R I V E R S I D E P U B L I C U T I L I T I E S

2018 Integrated Resource Plan: Cliffs Notes

WATER | ENERGY | LIFE

CITY OF RIVERSIDE

PUBLIC UTILITIES

City of Riverside

Riverside Public Utilities

Resource Operations & Strategic Analytics Division

2018 Integrated Resource Plan: Cliffs Notes

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Riverside Public Utilities

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1. An Overview of Riverside Public Utilities 2018 Integrated Resource Plan

Riverside Public Utilities *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 the utility's 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, the 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.

Both intermediate term (5-year forward) and longer term (20-year forward) resource portfolio and energy market issues are reviewed and analyzed in the 2018 IRP, 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.

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 presents more detailed justifications and rational for each guiding principle.

Table 1. Detailed justification and rationale for each guiding principle (for assessing the feasibility and desirability of new assets or contracts).

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

3. Document Organization

The entirety of the 2018 IRP document contains twenty (20) Chapters and five (5) Appendices. The chapter organization and layout sequentially follows the general goals discussed previously; 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.

Interested readers can use these IRP "Cliffs Notes" to review brief descriptions and summaries of each Chapter and Appendix contained in the primary 2018 IRP document. Each subsequent chapter description follows the same general layout:

- ***Chapter Summary:*** a one paragraph high-level summary of the chapter contents.
- ***Chapter Contents:*** a table of section contents for the chapter.
- ***Key Finding:*** critical findings from the analyses or discussions contained within the chapter; usually presented as bullet points.
- ***Important Highlights:*** important chapter tables or figures, if applicable.

Please note that these Cliffs Notes only provide a very high-level overview of each chapter's contents, analyses and findings. Interested readers are encouraged to refer to the primary 2018 IRP document for more detailed information.

Chapter 2. RPU System Load and Peak Demand Forecasts

Chapter Summary:

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 Contents:

Key Findings:

- RPU uses regression based econometric models to forecast both its total expected GWh system loads and system MW peaks on a monthly basis. These models are calibrated to historical monthly load and/or peak data extending back to January 2003.
- Both models include economic, calendar, weather and structural input predictor variables, as well as multiple Fourier frequency terms to adjust out seasonal effects.
- Both models account for engineering estimates of load and peak reduction due to energy efficiency programs and behind-the-meter solar PV installations, as well as expected load and peak growth due to future transportation electrification trends.
- Both forecasting equations produce accurate back-casted predictions of the utility's historical load and peak data.
- Staff's most current calibrations of these forecasting models suggest that RPU's loads and peaks are expected to grow by 1.4% and 0.5% annually over the next 20 years.

Important Highlights:

RPU is a summer peaking utility. Figure 2.1.1 shows hourly load profiles for typical weekdays in February and August 2017, respectively.

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

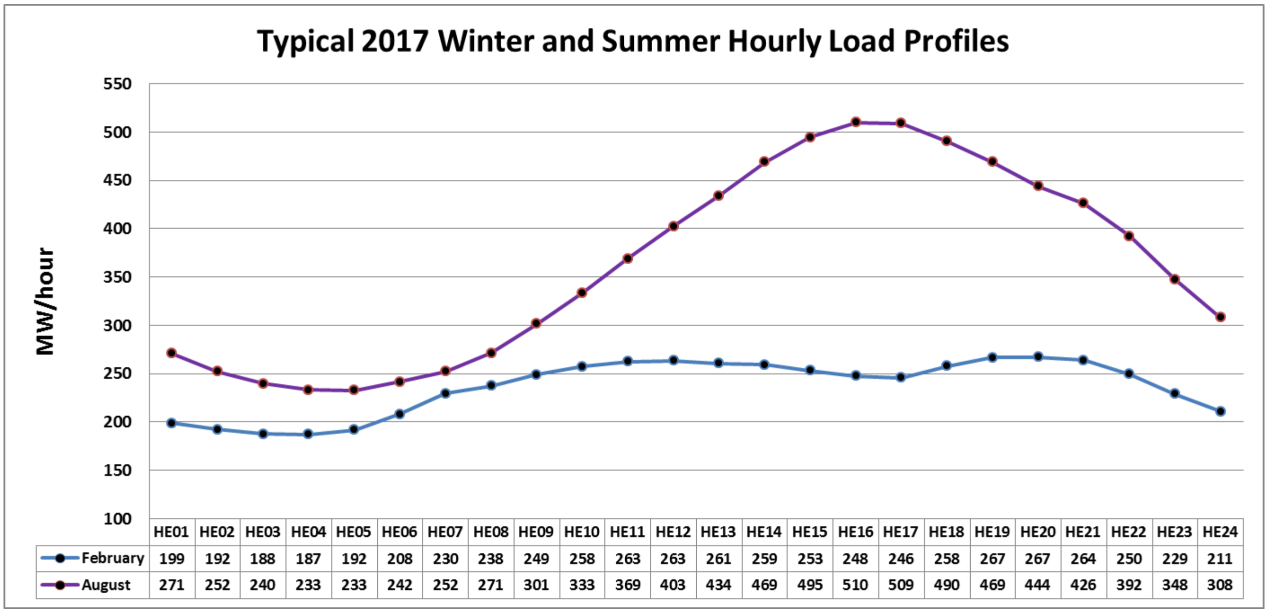


Figure 2.1.1. Hourly system load profiles for typical 2017 weekdays in February and August.

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	Multiple sine and cosine Fourier frequencies		X	X

Table 2.3.1 on page 2-15 in the IRP shows the pertinent model fitting and summary statistics for the total system load forecasting equation. The equation explains about 98.8% of the observed variability associated with the monthly 2003-2017 system loads.

Figure 2.3.1 below 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 back-casted load correlation exceeds 0.99.

Table 2.3.3 on page 2-20 in the IRP 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.

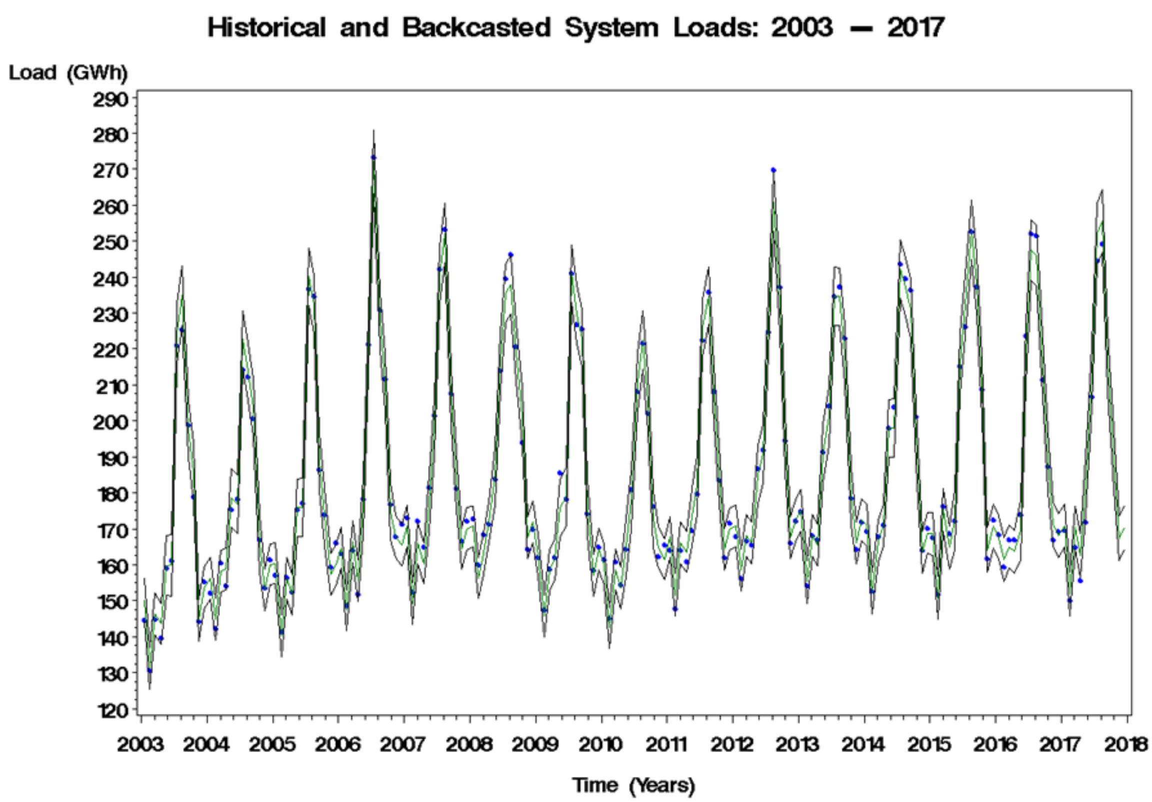


Figure 2.3.1. Observed and predicted total system load data (2003-2017), after adjusting for known weather conditions.

Based on these system load and peak forecasting equations, Table 2.4.1 shows the annual forecasted system loads and peaks for the 2018-2037 time frame. These forecasts represent the future RPU load and peak estimates used as a base case scenario in the IRP. 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.

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%

Chapter 3. RPU Generation and Transmission Resources

Chapter Summary:

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 Contents:

Key Findings:

- RPU relies on 18 different thermal (natural gas, nuclear, coal), hydro, and renewable (geothermal, solar PV, wind) resources to serve its native load.
- Since 2011, RPU has added 10 new renewable resources to its generation portfolio.
- The City holds entitlement rights to 3 distinct transmission projects, and is also a Participating Transmission Owner in the CAISO.

Important Highlights:

Figure 3.1.1 below shows the locations of all existing RPU generation resources.

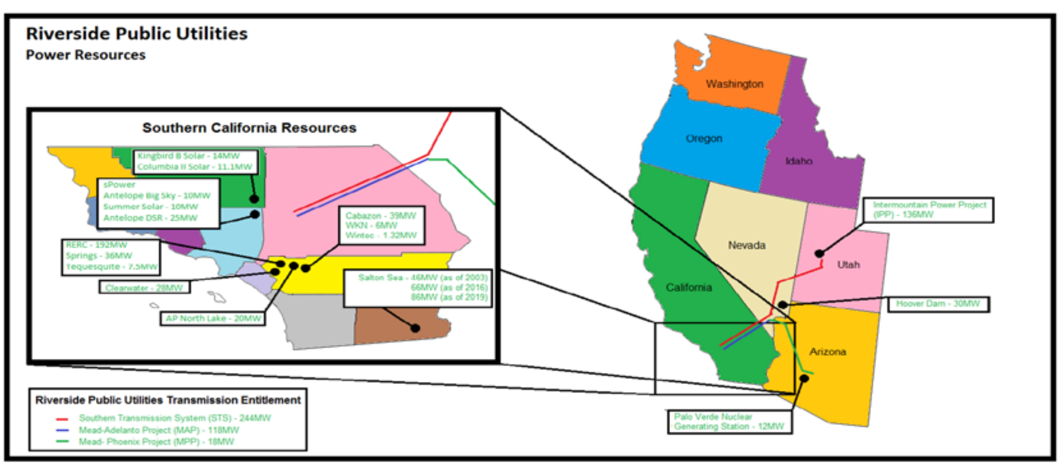


Figure 3.1.1. Physical locations of existing RPU long-term generation resources.

Table 3.1.1 presents a high level overview of RPU's current resource portfolio, with respect to both existing and anticipated 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

Chapter 4. RPU Existing Electric System

Chapter Summary:

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 industry technologies.

Chapter Contents:

Key Findings:

- 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.
- 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.
- RPU's underground distribution network contains over 817 miles of underground 15-kV and 5-kV class cable, which is also comprised of approximately 3,900 vaults and substructures.
- In conjunction with SCE, RPU is still planning on moving forward with the Riverside Transmission Reliability Project (RTRP). RTRP will provide additional transmission capacity to meet future projected load growth, as well as provide a second point of interconnection for system reliability and transmission capacity to import bulk electric power.
- As part of an ongoing effort to improve the utility's visibility into the distribution system, staff 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.

Important Highlights:

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).

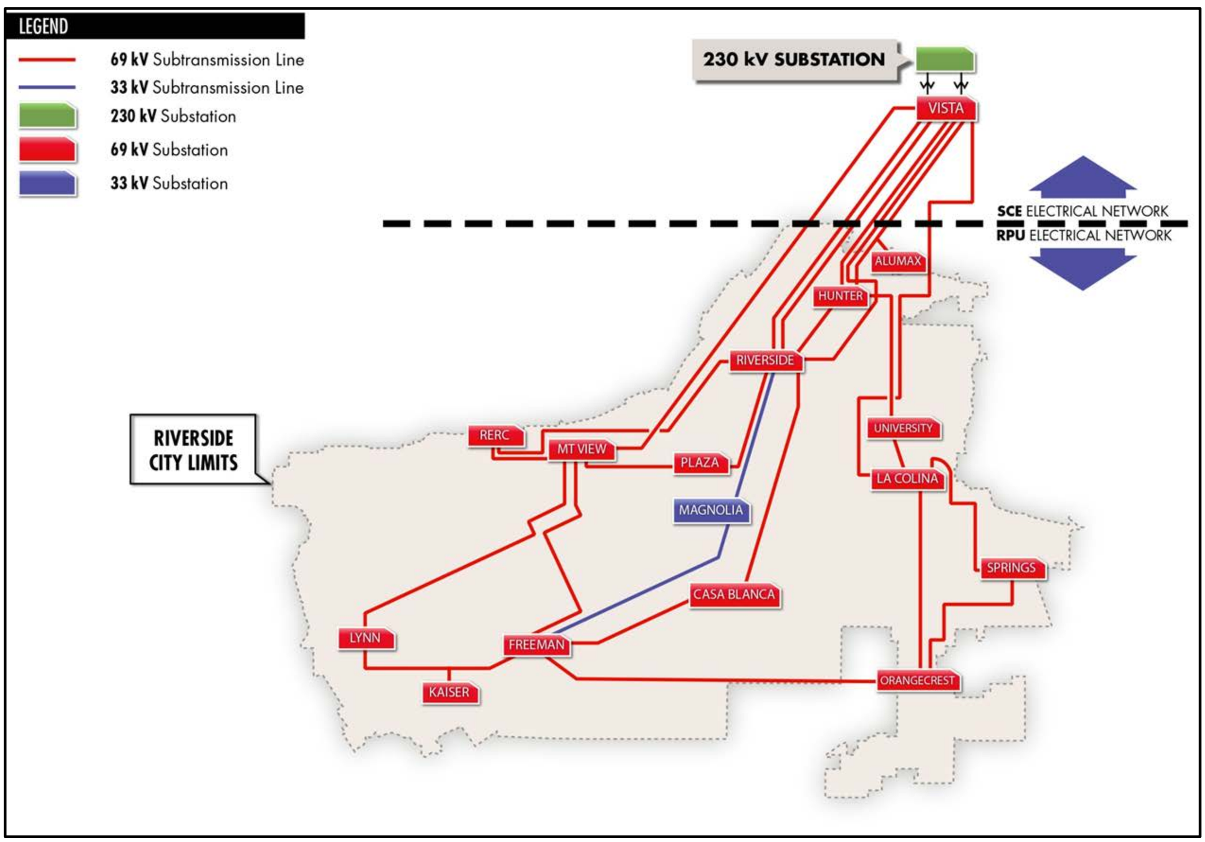


Figure 4.2.1. Existing RPU sub transmission electrical system.

Chapter 5. Important Legislative and Regulatory Mandates and CAISO Initiatives

Chapter Summary:

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 Contents:

Key Findings:

- SB X1-2 mandates that CA utilities must procure defined percentages of renewable resources to serve retail load.
- AB 32 mandates a statewide reduction of GHG emissions to 40% below 1990 levels by 2030.
- SB 1368 effectively prohibits CA utilities from entering into new coal contracts and/or renewing existing coal contracts.

- SB1 required CA utilities to establish a 10 year program for partially funding customer behind-the-meter solar PV installations, while SB 1037 requires all CA utilities to fund energy efficiency and demand reduction programs on an ongoing basis.
- AB 2514 mandates energy storage targets for the IOUs, while directing the governing bodies of POUs to consider setting their own energy storage targets.
- SB 380 placed 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. (This moratorium remains partially in place.)
- SB 350 expands renewable energy mandates and AB 398 extends the GHG Cap-and-Trade program for all CA utilities through 2030.
- In addition to the above mentioned CA legislative and regulatory mandates, multiple CAISO stakeholder initiatives are currently underway that could impose significant financial impacts on RPU.

Important Highlights:

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 section 5.2 of the IRP.

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. Staff plans to participate in these stakeholder processes and are currently tracking more than 20 in-flight CAISO Initiatives.

Chapter 6. Demand Side Management and Energy Efficiency

Chapter Summary:

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 Contents:

Key Findings:

- RPU offers many DSM and EE programs and provides educational resources to Riverside customers so that they can better manage their energy usage and lower their bills. Currently, the utility offers 15 commercial and 7 residential EE/DSM programs, as well as both commercial and residential Direct Installation programs.
- Funding for the RPU programs is provided by the public benefits charge (PBC) on all customer energy usage (currently set to 2.85% of all energy usage charges).
- RPU also partners with the Riverside County's Community Assistance Program and with the Southern California Gas Company to provide additional energy efficiency programs to low income customers.
- RPU has exceeded its 1% of retail sales annual EE savings goal in 6 of the last 7 fiscal years.
- Staff believes that the Ratepayer Impact Measure (RIM) test is the most appropriate cost-effectiveness test to use for comparing the cost-effectiveness of Demand Side measures to new Supply Side resources.

Important Highlights:

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 November 2017, the CEC adopted both statewide energy efficiency targets as well as recommended sub-targets for each utility. 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 achieve a doubling of energy efficiency savings from 2015 levels by January 1, 2030. 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 nearly double the CEC's sub-target for the utility.

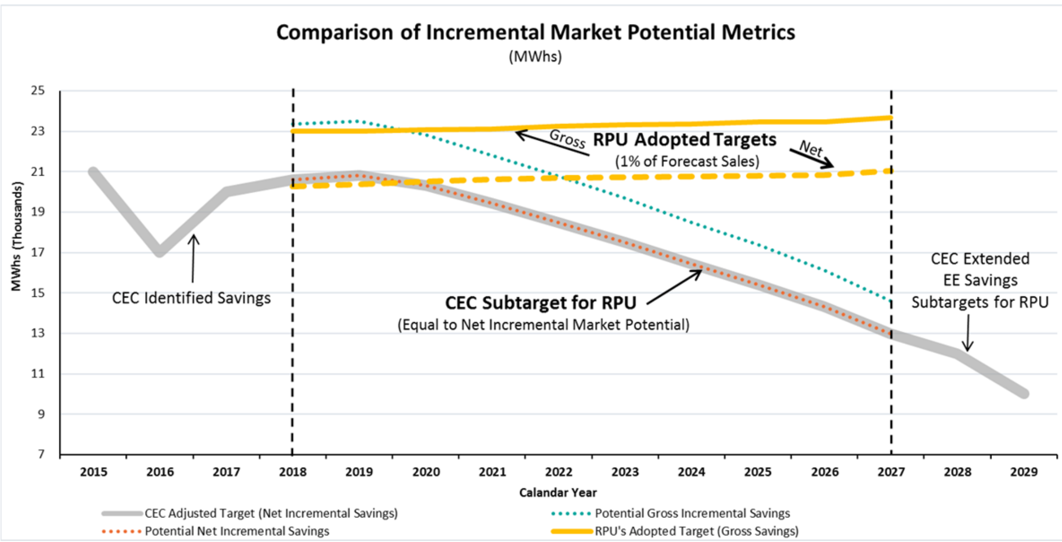


Figure 6.2.2. CEC adopted sub-targets compared to RPU adopted targets and potential Gross and Net incremental savings.

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; i.e., PCT, PACT, RIM, TRC and SCT (see Tables 6.3.1 and 6.3.2 in the IRP). While all of the cost effectiveness tests merit consideration, for purposes of the IRP, RPU focuses consideration on a variation of the Ratepayer Impact Measure (RIM) test for evaluating EE and DSM programs (referred to in the IRP as a Demand Side Net Value analysis). A Net Value analysis allows for the evaluation of the revenue needs of the utility and the impact of the EE programs on all customers, and thus can be directly compared to the Net Value calculations of Supply Side resources. These analyses are discussed in detail in Chapter 14.

Chapter 7. Market Fundamentals

Chapter Summary:

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 forward curve simulations used in the IRP.

Chapter Contents:

Key Findings:

- Staff assumes that future natural gas prices will escalate at 2% annually, which is consistent with mid-term ICE forecasts and the CEC SoCal Gas High Demand forecasts in its 2017 IEPR.
- Staff adopted the CEC low price carbon forecasts through 2030; these forecasts essentially follow the expected minimum (floor) CARB Carbon Auction Reserve prices. Carbon prices beyond 2030 were escalated at 7.3% annually.
- Staff developed a long-term structural price modeling relationship between natural gas, carbon and heavy-load power using 2019-2024 forward pricing data (see section 7.4 in the IRP). This fitted model was used to produce heavy-load forward power price forecasts in 2025-2037, based on forward natural gas and carbon costs for the same time period. This model projects that heavy-load power prices will increase at 3.8% annually after 2024.
- Staff adopted a slightly modified version of the CAISO forecasted TAC rate to forecast how much RPU will need to pay in transmission access charges through 2037.
- Based on recent market quotes, staff assumed that 2018 local RA costs $4.50/kW-month and that flexible RA costs $6.00/kW-month, and that all RA costs would be expected to escalate 3% annually.

Important Highlights:

Figure 7.2.1 shows the SoCal CityGate forward monthly price curve used to create all of the forward natural gas price simulations in the IRP. Likewise, Figure 7.5.1 shows the SP15 heavy-load (On-peak) forward monthly price curve used to create all of the forward heavy-load power price simulations in the IRP.

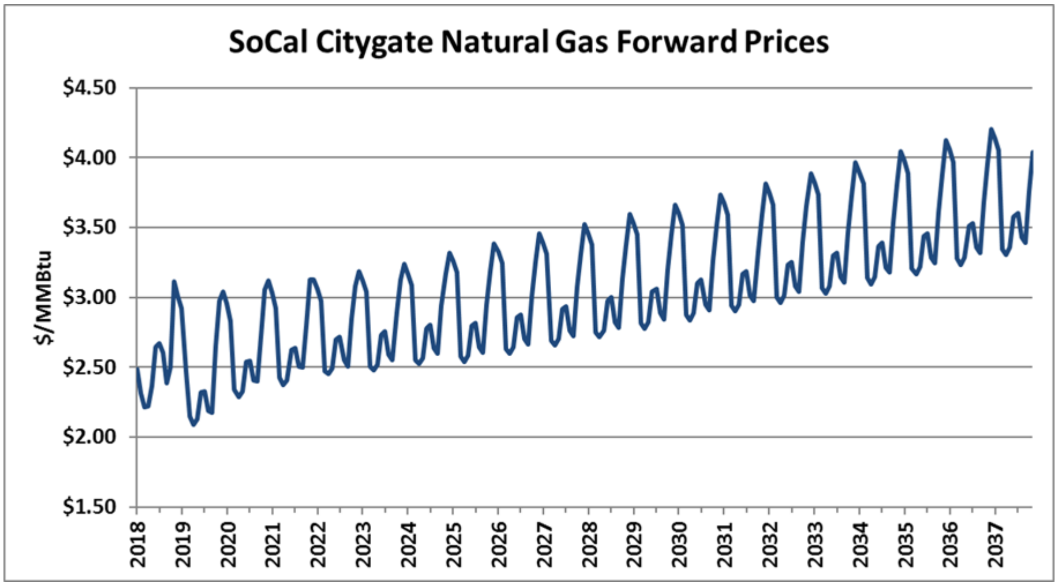


Figure 7.2.1. ICE natural gas forward prices for the SoCal Citygate Hub.

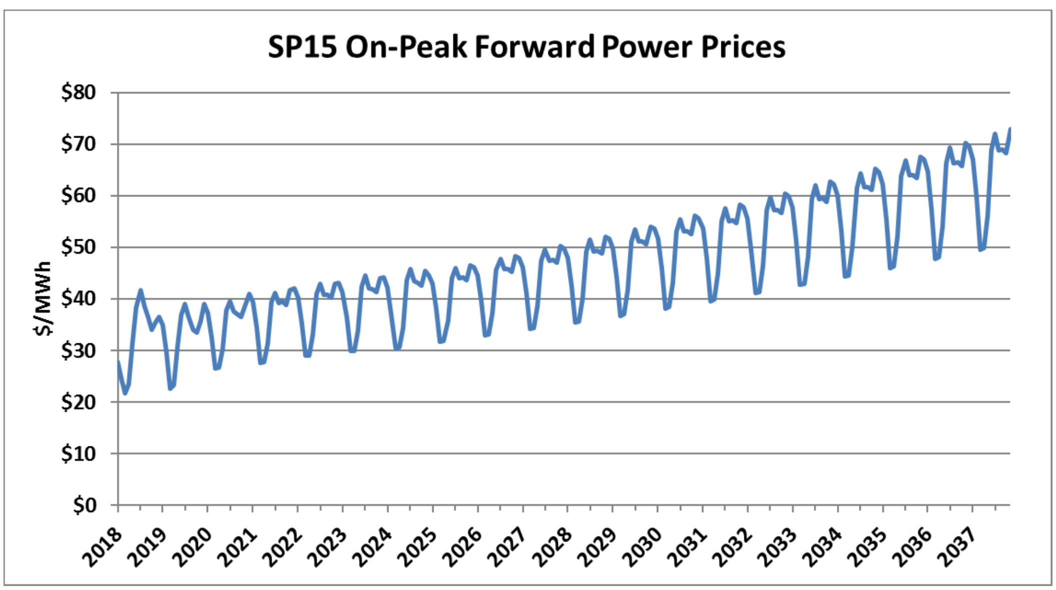


Figure 7.5.1. Shaped SP15 On Peak ICE monthly forward price curve.

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

Chapter Summary:

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 Contents:

Key Findings:

- RPU is on-track to procure a significant amount of renewable energy through 2022, well above the minimum RPS mandated levels.
- RPU's expected capacity and RA needs should be manageable, and mostly met using existing contracts and internal generation.
- Approximately 90% of RPU's customer load is naturally hedged via long-term contracts. The remaining open positions primarily occur in the summer and during spring planned outage events.
- Annual power supply net revenue uncertainty (NRU) is about 8 to 9 M$ a year through 2022. The corresponding 90% confidence interval is ±13 M$/year.
- Open energy positions (~6.5 M$/year) can be effectively hedged and managed; the corresponding cost-at-risk (CAR) metrics are relatively low (~3.5 M$/year)
- The utility has sufficient carbon allowances to cover all expected GHG emissions through 2022.
- Projected average net Power Resource budget increases are ~2.6% annually from FY18/19 through FY22/23.

Important Highlights:

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 may undertake in order to reduce budgetary pressure for rate increases.

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 responding to weather uncertainty.

Open short or long energy positions can be quantified 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.

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.

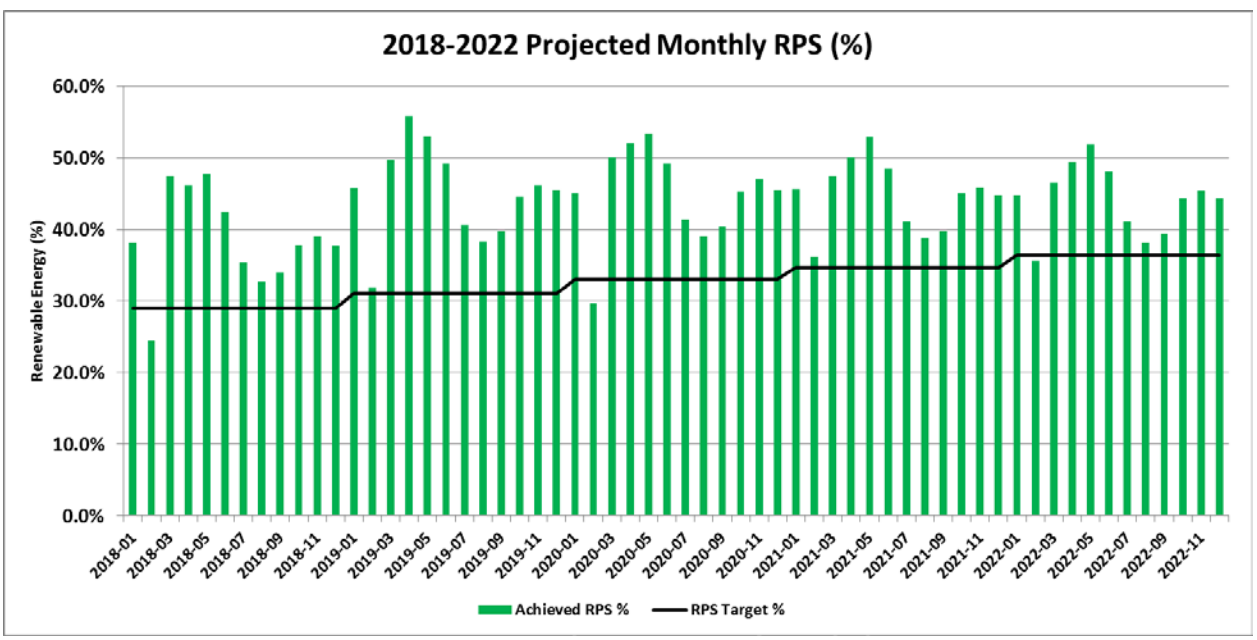


Figure 8.1.1. RPU five year forward renewable energy projections (2018-2022 timeframe).

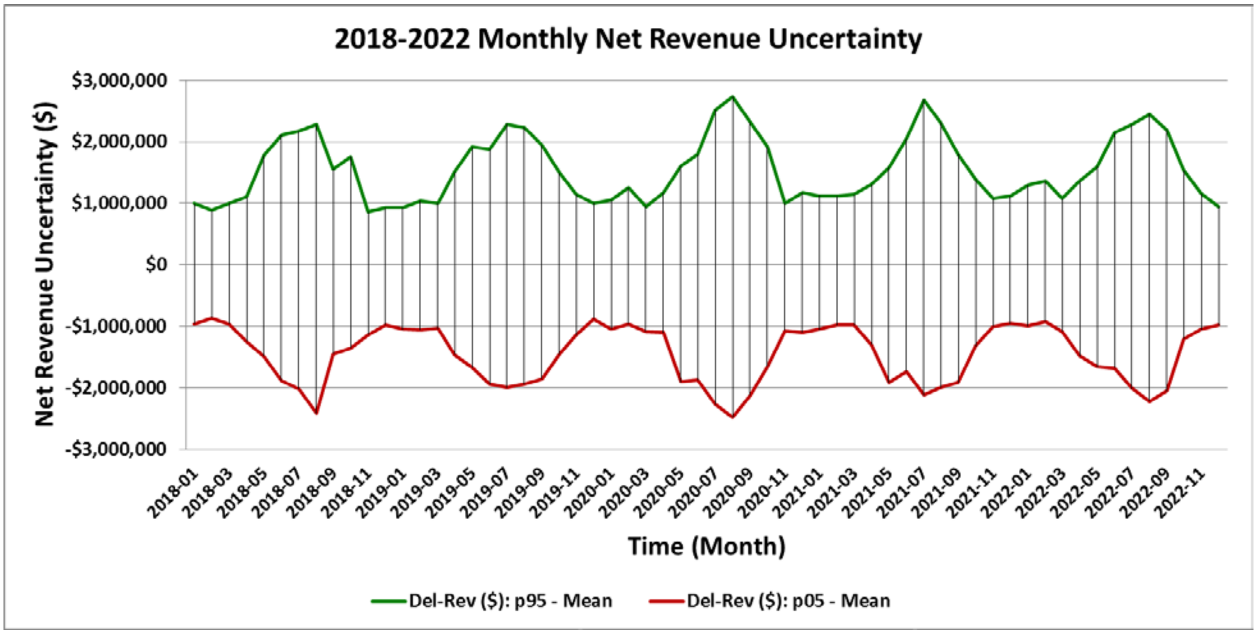


Figure 8.3.1. Monthly 5th and 95th percentile estimates of the net revenue uncertainty associated with RPU's power supply budget.

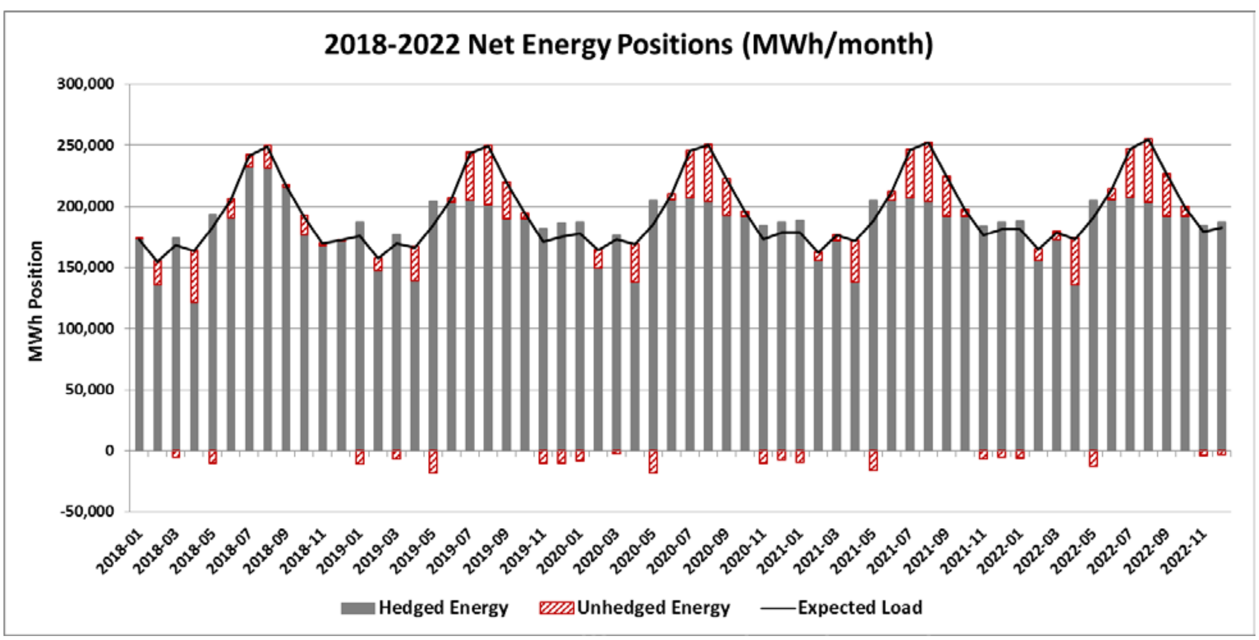


Figure 8.5.2. 2018-2022 forecasted monthly net energy positions (MWh/month).

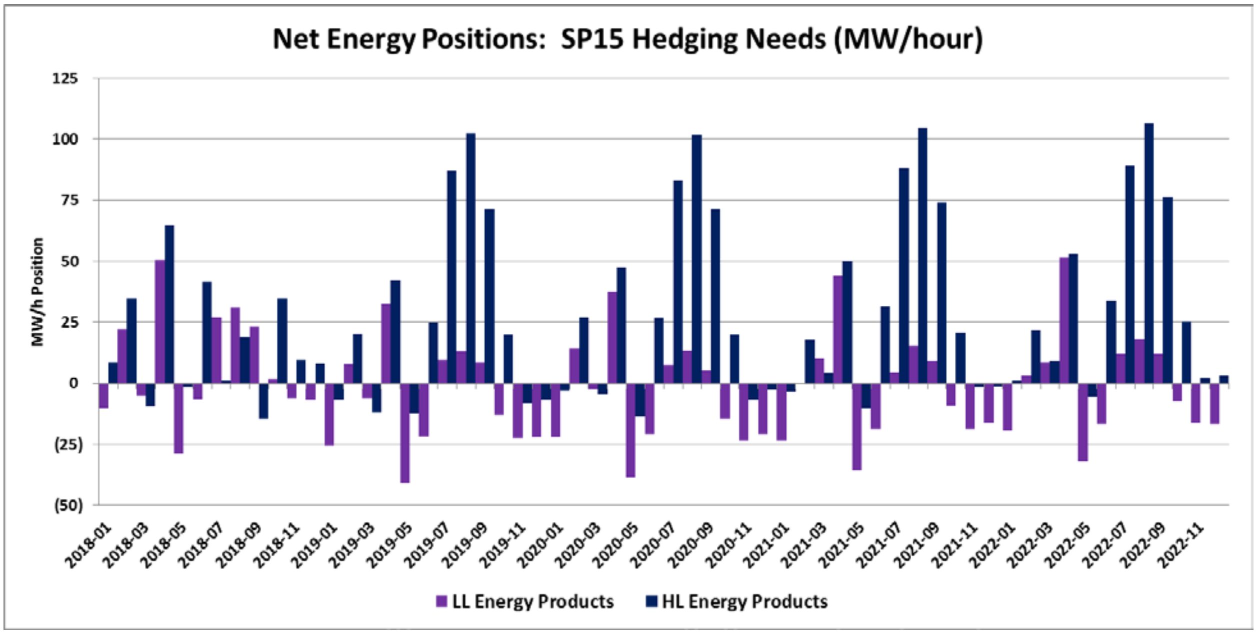


Figure 8.5.3. 2018-2022 NEP forecasted monthly open HL and LL energy positions (MW/hour).

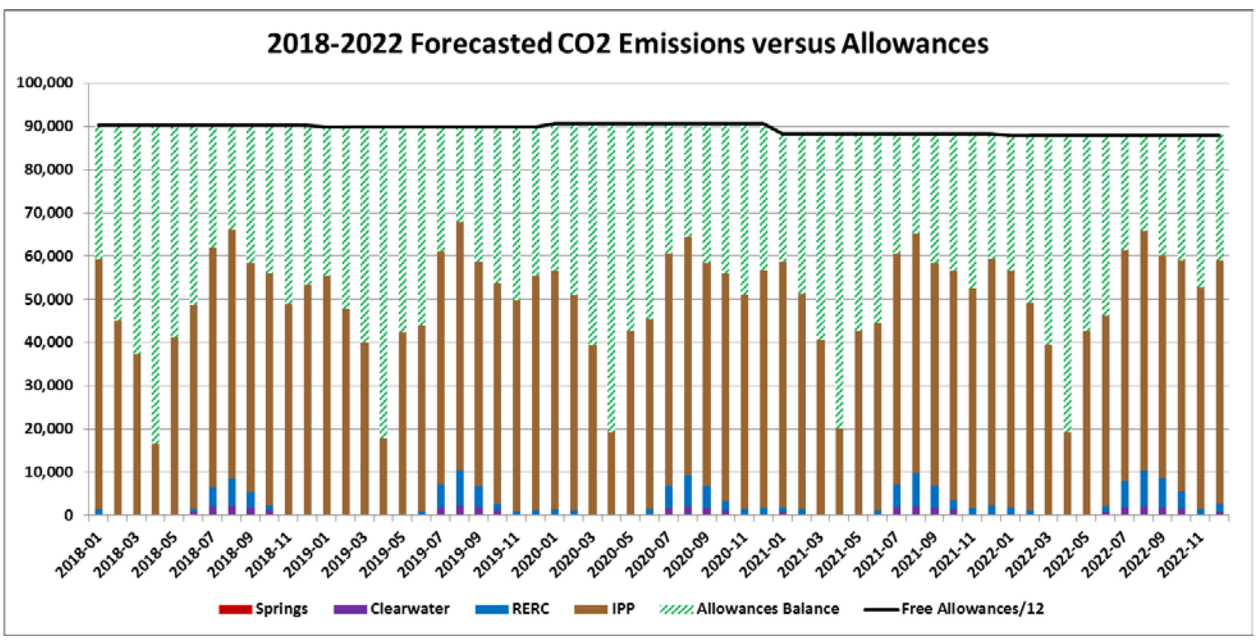


Figure 8.7.1. Forecasted monthly RPU carbon emission levels, by resource: 2018-2022 timeframe.

Chapter 9. GHG Emission Targets and Forecasts

Chapter Summary:

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 Contents:

Key Findings:

- Under the 53 MMT Electric sector target, RPU's utility specific target is 486,277 MT CO_2-e. Under the 42 MMT Electric sector target, RPU's 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, while treating the lower target as an aspirational goal.
- 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.
- RPU's Total and 1st Importer emission levels have been reducing in recent years due primarily to less reliance on the IPP Coal contract.

Important Highlights:

Table 9.3.1 summarizes the three GHG planning targets analyzed in this IRP.

Table 9.4.1 lists the utility's 1st Importer emissions and Total Portfolio emissions from 2011 through 2017; the 2011-2016 1st Importer values represent verified emissions (the 2017 data is currently undergoing verification).

Figure 9.5.1 summarizes various potential carbon reduction scenarios that the utility could achieve by adding increasing levels of renewable resources to the portfolio, by reaching a 50%, 58%, or 67% RPS by 2030. All scenarios assume that the IPP coal plants are replaced with natural gas plants in 2025 and that RPU ceases receiving IPP natural gas power in 2027. The upper blue, purple and green lines quantify RPU's Total Portfolio emissions under these three different 2030 RPS target scenarios, while the lower yellow line quantifies the utilities 1st Importer emission liabilities. In each of these scenarios, enough new (unspecified) renewable energy projects are added to the portfolio each year to ensure that the 2030 RPS target is fully satisfied.

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

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

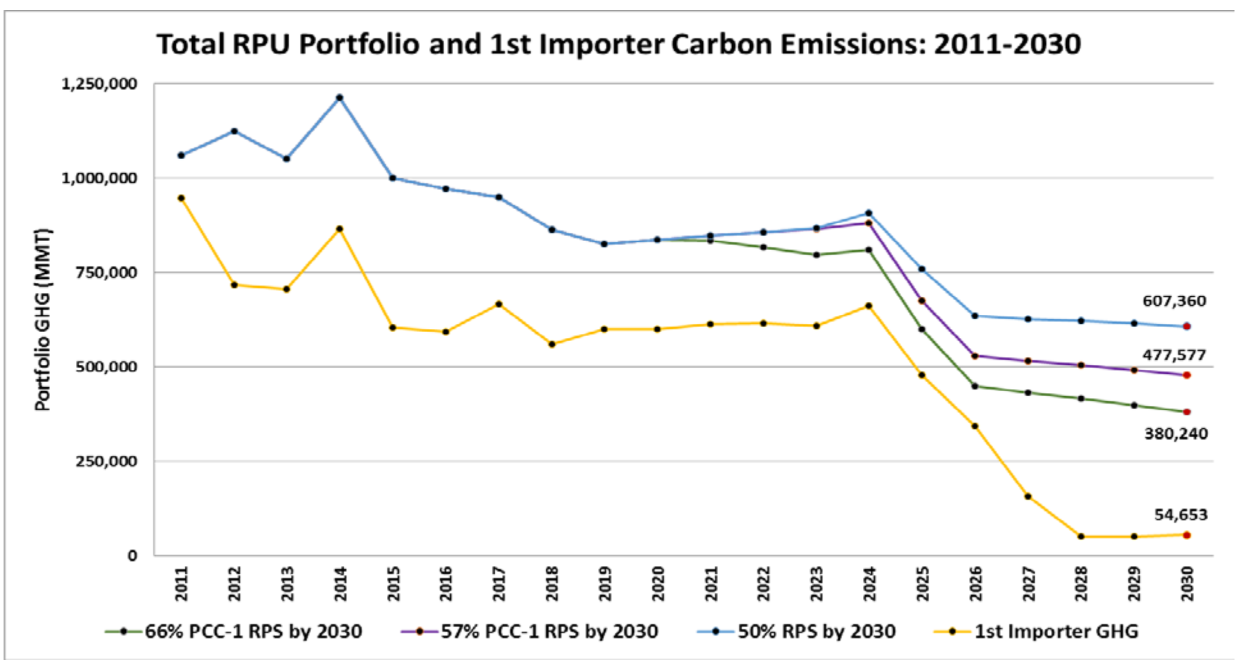


Figure 9.5.1. Historical and forecasted RPU GHG emission levels under different RPS target scenarios.

Chapter 10: Future Assumptions about Current Generation Resources

Chapter Summary:

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 Contents:

Key Findings:

- In order to facilitate the long-term (20-year forward) IRP planning/simulation studies, staff made reasonable assumptions about which expiring contracts will be extended, terminated, or replaced (with the same generation technology having equivalent pricing).
- Staff has now identified at least nine significant risks with the IPP Repowering contract and is recommending that RPU exercise its right to exit out from this contract extension.

Important Highlights:

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

Nine significant risks associated with the IPP Repowering contract have now been identified by staff. Each of these nine risks shown below is discussed in detail in section 10.2 of the IRP.

1. The 50 year contract commitment
2. Regulatory and legislative uncertainties
3. Generation and construction cost uncertainties
4. Natural gas infrastructure uncertainties
5. Future STS transmission upgrade costs
6. Unresolved transmission contracts
7. Conflicting operational goals of the participants
8. Future carbon cost uncertainties
9. IPP facility decommissioning costs

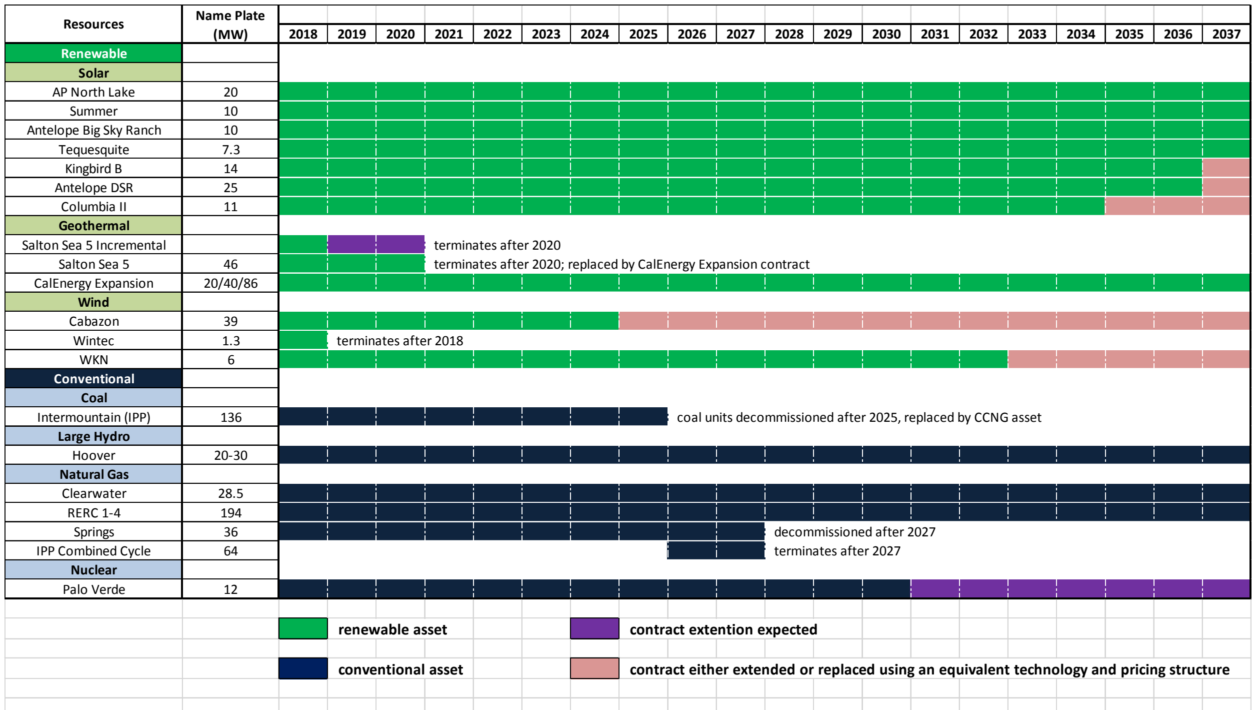


Figure 10.1.1. Assumptions about how current RPU contracts are treated in all subsequent IRP modeling assessments.

Chapter 11. Future Resource Adequacy Capacity Needs

Chapter Summary:

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 Contents:

Key Findings:

- Under the current CAISO RA paradigm, RPU must secure enough capacity resources to meet 115% of its forecasted peak load, as well as Local and Flexible capacity requirements assigned by the CAISO. However, RPU's future flexible RA requirements are uncertain as the CAISO is continually exploring significant changes to its Flexible Capacity paradigm.
- RPU's RA needs through 2024 should be manageable, and RPU can fill RA shortfalls by forward purchasing RA products. RPU anticipates spending an average of about 4.3 M$/year through 2024 to satisfy its RA obligations.
- The utility's RA shortfalls become significant from 2025 onward due to the retirement of IPP coal plant. To fill shortfalls during this timeframe, the utility will need to contract with additional capacity resources to replace those that have fallen out of its resource portfolio and continue to forward procure short-term RA products.
- Riverside does not experience a significant decline in its peak load RPS level as compared to its monthly average RPS levels because baseload geothermal resources supply about 70% of its renewable energy, and these resources directly contribute to meeting Riverside's peak load.

Important Highlights:

Figure 11.2.1 shows RPU's (1) forecasted 1-in-2 system peaks, (2) 115% system RA reserve margin requirements, (3) assumed local and flexible RA requirements (based on the CAISO's current RA paradigm), and (4) expected monthly capacity amounts provided by RPU's projected resource portfolio for the 2018-2037 timeframe.

Figure 11.2.2 highlights RPU's more immediate capacity needs during the 2018 through 2022 time horizon.

Table 11.2.1 shows the expected cost forecasts to fill RPU's RA shortfalls with forward purchased RA products during the 2018 through 2022 time horizon. Note that RPU had already filled its 2018 short RA positions as of the IRP's publication.

Figure 11.3.6 shows a bar chart of Riverside's monthly average and median peak window RPS levels for 2016, highlighting that Riverside's peak load RPS level does not significantly decline compared to its monthly average RPS level.

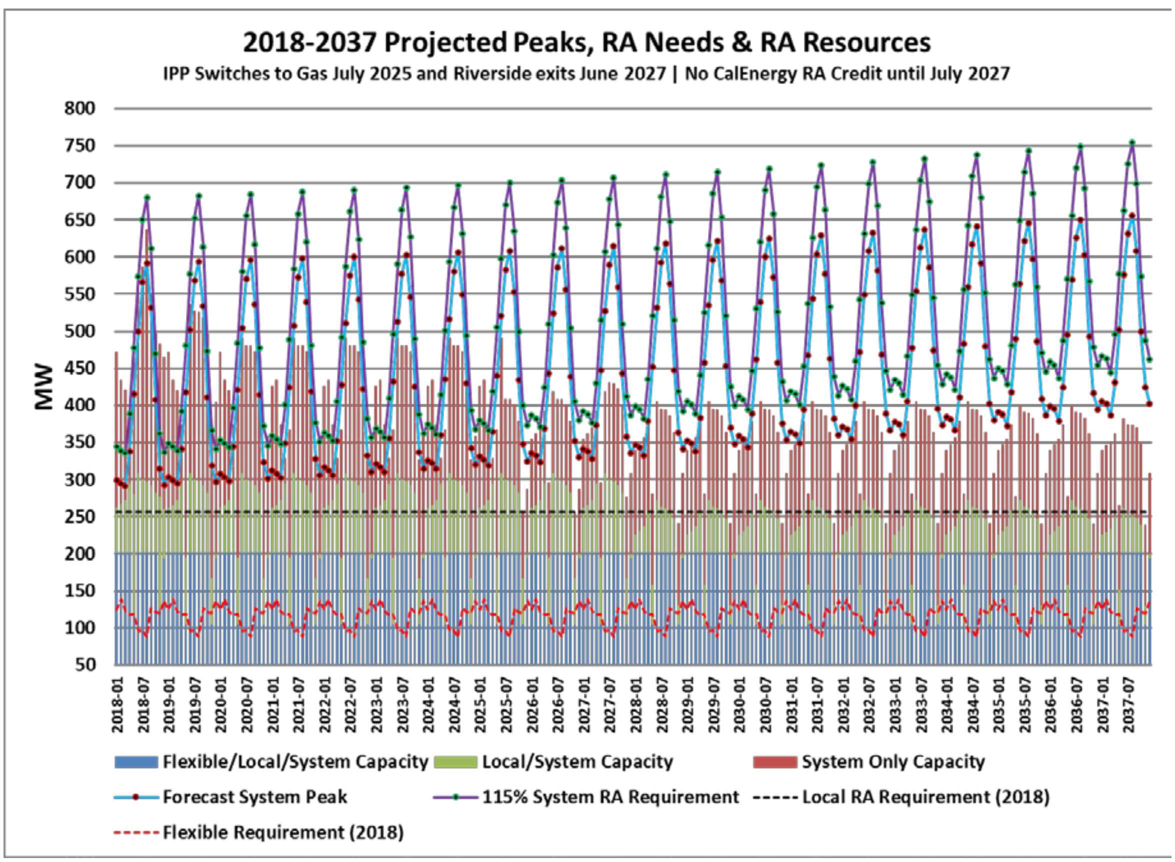


Figure 11.2.1. Riverside's 20-year forward capacity projections, system peaks and RA needs (2018-2037 timeframe).

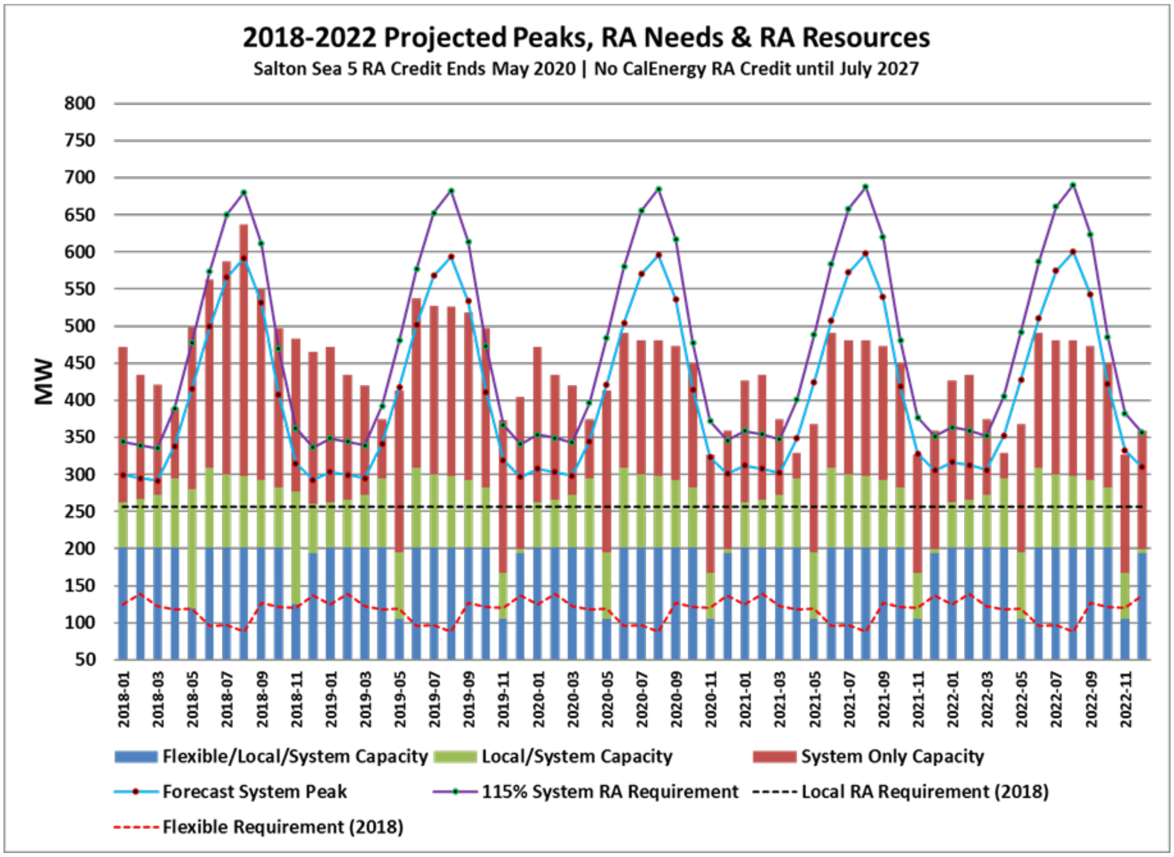


Figure 11.2.2. Riverside's 5-year forward capacity projections, system peaks and RA needs (2018-2022 timeframe).

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

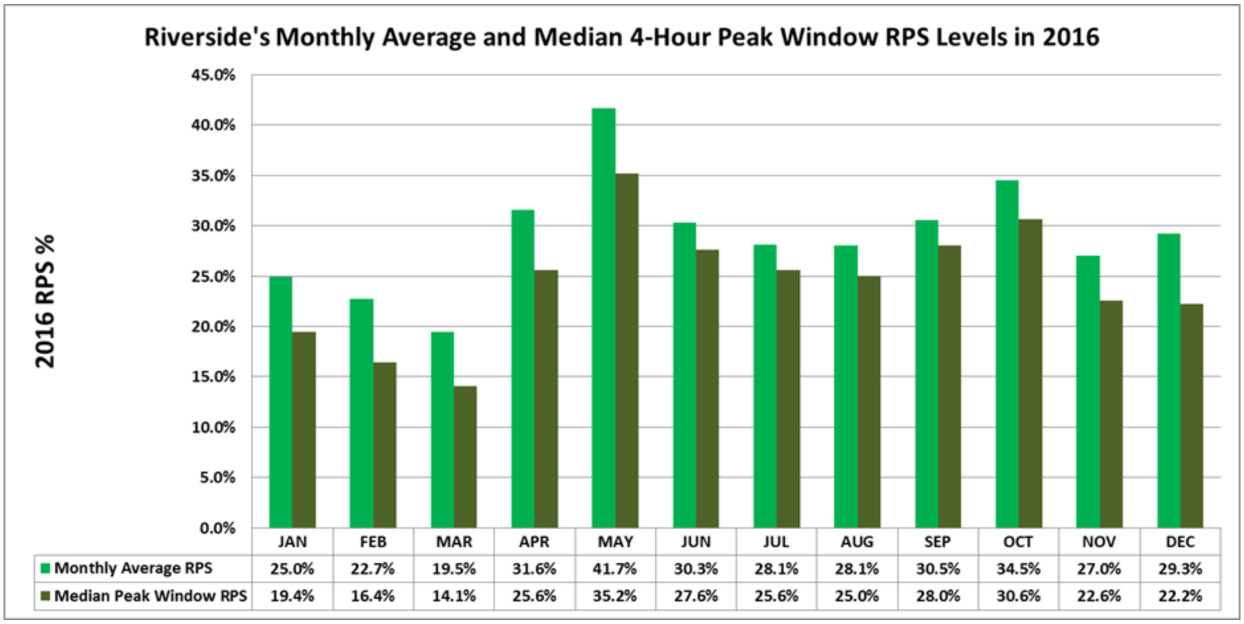


Figure 11.3.6. Riverside's actual monthly average and median peak window RPS levels in 2016.

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

Chapter Summary:

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 Contents:

Key Findings:

- A plausible future renewable energy procurement strategy is proposed that, if fully enacted, would allow RPU to reduce its 2030 GHG emissions to a level below its 385,000 MMT aspirational goal.
- RPU could still reduce its 2030 GHG emissions to a level below its 486,000 MMT official target by executing the first four of these five contracts.

Important Highlights:

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.

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.

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.

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. This figure also 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). Under this renewable energy procurement strategy, RPU can 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.

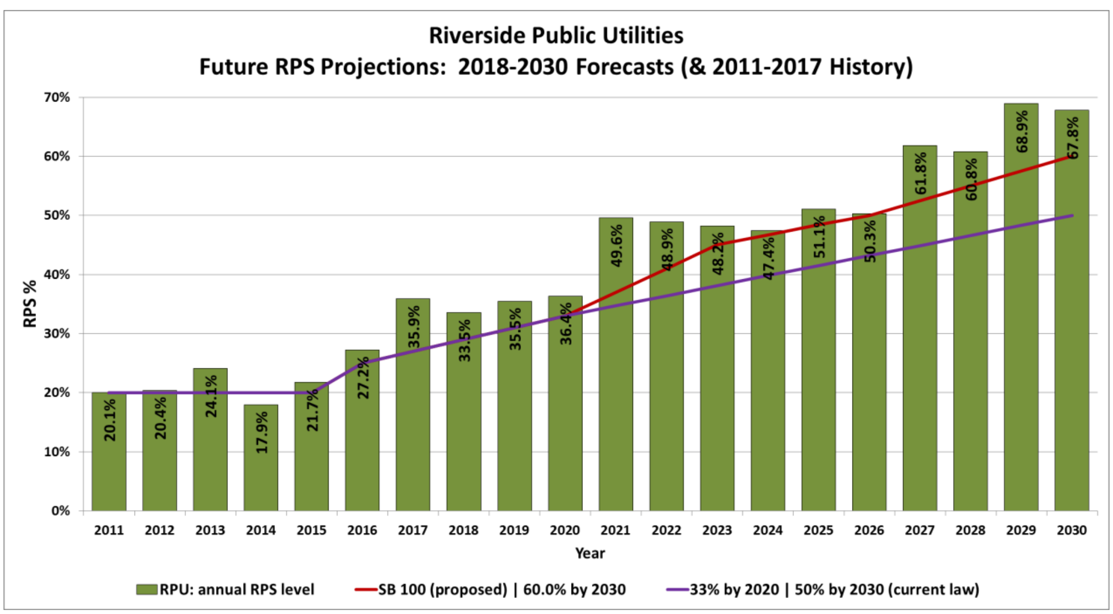


Figure 12.1.2. RPU's future forecasted RPS levels through 2030, if all five of the renewable resources shown in Table 12.1.1 are added to the utility's portfolio.

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

Chapter Summary:

In this chapter, seven plausible resource planning scenarios are 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 Contents:

Key Findings:

- Staff project that the Baseline Portfolio COS_{LN} growth rate is forecasted to be about 1.2% per year, with the utility's power resource costs growing at about 1.1% annually between 2020 and 2035 and the utility's all-other costs growing about 1.4% annually in this same time period.
- The Baseline Portfolio positions RPU to achieve a 50% RPS by 2030 and reach a 2030 GHG emission level of approximately 617,000 metric tons.
- The 53MMT Sector Target Portfolio positions RPU to achieve a 60% RPS by 2030 (after using some Excess Procurement credits) and reach a 2030 GHG emission level of approximately 446,000 metric tons, which is below the utility's official 2030 GHG planning target of 486,277 metric tons.
- The 42MMT Sector Target Portfolio positions RPU to exceed a 67% RPS by 2030 and reach a 2030 GHG emission level of approximately 350,000 metric tons, which is below the utility's aspirational 2030 GHG planning target of 385,137 metric tons.
- The expected cost increases associated with the 53MMT and 42MMT portfolios are relatively minor – about 1.5% and 2.6%, respectively, over the Baseline Portfolio in 2030. Adding in the corresponding risk components to each scenario reduces these increases to 0.6% and 1.2%.
- These results suggest that RPU should be able to achieve its official 2030 GHG planning target without significant rate stress, and perhaps even reach its aspirational target, barring significant increases in renewable energy costs.
- Resource specific net value analyses show that most of the studied renewable resources exhibit marginally negative net values (other than the Solar PV plus Storage contract), in the absence of avoided carbon credits.
- These analyses also show that the IPP repowering Project exhibits clearly negative net values in both 2030 and 2035 while the LMS 100 Tolling Agreement exhibits slightly positive net values in 2025 and 2030. This suggests that this latter tolling agreement represents a more economic, shorter-term strategy for replacing part of the expiring IPP coal contract.

Important Highlights:

Figure 13.5.3 shows the projected annual COS_{LN} estimates (shown in ₵/kWh units) for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio.

Table 13.5.1 shows the corresponding COS_{LN} estimates from Figure 13.5.3 for years 2020, 2025, 2030 and 2035.

Figure 13.5.4 shows the projected annual COS_{LN} uncertainty estimates (Std[COS_{LN}]) (shown in ₵/kWh units) for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio.

Table 13.5.2 shows the corresponding COS_{LN} uncertainty estimates (Std[COS_{LN}]) from Figure 13.5.4 for years 2020, 2025, 2030, and 2035.

Figure 13.5.5 shows the forecasted 2025, 2030, and 2035 COS_{LN} values with their corresponding risk estimates or "composite cost of service" estimate for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio.

Figure 13.6.1 shows the net value results for the new renewable resources studied in this chapter and highlights the impact of a significant increase in renewable pricing.

Figure 13.8.1 shows the net value results for all the new resources studied in this chapter.

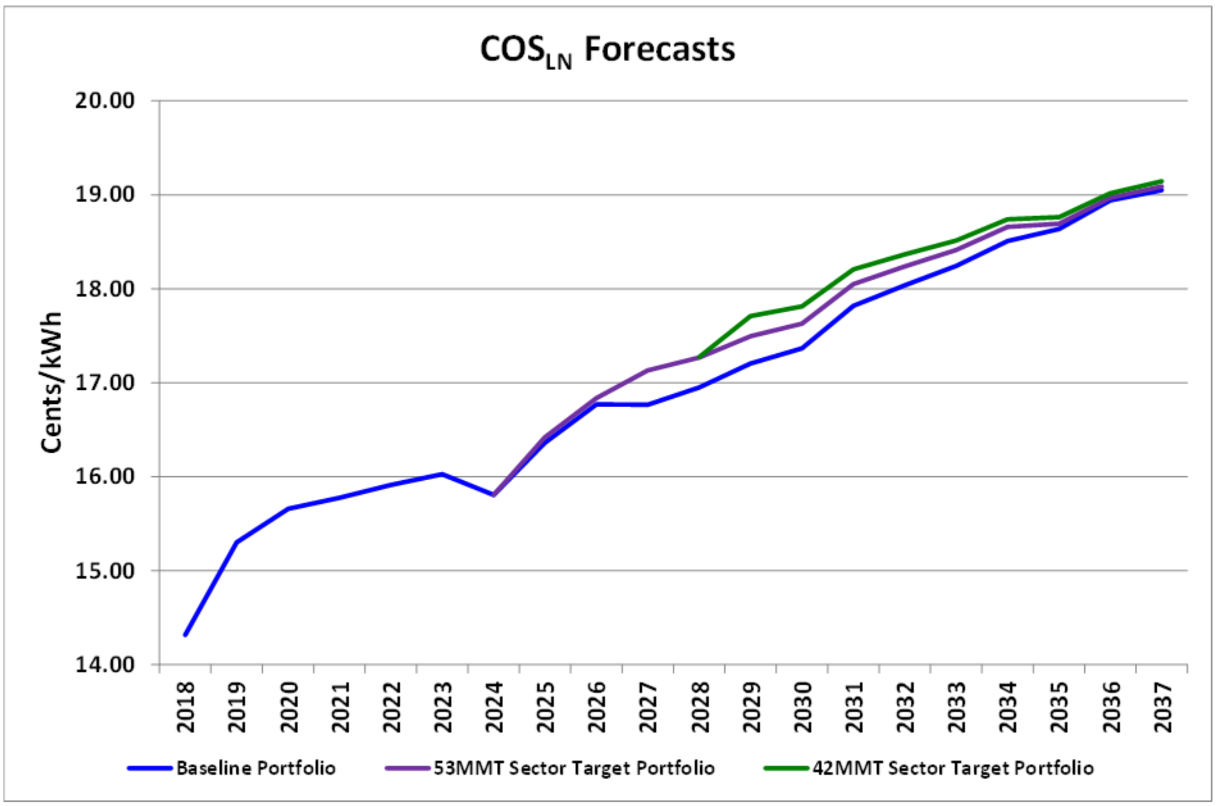


Figure 13.5.3. Projected annual COS_{LN} estimates under the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio.

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%	

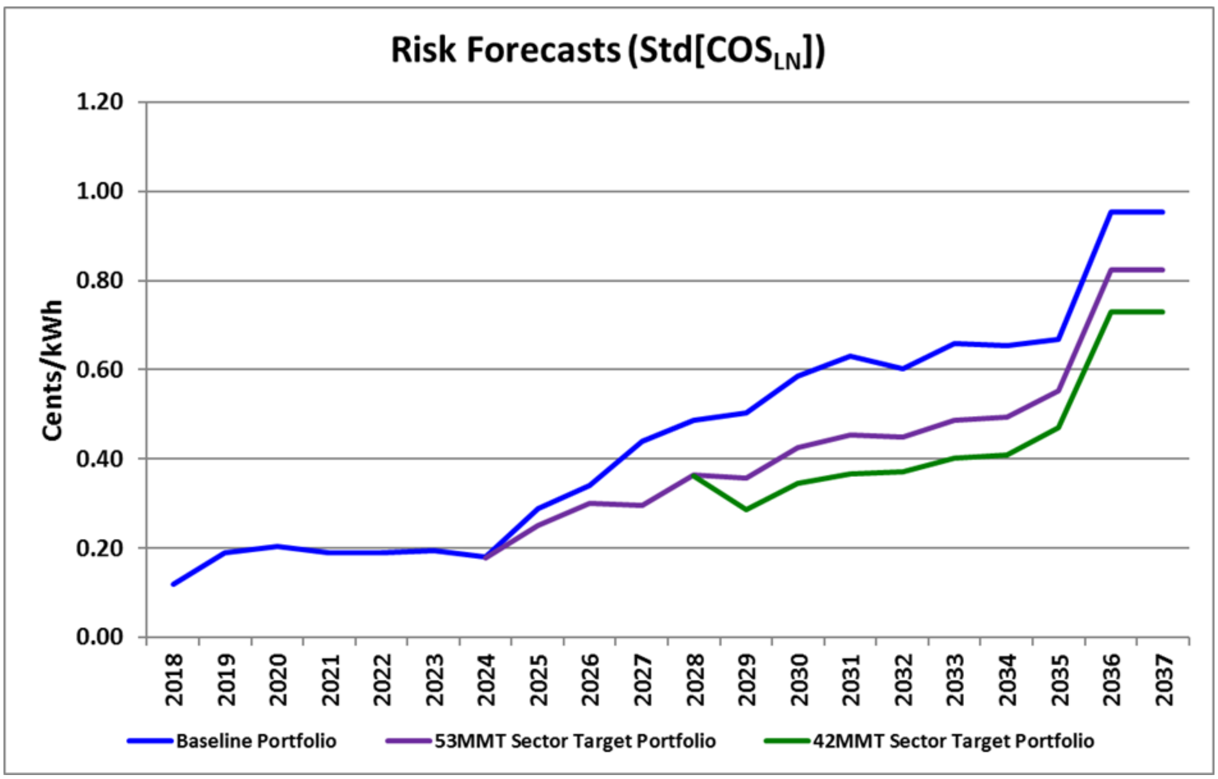


Figure 13.5.4. Corresponding annual COS_{LN} risk estimates (Std[COS_{LN}]) for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio.

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%

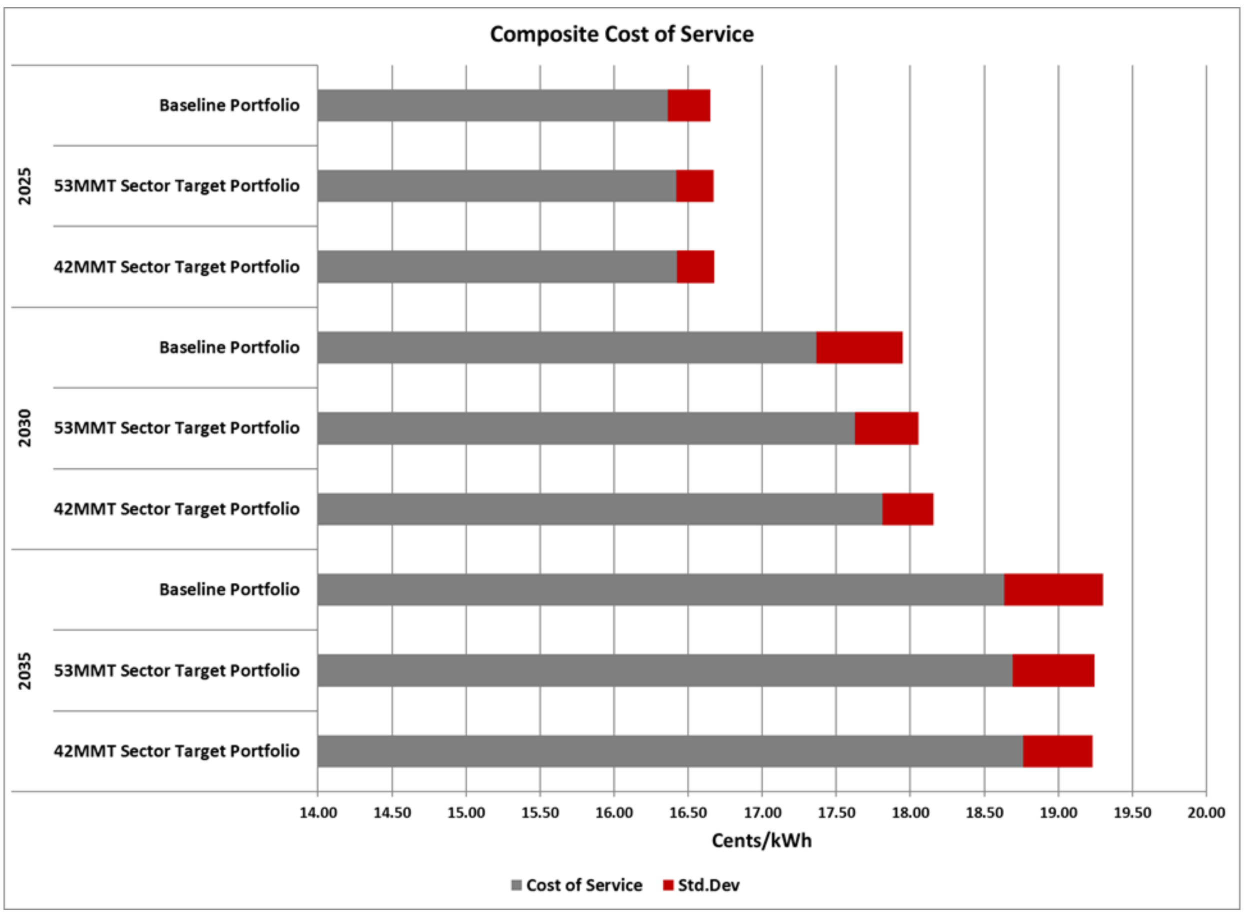


Figure 13.5.5. Forecasted 2025, 2030 and 2035 COS_{LN} values and corresponding risk estimates for the Baseline Portfolio, 53MMT Sector Target Portfolio, and 42MMT Sector Target Portfolio.

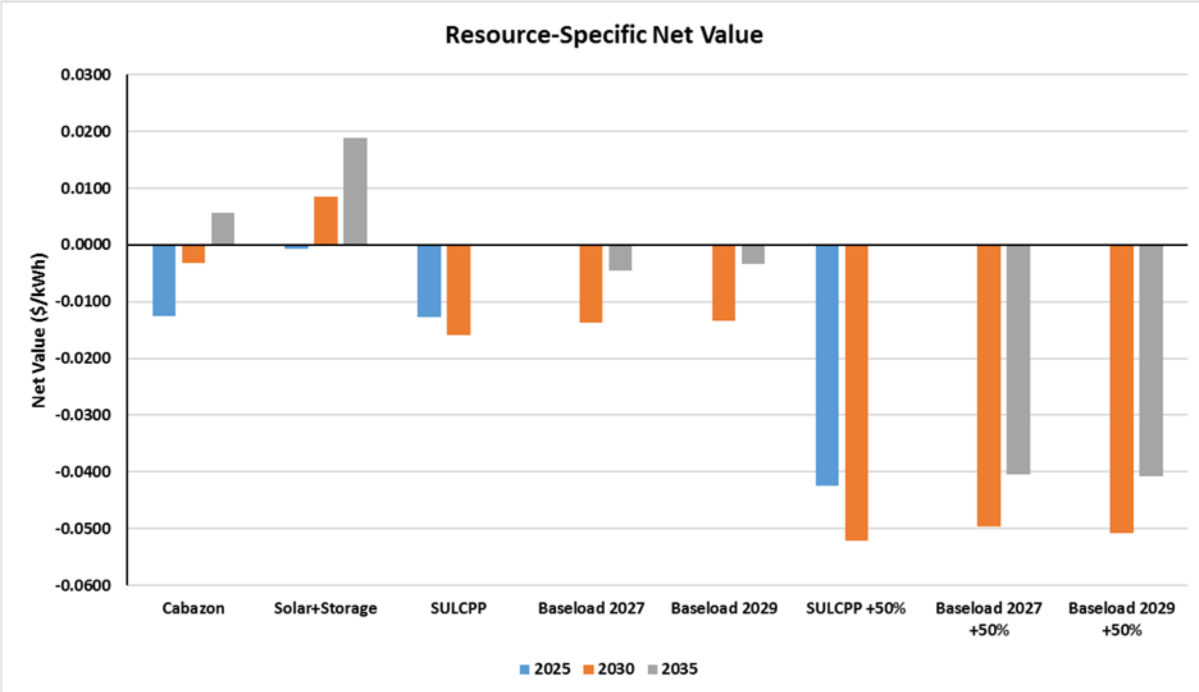


Figure 13.6.1. Resource-specific net values for RPU's future renewable/GHG-free resources under normal and high pricing.

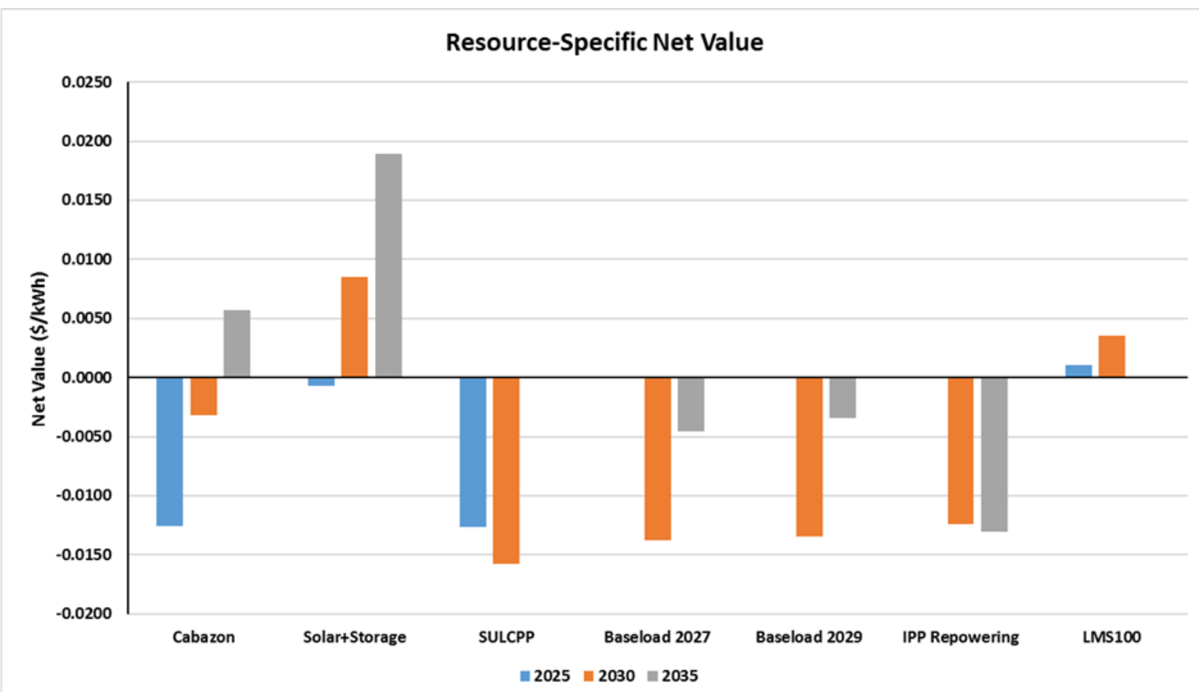


Figure 13.8.1. Resource-specific net values for RPU's future renewable/GHG-free resources under normal pricing, the IPP Repowering Project, and the LMS100 Tolling Agreement.

Chapter 14: Alternative Analyses - Higher Energy Efficiency Targets

Chapter Summary:

Chapter 14 presents an 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 Contents:

Key Findings:

- In this chapter, staff presents a methodology for calculating the value of avoided energy (VOAE) associated with EE savings, along with the corresponding unmet revenue estimates resulting from these same EE savings.
- 2018 VOAE estimates for most EE programs other than HVAC are estimated to be approximately $0.07/kWh; while 2018 VOAE HVAC estimates fall between $0.093/kWh to $0.097/kWh.
- The corresponding unmet revenue estimates range from $0.10/kWh to $0.15/kWh, resulting in net unmet revenue impacts from EE programs of $0.03/kWh to $0.06/kWh.
- The reciprocal value of an unmet revenue estimate can be directly compared to a supply-side net value calculation. This comparison can be used to make an optimal economic choice between procuring a new renewable resource versus increasing one or more EE programs in order to cost effectively reduce future GHG emissions.
- Since funding our EE programs is currently more expensive than procuring new renewable energy projects, staff does not recommend expanding our EE programs at this time.

Important Highlights:

Table 14.3.1 discusses each of the avoided cost components that are quantified in the VOAE calculation.

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 14.4.1 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.

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

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 to the utility.

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

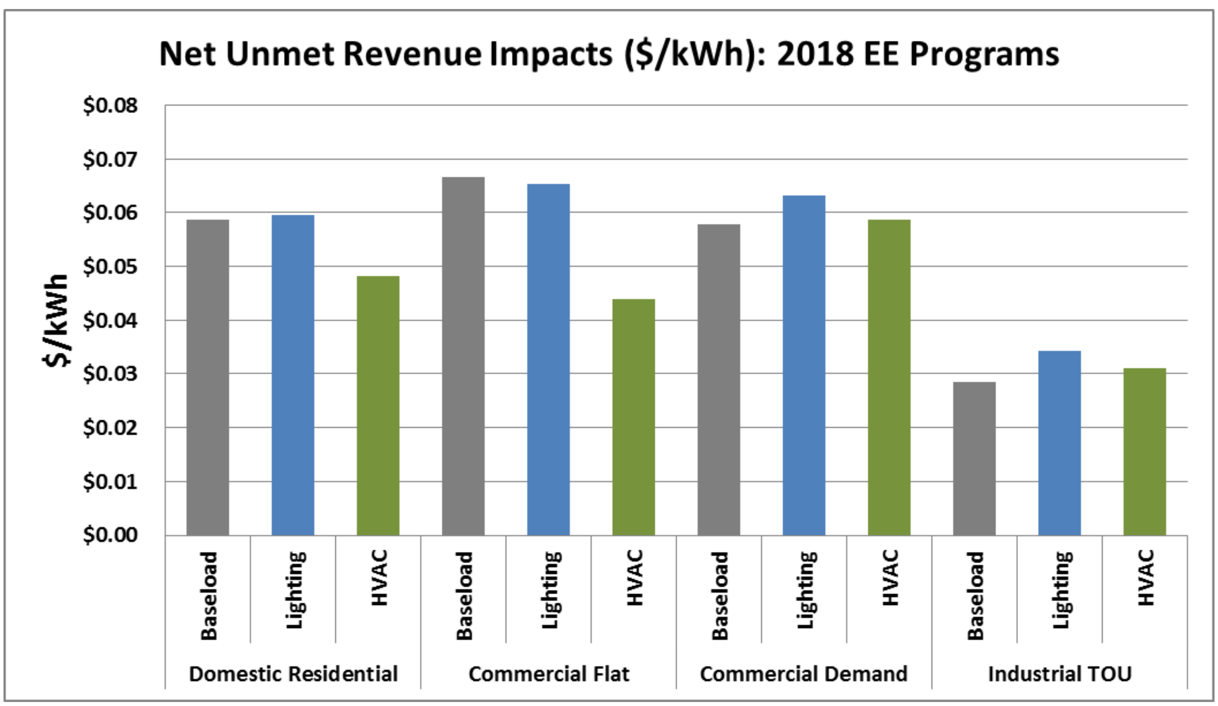


Figure 14.5.1. Net unmet revenue impacts by customer class and EE measure type ($/kWh).

Chapter 15. Energy Storage

Chapter Summary:

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 Contents:

Key Findings:

- Under contract, Ascend technical staff analyzed multiple battery configurations for their potential revenue generating capabilities in the CAISO day-ahead (DA) and real-time (RT) energy and ancillary service markets. Perhaps not surprisingly, high power, short duration batteries yielded the most revenue (on a $/kWh basis) under simulation.
- Ascend staff analyzed all battery configurations under both "perfect foresight" and "scheduled participation" bidding rules, using historical DA and RT CAISO energy and ancillary prices.

- The most cost effective modeling scenario was found to be a high power, short duration frequency regulation battery dispatched into the DA Ancillary Service market under perfect foresight conditions. This scenario produced a positive ROI, even though the battery configuration was only expected to have a useful lifetime of approximately three years.
- Although encouraging, these studies are subject to a number of technical modeling assumptions that are not fully verifiable. As such, RPU staff considers these results to be both preliminary and still somewhat speculative, and thus are not recommending that the utility purchase any utility-scale frequency regulation batteries at this time.

Important Highlights:

The five case studies analyzed by Ascend were 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.

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

In all five case studies, energy storage revenues were calculated using an optimization model that maximized the profits from the purchase and sale of energy across markets. Figure 15.4.3 shows a typical dispatch day for the 40 MW, 10 MWh battery configuration in case study #2. This battery participated in the real-time energy market when there were price spikes that made it worthwhile to leave the DA ancillary market.

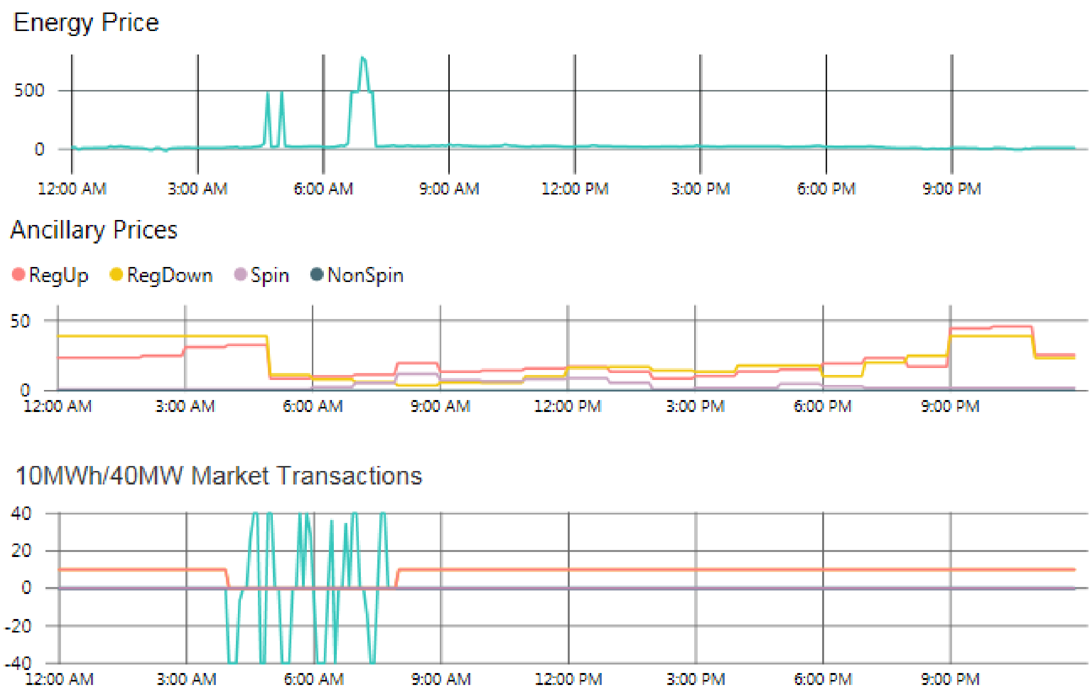


Figure 15.4.3. An example dispatch day for the 40 MW, 10 MWh battery configuration.

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 in Figure 15.5.1.

Based on theoretical throughput calculations, the approximate lifetimes for the battery scenarios examined in Cases #1, #2, #3 and #5 were calculated. The approximate lifetime revenues were then 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.

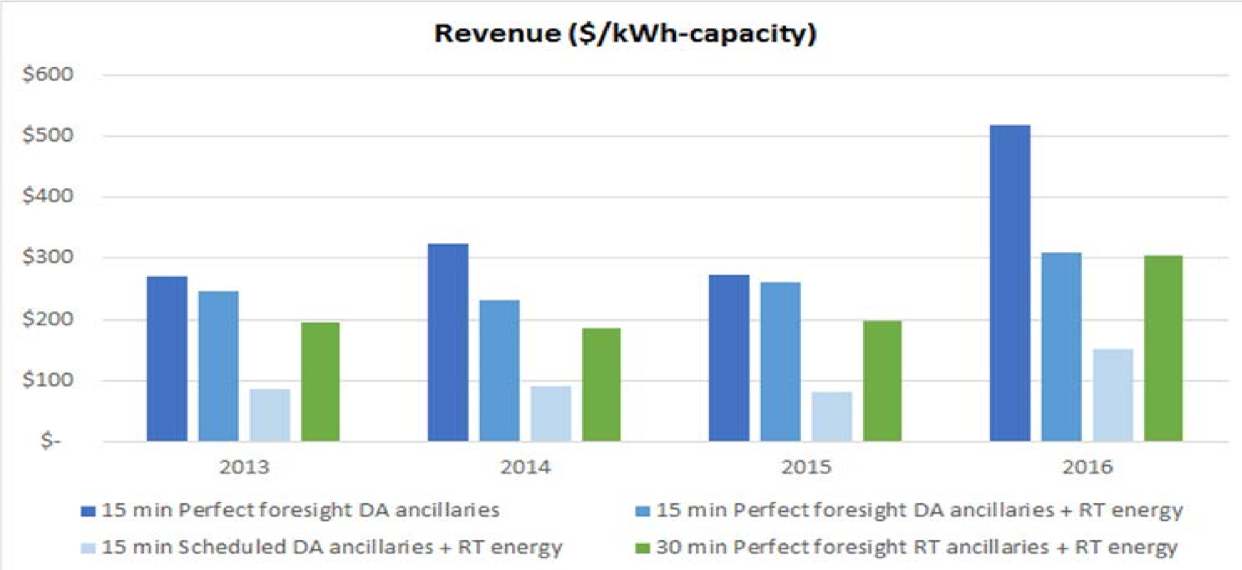


Figure 15.5.1. Annual $/kWh revenues for the short-duration battery scenarios examined in Case Studies #1, #2, #3 and #5 (30-minute battery only).

Table 15.2.1. 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

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, the expected battery life is very sensitive to the throughput assumptions and Case #1 exhibited the highest throughput metrics of all the cases studied. Additionally, the "perfect foresight" dispatch assumption may not be very realistic. More detailed battery simulation studies need to be carried out before staff can confidently recommend funding such a battery energy storage system.

Chapter 16. Retail Rate Design

Chapter Summary:

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 Contents:

Key Findings:

- RPU has proposed a 5 year electric utility rate plan that will result in a system average annual rate increase of 3% for typical electric customers. These rate increases, which start in January 2019, represent the utility's first rate increase since 2011.
- As part of the new rate plan, RPU is both adopting key changes to existing rates and introducing new rate tariffs (see Table 16.1.1 on page 16-3 in the IRP).
- Staff has developed an enhanced low-income assistance program (to help off-set rate increase impacts) that is being launched concurrently with the new rate plan.

Important Highlights:

RPU 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 to fund distribution system infrastructure and technology improvements, increased renewable energy and carbon reduction mandates, and increasing operational costs, in addition to providing better financial revenue stability.

Notwithstanding these proposed 3% annual 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.

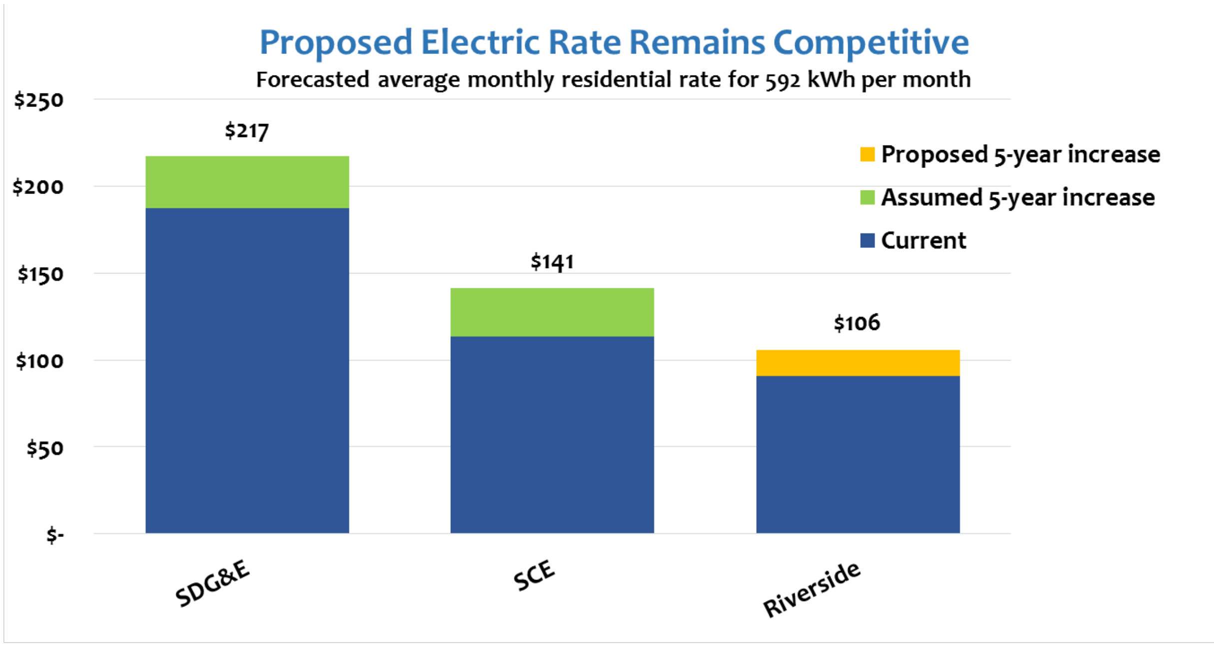


Figure 16.2.1. Forecasted monthly bills for a typical resident using 592 kWh a month, both now and after 5 years (under expected RPU, SCE, and SDG&E residential rate tariffs).

Chapter 17. Transportation Electrification

Chapter Summary:

Chapter 17 presents an overview of RPU's and the City of Riverside's efforts to support increasing levels of electric transportation. This 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 Contents:

Key Findings:

- Staff used the Light-Duty PEV Energy and Emission Calculator, version 3.5-3 (EV Calculator) spreadsheet tool, developed by the California Energy Commission (CEC), to analyze four different potential EV adoption scenarios for the RPU service area through 2030.
- While the "business as usual" scenario produced only minimal load growth and carbon reduction impacts, the higher adoption scenarios produced impacts that were much more

material. These higher impact scenarios suggest that RPU could see between 90,000 to 180,000 MWhs/year of increased load growth and 50,000 to 100,000 MT of carbon reduction by 2030.

- Staff also used consulting services from NewGen Strategies and Solutions, LLC, to analyze potential high-level distribution system impacts under two EV growth scenarios (i.e., specifically grid-wide charging patterns, diurnal load impacts, financial metrics, and the ability of a new EV only TOU rate tariff to influence diurnal charging patterns).
- These NewGen study results suggest that residential TOU rate tariffs could be effectively used to shift material amounts of charging loads to off-peak hours. However, additional planning and possibly new rate incentives will be needed, in order to avoid excessively stressing RPU's distribution system.

Important Highlights:

Using the EV Calculator, RPU analyzed four scenarios for the growth of EVs in the service territory. These four scenarios are defined in Table 17.3.1 below.

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%

The light-duty EV population in RPUs service territory is expected to increase under all scenarios modeled. Figure 17.3.3 shows the electric load or demand to meet the forecast EV population.

Likewise, Figure 17.3.4 shows the corresponding GHG emissions reductions that would be realized in the RPU service territory under each of these scenarios.

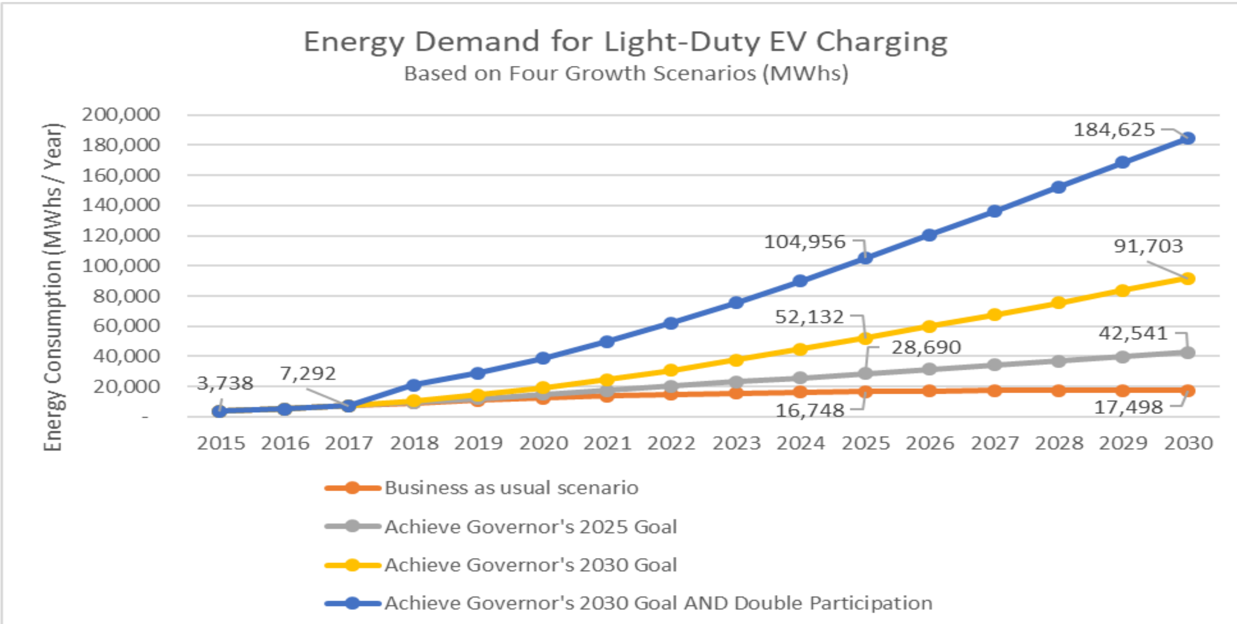


Figure 17.3.3. Energy demand from light-duty EV charging in Riverside using the CEC EV Calculator

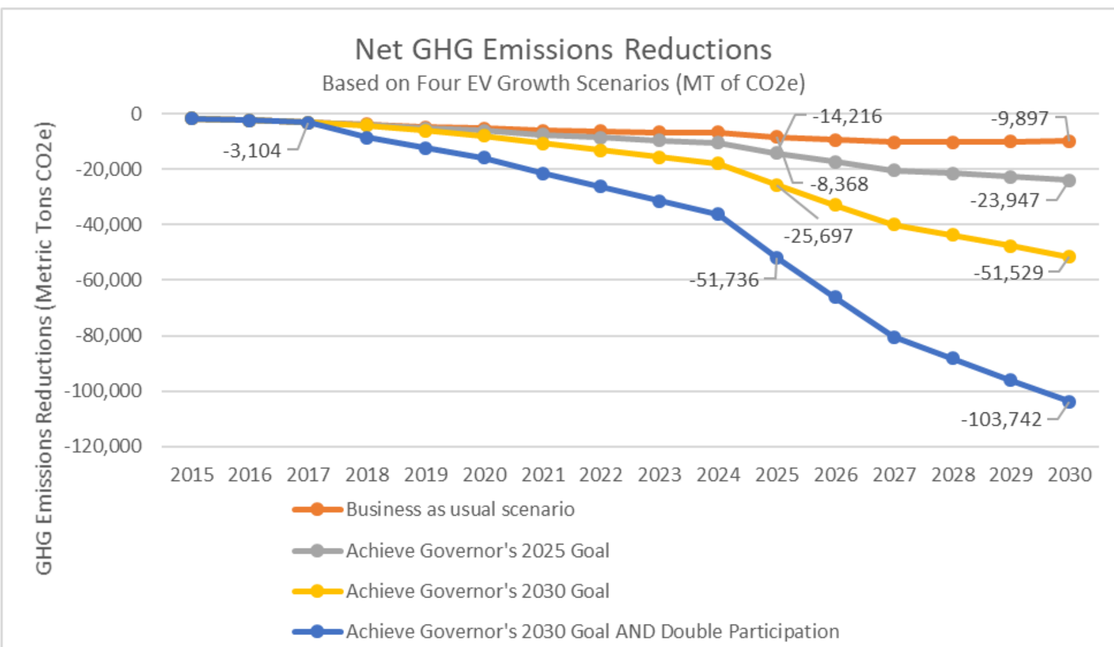


Figure 17.3.4. Net GHG emission reductions under four EV population growth scenarios using the CEC EV Calculator.

The LSAM Model was used 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. The diagram shows the baseline daily EV load forecast by the LSAM model as the dashed blue line and then illustrates the expected load shift due to customer migration and behavioral response to the EV-only TOU rate tariff.

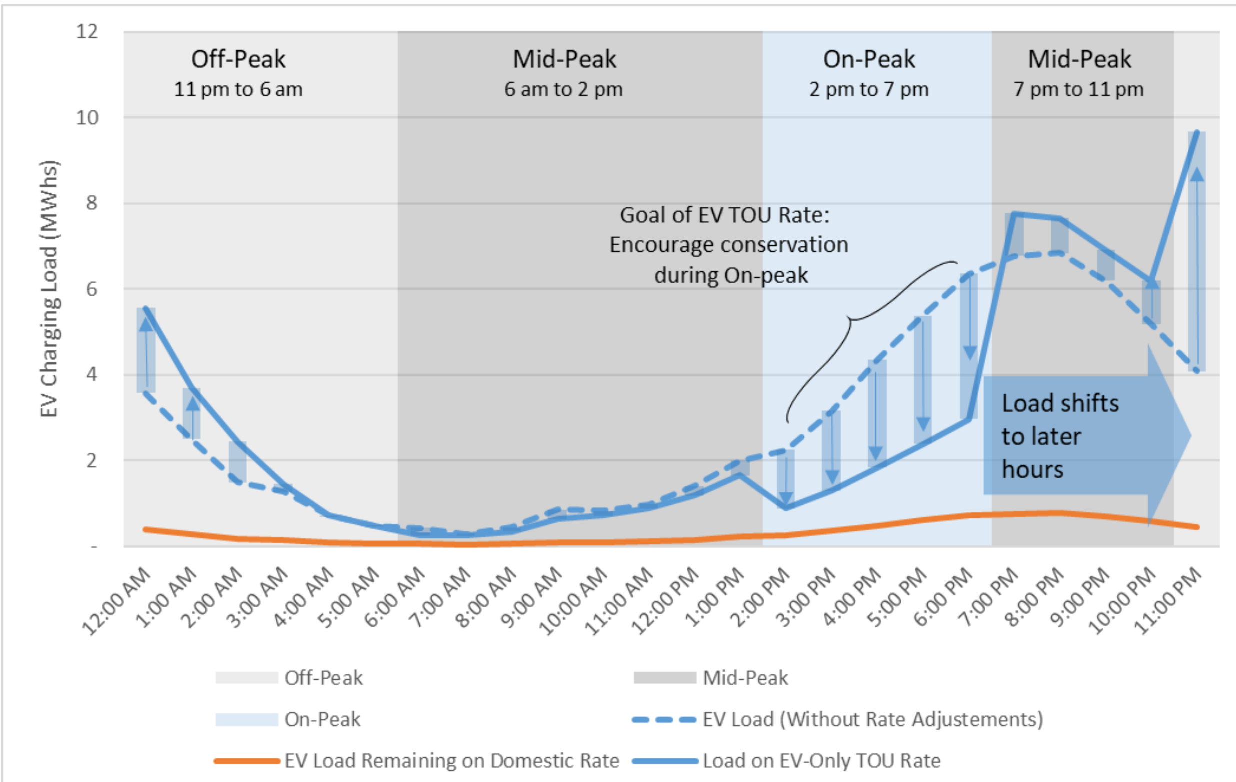


Figure 17.4.4. Effects of the EV TOU rate on EV charging load for a summer day in 2025, based on the LSAM model scenario assuming the Base EV adoption rate and low capacity charging equipment.

Chapter 18. Long Term Impacts of Customer DER Penetration

Chapter Summary:

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 analysis 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 Contents:

Key Findings:

- RPU can expect to reach its NEM 1.0 cap of 30.2 MW of installed solar PV capacity by or before the summer of 2020.
- Staff estimates that the current behind-the-meter average value of solar PV generation energy (VSPVGE) exported by Residential customers into the distribution system is about $0.07/kWh, which is significantly lower than the utility's retail rate.
- IF NEM 1.0 installations were allowed to continue indefinitely, RPU could expect to see about 21,000 behind-the-meter solar PV installations by 2037, with an annual within-class cost shift to non-NEM Residential customers of nearly $30,000,000.
- Alternative rate tariffs for future NEM customers must be developed to reduce this growing cost shift.

Important Highlights:

NewGen Strategies & Solutions, LLC created a Load Shape Analysis Model (LSAM©) that was used to study how different rate tariffs can impact both customer solar PV 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 different retail rate tariffs might be expected to impact future solar PV adoption levels, assuming that these rates become (or remain) the default residential rate tariff under the NEM 2.0 paradigm.

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 3-tier, inclining block (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 study results imply that this cost shift could increase 10-fold over the next 20 years, reaching 30 million dollars annually by 2037.

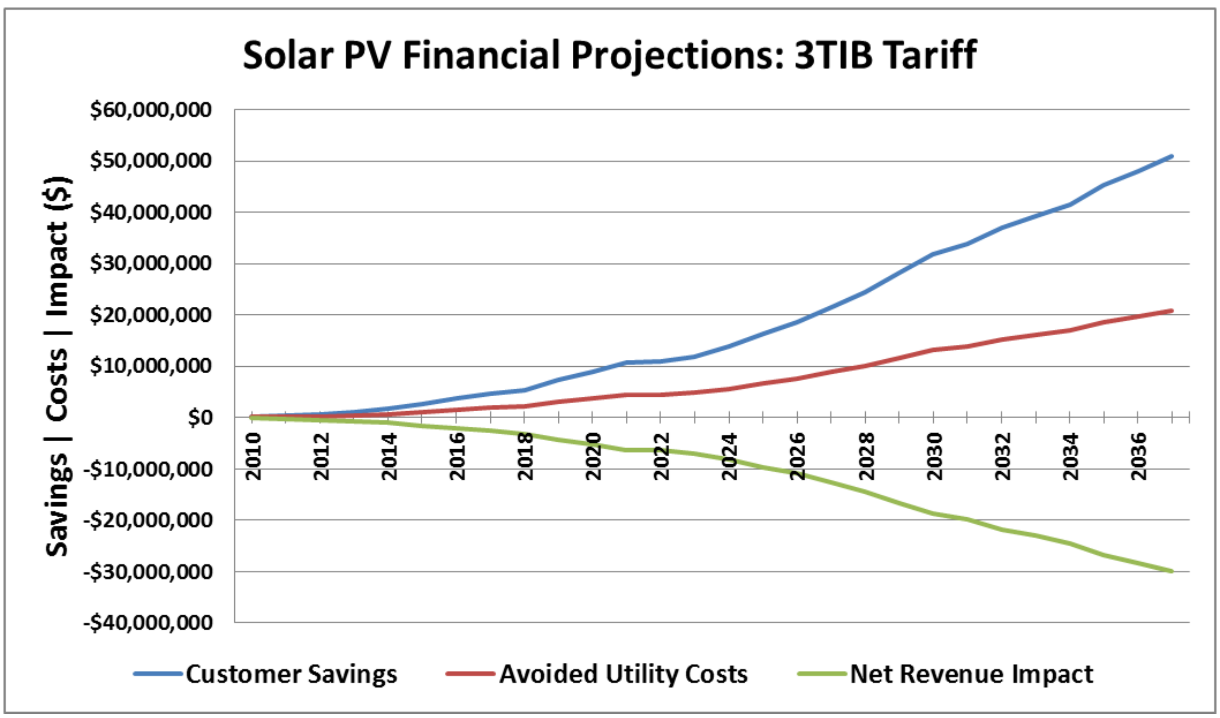


Figure 18.5.1. Expected annual customer savings, avoided utility costs and overall net revenue impacts under a NEM program that defaults to the 3TIB tariff through 2037.

Chapter 19. RPU Engagement with Disadvantaged Communities

Chapter Summary:

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 Contents:

Key Findings:

- The City has converted the bulk of its transportation and service vehicles to clean fuel alternatives.
- RPU has invested significant efforts at REC to minimize local emission pollutants (currently 35% below industry best practices for LM-6000 power plants).
- RPU has launched expanded low income assistance programs in conjunction with the new 2018 Rate Plan.
- RPU is currently developing new programs to refocus more EE rebates into identified Disadvantaged Community (DAC) areas.

Important Highlights:

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. CalEPA utilizes its environmental health screening tool, CalEnviro Screen to score and map DACs throughout the State based on the adopted evaluation criteria shown in Figure 19.1.1. Scoring is based on a basic ranking of the level of the impact.

Map 19.1.2 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

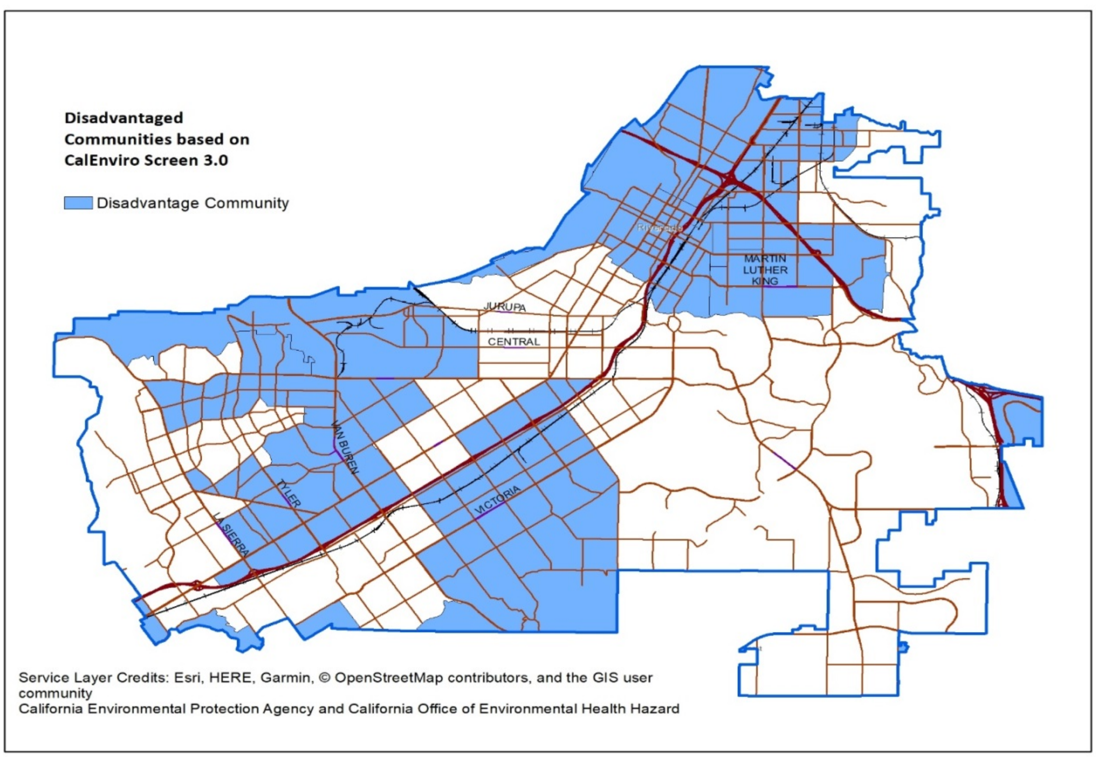
Sensitive Populations

- 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.



Map 19.1.2. Disadvantaged Communities in Riverside.

Chapter 20. Summary and Conclusions

Chapter Summary:

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.

Chapter Contents:

Key Findings:

- Sections 20.1 through 20.6 in Chapter 20 presents a very high-level summary of the key results and/or critical findings associated with the six primary IRP goals described in the Introduction.
- Section 20.7 briefly reviews the additional CEC mandated topics discussed in Chapters 16 and 19, respectively.

Important Highlights:

A significant number of diverse resource planning issues are discussed and analyzed in detail this 2018 Integrated Resource Plan. More detailed discussions of key results can be found 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. The Ascend Software Platform

Appendix Summary:

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. In PowerSimm, 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.

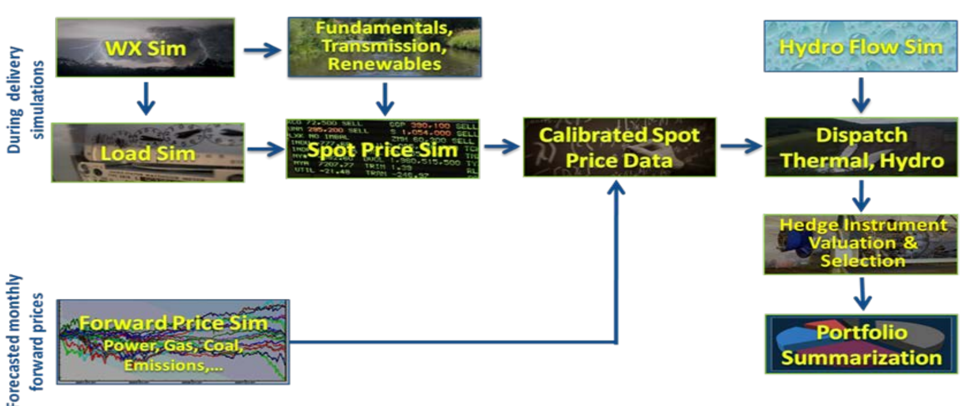
Appendix Contents:

Key Findings:

Software documentation – refer to Appendix for further details.

Important Highlights:

PowerSimm supports the ability to modify inputs, model impacts, and evaluate key sources of uncertainty, following the process flow shown below:



Appendices B, C, D, and E.

Appendix Summaries:

Appendix B provides the derivation of (and justification for) the 1.9 CAR multiplication factor referenced in Chapter 8. Likewise, Appendix C presents the full 5-Year Power Resource budget template (that corresponds to the summary budget table presented in Chapter 8).

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

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 contain the calculation details for each VOAE estimate presented in Chapter 14.

Contents of each Appendix:

Key Findings:

Reference material – refer to each Appendix for further details.

Important Highlights:

N/A