, these new resources or contracts will need to concurrently provide replacement energy and capacity for the Intermountain Power Project (IPP). 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 65 MW from July 2025 through June 2027, after which the IPP contract will terminate. Thus, RPU needs to determine how to replace up to 136 MW of baseload, carbon intensive coal energy with cleaner low (or zero) carbon alternatives by the middle of the next decade.

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 publically owned and investor owned utilities to develop new ways to integrate these various technologies in an efficient manner, and in some cases even challenging the fundamental business models of certain (slow to adapt) load serving entities. 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, this latest IRP should continue to be viewed as a dynamic roadmap to help guide our potential future long term decision making process, rather than as an absolute set of static procurement recommendations.

1.3 Document Organization

The entirety of this IRP document contains twenty (20) Chapters and five (5) 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 9-13), and related longer term planning activities on emerging technologies (Chapters 15-18). Additionally, Appendix A describes the production cost modeling software used to facilitate these IRP analyses, Chapter 19 describes RPU's engagement activities towards the City's disadvantaged communities, and Chapter 20 presents an overall summary of pertinent findings. The remaining Appendices describe secondary technical details associated with specific chapter analyses, 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 staff, including the key input variables and assumptions and pertinent model statistics. This chapter also presents the baseline 2018-2037 system energy and peak demand forecasts used throughout the 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; receiving 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 how the distribution system will need to be enhanced to accommodate the integration of new technologies.

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, fundamental market equilibrium constraints and carbon price forecasts to calibrate all of the forward curve simulations for our 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) unhedged energy costs and cost-at-risk (CAR) statistics, (g) GHG emission profiles and net carbon allocation positions, and (h) five-year forward Power Resource budget estimates.

Chapter 9. GHG Emission Targets and Forecasts

The fundamental purpose of the 2018 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. This chapter examines how much RPU's total GHG footprint must change (i.e., decrease) over time to meet three different, plausible 2030 emission targets. 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 Assumptions about Current Generation Resources

Chapter 10 examines all of Riverside's existing resource contracts that are scheduled to end before December 2037. 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. Additionally, this chapter provides an extended narrative on RPU's rational and justification for exiting the IPP Repowering contract after 2027.

Chapter 11. Future Resource Adequacy Capacity Needs

Chapter 11 reviews RPU's future capacity needs for the 20-year time horizon from 2018 through 2037. 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 various CAISO Resource Adequacy (RA) paradigms, many of which are currently being revised. This chapter discussed all of these various capacity issues in detail.

Chapter 12. Assumptions about Future Low-carbon and Carbon-free Resources

Chapter 12 presents and describes a set of potential future portfolio resource additions that are consistent with RPU's long-term carbon reduction goals. By definition, most of these proposed resource additions represent carbon-free renewable resources. However, a multi-year, low-carbon seasonal energy product is also proposed and discussed, in addition to two natural gas alternatives that could be used to replace some of RPU's retiring coal energy. The acquisition of these proposed resources will allow RPU to meet or exceed the utility's 2030 emission targets, and as such will form the basis for the long-term portfolio resources studies examined in chapter 13.

Chapter 13. Long Term (20 Year Forward) Portfolio Analyses

In this chapter, seven plausible resource planning scenarios were considered to assess GHG reduction targets, RPS mandates, and capacity and energy replacement. Chapter 13 first examines the projected budgetary impacts of meeting RPU's specific GHG targets, as first defined in Chapter 9. This budgetary assessment considers both the expected values and simulated standard deviations of RPU's fully loaded cost of service over the next twenty-year time horizon. Additionally, Chapter 13 presents resource-specific net value calculations for each resource discussed in Chapter 12. These net value calculations will also facilitate a comparison to energy efficiency programs in Chapter 14.

Chapter 14: Alternative Analyses - Higher Energy Efficiency Targets

Chapter 14 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. Note that Chapter 6 summarized RPU's adopted and forecast EE targets that are included in the power supply analysis. In contrast, this chapter focusses on the costs of these programs and what the impacts are 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. Energy Storage

Chapter 15 presents a financial viability assessment of energy storage (ES) as a stand-alone utility asset. Before RPU can procure viable and cost-effective batteries as stand-alone assets, the utility must evaluate a variety of battery characteristics under specific CAISO operating requirements. To help with this evaluation, the utility retained the services of ES consulting staff at Ascend Analytics. Ascend staff performed multiple ES studies to compare annual returns on batteries ($/kWh) across battery types and across markets. This chapter describes these studies in detail and presents a general summary of findings.

Chapter 16. Retail Rate Design

In 2015, following a comprehensive strategic and financial planning effort, the City of Riverside approved the "Utility 2.0" strategic plan for Riverside Public Utilities. This policy document presents a detailed integrated plan for maintaining the physical infrastructure and financial health of the utility, and ultimately helped define RPU's new proposed electric and water rate plans. 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 some important new rate tariffs that the utility plans to introduce in 2019, as well as the newly enhanced low-income and fixed-income assistance programs.

Chapter 17. Transportation Electrification

Chapter 17 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 17 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 18. Long Term Impacts of Customer DER Penetration

While RPU prides itself on fostering and facilitating increased amounts of behind-the-meter solar PV systems, it has long been recognized that the utility's rate structures do not fully recover the costs associated with supporting and integrating such systems. In order to better understand and plan for long-term, behind-the-meter solar PV penetration trends in the domestic residential rate class, RPU hired NewGen Strategies & Solutions, LLC to analyze and model these trends over the next 20 years. Chapter 18 provides a summary of these analyses and modeling results, specifically with respect to what the default residential rate tariff should be for future RPU residential NEM customers who install solar PV systems after the utility has reached its NEM 1.0 cap of 30.2 MW of installed solar PV capacity.

Chapter 19. RPU Engagement with 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 19 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 20. Summary and Conclusions

Chapter 20 reviews and summarizes the various findings associated with the comprehensive Integrated Resource Planning activities addressed throughout this IRP document. Recommendations concerning additional studies and further investigations are 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 the derivation of (and justification for) the 1.9 CAR multiplication factor.

Appendix C.

The full 5-Year Power Resource budget template can be found in Appendix C.

Appendix D.

RPU's recently adopted 2018 RPS Procurement Policy document can be found in Appendix D.

Appendix E.

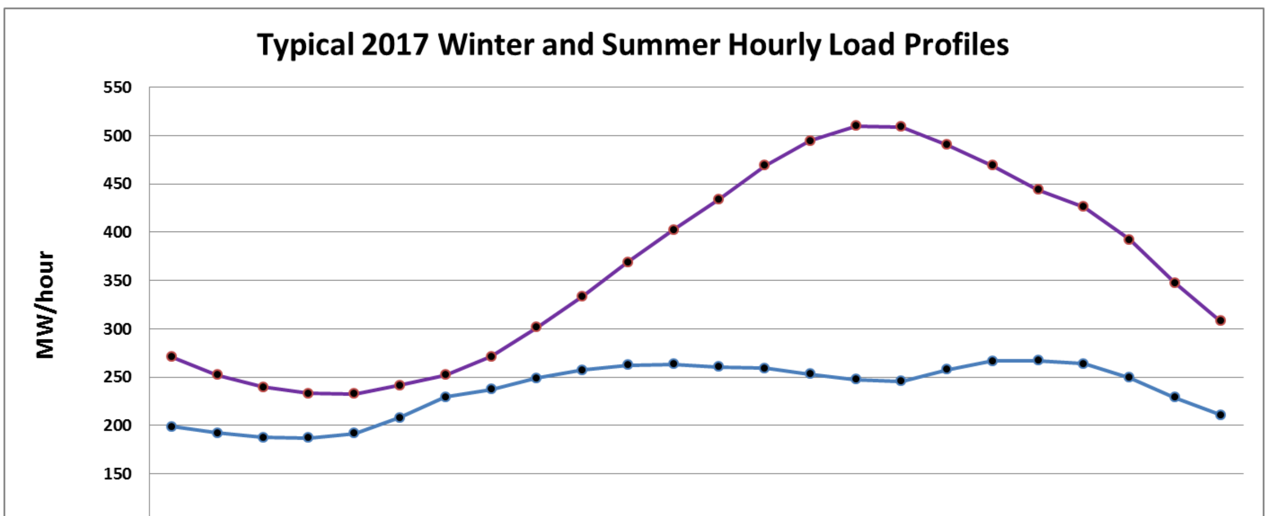
The Value of Avoided Energy (VOAE) calculations for the various RPU Energy Efficiency measures discussed in Chapter 14 are presented in Appendix E, in Tables E.1 through E.8. These tables present the calculation details for each VOAE estimate presented in this chapter.

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 2018-2037 system load and peak demand forecasts.

2.1 RPU Load Profiles

As of December 2017, RPU provided electrical service to approximately 109,300 metered customers across the City of Riverside, CA. Riverside represents a typical city in the Inland region of Southern California, in that the city experiences fairly warm summers and temperate winters. As such, the utility's loads and peaking needs are considerably higher in the summer months and much of RPU's long term planning activities revolve around meeting these needs. Figure 2.1.1 below shows hourly load profiles for typical weekdays in February and August 2017, respectively. In August, the utility expects to need about 50% more energy and 90% more capacity to meet the city's summer load serving requirements, as compared to February.



	HE01	HE02	HE03	HE04	HE05	HE06	HE07	HE08	HE09	HE10	HE11	HE12	HE13	HE14	HE15	HE16	HE17	HE18	HE19	HE20	HE21	HE22	HE23	HE24
February	199	192	188	187	192	208	230	238	249	258	263	263	261	259	253	248	246	258	267	267	264	250	229	211
August	271	252	240	233	233	242	252	271	301	333	369	403	434	469	495	510	509	490	469	444	426	392	348	308

Figure 2.1.1. Hourly system load profiles for typical 2017 weekdays in February and August.

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. Nearly all Industrial customers are billed under a time-of-use (TOU) rate. As of December 2017, RPU served approximately 97,400

Residential, 11,000 small and medium-sized Commercial and 850 Industrial customers, respectively. Notwithstanding the fact that nearly 90% of RPU's customers represent residential households, the total energy consumption by customer class is much more evenly distributed. Figure 2.1.2 shows how 2016 retail sales distributed across customer classes; it is worthwhile to note that the Industrial Customer class accounted for about 46% of total retail sales. The Residential Customer class accounted for exactly one-third of the utility's sales (33%), while Commercial customers accounted for another 20%. Miscellaneous (Other) accounts accounted for the remaining 1% of 2016 retail sales. Finally, as shown in figure 2.1.2, summer peaking needs are driven primarily by the summer AC (cooling) needs of the three customer classes, particularly the Residential customer class.

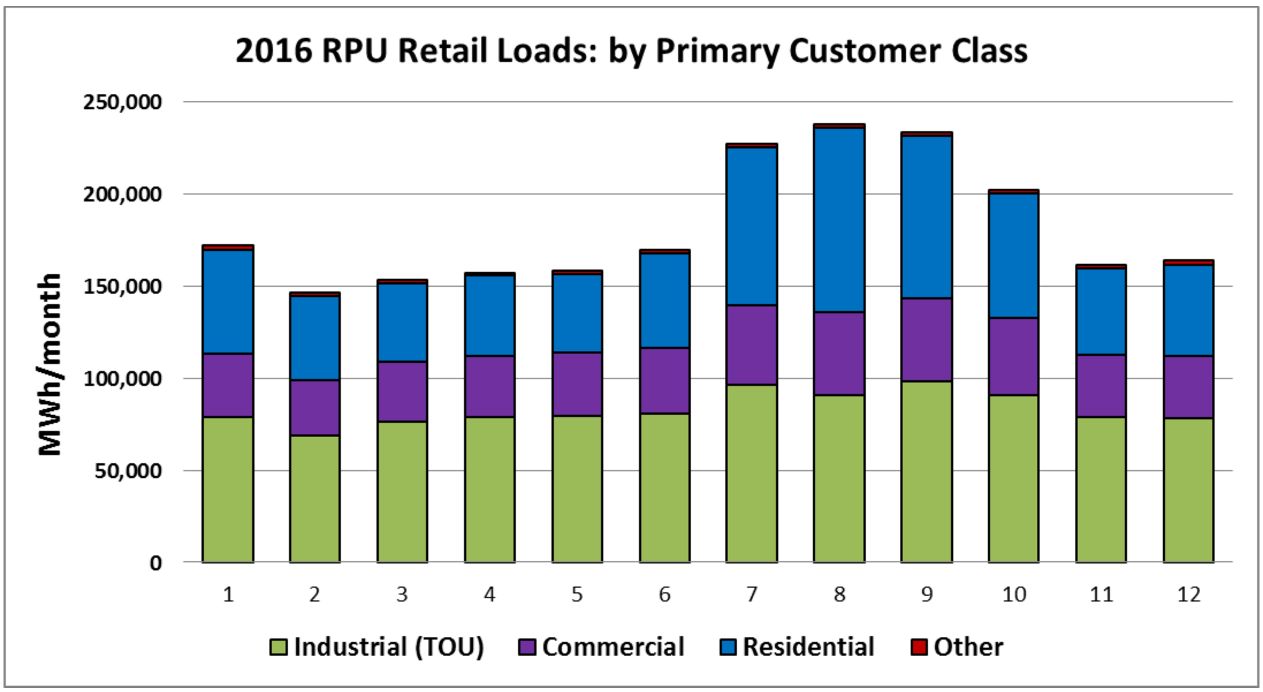


Figure 2.1.2. 2016 RPU retail sales by month and primary customer class.

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. Regression based econometric models are also used to forecast expected monthly retail loads (GWh) for each of the four primary customer classes. These models are calibrated to historical load and/or sales data extending back to January 2003. 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) an annual per capita personal income (PCPI) econometric input variable 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 the utility's measured Energy Efficiency (EE) programs, and (f) the expected net load gain due to increasing Electric Vehicle (EV) penetration levels within the RPU service territory. These models are used to project RPU wholesale gross and peak monthly loads and monthly retail sales twenty 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, RPU's current wholesale and retail forecasting models do explicitly capture and account for the effects of all active EE programs at their current funding and implementation levels, along with the impacts of customer installed solar PV distributed generation and EV penetration within the utility's service territory. This chapter describes the statistical methodology used to account for these EE, solar PV and EV effects in detail.

RPU does not currently administer any type of long-term, dispatch-able Demand Response program in its service territory. In response to the 2012 SONGS closure, 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 3 emergency situation. For large TOU customers, commercial time-of-use rate structures are used to encourage and incentivize off-peak energy use. Finally, there are no Electric Service Providers in RPU's service territory and the utility 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 based 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 the Residential, Commercial, Industrial and Other primary customer classes (GWh).

All primary monthly forecasting equations are statistically developed and calibrated to 14 years of historical monthly load data. The parameter estimates for each forecasting equation are updated every 6 to 12 months; if necessary, the functional form of each equation are updated or modified on an annual basis. Please note that this chapter only summarizes the methodology and statistical results for the monthly system load and peak forecasting equations. The monthly system load forecasting equation is described in section 2.3.1 and the system peak equation is described in section 2.3.3.

2.2.2 Input variables

The various weather, calendar, economic and structural input variables used in the monthly forecasting equations are defined in Table 2.2.1. Note that 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

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

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

Thus, two days with average temperatures of 73.3°F and 51.5°F 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 RPU's 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.

The calculations associated with each of these load and peak impact variables are described in greater detail in subsequent sections.

Finally, 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

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

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

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

Effect	Variable	Definition	Forecasting Eqns.	
			SL	SP
Economic	PCPI	Per Capita Personal Income ($1000)	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	
	SumXHD	Sum of monthly XHD's	X	
	MaxCD3	Maximum concurrent 3-day CD sum in month		X
	CDImpact	Interaction between SumCD and MaxCD3	X	X
	MaxHD	Maximum single XHD value in month		X
Structural (TOU, EE, PV,EV)	EconTOU	Expansion/contraction of New Industrial load	X	X
	Avoided_Load	Cumulative EE+PV-EV load (GWh: calculated)	X	
	Avoided_Peak	Cumulative EE+PV-EV 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 forecasts of future PCPI levels reflect the 15-year historical average for the region (i.e., approximately 2.9 % income growth per year). As previously stated, these data sets 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 historical averages; these forecasted monthly indices are shown in Table 2.2.2. Note that these average monthly values are used as weather inputs for all future time periods on/after 2018.

Table 2.2.2. Expected average values (forecast values) for future monthly weather indices; see Table 2.2.1 for weather index definitions.

Month	SumCD	SumXHD	MaxCD3	MaxHD
JAN	1.6	98.3	1.4	11.6
FEB	2.2	66.8	2.0	9.9
MAR	7.4	41.4	5.4	7.9
APR	26.8	14.4	13.9	4.6
MAY	88.7	2.1	28.2	1.1
JUN	212.1	0.1	45.5	0.1
JUL	340.8	0.0	57.0	0.0
AUG	362.4	0.0	59.8	0.0
SEP	243.7	0.1	50.2	0.0
OCT	93.0	2.7	30.9	1.3
NOV	14.6	27.4	10.4	6.7
DEC	2.7	77.1	2.5	10.4

2.2.4 Temporary Load/Peak Impacts Due to 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 the 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 time period. Table 2.2.3 shows how the "econTOU" indicator variable is defined, and what the resulting parameter estimate corresponds to in each equation. Note that 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 California Energy Commission (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. The steps performed in this analysis were as follows:

1. Staff first computed the sum totals of the 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 calculated the cumulative running totals for each component from July 2005 through December 2014 by performing a linear interpolation on the cumulative fiscal year components.
3. Staff then converted 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.
4. Finally, staff summed these three projected monthly program components together to estimate the cumulative projected monthly load and peak reduction estimates, directly attributable to measured EE activities.

Since 2014, staff has continued to update these projections as new information becomes available. It should be noted that these represent interpolated engineering estimates of energy efficiency program impacts.

In theory, if such estimates are unbiased and accurate, then when a regression variable containing these observations is introduced 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.

<table>
<tr><th rowspan="2">Month (i)</th><th colspan="3">Load Scaling Factors</th><th colspan="3">Peak Shaping Factors</th></tr>
<tr><th>Baseload</th><th>Lighting</th><th>HVAC</th><th>Baseload</th><th>Lighting</th><th>HVAC</th></tr>
<tr><td>Jan</td><td rowspan="12">0.0833 for all months</td><td>0.0970</td><td rowspan="12">$SumCD_{(i)}/1390$</td><td rowspan="12">1.0 for all months</td><td>1.164</td><td rowspan="12">$SumCD_{(i)}/362.4$</td></tr>
<tr><td>Feb</td><td>0.0933</td><td>1.119</td></tr>
<tr><td>Mar</td><td>0.0858</td><td>1.030</td></tr>
<tr><td>Apr</td><td>0.0784</td><td>0.940</td></tr>
<tr><td>May</td><td>0.0746</td><td>0.896</td></tr>
<tr><td>Jun</td><td>0.0709</td><td>0.851</td></tr>
<tr><td>Jul</td><td>0.0709</td><td>0.851</td></tr>
<tr><td>Aug</td><td>0.0746</td><td>0.896</td></tr>
<tr><td>Sep</td><td>0.0784</td><td>0.940</td></tr>
<tr><td>Oct</td><td>0.0858</td><td>1.030</td></tr>
<tr><td>Nov</td><td>0.0933</td><td>1.119</td></tr>
<tr><td>Dec</td><td>0.0970</td><td>1.164</td></tr>
</table>

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 seven years. Additionally, since the enactment of SB 1, RPU has 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.

Based on the installed AC capacity data, RPU can estimate the projected net annual energy savings and net coincident peak savings for both residential and non-residential customers, respectively. In the summer of 2017, staff reviewed all solar PV saving projections going back to calendar year 2002, in order to calculate the cumulative load and peak savings attributable to customer installed PV systems within RPU's service territory. These calculations were 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 the utility's distribution peaks occur in HE19 from November through February, and HE16 in March through October.) Staff then summed these projected monthly components together to estimate the cumulative projected monthly load and peak reduction estimates, directly attributable to solar PV distributed generation (DG) activities.

Once again, it should be noted that these calculations represent interpolated engineering estimates of solar PV DG impacts. 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, theory suggests that 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.). However, 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.

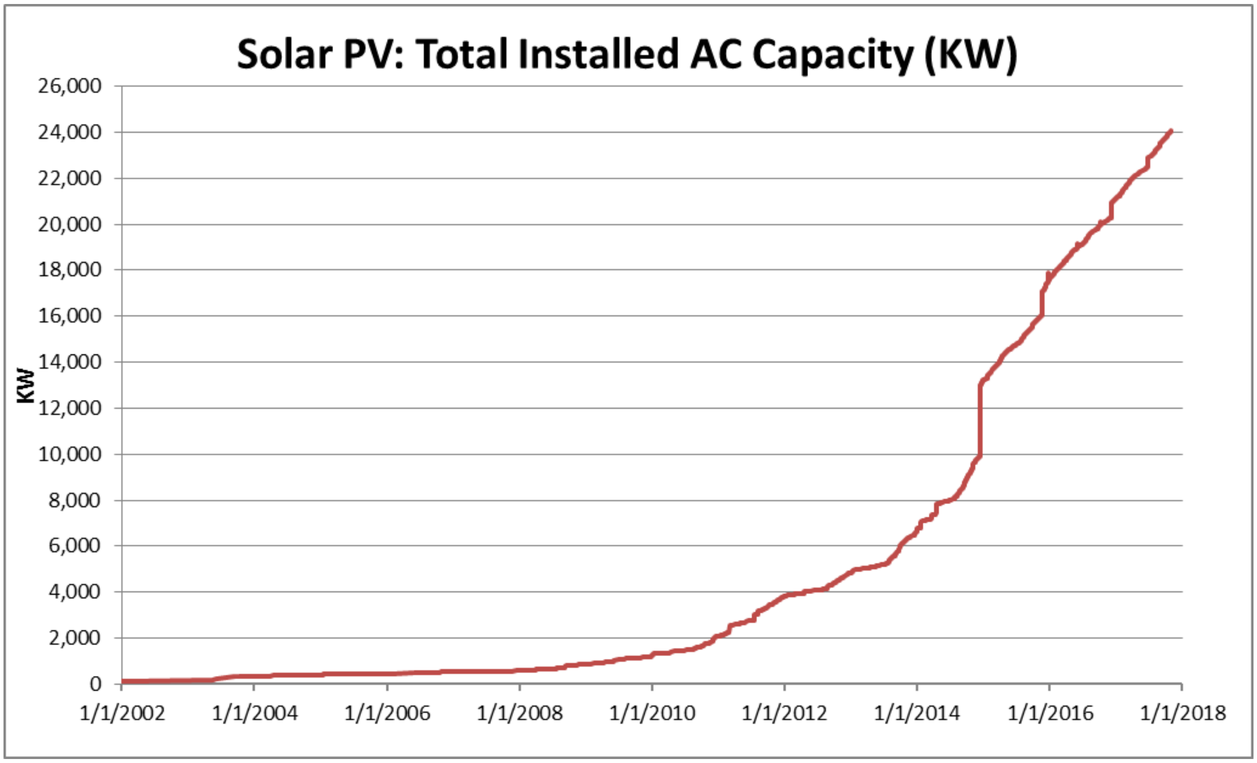


Figure 2.2.1. Total installed AC capacity of customer owned solar PV in the RPU service territory since 2002.

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	0.359
Apr	0.211	0.403
May	0.225	0.434
Jun	0.232	0.442
Jul	0.229	0.425
Aug	0.217	0.389
Sep	0.203	0.342
Oct	0.188	0.298
Nov	0.176	0
Dec	0.170	0

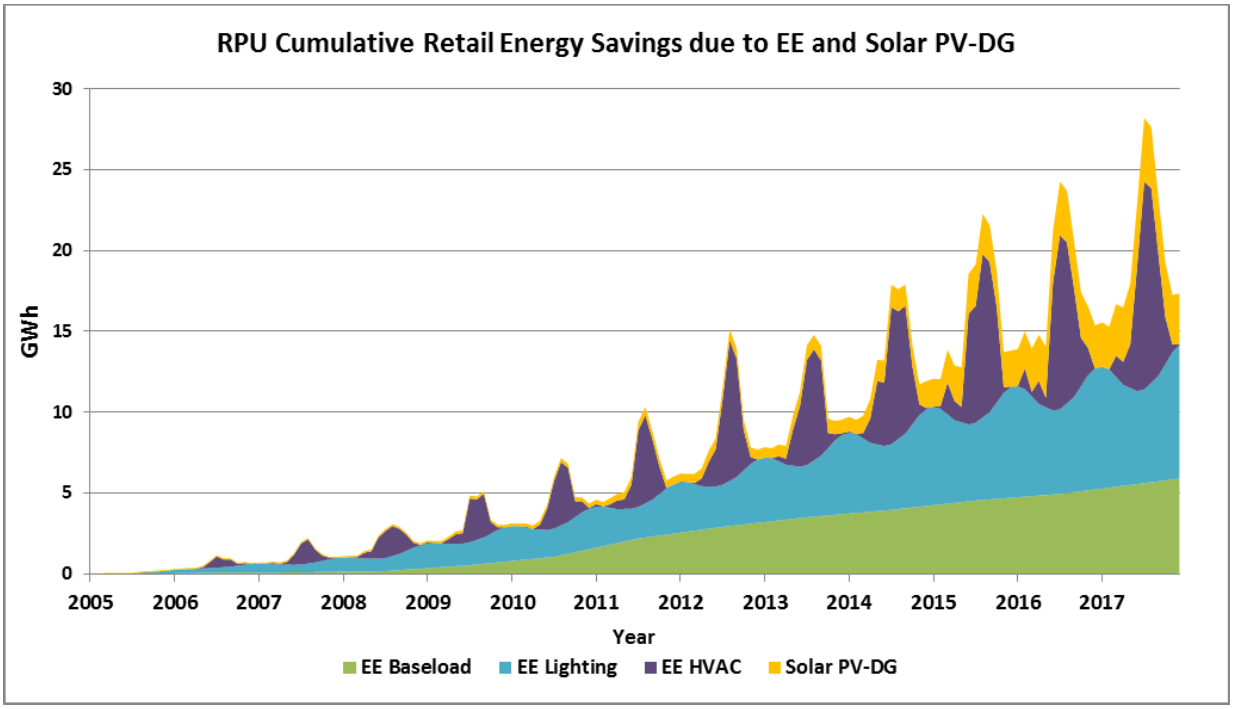


Figure 2.2.2. Calculated cumulative projected retail energy savings in the RPU service territory due to both EE program and solar PV distributed generation impacts over time.

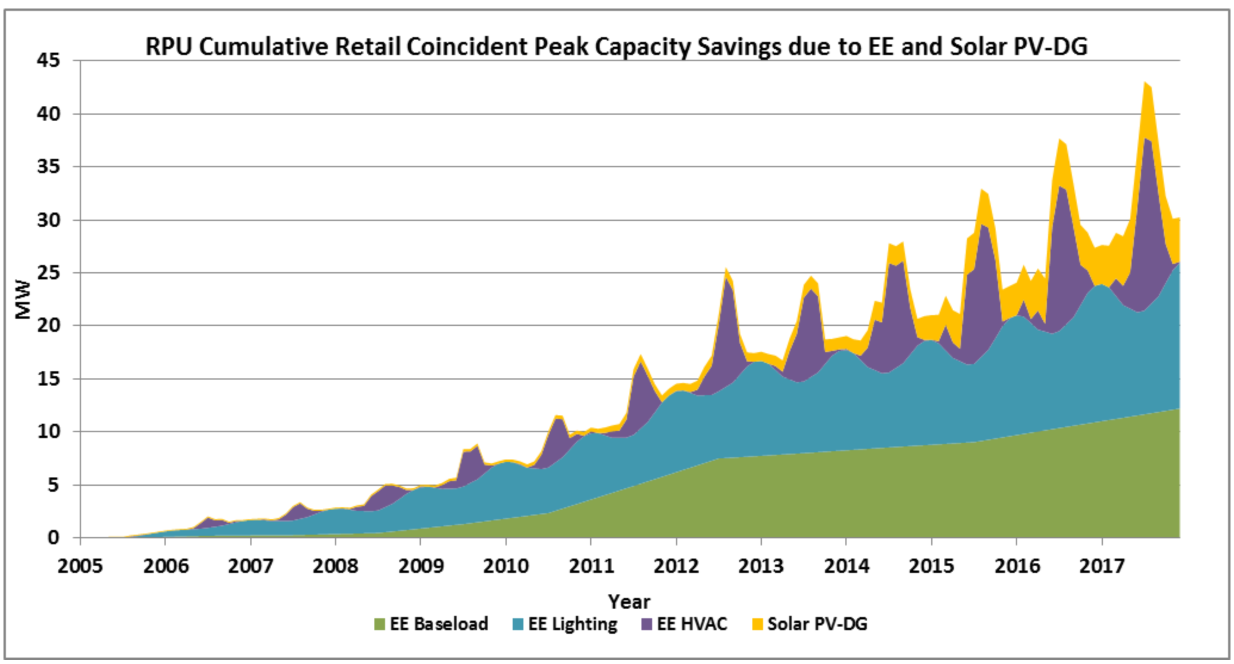


Figure 2.2.3. Calculated cumulative projected coincident peak capacity savings in the RPU service territory due to both EE program and solar PV distributed generation impacts over time.

2.2.7 Incremental Electric Vehicle Loads

In early 2017 the CEC released their Transportation Electrification Common Assumptions 3.0 model. This model can be used by CA utilities to forecast Electric Vehicle (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 a number of emission reduction metrics, in addition to the expected net load growth associated with the forecasted EV penetration level.

Staff has elected to use this model in the 2017 load forecasting equations and 2018 IRP to estimate the utility's expected net EV load growth. For baseline load forecasting purposes, a "business as usual" EV population growth pattern (i.e., 56,100 EV's in CA in 2017) was assumed, along with the default 0.56% Riverside estimate for defining the utility's service area PEV population as a percent of the state total. Staff also assumed 5% distribution losses within RPU's service territory and that 10% of the utility's customers EV charging load is self-supplied. Based on these input assumptions, Figure 2.2.4 shows the projected additional utility electrical load from new PEVs entering RPU's service territory between 2015 through 2030.

Note that for forecasting purposes, these incremental EV loads (above the 2015 baseline level) are treated as net load additions that effectively offset future EE and DG.PV (solar) load losses. Additionally, staff assumed that 75% of these net load gains will show up in the Residential customer class, with the remaining 25% spread evenly across the Commercial and Industrial classes.

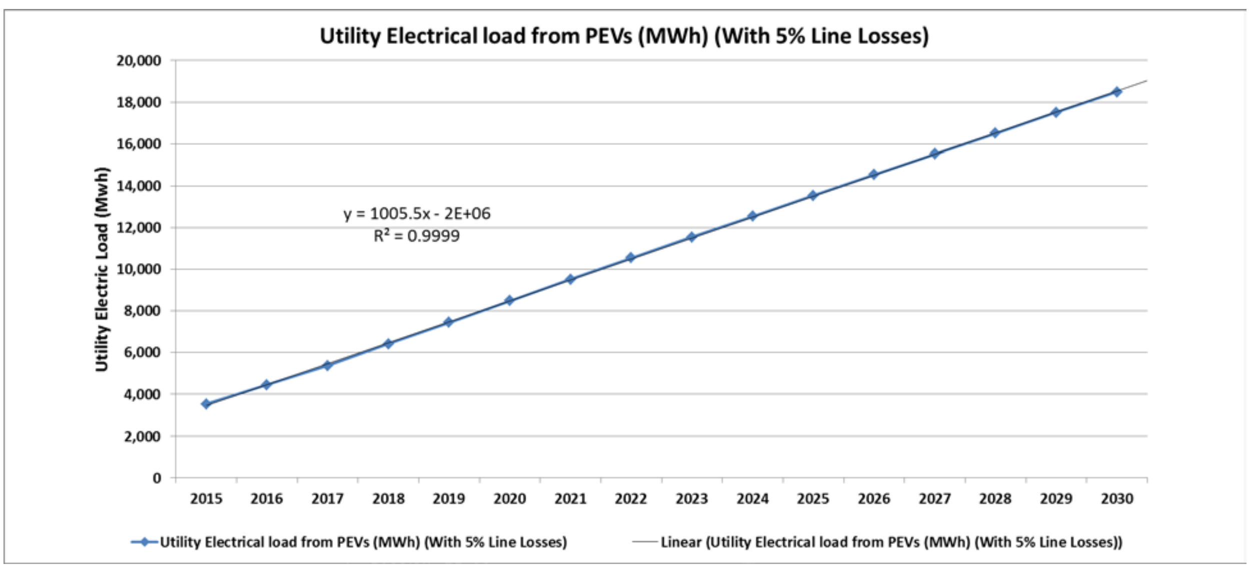


Figure 2.2.4. Projected 2015-2030 RPU electrical load from EV and PHEV penetration within the utility's service territory.

2.3 System Load and Peak Forecast Models

2.3.1 Monthly System Total Load Model

The regression component of the monthly total system load forecasting model is a function of the primary economic driver (PCPI), two calendar effects that quantify the number of weekdays (SumMF) and weekend days (SumSS) in the month, three weather effects that quantify the total monthly cooling and extended heating degrees (SumCD and SumXHD) and the interactive effect of the maximum three-day heatwave impact (MaxCD3), eight low order Fourier frequencies that quantify seasonal impacts both before and after distribution system upgrades (Fs1, Fc1, Fs2, Fc2, Fs2014a, Fc2014a, Fs2014b, and Fc2014b), one unconstrained Industrial load indicator variable (econTOU), and one initially unconstrained effect that captures the combined impacts of (avoided) EE, PV-DG and (incremental) EV 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

$$y_t = \beta_0 + \beta_1[PCPI_t] + \beta_2[SumMF_t] + \beta_3[SumSS_t] + \beta_4[SumCD_t] + \beta_5[SumXHD_t] + \beta_6[SumCD_t][MaxCD3_t]/100$$

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

$$+ \beta_{13}[Fs2014b_t] + \beta_{14}[Fc2014b_t] + \beta_{15}[econTOU_t] + \theta_1[EE_t+PV.DG_t-EV_t] + \varepsilon_{jt} \qquad \text{[Eq. 2.3.1]}$$

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 → Jan 2003) 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 16.7 and 8.0 GWh^2, suggesting that the variance ratio for the seasonal errors can be assumed to be 2:1. Additionally, the θ_1 parameter estimate was estimated to be -1.303 (0.101), which is reasonably close to the -1.05 avoided/incremental load impact assumption discussed in sections 2.2.5 through 2.2.7. Based on these results, Eq. 2.3.1 was refit using weighted least squares (SAS REG Procedure), where the θ_1 parameter estimate was constrained to be equal to -1.05.

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, all forecasted economic indices and structural effects (PCPI, econTOU, EE, PV-DG and EV) were treated as fixed variables and the forecasted weather indices were assumed to be random effects. Under such an assumption, the first-order Delta method estimate of the forecasting variance becomes

$$Var(\hat{y}_t) = \sigma_m^2 + Var\{\ \beta_4[SumCD_t] + \beta_5[SumXHD_t] + \beta_6[SumCD_t][MaxCD3_t]/100\ \} \qquad \text{[Eq. 2.3.3]}$$

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 was approximated via the analysis of historical weather data, after the parameters associated with the SumCD and SumXHD weather effects were 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 about 98.8% of the observed variability associated with the monthly 2003-2017 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 8.01 GWh^2; the corresponding summer component is twice this amount (16.02 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 these modeling assumptions are likewise 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 interaction between the SumCD and MaxCD3 is positive and statistically significant. Additionally, 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). Finally, RPU system load is expected to increase as the area wide PCPI index grows over time (i.e., this economic parameter estimate is > 0). However, this load growth will grow more slowly if future EE and/or PV-DG trends increase above their current forecasted levels, or more quickly if future EV penetration levels increase above their baseline levels.

Figure 2.3.1 shows the observed (blue points) versus calibrated (green line) system loads for the 2003-2017 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines) and the observed versus calibrated load correlation exceeds 0.99. Figure 2.3.2 shows the forecasted monthly system loads for 2018 through 2030, 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. Note also that these forecasts assume that future PV-DG installation rates will stabilize at approximately 2 MW of AC capacity per year (once the utility reaches its NEM 1.0 cap), and that the future calculated EE savings rate will continue to be approximately equal to 1% of the total annual system loads. Under these assumptions, the utility's system loads are forecasted to grow at 1.1% per year over the next ten years.

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

Gross Monthly Demand Model (Jan 2003 - Aug 2017): GWh units
Forecasting Model: includes Weather & Economic Covariates, Fourier Effects
pseudo TOU (unconstrained), 2014 Dist.system Adj and Avoided Load (PV + EE - EV)

Final Forecasting Equation: assumes constrained Avoided Demand Savings

Dependent Variable: GWhload Load (GWh)
Number of Observation Used: 176
Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	15	104340	6955.99373	868.06	<.0001
Error	160	1282.12160	8.01326		
Corrected Total	175	105622			

Root MSE	2.83077	R-Square	0.9879
Dependent Mean	176.83540	Adj R-Sq	0.9867
Coeff Var	1.60079		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	-110.31151	9.54998	-11.55	<.0001	0
PCPI	PCPI ($1,000)	1	3.59642	0.09650	37.27	<.0001	1.24443
SumMF		1	5.65973	0.31770	17.81	<.0001	1.60298
SumSS		1	4.84532	0.37928	12.78	<.0001	1.49294
SumCD		1	0.14824	0.01477	10.04	<.0001	55.78514
CDimpact		1	0.06160	0.01993	3.09	0.0024	35.39460
SumXHD		1	0.05040	0.00972	5.18	<.0001	2.63186
Fs1		1	-4.42577	0.75950	-5.83	<.0001	4.60403
Fc1		1	-5.70859	1.01770	-5.61	<.0001	7.99335
Fs2		1	1.09362	0.61457	1.78	0.0771	3.11007
Fc2		1	1.70306	0.48170	3.54	0.0005	1.91111
Fs2014a		1	-4.53164	0.96929	-4.68	<.0001	1.51380
Fc2014a		1	-2.95335	0.94062	-3.14	0.0020	1.43455
Fs2014b		1	4.15689	0.91896	4.52	<.0001	1.38141
Fc2014b		1	-0.04606	0.94319	-0.05	0.9611	1.45711
econTOU		1	6.38842	0.69456	9.20	<.0001	1.05338
avoided_load	EE+PV.DG-EV	1	-1.05000	0	n/a	n/a	0.0

Durbin-Watson D	1.277
Number of Observations	176
1st Order Autocorrelation	0.341

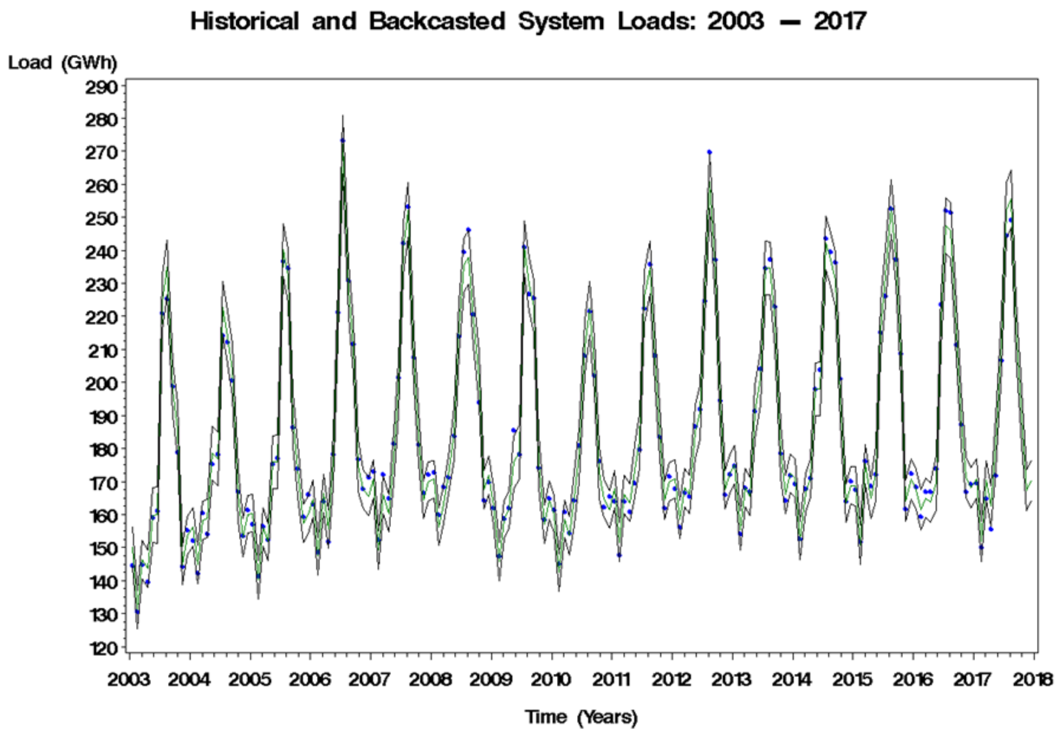


Figure 2.3.1. Observed and predicted total system load data (2003-2017), after adjusting for known weather conditions.

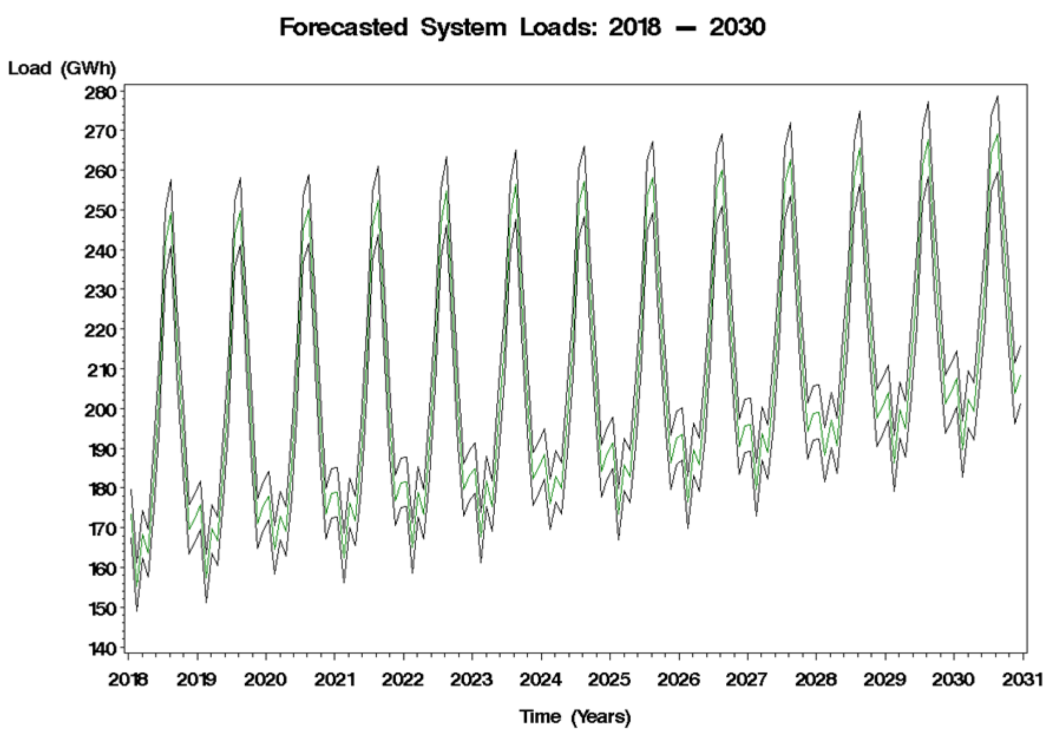


Figure 2.3.2. Forecasted monthly system loads for 2018-2030; 95% forecasting envelopes encompass model uncertainty only.

Table 2.3.2 shows the forecasted monthly RPU system loads for 2018, along with their forecasted standard deviations. In contrast to figure 2.3.2, these standard deviations quantify both model and weather uncertainty. The 2018 forecasts project that the annual system load should be 2291.2 GWh, assuming that the RPU service area experiences typical weather conditions throughout the year.

Table 2.3.2. 2018 monthly total system load forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Load (GWh)	Std.Dev (GWh)
JAN	173.5	3.17
FEB	155.1	3.69
MAR	168.4	4.69
APR	163.7	5.36
MAY	183.0	8.86
JUN	205.6	17.41
JUL	241.7	14.21
AUG	249.3	11.36
SEP	217.4	12.77
OCT	192.0	11.41
NOV	169.5	4.58
DEC	172.3	3.15
Annual TOTAL	2291.2	

2.3.3 Monthly System Peak Model

The regression component of the monthly system peak forecasting model is a function of the primary economic driver (PCPI), three weather effects that quantify the maximum three-day cooling requirements (i.e., 3-day heat waves), the interaction of this effect with the monthly cooling degrees and the maximum single day heating requirement (MaxCD3, SumCD and MaxHD, respectively), ten lower order Fourier frequencies that quantify seasonal impacts both before and after distribution system upgrades (Fs1, Fc1, Fs2, Fc2, Fs3, Fc3, Fs2014a, Fc2014a, Fs2014b and Fc2014b), one unconstrained Industrial peak indicator variable (econTOU), and one initially unconstrained effect that captures the combined impacts of (avoided) EE, PV-DG and (incremental) EV peaks. The heterogeneous residual variance (mean square prediction error) component is again defined to be seasonally dependent, but now where the summer period is defined to be one month longer (April through October). Mathematically, the model is defined as

$$y_t = \beta_0 + \beta_1[PCPI_t] + \beta_2[MaxCD3_t] + \beta_3[SumCD_t][MaxCD3_t]/100 + \beta_4[MaxHD_t] +$$

$$\beta_5[Fs(1)_t] + \beta_6[Fc(1)_t] + \beta_7[Fs(2)_t] + \beta_8[Fc(2)_t] + \beta_9[Fs(3)_t] + \beta_{10}[Fc(3)_t] +$$

$$+ \beta_{11}[Fs2014a_t] + \beta_{12}[Fc2014a_t] + \beta_{13}[Fs2014b_t] + \beta_{14}[Fc2014b_t] +$$

$$\beta_{15}[econTOU_t] + \theta_1[EE_t+PV.DG_t-EV_t] + \varepsilon_{jt} \qquad \text{[Eq. 2.3.4]}$$

where

$$\varepsilon_{jt \text{ for } j=1(\text{summer}),\, 2(\text{winter})} \sim N(0, \sigma_j^2). \qquad \text{[Eq. 2.3.5]}$$

In Eq. 2.3.4, y_t represents the RPU monthly system peaks (MW) for the calendar ordered monthly observations and forecasts (t=1 → Jan 2003) and the seasonally heterogeneous summer and winter 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 492.1 and 197.9 MW^2, suggesting that the variance ratio for the seasonal errors is reasonably close to a 2:1 ratio. Additionally, the θ_1 parameter estimate was estimated to be -1.055 (0.322), which almost exactly matches the -1.05 avoided/incremental peak impact assumption discussed in sections 2.2.5 through 2.2.7. Based on these results, Eq. 2.3.4 was refit using weighted 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

$$Var(\hat{y}_t) = \sigma_m^2 + Var\{ \beta_2[MaxCD3_t] + \beta_3[SumCD_t][MaxCD3_t]/100 + \beta_4[MaxHD_t] \} \qquad \text{[Eq. 2.3.6]}$$

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 97.4% of the observed variability associated with the monthly 2003-2017 system peaks. 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_peak parameter was constrained to be equal to -1.05.

As shown in Table 2.3.3, the estimate for the winter seasonal variance component is 218.8 MW^2; the corresponding summer component is twice this amount (437.6 MW^2). An analysis of the variance adjusted model residuals suggests that the model errors are again normally distributed, devoid of outliers and approximately temporally uncorrelated; implying that these 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 monthly system peaks increases as each of the weather indices increase, but the peaks appear to be primarily determined by the MaxCD3 index. (Recall that this index essentially quantifies the maximum cooling degrees associated with 3-day summer heat waves.) RPU system peaks are also expected to increase as the PCPI index improves over time (i.e., PCPI parameter estimate is > 0). Likewise, the peak loads will grow more slowly if future EE and/or PV-DG trends increase above their current forecasted levels, or more quickly if EV 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 2.3.3 shows the observed (blue points) versus calibrated (green line) system peaks for the 2003-2017 timeframe. Nearly all of the calibrations fall within the calculated 95% confidence envelope (thin black lines) and the observed versus calibrated load correlation exceeds 0.98. Figure 2.3.4 shows the forecasted monthly system peaks for 2018 through 2030, 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. Note that the utility's system peaks are forecasted to grow at just 0.4% per year over the next ten years.

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

Gross Monthly Peak Model (Jan 2003 - Aug 2017): MW units
Forecasting Model: includes Weather & Economic Covariates, Fourier Effects
pseudo TOU (unconstrained), 2014 Dist.system Adj, and Avoided Peak (PV + EE - EV)

Final Forecasting Equation: using optimized Forier coefs and constrained Avoided Peak Load Effect

Dependent Variable: peak Peak (MW)
Number of Observations Used: 176

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	15	1329764	88651	405.16	<.0001
Error	160	35009	218.80601		
Corrected Total	175	1364773			

Root MSE	14.79209	R-Square	0.9743
Dependent Mean	368.89432	Adj R-Sq	0.9719
Coeff Var	4.00985		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|	Variance Inflation
Intercept	Intercept	1	135.37471	15.57677	8.69	<.0001	0
PCPI	PCPI ($1,000)	1	5.59794	0.50176	11.16	<.0001	1.23228
MxCD3		1	2.83380	0.18781	15.09	<.0001	9.72788
CDimpact		1	0.23740	0.06190	3.84	0.0002	12.50081
MxHD1		1	1.84252	0.34492	5.34	<.0001	2.04283
Fs1		1	-22.84073	3.59551	-6.35	<.0001	3.77879
Fc1		1	-39.10284	4.43850	-8.81	<.0001	5.56814
Fs2		1	2.14027	3.28954	0.65	0.5162	3.26320
Fc2		1	-2.05045	2.47581	-0.83	0.4088	1.84892
Fs3		1	8.22466	2.12678	3.87	0.0002	1.34902
Fc3		1	8.10454	1.90719	4.25	<.0001	1.09717
Fs2014a		1	-4.16401	5.05280	-0.82	0.4111	1.50651
Fc2014a		1	-20.00732	4.93997	-4.05	<.0001	1.44904
Fs2014b		1	11.53635	4.76977	2.42	0.0167	1.36292
Fc2014b		1	4.59643	4.91722	0.93	0.3513	1.45037
econTOU		1	14.78063	3.63449	4.07	<.0001	1.05634
avoided_peak	EE+PV-EV	1	-1.05000	0	n/a	n/a	0.0

Durbin-Watson D	2.138
Number of Observations	176
1st Order Autocorrelation	-0.078

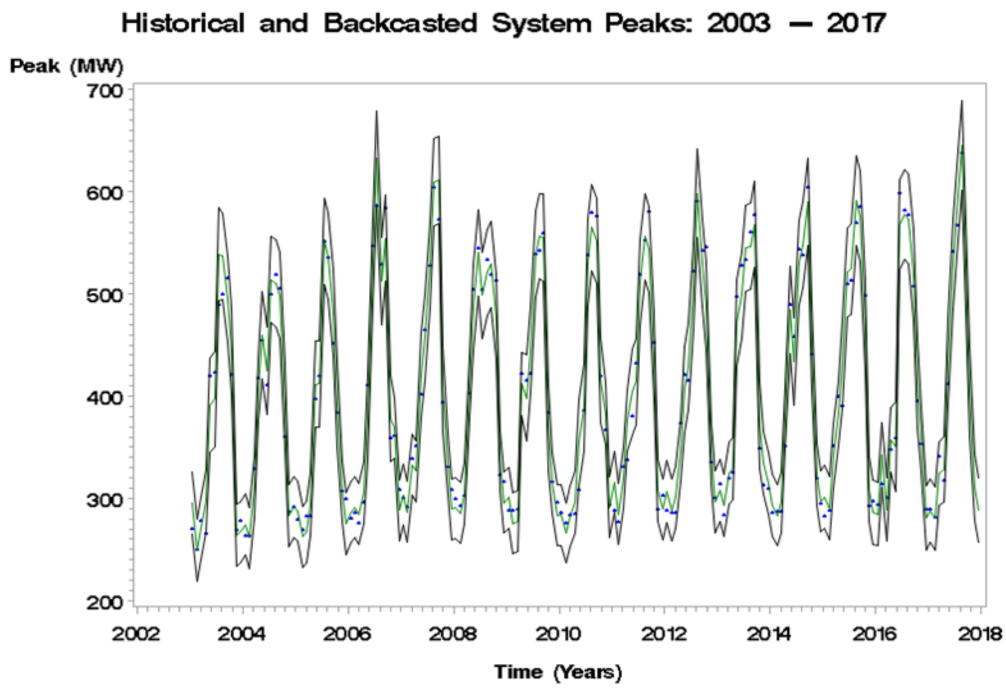


Figure 2.3.3. Observed and predicted system peak data (2003-2017), after adjusting for known weather conditions.

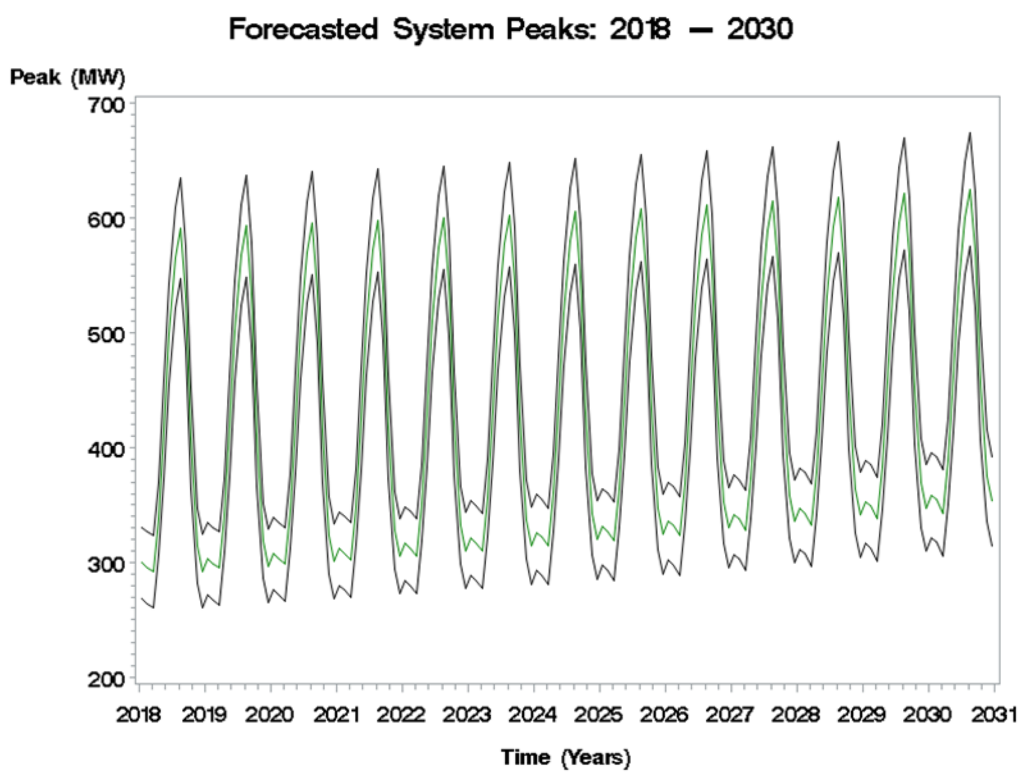


Figure 2.3.4. Forecasted monthly system peaks for 2018-2030; 95% forecasting envelopes encompass model uncertainty only.

Table 2.3.4 shows the forecasted monthly RPU system peaks for 2018, along with their forecasted standard deviations. In contrast to figure 2.3.4, these standard deviations quantify both model and weather uncertainty. The 2018 forecasts project that the maximum monthly system peak should be about 591.5 MW and occur in August, assuming that the RPU service area experiences typical weather conditions throughout the year. Note that this represents a 1-in-2 peak forecast, respectively.

Table 2.3.4. 2018 monthly system peak forecasts for RPU; forecast standard deviations include both model and weather uncertainty.

Month	Peak (MW)	Std.Dev (MW)
JAN	299.3	19.05
FEB	295.1	23.24
MAR	291.7	26.43
APR	338.3	44.95
MAY	415.1	46.67
JUN	499.3	57.63
JUL	565.8	41.40
AUG	591.5	39.70
SEP	531.2	40.76
OCT	408.2	46.63
NOV	314.9	34.21
DEC	292.5	17.89

2.3.5 Peak Demand Weather Scenario Forecasts

After calculating all of the 2018-2030 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 Eqs. 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 2018, the forecasted 1-in-5, 1-in-10, 1-in-20 and 1-in-40 peaks are 624.9, 642.4, 656.8 and 669.3, respectively.

2.4 2018-2037 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 2018-2037 time frame (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 a historical average annual PCPI growth rate (~ 2.9%/year), continue 1%/year energy efficiency efforts, a moderate amount of continued customer solar PV (DER) installations and a business-as-usual growth rate in electric vehicles. RPU's expected annual load and peak growth rates under this scenario are 1.4% and 0.5%, respectively. Note also that RPU's monthly retail loads across all classes should sum up to be approximately 5% less than these forecasted system loads, after adjusting for typical distribution system losses.

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

Year	Load Growth (GWh)	Peak Growth (MW)
2018	2,291.2	591.5
2019	2,314.8	593.4
2020	2,345.8	595.6
2021	2,366.9	597.9
2022	2,393.7	600.3
2023	2,422.5	602.9
2024	2,458.7	605.6
2025	2,484.4	608.5
2026	2,516.9	611.5
2027	2,550.6	614.6
2028	2,589.6	617.9
2029	2,622.2	621.4
2030	2,660.2	625.0
2031	2,699.6	628.8
2032	2,746.0	632.8
2033	2,782.3	637.0
2034	2,826.5	641.4
2035	2,873.3	645.9
2036	2,926.3	650.7
2037	2,970.4	655.7
Load/Peak Growth 2037 v.s. 2018	1.4%	0.5%

Conceptually, there are a number of 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 reasonable growth in local area per capita personal income. Any extended period of suboptimal personal income growth should 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, an accelerated electric vehicle adoption rate probably represents the primary factor that might significantly increase the utilities load growth (above these current forecasts). Later chapters in this IRP will examine the impacts associated with some of these alternative 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 of 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 utilities 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 regulatory mandates, particularly the need to achieve specific greenhouse gas (GHG) reduction targets and a commitment to incorporate an 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 3.1.1 shows the locations of all the existing resources referenced in Table 3.1.1.

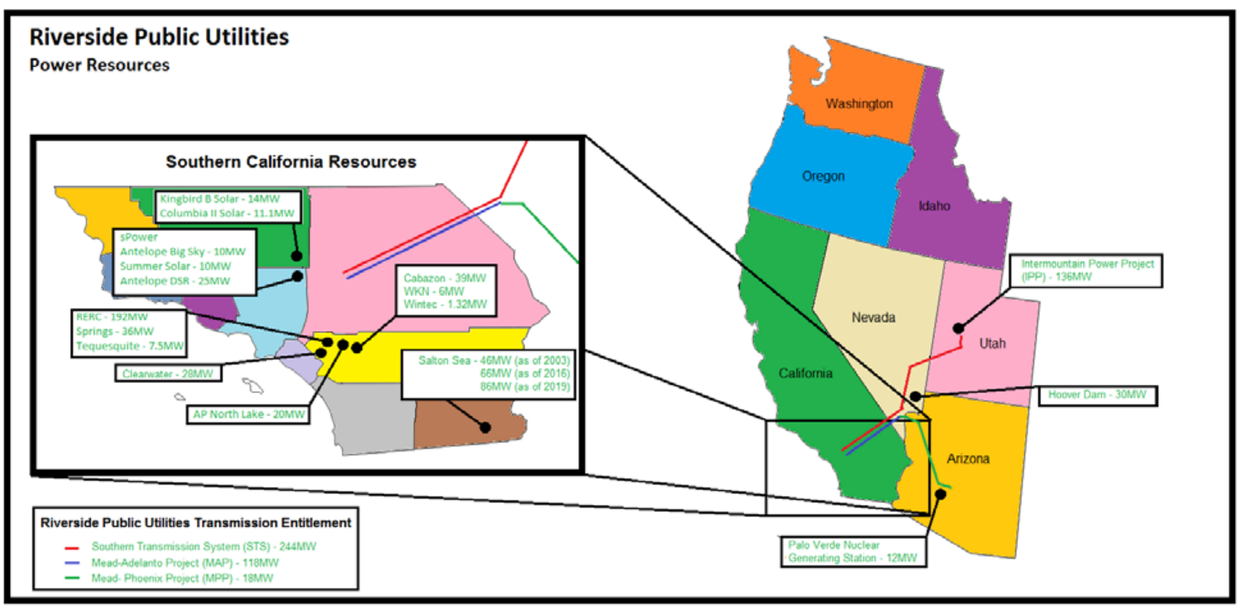


Figure 3.1.1. Physical locations of existing RPU long-term generation resources.

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

Existing Resources	Technology	Capacity (MW)	Contract End Date	Asset Type
Intermountain (IPP)	Coal, base-load	136	May-2027	Entitlement/PPA
Palo Verde	Nuclear, base-load	12	Dec-2030	PPA (SCPPA)
Hoover	Hydro, daily peaking	20-30	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
Salton Sea 5	Geothermal, renewable (base-load)	46	May-2020	PPA
Salton Sea 5 Incremental	Geothermal, renewable (base-load)	Up to 3	May-2018	PPA (WSPP)
Wintec	Wind, renewable	1.3	Dec-2018	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 w/PO & SO (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**
CalEnergy Portfolio	Geothermal, renewable (base-load)	20/40/86	(Feb-2016, Jan-2019, Jun-2020) Dec-2039	PPA
Recently Expired Contracts	**Technology**	**Nameplate Capacity (MW)**	**Termination (or Force Majeure) Date**	**Asset Type**
BPA 2	Exchange, daily peaking	15/60	May-2016	EEA
SONGS	Nuclear (base-load)	39	Feb-2012 Force Majeure	Ownership interest

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 May 2027. Specifically, the utility is entitled to receive 7.617% of the energy output from Units 1 & 2, or 68 MW per hour from each unit. Thus, in a typical year RPU can receive a maximum of 1,048,400 MWh of base-load energy if both plants run at their expected 88% capacity factors.

However, more recently, the plant's capacity factor has been significantly lower – as of FY16/17, it was 63.6% – due to the added dispatch cost of carbon and depressed pricing in the CAISO market.

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 IPP units generate any electricity. In FY16/17, this fixed cost component was $35,538,901, which translated to a fixed capacity cost of $21.78/kW-month and a 55.3% minimum take obligation. (More recently, this minimum take obligation has been decreasing as the long-term fixed-price coal contracts expire.) For all energy above the annual minimum take-or-pay obligation, RPU pays a flat $/MWh energy cost (incremental coal cost); as of June 2017, this variable fuel cost was approximately $22.69/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 our 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 2017, Palo Verde energy cost $9.02/MWh. Additionally, RPU also pays approximately $3,600,000 annually in fixed capacity costs (or $37.03/MWh, based on an expected delivery of 97,200 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 2017 – September 2018, RPU was entitled to approximately 31,500 MWh's of Hoover hydro energy, subject to the scheduling limits shown in Table 3.1.2. As of June 2017, Hoover energy cost $9.82/MWh. Additionally, RPU also pays approximately $550,000 annually in fixed capacity costs (or $17.46/MWh, based on an expected delivery of 31,500 MWh of annual energy).

Table 3.1.2. 2017-2018 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	2115	2558	2355	2383	2274	3366	3822	2992	2648	2451	2273	2270
MW/hour	17	16	12	17	19	19	18	21	23	23	24	24

RERC Units 1-4

RPU owns and operates four LM6000 peaking units; these units are collocated together at the RERC generation facility in the center of Riverside and connected directly to our local distribution system (69kV lines). RERC Units 1 and 2 become 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 both energy and 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 the 225 hour/month runtime limits, 1800 hour annual limits, and 40 starts-per-month constraints. Theoretically, these four units could generate 290,000 MWh of energy per year, although in practice these units typically produce 30,000 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 GE10 peaking units; these units are collocated together at the Springs generation and distribution facility in the eastern part of 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.

Generation hours for these GE10 units are primarily limited by the unit's 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 primarily used for distribution system voltage support and meeting local 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).

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 is a traditional take-and-pay PPA with a historic base-load, outage-adjusted capacity factor of about 87%. Traditionally, the Salton Sea 5 unit has delivered about 350,000 MWh per year of renewable base-load energy to the utility.

Salton Sea 5 Incremental

In May 2017, the City entered into a one year WSPP agreement to purchase up to 3 MW of additional geothermal energy when the CalEnergy Salton Sea 5 facility generates more than 46 MW. Riverside pays $53.93/MWh for the incremental energy. The agreement could be potentially extended on an annual basis through May 2020, the expiration of the Salton Sea 5 contract.

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.

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 is expected to deliver about 19,000 MWh per year of intermittent renewable energy to the utility. As of June 2017, RPU paid $66.46/MWh for this energy.

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 is expected to deliver about 55,500 MWh per year of intermittent renewable energy to the utility. The 2015 starting price for this energy was $83.90/MWh (with a 1.5% annual escalation rate) and includes all RA attributes.

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 are expected to deliver about 45,000 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 is expected to deliver about 41,800 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 is expected to deliver about 33,500 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 is expected to deliver about 15,000 MWh per year of intermittent renewable energy to the utility. The starting price for this energy is $81.30/MWh (with a 1.5% annual escalation rate) and includes all RA attributes.

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 intermittent renewable energy to the utility in January 2015. The price for this energy is $59.30/MWh flat for ten years and includes all RA attributes.

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 is expected to deliver about 71,000 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 on the contract to install up to 12.0 MW of energy storage at the project site

3.1.2 Future Resources

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 will step-up its geothermal energy from 46 MW to 86 MW by January 2019. As of February 2016, the utility began receiving an additional 20 MW of base-load geothermal energy from the portfolio, which will increase to 40 MW in January 2019. Additionally, when the Salton Sea 5 contract terminates in May 2020, the utility will simultaneously begin receiving an additional 46 MW of energy from the geothermal portfolio (thus maintaining 86 MW of total geothermal capacity in RPU's resource portfolio). Riverside's 86 MW of geothermal capacity is expected to produce approximately 656,000 MWh annually. The 2016 starting price for this additional energy is $72.85/MWh (with a 1.5% annual escalation rate) and includes all RA attributes.

3.1.3 Recently Expired Contracts

BPA-2

The BPA-2 contract terminated on April 30th, 2016. The contact was an energy exchange agreement (EEA) between Riverside and Bonneville Power Authority. Hence, there were no fixed capacity costs or energy costs per se; rather, the value of the contract depended upon the current energy prices in the SP15 and Mid-C markets. The exchange energy contract rules were fairly involved, but in general entitled the utility to receive a maximum of 15 MW per hour, 6 hours per day during the winter months (November-April) and 60 MW per hour, 6 hours per day during the summer months (July-October). RPU also received seasonal firm energy deliveries during May and June (40 MW per hour, 24 hours per day, 7 days a week) and was obligated to return all winter and summer peaking energy within a 24 hour period, by either wheeling power back up the NOB line or purchasing an appropriately sized off-peak energy product at Mid-C. RPU also had to return a total of 64,350 additional MW over the period of November 1 through April 15, during off-peak hours only. This additional energy (along with the seasonal firm energy return obligation) was typically covered using forward purchased Mid-CC energy products.

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 MWh's 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 2017, Riverside owed approximately $29.0 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 September 2014, total decommissioning costs for SONGs Units 2 and 3 are estimated at $4.4 billion of which Riverside's share is $79 million. The City had deposited $76.9 million in its decommissioning trust funds as of June 2017. Additionally, as of June 2017, Riverside had paid $18.9 million in decommissioning obligations, and the decommissioning liability balance was $64.7 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 a number of 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 funds in an unrestricted designated decommissioning reserve of $1.6 million per year.

3.2 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, the City 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.

Mead-Phoenix Transmission Project

Originally in connection with its entitlement to PVNGS 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. The City receives 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, the City 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. The City has an interconnection facilities agreement with SCE for the construction and interconnection of a new 230-69 kV transmission substation which will provide another interconnection of the City's system with SCE's transmission facilities. The $200 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 more detail in Chapter 4, section 4.7.

3.3 California Independent System Operator

The City 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 the City's transmission entitlements to the CAISO effective January 1, 2003. In November 2002, the City formally executed its Transmission Control Agreement with the CAISO.

On January 1, 2003, the City 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 the City's annual Transmission Revenue Requirement (TRR) as approved by the FERC. The City now obtains all of 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. The City participates in the CAISO CRR process to obtain the additional transmission congestion hedging rights necessary to hedge the majority of its load serving transmission requirements.

3.4 RPU's Evolving Resource Procurement Strategy

Ten 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, RPU 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 will increase to 40 MW in January 2019 and then to 86 MW in June 2020 (immediately after the expiration of the current 46 MW Salton Sea 5 contract). Note that by January 2019, these 86 MW's of geothermal capacity should supply RPU with approximately 656,000 MWh of base-load renewable energy.

Concurrently with the contracting of these new geothermal resources, RPU has entered into multiple new solar PV and wind renewable PPA's. Combined, these seven solar PV and two wind resources have 142 MW of nameplate capacity and are expected to supply 350,000 MWh of annual energy and meet 16% of the utility's renewable RPS target in 2018. Thus, Riverside's resource portfolio has evolved to incorporate increasing amounts of new solar and wind resources, in addition to the aforementioned renewable geothermal resources.

Together, these new PPA's will contribute a significant expansion of capacity and renewable energy to RPU's current resource portfolio. By 2020, Riverside expects to serve approximate 44% of its retail load using renewable resources. The combined effects of these new renewable resources on RPU's portfolio are presented in Chapter 8, along with additional power resource metrics on the utility's forecasted net positions, internal generation, and GHG emissions during the 2018-2022 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-kV through two 280 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 15 separate substations linked by a network of 69 kV and 33kV lines. Each substation steps down the power on the system from 69 kV /33 kV to 12 kV/4 kV for distribution to the RPU customers.

Figure 4.2.1 illustrates the existing RPU sub transmission electrical system. The existing RPU sub transmission system includes facilities constructed and operated at 69 KV and 33 kV. Currently, RPU's system comprises of 98.6 circuit miles of sub-transmission lines. Operating in closed loops, the sub transmission system serves 11 distribution substations, the RERC and Springs generation stations, and two customer stations (Alumax and Kaiser).

4.3 Substations

RPU owns and operates 15 substations that fall into three categories: distribution, customer, and generation. The ten (10) distribution substations served at 69 kV include 12 kV distributions, with four (4) of these substations also including legacy 4-kV distribution. The Freeman and Riverside substations include facilities that serve the older 33-kV sub transmission system, which supplies the Magnolia and Riverside 4-kV distribution substations. However, by the end of 2018 the Magnolia substation is scheduled to be deactivated, once all its 4-kV circuits are converted to 12-kV and transferred to neighboring substations. Table 4.3.1 lists RPU's substations, along with their types and ratings in alphabetical order.

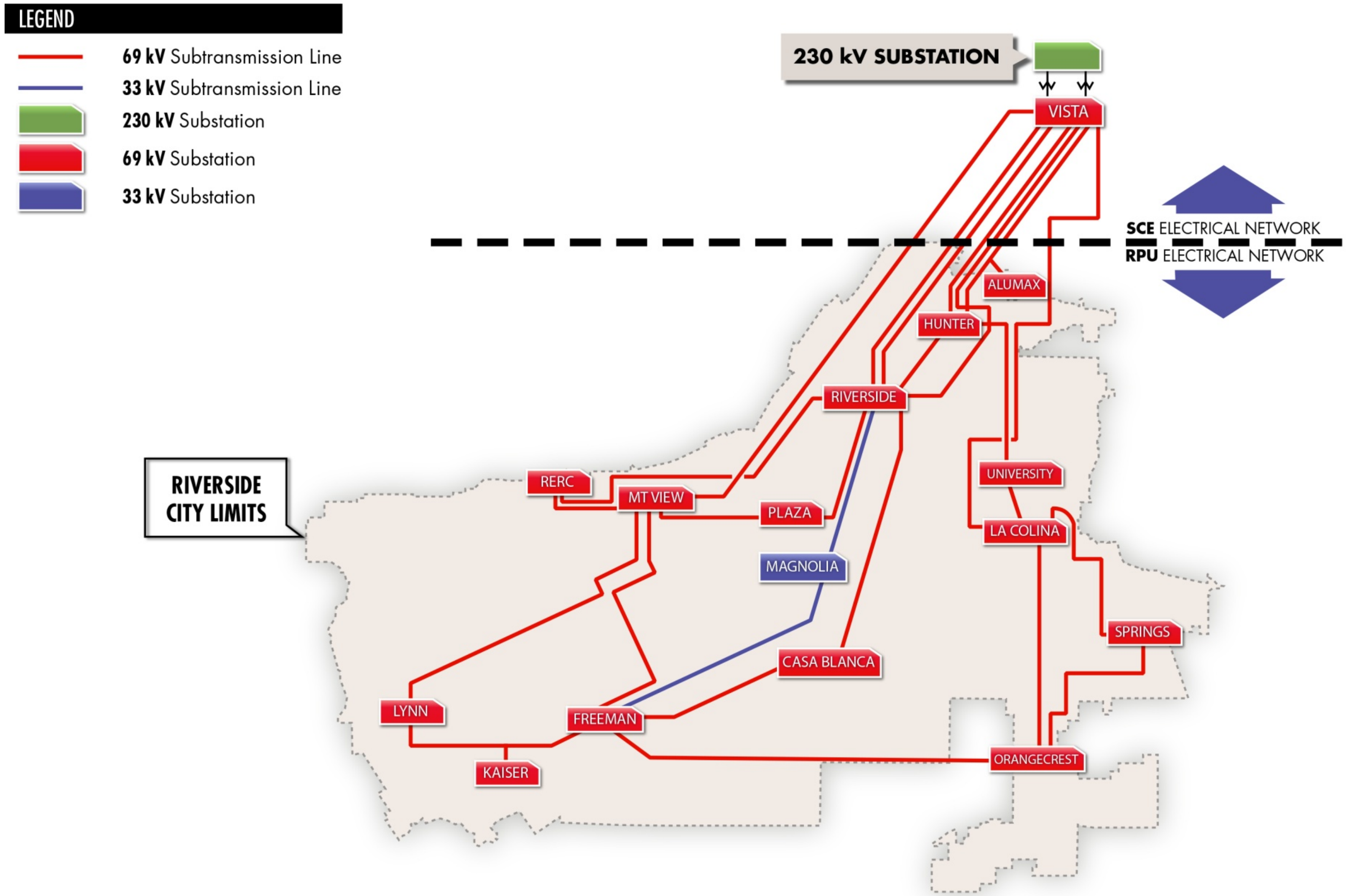


Figure 4.2.1. Existing RPU sub transmission electrical system.

Table 4.3.1. RPU substations; type and rating definitions.

Substation	Type	Rating
Alumax	Customer	69-4 kV
Casa Blanca	Distribution	69-12.5 kV
Freeman	Distribution	69-12.5 kV & 69-33 kV
Harvey Lynn	Distribution	69-12.5 kV
Hunter	Distribution	69-12.5 kV & 69-4 kV
Kaiser	Customer	69-4 kV
La Colina	Distribution	69-12.5 kV
Mountain View	Distribution	69-12.5 kV & 69-4 kV
Orangecrest	Distribution	69-12.5 kV
Plaza	Distribution	69-12.5 kV & 69-4 kV
RERC	Generation	69 kV
Riverside	Distribution	69-12.5 kV & 69-33 kV & 33-4 kV
Springs	Generation and Distribution	69-12.5 kV
University	Distribution	69-12.5 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 Kaiser	Casa Blanca Hunter * Mt. View * Plaza * University *	Freeman * Harvey Lynn * La Colina Orangecrest Springs	RERC Riverside

* 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 (ABB HCB) while the current standard for line protection uses line current differential relays (SEL 387L). Backup protection for the 69-kV lines is a mixture of directional overcurrent in the older relay schemes and step-distance 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 current RPU SCADA system was installed in 2007, including SCADA software provided by Open systems International (OSI) packaged under the Monarch product name.

4.5 Distribution Circuits

RPU's overhead distribution network contains 513 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 12 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 817 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.

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. Remote-reading radio frequency meters (ERT meters) are commonly used when there is no physical access to read the dials of the meter due to a safety hazard, or access is prevented by a locked or inaccessible location.

Meter reading data is kept in the MVRS and MV90Xi meter reading systems. The MVRS system is used for retrieving monthly meter readings for billing purposes. Information retained includes meter reads, meter location, and notes of safety. MV90Xi is a repository of interval data from more complex meter. Meter data for the MV90Xi system is gathered by meter-reading handheld devices, laptops that interrogate the meters, or remote communication (telephone or cellular) links.

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.

The proposed Riverside Transmission Reliability Project (RTRP) would provide RPU with long-term system capacity for load growth, along with needed system reliability and flexibility.

If ultimately approved and developed, the additional transmission capacity would become available through a new substation, named Wildlife Substation. Wildlife Substation would be a 220 kV substation owned and operated by SCE. This substation would 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 would 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 would take place at a second new substation, named Wilderness Substation. Wilderness Substation would be a 220/69 kV substation owned and operated by RPU. The Wildlife and Wilderness Substations would be located within the City of Riverside, adjacent to each other on property that is presently owned by RPU.

Upon the completion of RTRP, RPU's local system will need to be divided into two systems: the east system, served from Vista Substation, and the west system, served from the new Wilderness Substation. In addition, the interconnecting 69 kV lines between the east system (Vista Substation) and the west system (Wilderness Substation) will need to be configured as normally open. This division will also include the remaining sub-transmission line reinforcements that are needed to complete the RTRP upgrade.

4.8 Enhancements to the Distribution System to Integrate DER Technology

Energy Delivery Engineering (EDE) continues to review and approve all requests to interconnect distributed generation in accordance with Electric Rule 22.[1] 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 is participating in a DOE grant funded project to evaluate the use of micro-synchophaser units to identify power quality issues relayed to high penetration levels of distributed generation on the distribution system. EDE is also investigating the use of in line secondary voltage regulators and secondary static VAR compensation

[1] Reference: https://riversideca.gov/utilities/pdf/rates/2011/B%20%20Electric%20Rule%2022%20(6-21-11%20CC)%20approved.pdf

for high penetration transformers. EDE plans to issue a Request for Proposal to model the RPU distribution system, including all existing and planned interconnected distributed generation locations, to determine distributed generation limits for distribution circuit and substation equipment and recommended remedial action for circuits and substation equipment with existing or planned distributed generation in excess of those limits. Further details on these various studies and activities will be presented in Riverside's 2022 IRP.

4.9 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. In order to support the Operational Technology (OT) needs of the Utility, RPU consolidated existing functions and created new positions under the Operational Technology Office. The OTO is 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 includes existing and future OT systems, such as Advanced Distribution Management System (ADMS), Utility Work and Asset Management (UWAM), Advanced Metering Infrastructure (AMI), Geographic Information System (GIS), Supervisory Control and Data Acquisition (SCADA), Customer Information System (CIS), and field / monitoring devices. A visual representation of the Electric Utility Systems and critical utility operational data that the OTO is responsible for managing is shown in figure 4.9.1.

As part of an ongoing effort to improve the utility's visibility into the distribution system, the OTO has identified specific communications and information technology projects that need to be deployed as soon as reasonably possible. These include the deployment of an upgraded Geographic Information System and new Advanced Metering Infrastructure, Asset Management, Meter Data Management, Distribution Automation and Advanced Distribution Management Systems. All of these software systems have been identified as part of an integrated Operational Technology/Information Technology Master Plan strategy to improve organizational efficiency and to optimize deployment of distributed generation resources. Currently, the schedule for deployment of these systems is dependent upon the adoption and continued implementation of RPU's 2018 rate plan.

Figure 4.9.1. Critical utility systems and operational data under the responsibility of the Operation Technology Office.

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 2014 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, cost effectiveness, and resource selection is presented first. AB 2514 – Energy Storage, SB 859 – Biomass mandate, SB 350 – Clean Energy and Pollution Reduction Act of 2015, and AB 398 – the extension of the cap-and-trade program are some notable efforts to be discussed. 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 the phase-2 Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO 2) initiative, various Reliability Services and Commitment Cost Enhancements initiatives, and proposed changes to the Transmission Access Charge (TAC).

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 the bill is to achieve a 33% Renewable Portfolio Standard (RPS) by 2020. However, SB X1-2 also specified that all POU's must 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, the procurement of renewable resources must be predominantly from in-state renewable resources; e.g., starting in 2017, 75% of renewable resources within the target must be located in-state and no more than 10% can be from tradable renewable energy credits (TRECs).

SB X1-2 also requires 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 and is currently being updated again in 2018.

In June 2017, Riverside received an official CEC Compliance Determination notice that the RPS procurement targets for CP1 were met. By the end of calendar year 2016, Riverside met 27% of its retail sales from renewable resources and expects to receive a similar compliance notice for CP2. At the end of calendar year 2017, Riverside met 36% of its retail sales from renewable resources, exceeding the 2020 CP3 target three years earlier than mandated.

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 2017, SB 100 was introduced into legislation seeking another increase in renewable targets to 44% by 2024, 52% by 2027, and 60% by 2030, coupled with a 100% clean energy (i.e., carbon free) mandate by 2045. This bill is still pending approval in the state legislature and is expected to pass in some form in 2018.

With respect to the current RPS paradigm under SB 350, RPU is already well positioned to comfortably exceed all state specified renewable mandates for at least the next 6 years (i.e., through 2024). If SB 100 becomes law, then RPU is expected to remain above the minimum compliance levels through 2022. Under either scenario, it will be necessary to procure additional renewable energy resources in the early part of the next decade or use excess renewable energy credits to meet the increasing RPS mandates from 2024-2030.

With the constantly changing landscape on the required RPS levels and other initiatives that will be discussed later, the implementation of these increasing mandates will have a significant impact on the CAISO markets. It is expected that more intermittent renewable resources will be entering into the CAISO market, increasing the energy imbalance that currently exists. Also, with the expectation that energy storage will eventually become a required energy resource component in each utilities resource portfolio, further market realignment will be necessary to accommodate this new technology.

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 MRR and are not required 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 for imports from the Intermountain Power Project.

The Program requires electric utilities to have GHG allowances on an annual basis to offset 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, these must be purchased 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 of the utility's direct GHG compliance obligations.

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 generating resources with capacity factors greater than 60%that exceed GHG emissions of 1,100 lbs/MWh. SB 1368 essentially prohibits any long term investments in generating resources based on coal. Thus, SB 1368 disproportionally impacts Southern California POU's since these utilities have invested heavily in coal technology.

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. However, to the extent that significant numbers of coal plants throughout the Western US start 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 SB1 – California Solar Initiative

SB 1, enacted in 2006, requires municipal utilities to establish a program supporting the stated goal of the legislation to install 3,000 megawatts (MW) of photovoltaic (PV) resources in California. Municipal utilities are also required to establish eligibility criteria in collaboration with the CEC for funding solar energy systems receiving ratepayer funded incentives and meet reporting requirements regarding the installed capacity, number of installed systems, number of applicants, and awarded incentives.

As a Publicly Owned Utility (POU), RPU adopted a goal of providing $25 million over 10 years for customer incentives for PV installations. This amount represents Riverside's share of the statewide SB 1 solar goal for all POU's in California. RPU has expended close to $18 million in Public Benefit Funds for the SB 1 Program implementation. These expenditures resulted in over 1500 customers installing new PV systems within the service territory and over 12 MW of locally generated solar energy. This incentive program will sunset on December 31, 2017 and RPU will cease to provide SB 1 PV rebates.

5.1.5 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, regardless of size, to report on all investments in energy efficiency and demand reduction programs annually to the CEC, which is provided as a combined effort between CMUA, NCPA, and SCPPA. 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.

As part of the report, an update on the 10-year energy savings target is also included, which stems from AB 2021 that was approved 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 the 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. However, an open question remains with respect to which EE and/or DSM programs are most cost-effective in an integrated resource sense. This specific topic is explored in greater detail in Chapters 6 and 14.

5.1.6 AB 2514 - Energy Storage

AB 2514 "Energy Storage Systems" was signed into law on September 29, 2010. In 2012, AB 2227 amended the reporting timeline of the energy storage targets referenced in AB 2514. The law directs the governing boards of publicly-owned utilities (POUs) to consider setting targets for energy storage procurement, but emphasizes that any such targets must be consistent with technological viability and cost effectiveness. The law's main directives for POUs and their respective deadlines are as follows: (a) to open a proceeding by March 1, 2012 to determine appropriate targets, if any, for the utility to procure viable and cost-effective energy storage systems, and (b) to adopt an energy storage system procurement target by October 1, 2014, if determined to be appropriate, to be achieved by the utility by December 31, 2016, and a second target to be achieved by December 31, 2020. POUs were required to submit compliance reports to the CEC of their first adopted target by January 1, 2017. The utility's second adopted target compliance report is due to the CEC by January 1, 2021.

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 at a later time. Currently, the commercially available ES technologies (or soon to be available technologies) consist of pumped hydro generation, compressed air systems, batteries, and thermal ES systems.

On February 17, 2012, as per the statute, the Riverside Board of Public Utilities opened a proceeding to investigate the various energy storage technologies available and determine if Riverside should adopt energy storage procurement targets. RPU finished its investigation of energy storage pricing and benefits in September 2014 and adopted a zero (0) megawatts (MW) target based on the conclusion that the viable applications of energy storage technologies and solutions at the time were not cost effective. RPU had to reevaluate its assessment by October 1, 2017 and report to the CEC any modifications to its initial target resulting from this reevaluation. On September 11, 2017 RPU filed a report with the Board of Public Utilities adopting a target of deploying six (6) MWs of energy storage by December 31, 2020.

On March 3, 2015, the City Council approved the Ice Bear Pilot program for five (5) MW. The program is intended to reduce load during peak hours, improve energy efficiency, and demonstrate the City's proactive support of the State's energy storage goals. On July 28, 2015, the City Council approved a 20-year power purchase agreement for Riverside to procure renewable energy from the Antelope DSR Solar Photovoltaic Project that includes a built-in energy storage option for the buyers to exercise during the first fifteen years of operation.

On December 12, 2016, Riverside submitted its first compliance report to the CEC describing Riverside's proactive efforts in investigating viable energy storage options in the market and conducting energy storage pilot projects within the City.

5.1.7 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 total 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). This moratorium caused great concern regarding reliability in the upcoming summer and winter months. An action plan study area was initiated to review the summer and winter assessment that was conducted as a joint effort between the CPUC, CEC, CAISO, and LADWP. Although the area of study does not include nor immediately impact Riverside, it is highly plausible that RPU could still experience curtailed gas deliveries under certain adverse low-flow gas scenarios.

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 would disproportionally impact RPU due to the requirements to operate internal natural gas generation to maintain system reliability during the summer. Also, gas curtailments during high peak days could lead to severe service curtailments throughout Riverside. Therefore, RPU immediately increased internal communication across divisions, created internal gas curtailment procedures to address this specific issue, and created revised dispatch procedures when load forecasts exceed 400 MW. These tighter OFO tariff restrictions were scheduled to conclude upon the earlier of the return of Aliso Canyon to at least 450 MMcfd of injection capacity and 1,395 MMcfd of withdrawal capacity, or March 31, 2017. Aliso Canyon has not been able to meet its injection and withdrawal targets, therefore, these tighter OFO tariff restrictions will continue to remain in effect. In addition, RPU continues to communicate with the CAISO and SoCalGas on any changes that could impact our service territory.

On July 19, 2017, DOGGR issued a press release on their determination, in concurrence with the CPUC, that Aliso Canyon is 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. Withdrawals from Aliso

Canyon can be made during emergency conditions to avoid electric load shed and/or gas curtailments to customers.

RPU fulfilled its system reliability without any issues during multiple heat waves in both 2016 and 2017. Going forward, RPU will continue to monitor workshops and new legislation and regulations that impact the status of Aliso Canyon and its effect on the reliability of the utility's service territory. The latest status of the 114 injection well tests was as follows: 59 passed all tests, 52 were taken out of operation, and three wells have been plugged and abandoned.

5.1.8 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 publically 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.

Staff has calculated that the actual MW obligation share for RPU is 1.3 MW. It is expected that any procured biomass will be counted towards our RPS goals. The seven (7) affected POUs have elected to procure a contract together for economies of scale. Currently, coordination on this biomass procurement issue is occurring through a centralized SCPPA RFP.

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

SB 350, enacted in 2015, consists of a multitude of requirements to meet the Clean Energy and Pollution Reduction Act of 2015. The primary components that affect RPU are 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 is a specific Integrated Resource Planning (IRP) mandate embedded in the bill that applies to 16 POUs that have a 3-year average annual demand over 700 GWh, which includes Riverside.

RPU's last IRP was completed in 2014 and approved by the PUB and City Council in 2015 and will continue to be approved in this manner going forward. The current IRP addresses most of the required topics to some extent, but will require further study and expansion on certain topics.

By January 1, 2019, the governing board of RPU shall adopt an IRP and a process for updating the plan every 5 years. The IRP must 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. The IRP must be submitted to the CEC for review, of which the CEC will check if the statutory requirements have been met and will adopt guidelines to govern the submission of the IRP information. Currently, the CEC is working with the POUs to better determine the CEC's role in the IRP and the POUs governing body in the IRP process. On August 9, 2017, the CEC adopted the POU IRP Submission and Review Guidelines. The CEC continues to host various workshops on different components of the SB 350 requirement and Riverside has been monitoring these proceedings.

5.1.10 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 buildings (i.e., 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. RPU will need to provide consumption data for buildings meeting the legislative requirement upon owner's 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.

5.1.11 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 the retail suppliers' power source disclosure (PSD) and power content label (PCL) to their customers. GHG emissions intensity factors will need to be provided for all the retail electricity products. The inclusion of this new information requirement on the PCL will begin in 2020 for calendar year 2019 data. In addition to still being required to post the PCL on the city website, the bill 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 reinstated the inclusion of printed disclosures of the PCL with its September bills to the customers.

Currently, the CEC is hosting workshops on the GHG emissions disclosure requirements and have begun the rulemaking process of updating their PSD regulations. A pre-rulemaking phase is being conducted that includes an implementation proposal on AB 1110. RPU continues to monitor the workshops and draft regulations for any impacts to the utility's reporting and resources in meeting this requirement.

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

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

The unknown component of this law is that it is unclear whether RPU will be required to consign 100% of their allowances to the market and then purchase allowances back to fulfill its compliance obligations. Currently, POUs receive a sufficient amount of allowances each year to cover their compliance, without needing to consign these direct compliance allowances to the market for purchase. Other unknown components of the law are the excess allowance banking provisions and the specific GHG revenue spending requirement for revenues generated from the sale of excess allowances. ARB will be hosting more workshops and issuing the next iteration of regulation changes. RPU will continue to monitor the outcome and impacts of the upcoming regulations on its service territory and ratepayers.

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, also known as 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 cost impacts to Riverside's ratepayers are described in more detail below.

5.2.1 Bidding Rules Enhancements Initiative

This market initiative focuses on improving market efficiency and reinforcing reliability. Through this initiative, the ISO will evaluate the following:

1) Bidding rules related to the unrestricted flexibility of resources regarding changes of energy bid prices between the day-ahead and real-time markets, as well as across real-time hours.
2) The current restrictions on commitment cost changes between and within the day-ahead and real-time markets.
3) Further verification of generator resource characteristics that can improve market efficiency and grid reliability.

In May 2016, the CAISO implemented the Bidding Rules Enhancements Part A. The intent of Part A is to refine and improve the alignment between energy and commitment cost bidding rules. In November 2017, the CAISO implemented Part B, which refines and improves parameters used in commitment costs and in default energy bids, and allows for custom fuel regions that accurately reflect natural gas procurement. RPU continues to monitor this initiative as the CAISO's proposals may require significant market design and system changes.

5.2.2 Commitment Costs and Default Energy Bid Enhancements Initiative

This Initiative evaluates if commitment costs and default energy bids allow scheduling coordinators to accurately reflect and recover the generators' unit-specific marginal costs. The Initiative also evaluates if changes to the economic bidding of commitment costs and associated market power mitigation methodology could increase market benefits when bidding under competitive market dynamics.

This initiative addresses RPU's concerns with CAISO market design features that may affect bidding flexibility and market based offers for commitment costs. Although workshops began in 2017 for this initiative, implementation has been postponed from fall 2017 to fall 2018.

5.2.3 Commitment Costs Enhancements 3 Initiative

In this initiative, the CAISO proposes to change the definition of a "Use Limited" resource and the approval process regarding a resource seeking Use Limited status. In the future, resources would have to apply for Use-Limited status with proper documentation. It is crucial for RPU staff to understand proposed changes by the CAISO regarding Use-Limited resources as RPU owns and operates two Use-Limited natural gas power plants. The Use-Limited application process began in spring 2017 and went into effect in fall 2017. RPU submitted documentation to the CAISO that supports the two Riverside resources that are currently classified as Use-Limited. The remaining component of the initiative related to addressing a Use Limited resource's opportunity cost is still under evaluation and CAISO expects this to be completed by late summer 2018.

5.2.4 Flexible Resource Adequacy Criteria (FRAC) and Must Offer Obligation (MOO) 2 Initiative

The Flexible Resource Adequacy Criteria and Must Offer Obligation (FRAC-MOO) initiative was the initial step toward ensuring that adequate flexible capacity was available to CAISO to address the needs of the rapidly changing grid. Under FRAC-MOO, the first flexible capacity obligation was developed, recognizing that a resource adequacy program should include both the size (MW) of resource needs and the flexible attributes needed to reliably operate the grid. CAISO intended on making enhancements to the original FRAC-MOO design once it had experience operating under a flexible capacity paradigm and better understood the system's needs.

In June 2015, the CAISO issued the Reliability Services and FRAC-MOO Phase 2 Issue Paper and then later on in December 2015, issued the FRAC-MOO Phase 2 Straw Proposal to expand the scope of the original FRAC-MOO initiative, now known as FRAC-MOO 2. As part of FRAC-MOO 2, CAISO conducted a preliminary assessment of historical flexible resource adequacy (RA) showings. The general findings of the assessment was that "flexible capacity showings to date indicated that the flexible capacity product is not sending the correct signal to ensure flexible capacity will be maintained long-term".

This initiative will explore additional enhancements to flexible capacity requirements to help address generation oversupply and ramps less than three hours. This effort also pursues new rules to allow intertie resources and storage resources not operating under non-generator resource provisions to provide flexible capacity. Through this effort, the CAISO will also assess the impact of merchant variable energy resources on flexible capacity requirements. RPU is concerned about the future eligibility of its resources to provide flexible RA capacity and will continue to actively engage and participate in this initiative.

5.2.5 Review of Transmission Access Charge (TAC) Structure Initiative

This initiative will consider potential changes to the CAISO's current volumetric TAC structure for recovering participating transmission owners' (PTO) costs of owning, operating, and maintaining transmission facilities under CAISO operational control. The CAISO proposes to address at least two major TAC structure issues in this initiative:

(1) Whether to modify the TAC billing determinant to reduce TAC in PTO service areas for load offset by distributed generation (DG) output, and if so, what modification would be most appropriate, and

(2) Whether to modify the current volumetric structure of the TAC to consider using a demand based charge, either instead of or in addition to a volumetric charge, or a time-of-use pricing structure.

At this time, Riverside is concerned with possible cost-shifting that could increase TAC rates on RPU load and is actively engaged and participating in the initiative stakeholder process.

5.2.6 Reliability Services Initiative Phase 2

Reliability Services Initiative's (RSI) purpose is to create an efficient and durable market mechanism for backstop capacity procurement, develop necessary conforming changes to resource adequacy processes, and enhancing rules specific to Resource Adequacy resources. During the RSI - Phase 2 Stakeholder process, CAISO will finalize replacement and substitution rules for flexible and local capacity resources, as well as clarify processes and timelines for CAISO default resources adequacy rules and effective flexible capacity calculations.

This Phase 2 initiative will focus on application software changes, CAISO Business Practice Manual (BPM) changes, Customer Interface for Resource Adequacy (CIRA) modifications to the RA and Supply plan breakdown of local and system. The CAISO plans to redesign replacement rules for system RA and monthly RA processes, update planned and forced outage substitution rules, and allow market participants to select how much system/local MWs to substitute.

5.2.7 Other CAISO Initiatives

CAISO has many other initiatives currently underway; the list shown below represents a sampling of other areas that RPU staff is currently monitoring:

- Aliso Canyon Gas-Electric Coordination Phases 1-3
- Capacity Procurement Mechanism and Risk of Retirement Process Enhancements
- Congestion Revenue Rights Auction Efficiency Initiative
- Contingency Modeling Enhancements
- Energy Imbalance Market (EIM): Consolidated Energy Imbalance Market Initiative
- EIM: EIM Updates
- EIM: California Greenhouse Gas Compliance
- EIM: Imbalance Conformance Enhancements
- Energy Storage and Distributed Energy Resources Phase 2
- Regional Governance
- Regional RA
- Regional TAC Options

5.2.8 2018 Annual Policy Initiatives Roadmap

In January 2018, CAISO published its 2018 Final Policy Initiatives Roadmap, which establishes the framework of current and upcoming Initiatives that the CAISO will address over the next three years. The 2018 Roadmap proposes aggressive changes to its current Resource Adequacy Program, Day-Ahead Market Structure, and Transmission Access Charge 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.

6. Demand Side Management and Energy Efficiency

This chapter presents an overview of RPU's demand side management (DSM) programs, including energy efficiency (EE). RPU recognizes the important role that DSM and EE plays 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 the IRP. As such, this chapter reviews 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.

6.1 Background

Demand side management (DSM) and energy efficiency (EE) are important topics for a utility to consider when developing an IRP. These resources affect both 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. An important consideration for RPU's future resource strategy is to cost effectively utilize Energy Efficiency (EE) and Demand Side Management (DSM) programs.

6.1.1 What are Demand Side Management and Energy Efficiency?

DSM programs and systems allow customers to effectively manage the timing of energy usage. From the customer perspective, this is particularly important if they have time of use rates and want to reduce their bills. Customers utilizing DSM are able to shift their energy consumptions from a more expensive peak time to a time of day when energy costs are lower. A common DSM technology is the use of ice thermal storage in combination with, or in place of, air conditioning (HVAC) systems. Ice thermal systems generate and store ice at night when energy prices are lower. Air is then blown over the ice during the day to provide cooling in lieu of more energy intensive traditional air conditioning. This type of cooling can reduce costs for customers on time-of-use (TOU) energy and demand rates. For RPU, encouraging customers to shift their energy consumptions from the peak times of the day to off-peak hours also reduces costs incurred by the utility. Infrastructure system needs are reduced by not having to acquire and maintain as much infrastructure capacity as would have been needed for a higher peak demand and the costs associated with generation and energy procurement are also less due to the lower quantities of electricity procured during peak demand periods when market prices are higher.

While DSM programs simply shift energy consumption, EE programs reduce the overall amount of energy consumed. Depending on the technologies or methodologies used, EE products or practices may reduce energy consumption throughout the day, i.e. an efficient refrigerator that consumes less energy all day, or the reduction of consumption during specific times of the day, i.e. an efficient air conditioning system which must run less frequently in the afternoons. For customers, EE reduces the amount of energy they use, therefore reducing their bills. Additionally, by minimizing consumption and energy demand, less energy must be generated or acquired by RPU, which in turn can result in lower total utility infrastructure costs.

In summary, EE programs tend to save customers money by reducing the total amount of energy purchased, while DSM programs tend to reduce overall utility costs by avoiding or reducing energy usage during peak hours. In addition to the aforementioned benefits, EE and DSM programs also help RPU to:

- Defer the need to build physical generation assets,
- Reduce 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.

Notwithstanding these positive benefits, all EE and most DSM programs also impose costs on a utility, specifically in the area of "unmet revenue streams". Obviously, it is important to properly estimate these costs, in order to conduct an accurate cost/benefit analysis of each program.

6.1.2 Regulatory Requirements Affecting RPU

RPU began offering DSM and EE programs over 20 years ago. These programs ramped up in 1997 after the electricity markets in California were restructured in response to AB 1890. At that time, DSM and EE were recognized as important components in meeting California's energy goals. AB 1890 required all utilities to establish the public benefits charge to fund specified programs. For RPU the public benefits charge, still in existence today, is calculated as 2.85% of customer usage charges and provides approximately $7 to $10 million annually. These funds are mandated to be spent in the following four areas:

1. Cost-effective demand-side management services to promote 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 as a means to control the size of and demands on the electric grid. Annual reporting of the energy efficiency saving 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 has also lead to a push to reduce energy consumption based on a belief that "the less energy used, the fewer the emissions."[1] Thus, when EE is cost-effective, it represents a cost-effective means to reduce emissions. 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 DSM as well as demand response (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 nonutility programs.

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 this past year are all utilized. Descriptions of each of these data sources are contained in the following section.

6.2 DSM and EE Programs, Potential Energy Savings, and Energy Reduction Targets

Energy savings or the shifting of energy use is considered to be DSM or EE 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 benefit funds but may also be funded through grants. Non-

[1] 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)

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.

6.2.1 RPU Customer Programs

RPU offers many DSM and EE programs and provides educational resources to our customers so that they can better manage their energy usage and lower their bills. Funding for the RPU programs is provided by the public benefits charge (PBC) on all customer energy usage. It should also be noted that RPU partners with the Riverside County's Community Assistance Program and with the Southern California Gas Company[2] to provide additional energy efficiency programs to our low income customers. However, the energy savings resulting from the actions of these agencies are not included in RPU's reported EE savings or in our EE goals.

RPU DSM and EE Programs

The following section lists and describes each of RPU's DSM and 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.
- Commercial Food Service Program – Program specifically targeting commercial food service customers such as restaurants, hospitality providers, institutional, medical/hospital customers, schools and government customers. The program is offered in conjunction with Southern California Gas Company (SCGC) and provides customers with a comprehensive facility audit offering recommendations on specific energy efficiency measures, estimated return on investment, and applicable utility incentives.
- 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

[2] Energy savings resulting from programs funded by the Southern California Gas Company are not reported in RPU's IRP. RPU programs that encourage electrification of appliances and systems, such as water heaters, and paid for by RPU are not considered here.

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. RPU is also working with SCGC on this program. Customers are also offered additional technical and contracting assistance to bring large energy efficiency projects from concept to.

- 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.
- Upstream HVAC Rebate Program – Rebate incentive for commercial high efficiency HVAC equipment purchases that exceed Title 24 requirements, provided upstream at the wholesale distribution channel level, thereby encouraging distributors to stock and sell more efficient HVAC equipment.
- 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.
- Thermal Energy Storage Incentive – Feasibility study and incentives available for use of thermal energy storage based on program guidelines.
- Ice Energy Thermal Energy Storage Pilot Program – Combined thermal energy storage program and energy efficiency pilot program created in FY 14/15 and implemented in FY 15/16 to replace old HVAC equipment with new energy efficient equipment installed concurrently with Ice Bear thermal energy storage equipment.

Commercial Direct Installation Programs

- Small Business Direct Installation (SBDI) Program – This program provides 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.
- Cool Cash – Rebates for replacing Central Air Conditioners with a SEER rating of 15 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 March back of the bill (Res Cooling).
- 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.
- Whole House Rebate Program – Rebates for completing multiple energy efficiency measures as one project. Points are awarded for each type of measure and then multipliers are given at specific point intervals on a sliding scale to encourage implementation of multiple energy efficiency measures as one project under one application.

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 our established annual targets for FY 10/11 through FY 16/17, respectively.

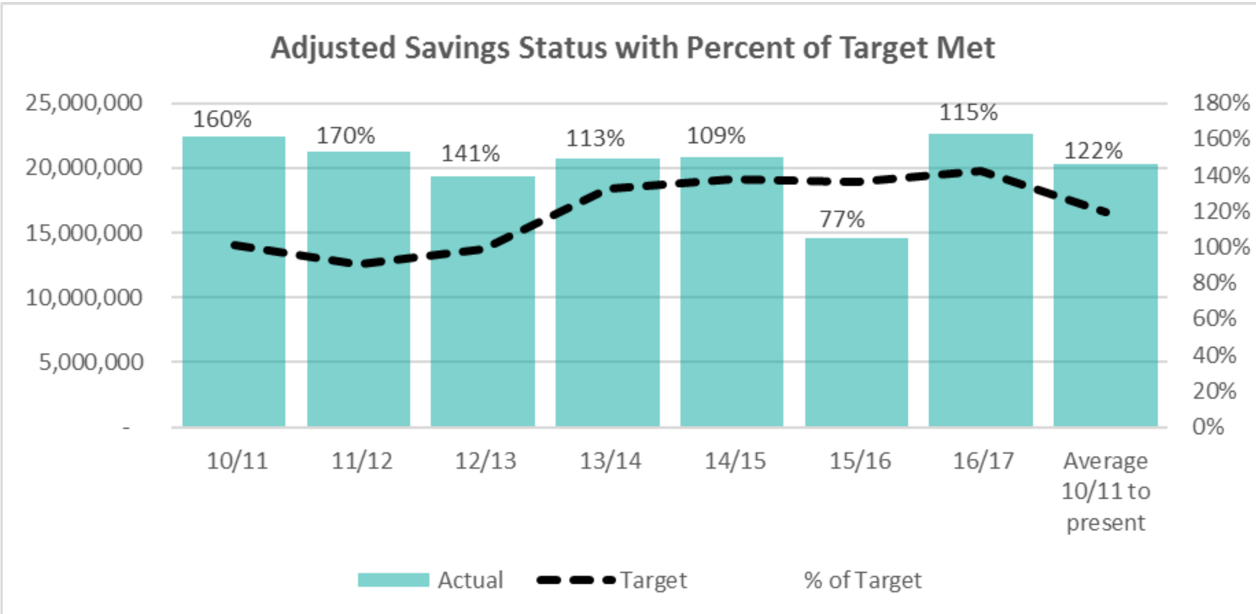


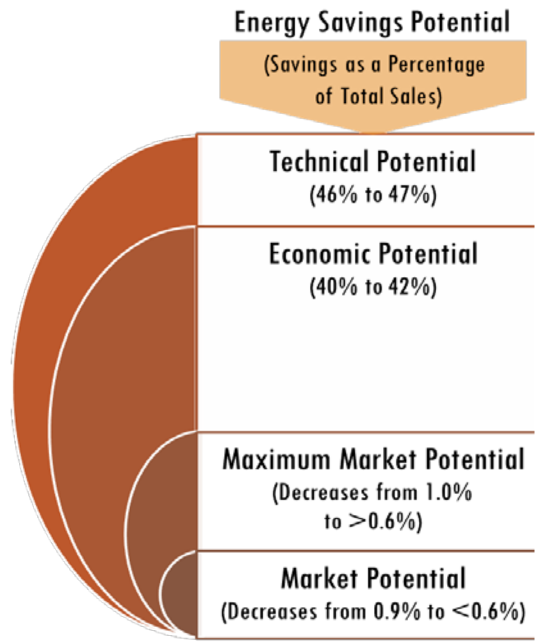
Figure 6.2.1. Reported EE savings for FY 10/11 through FY 16/17.

6.2.2. Energy Savings Potential and Targets

As noted above, 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 2016, RPU, along with other members of CMUA, engaged Navigant Consulting, Inc. to identify potential target goals for EE programs. To complete this analysis, Navigant used its most current Electricity Resource Assessment Model (ELRAM). Potential energy savings were developed for the years 2018 through 2027 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, Energy Efficiency in California's Public Power Sector, 11th Edition – 2017.[3] In conjunction with reporting on the potential savings identified in this report, RPU adopted EE savings targets in August 2017.

[3] CMUA, *Energy Efficiency in California's Public Power Sector, 11th Edition – 2017,* April 2017; see Appendix B.

Navigant's model, shown to the right, was used to develop utility specific estimates for technical, economic, and market potential energy savings.[4]



- Technical Potential. Technical potential energy savings are developed from the model as if every measure or program that can produce energy savings were implemented by all customers that the measure would apply to – regardless of cost-effectiveness. It also does not make any adjustment for existing market penetration of a measure. Additionally, no adjustment is made to account for the utility customer's awareness or willingness to install and implement the measures.

- Economic Potential. Economic potential adjusts the technical potential energy savings amount so that it only reflects the universe of measures that could be considered cost-effective to the customer. Similar to technical potential, no adjustment is made to account for the utility customer's awareness or willingness to install and implement the measures.

- Maximum Market Potential. Maximum market potential adjusts the economic potential energy savings to reflect the maximum energy savings potential that results from the suite of measures in RPU's customer programs, regardless of the budget commitment made. This adjustment removes potential energy efficiency savings that are not included in an incentivized customer program. Additionally, the savings potential is adjusted down to model the percentage of customers aware of and willing to install the measures. Energy savings potential of the programs is identified as both a potential net energy savings and energy savings that result specifically because the utility offered a rebate to the customer and gross energy savings. Finally, gross energy savings represents the total potential energy savings that the utility provides a rebate for, but also includes some customers who would have installed the measure without a utility incentive.

- Market Potential. Market potential energy savings refines the maximum market potential further to reflect program incentive levels (budgets) and historical program achievements. This step is often considered to be the realistic market potential for a set of utility programs if no or few changes occur in the EE program offerings. Market potential energy savings are calculated for both gross and net savings.

[4] Navigant Consulting, Inc., *Energy Efficiency Potential Forecasting for California's Publicly Owned Utilities,* Prepared for California Municipal Utilities Association, February 22, 2017.

Market potential energy savings estimates are conservative estimates of achievable energy efficiency from the suite of measures offered by a utility. 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 establish a more aggressive energy savings targets of 1% of forecast sales through 2030 based on gross energy savings form 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 that it was 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 August 2017) as well as the energy efficiency and demand reduction potential results from the Navigant analysis are shown in Tables 6.2.1 and 6.2.2, respectively.

6.2.3. Energy Savings Targets Adopted by RPU and the CEC

In November 2017, the CEC adopted both statewide energy efficiency targets as well as recommended sub-targets for each utility.[5] The CEC recommended a conservative approach when establishing the utility specific sub-targets. For POUs, including RPU, the CEC established the targets as the market potential (or net incremental energy savings) produced by the analysis completed by Navigant. Additionally, the CEC also extended the range of the sub-targets to reflect their mandated requirement to develop targets to be achieved a doubling of energy efficiency savings from 2015 levels by January 1, 2030. As such, the CEC sub-targets include the reported energy efficiency savings from 2015 through 2017. They also extend the net incremental EE savings from 2027 through the end of 2029. The CEC's sub-targets, along with the RPU adopted targets, are shown in Tables 6.2.1 and 6.2.2. Likewise, a comparison of the CEC's sub-targets to RPU's adopted targets and the potential gross and net incremental energy savings is shown in Figure 6.2.2. RPU's more aggressive energy efficiency targets are almost double the CEC's sub-target for the utility.

[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 6.2.1. Energy savings from Energy Efficiency programs (MWhs).

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Technical Potential	1,067,230	1,073,929	1,067,131	1,073,309	1,083,526	1,088,861	1,095,695	1,103,437	1,104,424	1,105,200
Economic Potential	936,287	938,800	949,896	955,080	961,242	966,345	971,436	975,381	991,668	992,736
GROSS Incremental Market Potential	23,369	23,508	22,830	21,817	20,779	19,695	18,500	17,374	16,124	14,601
GROSS Cumulative Market Potential	23,369	46,877	69,707	91,524	112,302	131,346	148,067	163,563	177,721	190,083
NET Incremental Market Potential	20,594	20,815	20,309	19,451	18,492	17,505	16,426	15,403	14,310	12,968
NET Cumulative Market Potential	20,594	41,409	61,719	81,170	99,662	116,581	131,430	145,170	157,742	168,729
Riverside Adopted Target	**22,990**	**23,010**	**23,070**	**23,110**	**23,250**	**23,320**	**23,370**	**23,450**	**23,470**	**23,688**

Source: Navigant Potential Study

Table 6.2.2. Demand reduction from Energy Efficiency programs (kWs).

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Technical Potential	301,032	301,974	302,054	302,801	304,233	304,163	305,191	306,343	306,035	305,675
Economic Potential	221,661	221,622	221,567	220,669	221,132	221,180	221,382	221,577	225,318	225,029
GROSS Incremental Market Potential	8,497	7,954	7,595	7,544	7,539	7,585	7,497	6,759	5,926	4,716
GROSS Cumulative Market Potential	8,497	16,452	24,047	31,591	39,129	46,660	53,872	60,331	65,943	70,312
NET Incremental Market Potential	7,091	6,703	6,441	6,400	6,361	6,370	6,276	5,646	4,959	3,974
NET Cumulative Market Potential	7,091	13,794	20,237	26,635	32,995	39,289	45,269	50,605	55,238	58,863

Source: Navigant Potential Study

Table 6.2.3. CEC adjusted subtargets 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.

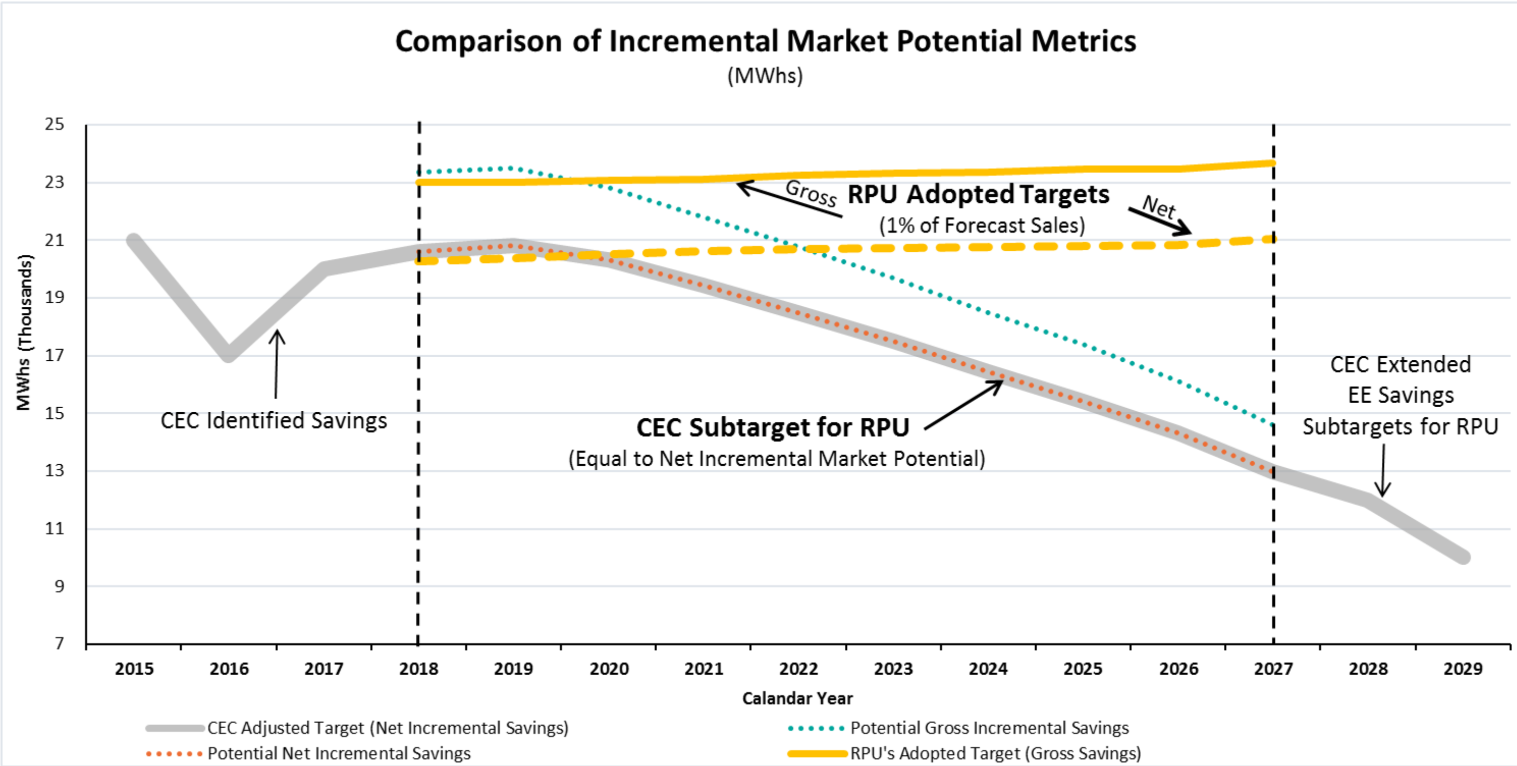


Figure 6.2.2. CEC adopted sub-targets compared to RPU adopted targets and potential Gross and Net incremental savings.

6.2.4 Energy Savings from Non-Utility Programs

In addition to the programs that RPU offers, RPU also recognizes that many state regulations, laws, and individual consumer preferences are also 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 and increase energy efficiency. Most 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 energy efficient standards. 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. 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 developments that do not demand as much electricity as the developments of the past.

These codes and standards represent energy savings that are not part of an RPU program but include energy savings that affect the forecast energy demand. As part of the potential energy savings analysis performed by Navigant and previously discussed, incremental and cumulative energy savings resulting from adopted codes and standards was provided in the potential study. For RPU, these savings are shown in Figure 6.2.3 below. For this IRP, these energy savings are included in the forecast energy demand and associated analysis.

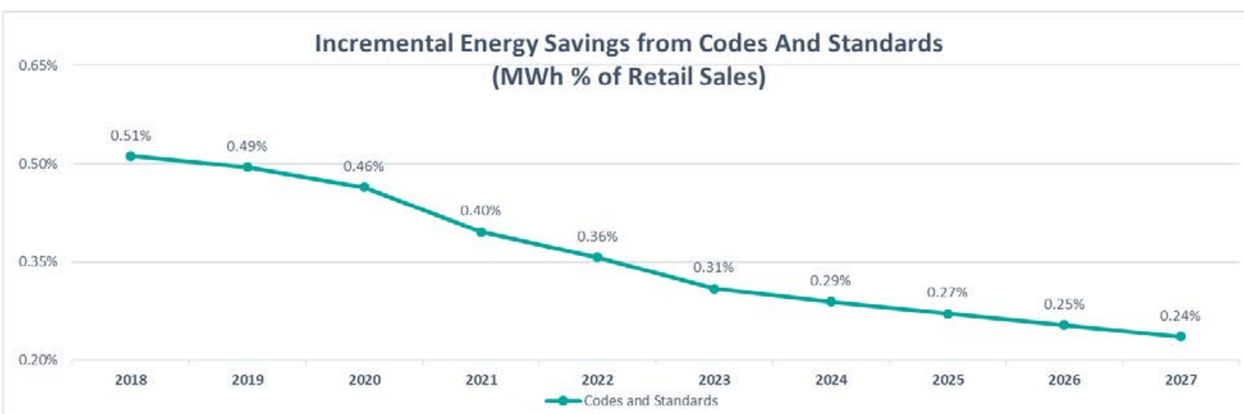


Figure 6.2.3. Incremental energy savings from Codes and Standards.

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. However, at this time, RPU does not have adequate data to estimate the energy savings resulting from the customer implementation of these technologies. As data becomes available, RPU will incorporate it into its IRP analysis.

Finally, RPU also recognizes a number of 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 come available, RPU will incorporate it into its 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 funding and direction for improvement in energy efficiency at schools.
- <u>Reporting Energy Use in Existing Buildings:</u> AB 802 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 Cost/Benefit Principles of EE and DSM Programs

Every EE or DSM program carries both costs and benefits to customers and utility. In theory, by examining these financial impacts, RPU should be able to identify the optimal mix of EE and DSM programs that maximize the benefits to participating customers and utility and minimizes any financial impacts on non-participating customers and the utility.

More specifically, each type of EE and DSM program will affect the participating customer, the non-participating customers, the utility, and society as a whole in different ways. Generally, a customer that participates in one or more of these programs reduces their costs and thus their payments to the utility. At the same time, the utility will typically reduce both its power supply costs and distribution system maintenance costs. However, if the utility's reduction in costs is less than the customer's reduction in costs, then the utility will experience a "net unmet revenue effect". If and when this occurs, the utility must in turn raise its rates across all customers to recover this unmet revenue stream. Hence, non-cost effective EE and DSM programs ultimately result in an effective rate increase for all non-participating customers.

To evaluate EE and DSM, the National Action Plan for Energy Efficiency and the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects, describe the five principal cost-effectiveness tests used to evaluate EE and DSM programs (Table 6.3.1).

Table 6.3.1. The five principal Cost-Effectiveness tests used in Energy Efficiency evaluations.

Test	Acronym	Key Question Answered	Summary Approach
Participant cost test	**PCT**	Will the participants benefit over the measure life?	Comparison of costs and benefits of the customer installing the measure
Program administrator cost test	**PACT**	Will utility bills increase?	Comparison of program administrator costs to supply-side resource costs
Ratepayer impact measure	**RIM**	Will utility rates increase?	Comparison of administrator costs and utility bill reductions to supply side resource costs
Total resource cost test	**TRC**	Will the total costs of energy in the utility service territory decrease?	Comparison of program administrator and customer costs to utility resource savings
Societal cost test	**SCT**	Is the utility, state, or nation better off as a whole?	Comparison of society's costs of energy efficiency to resource savings and non-cash costs and benefits

Source: National Action Plan for Energy Efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers. November 2008.*

Each test has a different purpose and evaluates the effectiveness of the program or group of programs based on the perspective of the participating customer, utility, program administrator, and other non-participating customers. Costs and benefits considered are different for each of the tests. A summary of the benefits and costs included in each of the principal cost-effectiveness test is identified in Table 6.3.2 on the following page.

While all of the cost effectiveness tests merit consideration, for purposes of the IRP, RPU focuses consideration on the Ratepayer Impact Measure test (RIM) for evaluating EE and DSM programs because it allows for the evaluation of the revenue needs and the impact of the programs on all customers. The ultimate goal of the analysis is to identify the optimal amount of demand side programs that can be reliably and cost effectively incorporated with our supply-side resources to meet our load serving needs. For full evaluation, the Program Administrator Cost Test (PACT) and Total Resource Cost Test (TRC) are also included. These tests are the primary tests used by the California Public Utilities Commission (CPUC) when evaluating EE and DSM portfolios for investor-owned utilities. In Chapter 14 an examination of the cost/benefit impacts of the various EE programs to quantify these net unmet revenue streams will be conducted in greater detail, to effectively address this issue.

Table 6.3.2. Summary of benefits and costs included in each Cost-Effectiveness test.

Test	Benefits	Costs
PCT	*Benefits and costs from the perspective of the customer installing the measure*	
	• Incentive payments • Bill savings • Applicable tax credits or incentives	• Incremental equipment costs • Incremental installation costs
PACT*	*Perspective of utility, government agency, or third party implementing the program*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs
RIM	*Impact of efficiency measure on non-participating ratepayers overall*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution	• Program overhead costs • Utility/program administrator incentive costs • Utility/program administrator installation costs • Lost revenue due to reduced energy bills
TRC*	*Benefits and costs from the perspective of all utility customers (participants and nonparticipants) in the utility service territory*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and • water if utility is electric) • Monetized environmental and non-energy benefits • Applicable tax credits	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)
SCT	*Benefits and costs to all in the utility service territory, state, or nation as a whole*	
	• Energy-related costs avoided by the utility • Capacity-related costs avoided by the utility, including generation, transmission, and distribution • Additional resource savings (i.e., gas and • water if utility is electric) • Additional resource savings (i.e., gas and • water if utility is electric) • Non-monetized benefits (and costs) such as cleaner air or health impacts	• Program overhead costs • Program installation costs • Incremental measure costs (whether paid by the customer or utility)

* The TRC is the primary cost test used by the CPUC to evaluate the cost-effectiveness of the investor owned utility EE and DSM program portfolios. The PACT is the secondary test applied and evaluated.

Source: National Action Plan for Energy Efficiency. *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy Makers*. November 2008.

7 Market Fundamentals

This chapter 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 to calibrate all the forward curve simulations for our IRP.

7.1 Ascend PowerSimm CurveDeveloper and Portfolio Manager

RPU primarily relies on the CurveDeveloper component of the Ascend software to manage the forward market price data shown in Table 7.1.1 below.

Table 7.1.1. ICE Forward market data.

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

The primary services that CurveDeveloper provides are as follows:

- Automatically harvesting the power and gas forward curves shown in Table 7.1.1 from the Intercontinental Exchange (ICE).
- Scrubbing the harvested forward curves to remove erroneous data points.
- Generating final power and gas forward curves that flow as inputs into the PowerSimm module and other downstream software processes.

The principal output of CurveDeveloper is the generation of monthly-granularity forward price curves (from the raw forward curves) that extend up to twenty-five years into the future. If the raw forward curves do not extend far enough into the future for long term planning, CurveDeveloper is capable of extrapolating them beyond the date range of available data using user-defined shaping factors and/or adders and escalation rates. As will be discussed in the following sections, CurveDeveloper performs this curve generation process on the raw ICE forward curves harvested for RPU.

The final power and gas forward curves generated by CurveDeveloper are used by PowerSimm Portfolio Manager to create simulated forward curve data, and they ultimately define the mean levels of the forward curve data in those simulations. Accounting for the volatility of prices and other parameters imbedded in the input forward curves, Portfolio Manager simulates multiple strips of forward curve data that can deviate from the mean, while maintaining an appropriate level of mean reversion to prevent prices from drifting to unreasonable levels. As a result, the simulations of forward prices are realistic and consistent with market expectations present in the input forward curves.

For more detailed information about the Ascend Portfolio Modeling software, please refer to Appendix A.

7.2 SoCal Citygate Forward Gas Prices

The ICE SoCal Citygate forward price curve consists of the forward price curve for Henry Hub plus the SoCal Citygate basis. ICE publishes the Henry Hub forward curve and SoCal Citygate basis seven (7) and four (4) years into the future, respectively, so an ICE SoCal Citygate destination price curve can be derived for the four (4) years that the forward curve and basis overlap. To extend this curve beyond four (4) years, RPU has defined the monthly shaping factors in Table 7.2.1 for the Henry Hub forward curve and the monthly shaping adders in Table 7.2.2 for the SoCal Citygate Basis.

Table 7.2.1. Monthly Shaping Factors to Extend the ICE Henry Hub Forward Curve.

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1.102	1.094	1.075	0.954	0.943	0.952	0.960	0.964	0.960	0.968	0.990	1.038

Table 7.2.2. Monthly Shaping Adders to Extend the ICE SoCal Citygate Basis.

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0.180	0.137	0.111	-0.135	-0.141	-0.127	0.056	0.059	-0.107	-0.180	0.095	0.181

RPU set CurveDeveloper to escalate the ICE Henry Hub Forward Curve at 2% per year, which is in line with long-term natural gas price forecasts from the California Energy Commission (CEC). As for the SoCal Citygate basis, RPU used no escalation, as an analysis of the ICE Socal Citygate basis revealed that it does not escalate overtime. The resulting 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.

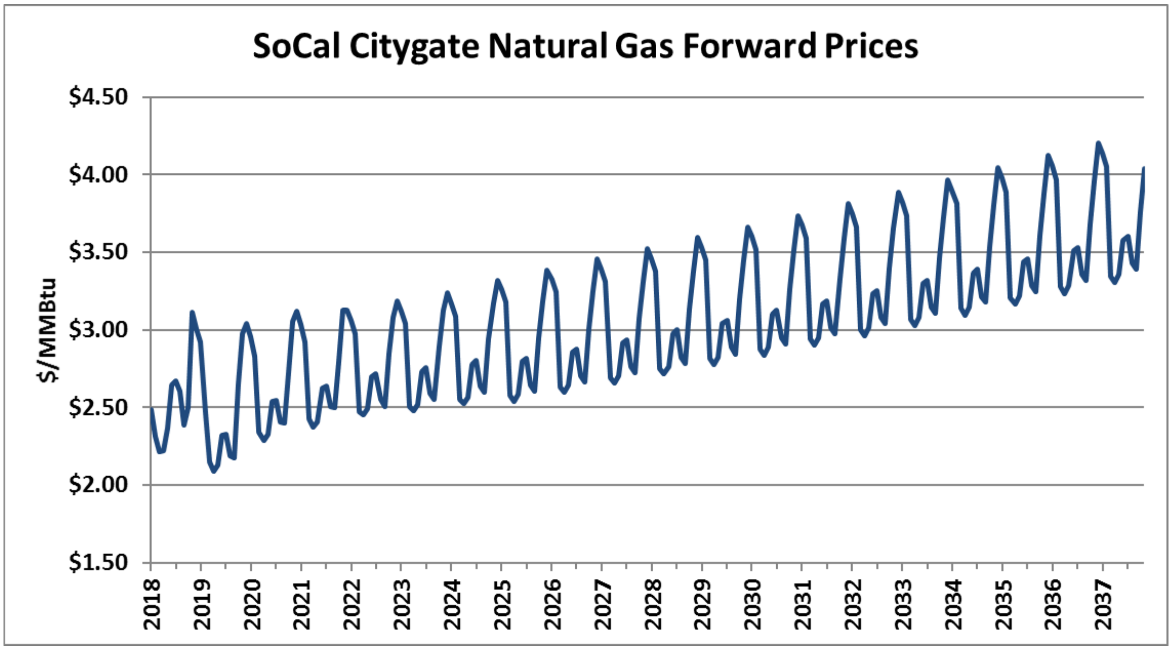


Figure 7.2.1. ICE natural gas forward prices for the SoCal Citygate Hub.

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 2017 IEPR report, the CEC developed three natural gas price reference cases – High Demand, Mid Demand, Low Demand – for major hubs in the Western Interconnect. The hub the CEC modeled that is closest to the SoCal Citygate hub is the SoCal Gas hub. A comparison of the CEC's SoCal Gas price forecast to RPU's extended SoCal Citygate ICE price forecast is shown in Figures 7.2.2 and 7.2.3; note that all natural gas forecasts are shown in real dollars.

As shown in Figure 7.2.4, the ICE forward natural gas curve for the SoCal Citygate Hub is consistent with the CEC SoCal Gas Hub forecasts, particularly the High Demand reference case. The ICE curve falls in between the forecasts for the High Demand and Mid Demand reference cases and escalates at a comparable rate in the 2019 through 2036 time horizon.

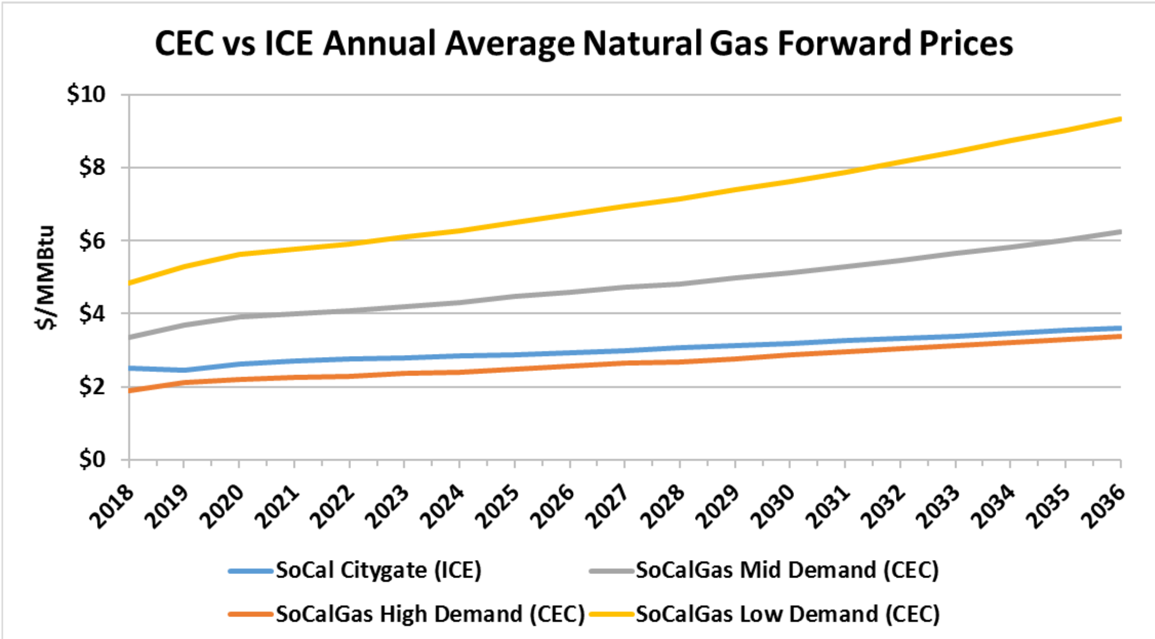


Figure 7.2.2. Annual Average ICE and CEC forward natural gas prices.

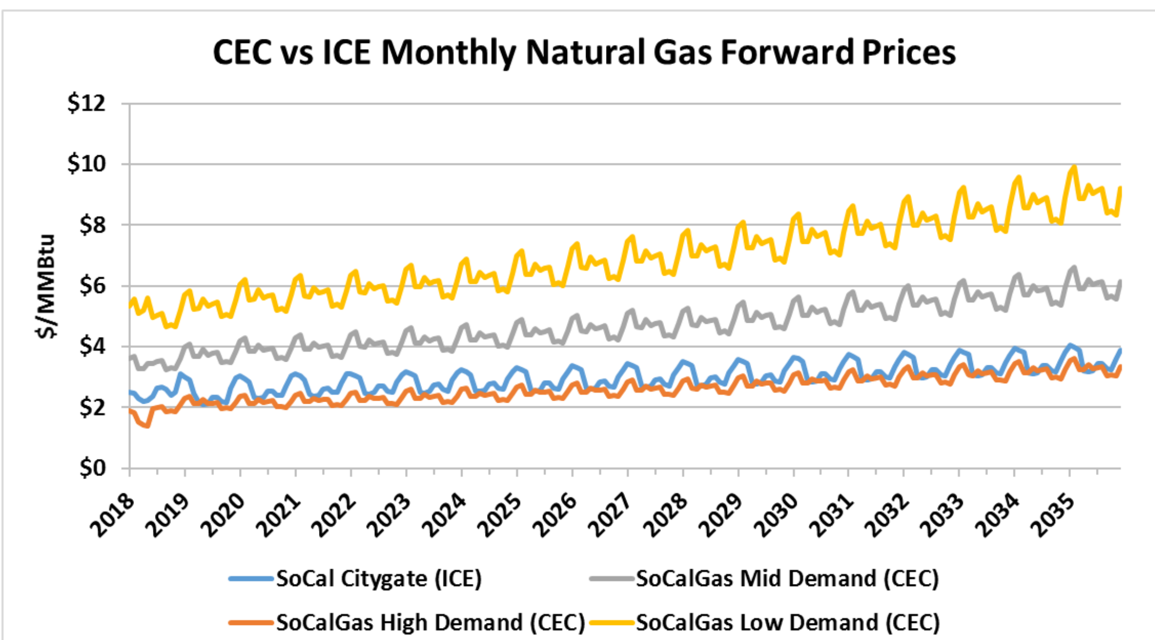


Figure 7.2.3. Monthly ICE and CEC forward natural gas prices.

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 2017 IEPR, the CEC developed a Low, Mid, and High carbon price forecast through 2030 [1] for use in simulation modeling. These forecasts are shown in Figure 7.3.1. The Low carbon price forecast follows the Auction Reserve Price calculation discussed above, and RPU has used this exact forecast and extended it for its own modeling for this IRP. To extend beyond 2030, RPU escalated the prices annually at 5% plus 2.31%, which is the CPI the CEC used for its 2030 carbon price. RPU's resulting carbon price forecast is shown in Table 7.3.1.

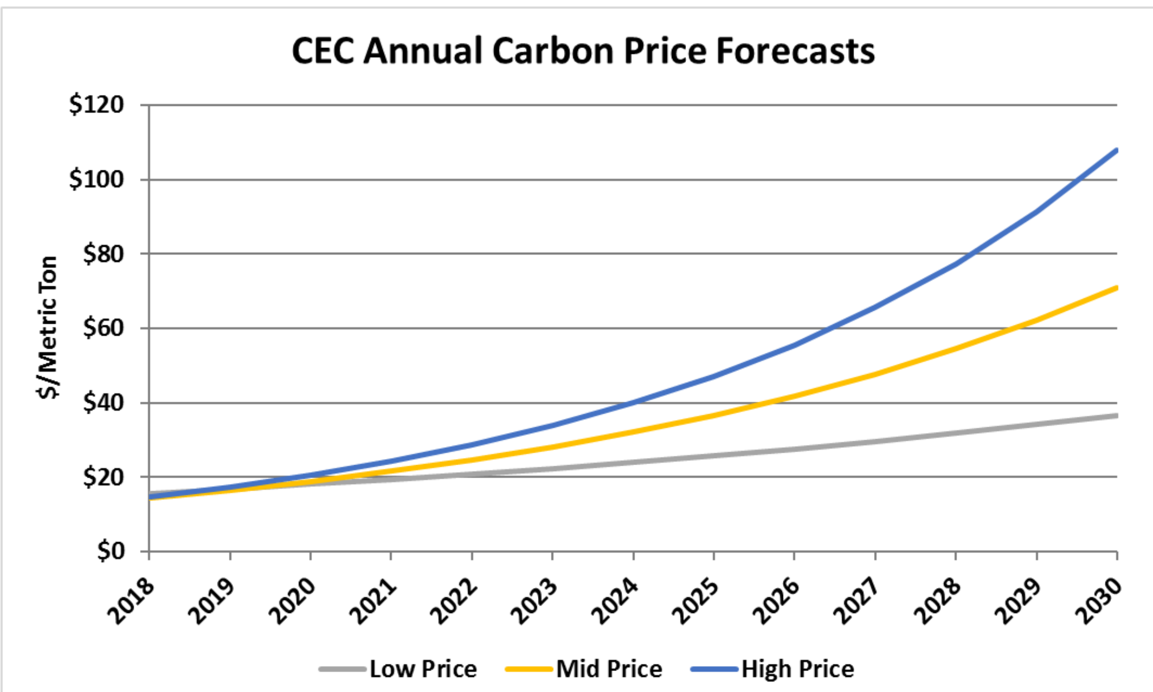


Figure 7.3.1. CEC's Annual Carbon Price Forecasts.

[1] http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-03/TN222145_20180116T123231_2017_IEPR_Revised_Carbon_Allowance_Price_Projections.xlsx

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

Year	Price ($/MT)
2018	15.60
2019	16.81
2020	18.08
2021	19.41
2022	20.83
2023	22.35
2024	23.97
2025	25.70
2026	27.56
2027	29.56
2028	31.73
2029	34.06
2030	36.55
2031	39.22
2032	42.08
2033	45.16
2034	48.46
2035	52.00
2036	55.80
2037	59.88

7.4 Long-term Structural Forward Market Price Relationships

Appropriate long-term forward market price forecasts for the California electricity markets (i.e., SP-15, NP-15, etc.) can be challenging to construct. More specifically, the traditional relationship between natural gas and electricity prices needs to be modified to accommodate for the additional influence of a GHG cost adder. The proper specification of this modified relationship is important, in order to ensure that any adjustments to future GHG price forecasts are translated appropriately into the forward electricity market price curves.

In order to better understand this relationship, consider the following hypothetical dispatch equation for determining the market price of electrical power generated from the marginal natural gas plant as a function of the cost of natural gas and carbon emissions:

$$E.Price \approx HR \bullet N.Gas + VOM + Ef \bullet CC \qquad [7.4.1]$$

In Eq. 7.4.1, the variables are defined as shown in Table 7.4.1 below:

Table 7.4.1 Variable names and descriptions for the variables shown in Eq. 7.4.1.

Name	Description
E.Price	$/MWh production cost (i.e., price) for one MWh of electricity
HR	MMBtu/MWh heat-rate of the marginal natural gas plant in the market
N.Gas	$/MMBtu cost for one MMBtu of natural gas
VOM	Variable operations and maintenance cost ($/MWh) of the marginal gas plant
Ef	Carbon emissions factor for the marginal gas plant expressed in Metric.Ton/MWh units
CC	Cost of carbon emissions, expressed in $/Metric.Ton units

Additionally, note that the carbon emissions factor (Ef) can be re-expressed as $Ef = 0.05307 \bullet HR$, where the constant term represents the CO_2 coefficient for calculating the metric tons of CO_2 in 1 MMBtu of natural gas.

Now, assume that Eq. 7.4.1 can be used to accurately capture the forward market price relationships between monthly heavy-load (HL) power prices, monthly natural gas prices, and our best annual estimates for the cost of future carbon emissions. Under this assumption, Eq. 7.4.1 can be re-expressed as

$$HL.Price_{i,j} \approx VOM + HR_i \bullet [N.Gas_{i,j} + 0.05307 \bullet CC_j] \qquad [7.4.2]$$

for a future month *i* and year *j*, where the heat rate of the marginal gas plant is allowed to vary by month and for simplicity the variable operations and maintenance (O&M) costs are assumed to remain approximately constant. Eq. 7.4.2 can be immediately recognized as a special type of Analysis of Covariance (ANOCOVA) model with a constant intercept term ($VOM = \beta_0$) and a seasonally dependent slope parameter ($HR_i = \beta_{1i}$) that responds to the appropriately weighted forward prices of both natural gas and carbon. Thus, if Eq. 7.4.2 effectively characterizes the forward market price relationships, then a properly specified ANOCOVA model should accurately describe the gas and carbon to power relationship. This proposed relationship can be tested by examining the future HL power, natural gas and carbon prices for the Southern California region.

Table 7.4.2 below presents the ANOCOVA modeling results for an assessment of forward ICE SP15 HL power price data as a function of SoCal Citygate natural gas prices and future CARB carbon emission costs. The monthly HL power and natural gas price forecasts were obtained from the ICE power and gas forward forecasts published on 12-26-2017. The future annual carbon emission prices represent the revised 2017 CEC IEPR Carbon price projections for the low price scenario (see Table 7.3.1), which essentially represent the future auction reserve price estimates (CPI + 5%). Note that the analysis shown in Table 7.4.2 is based on six years (72 months) of forward pricing data from January 2019 through December 2024.

Table 7.4.2. Single intercept, multiple slope ANOCOVA results for Equation 7.4.2.

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	12	2108.203	175.684	473.27	0.0000
Error	59	21.902	0.371		
Corrected Total	71	2130.105			
	Root MSE	0.609	R-Square	0.9897	
	Dependent Mean	37.827	Adj R-Sq	0.9876	
	Coeff Var	1.611			

Parameter Estimates					
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	1	1.508	1.256	1.20	0.2345
HR [JAN]	1	9.072	0.288	31.50	0.0000
HR [FEB]	1	8.869	0.294	30.15	0.0000
HR [MAR]	1	7.980	0.304	26.29	0.0000
HR [APR]	1	7.225	0.339	21.32	0.0000
HR [MAY]	1	7.347	0.344	21.37	0.0000
HR [JUN]	1	8.235	0.340	24.19	0.0000
HR [JUL]	1	9.979	0.322	31.00	0.0000
HR [AUG]	1	10.430	0.320	32.56	0.0000
HR [SEP]	1	10.194	0.331	30.78	0.0000
HR [OCT]	1	10.085	0.332	30.40	0.0000
HR [NOV]	1	9.377	0.313	29.96	0.0000
HR [DEC]	1	9.251	0.289	32.00	0.0000

As shown in Table 7.4.2, the proposed HL price forecasting equation provides an accurate fit to the observed HL ICE prices ($R^2 \approx 0.99$, root MSE ≈ \$0.61/MWh). Additionally, the heat-rate (slope) estimates are all intuitively reasonable. The most efficient CCNG units exhibit a heat-rate around 7,200 (or 7.2 MMBtu/MWh) and reasonably efficient simple cycle peaking plants exhibit heat-rates around 10,500; note that the estimated heat-rates all fall within this range. Figure 7.4.1 shows the model fitted versus observed SP15 forward HL prices; it is clear that the vast majority of the longer-term forward price structure is well described by Eq. 7.2.

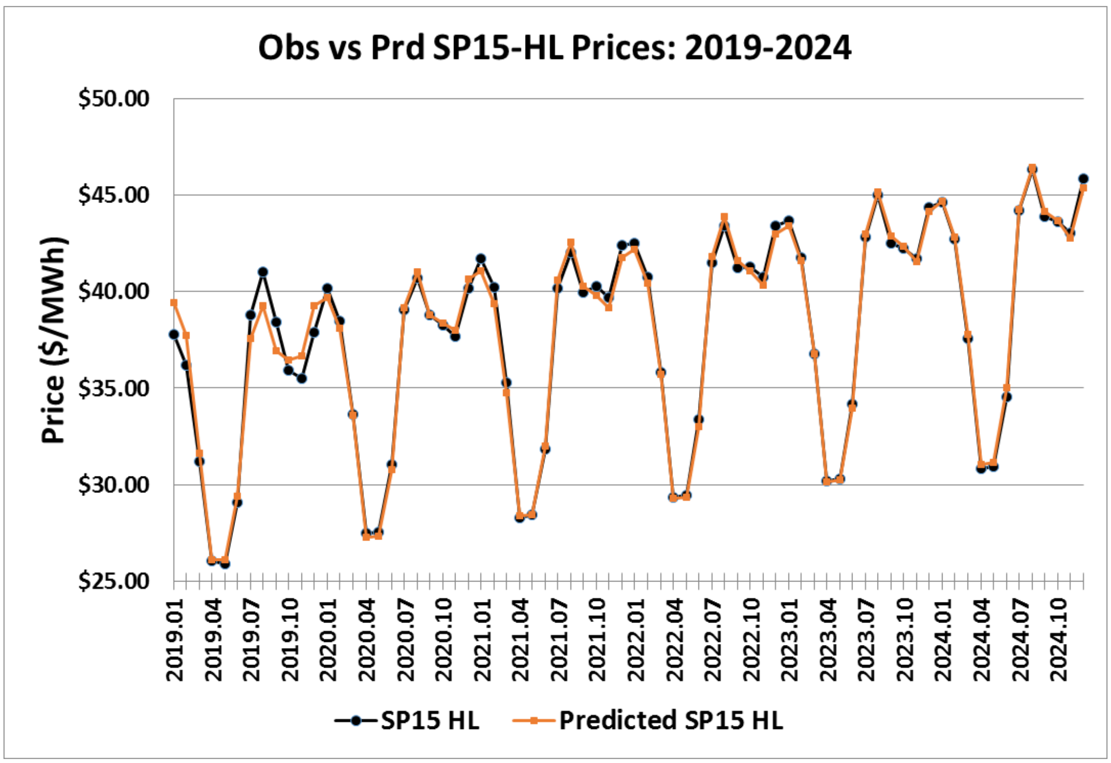


Figure 7.4.1. Model fitted versus observed SP15 forward HL prices: Jan 2019 through Dec 2024.

Once a forward forecasting model for SP15 HL prices has been determined, a similar model can be used to forecast SP15 light-load (LL) price data. More specifically, the HL to LL pricing relationships can be very accurately described using a traditional ANOCOVA model that predicts the LL price as a linear function of the HL price combined with 12 monthly shift (intercept) coefficients. An example of such a model is shown in Table 7.4.3, where the SP15 HL to LL price relationship is shown to be

$$LL_{i,j} \approx 0.934 \bullet HL_{i,j} + \Delta_i, \qquad [7.4.3]$$

for 12 unique monthly Δ shift estimates. Note that this LL price forecasting equation also provides an accurate fit to the observed LL ICE prices ($R^2 > 0.99$, root MSE ≈ $0.39/MWh). This prediction accuracy is confirmed in Figure 7.4.2, which shows the model fitted versus observed SP15 forward LL prices.

Table 7.4.3. ANOCOVA results for forecasting forward SP15 LL prices as a function of SP15 HL prices.

Analysis of Variance					
Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	12	79591.92	6632.66	43837.81	<.0001
Error	59	8.93	0.15		
Corrected Total	71	79600.84			
	Root MSE	0.389	R-Square	0.9938	
	Dependent Mean	32.948	Adj R-Sq	0.9906	
	Coeff Var	1.181			

Parameter Estimates					
Variable	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
month Int.01	1	-2.387	0.907	-2.63	0.0108
month Int.02	1	-1.567	0.870	-1.80	0.0769
month Int.03	1	-0.804	0.766	-1.05	0.2986
month Int.04	1	-0.472	0.634	-0.74	0.4602
month Int.05	1	-0.776	0.636	-1.22	0.2269
month Int.06	1	-3.281	0.710	-4.62	<.0001
month Int.07	1	-4.663	0.893	-5.22	<.0001
month Int.08	1	-4.565	0.935	-4.88	<.0001
month Int.09	1	-3.532	0.887	-3.98	0.0002
month Int.10	1	-2.500	0.876	-2.85	0.0060
month Int.11	1	-2.102	0.865	-2.43	0.0181
month Int.12	1	-1.938	0.920	-2.11	0.0393
SP15-HL	1	0.934	0.021	43.66	<.0001

Having established these forecasting models, long-term HL and LL SP15 power price forecasts can now be produced as a function of long-term natural gas and carbon price inputs. For example, the ICE reported SoCal Citygate natural gas price forecasts through 2024 exhibit about a 2% annual escalation factor. Likewise, the CEC IEPR Low Price carbon forecasts through 2030 escalate at about 7.3% annually. Assuming that both of these annual escalation factors continue through 2037, it can be verified that the corresponding SP15 HL and LL power prices in turn must escalate at 3.8% and 4.0% annually to maintain a consistent structural relationship. Figure 7.4.3 shows an example of this structural relationship, based on the aforementioned annual natural gas and carbon price escalators.

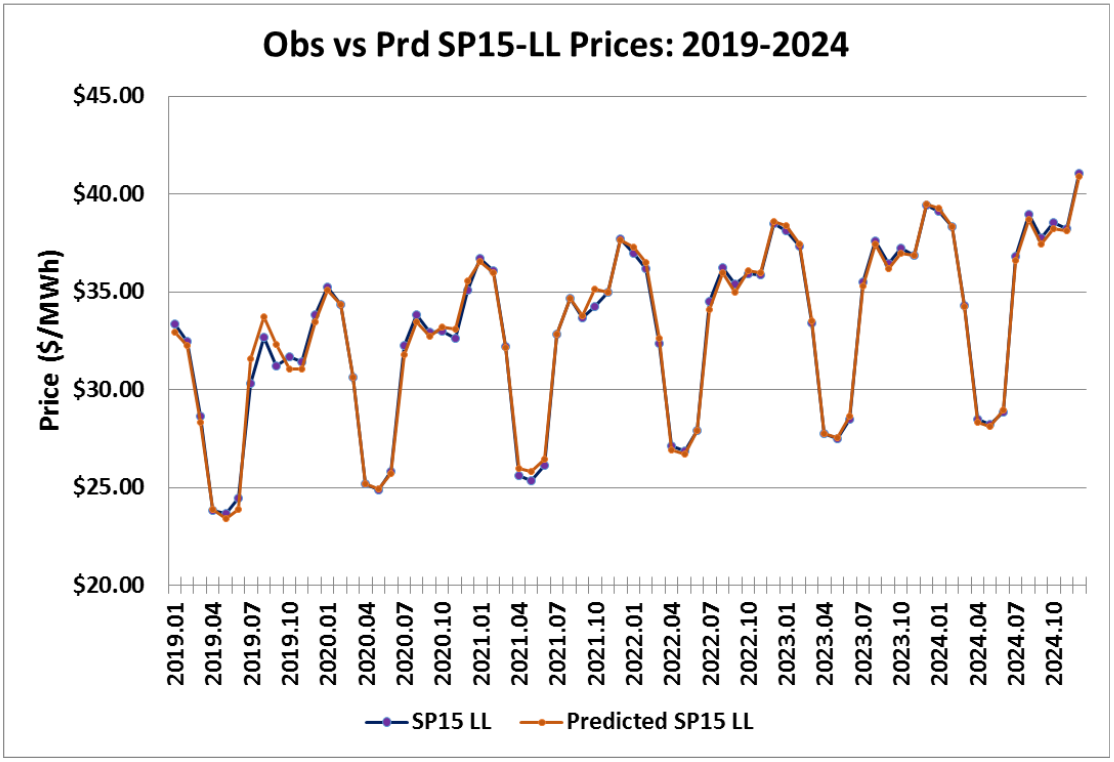


Figure 7.4.2. Model fitted versus observed SP15 forward LL prices: Jan 2019 through Dec 2024.

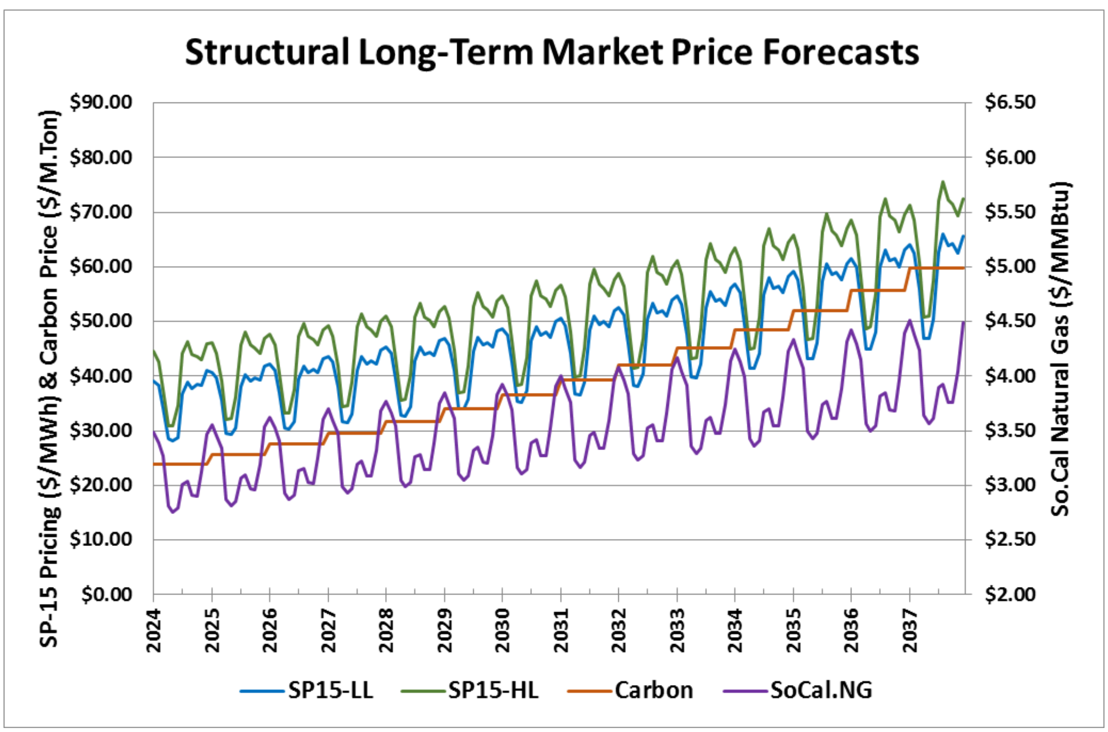


Figure 7.4.3. Structural long-term market price forecasts: 2024 - 2037.

Finally, it is worthwhile to note that these calibrated long-term structural relationships can be used to project how future electricity prices would need to change, based on significant changes occurring in either the underlying natural gas or carbon forecasts. Figure 7.4.4 below shows just one example of this concept. The carbon price forecast in Figure 7.4.4 is assumed to escalate at 15% annually after 2030, ultimately reaching a price of more than $97/ton in 2037. As a result of this, the corresponding HL and LL power prices also escalate more rapidly after 2030, ultimately reaching summer prices of $96/MWh and $85/MWh, respectively. Note that this result is solely due to the increase in the carbon price forecast, since the natural gas price forecast used in this example is identical to the gas price forecast shown in Figure 7.4.3 (i.e., 2% annual escalation through 2037).

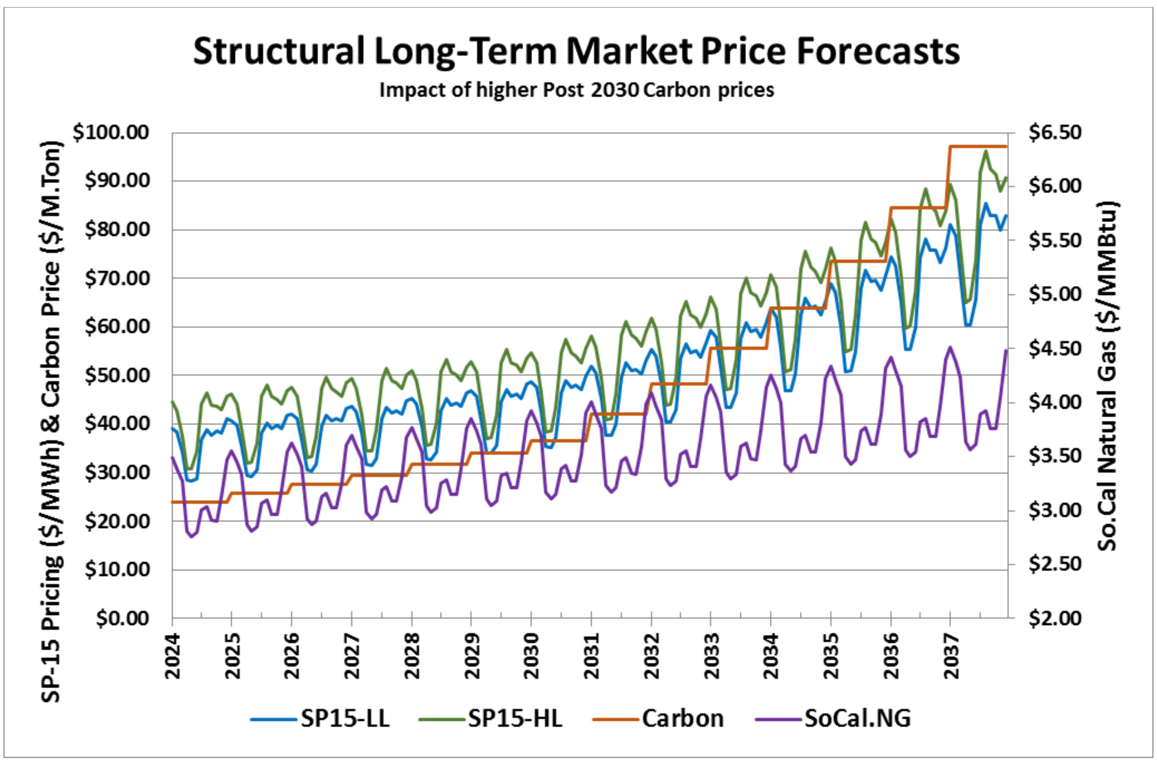


Figure 7.4.4. Adjusted long-term SP15 energy price forecasts, due to an accelerated increase in carbon costs after 2030.

7.5 Forward Power Prices

7.5.1 SP15 Forward Power Prices

ICE publishes on-peak and off-peak SP15 ICE electricity price curves, as well as curves for other power markets, seven years forward in time. Beyond the published term, CurveDeveloper has been set to escalate all the on-peak curves at 3.8% per year and the off-peak curves at 4.0% per year. In addition, RPU has set CurveDeveloper to apply RPU-defined monthly shaping adders to all forward curves it harvests. The monthly shaping adders used for the on and off-peak SP15 curves are shown in Table 7.5.1. The resulting on and off peak SP15 monthly forward curves are shown in Figures 7.5.1 and 7.5.2 below.

Table 7.5.1. Monthly Shaping Adders to Extend the ICE SP15 On and Off Peak Forward Curves.

Month	On Peak	Off Peak
Jan	6.025	5.693
Feb	4.325	4.793
Mar	-0.525	0.993
Apr	-7.025	-4.940
May	-6.925	-5.224
Jun	-3.109	-4.124
Jul	4.758	2.426
Aug	6.608	4.293
Sep	4.525	3.276
Oct	4.475	3.660
Nov	3.908	3.776
Dev	6.575	6.476

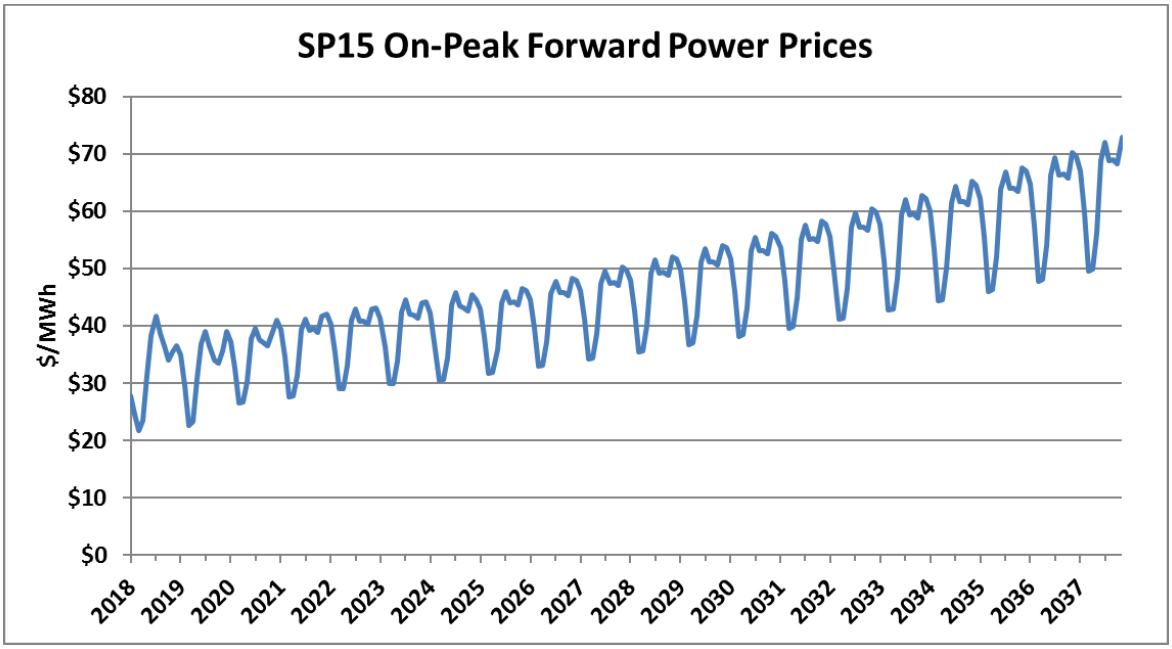


Figure 7.5.1. Shaped SP15 On Peak ICE monthly forward price curve.

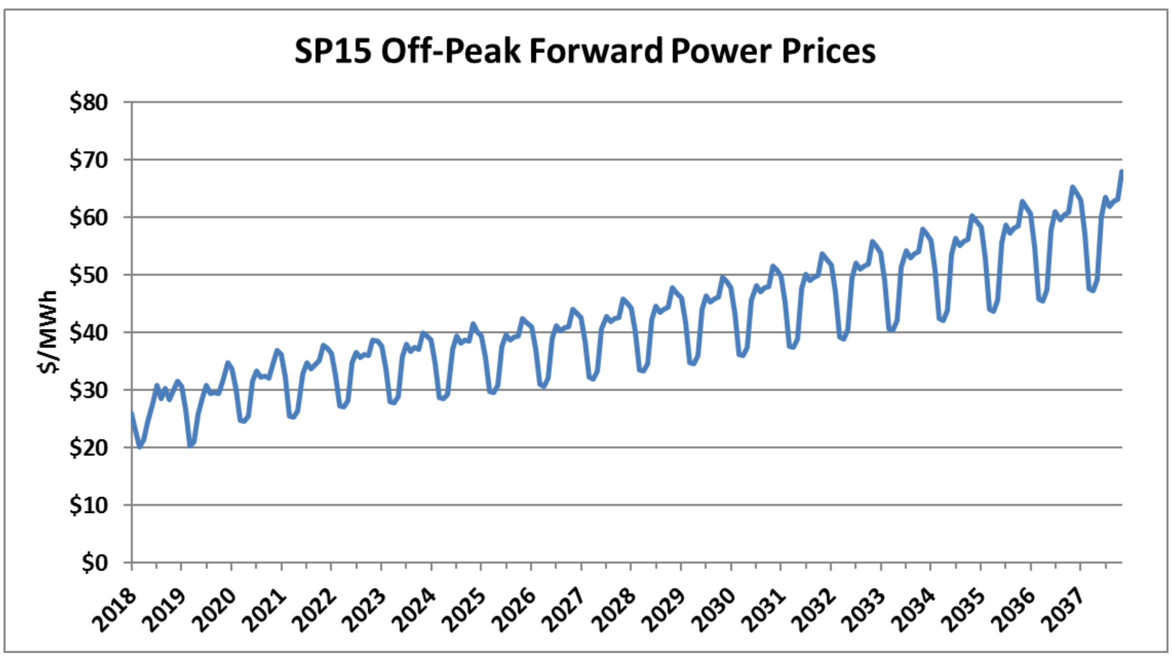


Figure 7.5.2. Shaped SP15 Off Peak ICE monthly forward price curve.

7.6 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 2037 only requires a projection of the CAISO TAC rate. The CAISO has such a projection through 2031 in its 2016-2017 Transmission Access Charge Model [2], 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 about 5% annually through 2023 and then decreasing about 0.8% annually between 2024 and 2031. For this IRP, rather than carry the decreasing trend through to 2037, RPU has elected to use the CAISO projected TAC rates through 2023, where they reach $14.11/MWh, and then hold that amount constant through the end of the 2037 study horizon. Table 7.6.1 and Figure 7.6.1 show the projected TAC rates used to calculate RPU's TAC costs associated with our system load growth forecast.

Table 7.6.1. CAISO TAC rate projections through 2037; for use in computing RPU's TAC costs.

Year	TAC Rate ($/MWh)
2018	11.05
2019	11.52
2020	12.27
2021	13.00
2022	13.67
2023 - 2037	14.11

[2] http://www.caiso.com/Documents/2016-2017TransmissionAccessChargeForecastModelwithNewCapital.xlsx

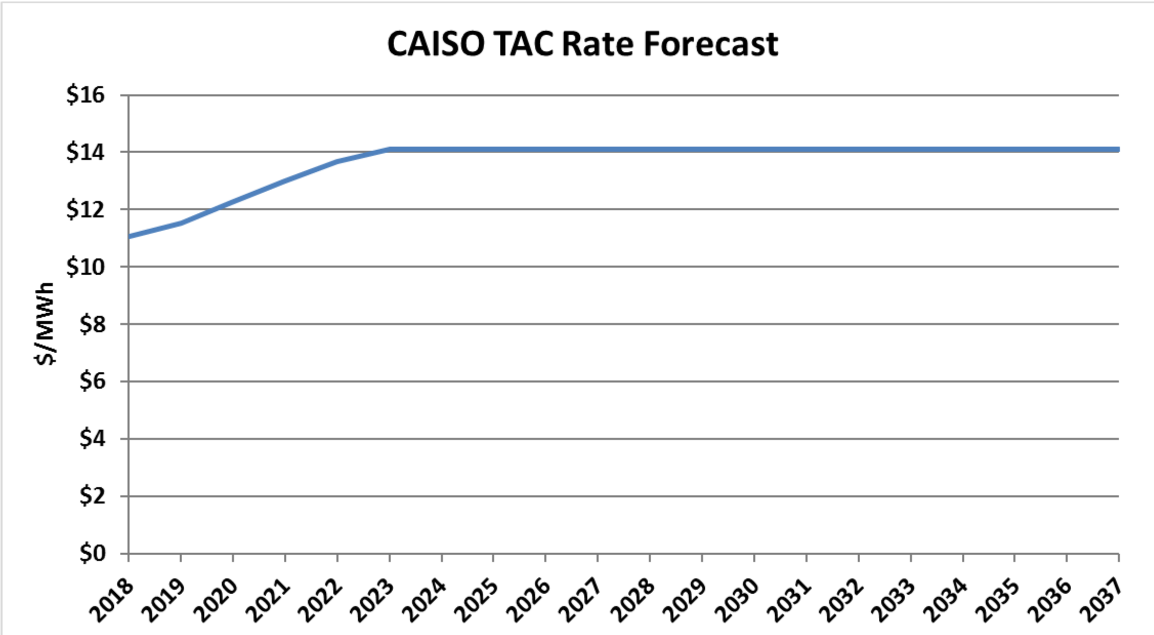


Figure 7.6.1. CAISO Transmission Access Charge rate forecast.

7.7 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 the CAISO is in the midst of redefining the RA paradigm for the second time. The CAISO last 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, as discussed in Section 5.2.4 and Section 11.2, the CAISO is in Phase 2 of the FRAC-MOO initiative and has proposed to completely redefine the flexible RA requirement introduced in Phase 1.

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, plus an additional adder for Flexible RA products. While these bundled prices only represent the current RA products and not the future RA products, they are the only reliable RA product market price benchmark RPU has available. The bundled RA pricing quotes RPU used to determine the cost of its future RA needs are shown in Table 7.7.1. The prices shown are for 2018 and escalate at 3% per year.

Table 7.7.1. Representative 2018 CAISO market RA prices for typical bilateral transactions.

Season	Product	Bundled Quote ($/kW-month)
January-December	System + Local	$4.50
January-December	System + Local + Flexible	$6.00

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)
- Unhedged Energy costs and Cost-at-Risk metrics (8.6)
- Forecasted GHG Emission profiles and net Carbon allocation positions (8.7)
- Five-year Forward Power Resource Budget forecasts (8.8)

All of 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, in order to reflect the latest CAISO market conditions and associated forward energy price curves. The analyses presented in this chapter reflect late December 2017 CAISO market conditions.

8.1 Renewable Energy Resources and RPS Mandate

As discussed in Chapter 3 (Section 3.1), a number of new renewable resources have begun delivering energy into the RPU portfolio within the last 36 months. Figure 8.1.1 shows the utility's projected monthly RPS percentage levels for the 2018-2022 timeframe, before accounting for any excess REC sales that RPU plans to undertake in order to reduce budgetary pressure for rate increases. Since 2017, RPU has been significantly exceeding minimum SB X1-2 RPS mandates and this trend is expected to continue for at least the next five (5) years. Additionally, it is worthwhile to note that all of these new renewable PPA's qualify as Portfolio Content Category 1 (PCC-1) products under the SB-2 paradigm 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 2018-2022 time frame, including the utility's expected versus mandated renewable percentages and associated GWh values. In 2017 RPU purchased 799.1 GWh of PCC-1 renewable energy, achieving an RPS of 35.9%. About 197.5 GWh of this energy represents excess renewable purchases that the utility plans to apply towards Excess Procurement. Given that RPU expects to receive excess renewable energy for the next five years, along with the need to minimize adverse rate increases, staff anticipate selling off some of this excess renewable energy at least through 2020. The expected excess RECs and the proposed excess sales are shown in the last two columns of Table 8.1.1, respectively. RPU expects to raise about 7.4 million dollars from these proposed excess sales, assuming that the corresponding PCC-1 RECs are sold for $16/MWh.

Note that RPU 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.

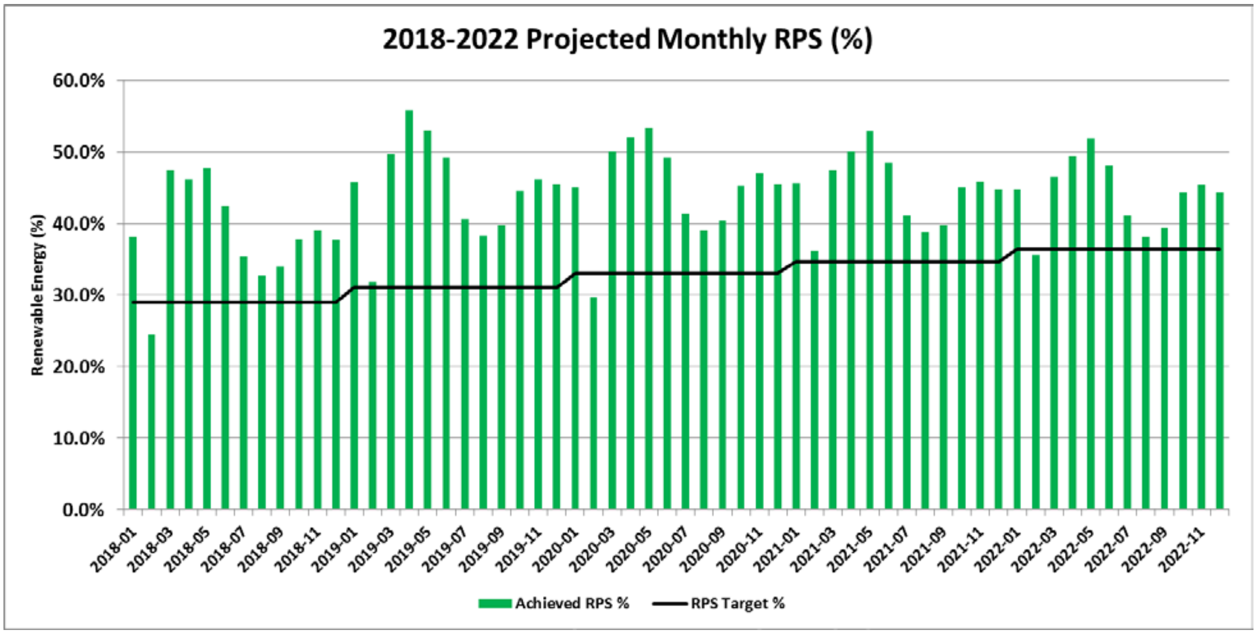


Figure 8.1.1. RPU five year forward renewable energy projections (2018-2022 timeframe).

Table 8.1.1. Pertinent RPU renewable energy statistics for the 2018-2022 timeframe.

Year	RPS Mandate (%)	Associated GWh Target	Expected RPS (%)	Expected GWh Amount (before sales)	Expected Excess RECs (GWh)	Proposed Excess Sales (GWh)
2018	29.0%	631.2	38.3%	834.4	203.2	107.0
2019	31.0%	681.7	44.7%	983.0	301.3	198.0
2020	33.0%	735.4	44.6%	994.0	258.6	157.5
2021	34.7%	780.2	44.4%	998.3	218.1	TBD
2022	36.4%	827.7	43.8%	997.0	169.3	TBD
Total Excess Sales over 5 Years (GWh):					1150.5	≥ 462.5

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 2018-2022 timeframe. Over the next five years, approximately 90% of the utility's expected system energy needs will be served using fixed-price contracts within the resource portfolio (including optional IPP energy), while another 2-4% will be served using internal generation assets (primarily during summer). The remaining 6-8% of energy needs will need to be acquired from the CAISO market, either via forward purchases or day-ahead market transactions. Note that the majority of the utility's open energy positions will occur in April (IPP and Salton Sea outages) and July through September (to meet summer peaking needs).

In Figure 8.2.1 below, the "IPP-Decking" energy represents decremented IPP coal 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. In some months, counting these excess IPP purchases creates (artificial) long energy positions. However, these "long" energy positions are always 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 hour-ahead 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.

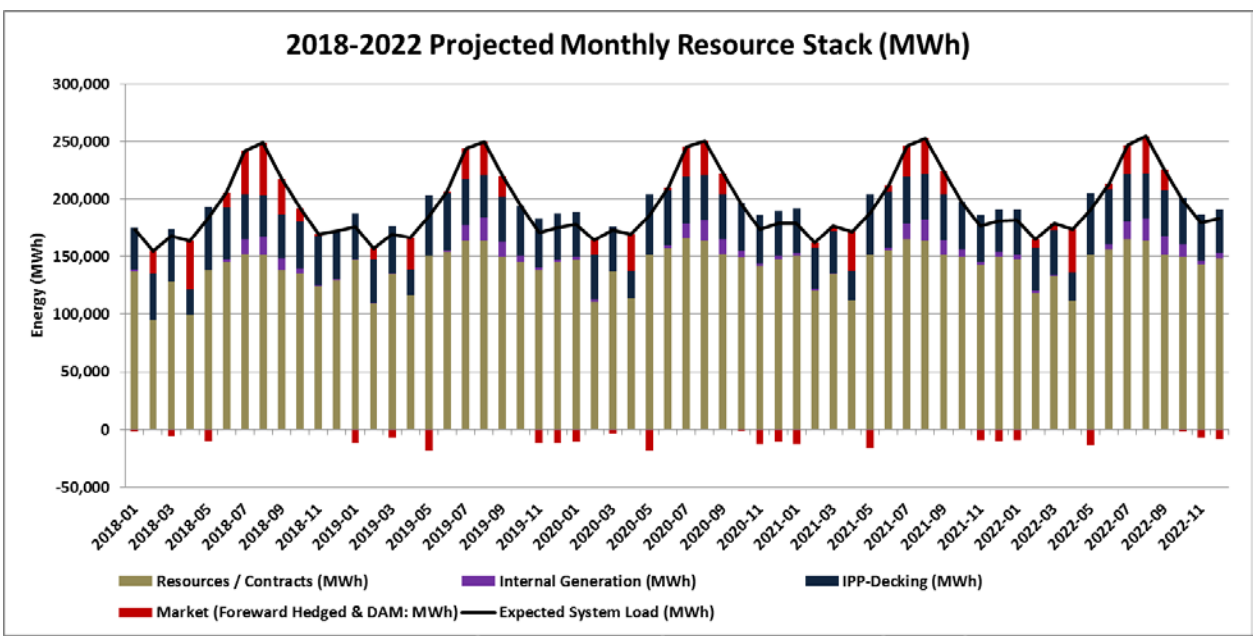


Figure 8.2.1. RPU five year forward resource stacks and system loads (2018-2022 timeframe).

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 December 2017 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	2018	2019	2020	2021	2022
Fixed resources/contracts	1,573.9	1,720.4	1,737.4	1,746.9	1,740.7
Internal Generation	49.8	58.1	62.4	68.3	80.8
IPP-decking	484.0	487.1	484.3	476.3	480.7
Net Market purchases	183.5	49.3	61.8	75.4	91.3
RPU System Load	2,291.2	2,314.8	2,345.8	2,366.9	2,393.5

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 of 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 ± 1 million dollars in winter months and ± 2.5 million dollars in summer months. The uncertainty around future DA market prices is primarily responsible for the winter NRU, while the summer NRU tends to be driven primarily by simulated load deviations. Table 8.3.1 shows the corresponding annual NRU standard deviations; for the next five years these annual standard deviations are all forecasted to be between 8 and 9 million dollars per year, 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 can either increase or decrease as much as 13 to 15 million dollars per year due to weather, load and/or market price volatility, respectively.

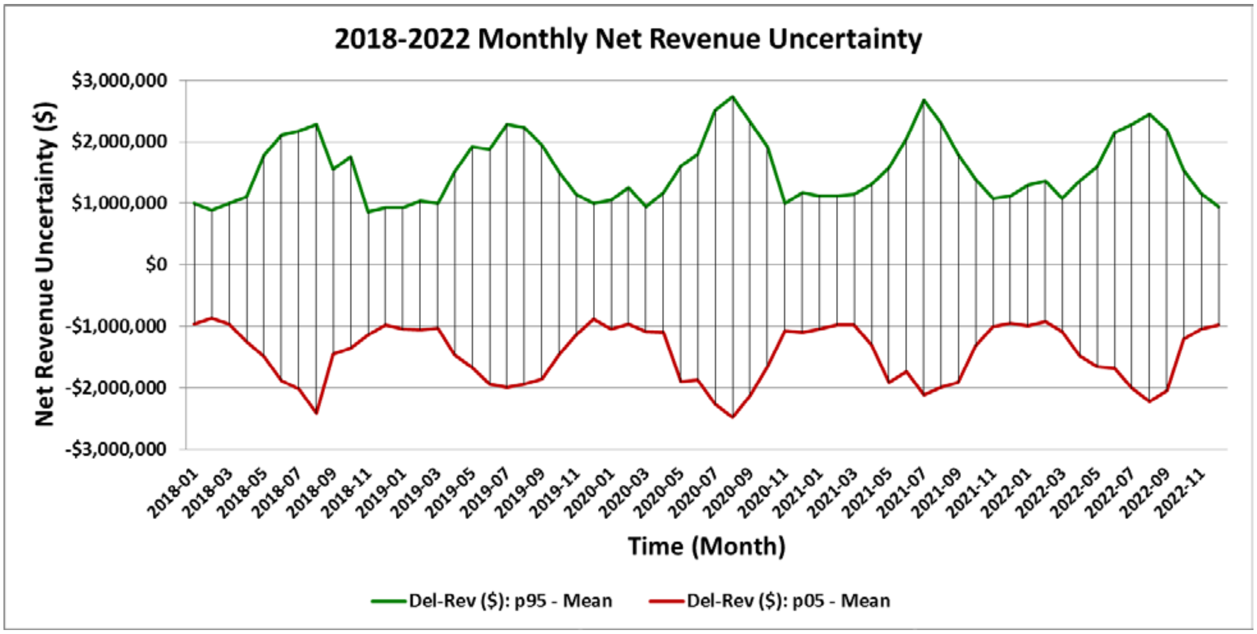


Figure 8.3.1. Monthly 5th and 95th percentile estimates of the net revenue uncertainty associated with RPU's power supply budget.

Table 8.3.1. 2018-2022 forecasted net revenue uncertainty standard deviations and corresponding 90% confidence intervals.

Metric/Statistic	2018	2019	2020	2021	2022
Annual NRU Std.Dev	$7.925 M	$8.377 M	$9.017 M	$8.527 M	$8.491 M
Corresponding 90% CI	± $13.08 M	± $13.82 M	± $14.88 M	± $14.07 M	± $14.01 M

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 2018-2022 timeframe. Not surprisingly, about 75% of RPU's annual internal generation is expected to come from the four RERC units, and all of these units primarily serve as summer (July-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 (with a minimum $5/MWh profit margin). The net revenue estimates account for the embedded carbon emission costs, but exclude all debt related financing costs (i.e., bond debt associated with engineering, design and construction costs). The "net margin-to-market" row quantifies the expected internal generation profit margin (in $/MWh units), referenced to current market prices and subject to the above set of assumptions.

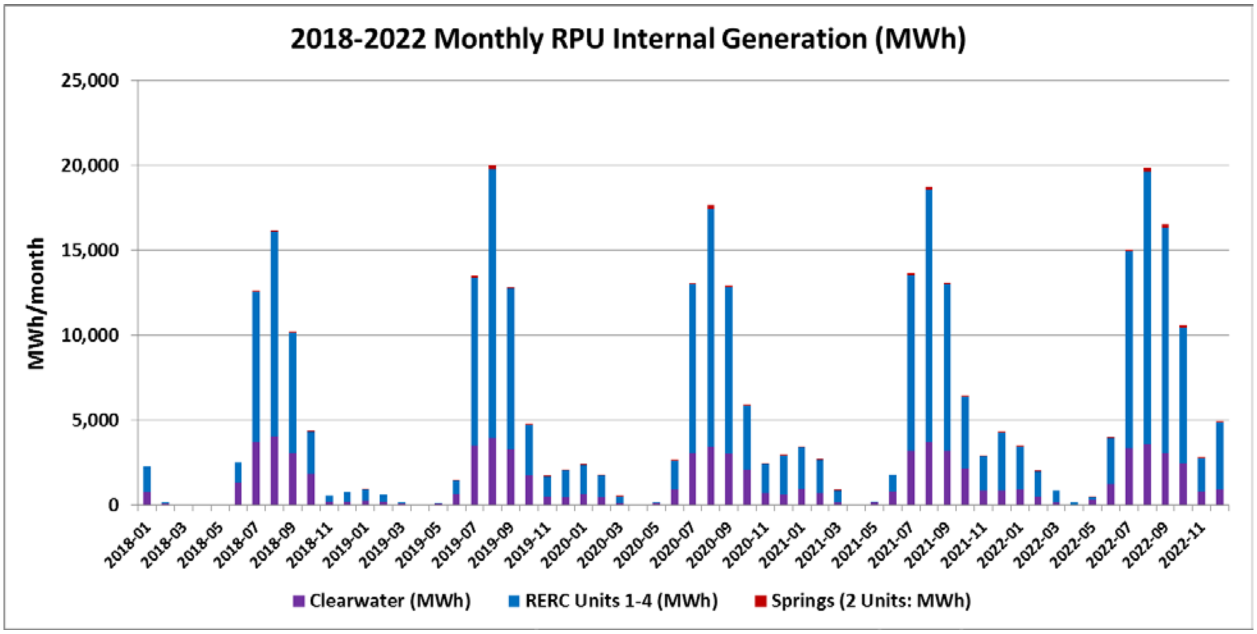


Figure 8.4.1. 2018-2022 forecasted monthly RPU internal generation amounts for RERC, Springs and Clearwater.

Table 8.4.1. 2018-2022 forecasted internal generation levels, gas burns and net revenue estimates.

Internal Generation	2018	2019	2020	2021	2022
Total generation (MWh)	40,136	56,036	66,314	77,551	93,504
Total gas burns (MMBtu)	386,308	540,565	641,195	749,748	905,230
Net revenue ($000)	$566.1	$898.0	$1,117.1	$1,310.2	$1,680.0
Net margin-to-market ($/MWh)	$14.10	$16.03	$16.85	$16.89	$17.97

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

$$H\% = 100 \times [\,Sys.Load - NEP] / Sys.Load \qquad \text{[Eq. 8.5.2]}$$

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 2018-2022 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, 11 of the 12 forthcoming 2018 months already satisfy this constraint. The RMC has also set the minimum annual H% targets shown in Table 8.5.1 for the 2018-2021 timeframe; RPU's current annual H% values are also shown in this table. These results show that RPU is already in compliance with respect to its annual targets through 2021, notwithstanding the need for some incremental hedging activities to bring specific months into compliance.

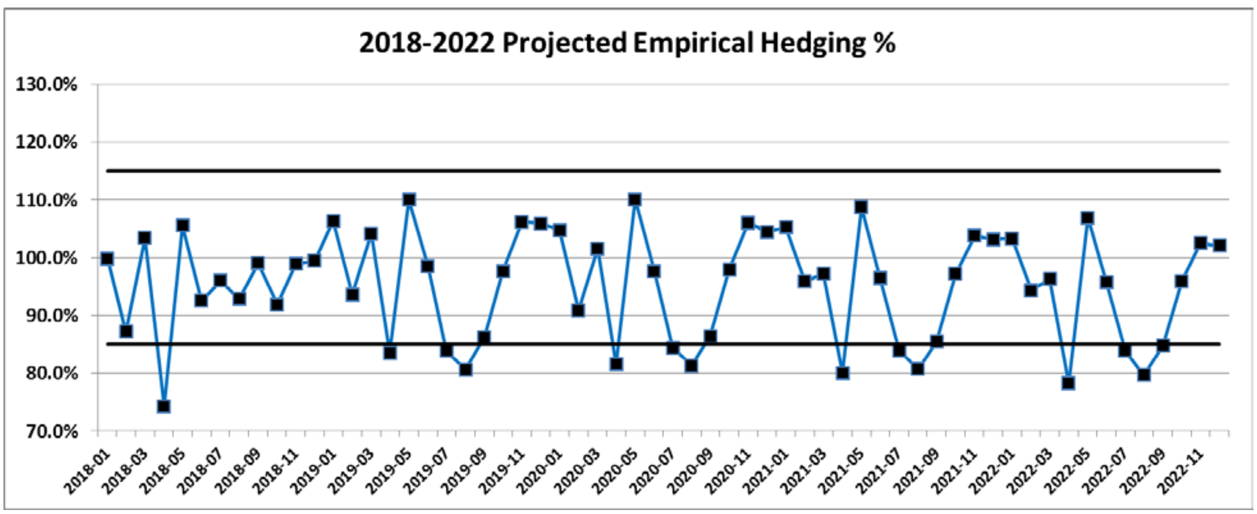


Figure 8.5.1. Forecasted monthly RPU hedging percentages for the 2018-2022 timeframe.

Table 8.5.1. RMC target versus current actual annual hedging percentages (H%); 2018-2022 timeframe.

Hedging Metric	2018	2019	2020	2021	2022
RMC Target Annual H%	95%	90%	85%	80%	n/a
Current NEP (GWh)	109.8	105.4	122.1	141.4	169.4
Current Annual H%	95.2%	95.4%	94.8%	94.0%	92.9%

RPU has historically layered in its natural gas hedges over a three year forward window, while implementing its power hedges over a one-to-two year forward window. Part of this strategy was 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). However, RPU's current set of forward hedges reflect a power only hedging strategy that extends over a shorter timeframe. As of December 2017, RPU had forward hedged 121,600 MWh of fixed price HL and LL SP15 energy products for 2018, but no natural gas. Over the last two years, natural gas forward prices have not proved to be cost competitive (in comparison to direct power purchases). Additionally, the Aliso Canyon issue has resulted in increasing penalties for imbalance gas and thus RPU has adopted a temporary strategy where gas is being hedged on a prompt-month basis only (when needed). Finally, RPU no longer has a need to purchase either SP15 energy or Citygate natural gas call options, due to already high annual hedging levels and consistently low market energy prices.

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 principal, 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 2018-2022 timeframe.

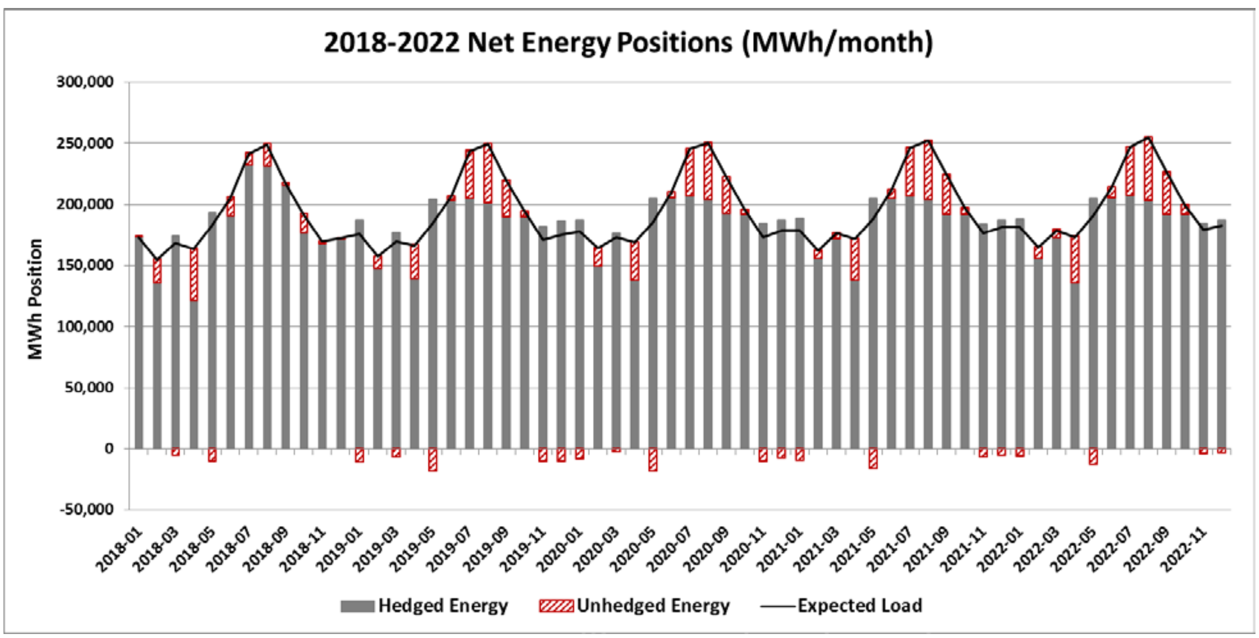


Figure 8.5.2. 2018-2022 forecasted monthly net energy positions (MWh/month).

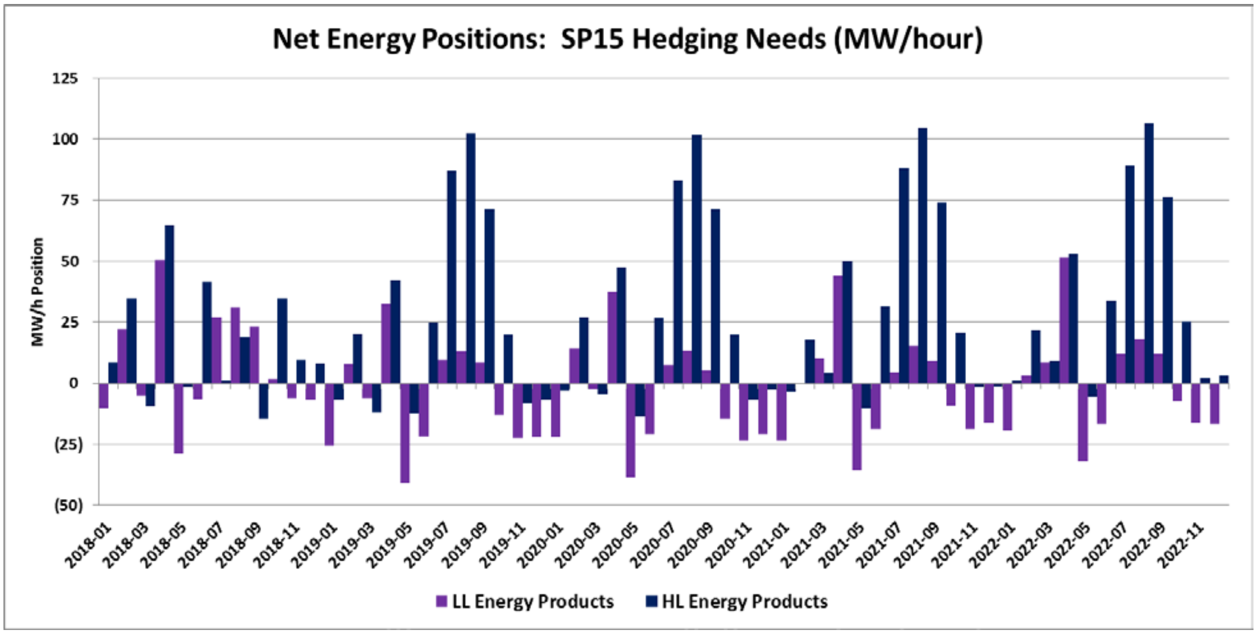


Figure 8.5.3. 2018-2022 NEP forecasted monthly open HL and LL energy positions (MW/hour).

As shown in Figures 8.5.2 and 8.5.3, RPU is well hedged for calendar year 2018, other than for some planned generation outages in April. Significant open energy positions occur in 2019 and beyond; primarily during April and July through September. The Q3 HL open positions reflect RPU's summer peaking energy needs, while the April HL and LL open positions are due to IPP and Salton Sea outage events.

Table 8.5.2 summarizes the utility's annual open LL and HL energy positions on both a GWh and MW/h basis for the next five years. Note that the GWh values shown in Table 8.5.2 partition out the NEP GWh's (shown in Table 8.5.1) across LL and HL hours, respectively. Note also that beginning in 2019 the LL resources already sum up to a hedging level slightly above 100% (before adjusting for any IPP-Decking activities).

Table 8.5.2. Open (unhedged) RPU annual LL and HL energy positions; 2018-2022 timeframe.

Energy Metric	2018	2019	2020	2021	2022
LL (GWh)	29.2	(27.5)	(22.7)	(14.2)	(2.5)
HL (GWh)	80.6	132.9	144.8	155.6	171.9
LL (MW/h)	8	(7)	(6)	(4)	(1)
HL (MW/h)	16	27	29	31	35

8.6 Unhedged Energy Costs and Cost-at-Risk Metrics

For any given hour of a particular day, a forecast of the hourly unhedged energy cost (HUEC) can be expressed as

$$HUEC\ (\$/h) = NEP\ (MWh/h) \times E_{PRICE}\ (\$/MWh) \qquad \text{[Eq. 8.6.1]}$$

where the HUEC is found by multiplying the NEP by a suitable forecast of that hour's energy price. These hourly values can then be "rolled-up" over any time interval of interest to produce a cumulative cost (or revenue) estimate for eliminating ("closing") a short or long energy position. For example, the Ascend software produces daily updated forecasts of future expected HL and LL UEC's, for each month of the year. The Ascend software can also calculate the corresponding standard deviations associated with these forecasted estimates; these standard deviations are in turn used to calculate unhedged energy "cost-at-risk" (CAR) metrics. Under the assumption that the simulated UEC forecast follows a Lognormal distribution, a reasonable CAR metric can be defined as *CAR = 1.90 x Std(UEC)*, where *Std(UEC)* represents the calculated standard deviation of the rolled-up unhedged energy cost. (Justification for the 1.90 factor is given in Appendix B.)

Figure 8.6.1 shows the forecasted monthly UEC's for RPU's unhedged HL energy, LL energy, and natural gas positions in the 2018-2022 timeframe. These cost estimates have been computed by rolling up the future HL and LL NEP's and then multiplying these positions by their corresponding monthly forward energy prices. The optimal amount of natural gas hedging is calculated automatically based on LM6000 heat-rate curves and the corresponding necessary gas volumes are estimated using a conversion factor of 10 MMBtu/MWh. Similarly, Table 8.6.1 summarizes the monthly HL energy and natural gas forecasts into annual cost estimates. (LL annual cost estimates are all negative on/after 2019 since RPU's LL energy needs are fully hedged after this point in time.) As shown in Table 8.6.1, staff currently expect to forward procure minimal amounts of natural gas in all years other than 2019, when the Q3 market heat-rates suggest that significant amounts of natural gas can be optimally procured in place of HL power. Additionally, staff currently expects to spend between 4.6 million dollars to 6.8 million dollars annually on or after 2019 to fully hedge all of open HL positions.

As discussed above, a CAR metric can be computed for each UEC estimate. Figure 8.6.2 shows the associated CAR metrics for the monthly LL and HL + natural gas estimates shown in Figure 8.6.1. Likewise, Figure 8.6.3 summarizes the rolled-up CAR metrics for the annual UEC's, respectively. RPU's HL + gas cost-at-risk indices grow slightly over time, increasing from 3.21 million dollars in 2018 to 4.07 million dollars in 2020. It is typical for CAR metrics to increase in magnitude over extended time horizons, if the expected costs of the open energy positions also increase in magnitude over time.

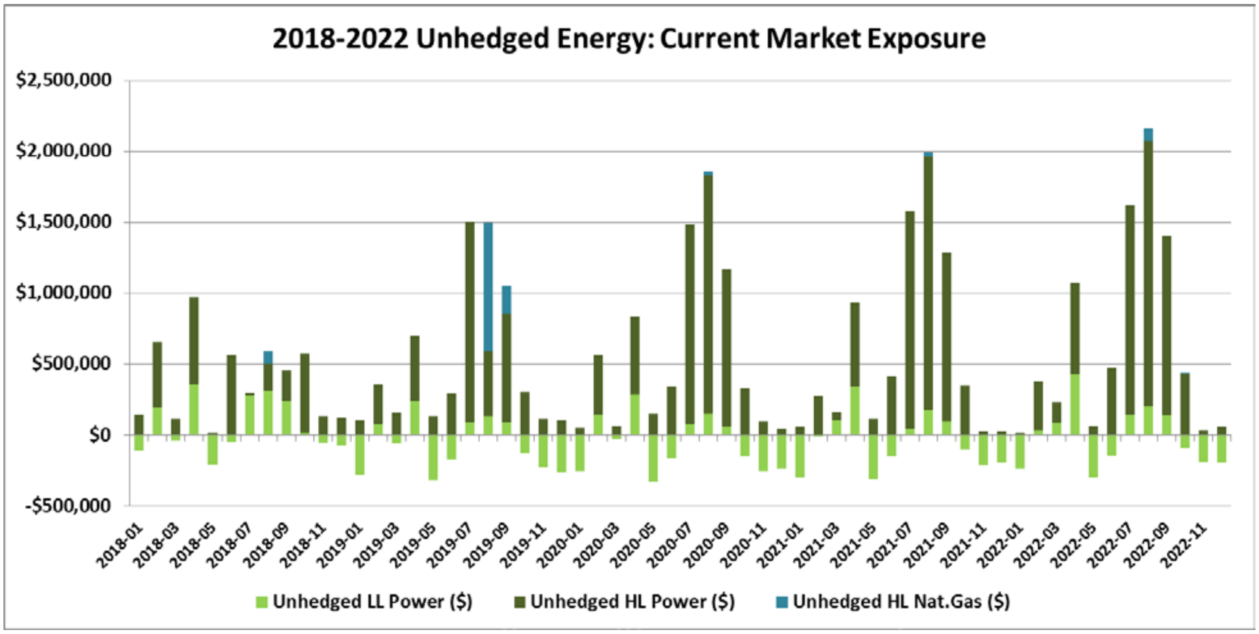


Figure 8.6.1. Forecasted monthly HL, LL, and natural gas unhedged energy costs: 2018-2022 timeframe.

Table 8.6.1. Annual unhedged HL + natural gas energy costs; 2018-2022 timeframe.

Hedging Metric	2018	2019	2020	2021	2022
HL energy costs ($000)	$3,155.8	$4,581.7	$6,237.1	$6,413.1	$6,825.5
Nat.Gas costs ($000)	$88.3	$1,094.2	$28.7	$33.1	$93.3
Total Hedging costs ($000)	$3,244.1	$5,675.9	$6,265.8	$6,446.2	$6,918.8

It is important to realize that while the CAR metrics shown in Figures 8.6.2 and 8.6.3 summarize the rolled-up cost uncertainty for specific time intervals, they do so at the hourly granularity level. Therefore, these metrics quantify both the cost uncertainty associated with the average open position for the respective time interval, and also the hour-to-hour uncertainty resulting from stochastic deviations in the expected weather, load and generation patterns. More formally, the variance of the UEC estimate can be partitioned into two distinct components, i.e.,

$$Var(UEC) = Var(OEP) + Var(WLG) \qquad \text{[Eq. 8.6.2]}$$

where *Var(OEP)* represents the variance associated with the average open energy position (for the time period of interest) and *Var(WLG)* represents the hour-to-hour uncertainty caused by random deviations in the expected weather, load and generation patterns. Traditional forward hedging purchases (or sales) can only reduce the *Var(OEP)* component; the *Var(WLG)* component will still exist even if the portfolio is perfectly hedged on average.

Figures 8.6.2 and 8.6.3 show how much the CAR metrics would be expected to change, assuming that the forward portfolio was perfectly hedged (i.e., all the open monthly energy positions were closed, etc.). In Figure 8.6.2 this is shown by the solid black line labeled "Net-0 COS ($)"; in Figure 8.6.3 these values are quantified as the "Net-0 Exposure ($)" amounts. It is clear from both figures that the vast majority of CAR estimates reflect hourly uncertainty in the weather, load and generation patterns. Or equivalently, very little of RPU's current cost-at-risk can be effectively reduced using further forward hedging activities. Given RPU's current degree of hourly load and generation uncertainty, about 2.2 and 3.3 million dollars should still be expected to be at risk annually during LL and HL time periods, even under an ideal 100% hedged scenario. Note that these figures represent the utility's baseline, minimal cost-at-risk conditions for its current resource portfolio, under a 100% fixed-price hedging strategy that avoids the use of any additional market call options or derivatives. (In practice however, the IPP contract acts like a physical call option - and thus nearly all of RPU's expected LL Net-0 CAR can also be eliminated by simply decking the resource when it is uneconomical to dispatch.)

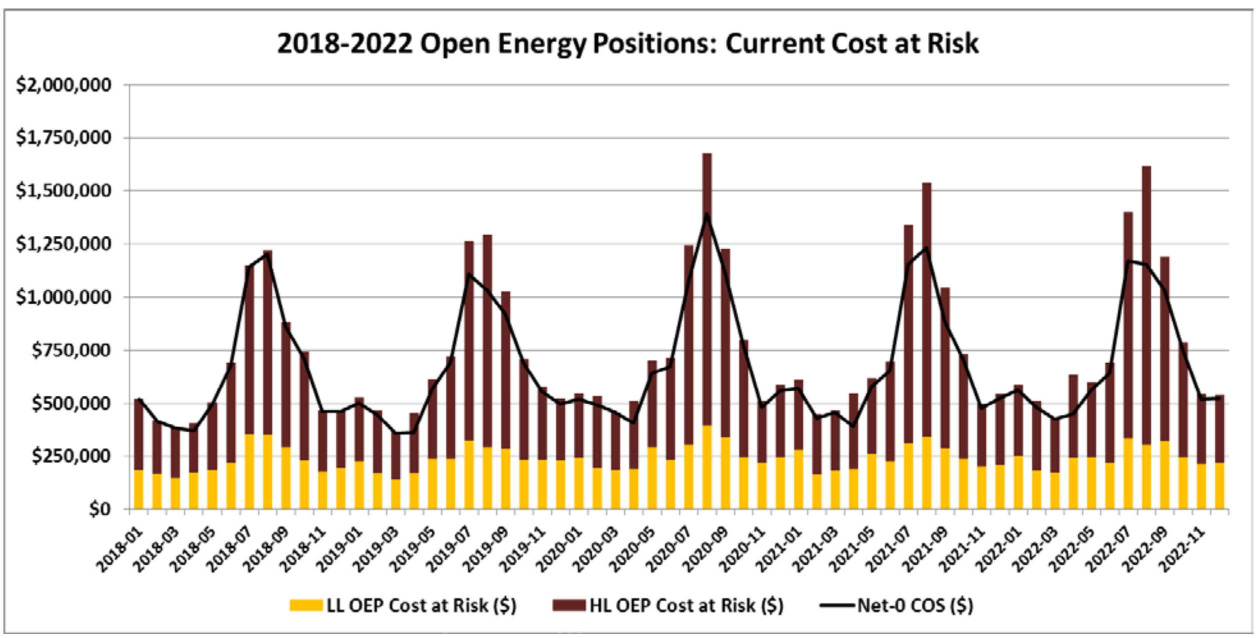
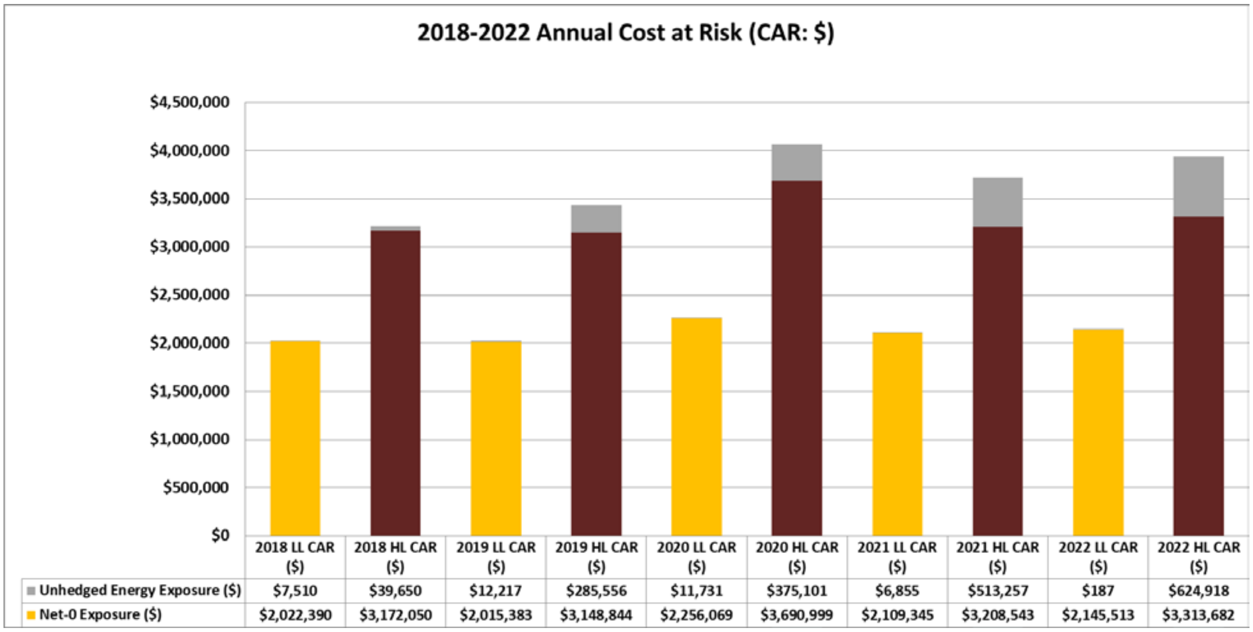


Figure 8.6.2. Forecasted cost-at-risk (CAR) metrics for the monthly UEC estimates shown in Figure 8.6.1.



	2018 LL CAR ($)	2018 HL CAR ($)	2019 LL CAR ($)	2019 HL CAR ($)	2020 LL CAR ($)	2020 HL CAR ($)	2021 LL CAR ($)	2021 HL CAR ($)	2022 LL CAR ($)	2022 HL CAR ($)
Unhedged Energy Exposure ($)	$7,510	$39,650	$12,217	$285,556	$11,731	$375,101	$6,855	$513,257	$187	$624,918
Net-0 Exposure ($)	$2,022,390	$3,172,050	$2,015,383	$3,148,844	$2,256,069	$3,690,999	$2,109,345	$3,208,543	$2,145,513	$3,313,682

Figure 8.6.3. Forecasted net-0 and unhedged energy exposure cost-at-risk (CAR) metrics for the monthly UEC estimates shown in Figure 8.6.1.

In summary, RPU is well hedged for calendar year 2018; nearly all of the remaining unhedged energy cost-at-risk is associated with stochastic hour-to-hour load and generation deviations that will not be further mitigated using fixed price monthly purchases or sales. However, there is some additional room to implement further HL hedging strategies in 2019 and beyond, particularly during the Q3 time period. Given RPU's current resource portfolio, the majority of these hedging activities should be focused towards closing open July through September summer HL energy positions and compensating for our April outage events.

8.7 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 8.7.1 shows RPU's annual allowance amounts for the 2018-2022 timeframe, along with RPU's annual forecasted 1st deliverer emission levels for this same period. Likewise, Figure 8.7.1 shows

RPU's forecasted 1st deliverer carbon emission levels by resource, at a monthly granularity level. As can be seen in this figure, the bulk of RPU's emissions are associated with the IPP coal contract. In general, RPU's annual emission levels are nearly proportional to the volume of energy deliveries received from this resource.

Table 8.7.1. RPU's annual carbon allocations, GHG emission profiles (million metric tons: MmT), allowance balances and projected auction income for the 2018-2022 timeframe.

	2018	2019	2020	2021	2022
CARB Allocations (MmT)	1.083	1.079	1.089	1.061	1.057
RPU Emissions (MmT)	0.591	0.592	0.600	0.608	0.610
Allowance Balance (MmT)	0.492	0.487	0.489	0.453	0.447
Carbon Cost ($/mT)	$15.60	$16.81	$18.08	$19.41	$20.83
Auction Income ($000)	$7,668	$8,182	$8,838	$8,784	$9,301

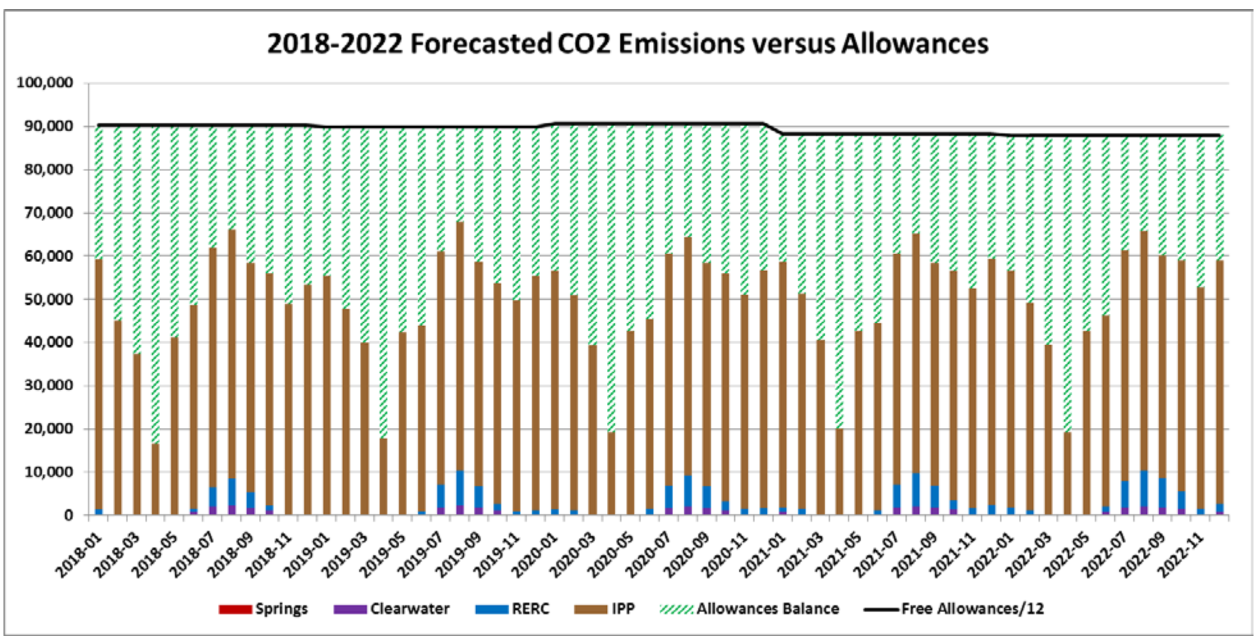


Figure 8.7.1. Forecasted monthly RPU carbon emission levels, by resource: 2018-2022 timeframe.

Table 8.7.1 also quantifies RPU's expected annual surplus carbon allowance positions for the same 2018-2022 time period. These surplus allowances are expected to be monetized through the quarterly CARB Carbon auction process; Table 8.7.1 shows the corresponding expected cash flow streams under the assumed auction price scenario discussed in Chapter 7, section 7.3. This scenario essentially represents the forecasted allowance floor price (set by CARB). Assuming that this scenario represents a reasonable auction price for the next five years, RPU can expect to receive approximately 8 to 9 million dollars per year in revenue from the sale of excess allowances. Currently, it is anticipated that this revenue stream will 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).

8.8 Five Year Budget Forecasts

All of 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, in order to reflect the latest market price forecasts and generation stack conditions.

Table 8.8.1 presents a summary of RPU's FY 17/18 through FY 22/23 budget forecasts, as of December 21, 2017. (These are the forecasts that were submitted into the most recent RPU FY 18/19 & 19/20 two year budget cycle.) As shown in Table 8.8.1, the utility's FY 18/19 net cost is projected to increase by approximately 12.5 million dollars over the prior year's FY 17/18 forecasts; this increase is primarily due to additional geothermal energy coming online in January 2019, in addition to increasing Transmission and Capacity costs. However, after FY 20/21, the overall budget should remain fairly stable through FY 22/23, assuming that the new CAISO initiatives do not impose significant additional market or procurement costs.

The lower portion of Table 8.8.1 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, Energy and Capacity costs to increase over the next two to three years, as the utility continues to decrease the GHG content of its portfolio. In contrast, SONGS related costs are expected to remain fairly constant over the next five years, and Capacity costs are expected to decrease significantly once the IPP debt service payments end.

The full five-year forward budget forecast is presented in Appendix C. These forecasts include detailed projections of various Capacity costs, SONGS related costs, Transmission related costs and revenues, generation energy and associated energy costs and revenues, wholesale CAISO sales and purchases, CO2 emissions and net allocation revenues, fuel costs, and net hedging costs, respectively.

Table 8.8.1. Five year forward power resource budget forecasts: fiscal years 17/18 through 22/23; all forecasts shown in $1000 units.

	FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
Summary						
Gross Costs	$ 195,327	$ 210,217	$ 221,849	$ 226,133	$ 218,974	$ 223,120
Gross Revenue	$ (41,625)	$ (44,009)	$ (45,486)	$ (42,164)	$ (38,575)	$ (39,422)
Net Costs	$ 153,702	$ 166,207	$ 176,363	$ 183,970	$ 180,399	$ 183,698
Summary						
Transmission	$ 59,920	$ 61,223	$ 64,378	$ 65,913	$ 65,855	$ 68,306
Energy	$ 88,958	$ 99,935	$ 105,320	$ 108,104	$ 110,770	$ 112,612
Capacity	$ 38,168	$ 41,640	$ 44,363	$ 46,307	$ 36,408	$ 35,784
SONGS	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000
Ice Bear	$ 1,621	$ 2,180	$ 2,183	$ 135	$ 137	$ 140
GHG Regulatory Fees	$ 150	$ 150	$ 150	$ 158	$ 165	$ 174
Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
Gas Burns + Net Hedge Cost or (Revenue)	$ 2,309	$ 888	$ 1,254	$ 1,316	$ 1,439	$ 1,904
Post 2020 Cap and Trade Cost	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL COST	$ 195,327	$ 210,217	$ 221,849	$ 226,133	$ 218,974	$ 223,120
CO2 Allowance Auction Revenue	$ (6,360)	$ (7,807)	$ (8,427)	$ (4,405)	$ -	$ -
TRR Revenue	$ (35,265)	$ (36,203)	$ (37,059)	$ (37,758)	$ (38,575)	$ (39,422)
PCC-1 RPS Sale	$ -	$ -	$ -	$ -	$ -	$ -
SUBTOTAL REVENUE	$ (41,625)	$ (44,009)	$ (45,486)	$ (42,164)	$ (38,575)	$ (39,422)
TOTAL	$ 153,702	$ 166,207	$ 176,363	$ 183,970	$ 180,399	$ 183,698
Summary (Cost/Gross Load)						
Adjusted Transmission	$ 10.88	$ 10.86	$ 11.70	$ 11.96	$ 11.45	$ 11.99
Energy	$ 39.26	$ 43.39	$ 45.12	$ 45.91	$ 46.51	$ 46.73
Capacity	$ 16.85	$ 18.08	$ 19.01	$ 19.67	$ 15.29	$ 14.85
SONGs	$ 0.88	$ 0.87	$ 0.86	$ 0.85	$ 0.84	$ 0.83
Total (all categories)	$ 67.84	$ 72.17	$ 75.56	$ 78.13	$ 75.74	$ 76.22

8.9 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 is on track to procure a significant amount of excess renewable energy, above and beyond the state's minimum mandated amounts. Since 2017, RPU has begun to rapidly accumulate excess renewable energy credits. Currently, the utility is planning on reselling some of this excess renewable energy to raise additional budget revenue during the 2018-2020 timeframe. However, even with these proposed sales, RPU will stay at or above a 33% RPS level through CY 2020.

- RPU has about 90% of its load serving needs naturally hedged through long-term PPA's and generation ownership agreements. The remaining 10% of open energy positions need to either be served using internal generation assets and/or actively hedged via the forward market purchases of energy and natural gas. Nearly all of the remaining open energy volumes are associated with Q3 HL needs and April outage events. RPU's current expected costs to fully close these open HL positions range from 5.7 to 6.9 million dollars annually in the 2019-2022 timeframe. The associated CAR metrics for the same time period currently range from 3.2 to 3.7 million dollars, respectively.

- RPU's forecasted power supply net revenue uncertainty (i.e., annual NRU standard deviations) range from 8 to 9 million dollars a year in the 2018-2022 timeframe. The corresponding 90% confidence intervals for annual potential revenue deviation are approximately ±13 to ±15 million dollars a year, respectively.

- RPU is expected to have more than enough carbon allowances to fully meet its direct emission compliance needs through 2022. Staff currently forecasts having an excess allowance balance of 450,000 to 500,000 credits annually. These excess credits are expected to be monetized through the CARB quarterly auction process, with a significant portion of the proceeds used to help offset RPU's incremental renewable energy costs.

- RPU's FY 18/19 power supply budget is projected to increase by approximately 12.5 million dollars over the prior year's FY 17/18 forecasts; this increase is primarily due to additional geothermal energy coming online in January 2019, in addition to increasing Transmission and Capacity costs. However, on/after FY 20/21, the overall budget should remain fairly stable through FY 22/23.

In summary, the utility is well positioned to meet its load serving needs over the next five years while focusing on controlling its internal portfolio costs. With respect to energy needs, some additional systematic forward hedging activities are required to maintain cash flow stability. However, there are no looming, critical energy procurement decisions that need to be made in the immediate term time horizon (i.e., in the next three to five years).

9 GHG Emission Targets and Forecasts

The fundamental purpose of the 2018 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 emissions target. RPU's specific 2030 GHG target has yet to be precisely determined under the current IRP paradigms being overseen by the Joint Agency (CPUC, CEC and CARB) planning process. However, the energy sectors overall target must be at least 40% below the sectors 1990 emission level, and CARB is proposing to endorse both the CPUC and CEC proposed ranges of preliminary individual targets for the utilities under their jurisdiction.

This chapter will examine how much RPU's total GHG footprint must change (i.e., decrease) over time to meet three different plausible 2030 emission targets. 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.

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 of the implied emissions associated with power that a utility uses to serve its native load. Many utilities are still arguing over how to define this metric, but RPU interprets this to be the calculated GHG emissions associated with all of the physical power that is scheduled into a CA balancing authority and reported on the CEC Power Content Label. Fortuitously, RPU is almost always short resources to meet its total native load, currently has no PCC-2 contracts (nor plans for obtaining any future PCC-2 resources), and also does not view PCC-3 TRECs as a legitimate means for offsetting future GHG emissions. As such, it is relatively straightforward for RPU to compute its (non-verified) historic and forecasted Total Portfolio emissions in a manner that will most likely be consistent with the interpretation that the CEC ultimately adopts under the AB 1110 proceedings. 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 should be (and is) used for all unspecified system power (and/or net CAISO market purchases) in these calculations.

9.2 1990 GHG Emissions Profile

As discussed in Chapter 5, AB 398 extended the CARB GHG program and mandates through 2030. 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 electric sector, this goal entails that the sector reduce their overall emissions down from 108 MMT (1990 level) to at least 65 MMT. Assuming that this 40% reduction is applied equally to all CA LSEs, a target GHG emission level can be easily calculated for Riverside after RPU's 1990 emission level has been determined.

Table 9.2.1 below shows RPU's calculated 1st Importer and Total Portfolio GHG emission levels for 1990. 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). As shown below, RPU had a Total GHG emission level of 1,079,740 metric tons (MT) in 1990. Hence, if the utility were to adopt a target that is 40% below this level, our goal should be to not exceed 647,844 MT of total portfolio emissions in 2030.

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).

Throughout the remainder of this chapter this value (647,844 MT) will be referred to as the 40% below 1990 (minimum reduction) goal. Although RPU's proposed 2030 GHG goal for planning purposes is lower than this target value, note that this calculation still provides a useful reference baseline for general planning purposes.

9.3 CEC POU-Specific GHG Emission Reduction Targets

In 2017 the CEC initiated a stakeholder process for determining how to set GHG planning targets for POUs. This stakeholder process was designed to elicit feedback from the POU community on an appropriate target setting methodology. In early 2018 the CEC released their proposed methodology for setting POU-specific GHG emission targets for POU Integrated Resource Plans. Details concerning the proposed CEC methodology can be found in the April 26, 2018 CEC GHG target setting report.

In their report, the CEC listed individual utility targets for the 16 largest POUs based on three different electricity sector targets: 30, 42, and 53 MMT CO_2-e. In the subsequent Draft Staff Report and Draft EA issued by CARB on April 27, 2018, CARB endorsed this target range for the POUs and suggested that each POU should choose one or more targets within this range for integrated resource planning purposes.

It should be noted that the 30 MMT sector target represents a 72% GHG reduction over the electric sectors 1990 emissions. This reduction level is far in excess of the 40% below 1990 legislative mandate and most likely unachievable under any reasonable cost containment scenario. Additionally, the 42 and 53 MMT targets still represent 61% and 51% GHG sector reductions, and thus both exceed the legislative mandate. Hence, for planning purposes RPU has elected to focus on these target levels.

Under the 53 MMT sector target, RPUs utility specific target is 486,277 MT CO_2-e. Likewise, under the 42 MMT sector target, RPUs utility specific target is 385,137 MT CO_2-e. RPU is electing to use the higher 486,277 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 reaching both of these targets, in addition to the previously discussed baseline legislative mandate. Table 9.3.1 below summarizes these three GHG planning targets, respectively.

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

GHG Planning Target	Description	MT CO2-e Emission Value
Baseline	40% below 1990 (utility specific)	647,844
53 MMT Sector Goal	Official RPU target	486,277
42 MMT Sector Goal	More aggressive GHG reduction scenario	385,137

9.4 Historic RPU Emissions: 2011-2017

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 2017; note that the 2011-2016 1st Importer values represent verified emissions (the 2017 data is currently undergoing verification). 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.

Table 9.4.1. RPU 1st Importer and Total Portfolio GHG emissions: 2011-2017.

Year	Total Portfolio Emissions ($MT\ CO_2$-e)	1st Importer Emissions ($MT\ CO_2$-e)
2011	1,060,786	947,826
2012	1,125,137	716,351
2013	1,052,228	705,696
2014	1,212,715	865,372
2015	1,000,612	604,101
2016	972,100	594,346
2017	949,583	665,613

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 into RPUs portfolio since 2012. Furthermore, 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.

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, any necessary incremental renewable energy amounts were then added into the portfolio, in order to meet a pre-specified (and adjustable) RPS target by 2030. 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).

Defining the forecasting methodology in this manner facilitated two types of analyses to be performed. Either a specific 2030 RPS target could be specified a priori, which in turn would yield the corresponding 2030 Total Portfolio emission level. Or a target portfolio emission level could be specified first and then an iterative procedure could be employed to identify the necessary RPS target level (for achieving the 2030 emission target). In either analysis, it was also possible to determine how much additional retail load reduction would need to occur in order to meet even more stringent GHG emission levels.

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

- The IPP coal plant is assumed to retire on June 30, 2025 and is replaced with a 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, enough new (unspecified) renewable energy projects are added to the portfolio each year to ensure that the 2030 RPS target is fully satisfied.

Figure 9.5.1 conveniently summarizes the various results from these emission forecasting scenario studies. The upper blue, purple and green lines quantify RPU's Total Portfolio emissions under three different 2030 RPS target scenarios, while the lower yellow line quantifies the utilities 1st Importer emission liabilities. Each of these scenarios is described in greater detail below.

The upper blue line shows RPU's Total Portfolio emissions under the current SB 350 50% RPS by 2030 mandate. In this analysis it is assumed that 90% of the RPS target is met using in-state PCC-1 renewable energy, while the remaining 10% of the RPS target is satisfied using TRECs. Technically, this scenario could also be referred to as the "45% PCC-1 RPS by 2030" mandate, since TRECs are being used to satisfy 10% of the RPS goal. Nonetheless, RPU exhibits a forecasted emission level of 607,360 MT CO_2-e under this scenario. This forecast is comfortably below the utility's baseline (minimum reduction) legislative mandate, but not low enough to meet RPU's proportion of either the 53 or 42 MMT Sector targets.

The upper purple line shows how RPU's Total Portfolio emissions decrease if the utility achieves a 57% PCC-1 RPS by 2030 mandate. Note that in this analysis it is assumed that 100% of this higher RPS target is met using in-state PCC-1 renewable energy; or equivalently, the utility does not purchase or use any TRECs. Under this scenario, RPU reaches a forecasted emission level of 477,577 MT CO_2-e by 2030, which is just slightly lower than RPU's proportion of the 53 MMT Sector target (i.e., 486,277 MT).

The upper green line shows how RPU's Total Portfolio emissions further decrease if the utility achieves a 66% PCC-1 RPS by 2030 mandate. Again, in this analysis it is assumed that 100% of this higher RPS target is met using in-state PCC-1 renewable energy. Under this latter scenario, RPU reaches a forecasted emission level of 380,240 MT CO_2-e by 2030, which is just marginally lower than RPU's proportion of the 42 MMT Sector target (i.e., 385,137 MT).

Finally, the lower yellow line shows how RPU's 1st Importer emissions decline under each of the previous three scenarios. Note that this 1st Importer emission path exhibits an identical pattern under each scenario, since none of these scenarios assume that RPU contracts for additional thermal resources at any point between now and 2030. Note also that these 1st Importer emission liabilities become quite low by 2028, after RPU has completely exited the IPP contract.

In addition to the data displayed in Figure 9.5.1, the following additional load reduction statistics were derived from the above discussed analyses. First, if RPU simply remains on a trajectory to meet a 50% RPS target by 2030 (and used 10% TRECs in partial satisfaction of this mandate), then the utility will need to further reduce its 2030 retail load by 282,905 MWh/year (or by 11.2%) to meet a GHG target of 486,277 MT CO_2-e. Likewise, the utility would need to reduce its 2030 retail load by 519,213 MWh/year (or by 20.6%) to meet a GHG target of 385,137 MT CO_2-e. In contrast, if RPU endeavors to meet a 57% PCC-1 RPS target by 2030 (using 100% PCC-1 renewable energy contracts), then the utility would need to further reduce its 2030 retail load by 215,982 MWh/year (or by 8.6%) to meet a GHG target of 385,137 MT CO_2-e.

In summary, these results help quantify what RPU must do to meet the more stringent (CARB imposed) 2030 emission levels. Specifically, RPU can only meet its officially adopted GHG 2030 target level of 486,277 MT (or a more aggressive lower level) through either/both increased RPS procurement strategies and/or reduced load growth (via increased EE and/or DER penetration levels).

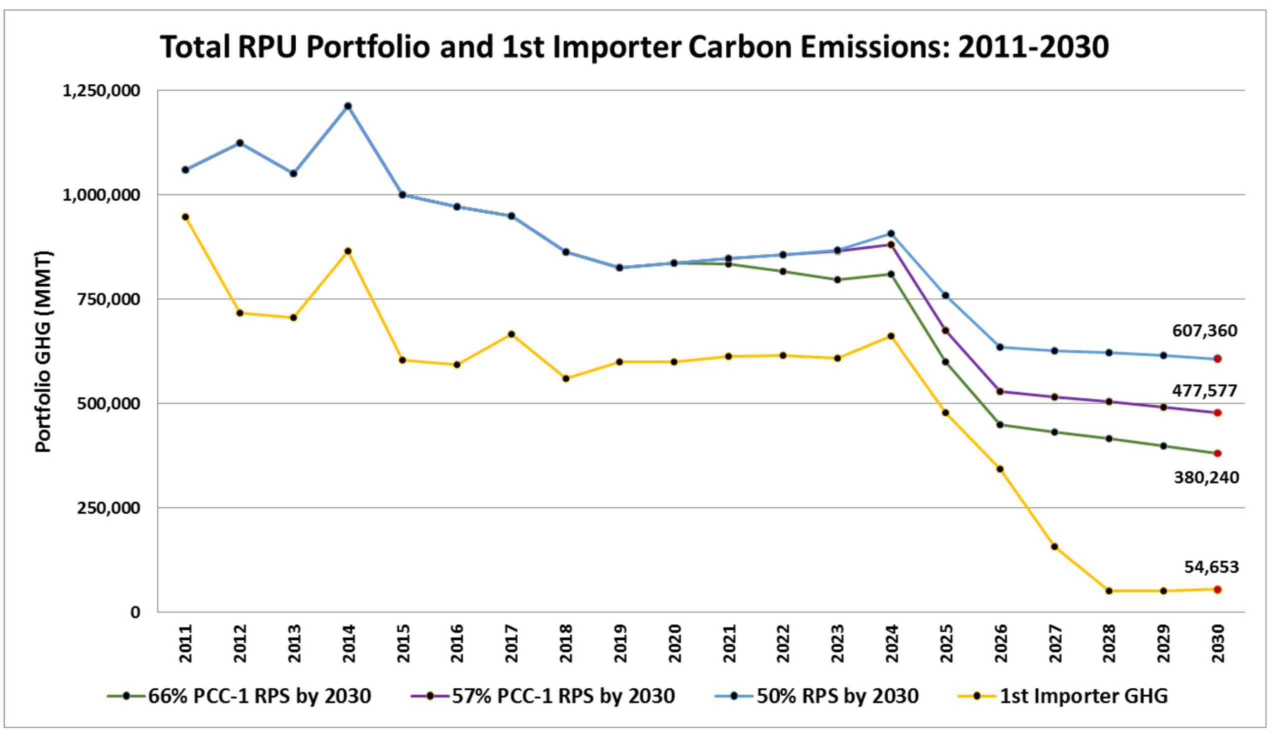


Figure 9.5.1. Historical and forecasted RPU GHG emission levels under different RPS target scenarios.

10. Future Assumptions about Current Generation Resources

Chapter 3 provided an overview of Riverside's portfolio of generation resources. This chapter examines all of Riverside's existing resource contracts that are scheduled to end before December 2037, specifically with respect to how these resources are modeled in the subsequent long-term portfolio impact analyses. 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. Additionally, this chapter provides an extended discussion concerning the IPP contract, including RPU's rationale and justification for exiting this contract in 2027.

10.1 Existing Generation Resources with Contracts that Expire before December 2037

Table 10.1.1 presents an overview of the utility's current generation resources with either contracts or expected lifetimes that expire before December 2037. In Table 10.1.1, each resource has been classified into one of three mutually exclusive groups defined as follows: (a) resources with contracts that will definitely be terminated before 2037 (or reach their end-of-life before 2037), (b) resources with contracts that RPU plans on extending, and (c) resources with contracts whose extensions are currently uncertain. Additional details concerning how each of these resources will be modeled in the long-term portfolio analyses are presented in subsequent sections.

10.1.1 Contracts Expected to be Terminated

The contracts associated with IPP, Salton Sea 5, and Wintec are all terminating well before 2037; these contracts are not currently expected to be either extended or renegotiated. Additionally, the Springs generation facility will reach its 25 year end-of-life cycle in 2027 and is 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). A detailed discussion about the IPP contract is presented in section 10.2; brief discussions concerning the remaining resources are presented below.

Salton Sea 5 (Primary PPA)

The Salton Sea 5 contract between Riverside and CalEnergy is scheduled to terminate on May 31, 2020. On June 1, 2020 this facility will transfer over into the CalEnergy portfolio of geothermal resources; Riverside will begin receiving an additional 46 MW of capacity from this portfolio on this same date. Hence, although this contract is terminating, Riverside should not experience any disruption in its primary geothermal energy deliveries.

Salton Sea 5 (Incremental Contract)

In May 2017, Riverside entered into a one year WSPP agreement to purchase up to 3 MW of additional geothermal energy when the CalEnergy Salton Sea 5 facility generates more than 46 MW. The agreement can be potentially extended on an annual basis through May 2020 (the expiration of the Salton Sea 5 contract). This agreement must terminate upon the termination of the primary Salton Sea 5 contract and cannot be extended under the CalEnergy Expansion contract.

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. This contract terminates in October 2018 and Riverside does not intend to pursue a contract extension for this facility.

Springs Generation Facility

RPU owns and operates four GE10 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 RA requirements. These units will reach their end of serviceable life by 2027, at which point they are expected to be decommissioned.

Table 10.1.1. Long-term RPU generation resources with contracts that expire before 2037.

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	Expected end-of-life: 2027
Salton Sea 5	Geothermal, renewable (base-load)	46	May-2020	Replaced by CalEnergy portfolio contract
Salton Sea 5 Incremental	Geothermal, renewable (base-load)	Up to 3	May-2018	Extended through May 2020, then terminates
Wintec	Wind, renewable	1.3	Dec-2018	Contract terminates
WKN	Wind, renewable	6	Dec-2032	TBD
Antelope DSR	Solar PV, renewable	25	Dec-2036	TBD
Kingbird B	Solar PV, renewable	14	Dec-2036	TBD
Columbia II	Solar PV, renewable	11	Dec-2034	TBD
Cabazon	Wind, renewable	39	Dec 2024	TBD

10.1.2 Contracts Expected to be Extended

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 recent developments, it is expected that GHG-free Palo Verde nuclear energy will continue to be delivered to Riverside at the same capacity allotment and CF% at least through 2045.

10.1.3 Contracts Subject to Extension or Replacement

As previously shown in Table 10.1.1, there are five additional renewable PPAs that have contract termination dates before 2037. Two of these PPAs are for wind facilities; i.e., Cabazon (2024) and WKN (2032). The remaining three PPAs are for solar PV facilities; i.e., Columbia II (2034), Kingbird (2036), and Antelope DSR (2036). Together, these five facilities supply Riverside with approximately 223,000 MWh a year of GHG-free renewable energy.

It is currently uncertain how many of these contracts may be extended. 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. As such, for purposes of this integrated resource planning process, staff has assumed that the contracts for all of these generation assets will be replaced with equivalent technology facilities under the same pricing structures through 2037.

Figure 10.1.1 shows the status of how all current contracts are treated in all subsequent IRP analyses and assessments performed over the 2018-2037 time-frame, respectively.

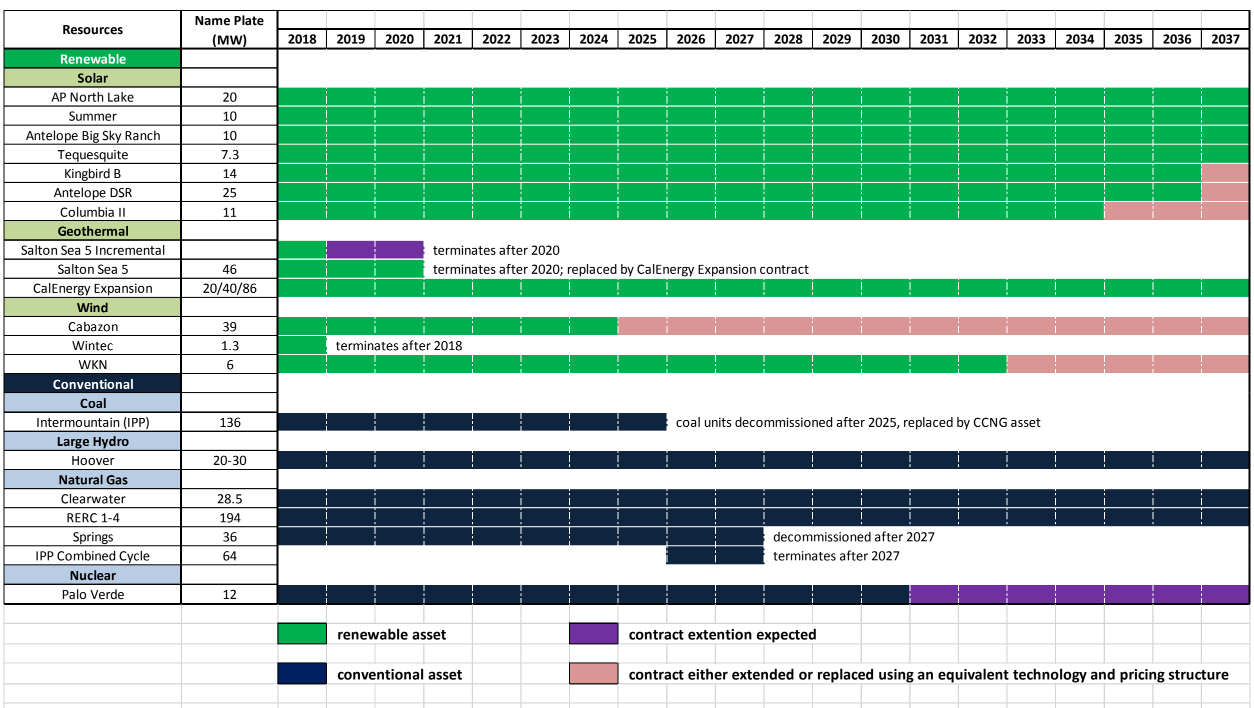


Figure 10.1.1. Assumptions about how current RPU contracts are treated in all subsequent IRP modeling assessments.

10.2 Justification for Exiting the IPP Repowering Project

RPU began examining the option of participating in the IPP repowering contract during the utilities 2014 Integrated Resource Planning (IRP) process. At that time, there were two primary motivating factors that staff believed might justify RPU's participation. The first was the potential to secure power from a natural gas generation facility at a cost slightly below a local tolling arrangement, and probably at a lower MW level than would otherwise be available from a local combined cycle natural gas (CCNG) plant. The second factor was the potential to retain excess transmission capacity on the Southern Transmission System (STS). This excess transmission could in theory be available for RPU to use to import future renewable or carbon free energy, or monetized in some other manner for the benefit of RPU rate-payers.

During the 2014 IRP process, staff examined the financial attractiveness of the IPP repowering option, based on the (very preliminary) cost factors available at that time. These analyses suggested that the repowering project should cost less than a local tolling option, provided all of the initial cost estimates were accurate. However, the monetizing of the excess STS capacity was not examined in these analyses. At the time of these studies, this excess STS capacity was viewed as a "free option" with little or no downside, and the costs for maintaining this transmission capacity had not yet been clearly defined.

Since these first studies were performed, the IPP repowering project has experienced a significant number of new developments. First, the CA participants have mutually agreed to retire the coal units two years ahead of schedule (i.e., by June 2025), thus accelerating the time line for the CCNG repowering project. However, the costs associated with this repowering project have steadily increased, even though the final configuration for the new natural gas generation asset is still being determined. Likewise, LADWP has now informed the CA participants that the STS DC line will require 1.2 to 1.3 billion dollars in transmission upgrades, and also that all participants will be expected to sign 50 year contract commitments for both the generation and transmission assets. Meanwhile, the state of California is moving aggressively to mandate a carbon-free grid by 2045 and the CAISO Board of Governors released a draft discussion paper in early 2018 proposing a natural gas "exit strategy" by 2030.

The two initial advantages of this repowering project (discussed above) led staff to initially recommend that RPU remain engaged in the contract negotiations. However, based on a multitude of events that have transpired over the last 12-18 months, staff has now identified no less than nine reasons for exiting this repowering contract. Each of these reasons is discussed in more detail below.

1. 50 Year Contract Commitment

A core requirement for participation in the repowering project is that each member must commit to a 50 year contract. However, this contract length is at least twice as long as the industry standard and imposes substantial risk on the member utilities, particularly the CA participants. It is very likely that California will legislatively mandate that nearly all carbon emitting, thermal generation assets cease operation on or before 2050, leaving the participants in this project with a stranded asset for 20 to 25 years before the contract expires.

2. Regulatory & Legislative Uncertainties

There are numerous regulatory uncertainties involved with building new thermal generation assets, even for assets built outside the state. This repowering project will require multiple SB 1368 filings, a NEPA review, an EIS/EIR, and potentially significant regulatory permitting for the proposed natural gas pipeline infrastructure. More importantly, bills have now been introduced in the CA state legislature that would require that all natural gas generation facilities interconnected to the CAISO cease operation by 2045 (which is in direct conflict with the 50 year contract discussed in #1 above). Power Resources staff carefully assesses every proposed generation project for both regulatory and legislative risks; staff considers the risk levels for this repowering project to be problematically high.

3. Generation Construction Cost Uncertainties

LADWP is the default lead agency overseeing the proposed generation and construction cost estimates. Although this study is designed to be transparent, Riverside does not have sufficient staff to maintain a high level of oversight on the process, or fully review the various cost drivers and cost uncertainties. Furthermore, each revised cost estimate has resulted in a higher $/MWh price for the anticipated generation energy. The most recent forecasted "all-in" bus-bar price for the generation energy is currently $53.65/MWh in 2025, excluding unforeseen gas infrastructure costs, STS transmission upgrade costs, and future carbon costs. This cost is already $15 to $20 higher than SP15 market price forecasts for the same time period (before adding in any of the excluded additional costs).

4. Natural Gas Infrastructure

To date, three different pipeline options have been studied for this project, with projected infrastructure costs ranging from $40M to $100M. However, all of these options may incur additional right-of-way acquisition costs. Additionally, LADWP foresees potential additional permitting hurdles and future cost uncertainties associated with all of the proposed options. Adding to this complexity is that various CA participants are proposing / advocating different ideas on fuel sourcing. Currently, there is no agreement amongst the participants for how to proceed on the natural gas infrastructure planning process.

5. Future STS Transmission Upgrade Costs

In addition to designing, permitting and building a new CCNG asset, the IPP repowering plan calls for major infrastructure upgrades and improvements to the STS DC transmission line. The preliminary cost estimate for these proposed upgrades is 1.2 to 1.3 <u>billion</u> dollars, with the costs to be shared proportionally amongst the participants. (RPU would be responsible for 5.3% of these costs.) In theory, these costs should be recoverable through the utilities TRR filing at FERC, but full cost recovery is not guaranteed. Nonetheless, all participants will need to begin paying for these transmission system upgrades before the repowering project is completed. Thus, RPU may experience a multi-year negative cash flow before recovering these costs through a modified TRR filing, in addition to the non-negligible risk of receiving less than 100% cost recovery through the FERC TRR filing process.

6. Unresolved Transmission Contracts

Additional transmission uncertainties are contract related. First, if RPU stays in the IPP repowering project then the utility will need to renegotiate a new Transmission Service Agreement (TSA) with LADWP. This TSA is needed to secure the last non-CAISO leg of the transmission path to the CAISO intertie point (through LADWP service territory). The costs for this new TSA are expected to be significantly higher than the current TSA that covers the existing IPP contractual agreement.

Second, RPU also currently has a TSA agreement with SCE for the CAISO leg of the transmission path; this TSA allows the City to file for approximately 10 million dollars a year of SCE imposed transmission costs (billed to Riverside from SCE and recovered in Riverside's TRR filing). However, this TSA contract is set to terminate in 2027 and SCE has indicated that they will not extend it (since Riverside is a PTO in the CAISO and thus has no need for this legacy transmission agreement). Hence, Riverside expects to lose this TSA even if the City remains in the IPP repowering contract.

7. Conflicting Operational Goals of Participants

Ever since this repowering project was initially proposed, the project participants have expressed conflicting operational goals for the plant. The Utah participants want to build a CCNG plant optimized for steady baseload operation. In contrast, the California participants (particularly the CAISO participants) are seeking to build a type of hybrid plant optimized for maximum dispatch and ramping flexibility. Unfortunately, it is proving to be very difficult to co-optimize these different operating characteristics, since the final operating characteristics significantly impact the ultimate plant design, gas scheduling strategy, and O&M cost allocation proposals. RPU staff believes that reaching consensus on this issue will be challenging at best, and may in turn lead to unanticipated contract disputes and/or an overall delay in the proposed project timeline.

8. Carbon Cost Uncertainties

Perhaps the single greatest risk associated with this project is the unknown future cost of carbon. Given the aggressive push towards carbon reduction by the state of California, it would seem fundamentally irresponsible for RPU to commit its ratepayers to a 50 year contract with a carbon emitting resource. Even a contract for half this length would represent a significant risk, given the uncertainty around future carbon costs. From a resource planning perspective, it should be noted that staff do not intend to analyze any tolling contracts with natural gas resources for contract lengths longer than 10 years in this IRP. Contracts in excess of 10 years simply carry too much future carbon price risk.

9. Decommissioning Costs

LADWP has already signed a contract with IPA to repower the IPP facility. It seems extremely unlikely that LADWP will break this contract, since they need to retain access to the Southern Transmission System (STS DC line) in order to continue receiving ~300 MW of renewable wind energy that they already have under long-term contract. Burbank and Glendale are motivated to stay in this repowering contract for similar reasons (i.e., access to LADWP transmission for renewable power).

In contrast, as a CAISO member RPU does not need this transmission path, as Riverside does not have any renewable contracts that depend upon access to the STS DC line. There is really no motivation for Riverside to remain in this repowering contract unless the contract is financially viable. This issue is important, because the cities that remain in the repowering contract must bear the majority of the costs for decommissioning the coal facilities (assuming that IPP is successfully repowered). Or equivalently, given that LADWP will almost certainly repower the facility in some manner, cities that opt out of the repowering contract simultaneously opt out of paying the majority of future coal plant decommissioning costs. This represents a significant, additional avoided cost benefit that Riverside could take advantage of by choosing to exit by 2019.

In summary, the IPP repowering contract no longer represents a financially viable option for RPU or Riverside rate payers. The fully loaded cost of this natural gas power will most likely exceed $70.00/MWh in 2025, once the expected typical production cost overruns, carbon cost component, and the potential for paying the LADWP OATT for transmission access are all factored in. Hence, it no longer appears plausible that the fully loaded costs of this repowering project will come in below what RPU would pay for a tolling contract with a local natural gas generation facility here in Southern California. Furthermore, the risk profiles of these two options are not even remotely comparable (i.e., a 10 year tolling arrangement versus a 50 year ownership model). Finally, the retention of capacity on the STS DC line appears to offer RPU few tangible benefits to counter-balance the new financial risks brought on by the need for 1.3 billion dollars in DC line upgrades. Thus, the two primary drivers for staff's original interest in this project have now become greatly diminished, while multiple new financial risks have simultaneously emerged.

For all of the above mentioned reasons, the RPU Power Resources division recommends that Riverside exercise its exit right under the IPP Repowering Agreement. Therefore, with respect to this current IRP process, staff has assumed that RPU will cease receiving power under this contract after June 2027. Staff has also assumed that the IPP coal plants will be decommissioned by June 2025 and that the final two years of reduced energy deliveries will originate from the (still to be built) CCNG facility. Note that additional details concerning these assumptions and forecasted portfolio cost impacts are presented in Chapter 13, respectively.

11. Future Resource Adequacy Capacity Needs

This chapter outlines RPU's future capacity needs for the 20-year time horizon from 2018 through 2037. 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 the current and future CAISO Resource Adequacy (RA) paradigms. Many of these RA paradigms are currently being revised, such as the allocation process for receiving additional import RA credits for new resources and the types of generation assets that will count towards flexible RA credit in the future. These issues are discussed in detail below.

11.1 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 of 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.

The amount of capacity needed in each category is derived from a different technical study. A brief discussion of each type of capacity requirement as well as RPU's specific requirements follows.

11.1.1 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%, which is what RPU uses for its planning reserve margin.

Figure 11.1.1 shows RPU's forecasted monthly system peaks and 115% system RA requirement from 2018 through 2037. Note that these forecasts are not adjusted for the CAISO's coincident peak.

Typically, Riverside's coincident peak adjustment factor is around 0.95. As discussed in Chapter 2, Riverside's forecasted peaks grow 0.5% per year.

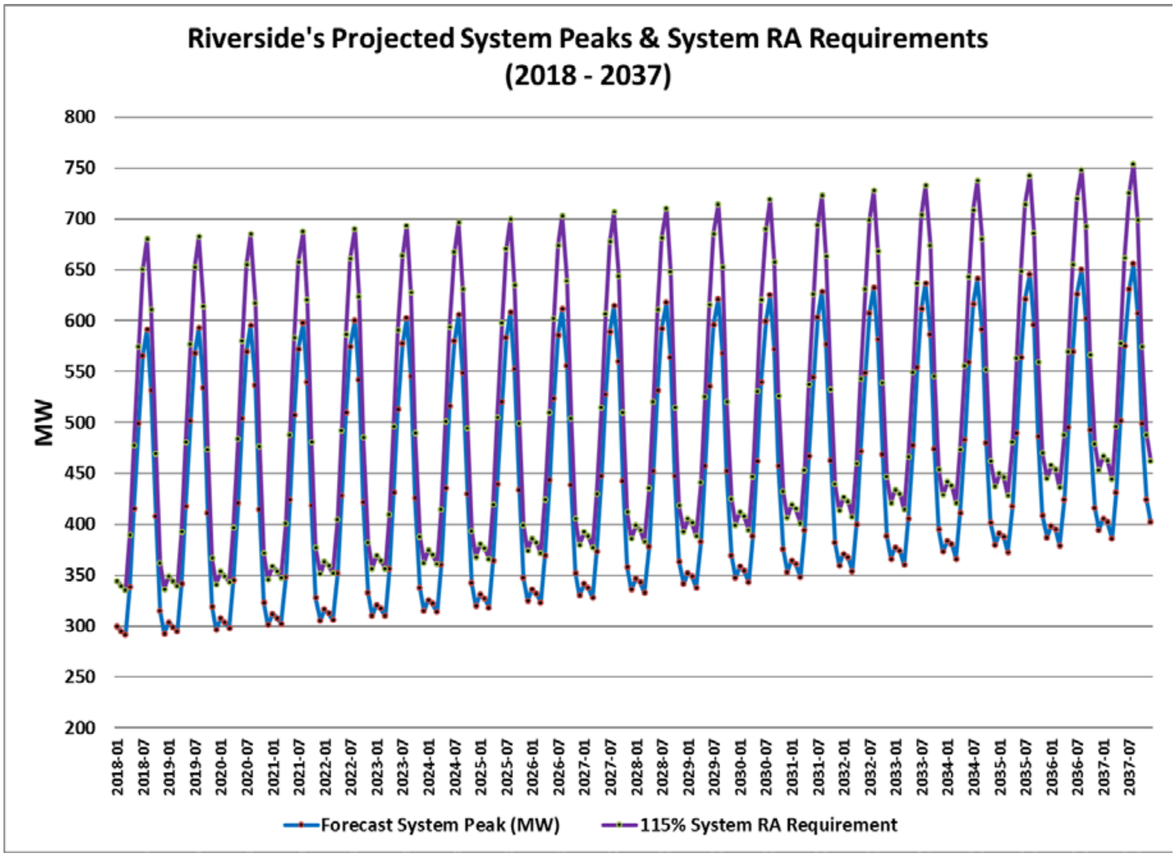


Figure 11.1.1. Riverside's 20-year forward system peaks and 115% system RA needs (2018-2037 timeframe).

11.1.2 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 an annual local capacity technical study in order 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.

Because it is derived from a CAISO technical study, RPU cannot forecast its local RA requirement as confidently as its system RA forecast. To get an idea about its future local RA requirements, staff looked at RPU's local RA requirements for the last five years (2014-2018), shown in Figure 11.1.2. RPU's Local RA requirement has trended downward over the past five years. However, in the past two years, the requirement has stabilized. For purposes of RPU's Local Capacity assessment in this IRP, the 2018 requirement of 255.98 MW is projected forward as its local RA requirement for 2018 through 2037.

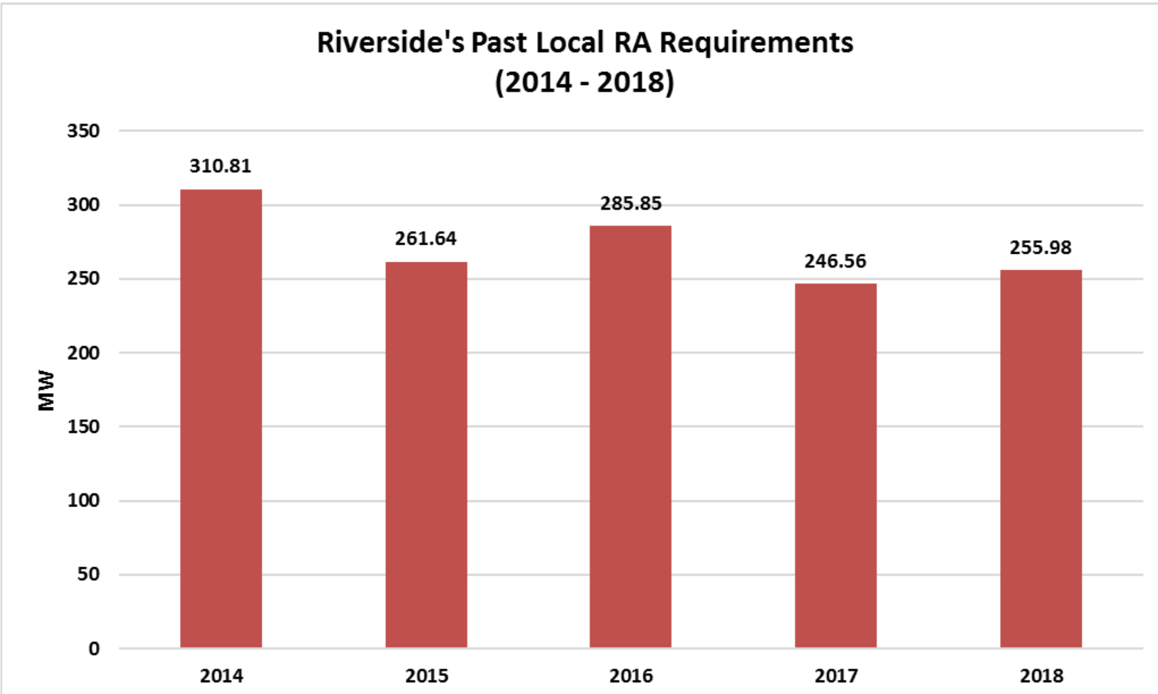


Figure 11.1.2. Riverside's local RA requirements for the past 5 years (2014-2018).

11.1.3 Flexible Capacity Requirement

The CAISO introduced the Flexible Capacity Requirement at the end of 2014 through Phase 1 of the Flexible Resource Adequacy and Must Offer Obligations (FRACMOO) initiative. The CAISO determines its flexible capacity need through an annual flexible capacity technical study. 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 divided 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.

As discussed above, the CAISO determines RPU's flexible RA requirement through a technical study that considers its contribution to the largest three-hour net load (load minus wind and solar) ramp for the CAISO system each month. As with the local RA requirement, the flexible RA requirement is derived from a CAISO technical study involving system-level data, which makes it difficult to independently forecast RPU's flexible capacity requirement. Unfortunately, RPU's previous years' flexible RA requirements do not provide any indication of future requirements, other than to reveal how volatile the requirements have been. Figure 11.1.3 shows RPU's flexible RA requirements from the requirement's inception in 2015 to 2018. The flexible RA requirements have varied considerably, swinging 50 MW to over 100 MW over the four years depending on the month.

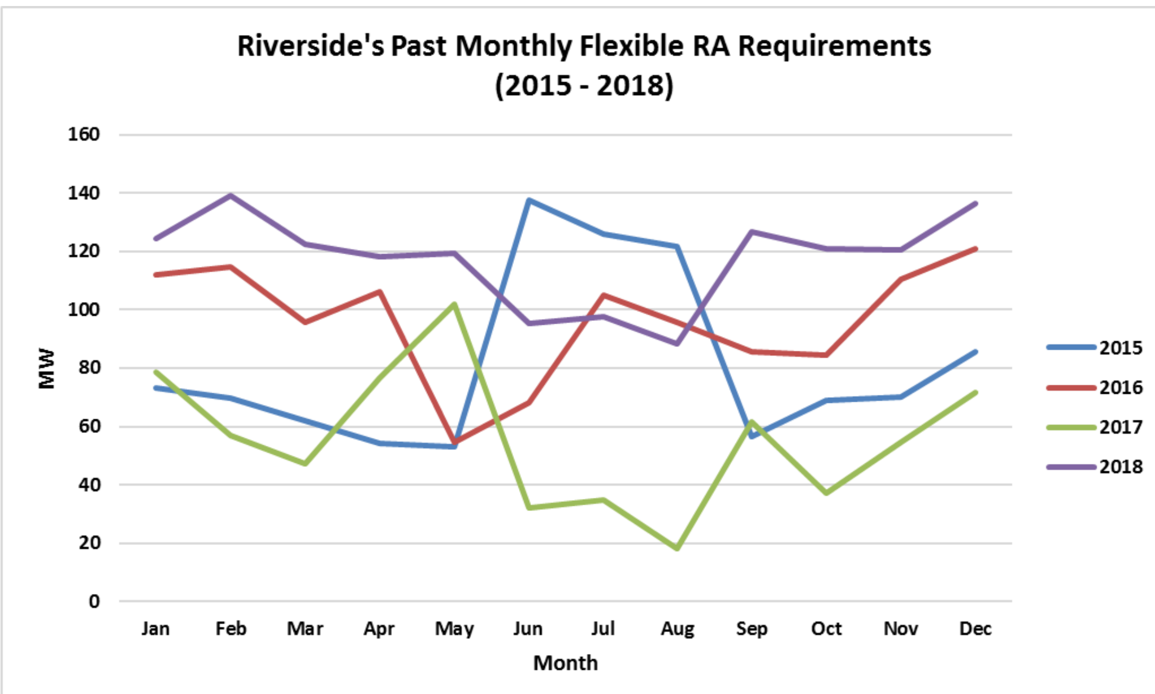


Figure 11.1.3. Riverside's flexible RA requirements for the past 4 years (2015-2018).

Given the extreme variation in the flexible RA requirements to date, staff is not confident about RPU's future RA requirements. A logical assumption staff can make is that procuring additional wind and solar resources that contribute to the system net load ramp will likely increase RPU's flexible RA requirement. Comparing RPU's past flexible RA requirements and the amount of wind and solar in its portfolio in those same years reveals that RPU's flexible RA requirement has been approximately equal to 82% of its total solar and wind capacity. As will be discussed in future chapters, RPU does not plan to add additional intermittent resources, particularly solar PV, to its portfolio unless those resources also have a battery storage component. While the impact of this type of resource on RPU's flexible RA requirements is largely uncertain, and the details of battery storage resource counting toward flexible RA requirements are still developing (the CAISO is still in the process of developing its policies for these resources), staff believes there might not be a large impact to RPU's flexible RA requirement. While adding the additional solar to its portfolio would increase its flexible RA obligation, the battery storage, as a potential flexible RA resource, could offset most of the additional flexible RA obligation. Therefore, RPU's current flexible RA requirement would not increase significantly in the future.

However, RPU may be facing a completely different flexible RA paradigm, and therefore requirement, within the next two years. The CAISO is continuing to explore further enhancements to flexible capacity requirements to help address generation oversupply and ramps less than three hours. As more and more intermittent renewable resources enter the CAISO market, the CAISO realizes the need for new and/or additional flexible capacity products that can more appropriately align with its market dispatch opportunities. Thus, the CAISO's RA paradigm, particularly Flexible RA, is evolving, and its outlook is uncertain. For instance, the CAISO is now in Phase 2 of the FRACMOO initiative and is proposing to eliminate the three existing flexible capacity products implemented during FRACMOO Phase 1 and replace them with three new Flexible RA products[1]:

- Five-minute dispatchable flexible capacity, whose system-wide requirement would be based on the range of historic uncertainty between the fifteen minute market and real time dispatch
- Fifteen-minute dispatchable flexible capacity, whose system-wide requirement would be based on the observed uncertainty between the Integrated Forward Market (IFM) and Fifteen Minute Market (FMM)
- Day-ahead load shaping, whose system-wide requirement would be based on the remaining capacity between the overall flexible capacity need and the capacity already addressed by the five- and fifteen-minute products

The CAISO is also working to determine the overall flexible capacity need and the need for each of these new products. While the CAISO has proposed a methodology for determining these needs and presented some example needs calculations, this process is inherently uncertain due to the unpredictable nature of ramping needs. The CAISO proposes to forecast monthly flexible capacity needs on a year-ahead basis, and LSEs would be required to procure 100% of their share of the needs for year ahead capacity showings. According to the schedule for the FRACMOO Phase 2 initiative, the CAISO envisions having CAISO Board approval for these new products by Q4 2018, with full implementation occurring in the 2019/2020 timeframe.

Clearly, there is significant uncertainty surrounding the future flexible RA paradigm, which makes a meaningful assessment difficult to perform in this IRP. However, to demonstrate its ability to satisfy a general flexible RA requirement based on the current paradigm, staff will assume that RPU's

[1] http://www.caiso.com/Documents/RevisedDraftFlexibleCapacityFrameworkProposal-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf

future flexible RA needs will be similar to its current requirement and carry its 2018 requirement forward as its requirement for future years.

11.2 Capacity, System Peaks and Resource Adequacy Needs

Figure 11.2.1 below shows RPU's expected monthly capacity amounts associated with its projected resource portfolio for the 2018-2037 timeframe. The capacity amounts are shown as colored bars, where the color signifies the different types and amounts of RA credit attributable to RPU's resource portfolio. The blue bars represent the amount of RPU's capacity that counts as flexible, local, and system RA; the green bars represent the amount that counts as local and system RA; and the red bars represent the amount that only counts as system RA. Note that these classifications are based on the CAISO's current RA paradigm. With the CAISO RA paradigm expected to change over time due to changing reliability needs, the types of resources needed to maintain grid reliability and countable for RA are also likely to change. As an example, the amount of RPU's capacity deemed as flexible (shown as blue bars) will likely change in the future as the CAISO develops new flexible requirements. Nonetheless, for purposes of this assessment, RPU is basing all analysis on the current paradigm.

Figure 11.2.1 also shows RPU's forecasted 1-in-2 system peaks, 115% system RA reserve margin requirements, and assumed local and flexible RA requirements, represented as super-imposed solid blue, solid purple, dashed black, and dashed red lines, respectively. The lines for the local and flexible requirements are dashed to signify that these requirements are only a snapshot of the 2018 requirements for each RA type, and future requirements are very uncertain – they are only meant to illustrate RPU's RA position given the current requirements. As shown in Figure 11.2.1, beyond 2018 (2018 RA has already been purchased), RPU will need to procure additional system RA capacity to meet its forecasted 1-in-2 peak and 15% reserve margin, especially in Q3. As far as local RA, RPU has sufficient local capacity to meet its assumed local RA requirement in every month, except those that have a maintenance event involving a local RA resource. In the near term, RPU's capacity shortfalls are manageable, and RPU can fill them with year-ahead system and local RA product purchases. In the longer term, RPU's capacity shortfalls become more significant as contracts expire and capacity resources fall out of RPU's portfolio. RPU will continue to need RA products but will also need to explore adding additional resources to its portfolio that provide RA capacity.

An important and known issue for RPU under the current CAISO paradigm that significantly affects its capacity needs during the 2018 through 2037 time horizon is the uncertainty of receiving intertie allocation for RA purposes for imported resources that are not currently grandfathered. The CAISO allocates intertie allocation on an annual basis using a peak load ratio share methodology after taking into account an entity's inventory of grandfathered resources. Currently, RPU's total import allocation for its grandfathered resources exceeds what CAISO determines as its allocable amount, so RPU is unable receive additional intertie allocation credit for newly contracted intertie resources. RPU expects this to remain the case until the grandfathered IPP contract expires in June 2027 at which point its amount of grandfathered resources will have decreased enough that it should be eligible to receive additional import allocation credit. However, with this allocation process, there is no certainty that RPU will be able to acquire a sufficient quantity of import allocation credit to count a contract's entire capacity as an RA resource.

For this future capacity needs assessment, given the intertie allocation issue, RPU makes the following assumptions with respect to its major intertie 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 from 136 MW 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 not receive RA capacity credit from the 86 MW CalEnergy Portfolio contract until July 2027

The following sections split the discussion of RPU's capacity needs into three time horizons: a five-year period from 2018 through 2022, a five-year period from 2023 through 2027, and a 10-year period from 2028 through 2037. The discussions highlight significant drivers of RPU's capacity needs during each period as well as the potential cost to fill capacity shortfalls with RA products.

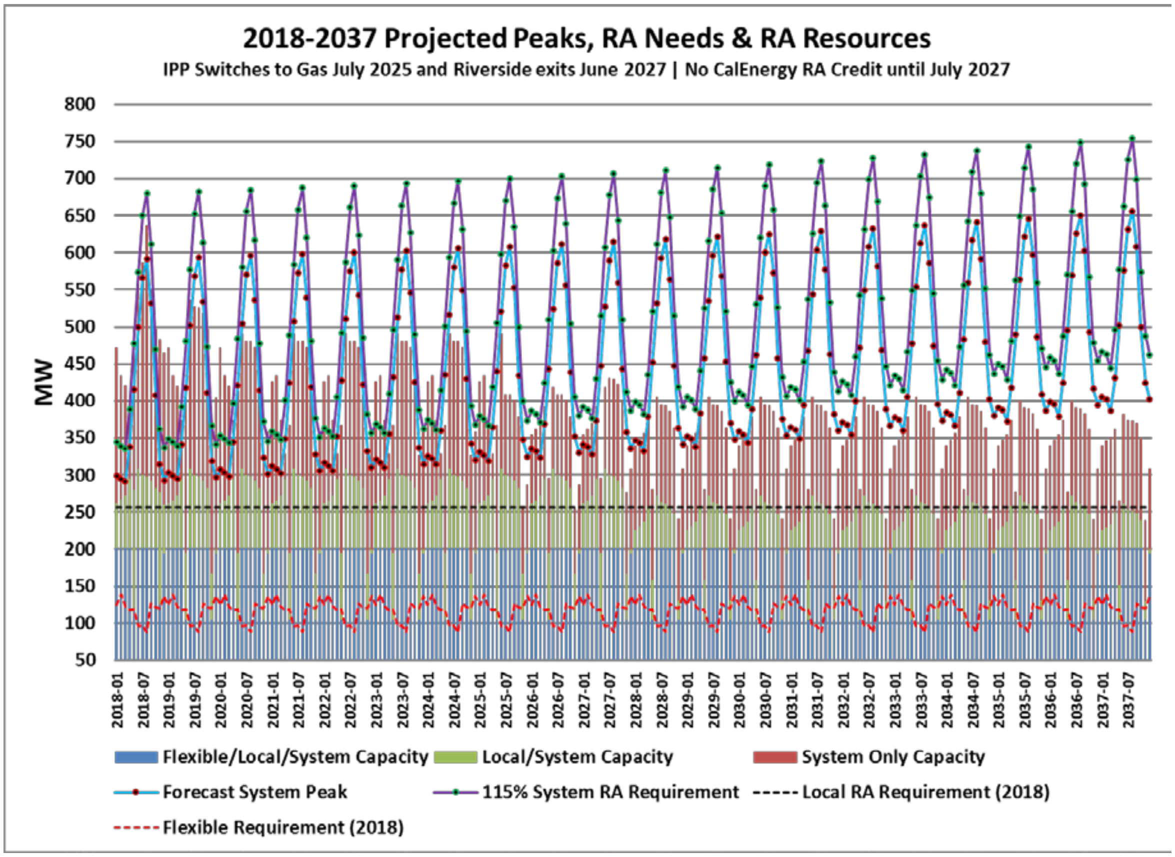


Figure 11.2.1. Riverside's 20-year forward capacity projections, system peaks and RA needs (2018-2037 timeframe).

11.2.1 Capacity, System Peaks and Resource Adequacy Needs (2018-2022 time horizon)

During the 2018 through 2022 time horizon, as shown in Figure 11.2.2, RPU has enough capacity in its resource stack to meet its expected 1-in-2 system peaks in most months outside of Q3. The exceptions are months such as April and May when some of RPU's capacity resources typically go offline for maintenance. A notable change in RPU's capacity stack is the loss of 46 MW of capacity as of May 2020 when the Salton Sea Unit 5 geothermal contract will expire. RPU will continue to receive these 46 MWs of energy from its CalEnergy Portfolio contract but will not be able to count these megawatts towards its RA obligation due to the intertie allocation issue discussed above. To fill these shortfalls and fully meet the 115% CAISO RA requirements, RPU will need to forward purchase additional system RA products.

Additionally, during the 2018 through 2022 time horizon, RPU has enough local and flexible capacity to satisfy its assumed local and flexible RA requirements in every month, except those in which a local RA resource is offline for scheduled maintenance. As shown in the figure below, this can occur in May, November, and December. RPU will need to procure additional local and flexible RA products to satisfy its respective RA requirements in these months.

Table 11.2.1 shows the expected cost forecasts to fill short RA needs over the next five years. Note that the 2018 short RA positions have already been filled using 2018 market RA purchases. For 2019-2022, it is assumed that RPU will execute additional system and local RA purchases to satisfy its CAISO RA requirements. Using the system and local RA cost assumption from Table 7.7.1, RPU anticipates spending 15.132 million dollars over the next five years to purchase additional system and local RA products to satisfy its RA obligations.

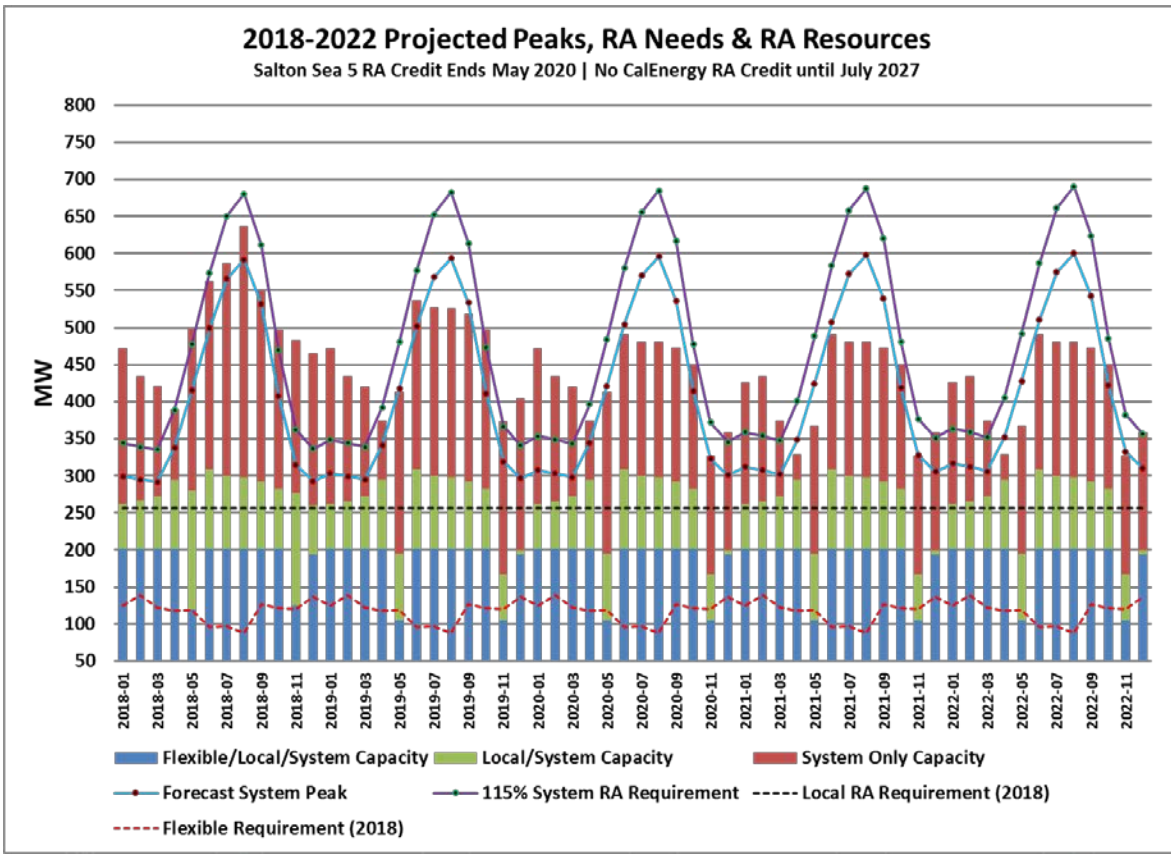


Figure 11.2.2. Riverside's 5-year forward capacity projections, system peaks and RA needs (2018-2022 timeframe).

Table 11.2.1. 2018-2022 short RA positions and expected RA cost forecasts.

Year	RA Needs (MW)	RA Cost ($/kW-month)	Expected Cost (million $)
2018	0.00	$4.50	0
2019	501.71	$4.64	2.325
2020	775.54	$4.77	3.702
2021	896.69	$4.92	4.409
2022	927.16	$5.06	4.696
		Total 5-Year Cost Forecast ($):	15.132

11.2.2 Capacity, System Peaks and Resource Adequacy Needs (2023-2027 time horizon)

Figure 11.2.3 presents RPU's capacity needs during the 2023-2027 timeframe. These capacity needs will increase beginning July 2025 when the IPP coal plant is retired, and RPU begins 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, a loss of 72 MW of capacity. RPU's capacity needs fluctuate again after June 2027. At this time, the IPP contract will expire, and RPU will exit the IPP NGCC plant, losing 64 MW of capacity credit from its portfolio. At the same time, the expiration of the IPP contract means that RPU will be eligible to receive additional RA import allocation from the CAISO. Therefore, RPU assumes that it will be able to begin counting the 86 MW of capacity from its CalEnergy Portfolio contract, which will help offset losing the 64 MW from the IPP NGCC. Additionally, RPU assumes that its Springs resource, which provides 36 MW of local and system capacity, will reach the end of its useful life and be retired at the end of 2027. With these changes, RPU will ultimately have a net loss of 86 MW of system capacity, 36 MW of which is local, in this timeframe, and significant monthly capacity shortfalls start to become apparent. RPU will still look to procure RA products to fill the shortfalls in this timeframe. However, it will need to add additional energy and capacity resources, both local and system, to its portfolio to replace resources that have fallen out of the portfolio. Potential resource additions will be explored in Chapter 12.

Table 11.2.2 shows RPU's expected cost forecasts to fill its short RA needs with RA product purchases during the 2023 through 2027 timeframe. RPU anticipates a total cost exposure of 37.237 million dollars over these five years to purchase additional RA products to meet RA needs. As mentioned above, RPU will also be looking to add new resources to its portfolio during this timeframe. Any potential resources should carry capacity credit and reduce RPU's short RA needs and costs.

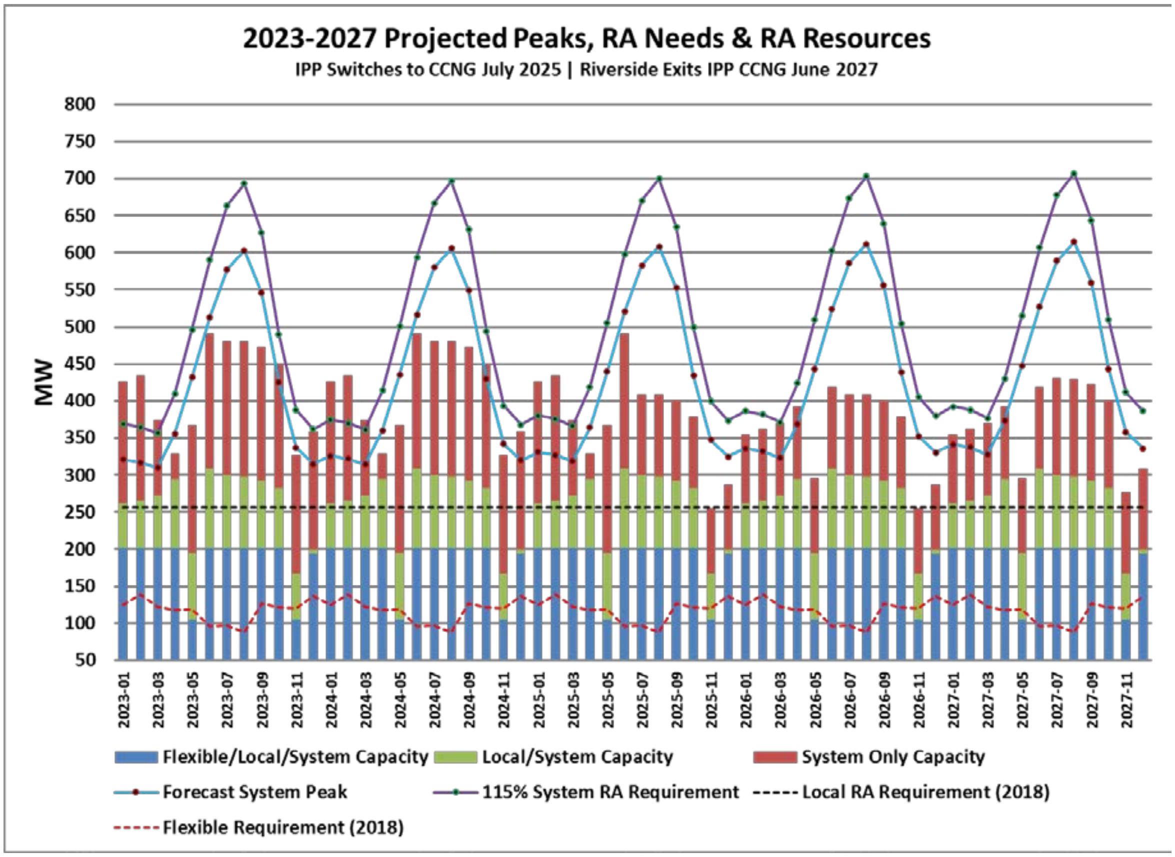


Figure 11.2.3. Riverside's forward capacity projections, system peaks and RA needs (2023-2027 timeframe).

Table 11.2.2. 2023-2027 short RA positions and expected RA cost forecasts.

Year	RA Needs (MW)	RA Cost ($/kW-month)	Expected Cost (million $)
2023	962.31	5.22	5.020
2024	1,001.24	5.37	5.380
2025	1,473.93	5.53	8.157
2026	1,649.88	5.70	9.405
2027	1,579.56	5.87	9.274
		Total 5-Year Cost Forecast ($):	37.237

11.2.3 Capacity, System Peaks and Resource Adequacy Needs (2028-2037 time horizon)

Figure 11.2.4 shows RPU's capacity needs for the final 10 years of this IRP's study horizon – 2028 through 2037. With IPP and Springs out of the portfolio, RPU's capacity needs are significant. There is clearly insufficient capacity left in the resource portfolio to meet expected system peaks during any month of the year. Additionally, RPU sees local RA shortfalls. RPU will be planning to add additional energy and capacity resources during this period to fulfill these RA shortfalls.

Table 11.2.3 shows RPU's expected cost forecasts to acquire sufficient RA credit to fulfill its RA needs during this 10-year period from 2028 through 2037. RPU anticipates its total cost exposure to be 158.270 million dollars over these ten years. Resource additions will be needed during this timeframe to satisfy capacity requirements.

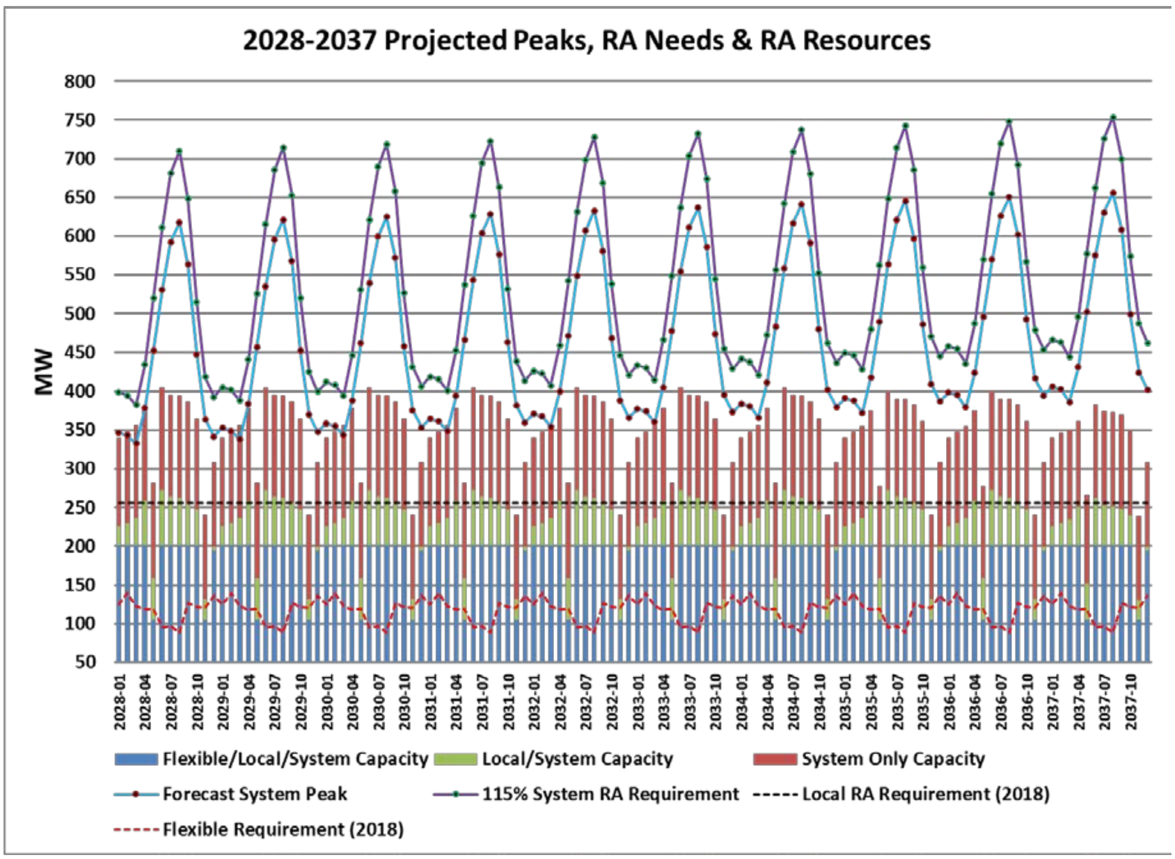


Figure 11.2.4. Riverside's forward capacity projections, system peaks and RA needs (2028-2037 timeframe).

Table 11.2.3. 2028-2037 short RA positions and expected RA cost forecasts.

Year	RA Needs (MW)	RA Cost ($/kW-month)	Expected Cost (million $)
2028	1,907.70	6.05	11.537
2029	1,974.49	6.23	12.299
2030	2,043.93	6.42	13.114
2031	2,116.07	6.61	13.984
2032	2,191.03	6.81	14.914
2033	2,268.89	7.01	15.907
2034	2,349.75	7.22	16.968
2035	2,463.91	7.44	18.326
2036	2,551.09	7.66	19.544
2037	2,747.25	7.89	21.678
		Total 10-Year Cost Forecast ($):	158.270

11.3 Net-Peak Demand

As discussed previously, the increasing amount of intermittent renewable resources entering the CAISO market is changing the CAISO's operational needs. The CAISO has illustrated these changing operation needs by plotting the expected normal system hourly load minus the amount of intermittent generation (i.e. the CAISO Duck Curve, see Figure 11.3.1). As shown in this figure, increasing intermittent generation, particularly solar PV, reduces net loads in the middle of the day and significantly increases the system-wide ramping requirement in the evening in order to meet the net-peak demand. The increased ramping requirement results from the combined effect of increasing evening loads with the rapid falloff of solar power generation when the sun goes done, presenting significant challenges to balance load and resources during a short, three-hour timeframe. The CAISO has sought to address these operational challenges through its flexible RA requirements, as discussed earlier in this chapter. The other issue the Duck Curve highlights is the potential for over-generation during the middle of the day. This can occur when energy from resources exceeds the net load (i.e. supply exceeds demand), a situation that can lead to negative energy prices in the CAISO market (i.e. the CAISO has to pay someone to take the excess energy).

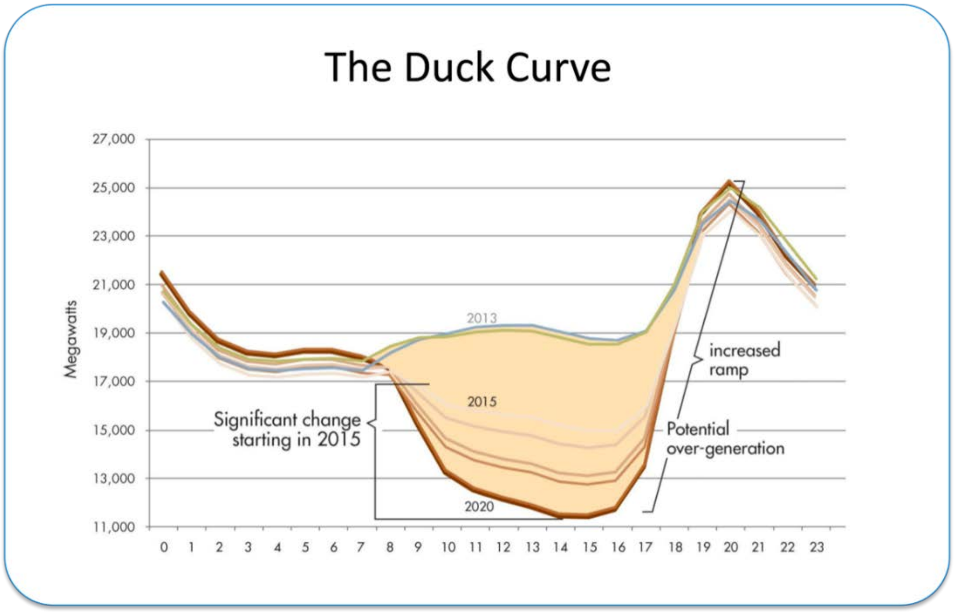


Figure 11.3.1. CAISO projected operational needs assessment through 2020, due to increasing intermittent generation within the CAISO system.

In addition to increased ramping requirements, the specific resources available to meet energy and reliability needs during the hour of net-peak demand are also 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 2019. RPU's net load in 2019 is representative of future years because all of RPU's contracted intermittent renewable resources are generating energy and affecting its net load. Any additional intermittent resources that RPU will consider adding to its portfolio in the future will have with battery energy storage, which will lessen their effect on RPU's net load.

Figure 11.3.2 below shows RPU's wholesale and net load for a typical winter day in February 2019. In the winter, RPU sees lower wholesale loads and a flatter diurnal wholesale load curve. The largest ramp is roughly 75 MW over 9 hours (HE04 – HE12). The wholesale peak load in HE20 is not much higher than the wholesale loads between HE11 and HE13. 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. The net-peak load now clearly occurs in the early evening; it shifts back one hour to H19, but it is just barely higher than HE20 and HE21. The largest ramp is now steeper and later in the day, requiring roughly 73 MW over 4 hours (HE16 – HE19).

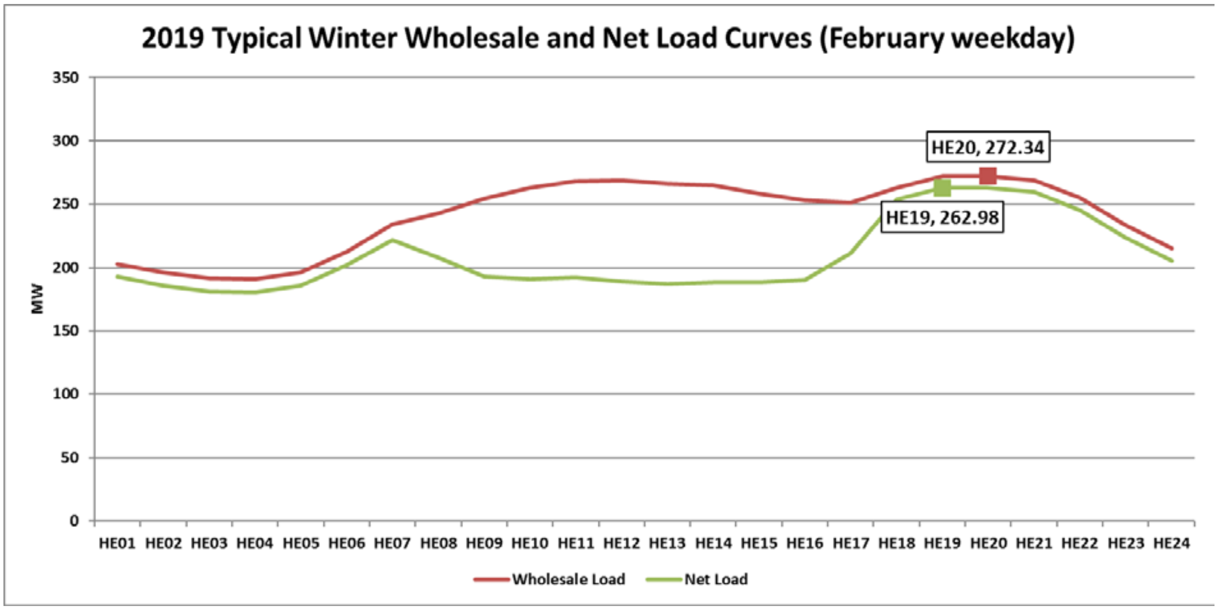


Figure 11.3.2. Riverside's projected diurnal wholesale and net load curves for a typical winter day in 2019.

Figure 11.3.3 shows RPU's wholesale load and net load for a typical summer day in August 2019. 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 HE16. RPU's ramp during the summer occurs over 12 hours (HE05 and HE16), when the wholesale load can climb at least 280 MW. Because of the higher loads, RPU's net load curve actually improves from a reliability standpoint, as it maintains the basic shape of the summer wholesale diurnal load curve but shifts down, reducing the peak and ramp. The net load curve still has a well-defined peak, but it is roughly 60 MW lower than the wholesale load peak and has shifted to the early evening at HE19. The net load curve ramp still occurs over 12 hours (HE08 – HE19), but the lower peak means the ramp only climbs roughly 250 MW.

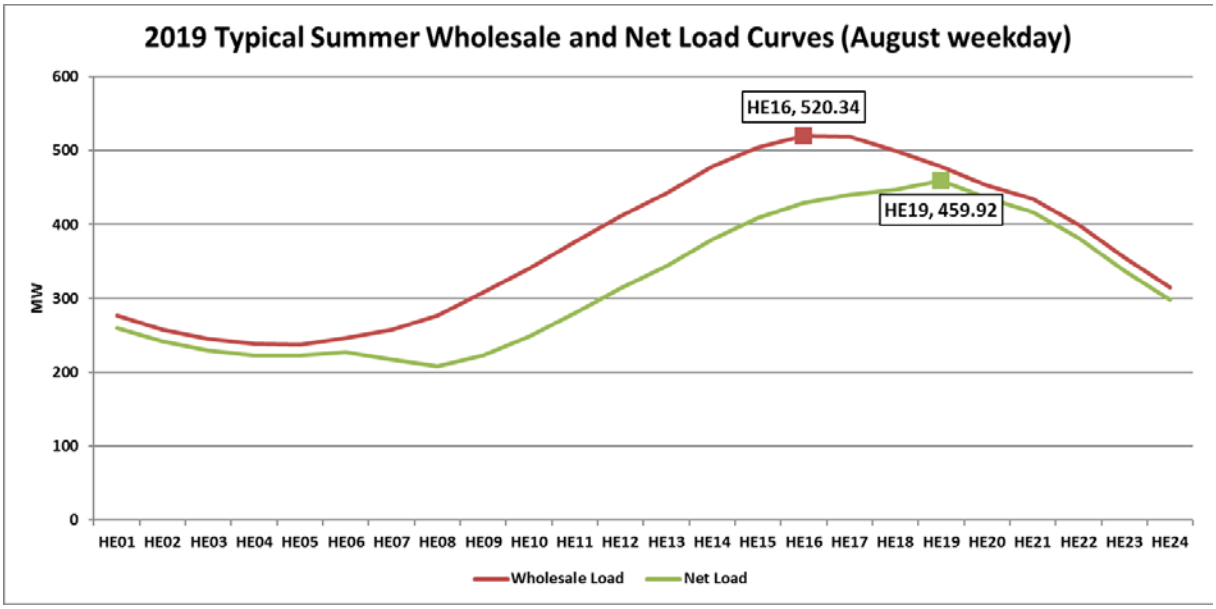


Figure 11.3.3. Riverside's projected diurnal wholesale and net load curves for a typical summer day in 2019.

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 would continue to exacerbate Riverside's duck curve in the winter. RPU's resources would 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 has been to procure only renewable resources that can serve its load (i.e. best-fit). Figures 11.3.4 and 11.3.5 show Riverside's typical diurnal net load curves for winter and summer (shown in Figures 11.3.2 and 11.3.3) 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. In 2019 and beyond, RPU will have 86 MW of baseload geothermal in its portfolio, which is significant because this baseload renewable resource contributes directly to meeting reliability needs during the hours of net-peak demand. Based on the figures, RPU's geothermal energy will serve about 33% and 19% of the hour of net-peak demand in the winter and summer, respectively.

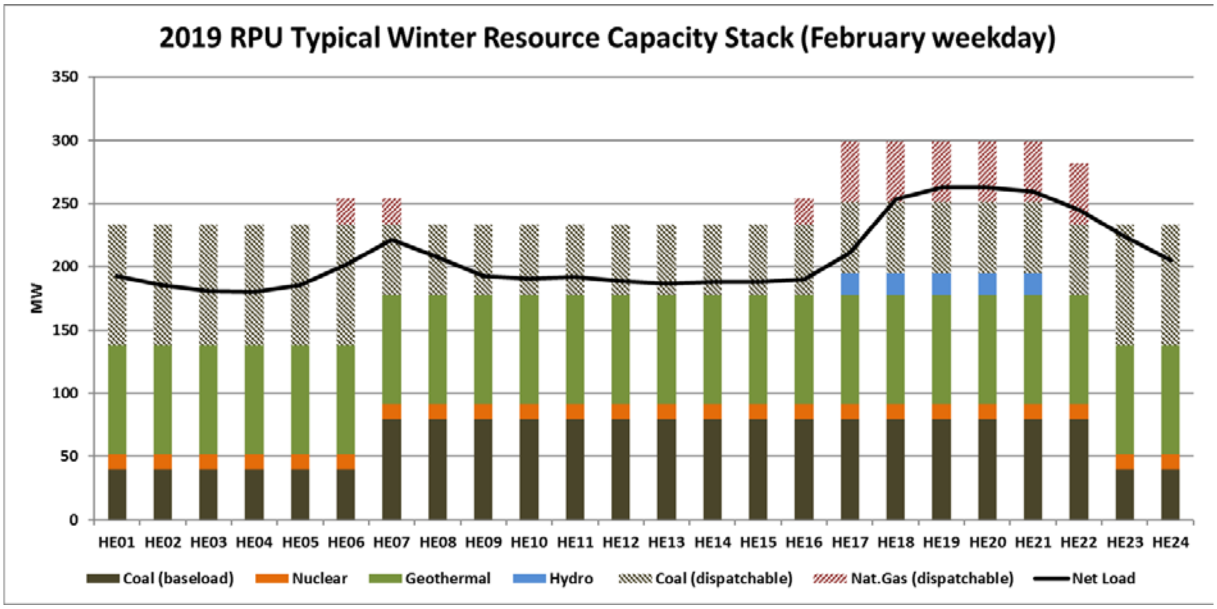


Figure 11.3.4. Riverside's projected diurnal net load curve and resource stack for a typical winter day in 2019.

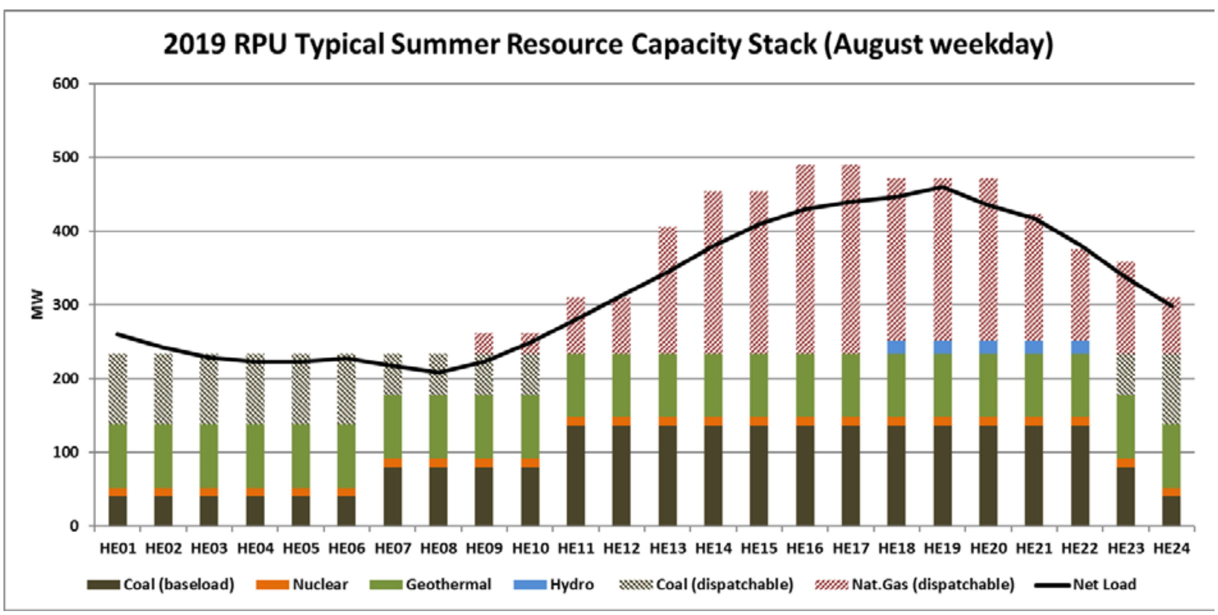
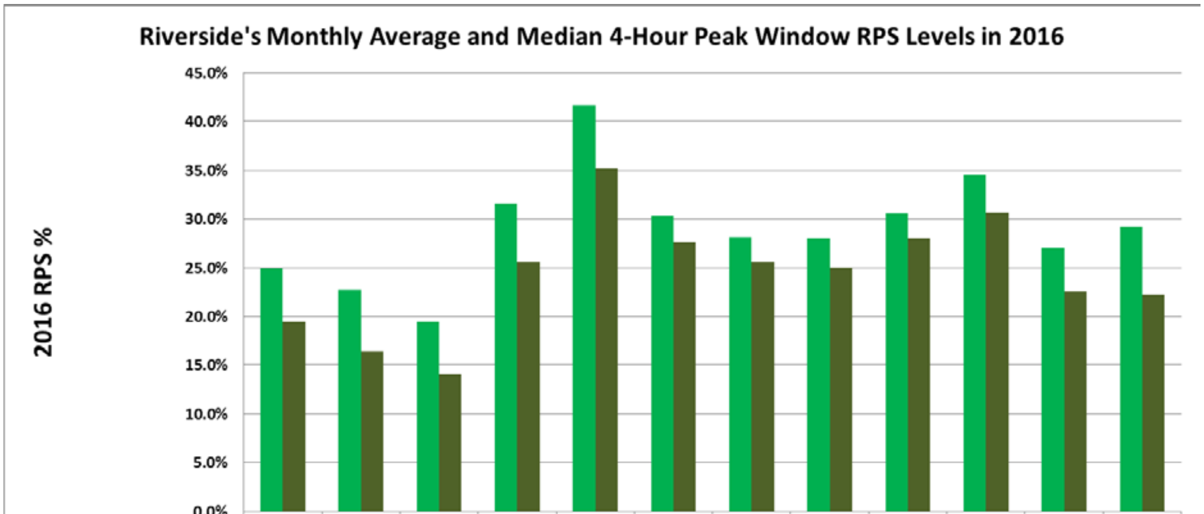


Figure 11.3.5. Riverside's projected diurnal net load curve and resource stack for a typical summer day in 2019.

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 2016 hourly load and renewable generation data. Figure 11.3.6 shows a bar chart of Riverside's monthly average and median peak window RPS levels for 2016. 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. RPU's renewable production level during the peak window exceeds the median RPS levels shown at least 15 days each month. As shown in Figure 11.3.6, Riverside does not experience a significant decline in its peak load RPS level as compared to its monthly average RPS levels. This is because baseload geothermal resources supply about 70% 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 20% mark, except during February and March when annual maintenance events occur, and is often at or above the 25% mark. Riverside hits these marks even without the final 20 MW segment of its new geothermal, which comes online in 2019. Once it is online, Riverside can expect both its monthly average and median peak window RPS indices to increase by 4% to 8%.



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly Average RPS	25.0%	22.7%	19.5%	31.6%	41.7%	30.3%	28.1%	28.1%	30.5%	34.5%	27.0%	29.3%
Median Peak Window RPS	19.4%	16.4%	14.1%	25.6%	35.2%	27.6%	25.6%	25.0%	28.0%	30.6%	22.6%	22.2%

Figure 11.3.6. Riverside's actual monthly average and median peak window RPS levels in 2016.

12. Assumptions about Future Low-carbon and Carbon-free Resources

Recall that Chapter 3 provided an overview of Riverside's portfolio of generation resources, while staff assumptions about all of RPU's existing resource contracts that are scheduled to end before December 2037 were reviewed in Chapter 10. Likewise, Chapter 9 examined how much RPU's total GHG footprint must decrease over time to meet the utility's 2030 emission targets. This issue was examined from the perspective of how much carbon-free energy RPU must have in its portfolio in order to meet these targets.

This chapter presents and describes a set of potential future portfolio resource additions that are consistent with RPU's long-term carbon reduction goals. By definition, most of these proposed resource additions represent carbon-free renewable resources. However, a multi-year, low-carbon seasonal energy product is also proposed and discussed, in addition to two natural gas alternatives that could be used to replace some of RPU's retiring coal energy. Notwithstanding this issue, the acquisition of these proposed resources will allow RPU to meet or exceed the utility's 2030 emission targets, and as such will form the basis for the long-term portfolio resources studies examined in chapter 13.

12.1 Proposed Carbon-free (Renewable) Resources

Figure 12.1.1 below shows RPU's forecasted renewable energy levels through 2030, based on the utility's current set of renewable generation assets. Note that this is the same figure that is shown in RPU's *Updated 2018 Renewable Energy Procurement Policy* document presented in Appendix D.

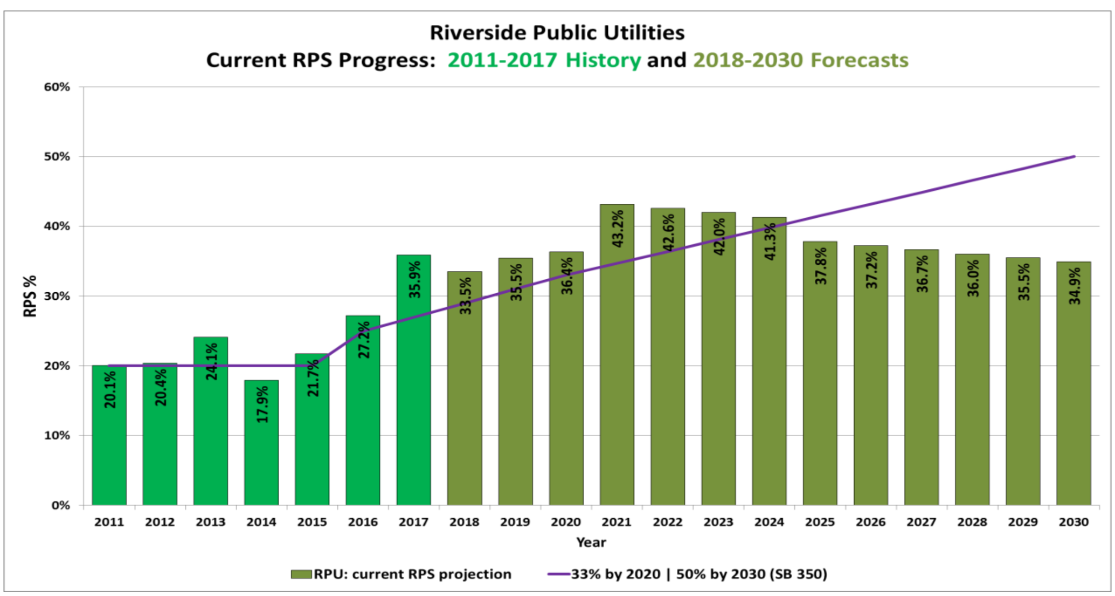


Figure 12.1.1. RPU's current forecasted RPS levels through 2030, as of June 2018.

From a planning perspective, RPU has sufficient renewable resources under contract to meet or exceed all of the utility's current SB 350 RPS requirements through 2024. Beyond 2024, the utility will either need to procure additional renewable resources or apply previously accumulated excess procurement credits towards meeting its renewable mandates. However, as already discussed in Chapter 9, even if RPU were to fully comply with the 50% by 2030 RPS mandate by solely procuring new renewable resources, the utility would still have a 2030 total portfolio carbon emission level of approximately 607,000 MT CO_2-e (i.e., well above RPU's 486,277 MT target level). Thus, it is reasonable to expect that the continued procurement of renewable resources by the utility will be primarily necessitated by future carbon reduction goals, as opposed to RPS legislative mandates per say.

Table 12.1.1 shows a hypothetical new resource procurement strategy that will ensure that RPU can meet either its share of the 53 MMT or 42 MMT carbon reduction sector goals. The contracts proposed to come online on or before 2025 represent specific, well defined projects or products that the utility is currently considering adding to its portfolio. In contrast, the post-2025 contracts represent generic baseload renewable assets that are yet to be identified.

Table 12.1.1. Proposed 2020-2030 RPU procurement strategy for new renewable resources.

New Renewable Resource	COD	Annual MWh
1. 44 MW Solar PV + 22 MW / 88 MWh BESS	2021	144,000
2. Extension and/or repower of 39 MW Cabazon Wind facility	2025	72,000
3. Contract for Summer (July-Sept) zero or near-zero carbon energy product (1)	2025	100,000
4. 40 MW baseload renewable asset (85% CF)	2027	298,000
5. 30 MW baseload renewable asset (85% CF) (2)	2029	223,000

Note (1): Seasonally shaped firm energy product, possibly comprised of either a blended set of PCC-1/PCC-2 assets, or a shaped product of near zero carbon, firm energy deliveries from the PowerEx or BPA control areas.
Note (2): The additional 30 MW may come from a new asset, or be incremental to the existing 40 MW asset.

If RPU were to successfully execute all five of these proposed new contracts, the utility would add approximately 837,000 MWh annually of carbon free energy to its resource portfolio by 2029. This additional carbon free energy would ensure that the utility would reach a 2030 total portfolio carbon emission level that is slightly lower than its proportional 42 MMT sector target (i.e., slightly lower than 385,000 MT CO_2-e). Likewise, if all but the final 30 MW baseload contract are brought online by 2027, RPU could still reach a 2030 total portfolio carbon emission level that is slightly lower than its officially adopted goal tied to the 53 MMT sector target.

Figure 12.1.2 shows RPU's future annual RPS projections through 2030, assuming that all five of the above mentioned contracts are successfully brought online by their specified commercial online dates. In addition to the annual RPS levels, Figure 12.1.2 shows the 50% by 2030 minimum RPS procurement targets currently mandated under existing SB 350 legislation (purple line), as well as the recently proposed, higher 60% by 2030 RPS targets specified in SB 100 (red line). Note that the cumulative annual RPS percentage levels meet or exceed both of these lines in all years on/after 2018, implying that RPU would exceed its minimum RPS compliance obligations in all compliance periods through 2030, regardless of which RPS legislative mandates are ultimately in effect. Additionally, RPU would exceed at 67% RPS level in 2030, using only PCC-1 energy products.

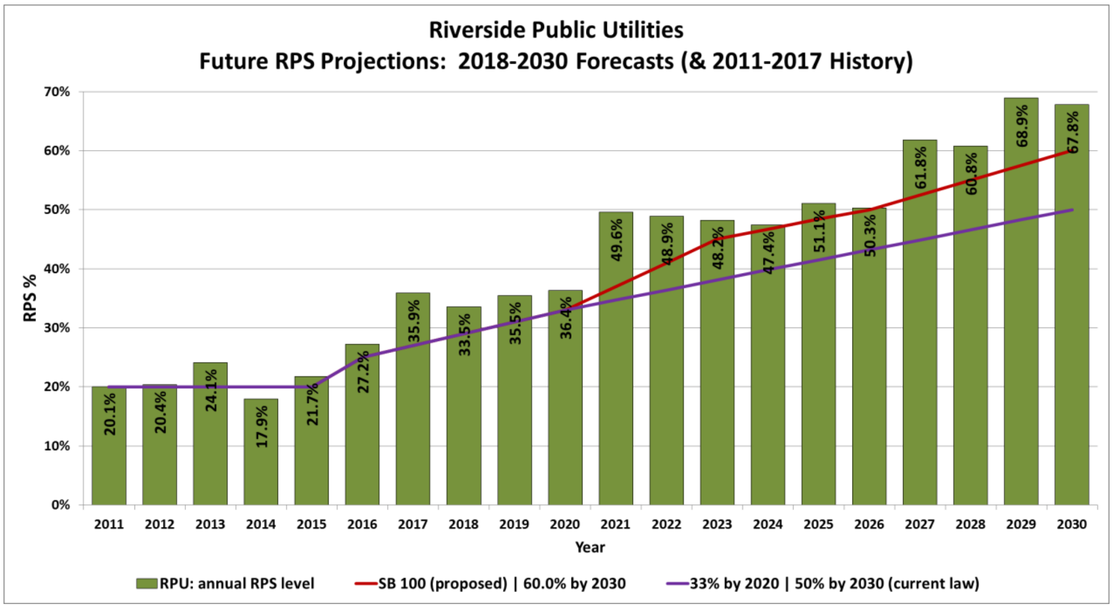


Figure 12.1.2. RPU's future forecasted RPS levels through 2030, if all five of the renewable resources shown in Table 12.1.1 are added to the utility's portfolio.

A plausible modification to the above renewable procurement plan is worth highlighting. As discussed above, RPU could forgo contracting for the final 30 MW of 2029 baseload renewable energy product and still meet its adopted carbon target tied to the 53 MMT goal for the energy sector. Additionally, the summer zero carbon product starting in 2025 could instead be comprised of "near zero carbon" firm energy deliveries from the PowerEx or BPA control areas (see section 12.2), without negatively impacting this carbon target. Figure 12.1.3 shows what the utility's future forecasted RPS levels should look like under such a modified procurement strategy. Specifically, note that these annual RPS levels still exceed the 50% by 2030 minimum RPS procurement targets every year through 2030. These same levels do not always exceed the more aggressive 60% by 2030 SB 100 procurement targets. Nonetheless, by 2024, sufficient excess renewable energy procurement volumes will have been accumulated to "fill in" the renewable energy shortfalls in 2025, 2026, 2029 and 2030, respectively. Thus the utility will be able to satisfy its minimum RPS compliance obligations in all compliance periods through 2030 even under the more aggressive SB 100 legislation, even if RPU were to follow this modified renewable procurement plan.

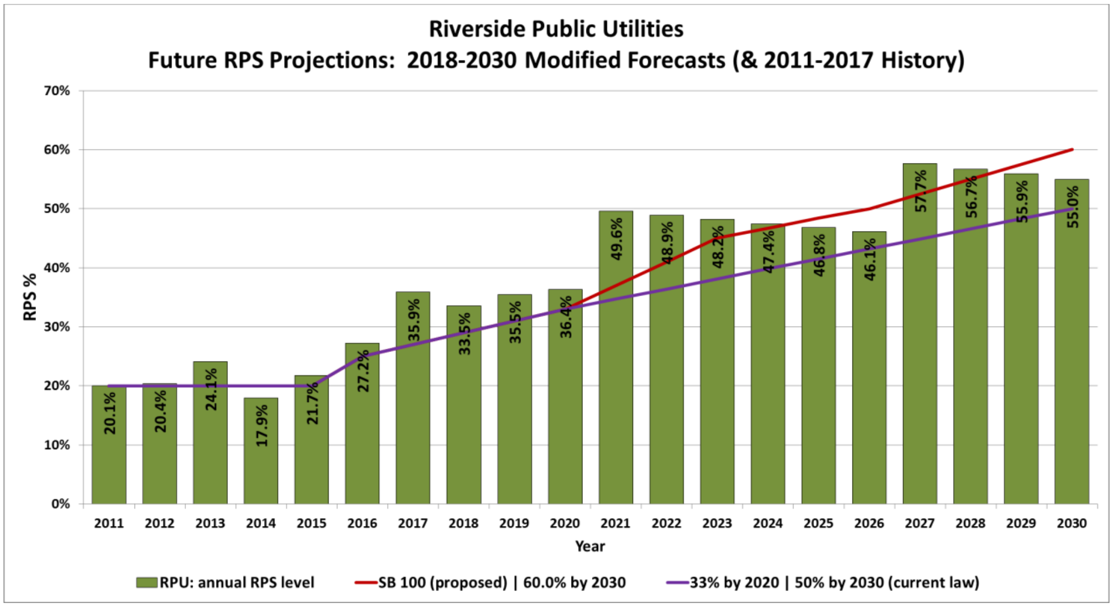


Figure 12.1.3. RPU's future forecasted RPS levels through 2030, if Table 12.1.1 renewable resources #1, #2 and #4 are added to the utility's portfolio.

12.2 Plausible Seasonal Energy Products

Riverside has a summer peaking load pattern with an annual load factor of about 42%. This implies that the utility's summer load serving needs are significantly greater than the winter load serving needs (for reference, see Figure 2.1.1). The utility has historically used both market power purchases and internal natural gas fired generation to serve this incremental need, given that this load pattern is inherently seasonal in nature.

As the utility attempts to significantly decrease its total carbon footprint, some form of zero carbon or near-zero carbon energy will need to be identified and procured to meet this seasonal load. This is currently a very challenging problem to solve, given that there are relatively few, if any renewable energy technologies that can be seasonally dispatched in an economical manner.[1] Thus, to address this issue in a practical manner, the utility must seek out an energy supplier that can deliver such energy on a seasonal schedule.

Currently, it is possible to procure seasonally shaped, firm zero or near-zero carbon block energy products from either major renewable power marketers or a balancing authority control area that CARB has certified as an Asset Controlling Supplier (ACS). A zero carbon block energy contract would typically be comprised of a blended PCC-1/PCC-2 energy product (typically sourced from Pacific Northwest wind facilities), delivered by a renewable power marketer over firm transmission on a pre-specified hourly

[1] Renewable biogas consumed in a traditional natural gas generation facility represents one technology that might be used to produce seasonal renewable energy, but biogas is still relatively expensive and RPU has no current plans to contract for such a fuel source.

schedule. Likewise, both BPA and PowerEx have received ACS certifications from CARB; note that both control areas have deemed carbon emission factors of approximately 0.02 MT CO_2-e / MWh. Thus, a near-zero block energy contract would simply be comprised of system power from either of these ACS control areas, again delivered over firm transmission on a pre-specified hourly schedule.

These energy products will be examined in more detail in subsequent chapters of this IRP. Note that the differences in the carbon footprints of these products are fairly immaterial, even for a PPA with a 100,000 MWh/year delivery schedule. The primary difference between these two products is regulatory in nature; i.e., one is considered to be a renewable energy product, while the other simply represents a near-zero carbon resource.

12.3 Potential Natural Gas Contracts or Projects

In addition to the proposed 2020-2030 procurement strategy for new renewable resources, RPU will also have the option to contract for new or existing natural gas generation facilities during the next decade. Two such facilities will be examined in Chapter 13 of this IRP: (1) a 10-year tolling contract beginning in 2023 for an existing LMS-100 generation facility located in Southern California, and (2) the 50-year ownership contract for a share of the CCNG facility proposed in the IPP repowering project.

RPU has received a preliminary indicative offer for a tolling agreement with a LMS-100 unit beginning in 2023. Although this contract would need to begin a few years before the utility's IPP coal contract ends, this natural gas facility could still serve as a useful "replacement" asset that would supply up to 100 MW/hour of gas fired generation in place of baseload coal energy (on/after 2025). Additionally, LMS-100 simple cycle gas turbines are fast start units designed to provide rapid load following and cycling services, and thus qualify for full FRAC RA benefits and Ancillary Services. The proposed tolling costs for this unit will be compared to the stacked value of these forecasted benefits in Chapter 13, in order to assess the financial attractiveness of this offer.

Likewise, RPU has been deeply involved in the negotiations involving the IPP Repowering project for over three years now. Staff has previously provided detailed justification for why Riverside should <u>not</u> contract for the latter repowering option (see section 10.2). However, for the sake of completeness, a full financial assessment of this CCNG contract will also be presented in Chapter 13.

Finally, it should be noted that the emission factors associated with both of these gas fired generation options are slightly below the default market power emission factor of 0.428 MT CO_2-e per MWh. Thus, contracting for either of these assets will not raise RPU's total carbon footprint, provided that all of the gas fired generation energy is only used to displace CAISO system power purchases.

13. Long Term (Twenty Year Forward) Portfolio Analyses

For this IRP, seven plausible resource planning scenarios were considered to assess GHG reduction targets, RPS mandates, and capacity and energy replacement. This chapter first examines the projected budgetary impacts of meeting RPU's specific GHG targets, as defined in Table 9.3.1. This budgetary assessment considers both the expected values and simulated standard deviations of RPU's fully loaded cost of service over the next twenty-year time horizon. Additionally, this chapter presents resource-specific net value calculations for each resource discussed in Chapter 12, which will also facilitate a comparison to energy efficiency programs in Chapter 14.

13.1 Modeling Inputs and Assumptions

All of the scenario studies discussed in this IRP have been performed using the Ascend Production Cost Modeling Software platform. The long-term load and market price inputs are discussed in Chapters 2 and 7, respectively. Likewise, RPU's carbon reduction goals and RPS mandates are described in Chapters 9 and 12, respectively. Table 13.1.1 lists the seven different forward portfolio scenarios that are studied in detail in this chapter. Further, Table 13.1.2 identifies the resources that are considered in each of the scenarios, and Tables 13.1.3 through 13.1.9 show the operating parameters and cost assumptions for each resource.

It should be noted that 100 simulation runs have been performed for each scenario shown in Table 13.1.1. These simulations allow 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 forecast.

Each of the 100 Ascend simulation runs associated with each scenario were performed at the hourly granularity over the same twenty year timeframe (January 1, 2018 through December 31, 2037), 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

$$TNPC = TGC + TLC - TGGR - HP(MtM) \qquad \text{[Eq. 13.1]}$$

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

- TGC: The total all generation costs other than CO_2 costs 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 was combined with RPU's primary additional fixed budgetary costs, in order to determine the overall annual load serving costs under each specific scenario. These additional fixed costs are described in greater detail in section 13.2.

Table 13.1.1. Input variable levels used in each of the seven different forward portfolio scenarios.

Portfolio/ Scenario	Electric Sector GHG Goal	2030 RPS	New Renewable Pricing	Capacity / Energy Replacement
Baseline	40% < 1990	50%	Normal	Market
1	53 MMT	~54% to 57%	Normal	Market
1*	53 MMT	~54% to 57%	High	Market
2	42 MMT	~63% to 66%	Normal	Market
2*	42 MMT	~63% to 66%	High	Market
3	42 MMT	~54% to 57%	Normal	IPP Repowering Project + Market
4	42 MMT	~54% to 57%	Normal	LMS 100 + Market

Table 13.1.2. Analysis names, descriptions, and portfolios of new resources.

Analysis Name	Resource Description	Portfolio/Scenario				
		Baseline	1 / 1*	2 / 2*	3	4
Solar+Storage	44 MW Solar PV + 22 MW / 88 MWh BESS	X	X	X	X	X
Cabazon	Extension and/or repower of 39 MW Cabazon Wind facility	X	X	X	X	X
Summer Ultra Low Carbon Power Purchase (SULCPP)	Contract for Summer (July-Sept) zero or near-zero carbon energy product		X	X	X	X
Baseload 2027	40 MW baseload renewable asset (85% CF)		X	X	X	X
Baseload 2029	30 MW baseload renewable asset (85% CF)			X	X	X
IPP Repowering	35 MW Share of IPP NGCC Repowering Project				X	
LMS100	Tolling Agreement w/ 100 MW LMS100 Natural Gas Generating Unit					X

Table 13.1.3. Solar+Storage operating parameters and cost assumptions.

Operating Parameters	
Term (years)	15
Contract Start Date	1/1/2021
Contract End Date	12/31/2035
Solar Capacity (MW)	44
Solar Degradation (%/year)	0.05
BESS Capacity (MW)	22
BESS Storage Duration (hours)	4
BESS Losses (%)	11
BESS Degradation (%/year)	2
BESS Charge Hours	HE10-HE14
BESS Discharge Hours	
Jan, Nov, Dec	HE17-HE20
Feb, Mar, Sep, Oct	HE18-HE21
Apr – Aug	HE19-HE22
Contract Pricing	
Power Cost – Solar ($/MWh)	$27.50
Power Cost Escalator (%)	0.0
BESS Cost - ($/kW-month)	$5.50
BESS Cost Escalator (%)	0.0

Table 13.1.4. Cabazon repowering operating parameters and cost assumptions.

Operating Parameters	
Term (years)	20
Contract Start Date	1/1/2025
Contract End Date	12/31/2044
Wind Capacity (MW)	39
Contract Pricing	
Power Cost ($/MWh)	$59.30
Power Cost Escalator (%)	0.0

Table 13.1.5. SULCPP operating parameters and cost assumptions; note: HL hours are HE07-HE22, Monday through Saturday, SP hours are HE13-HE20, Monday through Saturday.

Operating Parameters		
Term (years)		10
Contract Start Date		7/1/2025
Contract End Date		9/30/2034
Energy-Only Capacity (MW)		
HL = Heavy load hours	**Jul**	50HL + 50SP
SP = Super peak hours	**Aug**	75HL + 50SP
	Sep	50HL + 50SP
Contract Pricing		
Power Cost ($/MWh)	**HL**	**SP**
2025	$54.83	$71.27
2026	$56.98	$74.07
2027	$59.24	$77.01
2028	$61.62	$80.11
2029	$64.13	$83.37
2030	$66.76	$86.79
2031	$69.53	$90.38
2032	$72.43	$94.16
2033	$75.49	$98.14
2034	$78.71	$102.32

Table 13.1.6. Baseload-2027 Renewable operating parameters and cost assumptions.

Operating Parameters	
Term (years)	20
Contract Start Date	1/1/2027
Contract End Date	12/31/2046
Capacity (MW)	40
Capacity Factor (%)	85
Contract Pricing	
Power Cost ($/MWh)	$71.71
Power Cost Escalator (%)	0.0

Table 13.1.7. Baseload-2029 Renewable operating parameters and cost assumptions.

Operating Parameters	
Term (years)	20
Contract Start Date	1/1/2029
Contract End Date	12/31/2048
Capacity (MW)	30
Capacity Factor (%)	85
Contract Pricing	
Power Cost ($/MWh)	$74.60
Power Cost Escalator (%)	0.0

Table 13.1.8. IPP Repower Project operating parameter assumptions and cost estimates.

Operating Parameters	
Term (years)	50
Contract Start Date	7/1/2025
Contract End Date	6/15/2077
Plant Nameplate Capacity (MW)	840
RPU Share of Nameplate Capacity (MW)	35
Heat Rate (MMBtu/MWh)	7.093
RPU Minimum Generation Level (MW)	11
RPU Maximum Generation Level (MW)	35
Monthly Minimum Capacity Factor (%)	45
Operating Costs	
Fixed Cost ($/kW-month)	$6.67
Fixed Cost Escalator (%)	2.0
VOM Cost ($/MWh)	$3.15
VOM Cost Escalator (%)	2.0
Power Cost ($/MWh)[1]	$35.47
Power Cost Escalator (%)	2.0

[1]*Assumes a fixed $5/MMBtu natural gas price in 2027.*

Table 13.1.9. LMS100 operating parameter assumptions and cost estimates.

Operating Parameters	
Term (years)	10
Tolling Start Date	8/1/2023
Tolling End Date	7/31/2033
Plant Nameplate Capacity (MW)	100
Heat Rate (MMBtu/MWh)	8.800
Minimum Generation Level (MW)	35
Maximum Generation Level (MW)	98
Startup Natural Gas (MMBtu)	40
Operating Costs	
Fixed Cost ($/kW-month)	$10.00
Fixed Cost Escalator (%)	2.5
VOM Cost ($/MWh)	$1.50
VOM Cost Escalator (%)	2.5

13.2 Fixed Budgetary Costs and IRP Budget Assumptions

In addition to the calculation of the total net portfolio costs and other market-related costs discussed in Chapter 7, a number of other fixed budgetary costs and revenues must be properly specified in order to calculate future cost-of-service projections. The most important additional budget items are as follows:

- SONGS: The cost obligations associated with winding down the SONGS contract and initializing the decommissioning process.
- Transmission Project Costs and Transmission Revenue Requirement (TRR): The cost obligations associated with RPU's transmission agreements and projects and RPU's TRR.
- 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.
- Utility Personnel and O&M costs: RPU's "all-other" operational costs, not related to power supply activities.
- Long-term Debt Service costs: RPU's long-term Debt Service costs.
- General Fund Transfer Tax: RPU's obligation to transfer 11.5% of its gross annual revenues to the City of Riverside.

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

13.2.1 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 20-year time horizon studied in this IRP. These cost obligations are expected to be $2 million annually and fall under the following expense categories:

- Professional services
- Outside legal services
- Operations and maintenance
- Decommissioning fund expense

Note that the $2 million per year SONGS cost forecast is common across all IRP scenarios.

13.2.2 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 2037 that are used to calculate RPU's TAC costs are presented in Chapter 7.

13.2.3 Carbon Allowances & Revenues

The Cap and Trade Program in California is well defined through 2030, and RPU is to receive the annual allocations of Carbon allowances shown in Table 13.2.1. The allocations equate to metric tons (mt) of CO2. RPU can use the majority 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 section 8.7 for more discussion on this topic). For long-term budget forecasting purposes, staff has assumed that RPU sells its residual Carbon allowances at the corresponding annual Carbon prices shown in Table 7.3.1. in Chapter 7. However, these revenues are not included in the long-term budget forecast. As discussed in section 8.7, staff assumes that this revenue stream will flow into a designated fund (separate from the budget) to help offset costs associated with other legislatively imposed carbon reduction programs.

Beyond 2030, the California Cap and Trade allocation program is not defined. Therefore, staff has assumed that RPU receives no further Carbon allowance allocations beyond 2030. Thus, 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 2037 in each IRP scenario.

Table 13.2.1. RPU's Carbon allowances.

Year	Allowances
2018	1,082,987
2019	1,079,121
2020	1,088,787
2021	1,060,927
2022	1,056,559
2023	1,039,042
2024	1,015,558
2025	1,000,815
2026	991,145
2027	799,554
2028	609,032
2029	601,432
2030	583,388

13.2.4 CAISO Uplift Fees & other Power Resource Costs

In addition to the above mentioned budgetary costs, in 2018 RPU expects to pay $7.7 million annually for the following all-other, Power Resource related costs:

- ICE Bear Program — 1.9 million dollars
- CAISO Transmission uplift fees: — 2.1 million dollars
- CAISO Energy uplift fees: — 0.5 million dollars
- CAISO Congestion Revenue Rights: — 0.5 million dollars
- SCPPA Project Fees — 0.3 million dollars
- RPU Internal Generation (contingency costs): — 2.2 million dollars
- Legislative Mandates (reporting): — 0.2 million dollars

For the IRP analyses, staff escalates this 7.7 million dollar cost at 3% annually in order to produce future cost forecasts of these miscellaneous budgetary expenses. Note that these cost forecasts are common across all IRP scenarios.

13.2.5 Utility Personnel and O&M Costs

To derive an estimate of RPU's cost of service (a metric that can be used to compare the different IRP scenarios), a projection of RPU's all-other budget items not related to power supply activities is also needed. These all-other items fall into the following categories:

- Existing Debt Service
- New Debt Service on Long and Short Term Bonds
- Personnel and O&M
- Capital Financed by Rates
- Other Operating and Non-operating Revenues

Projections for these categories are shown in Table 13.2.6 and were provided by RPU's Utility Finance Group. Combining the projected all-other costs and revenues yields the final Total Adjusted Annual Expense projections, which are treated as common costs across all IRP scenarios and are assumed to be independent of any future power resource procurement decisions.

13.2.6 General Fund Transfer (GFT)

An additional cost category that directly impacts RPU's cost of service is the annual General Fund Transfer (GFT). The GFT has been approved by Riverside's residents on at least three separate occasions and is defined in Section 1204(f) of the City's Charter as an amount not to exceed 11.5 percent of gross operating revenues, exclusive of surcharges, for the last fiscal year. This expenditure is used to support general City services to the community such as police, fire, parks, museums, libraries, etc., that improve the quality of life in Riverside. Currently the GFT is calculated as 11.5% of RPU's gross customer sales and transmission revenues, thus a technically correct forecast of the GFT should be based upon a forecast of future RPU revenues. However, given the desire to specifically avoid forecasting revenues in this IRP analysis, staff has taken an alternative approach to estimating future GFT levels. More specifically, staff first calculated the total net cost of service (NCOS) before the GFT as the TNPC plus the sum of all of the additional portfolio costs discussed in sections 13.2.1 through 13.2.5. Mathematically, this formula can be expressed as

$$NCOS = TNPC + SONGS + TAC + GHG + RA + UFOC + AO \qquad \text{[Eq. 13.2]}$$

where the remaining variables represent the additional costs associated with SONGS, the CAISO Transmission Access charge, Carbon (GHG) emissions, system RA needs, CAISO uplift fees and other Power Resource costs (UFOC), and the all-other (AO) utility costs, including all long-term debt service requirements. Once the net COS has been determined, staff then divided this by the additional GFT ratio to produce a gross cost of service (GCOS) estimate; i.e.

$$GCOS = NCOS / 0.885 \qquad \text{[Eq. 13.3]}$$

where the 0.885 division factor is used to calculate the additional revenue that must be obtained in order for the utility's total revenues to be in balance with its total gross COS.

Table 13.2.2. RPU "all-other" operating cost forecasts: 2018 – 2037.

Year	Existing Debt Service ($000)	New Debt Service on Long and Short Term Bonds ($000)	Personnel and O&M ($000)	Capital Financed by Rates ($000)	Other Operating and Non-operating Revenues ($000)	Total Adjusted Annual Expenses ($000)
2018	38,105	1,031	80,980	3,997	9,475	114,637
2019	36,705	4,243	84,802	3,362	10,200	118,911
2020	35,652	6,424	87,878	2,015	10,745	121,222
2021	35,619	7,447	90,956	1,646	11,234	124,433
2022	35,587	10,804	94,165	2,019	11,368	131,206
2023	35,552	13,139	96,426	2,480	11,487	136,110
2024	35,429	14,169	98,142	2,529	11,611	138,658
2025	35,318	17,573	100,083	2,580	11,737	143,815
2026	35,282	19,946	102,063	2,631	11,865	148,057
2027	35,254	20,976	103,539	2,684	11,995	150,458
2028	35,237	24,380	105,056	2,738	12,128	155,283
2029	35,209	26,318	107,157	2,792	12,262	159,215
2030	35,173	26,912	109,300	2,848	12,398	161,836
2031	35,126	30,316	111,486	2,905	12,536	167,297
2032	35,071	31,934	113,716	2,963	12,676	171,008
2033	35,012	32,209	115,990	3,023	12,819	173,415
2034	33,981	35,613	118,310	3,083	12,964	178,023
2035	32,952	37,186	120,676	3,145	13,111	180,847
2036	32,902	37,414	123,090	3,208	13,260	183,353
2037	32,859	40,818	125,551	3,272	13,412	189,088

13.2.7 Load Normalized Cost of Service (COS_{LN}) Metrics

As defined above, this GCOS estimates represent the utility's all-in cost of service forecasts for the various IRP scenarios discussed in this chapter. To a significant degree, these GCOS estimates increase as the load metric increases. Hence, for planning purposes it is more useful to examine a "load normalized" gross COS metric, since this essentially corresponds to the future average retail rate that RPU must charge to fully recover all of its expected costs. In the following IRP analyses, this load normalized metric (COS_{LN}) is defined as

$$COS_{LN} = GCOS / Retail.Load \qquad \text{[Eq. 13.4]}$$

where by definition the retail load is set equal to 95% of the utility's total system load forecasts, respectively.

This being said, it is important to recognize that these COS_{LN} estimates are primarily designed to facilitate an effective comparison between the different IRP scenarios, rather than to forecast the utility's absolute expected rate requirements twenty years into the future. Additionally, it should also be noted that the calculated standard deviations for these COS_{LN} estimates only quantify the uncertainty associated with the TNPC variable. All other variables incorporated into the NCOS 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 remainder of this chapter focuses on how these forecasted cost of service metrics change across the various scenarios shown in Table 13.1.1. The primary goal of these analyses will be to quantify both the absolute and relative cost of service and risk differences between these scenarios, in order to determine the cost impact associated with achieving RPU's GHG emissions goals. Additionally, the net value that each potential new resource brings to the RPU portfolio will also be assessed and quantified.

13.3 Baseline Portfolio

As shown in Table 13.1.1, the Baseline Portfolio of resources studied in this IRP positions RPU to achieve a 2030 portfolio GHG emission level that is 40% below its portfolio emissions in 1990 and meet the current RPS mandate of 50% by 2030. In addition to the main portfolio assumptions outlined in section 10.1.3, the Baseline Portfolio also includes renewable the Solar+Storage and Cabazon resources listed in Table 13.1.2. These additional renewable resources have pricing considered normal or consistent with pricing currently available for similar projects in the market. Additional capacity and energy needs not satisfied by this Baseline Portfolio of resources are met with short-term RA product purchases and CASIO energy market purchases, respectively.

13.3.1 Baseline Portfolio GHG Emissions

Figure 13.3.1 shows RPU's projected Total Portfolio and 1st Importer GHG emissions from 2018 through 2037 under the Baseline Portfolio. As shown in the graph, the Baseline portfolio achieves an emission level of 617,308 metric tons of GHG in 2030, which is below RPU's utility-specific 40% below 1990 emission level of 647,844 metric tons that was presented in Table 9.3.1. Note that the upward trajectory of RPU's portfolio emissions beyond 2026 is due to forecasted load growth and having to purchase additional CAISO market energy with a 0.428 MT/MWh emissions factor. It is conceivable that this emission factor for market energy purchases will decrease in the future because of more renewable energy entering the market energy pool, displacing energy from thermal resources. However, as of writing this IRP, there are no official estimates of future GHG emission factors for CAISO market energy. Therefore, in this analysis, the 0.428 MT/MWh emission factor is held constant throughout the study horizon and applied to all future projected market energy purchases.

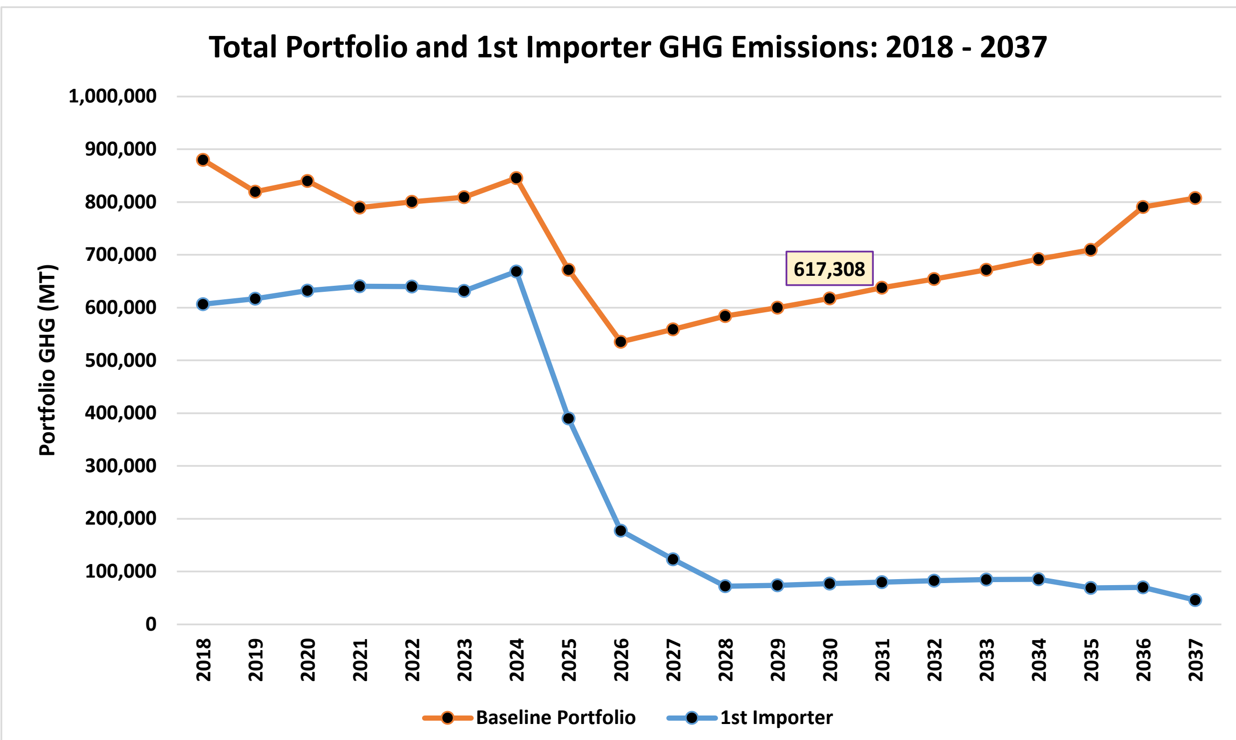


Figure 13.3.1. RPU's projected GHG emissions under the Baseline Portfolio.

13.3.2 Baseline Portfolio RPS

Figure 13.3.2 shows RPU's projected RPS percentage under the Baseline Portfolio. In 2030, the Baseline Portfolio achieves a 44.4% RPS with all PCC-1 renewable resources. To get to a 50% RPS, RPU can use a combination of PCC-3 renewable energy credits and excess procurement credits. PCC-3 renewable energy credits can count towards 10% of RPU's RPS compliance, which would add 5% to its RPS percentage, bringing it to 49.4%. The remaining balance required for compliance can be met with excess procurement credit that RPU has built up by exceeding the mandated RPS percentages earlier in the study horizon. Just as projected load growth is the main factor for the increasing trajectory of portfolio GHG emissions, it is also the main factor for the decreasing trajectory of the RPS percentage. RPU will need to procure additional renewable resources beyond 2030 to satisfy longer-term RPS mandates.

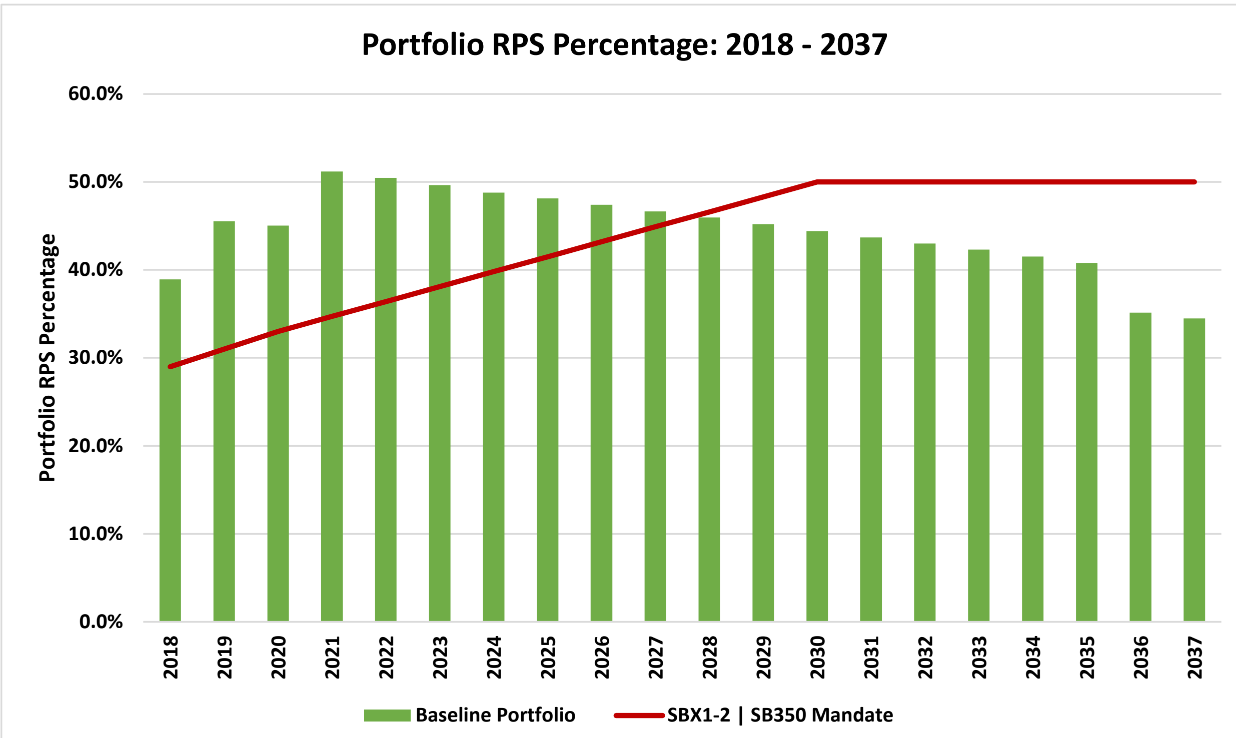


Figure 13.3.2. RPU's projected RPS percentage under the Baseline Portfolio.

13.3.3 Baseline Portfolio Impacts on RPU's COS_{LN}

Figure 13.3.3 shows a breakout of the cost of service components (shown in ₵/kWh units) for the Baseline Scenario. Specifically, the graph shows how much RPU's portfolio costs, all-other costs, and GFT impact the overall cost of service. As shown in the graph, power resource portfolio costs are substantial – making up over half of RPU's cost of service, with the other half coming from the all-other budget costs and GFT combined. Compared to the all-other costs, the portfolio costs are roughly 43% higher but growing slightly slower (1.1% annually versus 1.4% annually) between 2020 and 2035. This graph also shows the portfolio risk (red-hatched area) associated with the Baseline Portfolio. As shown in the graph, this risk increases over time reflecting the increasing uncertainty of future market conditions.

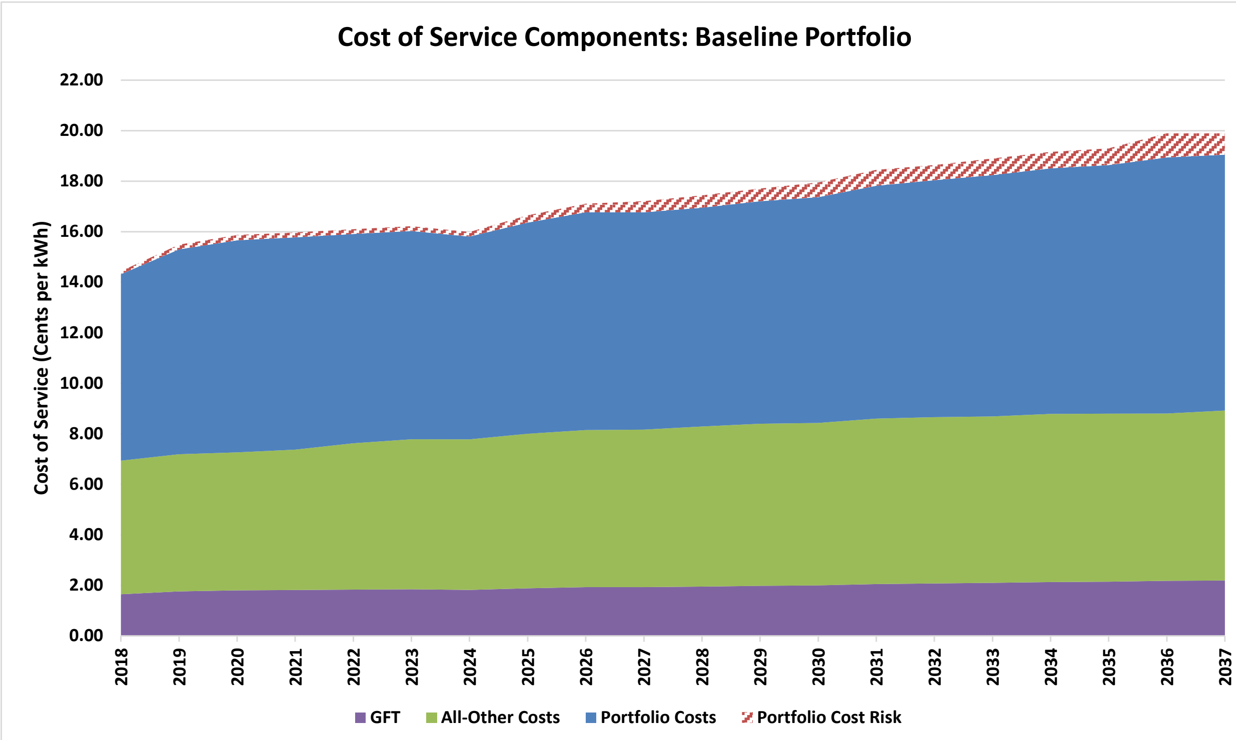


Figure 13.3.3. Projected annual COS_{LN} components under the Baseline Portfolio.

Figure 13.3.4 shows the projected annual COS_{LN} estimates (shown in ₵/kWh units) for the Baseline Portfolio. Note that these are the same estimates as indicated by the top of the blue area in Figure 13.3.3. However, the cost of service growth appears steeper because the scale of the y-axis starts at 14 ₵/kWh, instead of 0 ₵/kWh. The change in scale helps to highlight year-to-year changes in the cost of service. Additionally, Table 13.3.1 shows the corresponding COS_{LN} estimates for years 2020, 2025, 2030 and 2035, respectively, and the annual COS_{LN} growth rate for this scenario is shown in the last column.

Figure 13.3.5 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]), again shown in ₵/kWh units) for the Baseline Portfolio shown in Figure 13.3.4. These are equal to the red-hatched area shown in Figure 13.3.3. In Figure 13.3.5, note that the portfolio risk begins to increase on/after 2025. This effect is a direct result of the IPP resource repowering to a smaller natural gas combined cycle plant in 2025 and subsequently falling out of the utility's resource portfolio when the contract terminates in 2027. As these changes occur, the IPP project (which essentially represents a fixed price generation asset) is replaced with open, unhedged SP15 market energy purchases, which are subject to significant price uncertainty. With respect to the relative portfolio risk, values at or below 2.5% represent a well-hedged portfolio that can effectively withstand significant market price swings. Higher values indicate more potential cash flow uncertainty and corresponding portfolio risk. Table 13.3.2

shows that the portfolio risk increases to around 0.7 ₵/kWh under the Baseline Portfolio (3.6% relative risk), which is higher than the utility's current risk level (~ 1.3%).

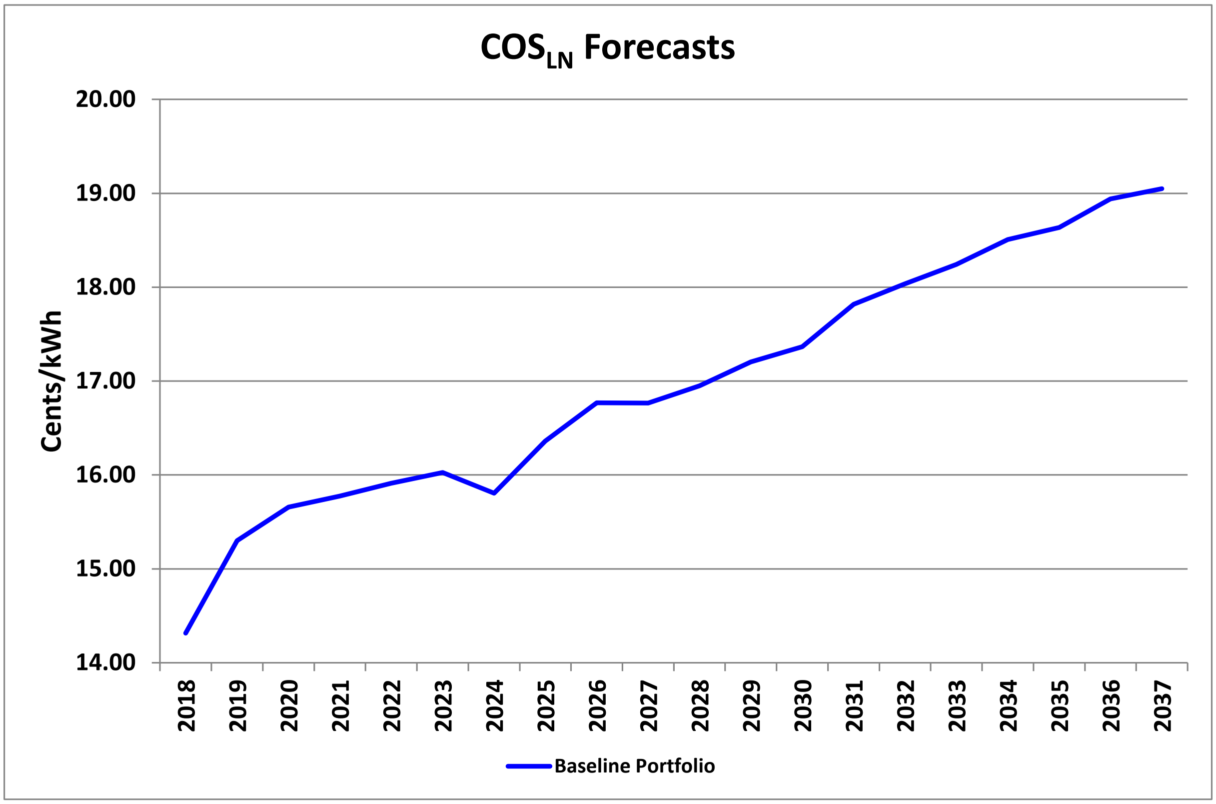


Figure 13.3.4. Projected annual COS_{LN} estimates under the Baseline Portfolio.

Table 13.3.1. Figure 13.3.3 COS_{LN} estimates for years 2020, 2025, 2030 and 2035, along annual growth rates. All cost units shown in ₵/kWh.

Scenario	2020	2025	2030	2035	Annual GR
A. Baseline Portfolio	15.659	16.362	17.365	18.636	1.2%

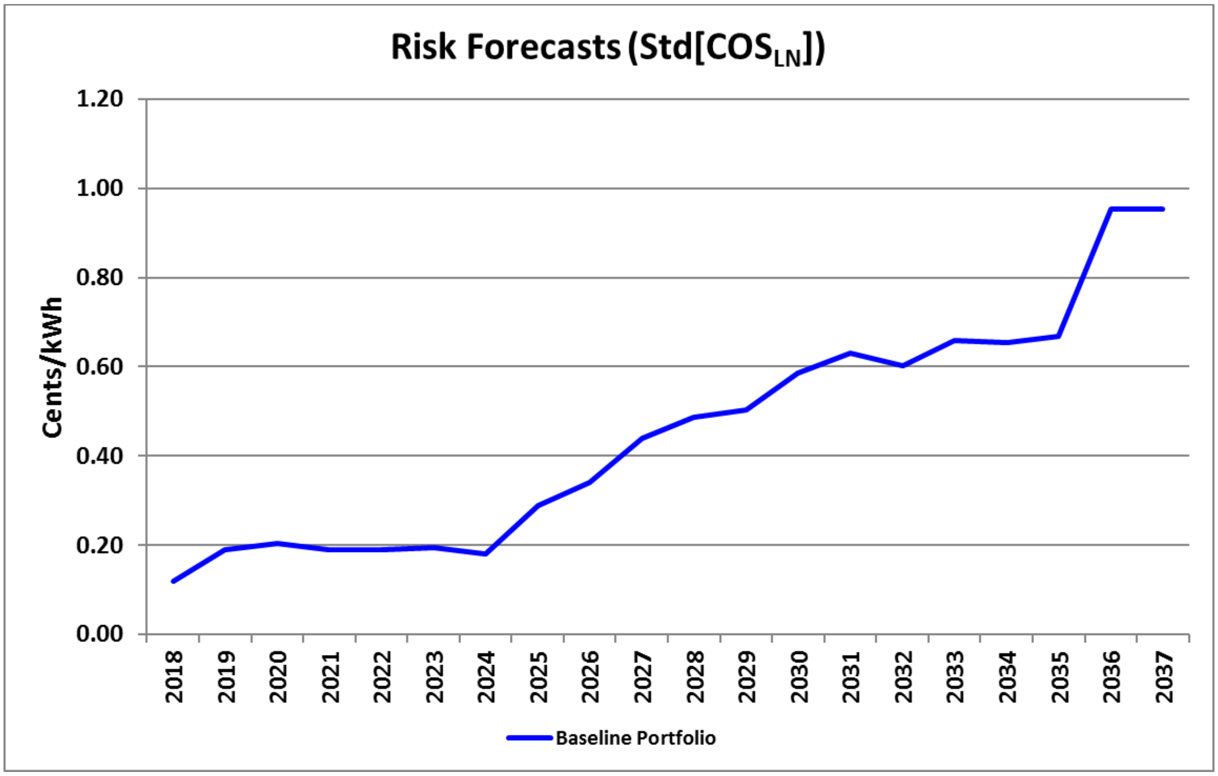


Figure 13.3.5. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the Baseline Portfolio.

Table 13.3.2. Figure 13.3.4 COS_{LN} risk estimates for years 2020, 2025, 2030 and 2035, along with relative risk levels. All cost units shown in ₵/kWh.

Scenario	2020	2025	2030	2035
A. Baseline Portfolio	0.205	0.288	0.587	0.668
Relative Risk of Scenario A	1.3%	1.8%	3.4%	3.6%

13.4 53MMT Sector Target Portfolio

As shown in Table 13.1.1, the 53MMT Sector Target Portfolio builds upon the Baseline Portfolio and positions RPU to achieve a 2030 portfolio GHG emission level that meets its targeted utility-specific GHG emissions share under the 53MMT Electric Sector GHG target and exceed the current RPS mandate of 50% by 2030. In addition to all the portfolio assumptions and resources included in the Baseline Portfolio, the 53MMT Sector Target Portfolio also includes the SULCPP and Baseload-2027 resources listed in Table 13.1.2. As in the Baseline Portfolio, these additional renewable resources have pricing considered normal or consistent with pricing currently available for similar projects in the market.

Likewise, additional capacity and energy needs not satisfied by this 53MMT Sector Target Portfolio of resources are met with short-term RA product purchases and CASIO energy market purchases, respectively.

13.4.1 53MMT Sector Target Portfolio GHG Emissions

Figure 13.4.1 shows RPU's projected Total Portfolio and 1st Importer GHG emissions from 2018 through 2037 under the 53MMT Sector Target Portfolio. As shown in the graph, this portfolio achieves an emission level of 445,603 metric tons of GHG in 2030, which is well below the GHG emission level achieved under the Baseline Portfolio and also lower than RPU's 53MMT utility-specific target of 486,277 metric tons that was presented in Table 9.3.1.

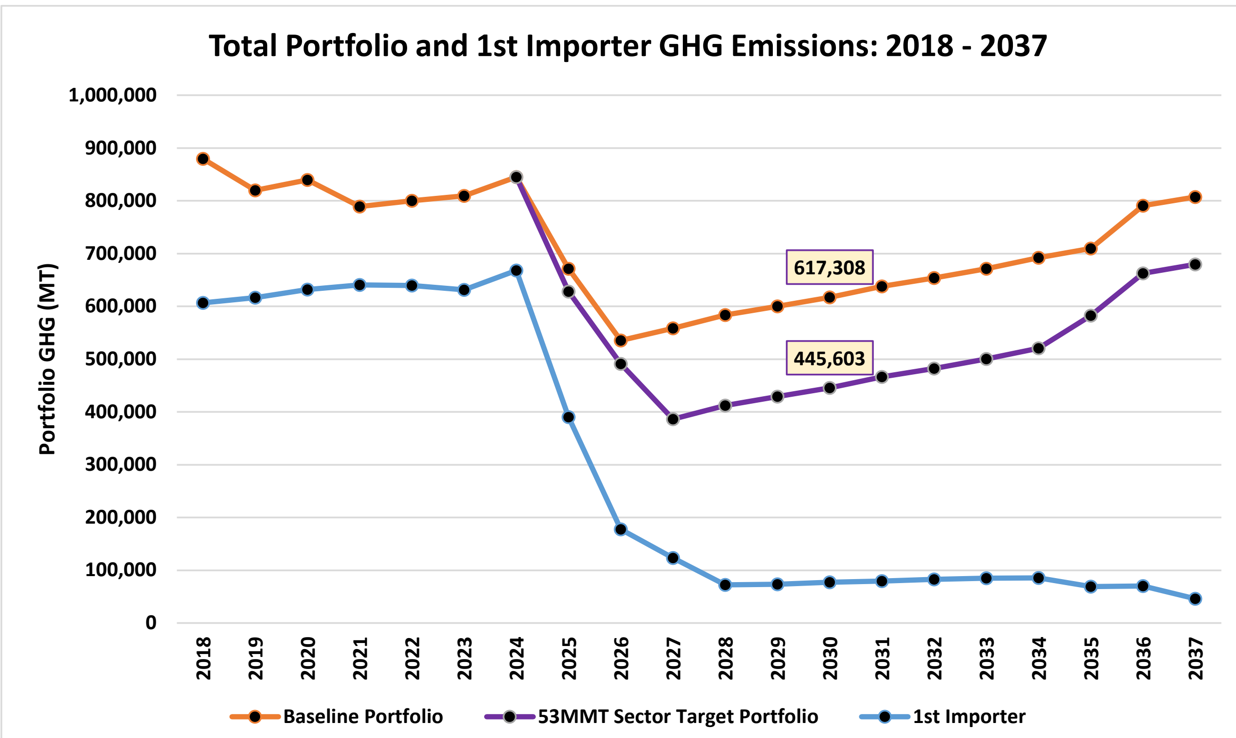


Figure 13.4.1. RPU's projected GHG emissions under the 53MMT Sector Target Portfolio.

13.4.2 53MMT Sector Target Portfolio RPS

Figure 13.4.2 shows RPU's projected RPS percentage under the 53MMT Sector Target Portfolio. In 2030, this portfolio achieves a 56.2% RPS with all PCC-1 renewable resources, which exceeds the current 50% RPS mandate. The orange bars in the chart show the incremental RPS percentage provided by the renewable capacity and energy added to this portfolio starting in 2027.

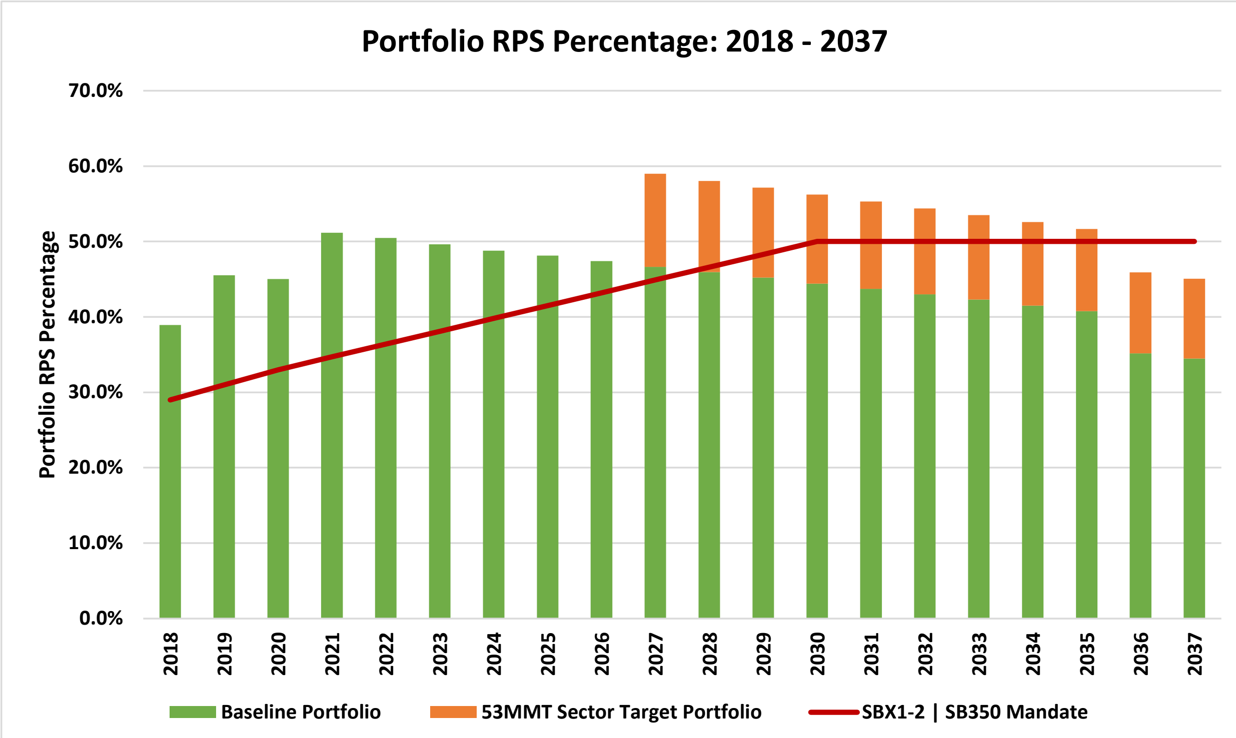


Figure 13.4.2. RPU's projected RPS percentage under the 53MMT Sector Target Portfolio.

13.4.3 53MMT Sector Target Portfolio Impacts on RPU's COS_{LN}

Figure 13.4.3 shows the projected annual COS_{LN} estimates (shown in ₵/kWh units) for the 53MMT Sector Target Portfolio compared to the Baseline Portfolio. Additionally, Table 13.4.1 shows the corresponding COS_{LN} estimates for years 2020, 2025, 2030 and 2035, respectively, and summarizes some relevant scenario comparisons. More specifically, the annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom row quantifies pertinent percentage cost increases compared to the Baseline Portfolio.

As shown in Figure 13.4.3., the COS_{LN} forecasts for the 53MMT Sector Target Portfolio increase over the Baseline Portfolio in the period after 2024. This increase is the direct effect of the SULCPP and Baseload-2027 resources entering the portfolio in 2025 and 2027, respectively. In Table 13.4.1, the percentage cost increase comparison for "Scenario B vs A" quantifies the impact of these new resources on the utility's expected cost of service. This cost increase is forecasted to be about 1.5% in 2030 when both resources are in the portfolio.

Figure 13.4.4 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]), again shown in ₵/kWh units) for the 53MMT Sector Target Portfolio compared to the Baseline Portfolio. Note that as the new resources enter the portfolio in the period after 2024, the COS_{LN} uncertainty estimates decrease. This is because the new resources are fixed-price, and they replace a portion of the unhedged SP15 market purchases being made in the Baseline portfolio that were subject to price uncertainty.

Table 13.4.2 shows that the portfolio risk decreases to around 0.6 ₵/kWh under the 53MMT Sector Target Portfolio (3.0% relative risk). This is still higher than the utility's current risk level (~ 1.3%) but nonetheless an improvement over the Baseline Portfolio.

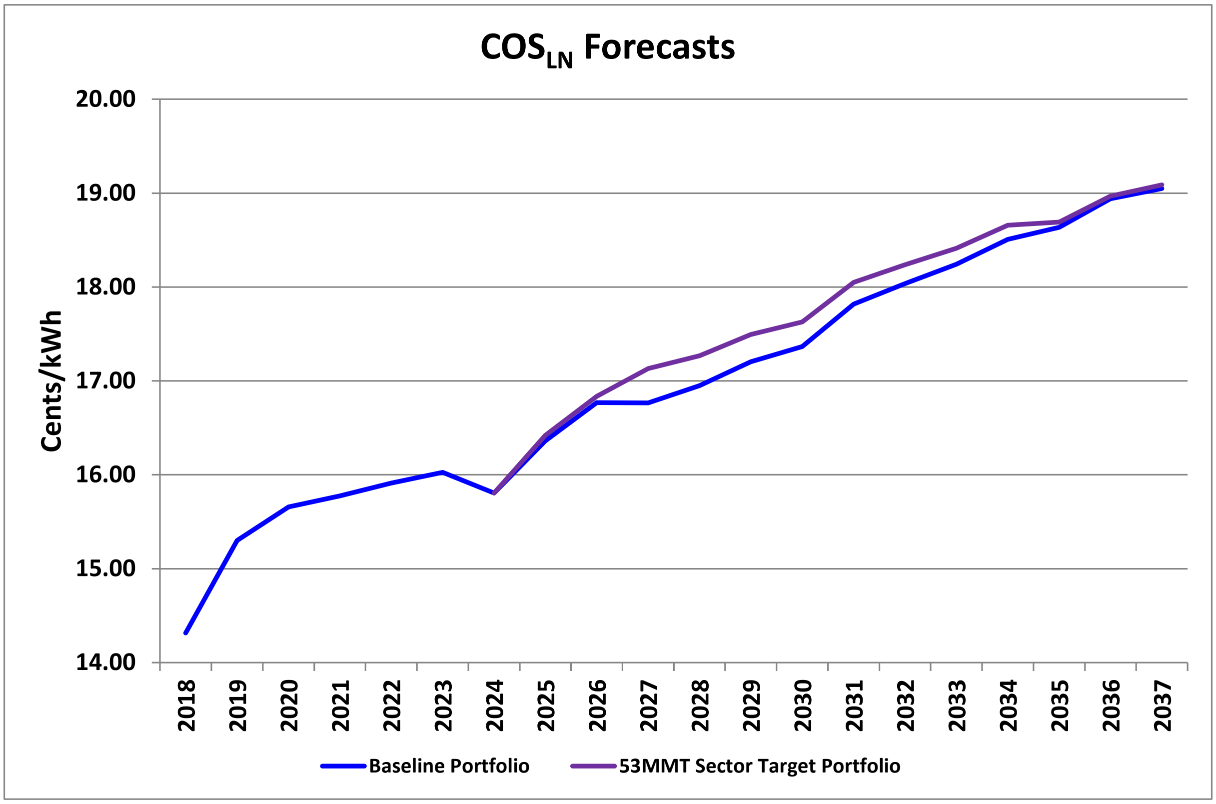


Figure 13.4.3. Projected annual COS_{LN} estimates under the 53MMT Sector Target Portfolio compared to the Baseline Portfolio.

Table 13.4.1. Figure 13.4.3 COS_{LN} estimates for years 2020, 2025, 2030 and 2035, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2020	2025	2030	2035	Annual GR
A. Baseline Portfolio	15.659	16.362	17.365	18.636	1.2%
B. 53MMT Sector Target Portfolio	15.659	16.421	17.628	18.691	1.2%
B vs A	0.0%	0.4%	1.5%	0.3%	

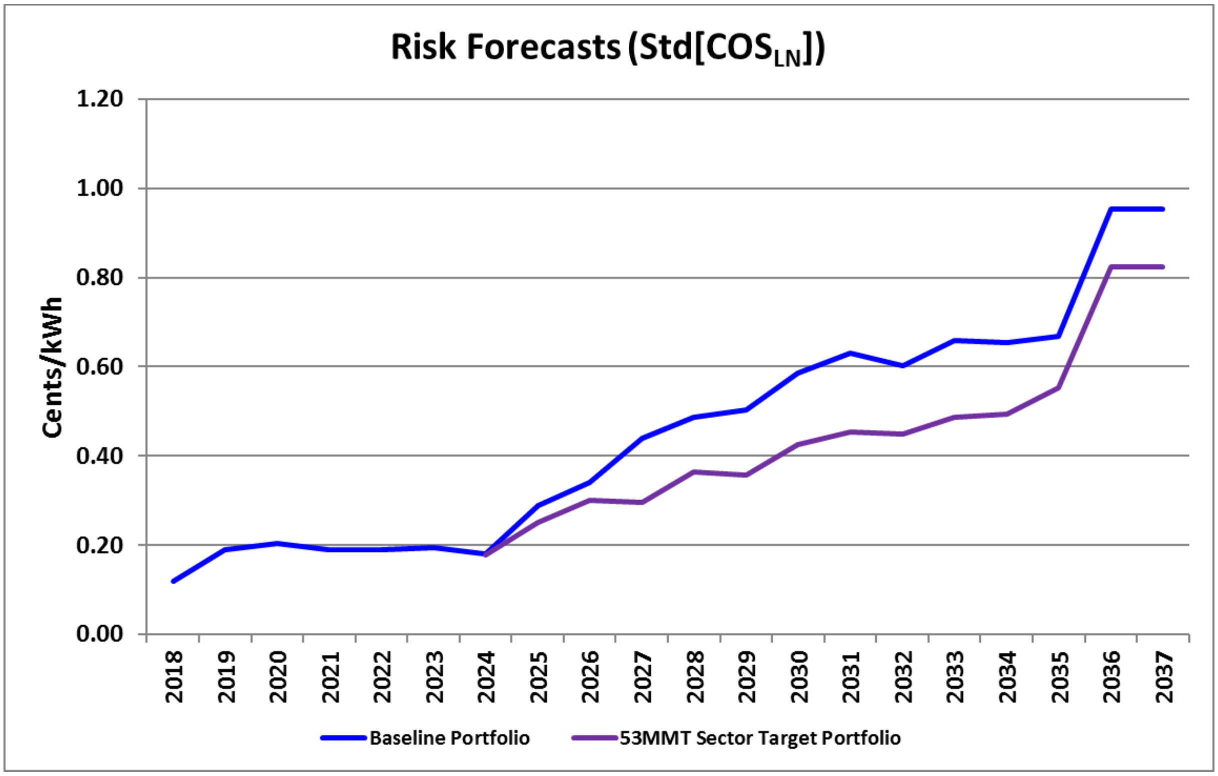


Figure 13.4.4. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the 53MMT Sector Target Portfolio compared to the Baseline Portfolio.

Table 13.4.2. Figure 13.4.4 COS_{LN} risk estimates for years 2020, 2025, 2030 and 2035, along with relative risk levels. All cost units shown in ₵/kWh.

Scenario	2020	2025	2030	2035
A. Baseline Portfolio	0.205	0.288	0.587	0.668
B. 53MMT Sector Target Portfolio	0.205	0.250	0.426	0.552
Relative Risk of Scenario A	1.3%	1.8%	3.4%	3.6%
Relative Risk of Scenario B	1.3%	1.5%	2.4%	3.0%

13.5 42MMT Sector Target Portfolio

As shown in Table 13.1.1, the 42MMT Sector Target Portfolio further builds upon the Baseline Portfolio and positions RPU to achieve a 2030 portfolio GHG emission level that meets its targeted utility-specific GHG emissions share under the 42MMT Electric Sector GHG target and exceeds the current RPS mandate of 50% by 2030. In addition to all the portfolio assumptions and resources included in the Baseline Portfolio and the 53MMT Sector Target Portfolio, the 42MMT Sector Target Portfolio also includes the Baseload-2029 resource listed in Table 13.1.2. Again, this additional renewable resource has pricing considered normal and consistent with pricing currently available for similar projects in the market. Moreover, additional capacity and energy needs not satisfied by this 42MMT Sector Target Portfolio of resources are met with short-term RA product purchases and CASIO energy market purchases, respectively.

13.5.1 42MMT Sector Target Portfolio GHG Emissions

Figure 13.5.1 shows RPU's projected Total Portfolio and 1st Importer GHG emissions from 2018 through 2037 under the 42MMT Sector Target Portfolio. As shown in the graph, this portfolio achieves an emission level of 349,502 metric tons of GHG in 2030, which is comfortably below RPU's 42MMT utility-specific target of 385,137 metric tons that was presented in Table 9.3.1.

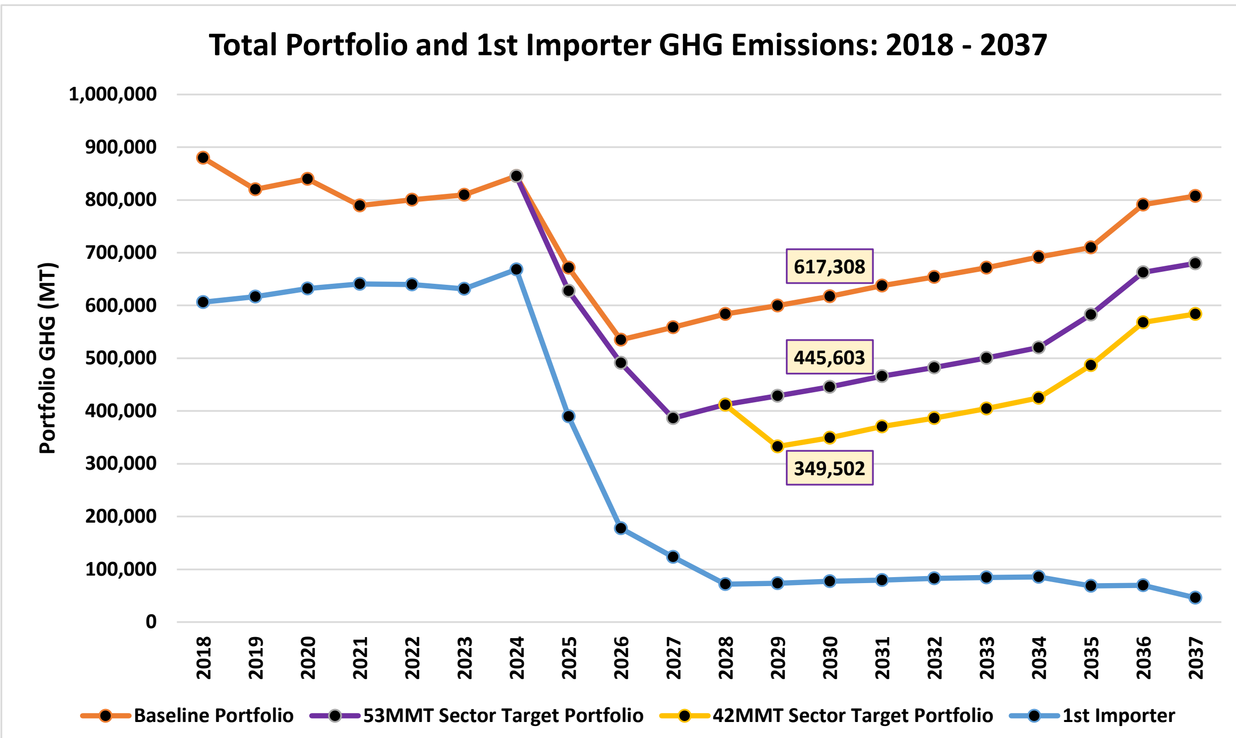


Figure 13.5.1. RPU's projected GHG emissions under the 42MMT Sector Target Portfolio.

13.5.2 42MMT Sector Target Portfolio RPS

Figure 13.5.2 shows RPU's projected RPS percentage under the 42MMT Sector Target Portfolio. In 2030, this portfolio achieves a 65.1% RPS with all PCC-1 renewable resources, which exceeds the current 50% RPS mandate. The yellow bars in the chart show the incremental RPS percentage provided by the renewable capacity and energy added to this portfolio starting in 2029.

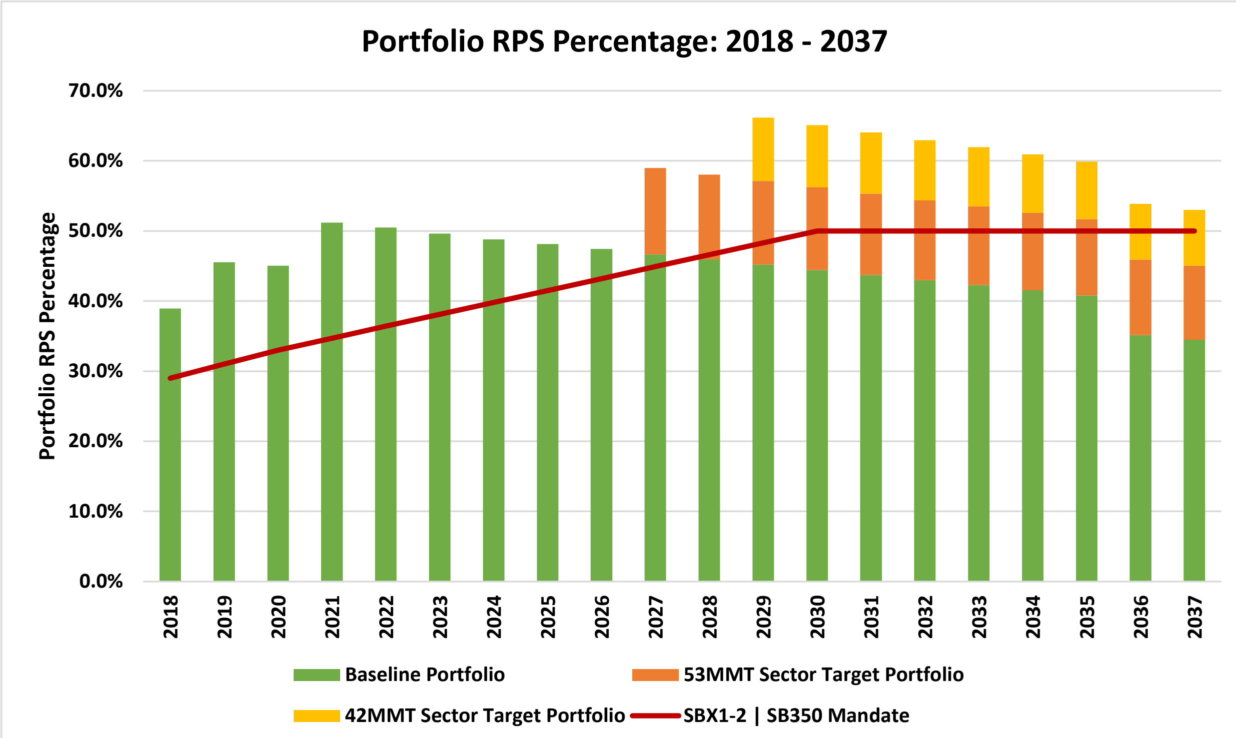


Figure 13.5.2. RPU's projected RPS percentage under the 42MMT Sector Target Portfolio.

13.5.3 42MMT Sector Target Portfolio Impacts on RPU's COS_{LN}

Figure 13.5.3 shows the projected annual COS_{LN} estimates (shown in ₵/kWh units) for the 42MMT Sector Target Portfolio compared to the Baseline and 53MMT Sector Target Portfolios. Additionally, Table 13.5.1 shows the corresponding COS_{LN} estimates for years 2020, 2025, 2030 and 2035, respectively, and summarizes some relevant scenario comparisons. More specifically, the annual COS_{LN} growth rate for each scenario is shown in the last column, and the bottom row quantifies pertinent percentage cost increases compared to the Baseline Portfolio.

As shown in Figure 13.5.3., the COS_{LN} forecasts for the 42MMT Sector Target Portfolio increase over the 53MMT Sector Target Portfolio in the period after 2028. This increase is the direct effect of the Baseload-2029 resource entering the portfolio in 2029. In Table 13.5.1, the percentage cost increase comparison for "Scenario C vs A" quantifies the impact of the additional new resource on the utility's expected cost of service. Compared to the Baseline Portfolio, this cost increase is forecasted to be 2.6% in 2030 when all new resources listed in Table 12.1.1 are in the portfolio.

Figure 13.5.4 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]), again shown in ₵/kWh units) for the 42MMT Sector Target Portfolio compared to the Baseline and 53MMT Sector Target Portfolios. As with the 53MMT Sector Target Portfolio, the COS_{LN} uncertainty estimates for the 42MMT Sector Target Portfolio decrease when a new fixed-price resource enters the portfolio. The new resource that enters the portfolio in 2029 brings the portfolio risk down about 0.07 ₵/kWh compared to the 53MMT Sector Target Portfolio and about 0.2 ₵/kWh overall compared to the Baseline Portfolio. Table 13.5.2 shows that the portfolio risk decreases to around 0.5 ₵/kWh under the 42MMT Sector Target Portfolio (2.5% relative risk).

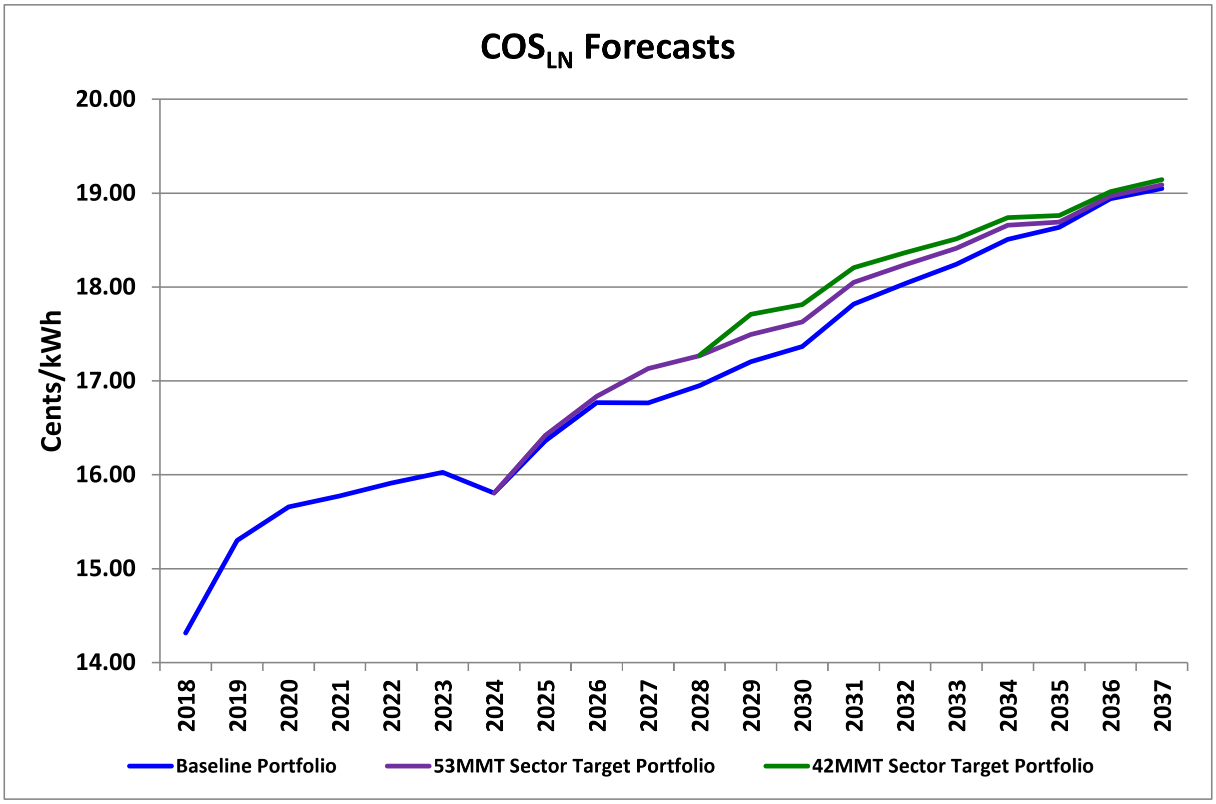


Figure 13.5.3. Projected annual COS_{LN} estimates under the 42MMT Sector Target Portfolio compared to the 53MMT Sector Target Portfolio and Baseline Portfolio.

Table 13.5.1. Figure 13.5.3 COS_{LN} estimates for years 2020, 2025, 2030 and 2035, along with relevant scenario comparisons (annual growth rates and relative cost increases). All cost units shown in ₵/kWh.

Scenario	2020	2025	2030	2035	Annual GR
A. Baseline Portfolio	15.659	16.362	17.365	18.636	1.2%
B. 53MMT Sector Target Portfolio	15.659	16.421	17.628	18.691	1.2%
C. 42MMT Sector Target Portfolio	15.659	16.421	17.813	18.762	1.2%
B vs A	0.0%	0.4%	1.5%	0.3%	
C vs A	0.0%	0.4%	2.6%	0.7%	

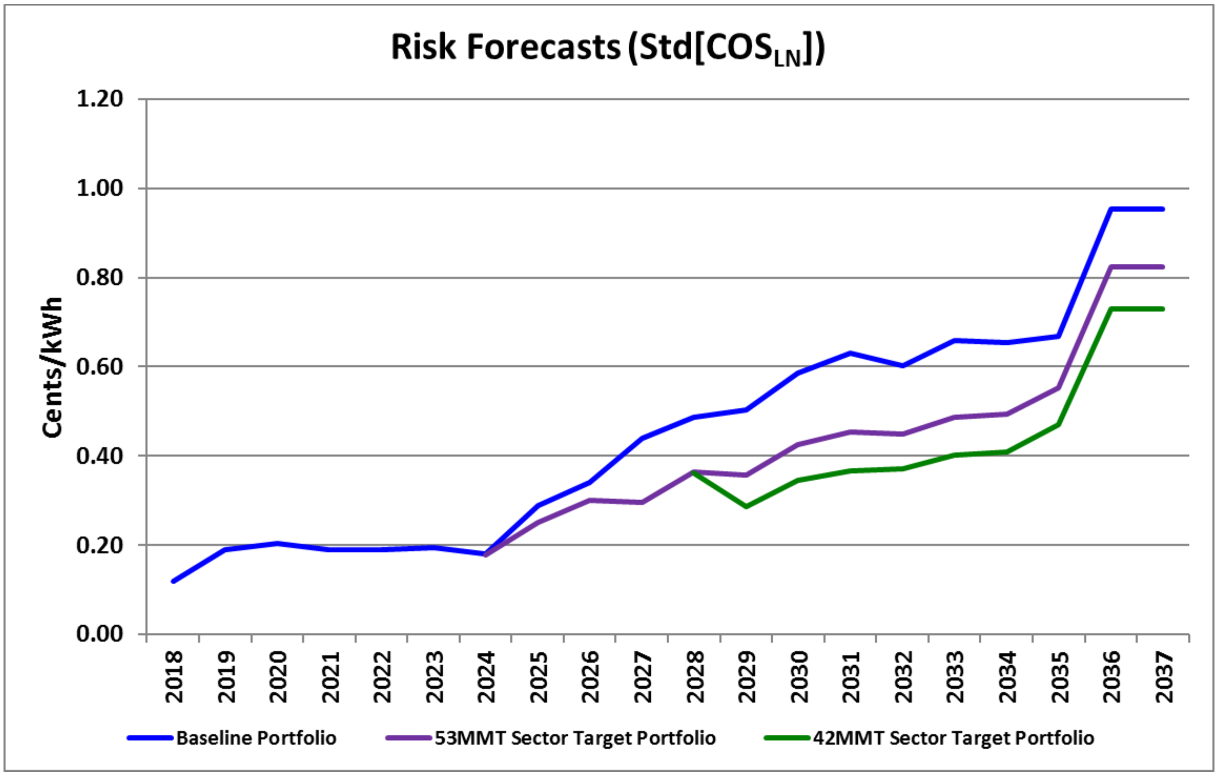


Figure 13.5.4. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the 42MMT Sector Target Portfolio compared to the 53MMT Sector Target Portfolio and Baseline Portfolio.

Table 13.5.2. Figure 13.5.4 COS_{LN} risk estimates for years 2020, 2025, 2030 and 2035, along with relative risk levels. All cost units shown in ₵/kWh.

Scenario	2020	2025	2030	2035
A. Baseline Portfolio	0.205	0.288	0.587	0.668
B. 53MMT Sector Target Portfolio	0.205	0.250	0.426	0.552
C. 42MMT Sector Target Portfolio	0.205	0.250	0.346	0.470
Relative Risk of Scenario A	1.3%	1.8%	3.4%	3.6%
Relative Risk of Scenario B	1.3%	1.5%	2.4%	3.0%
Relative Risk of Scenario C	1.3%	1.5%	1.9%	2.5%

13.5.4 Risk Integrated Cost of Service

The previously discussed key results are conveniently summarized in the vertical bar chart shown in Figure 13.5.5. This chart combines the forecasted 2025, 2030, and 2035 COS_{LN} values with their corresponding risk estimates to produce an overall “composite cost of service” estimate for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio. The composite costs of service estimates are very close across scenarios in each specified year. In 2030, when the Solar+Storage, Cabazon, SULCPP, Baseload-2027, and Baseload-2029 resources are all online in their respective portfolios, the increase in the composite cost of service between each portfolio is relatively minimal (i.e., < 1%). Therefore, RPU should be able to achieve its GHG emissions targets with relatively minimal cost impacts, provided that renewable prices remain at normal levels.

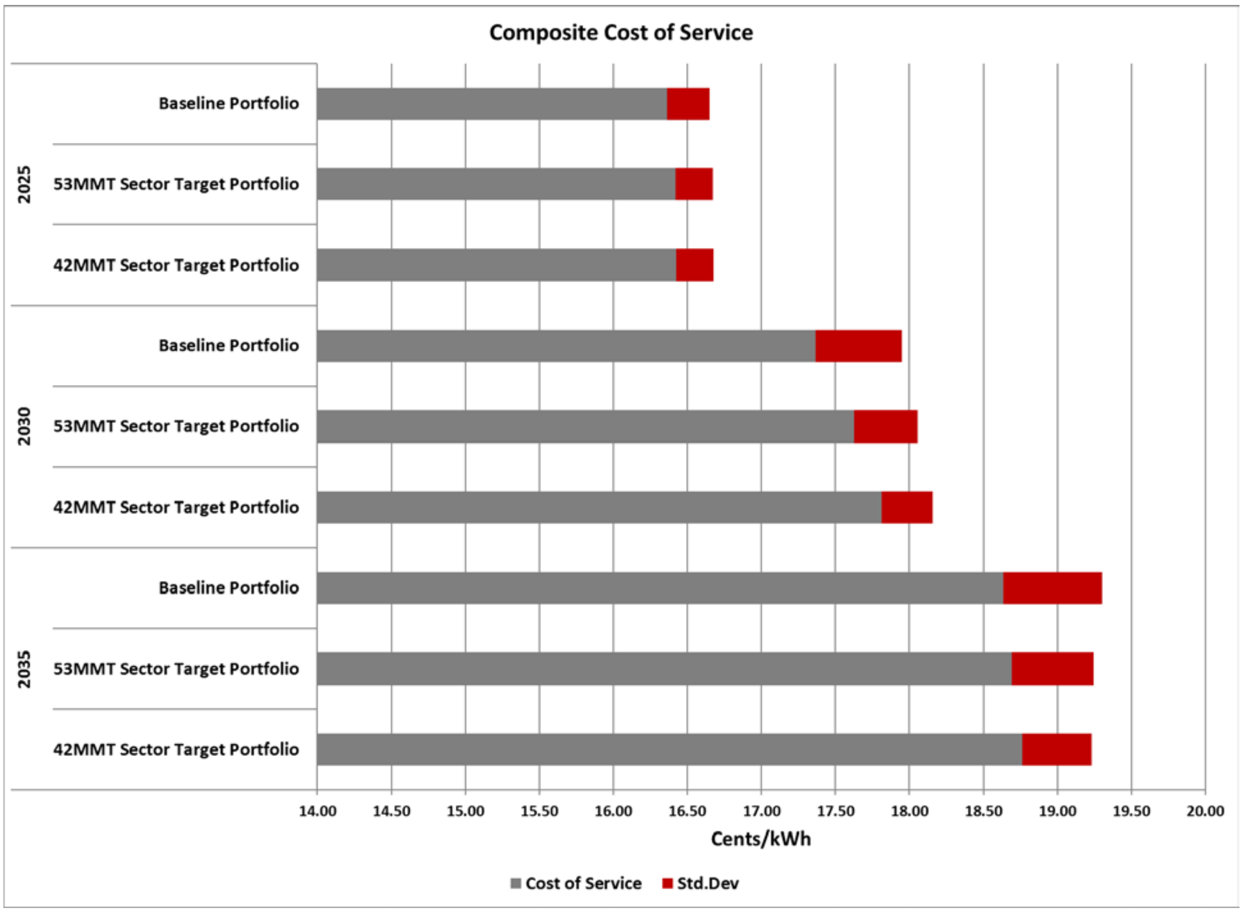


Figure 13.5.5. Forecasted 2025, 2030 and 2035 COS_{LN} values and corresponding risk estimates for the Baseline, 53MMT Sector Target, and 42MMT Sector Target portfolios.

13.6 Resource-Specific Net Value Analysis

In addition to examining the overall cost of service and risk estimates associated with the different resource portfolios, another important metric to analyze is the overall net value of each of the five new resources considered in the GHG reduction scenarios presented in the previous sections. Assessing the overall net value of each specific resource reveals the cost or value each resource brings to the overall portfolio. Additionally, showing the net value on a $/kWh basis allows for side-by-side comparisons to demand-side resources such as specific energy efficiency programs, which will be presented in Chapter 14.

In this section, the $/kWh net value for the following resources will be presented:

- Solar+Storage
- Cabazon
- SULCPP
- Baseload-2027
- Baseload-2029

The $/kWh net value for the IPP Repowering Project and LMS100 tolling agreement will be presented in Sections 13.7 and 13.8, respectively.

13.6.1 Methodology for Calculating the Net Value Metric

Calculating the overall net value metric for a resource involves the aggregation of three components, at least one of which that is not automatically captured in a COS_{LN} analysis. The main component is the simulated net revenue that the resource earns from participating in the CAISO market. This is a core output variable from the Ascend Production Cost Modeling Software, and at a high level, equals the gross revenue the resource earns from selling its energy into the CAISO market less its total fixed and variable costs. However, along with the net revenue variable, two additional value components can be applied based on other marketable attributes a particular resource might possess. For the new resources discussed in this section, these additional value components include:

- RA/Capacity Value (including system, local, and/or flexible capacity values)
- Avoided Carbon emission costs

The appropriate annual RA value attributable to each resource is calculated by summing the product of the RA market value and the kW amount of RA credit that the resource can provide each month of the year. In the following analyses, staff has assumed that the market RA value is $4.50/kW-month in 2018 and escalates 3% annually (as discussed in Chapter 11). The kW amount of RA that a particular resource can provide is dependent on the CAISO's rules governing RA credit. For baseload resources, the kW amount of RA credit is typically equal to the nameplate capacity of the resource. For wind and solar resources, the CAISO publishes specific monthly net qualifying capacity (NQC) technology factors, as shown in Table 13.6.1, that can be multiplied by the nameplate capacity of the corresponding resource to determine the kW amount of RA credit that these resources can provide each month of the year. Lastly, for Solar+Storage resources, RA credit can come from both the solar and storage components, depending on the system's configuration. The kW amount of RA credit coming from the solar component is determined using the CAISO's NQC solar technology factors (as discussed above) and the credit coming from the storage component is equal to its nameplate capacity. However, for the Solar+Storage resource discussed in this section, staff has assumed that the RA credit from the storage component will go towards offsetting additional flexible RA requirements that the CAISO will impose on RPU due to the addition of the intermittent solar resource to its portfolio. Under this assumption, the Solar +Storage resource only receives an additional RA value for its solar component in this analysis.

Table 13.6.1. CAISO-published wind and solar technology factors used to determine RA credit.

Month	Solar	Wind
1	0.0%	11.3%
2	2.4%	17.3%
3	10.4%	18.3%
4	33.2%	31.4%
5	30.5%	30.6%
6	44.8%	47.5%
7	41.7%	29.7%
8	41.0%	26.5%
9	33.4%	26.5%
10	29.4%	8.8%
11	4.1%	8.4%
12	0.0%	15.2%

The second value component to calculate is the annual avoided carbon costs associated with each resource. As discussed earlier in section 13.2.3, staff previously assumed that any additional revenue generated from the sale of excess Carbon allowances flows directly into a designated fund separate from RPU's operating budget. Thus, any savings gained by avoiding the use of Carbon allowances was not reflected in the COS_{LN} calculations. However, valid arguments can be made for accounting for such avoided costs when computing the net value metric, particularly if direct comparisons are to be made between supply-side and demand-side resources. Additionally, it makes sense to account for these avoided costs when quantifying RPU's Total Portfolio GHG emission costs.

In summary, Table 13.6.2 identifies the additional value components that are appropriate to consider for the resources discussed in this section. All of these resources should receive additional credit for their avoided carbon costs. Likewise, with the exception of the SULCPP, all of these resources create additional RA value. (The SULCPP is assumed to be an energy-only transaction with no added RA benefits.)

Table 13.6.2. Additional value components appropriate for resources shown in Table 13.6.1.

Resource	Additional Value Components	
	RA Credit	Avoided Carbon Cost
Solar+Storage	Solar NQC only[1]	Yes
Cabazon	Wind NQC	Yes
SULCPP	None	Yes
Baseload 2027	40,000 kW per month	Yes
Baseload 2029	30,000 kW per month	Yes

[1]RA credit for battery is assumed to offset additional flexible RA requirement incurred from the solar resource.

Once the additional value components are determined, adding them to the simulated net revenue component yields the net value metric on a dollar basis, which can then be converted to a \$/kWh basis by dividing the net value by the kWh of generation that the resource produces. The equations below summarize this net value calculation methodology.

Net Value (\$) = Net.Revenue + RA.Credit + Avoided.GHG.Cost [Eq. 13.5]

Net Value (\$/kWh) = Net Value (\$) / Resourse-specific.Generation [Eq. 13.6]

However, it should again be noted that both the net revenues and RA credits are already captured in the COS_{LN} calculations, while the avoided carbon costs are not. Therefore, two sets of resource specific net value estimates will be discussed in the next section; i.e., budgetary estimates that exclude the avoided carbon costs and planning estimates that include avoided carbon costs. The former quantify the direct budgetary impacts associated with adding each resource to the portfolio (on a \$/kWh basis), while the latter quantify the avoided carbon costs that RPU would realize if the utility's carbon allocation credits were treated as a fungible asset (as is done when valuing EE/DSM programs).

13.6.2 Resource-Specific Budgetary Net Value Results

Figure 13.6.1 shows the resulting budgetary net values for each of the five new resources in 2025, 2030, and 2035, where all estimates exclude the additional values associated with the avoided carbon costs. Note that the two baseload renewable resources do not start until after 2025, and the SULCPP ends before 2035, so they do not have Net Values in 2025 and 2035, respectively. As shown in the graph, the new resources show mostly negative net values, which aligns with the increasing COS_{LN} results shown earlier in this chapter. However, the Solar+Solar resource stands out with a break-even net value in 2025 and positive net values thereafter. Additionally, Cabazon shows a positive net value after 2030. The SULCPP has a negative net value in its two snapshot years but is not prohibitive from a cost of service perspective. The contract premium above market for this resource is reasonable given that it provides a shaped energy product during the expensive summer on-peak period, and the energy is essentially GHG-free.

While the net value analysis for these resources looks encouraging under the assumption of normal contract pricing, an important consideration is the impact that significantly increased pricing for these new resources can have on their net values. To study this impact, the contract pricing for the SULCPP, Baseload 2027, and Baseload 2029 was increased by 50%; the resulting net value estimates for these resources are also shown in Figure 13.6.1. As shown in the graph, increasing contract prices by 50% significantly changes the net value proposition for these resources. The revised net values for the new baseload renewable and SULCPP resources become significantly negative. Negative net values of these magnitudes can cause significant upward pressure on RPU's cost of service and may warrant consideration of alternative demand-side resources, such as expanded energy efficiency programs (see Chapter 14).

13.6.3 Alternative Net Value Results (after including Avoided Carbon Costs)

Figure 13.6.2 shows the net values for the five new resources inclusive of their respective Avoided Carbon Costs. As carbon-free resources, each MWh of energy they generate is a MWh that RPU does not have to purchase from unspecified carbon-emitting resources, which carry a carbon emission factor of 0.428 MT/MWh. By not purchasing energy from carbon-emitting resources, RPU does not have to surrender carbon allocations that are valued at the forward carbon price curve (see Table 7.3.1). Therefore, each resource's Avoided Carbon Cost is a function of its annual generation, the 0.428 MT/MWh emission factor for unspecified resources, and the carbon price curve. When calculating the Avoided Carbon Cost on a $/kWh basis, the calculation simplifies to the following equation:

$$\textit{Avoided Carbon Cost (\$/kWh)} = (0.428 * \textit{Carbon Price}) / 1000 \qquad \text{[Eq. 13.7]}$$

As shown in the graph, the Avoided Carbon Costs represent significant value to GHG-free resources. Compared to Figure 13.6.1, the five new resources now either come close to breaking even or have positive net values under normal pricing. Additionally, when the contract pricing for the SULCPP, Baseload 2027, and Baseload 2029 is increased by 50%; the resulting net value estimates are not as pronouncedly negative as before. That being said, these negative net values would still be expected to cause upward pressure on RPU's cost of service and could warrant consideration of alternative load reduction (EE) programs.

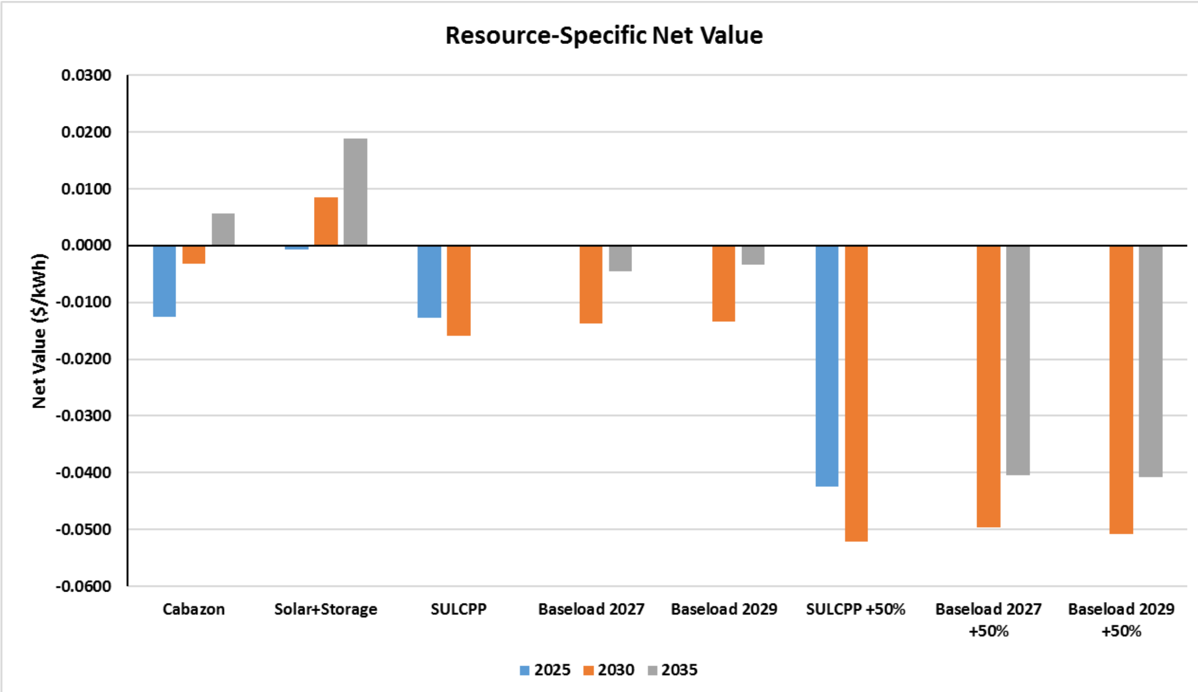


Figure 13.6.1. Resource-specific net values for RPU's future renewable/GHG-free resources under normal and high pricing.

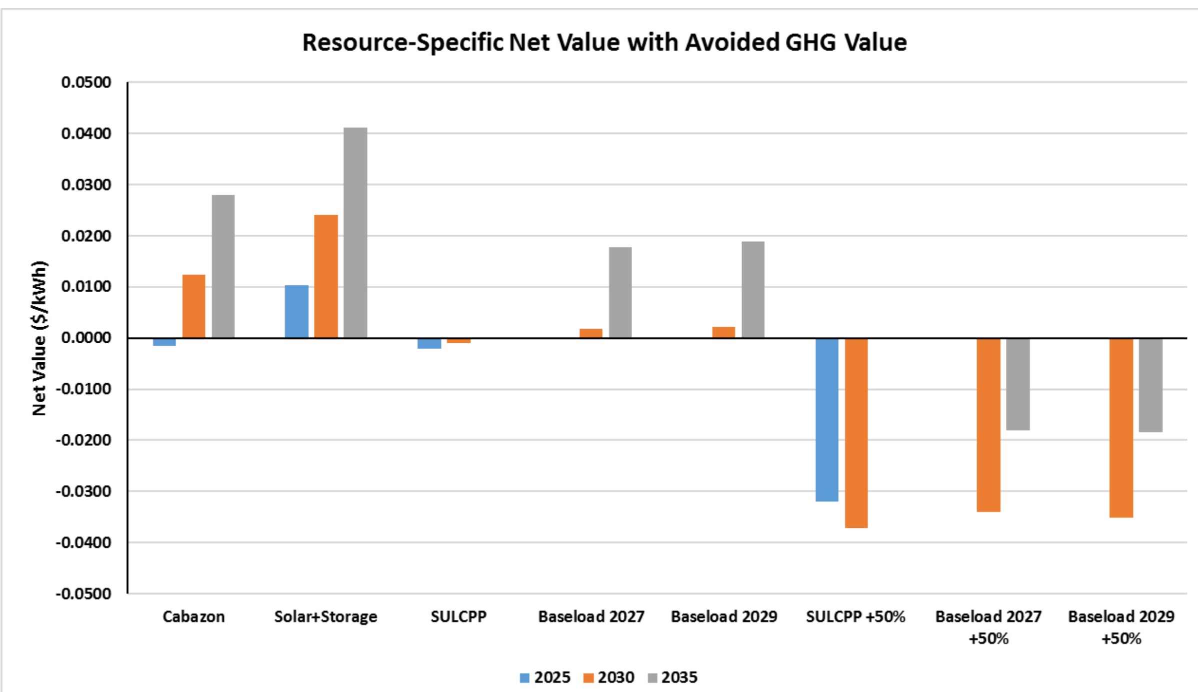


Figure 13.6.2. Resource-specific net values with avoided GHG value for RPU's future renewable/GHG-free resources under normal and high pricing.

13.7 Net Value Analysis: IPP Repowering Project

As discussed in Section 12.3, RPU is also analyzing the net value associated with its 4.167% or 35 MW share of the IPP Repowering Project, which is planned as an 840 MW NGCC. To perform this analysis, the most recent operating parameter assumptions and cost estimates for the project, as shown in Table 13.1.8, were used to quantify a reasonable estimate of net value of the project to RPU.

The net value calculation for the IPP Repowering Project follows the same general methodology as discussed in Section 13.6.1. Specifically, the Ascend Production Cost Modeling software simulated the project's net revenue, and additional value streams that the project could provide were added. For this project, RA is the only additional value that was included. The RA value calculation again used $4.50/kW-month escalating at 3% per year as the market RA value, and because the project is a baseload resource, staff assumed it would receive its full 35 MW share as RA credit.

However, the project also has some additional fixed costs that needed to be included in the net value calculation. These costs are separate and in addition to the project's direct operating costs. Specifically, RPU will also have to pay its proportionate share of decommissioning costs related to the existing IPP coal project, gas pipeline-related costs, and STS upgrade costs. RPU's share of the STS upgrade costs were assumed to be recoverable through RPU's Transmission Revenue Requirement (TRR), so they were not factored into this analysis. RPU's share of the decommissioning and gas pipeline costs are derived and presented in Table 13.7.1 and Table 13.7.2 below. The decommissioning and gas pipeline costs were combined with the project's net revenue and RA value to derive the project's net value to RPU.

Table 13.7.1. Estimation of RPU's annual decommissioning costs associated with the IPP coal project.

Total Decommissioning Costs ($)	260,000,000
Debt Rate (%)	4.00
Debt Term (years)	20
Annual Debt Service ($)	19,131,255
Total Project Size (MW)	840
RPU's Project Share (%)	4.167
RPU's Annual Debt Service Share ($)	**797,199**

Table 13.7.2. Estimation of RPU's annual costs associated with the gas pipeline for the IPP Repowering Project.

Gas Pipeline Annual Transporter Cost ($)	25,200,000
RPU's Project Share (%)	4.167
RPU's Annual Gas Pipeline Cost ($)	**1,050,084**

13.7.1 IPP Repowering Project Net Value Results

Figure 13.7.1 shows the net value results for the IPP Repowering Project alongside the net value results for the new renewable/GHG-free resources that were presented in Figure 13.6.1. As shown in the graph, the IPP Repowering Project has a negative net value in 2030 and 2035, meaning it will directly increase RPU's power resource costs and consequently RPU's cost of service. This impact is particularly noticeable in 2035, when the expected significant carbon costs associated with this repowered project energy begin to more materially impact the all-in energy cost.

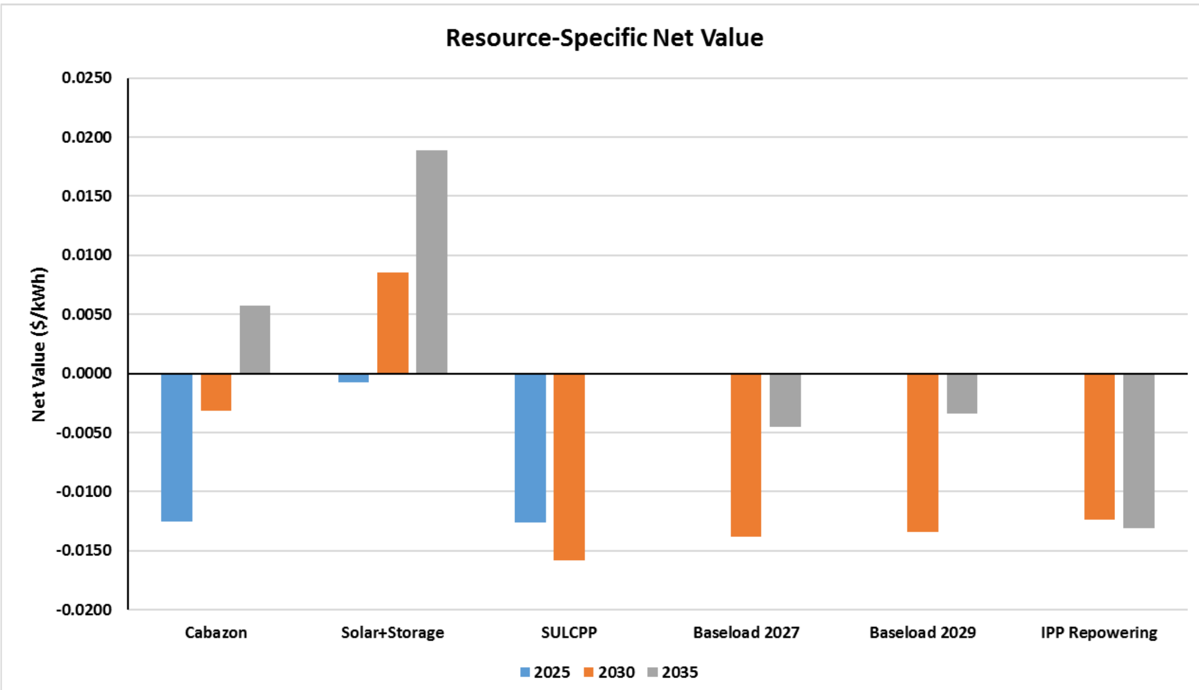


Figure 13.7.1. Resource-specific net values for RPU's future renewable/GHG-free resources under normal/high pricing and the IPP Repowering Project.

13.8 Net Value Analysis: LMS100

As a potential alternative to the IPP Repowering Project, staff also performed a net value analysis for a tolling agreement with a LMS100 gas plant located in Southern California (also discussed in Section 12.3). Under this potential tolling agreement, RPU would toll one 100 MW LMS100 unit for 10 years beginning in August 2023.

RPU modeled the LMS100 generation asset in the Ascend Production Cost Modeling Software with the operating specifications and operating cost estimates shown in Table 13.1.9. Additionally, RPU assumed that it would procure forward fixed price natural gas at a 5% premium above the market forward price for the plant's operation. Specifically, RPU would purchase forward natural gas contracts for 7,500 MMBtu/day in Q1, 5,000 MMBtu/day in Q2, and 10,000 MMBtu/day in Q3 and Q4.

Again, the net value calculation for the LMS100 tolling agreement followed the same general methodology as discussed in Section 13.6.1. For this particular tolling agreement, two additional values were added to the net revenue. First, the LMS100 should qualify for 100 MW of Flexible RA credit, which is worth more than System RA in the market. Therefore, the LMS100's 100 MW of RA credit was valued using a higher market price curve, starting at $6.00/kW-month in 2018 and escalating at 3% per year thereafter. Second, the LMS100 is capable of providing Ancillary Services – Spin, Non-Spin, Regulation Up, and Regulation Down – in the CAISO market, which could produce additional value streams for RPU. RPU's production cost modeling software is currently not set up to simulate and value Ancillary Service participation, so in order to account for the added value potential, staff assumed that the LMS100's Ancillary Service revenue would equal 25% of its simulated generation net revenue, or roughly $900,000 per year. The final net value for the LMS100 tolling agreement includes these values and accounts for the additional cost of procuring forward natural gas hedges at a 5% premium to market.

13.8.1 LMS100 Net Value Results

Figure 13.8.1 shows the net value results for the LMS100 Tolling Agreement alongside the net value results for all the resources presented in Figure 13.7.1. As shown in the graph, the LMS100 has a positive net value in 2025 and 2030 under its current pricing assumptions and appears to represent an economically viable shorter-term alternative to the IPP Repowering Project. Hence, a more detailed investigation and modeling of this Tolling Agreement is potentially warranted, especially if the utility is interested in pursuing an alternative to the IPP natural gas generation Repowering Project.

13.9 Summary of Key Findings

This chapter has reviewed how RPU resource planning staff conducts long term portfolio studies and uses these results to derive COS_{LN} metrics for each study under consideration. Staff has specifically focused on the scenarios described in Table 13.1.1; the bulk of which were focused towards determining the cost impacts related to increasingly more aggressive carbon reduction strategies. Staff also quantified the COS_{LN} risk components associated with each scenario; in order to better understand the combined cost + risk components of each reduction strategy.

In addition to these analyses, staff defined and quantified various net value metrics for each generation asset under consideration in the various studies, in addition to two relevant natural gas generation assets (the IPP Repowering Project and the LMS100 Tolling Agreement, respectively). These net value metrics provide further insight into the budgetary impacts and/or financial viability of each proposed generation asset at various future points in time.

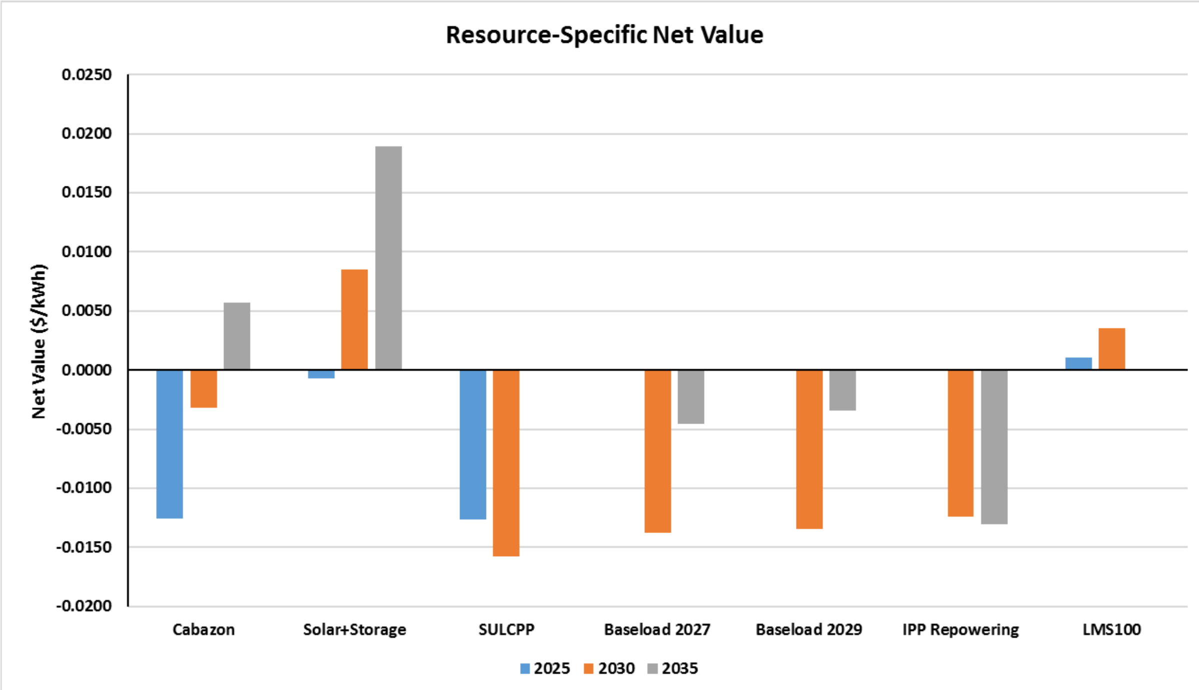


Figure 13.8.1. Resource-specific net values for RPU's future renewable/GHG-free resources under normal/high pricing, the IPP Repowering Project, and the LMS100 Tolling Agreement.

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

1. Based on a careful analysis of RPU's primary cost of service components, staff project that the utility's power resource costs will grow at about 1.1% annually between 2020 and 2035, while the utilities all-other costs will grow slightly faster; i.e., 1.4% annually in this same time period. Overall, given that the power resource costs represent more than one half of the total utility budget, the Baseline Portfolio COS_{LN} growth rate is forecasted to be about 1.2% per year.

2. In the Baseline Portfolio, sufficient new renewable resources are acquired in the early part of the next decade to ensure that RPU could (1) meet a 50% by 2030 RPS mandate (using a combination of Excess Procurement credits and additional Tradable REC purchases), and (2) reach a 2030 GHG emission level of approximately 617,000 metric tons.

3. In the 53MMT Sector Target Portfolio, sufficient new renewable resources are acquired throughout the next decade to ensure that RPU could (1) meet a 60% by 2030 RPS mandate (using either Excess Procurement credits or additional Tradable REC purchases), and (2) reach a

2030 GHG emission level of approximately 446,000 metric tons. Note that this emission level is well below the utility's official 2030 GHG planning target (i.e., 486,277 MT CO_2-e).

4. In the 42MMT Sector Target Portfolio, sufficient new renewable resources are acquired throughout the next decade to ensure that RPU could (1) exceed a 60% by 2030 RPS mandate (based solely on new renewable energy purchases), and (2) reach a 2030 GHG emission level of approximately 350,000 metric tons. Note that this emission level is comfortably below the utility's aspirational 2030 GHG planning target of 385,137 MT CO_2-e.

5. The corresponding COS_{LN} calculations for these studies suggest that the 53MMT scenario would result in about a 1.5% increase in total customer energy costs in 2030 over the expected energy costs in the Baseline Portfolio. Likewise, the 42MMT scenario would result in about a 2.6% increase in total customer energy costs in 2030 over the Baseline Portfolio. However, after adding in the corresponding risk components to each scenario, these combined energy cost + risk increases reduce to 0.6% and 1.2%, respectively. (See Tables 13.5.1, 13.5.2, and Figure 13.5.5.)

6. Overall, even in the absence of the risk adjustment, the expected cost increases associated with the 53MMT and 42MMT portfolios are relatively minor. This suggests that RPU should at least be able to achieve its official 2030 GHG planning target without significant rate stress, and perhaps even reach its aspirational target. However, these results depend strongly on the assumed future pricing for renewable energy assets; for example, a 50% increase in renewable energy costs would make these targets much more difficult to reach.

7. The corresponding asset specific net value analyses show that most of the studied renewable assets exhibit marginally negative net values (other than the Solar PV + Storage contract), in the absence of any additional avoided carbon credits. However, the consideration of such credits shifts all of the net value calculations up by about $0.015/kWh in 2030 and by about $0.020/kWh in 2035.

8. Finally, these same asset specific net value analyses suggest that the IPP Repowering Project exhibits clearly negative net values in both 2030 and 2035. In contrast, the LMS100 Tolling Agreement exhibits slightly positive net values in 2025 and 2030, suggesting that this latter tolling arrangement represents a more financially viable (and hence justifiable) shorter-term strategy for replacing part of the expiring IPP coal contract.

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 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).

14.1 Avoided Energy (VOAE) Cost 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 for the energy the participating customer is not consuming – this is the value of avoided energy (VOAE). 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 benefit 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 VOAE costs from customer adopted EE measures. The approach proposed here is conceptually similar to the methodology in the CPUC Distributed Energy Resource avoided cost tool. The methodology for the various cost components discussed in that tool are adapted here to better reflect RPU's actual avoided costs and revenue losses associated with the EE program. This specific discussion focuses on valuing the

[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.

average avoided cost impact of multiple customer EE measures grouped into three broad EE measure categories: Baseload, Lighting, and HVAC categories. This methodology can also in principle be used to value a specific EE measure.

14.2 Conceptual Avoided Cost Components (Benefits Resulting from EE Measures)

Within the RPU service territory, the following avoided cost components comprising the measure of benefits should be recognized, analyzed and (if appropriate) valued, when computing the implied VOAE:

- Generation energy
- Generation capacity
- Ancillary services
- Transmission costs
- Distribution costs
- Environmental/GHG costs
- Avoided RPS costs
- System losses

As a publically owned municipal utility, RPU should endeavor to accurately value as many of these avoided costs as reasonably possible in order to determine an accurate VOAE estimate for each EE category. This being said, RPU must also recognize that not all of these proposed avoided costs actually exist within the distribution system. With respect to the eight avoided cost categories listed above, reasonably objective methodologies are proposed for appropriately valuing five of these components (e.g., generation energy, generation capacity, environmental/GHG costs, avoided RPS costs, and system losses). However, staff is currently unable to identify any avoided costs associated with two categories (ancillary services and transmission costs). Additionally, the calculation of RPU's avoided distribution system costs is quite complicated and typically location specific. To address this, a generic cost estimates for this category is used (in place of any analytically derived estimates). Further justification concerning the assessment of each of these avoided cost components is described below.

Avoided Generation Energy Costs

Every kWh of energy reduced due to an EE measure represents one less kWh of energy that RPU must supply. Thus, the value of this energy should be recognized in any avoided cost calculation.

Avoided Generation Capacity Costs

To the extent that an EE measure reduces energy during peak energy needs, RPU can expect to achieve savings in its system resource adequacy (RA) costs. Additionally, RPU's local RA requirement should also decrease as additional EE measures are adopted. Both of these avoided costs should be recognized and quantified in the avoided cost calculation.

Ancillary Services

RPU receives no identifiable ancillary service benefits as more customers implement EE measures within the RPU service territory. In general, RPU receives minimal ancillary service revenues from the CAISO for internal generation assets and pays very minimal CAISO ancillary service uplift costs. Staff therefore recommends that a zero value 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 the utility's system load. However, RPU's transmission revenue requirement (TRR) payments are also based upon the same MWh system load, and this $/MWh payment currently exceeds the CAISO TAC rate. Basically, RPU receives more revenue from transmission than it receives in transmission costs. Therefore, RPU receives no avoided transmission cost benefits due to reductions in system load and hence staff recommends that a zero value be assigned to this avoided cost component.

Avoided Distribution Costs

In theory, RPU should be able to potentially avoid (or at least defer) specific distribution upgrade costs if the load is reduced on a circuit at or near its maximum capacity. However, RPU does not currently possess the ability to accurately quantify these costs. As such, staff instead recommends using generic avoided cost estimates for this cost category, where these estimates depend upon the particular EE program categories.

Avoided Environmental/Greenhouse Gas (GHG) Costs

Under the Cap-and-Trade program, RPU must surrender GHG emission credits, called allowances, to CARB to offset carbon emissions from first importer generation assets and in-state generation resources that RPU either owns or is a contractual participant in. The value of these allowances represents an objective cost estimate of avoided GHG emissions in the marketplace. In principle, if an argument can be made that as additional EE savings "replace" the incremental purchase of non-zero emission system energy, an equivalent cost savings could be assigned to the avoided carbon in the (non-purchased) system energy. As such, the value of this avoided carbon footprint represents an additional avoided cost that can be directly attributed to the EE measure or program.

Conceptually, this value can be readily quantified. However, the above argument is based on an assumption that RPU would have met the extra load serving needs using system power having a carbon emission factor equal to the system average emission factor. This calculated avoided cost only represents an accurate (and by definition, socialized) 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 retail sales each year (for example, 25% in 2016). In principle, RPU will need to acquire proportionally less wholesale renewable energy as additional EE measures reduce the utility's system load serving needs. Hence, the value of this "avoided" wholesale renewable energy represents another avoided cost that can be directly attributed to an EE measure or program.

The problematic issue associated with this avoided cost component pertains to the appropriate valuation of the avoided wholesale renewable energy. Multiple valuation approaches can be proposed, and the appropriate approach will depend in part on the utility's current renewable energy position (i.e., is it long or short in renewable energy with respect to its current mandate). However, notwithstanding this issue, staff believes that this avoided cost should be recognized in the avoided cost calculation.

System Losses

Nearly all of the applicable cost components discussed above need to recognize the fact that customer EE measures directly impact the secondary distribution system, and thus are not subject to the various transmission and high voltage distribution system losses that affect 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.

14.3 Avoided Cost Calculation Methodology

Based on the above avoided cost components, a practical VOAE 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, carbon, RPS, and distribution 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 of this information has been quantified, VOAE 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 2018 monthly market energy costs used to value the avoided energy patterns. Note that these estimates remain the same for the Residential (RES) and Commercial + Industrial (Comm/Indst) customer classes within each EE program category. 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 some of these estimates change across customer classes within each EE program category, respectively.

Table 14.3.1. Avoided cost components for use in the VOAE 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 or heavy-load 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.
Environmental (Carbon Credit)	ARB Carbon clearing prices (last four quarters) + 7% cost adder. CAISO system average emission factor (EF).	Greater of prior year's average ARB Carbon clearing prices + 7% cost adder or current year's floor price, multiplied by the CAISO average emission factor.
RPS Credit	Delta price difference (SP15 energy forecast - average renewable pricing in RPU portfolio). Annual RPS target (proportion).	Delta price difference between SP15 energy forecast and average renewable pricing in RPU portfolio, multiplied by RPS target
Distribution	Use default avoided cost estimates for each corresponding EE program.	Assume $0.01/kWh avoided costs for Baseload and Lighting programs, and $0.02/kWh avoided costs for HVAC programs (across all customer classes).
System Losses	Average distribution loss factor (proportion).	Divide sum of $/kWh components (Energy, Capacity [system and local], Carbon, RPS credit, and Distribution) 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 and 2018 forward market energy costs ($/MWh) for Baseload, Lighting and HVAC EE programs.

Month	Seasonal avoided energy pattern			SP15 Flat or HL market energy costs		
	Baseload	Lighting	HVAC	Baseload	Lighting	HVAC
Jan	0.0833	0.0970	0	$36.34	$36.34	$40.15
Feb	0.0833	0.0933	0	$33.11	$33.11	$34.35
Mar	0.0833	0.0858	0	$26.37	$26.37	$27.25
Apr	0.0833	0.0784	0.0196	$23.40	$23.40	$24.40
May	0.0833	0.0746	0.0649	$23.47	$23.47	$24.75
Jun	0.0833	0.0709	0.1551	$30.51	$30.51	$33.25
Jul	0.0833	0.0709	0.2492	$34.59	$34.59	$38.45
Aug	0.0833	0.0746	0.2650	$36.48	$36.48	$40.15
Sep	0.0833	0.0784	0.1782	$34.62	$34.62	$38.10
Oct	0.0833	0.0858	0.0680	$34.47	$34.47	$36.90
Nov	0.0833	0.0933	0	$32.31	$32.31	$34.65
Dec	0.0833	0.0970	0	$33.67	$33.67	$36.10

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	0.8	1.0	0.0	0.8	1.0	0.0
Feb	0.8	1.0	0.0	0.8	1.0	0.0
Mar	0.8	1.0	0.0	0.8	1.0	0.0
Apr	0.8	0.7	0.5	0.8	1.0	0.5
May	0.8	0.4	1.0	0.8	1.0	1.0
Jun	0.8	0.1	1.0	0.8	1.0	1.0
Jul	0.8	0.1	1.0	0.8	1.0	1.0
Aug	0.8	0.1	1.0	0.8	1.0	1.0
Sep	0.8	0.1	1.0	0.8	1.0	1.0
Oct	0.8	0.5	1.0	0.8	1.0	1.0
Nov	0.8	1.0	0.0	0.8	1.0	0.0
Dec	0.8	1.0	0.0	0.8	1.0	0.0
Annual CF	65%	35%	15%	75%	65%	20%

Table 14.3.4. Final VOAE cost calculations for Baseload, Lighting, and HVAC EE programs, by customer class. (Detailed calculations presented in Appendix E, Tables E.1 through E.6.)

Customer Class	Baseload	Lighting	HVAC
Residential class	$0.0702/kWh	$0.0695/kWh	$0.0964/kWh
Comm/Indst class	$0.0698/kWh	$0.0712/kWh	$0.0926/kWh

After quantifying all of these assumptions and avoided cost estimates, VOAE estimates can be calculated for each EE program category and customer class. The detailed calculations supporting each VOAE estimate are shown in Appendix E, Tables E.1 through E.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.

14.4 Unmet Revenue Calculations for Energy Efficiency Programs

Similar to the VOAE 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 have to be transferred to non-participating customers. The approach proposed here is fairly 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.

14.4.1 RPU Rate Schedules

Table 14.4.1 shows the current rate schedules for RPU's four primary customer classes: Domestic Residential (DOM), Commercial Flat (CF), Commercial Demand (CD), and Industrial TOU (TOU). Unmet revenue impacts can be estimated from these rate schedules, once certain assumptions are made about how the corresponding reduced electricity usage patterns distribute across customers. For example, consider the Domestic Residential customer class. An analysis of RPU's Residential bills over the last three years indicates that on average 62.3%, 26.5% and 11.2% of the utility's customer's highest energy usage falls into tiers 1, 2, and 3, respectively. Thus, for both the Baseload and Lighting EE categories, a reasonable unmet revenue estimate (URE) can be calculated as:

$$DOM.URE \ = \ 0.623(0.1035) + 0.265(0.1646) + 0.112(0.1867) \ = \ \$0.1290/kWh \quad \text{[Eq. 14.1]}$$

where Eq. 14.1 implicitly assumes that the adopted individual EE measures within each Baseload and Lighting EE category are uniformly distributed across the DOM customer class.

Table 14.4.1. Current rate schedules for the four primary customer classes: Domestic Residential (DOM), Commercial Flat (CF), Commercial Demand (CD) and Industrial TOU (TOU).

Customer Class	Tariff Component	Details	Rate
Domestic Residential	Customer	all customers	$8.06
	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	$0.1035
		Summer Tier 2: 751-1500 kWh	$0.1646
		Summer Tier 3: > 1500 kWh	$0.1867
		Winter Tier 1: 0-350 kWh	$0.1035
		Winter Tier 2: 351-750 kWh	$0.1646
		Winter Tier 3: > 750 kWh	$0.1867
Commercial Flat	Customer	all customers	$20.50
	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	$0.1351
		Tier 2: > 15,000 kWh	$0.2064
Commercial Demand	Reliability	all customers	$90.00
	Minimum Demand	first 20 kW or less	$209.65
	Excess Demand	all excess kW (> 20)	$10.48
	Energy	Tier 1: 0-30,000 kWh	$0.1111
		Tier 2: > 30,000 kWh	$0.1217
Industrial TOU	Customer	all customers	$704.66
	Reliability	all customers	$1,100.00
	Energy	On-peak, per kWh	$0.1033
		Mid-peak, per kWh	$0.0828
		Off-peak, per kWh	$0.0727
	Demand	On-peak, per kW	$6.88
		Mid-peak, per kW	$2.74
		Off-peak, per kW	$1.31

14.4.2 Reduced Energy Usage Patterns

Table 14.4.2 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 a three-year 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 14.4.2. 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)	Summer Tier 1: 0-750 kWh	-	39.8%
	Summer Tier 2: 751-1500 kWh	-	44.3%
	Summer Tier 3: > 1500 kWh	-	15.8%
	Winter Tier 1: 0-350 kWh	-	32.8%
	Winter Tier 2: 351-750 kWh	-	46.0%
	Winter Tier 3: > 750 kWh	-	21.2%
	Tier 1 (annual average)	62.3%	-
	Tier 2 (annual average)	26.5%	-
	Tier 3 (annual average)	11.2%	-
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%

In order 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 14.4.3. 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 of 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.

In addition to lost revenue from avoided energy charges, the CD and TOU customer classes will also show a revenue loss from avoided demand charges. The annual savings in demand charges per kW of installed EE were estimated for each EE category / customer class combination; these estimates are shown in Table 14.4.4. Upon dividing these estimates by the number of annual hours that the EE measures are expected to impact (see the annual capacity factors in Table 14.3.3), it is possible to determine the equivalent $/kWh values for these avoided demand charges. Adding these values back to the corresponding avoided energy charges then yields the final, total $/kWh unmet revenue estimates for each of these four customer classes.

Table 14.4.3. 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%

Table 14.4.4. Estimated annual demand charges saved per kW by EE measure category.

EE Measures	Demand Impact Components	Value
Commercial Demand (Baseload)	Annual Demand Savings ($) per kW	$100.61
	Number of Hours per Year	6570
	Ratio (kWh adder to unmet rev est.)	$0.0153
Commercial Demand (Lighting)	Annual Demand Savings ($) per kW	$125.76
	Number of Hours per Year	5694
	Ratio (kWh adder to unmet rev est.)	$0.0221
Commercial Demand (HVAC)	Annual Demand Savings ($) per kW	$68.12
	Number of Hours per Year	1752
	Ratio (kWh adder to unmet rev est.)	$0.0389
Industrial TOU (Baseload)	Annual Demand Savings ($) per kW	$104.93
	Number of Hours per Year	6570
	Ratio (kWh adder to unmet est.)	$0.0160
Industrial TOU (Lighting)	Annual Demand Savings ($) per kW	$115.44
	Number of Hours per Year	5694
	Ratio (kWh adder to unmet est.)	$0.0203
Industrial TOU (HVAC)	Annual Demand Savings ($) per kW	$46.70
	Number of Hours per Year	1752
	Ratio (kWh adder to unmet rev est.)	$0.0267

14.5 Calculated Net Unmet Revenue Impacts

Upon performing all of the necessary avoided energy and demand calculations, the final $/kWh unmet revenue estimates for each customer class and EE category can be produced. This unmet revenue represents costs the utility bears that are not avoided by the energy savings resulting from the EE programs. Table 14.5.1 and Figure 14.5.1 show these unmet revenue estimates, along with the previously derived VOAE estimates for the same customer class - EE measure category combinations. The computed differences represent the corresponding net unmet revenue estimates. As such, these represent a lower bound on the costs passed onto our non-participating customers by each EE program, respectively.

The following are the key take-away points from Table 14.5.1 and Figure 14.5.1. First, none of the EE program categories are revenue neutral for any of the four primary customer classes. This should not be that surprising, since RPU's energy rates are designed to collect all of the utility's fixed operating costs (i.e., infrastructure, personnel, and O&M), in addition to its variable power supply costs.

Second, the EE programs for Industrial TOU customers appear to be $0.02/kWh to $0.03/kWh less expensive (on an unmet revenue basis) than any of the EE programs for the remaining customers. This implies that on a total cost basis, RPU can lower the amount of unmet revenues by investing proportionally more of its EE expenditures in this customer class.

Table 14.5.1. 2018 unmet revenue estimates by customer category and EE measure category.

Customer Class	EE Measure Category	Cost Unmet Revenue ($/kWh)	Benefit VOAE ($/kWh)	Delta ($/kWh)	Benefit/Cost Ratio
Residential	Baseload	$0.1290	$0.0702	$0.0588	0.54
	Lighting	$0.1290	$0.0695	$0.0595	0.54
	HVAC	$0.1446	$0.0964	$0.0482	0.67
Comm Flat	Baseload	$0.1365	$0.0698	$0.0667	0.51
	Lighting	$0.1365	$0.0712	$0.0653	0.52
	HVAC	$0.1365	$0.0926	$0.0439	0.68
Comm Demand	Baseload	$0.1277	$0.0698	$0.0579	0.55
	Lighting	$0.1345	$0.0712	$0.0633	0.53
	HVAC	$0.1513	$0.0926	$0.0587	0.61
Industrial TOU	Baseload	$0.0984	$0.0698	$0.0286	0.71
	Lighting	$0.1054	$0.0712	$0.0342	0.68
	HVAC	$0.1236	$0.0926	$0.0310	0.75

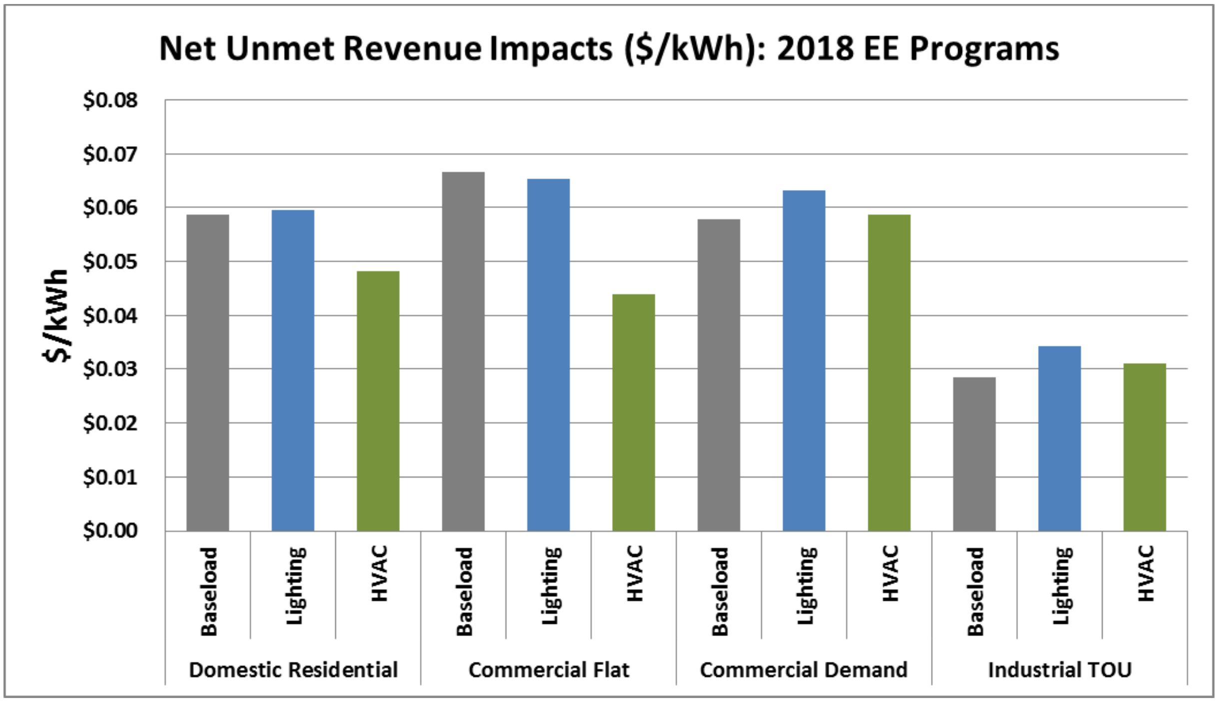


Figure 14.5.1. Net unmet revenue impacts by customer class and EE measure type ($/kWh).

Third, while every effort has been made by staff to derive reliable and analytically based estimates, it should still be emphasized that these values still encompass a fair amount of uncertainty. Realistically, the uncertainties around the delta differences may be as high as ± 30%. These uncertainties should be recognized if/when these differences are used for integrated resource planning purposes.

Finally, to determine the cost effectiveness of higher EE program activities (for achieving specific carbon reduction goals), these unmet revenue differences can be directly compared to the net value estimates for individual renewable energy projects. More specifically, note that (the negative value of) a demand-side unmet revenue estimate and a supply-side net value estimate measure the exact same economic variable; i.e., the overall cost-effectiveness of the proposed project or measure. Hence, these estimates are directly comparable, provided that they reference the same point in time and result in equivalent amounts of carbon reduction.

14.6 Assessing the Cost Effectiveness of Supply-side versus Demand-side Resources

The last paragraph in section 14.5 is worth expanding on. More specifically, from a resource planning perspective, a utility should always seek to find the least cost, least risk solution to whatever regulation or mandate that it must fulfill. With respect to carbon reduction, a utility can reduce its carbon footprint by either encouraging its customers to reduce their demand, or meeting such demand with lower carbon resources. Essentially, this represents the classic demand-side versus supply-side optimization problem that all resource planning professionals must continuously assess.

As discussed in detail in Chapter 13, the advantage of the project specific "net value" calculations is that these numbers allow one to directly compare and determine the cost-effectiveness of each proposed supply-side resource. Additionally, as mentioned above in section 14.5, the negative value of an EE unmet revenue estimate is exactly the same as a net value estimate. Hence, these estimates can be directly compared to each other, provided that they are referenced to the same point in time. Such a comparison immediately reveals the overall cost effectiveness of each asset or measure. For example, if serving the same amount of load with a higher percentage of renewable energy results in a net value estimate that exhibits a larger $/kWh impact estimate than a specific EE program estimate, then the purchase of this renewable energy should be favored over increasing those corresponding EE program activities.

An example of projected 2030 net unmet revenue estimates for the HVAC EE category is shown in Table 14.6.1. By projecting these net unmet revenue estimates out to 2030, it is now possible to directly compare them to the 2030 net value estimates for the supply-side (renewable energy) resources that were previously derived and discussed in Chapter 13 (see Figure 13.6.3). This comparison is shown in Figure 14.6.1 on the next page. This comparison clearly shows that the expected future costs of the modeled renewable energy assets are currently low enough to make these new renewable energy contracts the preferred (i.e., least cost) solution for reducing RPU's total carbon footprint. (These renewable energy asset net value estimates are shown as the blue bars in the bar chart.) However, if the expected costs of the post-2025 assets increase by 50% (purple bars), then these purchases would no longer necessarily represent the least cost solution when compared to the HVAC EE measures (green bars). For example, the HVAC EE measure for the Industrial TOU customer class would now actually be the least cost option, and thus represent the preferred resource for reducing carbon, etc.

Currently, RPU is unable to offer any bundled set of EE measures that produce positive net value estimates; unfortunately, all of the EE measures result in net lost revenue to the utility (and thus within class subsidies). Therefore, provided that RPU can identify and contract for supply-side renewable resources at reasonable costs, staff will continue to recommend that the utility first try to fulfill its 2030 carbon reduction mandates through the procurement of new renewable contracts. However, RPU is still committed to achieving its adopted 1% per year EE savings goals. Additionally, the utility regularly reassesses the net value of all supply-side and demand-side resources, so that this information can be incorporated into RPU's ongoing integrated resource planning process and optimized resource procurement strategy.

Table 14.6.1. Projected 2030 unmet revenue estimates by customer category for the HVAC EE category.

Customer Class	EE Measure Category	Cost Unmet Revenue ($/kWh) (1)	Benefit VOAE ($/kWh) (2)	Delta ($/kWh)	Benefit/Cost Ratio
Residential	HVAC	$0.1983	$0.1446	$0.0537	0.73
Comm Flat	HVAC	$0.1872	$0.1392	$0.0480	0.74
Comm Demand	HVAC	$0.2075	$0.1392	$0.0683	0.67
Industrial TOU	HVAC	$0.1695	$0.1392	$0.0303	0.82

(1) Calculated from Table 14.5.1., assuming that RPU rates increase by 3% annually through 2022 and then at 2.5% annually thereafter.

(2) Calculated using 2030 cost projections consistent with previously discussed IRP modeling assumptions; see Appendix E, Tables E.7 and E.8 for further details.

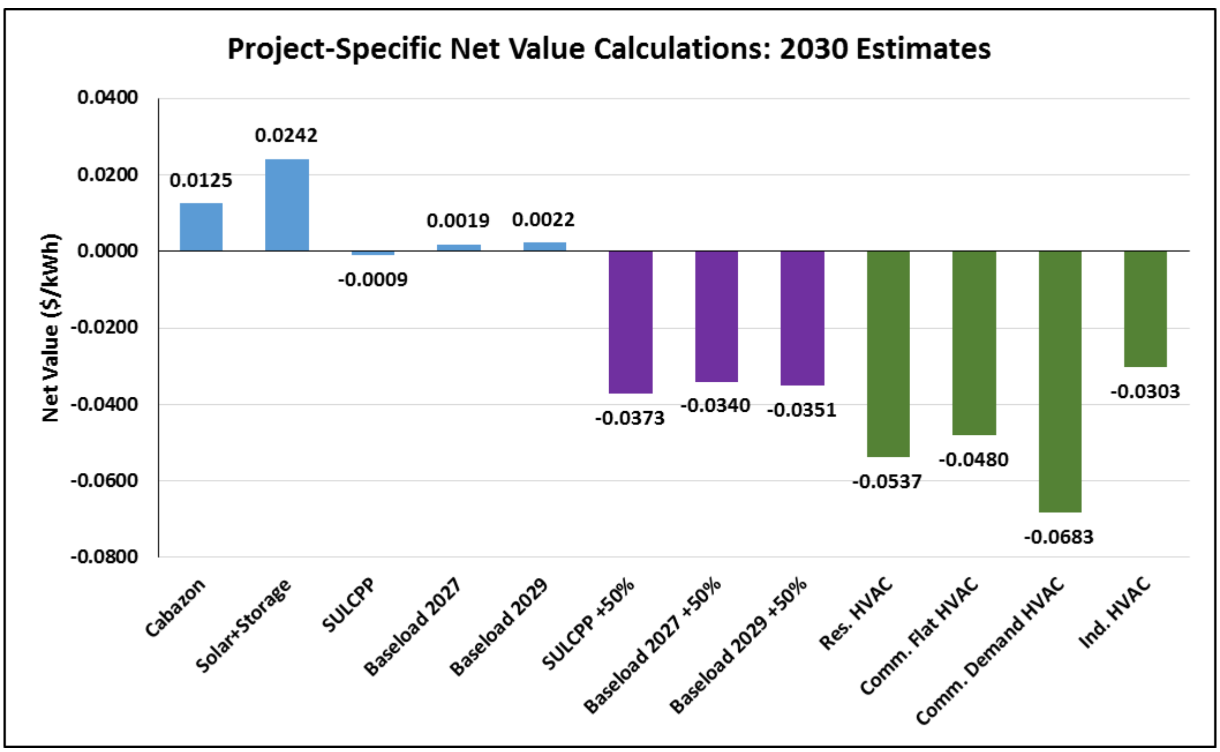


Figure 14.6.1. Comparison of demand-side (HVAC) to supply-side (proposed renewable resources) net value estimates; CY 2030 projections.

15. Energy Storage

This chapter presents a financial viability assessment of energy storage (ES) as a stand-alone utility asset. Before RPU can procure viable and cost-effective batteries as stand-alone assets, the utility must evaluate a variety of battery characteristics under specific CAISO operating requirements. To help with this evaluation, the utility retained the services of ES consulting staff at Ascend Analytics.

The Ascend staff performed multiple ES assessment studies designed to answer the following two questions for RPU:

- What types of batteries (in terms of power and duration) are most economic to operate under CAISO market conditions?
- In which CAISO markets and to what degree is it most economic to participate with batteries?

Ascend staff used these studies to compare annual returns on batteries ($/kWh) across battery types and across markets. This chapter describes these studies in detail and presents their general summary of findings.

15.1 CAISO Market Regulations for Storage Participation

The CAISO has adopted the Non-Generating Resource (NGR) model to allow for the participation of "Limited Energy Storage Resources", such as batteries and flywheels, in the wholesale energy and ancillary services markets. This model allows for both positive and negative energy bids as the battery can be either discharging and providing energy to the grid or charging and absorbing energy from the grid. The model also includes the battery's state of charge (SOC) and limits on the state of charge.

The CAISO offers a Regulation Energy Management (REM) program for NGRs where the ISO manages the SOC within the resource's limits while it participates in regulation. In this program, the resource can bid up to the power it can provide for 15 minutes given its rated energy, but its participation is limited to regulation up and down products.[1] The election to participate in this program can only be changed on a monthly basis.[2] If the resource chooses not to participate in the REM program, it is subject to higher minimum continuous energy requirements. There is a 30-minute continuous energy requirement for day-ahead and real-time spin and non-spin bids as well as real-time regulation bids, and there is a 60-minute continuous energy requirement for day-ahead regulation bids for any resource not in the REM program.[3]

Although batteries are highly dispatchable (making them an ideal resource for quickly reacting to market signals and capturing price spikes), these minimum continuous energy requirements can force batteries to operate at sub-optimal levels. The following case studies are designed to calculate the impact of these requirements on annual returns, lifetime returns, and throughput.

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[1] CAISO Business Practice Manual for Market Operations, page 40.
[2] Xu, Bolun, Yury Dvorkin, Daniel S. Kirschen, C.A. Silva-Monroy, and Jea-Paul Watson. "A Comparison of Policies on the Participation of Storage in U.S. Frequency Regulation Markets". *Power and Energy Society General Meeting.* 2016.
[3] http://www.caiso.com/Documents/NGR-REMOverview.pdf

15.2 Modeling Inputs

15.2.1 Strategic Cases

The five case studies analyzed by Ascend are designed to both mimic RPU's primary options for operating a battery in the CAISO Market and identify the ideal market conditions for generating high battery revenues. Table 15.2.1 describes the characteristics of the five battery cases modeled by Ascend staff.

Table 15.2.1. The characteristics of the five battery cases modeled by Ascend Energy Storage Consulting staff.

Case		1		2		3		4		5	
Name		**Day-Ahead Ancillary Markets - Perfect Foresight**		**Day-Ahead Ancillary Markets and Real-Time Energy - Perfect Foresight**		**Day-Ahead Ancillary Markets and Real-Time Energy - Scheduled Participation**		**Day-Ahead Ancillary Markets and Real-Time Energy - Scheduled Participation plus Costless Adder**		**Real-Time Ancillary Markets plus Real-Time Energy**	
Battery		40MW/10 MWh	10MW/40 MWh	40MW/10 MWh	10MW/40 MWh	40MW/10 MWh	10MW/40 MWh	40MW/10 MWh	10MW/40 MWh	20MW/10 MWh	20MW/20 MWh
Duration		15 minute	4 hour	15 minute	4 hour	15 minute	4 hour	15 minute	4 hour	30 minute	1 hour
CAISO Minimum Continuous Energy Requirements	DA Regulation Up/Down	15 min		60 min		60 min		60 min		60 min	
	RT Regulation Up/Down	15 min		30 min		30 min		30 min		30 min	
	Spin and Non-Spin	NA		30 min		30 min		30 min		30 min	
Scheduled Participation		None		None		Fixed hour		Fixed hour		None	
Variable Cost		$0/MWh		$0/MWh		$0/MWh		$5/MWh		$0/MWh	
Costless Adder		$0/MWh		$0/MWh		$0/MWh		$95/MWh		$0/MWh	

15.2.2 Battery Parameters

Two main battery durations were modeled in the first four case studies: a 15-minute battery, typical for regulation participation, and a 4-hour battery, typical for resource adequacy and load shifting applications. A 30-minute battery and a 1-hour battery were also considered in case study #5, in light of the 30-minute continuous energy requirements for mixed participation in real-time energy and ancillary products. Modeling a 30-minute battery and a 1-hour battery allows the battery to bid full or half power (respectively) into the RT ancillary services market, better utilizing the battery's power. Table 15.2.2 shows the assumed battery parameter values used in all of the five case studies.

Table 15.2.2. Assumed battery parameter values used in all case studies.

Parameter	Value
Charging losses	5%
Discharging losses	5%
VOM	$0/MWh

For simplicity, no variable costs beyond the battery inefficiency were considered in Cases #1, #2, #3, and #5. However, a sensitivity case (Case 4) was also run with a $5/MWh variable cost and a $95/MWh costless adder in order to force trades only at price spikes in the real-time energy market.

15.2.3 Market Prices

The average annual day-ahead (DA) and real-time (RT) ancillary market prices used in all case studies are shown in the tables 15.2.3 and 15.2.4 below.

Table 15.2.3. Average annual historical DA ancillary prices used in all case studies.

Average DA Ancillary Prices				
Year	**RegUp**	**RegDown**	**Spin**	**NonSpin**
2013	$ 4.56	$ 3.25	$ 2.74	$ 0.20
2014	$ 5.41	$ 3.90	$ 3.34	$ 0.14
2015	$ 4.76	$ 3.08	$ 2.84	$ 0.30
2016	$ 8.21	$ 6.89	$ 4.39	$ 0.24
2017	$ 5.81	$ 3.51	$ 4.90	$ 0.09

Table 15.2.4. Average annual historical RT ancillary prices used in all case studies.

Average RT Ancillary Prices				
Year	**RegUp**	**RegDown**	**Spin**	**NonSpin**
2013	$ 2.27	$ 1.31	$ 0.53	$ 0.16
2014	$ 2.62	$ 1.04	$ 1.09	$ 0.19
2015	$ 2.36	$ 1.11	$ 0.70	$ 0.43
2016	$ 6.11	$ 4.19	$ 0.41	$ 0.03
2017	$ 5.40	$ 2.52	$ 1.32	$ 0.44

Over the last few years, the real-time SP15 energy prices have also experienced a significant number of price spikes (defined here as prices over $100/MWh). These price spikes provide the vast majority of RT energy revenue opportunities and were exclusively used for RT energy discharges in Case study #4 with the $5/MWh variable operating cost and $95/MWh costless adder. These price spikes were also used to determine the scheduled hours for energy market participation in the scheduled participation scenarios. Specifically, any hour in a month that experienced over five price spikes was set aside for RT energy market participation, as shown in Figure 15.2.1 below.

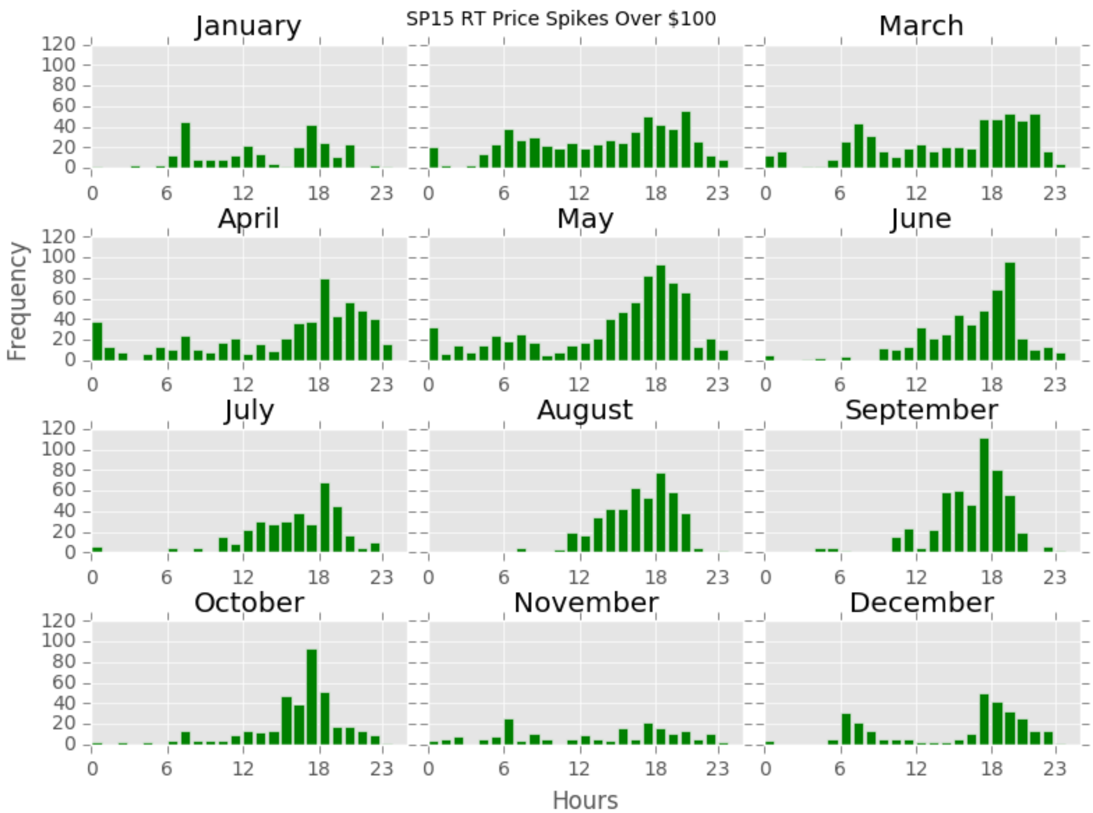

Figure 15.2.1. Frequency of RT prices spikes over $100/MWh by month for 2015**.**

15.2.4 Ancillary Product Dispatch

It is impossible to know for certain what the level of average power dispatched towards ancillary products should be in the CAISO market. Thus, Ascend staff assumed that the average power dispatched in the ancillary products was equal to 10% of the ancillary capacity bid, similar to the assumptions used in other studies.[4] When or if confirmatory ES studies are performed, this assumption should be further verified by examining a battery regulation dispatch signal from the CAISO.

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[4] Beer, Sebastian, Tomás Gómez, David Dallinger, Ilan Momber, Chris Marnay, Member, Michael Stadler, and Judy Lai. "An Economic Analysis of Used Electric Vehicle Batteries Integrated into Commercial Building Microgrids" *IEEE Transactions on Smart Grid*. March 2012.

15.3 Technical Modeling Details (High Level Overview)

In all five case studies, ES revenues were calculated using an optimization model that maximized the profits from the purchase and sale of energy across markets. This optimization model used a five-minute time step, corresponding to the settlement period in the CAISO RT energy market. Every battery configuration was also subject to physical storage and power constraints, which were in turn defined by the storage capacity and worst case charge and discharge rates for each scenario.

Additional constraints were built into the simulation studies in order to model the various CAISO market regulations. These additional constraints controlled the allowable energy market participation rate, the DA and RT regulation participation rates, and the amount of capacity bid into both the spin and non-spin markets. Furthermore, in Case #4 a costless adder was used to control energy sales into the RT energy market. Finally, all DA ancillary participation was constrained to be the same across the entire hour, since the CAISO DA market is an hourly market.

15.4 Modeling Results

15.4.1 Case 1: Participation in Day-Ahead Ancillary Markets

In Case #1, the batteries were assumed to only participate in the DA regulation up and regulation down markets. Therefore, it is also reasonable to assume that the resources would take advantage of the CAISO REM program and participate with their full power (for any duration battery with at least 15 minutes of rated power). Note that the revenue potential in the ancillary service market is dependent on power rather than energy, thus the 40MW/10MWh battery has much higher returns than the 10MW/40MWh battery, as shown in Figure 15.4.1 below.

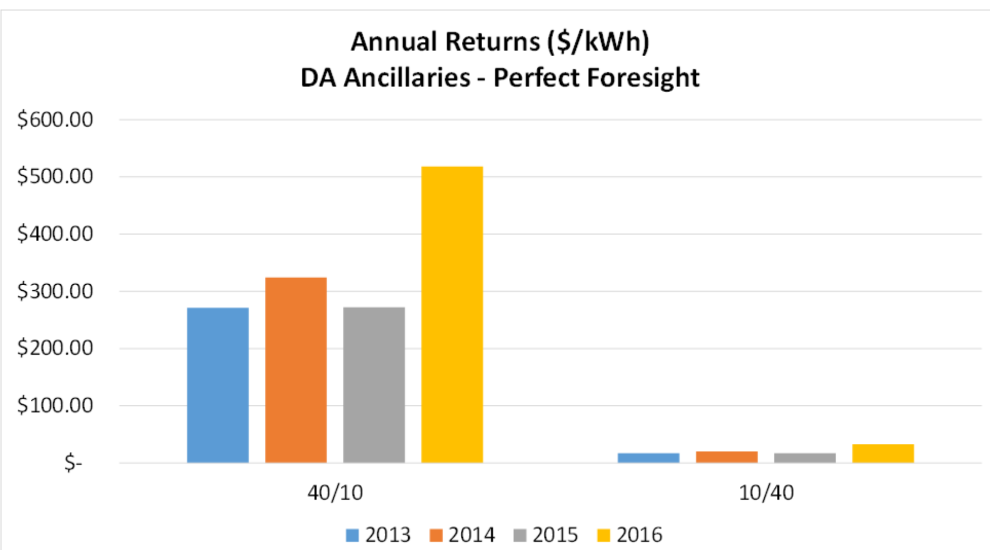

Figure 15.4.1. Annual returns for the 15-minute and 4-hour Battery in Case Study #1; participation in the DA regulation up and regulation down ancillary markets.

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15.4.2 Case 2: Participation in Day-Ahead Ancillary Markets plus Real-Time Energy – Perfect Foresight

In Case #2, the batteries were assumed to be supplying a mix of ancillary and energy services and thus were limited to 30-minute power bids in the spin and non-spin markets and 60-minute power bids in day-ahead regulation. Unfortunately, the resulting revenues from this combined participation strategy were found to be $50-$200/kWh less than the participation in just ancillary services, primarily due to these power restrictions. As shown in Figure 15.4.2 below, the high-power, short-duration battery once again earned the most revenue.

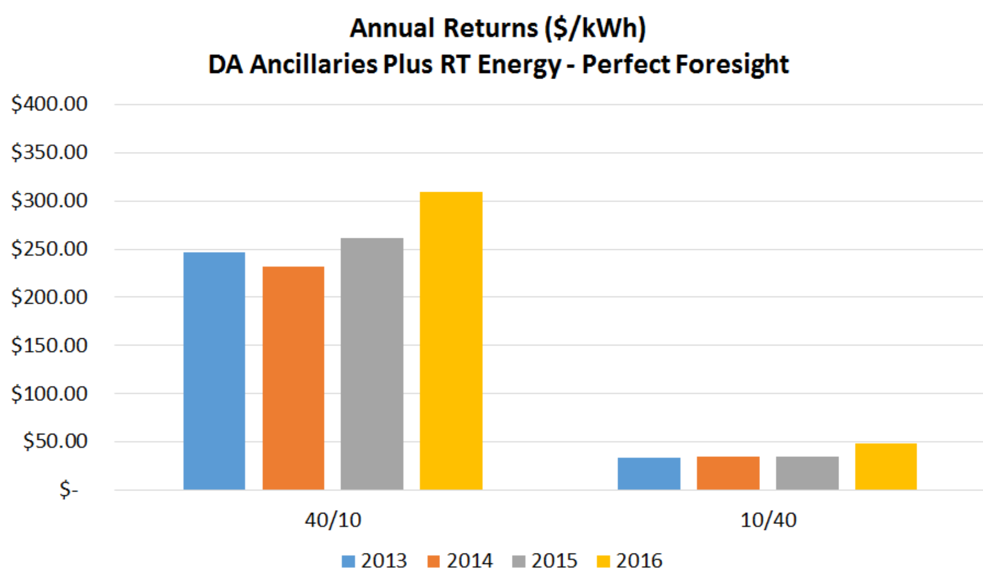

Figure 15.4.2. Annual returns for the 15-minute and 4-hour Battery in Case Study #2; participation in the DA ancillary markets plus RT energy market.

Figure 15.4.3 shows a typical dispatch day for the 40 MW, 10 MWh battery configuration. Note that this battery participated in the real-time energy market when there were price spikes that made it worthwhile to leave the DA ancillary market. However, since the battery was out of the ancillary market for the entire hour, it then had to cycle more during the hour whenever the price differential was greater than the cost of the energy lost to inefficiency. This battery also tended to participate in regulation up and down instead of spinning reserves since the combined revenue from those two products was higher than participating in spinning reserves at twice the power. This trend was found to generally hold throughout the analyzed study time horizon.

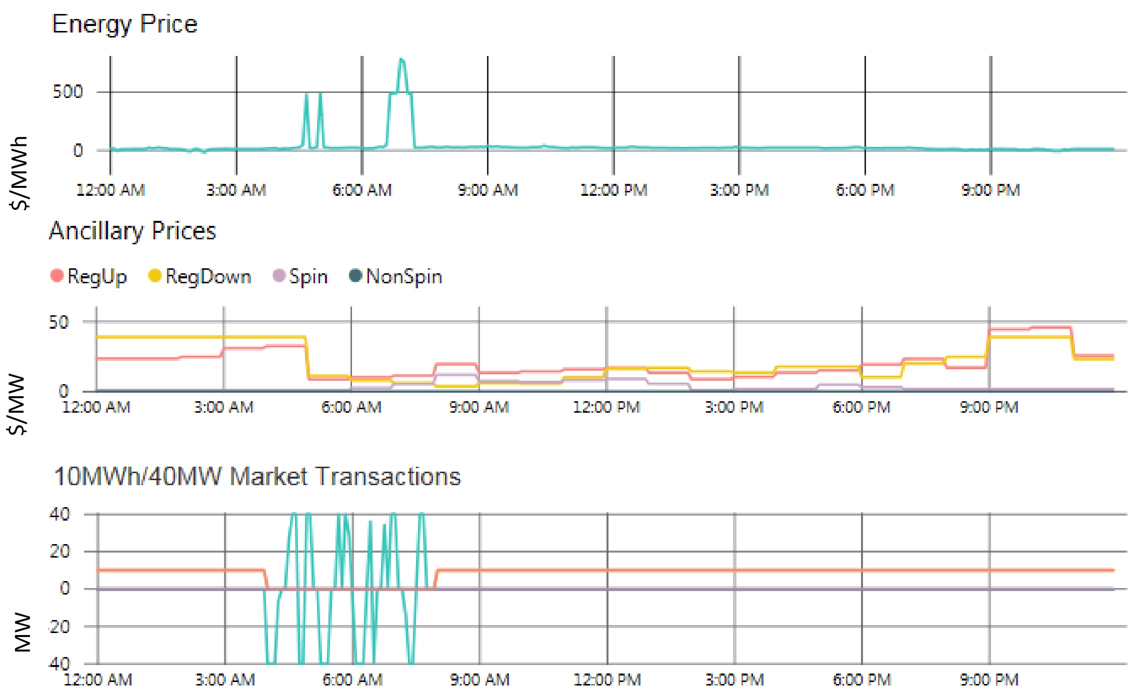

Figure 15.4.3. An example dispatch day for the 40 MW, 10 MWh battery configuration.

15.4.3 Case 3: Participation in Day-Ahead Ancillary Markets plus Real-Time Energy – Scheduled Participation

As in Case #2 above, in Case #3 the battery's bids in the ancillary service markets were limited by the ISO continuous energy limits. However, in Case #3 the hours when each battery could participate in the real-time energy market were also pre-specified to coincide with historical price spikes (instead of using perfect information about when price spikes would occur). This reduced the historical revenues across both battery configurations by approximately 50%, but the relative benefit of the short duration, high-power battery is still clear in Figure 15.4.4.

15.4.4 Case 4: Participation in Day-Ahead Ancillary Markets plus Real-Time Energy – Scheduled Participation with a Costless Adder

Case #4 built on Case #3 by adding a $95/MWh costless adder to the energy bids, plus a $5/MWh variable operating cost to mimic the behavior of bidding $100/MWh in the RT energy market. Note that this case study essentially removed the influence of "perfect knowledge" about the energy prices. Overall, the total revenue was found to be nearly identical to Case #3 (see Figure 15.4.5), but a very small amount of the revenue shifted from RT revenue to ancillary revenue. This change in revenue was relatively small because most of the RT energy transactions were already occurring during price spikes.

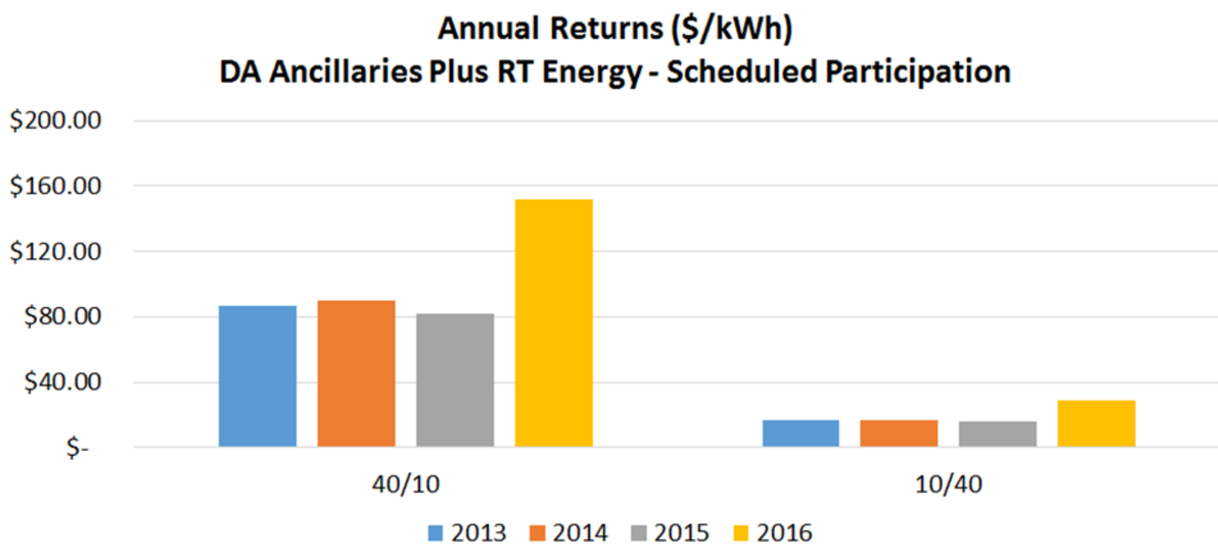

Figure 15.4.4. Annual returns for the 15-minute and 4-hour Battery in Case Study #3; participation in the DA ancillary markets plus RT energy market using pre-scheduled energy time periods.

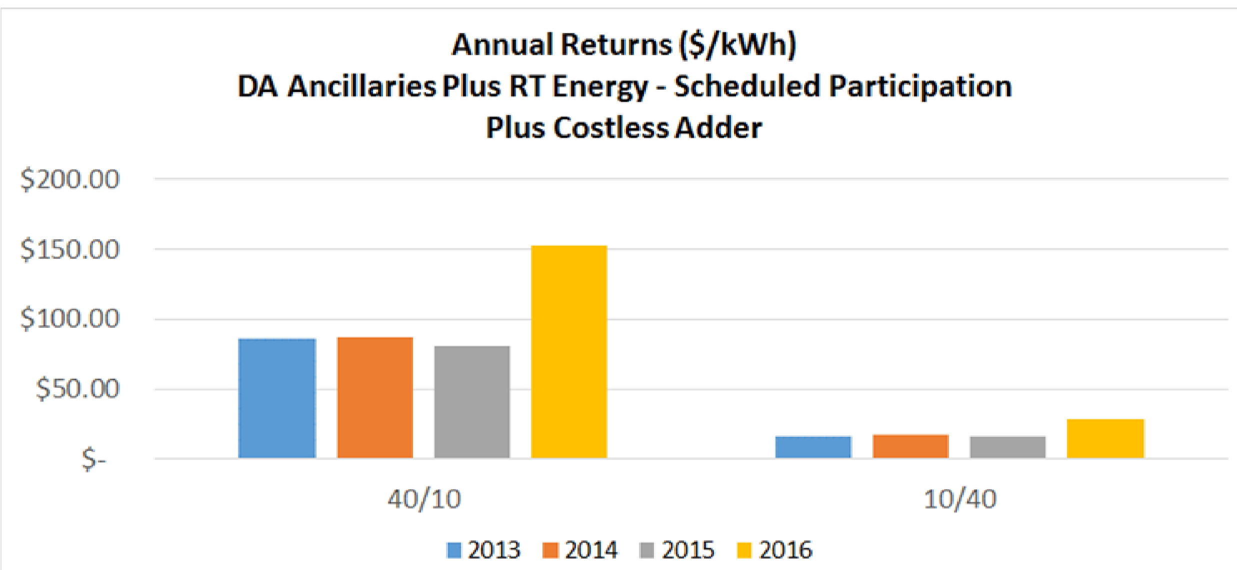

Figure 15.4.5. Annual returns for the 15-minute and 4-hour Battery in Case Study #3; participation in the DA ancillary markets plus RT energy market using pre-scheduled energy time periods and a $95/MWh costless adder.

15.4.5 Case 5: Participation in Real-Time Ancillary Markets plus Real-Time Energy – Perfect Foresight

In this final case study, 20MW/10MWh and 20MW/20MWh batteries that can bid full or half power, respectively, were dispatched into the real-time ancillary service market with perfect information. In theory, although these batteries could better utilize their power in the ancillary service market, the average RT prices were lower than in the DA ancillary-service market prices. Hence, the revenues were not sufficient to make up for exclusive participation in the regulation market with just a 15-minute battery. Figure 15.4.6 shows the resulting annual $/kWh returns for these two battery configurations.

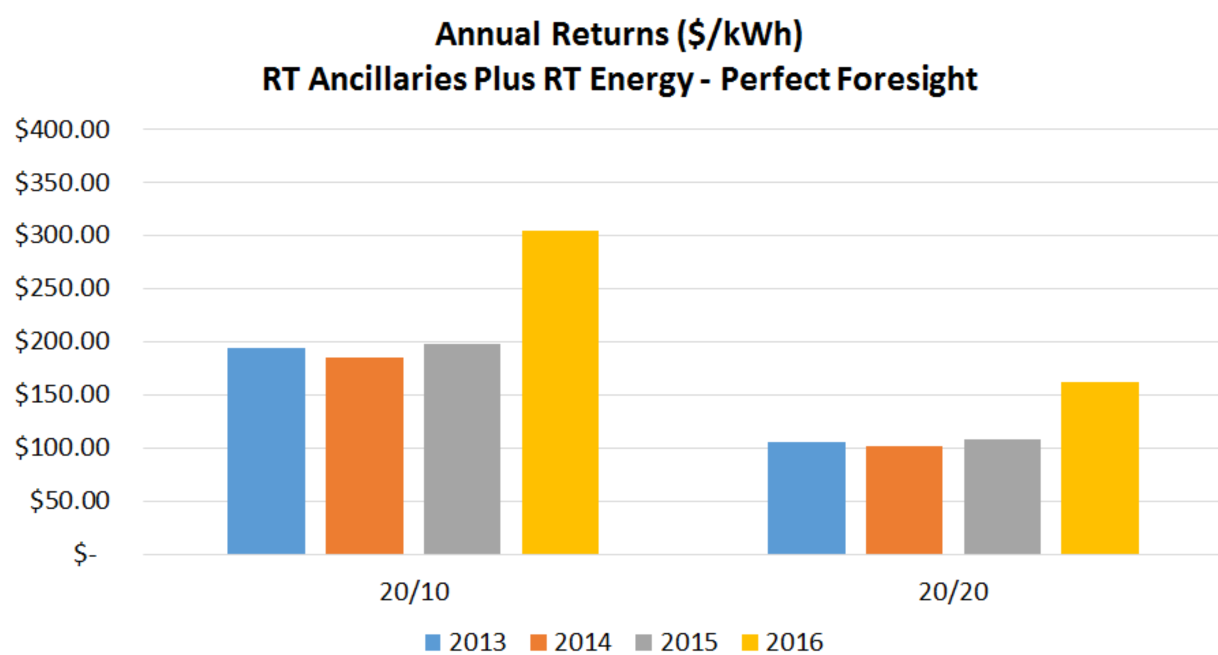

Figure 15.4.6. Annual returns for the 30-minute and 1-hour battery configurations examined in Case Study #5; assuming participation in the RT Ancillary and Energy markets with perfect foresight.

15.5 Comparison across Participation Modes

The following graphs compare the revenues, throughput, and lifetime earnings for each of the five case studies. Given that short-duration batteries far outperform long-duration batteries regardless of market participation, only the short-duration battery configurations are summarized here. Additionally, Case #4 (*Participation in Day-Ahead Ancillary Markets plus Real-Time Energy – Scheduled Participation with a Costless Adder*) is not included here since it was found to yield almost equivalent revenues to Case #3 (no costless adder).

15.5.1 $/kWh Revenue

Due to the power restrictions in the CAISO market and the high value of the DA ancillary prices, participating solely in the ancillary services with a 15-minute battery (Case #1) was found to yield the highest revenues per installed kWh. The $/kWh revenue results for Cases #1, #2, #3 and #5 are shown below in Figure 15.5.1.

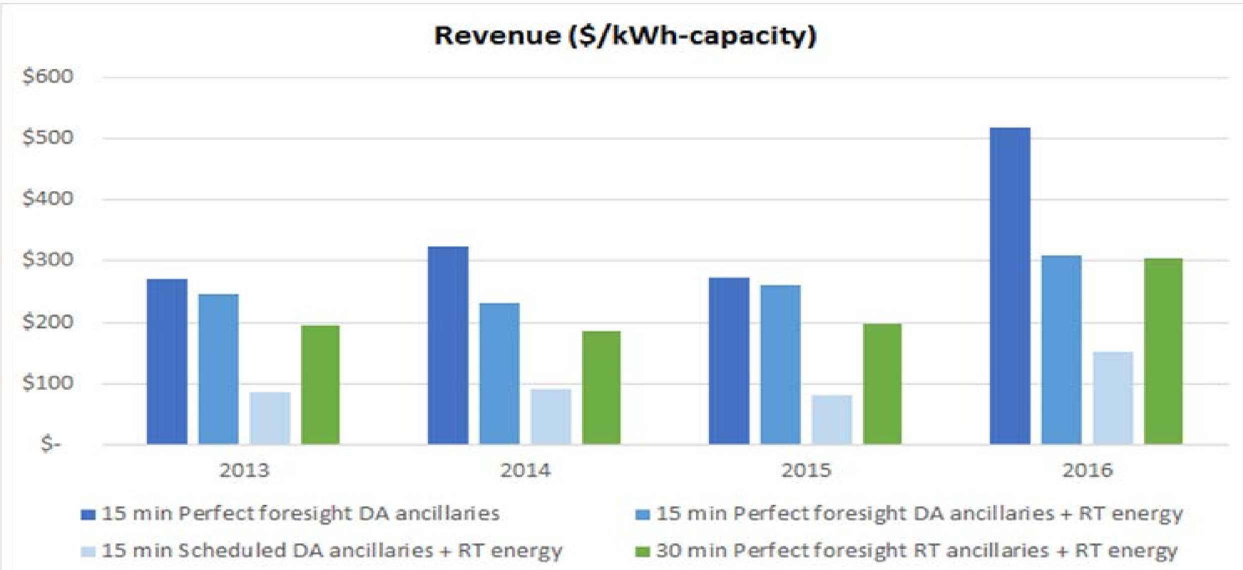

Figure 15.5.1. Annual $/kWh revenues for the short-duration battery scenarios examined in Case Studies #1, #2, #3 and #5 (30-minute battery only).

15.5.2 Throughput

In a battery energy storage system, the average annual "throughput" is defined to be the ratio of the kWh-discharged over a year divided by the kWh-installed in the system. The throughput represents a critical metric to track and model, since it directly impacts the expected life of the energy storage system.

The annual average throughput was calculated for each of the five previously discussed case studies; the resulting throughput estimates for Cases #1, #2, #3 and #5 are shown in Figure 15.5.2. Scheduled participation greatly reduces throughput compared to perfect foresight in the same markets, since it removes many energy market transactions that are only slightly more profitable than ancillary market participation but require much more average power. As shown in Figure 15.5.2, participation in only DA ancillaries (Case #1) has the highest throughput. Note that in Case #1 the batteries were bidding in four times more power than allowed for ancillaries in the mixed market participation scenarios. In contrast, scheduled participation in the DA ancillaries and RT energy markets had by far the lowest throughput. This result is important from a life expectancy perspective, since high throughput levels significantly shorten the expected lifetime of the energy storage system.

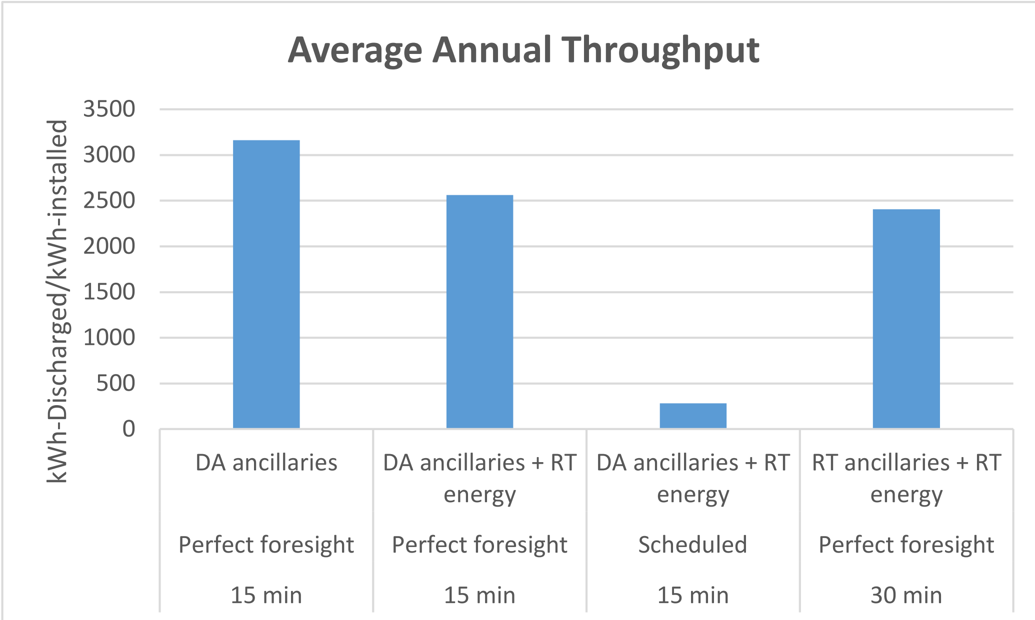

Figure 15.5.2. Average annual throughput estimates for the short-duration battery scenarios examined in Case Studies #1, #2, #3 and #5 (30-minute battery only).

15.5.3 Lifetime Earnings

Based on the throughput calculation shown above, the approximate lifetimes for the battery scenarios examined in Cases #1, #2, #3 and #5 can be calculated. Likewise, the approximate lifetime revenue can be calculated using the approximate lifetimes in conjunction with the historical revenue calculations for previous years. These results are shown in Table 15.5.1, along with capital cost quotes from Samsung (for systems installed in 2018).

Based on the approximate lifetime revenue estimates, all four case studies examined here would be expected to be marginally profitable. However, it should also be pointed out that the “perfect foresight” dispatch criterion represents a primarily hypothetical “best-case” scenario. In practice, staff would not have perfect foresight into near-term future market conditions, thus Case #3 probably represents the most reasonable and realistic assessment of the potential value proposition provided by short-duration battery configurations.

Table 15.5.1. Approximate Lifetime, Lifetime Revenue, and Capital Costs of short-duration battery scenarios examined in Case Studies #1, #2, #3 and #5 (30-minute battery only).

Battery Type	Mode	Markets	Approx. Lifetime (years)	Approx. Lifetime Revenue ($/kWh-installed)	Capital Cost ($/kWh-installed)
15 min	Perfect foresight	DA ancillaries	3	$893	$550
15 min	Perfect foresight	DA ancillaries + RT energy	4	$868	$550
15 min	Scheduled	DA ancillaries + RT energy	10	$689	$550
30 min	Perfect foresight	RT ancillaries + RT energy	4	$731	$625

15.6 Additional Considerations for Battery Bidding Strategy

In the Regulation Energy Management (REM) program, the CAISO manages a batteries' state of charge (SOC) while it participates in regulation. However, the cost of charging clearly depends on when the battery charges, since the market prices are constantly changing. Due to CAISO's level of control and utilities' relative lack of control over a batteries' SOC, a utility must also consider potential charging costs when modeling battery revenue.

To quantify the possible range of charging costs that a utility might incur from participating in CAISO's REM program with a battery, Ascend calculated annual charging costs under three different operating scenarios:

- Upper bound: Charging is optimized based solely on time and not on prices. In this case, the battery is constantly charging just enough to make up for net losses, meaning it pays the average market price to charge.
- Lower bound: Charging is optimized based solely on prices. Hence, the battery does not necessarily provide its full regulation capacity bid into the market for a full hour, as required by the CAISO. Instead, it exits out of the regulation market to charge when prices are lowest within a two-hour window.
- Optimal: The battery charges when prices are lowest, but is also constrained by the CAISO's requirement that the battery provide its full regulation capacity bid for each hour that it enters into the market. This case reflects a reasonable operating strategy that is both cost-minimizing and compliant with market regulations.

Ascend analyzed potential charging costs for a 40MW/10MWh battery at both 10% and 30% average power. According to the CAISO's sample regulation data, most resources are dispatched below 10% average power for both regulation up and down. However, some resources were dispatched to an average of 25%-28% on some days,[5] so a 30% average power provides a useful upper bound. Table 15.6.1 summarizes these annual charging costs for each case.

Table 15.6.1. Annual charging costs for a 40MW/10MWh battery under three operating scenarios and two average power levels.

Average Power	Charging Based On:	Annual Charging Costs
10%	time	$600,000
	prices	$19,000
	time and prices	$62,000
30%	time and prices	$172,000

Under the optimal operation scenario (i.e., based on both time and prices) and at 10% average power, annual operating costs are about $62,000. This equates to about 2% of the forecasted revenue. At 30% average power, annual charging costs would be about three times higher; i.e., $172,000. This latter estimate represents just over 6% of the forecasted revenue for the 40MW/10MWh battery.

Finally, Ascend also considered the impacts of mileage payments on charging costs. However, in all case studies it was found that because CAISO market mileage bids are close to $0/MW, mileage payments would change the revenue forecasts by less than one percent. Therefore, since these nominal payments would not influence any of the bidding strategies, Ascend excluded them from these modeling analyses.

15.7 Summary of Findings

This chapter has described five battery energy storage system case studies involving a range of battery sizes, where these case studies have been focused on evaluating the most profitable battery configuration and operational strategy for RPU. In the absence of additional RA benefits, these results demonstrate that (1) higher-power, shorter-duration batteries generate more revenue than lower-power, longer-duration batteries, regardless of the market participation strategy, and (2) participating in only the day-ahead ancillary market with a 15-minute battery (Case #1) yields the greatest annual and lifetime revenues. More specifically, Case #1 (Participation in Day-Ahead Ancillary Markets with Perfect Foresight) was designed to mimic the CAISO's current REM program, where a battery faces lower continuous energy requirements (15 minutes of continuous power in day-ahead and real-time markets) and can only participate in the day-ahead ancillaries market. In the REM program, the CAISO controls all

[5] From "Automatic Generation Control Market Simulation Data" for April 17, 18, 19, 24, 25, and 26 of 2012; retrieved from http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=40AFAA2A-8570-42DF-9A3F-A94032DE1376.

battery operations using charging and discharging signals that incorporate Automatic-Generation-Control and State-Of-Charge energy management. In theory, the use of perfect foresight dispatch instructions in this case should mimic the CAISO's control of the battery, although currently there is no way to definitively verify this assumption.

The second most profitable scenario was Case #2 (Participation in Day-Ahead Ancillary Markets and Real-Time Energy Markets with Perfect Foresight). Revenues in this case were found to be \$50-\$200/kWh less than participating in just day-ahead ancillaries, because the battery was limited by stricter continuous energy requirements (60-minute power for day-ahead regulation and 30-minute power for spin and non-spin). However, this case represents an ideal scenario. In reality, battery operators do not dispatch with perfect foresight because they cannot perfectly predict real-time price spikes.

Cases #3 and #4 compensate for this unrealistic assumption in Case #2 by mimicking RPU's likely dispatch operations via the incorporation of scheduled participation rules. In Case #3 (Participation in Day-Ahead Ancillary Markets Plus Real-Time Energy with Scheduled Participation), the hours in which the battery participated in the RT market were chosen based on historical price spike patterns. This represents an opportunity cost for the battery, since the battery can miss out on capturing higher prices in the day-ahead ancillary market whenever it is forced to participate in the RT energy market during hours with few price spikes.

To further mimic realistic bidding strategies, Ascend incorporated a costless adder in addition to the scheduled participation rules into Case #4, forcing the battery to only operate in the real-time energy market when real-time prices spiked above \$100/MWh within the hours scheduled for energy market participation. In this scenario, the battery foregoes participating in the RT energy market when prices are *nominally* profitable (but still less than \$100/MWh). The addition of this costless adder was found to decrease RT energy revenues and increase ancillary revenues. Overall however, the total revenues in this case were nearly identical to the case without the costless adder.

Lastly, Case #5 was designed to assess if a battery would be better able to utilize its power in the RT ancillary market. However, since the average prices in the RT ancillary market have been historically less than the prices in the DA ancillary market, this case yielded revenues less than those found in Cases #1 and #2, where the battery operated in the DA ancillary market.

Overall, these case studies suggest that the deployment of a short-duration battery configuration might potentially pay for itself over the expected life of the project. However, this conclusion is at best preliminary and subject to a number of critical assumptions. For example, Case #1 assumes that the CAISO would use dispatch instructions that closely mimic perfect foresight assumptions, but RPU staff have no practical means to verify this. Additionally, the expected battery life is very sensitive to the throughput assumptions and Case #1 exhibited the highest throughput metrics of all the cases studied. Realistically, it is very uncertain if a 15 minute battery could sustain this level of cycling over three years without seriously degrading. More detailed battery simulation studies would definitely need to be carried out before the utility could confidently commit to funding such a battery energy storage system.

Perhaps more importantly, RPU is currently not under any obligation to perform or supply load following services; the utility instead relies on the CAISO for such services. While RPU could certainly deploy a battery configuration to provide such services to the CAISO, the utility would essentially be offering such services as a merchant generator. To date, Riverside has not elected to either build or contract for any type of generation or frequency regulation asset solely for the purposes of capturing merchant generation revenue; such endeavors are generally considered to be too speculative and outside the core mission of a municipally owned public utility.

Finally, although the longer duration battery configurations were clearly found to not be as cost effective from either an energy or ancillary services viewpoint, these analyses also did not factor in any of the RA value streams that such longer duration configurations provide. This RA value could be quite significant, particularly if the 4-hour battery configurations can successfully qualify for the new types of RA products being developed under the FRAC-MOO 2 stakeholder process. Hence, for all of the above mentioned reasons, these study results should be considered preliminary in nature and subject to further validation/verification efforts.

16. Retail Rate Design

In 2015, following a comprehensive strategic and financial planning effort, the City of Riverside approved the "Utility 2.0" strategic plan for Riverside Public Utilities. This policy document presents a detailed integrated plan for maintaining the physical infrastructure and financial health of the utility, and can be found online at: http://www.riversideca.gov/utilities/utility20/popup.asp. Additionally, in 2016 and 2017, the following related items were completed:

- RPU completed both electric and water cost of service and rate design studies to finance Utility 2.0 objectives.
- Staff presented a rate proposal based on these studies to Board and City Council in August and September 2017, respectively.
- Staff conducted a citywide community outreach initiative on the rate proposals, including over 50 public community outreach meetings to address the drivers behind the proposed rate increases and low-income customer concerns.
- The Board of Public Utilities and City Council received and conceptually approved a revised rate proposal in November 2017 and January 2018, and directed staff to: increase support for low-income and fixed income customers, establish a community based Agricultural Water Rates Task Force, plan annual rate reviews to avoid future "stair-step" electric and water rate increases, and include information on the General Fund Transfer on utility bills. City Council also directed staff to submit a final set of electric and water rate proposals in May 2018 for approval and adoption.

All of the relevant rate increase documents referenced above can be found online at: http://www.riversideca.gov/utilities/rateplan/documents.asp.

16.1 Overview of the 2017 RPU Electric Rate Proposal

In November 2017, after 18 months of iterative work and development, RPU proposed a revised five-year (fiscal years 2018/19 through 2022/23) electric utility rate plan that will result in a five-year system average annual rate increase of 3% for typical electric customers. For an individual customer, the rate increases and associated bill impacts will vary by customer class and consumption levels. (For a typical residential customer, the estimated five-year annual electric rate increase will be $3.02 per month.) This proposed rate increase represents the utility's first electric rate increase since 2011 and is necessary for the following reasons:

- To help fund infrastructure investments, including upgrades to electric substation components and underground equipment;

- To meet 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; and
- To maintain strong bond ratings and low debt costs.

RPU also recommended a redesign of its rates over a five-year period to better align with its cost of serving customers and its revenue requirements. The 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. These changes are reflected in the overall rate increases that were proposed. An outline of the specific key changes to RPU's rate structure is shown in Table 16.1.1 below.

On May 22, 2018, the City Council approved RPU's proposed 5-year electric rate increases on a 4-3 vote, subject to the following additional conditions: (1) that the first rate increase be delayed from July 1, 2018 to January 1, 2019, and (2) that each additional rate increase taking effect on January 1 of the subsequent years be first review by City Council. During these subsequent review processes City Council shall determine (on an annual basis) if the subsequent proposed 3% rate increases are reasonable and justified.

16.2 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, sales of excess renewable power, scheduling coordinator services to other agencies, and leases of real property owned by RPU. Additionally, RPU has strategically reduced operating costs through use of new technologies, including various upgrades to the utility's operational technology platforms and the proposal to use of a line of credit to partially fund electric reserves. This latter proposal 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 were tasked with reviewing their budgets and reducing costs wherever possible. Savings were obtained through personnel and non-personnel reductions reflected in the upcoming two-year budget and five year financial plan totaling approximately $4 million annually. It should also be noted that even with these proposed rate increases, the monthly electric bill for a typical Riverside resident will still remain considerably lower than the bills for similar residents in neighboring communities. Figure 16.2.1 shows a comparison of the forecasted monthly electric bills for the same typical resident residing in Riverside, SCE and SDG&E service territories, both currently and after five years, respectively.

Finally, on April 23, 2018, the Public Utilities Board received a report and presentation on Riverside Public Utilities proposed budget for fiscal years 2018/19 and 2019/20. This proposal included the elimination of five (5) unfunded positions and transfer of nine (9) RPU funded staff to City departments to consolidate various internal non-core services including communications and human resources for efficiency purposes. Following discussion, the Board moved forward with all recommendations, with the exception relating to the proposed reduction and/or transfer to the General Fund of RPU positions to the City's departments, pending consideration of this issue by the RPU Finance/Customer Engagement Committee. The total savings generated from the proposed personnel reductions and transfers equals approximately $1.25 million in annual savings within the two-year budget. This $1.25 million in annual budget savings was necessary to meet the cost structure of the proposed rate plan.

Table 16.1.1. Key proposed changes to RPU's electric rate tariffs.

Key Changes	Current Rates	Proposed Rates
Fixed Cost Recovery Concept	No fixed charges that recover distribution infrastructure costs. Most of the fixed distribution system costs are recovered through variable energy charges in the current charges. Note that the current Reliability Charge is solely used to pay for costs associated with the Riverside Transmission Reliability Project (RTRP) and Riverside Energy Resource Center (RERC).	Currently, the electric utility's fixed costs are approximately 54%, however we collect only 23% though fixed charges. By the fifth year of the rate plan, RPU will collect approximately 29% of our fixed costs through fixed charges. This adjustment helps RPU meet its objective of increased revenue stability and reflect how actual costs are incurred.
Distribution System Cost Recovery (Network Access Charge)	No fixed charge like this currently exists. Additionally, our current Customer Charge only covers billing systems and metering services costs.	Introduce a Network Access Charge (NAC) to ensure for the adequate recovery of RPU's distribution infrastructure costs. This fixed charge contributes to collection of fixed costs as noted above. The NAC will be applied to all customer classes.
Industrial Time of Use (TOU) Reliability Charge	Currently, the Reliability Charge is not differentiated amongst TOU customers.	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.
Residential Class: Seasonal Rate Adjustment	Currently a 3 month seasonal rate structure – Summer season from June 16 to September 15.	Extend into a 4 month summer residential season (June 1 to September 30) to more accurately reflect summer weather and usage patterns.
Electric Vehicles (EV)	Currently, RPU has one residential domestic time of use (DTOU) rate, but this rate has a low adoption level and is not well suited for EV owners.	Introduce two new DTOU rates for residential EV customers to encourage EV adoption and off-peak charging.
Demand Charge Transition	Customers transitioning between commercial flat and demand classes experience rate shock due to the minimum demand charge (20 kW) in the commercial demand class.	Lower 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.
High Voltage (HV) Rate	Currently there is no differentiation for HV customers in the industrial TOU Rate.	Offer a high voltage adjustment (discount) for customers that take service at the primary voltage level (4 kV to 69 kV).
Optional Renewable Energy Rate	Not currently offered.	New program offers customers the option to purchase 100% green/renewable energy and is in line with successful peer utility green energy programs.

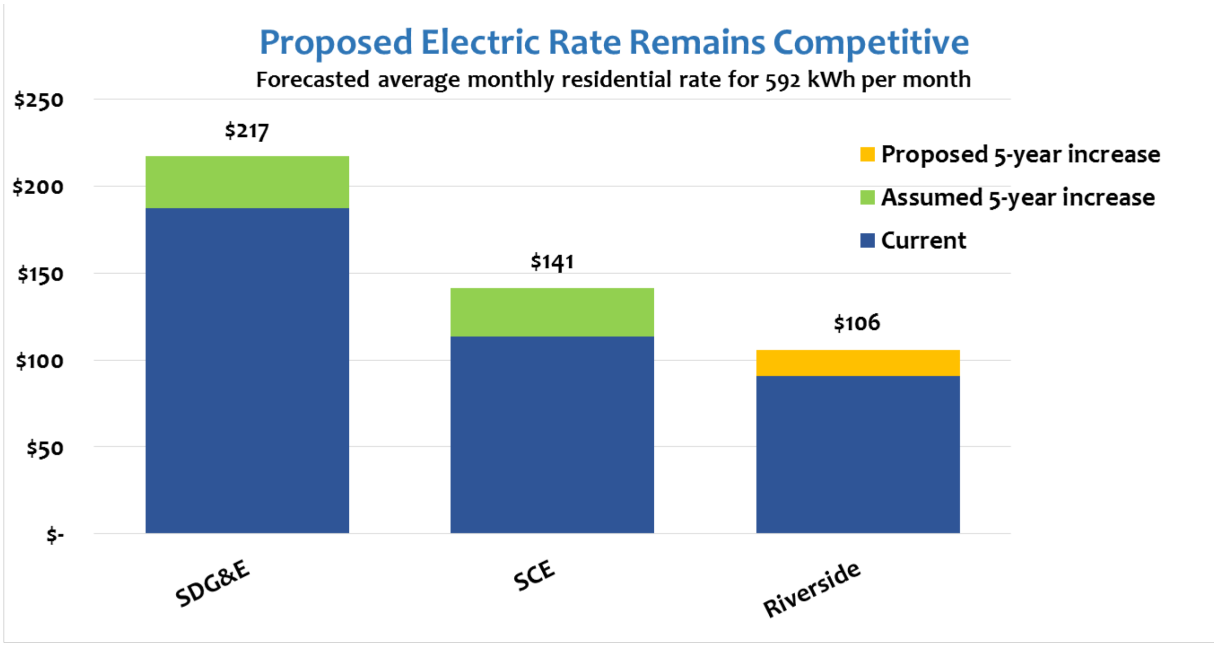

Figure 16.2.1. Forecasted monthly bills for a typical resident using 592 kWh a month, both now and after 5years (under expected RPU, SCE, and SDG&E residential rate tariffs).

16.3 Important New Rate Tariffs

As shown in Table 16.1.1, RPU is proposing a number of key changes to existing rates, but also introducing new rate tariffs as well. More specifically, RPU plans to allow both its commercial and residential customers the option to subscribe to a 100% renewable energy tariff (RET) rate. Under the 100% RET option, RPU customers will be able to voluntarily elect to purchase and receive 100% renewable energy in place of the utility's current energy mix, by paying a minimal $/kWh fee on top of their otherwise applicable tariff (OAT).

Likewise, RPU will be introducing two new domestic TOU rate tariffs for residential EV customers (a "whole-house" tariff and a "separately metered EV" tariff). These two new TOU tariffs are designed to encourage PHEV and BEV adoption, as well as load shifting to off-peak hours. Additionally, the utility is currently exploring the idea of opening up the whole-house domestic TOU rate as an optional rate for all residential customers, to further incentivize and reward customers who are able to effectively shift some of their load to off-peak hours. Finally, the utility may assign this to become the default rate tariff for residential customers who install behind-the-meter distributed energy resources, once RPU exceeds its NEM 1.0 DER capacity cap. (More information on this latter topic is presented in Chapter 18.)

16.4 Enhanced Low-Income and Fixed-Income Assistance

At the November 2017 rate workshop, the Board and City Council also conceptually approved the development of an enhanced low-Income and fixed income assistance program to help off-set rate increase impacts on our lowest income customers. This program includes Sharing Households Assist Riverside Energy (SHARE) Program enhancements, Energy Savings Assistance Program (ESAP) enhancements, a comprehensive outreach campaign, and a needs assessment for developing additional program enhancements aligned with future rate increases. Proposed changes to the SHARE and ESAP programs, to be implemented in alignment with the rate increases, include:

- Enhance SHARE Program by implementing the following changes:
  - Increase eligibility from 150% to 200% of the Federal poverty level;
  - Increase the $150 *annual* electric bill credit to a $14 *monthly* electric bill credit (up to $168/year);
  - Add annual deposit assistance and emergency assistance (up to $150/year);
  - Work with Community Action Partnership to create more convenient options for customers to sign up for program benefits.
- Enhance ESAP by implementing the following changes:
  - Align program eligibility with SHARE and partner agency programs; and
  - Automatically sign up customers who qualify for the SHARE program.
- Implement comprehensive multi-media and multi-lingual outreach campaign specifically targeting low-income and fixed income utility customers.
- Initiate a needs assessment to increase program assistance in parallel with rate increases, fully develop community partnerships, coordinate ongoing stakeholder process, develop benchmarks and metrics, and explore areas of program expansion/improvement inclusive of Housing First Program alignment.

More details on these proposed program enhancements can be found online with the previously mentioned rate increase documents, as well as in the expanded discussion presented in Chapter 19.

16.5 Projected Financial Impacts

Overall, the total additional revenue over the five-year period for this rate increase is projected to be $137 million for the electric utility, or approximately $27 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 over $223 million for the electric utility in order to fully fund the above mentioned infrastructure, operations, and power supply costs.

17. 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. RPU works 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. RPU is required to address transportation electrification in the IRP pursuant to Senate Bill 350's requirement for the RPU to develop and submit an IRP to the California Energy Commission (CEC).

This chapter also reviews the policy and regulatory environment around transportation electrification and the status of electrification in the RPU service territory. Additionally, forecasts for EVs and their associated loads and load profiles in the service territory are examined, along with the forecasted GHG emissions reductions corresponding to these various EV penetration scenarios. The forecast for EVs and the associated loads are based on the Light-Duty PEV Energy and Emission Calculator, version 3.5-3 (EV Calculator) spreadsheet tool, developed by the California Energy Commission (CEC) in consultation with the California Air Resources Board (CARB) and the California Public Utilities Commission (CPUC). Building on the results from the EV Calculator, RPU also worked with NewGen Strategies & Solutions, LLC to analyze the daily load profiles from residential EVs and how the residential EV time-of-use rate will affect load. The results of these analyses are also described. Forecasts for medium and heavy-duty vehicles are planned but not currently underway.

17.1 Overview of Transportation Electrification

Since the passage of Assembly Bill 32 in 2006, the State of California has had increasingly aggressive goals to transform the transportation sector in order to reduce GHG emissions. Since almost 40% of the GHG emissions tracked by the state result from the combustion of fossil fuels, State policies and regulations are currently focusing on reducing emissions from this sector. A 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 compressed natural gas as a transition from traditional gasoline and diesel and use of hydrogen fuel cells in vehicles, the State has focused on electricity as the primary alternative fuel. Expanding electrification of the transportation section, referred to as transportation electrification (TE), will have the additional benefits of decreasing nitrogen oxides (NO_x) and fine particulate matter (PM_{10} and $PM_{2.5}$) emissions, leading criteria pollutants in the South Coast Air Basin.

As stated in prior chapters, RPU is required to consider and address transportation electrification (TE) in its IRP per SB 350. 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 impacts resulting from EVs.

The growth in the number of light-duty EVs in California's statewide vehicle fleet is well underway and is expected to continue. A recent report produced by Next 10 released in January 2018 reported that 4.5% of California's light-duty vehicle fleet were comprised of EVs.[1] By the end of 2017, there were over 300,000 EVs in California. In Riverside, there are an estimated 2,000 light-duty EVs owned by residents as well as businesses. Recent state policies also support the transition of medium and heavy-duty vehicles, including freight transport (both trucks and trains) to both full and hybrid EVs.

As the vehicle fleet transitions from ICE vehicles to EVs, the electric grid will need to change to deal with the new load and be able to accommodate the demand and timing of charging as well as consider the use of fleets as a type of energy storage system. Specifically, EV charging represents a new type of load that has a unique profile and the potential for high electricity demand. This chapter addresses RPU's current efforts and the planned increase in electric vehicles and the GHG emissions reductions.

17.1.1 State Policy and Regulation Supporting Transportation Electrification

As noted above, California has some of the most aggressive policies promoting the electrification of the transportation sector. RPU's role as the provider of electricity is to support, plan for, and ensure that the infrastructure and generation will be available to achieve these goals.

Because transportation electrification is a priority action to help the State meet it's near and long term climate change goals for reducing GHG emissions to 40% below 1990 levels by 2030, it has been a focus of State actions. 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) establishing goals for deployment of light-duty EVs and the deployment of charging infrastructure in the State:

- 1.5 million electric vehicles on the road by 2025 [2]
- 5 million electric vehicles on the road by 2030 [3]
- 250,000 public EV chargers, including 10,000 direct current fast chargers, in California by 2030.[4]

Numerous State analysis and studies have been developed subsequent to each of these executive orders. Importantly, in 2016 the State issued its Zero-Emission Vehicle (ZEV) Action Plan [5]

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[1] Perry, F. Noel; Kredell, Colleen, Perry, Marcia E., and Leonard, Stephanie, "The Road Ahead for Zero-Emission Vehicles in California: Market Trends and Policy Analysis," Next 10, January 2018.

[2] California Executive Order No. B-16-2012, March 23, 2012, https://www.gov.ca.gov/2012/03/23/news17472/.

[3] California Executive Order No. B-32-15, July 17, 2015, https://www.gov.ca.gov/2015/07/17/news19046/.

[4] California Executive Order No. B-48-18, January 26, 2018, https://www.gov.ca.gov/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/.

[5] Office of Governor Edmund G. Brown Jr. and the Governor's Interagency Working Group on Zero-Emission Vehicles, "2016 ZEV Action Plan: An updated roadmap toward 1.5 million zero-emission vehicles on California

identifying strategies necessary to achieve the 2025 EV goal. Six broad goals were established for State government:

1. Achieve mainstream consumer awareness of ZEV options and benefits
2. Make ZEVs an affordable and attractive option for drivers
3. Ensure convenient charging and fueling Infrastructure for greatly expanded use of ZEVs
4. Maximize economic and job opportunities from ZEV technologies
5. Bolster ZEV market growth outside of California
6. Lead by example integrating ZEVs throughout State government

These state-level 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 regulation, guidance, funding recommendations and internal actions in concert to implement and achieve the goals identified in the ZEV Action Plan and towards the executive orders.

For RPU, these goals provide a policy framework and the tools necessary to develop forecasts in order to analyze anticipated future load and load profile scenarios from which to plan for necessary infrastructure improvements. With each state agency coordinating policies and planning for these desired future outcomes, RPU is and has incorporated those goals in the IRP analysis and recommendations.

17.1.2 Local Policy & Actions Supporting Transportation Electrification

TE is not solely the responsibility of RPU; within the City of Riverside it represents a cross-departmental effort that must also be coordinated within the broader community. Community-wide efforts have resulted in the City's adoption of two documents that provide policy direction for electrification efforts – the Green Action Plan adopted in 2012 and the Climate Action Plan adopted in 2016. The Climate Action Plan is the companion document to the Economic Prosperity Action Plan, both of which are part of the City's Restorative Growth Print. Key goals and strategies in both of these documents are to reduce emissions from vehicles – in the form of reducing vehicle miles traveled, encouraging biking as a means of transportation, and also TE.

As indicated above, RPU along with the City has a long history of supporting transportation electrification. To further these efforts and accommodate the increasing demand and need for EV charging infrastructure, in mid-2018, RPU initiated the development of a Transportation Electrification Strategy (TE Strategy). With an expected completion in early 2019, this effort will provide for community education, support for RPU customers, and planning for EV growth in the service territory.

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roadways by 2025," October 2016, https://www.gov.ca.gov/wp-content/uploads/2018/01/2016_ZEV_Action_Plan-1.pdf.

In the interim, the RPU has opted into the Low Carbon Fuel Standard Program (LCFS) and is continuing to coordinate with all City departments on EV charging infrastructure analysis and efforts. Since the TE Strategy has not been completed, the full EV plan is not reflected in this IRP and will be discussed and evaluated in future IRP documents. However, the following items briefly describe the City and RPU's efforts and programs that support TE.

EV EDUCATION AND AWARENESS

RPU has a robust public education and marketing program that reaches customers through a variety of avenues. Notably and relevant to TE, RPU's *GreenRiverside* website (www.greenriverside.com) includes an EV specific webpage that provides the public with information about EVs as well as how to find public access charging stations, how to apply for EV charging building permits, residential EV rates, and more.

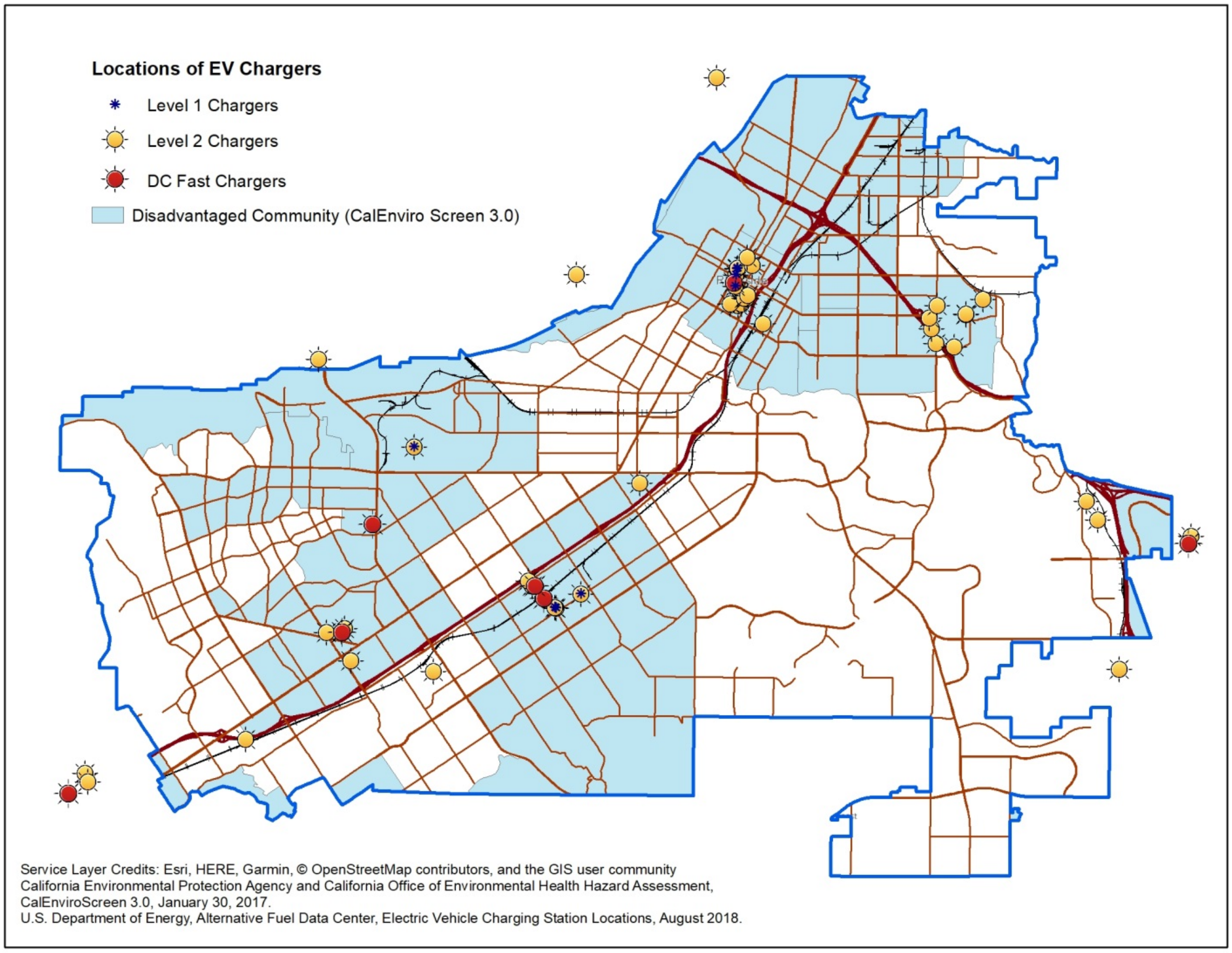
RPU also supports and attends numerous community events and provides EV education and information to attendees. More specifically, RPU collaborates with the local community and neighboring utilities to support educational events for the public. One example is RPU's active participation and coordination efforts for an EV ride and drive event as part of National Drive Electric Week. This event is a partnership between RPU, the City of Colten Electric Utility, the University of California - College of Engineering Bourns Center for Environmental Research and Technology, and EV Nirvana, as well as national sponsors that include Plug-In America, the Sierra Club and the Electric Auto Association. This event will include not only the opportunity for attendees to test drive EVs but also to learn more about EVs from event volunteers who own EVs and drive them daily.

EV CHARGING LOCATIONS

City and RPU policies strongly support the deployment of EV charging infrastructure. The Green Action Plan policies established goals supporting the installation of public access EV charging infrastructure as well as streamlined permitting processes for private parties to install EV charging infrastructure. These policies have led to a growing number of EV charging locations throughout the City, as shown in Map 17.1.1.

There are 45 locations in Riverside that offer 104 Level 2 and 37 DC fast charge plugs for public access EV charging.[6] RPU and the City have installed over 17 Level 2 public access chargers as well as one, public access DC fast charger. In late 2017, Tesla installed its first Riverside supercharger station, with 24 chargers, located in the downtown area of the City.

[6] U.S. Department of Energy, Alternative Fuels Data Center, Electric Vehicle Charging Station Locations dataset accessed by Tracy Sato on July 26, 2018.
https://www.afdc.energy.gov/fuels/electricity_locations.html#/find/nearest?fuel=ELEC



Map 17.1.1. Map of EV chargers and location of disadvantaged communities in Riverside, California.

Map 17.1.1 shows the locations of publicly available 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. They are also, notably, located in disadvantaged communities as identified by CalEnviro Screen 3.0.

As part of the TE Strategy, RPU will be exploring options to increase the availability of EV charging in areas of the City that are primarily rental housing. Since most EV charging is expected to occur at home, ensuring that access to EV charging in areas with rental housing, including multiple-family rental housing, will be important to promote overall EV adoption.

STREAMLINED PERMIT PROCESS

Facilitation 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. This process is available for the installation of both residential EV charging as well as non-residential charging.

EV REBATES

Providing incentives for EVs and charging infrastructure is also a key component of the City's policies. An alternative fuel vehicle rebates program was implemented by the City in 2017. Under the program, residents of Riverside may receive up to a $500 vehicle rebate for a battery electric vehicle (BEV) and $250 for neighborhood electric vehicles and electric motorcycles. As mentioned above, RPU is actively developing new programs that offer rebates for EV charging equipment as part of the TE Strategy currently being developed.

CLEAN FLEET

The City has also approached clean transportation by supporting a robust clean fleet program. This program has resulted in about 50% of the City's light-duty fleet, 35% of the medium duty fleet and over 55% of the heavy duty fleet converting over to alternative fuels. Additionally, RPU supports efforts from non-residential customers to convert their fleets to cleaner technologies. In particular, RPU partners with customers to support grant applications for EV infrastructure and vehicles where appropriate.

EV TIME-OF-USE RATE FOR RESIDENTIAL CHARGING

The City of Riverside and RPU's Public Utility Board have approved a new EV-only time-of-use (TOU) rate tariff 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 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.

To use this rate tariff, customers will be required to have or 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 on their EV charging equipment to manage when their vehicle charges.

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 kWh's used with seasonal adjustments. Since EV charging can result in substantial energy usage in a given 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 17.1.1 and 17.1.2 illustrate the pricing differences offered under the EV-only TOU rate tariff compared to the standard residential domestic rate tiers. Both figures show pricing effective as of January 1, 2019 for calendar year 2019.

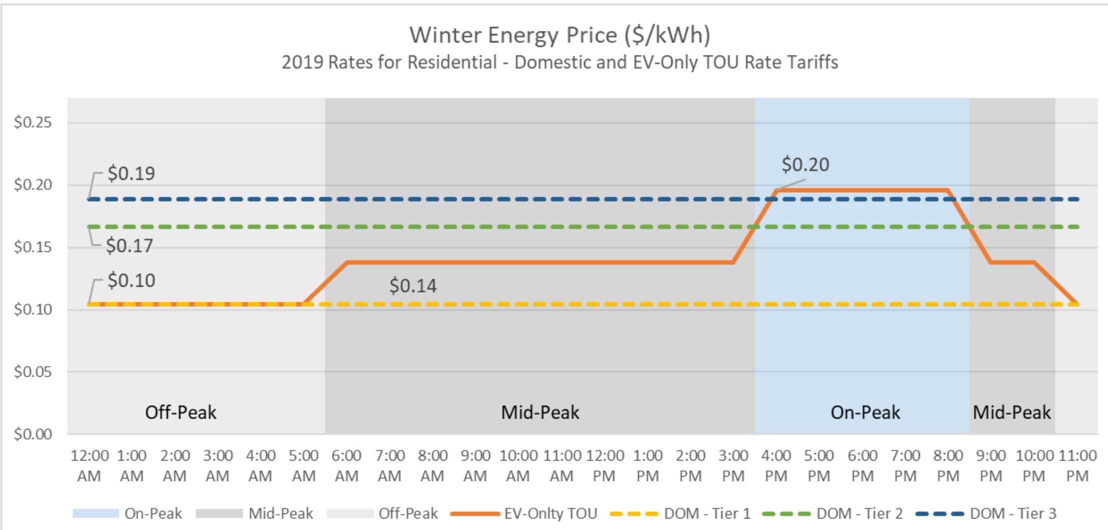


Figure 17.1.1. Illustration of the winter season EV-only TOU rate by hour, as compared to the tier prices of the residential domestic rate tariff.

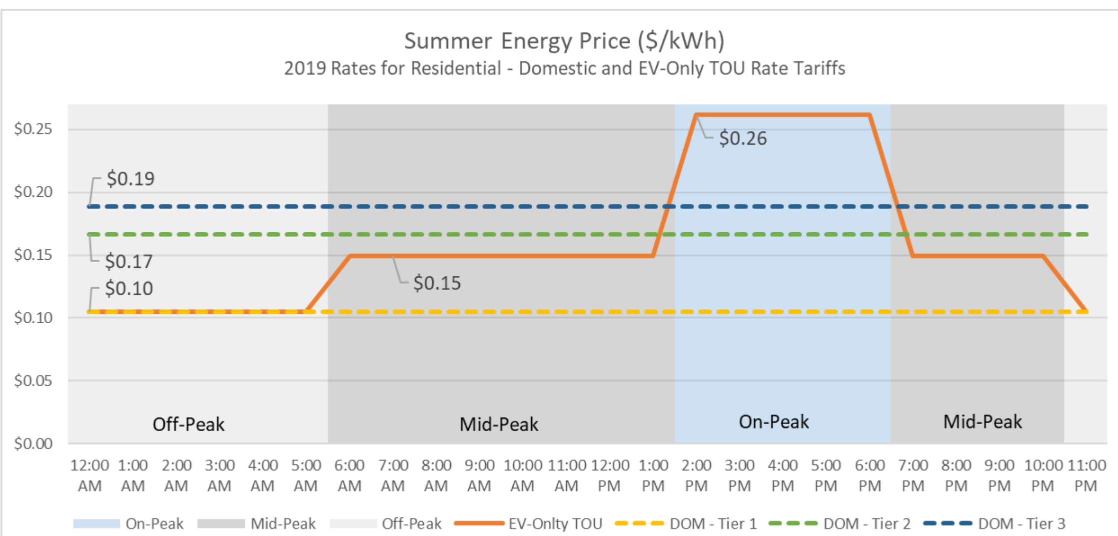


Figure 17.1.2. Illustration of the summer season EV-only TOU rate by hour, as compared to the tier prices of the residential domestic rate tariff.

17.2 EV Charge Load & Avoided GHG Emissions

Staff has used two analytical tools to help RPU better understand the impacts that will be realized by EVs and to better prepare for the increasing EV population in the City. These analyses focused on light-duty electric vehicles, primarily in the residential sector, though it is acknowledged that there will be an impact from medium and heavy-duty vehicle electrification. The two tools used include:

- The Light-Duty PEV Energy and Emissions Calculator, version 3.5-3 [7] (EV Calculator) released on February 27, 2018 and produced by the Energy Commission in consultation with the Air Resources Board and California Public Utilities Commission. This tool was used to forecast the number of light-duty EVs, charging load, and GHG emissions reductions.

- The NewGen Strategies & Solutions (NewGen) Load Shapes Analysis Model (LSAM Model). This tool was used to evaluate residential charging profiles by time of day and assess the impact of implementing an EV Time-of-Use (TOU) Rate.

17.3 Annual EV Energy Demand and Net GHG Emissions Reductions Using the CEC EV Calculator

The CEC staff developed the EV Calculator at the request of publicly-owned utilities statewide. It is a spreadsheet-based tool that estimates and reports the energy and GHG emissions impact of light-duty EVs deployed in a utility's service territories. As noted above, RPU used the EV calculator to develop forecasted deployment of EVs, along with the annual charge load and net GHG emission reductions that would be associated with the deployment of EVs. Most model assumptions and data were developed by the CEC, CPUC and CARB and are fully described in the EV Calculator.[8] A brief description of these assumptions is included to provide context for the model results.

17.3.1 Scenarios Evaluated

Using the EV Calculator, RPU analyzed four scenarios for the growth of EVs in the service territory. In each scenario the EV population has been forecasted from years 2018 through 2030. The number of EVs in 2015 through 2017 is based on EV registrations reported by the California Department of Motor Vehicles. These included a business-as-usual scenario and three other scenarios based on meeting the State's goals for EV sales and increasing Riverside's share of the Statewide EV population. These four scenarios are defined in Table 17.3.1. Note that Scenario 2 is most closely aligned with current state energy demand forecasts and existing or expected near-term state policy.

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[7] California Energy Commission, "Light-duty PEV Energy and Emissions Calculator, version 3.5-3," February 27, 2018, http://www.energy.ca.gov/sb350/IRPs/documents/Light_Duty_Plug-In_EV_Energ_and_Emission_Calculator.xlsx.

[8] See http://www.energy.ca.gov/sb350/IRPs/documents/Light_Duty_Plug-In_EV_Energ_and_Emission_Calculator.xlsx.

Table 17.3.1. Light-duty Electric Vehicle scenarios analyzed using the CEC EV Calculator.

	Scenario	Goal for Number of EVs Statewide	RPU Percent Share of EVs
1	Business as Usual	Forecast EV growth based on consumer demand without new federal, state or local policy or incentives.	0.61%
2	**Governor's 2025 Goal**	**1.5 million EV sales by 2025** To be achieved by existing federal, state or local policy and incentives currently approved or under development.	**0.61%**
3	Governor's 2030 Goal	5.0 million EV sales by 2030 Achievement will require new, yet still to-be-defined federal, state, or local policy and incentives.	0.61%
4	Governor's 2030 Goal with double RPU share	5.0 million EV sales by 2030 Achievement will require new, yet still to-be-defined federal, state, or local policy and incentives, as well as shifts in consumer buying in Riverside.	1.22%

17.3.2 EV Population and Energy Demand Forecast – Model Assumptions

To determine the amount of electricity needed to support EVs in RPUs service territory, the EV Calculator uses many interrelated assumptions; however, the basic formula to determine energy demand each year is as follows.

Energy Demand = (Total # of EVs) x (Miles traveled) x (Battery efficiency) [Eq. 17.1]

where:

Total # of EVs: New EVs deployed or sold by type of EV (PHEV or BEV) plus the total number of EVs by type retained for operation from the prior year.

Miles traveled: The number of miles traveled based on EV type, age of vehicle and battery range.

Battery efficiency: The amount of energy necessary to travel one mile based on EV type and battery range.

An important distinction made in the model is the interpretation of the State goals for EVs into modeled characteristics. The EV Calculator assumes that the State's EV goals represent the cumulative number of EVs deployed or sold each year within the State. This does not mean that there will be that same number of EVs operating in the State in the given year. The actual number of EVs that are operational in the State is less than simply summing up the number of EVs sold over time. For example, the 2025 State goal is to have sold or deployed 1.5 million vehicles in California; however, the model assumes that the actual number of vehicles that are operating and being used in that year is less – or about 1.34 million vehicles.

This assumption is based on vehicle retention factors. Each year, a portion of the existing vehicle fleet becomes inoperable, is sold or moves out of state, or is simply used less by the owner for many reason including the purchase of an additional vehicle. The model assumes existing vehicle life and operational expectancies when modeling the total number of EVs operating each year based on data statistics and models developed by CARB.

Other factors affecting electricity demand at point-of-charge (where the EV plugs in to charge) include the vehicle mix, the number of miles each type of vehicle is driven and the efficiency of the battery. The model assumes that 50% of future EVs sold each year will be plug-in hybrid EVs (PHEVs). The remaining 50% are assumed to be battery EVs (BEVs) that run solely on electricity. BEVs are further divided into short-range and long-range BEVs. The model assumes the proportion of short-range BEVs decreases over time while the portion of long-range BEVs increases over time. Figure 17.3.1 shows the changes in the proportion of new vehicle sales by each EV type assumed in the EV Calculator.

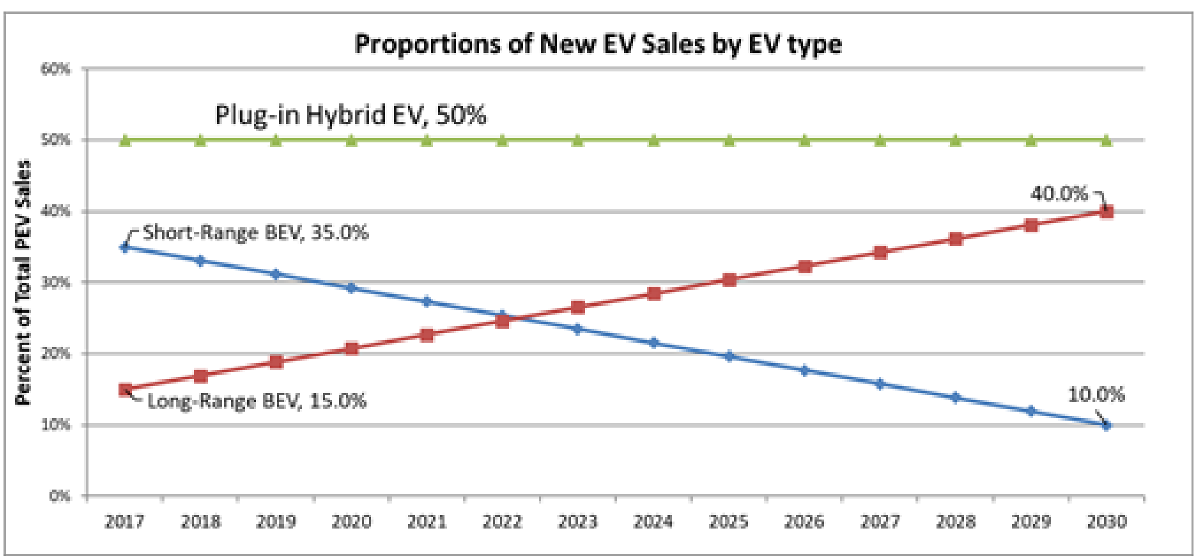


Figure 17.3.1. Proportion of new vehicle sales by type of EV by year assumed in the CEC EV Calculator.

This mix of EV types results in differences in the vehicle miles traveled using electricity each year. Short-range BEVs will travel fewer miles on average than long-range BEVs. Also, over time, as vehicles age, they are driven less each year. Therefore, older EVs will drive fewer miles than new EVs.

Once the miles traveled is determined, estimating the amount of energy needed to charge the batter relies on the EVs battery efficiency. Battery efficiency is similar to the miles-per-gallon rating for traditional internal combustion engine vehicles. It is the kWh necessary to travel a specified distance. The battery efficiency is expressed in terms of kWh or MWh per one mile. Each year, new EVs have demonstrated improvements in the battery efficiency meaning that the amount of electricity required for each mile has been decreasing. The CAR and the CEC have developed different assumptions for future battery efficiency. RPU utilized the CEC's input data in the EV Calculator.

Finally, to determine the amount of electricity that must be procured to serve EVs at their point of charge, the amount of electricity lost during transmission must be taken into account. For RPU, the assumed line losses in the modeling are 5.4%. Therefore, the electricity demand to support EVs is the amount of electricity demand to charge the EVs plus the amount of electricity lost during transmission.

17.3.3 EV Population and Energy Demand Forecast – Model Results

The light-duty EV population in RPUs service territory is expected to increase under all scenarios modeled. Figure 17.3.2 and Table 17.3.2 show the forecast residential light-duty EV population for RPU. Figure 17.3.3 and Table 17.3.3 show the electric load or demand to meet the forecast EV population (including the additional 5.4% load necessary to account for line losses).

The EV population in years 2015 through 2017 reflects actual EV registrations and is the same for all scenarios. Between 2015 and 2017, the EV population and energy demand in Riverside almost doubled from 1,021 EVs using 3,728 MWhs of electricity in 2015 to 2,004 EVs using 7,292 MWhs in 2017. This doubling in the number of EVs is reflective of the State's existing and aggressive policies to promote EVs, federal and state rebates on EVs and the increasing number of available EVs on the market at lower price points.

However, many incentive programs are phasing out. In particular, the $7,500 federal tax credit that was available to people who purchased EVs is being reduced or eliminated because automakers have been so successful in selling their vehicles that they have met the federal program funding limits. Therefore, without additional support, the growth in the EV population is expected to remain relatively flat, as reflected in the business-as-usual scenario. The business-as-usual scenario results in only minimal EV growth as these programs supporting EV growth phase out. For Riverside, this would result in continued growth that would bring the number of EVs to 4,899 in 2025 and only very slight growth to 5,224 in 2030. Energy demand would increase from 7,262 MWhs in 2017 to an estimated 17,498 MWhs in 2030 resulting in a negligible increase in load; i.e., less than a 0.5% increase in RPU load over about 13 years.

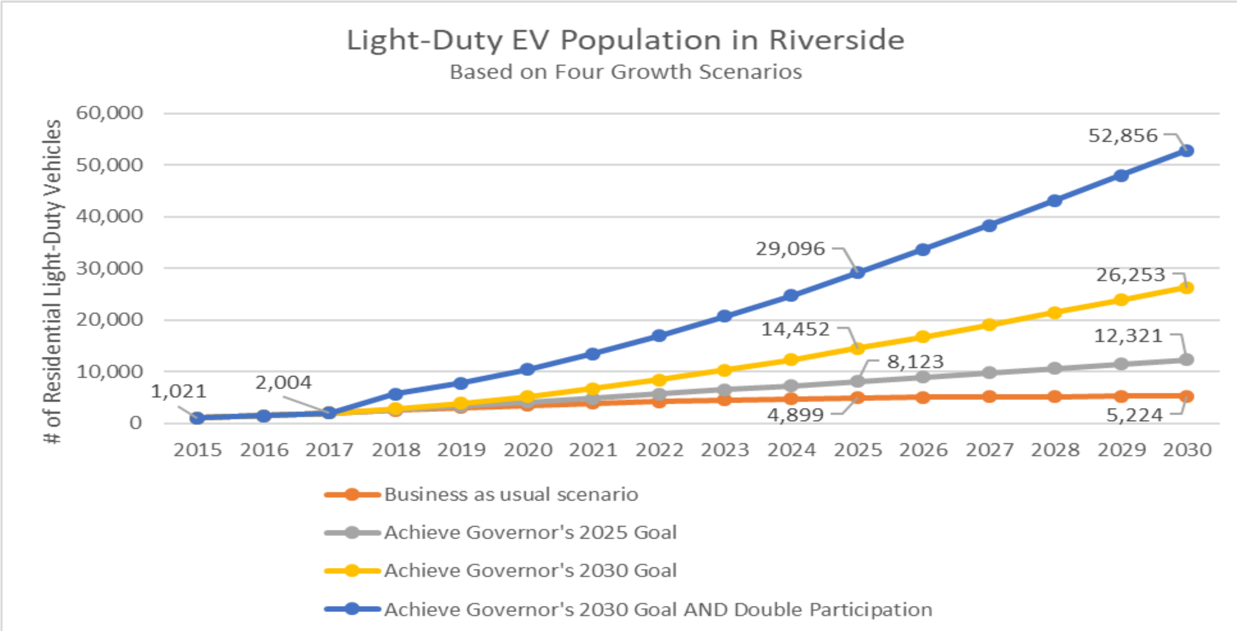


Figure 17.3.2. Forecasted light-duty EV population in Riverside using the CEC EV Calculator.

Table 17.3.2. Forecasted number of EVs in RPU's service territory using the CEC EV Calculator.

Year	Business-as-Usual	Governor's 2025 Goal	Governor's 2030 Goal	Governor's 2030 Goal and Double EV Share
2015	*1,021*	*1,021*	*1,021*	*1,021*
2016	*1,449*	*1,449*	*1,449*	*1,449*
2017	*2,004*	*2,004*	*2,004*	*2,004*
2018	2,536	2,631	2,817	5,672
2019	3,032	3,317	3,876	7,804
2020	3,483	4,052	5,170	10,408
2021	3,881	4,826	6,681	13,450
2022	4,222	5,628	8,388	16,887
2023	4,503	6,449	10,269	20,674
2024	4,728	7,283	12,298	24,760
2025	4,899	8,123	14,452	29,096
2026	5,024	8,966	16,704	33,630
2027	5,111	9,808	19,030	38,313
2028	5,167	10,648	21,409	43,102
2029	5,203	11,486	23,821	47,958
2030	5,224	12,321	26,253	52,856

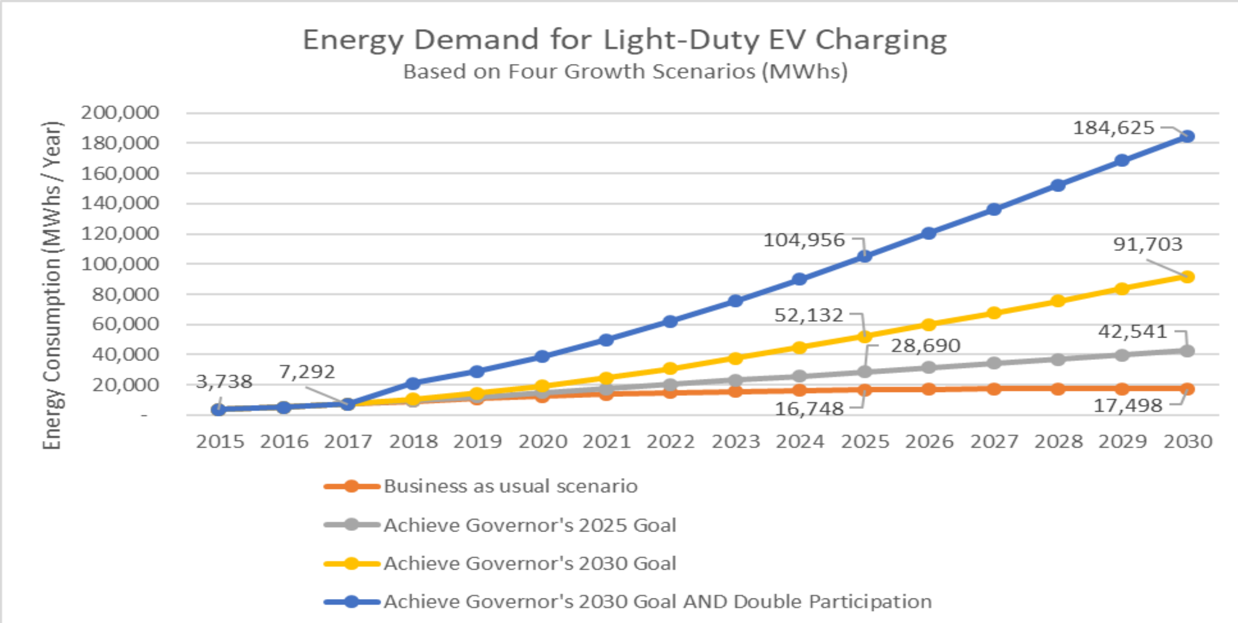


Figure 17.3.3. Energy demand from light-duty EV charging in Riverside using the CEC EV Calculator.

Table 17.3.3. Utility electrical load from EV charging (MWh/year) using the CEC EV Calculator.

Year	Business-As-Usual	Governor's 2025 Goal	Governor's 2030 Goal	Governor's 2030 Goal and Double EV Share
2015	*3,738*	*3,738*	*3,738*	*3,738*
2016	*5,335*	*5,335*	*5,335*	*5,335*
2017	*7,292*	*7,292*	*7,292*	*7,292*
2018	9,222	9,617	10,390	20,919
2019	10,944	12,103	14,380	28,950
2020	12,460	14,732	19,191	38,638
2021	13,749	17,452	24,721	49,770
2022	14,807	20,232	30,883	62,177
2023	15,646	23,047	37,576	75,651
2024	16,284	25,869	44,685	89,964
2025	16,748	28,690	52,132	104,956
2026	17,068	31,494	59,815	120,424
2027	17,275	34,283	67,670	136,240
2028	17,399	37,051	75,630	152,266
2029	17,467	39,803	83,653	168,418
2030	17,498	42,541	91,703	184,625

Note: Assumes 5.4% transmission line losses.

In contrast to the business-as-usual scenario, California's aggressive goals for TE strongly suggest that there will be continued State level support for sustainable EV growth. In particular, meeting the Governor's 2025 goal for the State to have achieved 1.5 million EV deployed has been a driving factor in State program development. Program and regulatory rule updates are currently underway that will continue or increase support of continued growth in the EV population. Under the scenario to meet the Governor's 2025 goal, the EV population in Riverside is expected to grow to 12,321 by 2030 and result in an energy demand of 43,541 MWhs. This represents a little more than 2% of RPU anticipated load in 2030. This near term growth is supported by State policy and regulatory efforts currently under development including, including but not limited to, changes in the Low Carbon Fuel Standard Program and budgeted funding allocations for research and grants from the CEC, CARB and other state agencies.[9]

RPU also evaluated two additional scenarios that met the Governor's 2030 Goal of 5.0 million EVs deployed in the State. The first of these two scenarios maintained the share of EVs currently in Riverside at 0.61% of the EVs in the State with the EV population in 2030 growing to over 26,000. Energy demand would increase to almost 92,000 MWhs representing 4.6% of RPU's load. The second scenario tested the outcome of doubling Riverside's share of EVs to 1.22%. By 2030, the population of EVs in Riverside would grow to almost 53,000 with a demand of 184,625 MWhs. This represents about 9% of RPU's load.

While these last two scenarios were evaluated, RPU determined that the timing of when the new EVs would enter Riverside's EV population was very uncertain. The model assumes an average annual growth in the EV population. As a result, the EV population by 2025 also increases and exceeds the 2025 goal. However, this growth trajectory may not be supported by the vehicles available in the market before 2025. Likewise, the policy and regulatory environment to support such EV growth (necessary to achieve this 2030 goal) has yet to be developed. Hence, these last two scenarios are currently considered unlikely, although RPU still recognizes the need to plan for the State's aspirational 2030 goal of having 5 million EVs deployed.

[9] Two examples of these policies and funding include the CEC's Alternative and Renewable Fuel and Vehicle Technology Program at http://www.energy.ca.gov/altfuels/ and information on CARB's Advanced Clean Cars Program at https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program.

17.3.4 Estimated Changes in GHG Emissions

RPU also utilized the EV calculator to estimate the GHG emissions reductions that would result from the modeled EV population scenarios. The EV calculator estimates the net GHG emissions reductions as the difference between the avoided GHG emissions (had vehicles used internal combustion engines) and the GHG emissions from the generation of electricity used by EVs. Avoided GHG emissions are the emissions that would have been associated with the vehicle had it used gasoline. The model takes into consideration the increases in the efficiency of the vehicles, the mix of vehicle types, and calculates emissions based on the fuel type, fuel efficiency, vehicle age, and annual miles driven. The carbon intensity of gasoline is also included in the calculations. The model allows users to select assumptions established by either CARB or by the CEC for these purposes. RPU opted to use the CEC's assumptions for these factors.

To estimate the GHG emissions associated with the electricity used to charge the EV's, RPU used the emissions factor (MT CO_2e / MWh) associated with the generation portfolio that meets RPUs emissions target for the electricity sector to reduce GHG emissions to 53 million MT CO_2e. The emissions factors input into the model are shown in Table 17.3.4 below.

Table 17.3.4. Annual emission factors for electricity used for EV charging.

Year	Emissions Factor (MT CO_2e / MWh)
2015	0.433
2016	0.423
2017	0.407
2018	0.404
2019	0.373
2020	0.377
2021	0.351
2022	0.351

Year	Emissions Factor (MT CO_2e / MWh)
2023	0.352
2024	0.362
2025	0.266
2026	0.205
2027	0.160
2028	0.168
2029	0.172
2030	0.176

Figure 17.3.4 and Table 17.3.5 on the following page show the GHG emissions reductions for Riverside. Under all scenarios, the emissions savings for 2015 through 2017 are the same. For these three years, the GHG emissions reductions are just under 7,000 metric tons (MT). Even under the business-as-usual scenario, the GHG emissions reductions are substantial by 2030. Between 2018 and 2030, the cumulative GHG emissions reductions associated with the EV population growing from 3,807 vehicles to almost 10,000 vehicles is over 97,000 MT. In 2030 alone, the net GHG emissions reduction

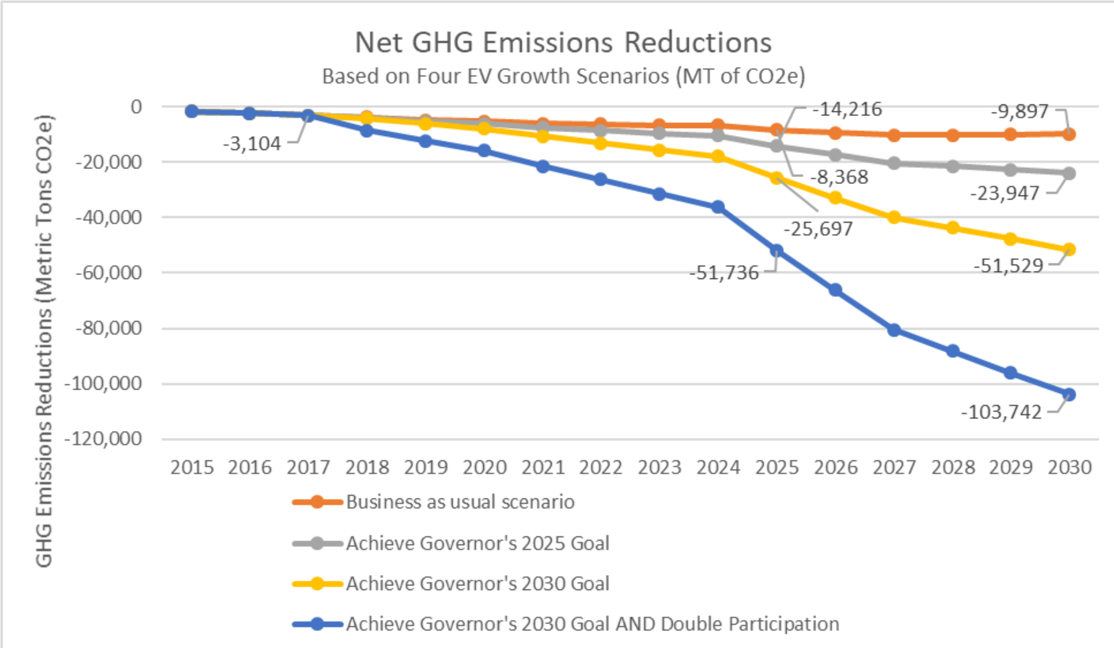


Figure 17.3.4. Net GHG emission reductions under four EV population growth scenarios using the CEC EV Calculator.

Table 17.3.5. Net annual GHG emission reductions under four EV population growth scenarios using the CEC EV Calculator.

Year	Business-As-Usual	Governor's 2025 Goal	Governor's 2030 Goal	Governor's 2030 Goal and Double EV Share
2015	*1,620*	*1,620*	*1,620*	*1,620*
2016	*2,245*	*2,245*	*2,245*	*2,245*
2017	*3,104*	*3,104*	*3,104*	*3,104*
2018	3,807	3,954	4,243	8,543
2019	4,737	5,203	6,118	12,317
2020	5,234	6,131	7,893	15,891
2021	6,029	7,576	10,613	21,367
2022	6,385	8,633	13,044	26,262
2023	6,650	9,690	15,659	31,526
2024	6,662	10,471	17,947	36,133
2025	8,368	14,216	25,697	51,736
2026	9,477	17,367	32,857	66,151
2027	10,299	20,319	39,989	80,509
2028	10,150	21,496	43,769	88,120
2029	10,029	22,738	47,687	96,008
2030	9,897	23,947	51,529	103,742

is 9,897 MT CO_2e – essentially eliminating the equivalent emissions from over 1.1 million gallons of gasoline.[10]

Under the scenario of meeting the 2025 goal of 1.5 million deployed EVs, the GHG emissions reductions cumulatively total 171,741 MT with the growth of EVs from 3,954 in 2018 to 23,947 in 2030. The annual emissions reductions in 2030 are almost 24,000 MT CO_2e, which is equivalent to the emissions that would have been produced by almost 2.7 million gallons of gasoline.[11] Likewise, the emissions reductions associated with the two additional scenario – meeting the 2030 goal of 5 million EVs deployed and meeting the goal and doubling Riverside's share of the statewide EVs results in cumulative GHG emissions reductions of 317,046 MT CO_2e and 638,305 MT CO_2e, respectively.

17.4 Daily EV Load Profile with Implementation of a Residential EV TOU Rate.

A key factor to evaluate when forecasting new EV load is the time of day when the load occurs. EV load is not constant throughout the day. Rather, most EV charging for residential customers occurs at home at the end of a trip – typically at the end of a work day. The time it takes to charge the EV is a combination of factors including the amount of charge needed and the charging capacity of both the vehicle and the charging equipment. It is necessary to take these factors into consideration for resource planning, since the number of EVs that may be charging on any given day can change the daily load profile.

RPU engaged NewGen Strategies & Solutions, LLC to analyze and model the impacts of residential EV charging on RPU's load, as well as the anticipated charging load changes that may result from customer's opting to use a recently adopted time-of-use (TOU) rate tariff for only EV charging. NewGen staff used their LSAM model to analyze three EV scenarios, which in turn were used to quantify the rate impacts of different EV growth forecasts, charging profiles, and the utility's recently approved residential EV-TOU rate. This section describes the model and results of this analysis.

Since the NewGen study was not completed until mid-July 2018, these daily load profiles are not incorporated into RPU's current IRP demand forecast. However, they are described here for information purposes [12] and will be incorporated into future forecasting analyses, as well as future evaluations of distribution grid impacts.

[10] Equivalent gallons of gasoline estimated using the U.S. Environmental Protection Agencies Greenhouse Gas Equivalencies Calculator last updated on September 2017 at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

[11] Ibid.

[12] Daily EV load profiles are provided as reference and as requested in the CEC Public Owned Utility Integrated Resource Plan Submission and Review Guidelines. See page 9, list item #1.

17.4.1 Scenarios Evaluated and EV Adoption

NewGen staff evaluated three different EV scenarios that considered EV adoption rates and EV charging equipment capacity. The EV adoption rates were used to determine the EV population in each year while charging equipment capacity influenced the timing and energy charging volumes. The LSAM model derived EV populations from the first version of the CEC's EV Calculator [13] and targeted achievement of the statewide 2025 goal of 1.5 million deployed EVs. Riverside's share of EVs was assumed to be 0.58% of the statewide number of EVs. Year 2016 is the base year from which EV growth is calculated. The annual EV population for both scenarios is shown in Table 17.4.1 and illustrated in Figure 17.4.1.

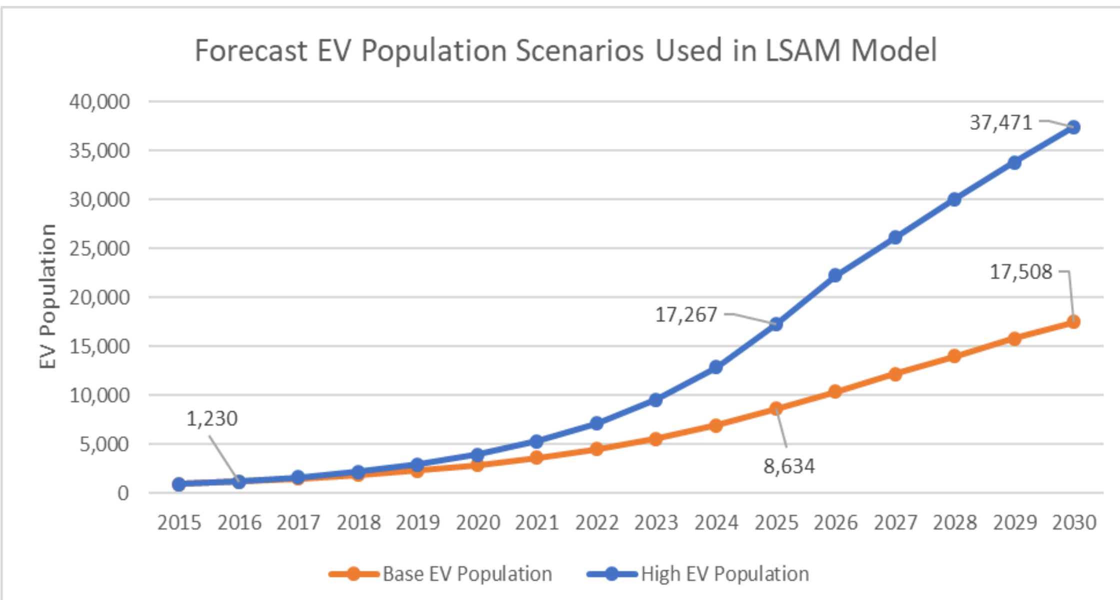


Figure 17.4.1. Forecasted EV population scenarios used in the LSAM model.

[13] The CEC's EV Calculator's earlier versions had slightly different modeling assumptions than those described in the previous sections. Any numeric differences are a result of the differences in the versions of the model.

Table 17.4.1. Forecasted annual EV populations used in the LSAM model.

Year	Base EV	High EV
2015	931	931
2016	1,230	1,230
2017	1,527	1,650
2018	1,897	2,212
2019	2,355	2,967
2020	2,924	3,979
2021	3,631	5,337
2022	4,509	7,158
2023	5,599	9,600
2024	6,953	12,875
2025*	8,634	17,267
2026	10,408	22,274
2027	12,225	26,165
2028	14,040	30,049
2029	15,812	33,841
2030	17,508	37,471

*The Base EV scenario represents Riverside's share of the EV Population that meets the State's 2025 Goal for 1.5 million EVs deployed.

The Base EV adoption scenario reflects achievement of Riverside's 0.58% share of EVs for the State's 2025 goal of 1.5 million EVs, based on the results of the EV Calculator (i.e., 8,634 EVs). EV growth between 2016 and 2025 grows at a compound annual growth rate (CAGR) of 24.2%. After 2025, the CAGR declines by 15% each year. The EV population grows from 1,230 vehicles in 2016 to 8,634 in 2025 and 17,508 in 2030.

The High EV adoption scenario assumed that Riverside's share of the number of EVs statewide is double the Base EV scenario (i.e., 1.15%) and that the state again achieves the 2025 goal of 1.5 million total EVs. The CAGR between 2016 and 2025 is 34.1% and declines annually by 15% thereafter. Under this scenario, the EV population grows from 1,230 vehicles in 2016 to 17,267 by 2025 and 37,471 by 2030.

The LSAM model evaluated the two adoption forecasts along with the capacity of the EV charging equipment. EV charging capacity is an important factor in determining both the charging load for the EV and the length of time the EV will charge. The charging equipment technology modeled included three representative charging capacities. The percentage of charging used in a given year shifted over time. The low capacity scenario shifted to higher capacity charging equipment more slowly over time than the high capacity scenario. Table 17.4.2 shows the technology change assumed in the model. The three scenarios tested by the LSAM Model were as follows:

Table 17.4.2. Charging equipment market share assumed in the LSAM model.

Scenario	Charging Equipment	2009 Market Share	2037 Market Share
Low Capacity	Level 1: 15 Amps, 120 Volts (1.8 kW demand)	80%	40%
	Level 2: 15 Amps, 240 Volts (3.6 kW demand)	20%	50%
	Level 2+: 30 Amps, 240 Volts (7.2 kW demand)	0%	10%
High Capacity	Level 1: 15 Amps, 120 Volts (1.8 kW demand)	80%	20%
	Level 2: 15 Amps, 240 Volts (3.6 kW demand)	20%	25%
	Level 2+: 30 Amps, 240 Volts (7.2 kW demand)	0%	55%

- Base EV Adoption with Low Capacity Charging Equipment (Base EV/Low Capacity)
- High EV Adoption with High Capacity Charging Equipment (High EV/High Capacity)
- High EV Adoption with Low Capacity Charging Equipment (High EV/Low Capacity)

The Base EV/Low Capacity Scenario most closely aligns with the scenario from the EV Calculator that meets the State's 2025 Goal of 1.5 million EVs deployed.

17.4.2 Assumptions for Daily EV Load Profile

Since the LSAM Model forecasts a daily load profile, vehicle charging profiles and charging capacity assumptions also needed to be developed. The model identifies the times that various EVs will begin charging in a given day and how much charge those vehicles will require based on the average percentage of trips that occur in a given hour and the average length of these trips. This driving pattern data was derived from data obtained from the National Household Transportation Survey. The LSAM model assumes that EVs that do travel on a given day will charge at home and that all EVs will have access to home charging.

The LSAM model also does not differentiate between plug-in hybrid EVs and BEVs. Average distance traveled by vehicles returning in a given hour establishes the amount of charge the vehicles need. The model assumes an average EV efficiency of 0.3434 kWh/mile, which is the average of vehicles being introduced to market in 2018. Therefore, for an EV that travels 100 miles, that vehicle would require 34.34 kWh to recharge the vehicle battery (before accounting for losses).

Figure 17.4.2 shows the percent of vehicles that arrive home in a given hour and the average number of miles those vehicles have driven for that trip. The majority of trips (55%) end at home between 3 p.m. and 8 p.m., which coincides with RPU's summer on-peak period and a portion of the winter on-peak period. Average trip length ranges from 19 miles to 31 miles during these hours. These vehicles will have some flexibility in their charging times because they will require shorter charging amounts than longer length trips. However, while there are fewer trips arriving home in late

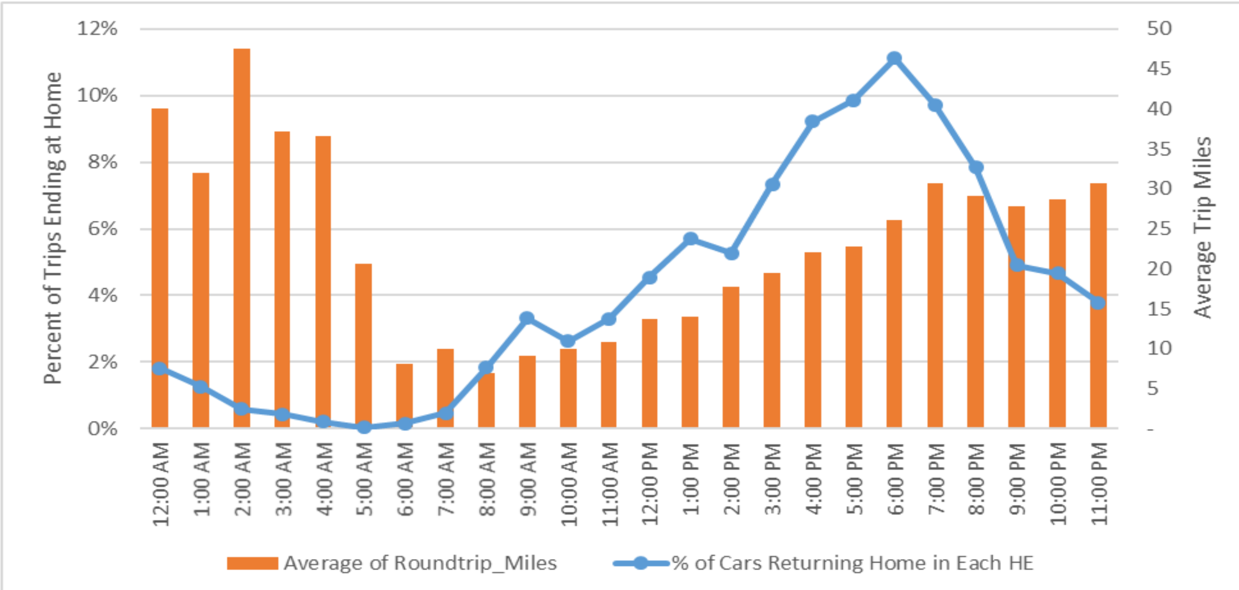


Figure 17.4.2. Average vehicle trip miles and number of trips ending at home. All estimates based on National Household Transportation survey data for the Riverside Metropolitan Statistical Area.

night and very early morning hours, the average trip length was longer. Vehicles that made these trips will require longer charging times or larger capacity charging equipment.

The LSAM model assumes that the EV using the charging equipment will accept the maximum amount of energy that can be provided by the charger technology. If the vehicle uses Level 2+ charging equipment, the model assumes that the EV will be able to accept the full 7.2 kW provided. Charging demand in each hour is determined by multiplying the number of EVs returning home in that hour by the peak demand of the assumed charger being used. For example, if 100 EVs had returned home at 5 p.m. in 2009, 80 EVs would charge using Level 1 equipment and 20 EVs would charging using Level 2 equipment.

The LSAM model uses this information to calculate the amount of EV charge demanded each hour. More specifically, the EV charge demand for a specific hour is the product of the following estimates: (1) total number of EVs for the given year, (2) share of EVs arriving at hour in that hour, (3) average miles traveled in that hour, and (4) the assumed average EV efficiency of 0.3434 kWh/mile. The EV charge demand is then distributed to individual hours of the day based on the proportion of the EVs using each of the three types of charging equipment (described previously in Table 17.4.2).

The daily charging profile is the summation of the charging in each hour based on the distribution of charging demand. Therefore, before any adjustments are made to the charging start times based on the customer's choices for charge time, the EV charge load distribution is the same for every day. The daily load provide for each year only varies based on the number of vehicles needing to charge each day.

To illustrate the daily load profile for EV charging without adjustment to charge times, the LSAM model results for year 2025 for the three EV adoption and charging capacity scenarios are shown in Figure 17.4.3. Likewise, summary information on daily total demand and minimum and maximum demand are provided in Table 17.4.3.

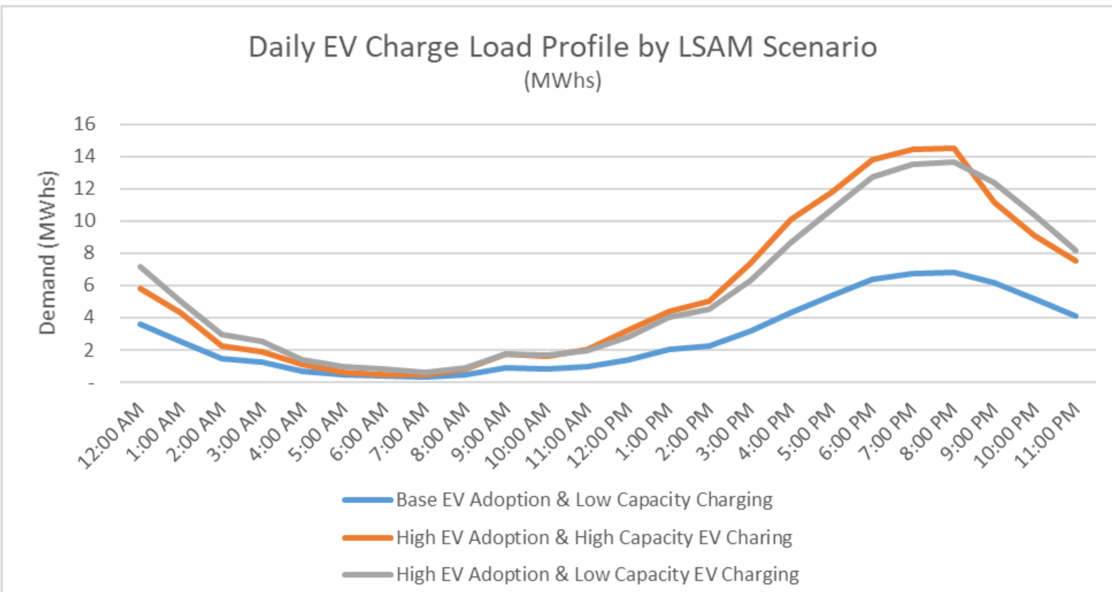


Figure 17.4.3. Example of year 2025 daily EV charging load profile for the three EV adoption and charging scenarios evaluated by the NewGen LSAM model.

Table 17.4.3. Summary of daily energy demand for the three EV charging scenarios in 2025.

Trip End Time	Scenario – EV Daily Energy Demand (MWhs)		
	Base EV Adoption & Low Capacity Charging	High EV Adoption & High Capacity EV Charging	High EV Adoption & Low Capacity EV Charging
EV Population	**8,634**	**17,267**	**17,267**
Daily Total EV Load (MWhs)	**67.76**	**135.52**	**135.52**
Minimum Hourly EV Load (MWhs)	0.29	0.43	0.59
Maximum Hourly EV Load (MWhs)	6.84	14.51	13.68

Of particular note are the differences in the maximum or peak EV charging demand in the daily profiles for high EV adoption under the two different charging capacity scenarios. With greater usage of high capacity charging equipment, the peak demand is greater. Under the High EV adoption with high capacity charging equipment, the peak demand is 14.51 MWhs compared to only 13.68 MWhs under the High EV adoption with low capacity charging equipment. This demonstrates that customers adopting higher capacity charging equipment will place higher demands on the distribution grid for shorting periods of time. RPU anticipates that these impacts on the distribution grid will need to be carefully evaluated as EV adoption rates in various areas of the City increase over time.

17.4.3 Assumptions for Charging Elasticity of Demand Analysis Based on EV-Only TOU Rate Tariff and Domestic Rate Tariff

As mentioned previously, the new residential (domestic) EV-only TOU rate tariff becomes effective January 1, 2019. This new rate is designed to send a price signal to conserve energy during the middle of the day and evening Mid- and On-peak hours. Customers opting to use this rate are required to have a separate EV only electric meter and the rate is only applicable to the EV charging. The LSAM model estimates the changes in this load as customer opt for the EV-only TOU rate, along with the corresponding revenue resulting from EV charging load.

To determine the applicable rates to use in the revenue analysis, the LSAM model assumes that some customers will remain on the standard Residential Domestic rate while the majority of customers will shift to the new EV-only TOU rate tariff over time. Table 17.4.4 shows the assumptions used to model the migration of customers from the Residential Domestic rate tariff to the EV-only TOU rate tariff. For each year, the LSAM model calculates the proportion of EV load that remains on the Residential Domestic rate and the portion that migrates to the EV-only TOU rate.

Table 17.4.4. EV customer tariff migration assumptions.

Type of Load	Domestic Rate Tariff	EV-Only TOU Rate Tariff
EVs existing prior to 2018	100% until 2018. After 2018, existing EVs slowly migrate to EV-Only TOU rate with 15% of EVs remaining on Domestic rate.	25% in 2018 increasing to 85%
EVs bought after 2018	5%	95%

To determine the applicable energy rate to apply to the EV load, the LSAM model uses two different assumptions for the two rate tariffs. The domestic rate tariff, as discussed previously in the chapter, has different tiers based on energy consumption or household demand. For EV load that remains on the domestic rate tariff, the EV energy usage was split between rate tiers with 50% assumed to be in the Tier 2 and 50% in the Tier 3.

For EV load on the EV-Only TOU rate tariff the load shifts between the On-, Mid-, and Off-peak periods for summer and winter seasons [14] based on an assumed price elasticity measure of 30%. This translates to a 30% reduction in load (shift to a different time period) given a 100% pricing differential between a higher and lower priced period. To determine revenue, the load was multiplied by the relevant rate for each peak period for the given year.

The assumed elasticity is three times the elasticity generally assumed for overall household load because both EV charging equipment and many EVs themselves can be programmed to set the time the vehicle will charge. Therefore, behavioral impediments to shifting load to different time periods are minimized. Using this assumed elasticity, the EV load in a given hour is calculate by multiplying the pricing differential for the price for the EV-Only TOU period and the Off-Peak energy rate by the assumed demand elasticity.

17.4.4 Key Results from the NewGen LSAM Model

Recall that the LSAM Model is able to determine the amount of residential EV load shifted due to the EV-Only TOU Rate Tariff and calculate the expected revenue from the resulting EV load. Figure 17.4.4 illustrates the expected effects of the EV-only TOU rate on the EV charging load for a summer day in 2025 assuming the Base EV adoption and low capacity EV charging equipment scenario. The diagram shows the daily EV load forecast by the LSAM model as the dashed blue line. It then illustrates the expected load shift due to customer migration and behavioral response to the EV-only TOU rate tariff for determining when EVs will charge.

[14] Summer season electric rates begin on June 1st of each year and end on September 30th of each year. All remaining days of the year are considered Winter season.

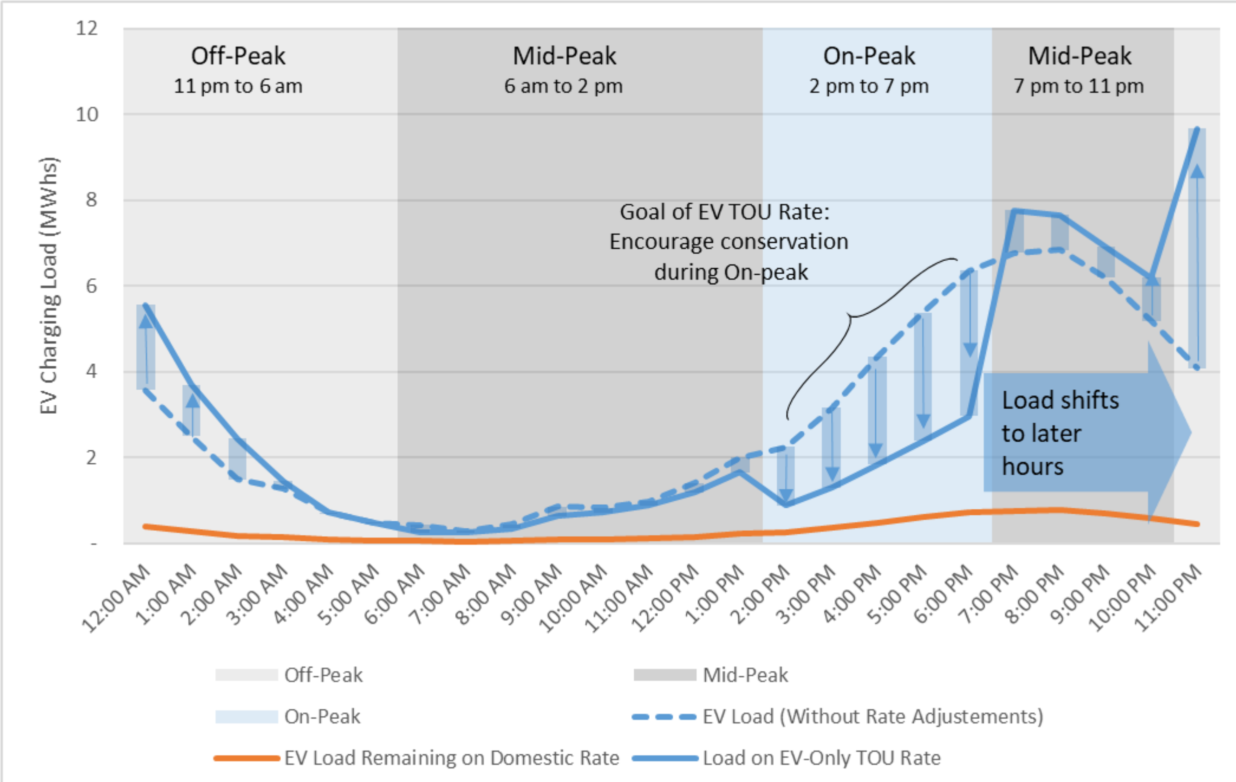


Figure 17.4.4. Effects of the EV TOU rate on EV charging load for a summer day in 2025, based on the LSAM model scenario assuming the Base EV adoption rate and low capacity charging equipment.

Table 17.4.5 details the daily load profile for the EV charge load shown in Figure 17.4.4. As shown, the daily EV load is forecast to be 67.76 MWhs. Of this, 7.58 MWhs are expected to remain on the residential domestic rate. EV charging load under this rate tariff does not shift to other times of the day.

The remaining 60.18 MWhs are expected to fall under the EV-only TOU rate tariff. Prior to any changes in the charging time that result from the EV-only TOU rate, EV charging would have been expected to peak at 8:00 PM with an estimated load of 6.07 MWhs. After applying the assumed elasticity based on the TOU rate, the EV load shifts from On-peak hours to both Mid-peak and Off-peak and some Mid-peak charging load shifts to Off-peak. In fact, about 64%, over 12 MWhs, shifts out of the On-peak hours – the majority of which is shifted to Off-peak. The shift does increase the load during evening Mid-peak hours as well as the load during Off-peak hours. Notably EV load peaks at 11:00 pm at 9.17 MWhs instead of 8:00 pm. This represents a shift in peak load of 3 hours and 2.36 MWhs.

Table 17.4.5. Sample daily EV load including load adjustments for load on EV-Only TOU rate from LSAM Model for summer 2025, under the Base EV Adoption and Low Capacity charging equipment scenario.

Hour of Day	Applicable TOU Rate	EV Load (Without Rate Adjustments)	EV Load Remaining on Domestic Rate	EV Load on EV-Only TOU Prior to Adjustment for EV-Only TOU Rate	EV Load on EV-Only TOU Rate Adjusted with Assumed Elasticity	Amount of Load Shifted Due to EV-TOU Rate
12:00 AM	Off-peak	3.57	**0.40**	3.17	**5.16**	1.99
1:00 AM		2.50	**0.28**	2.22	**3.41**	1.20
2:00 AM		1.49	**0.17**	1.33	**2.27**	0.94
3:00 AM		1.27	**0.14**	1.13	**1.30**	0.17
4:00 AM		0.71	**0.08**	0.63	**0.63**	-
5:00 AM	Mid-peak	0.48	**0.05**	0.42	**0.42**	-
6:00 AM		0.42	**0.05**	0.37	**0.21**	(0.17)
7:00 AM		0.29	**0.03**	0.26	**0.21**	(0.05)
8:00 AM		0.44	**0.05**	0.40	**0.30**	(0.10)
9:00 AM		0.86	**0.10**	0.76	**0.54**	(0.22)
10:00 AM		0.83	**0.09**	0.74	**0.62**	(0.11)
11:00 AM		0.97	**0.11**	0.86	**0.77**	(0.10)
12:00 PM		1.40	**0.16**	1.24	**1.03**	(0.22)
1:00 PM		2.00	**0.22**	1.77	**1.43**	(0.34)
2:00 PM	On-peak	2.25	**0.25**	2.00	**0.63**	(1.37)
3:00 PM		3.16	**0.35**	2.80	**0.94**	(1.86)
4:00 PM		4.34	**0.49**	3.86	**1.35**	(2.51)
5:00 PM		5.38	**0.60**	4.78	**1.78**	(3.00)
6:00 PM		6.35	**0.71**	5.64	**2.25**	(3.39)
7:00 PM	Mid-peak	6.77	**0.76**	6.01	**7.00**	0.99
8:00 PM		6.84	**0.77**	6.07	**6.88**	0.81
9:00 PM		6.18	**0.69**	5.49	**6.22**	0.73
10:00 PM		5.18	**0.58**	4.60	**5.61**	1.01
11:00 PM	Off-peak	4.07	**0.46**	3.62	**9.20**	5.58
Daily Total EV Load		**67.76**	**7.58**	**60.18**	**60.18**	
Minimum Hourly EV Load		**0.29**	**0.03**	**0.26**	**0.21**	
Hour of Day for Minimum Load		**7:00 AM**	**7:00 AM**	**7:00 AM**	**7:00 AM & 6:00 AM**	
Maximum Hourly EV Load		**6.84**	**0.77**	**6.07**	**9.20**	
Hour of Day for Maximum or Peak Load		**8:00 PM**	**8:00 PM**	**8:00 PM**	**11:00 PM**	

The revenue expectations from EV charging load are substantial, as shown in Table 17.4.6. Annual revenue from EV charging under the Base EV/Low Charge scenario increases from less than $1 million per year to about $16.8 million annually by 2030. Revenue expectations double to about $36 million annually as expected under the two High EV adoption scenarios; though slightly more revenue is anticipated under the high charging capacity scenario than the low charging capacity scenario (simply because more charging occurs during mid-peak hours than off-peak hours).

Table 17.4.6. Forecast revenue from modeled EV load and load profiles based on adoption of the EV-only TOU rate tariff through 2030, as derived from the NewGen LSAM model.

	High EV Adoption / High Charge Capacity			High EV Adoption / Low Charge Capacity			Base EV Adoption / Low Charge Capacity		
Year	**DOM**	**EV-TOU**	**Total Revenue**	**DOM**	**EV-TOU**	**Total Revenue**	**DOM**	**EV-TOU**	**Total Revenue**
2018	$0.7	$0.2	$0.9	$0.7	$0.2	$0.9	**$0.6**	**$0.2**	**$0.8**
2019	$0.6	$1.2	$1.9	$0.6	$1.2	$1.8	**$0.6**	**$0.8**	**$1.4**
2020	$0.6	$2.1	$2.7	$0.6	$2.0	$2.6	**$0.6**	**$1.3**	**$1.9**
2021	$0.6	$3.3	$3.9	$0.6	$3.1	$3.8	**$0.6**	**$2.0**	**$2.5**
2022	$0.7	$4.9	$5.6	$0.7	$4.8	$5.4	**$0.6**	**$2.8**	**$3.4**
2023	$0.7	$7.1	$7.8	$0.7	$6.9	$7.6	**$0.6**	**$3.8**	**$4.4**
2024	$0.8	$10.1	$10.9	$0.8	$9.7	$10.5	**$0.6**	**$5.0**	**$5.6**
2025	$0.9	$14.2	$15.0	$0.9	$13.7	$14.5	**$0.6**	**$6.6**	**$7.2**
2026	$1.0	$19.0	$20.0	$1.0	$18.3	$19.3	**$0.6**	**$8.3**	**$8.9**
2027	$1.1	$23.0	$24.1	$1.1	$22.2	$23.3	**$0.6**	**$10.2**	**$10.8**
2028	$1.2	$27.2	$28.4	$1.2	$26.2	$27.4	**$0.7**	**$12.1**	**$12.8**
2029	$1.3	$31.5	$32.8	$1.3	$30.4	$31.7	**$0.7**	**$14.1**	**$14.8**
2030	$1.4	$35.9	$37.3	$1.4	$34.6	$36.0	**$0.7**	**$16.1**	**$16.8**

17.5 Summary of Findings about TE & Next Steps

The electrification of the transportation system has a number of benefits to RPU and its customers, but also presents a number of challenges. TE represents a significant new source of load and thus a new source of revenue. As the TE Strategy is developed, it will be establishing and consolidating relevant City policies. However, it will also need to address the challenges that TE brings.

1. First, there is significant uncertainty in the accuracy of the forecasts and estimates discussed in this chapter. As discussed in both models, 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 are still being developed. Similar to the computer industry of years past,

the rapid changes in technology are improving both EVs and chargers, but are also much more challenging to plan for. Minimal historical information is available for utilities to use in forecasting. Therefore, the assumptions made now may not accurately represent what will actually occur in the future. This affects the anticipated charging loads, load profiles as well as technology adoption and EV population forecasts. RPU staff 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 have significant impacts on the forecast results.

2. Second, revenue forecasts for the charging of EVs in this chapter are limited to residential charging. The expected net revenues from charging will change as public access and workplace charging increases. RPU has not yet developed rate tariffs for non-residential charging and has not yet developed EV charge load forecasts for such charging. Additionally, charge loads for medium and heavy-duty vehicles and freight movement will also be necessary. Development of forecasts for these additional unique EV loads will be needed to fully evaluate both the impacts of EV charging on the distribution grid as well as the revenue benefits that may be realized.

3. Third, as the State's regulatory environment changes, electricity markets change due to increasing levels of renewables and the amount of rooftop PV increases, RPU's rate tariffs for TE will likely need to be 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. Fourth, 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. 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. Finally, TE has the additional and significant benefit of reducing air pollutants and GHG emissions. While significant strides have been made to reduces 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 with the emissions from electricity generation taken into account, 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.

18. Long Term Impacts of Customer Solar PV Penetration

Rapid changes within the electric industry, coupled with the steady decline in the costs of distributed energy resources (particularly behind-the-meter rooftop solar PV systems) has led to an increasing number of customers opting into Net Energy Metering (NEM) agreements. While RPU prides itself on fostering and facilitating increased amounts of behind-the-meter solar PV systems, it has long been recognized that the utility's rate structures do not fully recover the costs associated with supporting and integrating such systems. This issue is particularly problematic in the Domestic residential rate class, where RPU's three tier, inclining block rate structure leads to large within-class customer subsidies under the current NEM paradigm.

In order to better understand and plan for long-term, behind-the-meter solar PV penetration trends, RPU hired NewGen Strategies & Solutions, LLC to analyze and model these trends over this IRP cycle. This chapter provides a summary of these analyses and modeling results, specifically with respect to what the default residential rate tariff should be for future RPU residential NEM customers who install solar PV systems after the utility has reached its NEM 1.0 cap of 30.2 MW of installed solar PV capacity.

18.1 Domestic Residential Rate Tariffs

RPU currently offers a three tier, inclining block (3TIB) rate tariff to the vast majority of residential customers within the utility's service territory. The specific 3TIB tariff structure is shown in Table 18.1.1. Note that this is also the current default rate structure for all residential customers who install behind-the-meter solar PV systems under NEM agreements.

As part of the new rate plan, RPU is introducing a new two tier, domestic time-of-use (2T-DTOU) rate tariff. This optional rate tariff has been specifically developed for plug-in hybrid electric vehicle (PHEV) and battery electric vehicle (BEV) owners, as well as residential customers who can voluntarily shift significant amounts of their load to off-peak hours. This new rate structure is simple for RPU customers to understand, compatible with current TOU metering capabilities, and delivers a more accurate pricing signal to our customers. Additionally, the proposed 2T-DTOU rate structure does not allow for material arbitrage opportunities against the current 3TIB tariff, regardless of the customers average kWh/month usage level.

The TOU time periods for the proposed 2T-DTOU structure are shown in Table 18.1.2. Note that these Off-, Mid- and On-peak periods are applicable seven days a week during both the Summer (June-September) and Winter (October-May) seasons, and that the Off-peak period does not change across seasons. These simplified time periods are designed to send a clear price signal to RPU customers to conserve energy during the late afternoon / early evening ramping periods. Table 18.1.3 shows the corresponding hourly intervals for these three time periods, by season.

Table 18.1.1. Current RPU domestic residential rate tariff.

Tariff Component	Details	Rate
Monthly Customer Charge	all customers	\$8.06
Monthly Reliability Charge	0-100 Amp panel	\$10.00
	101-200 Amp panel	\$20.00
	201-400 Amp panel	\$40.00
	> 400 Amp panel	\$60.00
Monthly Energy Rates	Summer Tier 1: 0-750 kWh	\$0.1035
	Summer Tier 2: 751-1500 kWh	\$0.1646
	Summer Tier 3: > 1500 kWh	\$0.1867
	Winter Tier 1: 0-350 kWh	\$0.1035
	Winter Tier 2: 351-750 kWh	\$0.1646
	Winter Tier 3: > 750 kWh	\$0.1867

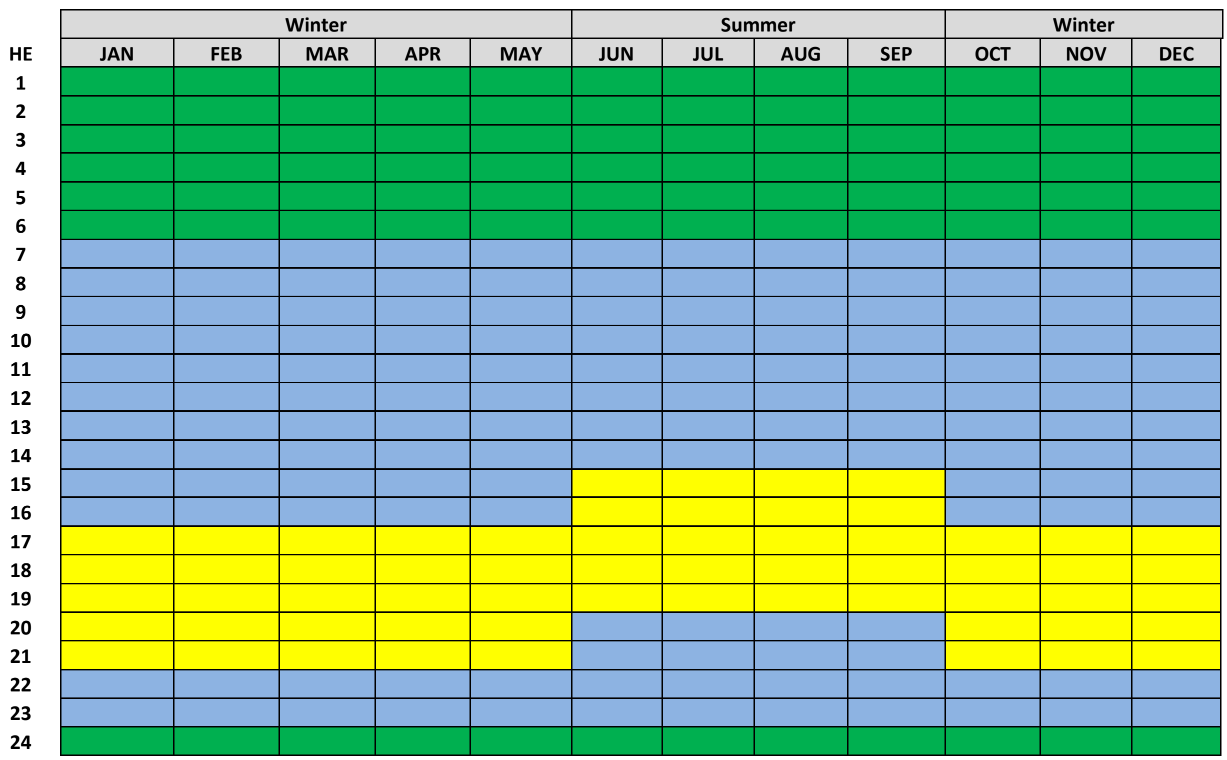
All residential customers under this new 2T-DTOU rate tariff will automatically pay the exact same customer and reliability charges as they would under the utility's current 3TIB tariff. The fundamental difference between the two tariffs concerns how the energy billing determinants are applied. In the 2T-DTOU tariff, these billing determinants correspond to the accumulated energy usage in the defined TOU time periods, as opposed to just the total accumulated energy in the month. Table 18.1.4 shows the specific energy billing determinants associated with the new 2T-DTOU rate. Note that the 2T-DTOU tariff encourages customers to shift flexible On-peak load to either the Mid- or Off-peak time periods (to take advantage of lower priced energy rates), and/or charge electric vehicles during the Off-peak time period. Equivalently, this new tariff sends a more accurate price signal to RPU residential customers, given that the relative differences in the TOU energy billing determinants more accurately reflect RPU's actual generation cost-of-service metrics. Likewise, the two tier billing structure continues to encourage customers to conserve energy (particularly in the On-peak hours).

Although the new 2T-DTOU rate is being primarily introduced for PHEV/BEV owners, its more accurate pricing signals also make it a good default candidate tariff for a NEM 2.0 successor program. RPU expects to reach its NEM solar PV cap of 30.2 MW of installed behind-the-meter capacity within the next 18 months. Once this cap is reached, the utility would like to propose an alternative default rate structure for future residential customers who wish to interconnect behind-the-meter solar PV systems, specifically a new rate structure that reduces the customer within-class subsidy impacts under the current NEM program (based on the 3TIB rate). Although not ideal, this new 2T-DTOU rate structure could represent a more equitable default structure for new solar PV customers.

It should be clearly understood that RPU's current NEM program is contributing to within-class customer subsidies in the Residential rate class. This is occurring because the majority of the utility costs for this class are fixed, but the majority of utility revenue is being collected through variable energy charges. This recovery of fixed costs through variable charges creates an imbalance when net metered customers are compensated (or credited) for their excess generation at retail rates, which over time forces non-NEM customers to pay a greater share of these costs through escalated variable charges.[1,2] Mitigating the impacts of this within-class subsidy effect becomes critically important as significantly more customers install solar PV systems; note that the remainder of this chapter is dedicated towards examining this issue in much greater detail.

Table 18.1.2. Three time period domestic Residential TOU structure (Off-peak: green, Mid-peak: blue, On-peak: yellow).

Residential TOU periods (7 days a week, including all holidays)



[1] American Public Power Association. *Distributed Generation: An Overview of Recent Policy Developments.* 2014
[2] American Public Power Association. *Rate Design Options for Distributed Energy Resources.* 2016

Table 18.1.3. Corresponding domestic TOU time periods (hourly intervals).

	Summer (June 1 – September 30)	Winter (October 1 – May 31)
Off-peak	11 PM to 6 AM	11 PM to 6 AM
Mid-peak	6 AM to 2 PM & 7 PM to 11 PM	6 AM to 4 PM & 9 PM to 11 PM
On-peak	2 PM to 7 PM	4 PM to 9 PM

Table 18.1.4. Proposed two-tier domestic TOU summer and winter energy rates and tier allotments.

	Summer			Winter		
	On-peak	Mid-peak	Off-peak	On-peak	Mid-peak	Off-peak
Tier-1	$0.1746	$0.1135	$0.0873	$0.1310	$0.1048	$0.0873
Tier-2	$0.2794	$0.1816	$0.1397	$0.2095	$0.1676	$0.1397
Tier 1 kWh Allotment	330	550	220	135	250	115

18.2 Avoided Cost of Energy for Behind-the-Meter Solar PV Systems

18.2.1 Avoided cost assumptions

A calculation methodology is now presented for determining the appropriate value of production energy from behind-the-meter customer solar PV generation. The approach proposed here is essentially identical to the methodology used for calculating the value of avoided energy due to EE measures (see Chapter 14, section 14.2).

Once again, the following avoided cost components should be recognized, analyzed and (if appropriate) valued when computing the implied value of solar PV production energy:

- Generation energy
- Generation capacity
- Ancillary services
- Transmission costs
- Distribution costs
- Environmental/GHG costs
- Avoided RPS costs
- System losses

With respect to the eight avoided cost categories listed above, reasonably objective methodologies can again be proposed for appropriately valuing five of these components (e.g., generation energy, generation capacity, environmental/GHG costs, avoided RPS costs and system losses), and staff cannot identify any avoided costs associated with two additional categories (ancillary services and transmission costs). As in the case of assessing EE impacts, the calculation of avoided distribution system costs is quite complicated and typically location specific. However, unlike EE impacts, excessive over-production of solar PV generation can actually lead to significant bi-directional energy flow on certain circuits, resulting in additional distribution costs to accommodate such energy flows. Hence, it is not unrealistic to expect that in certain scenarios excess solar generation will actually lead to increased (rather than avoided) distribution system costs.

Notwithstanding these issues, the valuation of each of these avoided cost components follow the same logic used in section 14.2. Furthermore, since RPU does not currently possess the ability to accurately quantify location specific distribution costs or benefits, staff recommends using a generic avoided cost estimate for this cost category that is marginally lower than the generic estimate used for baseload EE impacts.

18.2.2 Avoided cost calculation methodology

Based on the above avoided cost components, a practical value of solar PV generation energy (VSPVGE) calculation methodology can be derived and used to estimate the $/kWh value of such energy. Again, a few caveats concerning these calculations are worth expanding upon. First, it is necessary to specify certain additional assumptions about the solar PV energy generation pattern for a typical rooftop system. For example, one must specify both the annual and monthly capacity factors (CF) for a typical system, as well as the expected kW peak load reduction probabilities for each month of the year. After these assumptions have been determined, additional avoided cost values for the energy, capacity, carbon, RPS and distribution credits again need to be quantified, along with the distribution loss adjustment factor. Table 18.2.1 discusses each of these avoided cost values in more detail. Once all of this information has been quantified, a VSPVGE estimate can be computed.

Table 18.2.2 shows the baseline calculations for determining the inputs into the VSPVGE calculation methodology. As previously discussed in Chapter 2, a typical south facing rooftop solar PV system is assumed to have a 20% annual CF and monthly CF's and kW peak reduction probabilities matching those shown in Table 2.2.5. (These monthly CF's have been converted into seasonal weighting of avoided kWh estimates by determining the kWh/month production numbers for a 1 kW AC system and then dividing each monthly estimate by 1,752 kWh.) These values can then be used in conjunction with the SP15 heavy-load energy prices also shown in Table 18.2.2 to calculate an appropriate energy credit. Likewise, the kW peak reduction probabilities can be used in conjunction with assumptions about system and local capacity costs to calculate appropriate capacity credits.

After quantifying all of these assumptions and avoided cost estimates, a VSPVGE estimate can be calculated for a typical south facing rooftop solar PV system. The detailed calculations supporting this VSPVGE estimate is shown in Table 18.2.3; note that this estimate is ~ $0.07/kWh. This estimates quantifies RPU's avoided costs (i.e., budgetary savings) for the gross solar generation energy from a customer's PV system on a $/kWh basis, respectively.

Table 18.2.1. Avoided cost components for use in the VSPVGE calculation methodology for valuing production energy from behind-the-meter solar PV generation.

Component (Avoided Costs)	Metrics (used in calculations)	Proposed Methodology (for deriving avoided cost estimate)
Energy	SP15 Forward heavy-load electricity 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 $/month system RA costs. Peak hour reduction probability for corresponding PV production.	Estimate monthly system RA costs ($/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.
Environmental (Carbon Credit)	ARB Carbon clearing prices (last four quarters) + 7% cost adder. CAISO system average emission factor (EF).	Greater of prior year's average ARB Carbon clearing prices + 7% cost adder or current year's floor price, multiplied by the CAISO average emission factor.
RPS Credit	Delta price difference (SP15 energy forecast - average renewable pricing in RPU portfolio). Annual RPS target (proportion).	Delta price difference between SP15 energy forecast and average renewable pricing in RPU portfolio, multiplied by RPS target
Distribution	Use default avoided cost estimates for expected distribution system impacts.	Assume $0.0075/kWh avoided costs for average distribution system impacts, which recognizes potential increased costs due to over-generation, as well as potential benefits.
System Losses	Average distribution loss factor (proportion).	Divide sum of $/kWh components (Energy, Capacity [system and local], Carbon, RPS credit, and Distribution) 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 18.2.2. Assumed baseline calculations for determining the inputs into the VSPVGE calculation methodology (i.e., seasonal weighting of avoided kWh values, kW peak reduction probabilities, and SP15 heavy-load market energy prices)**.**

Month	Seasonal weighting of avoided kWh calculations			kW Peak Reduction Prob (2)	SP15 heavy-load market energy costs ($/MWh)
	Monthly CF (1)	kWh/m calcs	kWh weighting coefficients		
Jan	0.172	127.97	0.0703	0	$40.15
Feb	0.181	121.63	0.0694	0	$34.35
Mar	0.195	145.08	0.0828	0.359	$27.25
Apr	0.211	151.92	0.0867	0.403	$24.40
May	0.225	167.40	0.0955	0.434	$24.75
Jun	0.232	167.04	0.0953	0.442	$33.25
Jul	0.229	170.38	0.0972	0.425	$38.45
Aug	0.217	161.45	0.0921	0.389	$40.15
Sep	0.203	146.16	0.0834	0.342	$38.10
Oct	0.188	139.87	0.0798	0.298	$36.90
Nov	0.176	126.72	0.0723	0	$34.65
Dec	0.170	126.48	0.0722	0	$36.10

Notes: (1) from Table 2.2.5, column 2 (load scaling factors); (2) from Table 2.2.5, column 3 (peak shaping factors).

Table 18.2.3. Detailed calculations within the VSPVGE worksheet (for deriving the value of production energy from a behind-the-meter solar PV system).

	2018 VSPVGE Worksheet (for deriving a value for production energy from BTM solar PV)											
kW[AC] nameplate	1.00											
PV Assumptions:	**typical South facing, 20% annual AC CF**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	0.000	0.000	0.359	0.403	0.434	0.442	0.425	0.389	0.342	0.298	0.000	0.000
Seasonal weighting of avoided kWh:	0.0730	0.0694	0.0828	0.0867	0.0955	0.0953	0.0972	0.0921	0.0834	0.0798	0.0723	0.0722
Assumed annual hours of operation:	1752											
Annual kWh Output:	1,752.0	**CF:**	**20.0%**									
Energy Credit												
SP15 HL Power Cost - 2018 ($/MWh)	$40.15	$34.35	$27.25	$24.40	$24.75	$33.25	$38.45	$40.15	$38.10	$36.90	$34.65	$36.10
MWh/month credit:	$2.93	$2.38	$2.26	$2.12	$2.36	$3.17	$3.74	$3.70	$3.18	$2.94	$2.51	$2.61
Annual MWh credit:	$33.89											
kWh value:	$0.03389										**Weighted Ave $/MWh Energy:**	$33.90
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.00	$0.00	$0.27	$0.30	$0.65	$0.66	$1.91	$1.75	$1.54	$0.60	$0.00	$0.00
Annual kW credit:	$7.68											
kWh value:	$0.00439											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$7.05											
kWh value:	$0.00402						**2017**	**2018**	**2018**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$10.90		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$18.71				**Weighted Ave $/MWh Energy:**	$33.90		**$/MWh**				
kWh value:	0.01068				**2018 Target RPS:**	29.00%		$10.68				
Distribution Benefit Credit	0.0075		(recognizes potential distribution costs due to overgeneration, as well as benefits)									
Sum of Credits ($/KWh):	$0.0667											
Annual $ Value per installed kW:	$78.23											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0705											
Loss Adjusted Annual $ Value:	$82.69											
$/kWh VOAE:	**$0.0705**		**← value to RPU for avoided load savings due to BTM solar PV**									
Annual $ Value per installed kW:	**$82.69**											

18.3 Tariff Specific NEM Induced Cost Shifts for Typical Residential Solar PV Customers

The average NEM cost shift effect under both the 3TIB and 2T-DTOU retail rate structures are quantified in this section. Given that RPU does not collect interval level meter data (for all but a fraction of very large TOU customers), this analysis is based on SCE Domestic proxy load data and engineering calculated hourly diurnal solar PV production levels.

A historical analysis of RPU residential NEM customer billing data indicates that the typical NEM customer has installed a solar PV system that offsets about 88% of their annual home energy load. Additionally, these customers tend to be higher use energy customers (based on an analysis of their annual energy use levels immediately preceding the installation of their solar PV systems). Thus, as a point of reference, RPU staff computed the expected NEM cost shifts for a typical residential customer who offsets 88% of their annual energy needs via a solar PV system and uses an average of either 800/kWh or 1,200/kWh a month.

Custom SAS programming code was developed and used to perform all of the relevant analyses, after scaling the proxy load data and hourly PV production levels to match the typical customer profiles discussed above. These analyses included (1) determining each customers hourly gross load, hourly gross solar PV generation, and resulting hourly net load, (2) computing each customer's monthly bill before accounting for any solar PV generation (i.e., the pre-NEM bill), (3) computing each customer's monthly bill under the NEM 1.0 paradigm (i.e., the post-NEM bill under the current rate tariff), and (4) computing the apparent value of the solar PV generation to RPU using the avoided DER cost calculation discussed in section 18.2. In all analyses it was assumed that all excess solar PV generation would be credited at the applicable retail rate for the corresponding rate tariff.

Table 18.3.1 shows the NEM cost shift calculations associated with the 3TIB and 2T-DTOU rate tariffs, for both a typical 800/kWh-month and 1,200/kWh-month customer. All dollar values are shown on an annual basis, these values include (1) the "Bill before NEM" amount, (2) the "Bill after NEM" amount, (3) the "Buy-all / Sell-all" amount quantifying the value of the customer solar PV generation to RPU, expressed as the pre-NEM bill minus the utility avoided costs associated with the PV generation, (4) the corresponding cost shift amount, which represent the lost net revenue amount that must be shifted to (i.e., collected from) non-NEM customers, and (5) the normalized $/kW cost shift amount, which was calculated as the absolute cost shift amount divided by the installed capacity size of the rooftop PV system. Note that this last column quantifies the degree of the cost shift severity on a per-kW of installed capacity basis.

The normalized $/kW cost shift figures shown in Table 18.3.1 suggest that the apparent within-class subsidy would be reduced somewhat under the 2T-DTOU rate tariff; specifically by about 16% to 18% for these two customer profiles. Equivalently, an 800/kWh-m customer who installs a solar PV system would expect to pay about $6.00 more per month on their utility bill under the 2T-DTOU tariff, as opposed to the current 3TIB rate tariff. (Likewise, the 1,200/kWh-m customer would pay $15.65 more per month.) Thus, the 2T-DTOU tariff would be somewhat more effective at reducing the current magnitude of the apparent cost shift, although it comes nowhere close to eliminating it.

Assuming that the 2T-DTOU tariff represents a more appropriate rate tariff for future NEM customers, the impacts that such a tariff might have on future solar PV adopting rates represents the obvious next question. The remainder of this chapter addresses this question in detail.

Table 18.3.1. Final NEM cost shift calculations under the 3TIB and 2T-DTOU rate tariffs, for typical RPU residential customers who consume an average of 800/kWh and 1,200/kWh per month in electricity.

Metric	**Cost-shift results: 800 kWh/month**		**Cost-shift results: 1,200 kWh/month**	
Rate Tariff	3TIB	2T-DTOU	3TIB	2T-DTOU
System kW	4.82	4.82	7.23	7.23
Bill before NEM ($)	$1,445.81	$1,436.73	$2,410.61	$2,418.43
Bill after NEM ($)	$335.96	$408.07	$515.52	$703.33
Buy-all | Sell-all ($)	$854.43	$845.35	$1,523.52	$1,531.35
Cost Shift ($)	$518.47	$437.28	$1,008.00	$828.02
$/kW Cost Shift	$107.57	$90.72	$139.42	$114.53
% Reduction in Shift		15.7%		17.9%
$ Reduction in Shift		$16.84		$24.89

18.4 Long Term Behind-the-Meter Solar PV Penetration Assumptions

NewGen has created a Load Shape Analysis Model (LSAM©) that can be used to study how different rate tariffs can impact both customer solar PV and EV adoption levels, which in turn impact future diurnal load shape forecasts and retail revenues. Under contract with RPU, NewGen staff used LSAM to assess how the 3TIB and 2T-DTOU rate tariffs might be expected to impact future solar PV adoption levels, assuming that one of these two rates become (or remain) the default residential rate tariff under the NEM 2.0 paradigm. This section briefly describes the key input assumptions used in LSAM for this solar PV adoption impact study.

18.4.1 PV hourly production profile

The hourly solar PV production levels were based on engineering estimates derived from the PV Watts simulation software, using a typical south-facing rooftop system.

18.4.2 Historic PV customer economics

The historical gross installed cost of solar data was obtained from both NREL and California Solar Initiative data bases; these estimates compared favorably to historical RPU cost information. All information on historical local incentive payments (i.e., $/watt rebates) were provided by RPU. All Federal Tax Incentives (Investment Tax Credit – ITC) were modeled based on historic implementation patterns and the currently planned incentive sunset schedule (currently 30% and declining to a permanent 10% from 2020-2022).

RPU provided both historic and planned future rates for both the 3TIB and 2T-DTOU rate tariffs through 2022. Historic applicability of Reliability charges for existing PV customers was determined by analyzing how the typical energy usage correlates to amps and Reliability Tiers. Finally, in order to determine the impacts of seasonal rates on the solar value proposition, NewGen performed an analysis on RPU's historic residential billing database. This analysis was used to develop average monthly energy consumption estimates from total annual energy consumption values.

18.4.3 Future PV customer economics

The forecasted costs for residential solar PV systems through 2037 were derived from NREL estimates. Post-2022 3TIB and 2T-DTOU rates were assumed to increase at a 2.5% annual growth rate. Additionally, it was assumed that RPU would reach its NEM 1.0 cap (30.2 MW) by 2020.

To estimate the total number of PV systems that might be deployed within the RPU service territory, NewGen staff calculated both the Technical and Economic Market potential for such installations. The Technical Market took the total number of residential customers (~95,000 taken from Cost of Service data), and subtracted 16,588 customers identified to be Multi-Family customers. From the remaining customers (~78,500), based on Google Sunroof [3], NewGen staff assumed 89% of buildings were solar viable, but only 65% are owner-occupied [4] and could thus have ownership control over the property to decide to install solar. This yielded an approximate Technical Market potential of about 45,400 locations (i.e., 78,500 x 0.89 x 0.65 ≈ 45,400).

The Economic Market Potential equation was calibrated to historic RPU adoption data. This equation relates solar economics to the number of customers within the Technical Market that would be interested in buying solar PV systems. The equation is defined as:

$$Market\ Potential = e^{(-SP*PB)} \qquad \text{[Eq. 18.1]}$$

where *SP* = sensitivity to payback (a fitted constant) and *PB* = payback (based on PV economics). NewGen staff optimized the least squared difference between actual historic RPU PV adoption data and Eq. 18.1, determining a value of 0.3082 for the *SP* parameter coefficient.[5]

NewGen staff also used a Bass Diffusion Model to control the rate of solar PV adoption over time. The Bass Diffusion Model was used to potentially constrain PV adoption over time given a level of Market Potential as calculated in a given year based on PV customer economics. The Bass Diffusion Model used three constants to determine the shape of the diffusion curve: The year of market viability (*T*), the "Coefficient of Innovation" (*P*) or the impact of early adopters on PV diffusion, and the "Coefficient of Imitation" (*Q*) or the impact of laggard adopters on PV diffusion. The Bass Diffusion Curve equation was defined as follows:

[3] Source: Project Sunroof data explorer (April 2018)
[4] https://www.census.gov/quickfacts/fact/table/riversidecountycalifornia/HSG445216#viewtop
[5] As a point of comparison, the RW Beck Value of Solar study completed for Arizona Public Service in 2009 used 0.3 as the SB coefficient, and multiple studies since 2009 have used that value as a check of reasonableness for location-specific assumptions.

$$Adoption\ Rate\ (t) = \frac{1 - e^{-(p+q)*T}}{1+(\frac{q}{p})e^{-(p+q)*T}} \qquad \text{[Eq. 18.2]}$$

In this specific analysis, NewGen staff used two diffusion curves to reflect different timing of full market penetration depending on a more or less beneficial set of customer economics. The corresponding coefficient values were determined by optimizing the forecast equation to historical RPU adoption patterns; these estimated coefficients are shown in Table 18.4.1 below. Note that the Diffusion Curves produced by these equations reflect the percentage of the technical market that has adopted PV systems by a given year since market initiation.

Table 18.4.1. Optimized Bass Diffusion coefficients for the "more favorable" and "less favorable" economic payback scenarios.

Variable	Value	More Favorable PV Economics (< 13 year payback)	Less Favorable PV Economics (> 13 year payback)
T	2006 [6]		
p		.003557	.002005
q		.458	.223

18.4.4 PV impacts on revenue

Solar PV revenue impacts were calculated by comparing the bill credits of historically installed PV systems in each year since they were installed to an assumed avoided cost rate. This avoided cost rate was set equal to $0.07/kWh in 2018 and escalated at 2.5% per year across future years. Additionally, PV system production degradation was assumed to be 0.5% per year, and each year's net energy consumption was calculated based on the average energy usage prior to the PV installation, the assumed PV production after degradation and the relevant year's RPU rate tariff.

18.5 Key Results from the NewGen Solar PV Penetration Study

Figure 18.5.1 shows a plot of the financial implications associated with the current NEM paradigm for RPU; i.e., the expected annual customer savings, avoided utility costs and overall net revenue impacts the utility would experience in the domestic residential customer class if the NEM 1.0 program was to continue under the present 3TIB rate structure. Currently, staff estimates that there is slightly over a 3 million dollar cost shift occurring within this customer class. However, the NewGen

[6] 2006 was selected based on its corresponding to an early year of PV adoption in RPU's territory, and it created a high-quality fit of the forecast against actual historic adoption. Further, it acknowledges that the small number of PV systems purchased prior to 2006 may have been purchased for reasons other than pure economics, as the price of PV was substantially higher and paybacks longer than is reasonable in the context of more recent data.

study results imply that this cost shift could reach 30 million dollars annually by 2037, which clearly represents an unsustainable trend.

Figure 18.5.2 shows the expected number of behind-the-meter solar PV systems installed in the RPU service territory under both the 3TIB and 2T-DTOU tariff structures. Likewise, Figure 18.5.3 shows the annual amount of energy produced by these same solar PV systems under both tariff structures. Both of these plots show a similar set of patterns; specifically that new solar installations drop off considerably from 2020 through 2023 under the 2T-DTOU tariff. (Recall that if adopted, the 2T-DTOU tariff would kick in on/after 2020 upon reaching the NEM 1.0 cap.) However, after 2023, the upward trend in installations (and corresponding energy generation) would resume at essentially the same rates under either tariff scenario. Note that the temporary slowdown of installations in the 2020 to 2023 time period is due to both the adoption of the alternative tariff and the expiration of the investment tax credits. (Under the 3TIB tariff scenario, a similar slowdown can be seen in the 2021-2022 time period in response to the reduction in the ITC.)

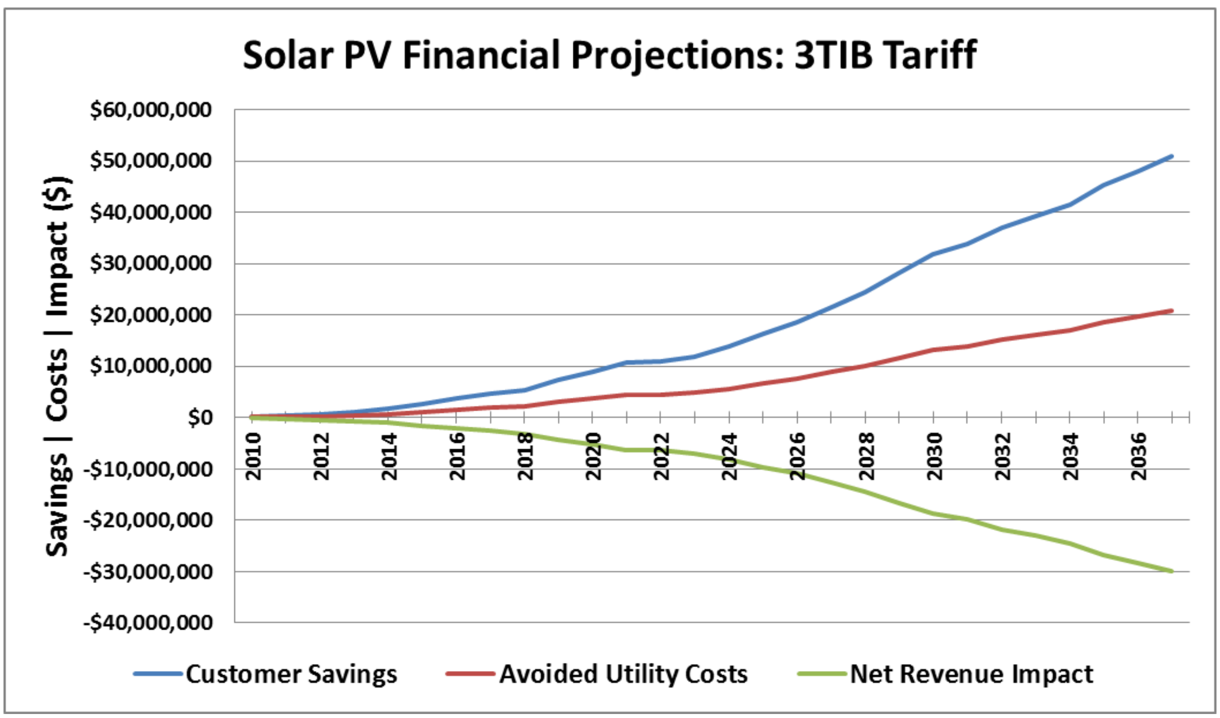


Figure 18.5.1. Expected annual customer savings, avoided utility costs and overall net revenue impacts under a NEM program that defaults to the 3TIB tariff through 2037.

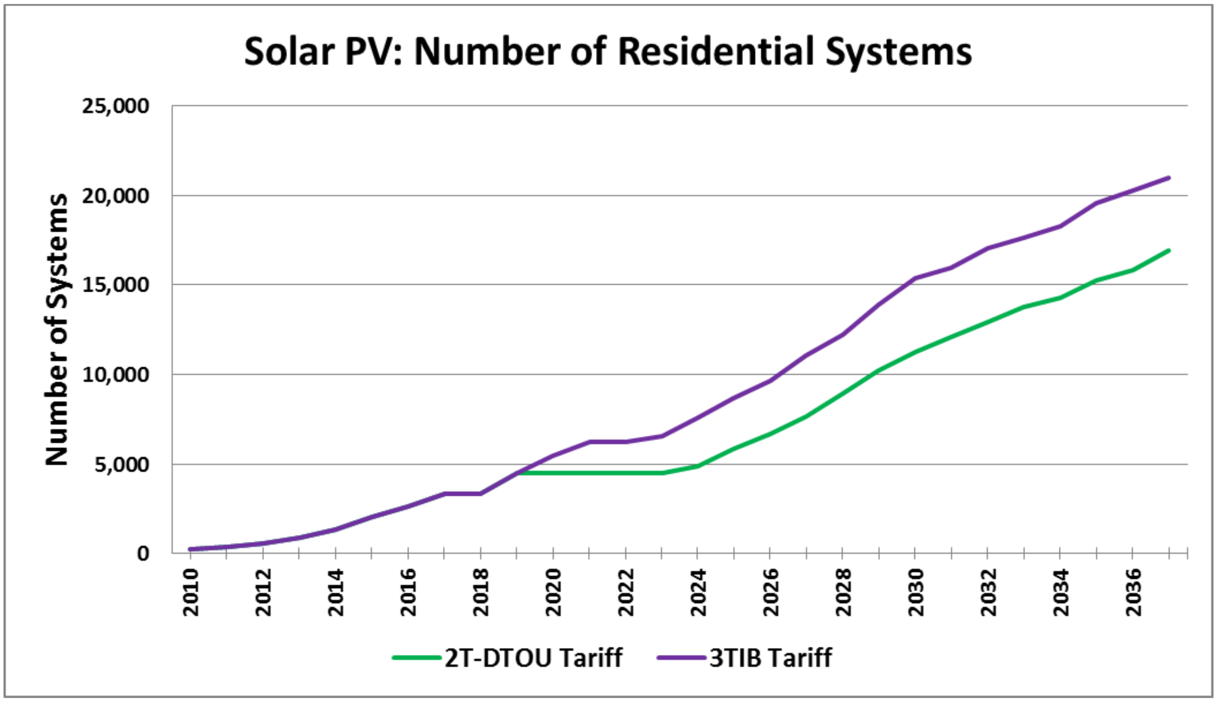


Figure 18.5.2. Expected number of behind-the-meter, NEM solar PV systems installed in the RPU service territory under both the 3TIB and 2T-DTOU tariff structures.

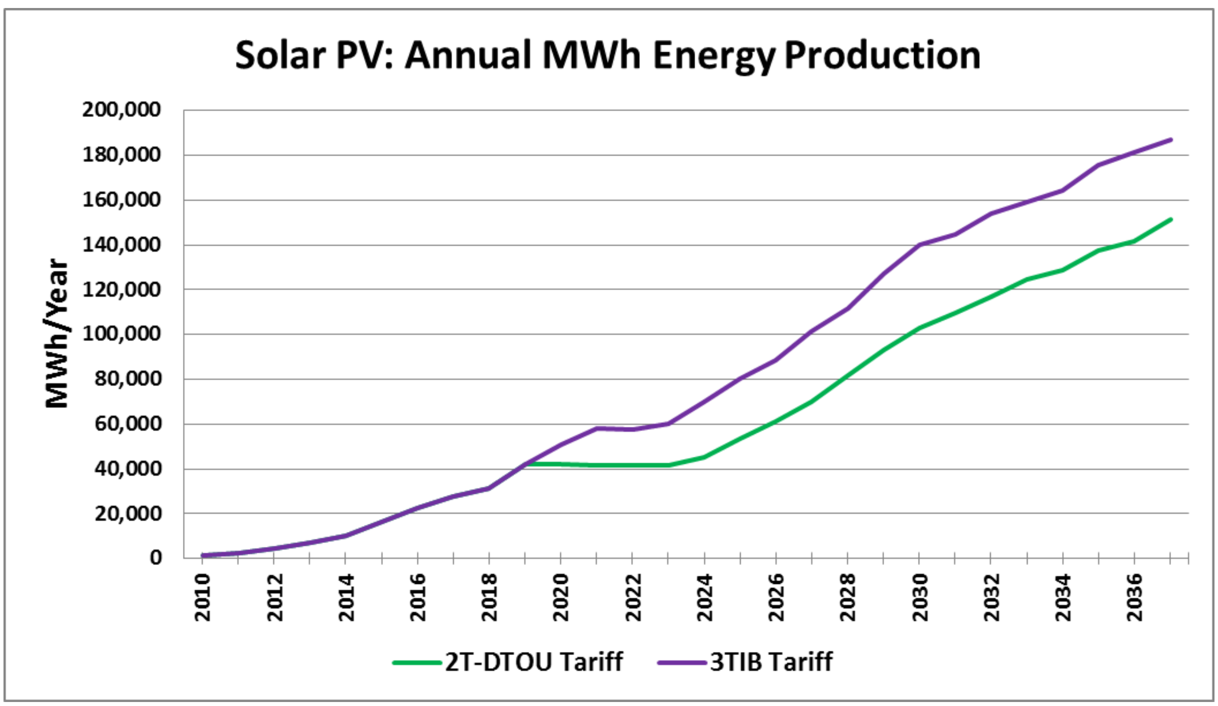


Figure 18.5.3. Expected annual generation energy (MWh/year) from behind-the-meter, NEM solar PV systems installed in the RPU service territory under both the 3TIB and 2T-DTOU tariff structures.

The slowdown in installations in the 2020-2023 time period under the 2T-DTOU tariff results in a systematic impact on the ultimate number of installed solar PV systems by 2037. Under this alternative tariff, RPU would expect to serve and balance approximately 17,000 residential homes with solar systems, rather than 21,000. Likewise, these homes would produce about 150,000 MWh/year of self-generated energy under the 2T-DTOU tariff, rather than 190,000 MWh/year under the 3TIB tariff. These differences have a material impact on the expected cost shifts through 2037. Figure 18.5.4 shows the expected annual customer savings, avoided utility costs and overall net revenue impacts the utility would experience in the domestic residential customer class under a NEM 2.0 program with a default 2T-DTOU rate structure. Note that the calculated cost shift has now been reduced to about 20 million dollars annually by 2037; still unsustainable, but also now one third less than the previous negative net revenue trend shown in Figure 18.5.1.

Finally, Figure 18.5.5 shows the expected customer pay-back periods under both tariff scenarios. It is worthwhile to note that the time to full system cost recovery by a typical residential customer is only increased by 1.5 years under the alternative 2T-DTOU rate tariff. Thus, an average residential customer would still be expected to recover all of their up-front costs and save money under the alternative NEM 2.0 program that defaults to the 2T-DTOU rate structure; it would just take them marginally longer to do so.

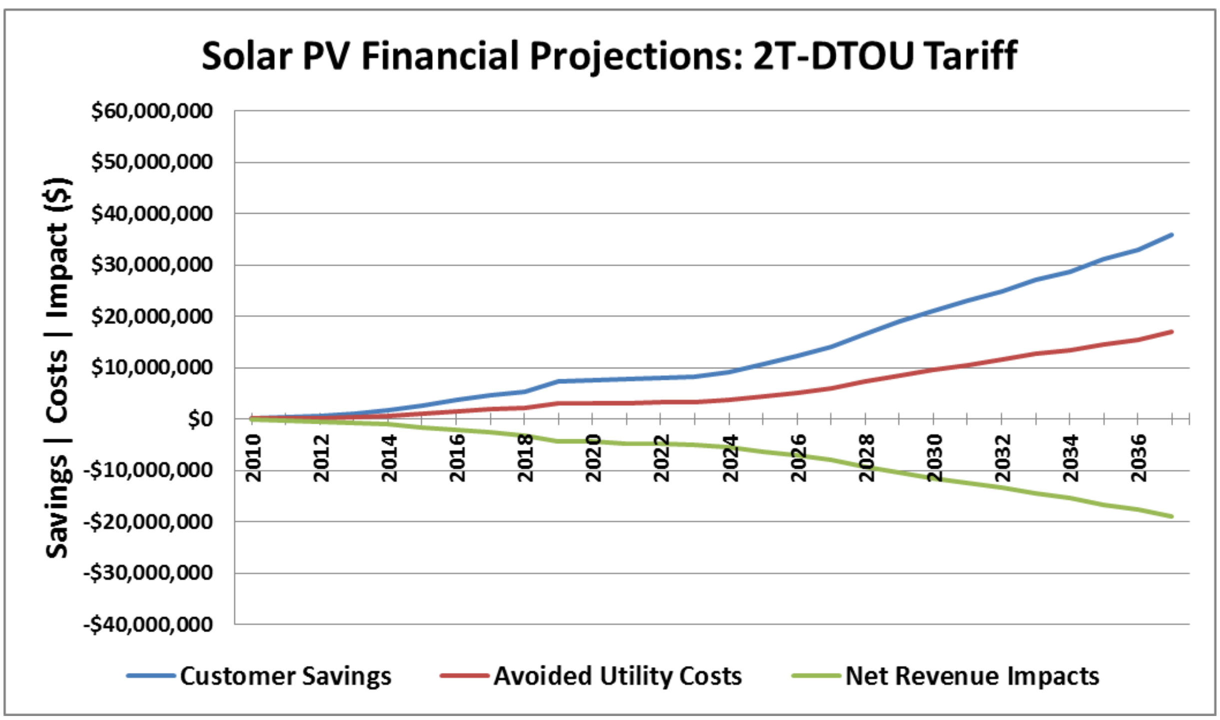


Figure 18.5.4. Expected annual customer savings, avoided utility costs and overall net revenue impacts under a NEM program that defaults to the 2T-DTOU tariff on/after 2020.

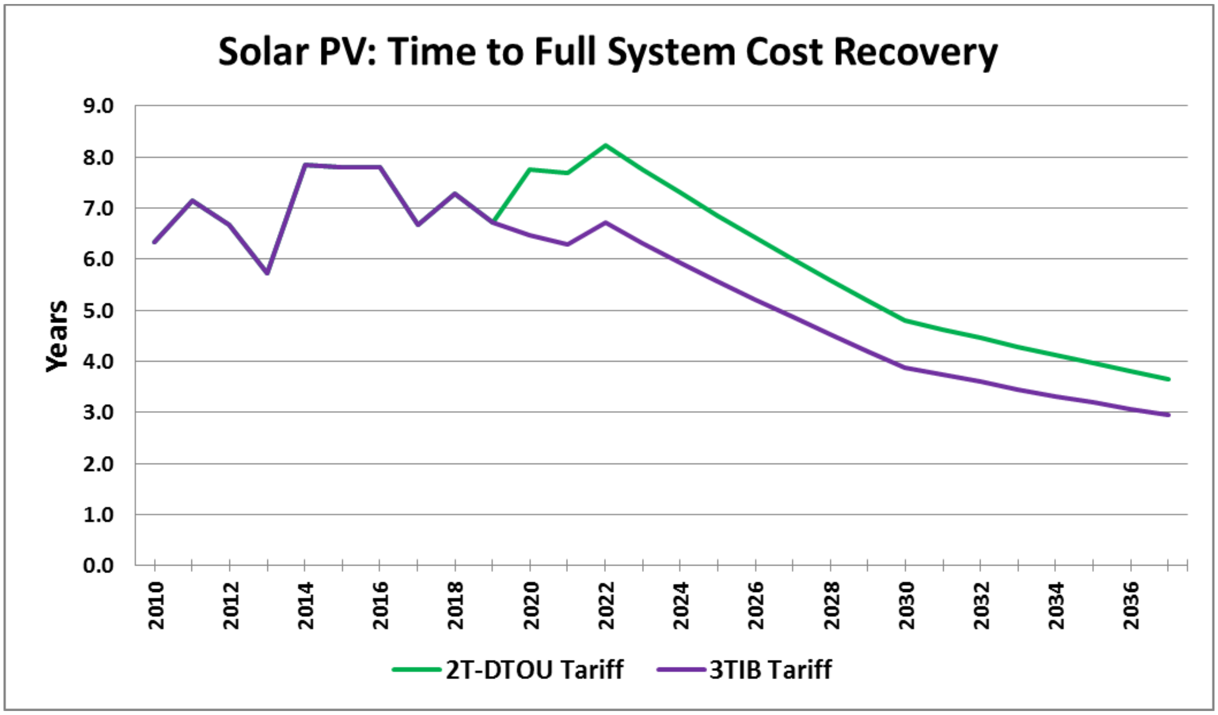


Figure 18.5.5. Expected customer pay-back periods for behind-the-meter, NEM solar PV systems installed in the RPU service territory under both the 3TIB and 2T-DTOU tariff structures.

18.6 Summary of Findings & Next Steps

A number of key results can be derived from the NewGen study results shown in section 18.5. However, the four most pertinent points are summarized below.

1. First, the expected long-term net revenue impacts under the current NEM 1.0 paradigm are very sobering. If RPU were to see 21,000 behind-the-meter solar PV installations by 2037 and assuming that the utility allowed all of these customers to retain the 3TIB rate as their default tariff, the annual cost-shift to non-NEM residential customers would be nearly $30,000,000. This magnitude of within-class customer subsidy is clearly unsustainable and unjustified, and in all likelihood would never be fully recovered.

2. Second, while assigning the 2T-DTOU rate as the default tariff for all post-2020 NEM 2.0 customers slows down the negative net revenue impacts, it clearly does not solve the entire cost-shift issue. Based on prior solar PV adoption trends, this alternative default rate structure will only slow down future adoption rates for about five years after its implementation. After 2025, the time it takes a customer to fully recover their system investment costs drops below seven years and the installation rates increase rapidly thereafter. This is perhaps not that surprising, since this alternative rate tariff only addresses less than 20% of the expected cost-shift effect (see Table 18.3.1).

3. Third, the forecasted magnitude of the expected net revenue impacts depend heavily on the assumed future $/kWh avoided cost estimates. In this study it was assumed that the current avoided cost value is about $0.07/kWh and that these avoided costs escalate at 2.5% per year. However, it was also pointed out that this avoided cost might be noticeably higher (or lower) – and depends heavily upon future distribution system circuit impacts. Thus, if future solar PV installations could be directed towards more beneficial locations within the distribution system, these avoided costs would be expected to increase more rapidly, in turn lowering the future negative net revenue impact(s).

4. Lastly, further rate tariff modifications will probably be necessary to encourage more solar PV installations on more beneficial circuits, and/or discourage the practice of feeding back excessive over-generation into the distribution system. One potential idea could be to categorize and compensate hourly solar PV generation energy depending upon how it is used; for example, crediting energy that offsets customer load at the retail rate while paying a wholesale rate for excess energy flowing back to the grid. This type of billing arrangement can be easily handled using advanced metering infrastructure (AMI) technology and would encourage customers to self-consume a greater proportion of their self-generated energy (by either encouraging the installation of smaller systems and/or the addition of energy storage options). Such a modified billing approach deserves further investigation.

Overall, additional investigations need to be performed to determine the most appropriate default rate tariff for future solar PV customers under the NEM 2.0 paradigm. Nonetheless, as previously discussed, RPU is expected to reach its NEM cap of 30.2 MW in the next 12-18 months, so this issue needs to be addressed now. Riverside Public Utilities is committed to accommodating behind-the-meter solar PV generation, as well as fostering its growth throughout the city. However, the utility must also find a way to promote this growth in a fair and equitable manner. A key component of this effort will be to identify a NEM 2.0 default rate tariff that minimizes the current within-class subsidy effect to the greatest extent possible. This new tariff must in turn ensure both long-term sustainable growth in distributed energy resources and reasonable rate equity among both NEM and non-NEM customers. Both of these goals must be achieved in tandem to ensure that RPU can to continue to serve all of its residential customers with safe and reliable power at the lowest possible rates.

19. 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 350 (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).[1] RPU's efforts that address the Barriers Study recommendations are presented at the end of this chapter.

19.1 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 two of the 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 200% of the Federal Poverty Level (200% FPL) as shown in Table 19.1.1 below.

Table 19.1.1. Income Eligibility based on 200% of the 2018 FPL and Number of Persons in a Household.[2]

Household Size*	1	2	3	4	5	6	7	8
Annual Income	$24,280	$32,920	$41,560	$50,200	$58,840	$67,480	$76,120	$84,760

* More than 8: $84,760 plus $8,640 for each additional person.

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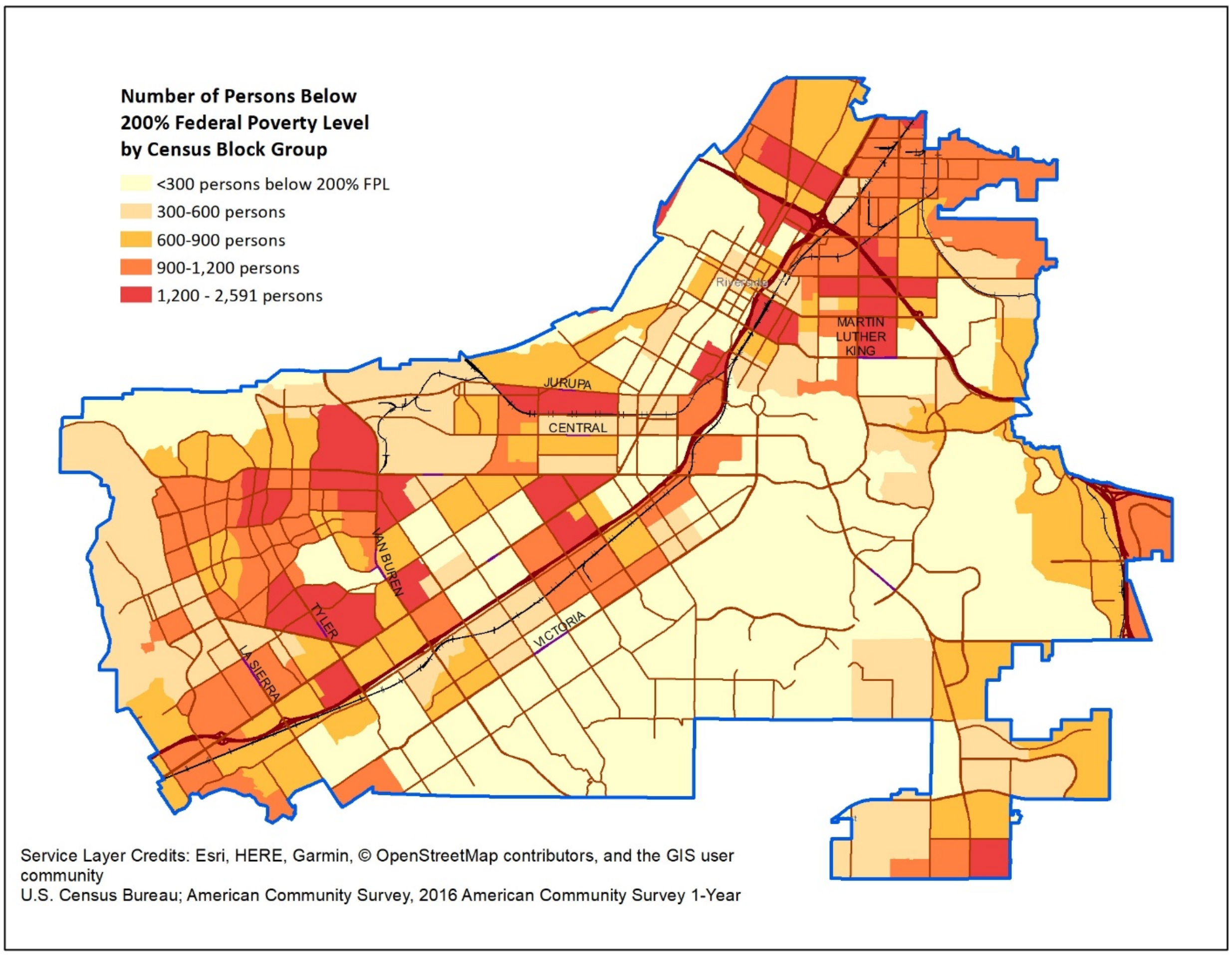
[1] Scavo, Jordan, Suzanne Korosec, Estaban Guerroro, Bill Pennington, and Pamela Doughman. *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities.* California Energy Commission, Publication Number: CEC-300-2016-009-CMF. 2016.

[2] The Federal Poverty Guidelines are issued each year by the U.S. Department of Health and Human Services; determination of the 200% level means that the income levels identified by the HHS are doubled 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", 83 FR 2642, January 18, 2018.

To map where eligible customers are located, RPU has used data from the U.S. Census Bureau American Community Survey. Map 19.1.1 shows the estimated number of persons in each block group that are below the 200% FPL. There are areas of the City with a higher concentration of lower income people, though they reside in all areas. Based on the 2016 American Community Survey, the City of Riverside's population was estimated to be 312,384.[3] Of this population, approximately 34% had household incomes below 200% FPL.[4]



Map 19.1.1. 2016 estimated population below the 200% Federal Poverty level.

[3] U.S. Census Bureau; American Community Survey, 2016 American Community Survey 1-Year Estimates, Table B17002; generated by Tracy Sato; using American FactFinder; <http://factfinder2.census.gov>; (August 5, 2018).
[4] Ibid.

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 66,496 family households of which 31% were estimated to have incomes below 200% FPL.[5] 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 25,444 households have household incomes below 200% FPL[6] (see Table 19.1.2).

Table 19.1.2. Summary of Population and Households by family and non-family with income below 200% of the Federal Poverty Level.[7]

	Total	**Below 200% Federal Poverty Level**	**Percent Below 200% Federal Poverty Level**
Population	312,384	106,720	34%
Households*	91,940	30,458	33%
Family Households	66,496	20,657	31%
Non-Family Households	25,444	9,801	39%

* 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 includes groups of unrelated people living together, such as in group homes and some dormitories.

Disadvantaged Communities

A Disadvantaged community (DAC) is a more recent consideration for RPU. 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.

[5] U.S. Census Bureau; American Community Survey, 2016 American Community Survey 1-Year Estimates, Table B17026; generated by Tracy Sato; using American FactFinder; <http://factfinder2.census.gov>; (August 5, 2018).
[6] U.S. Census Bureau; American Community Survey, 2016 American Community Survey 1-Year Estimates, Table B19201; generated by Tracy Sato; using American FactFinder; <http://factfinder2.census.gov>; (August 5, 2018).
[7] U.S. Census Bureau; American Community Survey, 2016 American Community Survey 1-Year Estimates, Tables B17024, B17026, and B19201; generated by Tracy Sato; using American FactFinder; <http://factfinder2.census.gov>; (August 5, 2018).

(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.

In order to meet this requirement, CalEPA utilized and updated its environmental health screening tool, CalEnviro Screen to score and map DACs throughout the State based on adopted evaluation criteria.[8] In 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 19.1.1 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 a DAC. 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 19.1.2 on the following page identifies the locations in Riverside that are identified as DACs. Approximately 44% of the City's population resides in a DAC.

Pollution Burden

Exposures
- Ozone Concentrations
- PM 2.5 Concentrations
- Diesel PM Emissions
- Drinking Water Contaminants
- 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 19.1.1. Indicator Criteria Identifying Disadvantaged Communities.

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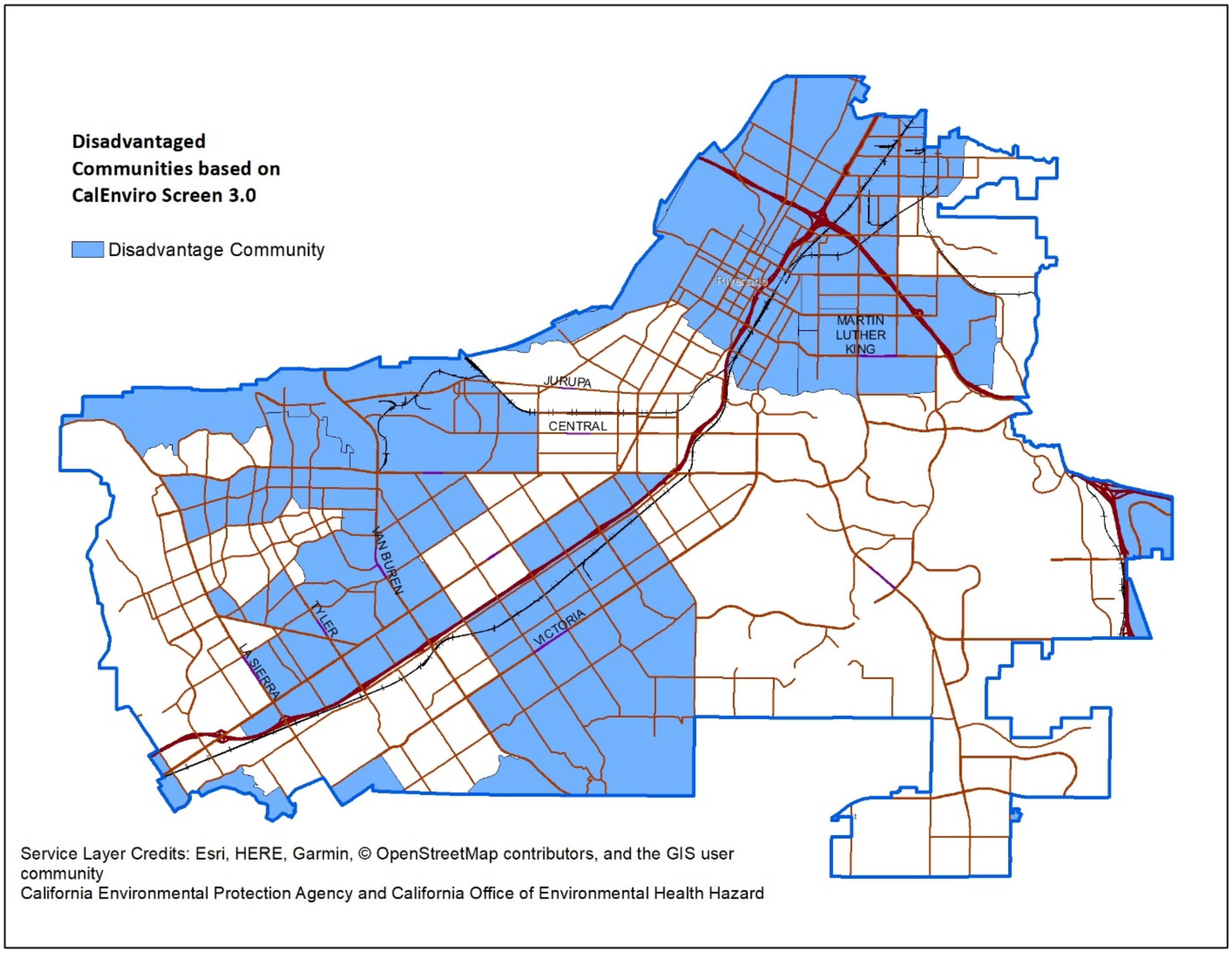
[8] California Environmental Protection Agency, CalEnviro Screen 3.0, https://oehha.ca.gov/calenviroscreen/report/calenviroscreen-30, accessed November 2017.



Map 19.1.2. Disadvantaged Communities in Riverside.

According to CalEnviro Screen, 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.

19.2 RPU Sustainability Efforts Reducing Air Pollutants and Greenhouse Gas Emissions

The City of Riverside has long been committed to implementing 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 converted 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 over 50% of the City's non-emergency vehicles to alternative fuels, and continued installation of solar PV systems throughout the City.

In 2009, the City adopted a Sustainable Riverside Policy Statement developed by a community-wide Clean Green Task Force. The policy statement subsequently was the basis for the Riverside Green Action Plan [9] (GAC), adopted in 2012. The GAC has been the policy framework for the City, including RPU to reduce greenhouse gas emission, reduce air pollutants and operate more sustainably. In 2016, the City adopted the Riverside Restorative Growth Print [10] – a combination climate action plan and economic development plan that complements the GAC. The Growth Print strives to ensure that the City will thrive both economically as well as sustainably.

The City has been recognized for its sustainability efforts. In 2014, Riverside was named "California's Coolest City" by the CARB. Then 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) in 2015. Also, in 2015, the City was the first in the State to join the Audubon Society's prestigious Sustainable Communities Program.

The GAC and Restorative Growth Print guide the 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 from the GAP have been highlighted as particularly relevant to this discussion:

<u>Energy</u>

- Increase the use of non-greenhouse gas (GHG) emitting energy by 2020 to 50% with at least 33% coming from renewable sources.
- Save 1% of communities load annually based on a 2004 baseline, and reduce the City's peak electric load demand by 10% overall.
- Install at least 20 MW of photovoltaic (PV) systems by 2020.

<u>Greenhouse Gas Emissions</u>

- Create a climate action plan to reduce GHG emissions to 7% below the 1990 City baseline utilizing the City boundaries as defined in 2008.

[9] City of Riverside, "Green Action Plan", City of Riverside, 2012. The full document can be found at: www.greenriverside,com.
[10] City of Riverside, "Riverside Restorative Growth Print", January 5, 2016. The full document can be found at: https://riversideca.gov/planning/rrg/.

Transportation

- Reduce mobile sources of pollution 5% by 2020.
- Increase the number of clean vehicles in the non-emergency City fleet to at least 60%.

In addition to meeting these IRP specific goals, RPU plays an important role in meeting or supporting all of the goals in the GAP 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.

19.2.1 RPU Reduction in GHG Emissions

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 utilized by all customers. As discussed in Chapters 8, 12, and throughout this IRP, in 2017, 36% of RPU's electricity came from renewable resources that included geothermal, biomass, solar, and wind. Another 6% of RPU's generation resources were made up with GHG-free resources (large hydropower and nuclear). RPU is on track to have a 2020 portfolio of resources comprised of 50% non-greenhouse gas (GHG) generation. About 44% will come from renewable sources eligible under the State RPS program with the remaining 6% coming from large hydro and nuclear generation.

Locally, Riverside currently has about 27 MW of installed rooftop and customer owned solar PV systems. These systems provide approximately 50,000 MWhs of GHG-free electricity annually.

19.2.2 Clean Fleet Vehicles

The GAP specifically addresses the transportation sector as noted above and states that it is vital to continue to improve "regional mobility and vehicle emissions" in order to have "a positive impact on transportation and combat mobile emission issues". 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 CNG fueling station at the Water Quality Control Plant, installing electric vehicle charging stations at various City facilities, and purchasing 551 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 the adopted GAP and Restorative Growth Print.

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, the class of vehicle needed for replacement (with maximum energy efficiencies in mind);
- A "right sizing" program to insure 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 in close proximity to 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; and
- Expansive staff training in the benefits of and properly maintaining green fleet vehicles.

19.2.3 Reducing Power Plant Emissions

RPU owns 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.

RPU's most important electric generation station, the Riverside Energy Resource Center (RERC), was built to be used during critical 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 has further reduced harmful pollutants by 30% beyond those required by regulators and supplied by the equipment manufactures. 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.

The RERC staff continues research in conjunction with General Electric and other leaders to further fine tune and reduce emissions. An experimental cutting-edge measuring device being tested shall lead to a more precise emissions control further lowering emissions simultaneously adapting to the changing electrical grid and environmental demands of California.

19.2.4 Access to Financing for Energy Efficiency Upgrades and Solar

As identified in the Barriers study, offering options for financing energy efficiency and solar systems is an important action for increasing access in low-income communities. RPU and the City of Riverside have agreements in place allowing eleven providers to offer property assessed clean energy (PACE) financing to property owners. The programs are voluntary and provide property owners who wish to participate in the programs a means of financing energy efficiency and solar PV systems. They are assessed program costs on their property tax bills to re-pay the debt associated with the financing.

The first program began in April 2011 when the City Council adopted a Resolution of Participation and an Implementation Agreement that allowed for Western Riverside Council of Governments (WRCOG) to develop and implement a PACE Program called the Home Energy Renovation Opportunity (HERO) in Riverside. As of 2016, the HERO Program has financed approximately $50 million in residential projects and $575,000 for commercial projects within the City of Riverside. In 2016, the City approved another ten PACE providers, bringing the total number of PACE providers to eleven. A streamlined annual application process was also approved to allow additional providers into the market in an efficient manner.

19.2.5 RPU Low and Fixed Income Assistance and Targeted Energy Efficiency Programs

RPU has offered low-income assistance since 1989. In November 2017, the RPU Board and Riverside City Council conceptually approved its most recent enhancements to RPU's low-income and fixed income assistance program, including the Sharing Households Assist Riverside Energy (SHARE) Program and Energy Savings Assistance (ESAP) Program. Board and Council directed staff to undertake a comprehensive outreach campaign, as well as to prepare a needs-assessment for the development of additional program enhancements to be aligned with future rate increases and other City and partner agency assistance programs. The SHARE program provides financial assistance to qualified customers, while the ESAP program is a direct-install program that provides no-cost energy efficiency upgrades to qualified customers. These proposed enhancements were approved by the Riverside City Council on May 14, 2018. RPU's enhanced programs, effective on July 1, 2018:

- Enhanced the SHARE Program by implementing the following changes:
    - Increase eligibility from 150% to 200% of the Federal poverty level;
    - Change the $150 annual electric bill credit to a $14 monthly electric bill credit (up to $168/year);
    - Add annual deposit assistance and emergency assistance (up to $150/year);
    - Add a $2.25 monthly water bill credit (up to $27/year); and
    - Work with Riverside County's Community Action Partnership (Implementing agency for the Federal Low Income Home Energy Assistance Program – LIHEAP)

to create more convenient options for customers to sign up for program benefits.

- Enhanced the ESAP by implementing the following changes:
  - Align program eligibility with SHARE and partner agency programs; and
  - Automatic sign up customers who qualify for the SHARE program.

- Continued the implementation of an ongoing comprehensive multi-media and multi-lingual outreach campaign specifically targeting low-income and fixed income utility customers.

- Initiated a needs assessment to increase program assistance in parallel with rate increases, fully develop community partnerships, coordinate ongoing stakeholder process, develop benchmarks and metrics, and explore areas of program expansion/improvement inclusive of Riverside's Housing First Program alignment.

In addition to the SHARE and ESAP programs offered directly to residential customers, RPU recognizes that many low and fixed income residents do not own the homes that they live in and thus may not have access to all of RPU's energy efficiency programs. To assist customers, RPU offers a multi-family and mobile home direct install program that provides these residents direct installation measures including HVAC tune-ups, lighting efficiency upgrades, weatherization, and Tier 2 advanced power strips. Further, energy efficiency measures in common areas are provided to building owners under this program.

Finally, RPU offers over 40 energy efficiency rebates that are available to all customers including low and fixed income customers. These programs are continuously being reviewed to ensure that the all customers have opportunities to reduce their energy consumption.

19.2.6 Low-Income Household Needs Assessment and Improved Data Analysis

As discussed in the previous section, RPU was directed to develop a needs assessment for its low and fixed income customers concurrent with the electric rates approved in May 2018. The needs assessment will be completed in early 2019 and will include a literature review, demographic analysis, and on-going communications and outreach with low-income customers and stakeholders. A customer survey may also be included in this work effort.

RPU will include an evaluation of alignment or expansion of program eligibility to include the California Housing and Community Development (HCD) income guidelines. This was a recommendation that came out of meetings held with community representatives for the low-income community. These guidelines identify low-income households as those making 80% or less than the area median income for the household size. HCD issues the State Income Limits annually with income limits specific to each county in the state.[11] As shown in Figure 19.2.1, the State Income Limits are similar to the 200% FPL. The forthcoming needs assessment will evaluate the impact of determining eligibility by either measure.

RPU will utilize numerous data sources to determine the population and number of customers that fall into the various categories of low and fixed income as well as disadvantaged. Where applicable, RPU is developing data using the geographic information systems (GIS) in order to evaluate whether utility programs are reaching customers in areas of the City with concentrations of low-income customers. Both Census Tract and Block Group geographies will be used to identify focus areas. RPU is currently developing data that will allow all energy efficiency, solar, and electric vehicle data to be evaluated to ensure that all customers have access and opportunity to participate.

RPU will be expanding upon the data it will review as its needs-assessment is developed. RPU also sees a great benefit in incorporating and aligning analysis with the State's efforts to ensure equitable access to clean energy. In particular, RPU expects to incorporate analysis that will align with data and metrics developed for the California Energy Commission's Energy Equity Indicators [12] project, which tracks the state's progress advancing recommendations from the SB 350 Low-Income Barriers Study.

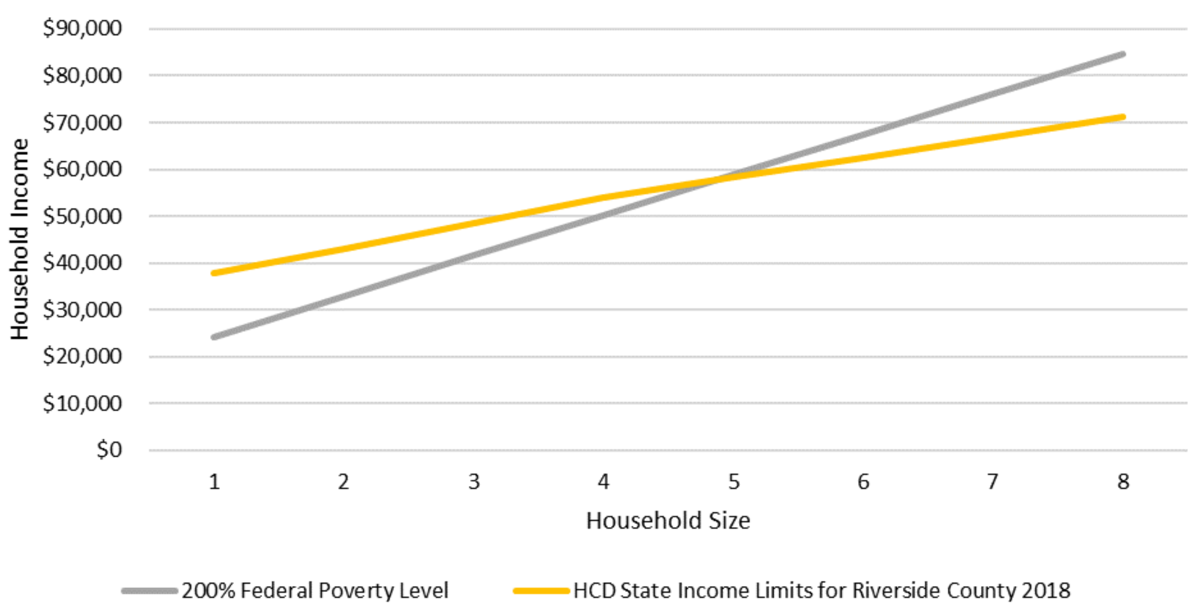


Figure 19.2.1. Comparison of State Income Limits and 200% Federal Poverty Level (2018).

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[11] State of California, Department of Housing and Community Development, "State Income Limits for 2018", April 26, 2018. http://www.hcd.ca.gov/grants-funding/income-limits/state-and-federal-income-limits/docs/inc2k18.pdf.

[12] California Energy Commission, Energy Equity Indicators, http://www.energy.ca.gov/sb350/barriers_report/equity-indicators.html.

20. Conclusion

As stated in the Introduction, this *2018 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 cost of service. The six primary goals of this IRP were broadly summarized as follows:

- To provide an overview of RPU (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 capacity and resource adequacy requirements, (b) renewable portfolio standard (RPS) mandates, (c) carbon emission goals and mandates, (d) power resource budgetary objectives, and (e) cash-flow at risk metrics.
- To examine and analyze certain critical longer term power resource procurement strategies and objectives, specifically those that could help RPU reach its 2030 carbon reduction goals, and quantify how such strategies and objectives impact the utility's future cost-of-service.
- To begin to assess how various emerging technologies may concurrently impact RPU carbon reduction goals and future cost-of-service metrics, in order to better define future actions 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, 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 9-13, and various emerging technologies have been examined in Chapters 15, 17 and 18. Additionally, RPU's most recent electric rate plan has been reviewed in Chapter 16 and the utility's commitment to serving its disadvantaged community members has been discussed in Chapter 19. Overall, staff has attempted to compile and present information in these chapters that addresses these six primary IRP goals in a comprehensive and analytical manner.

This final chapter provides a high-level review 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 in the following sections.

20.1 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 2018-2037 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 0.5% 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 647 MW of nameplate capacity; by 2019 this number should increase to about 667 MW of capacity, as the last component of the CalEnergy geothermal portfolio comes online.
- ✓ RPU is a vertically integrated utility that operates electric generation, sub transmission, and distribution facilities; receiving the vast majority 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 RTRP is fully adopted, SCE will expand its regional electrical system to provide Riverside a second source of transmission capacity to import bulk electric power, which in turn could significantly alter the utility's long-term internal resource procurement needs.
- ✓ As part of an ongoing effort to improve the utility's visibility into the distribution system, the utility has identified specific communications and information technology projects that need to be deployed as soon as reasonably possible. These include the deployment of an upgraded Geographic Information System and new Advanced Metering Infrastructure, Asset Management, Meter Data Management, Distribution Automation and Advanced Distribution

Management Systems. All of these software systems have been targeted to improve organizational efficiency and to optimize the deployment of distributed energy resources (DERs).

20.2 Important Legislative and Regulatory Mandates

Chapter 5 provided an overview and discussion 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. In particular, the following legislative, regulatory, and CAISO mandates and initiatives are expected to significantly impact RPU.

- ✓ SB X1-2 and SB 350 – Renewable Portfolio Standard (RPS): SB X1-2, signed into law in 2011, which mandates that in-state electric utilities procure 33% of renewable resources to serve retail loads by 2020, and SB 350, signed into law in 2015, which extended the RPS to 50% by 2030.

- ✓ AB 32 and AB 398 – California Greenhouse Gas (GHG) Reduction Mandate: AB 32, signed into law in 2006, which mandates statewide reduction of GHG emissions to 1990 levels by calendar year 2020, and AB 398, signed into law in 2017, which extended the cap-and-trade program through 2030.

- ✓ SB 1368 – Emission Performance Standard: SB 1368, signed into law in 2006, which mandates that electric utilities are prohibited to make long term financial commitments (commitments greater than 5 years in duration) for base-load generating resources that exceed GHG emissions of 1,100 lbs/MWh.

- ✓ AB 2514 – Energy Storage: AB 2514, signed into law in 2010, which directs the governing boards of publicly-owned utilities (POUs) to consider setting targets for energy storage procurement by October 2014 and October 2017 and achieving these targets by January 2017 and January 2021, respectively.

- ✓ SB 380 – Moratorium on Natural Gas Storage in Aliso Canyon: SB 380, signed into law in 2016, which placed a moratorium on Aliso Canyon's natural gas storage usage until all injection wells were rigorously tested and certified as safe to use.

- ✓ SB 859 – Budget Trailer Bill (Biomass Mandate): SB 859, signed into law in 2016, which mandates that the three IOU's and seven largest POU's contract for and procure their pro-rata share of 125 MW of in-state biomass capacity for at least five years.

- ✓ CAISO Bidding Rules and Commitment Cost Initiatives: the implementation of new energy and commitment cost rules to improve alignment between the day-ahead and real-time CAISO markets.

- ✓ CAISO Flexible Resource Adequacy and Enhanced Must Offer Obligation (FRAC-MOO 2): continued revisions to the CAISO RA paradigm, aimed at acquiring control over significant amounts of participating member's flexible capacity that can be ramped up and down fairly quickly to assist in managing CAISO system supply and demand balance needed to integrate increasing amounts of intermittent renewable resources.
- ✓ CAISO TAC Structure Initiative: a proposal to modify the current volumetric TAC charge into a combined volumetric + demand charge structure.

All of these current mandates and initiatives have and continue to constrain RPU's power procurement decisions and impact RPU's power supply costs, sometimes in a detrimental manner. In Chapter 5 these mandates and initiatives are examined in detail, along with suggestions for potentially mitigating at least some of their more egregious future costs and impacts.

20.3 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 plays 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), none of RPU's current EE program categories are revenue neutral for any of the utility's four primary customer classes. This result is not surprising, given that RPU's energy rates are designed to collect all of the utility's fixed operating costs (i.e., infrastructure, personnel, and O&M), in addition to its variable power supply costs. However, the EE programs for Industrial TOU customers were found to be \$0.02/kWh to \$0.03/kWh less expensive (on an unmet revenue basis) than any of the EE programs for the remaining customers. Therefore, on a total cost basis, RPU can lower the amount of unmet revenues associated with its EE programs by investing proportionally more of its EE expenditures in this customer class. Additionally, by recasting these unmet revenue estimates into net value calculations, staff can determine if and when the future expansion of various EE programs should prove to be more cost effective than continuing to contract for new renewable resources.

20.4 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
- Unhedged Energy costs and Cost-at-Risk metrics
- Forecasted GHG Emission profiles and net Carbon allocation positions
- Five-year Forward Power Resource Budget forecasts

All of the analyses presented in this chapter were performed using the Ascend Portfolio Modeling software platform, and referenced late December 2017 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 is on track to procure a significant amount of excess renewable energy, above and beyond the state's minimum mandated amounts. Since 2017, RPU has begun to rapidly accumulate excess renewable energy credits. Currently, the utility is planning on reselling some of this excess renewable energy to raise additional budget revenue during the 2018-2020 timeframe. However, even with these proposed sales, RPU will stay at or above a 33% RPS level through CY 2020.

- ✓ RPU has about 90% of its load serving needs naturally hedged through long-term PPA's and generation ownership agreements. The remaining 10% of open energy positions need to either be served using internal generation assets and/or actively hedged via the forward market purchases of energy and natural gas. Nearly all of the remaining open energy volumes are associated with Q3 HL needs and April outage events. RPU's current expected costs to fully close these open HL positions range from 5.7 to 6.9 million dollars annually in the 2019-2022 timeframe. The associated CAR metrics for the same time period currently range from 3.2 to 3.7 million dollars, respectively.

- ✓ RPU's forecasted power supply net revenue uncertainty (i.e., annual NRU standard deviations) range from 8 to 9 million dollars a year in the 2018-2022 timeframe. The corresponding 90% confidence intervals for annual potential revenue deviation are approximately ±13 to ±15 million dollars a year, respectively.

- ✓ RPU is expected to have more than enough carbon allowances to fully meet its direct emission compliance needs through 2022. Staff currently forecasts having an excess allowance balance of 450,000 to 500,000 credits annually. These excess credits are expected to be monetized through the CARB quarterly auction process, with a significant portion of the proceeds used to help offset RPU's incremental renewable energy costs.

- ✓ RPU's FY 18/19 power supply budget is projected to increase by approximately 12.5 million dollars over the prior year's FY 17/18 forecasts; this increase is primarily due to additional geothermal energy coming online in January 2019, in addition to increasing Transmission and Capacity costs. However, on/after FY 20/21, the overall budget should remain fairly stable through FY 22/23.

In summary, the utility is well positioned to meet its load serving needs over the next five years while focusing on controlling its internal portfolio costs. With respect to energy needs, some additional systematic forward hedging activities are required to maintain cash flow stability. However, there are no looming, critical forward hedging procurement decisions that need to be made in the immediate term time horizon (i.e., in the next three to five years).

20.5 Critical Longer Term Power Resource Issues

The fundamental purpose of the 2018 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 13 examined the critical longer term power resource planning issues surrounding this goal.

This discussion was initiated in Chapter 9 by first establishing the utility's 2030 GHG emission targets. Three distinct targets were proposed: (1) a baseline, 40% below 1990 goal, (2) a utility emission target that aligned with the electricity sectors 53 MMT target, and (3) a utility target that aligned with the electricity sectors 42 MMT target. These corresponding emission targets, originally shown in Table 9.3.1, are reproduced in Table 20.5.1. Note that the 53 MMT Sector goal represents RPU's officially adopted target, while the 42 MMT Sector goal serves as an aspirational target.

After deriving these targets, staff then determined how much RPU's total GHG footprint must change (i.e., decrease) over time to meet these plausible 2030 emission goals. This issue was examined from the perspective of how much additional carbon-free energy RPU must add to its portfolio between now and 2030. As discussed in Chapter 9, staff determined that RPU essentially needs to achieve a 57% RPS by 2030 to meet its officially adopted emission target, and/or achieve a 66% RPS by 2030 to meet its aspirational target.

Table 20.5.1. The three RPU GHG planning targets analyzed in this 2018 IRP.

GHG Planning Target	Description	MT CO2-e Emission Value
Baseline	40% below 1990 (utility specific)	647,844
53 MMT Sector Goal	Official RPU target	486,277
42 MMT Sector Goal	More aggressive GHG reduction scenario	385,137

Next, in Chapter 10 staff examined all of the utility's current resource contracts that are scheduled to end before December 2037; the goal being to identify resources with contracts that are likely to be extended (at least for integrated resource planning purposes). Likewise, in Chapter 11 staff reviewed RPU's future capacity needs for the 20-year time horizon from 2018 through 2037. 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 various CAISO Resource Adequacy (RA) paradigms, many of which are currently being revised. Finally, staff also analyzed and discussed RPU's "Net-Peak" demand forecasts for 2019 in this chapter as well.

Having thoroughly reviewed RPU's future capacity expansion needs, in Chapter 12 staff presented and described a set of potential future portfolio resource additions that are consistent with RPU's long-term carbon reduction goals. Most of these proposed resource additions represented carbon-free renewable resources. However, a multi-year, low-carbon seasonal energy product was also proposed and discussed, in addition to two natural gas alternatives that could be used to replace some of RPU's retiring coal energy. As originally shown in Table 12.1.1 and reproduced here as Table 20.5.2, the acquisition of all of these proposed "near carbon-free" resources would allow RPU to successfully meet or exceed the utility's aspirational 2030 emission target.

Table 20.5.2. Proposed 2020-2030 RPU procurement strategy for new renewable resources.

New Renewable Resource	COD	Annual MWh
1. 44 MW Solar PV + 22 MW / 88 MWh BESS	2021	144,000
2. Extension and/or repower of 39 MW Cabazon Wind facility	2025	72,000
3. Contract for Summer (July-Sept) zero or near-zero carbon energy product	2025	100,000
4. 40 MW baseload renewable asset (85% CF)	2027	298,000
5. 30 MW baseload renewable asset (85% CF)	2029	223,000

Finally, in Chapter 13, seven plausible resource planning scenarios were considered to assess how they impacted the utility's GHG reduction targets, RPS mandates, and capacity and energy replacement needs. More specifically, Chapter 13 examined the projected budgetary impacts of meeting RPU's specific GHG targets, as defined in Chapter 9. This budgetary assessment considered both the expected values and simulated standard deviations of RPU's fully loaded cost of service over the next twenty-year time horizon. Additionally, Chapter 13 also presented resource-specific net value calculations for each resource discussed in Chapter 12, to determine the overall cost-effectiveness of each resource.

The key budgetary impact results are conveniently summarized in the vertical bar chart shown in Figure 20.5.1 (as adapted from Figure 13.5.5). This chart combines the forecasted 2025, 2030, and 2035 COS_{LN} values with their corresponding risk estimates to produce an overall "composite cost of service" estimate for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio. The composite costs of service estimates are very close across scenarios in each specified year. In 2030, when the Solar+Storage, Cabazon, SULCPP, Baseload-2027, and Baseload-2029 resources are all online in their respective portfolios, the increase in the composite cost of service between each portfolio is relatively minimal (i.e., < 1%). Therefore, RPU should be able to achieve its GHG emissions targets with relatively minimal cost impacts, provided that renewable prices remain at normal levels.

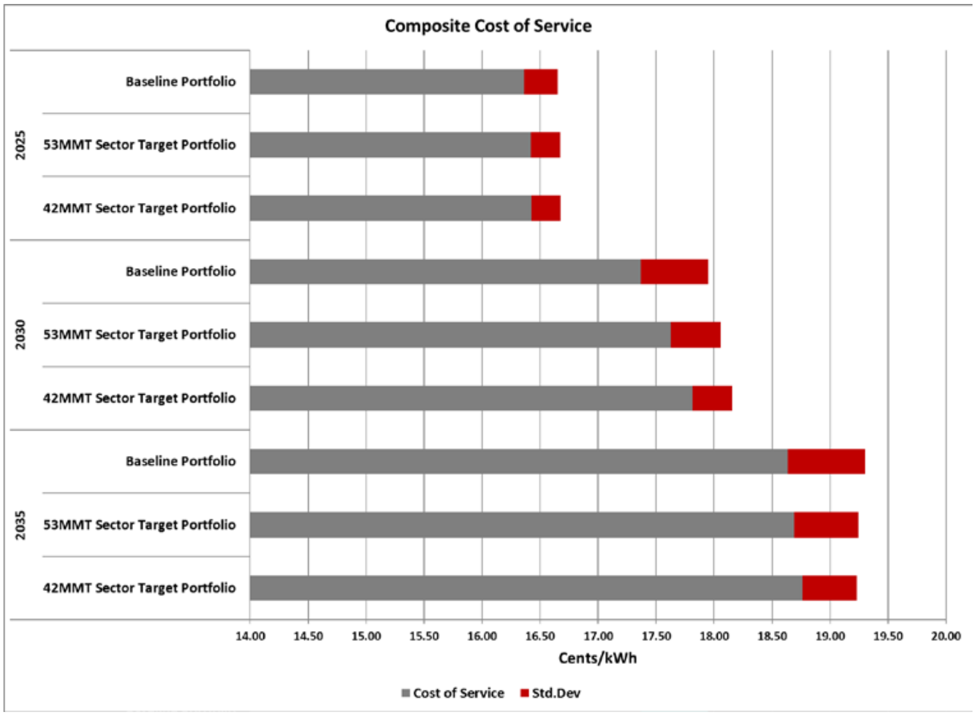

Figure 20.5.1. Forecasted 2025, 2030 and 2035 COS_{LN} values and corresponding risk estimates for the Baseline, 53MMT Sector Target, and 42MMT Sector Target portfolios.

Some of the other more pertinent findings presented in Chapter 13 are also briefly summarized below.

- ✓ Based on a careful analysis of RPU's primary cost of service components, staff project that the utility's Baseline Portfolio COS_{LN} growth rate is forecasted to be about 1.2% per year between 2020 and 2035.

- ✓ In the 53MMT Sector Target Portfolio, sufficient new renewable resources are acquired throughout the next decade to ensure that RPU could (1) meet a 60% by 2030 RPS mandate (using either Excess Procurement credits or additional Tradable REC purchases), and (2) reach a 2030 GHG emission level of approximately 446,000 metric tons. Note that this emission level is well below the utility's official 2030 GHG planning target (i.e., 486,277 MT CO_2-e).

- ✓ In the 42MMT Sector Target Portfolio, sufficient new renewable resources are acquired throughout the next decade to ensure that RPU could (1) exceed a 60% by 2030 RPS mandate (based solely on new renewable energy purchases), and (2) reach a 2030 GHG emission level of approximately 350,000 metric tons. Note that this emission level is comfortably below the utility's aspirational 2030 GHG planning target of 385,137 MT CO_2-e.

- ✓ The corresponding COS_{LN} calculations for these studies suggest that the 53MMT scenario would result in about a 1.5% increase in total customer energy costs in 2030 over the expected energy costs in the Baseline Portfolio. Likewise, the 42MMT scenario would result in about a 2.6% increase in total customer energy costs in 2030 over the Baseline Portfolio. However, after adding in the corresponding risk components to each scenario, these combined energy cost + risk increases reduce to 0.6% and 1.2%, respectively. (See Tables 13.5.1, 13.5.2, and Figure 13.5.5.)

- ✓ Overall, even in the absence of the risk adjustment, the expected cost increases associated with the 53MMT and 42MMT portfolios are relatively minor. This suggests that RPU should at least be able to achieve its official 2030 GHG planning target without significant rate stress, and perhaps even reach its aspirational target. However, these results depend strongly on the assumed future pricing for renewable energy assets.

Finally, with respect to the asset specific net value analyses, these analyses showed that most of the studied renewable assets exhibit marginally negative net values, in the absence of any additional avoided carbon credits. However, the proposed 2021 Solar PV + Storage contract exhibits a positive return on investment (ROI), implying that the utility could actually lower its overall cost of service by contracting for this resource. Additionally, these same asset specific net value analyses suggest that the IPP Repowering Project exhibits clearly negative net values in both 2030 and 2035. In contrast, the LMS100 Tolling Agreement exhibits slightly positive net values in 2025 and 2030, suggesting that this latter tolling arrangement represents a more financially viable (and hence justifiable) shorter-term strategy for replacing part of the expiring IPP coal contract. As discussed at length in Chapter 10, staff currently recommends that RPU exit out of the long-term IPP repowering contract.

20.6 Emerging Technologies

The latter part of this IRP reviewed various emerging technology issues and special topics. Chapters 15, 17 and 18 specifically addressed emerging technology issues; namely Energy Storage, Transportation Electrification, and future customer DER penetration trends.

Chapter 15 presented a financial viability assessment of energy storage (ES) as a stand-alone utility asset. To help with this evaluation, the utility retained the services of ES consulting staff at Ascend Analytics. Ascend staff performed multiple ES studies to compare annual returns on batteries ($/kWh) across battery types and across markets. These case studies suggested that the deployment of a short-duration, 15-minute battery configuration might potentially pay for itself in the CAISO frequency regulation market over the expected life of the project. However, this conclusion was very tentative and subject to a number of critical assumptions, the most important being the assumed level of battery cycling (which directly determined the expected life forecasts). Overall, staff concluded that more detailed battery simulation studies would definitely need to be carried out before the utility could confidently commit to funding such a battery energy storage system.

Chapter 17 presented an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. This discussion addressed the anticipated energy demand and reduced greenhouse gas (GHG) emissions that would result from the 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. Therefore, Chapter 17 reviewed the policy and regulatory environment around transportation electrification, as well as the status of electrification in the RPU service territory. Additionally, multiple forecasts for EVs and their associated loads and load profiles in the utility's service territory were presented in Chapter 17, along with their corresponding GHG emissions reduction calculations. These results suggest that RPU could experience up to 185,000 MWh/year of load growth and 100,000 MT of carbon reductions in 2030, under the most aggressive EV penetration scenario.

Similarly, the long term financial impacts of customer DER penetration trends were examined and discussed in Chapter 18. While RPU prides itself on fostering and facilitating increased amounts of behind-the-meter solar PV systems, it has long been recognized that the utility's rate structures do not fully recover the costs associated with supporting and integrating such systems. RPU hired NewGen Strategies & Solutions, LLC to analyze and model these trends over the next 20 years in the Domestic Residential rate class. These results showed that the expected long-term net revenue impacts under the current NEM 1.0 paradigm are very sobering. Specifically, the RPU service territory could potentially see 21,000 behind-the-meter solar PV installations by 2037, resulting in an annual cost-shift to non-NEM residential customers of nearly $30,000,000 under the current Domestic Residential rate schedule. The magnitude of this within-class customer subsidy is clearly unsustainable and unjustified; thus, alternative default rate schedules for future (post NEM 1.0) solar customers must be developed and implemented.

20.7 Other Important Issues & Topics

In 2015, following a comprehensive strategic and financial planning effort, the City of Riverside approved the "Utility 2.0" strategic plan for Riverside Public Utilities. This policy document presented a detailed integrated plan for maintaining the physical infrastructure and financial health of the utility, and ultimately helped define RPU's new proposed electric and water rate plans. With reference to this plan, Chapter 16 briefly reviewed and summarized the utility's new electric rate proposal, including its justification for why the new electric rate plan is fair and reasonable. This chapter also described the new Domestic TOU and 100% renewable energy rate tariffs that the utility plans to introduce in 2019, as well as the newly enhanced low-income and fixed-income assistance programs.

Finally, 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 19 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 Barriers Study report recommendations were also presented at the end of this chapter.

In summary, a significant number of diverse resource planning issues have been discussed and analyzed in detail this 2018 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 suggested some strategies that RPU can implement now in order to continue to provide the highest quality water and electric services at the lowest possible rates to benefit the Riverside community. The analyses, findings and recommendations presented in this 2018 Integrated Resource Plan are designed to assist Riverside Public Utilities to continue to achieve this goal in a proactive, intelligent, and optimal manner.

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.

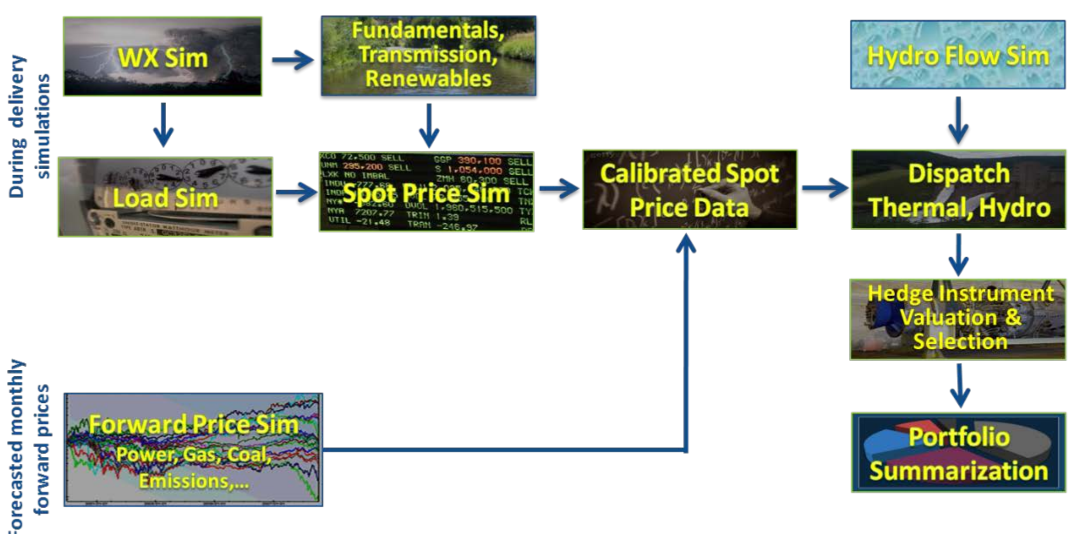

Figure A.1.1. PowerSimm simulation framework.

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.

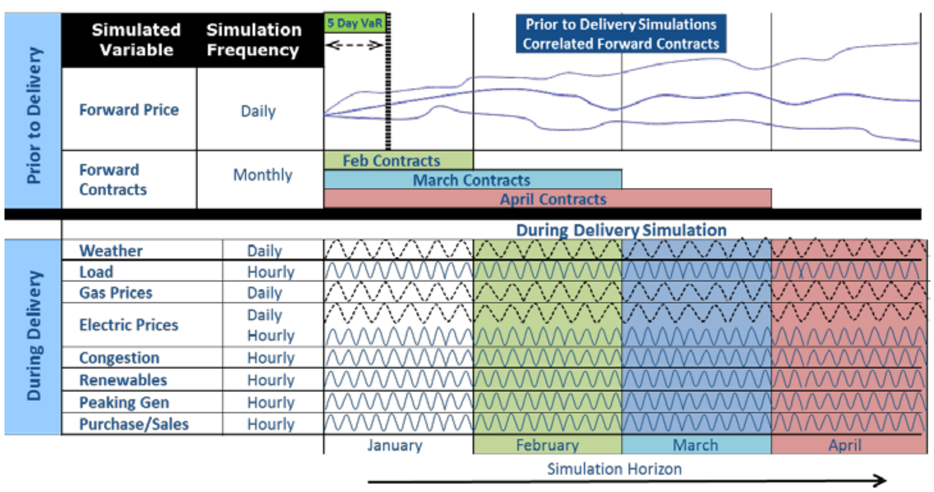

Figure A.1.2. Simulation framework of forward and spot prices.

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.

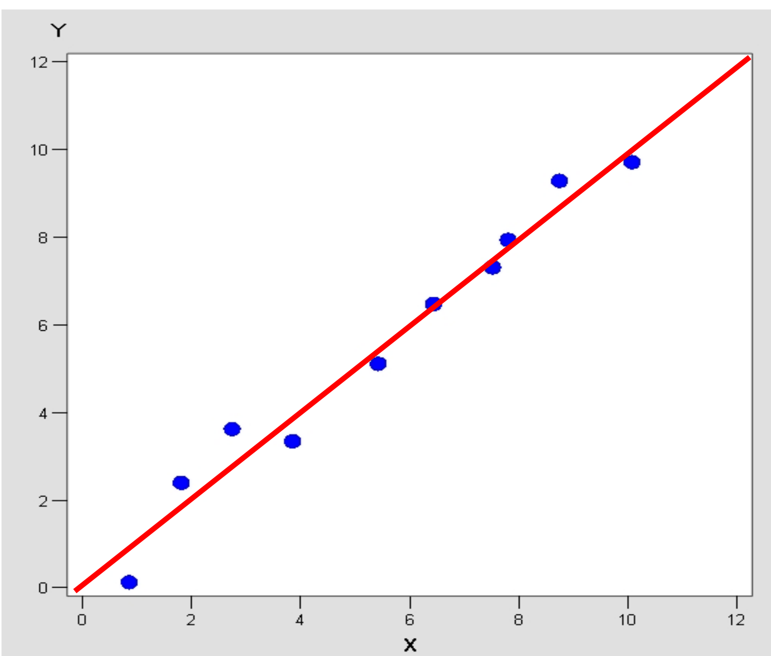

Figure A.2.1. Example of a traditional regression analysis.

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.

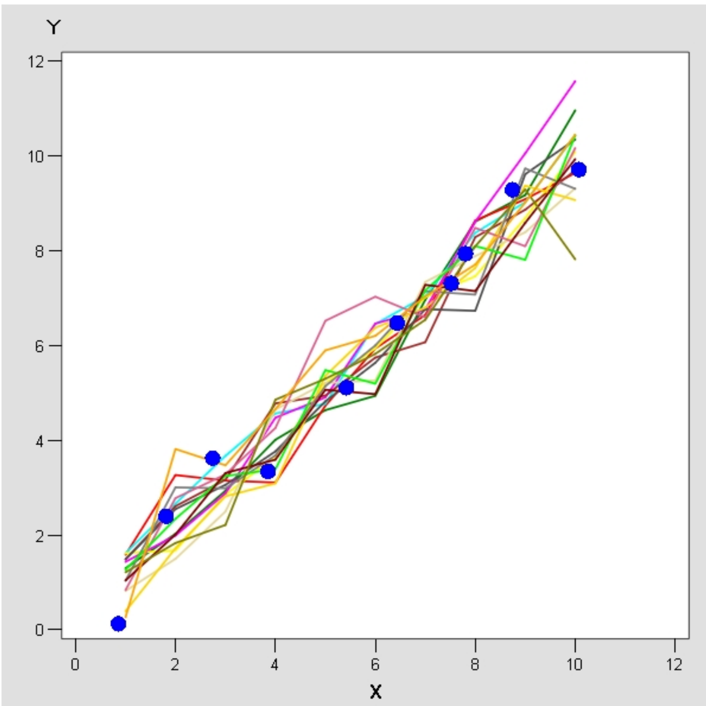

Figure A.2.2. Monte Carlo simulations.

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 2*i* 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.

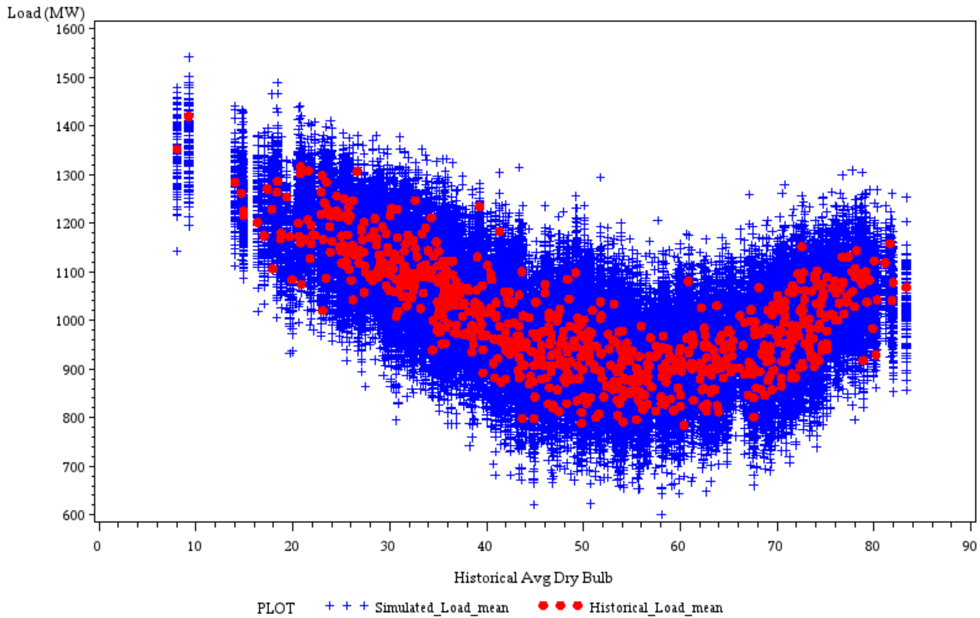

Figure A.2.3. Simulated and historical load and weather data.

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, 5^{th}, and 95^{th} 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, 5^{th}, and 95^{th} 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, 5th, and 95th 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, 5th, and 95th 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

Derivation of the 1.9 multiplication Factor for the CAR Calculation

By definition, the Value-at-Risk (VAR) metric and/or Cost-at-Risk (CAR) metric for an observed or simulated distribution of data is defined to be the difference between the 95th percentile and the mean. Mathematically, this can be expressed as

$$VAR\ or\ CAR = P_{95} - Mean$$

This definition is very practical, in the sense that it makes no assumptions about the statistical properties of the underlying data distribution.

When one can make a reasonable assumption about the type of statistical distribution that the data arises from, it is also possible to express the VAR and CAR metrics as a simple function of the standard deviation. For example, if the data arises from a Normal distribution with a mean of μ and a standard deviation of σ, then it is simple to show that CAR = 1.65σ. Note that 1.65 represents the appropriate multiplication factor (*F*) that solves the constraint equation

$$\frac{E\{P_{95}\} - \mu}{\sigma} = F$$

where *E*{ } represents the expectation and $E\{P_{95}\} = \mu + 1.65\sigma$, etc.

The Normal distribution is not a particularly good approximation to most data distributions that are derived from observed or simulated market price data. However, the Lognormal distribution often is a good approximation (particularly for cost-based metrics), since most production cost modeling platforms simulate market price data using Lognormal distribution functions. (Note that the Ascend software follows this approach; i.e., the log of the mean-adjusted price data follows a Normal distribution, hence the mean-adjusted price data follows a Lognormal distribution.) Under the assumption that log(X) follows a Normal(μ, σ) distribution, where X represents the data being examined, the expected values of the mean, standard deviation, and 95th percentile of the back-transformed data are:

$$Mean(X) = \exp(\mu + 0.5\sigma^2) = \exp(\mu)\exp(0.5\sigma^2)$$

$$Standard.Deviation(X) = \exp(\mu)\sqrt{\exp(\sigma^2)\,[\exp(\sigma^2) - 1]}$$

$$P_{95}(X) = \exp(\mu + 1.65\sigma) = \exp(\mu)\exp(1.65\sigma)$$

Upon plugging these expectations into the constraint equation, one can obtain the following formula for the multiplication factor:

$$F = \frac{\exp(1.65\sigma) - \exp(0.5\sigma^2)}{\sqrt{\exp(\sigma^2)[\exp(\sigma^2) - 1]}}$$

This formula does not yield a single solution, but instead represents a nonlinear function of the standard deviation. However, it can be readily verified that the maximum value that the factor can take is approximately 1.9 (see Figure B.1), and this value lies within the range of 1.7 to 1.9 for reasonable values of σ (e.g., $0.1 < \sigma < 1$). Thus, for Lognormally distributed data distributions, a VAR or CAR metric calculated as 1.9 times the observed standard deviation should yield a reasonable (abet possibly conservative) estimate, as compared to the traditional VAR or CAR calculation.

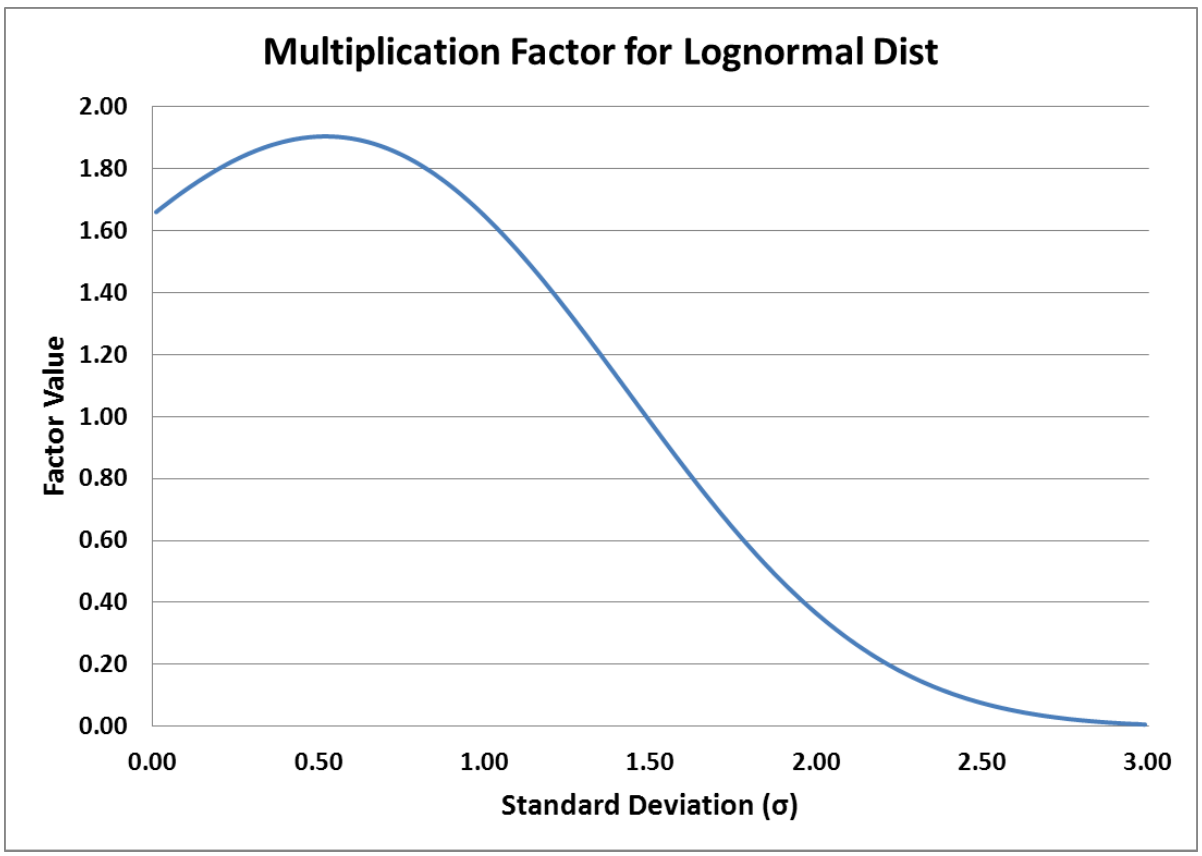

Figure B.1. A plot of the VAR and/or CAR multiplication factor for Lognormally distributed data, as a function of standard deviation (of the log-transformed data).

APPENDIX C
5 Year Power Resource Budget Projections
*****All Costs/Revenues in ($1000)*****

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
1							
2	**Capacity Cost**						
3	Hoover	$ 562	$ 515	$ 550	$ 512	$ 522	$ 528
4	IPP	$ 32,898	$ 35,911	$ 37,917	$ 38,856	$ 28,674	$ 27,763
5	Palo Verde	$ 3,544	$ 3,700	$ 3,800	$ 4,000	$ 4,100	$ 4,200
6	RA Capacity	$ 1,164	$ 1,513	$ 2,096	$ 2,939	$ 3,111	$ 3,293
7	**Total Capacity Cost**	**$ 38,168**	**$ 41,640**	**$ 44,363**	**$ 46,307**	**$ 36,408**	**$ 35,784**
8							
9	**Other Fixed Cost**						
10	AB-32 Implementation	$ 150	$ 150	$ 150	$ 158	$ 165	$ 174
11	Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
12	**Total Other Fixed Cost**	**$ 2,350**	**$ 2,350**	**$ 2,350**	**$ 2,358**	**$ 2,365**	**$ 2,374**
13							
14	**Ice Bear**						
15	Ice Bear Installation Cost	$ 1,520	$ 2,050	$ 2,050	$ -	$ -	$ -
16	Ice Bear O&M Cost	$ 101	$ 130	$ 133	$ 135	$ 137	$ 140
17	**Total Ice Bear Cost**	**$ 1,621**	**$ 2,180**	**$ 2,183**	**$ 135**	**$ 137**	**$ 140**
18							
19	**SONGs Cost**						
20	Professional Services	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50
21	Outside Legal Services	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50
22	Decommissioning Operations	$ -	$ -	$ -	$ -	$ -	$ -
23	O&M - Maint/Repair	$ 400	$ 400	$ 400	$ 400	$ 400	$ 400
24	Insurance Charges - Direct	$ -	$ -	$ -	$ -	$ -	$ -
25	Decommissioning Fund Exp	$ 1,500	$ 1,500	$ 1,500	$ 1,500	$ 1,500	$ 1,500
26	Taxes and Assessments	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
27	Nuclear Fuel Purchases	$ -	$ -	$ -	$ -	$ -	$ -
28	Capital Costs Related to Decomm.	$ -	$ -	$ -	$ -	$ -	$ -
29	**SONGS Extra Costs - Total**	**$ 2,000**	**$ 2,000**	**$ 2,000**	**$ 2,000**	**$ 2,000**	**$ 2,000**

APPENDIX C
5 Year Power Resource Budget Projections
All Costs/Revenues in ($1000)

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
30							
31	**IPP Cost (Reference)**						
32	IPA Budget Total	$ 42,275	$ 44,567	$ 46,812	$ 47,997	$ 38,069	$ 37,418
33	IPA Budget Fixed Fuel Cost	$ 8,889	$ 7,754	$ 7,962	$ 8,176	$ 8,395	$ 8,620
34	IPA Budget Incremental Fuel Cost	$ 9,377	$ 8,655	$ 8,895	$ 9,141	$ 9,394	$ 9,654
35	RPU Budget Fixed Cost Adjusted	$ 32,898	$ 35,911	$ 37,917	$ 38,856	$ 28,674	$ 27,763
36	RPU Budget Incremental Fuel Cost	$ 5,613	$ 6,439	$ 6,408	$ 6,624	$ 6,774	$ 6,948
37	**Total RPU IPP Cost**	**$ 38,511**	**$ 42,350**	**$ 44,324**	**$ 45,480**	**$ 35,449**	**$ 34,711**
38							
39							
40	**Transmission Revenue (TRR)**	**$ (35,265)**	**$ (36,203)**	**$ (37,059)**	**$ (37,758)**	**$ (38,575)**	**$ (39,422)**
41							
42	**Transmission Cost**						
43	Mead-Adelanto	$ 3,373	$ 3,394	$ 2,653	$ 475	$ 482	$ 486
44	Mead-Phoenix	$ 353	$ 320	$ 319	$ 252	$ 54	$ 55
45	STS	$ 11,735	$ 10,621	$ 11,958	$ 12,989	$ 10,869	$ 10,860
46	NTS	$ 1,136	$ 1,251	$ 1,335	$ 1,368	$ 845	$ 787
47	SCE	$ 14,054	$ 14,953	$ 15,551	$ 16,173	$ 16,820	$ 17,493
48	SCE WDAT	$ 1,298	$ 1,298	$ 1,298	$ 1,298	$ 1,298	$ 1,298
49	LADWP Service Agreements	$ 1,301	$ 1,301	$ 1,301	$ 1,301	$ 1,301	$ 1,301
50	**Subtotal**	**$ 33,250**	**$ 33,138**	**$ 34,415**	**$ 33,856**	**$ 31,669**	**$ 32,280**
51	ISO TAC Load	$ 24,670	$ 25,985	$ 27,758	$ 29,741	$ 31,755	$ 33,474
52	ISO Transmission Charges	$ 2,000	$ 2,100	$ 2,205	$ 2,315	$ 2,431	$ 2,553
53	**Subtotal**	**$ 26,670**	**$ 28,085**	**$ 29,963**	**$ 32,057**	**$ 34,186**	**$ 36,026**
54	**Total Transmission Cost**	**$ 59,920**	**$ 61,223**	**$ 64,378**	**$ 65,913**	**$ 65,855**	**$ 68,306**
55							
56	**Total Net Transmission Cost**	**$ 24,655**	**$ 25,020**	**$ 27,319**	**$ 28,155**	**$ 27,280**	**$ 28,884**

APPENDIX C
5 Year Power Resource Budget Projections
All Costs/Revenues in ($1000)

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
57							
58	**Resource Energy (MWh)**						
59	CalEnergy Portfolio	147,004	226,279	336,127	650,415	650,658	649,685
60	Clearwater	15,029	9,652	11,697	11,847	12,969	14,674
61	Hoover	30,363	30,005	30,002	30,005	30,005	30,005
62	IPP	640,821	598,364	589,727	591,279	589,932	589,341
63	Palo Verde	93,020	91,450	92,686	92,841	92,832	92,090
64	RERC	54,486	18,775	28,722	31,166	33,282	44,729
65	Salton Sea	324,970	322,261	295,636	0	0	0
66	Springs	691	70	182	262	248	441
67	North Lake Solar	55,402	54,687	54,311	53,859	53,487	53,137
68	Antelope Big Sky Ranch & Summer Solar	44,333	44,248	44,133	43,800	43,572	43,348
69	Tequesquite Solar	15,811	15,791	15,744	15,634	15,555	15,478
70	Wintec Wind	4,644	2,131	0	0	0	0
71	WKN Wind	21,428	21,519	21,519	21,519	21,519	21,519
72	Cabazon Wind	70,927	71,220	71,395	71,220	71,220	71,220
73	Kingbird Solar	41,211	41,141	41,046	40,730	40,527	40,324
74	Columbia II Solar	33,152	33,056	32,891	32,667	32,519	32,331
75	Antelope DSR Solar	70,778	70,681	70,456	69,976	69,627	69,278
76	SS5 Additional	10,895	0	0	0	0	0
77	**Total Energy Generation (MWh)**	**1,674,965**	**1,651,331**	**1,736,273**	**1,757,219**	**1,757,951**	**1,767,599**

APPENDIX C
5 Year Power Resource Budget Projections
All Costs/Revenues in ($1000)

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
78							
79	**Total Energy Cost (no CO2)**						
80	CalEnergy Portfolio	$ 10,947	$ 17,151	$ 25,806	$ 50,641	$ 51,421	$ 52,114
81	Clearwater	$ 515	$ 319	$ 377	$ 378	$ 421	$ 490
82	Hoover	$ 303	$ 308	$ 328	$ 302	$ 309	$ 310
83	IPP	$ 5,613	$ 6,439	$ 6,408	$ 6,624	$ 6,774	$ 6,948
84	Palo Verde	$ 757	$ 940	$ 982	$ 1,013	$ 1,043	$ 1,066
85	RERC	$ 2,097	$ 693	$ 1,056	$ 1,128	$ 1,222	$ 1,677
86	Salton Sea	$ 24,057	$ 24,215	$ 22,519	$ -	$ -	$ -
87	Springs	$ 37	$ 3	$ 9	$ 13	$ 12	$ 22
88	North Lake Solar	$ 4,497	$ 4,506	$ 4,541	$ 4,571	$ 4,608	$ 4,646
89	Antelope Big Sky Ranch & Summer Solar	$ 3,159	$ 3,153	$ 3,144	$ 3,121	$ 3,105	$ 3,089
90	Tequesquite Solar	$ 1,315	$ 1,333	$ 1,349	$ 1,359	$ 1,373	$ 1,386
91	Wintec Wind	$ 281	$ 130	$ -	$ -	$ -	$ -
92	WKN Wind	$ 1,492	$ 1,534	$ 1,571	$ 1,609	$ 1,647	$ 1,687
93	Cabazon Wind	$ 4,206	$ 4,223	$ 4,234	$ 4,223	$ 4,223	$ 4,223
94	Kingbird Solar	$ 2,833	$ 2,828	$ 2,822	$ 2,800	$ 2,786	$ 2,772
95	Columbia II Solar	$ 2,320	$ 2,313	$ 2,302	$ 2,286	$ 2,276	$ 2,263
96	Antelope DSR Solar	$ 3,804	$ 3,799	$ 3,787	$ 3,761	$ 3,742	$ 3,724
97	SS5 Additional	$ 588	$ -	$ -	$ -	$ -	$ -
98	**Subtotal Generation Cost**	**$ 68,821**	**$ 73,887**	**$ 81,233**	**$ 83,830**	**$ 84,962**	**$ 86,416**
99	CAISO Energy Charges	$ 448	$ 448	$ 448	$ 461	$ 475	$ 490
100	CRR Auction Cost	$ 500	$ 525	$ 552	$ 580	$ 609	$ 640
101	SCPPA Project Fees	$ 217	$ 335	$ 343	$ 353	$ 361	$ 368
102	Biomass Mandate	$ -	$ 639	$ 639	$ 639	$ 639	$ 639
103	**Subtotal Generation Cost**	**$ 69,986**	**$ 75,833**	**$ 83,215**	**$ 85,863**	**$ 87,046**	**$ 88,552**
104	Power Forward Contract Net Hedge Cost/(Revenue)	$ (1,334)	$ (30)	$ -	$ -	$ -	$ -
105	**Total Generation Cost**	**$ 68,651**	**$ 75,803**	**$ 83,215**	**$ 85,863**	**$ 87,046**	**$ 88,552**

APPENDIX C
5 Year Power Resource Budget Projections
*****All Costs/Revenues in ($1000)*****

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
106							
107	**CO2 Emissions, Costs, and Revenues**						
108							
109	**CO2 Emissions (metric tons)**						
110	Clearwater	7,621	4,899	5,937	6,038	6,606	7,485
111	IPP	586,976	548,087	540,175	541,597	540,363	539,822
112	RERC	27,858	9,626	14,719	15,989	17,067	22,933
113	Springs	514	52	136	195	184	328
114	**Total Emissions**	**622,969**	**562,663**	**560,967**	**563,818**	**564,221**	**570,568**
115							
116	**CO2 Cost**						
117	Clearwater	$ 122	$ 84	$ 108	$ 116	$ 133	$ 158
118	IPP	$ 9,632	$ 9,553	$ 9,961	$ 10,532	$ 11,046	$ 11,573
119	RERC	$ 446	$ 164	$ 266	$ 306	$ 343	$ 484
120	Springs	$ 8	$ 1	$ 2	$ 4	$ 4	$ 7
121	**Total CO2 Cost**	**$ 10,209**	**$ 9,802**	**$ 10,338**	**$ 10,957**	**$ 11,526**	**$ 12,223**
122							
123	**CO2 Allowances and Auction Revenues**						
124	CO2 Allowances (metric tons)	1,075,313	1,081,054	1,083,954	1,074,857	1,058,743	1,047,801
125	CO2 Allowances Available for Sale at Auction	452,343	518,391	522,987	511,039	494,522	477,232
126	CO2 Auction Floor Price ($/metric ton)	14.06	$ 15.06	$ 16.11	$ 17.24	$ 18.45	$ 19.74
127	CO2 Auction Revenue (Calculated)	$ (6,360)	$ (7,807)	$ (8,427)	$ (8,811)	$ (9,123)	$ (9,420)
128	**CO2 Auction Revenue (Budgeted)**	**$ (6,360)**	**$ (7,807)**	**$ (8,427)**	**$ (4,405)**	**$ -**	**$ -**
129							
130	**Post 2020 Cap and Trade Cost**						
131	**CO2 Cost Post -2020 (Calculated)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

APPENDIX C
5 Year Power Resource Budget Projections
All Costs/Revenues in ($1000)

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
132							
133	**Wholesale CAISO Sales (MWh)**						
134	Total Energy Generation Sold into SP15	1,674,965	1,651,331	1,736,273	1,757,219	1,757,951	1,767,599
135							
136	**Wholesale CAISO Revenue**						
137	CalEnergy Portfolio	$ (4,780)	$ (6,841)	$ (10,490)	$ (21,218)	$ (22,069)	$ (22,780)
138	Clearwater	$ (837)	$ (504)	$ (622)	$ (634)	$ (708)	$ (839)
139	Hoover	$ (1,296)	$ (1,197)	$ (1,214)	$ (1,240)	$ (1,277)	$ (1,324)
140	IPP	$ (23,368)	$ (20,548)	$ (20,616)	$ (21,436)	$ (22,224)	$ (22,975)
141	Palo Verde	$ (3,034)	$ (2,843)	$ (2,935)	$ (3,043)	$ (3,163)	$ (3,239)
142	RERC	$ (3,592)	$ (1,149)	$ (1,803)	$ (1,968)	$ (2,131)	$ (2,968)
143	Salton Sea	$ (10,512)	$ (9,964)	$ (9,368)	$ -	$ -	$ -
144	Springs	$ (59)	$ (5)	$ (15)	$ (21)	$ (20)	$ (37)
145	North Lake Solar	$ (1,838)	$ (1,705)	$ (1,704)	$ (1,728)	$ (1,780)	$ (1,822)
146	Antelope Big Sky Ranch & Summer Solar	$ (1,445)	$ (1,363)	$ (1,365)	$ (1,388)	$ (1,436)	$ (1,468)
147	Tequesquite Solar	$ (537)	$ (502)	$ (503)	$ (510)	$ (527)	$ (540)
148	Wintec Wind	$ (148)	$ (71)	$ -	$ -	$ -	$ -
149	WKN Wind	$ (685)	$ (652)	$ (661)	$ (681)	$ (707)	$ (731)
150	Cabazon Wind	$ (2,264)	$ (2,172)	$ (2,211)	$ (2,278)	$ (2,366)	$ (2,443)
151	Kingbird Solar	$ (1,375)	$ (1,280)	$ (1,283)	$ (1,299)	$ (1,341)	$ (1,376)
152	Columbia II Solar	$ (1,113)	$ (1,041)	$ (1,040)	$ (1,055)	$ (1,091)	$ (1,118)
153	Antelope DSR Solar	$ (2,345)	$ (2,191)	$ (2,194)	$ (2,226)	$ (2,299)	$ (2,357)
154	SS5 Additional	$ (351)	$ -	$ -	$ -	$ -	$ -
155	**Total Generation Revenue**	**$ (59,580)**	**$ (54,028)**	**$ (58,023)**	**$ (60,725)**	**$ (63,139)**	**$ (66,019)**

APPENDIX C
5 Year Power Resource Budget Projections
*****All Costs/Revenues in ($1000)*****

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
156							
157	**Gross Load (includes internal gen.) in MWh**						
158	Gross System Load	2,265,801	2,303,049	2,334,157	2,354,656	2,381,771	2,410,005
159	Total Load Cost	$ 78,301	$ 74,954	$ 77,017	$ 79,961	$ 83,832	$ 87,759
160							
161	**Net CAISO Energy Position**						
162	Net Market Purchases or (Sales) in MWh	590,836	651,718	597,883	597,437	623,819	642,407
163	Net Cost of Market Purchases or (Sales)	$18,721	$20,926	$18,995	$19,236	$20,693	$21,740
164	Market Contingency Reserve	$3,895	$4,094	$4,365	$4,322	$4,469	$4,224
165							
166	**Gas Burn (MMBtu)**						
167	Clearwater	143,346	92,138	111,669	113,567	124,260	140,795
168	RERC	523,982	181,054	276,855	300,737	321,016	431,352
169	Springs	9,674	985	2,553	3,662	3,468	6,171
170	**Total Burn**	**677,002**	**274,177**	**391,077**	**417,966**	**448,744**	**578,319**
171							
172	**Fuel Cost**						
173	Clearwater	$ 478	$ 294	$ 348	$ 348	$ 389	$ 453
174	RERC	$ 1,797	$ 590	$ 898	$ 957	$ 1,039	$ 1,431
175	Springs	$ 34	$ 3	$ 8	$ 11	$ 11	$ 20
176	Gas Forward Contract Net Hedge Cost/(Revenue)	$ -	$ -	$ -	$ -	$ -	$ -
177	**Subtotal**	**$ 2,309**	**$ 888**	**$ 1,254**	**$ 1,316**	**$ 1,439**	**$ 1,904**
178	Variable O&M Costs (RERC, Clearwater, Springs)	$ 341	$ 128	$ 188	$ 202	$ 217	$ 285
179	**Total Fuel Cost**	**$ 2,650**	**$ 1,015**	**$ 1,443**	**$ 1,519**	**$ 1,655**	**$ 2,189**

APPENDIX C
5 Year Power Resource Budget Projections
*****All Costs/Revenues in ($1000)*****

Line		FY 2017/2018	FY 2018/2019	FY 2019/2020	FY 2020/2021	FY 2021/2022	FY 2022/2023
180							
181	Summary						
182	Gross Costs	$ 195,327	$ 210,217	$ 221,849	$ 226,133	$ 218,974	$ 223,120
183	Gross Revenue	$ (41,625)	$ (44,009)	$ (45,486)	$ (42,164)	$ (38,575)	$ (39,422)
184	Net Costs	$ 153,702	$ 166,207	$ 176,363	$ 183,970	$ 180,399	$ 183,698
185							
186	Summary						
187	Transmission	$ 59,920	$ 61,223	$ 64,378	$ 65,913	$ 65,855	$ 68,306
188	Energy	$ 88,958	$ 99,935	$ 105,320	$ 108,104	$ 110,770	$ 112,612
189	Capacity	$ 38,168	$ 41,640	$ 44,363	$ 46,307	$ 36,408	$ 35,784
190	SONGS	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000	$ 2,000
191	Ice Bear	$ 1,621	$ 2,180	$ 2,183	$ 135	$ 137	$ 140
192	GHG Regulatory Fees	$ 150	$ 150	$ 150	$ 158	$ 165	$ 174
193	Contingency Generating Plants	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200	$ 2,200
194	Gas Burns + Net Hedge Cost or (Revenue)	$ 2,309	$ 888	$ 1,254	$ 1,316	$ 1,439	$ 1,904
195	Post 2020 Cap and Trade Cost	$ -	$ -	$ -	$ -	$ -	$ -
196	SUBTOTAL COST	$ 195,327	$ 210,217	$ 221,849	$ 226,133	$ 218,974	$ 223,120
197	CO2 Allowance Auction Revenue	$ (6,360)	$ (7,807)	$ (8,427)	$ (4,405)	$ -	$ -
198	TRR Revenue	$ (35,265)	$ (36,203)	$ (37,059)	$ (37,758)	$ (38,575)	$ (39,422)
199	PCC-1 RPS Sale	$ -	$ -	$ -	$ -	$ -	$ -
200	SUBTOTAL REVENUE	$ (41,625)	$ (44,009)	$ (45,486)	$ (42,164)	$ (38,575)	$ (39,422)
201							
202	TOTAL	$ 153,702	$ 166,207	$ 176,363	$ 183,970	$ 180,399	$ 183,698
203							
204	Summary (Cost/Gross Load)						
205	Adjusted Transmission	$ 10.88	$ 10.86	$ 11.70	$ 11.96	$ 11.45	$ 11.99
206	Energy	$ 39.26	$ 43.39	$ 45.12	$ 45.91	$ 46.51	$ 46.73
207	Capacity	$ 16.85	$ 18.08	$ 19.01	$ 19.67	$ 15.29	$ 14.85
208	SONGs	$ 0.88	$ 0.87	$ 0.86	$ 0.85	$ 0.84	$ 0.83
209	Total (all categories)	$ 67.84	$ 72.17	$ 75.56	$ 78.13	$ 75.74	$ 76.22

APPENDIX D

Riverside Public Utilities
Updated 2018 Renewable Energy Procurement Policy

1. Introduction

The recently adopted SB 350 legislation and the associated California Energy Commission (CEC) SB X1-2 derived RPS regulations requires that Riverside Public Utilities (RPU) adopt, implement and periodically update a Renewable Energy Resource Procurement Policy that complies with the Renewable Portfolio Standards (RPS) incorporated into Section 399.30 of the Public Utilities Code. Additionally, RPU must submit this Procurement Policy to the CEC within 30 days of its official adoption. Pursuant to this legislative mandate, RPU is adopting this "Updated 2018 Renewable Energy Procurement Policy". This RPU Procurement Policy supersedes all prior Procurement Policy documents and guidelines issued by RPU.

1.1 Report Outline and Contents

This report summarizes RPUs current and pertinent renewable energy procurement policy guidelines. These guidelines are designed to meet or exceed all of the renewable energy procurement goals mandated by SB X1-2 and SB 350 legislation, as outlined in the CEC RPS Enforcement Guidelines. The following RPS topics are specifically addressed:

- Portfolio Content Categories
- Procurement Requirements
- Long-term Contracting Requirements
- Historic Carryover Credits
- Excess Procurement Rules and Measures
- Voluntary Green Pricing Tariffs
- Delay of Timely Compliance Rules
- Other Optional Compliance Measures

Additionally, the latter part of this report briefly summarizes how the current renewable resources in Riverside's power resource portfolio are being used to meet these RPS mandates.

2. Portfolio Content Categories

Under SB X1-2 and SB 350, all CA Publicly Owned Utilities (POUs) are required to meet both minimum RPS procurement requirements and minimum portfolio content category requirements. All renewable generation assets either contracted for or built after June 1, 2010 must be categorized into one of three distinct portfolio content categories, with Portfolio Content Category 1 representing the preferred category of assets that load serving entities should contract for. At a very high level, categories 1, 2 and 3 represent in-state renewable resources, out-of-state (firmed and shaped) renewable resources, and tradable renewable energy credits (TRECs), respectively.

More formal definitions for each portfolio content category are provided below. Interested readers should refer to the appropriate CEC technical publications for precise technical definitions.[1]

2.1 Portfolio Content Category 1

Portfolio Content Category 1 (PCC-1) electricity products must be procured bundled to be classified as PCC-1, and the POU may not resell the underlying electricity from the electricity product back to the eligible renewable energy resource from which the electricity product was procured. These products must have a first point of interconnection to the WECC transmission grid. PCC-1 electricity products must also meet one of the following criteria:

- Electricity products must be generated by an eligible renewable energy resource that has its first point of interconnection either within the metered boundaries of one of the following five California balancing authority areas: CAISO, LADWP, BANC, IID or TID, or a distribution system used to serve end users within the metered boundaries of one of these five California balancing authority areas.
- Electricity products from the eligible renewable energy resource with a first point of interconnection outside the metered boundaries of a California balancing authority must be scheduled into a California balancing authority using either firm transmission without substituting electricity from another source, or via a dynamic transfer agreement (between balancing authority areas). Under either scenario, this electricity must be scheduled or transferred into a California balancing authority on an hourly or sub-hourly basis, and the POU's

[1] Refer to *Enforcement Procedures for the Renewable Portfolio Standard for Local Publicly Owned Electric Utilities*, April 2016, as well as *Amendments to Regulations Specifying Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (Pre-Rulemaking Draft)*, August 2016.

governing board or other authority must have approved the agreement before the electricity is generated.

2.2 Portfolio Content Category 2

Portfolio Content Category 2 (PCC-2) electricity products must be generated by an eligible renewable energy resource that is interconnected to a transmission network within the WECC service territory, and the electricity must be matched with incremental electricity that is scheduled into a California balancing authority. PCC-2 electricity products must be procured bundled and must meet all of the following criteria:

- The first point of interconnection to the WECC transmission grid for both the eligible renewable energy resource and the resource providing the incremental electricity must be located outside the metered boundaries of a California balancing authority area.
- The incremental electricity used to match the electricity from the eligible renewable energy resource must be incremental to the POU. More specifically, "incremental electricity" means electricity that is not in the portfolio of the POU claiming the electricity products for RPS compliance prior to the date the contract or ownership agreement for the electricity products from the eligible renewable energy resource, with which the incremental electricity is being matched, is executed by the POU or other authority, as delegated by the POU governing board.
- The contract or ownership agreement for the incremental electricity is executed by the governing board or other authority, as delegated by the POU governing board, at the same time or after the contract or ownership agreement for the electricity products from the eligible renewable energy resource is executed.
- The incremental electricity must be scheduled into the California balancing authority within the same calendar year as the electricity from the eligible renewable energy resource is generated.
- The electricity from the eligible renewable energy resource must be available to be procured by the POU and may not be sold back to that resource.

2.3 Portfolio Content Category 3

All unbundled renewable energy credits and other electricity products procured from eligible renewable energy resources located within the WECC transmission grid that do not meet the requirements of either a PCC-1 or PCC-2 product are deemed to fall within Portfolio Content Category 3 (PCC-3).

3. RPS Procurement Requirements

RPU's renewable energy procurement targets are defined below for Compliance Periods 1 (2011-2013), 2 (2014-2016), 3 (2017-2020), 4 (2021-2024), 5 (2025-2027) and 6 (2028-2030). These targets meet or exceed all of the minimum mandates specified in SBX1-2 and SB 350, respectively.

3.1 Definitions

EP_X = Electricity products retired for the specified year X; this may include excess procurement and historic carryover that the POU has chosen to apply to the compliance period containing year X

RS_X = Total retail sales made by the POU for the specified year X

3.2 Riverside Public Utilities Historical RPS Procurement Targets

For the compliance period beginning January 1, 2011, and ending December 31, 2013, a POU shall demonstrate it has procured electricity products sufficient to meet or exceed an average of 20 percent of its retail sales over the three calendar years in the compliance period. The numerical expression of this requirement is:

$$(EP_{2011} + EP_{2012} + EP_{2013}) \geq 0.200(RS_{2011} + RS_{2012} + RS_{2013})$$

<u>RPU has successfully met this procurement target and the CEC has deemed RPU to be compliant.</u>

For the compliance period beginning January 1, 2014, and ending December 31, 2016, a POU shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 20 percent of its 2014 retail sales, 20 percent of its 2015 retail sales, and 25 percent of its 2016 retail sales. The numerical expression of this requirement is:

$$(EP_{2014} + EP_{2015} + EP_{2016}) \geq 0.200(RS_{2014}) + 0.200(RS_{2015}) + 0.250(RS_{2016})$$

<u>RPU has successfully met this procurement target. The CEC is currently in the process of reviewing the 2014-2016 RPS claims submitted by the utility.</u>

3.3 RPU's Current and Future RPS Procurement Targets

For the compliance period beginning January 1, 2017, and ending December 31, 2020, a POU shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 27 percent of its 2017 retail sales, 29 percent of its 2018 retail sales, 31 percent of its 2019 retail sales, and 33 percent of its 2020 retail sales. The numerical expression of this requirement is:

$$(EP_{2017} + EP_{2018} + EP_{2019} + EP_{2020}) \geq 0.270(RS_{2017}) + 0.290(RS_{2018}) + 0.310(RS_{2019}) + 0.330(RS_{2020})$$

For the compliance period beginning January 1, 2021, and ending December 31, 2024, a POU shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 34.8 percent of its 2021 retail sales, 36.5 percent of its 2022 retail sales, 38.3 percent of its 2023 retail sales, and 40.0 percent of its 2024 retail sales. The numerical expression of this requirement is:

$$(EP_{2021} + EP_{2022} + EP_{2023} + EP_{2024}) \geq 0.348(RS_{2021}) + 0.365(RS_{2022}) + 0.383(RS_{2023}) + 0.400(RS_{2024})$$

For the compliance period beginning January 1, 2025, and ending December 31, 2027, a POU shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 41.7 percent of its 2025 retail sales, 43.3 percent of its 2026 retail sales, and 45.0 percent of its 2027 retail sales. The numerical expression of this requirement is:

$$(EP_{2025} + EP_{2026} + EP_{2027}) \geq 0.417(RS_{2025}) + 0.433(RS_{2026}) + 0.450(RS_{2027})$$

For the compliance period beginning January 1, 2028, and ending December 31, 2030, a POU shall demonstrate it has procured electricity products within that period sufficient to meet or exceed the sum of 46.7 percent of its 2028 retail sales, 48.3 percent of its 2029 retail sales, and 50.0 percent of its 2030 retail sales. The numerical expression of this requirement is:

$$(EP_{2028} + EP_{2029} + EP_{2030}) \geq 0.467(RS_{2028}) + 0.483(RS_{2029}) + 0.500(RS_{2030})$$

3.4 Portfolio Content Category Requirements

In addition to the section 3.3 procurement requirements, for all compliance periods on/after January 1, 2017, RPU must ensure that at least 75% of all of the renewable electricity products procured pursuant to a contract agreement executed on or after June 1, 2010 and retired during each compliance period meet the definition of a PCC-1 product. Additionally, RPU must ensure that no more than 10% of all of the renewable electricity products procured on or after June 1, 2010 and retired during each compliance period meet the definition of a PCC-3 product.

3.5 Long-term Contracting Requirement

In addition to the section 3.3 procurement and section 3.4 content category requirements, for all compliance periods on/after January 1, 2017, RPU must ensure that at least 65% of all of the renewable energy credits (RECs) applied towards the utilities procurement target for each compliance period shall be from contracts of 10 years or more in duration or from ownership agreements. Note that if any electricity product is procured under a contract that has been amended to extend the end date of the contract, the duration of the amended contract will be calculated from the original contract start date to the amended contract end date.

4. Historic Carryover Credits

In August 2015 the CEC notified RPU that Riverside's claims for 769,145 MWh of Historic Carryover credits had been officially reviewed and approved by staff. Riverside had applied for these credits in late 2012, based on the utility's early efforts towards procuring excess renewable energy in the 2002-2010 timeframe. In January 2017 the CEC issued and adopted the POU Renewables Portfolio Standard Verification Results for Compliance Period 1. These results officially deemed Riverside fully RPS compliant for Compliance Period 1 and also awarded the 769,145 MWh of Historic Carryover credits to the utility.

Historic Carryover credits can be used on a one-for-one basis to reduce a utility's minimum compliance period procurement targets. If a utility is already able to fully meet its compliance period procurement targets, these credits can still be applied and used to create additional Excess Procurement credits (see section 5), subject to the utility satisfying all applicable Excess Procurement accounting rules and regulations. As such, RPU reserves the right to apply some or all of its 769,145 MWh of Historic Carryover credits to its current or future compliance period procurement targets, and in doing so generate additional Excess Procurement credits for later use.

5. Excess Procurement Rules and Measures

Excess Procurement credits can be generated when a utility retires more RECs than are needed to fully meet all of the renewable energy procurement targets in a specific compliance period. Credits that are generated by the utility are subject to CEC certification; once certified, these excess procurement credits can be used by the utility to help meet the renewable energy procurement targets associated with future compliance periods.

5.1 RPU Adopted Excess Procurement Measures

RPU hereby adopts the following Excess Procurement measures, so that the utility may apply excess procurement credits generated in any compliance period on/after Compliance Period 3 to any subsequent compliance period. The generation of any Excess Procurement credits will be subject to the following limitations:

- No retired RECs associated with electricity products that are classified as PCC-2 or PCC-3 products may be counted as excess procurement.
- All retired PCC-2 and PCC-3 RECs that exceed the maximum limits for PCC-2 and PCC-3 products in a compliance period must be subtracted from the calculation of Excess Procurement.

For clarity, Excess Procurement shall be calculated as follows:

Excess Procurement $= (EP_x) - (RPS_x + S2_x + S3_x)$

where

EP_x = *Electricity products retired for the RPS procurement target for compliance period X.*

RPS_x = *The RPS procurement target calculated in section 3.3 for compliance period X.*

$S2_x$ = *Retired PCC-2 RECs in excess of the maximum allowable amount for compliance period X.*

$S3_x$ = *Retired PCC-3 RECs in excess of the maximum allowable amount for compliance period X.*

6. Voluntary Green Pricing Tariffs

Beginning January 1, 2014 a POU may exclude from its retail sales the MWhs generated by eligible renewable energy resources that are credited to customers who voluntarily elect to participate in a “green energy” tariff offered by that POU.

6.1 RPU Proposal to Offer a 100% Renewable Energy Tariff Option

RPU hereby reserves the right to offer a 100% renewable energy tariff (RET) option to its customers, either as an optional tariff in the utility's 2018 General Rate Case proposal or at some future date. Under the 100% RET option, RPU customers will be able to voluntarily elect to purchase and receive 100% renewable energy in place of the utility's current energy mix. This 100% RET option shall satisfy the following requirements:

- The renewable electricity products credited to the customer and excluded from retail sales shall consist solely of PCC-1 products.
- Any RECs associated with the electricity products credited to a participating customer under the program shall not be used by the utility for compliance with its own RPS procurement requirements. Additionally, these RECs shall be retired on behalf of the participating customer in WREGIS and shall not be further sold or monetized for any purpose. (Customers who participate in this 100% RET option and maintain their own WREGIS accounts may elect to have RPU retire their RECs into their own WREGIS accounts by submitting a written request to the utility.)
- The electricity products excluded from retail sales shall be procured by RPU from eligible renewable energy resources that are located in the greater Southern California region.

7. Delay of Timely Compliance

From time to time, due to unforeseen events beyond Riverside's control, RPU may not meet the RPS procurement targets specified in section 3. Riverside hereby adopts the following Delay of Timely Compliance rules consistent with SB X1-2 and SB 350 RPS mandates and CEC enforcement regulations for such events. Valid Delay of Timely Compliance events can be briefly summarized as follows:

- Inadequate transmission capacity exists to allow for the contracted amount of electricity to be delivered from an eligible renewable energy resource using the current operational protocols of the CAISO balancing authority.
- Permitting, interconnection, or other system-related circumstances beyond the control of Riverside have delayed the Commercial Operation Date of a contracted, eligible renewable energy resource.
- Unanticipated curtailment of eligible renewable energy resources was necessary to address the needs of a balancing authority.

8. Other Optional Compliance Measures

On November 18, 2011 and December 13, 2011, Riverside's Public Utilities Board and City Council, respectively, formally adopted Riverside Public Utilities SB X1-2 Enforcement Program. This Enforcement Program contains additional cost limitations associated with this RPS Procurement Policy. Riverside reserves the right to update both this Procurement Policy and the associated Enforcement Program as needed, in order to comply with future statutory and/or regulatory RPS mandates.

9. RPU RPS Progress to Date

Riverside has been actively contracting for new, cost effective, long-term renewable resources with expected commercial operation dates in the 2013-2019 timeframe. As of December 31, 2016, the City of Riverside had formally approved nine new long-term PCC-1 renewable resource contracts. Each of these additional contracts were identified and selected for RPU's renewable portfolio using a best-fit, least-cost procurement strategy with the goal of exceeding a 33% RPS mandate by 2020.

As shown in Figure D.1 on the next page, these additional PCC-1 resources should supply Riverside with enough new renewable energy to significantly exceed all of its minimum renewable energy procurement, portfolio content category and contracting length mandates well beyond 2020. More specifically, provided these contracts continue to perform as expected, Riverside expects to remain fully compliant with all current SB 350 RPS regulations through 2024 (i.e., through Compliance Period 4), before needing to rely on any excess procurement credits. Additionally, Riverside expects to receive excess PCC-1 renewable energy from 2017 through 2023 under current SB 350 compliance obligations. This energy will most likely be "banked" as excess procurement for use in later compliance years, but the utility reserves the right to instead monetize some or all of this excess procurement if such activities are in the best interest of RPU ratepayers.

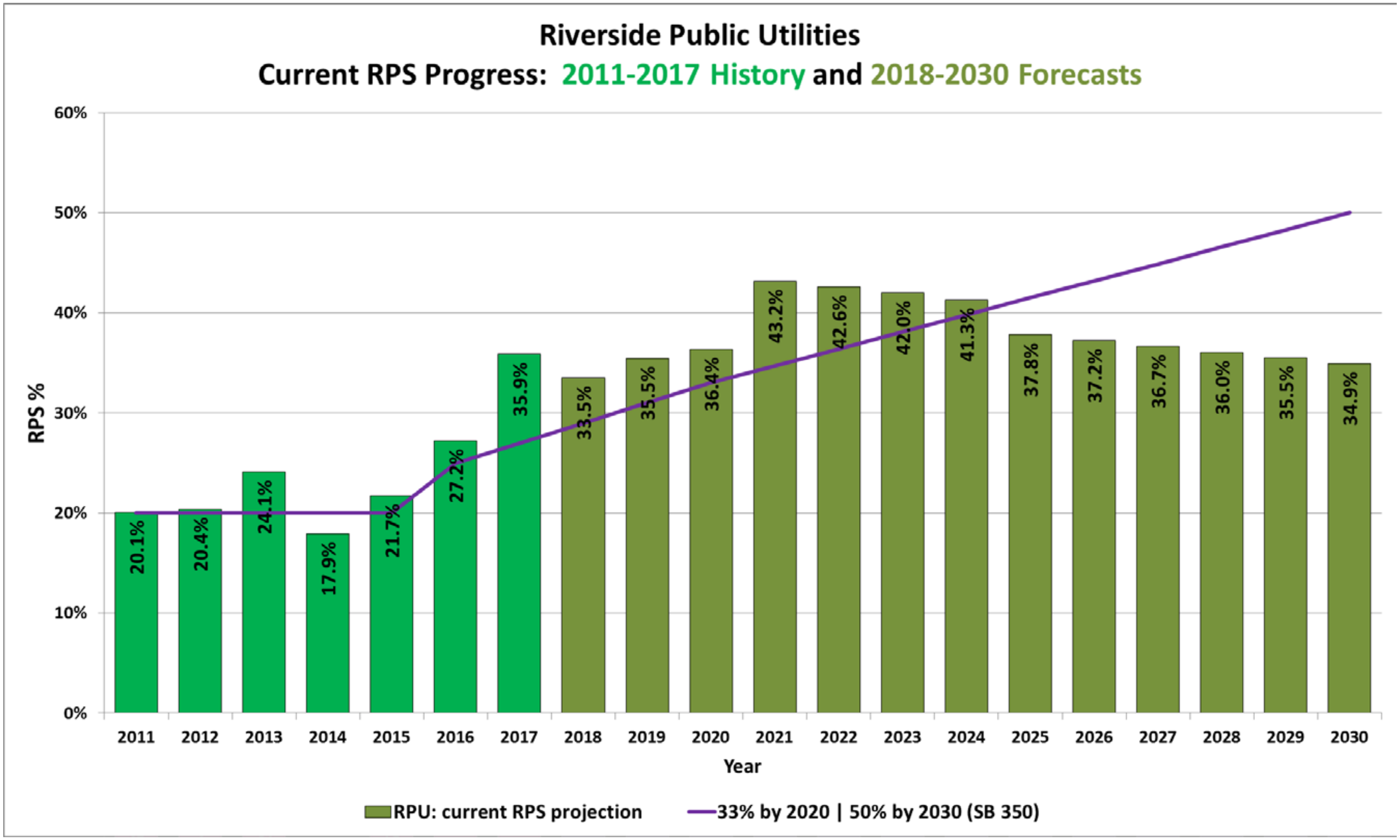

Figure D.1. Riverside's achieved (2011-2017) and forecasted (2018-2030) renewable energy amounts, by year. Note that the overlaid purple line defines the current CA (SB 350) RPS procurement mandate.

APPENDIX E

Value of Avoided Energy (VOAE) Calculations

The following tables show the VOAE calculations for Baseload, Lighting and HVAC EE programs by customer class, as reported in Chapter 14, Tables 14.3.4 and 14.6.1.

Table E.1. VOAE calculations for the 2018 Baseload Residential customer EE measure.

2018 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**Baseload (Residential)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
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:	5694											
Annual kWh Output:	5,694.0	**CF:**	**65.0%**									
Energy Credit												
SP15 Flat Power Cost - 2018 ($/MWh)	$36.34	$33.11	$26.37	$23.40	$23.47	$30.51	$34.59	$36.48	$34.62	$34.47	$32.31	$33.67
MWh/month credit:	$3.03	$2.76	$2.20	$1.95	$1.96	$2.54	$2.88	$3.04	$2.88	$2.87	$2.69	$2.81
Annual MWh credit:	$31.61											
kWh value:	$0.03161										**Weighted Ave $/MWh Energy:**	$31.61
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.60	$0.60	$0.60	$0.60	$1.20	$1.20	$3.60	$3.60	$3.60	$1.60	$0.60	$0.60
Annual kW credit:	$18.40											
kWh value:	$0.00323											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$22.90											
kWh value:	$0.00402						**2017**	**2018**	**2018**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$35.41		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$64.59				**Weighted Ave $/MWh Energy:**	$31.61		**$/MWh**				
kWh value:	0.01134				**2018 Target RPS:**	29.00%		$11.34				
Distribution Benefit Credit	0.0100	(assume $0.01/kWh for Baseload and Lighting; $0.02/kWh for HVAC)										
Sum of Credits ($/KWh):	$0.0664											
Annual $ Value per installed kW:	$172.91											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0702											
Loss Adjusted Annual $ Value:	$182.78											
$/kWh VOAE:	**$0.0702**	**← value to RPU for avoided load savings due to EE category**										
Annual $ Value per installed kW:	**$182.78**											

Table E.2. VOAE calculations for the 2018 Baseload Commercial & Industrial customer EE measure.

2018 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**Baseload (Comm/Indst)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80
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:	6570											
Annual kWh Output:	6,570.0	**CF:**	**75.0%**									
Energy Credit												
SP15 Flat Power Cost - 2018 ($/MWh)	$36.34	$33.11	$26.37	$23.40	$23.47	$30.51	$34.59	$36.48	$34.62	$34.47	$32.31	$33.67
MWh/month credit:	$3.03	$2.76	$2.20	$1.95	$1.96	$2.54	$2.88	$3.04	$2.88	$2.87	$2.69	$2.81
Annual MWh credit:	$31.61											
kWh value:	$0.03161										**Weighted Ave $/MWh Energy:**	$31.61
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.60	$0.60	$0.60	$0.60	$1.20	$1.20	$3.60	$3.60	$3.60	$1.60	$0.60	$0.60
Annual kW credit:	$18.40											
kWh value:	$0.00280											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$26.42											
kWh value:	$0.00402						**2017**	**2018**	**2018**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$40.86		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$74.53				**Weighted Ave $/MWh Energy:**	$31.61		**$/MWh**				
kWh value:	0.01134				**2018 Target RPS:**	29.00%		$11.34				
Distribution Benefit Credit	0.0100		(assume $0.01/kWh for Baseload and Lighting; $0.02/kWh for HVAC)									
Sum of Credits ($/KWh):	$0.0660											
Annual $ Value per installed kW:	$191.82											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0698											
Loss Adjusted Annual $ Value:	$202.77											
$/kWh VOAE:	**$0.0698**		**← value to RPU for avoided load savings due to EE category**									
Annual $ Value per installed kW:	**$202.77**											

Table E.3. VOAE calculations for the 2018 Lighting Residential customer EE measure.

2018 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**Lighting (Residential)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	1.00	1.00	1.00	0.70	0.40	0.10	0.10	0.10	0.10	0.50	1.00	1.00
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:	3066											
Annual kWh Output:	3,066.0	**CF:**	**35.0%**									
Energy Credit												
SP15 Flat Power Cost - 2018 ($/MWh)	$36.34	$33.11	$26.37	$23.40	$23.47	$30.51	$34.59	$36.48	$34.62	$34.47	$32.31	$33.67
MWh/month credit:	$3.52	$3.09	$2.26	$1.83	$1.75	$2.16	$2.45	$2.72	$2.71	$2.96	$3.01	$3.27
Annual MWh credit:	$31.75											
kWh value:	$0.03175									**Weighted Ave $/MWh Energy:**		$31.75
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.75	$0.75	$0.75	$0.53	$0.60	$0.15	$0.45	$0.45	$0.45	$1.00	$0.75	$0.75
Annual kW credit:	$7.38											
kWh value:	$0.00241											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$12.33											
kWh value:	$0.00402											
Environmental (Carbon) Credit			**Q4 Auction**	**Q3 Auction**	**Q2 Auction**	**Q1 Auction**	**2017 Average Value**	**2018 Floor Price**	**2018 Ref Value**	**CAISO UI-EF**	**$/MWh**	
Annual kWh credit:	$19.07		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$34.66				**Weighted Ave $/MWh Energy:**	$31.75		**$/MWh**				
kWh value:	0.01130				**2018 Target RPS:**	29.00%		$11.30				
Distribution Benefit Credit	0.0100	(assume $0.01/kWh for Baseload and Lighting; $0.02/kWh for HVAC)										
Sum of Credits ($/KWh):	$0.0657											
Annual $ Value per installed kW:	$105.18											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0695											
Loss Adjusted Annual $ Value:	$111.18											
$/kWh VOAE:	**$0.0695**	**← value to RPU for avoided load savings due to EE category**										
Annual $ Value per installed kW:	**$111.18**											

Table E.4. VOAE calculations for the 2018 Lighting Commercial & Industrial customer EE measure.

2018 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**Lighting (Comm/Indst)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
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:	5694											
Annual kWh Output:	5,694.0	**CF:**	**65.0%**									
Energy Credit												
SP15 Flat Power Cost - 2018 ($/MWh)	$36.34	$33.11	$26.37	$23.40	$23.47	$30.51	$34.59	$36.48	$34.62	$34.47	$32.31	$33.67
MWh/month credit:	$3.52	$3.09	$2.26	$1.83	$1.75	$2.16	$2.45	$2.72	$2.71	$2.96	$3.01	$3.27
Annual MWh credit:	$31.75											
kWh value:	$0.03175								**Weighted Ave $/MWh Energy:**			$31.75
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
Annual kW credit:	$23.00											
kWh value:	$0.00404											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$22.90											
kWh value:	$0.00402						**2017**	**2018**	**2018**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$35.41		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$64.36				**Weighted Ave $/MWh Energy:**	$31.75		**$/MWh**				
kWh value:	0.01130				**2018 Target RPS:**	29.00%		$11.30				
Distribution Benefit Credit	0.0100		(assume $0.01/kWh for Baseload and Lighting; $0.02/kWh for HVAC)									
Sum of Credits ($/KWh):	$0.0673											
Annual $ Value per installed kW:	$177.42											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0712											
Loss Adjusted Annual $ Value:	$187.55											
$/kWh VOAE:	**$0.0712**		**← value to RPU for avoided load savings due to EE category**									
Annual $ Value per installed kW:	**$187.55**											

Table E.5. VOAE calculations for the 2018 HVAC Residential customer EE measure.

2018 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**HVAC (Residential)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	0.00	0.00	0.00	0.50	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Seasonal weighting of avoided kWh:	0.0000	0.0000	0.0000	0.0196	0.0649	0.1551	0.2492	0.2650	0.1782	0.0680	0.0000	0.0000
Assumed annual hours of operation:	1314											
Annual kWh Output:	1,314.0	**CF:**	**15.0%**									
Energy Credit												
SP15 HL Power Cost - 2018 ($/MWh)	$40.15	$34.35	$27.25	$24.40	$24.75	$33.25	$38.45	$40.15	$38.10	$36.90	$34.65	$36.10
MWh/month credit:	$0.00	$0.00	$0.00	$0.48	$1.61	$5.16	$9.58	$10.64	$6.79	$2.51	$0.00	$0.00
Annual MWh credit:	$36.76											
kWh value:	$0.03676										**Weighted Ave $/MWh Energy:**	$36.76
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.00	$0.00	$0.00	$0.38	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.00	$0.00
Annual kW credit:	$18.88											
kWh value:	$0.01436											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$5.28											
kWh value:	$0.00402						**2017**	**2018**	**2018**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$8.17		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$12.94				**Weighted Ave $/MWh Energy:**	$36.76		**$/MWh**				
kWh value:	0.00985				**2018 Target RPS:**	29.00%		$9.85				
Distribution Benefit Credit	0.0200		(assume $0.01/kWh for Baseload and Lighting; $0.02/kWh for HVAC)									
Sum of Credits ($/KWh):	$0.0912											
Annual $ Value per installed kW:	$82.04											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0964											
Loss Adjusted Annual $ Value:	$86.72											
$/kWh VOAE:	**$0.0964**		**← value to RPU for avoided load savings due to EE category**									
Annual $ Value per installed kW:	**$86.72**											

Table E.6. VOAE calculations for the 2018 HVAC Commercial & Industrial customer EE measure.

2018 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**HVAC (Comm/Indst)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	0.00	0.00	0.00	0.50	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Seasonal weighting of avoided kWh:	0.0000	0.0000	0.0000	0.0196	0.0649	0.1551	0.2492	0.2650	0.1782	0.0680	0.0000	0.0000
Assumed annual hours of operation:	1752											
Annual kWh Output:	1,752.0	**CF:**	**20.0%**									
Energy Credit												
SP15 HL Power Cost - 2018 ($/MWh)	$40.15	$34.35	$27.25	$24.40	$24.75	$33.25	$38.45	$40.15	$38.10	$36.90	$34.65	$36.10
MWh/month credit:	$0.00	$0.00	$0.00	$0.48	$1.61	$5.16	$9.58	$10.64	$6.79	$2.51	$0.00	$0.00
Annual MWh credit:	$36.76											
kWh value:	$0.03676										**Weighted Ave $/MWh Energy:**	$36.76
System Capacity Credit												
kW/month value:	$0.75	$0.75	$0.75	$0.75	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.75	$0.75
kW/month credit:	$0.00	$0.00	$0.00	$0.38	$1.50	$1.50	$4.50	$4.50	$4.50	$2.00	$0.00	$0.00
Annual kW credit:	$18.88											
kWh value:	$0.01077											
Additional Local Capacity Credit												
kW/year value:	$36.00	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$7.05											
kWh value:	$0.00402						**2017**	**2018**	**2018**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$10.90		$15.06	$14.75	$13.80	$13.57	$14.30	$14.53	$14.53	0.4280	$6.22	
kWh value:	$0.00622											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$70.73						
Annual kWh credit:	$17.26				**Weighted Ave $/MWh Energy:**	$36.76		**$/MWh**				
kWh value:	0.00985				**2018 Target RPS:**	29.00%		$9.85				
Distribution Benefit Credit	0.0200		(assume $0.01/kWh for Baseload and Lighting; $0.02/kWh for HVAC)									
Sum of Credits ($/KWh):	$0.0876											
Annual $ Value per installed kW:	$90.84											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.0926											
Loss Adjusted Annual $ Value:	$96.02											
$/kWh VOAE:	**$0.0926**		**← value to RPU for avoided load savings due to EE category**									
Annual $ Value per installed kW:	**$96.02**											

Table E.7. VOAE calculations for the 2030 HVAC Residential customer EE measure. (Updated 2030 values highlighted in yellow.)

	2030 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)											
kW/h	1.00											
EE Type:	HVAC (Residential)											
Month	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Monthly kW Peak reduction Prob:	0.00	0.00	0.00	0.50	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Seasonal weighting of avoided kWh:	0.0000	0.0000	0.0000	0.0196	0.0649	0.1551	0.2492	0.2650	0.1782	0.0680	0.0000	0.0000
Assumed annual hours of operation:	1314											
Annual kWh Output:	1,314.0	CF:	15.0%									
Energy Credit												
SP15 HL Power Cost - 2018 ($/MWh)	$53.60	$51.71	$45.97	$38.18	$38.42	$43.23	$53.05	$55.50	$53.09	$53.20	$52.65	$56.15
MWh/month credit:	$0.00	$0.00	$0.00	$0.75	$2.49	$6.70	$13.22	$14.71	$9.46	$3.62	$0.00	$0.00
Annual MWh credit:	$50.95											
kWh value:	$0.05095								Weighted Ave $/MWh Energy:			$50.95
System Capacity Credit												
kW/month value:	$1.07	$1.07	$1.07	$1.07	$2.14	$2.14	$6.42	$6.42	$6.42	$2.85	$1.07	$1.07
kW/month credit:	$0.00	$0.00	$0.00	$0.54	$2.14	$2.14	$6.42	$6.42	$6.42	$2.85	$0.00	$0.00
Annual kW credit:	$26.93											
kWh value:	$0.02049											
Additional Local Capacity Credit												
kW/year value:	$51.33	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$7.53											
kWh value:	$0.00573						2030	2030	2030			
			Q4	Q3	Q2	Q1	Average	Floor	Ref	CAISO		
Environmental (Carbon) Credit			Auction	Auction	Auction	Auction	Value	Price	Value	UI-EF	$/MWh	
Annual kWh credit:	$20.56		$36.55	$36.55	$36.55	$36.55	$36.55	$36.55	$36.55	0.4280	$15.64	
kWh value:	$0.01564											
RPS Credit					RPU Renewable PPA's ($/MWh):	$76.79						
Annual kWh credit:	$20.37				Weighted Ave $/MWh Energy:	$50.95		$/MWh				
kWh value:	0.01550				2018 Target RPS:	60.00%		$15.50				
Distribution Benefit Credit	0.0285											
Sum of Credits ($/KWh):	$0.1368											
Annual $ Value per installed kW:	$126.34											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.1446											
Loss Adjusted Annual $ Value:	$133.55											
$/kWh VOAE:	$0.1446		← value to RPU for avoided load savings due to EE category									
Annual $ Value per installed kW:	$133.55											

Assumptions:
1. All power and carbon costs reflect projected 2030 costs.
2. RA costs inflated by 3% annually to produce 2030 estimates.
3. Distribution benefit credit inflated by 3% annually to produce 2030 estimate.
4. RPU's weighted 2030 renewable PPA cost reflects the 42 MMT carbon reduction scenario and a 60% RPS target.
5. All other terms held constant (i.e., equivalent to 2018 estimates).

Table E.8. VOAE calculations for the 2030 HVAC Commercial & Industrial customer EE measure. (Updated 2030 values highlighted in yellow.)

2030 VOAE Worksheet (for deriving a value for avoided energy due to EE savings)

kW/h	1.00											
EE Type:	**HVAC (Comm/Indst)**											
Month	**JAN**	**FEB**	**MAR**	**APR**	**MAY**	**JUN**	**JUL**	**AUG**	**SEP**	**OCT**	**NOV**	**DEC**
Monthly kW Peak reduction Prob:	0.00	0.00	0.00	0.50	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00
Seasonal weighting of avoided kWh:	0.0000	0.0000	0.0000	0.0196	0.0649	0.1551	0.2492	0.2650	0.1782	0.0680	0.0000	0.0000
Assumed annual hours of operation:	1752											
Annual kWh Output:	1,752.0	**CF:**	**20.0%**									
Energy Credit												
SP15 HL Power Cost - 2018 ($/MWh)	$53.60	$51.71	$45.97	$38.18	$38.42	$43.23	$53.05	$55.50	$53.09	$53.20	$52.65	$56.15
MWh/month credit:	$0.00	$0.00	$0.00	$0.75	$2.49	$6.70	$13.22	$14.71	$9.46	$3.62	$0.00	$0.00
Annual MWh credit:	$50.95											
kWh value:	$0.05095										**Weighted Ave $/MWh Energy:**	$50.95
System Capacity Credit												
kW/month value:	$1.07	$1.07	$1.07	$1.07	$2.14	$2.14	$6.42	$6.42	$6.42	$2.85	$1.07	$1.07
kW/month credit:	$0.00	$0.00	$0.00	$0.54	$2.14	$2.14	$6.42	$6.42	$6.42	$2.85	$0.00	$0.00
Annual kW credit:	$26.93											
kWh value:	$0.01537											
Additional Local Capacity Credit												
kW/year value:	$51.33	(annual average adder)										
kW reduction /MWh production factor:	0.1117											
Annual kW credit:	$10.05											
kWh value:	$0.00573						**2030**	**2030**	**2030**			
			Q4	**Q3**	**Q2**	**Q1**	**Average**	**Floor**	**Ref**	**CAISO**		
Environmental (Carbon) Credit			**Auction**	**Auction**	**Auction**	**Auction**	**Value**	**Price**	**Value**	**UI-EF**	**$/MWh**	
Annual kWh credit:	$27.41		$36.55	$36.55	$36.55	$36.55	$36.55	$36.55	$36.55	0.4280	$15.64	
kWh value:	$0.01564											
RPS Credit					**RPU Renewable PPA's ($/MWh):**	$76.79						
Annual kWh credit:	$27.16				**Weighted Ave $/MWh Energy:**	$50.95		**$/MWh**				
kWh value:	0.01550				**2018 Target RPS:**	60.00%		$15.50				
Distribution Benefit Credit	0.0285											
Sum of Credits ($/KWh):	$0.1317											
Annual $ Value per installed kW:	$142.49											
Distribution Loss Factor Adjustment	5.40%											
Loss Adjusted kWh value:	$0.1392											
Loss Adjusted Annual $ Value:	$150.62											
$/kWh VOAE:	**$0.1392**		**← value to RPU for avoided load savings due to EE category**									
Annual $ Value per installed kW:	**$150.62**											

Assumptions:

1. All power and carbon costs reflect projected 2030 costs.
2. RA costs inflated by 3% annually to produce 2030 estimates.
3. Distribution benefit credit inflated by 3% annually to produce 2030 estimate.
4. RPU's weighted 2030 renewable PPA cost reflects the 42 MMT carbon reduction scenario and a 60% RPS target.
5. All other terms held constant (i.e., equivalent to 2018 estimates).