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Electric Rate Trends Study

Riverside Public Utilities

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Section 1
INTRODUCTION

Riverside Public Utilities

Riverside Public Utilities (RPU) is the department of the City of Riverside (City) that manages the electric and water utilities owned, controlled, and operated by the City. RPU generates, transmits, and distributes electricity throughout its 81.5 square mile service territory. RPU is the sole provider of electric service within its territory, and with only a few exceptions, serves virtually no customers outside of its boundaries.

RPU currently services approximately 112,000 electric customers with approximately 2.12 million megawatt-hours (MWh) and a system peak demand of approximately 630 megawatts (MW).

Cost of Service Study

This report is part of an Electric Cost of Service (COS) Study prepared by NewGen Strategies and Solutions, LLC (NewGen). RPU faces difficult challenges with the ever-changing electric industry such as changes to the U.S. and regional energy policies and changes to costs and customer behavior. These industry-wide changes are the reason for RPU's own progressive policy changes to address fixed cost recovery, integrated distributed generation and self-generation, increased conservation and energy efficiency, and future environmental legislation. It is important for RPU to recognize these challenges while continuing its work evolving electricity rates and rate structures to ensure customer equity, remain competitive among other electric utilities, and ensure the long-term financial stability of the utility.

The COS Study is intended to recognize and implement solutions to challenges arising from regulatory mandates, customer choice, and customer behavior. As customers have more options for their electricity usage, RPU must be able to respond to their customers' needs and changing behavior quickly.

Rate Trends Study

The purpose of the Electric Rate Trend Study (Study) within the COS Study is to evaluate and analyze different rate structures in the electric utility industry and how they could influence, impact, or apply to RPU currently and in the future. The different rate structures and industry concepts researched include emerging technologies and their future implications, electricity pricing, customer classification, and new customer choices, among others. The Study includes current rate offerings from investor-owned utilities (IOUs) and various municipal utilities with similar attributes to RPU. The use of multiple IOUs and municipal utilities is intended to best inform RPU of the different rate trends and rate structures in the California area and in the broader United States (U.S.).

The goal of this Study is to help RPU develop rates that are both COS based and a reflection of the industry. With the COS results and the knowledge gained from this Electric Rate Trend Study, RPU will be in the best position to design electric rates with the future of the utility and industry in mind.

In this report, Section 2 sets out the general rate making principles and Section 3 discusses the various electric rate alternatives based on recent and emerging trends in the electric utility industry. Section 3 highlights various summary rate matrices showing the rate structures of the utilities researched; their advantages and disadvantages; rankings of the alternative rates; and short-, mid-, and long-term considerations. Section 4 of this report provides general recommendations, including the results of the rate rankings and a summary matrix. Finally, implementation considerations such as customer acceptance, usage patterns, technology, and costs and benefits are discussed in Section 5.

This study was developed by NewGen with input from RPU management and staff. We wish to express our appreciation for the spirited cooperation and valuable assistance given to us throughout this Study by each member of RPU's management and staff.

Section 2
GENERAL RATE MAKING PRINCIPLES

Rate design is the process of establishing electric rates and charges using the completed COS Study. The electric rates are designed to recover the revenue requirement of the system in an equitable manner. The rates must be consistent with the COS results and applicable standards and/or requirements of local, state, and federal regulations. Rates should be designed to best reflect overall revenue stability, financial health, historical rate structures, energy efficiency and conservation, competitiveness among neighboring electric utilities, and the management and operations policies of the utility.

In rate cases throughout the country, general ratemaking principles proposed by James Bonbright are often referenced. Bonbright's Eight Utility Rate Design Principles, which he first identified in his text titled *Principles of Public Utility Rates* (released in 1961 and updated in 1988), are as follows:

1. Practical: simple, understandable, acceptable
2. Uncontroversial as to interpretation
3. Should meet revenue requirements
4. Should provide stable revenues
5. Should provide stable rates
6. Fairness among customer classes
7. Avoidance of undue discrimination
8. Should be economically efficient

These ratemaking principles are not concrete or absolute, which has allowed them to stay relevant for so many years. Ratemaking must be flexible as there can be instances where these principles conflict with one another. For municipal utilities, electric rates should be based on a rate policy targeting the lowest possible prices consistent with fulfilling customer requirements and producing quality service.

RPU's ratemaking principles provide that rate structures will be designed to provide a transition to rates that align with the transformational changes occurring in the electric industry. RPU's rates shall be designed to achieve the following goals:

- Achieve full recovery of costs
- Equitably allocate costs across and within customer classes
- Encourage efficient use of electricity
- Provide rate stability
- Offer flexibility and options
- Maintain rate competitiveness in region
- Be simple and easy to understand

The following sections provide a discussion of various rate making considerations that will be incorporated into RPU's rate design process.

Alignment with Policies and Strategic Objectives

The COS Study lays the foundation for developing electric rates and also provides an opportunity to confirm that the electric rates are aligned with the policies and long-term goals of RPU. The policies and objectives of the utility will determine how the utility approaches COS methodology and rate design. The policies and objectives of RPU consist of five cross-cutting threads discussed in this section and six strategic policies that include community well-being, environmental stewardship, and economic opportunity—to name a few. Different approaches to the COS and rate design will produce different results, which is why it is important to understand the driving policies and strategic objectives of the utility. Building off the eight rate design principles listed earlier in the Study, the following are some objectives that may be considered:

1. **Conservation** – A beneficial outcome to the utility as a result of innovative rate structures and trends such as time-of-use, volumetric rates, and distributed resources systems. These cost of service-based rates and structures send price signals to customers to conserve energy whether conservation is the rate structure's intent or not.
2. **Demand-Side Management (DSM)** – Public policy objective intended to lower overall costs to the utility and its customers.
3. **Distributed Generation** – Major consideration when developing net metering rates and feed-in tariffs for customers with distributed energy resources.
4. **Revenue Stability** – Common objective that can be achieved by aligning fixed and variable charges with fixed and variable utility costs.
5. **Cost Tracking** – The ability to measure and pass through costs on a time-of-use (TOU) or real-time basis. This provides price signals to customers intended to modify behavior to benefit the customers and utility.
6. **Economic Development** – Rates often considered by publicly owned utilities are targeted to attract new customers to increase customer demand and in turn provide a larger base to allocated utility fixed costs.
7. **Support Mandates** – Support from legislative and regulatory bodies as well as other regulations and public policies.

The rate design must have a balance between the economics of operating a utility, the policies and objectives of the utilities and its governing bodies, and the unique needs and preferences of the community. In California specifically, there are a number of state-specific mandates to consider such as Proposition 26, Feed-in Tariff compliance, Greenhouse Gas (GHG) reduction, Renewable Portfolio Standards, Solar Power initiatives, and others.

The Electric Cost of Service Analysis and Rate Design Project supports the City Council Strategic Plan 2025 Priorities and Goals, and aligns with the City Council's Strategic Plan 2025 Cross-Cutting Thread themes:

1. **Community Trust** – The Electric Cost of Service Analysis and Rate Design Project is transparent and developed with our customers' and the community's well-being as a top priority.
2. **Equity** – The Electric Cost of Service Analysis and Rate Design Project includes an equitable allocation of costs among customer classes which is incorporated into the resulting rate design recommendation.

3. **Fiscal Responsibility** – The Electric Cost of Service Analysis and Rate Design Project incorporates a forecasted revenue requirement that includes operating and capital expenditures funded by the prudent use of rate revenue, bond proceeds, and reserves.
4. **Innovation** – The Electric Cost of Study Analysis and Rate Design Project includes this Electric Utility Rate Trend Study that evaluates emerging rate structures, technologies, and trends, and how they may apply or be implemented by RPU.
5. **Sustainability & Resiliency** – The Electric Cost of Service Analysis and Rate Design Project will design future rates for a five-year period to equitably recover costs while maintaining the financial health of RPU.

Appropriate Rate Levels

The revenue authorized for a utility to collect through its electric rates and charges is the rate level. The rate level among different customer classes differs based on the nature of the customer class. Customer class attributes such as unique costs, usage characteristics, and delivery requirements create differing rate levels. The utility's overall rate level should ensure the revenue adequacy and meet the revenue requirement. In setting appropriate rate levels, there are trade-offs among the rate design policies and objectives.

Energy Efficiency and Conservation

In the past, regulators and rate designers have had a desire to adopt rates that encourage conversation and energy efficiency. However, as the electric utility industry has evolved and energy efficiency of buildings, homes, and appliances has drastically increased, energy conservation has become a result of most updated and/or innovative rate structures. For example, time-of-use rate structures are typically implemented with the goal of overall load flattening on the system, but the same price signals sent to the customer to impact their behavior to flatten the load curve also promote energy conservation for the customer. As people continue to monitor and improve their own energy efficiency, energy conservation will increase as a result, allowing electric utilities to focus the intent or goal of a rate structure on other elements of the electric utility industry.

Customer-Sited Distributed Energy Resources

Distributed Energy Resources (DER) systems are small-scale on-site power sources located at or near a customer's premises. Examples of DER systems include rooftop solar panels, energy storage devices, small-scale wind turbines, combined heat and power systems, and fuels cells. Customers with DER systems are connected to the local electric grid. These customers use the electric grid to both buy and sell power depending on whether the DER system is meeting their power supply needs. When the DER system is producing more power than is used by the customer, the excess power is generally sold to the utility. When the DER system is producing less power than is used by the customer, the remaining power needed is purchased from the utility. The use of DER systems at customer locations has the potential to reduce energy sales without reducing the fixed costs of the system. As customers change their usage patterns and introduce on-site generation, the utility may not be assured of full fixed-cost recovery through variable energy rates alone. RPU, along with many other utilities, has experienced revenue loss due to mandated rate structure programs not adapted for customer DER installations.

Self-Generation Program

In response to the increased popularity of DER systems and the potential risks to a utility based on outdated net metering rates, RPU has recently introduced a new self-generation program for new renewable DER customers. In the self-generation program, customers use a bidirectional meter to measure energy consumption from the grid and excess energy generation supplied to the grid. The energy consumed and supplied is recorded and priced hourly so that customers are compensated for the excess electricity generated and supplied to the grid at the time of generation. To accomplish this, the self-generation program will be on a time-of-use rate that will provide the customer with pricing signals to impact their consumption and generation behavior. In this new program, RPU will not be purchasing or crediting excess generation at the retail energy rate and instead will use an avoided cost of energy (ACOE) rate. This ACOE rate is developed using many components of the electric utility's energy generation and delivery process to accurately account for both the benefits a renewable DER customer provides to the system and the system costs potentially avoided by a renewable DER customer. Through the use of this ACOE rate, RPU ensures that it is not overpaying for excess energy generation received from its customers, and non-Self-Generation Program customers are not subsidizing the Self-Generation Program customers.

Electric Utility Business Challenges

The electric industry, as with many other industries, is facing increasing business challenges. In particular, many utilities are relying on rate structures created years ago that do not address any of the new trends and changes to the electric industry. These outdated rate structures may be creating a misalignment between fixed and variable costs incurred by the utility and costs recovered by the utility through rates. Historically, load growth and energy consumption increased consistently each year, allowing a utility to recover a large portion of its fixed costs through a variable energy charge. This worked when energy consumption within rate classes did not vary significantly.

Recently, load growth estimates across the electric utility industry have been much lower. Because of this trend, utilities around the country are often working to promote load growth while still keeping a careful eye on the market forecasts and risks associated with the load growth. Utilities now offer rates to encourage high load factor use and energy efficiency which, as a result, increases energy conservation. As mentioned earlier in this report, DER systems also create a unique business challenge since these systems lead to reduced energy sales without a reduction in utility fixed costs. Since utilities have relied on variable energy charges to collect a majority of their fixed costs for so long, these historical rate structures have created strains on a utility's ability to recover revenue. Ideally, a utility's fixed and variable costs should be able to recover required revenue regardless of customer actions such as increased energy efficiency or installed on-site generation.

Electric Vehicles

As the electric vehicle (EV) market continues to grow and gain popularity across the country, electric utilities need to understand the impacts on their systems from EV charging. There are two key elements for a utility to focus on regarding the charging and use of EVs: first, the size of service needed to charge the vehicle or vehicles; and second, the time periods when charging is occurring. Older electric distribution systems that typically support single transformer homes generally do not have the capacity at a local level to support a large influx of EV charging. Additionally, charging EVs during on-peak times (afternoon/evening hours) either at home or at a public charging station places added strain and cost on the utility system. These added costs to the system are generally not recovered through typical electric rates. A connection charge for EV customers is a reasonable way to recover the additional investment costs. As the use and popularity of EVs continue to grow, it is sensible for a utility to prepare for high EV penetration in the future.

Rates applicable to customers with EV charging should include a TOU component to reflect the accurate cost to serve those customers and to decrease the potential strain on the system caused by EV charging during peak periods. The increase of EV charging offers an opportunity to introduce true marginal cost considerations into rate design as EV charging is a unique addition to the system. With a TOU rate, customers can pay a lower rate for charging their EV during off-peak times (at night) compared to a higher rate for charging during on-peak times (during the day). For public charging stations, a TOU rate can be designed to collect system costs incurred from the station. Controlling when a public charging station is available (i.e., only during off-peak periods) can accomplish the same cost recovery goals as the TOU rates.

RPU currently offers an EV-specific TOU rate for customers in single-family residences. Under this rate, the EV charging for the customer is placed on a separate meter and is charged the same customer charge as the TOU customers but has a simpler TOU structure that does not include tiers at each period.

On top of rates for public charging stations and residential EV charging rates, it is important to discuss the potential for commercial and industrial EV charging rates (i.e., EV fleet rates). In a typical commercial or industrial rate, the customers are charged for their demand as well as their energy. This creates a potential concern when adding EV fleet charging to these customers' systems that the customers' demand charges may increase substantially. Designing EV charging rates for fleet charging must include a special focus on the demand charges. One option to address this issue is to offer a voltage discount to customers on a dollars per kilowatt basis where the discount is larger for higher voltage usage. This option is currently in place at some investor-owned utilities. Additionally, RPU currently offers a high voltage discount to its commercial and industrial TOU customers in the form of a high voltage network access charge that is lower than the network access charge applied to non-high voltage customers.

Embedded, Marginal, and Market-Based Pricing

Embedded pricing is the most traditional pricing method in which prices are based on an average historical cost. Market-Based Pricing is based on the current price of electricity in a given market. These prices vary significantly with the time of year and the time of day. Marginal costs are based on the marginal cost of supply, meaning the cost of supply is the cost for the next incremental amount of energy produced. Generally, marginal prices are assumed to be higher than current average costs.

Energy Storage

As renewable energy resources and the use of distributed energy resources continue to expand in the electric industry, technology used to store energy from these types of intermittent sources has been a major breakthrough. Energy storage devices can manage the amount of power supplied to a utility's customers and the time at which it is supplied, meaning energy storage devices can provide some or all of the power requirements to a customer during peak periods. Energy storage makes renewable energy sources dispatchable with much smoother operation.

Utility programs for renewable DER customers that have TOU-based rates, as is the case for RPU's Self-Generation Program, provide a strong incentive for those customers to install an energy storage device. This allows customers to decide if energy generated on-site will be immediately supplied back to the grid or stored for usage during a different time, such as an on-peak period with higher energy rates.

The U.S. Department of Energy's Energy Storage Systems Program works with utilities around the country, the California Energy Commission, and many other entities in the electric industry to facilitate major energy storage projects. Through this program, research and advancement of energy storage devices is continuing to push forward. The Energy Storage System Program highlights improved value of renewable energy generation, cost reductions through capacity and transmission payment deferral, and improved stability and reliability of transmission and distribution systems as enhancements provided by energy storage devices.[1]

Equity and Fairness

Equity is a term commonly used in state statutes and laws that authorize publicly owned utilities and define utilities' regulatory objectives. Equity can be described or characterized in the electric industry as producing no undue discrimination between customers as well as implementing fair rates. Developed rates should be able to demonstrate they are fair and not unduly discriminatory to any customer or customer class. Additionally, California law requires that charges for electric service should not exceed the reasonable cost for providing that service.

Fixed and Variable Costs

An important aspect of the COS analysis is the classification of costs into fixed costs and variable costs. Fixed costs are costs associated with labor, equipment, debt service, and infrastructure. They are related to the generation, transmission, and distribution services of the utility with little to no correlation to the amount of energy sold. Variable costs are costs associated with fuel, some aspects of generation and transmission, and variable operations and maintenance. These costs vary with the amount of energy sold. The rate design process accounts for variable and fixed costs when determining energy and demand charges; however, fixed costs have historically been recovered through the energy charges.

RPU introduced increased fixed costs in the form of an increased customer charge and a network access charge following the last COS study in 2017. The full increase in the domestic customer charge raises the previous customer charge of $8.06 to $12.06 by the start of 2023 by increasing the customer charge incrementally each year while the network access charge is a flat charge based on the customer's daily average energy usage. Increasing the customer charge and adding the network access charge more closely aligns the charges to a COS-based fixed charge.

Functional Unbundling

In the Cost of Service analysis, costs are divided into generation, transmission, and distribution costs to help determine the rates for each class of service. The process of functional unbundling is done to ensure customers are charged for the costs on the system they incur and are not charged for costs on the system they do not incur. This allows the utility to better understand its cost to serve customers for each of its functions or business units. The COS analysis will unbundle the costs of providing electric service and provide RPU with insights for the rate design process.

[1] Source: U.S. Department of Energy – https://www.energy.gov/oe/energy-storage

Low-Income Rate Programs

Historically, the electric industry tries to keep rates for low-income customers, especially residential customers, as low as possible. More specifically, utilities typically try to keep the monthly customer charges as low as possible to protect low use customers who may be both low income and/ or fixed income. On a percentage basis, increased customer charges have the greatest impact on low usage and low-income customers. In 2006, California adopted AB1890 which requires all utilities, including RPU, to establish a surcharge on electric usage to fund public benefit programs. One example of a surcharge funding a program is bill assistance services for qualifying low-income customers.

Rate Design Objectives

In the rate design process, policies and objectives of the utility and the regulatory bodies must be considered along with the cost of electric service. For example, there may be objectives to modify customer electricity usage behavior to flatten the load curve or respond to varying utilities' costs. These objectives can be accomplished by implementing TOU rates. Before these policies and objectives can be included in the rate design and implemented in electric rate structures, the utility must decide which policies and objectives are desirable and acceptable and to what degree they should be enacted.

Small Domestic Class and Multi-Family Electricity Use

Multi-Family residential units such as apartment complexes, condominiums, and duplexes typically have two options for measuring electric usage: master-metering or submetering. Complexes using a master-meter approach have one electric meter for the entire complex that captures the electricity usage for all units in the complex. There is only one electric bill from the utility to the entire building complex and it is up to the building managers to handle the electric bill of the individual units. In the sub-metering approach, each individual unit in a complex has its own dedicated electrical meter that is owned by the utility. Each individual tenant pays their electric bill directly to the utility based on their usage.

Providing individual units in a multi-family complex with a separate meter or specific domestic class improves the equity of the electricity costs for all individual units because it charges their usage directly rather than for the entire complex. These units in multi-family complexes are inherently more energy efficient than a standard residence because they are smaller in size and typically have less inhabitants. RPU should consider designing a low usage, domestic rate class to equitably charge these domestic customers for their costs.

Time-of-Use Power Costs

With the use of advanced metering and smart grid technologies, the electric utility industry is increasingly moving to rates based on when the energy is consumed rather than how much energy is consumed. Using rates based on time of use can reduce the utility's exposure to market costs that are based on real-time wholesale power markets. Creating time-of-use periods that are easy to understand, such as on-peak, mid-peak, and off-peak periods, allows customers to react to the varying power costs the utility experiences and also incentivizes customers to shift load to off-peak periods. The economic incentive provided to the customer for shifting load to the off-peak period must be noticeable. Generally speaking, on-peak prices need to be at least 2–3 times higher than off-peak prices.[2] Time-of-use power costs allow the utility to use existing generators more efficiently as well as to optimize transmission lines, distribution lines, and customer systems to hopefully defer the construction of additional resources.

RPU currently offers TOU rates for its domestic, large commercial, and industrial customers. Domestic TOU customers pay the same flat rates as the standard domestic service schedule while the energy rates vary over the added TOU periods. The periods used by RPU are as follows:

- On-Peak: 2 p.m.–7 p.m. in the summer; 4 p.m.–9 p.m. in the winter
- Mid-Peak: 6 a.m.–2 p.m. and 7 p.m.–11 p.m. in the summer; 6 a.m.–4 p.m. and 9 p.m.–11 p.m. in the winter
- Off-Peak: 11 p.m.–6 a.m. in the summer and winter

Additionally, RPU's domestic TOU rates have a tiered rate element to them. For each period there are two energy tiers based on energy consumption. These energy tiers vary based on the season as well as the TOU period.

Large commercial and industrial TOU customers pay a flat customer charge, a tiered reliability charge based on maximum demand, a network access charge, and TOU-based demand and energy charges. The TOU periods used by RPU for the large commercial and industrial customers are as follows:

- On-Peak: 12 p.m.–6 p.m. in the summer; 5 p.m.–9 p.m. in the winter
- Mid-Peak: 8 a.m.–12 p.m. and 6 p.m.–11 p.m. in the summer; 8 a.m.–5 p.m. in the winter
- Off-Peak: All other hours

[2] Source: Energy News Network – https://energynews.us/2019/12/02/survey-customer-education-needed-for-time-of-use-rates-to-be-successful/

Section 3
ELECTRIC RATE ALTERNATIVES

RPU's Current Rate Structure

The majority of RPU's customers, approximately 90%, are served under Schedule D, Domestic Service. Schedule D customers account for about 35% of RPU's annual energy sales. These customers are billed a monthly charge of $11.26 that is independent of energy use, and these customers pay a monthly reliability charge that ranges from $10 to $60 depending on the size of residence and ampere panel size. Monthly customer charges and reliability charges are flat rate charges to a customer to recover fixed utility costs. Additionally, Schedule D customers pay a network access charge that is a monthly charge ranging from $1.94 to $10.24 based on the daily average kilowatt-hour (kWh) usage of the customers. The Schedule D energy charge, a variable charge reflecting energy usage billed on a dollars per kilowatt-hour basis, uses an inclining block rate, meaning when energy usage exceeds certain tiers or blocks, the energy rate for usage in the higher tiers or blocks is higher than the previous tier or block. In this schedule, there are 3 tiers each for the summer and winter season with corresponding rates to each seasonal tier. In the summer, Tier 1 usage is 0–750 kWh, Tier 2 usage is 751–1,500 kWh, and Tier 3 usage is anything over 1,500 kWh. In the winter, Tier 1 usage is 0–350 kWh, Tier 2 usage is 351–750 kWh, and Tier 3 usage is anything over 750 kWh. The energy charges for both the summer and winter tiers increase as follows: Tier 1 = $0.1087/kWh, Tier 2 = $0.1729/kWh, Tier 3 = $0.1961/kWh. The overall increase from Tier 1 to Tier 3 is approximately 80%.

General Service customers served under Schedule A are billed on either a flat rate basis, if their monthly demand is less than 20 kilowatts (kW), or a demand basis, if their monthly demand is greater than 20 kW and less than 150 kW. Under the flat rate, customers pay a monthly customer charge, reliability charge, and network access charge in addition to an inclining block tiered energy rate. The customer charge is $20.50. The reliability charge and network access charge are a monthly flat rate based on energy usage ranging from $10 to $60 for the reliability charge and $2.79 to $33.86 for the network access charge. In the flat rate option, the energy charge is split into two tiers with Tier 1 usage ranging from 0–15,000 kWh and Tier 2 usage being anything over 15,000 kWh. The energy rates for these two are $0.1450/kWh and $0.2215/kWh, respectively.

Under the demand basis rate in Schedule A, customers pay a monthly customer charge of $17.68 and a monthly reliability charge of $90. Demand basis rate customers pay a network access charge of $1.40/kW and two demand charges: one, flat demand charge of $160.20 for the first 15 kW or less, and a second demand charge of $10.68/kW for all kW over 15 kW. Similar to the flat rate Schedule A customers, the demand basis customers have a two-tier energy charge with Tier 1 usage as 0–30,000 kWh and Tier 2 usage as anything over 30,000 kWh. The energy rates for these two are $0.1212/kWh and $0.1328/kWh, respectively.

The third primary rate offering by RPU is the Schedule TOU – Large General and Industrial Service offering. This rate is applicable to customers with a load of 150 kW or greater. These customers are billed a monthly customer charge of $666.28 and a flat reliability charge based on their maximum demand. There are six tiers of maximum demands that apply to the reliability charge; these tiers are: 0–100 kW, 100–150 kW, 15–250 kW, 250–500 kW, 500–750 kW, and anything over 750 kW. Additionally, customers pay an on-peak, mid-peak, and off-peak demand charge per kW or $7.27/kW, $3.64/kW, and $1.82/kW, respectively. Customers receiving service at 12,000 volts or higher will pay a high voltage network access charge while all other customers on this rate will pay the normal network access charge. Both of these charges are passed on max demand in the billing period. Finally, these customers pay an energy charge for the on-peak, mid-peak, and off-peak periods of $0.1124/kWh, $0.0922/kWh, and $0.0787/kWh, respectively.

RPU also offers a variety of other rates such as rates for domestic TOU, economic development, standby service, agriculture and pumping, streetlighting, net energy metering, and feed-in tariffs, to name a few. RPU's rates compare very favorably to other California utilities. As of March 1, 2022, the typical monthly electric bill for a medium-sized residential RPU customer using 600 kWh a month is approximately $103, assuming an average daily kWh consumption between 12–25 kWh. This typical customer's bill would be approximately $207 at Pacific Gas & Electric (PG&E) and $174 at Southern California Edison (SCE). PG&E's approximate customer bill was calculated using an "all-in" average energy rate provided by PG&E in order to estimate energy usage through different peak periods.

Recent Developments

In the electric utility industry, the ongoing developments surrounding customer-owned renewable distributed energy resources and Net Energy Metering (NEM) are increasingly important. In December 2021, the California Public Utility Commission (CPUC) released its proposed decision on the most recent NEM tariff, NEM 3.0. The proposed decision is called the Net Billing Tariff and is the third revision to the NEM tariffs in California. If the Net Billing Tariff is approved, it will immediately apply to the investor-owned utilities in the state, but it will also provide guidance for municipal utilities who are improving and/or adopting NEM tariffs. The Net Billing Tariff is based on the avoided cost concept and creates an average hourly value or price of energy at each hour of a given month. This avoided cost concept is intended to compensate customers the value of their energy exported to the grid based on the cost to the utility of buying clean energy from another source.

Two additional components proposed in the Net Billing Tariff are a grid participation charge and a market transition credit. The grid participation charge is designed to ensure net billing customers are paying the same fixed costs to the utility as non-net billing customers. This charge is based on the size of the distributed energy resource, primarily solar systems, of the customer. The market transition credit is also proposed in the Net Billing Tariff to incentivize energy storage. The market transition credit is an added credit to the customer that is designed to help customers pay back the costs of both a solar system and an energy storage system within the first 10 years after the purchase. This credit in addition to TOU energy pricing incentivizes customers to install and use solar energy storage by both issuing a credit to help the payback of the system and by allowing customers to limit energy consumption from the grid during on-peak periods with higher energy prices.

Another major development in the electric utility industry, especially in the state of California, is the growth and acceptance of Community Choice Aggregation (CCA). CCAs provide customers with the opportunity to choose cleaner energy sources for their own energy and are only available for customers within an IOU service territory, not a publicly owned utility service territory. CCA customers still utilize the transmission and distribution services of the IOU serving their area, but they are able to avoid or decline the energy generation of the IOU and instead receive cleaner energy from the CCA. As of 2021, CCA programs serve about 28% of the load in California's three largest IOUs, and this number is expected to rise to around 38% in the next year.[3] As the CCA movement continues to grow in California and across the

[3] Source: S&P Global – "California CCA Membership Surpasses 200 Communities, 28% of Utility Load," April 15, 2021.

U.S., it is important for electric utilities to understand the potential impacts to their electric production and their customers caused by the ever-growing CCA programs.

Tiered Rates

Tiered rates are designed based on energy usage tiers or blocks that can either be inclining block rates or declining block rates. Inclining block rates have a higher energy charge for each increasing block of energy usage. Declining block rates are the opposite and have a lower energy charge for each increasing block of energy usage. In the past, declining blocks were commonly used in the electric utility industry to promote energy usage by incentivizing customers to use additional energy and reach the higher blocks of energy usage that have lower rates. Today, the electric utility industry has shifted away from declining block rates towards inclining block rates. Utilities using inclining block rates implement the rates based on cost of service and as a result the rates incentivize energy conservation, energy efficiency, and a higher load factor for the customer. Appendix A-1 illustrates which of the selected California utilities have tiered rates, including RPU. Recently, many IOUs in California have been moving away from tiered rates and towards TOU rates.

Regulatory and Power Cost Adjustments

A power cost adjustment is a clause for a rate adjustment that automatically adjusts retail rates to reflect the variations and volatility of power supply costs that are outside the control of the utility. If power supply costs, such as fuel, increase, the power cost adjustment rate increases, and vice versa. Similarly, regulatory adjustments are charged by some utilities to recover regulatory costs. This regulatory adjustment is often a separate line item on a customer's bill. Most California utilities, including RPU, have a power cost adjustment applied to some or all of their rate structures. RPU currently has a power cost adjustment in their General Provisions, titled the Power Cost Adjustment Factor (PCAF), but is outdated and has not used the PCAF for many years.

RPU currently has many procedures in place to mitigate the risks of cost fluctuations typically included in power and regulatory cost adjustments, including RPU's current fiscal and reserve policies, maintaining reserve levels, long-term financial planning, and power supply long and short-term planning. Although cost adjustment mechanisms can provide cost recovery certainty to a utility, they can also provide rate uncertainty to customers and become and administrative burden. As a result, it may not be prudent for RPU to implement cost adjustments at this time, but to continue to monitor exposure to fluctuations in power costs, increasing regulatory costs, and other utilities' practices and if necessary, respond by implementing in the future. Due to RPU's current PCAF being outdated and requiring a significant update in order to implement, RPU can consider discontinuing the PCAF.

High Voltage Rates and Power Factor Charges

Large customers who receive service at high voltage levels have lower loss factors and a limited use of a system's low voltage distribution. Because of this, large customers typically have lower demand and energy charges. RPU, as with most other utilities, has a separate high voltage network access charge for large customers that receive service at high voltage levels that is lower than the network access charge for an average-sized customer.

The power factor is a ratio of kilowatts to kilovolt-amperes that is used to measure or quantify the efficiency of energy used by a facility or customer. Large service customers often pay a power factor charge if the power factor is below a certain ratio, typically 95%. Most of the California utilities reviewed in this Study include power factor charges, as shown in Appendix A-1. RPU does not currently have a power factor charge but should monitor system and customer load factors to understand the impacts of low power factor customers. Monitoring power factors of the entire system as well as individual customers is a practice that is highly benefitted by the use of advanced metering infrastructure (AMI) because of the amount and timeliness of the data.

Increased Fixed Charges

Increased fixed charges may be collected through an increase in the monthly customer charge. Customer charges are flat rate charges that are not dependent on a customer's energy usage. The following table shows the current residential and small commercial customer charges at various California utilities as of March 2022.

Table 3-1
Fixed Customer Charges ($)

	Residential	Schedule	Small Commercial	Schedule
Alameda	$17.30	D1	$29.00	A1
Anaheim	$5.00	D	$15.00	GSA-1
Azusa	$5.80	D	$10.00	G-1
Burbank	$9.21	Residential	$10.13	C
Glendale (1)	$15.00–$15.50	L-1-A	$18.60–$19.22	L-2-A
Los Angeles	$10.00	R-1(A)	$7.00	A-1(A)
Palo Alto	$0.00	E-1	$0.00	E-2
Pasadena	$8.96	R-1	$9.42	S-1
Redding (2)	$20.00	E1	$30.00	E2
Riverside (3)	$23.20	D	$23.29	A
SMUD	$23.05	R	$28.85	CI-TOD1
SCE (1)	$9.30–$9.61	D	$17.85–$18.45	GS-1

(1) Customer charge on a per day basis, values shown on a monthly basis.
(2) Network Access Charge used as a customer charge.
(3) Includes Reliability Charge and Minimum Tier 1 Network Access Charge included in customer charge.

Since the last rate trend study prepared for RPU in 2016, only two of the utilities evaluated had no increase to fixed charges, and one utility had a decrease in fixed charges. The following table summarizes the changes in fixed charges from 2016 to 2022.

Table 3-2
Changes in Fixed Customer Charges ($)

	Residential	Small Commercial
Alameda	$5.80	$9.15
Anaheim	$0.00	$0.00
Azusa	$1.99	$3.04
Burbank	$2.10	$0.31
Glendale (1)	$4.50	$0.60
Los Angeles	$0.00	$0.50
Palo Alto	$0.00	$0.00
Pasadena	$0.95	$1.00
Redding (2)	$7.00	$10.00
Riverside (3)	$5.14	$2.79
SMUD	$5.05	$10.85
SCE (1)(4)	($0.57)	($7.23)

(1) Customer charge on a per day basis.
(2) Network Access Charge used as a customer charge.
(3) Includes Reliability Charge and Minimum Tier 1 Network Access Charge.
(4) Negative values indicated a reduced fixed charge.

Residential and Small Commercial Demand Charges

Smaller customers, such as residential and small commercial customers, can be billed for their maximum monthly demand just as large commercial customers are typically billed. Demand charges are designed to collect more fixed costs directly rather than trying to collect fixed costs through energy charges. The demand charges can be used to address issues such as fixed cost recovery from net metering customers. To bill residential and small commercial customers demand charges requires advanced metering technology capable of measuring demand. Residential demand charges are not common in the electric utility industry; however, they have been applied by various utilities across the country with many more utilities proposing the concept. Typical commercial demand charges start in the range of 20 kW to 30 kW. Table 3-3 shows the threshold for demand charges for various California utilities as of March 2022. Since the last RPU rate trend study in 2016, there have been no changes to the demand rate thresholds for the evaluated utilities.

Table 3-3
Commercial Demand Rate Thresholds

	Demand Threshold	Schedule
Alameda	8,000 kWh	A2
Anaheim	15 kW	GS-1B
Azusa	20 kW	G-2
Burbank	20 kVA	D
Glendale	20 kW	LD-2-A
Los Angeles	30 kW	A-2(B)
Palo Alto	8,000 kWh	E-2
Pasadena	30 kW	M-1
Redding	25 kW	E7
Riverside	20 kW	A
SMUD	20 kW	CI-TOD-1
SCE	20 kW	GS-2

Commercial Rates and Business Growth

Some utilities offer an economic rate for qualifying commercial customers that is a discount of the typical commercial or general service rates. Rates are targeted to attract new customers to increase customer demand. This creates a larger sales base over which the utility can spread fixed costs. Economic development rates are almost exclusive of publicly owned utilities. This special rate must be in line with the economic realities of the utility, the policies and objectives of the utility, and the unique needs of the community. RPU and other California utilities offer an economic development rate.

Electric Vehicle Time-of-Use Rates and Charging Stations

EV TOU rates often utilize a separate meter for the EV charging system that is billed on a TOU basis. These rates most commonly offer lower rates during off-peak periods and higher rates during on-peak periods. Electric utilities must have a vested interest in the adoption of EVs and ensuring EVs are charged at times that support the efficiency of the grid. In the first quarter of 2020, California had approximately 32% of the country's electric vehicle supply equipment while also experiencing a 9% increase in EV supply equipment from 2019 to 2020—meaning EV charging and infrastructure in the state of California is a major necessity.[4] Domestic EV customers usually have the option to install a separate meter solely for their EV charger as RPU customers do. This prevents the customer from reaching higher energy tiers with more costly energy charges since the EV charger usage will not be included on their main house electric meter. RPU, along with other California utilities, currently offers an EV TOU rate. However, RPU does not currently have EV charging rates for public Level 2 chargers owned and operated by the City or RPU. As a part of the pending cost of service and rate studies, these rate options will be further explored. Additionally,

[4] Source: "Electric Vehicle Charging Infrastructure Trends from the Alternative Fueling Station Locator: First Quarter 2020" – National Renewable Energy Laboratory.

RPU's current rate for DC (direct current) fast charges will be further evaluated as all EV charging rate structures and rate options are evaluated.

Standby Charge

Standby rates are charged to DER customers to cover the utility's cost of system capacity availability to serve a DER customer's power requirements when they are not using their own generation. Standby service or partial requirements service are the retail electric services that customers with DER, on-site generation, and non-emergency generation typically want. These types of services can be either a completely separate tariff replacing the full-requirements tariff or an additional tariff or rider that applies on top of the standard full-requirements tariff. Many utilities providing these services typically specify the tariffs as either supplemental, backup, or maintenance partial requirements service. RPU and most California utilities currently have a standby charge. In RPU's case, it is referred to as Schedule S – Stand-by Service.

Net Metering Rates

NEM or net metering is a utility program that allows customers to sell excess electricity generated by their on-site DER systems. Net metering policies were first introduced years ago to encourage the growth and penetration of DER systems. Initially, most utilities bought or issued a credit for the excess electricity from their NEM customers at the full retail electric rate. A full retail electric rate includes more than just the cost of power supplied; it includes all of the fixed costs associated with poles, wires, meters, technologies, and other infrastructure that make the utility's grid safe and reliable. When utilities offered their NEM customers the full retail rate, the NEM customers essentially avoided paying the fixed costs associated with the electric grid. As DER systems became more popular and available, the number of customers avoiding these fixed costs increased dramatically, creating financial strain on utilities.

To address these potential avoided costs issues, utilities have been updating NEM rates to purchase excess electricity from NEM customers at less than the retail electric rate. An emerging method to determine the rate at which excess electricity is purchased is sometimes called "Value of Solar." When evaluating the value of solar, the goal is to identify the cost of only the electricity supplied to the grid. From a utility's perspective, purchasing power from NEM customers at the retail electric rate is a financial detriment because they are paying a price for the excess electricity that includes the fixed costs of the system. RPU's self-generation program was created in part to address the "Value of Solar" concept or the "Avoided Cost of Energy" as it is called in the self-generation program.

California publicly owned utilities are required to offer NEM under current law until a 5% NEM cap is reached. At that point, utilities can offer alternative rate structures, also called NEM 2.0. There are continuing developments in the NEM rates field including the upcoming NEM 3.0 and NEM aggregation, which is mentioned later in this report.

The following map shows the states with a net metering policy.

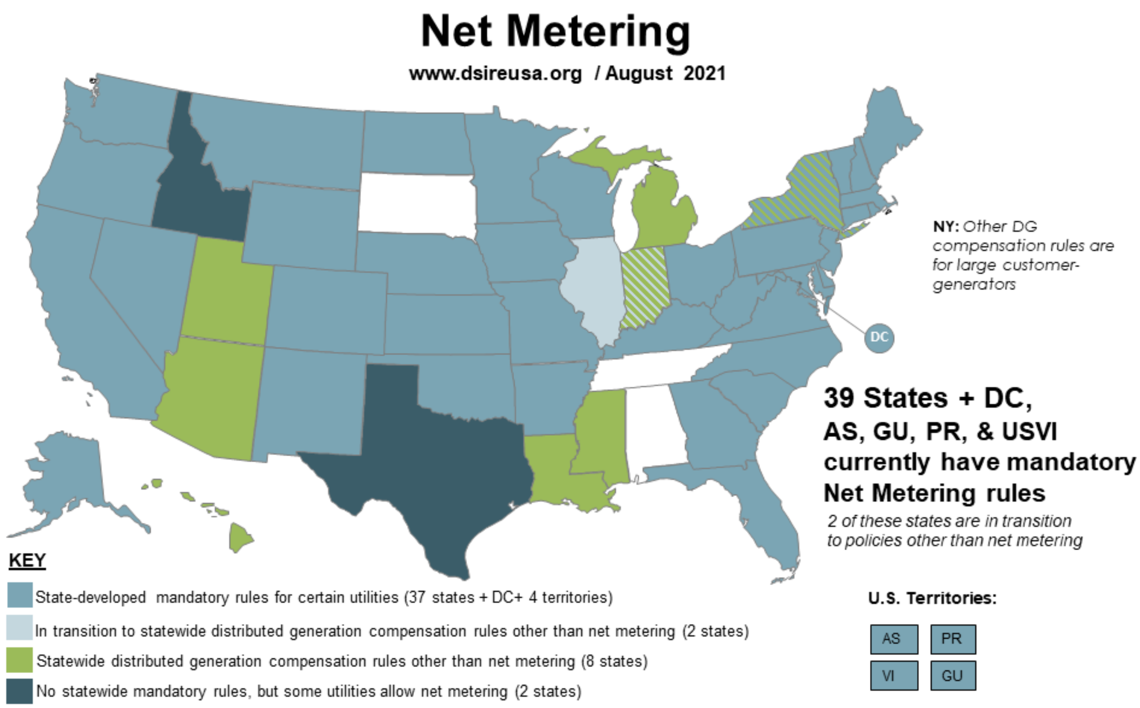

Figure 3-1. Net Metering Map[5]

Feed-In Tariffs

Feed-in tariffs (FIT) are used by a utility to encourage deployment of renewable technologies. In a typical FIT program, customers who own an eligible renewable generation device or facility, such as rooftop solar photovoltaic systems, receive a set price from the utility for all the electricity provided to the grid which the customer generated. Historically, FITs have been used to a limited degree across the U.S.; however, the use of FITs has been growing. Most California utilities shown in Appendix A-1 currently have a feed-in tariff. RPU currently has a feed-in tariff that is applied on a first-come, first-serve basis until the program cap is reached.

The following map shows states that currently have feed-in tariffs in place.

[5] Source: dsireusa.org/resources/detailed-summary-maps

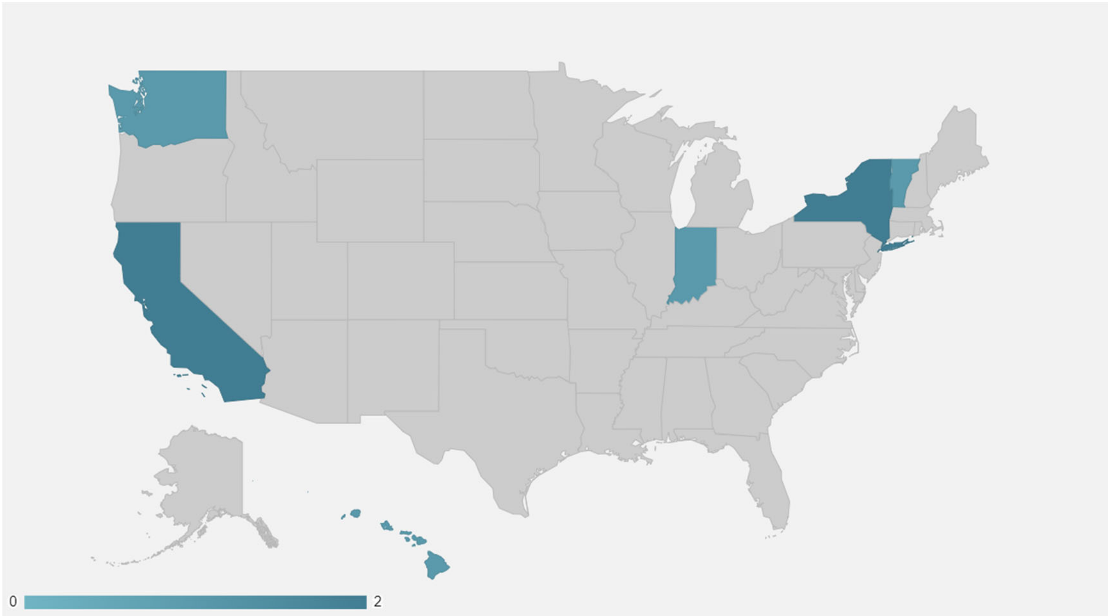

Figure 3-2. States with Feed-in Tariffs as of March 2022[6]

Community Solar

Community Solar is a voluntary solar-electric system program that is owned by multiple community members. The Community Solar members receive power and/or financial benefits through the program. The main driver for Community Solar programs is the fact that not all customers of a given energy market have the ability to install on-site solar facilities. A 2008 study by the National Renewable Energy Laboratory found that only 22 to 27% of residential rooftop space is useable for on-site photovoltaic systems. Issues such as the structure of the residence, the shading at the rooftop space, or ownership conflicts are attributed to the low percentage of usable rooftop space. Solar options are needed for renters, those with shaded roofs, and those who choose not to install an on-site photovoltaic system at their residence for their own personal reasons. These solar incentive programs are funded by ratepayers and/or taxpayers. In the spirit of equity, solar energy programs need to be designed to allow all contributors to participate. Community Solar programs are typically owned and operated by the utility and are open to voluntary participation.

Currently, several California utilities listed in Appendix A-1 and other utilities across the country have Community Solar programs which their customers are able to participate in voluntarily.

The following map in Figure 3-3 shows the states with community solar programs as well as the type of policy associated with their community solar program as of December 2021. It is important to note for the following figure that in February 2020, the California Energy Commission approved its first community solar project as a means of meeting the California solar mandate.

[6] Source: programs.dsireusa.org/system/program/maps

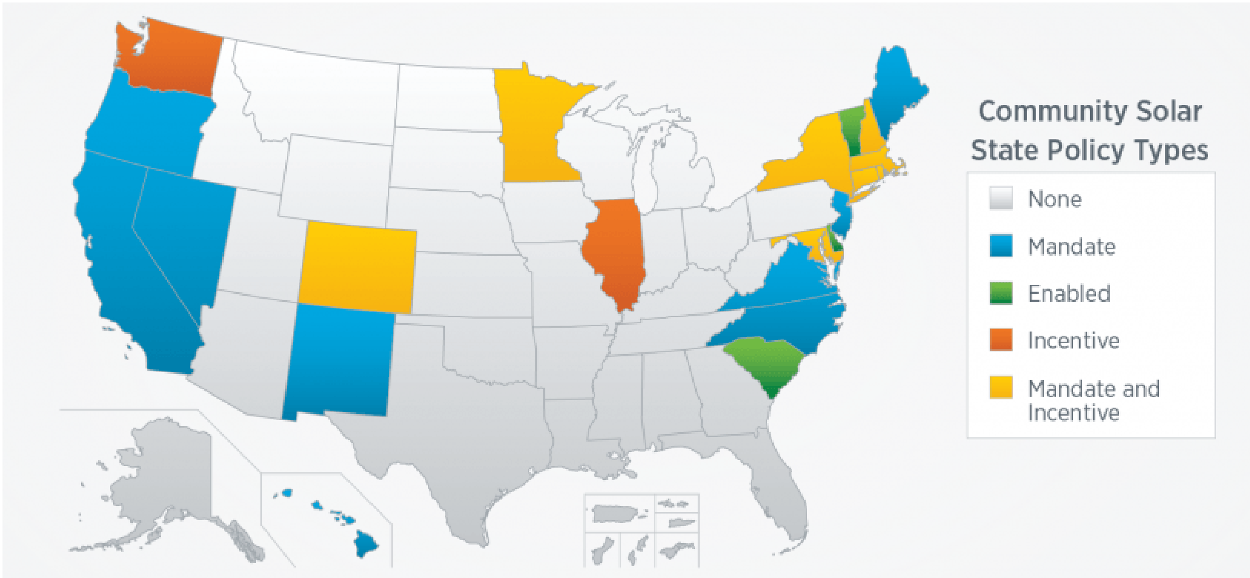

Figure 3-3. States with Community Solar[7]

Virtual/Aggregated Self Generation

Virtual or Aggregated Self Generation is a modification to net metering that allows customers with multiple meters and/or buildings to offset energy usage at all meters or buildings with energy generated at one meter or building. Without this modification to net metering, customers who own multiple buildings in a campus, for instance, have no way of sharing the self-generated energy across the various buildings in the campus. Of the California utilities shown in Appendix A-1, only SCE has virtual/aggregated self-generation programs in place.

Real-Time and Critical Peak Pricing

Market prices of electricity that vary hourly are called real-time pricing rates. These types of pricing rates encourage customers to react to the real-time variations in the market price. Los Angeles Department of Water and Power (LADWP), SCE, and Silicon Valley Power (SVP) currently offer real-time pricing options. Real-time pricing rates are not as common because of the technological barriers to implementation. Real-time pricing rates require advanced metering, communications, and increased administrative costs.

Critical Peak Pricing (CPP) is employed by utilities to reward customers for voluntarily reducing electricity usage during the highest peak demand periods and/or shifting electricity usage to off-peak periods. There are a few critical peaks per year due to weather or system conditions. In a CPP rate, the critical peak times are limited to specified days and times. There is a limit to the frequency and total number of hours per year that are considered critical peak. For example, SCE's critical peak times are weekdays between 4 p.m. and 9 p.m. with 12–15 CPP events per year. SCE is one of the few California utilities with critical peak pricing, but Sacramento Municipal Utility District is offering critical peak pricing in their 2022–2023 rate change. The barriers for RPU to implement CPP are similar to the barriers to implement real-time pricing—required advanced metering, communications, and increased administrative costs.

[7] Source: energy.gov/communitysolar/community-solar-market-trends

Time-of-Use Pricing for All Residential and Commercial Customers

TOU rates are usually optional for utility customers, but some utilities have made these rates mandatory. Most of the California utilities shown in Appendix A-1, including RPU, have TOU rates. As advanced metering technologies have become more accessible, some California IOUs are moving towards collapsing tiered rates and transitioning to only TOU rates. In these California IOUs, the TOU rate is the default rate for all customers.

Unbundling and Decoupling

Unbundling is the process of separating rates and charges on an electric bill for the specific services that make up the entire energy process. In unregulated markets, each aspect of the energy supply and electric service are a separate service with separate charges and billing line items. These types of rates are considered unbundled rates. Conversely, bundled rates are found in regulated markets and have a fixed kWh rate which includes all the costs of the energy supply and electric services in one charge and one billing line item. Currently, RPU does not publish unbundled rates, but it is important to note a handful of California utilities do publish unbundled rates (California IOUs are mandated to publish unbundled rates).

Decoupling, or more specifically revenue decoupling, is a rate adjustment mechanism that separates a utility's fixed cost recovery from the amount of electricity sold. With decoupling, utilities collect revenues based on the determined revenue requirement. Periodically these revenues are "trued-up" to the previously set revenue requirement using an automatic rate adjustment. The goal of decoupling is to have the actual revenues track more closely to its projected revenue requirement to bring revenue stability. With decoupling, revenues should increase or decrease with changes in sales.

Seasonal Rates

Seasonal rates are rates that vary according to the summer or winter seasons. With Southern California's temperature variability between seasonal months, a seasonal residential tier structure can be used to provide larger tiers in the summer to capture added energy usage for additional use of air conditioning. At this point, most utilities in California, including RPU, and across the country employ seasonal rates.

Streetlighting and LEDs

Utilities have begun including rates for light-emitting diode (LED) lighting fixtures. Historically, rates for unmetered streetlighting are set for each lamp type. With the increase in installed LED fixtures, some utilities have streetlighting specifically for LED lighting. Many of the California utilities in Appendix A-1, including RPU, currently have rates specifically for LED streetlighting.

Voluntary Green Pricing Programs

A green pricing program allows customers to voluntarily buy green power or renewable energy credits at a higher rate than the standard energy rate. Voluntary green pricing programs are a great way to increase the renewable energy purchases of a utility's customers. A 2019 report by the National Renewable Energy Lab (NREL) found that about 8 million customers procured around 164 million MWh of renewable energy through green energy sales in 2019, accounting for roughing 4% of US electricity sales.[8] Similar to other California utilities, RPU currently offers an optional renewable energy rate available to all customers. Participating customers help RPU achieve its renewable energy goals. RPU customers who opt into this program agree to pay an additional $0.0179/kWh of electricity they use. The funds raised through this program cover the increased costs of renewable energy served to the customers.

Low-Income Programs

RPU currently offers low-income assistance programs. RPU's SHARE Program is funded from the Public Benefits Charge, which is a 2.85% surcharge on the electric retail rate. Qualifying low-income customers receive a SHARE Program emergency/deposit assistance of $250 from RPU on their utility bill once every twelve months, after their annual application has been approved. Qualifying low-income customers also receive a SHARE electric monthly credit of $15.50 and water monthly credit of $3.00 on their utility bill.

Optional Rates with High Fixed Charges

A rate structure that is not very common at this time is optional rates with higher fixed charges. Under this rate structure, customers would have the option to select a rate that includes a higher fixed charge than the standard rate structure. An optional rate with higher fixed charges may have lower energy charges or more consistent energy charges throughout an entire day. Customers who may be interested in selecting this rate are customers whose energy usage cannot be shifted to different times of the day and who may be seeing high energy bills due to high energy usage during on-peak times.

Network and Transmission Access Charges

A network access charge is a charge designed to recover fixed costs incurred by the utility that are related to the electric grid. Network access charges can be a monthly flat charge for all customers on a specific rate schedule or a charge based on a customer's energy usage in a given month. Regardless of the energy usage, a network access charge is still collected. Network access charge funds are typically used for infrastructure improvements required to serve the utility's customers. Much like a network access charge, discussed previously in this report, transmission access charges are fixed charges applied to a customer to recover the costs incurred by the customer's use of the transmission system. Transmission access charge revenues are typically applied to the operation, maintenance, and improvement of transmission assets.

Advanced Metering Infrastructure

AMI is a metering system that records electric consumption on an hourly or more frequent basis and transmits data back to a central collection point. AMI technology is becoming more common for IOUs and POUs across the country as the benefits it provides to a utility outweigh the costs and time associated with installing. AMI provides a massive amount of data regarding items like cumulative kWh usage, peak demand, load profile, and time-of-use and peak energy readings. This data can be used to transmit demand response messages, automate net metering, discover and/or verify power outages, and provide tamper notifications, among other things. AMI data is not only incredibly informative and helpful to an

[8] Source: "Status and Trends in the Voluntary Market (2019 Data)" Presentation by NREL at the renewable Energy Markets Conference – September 23, 2020.

electric utility, but also required to implement innovative rate structures. Rate structures such as residential or commercial demand charges and critical-peak or real-time pricing are not possible without AMI. Other rate structures such as time-of-use rates, EV charging rates, and virtual net metering are greatly enhanced by AMI systems. Appendix A-2 describes the advantages and disadvantages of the different rate structures and designates which rate alternatives are benefited by AMI and which rate alternatives require AMI to operate.

RPU currently projects full commercial AMI coverage by mid-2023, with about 12,000 commercial meters. On the residential side, RPU currently projects 14,000 AMI meters installed for residential customers by the end of 2024, representing about 14% of their residential customers. These meters will be installed spatially to ensure that nearly all the existing meter signals can be collected by RPU's existing AMI meters so that meter readings for the entire residential customer class can be collected at least once per day in an automated manner. Additionally, existing residential non-AMI meters will continue to be replaced by AMI meters in future years at the rate of about 10,000 to 15,000 meters per year. RPU anticipates nearly all electric customers will have AMI meters before the end of 2028. Continuing on this current AMI program path is imperative for RPU to remain up to date with the ongoing changes in the electric utility industry.

Summary Rate Matrices

The electric rate alternatives are summarized in Appendices A-1, A-2, A-3, and A-4. Appendix A-1 summarizes the various types of rates offered by some California utilities and selected utilities outside the state of California. Appendix A-2 describes the advantages and disadvantages of each rate alternative. Appendix A-3 summarizes the industry considerations in the short-, mid-, and long-term for each rate alternative. Appendix A-4 grades the rate alternatives on a desirability scale from 1–3 relative to customer acceptance, changes in customer usage, technology required and its costs, barriers to new rates, risks, and the costs and benefits to both the utility and the customer.

As shown in Appendix A-1, most California utilities offer a variety of rate alternative. No utilities were found to have a residential demand charge and there were some rate alternatives only offered by a few utilities. Currently, only SVP offers an optional rate with high fixed prices, and SVP along with SCE offer aggregated self-generation. All the California utilities have a net metering rate, and many have feed-in tariffs as well as LED streetlighting rates. At this time, only SCE and SVP offer both real-time pricing and critical peak pricing.

Appendix A-2 summarizes the advantage and disadvantages of each rate alternative with the utility and customer perspectives in mind and designates which rate alternatives require AMI technology and which rate alternatives are benefited by AMI technology. For example, with both net metering and feed-in tariffs, DER systems are heavy promoted. Both of these rates help the utility meet California mandates, but the utility may not entirely recover fixed distribution costs with a net metering rate. On the customer side, having both a feed-in tariff and a net metering rate may cause confusion regarding which program is best suited for them.

Appendix A-3 summarizes the industry-wide considerations of the rate alternatives for the short-, mid-, and long-term. In this table, short-term considerations mainly describe which rate alternatives are current practiced in utilities or not, while the mid-term and long-term considerations discuss the potential for a rate alternative to become a common utility practice or not in the future. The perspective of these industry-wide considerations is specific to publicly owned utilities. The industry considerations may be slightly different for investor-owned utilities for some rate alternatives.

Appendix A-4 summarizes the rate evaluations on a scale of 1 to 3, with 1 being not desirable and 3 being desirable, according to customer acceptance, changes in customer usage patterns, technology required and its costs, barriers, risk, and the costs and benefits to both the utility and the customer. For example, reliability charges, regulatory adjustments, and power cost adjustments are ranked as desirable (3 on the scale) in terms of the costs and benefits from the utility perspective while the same rate alternatives are ranked as not desirable (1 on the scale) in terms of costs and benefits to the customer. This is because these types of charges help the utility collect fixed costs and ensure revenue stability, but from a customer's perspective they may be only viewed as extra charges and line items on the electric bill.

On the far right of Appendix A-4 are both cumulative scores for each rate alternative and average scores. These scores are color coded from red to yellow to green for low to high scores to help easily identify the highest scoring rate alternatives. The highest scoring rate alternatives in terms of the desirability scale are seasonal rates, high voltage rates, economic development rates, voluntary green pricing, and reliability charges. All these rate alternatives are currently used by RPU. The highest scoring rate alternatives that are not currently used by RPU are regulatory adjustment charges, unbundled rates, and decoupled rates. The lowest scoring rate alternatives that are not currently used by RPU are residential demand charges, real-time pricing, and critical peak pricing.

Section 4
GENERAL RECOMMENDATIONS

Summary Rate Matrix

Appendix A-5 summarizes the recommendations based on the review of trends and the results of Appendices A-1 through A-4. The recommendations are summarized in terms of short-, mid-, and long-term recommendations. Some of the highlights of the recommendations are as follows:

1. RPU should continue its current practices, monitoring and updating its rate structure as necessary based on COS analyses, regarding seasonal rates, economic development rates, stand-by charge, and TOU rates.
2. RPU should continue its current practices regarding domestic EV charging rates and implement EV charging rates for commercial customers and public charging stations while also monitoring other utilities' practices and the applicable regulations and mandates of local, state, and federal regulatory bodies.
3. RPU should continue using fixed cost recovery mechanisms like reliability charges and network access charges. RPU should continue analysis of these cost recovery mechanisms to ensure they are in line with COS results.
4. RPU should continue its plan to close the current net energy metering program and to implement the proposed self-generation program and continue to offer the feed-in tariff while also analyzing customer acceptance and customer knowledge of these types of rates. RPU should consider educating customers regarding the details and differences of the rates. As these rates are analyzed and modified as necessary, RPU should investigate potential aggregated self-generation programs consistent with potential state mandates.
5. RPU should not implement residential demand charges, real-time pricing rates, or critical peak pricing rates at this time but should monitor other utilities' practices in regard to these rate alternatives.
6. RPU should not implement cost adjustment such as power cost adjustment, regulatory adjustment, or decoupling at this time but should monitor exposure to fluctuations in power costs, increasing regulatory costs, and other utilities' practices in regard to these rate alternatives. It is also recommended that RPU discontinue the current obsolete power cost adjustment factor due to the structure being out of date and not implemented for many years.
7. RPU should consider collapsing tiered rates with the goal of eventually transitioning out of tiered rates into entirely TOU rates for domestic and small and medium commercial customers.
8. RPU should explore a small domestic rate for individually metered building units to charge customers more equitably for their costs.

Section 5
GENERAL IMPLEMENTATION CONSIDERATIONS

When implementing the recommendations, the following elements should be considered by RPU's management and staff. Appendix A-3 summarizes these considerations.

Customer Acceptance

Even though a particular rate structure may be ideal from a utility perspective, the customer acceptance of the new rate or rate structure must be considered. For example, increasing the customer charge helps the utility recover its fixed costs, but for low usage customers the acceptance may be poor. For low usage customers, such as customers using around 500 kWh per month, increasing the customer charge will increase the user's total bill quite dramatically. The desired rate structures of the utility and their outcomes must be balanced with rates that are acceptable to customers. On the other hand, some rate alternatives are easy to comprehend by electric customers and have high customer acceptance. Rate alternatives such as EV TOU rates, community solar programs, and seasonal rates typically experience higher levels of customer acceptance.

Customer Usage Patterns

Customer usage patterns must be monitored and analyzed before and after rate changes to see the impact of the rate change on a customer's energy usage, demand, load factor, and on-peak vs. off-peak usage. An objective of rate design is to influence customer behavior and impact customer usage patterns to achieve the goals of the utility, such as increased efficiency of the system and reducing overall costs. However, it is possible that the new rate change impacts customers' energy usage to an unpredictable degree that leads to lower revenues than expected. An inclining block rate that is intended to promote energy conservation by charging higher energy rates at higher usage tiers has the chance to reduce customers' usage throughout the system with the consequence of reduced revenues.

Technology Considerations

Technology associated with the implementation of a new rate alternative or rate structure must be considered. Alternative rates such as TOU rates require advanced metering and updated or revised billing systems to properly analyze and bill energy usage at each hour of the day. Newer rate alternatives such as real-time pricing and critical peak pricing require even more technology including advanced metering, updated communications systems, and advanced billing. The technologies for some newer rate alternatives are still being developed or improved while other technologies are currently commercially available.

Barriers

On top of specific technological barriers, there are other barriers such as legal, social, administrative, and regulatory barriers to alternative rates that need to be considered. An example of a social barrier is the impact of increased fixed charges on low energy users or low-income customers. The administrative barrier to most of these rate alternatives is the increased burden on the administrative staff of the utility. Additionally, there is always the opportunity for legal and regulatory barriers to arise from items such as mandates from federal and state regulatory bodies or local municipalities.

Risks

Since there are uncertainties regarding how a new rate alternative may impact customer usage and behavior, the expected revenues may be not as projected. Revenues which are lower than projected create a financial risk for a utility. Additionally, some rate alternatives may create risks as a result of lower sales and less recovery of a utility's fixed costs.

Costs and Benefits

The costs and benefits of implementing a new rate alternative must be considered when evaluating potential new rate alternatives. The costs and benefits of both the utility and the customer must be considered. Some rate alternatives may have significant cost barriers to the utility such as advanced metering requirements, while other rate alternatives may have low-cost barriers to implement. Other rate alternatives may benefit the utility through increased cost recovery while also offering specific rate alternatives for specific customer classes.

Next Steps and Moving Forward

Appendix A-5 provides a general roadmap detailing the next steps in the short-term and long-term future. After the completion of the COS analysis and development of rates, a more detailed plan of the short-term and long-term future can be determined. The following is a summary of the next steps.

1. Complete COS Analysis with Proposed Rates
2. Public Involvement and Education for Proposed Rates
3. Implement Proposed Rates

Table A-1
Riverside Public Utilities
Rate Trends Study
Types of Rates Offered by California Utilities

		Alameda	Anaheim	Austin Energy	Azusa	Burbank	Glendale	Green Mountain Power	Los Angeles	Palo Alto	Pasadena	Redding	Riverside	Sacramento	So.Calif. Edison	Silicon Valley Power
	Current RPU Rate Offerings															
1	Economic Development Rate	✓	✓		✓						✓	✓	✓	✓	✓	✓
2	Electric Vehicle TOU Rate- Residential	✓	✓	✓	✓	✓		✓	✓				✓	✓	✓	✓
3	EV Public Charging Stations	✓	✓	✓		✓	✓		✓	✓	✓		✓	✓		
4	Feed-In Tariff		✓				✓		✓	✓			✓	✓	✓	✓
5	High Voltage Rates	✓	✓	✓	✓					✓		✓	✓		✓	✓
6	Increased Fixed Charge	✓			✓	✓	✓				✓	✓	✓	✓		
7	Net Metering Rate / Self-Generation / NEM 2.0	✓	✓		✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓
8	Network Access Charge										✓	✓	✓			
9	Reliability Charge					✓			✓				✓			
10	Seasonal Rates	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓
11	Medium and Large Commercial Demand Charge	✓			✓		✓	✓	✓				✓	✓	✓	✓
12	Standby Charge	✓		✓	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓
13	Street Lighting LED Rates	✓		✓				✓		✓	✓		✓	✓	✓	
14	Tiered Rates	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓
15	TOU for Residential (Tiered and Non-Tiered)	✓	✓	✓		✓	✓	✓	✓	✓	✓		✓	✓	✓	✓
16	TOU for Large Commercial and Industrial		✓		✓	✓	✓			✓	✓		✓	✓	✓	✓
17	Voluntary Renewable Pricing	✓	✓	✓		✓		✓	✓	✓	✓		✓	✓	✓	✓
	Other Innovative Rate Offerings not Currently Offered by RPU															
18	Small Residential Class		✓								✓	✓		✓	✓	
19	Residential Demand Charge															
20	Small Commercial Demand Charge	✓			✓		✓	✓	✓					✓	✓	✓
21	TOU for Small & Medium Commercial		✓		✓	✓	✓		✓	✓	✓			✓	✓	✓
22	Commercial and Industrial EV Charging		✓												✓	
23	Critical Peak Pricing							✓						✓	✓	✓
24	Real-Time Pricing								✓						✓	✓
25	Decoupling						✓		✓							
26	Optional Rates with High Fixed Charges															✓
27	Power Factor Charges	✓	✓		✓		✓		✓	✓	✓	✓		✓	✓	✓
28	Power Cost Adjustment	✓	✓	✓	✓	✓	✓		✓		✓	✓			✓	✓
29	Regulatory Adjustment		✓	✓			✓					✓				
30	Special Rates/Charges (i.e. Wildfire Rate)											✓			✓*	
31	Transmission Access Charge			✓							✓				✓	
32	Unbundled Rates	✓					✓			✓	✓				✓	✓
33	Community Solar			✓					✓					✓	✓	✓
34	Virtual / Aggregated Self-Generation														✓	✓

✓* Note: SoCal Edison using previously established DWR Bond Charge to support wildfire fund.

Table A-2
Riverside Public Utilities
Rate Trends Study
Advantages and Disadvantages of Rate Structure

		Advantages	Disadvantages	AMI Required	AMI Provides Benefit
	Current RPU Rate Offerings				
1	**Economic Development Rate**	May increase high load factor customers; may lower average costs	Existing customers may not accept; not based on cost of service		
2	**Electric Vehicle TOU Rate- Residential**	Provides incentive for charging off-peak; may improve system and circuit load factor and lower average costs	Requires separate metering and special billing		✓
3	**EV Public Charging Stations**	Provides utility owned EV public charging stations; justified based on cost of service	Administrative burden		✓
4	**Feed-In Tariff**	Cost based method for promoting distributed generation	Customer confusion between net metering and FIT; customer may prefer long-term pricing		✓
5	**High Voltage Rates**	Tracks costs for high voltage users; justified based on cost of service	Administrative burden to identify customers qualifying for rate (This is less of an administrative burden than individual contracts)		✓
6	**Increased Fixed Charge**	Recovers utility fixed costs; justified based on cost of service	Customer acceptance may be poor; impacts small users		
7	**Net Metering Rate / Self-Generation / NEM 2.0**	Promotes distributed generation; helps meet California mandates	Does not recover fixed distribution costs		✓
8	**Network Access Charge**	Recovers utility fixed costs; especially from low energy users or DER systems users	Adds complexity to bills with an additional bill item; customer acceptance may be poor		✓
9	**Reliability Charge**	Recovers utility fixed costs; debt service on internal generation and transmission	Delay in transmission projects		✓
10	**Seasonal Rates**	Tracks costs by season	Adds complexity to bills		
11	**Medium and Large Commercial Demand Charge**	Recovers utility fixed costs; justified based on cost of service	High charges for customers with poor load factors	✓	✓
12	**Standby Charge**	Recovers fixed distribution costs	Adds complexity to bills; may discourage distributed generation; does not apply to NEM		
13	**Street Lighting LED Rates**	Recovers cost by LED fixture type if energy is unmetered	Administrative burden		
14	**Tiered Rates**	Recovers utility costs; can result in customer conservation	Impacts large users; may produce revenue volatility		
15	**TOU for Residential (Tiered and Non-Tiered)**	Sends price signals to change customer behavior; may improve system load factor and lower average costs	Requires advanced metering and may not be understood by customers		✓
16	**TOU for Large Commercial and Industrial**	Sends price signals to change customer behavior; may improve load factor of larger customers	Requires advanced metering and may not be understood by customers		✓
17	**Voluntary Renewable Pricing**	Provides options for customers and utility to increase renewables	None		
	Other Innovative Rate Offerings not Currently Offered by RPU				
18	**Small Residential Class**	Justified based on cost of service; provides utility and customers with more accurate usage information	Requires separate metering and special billing; may not be understood by customers		✓
19	**Residential Demand Charge**	Recovers utility fixed costs; justified based on cost of service	Requires advanced metering; customer acceptance may be poor		✓
20	**Small Commercial Demand Charge**	Recovers utility fixed costs; justified based on cost of service	Requires advanced metering; customer acceptance may be poor		✓
21	**TOU for Small & Medium Commercial**	Sends price signals to change customer behavior; may improve system load factor and lower average costs	Requires advanced metering and may not be understood by customers		✓
22	**Commercial and Industrial EV Charging**	Provides incentive for charging off-peak; may improve system load factor; provides more public EV stations	Administrative burden		✓
23	**Critical Peak Pricing**	Cost based rate; may be advantageous for industrial customers	Requires advanced metering, communications and billing systems	✓	✓
24	**Real-Time Pricing**	Pure cost based rate; may be advantageous for industrial customers	Requires advanced metering, communications and billing systems	✓	✓
25	**Decoupling**	Could improve fixed cost recovery	Difficult to quantify and incorporate reserve balances. May require refund of overcollection of fixed cost recovery		
26	**Optional Rates with High Fixed Charges**	Recovers utility fixed costs; offers bill certainty to customer	Lower energy rates do not promote conservation with contradicts a CA state mandate		
27	**Power Factor Charges**	Tracks and allocates costs for low power factor users	Administrative burden of metering and billing		✓
28	**Power Cost Adjustment**	Recovers utility costs	Customer acceptance may be poor; adds complexity to bills		
29	**Regulatory Adjustment**	Recovers utility costs	Adds complexity to bills		
30	**Special Rates/Charges (i.e. Wildfire Rate)**	Recovers costs for unique situations outside the control of the utility.	Adds complexity to bills with an additional bill item; customer acceptance may be poor		
31	**Transmission Access Charge**	Recover utility fixed costs for transmission assets	Adds complexity to bills with an additional bill item; customer acceptance may be poor		
32	**Unbundled Rates**	Tracks costs by generation, transmission, and distribution	Adds complexity to bills; customer acceptance may be poor		
33	**Community Solar**	Helps meet California mandates; may be better for utility than DG	Customer acceptance may not be as high as DG		✓
34	**Virtual / Aggregated Self-Generation**	Promotes distributed generation and community causes	Adds complexity to distributed generation customers' service, requires advanced metering		✓

Table A-3
Riverside Public Utilities
Rate Trends Study
Industry Short, Mid, Long Term Considerations

		Short-Term (1 Year) Consideration	Mid-Term (2-5 Years) Consideration	Long-Term (>5 Years) Consideration
	Current RPU Rate Offerings			
1	Economic Development Rate	Practice of some utilities	May become more common utility practice	May become more common utility practice
2	Electric Vehicle TOU Rate- Residential	Practice of some utilities	Likely to become more common utility practice	Likely to become more common utility practice
3	EV Public Charging Stations	Practice of some utilities	Likely to become more common utility practice	Likely to become more common utility practice
4	Feed-In Tariff	Practice of some utilities	Likely to become more common utility practice	Likely to become more common utility practice
5	High Voltage Rates	Common utility practice	Likely to remain common utility practice	Likely to remain common utility practice
6	Increased Fixed Charge	Not common utility practice	May become more common utility practice	Likely to become more common utility practice
7	Net Metering Rate / Self-Generation / NEM 2.0	Common utility practice	Likely to remain common utility practice	Likely to remain common utility practice
8	Network Access Charge	Practice of some utilities	May become more common utility practice	May become more common utility practice
9	Reliability Charge	Not common utility practice	May become more common utility practice	May become more common utility practice
10	Seasonal Rates	Common utility practice	Likely to remain common utility practice	Likely to remain common utility practice
11	Medium and Large Commercial Demand Charge	Common utility practice	Likely to become more common utility practice	Likely to become more common utility practice
12	Standby Charge	Practice of some utilities	May become more common utility practice	Likely to become more common utility practice
13	Street Lighting LED Rates	Practice of some utilities	Likely to remain common utility practice	Likely to remain common utility practice
14	Tiered Rates	Common utility practice	May become less common utility practice	Likely to become less common utility practice
15	TOU for Residential (Tiered and Non-Tiered)	Pilot programs are common utility practice	Likely to become more common utility practice	Likely to become more common utility practice
16	TOU for Large Commercial and Industrial	Common utility practice	Likely to remain common utility practice	Likely to remain common utility practice
17	Voluntary Renewable Pricing	Practice of some utilities	Likely to become more common utility practice	Likely to become more common utility practice
	Other Innovative Rate Offerings not Currently Offered by RPU			
18	Small Residential Class	Not common utility practice	Unlikely to become common utility practice	May become more common utility practice
19	Residential Demand Charge	Not common utility practice	Unlikely to become common utility practice	May become more common utility practice
20	Small Commercial Demand Charge	Not common utility practice	Unlikely to become common utility practice	May become more common utility practice
21	TOU for Small & Medium Commercial	Practice of some utilities	Likely to become more common utility practice	Likely to become more common utility practice
22	Commercial and Industrial EV Charging	Practice of some utilities	Likely to become more common utility practice	Likely to become more common utility practice
23	Critical Peak Pricing	Not common utility practice	Unlikely to become common utility practice	May become more common utility practice
24	Real-Time Pricing	Not common utility practice	Unlikely to become common utility practice	May become more common utility practice
25	Decoupling	Not common utility practice	Unlikely to become common utility practice	Unlikely to become common utility practice
26	Optional Rates with High Fixed Charges	Not common utility practice	Unlikely to become common utility practice	Unlikely to become common utility practice
27	Power Factor Charges	Practice of some utilities	Unlikely to become common utility practice	May become more common utility practice
28	Power Cost Adjustment	Practice of some utilities	May become more common utility practice	May become more common utility practice
29	Regulatory Adjustment	Practice of some utilities	May become more common utility practice	May become more common utility practice
30	Special Rates/Charges (i.e. Wildfire Rate)	Not common utility practice	Unlikely to become common utility practice	Unlikely to become common utility practice
31	Transmission Access Charge	Not common utility practice	Unlikely to become common utility practice	Unlikely to become common utility practice
32	Unbundled Rates	Not common utility practice	Unlikely to become common utility practice	Unlikely to become common utility practice
33	Community Solar	Not common utility practice	May become more common utility practice	Likely to become more common utility practice
34	Virtual / Aggregated Self-Generation	Not common utility practice	May become more common utility practice	Likely to become more common utility practice

Table A-4
Riverside Public Utilities
Rate Trends Study
Rate Structure Rankings

		Customer Acceptance	Change in Customer Usage	Technology Required	Customer Costs of Technology	Utility Costs of Technology	Barriers to New Rates	Risks Utility Perspective	Costs and Benefits Utility Perspective	Costs and Benefits Customer Perspective	Cumulative Score	Average Score
Current RPU Rate Offerings												
1	Economic Development Rate	2	3	3	3	3	3	2	2	3	24	2.67
2	Electric Vehicle TOU Rate- Residential	3	3	2	1	2	3	3	3	2	22	2.44
3	EV Public Charging Stations	2	2	2	3	1	3	2	2	3	20	2.22
4	Feed-In Tariff	2	2	2	2	1	2	2	2	2	17	1.89
5	High Voltage Rates	2	3	3	3	3	3	3	3	2	25	2.78
6	Increased Fixed Charge	1	2	3	3	3	2	3	3	2	22	2.44
7	Net Metering Rate / Self-Generation / NEM 2.0	3	3	2	2	1	2	2	2	3	20	2.22
8	Network Access Charge	2	2	3	3	3	3	3	3	2	24	2.67
9	Reliability Charge	2	2	3	3	3	3	3	3	1	23	2.56
10	Seasonal Rates	3	2	3	3	3	3	3	3	2	25	2.78
11	Medium and Large Commercial Demand Charge	1	3	2	2	2	2	2	2	2	18	2.00
12	Standby Charge	2	3	3	3	2	2	3	2	3	23	2.56
13	Street Lighting LED Rates	3	1	3	3	3	3	3	3	1	23	2.56
14	Tiered Rates	2	3	3	3	3	2	2	3	2	23	2.56
15	TOU for Residential (Tiered and Non-Tiered)	3	3	2	3	1	2	2	2	3	21	2.33
16	TOU for Large Commercial and Industrial	3	3	2	3	1	2	2	3	2	21	2.33
17	Voluntary Renewable Pricing	3	1	3	3	3	3	3	3	2	24	2.67
Other Innovative Rate Offerings Not Currently Offered By RPU												
18	Small Residential Class	2	1	2	3	2	2	2	2	2	18	2.00
19	Residential Demand Charge	1	3	2	1	2	1	1	2	2	15	1.67
20	Small Commercial Demand Charge	1	3	2	2	2	2	2	2	2	18	2.00
21	TOU for Small & Medium Commercial	2	3	2	3	1	2	2	2	3	20	2.22
22	Commercial and Industrial EV Charging	3	2	1	1	2	2	3	2	1	17	1.89
23	Critical Peak Pricing	1	3	1	3	1	1	2	1	1	14	1.56
24	Real-Time Pricing	1	3	1	3	1	1	2	1	1	14	1.56
25	Decoupling	2	1	3	3	3	3	3	3	1	22	2.44
26	Optional Rates with High Fixed Charges	3	2	2	2	3	2	2	3	2	21	2.33
27	Power Factor Charges	3	3	1	3	1	2	3	3	2	21	2.33
28	Power Cost Adjustment	2	2	2	2	2	2	3	2	2	19	2.11
29	Regulatory Adjustment	2	2	1	2	2	2	3	2	2	18	2.00
30	Special Rates/Charges (i.e. Wildfire Rate)	1	1	3	3	3	3	3	3	1	21	2.33
31	Transmission Access Charge	1	1	3	3	3	3	3	3	1	21	2.33
32	Unbundled Rates	2	1	3	3	3	3	3	3	1	22	2.44
33	Community Solar	3	1	2	3	1	3	3	3	2	21	2.33
34	Virtual / Aggregated Self-Generation	3	2	2	3	1	2	2	1	3	19	2.11

3	= Desirable
2	= Moderate
1	= Not Desirable

Color Scale	Cummulative Score	Average Score
	14 - 20	1.5 - 2.2
	20 - 23	2.2 - 2.5
	23 +	2.5 +

Table A-5
Riverside Public Utilities
Rate Trends Study
Summary of Recommendations

		Short-Term (1 Year) Consideration	Mid-Term (2-5 Years) Consideration	Long-Term (>5 Years) Consideration
Current RPU Rate Offerings				
1	Economic Development Rate	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice
2	Electric Vehicle TOU Rate- Residential	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice
3	EV Public Charging Stations	Continue current practice and modify rates as necessary	Continue current practice and modify rates as necessary	Continue current practice and modify rates as necessary
4	Feed-In Tariff	Continue current practice and monitor mandates and other regulations	Continue current practice and monitor mandates and other regulations	Continue current practice and monitor mandates and other regulations
5	High Voltage Rates	Continue current practice and monitor	Continue monitoring high voltage usage	Continue monitoring high voltage usage
6	Increased Fixed Charge	Continue fixed charges based on COS and balance customer acceptance	Continue tracking with COS and monitor customer acceptance	Continue tracking with COS and monitor customer acceptance
7	Net Metering Rate / Self-Generation / NEM 2.0	Continue current practice and monitor mandates and other regulations	Continue current practice and monitor mandates and other regulations	Continue current practice and monitor mandates and other regulations
8	Network Access Charge	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice
9	Reliability Charge	Continue current practice	Continue current practice	Continue current practice
10	Seasonal Rates	Continue current practice	Continue current practice	Continue current practice
11	Medium and Large Commercial Demand Charge	Continue current practice	Continue current practice	Continue current practice
12	Standby Charge	Continue current practice	Continue current practice	Continue current practice
13	Street Lighting LED Rates	Modify LED rates as needed	Modify LED rates as needed	Modify LED rates as needed
14	Tiered Rates	Evaluate and consider collapsing tiers	Evaluate and consider as optional rate to TOU	Evaluate and consider replacing entirely with TOU rates.
15	TOU for Residential (Tiered and Non-Tiered)	Revise TOU rates as necessary and monitor other utilities' practice	Revise TOU rates as necessary and consider as default rate	Gauge and monitor customer acceptance of a default TOU rate
16	TOU for Large Commercial and Industrial	Continue current practice	Continue current practice	Continue current practice
17	Voluntary Renewable Pricing	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice
Other Innovative Rate Offerings not Currently Offered by RPU				
18	Small Residential Class	Consider implementation and monitor customer acceptance	Consider implementation and monitor customer acceptance	Consider implementation and monitor customer acceptance
19	Residential Demand Charge	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice	Continue current practice and monitor other utilities' practice
20	Small Commercial Demand Charge	Continue current practice and monitor other utilities' practice	Consider as a pilot program and monitor customer acceptance	Consider as a pilot program and monitor customer acceptance
21	TOU for Small & Medium Commercial	Revise TOU rates as necessary and monitor other utilities' practice	Revise TOU rates as necessary and monitor other utilities' practice	Revise TOU rates as necessary and monitor other utilities' practice
22	Commercial and Industrial EV Charging	Implement and monitor customer acceptance	Continue and monitor customer acceptance	Continue and monitor customer acceptance
23	Critical Peak Pricing	Do not implement but monitor other utilities' practice	Do not implement but monitor other utilities' practice	Do not implement but monitor other utilities' practice
24	Real-Time Pricing	Do not implement but monitor other utilities' practice	Do not implement but monitor other utilities' practice	Do not implement but monitor other utilities' practice
25	Decoupling	Do not implement but monitor other utilities' practice	Do not implement but monitor other utilities' practice	Do not implement but monitor other utilities' practice
26	Optional Rates with High Fixed Charges	Continue current practice and monitor other utilities' practice	Consider as a pilot program and monitor customer acceptance	Consider as a pilot program and monitor customer acceptance
27	Power Factor Charges	Do not implement but continue to monitor	Do not implement but continue to monitor	Do not implement but continue to monitor
28	Power Cost Adjustment	Do not implement but continue to monitor exposure to fluctuations in power costs	Do not implement but continue to monitor exposure to fluctuations in power costs	Do not implement but continue to monitor exposure to fluctuations in power costs
29	Regulatory Adjustment	Do not implement but continue to monitor regulatory costs	Do not implement but continue to monitor regulatory costs	Do not implement but continue to monitor regulatory costs
30	Special Rates/Charges (i.e. Wildfire Rate)	Do not implement but monitor regulations and mandates regarding special rates	Monitor regulations and mandates regarding special rates	Monitor regulations and mandates regarding special rates
31	Transmission Access Charge	Do not implement but monitor other utilities' practice	Consider implementing as a pilot program and monitor other utilities' practice	Consider implementing as a pilot program and monitor other utilities' practice
32	Unbundled Rates	Do not implement but consider educating customer about unbundled rates	Consider as a pilot program and monitor customer acceptance	Consider as a pilot program and monitor customer acceptance
33	Community Solar	Investigate potential community solar projects	Monitor other utilities' practices and increase community interest	Monitor other utilities' practices and increase community interest
34	Virtual / Aggregated Self-Generation	Investigate possible aggregated self-generation programs and rates	Continue investigating and monitor other utilities practice	Monitor other utilities' practice and consider as a pilot program