Attachment

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REPORT

COST OF SERVICE AND RATE STRATEGY REPORT

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SAN JOSE CLEAN ENERGY
A Program of the City of San José

Prepared for:
San Jose Clean Energy

COST OF SERVICE AND RATE STRATEGY REPORT

In support of the Cost of Service Ratemaking Study (Study) for the San Jose Clean Energy (SJCE), NewGen Strategies and Solutions (NewGen) developed the following report providing a background on the cost of service (COS) process and summarizing Study results. This report will provide a primer on the key elements in the COS process, tailoring of the COS process elements to community choice aggregators (CCAs), summary of the Study results, and recommended SJCE rate strategy for 2023. The report includes the following:

- SJCE Rate Setting History
- COS Process
- COS Results
- Recommended Rate Strategy

SJCE Rate Setting History

Since beginning service in 2019, SJCE has set its rates to parallel the incumbent investor-owned utility (IOU), Pacific Gas & Electric (PG&E). This rate setting approach is commonly utilized by CCAs in California to offer competitive product pricing with a higher renewable or clean energy content than the IOU while minimizing customers choosing to leave or opt out of the CCA's service. PG&E's generation rates compete directly with SJCE and other CCAs' power supply products and rates. In applying this rate setting approach, SJCE's rates are pegged or linked directly to PG&E's generation rates and subsequent changes. Thus, as PG&E changes its generation rates, SJCE follows suit and changes its rates accordingly. For example, if SJCE rates were set at 1% less than PG&E's rates and PG&E's generation rates decreased by 15%, SJCE's rates would also decrease by approximately 15% to maintain the 1% discount to the incumbent IOU.

While ensuring a competitive rate, this rate setting, or mirroring strategy, poses challenges to CCAs and proves difficult to proactively manage financial performance. Adding to this complexity, all CCA customers must pay a power charge indifference adjustment (PCIA) fee to cover the investor-owned utility above-market costs from legacy energy contracts and generation assets. The PCIA rates are set annually, can be volatile, and fluctuate depending on the California Independent System Operator (CAISO) market pricing. This complexity and volatility in the generation and PCIA rates can lead to significant swings in the competitive position of a CCA to the incumbent IOU. These swings in rates often limit the ability of a CCA to ensure full cost recovery from its rates and subjects customers to swings in rates for a power supply product.

SJCE currently offers three energy products to its customers:

- GreenSource: SJCE's standard product currently providing 60% renewable energy and at least 80% carbon-free energy content. GreenSource is the standard product for SJCE customers and is used to benchmark to PG&E rates for the rate discount strategy.
- GreenValue: SJCE's lower-cost service with renewable content of 40% and 80% carbon-free energy content.
- TotalGreen: SJCE's 100% renewable energy content product.

Currently, the GreenSource product is set to 8% above PG&E equivalent generation rates including the PCIA and Franchise Fee Surcharge. The GreenSource product makes up the vast majority of the SJCE revenues and customer product selections. The GreenValue product is currently set to parity with PG&E rates, and the TotalGreen product is set at $0.005 to $0.01 per kilowatt-hour (kWh) above the GreenSource product depending on the customer class.

To gain a more detailed understanding of its costs, competitive position, and setting rates to ensure financial stability, SJCE commenced a COS study. By completing and applying a COS study, SJCE can ensure it sets rates to fully recover its costs incurred to provide power supply services. It also provides SJCE and stakeholders the data required to proactively manage financial performance, mitigate the fluctuations in the CAISO market and PCIA rates, and inform its competitive position now and into the future.

Cost of Service Process

Utility ratemaking has long been grounded in the concept of charging customers "cost-based rates." As this concept is both rooted in and a necessary outcome of regulating a monopoly enterprise, it is meant to ensure that the price paid by customers is fair and reasonable, and that it represents the full costs that the utility incurs to deliver electric service. At a conceptual level, the COS calculates the costs individual customers pay for the costs they impose on the system for service (i.e., use of electricity). However, at a practical level the application of this concept can be ambiguous and subject to different interpretations. Although all COS analyses are grounded in common principles, the application of these principles can vary widely. As a result, experience, judgment, precedent, and reasonableness—the "art" of COS and ratemaking studies—become critically important elements of the process and often have a significant impact on the outcome.

As a tool to guide the "art" of COS and ratemaking, James Bonbright's *Principles of Public Utility Rates* is widely regarded and referenced as a foundation for ratemaking. Bonbright included eight principles to guide ratemaking. These eight principles help guide COS, cost allocation, and rate design decisions for utilities and are summarized in Figure 1.

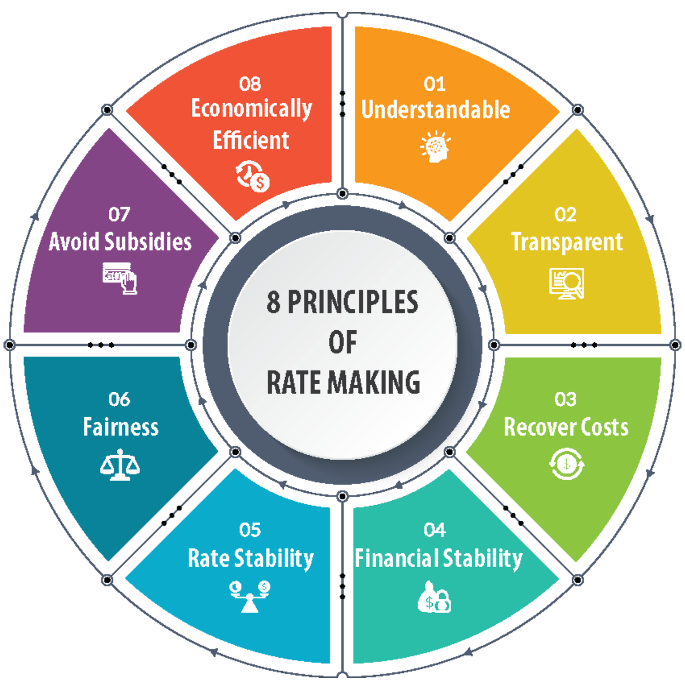

Figure 1: James Bonbright's Eight Principles of Ratemaking

There are five steps in the overall ratemaking process which includes the specific COS elements. These five steps are summarized in the following figure.

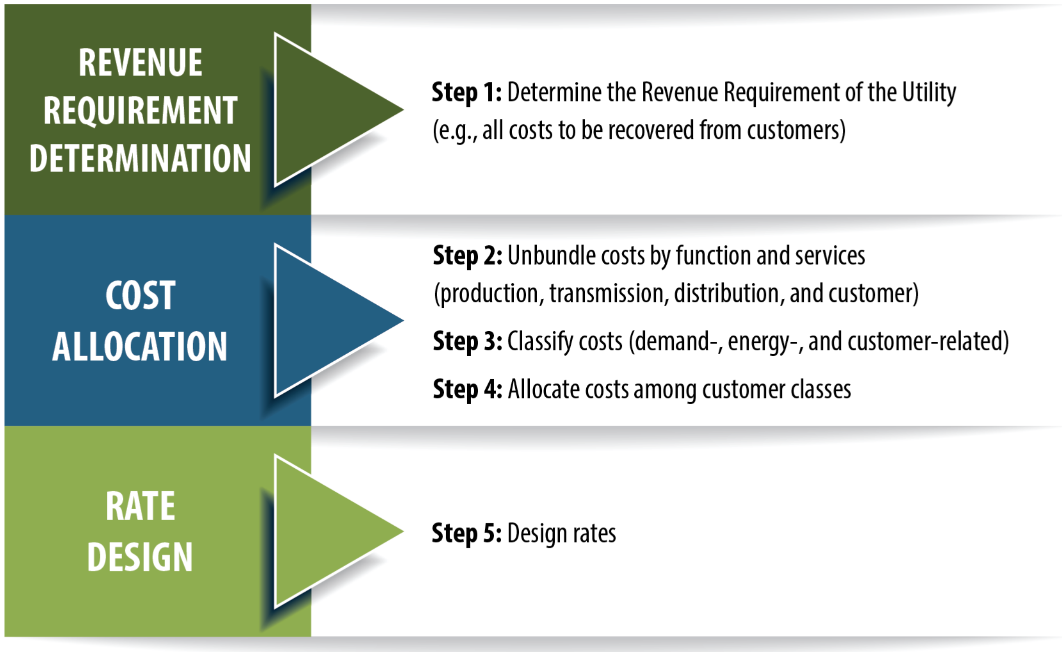

Figure 2: Ratemaking Process

Determining the Revenue Requirement (Step 1)

Step 1 includes developing the revenue requirement and gathering all the costs that the utility incurs to operate and to deliver electric service to its customers. The revenue requirement is the foundation of the COS study and is determined by first taking audited (historical) or future budgeted (projected) financials to create a “base year” or base set of costs to operate the utility. Known and Measurable adjustments are then applied to the Base Year to create a Test Year revenue requirement that reflects the financial and operating conditions that are expected to occur while the rates from the COS will be in effect. A historical or projected basis may be used for the Test Year revenue requirement by the utility.

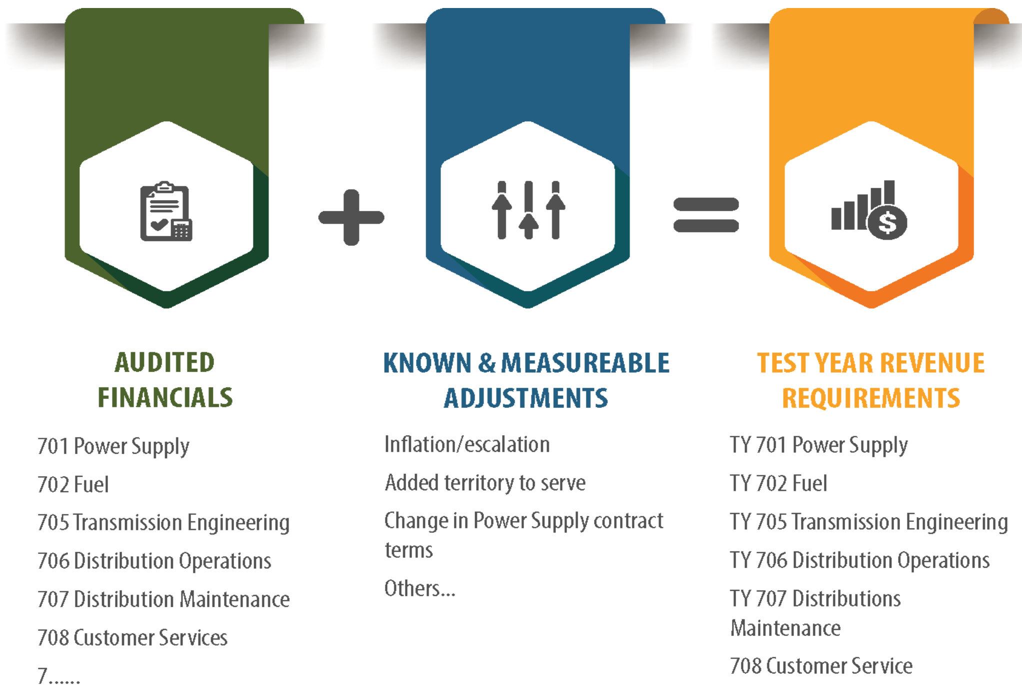

Figure 3: Test Year Development

SJCE’s revenue requirement is based on a Cash Basis which refers to the utility’s cash needs to fund operations. The Cash Basis is typically used by public power or municipally owned utilities and includes only cash-related expenses. A utility’s cash-related expenses include operations and maintenance (O&M) expenses, capital expenses, debt service, taxes, and other income/expenses. The Cash Basis also allows for inclusion of a cash margin above the debt service levels to meet debt service coverage ratio (DSCR) covenants typically included in the Bond Covenants. Utilities are often required to maintain a margin of net revenues of 1.X times the total debt service. Typically, the DSCRs are 1.1 to 1.5 times the total debt service.

In addition to the Cash Basis for developing a revenue requirement, there are two methodologies used to develop a COS study. The two methodologies are an embedded cost study and a marginal cost study. In practice, the vast majority of COS studies performed by utilities are embedded cost studies. However, marginal cost studies are used in California by the California Public Utilities Commission (CPUC) and IOUs. Most municipal, public power, and CCA electric utilities use the embedded cost approach in California. An Embedded Cost Study relies on the accounting records of the utility for the basis of the Test Year. Embedded costs are simply the historical or known costs of the utility. This represents the average system costs assuming all utility resources are spread across all customers.

SJCE's Test Year revenue requirement was developed from SJCE's forecasted FY 2023 through FY 2025 expenses as provided in the SJCE proforma model (SJCE Proforma). The Test Year revenue requirement represents the average annual values or the "mid-point" of that three-year period. Known and measurable adjustments were then applied based on conversations with staff to reflect the financial and operating conditions that are expected to occur while the rates from the COS are in effect. The following adjustments were made to the Test Year:

- Only PCC1 renewable categories would be purchased going forward; thus, other renewable energy accounts were eliminated or set to $0.
- Increased bank usage fees to allow for increased letter of credit use in the future.
- Assumed that SJCE would contribute to their cash reserves to meet 180 days working capital goal in two years.

The Test Year revenue requirement is then compared to revenues at current SJCE rates. Comparing COS results to current rates helps to inform if the rates are under or over collecting at the system level, as well as at the customer class level. Current revenues are developed by applying current rates (rates in effect at the time of the COS) to the most recent year of billing determinants (FY 2022). Billing determinants are detailed demand and usage data split up into the various methods used to bill customers including class, seasons, time of use periods, and voltage. It is important to use "current revenues" rather than "actual revenues" because current rates were not in effect throughout all of FY 2022.

Table 1
Revenue Requirement

Item	Amount
Power Supply	$363,000,000
Other O&M	$22,738,539
Misc. Expenses	$7,648,023
Debt Service	$3,390,940
Contribution to Reserves	$71,427,488
Total Revenue Requirement	$468,204,990
Revenues at Current Rates	$504,345,906
Difference	$36,140,916

Power supply costs make up 78% of SJCE's revenue requirement. Power supply costs include CAISO related fees, capacity, energy purchases, and renewable energy. Contribution to reserves is included in the revenue requirement to ensure SJCE reaches their goal of 180 days working capital within two years of rates implemented based on the COS results. If SJCE implements rates at levels higher than the COS, it will achieve the 180 day goal before the two-year time period. 180 days of operating cash reserves is an industry practice and supports working capital needs, as well as cash for unexpected events or large changes in the CAISO market for energy purchases. Maintaining operating reserves will help SJCE avoid price spikes during times of market volatility, further improve their competitive position with PG&E, and support stable rates for their customers.

Cost Allocation (Steps 2 through 4)

The cost allocation process consists of functionalizing the Test Year revenue requirement, classifying costs, and then allocating the costs to each customer class. Functionalization of costs assigns and allocates the Test Year revenue requirement to the four operating functions of a utility: production, transmission, distribution, and customer. Then, within each function, these costs are classified as demand, energy, or customer related. The classification of costs also identifies the fixed and variable costs of the utility. These steps are illustrated in the following figure in steps 2–4 after the Test Year revenue requirement is completed.

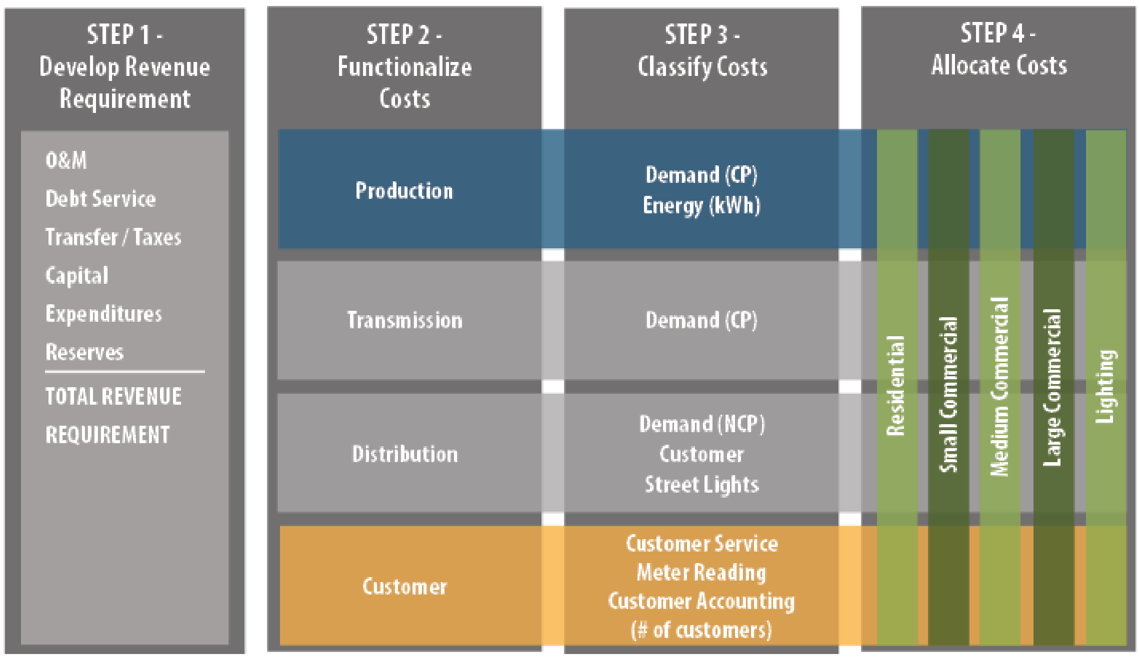

Figure 4: Cost Allocation

Functionalization – Direct Assignment and Allocation Factors

Step 2 functionalization translates the Test Year revenue requirement into the four functions of the utility: production, transmission, distribution, and customer. The assignment of costs to a function or customer class falls into two general categories: 1) direct assignments and 2) derived allocations. Direct assignments are costs that are readily associated with a specific activity or are directly assigned to a utility function. For example, the purchase power contracts are an expense solely related to power supply, so they are directly assigned to that function. Costs applicable to multiple functions at a utility, such as administrative and general (A&G) expenses, are treated differently and are allocated to all functions using a derived allocator.

Derived allocators are allocation factors based on the sum, average, or weighted effect of different underlying factors. Derived allocators can be complex and should reflect the logical answer to the following question: what underlying activities drive the cost of this item? For example, A&G expenses may be allocated to the functions based on the amount of labor costs within each function. Thus, if 40%

of the utility labor costs are in distribution, 40% of the A&G expenses would be allocated to the distribution function.

For CCAs, the majority of the Test Year revenue requirement, once functionalized, will be in production as the remaining three functions are primarily provided by the incumbent IOU. However, there will or can be portions of a CCA's Test Year revenue requirement that are related to the customer function. As CCAs both have and routinely invest in customer service and customer programs, those costs should be directly assigned to the customer function where possible. CCAs will also have A&G costs in operating the overall organization, and those costs will typically be allocated to the production and customer functions as applicable.

SJCE's functionalized revenue requirement is shown in Table 2. Please note, contribution to cash reserves was kept as a separate line item in the functionalized revenue requirement to ensure proper recovery and eventual allocation of the margin equitably to each customer class within the COS.

Table 2
Functionalized Revenue Requirement

Function	Amount
Power Supply	$382,203,897
Customer	$14,573,605
Contribution to Reserves	$71,427,488
Total	$468,204,990

By translating SJCE's revenue requirement into functions, we can see that the majority of SJCE's revenue requirement falls into the power supply function. The power supply function includes the energy and capacity costs discussed previously in Step 1's revenue requirement. In addition to the direct power supply costs, a portion of SJCE's O&M expenses are functionalized into the power supply function to account for the indirect cost of managing power supply operations. These costs include staffing, consultants, city overhead, office leases, and other miscellaneous non-personnel charges. The customer function includes costs associated with serving customers. These include billing/data systems, advertising/communication, and uncollected accounts (i.e., bad debt). Similar to power supply, a portion of SJCE's O&M expenses are also functionalized to customer function. SJCE's last function is the contribution to reserves. As discussed in Step 1's revenue requirement, this is the cost of meeting SJCE's working capital reserve goal equal to 180 days of operating expenses. This is functionalized separately so we can ensure and demonstrate it is allocated equitably to the different customer classes in later steps.

Classification of Costs

The third step in the COS and rate design process, as shown in Figure 4, is to classify the functionalized revenue requirement. System costs can be classified into four generally accepted ratemaking cost classifications: (1) demand or fixed costs, (2) energy or variable costs, (3) customer-related costs, and (4) directly assignable costs. In order to provide a reasonable basis for the assignment of total revenue requirements (costs) to each customer class, costs for each function have been analyzed and classified into four categories as described below.

- Demand Costs – Capacity (fixed- or demand-related) costs are those costs incurred to maintain a utility system in a state of readiness to serve, enabling it to meet the total combined demands of its customers. Capacity costs typically include the fixed portion of O&M expenses, debt service, capital expenditures, and other costs that are generally fixed and do not vary materially with the quantity of usage or that cannot be designated specifically as a customer or variable cost.

- Energy Costs – Energy, or variable, costs are costs that vary directly with energy usage, including such items as fuel, energy-related purchased power, and a portion of O&M expenses.
- Customer Costs – Customer costs are those costs directly related to the number and type of customers, such as customer accounting, customer service, billing, and meter-related expenses.
- Direct Assignment Costs – Direct assignment costs are those costs that are readily identifiable and applicable to a particular customer or customer class (e.g., Lighting).

As the majority of CCA-related costs and the Test Year revenue requirement are production or power supply-related costs, the classification of production or power supply costs is critical in the COS effort and has the greatest impact on calculating the costs to serve each customer class (e.g., residential, small commercial, etc.). When classifying power supply-related costs, CCAs should evaluate and consider cost drivers such as resource adequacy, contract structure (e.g., "take or pay" or demand/energy charges), energy purchases, and time-based energy purchases (i.e., hourly and/or seasonal). Figure 5 illustrates options and classification considerations for power supply costs tailored to CCAs' operations and markets.

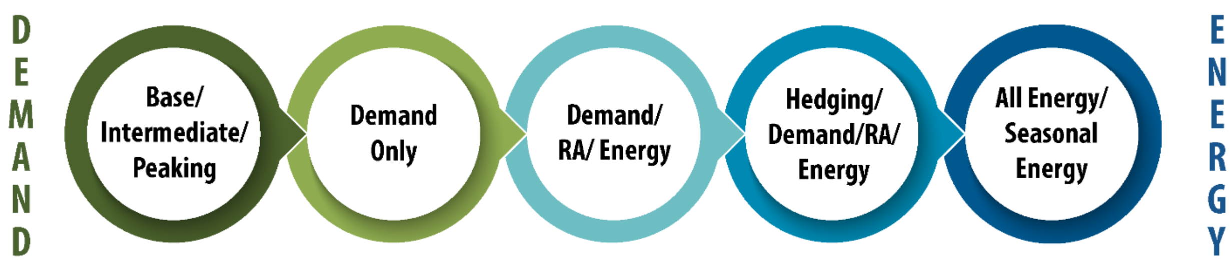

Figure 5: Power Supply Classification Options

After completing the classification of costs and the Test Year revenue requirement, the utility will have a summary of the total fixed versus variable costs they must recover. Fixed cost recovery continues to grow in importance for utilities as distributed energy resources (DER) and loss of load trends continue. Historically, utilities have recovered fixed costs, such as demand-related costs, in energy or kWh rates. For example, the residential customer classes typically have a fixed monthly charge and a variable energy or kWh charge. Thus, in the residential class and rates, fixed costs are typically recovered in a $/kWh rate. As the overall load and consumption in these classes decline, the utility begins under-recovering their total costs to deliver service, requiring even larger rate increases. Understanding the utility's overall cost structure and fixed versus variable costs better informs ratemaking decisions and quantifies risk related to demand destruction and declining loads. The classified Test Year Revenue Requirement is shown in Table 3.

Table 3
Classified Revenue Requirement

Classification	Amount	%
Customer	$17,197,131	4%
Demand	$122,703,023	26%
Energy	$328,304,836	70%
Total	$468,204,990	100%

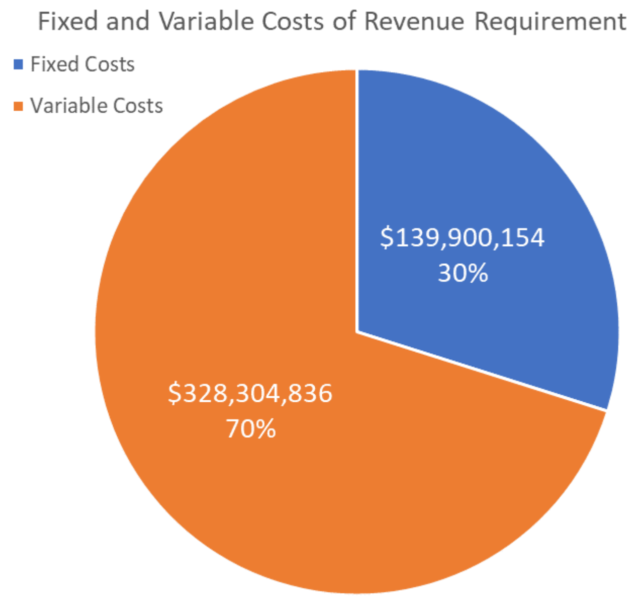

Figure 6: Fixed and Variable Costs

By classifying SJCE's Test Year revenue requirement, we can better break down SJCE's power supply costs into demand and energy. The demand classification is primarily driven by CAISO and resource adequacy-related costs. These fixed costs are important to maintain reliable service to customers during peak times and to maintain compliance with CAISO regulations. These fixed, demand classified costs are the COS basis for eventually developing the demand ($/kW) related charges in rate making. The variable, energy classified costs are primarily driven by contracted, open energy purchases, and renewable portfolio costs. These costs vary by how much energy ($/kWh) SJCE's customers consume. These contracted and renewable costs are also related to serving SJCE customers the different mix of renewable energy based on the customer's product selection (i.e., GreenValue, GreenSource, and TotalGreen). These variable, energy classified costs are the COS basis for eventually developing the energy ($/kWh) related charges in rate making. The customer classification includes the customer-related costs as discussed in Step 2 and serves as the COS basis for developing the monthly customer or base charges ($/month) in rate making. Please note, for classification reporting purposes and Table 3, we have allocated the contribution to reserves of $71 million to each classification, rather than maintaining a separate classification of the costs to fund reserves, so we may illustrate the amount or levels of fixed and variable costs for SJCE. Thus, each classified cost in Table 3 includes its pro rata share of the reserves or margin. For the allocation of the costs to customer classes, we maintained a separate classification for contribution to reserves to allow and demonstrate an equitable allocation to each customer class.

Allocation of Costs to Customer Classes

Integral to the cost allocation process is the development of allocation factors to translate the classified costs within each function to the customer classes. These allocation factors are based on the customer class consumption and operating characteristics. In allocating costs to customer classes, it is important to consider items such as: varying service voltages, metering requirements, level of customer service support, contribution to system peak demands, and overall consumption levels. The objective for each discrete classified cost is to identify what is causing that cost to be incurred by the utility. However, the "art" of a COS and ratemaking effort is predominant in the selection of allocation factors. The selection of the cost allocation methodology for the customer classes tends to be the most controversial area in a COS study.

Cost allocations are developed for each cost classification and are used to spread the costs to each customer class. Examples of allocation factors for demand, energy, and customer classified costs are illustrated below.

- Demand: class contributions to the localized or system peak demand. System demand is labeled coincident peak (CP) demand while localized demand or peak demands for customer classes are non-coincident peak (NCP) demand. Example allocation factors for the production and transmission demand costs include 12-month CP, 4-month CP, and 1-month CP. Example allocation factors for distribution demand costs include 12-month NCP, 4-month NCP, and 1-month NCP. There are additional blended or hybrid allocation factors for production costs such as an average and excess demand (AED), which blends average demands and coincident peak demands.
- Energy: class consumption of energy. This is typically the net energy for load (NEFL) or total energy (i.e., kWh) needed at the generators to deliver retail energy consumption.
- Customer: number or weighted number of customers by class. Depending on the customer classified cost, a total number of customers/meters (i.e., unweighted) or weighted customer totals are used to allocate costs. Weighting customer totals by class reflects the customer class's respective use or lack of use of the cost. For example, customer service costs may be 10 times greater per customer for a large industrial customer versus a typical residential customer.
- Contribution to Reserves: while this is not a typical classification of costs, a separate allocation for the contribution to reserves was included to show the margin allocation to the classes. This ensures and demonstrates that the margin is allocated equally to classes (i.e., each class includes the same percentage margin on costs in the COS results).

Cost of Service Results

The first step in evaluating the COS results is to compare the projected revenues under current rates for SJCE to the total COS or Test Year Revenue Requirement. This informs SJCE on a system-level basis if the entire CCA is adequately recovering costs at current rates. Figure 7 compares the systemwide revenues to the Test Year revenue requirement.

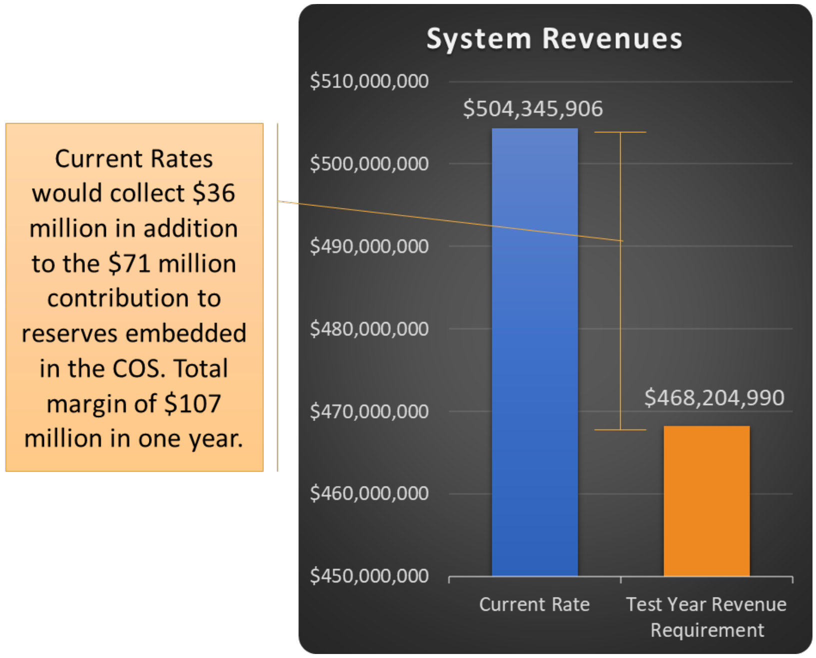

Figure 7: SJCE Total Revenues at Current Rates vs. Test Year Revenue Requirement

The system revenues shown in Figure 7 represent the current rates charged by SJCE to its customers. This is calculated as the rates that are in effect as of September 2022 applied to the forecasted retail sales. This provides a projection of the total system revenues and revenues by each customer class for calendar year 2023 and the Test Year period of 2023 through 2025. As seen in the figure, current rates are projected to generate an excess margin of $36 million or 8% more than the COS. This $36 million is in excess of the $71 million already included in the COS for SJCE. Thus, SJCE is projected to generate a total margin of $107 million based on the budgeted expenses and projections in the COS.

After evaluating the systemwide basis of over or under collection of costs, each customer class is then evaluated for its contribution to margin or over/under collection of the class COS. Each class COS is calculated by allocating Test Year revenue requirement and classified costs to each customer class. This class COS, or the costs to serve each class at SJCE, is then compared to the projected revenues at current rates for each class to determine if or how each class is over or under recovering their costs imposed on the system. Figure 8 illustrates the projected residential rate revenues at current rates compared to the residential customer class COS.

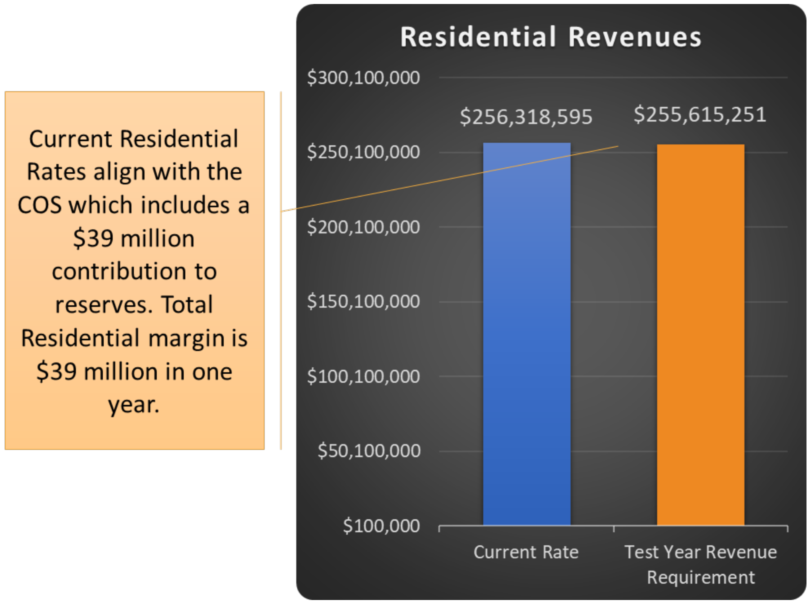

Figure 8: Residential Class Revenues at Current Rates vs. Test Year Revenue Requirement

As seen in Figure 8, the residential customer class is generating a margin close to the COS with the projected revenues at current SJCE rates. As seen in Figure 7, the systemwide average excess margin is 8%; thus, the excess margin in the residential class is less than the average for the system. Figure 9 shows the effective or average rates ($/kWh) for each customer class's COS and current rates.

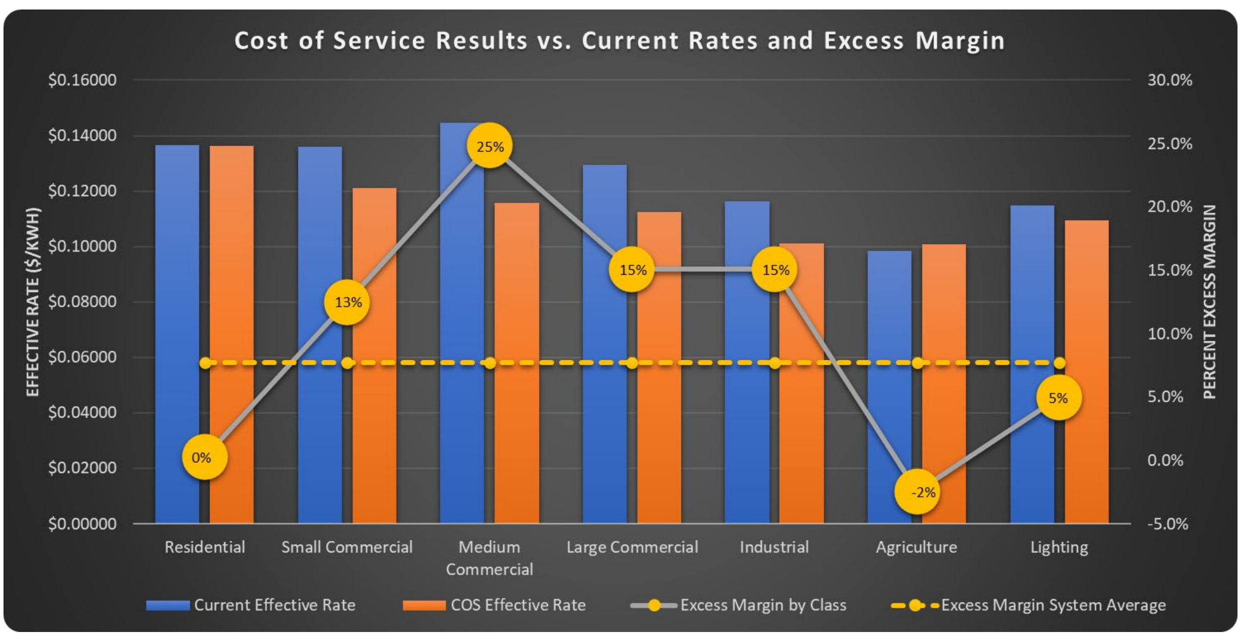

Figure 9: SJCE Customer Class COS and Excess Margin at Current Rates

Figure 9 shows the system average excess margin is 8%, while on a customer class basis those excess margins vary from a low of -2% in the agricultural class to a high of 25% for the medium commercial class. As the excess margin varies by class and some contribute more or less margin than the system average of 8%, this was not unexpected. This is typical across the industry and an expected outcome from CCAs that have set rates indexed to the incumbent IOU's rates.

As SJCE set rates indexed and at a multiplier to PG&E rates, the rates reflect the IOU's COS and rate making process. The PG&E rates are an outcome of the CPUC regulatory process and are subject to political or policy influence in a rate proceeding. In addition, PG&E's COS and rates may and likely are not reflective of SJCE's COS. Thus, it is expected that the margins are not all equal in each customer class and would vary from the SJCE COS. By developing the COS, SJCE can now adjust rates by class to refine the margins or even create equal margins in each class in rate making, if desired.

Competitive Benchmarking

For CCAs it is important to add another lens to the evaluation and application of the COS results. Comparing COS results to the incumbent IOU rates informs the CCAs of the potential savings their services can provide to customers and where margins may or may not exist. When benchmarking CCA rates to the incumbent IOU, it is important to include the following applicable surcharges to the generation rates:

- SJCE Retail Rate:
    - 2018 vintage PCIA (the majority of SJCE customers are 2018 vintage)
    - 2018 vintage franchise fee
- PG&E Retail Rate:
    - Most recent year vintage PCIA

Adding these surcharges allows for an accurate comparison and benchmarking for what a SJCE retail customer would be charged at each utility for the same service. Figure 10 summarizes SJCE's current rates with varying levels of the PCIA rates from current levels to expected 2023 levels compared to the same PG&E Generation service rates at the same PCIA levels.

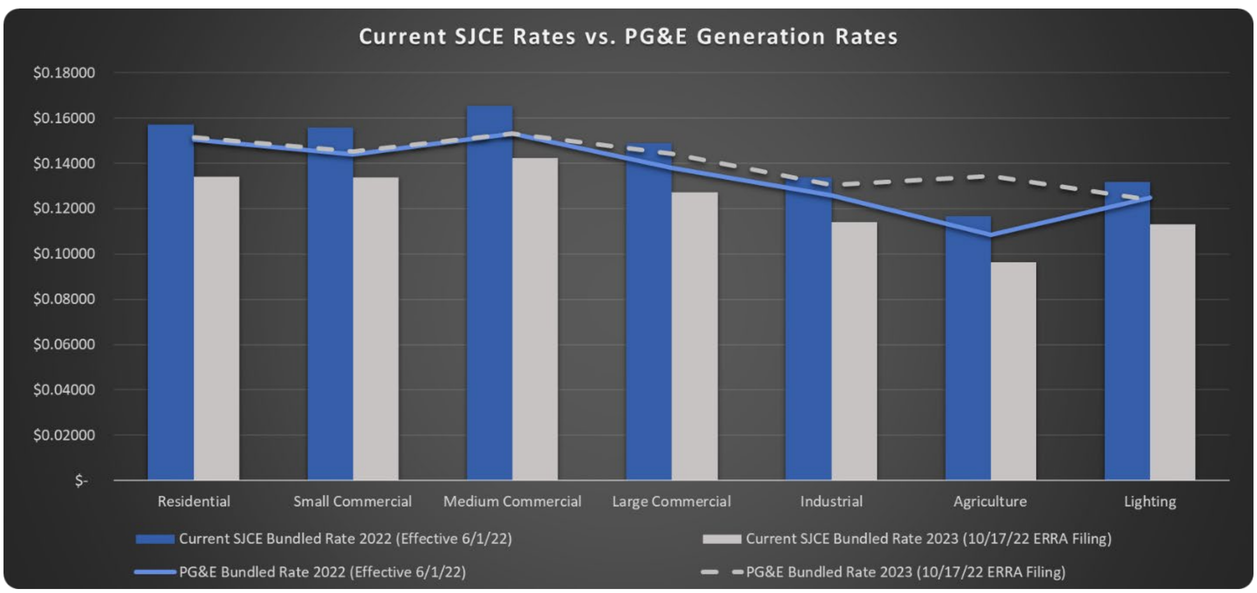

Figure 10: SJCE and PG&E Equivalent Generation Service Rates

On a customer class average basis, SJCE's current rates (shown in the blue bar) are currently 6% higher than current PG&E rates (shown in the blue line). This difference will change based on the expected PG&E and PCIA rates to be implemented at the beginning of 2023. SJCE's current rates with expected PCIA for 2023 (shown in the gray bar) are projected to be 12% lower than equivalent 2023 PG&E generation rates (shown in the gray dashed line). This means that if SJCE did not change rates from current levels, starting in 2023 with the application of the new PCIA rates, customers would be receiving an overall discount of 12% on average. Please note, this discount to PG&E would vary from class to class; however, on average the entire system would be at a 12% discount. This improved competitive position from a 6% premium currently to a 12% discount in 2023 is due to the projected reduction in the PCIA rates and upward pressure on PG&E's generation rates to bundled customers.

As previously stated, the SJCE COS is less than the current SJCE rates. Thus, SJCE retail rates could be reduced from current levels and still meet the COS financial obligations. Figure 11 also summarizes this comparison of the COS to the current and projected PG&E generation rates. As expected, the PG&E retail rates are substantially higher than the SJCE COS which provides substantial "headroom" for acquiring additional margin and revenues while remaining competitive with PG&E.

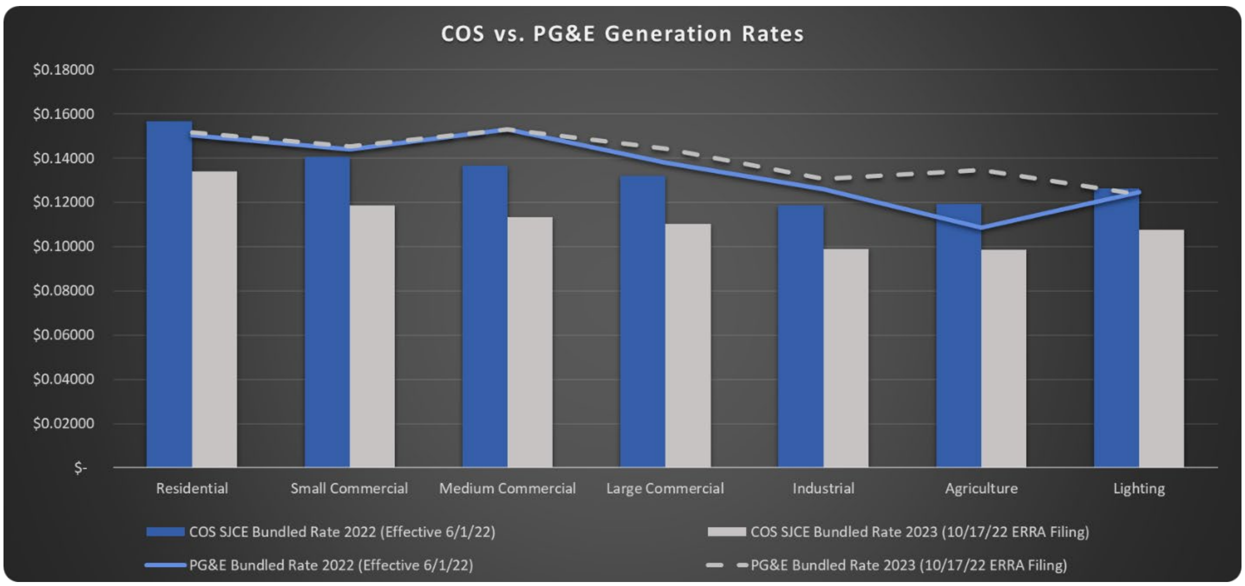

Figure 11: SJCE COS and PG&E Equivalent Generation Service Rates

As seen in Figure 11, SJCE's COS rates (shown in the blue bar) are currently 1% lower than current PG&E rates (shown in the blue line) on a systemwide basis. This difference will change based on the expected PG&E and PCIA rates that will be effective at the beginning of 2023. SJCE's COS rates with 2023 expected PCIA (shown in the gray bar) are projected to be 21% lower than 2023 PG&E rates (shown in the gray dashed line).

Rate Design (Step 5)

Rate design is the culmination of a COS study where the rates and charges for each customer classification are established in such a manner that the total revenue requirement of the utility will be recovered in the most equitable and consistent manner, to the extent reasonable and practical. Rate design is informed by the COS results; however, other considerations such as the utility's strategy, community concerns, and competitiveness also play an important role. Thus, rates are often used to send a pricing signal to customers to drive certain desired behaviors. Those desired behaviors may align with the COS results or may incentivize overall reduction in energy use.

The COS results provide demand, energy, and customer specific unit costs or rates (i.e., $/month or $/kW) that inform or guide the eventual rates that recover costs. If these unit costs are used to develop the individual rates for each customer class, the rates would fully align how costs are incurred with how the costs are recovered from customers. However, each customer class's rates are not typically exactly aligned with the COS unit costs. In fact, the unit costs are often used to inform time-based rates such as time of use (TOU) energy rates that include a higher rate for energy consumed "on-peak" versus "off-peak."

Ratemaking typically includes the design of the following charges, as applicable by class:

- Customer or Base Charge: monthly charge related to customer functional and classified costs such as customer service, the customer portion of infrastructure, and customer accounting (i.e., billing).
- Energy Charges: charge per kWh of energy consumed. Types of energy charges include flat, seasonal, inclining/declining blocks, and TOU. Based on the overall rate strategy of the utility and desired behaviors, certain types of energy charges are evaluated and implemented. For example, to encourage energy conservation, a utility would consider an inclining block charge so that customers pay more per kWh of energy used the more they consume.
- Demand Charges: charge per kW per month of capacity imposed on the system by the customer. Demand charges are typically applied to commercial and industrial classes; however, with the proliferation of advanced metering infrastructure (AMI), demand charges are becoming more frequent in residential customer classes. Types of demand charges include monthly peak demand, 12-month ratchet peak demand, seasonal, and time-of-day.
- Pass-through Charges: energy or demand charges used to recover differences in the actual versus the projected costs of fuel, market purchases, or other charges that the utility cannot directly control. These are typically calculated and changed on a monthly or other periodic basis to align with cost recovery. These pass-through charges are not often used by the IOUs but could be an option to CCAs.

In ratemaking, utilities should consider the size of the rate changes compared to current conditions and impacts on customer classes when implemented. Gradualism is a technique often used as a rate implementation tactic to reduce the "rate shock" or dramatic change in rates from the current conditions or across classes. As the name implies, gradualism gradually adjusts rates over time to avoid dramatic changes to or between customer classes. The tactic allows utilities to work toward COS results over time while also allowing customers to prepare for the longer-term changes in the rates and pricing signals. For example, rather than implementing a needed 15% rate increase in one year, utilities often consider a phase-in or gradual approach to increasing rates at 5% per year for three years. This tactic is also used to rebalance the rate revenues between classes. If the COS identified one class that needs a substantial increase while others indicate a small decrease, the shift in the rates could happen over a period of two to three years, rather than all at once. This gradualism approach could be used by SJCE to adjust margins by class, if or when desired.

CCA Considerations for Rate Design

As CCAs are primarily incurring power supply-related costs, these costs can vary in structure (i.e., fixed versus variable) and are often subject to market volatility. The COS results and outcome informs the fixed and variable basis for the costs incurred by the CCA; however, the CCA's overall strategy and competitive environment should also guide ratemaking. In California, net energy metering (NEM) and overall load/demand destruction trends affect fixed cost recovery and can lead to subsidization concerns.

In developing power supply or production-related charges that directly compete with the incumbent utility, a CCA must consider the pricing signals inherent in their cost basis versus the pricing signals inherent in the rates of the incumbent utility. For example, the fixed and variable cost basis for a CCA may vary significantly from the incumbent utility. Thus, the pricing signals from the incumbent utility may incentivize and attract a different type of customer load profile than the CCA. This difference in pricing signals is also seen in the varying margins by class for SJCE as illustrated in Figure 9. The COS for a CCA may and likely will differ from the COS for an IOU. Thus, if all classes were placed at a COS rate, some customer classes may benefit by moving to a CCA and others may benefit from being with the IOU.

The PCIA also plays a major role in CCA ratemaking considerations and competitive position. As there are multiple PCIA vintages applied to a CCA's customer base, the competitive position of the CCA to the incumbent utility may vary based on the customer's PCIA vintage applied.

Due to billing complexities associated with integrating a CCA's rates with the incumbent utility's billing system, a CCA may be confined to the billing periods or TOU periods defined by the incumbent. This restriction may limit the CCA's ability to send more refined pricing signals to their customers that are fully aligned with their COS for production costs. While a CCA may be limited in the TOU periods applied to their customers, they can adjust and refine pricing signals in those predetermined periods to generally align with and reflect their cost basis.

NEM rates within CCA territories are another critical ratemaking element when considering the COS results and fixed cost recovery of power supply costs. NEM rates rarely, if ever, fully recover the fixed costs that the customers impose on the power supply operations and costs; thus, they often lead to subsidization or increased costs on other customers. As clean energy and distributed renewable energy often align with and are supported by CCAs, the NEM rate strategy should consider cost recovery along with the CCA policy/strategy implications.

SJCE Recommended Rate Strategy and Implementation

Completing the COS provides SJCE important insights to setting rates that adequately recover costs and their cost-based competitive position relative to PG&E. As shown in Figure 7, current rates are projected to collect a total margin of $107 million above costs for a calendar year period. This equates to providing $107 million in cash reserves by the end of a 12-month period during which the rates are in effect, based on the assumptions and CAISO market projections included in the SJCE proforma. This $107 million cash reserve contribution in addition to the existing cash balance expected at the end of calendar year 2022 would essentially achieve the SJCE cash reserve goal and target by the end of calendar year 2023, which is approximately one year ahead of the identified target date.

While the current rates are expected to generate the targeted cash needs within 12 months, it is important to understand the current SJCE rates and their competitive position with respect to PG&E generation rates in 2023. Figure 10 shows that the SJCE current rates with the vintage 2018 PCIA expected in 2023 are projected to be 12% less than PG&E generation rates on a systemwide basis. Furthermore, Figure 11 shows that the SJCE COS-based rates, which include a $71 million per year contribution to cash reserves, are 21% less than the PG&E generation rates on a systemwide basis. This 21% difference between the COS results and PG&E generation rates provides a significant opportunity for SJCE's consideration.

Based on the significant margin between the COS and expected PG&E generation rates applicable in 2023, SJCE could maintain current rates and generate an estimated $107 million in cash reserves. In fact, SJCE could even increase rates to equal or provide a discount to PG&E generation rates and provide an even larger margin and higher level of cash reserves in 2023 than the $107 million with current rates. The available margin between SJCE and PG&E's generation rates is primarily driven out of the elevated prices in the CAISO energy market. As the CAISO and energy markets across the country are often volatile and impacted by the price of natural gas, this large margin opportunity between SJCE's COS and the current rates may be temporary.

As the CAISO market remains elevated for energy prices and historically the PG&E generation rates have not maintained this high level, NewGen recommends that SJCE consider maintaining and even increasing rates to equal or provide a 1% discount (or similar level) to PG&E generation levels. This strategy captures most, if not all, of the additional margin created by the conditions in the CAISO market and PG&E's generation rates. By capturing this additional margin available in the market in 2023, SJCE improves its financial performance and position while providing greater flexibility in the future to respond to changing market and competitive position(s). As there is significant uncertainty in the CAISO market which could drive volatility in the future PCIA and PG&E generation rates, improving the SJCE financial position in 2023 by maintaining or increasing rates provides the targeted cash reserve levels in 2023 and flexibility for 2024.

This flexibility could be applied to SJCE rates as the PCIA rates may increase substantially and PG&E generation rates may decline in 2024 or subsequent years. If the PCIA and generation rates return to historical levels in 2024, it would erode SJCE's current competitive position. At that point, if SJCE's rates increased to levels above PG&E, SJCE would have the flexibility to reduce rates and maintain existing equity with PG&E. As SJCE has now completed the COS, it can evaluate the amount of margin contribution (if any) in 2024 to reduce rates and remain competitive with PG&E while providing greater value to its customers.

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