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REPORT

2022 POWER RATES STUDY FINAL REPORT

MAY 11, 2022

San Francisco Water Power Sewer

Services of the San Francisco Public Utilities Commission

Prepared for:
San Francisco Public Utilities Commission
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San Francisco, California 94102

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EXECUTIVE SUMMARY

The San Francisco Public Utilities Commission (SFPUC) supplies high quality water, power, and wastewater services in the City and County of San Francisco (referred to as the City). Within the SFPUC, the Power Enterprise meets the electricity needs of San Francisco's municipal, business, residential, and wholesale customers. To accomplish that, Power Enterprise operates two retail electricity programs, Hetch Hetchy Power, San Francisco's publicly owned utility (POU), and CleanPowerSF, San Francisco's community choice aggregation program. Hetch Hetchy Power generates, schedules, purchases, sells, transmits, distributes, meters and bills electricity to retail and wholesale customers, responds to outages, and owns, operates, and maintains the majority of the City's streetlight system. Hetch Hetchy Power customers include City and County agencies and a growing number of commercial and residential customers including those associated with the build out of redevelopment communities (like Treasure and Yerba Buena Islands, Candlestick/Hunter's Point, and Mission Rock). CleanPowerSF schedules, purchases, and sells electricity to residential and commercial customers located exclusively in the City. Through these two programs, the Power Enterprise serves over 70% of the electricity consumed in San Francisco. The vitality of San Francisco communities depends on the safe, reliable, sustainable, innovative electric service Power Enterprise staff provide every day. This Study was designed to evaluate the cost of service (COS) and to recommend appropriate rate structures for both Hetch Hetchy Power and CleanPowerSF.

The Power Enterprise serves customers with a unified staff, sharing operating resources, but the two retail programs have distinct costs of service and ratepayers. The City Charter (and State law) requires that revenues from ratepayers be used to benefit those ratepayers – no comingling of revenues from the two sets of ratepayers is allowed. To reinforce the separation of ratepayer funds, the Hetch Hetchy Power program is part of the Hetch Hetchy Water and Power Enterprise Fund while the CleanPowerSF program is a separate fund, the CleanPowerSF Enterprise Fund, established in FY16-17.

Hetch Hetchy Hydroelectric Power, a byproduct of delivering water to the Bay Area, is the largest single generation component of Power Enterprise's energy supply portfolio. The portfolio also includes owned biogas, solar, storage and energy efficiency resources, as well as purchased solar, storage, wind, and geothermal resources under long term contracts. Power Enterprise plans for and manages these power supplies, manages new energy resources on behalf of its customers, and for Hetch Hetchy Power customers, also plans for and manages the related transmission and distribution infrastructure needs.

Both Hetch Hetchy Power and CleanPowerSF offer customer programs and reinvest profits back into the community. While structurally, Hetch Hetchy Power and CleanPowerSF are distinct, they share labor resources for their customer services/programs as well as the general and administrative (overhead) services provided within the Power Enterprise. Together, the programs work to reduce the City's carbon footprint, combat climate change, and create a better, brighter future for San Francisco with safe, reliable, and affordable electric services responsive to community needs and sensitive to environmental impacts. This Report provides a summary of the analysis conducted for the Study for each organization to establish their COS and to provide specific rate recommendations.

Study Objectives

The SFPUC is required to retain an independent rate consultant at least every five years to evaluate the COS of the power systems and to recommend appropriate rate structures. Costs for SFPUC operations were evaluated over a five-year period, including projections for customers and customer load growth. The analysis was developed to allow the SFPUC to utilize the tools and methodologies to set rates within the five-year time frame. Due to the short-term growth projections and the changes included for this Study, however, the recommended rates, charges, and fees for power service are developed for a two-year period (two-year rate plan) beginning Fiscal Year (FY) 2022–2023 and concluding Fiscal Year 2023–2024. The first phase of rates is designed to be in effect July 1, 2022, and the second phase of rates is designed to be in effect July 1, 2023. It is anticipated that rates for July 1, 2024 – June 30, 2027, will be adopted in 2023 informed by this Study and then-current market conditions. This Study is designed to establish a foundational methodology for financial planning and fair rate-setting for SFPUC It provides an opportunity to reassess the SFPUC's existing financial policies and priorities and to develop rates that better achieve its goals. Rates and charges are designed such that the total revenue needed for the system will be recovered in an equitable manner and consistently with the SFPUC policies.

For Hetch Hetchy Power, those policies include transitioning rates away from historic Pacific Gas and Electric Company (PG&E) structures and current rate levels towards those consistent with the COS identified in the Study. This includes updating and modernizing the customer classes used by Hetch Hetchy Power, as well as developing new rates for residential electric heating customers, maintaining low-income rates, while transitioning municipal customers towards COS.

For CleanPowerSF, policies include establishing rates that are not dependent on changes to PG&E rates. For this Study, this means transitioning to class COS rates over the rate plan period while maintaining the ability to offer unique products and services within a range of rates that are comparable to PG&E for generation services. An additional objective for CleanPowerSF is to increase its financial reserves to allow for increased liquidity to be able to respond to potential changes in energy market conditions. Further, CleanPowerSF is dedicated to continuing to offer its SuperGreen 100% renewable energy rate at a premium that is affordable, equitable and supports development of local renewable resources.

Specific Study objectives include the following:

- Review the SFPUC's financial policies applied to cost of service and rate design
- Incorporate industry best practices for power rates and fees
- Develop forecasts of revenue requirements for financial planning and forecasting
- Properly functionalize/allocate costs for equitable, financially sustainable, and legal rates
- Allocate shared Power Enterprise costs (finance, admin, etc.) between Hetch Hetchy Power and CleanPowerSF
- Develop framework for sharing costs between new and existing Hetch Hetchy Power customers, and develop appropriate permit review, line extension, capacity, and/or connection fees to allocate costs fairly
- Create a plan and timeline to normalize Hetch Power rate structure, decouple from PG&E rates, and transition to cost of service rates for all customers
- Set rates to support the operations, maintenance, programmatic, and capital needs of the SFPUC Power Enterprise
- Design rates that provide a financial incentive for customers to implement environmentally friendly practices
- Evaluate affordability of rates for low-income customers and recommend rates or programs that address disproportionate burdens
- Address concerns regarding market price volatility and uncertainty in future costs

This Study utilizes industry accepted methodology to assign utility costs to the various functions, or business units, of the organization. These functionalized costs are classified based on their underlying cost causation and are allocated to the various customer classes served by the utility. This Study utilized historic and projected load and expense data provided by SFPUC to create a future Test Year (TY) period for which rates were designed. For this Study, the Test Year is the average for FY 2022–2023 and FY 2023–2024. However, the transitioning nature of the recommended rates results in specific rates for each year of the rate plan period.

There were operational challenges encountered during the development of this Study, particularly regarding the development of accurate billing data and estimates for projected load by class for the Hetch Hetchy Power customers. Hetch Hetchy Power has a relatively small customer base and is projecting significant growth over the next few years. However, these growth forecasts do not contain sufficient detail needed to calculate revenue and rate estimates (e.g., counts of customers by rate class, usage during time-of-use periods and demand billing forecasts). As a result, Hetch Hetchy bill and revenue forecasts rely on a combination of usage patterns of existing customers and staff expertise regarding expected changes in new, future loads.

Pre-coronavirus (COVID-19) billing data from FY 2018–2019 was utilized as the base year under the assumption that customer usage would return to “normal” during the period of this Study. Advanced meter data from 2018-19 was analyzed to determine customer load profiles; however, AMI data was not available for all customers for an annual billing cycle. Where necessary, customer load profiles were supplemented with industry standard assumptions, or based on similar Hetch Hetchy customers. Additionally, the SFPUC recently implemented a new billing system, which made comparison to historic values difficult. The assumptions regarding changes in customers and customer load are critical to the underlying analysis developed for this Study and the projection of revenues from the recommended rates. To the extent that load and customer numbers are different than the anticipated values, the revenue (and expenses) will be impacted accordingly.

Hetch Hetchy Power

The projected Test Year revenue requirement for Hetch Hetchy Power is projected to be approximately $171.7 million, which includes costs for operations and maintenance (O&M), power purchases, transmission and distribution, debt service, and rate-funded capital improvements. This value reflects offsets to Hetch Hetchy Power net retail costs from wholesale sales, recovery of programmatic costs, and other revenue sources. Additionally, this value includes contributions to reserves from retail rates of approximately $5 million per year (average of the two-year Test Year).

The revenue requirement was functionalized, classified (or sub-functionalized), and allocated to the customer classes served by Hetch Hetchy Power, which include residential, small commercial, medium commercial, large commercial, and industrial. Individual customer class characteristics were utilized to develop allocation methods, including those related to demand (peak demand for the system and for each class), energy (total sales, as well as total energy required for load), customers (including customer numbers in each class), and others. Allocations by labor costs for various personnel groups provided by the SFPUC were also utilized in the functionalization, classification, and allocation processes. The San Francisco International Airport (SFO) is a very large customer for Hetch Hetchy Power. For the purposes of rate design, the majority of the costs to serve the SFO load are recovered through the recommended industrial rate. Historic rate classes served by Hetch Hetchy Power include Municipal Enterprise departments of the City, such as SFO; “General Use Municipal” ” (or “GUSE”) departments of the City; and retail non-municipal customers, which include residential and commercial customers.

The rates for these historic rate classes differ widely in both their level and structure, and the rate at which a customer pays is largely a function of Hetch Hetchy Power history. One objective of this Study is to transition these rates and rate structures from their historic rate classes to industry standard rates and rate structures defined by customer class, rather than City department.

It should also be noted that Hetch Hetchy Power owns and maintains a significant number of streetlights in the City which provide a benefit for all of its residents and businesses, not just those that are power customers. While Hetch Hetchy Power provides power to streetlights, in the future these facilities may be serviced by PG&E, as it may become cost prohibitive for Hetch Hetchy Power to do so due to regulatory requirements. This Study assumes that streetlights will no longer continue to provide revenues for Hetch Hetchy Power, however, the associated maintenance costs for City-owned streetlights will be borne by the program. The costs for the streetlight systems are collected from all customer classes based on an allocation of energy sales by class.

Rate recommendations for individual customer classes and rate codes are presented herein. For residential rates, the recommended rates are designed to limit the rate impact for the class on average to approximately 10% for each year of the rate plan. The rate change for individual customers will depend on their usage and current rate schedules. The recommended rate changes for the residential class include increasing the customer service charge and increasing the energy rates incrementally for each year of the rate plan. Due to the limit on annual rate increases, residential rates will not be at their COS at the end of the two-year Test Year but will be significantly closer than they are today.

Other changes to the residential customer class include a new rate offering for residents with electric heating (R-1E), consistent with the City's policies for increasing beneficial electrification applications. Additionally, changes to the recommended rate structures for residential customers include redefining the existing tiers based on analysis of usage patterns and seasonal PG&E rate structures (between customers with natural gas and electric service, and those with electric heating service). The recommended tiers include an expansion of the amount of energy within the second tier of usage for gas and electric customers for the summer and winter periods, and a significant increase in the amount of energy in the second tier for electric heating customers during the winter periods. Hetch Hetchy Power proposes to continue its low-income discount programs for its residential customers, which is equivalent to a 30% decrease for each rate component, as well as continued investment in its other residential energy rate programs.

Commercial rate changes include shifting retail customers with less than 75 kilowatt (kW) per month demand into the small commercial class (from the medium commercial class), increasing the customer service charges to collect a defined percent of the total revenue requirement by class, and adjusting the pricing differential between existing time of use (TOU) periods. Rates for commercial customers served under the current GUSE rates will be increased by a total effective rate of $0.03/kWh per year until such time as they achieve their COS rate. Because the GUSE rate for some customer classes is significantly under their COS, and annual increases are capped, many GUSE rates will not be at their COS at the end of the two-year Test Year, but will be significantly closer than they are today. While the GUSE rate is being phased out, this implementation policy will continue to require a subsidy over the near term, which is recovered from all Hetch Hetchy Power customers except those in the residential class. The GUSE customer rate structures are recommended to change from an energy only rate to a rate structure consistent with the retail rate offerings currently in place for the respective customer class. Further, an objective of this Study is to transition the existing Enterprise customers and retail customers to similar rates by the end of FY 2023–2024. Other adjustments to commercial customer classes include development of voltage level discounts based on cost of service for customers taking service at primary and transmission level.

The Test Year revenue requirements for Hetch Hetchy Power was determined to be approximately $171.8 million. Table ES-1 provides a summary of the Hetch Hetchy Power revenue requirement by class, the projected revenue from current rates, and the projected revenue from the recommended rates provided herein.

Table ES-1
Hetch Hetchy Power – Revenue Requirement, Projected Revenue by Customer Class for Test Year ($000)

Class	TY Revenue Requirement (1)	TY Projected Revenue Current Rates	TY Projected Revenue Recommended Rates	$ Change from Current Rates	% Change from Current Rates
Residential	$12,884	$7,102	$6,072	($1,030)	(14%)
Small Commercial	$16,606	$12,002	$13,463	$1,461	12%
Medium Commercial	$29,078	$19,645	$24,082	$4,437	23%
Large Commercial	$19,553	$14,550	$17,467	$2,918	20%
Industrial	$93,636	$115,166	$110,671	($4,495)	(4%)
Total Revenue Requirement (2)	$171,756	$168,464	$171,756		

(1) Cost of Service (COS.)

(2) Numbers may not add due to rounding.

For Hetch Hetchy Power, the projected Test Year revenue requirement is approximately $171.8 million. The projected revenue at current rates, which incorporates the estimated load growth over the Test Year period, is estimated to be approximately $168.5 million. The projected revenue at recommended rates provided herein is designed to recover revenue requirement ($171.8 million).

Table ES-2 provides a similar summary of the CleanPowerSF projected test year revenue requirement, the projected test year revenue at current rates, the projected revenue from recommended rates, the projected change from current rates (in dollars), and the percent change from current rates.

CleanPowerSF

The CleanPowerSF revenue requirement for the Test Year is estimated to be approximately $302.5 million. Costs include purchases of renewable energy, shaped energy, capacity, energy open positions, CAISO costs, contingency, and operating and other costs. Renewable energy costs include long-term renewable energy power purchase agreements (PPAs), short-term renewable energy credits (RECs), and greenhouse gas-free (GHG-free) attribute contracts and open position costs. Shaped energy includes bi-lateral non-renewable energy contracts. Capacity cost includes resource adequacy (RA) costs, which include storage costs from long-term renewable energy PPAs. Energy open positions include costs for firming and shaping the energy purchased from renewable resources, which is primarily related to purchases from the CAISO market. CAISO charges are charges from the market for ancillary services. Contingency costs are included in the budgetary process to allow for unexpected changes in power supply costs. Operating and other costs include labor, operational costs, and capital plans. Anticipated contributions to internal reserves (margin) are also included in the operating and other costs category.

As a CCA, CleanPowerSF does not offer delivery service; therefore, the majority of these costs are assigned to the Power Supply function. However, a portion of its costs are related to the customer service function, which includes billing as well as energy programs offered for its customers.

Recommended rate changes to CleanPowerSF include a transition to the cost of service by customer class. This transition is recommended to occur at even increments, such that approximately half of the recommended rate change is anticipated to be implemented on July 1, 2022, and the remainder of the recommended rate change is to be implemented July 1, 2023. CleanPowerSF customer classes include residential, small general service, medium general service low demand (which are less than 499 kW), medium general service high demand, large general service, and outdoor lighting. The default product offered by CleanPowerSF is the "Green" energy rate, which is certified as containing a minimum of 50% renewable energy.

CleanPowerSF also offers a "SuperGreen" product that is 100% renewable energy as a premium product. The SuperGreen is sold as a voluntary rate rider that is in addition to the standard energy product. An analysis of the SuperGreen costs was conducted for this Study which indicated that the current pricing for the SuperGreen products recover their costs. This analysis reflects the costs for CleanPowerSF for the contracts that have been entered into on behalf of the SuperGreen customers, as well as some of the benefits provided to the system from those contracts. CleanPowerSF has decided to slightly modify the premium pricing for the SuperGreen product to continue to encourage investment in renewable resources within the City.

Table ES-2
CleanPowerSF – Revenue Requirement, Projected Revenue by Customer Class for Test Year ($000)

Class	TY Revenue Requirement (1)	TY Projected Revenue Current Rates	TY Projected Revenue Recommended Rates	$ Change from Current Rates	% Change from Current Rates
Residential	$140,020	$157,564	$138,982	($18,583)	(12%)
Small General Service	$42,297	$51,753	$42,871	($8,882)	(17%)
Medium General Service (Low Demand)	$34,765	$46,993	$36,463	($10,530)	(22%)
Medium General Service (High Demand)	$63,795	$79,440	$65,008	($14,432)	(18%)
Large General Service	$21,418	$28,432	$22,558	($5,874)	(21%)
Outdoor Lighting	$168	$160	$160	($0.8)	(0.2%)
Total Revenue Requirement (2)	$302,464	$364,342	$306,042	($58,300)	

(1) COS.

(2) Numbers may not add due to rounding.

The recent dramatic increase in PG&E rates (March 1, 2022) resulted in CleanPowerSF adjusting their rates to match, in accordance with current policy. As shown in Table ES-2, the projected revenues for the two-year Test Year if no changes to retail rates were made would result in an estimated $364.3 million in revenue. However, CleanPowerSF costs for this period are estimated to be approximately $302.5 million (TY Revenue Requirement). The results of the recommended rate changes provided here project an estimated $306 million over the two-year rate plan (TY Projected Revenue Recommended Rates), which is a reduction in the revenue from current rates of approximately $58.3 million. However, not all rate classes have the same projected revenue from recommended rates, as discussed herein, as rates are designed to recover the class COS determined from this analysis.

Future Rates/Rate Changes

Several of the ambitious plans for the Study are recommended to be implemented after July 1, 2022, and after additional analysis and internal and external communications and messaging. For Hetch Hetchy Power, these include the refinement of the existing net energy metering (NEM) rates and the premium renewable energy tariff (like the SuperGreen product offered by CleanPowerSF). Hetch Hetchy Power also anticipates introducing revisions to its line extension policy to align with its transition to cost of service-based rates. Further, Hetch Hetchy Power anticipates reviewing changes to the cost and risk sharing agreement between its water and power operations. Additionally, both Hetch Hetchy Power and CleanPowerSF anticipate a reexamination of the TOU rate periods based on analysis of usage periods and associated costs, as well as developing a peak day pricing program, along with other demand management programs. Finally, the transition to COS for all Hetch Hetchy Power customers is being phased in to prevent rate shock from significant rate increases for any specific class. As a result, not all Hetch Hetchy Power rates will have reached COS by the end of the two-year Test Year, and the phase-in will need to continue in subsequent years to finish the transition. These future rate proposals could be undertaken by SFPUC staff whenever possible.

Recommendations

Based on the conclusions and supporting analyses presented herein, the following recommendations are a result of this Study:

- The Commission should adopt rates as described and recommended in the two-year rate plan in this Report.
- The SFPUC should continue to invest in infrastructure, equipment, and personnel to ensure its ability to meet customer demand for innovation and reliable power supply.
- The SFPUC should continue to monitor and evaluate evolving technologies, systems, and operations to maximize its investments.
- The SFPUC should continue to evaluate the impact of the changes in rates, rate tiers, and rate structures developed herein in light of the projections of load growth to ensure financial stability of both Hetch Hetchy Power and CleanPowerSF.
- The SFPUC should utilize the results of this rate Study to develop future year rate proposals as necessary.

Section 1
INTRODUCTION

Glossary of Terms

CCA	Community Choice Aggregation is an opportunity for local government to provide residents and businesses in its jurisdiction alternative electricity supply services to the investor owned utility. It allows local entities in California to aggregate the buying power of individual customers within a defined jurisdiction in order to secure energy supply and meet local energy policy objectives . The investor-owned utility in each jurisdiction continues to deliver the electricity and bill customers.
Down-country	"Down-country" refers to the Power Enterprise, the portion of Hetch Hetchy Water and Power that consists of in-City power operations and all power utility wholesale and retail transactions.
Enterprise	Enterprise rates are standard rate schedules. Enterprise customers include the San Francisco International Airport (SFO), Enterprise departments, Port tenants, and some private customers.
GUSE	GUSE refers to "General Use" rates, which are charged to General Fund departments, education districts, governmental agencies, and some private customers.
Hetch Hetchy Water and Power	Throughout this report, "Hetch Hetchy Water and Power" will be used as the umbrella term to describe both Hetch Hetchy Water and Hetch Hetchy Power. Hetch Hetchy Water (also known as "Up-country") operates and maintains the Hetch Hetchy Project, which includes both Water Enterprise and Power Enterprise expenses and Hetch Hetchy Power (also known as "Down-country") is responsible for all San Francisco Public Utilities Commission (SFPUC) power utility commercial transactions and in-City power operations.
PCIA	Power Cost Indifference Adjustment is an exit fee charge by PG&E to customers that choose another provider of electricity generation service through direct access or community choice aggregation (CCA). The fee is designed to allow PG&E to recover the above-market costs of energy resources that were already contracted on a customer's behalf by PG&E .
Retail	Retail rates are Hetch Hetchy Power's standard rates schedules. Customers are mainly private non-municipal customers in redevelopment areas.
Up-country	"Up-country" refers to Hetch Hetchy Water and Power Division, which maintains, and improves water and power facilities, dams and reservoirs, water transmission systems, power generation facilities, and power transmission assets all located in the up-country (Sierra Nevada mountains and foothills).
45/55 Split	All costs associated with water operations under the Hetchy Water and Power Division are funded by the Water Enterprise, while all operations associated with power are funded by the Power Enterprise. For joint operations, the Water Enterprise is responsible for 45% of operating and capital costs, while the Power Enterprise is responsible for the remaining 55%.

Background

The San Francisco Public Utilities Commission (SFPUC) supplies high quality water, power, and wastewater services to the City and County of San Francisco (referred to as the City). The agency also supplies wholesale water to three other Bay Area counties, drinking water and power services to certain retail customers outside the City, and wastewater services to three municipal service providers in San Mateo County. These utility services are provided through the maintenance, operations, and development of the SFPUC's three enterprises: the Water Enterprise, the Wastewater Enterprise, and the Power Enterprise.

The SFPUC has provided electricity to City departments and related entities for over 100 years, starting in 1918 and expanding to serve City facilities throughout San Francisco in 1945. The departmental entity of the Power Enterprise was created in February 2005 as part of an agency reorganization effort to separate electric utility services from the Water and Wastewater Enterprises, and now is comprised of two retail electric service programs, Hetch Hetchy Power, San Francisco's publicly owned utility (POU), and CleanPowerSF, San Francisco's community choice aggregation program.

The Hetch Hetchy Water and Power Enterprise Fund is comprised of two key components: Hetch Hetchy Water, which operates and maintains the Hetch Hetchy Project, and Hetch Hetchy Power, which is responsible for all SFPUC power utility commercial transactions and in-City power operations. The Hetch Hetchy Project provides water for distribution through the Water Enterprise and hydroelectric power to municipal and other customers through the Power Enterprise. A number of the facilities of the Hetch Hetchy Project are joint assets and are used for both water transmission and power generation and transmission, benefitting both the Water Enterprise and the Power Enterprise. All power sales revenues are allocated to power and joint activities of the Hetch Hetchy Project and to Power Enterprise.

The Hetch Hetchy Project is the primary source of power supplying the Hetch Hetchy Power retail electric service program. The Hetch Hetchy Power program serves about 4,500 retail accounts.

CleanPowerSF is the electrical power community choice aggregation program. Under CleanPowerSF, the SFPUC pools the electricity demands of many City residents and businesses that are retail electric distribution customers of PG&E for the purpose of buying electricity on behalf of such customers. CleanPowerSF, which currently serves over 380,000 accounts, gives residential and commercial electricity consumers in San Francisco a choice of having their electricity supplied from clean renewable sources, such as solar and wind, at competitive rates.

Figure 1-1 provides a simplified schematic of the "service territories" for Hetch Hetchy Power (referred to as HHP in the graphic below) and CleanPowerSF (referred to as CPSF). The schematic suggests that there are solid areas that are served by each operation; however, the dispersion of customers is much more diverse. As discussed herein, Hetch Hetchy Power serves selected customers and locations within the City and in neighboring counties (municipally owned facilities), whereas CleanPowerSF serves the majority of other customers in San Francisco. While not shown below, there are scattered Hetch Hetchy Power customers in other locations throughout California; typically adjacent to Hetchy facilities.

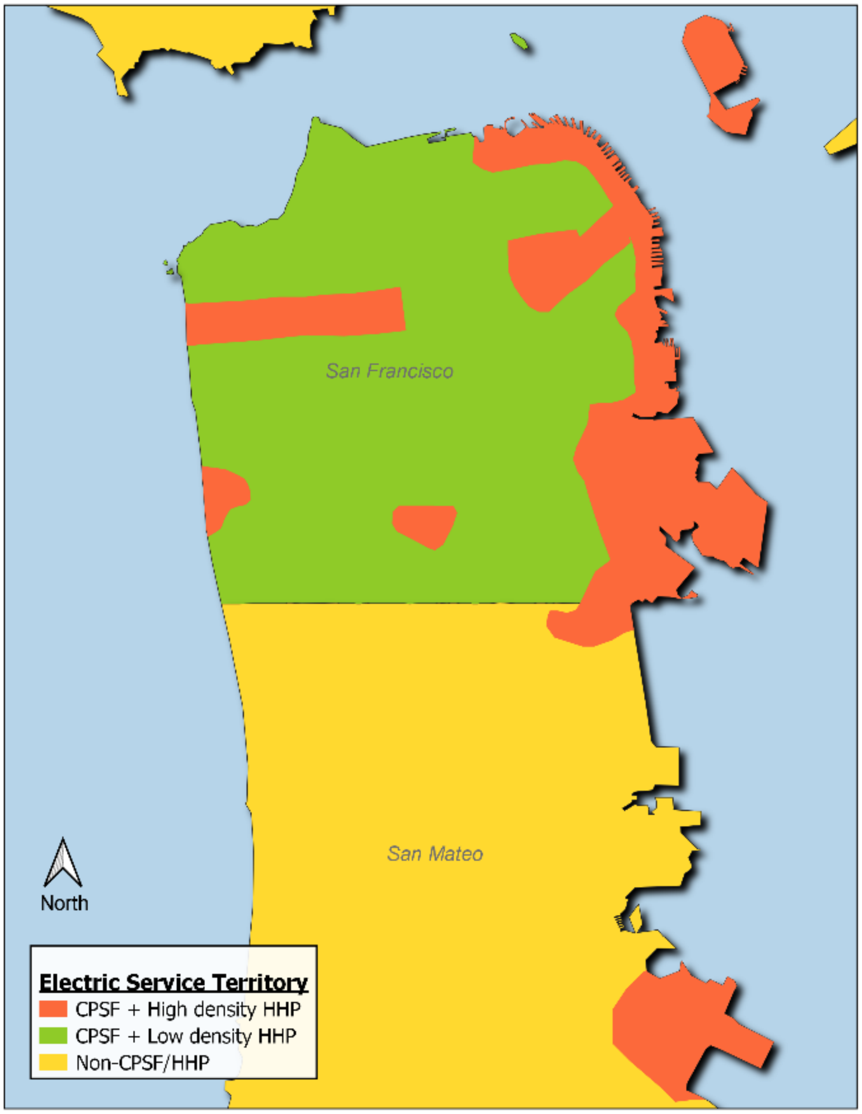

Figure 1-1. Schematic Estimate of Electric Service Territory

Hetch Hetchy Water and Power

Hetch Hetchy Water and Power was formed in 1913, when the Raker Act granted the City and County of San Francisco the right to build and operate the Hetch Hetchy Water and Power system on federal lands. More than 100 years later, the SFPUC still supplies the City with clean and reliable water and power services through the passing of this Act.

Hetch Hetchy Power's portfolio consists of hydroelectric generation, on-site (distributed) solar at SFPUC and other City/County facilities, and third-party purchases. These third-party purchases are typically made through month-ahead, day-ahead, and spot purchases on the California Independent System Operator (CAISO) market. All market purchases are subject to established risk management practices and guidelines, including trading limits and counterparty credit requirements. The Hetch Hetchy Power supply portfolio is managed to ensure a 100% greenhouse gas-free (GHG-free) product.

Hetch Hetchy Power is committed to the development of clean and “green” power to address environmental concerns and community objectives. This commitment results in continued efforts to evaluate and expand its existing resource base to include additional renewable generation sources, including distributed renewable generation, demand management, and energy efficiency programs. Hetch Hetchy Power’s mission is to provide safe and reliable energy service at reasonable cost to customers, with an attention to the environmental effects and community concerns.

Customer Base

Municipal customers were Hetch Hetchy Power’s only customers for many years, and still make up most of Hetch Hetchy Power’s customer base. In Fiscal Year (FY) 2020–2021, approximately 71% of charges for service were from municipal sales. Notably, one customer, the San Francisco International Airport (SFO or Airport) accounts for over 32% of total Hetch Hetchy Power sales by volume. Because of the outsize importance of this load, SFO costs have been tracked separately; however, for purposes of rate design and cost allocation, SFO is grouped with the other Hetch Hetchy Power Industrial customer class.

Recently, Hetch Hetchy Power has grown its retail customer base, designing and constructing new transmission and distribution facilities to serve more retail customers, such as the Hunter’s Point Shipyard and the Transbay Transit Center. This expansion has primarily occurred in distinct geographic regions where new development is happening, particularly neighborhoods developed by the Successor Agency to the San Francisco Redevelopment Authority. Hetch Hetchy Power’s expansion was facilitated by Board of Supervisors’ Ordinance No. 0247, which amended the San Francisco Administrative Code Chapter 99 to clarify the requirement for the City to provide electric service to City departments and facilities and to evaluate the feasibility of providing electric power to new developments and projects. Section D of the Ordinance states that “the City should consider the feasibility of supplying electricity to all new City developments, including, without limitation, military base reuse projects, redevelopment projects, projects occupying any portion of public land, and projects funded in whole or in part by local, State, or Federal funds and other City projects.” Section E states that “in addition to the types of projects identified in (d) above, certain other private projects seeking City approvals including but not limited to new or substantial rehabilitation of more than 10 residential units or new or substantial rehabilitation of more than 10,000 square of occupiable space, present good opportunities for City electric service.” These neighborhoods developed by the Successor Agency to the San Francisco Redevelopment Authority therefore meet the outlined requirements.

Other retail customers, however, may choose Hetch Hetchy Power as their power provider if SFPUC determines the service is feasible. Part of the SFPUC’s long-term business plan is to own a City-wide distribution system to provide electric service to existing and future customers, so future retail growth is projected in current plans. This customer growth is anticipated to create large revenue increases. Hetch Hetchy Power’s long-term goal is to increase its retail sales well above 150 megawatts (MW) by serving additional customers that are currently served by PG&E and/or by serving growing redevelopment areas in San Francisco. Growth to 300 MW or more will allow Hetch Hetchy Power to spread its current fixed costs across a larger customer base and to bring the full value of its supplies to San Francisco, while keeping rates for customers affordable and increasing net revenues available to support Power’s capital investment needs.[1]

In addition to these retail customers, the 1913 Raker Act obliges Hetch Hetchy Power to make wholesale power in excess of its needs available to the Modesto and Turlock Irrigation Districts. However, since 2018,

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[1] The load growth included in Hetch Hetchy Power’s financial plan and this report is not inclusive of load growth that would result from a successful acquisition of the PG&E grid. That City initiative is not modeled in this Study.

the Districts have declined to purchase power from Hetch Hetchy Power. Excess power supply not needed to serve Hetch Hetchy Power customers is sold to CleanPowerSF and on California energy markets, mainly via CAISO.

Infrastructure

Per the terms of the 1913 Raker Act, Hetch Hetchy Water and Power developed hydroelectric facilities, transmission facilities, and other electric utility infrastructure to serve its customer base. Subsequently, the City built certain distribution facilities to deliver power to end-use customers. A number of the facilities operated by Hetch Hetchy Project staff are joint assets used for both water storage and transmission and electric generation and transmission, benefitting both Water and Power Enterprise operations.

The Hetch Hetchy Project includes the O'Shaughnessy Dam; the Hetch Hetchy Reservoir; the Canyon and Mountain Tunnels; the Kirkwood, Moccasin, and Holm Powerhouses; Cherry Lake and its dam; Lake Eleanor and its dam; the related water storage and transportation and hydroelectric generating facilities down to and including the Moccasin Powerhouse, all located in Yosemite National Park, Stanislaus National Forest, and Tuolumne County, the rights to which were granted to the City by the Raker Act; and the related transmission facilities down to Newark. Operating and capital costs that jointly benefit both ratepayer groups—water and power—are allocated 45% to the Water Enterprise and 55% to the Power Enterprise under existing policies.

In some cases, Hetch Hetchy Power does not own transmission and distribution facilities to reach every customer. In these cases, Hetch Hetchy Power relies on the transmission system operated by the CAISO and the distribution system of Pacific Gas and Electric Company (PG&E), the investor-owned utility operating within the City. The SFPUC must pay the CAISO for transmission access and pay PG&E for the use of its distribution system through the Wholesale Distribution Tariff (WDT). The rates for WDT are regulated by the Federal Energy Regulatory Commission. In recent years, the rates for these services and PG&E's restrictions on the City's use of PG&E facilities have led to ongoing disputes and litigation between the SFPUC and PG&E. This complex relationship with PG&E—as both a competitor and a partner—is a major feature in Hetch Hetchy Power's strategic operations.

Hetch Hetchy Power Rates

A major objective of this Study, as discussed herein, is to transition all customers to rates based on their customer class (i.e., residential, small commercial, industrial), and to move all rates to their cost of service. This transition is designed to support the fiscal health of Hetch Hetchy Power, improve the fairness of Hetch Hetchy Power's rates, vastly simplify billing administration, and set up the program to implement modern rate structures to support its policy goals.

CleanPowerSF

In 2004, the City and County of San Francisco established and elected to implement a Community Choice Aggregation (CCA) program, now known as CleanPowerSF. However, it was not until May 2016 that CleanPowerSF began serving customers . Under a CCA structure, the incumbent investor-owned utility (in this case PG&E) provides delivery services (transmission and distribution) and customer service (billing, metering, etc.) and the CCA provides power supply. CleanPowerSF aggregates the electricity demands of the residents and businesses it serves to buy electricity on behalf of those customers.

Customers are assigned to the CCA upon its formation but may "opt-out" of service from the CCA (and return to full bundled energy service by PG&E). CCAs allow communities to control the sources of supply and the uses of the service revenues, reinvesting in local initiatives. In San Francisco, the CCA promotes the use of renewable energy, invests in local energy programs and supplies, and provides local control on the rates offered to customers. Specifically, CleanPowerSF allows the SFPUC to achieve several complimentary goals, including affordable and competitive electricity generation rates, a renewable and carbon-free generation resource portfolio, opportunities for local renewable generation, and high-quality customer service. As of 2022, CleanPowerSF does not own any of its own power infrastructure, and instead either enters into long-term contracts for storage or power products called “power purchase agreements” or “PPAs” or purchases power on the wholesale market to procure its supply.

CleanPowerSF gradually enrolled customers over several years, including volunteers, adding phases of customers in geographic regions of the City. CleanPowerSF completed its enrollment in 2019, and now serves approximately 60% of the City’s total power load. Other than customers who have opted out of CleanPowerSF to remain with PG&E, municipal and some retail load is served by Hetch Hetchy Power (see above) and some larger commercial and industrial customers may choose “direct access” service. Direct access allows certain customers in the retail power market to source their power from third parties, while PG&E would continue to be responsible for the energy’s transmission and distribution. As with Hetch Hetchy Power, the relationship between CleanPowerSF and PG&E as both partners and competitors has a direct impact on the program’s strategy and operations.

CleanPowerSF Rates

CleanPowerSF offers customers within the City two primary options for its rates. Customer can choose the default “Green” product, which as of 2020 provides greater than 50% renewable power, or its “SuperGreen” product, which is certified as 100% Green-e renewable. The SuperGreen product is priced at a premium rate that varies by class and is in addition to the default Green power rate. Like all CCAs, because the incumbent utility provides the billing service, all CleanPowerSF tariff schedules must mirror those of PG&E.

In addition to paying the CleanPowerSF generation rate, CleanPowerSF customers must also pay a Power Cost Indifference Adjustment (PCIA) rate and Franchise Fees Surcharge (FFS) rate to PG&E. All customers in California (except those served by a publicly owned utility) pay a PCIA and FFS, though the exact rates vary across the state and over time. For customers of PG&E or other investor-owned utilities, the PCIA is embedded as part of their generation rate.

The PCIA is a charge to recover PG&E’s costs for generation resources that are currently above market rate, and to which PG&E committed prior to a CCA customer’s switch to an alternative supplier. The PCIA is intended to prevent customers remaining with PG&E from unfairly shouldering the burden of excess power supply they do not need. PCIA rates are associated with a specific year in which the customer left the bundled service from PG&E. For CleanPowerSF, the PCIA vintage used for rate analysis is 2018, the year in which the majority of the customers switched from PG&E to CleanPowerSF. The PCIA rate varies depending on the market conditions for power; generally, the higher the projected wholesale energy rate in the CAISO market, the more value is placed on the “stranded” generation resources, and the lower the PCIA. The PCIA is regulated by the CPUC through various litigated rate hearings. The FF surcharges are collected by PG&E as an agent for fees levied by the CPUC on behalf of cities and counties within PG&E’s service territory for all customers.

For customers served by PG&E bundled service, the PCIA and FF surcharges are included in their generation rate. For CleanPowerSF, these costs are added to the generation rate for unbundled service. Historically, the PCIA and FFS have represented approximately 30% of the average generation cost of CleanPowerSF customers. A “competitive” rate for CleanPowerSF must not only consider the comparable PG&E generation rate, but also account for these additional PG&E fees. To maintain the same effective generation costs for CleanPowerSF customers compared to PG&E bundled generation customers, increases in the PCIA drive reductions in CleanPowerSF's generation rates. Because of these competitive pressures and constraints, CleanPowerSF needs to consider PG&E's rates in its own rate-setting and have the ability to react quickly to changes in the market, raising or lowering its rates to cover costs or compete with PG&E.

During the rollout of the program, the policy goal of competitive rates was identified as the highest priority to prevent mass opt-outs. As a result, CleanPowerSF rates have up until this point been set to follow PG&E, after accounting for the PCIA and FFS, rather than being based on CleanPowerSF's cost of service. This is the first rate study for CleanPowerSF, and decoupling from PG&E rates to rates based on CleanPowerSF's cost of service is one of the Study's major goals. It should be noted that on March 1, 2022, PG&E updated its rate schedules, including rates for generation, and CleanPowerSF adjusted its rates to reflect those offered by PG&E at that time.

Study Schedule/Background

This Study was initiated in March 2021 and is anticipated to conclude with the implementation of the recommended rates and rate structures for Hetch Hetchy Power and CleanPowerSF on July 1, 2022 (the beginning of FY 2022–2023). This section provides a summary of the Study mandate, the deliverables developed for the Study, and the Project Teams involved in the Study.

Study Mandate

Per Section 8B.125 of the City & County of San Francisco Charter, the SFPUC is required to retain an independent rate consultant at least every five years to evaluate the cost of service of the power systems and to recommend appropriate rate structures. The last power rate study was completed in FY 2015–2016 for rates beginning FY 2016–2017. This Study is designed to recommend rates, charges, and fees for power service beginning FY 2022–2023. If required, this project will also include any implementation steps needed for the Customer Service, Finance, or the Power Enterprises to administer changes to the rate structure.

Project Team

NewGen Strategies and Solutions, LLC (NewGen) was retained by the City and County of San Francisco, through a competitive request for proposal (RFP) solicitation, to assist the SFPUC with the development of the 2022 Power Rates Study. The NewGen Team included representatives from Bell Burnett and Associates (BB&A). NewGen is a management and economic consulting firm specializing in serving the utility industry and market. Established in August 2012, NewGen primarily serves public sector utilities and provides nationally recognized expertise in utility cost of service and rate design studies, financial feasibility studies, and other economic analysis for electric, water, wastewater, solid waste, and natural gas utilities. BB&A is a management and strategic consulting firm serving the utility industry and public sector clients in the West, particularly in California. BB&A offers an independent development, review, and assessment of strategic plans and initiatives.

Summary of Deliverables

Table 1-1 provides a summary of the deliverables developed as part of this Study, including the approximate date of delivery for each deliverable, as identified in the Project Charter, which was developed from the scope of services requested from the SFPUC. Some of these deliverables were developed by SFPUC staff and some were developed by the rates consultant. The beginning and ending dates were approximated and adjusted as the Study progressed. Outreach activities envisioned to support this Study were developed and conducted by staff.

Table 1-1
Summary of Project Deliverables

Milestones	Deliverables	Date
Identification of Specific Rates and Fees to be Developed	• List of rates, fees, and tariffs to be developed • List of key rate or policy areas that the consultant should research • Short memos or whitepapers on key rate or financial policy areas for revision	October 2020–May 2021
Customer Profiles	• Customer power usage data • Model of SFPUC customers' characteristics that includes geographic, demographic, and economic information to inform affordability discussions, etc. • Expected trends in customer growth/electrification that feed into financial forecasts	November 2020–July 2021
Revenue Requirement	• Updated capital plans and budgets • Revenue requirement model with documentation • Chapter in Rate Study Report • Presentations to Rates Steering Committee • Presentations to Rate Fairness Board	February 2021–January 2022
Cost of Service Analysis	• Cost of service model with documentation • Chapter in Rate Study Report • Presentations to Steering Committee • Presentations to Rate Fairness Board	November 2021–March 2022
Development of Power Rates and Charges	• Rate model with documentation • Chapter in Rate Study Report • Schedule of miscellaneous fees and supporting documentation • Final Rate Study Report	January 2022–April 2022
Outreach Phase 1: Ratemaking Education & Engagement (staff)	• Meetings with key customers and stakeholders • Meetings with Rate Fairness Board • Briefings with Commissioners and Supervisors • Briefings with Mayor's Office and impacted City departments	November 2020–July 2021
Outreach Phase 2: Rate Change Communications (staff)	• Meetings with key customers and stakeholders • Briefings with Commissioners and Supervisors • Briefings with Mayor's Office and impacted City departments • Multiple meetings with community groups and the general public	July 2021–June 2022
Rate Implementation	• New rates adopted	July 1, 2022

SFPUC Project Team

The SFPUC Project Team was led by the Rates Administrator in the SFPUC's Financial Services division. Other divisions within the SFPUC organization provided insight and additional analysis during the Study process, including staff from across the Power Enterprise (Hetch Hetchy Water, Hetch Hetchy Power, and CleanPowerSF), Customer Services, IT, and Communications. NewGen would like to express our true appreciation for the spirted cooperation and valuable assistance given through the course of this Study by each member of the SFPUC's management and staff.

Rate Steering Committee

The Rate Steering Committee is made up of executive leadership staff from across the agency, particularly External Affairs, Business Services, and the Power Enterprise. The Steering Committee provides high-level direction on the project. Responsibilities include:

- Confirm the project's goals and objectives
- Make decisions on policy direction questions
- Make decisions on escalated issues
- Assist in the resolution of roadblocks
- Keep abreast of major project activities
- Keep senior management informed as needed

Monthly presentations were developed and provided to the Rate Steering Committee throughout the process of the Study, beginning September 2020 and concluding April 6, 2022.

Rate Fairness Board

In addition to requiring the SFPUC to retain an independent rates consultant every 5 years, Section 8B.125 of the City and County of San Francisco Charter also requires the SFPUC to establish a Rate Fairness Board consisting of seven members:

- The City Administrator or his or her designee
- The Controller or his or her designee
- The Director of the Mayor's Office of Public Finance or his or her designee
- Two residential City retail customers, consisting of one appointed by the Mayor and one by the Board of Supervisors
- Two City retail business customers, consisting of a large business customer appointed by the Mayor and a small business customer appointed by the Board of Supervisors

Per City Charter, the Rate Fairness Board reviews the 5-year rate forecast, holds public hearings on annual rate recommendations before SFPUC adoption, provides a report and recommendations to the SFPUC on the rate proposal, and submits to the SFPUC rate policy recommendations for the Commission's consideration. During the process of the Study, five presentations were developed and provided to the Rate Fairness Board, beginning December 3, 2019, and concluding on April 8, 2022.

SFPUC Commission

The San Francisco Public Utilities Commission consists of five members nominated by the Mayor and approved by the Board of Supervisors. They are the approval body for all the SFPUC rates and fees. A presentation of the recommended rates and rate structures for Hetch Hetchy Power and CleanPowerSF is anticipated to be provided to the San Francisco Public Utilities Commission in May 2022.

Study Objectives

This Study is designed to be a key foundational methodology for financial planning and fair rate-setting for the SFPUC. It provides an opportunity to reassess the SFPUC's financial policies and priorities and to develop rates that better achieve those goals. This Study culminates in a set of recommended rate designs, in which the cost recovery mechanisms (rates and charges) for each customer class and rate code are established. Rates and charges are designed such that the total revenue needed for the system will be recovered in an equitable manner that is consistent with the results of the Study. In addition, rate design considers and reflects the SFPUC's overall revenue objectives for the utility, its historical rate structures in place, and policy considerations for various programs, as well as legal requirements and other energy related policies established by the Commission.

Table 1-2 provides a list of the SFPUC's objectives, with the specific application identified for this Study.

Table 1-2
Study Goals and Objectives

Study Goals and Objectives	Implementation
Review the SFPUC's financial policies applied to cost of service and rate design	Incorporated updated policies for CleanPowerSF reserves
Industry best practices for power rates and fees	Standardized approach for cost of service analysis
Develop forecasts of revenue requirements for financial planning and forecasting	Incorporated planning into financial model for cost of service analysis
Properly functionalize/allocate costs for equitable, financially sustainable, and legal rates	Allocation process based on principles of cost causation
Allocate shared Power Enterprise costs (finance, admin, etc.) between Hetch Hetchy Power and CleanPowerSF	Incorporated allocation methods provided by SFPUC staff into cost of service analysis
Develop framework for sharing costs between new and existing Hetch Hetchy Power customers, and develop appropriate permit review, line extension, capacity, and/or connection fees to allocate costs fairly	Conducted Line Extension review and workshop with SFPUC management and staff
Create a plan and timeline to normalize Hetch Power rate structure, decouple from PG&E rates, and transition to cost of service rates for all customers	Developed 2-year rate plan with recommendations for additional rate strategies
Set rates to support the operations, maintenance, programmatic, and capital needs of the SFPUC Power Enterprise	Rates set to recover projected revenue requirements based on projected billing determinants by class
Design rates that provide a financial incentive for customers to implement environmentally friendly practices	Developed time of use (TOU) and tiered rates based on underlying cost responsibility into recommended rate design
Evaluate affordability of rates for low-income customers and recommend rates or programs that address disproportionate burdens	Incorporated low-income discounts and maintained low tier thresholds as directed by the SFPUC
Address concerns regarding market price volatility and uncertainty in future costs	Recommend a two-year rate plan with tools for the SFPUC to update and monitor future revenues and expenses

Review Financial Policies

As indicated in Table 1-2, as part of the comprehensive Study, the NewGen team reviewed the SFPUC's financial policies in areas such as debt service coverage, cash versus debt capital financing, reserves, and rates to determine recommended changes as described in this Report. This includes modifying the reserve policy for CleanPowerSF and increasing reserve levels for both CleanPowerSF and Hetch Hetchy Power to address concerns regarding market exposure and volatility in market prices.

Industry Best Practices

Another objective of this Study was to utilize industry best practices to provide clear, documented support for power rates and fees, which were incorporated into the cost of service and rate design modeling. This included properly functionalizing costs and allocating them to customer classes to ensure that power rates are equitable, financially sustainable, and meet legal requirements. This process results in recommended retail rates for SFPUC customers that support the operations and maintenance (O&M), programmatic, and capital needs of the SFPUC Power Enterprise

Forecast Revenue Requirement

As part of this modeling effort, the NewGen team reviewed and incorporated the forecasts of revenue requirement developed by SFPUC staff into the cost of service process, which will allow SFPUC staff to create analyses for financial planning and forecasting after completion of the Study. NewGen reviewed staff estimates for splitting costs and risks associated with the Hetch Hetchy Power up-country power and joint assets (operating and capital) between Water and Power Enterprises; however, additional analysis may be required due to the complexity of the arrangement. NewGen also reviewed the proposed methods developed by SFPUC staff for allocating shared Power Enterprise costs (finance, admin, etc.) between Hetch Hetchy Power and CleanPowerSF. These elements were included in the revenue requirement portions of the respective cost of service analyses for each entity.

Review Fees/Cost Sharing

SFPUC policies and fees associated with sharing costs between new and existing Hetch Hetchy Power customers were reviewed as part of this Study. This included a review of the permit review process, line extension charges, capacity, and/or connection fees currently utilized to fairly allocate costs. This process culminated in a line extension workshop facilitated by NewGen with management and staff from the SFPUC. While Hetch Hetchy Power did not make changes to the current line extension policy and practices in place, the Study provided potential recommendations and options for future consideration. SFPUC staff intend to propose changes to some existing fees based on these recommendations.

Rate Strategy

The NewGen Team worked with the SFPUC Team to create a rate strategy plan and timeline to normalize Hetch Hetchy Power rate structures, decouple both Hetch Hetchy Power and CleanPowerSF from PG&E rates, and transition to cost of service rates for all customers. Addressing how collective City energy programs are allocated equitably to rate classes is a critical element of this Study. An additional element of this strategy, which is further described below, is to transition from the “legacy” Hetch Hetchy Power customer nomenclature and classes (GUSE, Municipal Enterprise, Retail) into more traditional customer classes, such as residential, commercial, and industrial.

Currently, CleanPowerSF updates its rates with each change in PG&E’s retail rates, which can lead to multiple rate changes within a single fiscal year. An objective of this Study was to develop rates that are not dependent on PG&E and that reflect the SFPUC’s costs to serve their customers. This will allow for rate stability for those customers whose rates were previously tied to PG&E and will ensure that budgeted programs for both CleanPowerSF and Hetch Hetchy Power can be funded, if approved by the Commission.

This process culminated in the development of the recommended two-year retail rate plan, which recommends retail rates and rate strategies for each rate class for FY 2022–2023 and FY 2023–2024. While the Study covers five years, as required by the Charter, a two-year rate plan was chosen to address concerns regarding future market price volatility for energy (which can dramatically impact the utility’s operations), as well as other uncertainties in estimating future costs and demands as usage emerges from the changes caused by the COVID-19 pandemic. As indicated, the models and methodologies developed for this Study can be used by the SFPUC at the completion of this Study for their use for future rate plans; updated models will be used to propose rates for FY 2024–2025 onward.

Innovative Rate Designs for Policy Goals

The rate recommendations developed as part of this Study include financial incentives for customers to implement environmentally friendly energy usage behaviors, such as energy conservation, decarbonization, and shifting load to times of the day with more renewable sources (time of use or TOU-based rates). Additionally, NewGen evaluated the affordability of the recommended rates for low-income customers and recommended rates or programs that address disproportionate burdens. The recommended rate plan also includes transitions to cost of service-based rates for customers whose rates are currently above or below their respective costs. Further, the rate plan is intended to send cost-based price signals for all customers served by the Power Enterprise, and to create rates that support customer growth and expansion of services and rate offerings.

Cost of Service Process

The COS process is an industry-accepted framework that assigns or allocates costs to each customer class served by a utility. This process determines the "cost to serve" each customer class within the utility. The COS process involves a series of steps to identify costs and allocate them by function, classification, and ultimately customer class. Additionally, it is recognized that electric utility costs are typically characterized as either fixed or variable; fixed costs are those that do not change with the production of electricity, whereas variable costs are directly related to the amount of electricity produced and/or purchased. These costs are typically further characterized as those that are demand based, customer based, and energy based. A summary of the steps in the COS process, as well as a description of the types of costs incurred to operate an electric utility, are described below.

Steps in the COS Process

The process of conducting a cost of service/rate design analysis generally proceeds as follows and is graphically depicted in Figure 1-2 below.

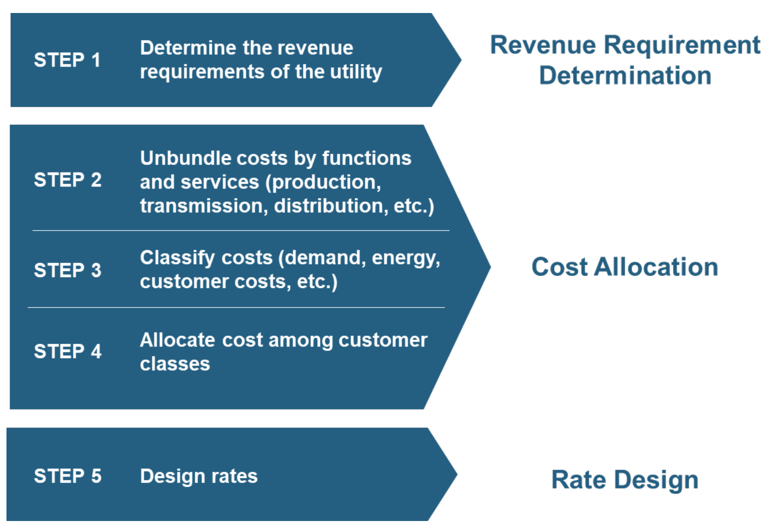


Figure 1-2. Cost of Service Process

Step 1. Establish the Revenue Requirement

The revenue requirement determines the total revenues the utility must collect over a specified period of time to serve its customers, maintain its debt service obligations, invest in its system, and provide additional funds required by fiscal and reserve policies, as appropriate. The period of time covered by the Revenue Requirement (as well as the ensuing rates) is defined as the Test Year.

Step 2. Functional Unbundling

Functional unbundling refers to categorizing the utility's Revenue Requirement between its four major business units or functions (as appropriate), including:

- Production
- Transmission
- Distribution
- Customer Service

Step 3. Classify Costs Within Functional Area

Costs are classified based on the drivers within each functional area. Drivers of cost include system demand, energy consumption, the number of customers being serviced, or costs that are directly attributed (or allocated) to a specific class or customer. This process may include "sub-functionalizing" the cost categories to align their costs and cost causation, as further explained herein.

Step 4. Allocation of Costs across Customer Classes

After costs have been classified to a functional area (production, transmission, distribution, or customer service), costs are further categorized based on the customer usage characteristics of the system. Costs are then allocated to customer classes, allowing COS to be determined for each class.

Step 5. Design Rates

Rate design is based on a combination of analysis of the customer class Revenue Requirements (the allocated share of the system costs) and policy decisions.

Types of Electric Utility Costs

Demand-based Costs

In general, most of an electric utility's cost structure are demand-based costs. Demand-based costs are associated with fixed costs related to existing and future investments made to produce, transmit, and deliver electrical power from the generation resources to its customers. For the Power Enterprise, these costs include the debt service associated with its investments, as well as a portion of its contracts for purchased power. The labor and materials associated with the O&M and administration of these systems are also demand-based costs, as the labor costs are typically fixed in the short term (budget cycle). In the short term, fixed costs do not change and represent the ongoing costs to meet the needs of the utility.

Demand (fixed) costs are defined as those that are incurred to maintain a "readiness to serve," an electric system capable of meeting the total combined demands of all customers at all hours, including peak demand. Demand costs are those costs that are generally fixed in the short run, do not materially vary directly with the number of kilowatt hours (kWh) generated or sold, and are not defined as customer costs.

In the COS process, these costs are assigned based on the electric demand (measured in kilowatts, or kW) that a specific customer or customer class places on the system. Hetch Hetchy Power, like most utilities, has a cost structure that is highly fixed, which is typical of highly capital-intensive entities. However, CleanPowerSF costs are primarily variable, as they relate to the costs incurred to purchase energy only on behalf of their customers.

Customer-based Costs

Customer-based costs for electric utilities are fixed costs as well, but are costs incurred in direct support of the customers served by a utility. Customer costs are defined as those directly related to the number, type, and size of customer, such as customer accounting and bill collecting, and the costs of meters and services. Also, a portion of the distribution investment and operating costs are classified to customer costs because the size and design of the distribution system is a function of both the number of customers and their load (demand).

For Hetch Hetchy Power, customer-related costs include the costs associated with the labor, equipment, and investments for customer accounting, billing, and customer assistance (call centers). For CleanPowerSF, these costs include labor and program costs, including customer assistance, as well as third-party costs for billing and data access from PG&E. For the Power Enterprise, a portion of overhead labor costs (provided by other bureaus and other departments) are allocated to the customer-related costs, as they are designed to support this function. During the COS process, these costs are allocated by the number of customers within a class and may be weighted to represent the relatively larger amount of time spent to serve larger and more complex customers.

Energy-based Costs

Energy-based costs for electric utilities are typically variable costs that change with the fluctuations in electric load. The primary example of energy-related costs for the Power Enterprise are purchased power costs. During the COS process, these are allocated to the customer classes by the amount of energy they are projected to utilize within a selected period of time (during the Test Year).

Other Types of Costs

In the COS process, there are other costs that are not defined or allocated to those categories which include demand, customer, or energy-related costs. These include those that are revenue related and those that are directly assigned to classes, as described below.

Revenue-Related Costs

Revenue-related costs are associated with the amount of revenue generated by each utility’s operations. For some of the cost allocations used herein for certain programmatic expenses, for example, a total revenue requirement allocator was developed to assign costs to functions, sub-functions, classifications, or classes as described herein.

Direct Assignment Costs

There is another category of cost classification that is known as “direct assignment.” The direct assignment costs may be related to demand, energy, customer, or another type of classification; however, these costs are removed from the overall revenue requirement and are allocated directly to a specific customer class or customer.

SFPUC COS Considerations

For the purposes of this Study, two separate COS/rate design analyses were developed: one for Hetch Hetchy Power and one for CleanPowerSF. This is because these two utilities operate independently of each other while sharing costs of certain overhead responsibilities.

As indicated above, the objectives of this Study were to establish a COS-based methodology for the two utility operations, Hetch Hetchy Power and CleanPowerSF. The COS methodology will be utilized to align retail rates with the service offerings to the various customer classes. Further, the COS methodology will form the basis for future rate offerings as both utilities continue to evolve and offer additional products and services in the future.

Hetch Hetchy Power currently offers services to three distinct customer groups, based generally on the type of customer that is being served (if they are a municipal or non-municipal customer). These customer groups include the General Use Municipal, which are municipal departments and other public agencies, referred to as GUSE customers; the Enterprise Municipal customers, which are municipal load customers as well but are not included in the GUSE categorization; and retail customers (non-municipal customers). These distinctions in customer classes are a result of the history of Hetch Hetchy Power that has evolved over time, as discussed above.

Retail customers include a variety of residential and commercial customers primarily located in areas that San Francisco has redeveloped. The current rates and rate structures are different for the three groups of Power Enterprise customers. Rates for the GUSE customers consist of a flat energy rate ($/kwh). Rates for Enterprise customers are set equal to the corresponding rates offered by PG&E. Rates for the retail customers are set at an approximate 10% discount to the equivalent corresponding PG&E rate (i.e., residential, commercial, industrial, etc.).

Hetch Hetchy Power anticipates significant growth for its residential and small commercial classes due to anticipated completions of various redevelopment efforts within this City. This growth results in increased costs to serve these customers. Further, changes within the City's policies regarding future development and restrictions on the installation of new natural gas connections result in a projected increase in the number of residential customers who will be utilizing electric heating and thus increase load. The implications of this growth are described herein and should be noted accordingly.

Currently, CleanPowerSF generation rates are tied to PG&E generation rates, as well as charges for the PCIA and other charges. The current policy allows for the Power Enterprise to adjust CleanPowerSF rates concurrent with adjustments in PG&E rates. Further, CleanPowerSF rates can be higher than PG&E rates if supported by costs. Most recently, PG&E implemented a new set of rates, including generation rates and PCIA rates on March 1, 2022, and CleanPowerSF and Enterprise customer rates were updated accordingly.

The revenue requirement for this Study was developed from the SFPUC's 10-year financial model (the 10-year Financial Pro Forma Model) as well as the Power Matrix model, both of which develop projections of costs for Hetch Hetchy Power and CleanPowerSF operations based on assumptions of power supply costs, load growth, investments, and other items, as necessary.

It should be noted that as part of this Study, various assumptions regarding projected expenses and revenues were developed in coordination with the SFPUC staff and management. To the extent that assumptions as stated regarding these projections are not realized, the recommended rates and rate structures as developed herein may or may not be sufficient to meet the revenue requirements for the period identified.

Section 2
SYSTEM CHARACTERISTICS

Introduction

The purpose of this section is to provide a summary of the system characteristics utilized for this Study that are unique to each SFPUC operation. System characteristics are defined for the Test Year period, which is defined for this Study to be the average of the two-year period of FY 2022–2023 and FY 2023–2024. The SFPUC's fiscal year ends June 30, so FY 2022–2023 is the period from July 1, 2022, to June 30, 2023, and similarly FY 2023–2024 is the period from July 1, 2023, to June 30, 2024. This section includes a description of the Hetch Hetchy Power operations, as well as CleanPowerSF. Figure 2-1 portrays an overview map of the Hetch Hetchy power generation and transmission assets, provided by the SFPUC for this Report.

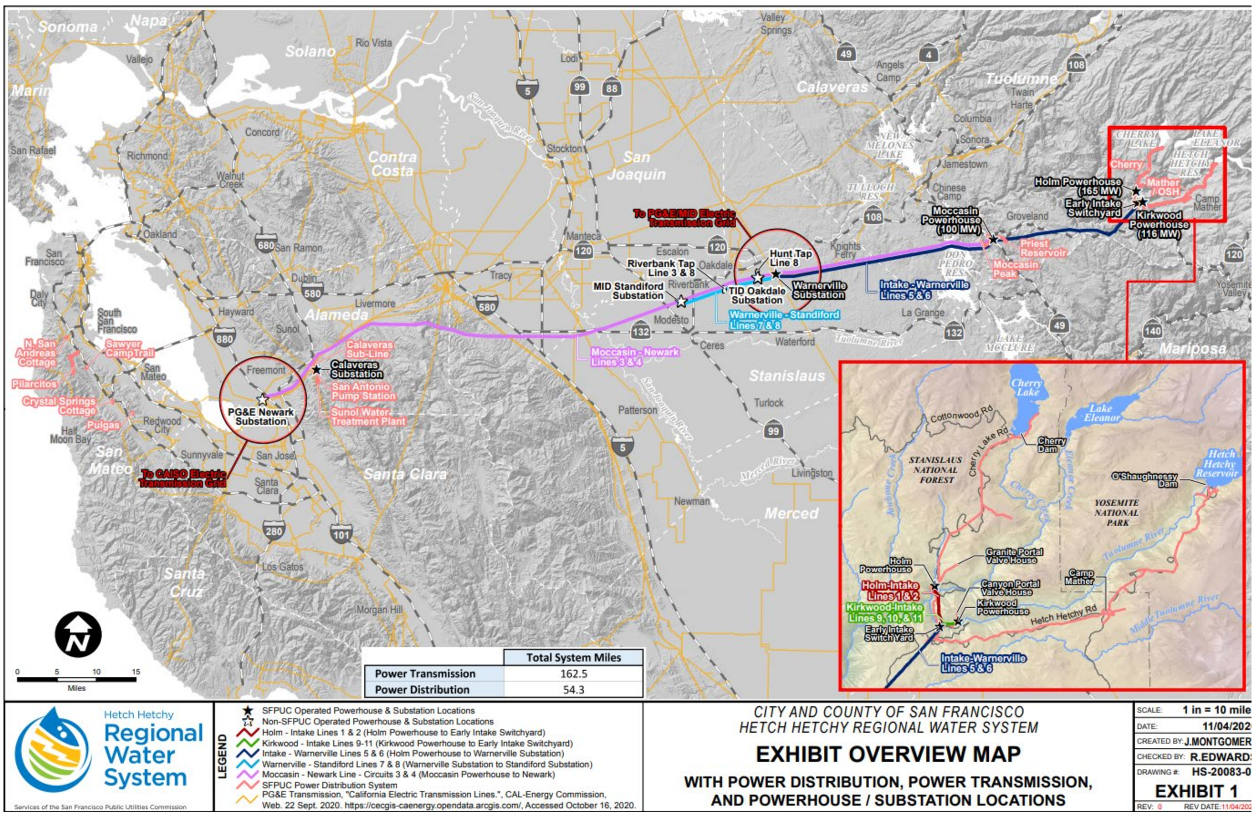
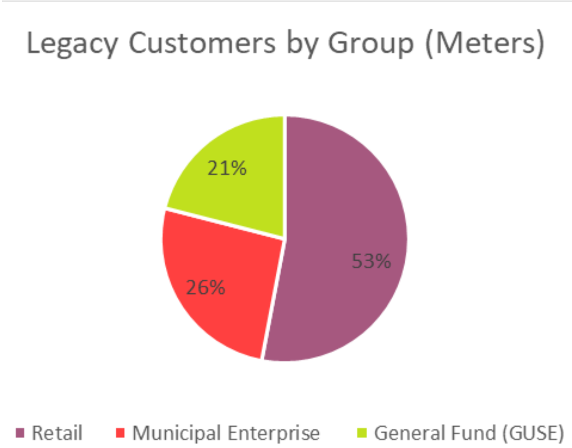


Figure 2-1. Hetch Hetchy Project Power Generation and Transmission Assets – Exhibit Overview Map

Hetch Hetchy Power Characteristics

As indicated in Section 1, Hetch Hetchy Power consists of generation, transmission, and limited distribution assets that generate power and deliver to its customers . Additionally, it pays PG&E to deliver power to many of its customers through access to PG&E's transmission and distribution assets. Historically, Hetch Hetchy Power provided electricity to the City's municipal operations; however, as the City has expanded its public housing and redevelopment areas, it has continued to serve additional direct retail customers. As previously indicated, one objective for this Study is to normalize the customer classes served by Hetch Hetchy Power. Therefore, the historic categories of GUSE, Municipal Enterprise, and Retail are transitioned to industry standard customer classes for the Test Year. Figure 2-2 provides a summary of the legacy rate groups (as a % of total) compared to the proposed rate customers by class. For the purposes of this report, the system characteristics are described in terms of the proposed customer classifications. However, for the purposes of rate design, several of the legacy distinctions are utilized due to rate strategy.



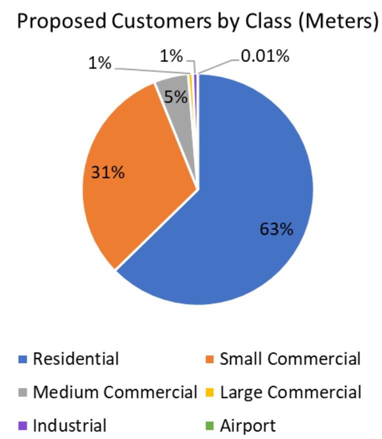


Figure 2-2. Hetch Hetchy Power Customers by Class by Type (Legacy vs. Proposed)

As previously indicated, growth in both load and numbers of customers in several areas of the City is assumed to occur during the Test Year, as projected by the SFPUC. Figure 2-3 provides a summary of the anticipated energy sales (by percentage) for each of the proposed customer classes utilized for this Study.

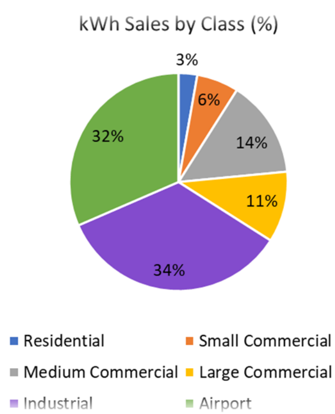


Figure 2-3. Hetch Hetchy Power Load by Customer Class for the Test Year Period (FY 2023–2024)

Growth in Customer Load

Hetch Hetchy Power is projecting significant changes to its customer classes over the Test Year period. This includes changes within classes as well as across classes. Retail residential customers, for example, are anticipated to increase significantly from approximately 1,680 customers in FY 2021–2022 to 2,840 in FY 2022–2023 to 5,735 in FY 2023–2024. This increase is anticipated from the redevelopment of various properties in the City, including Treasure and Yerba Buena Islands, Hunter's Point Shipyard, and affordable housing properties, which are anticipated to be primarily residential load. As a result, the total load associated with the residential class is anticipated to increase significantly. Table 2-1 below provides a summary of the projected increases by load for each class (and total system), as well as the anticipated increase in number of customers for each rate class.

As noted previously, the assumptions regarding changes in customers and customer load are critical to the underlying analysis developed for this Study and the projection of revenues from the recommended rates. To the extent that load and customer numbers are different than the anticipated values, the revenue (and expenses) will be impacted accordingly. Because of the magnitude of this change, it is recommended that Hetch Hetchy Power continue to monitor customer growth, expenses, and revenues on a monthly basis relative to the assumptions developed herein.

Table 2-1
Projection of Load and Customer Numbers by Customer Class – Hetch Hetchy Power

Rate Class	FYE 2023 Load (MWh)	FYE 2024 Load (MWh)	% Change	FYE 2023 Customers	FYE 2024 Customers	% Change
Residential	22,696	32,969	45%	2,843	5,735	102%
Small Commercial	55,628	69,429	25%	1,902	2,366	24%
Medium Commercial	140,466	150,810	7%	307	348	14%
Large Commercial	98,552	113,391	15%	41	46	12%
Industrial	623,637	702,981	13%	45	50	12 %
Total	940,978	1,069,580	14%	5,137	8,545	66%

Source: SFPUC 10 Year Financial Pro Forma Model and Power Matrix. Note, numbers may not add due to rounding.

Hetch Hetchy Power Streetlights

Hetch Hetchy Power currently owns, operates, and maintains approximately 60% of the streetlights in the City; the remainder are owned and maintained by PG&E. The SFPUC provides power to both the PG&E-owned and the SFPUC-owned streetlights. However, because the City must utilize PG&E's distribution facilities to deliver power to the streetlights, it pays PG&E through its wholesale distribution access tariff (the WDT rate). This rate has increased in recent years and is projected to increase in the future; moreover, the latest WDT terms now mandate that all interconnections be metered and served at primary voltage, which would require installation of onerous, unnecessary, and expensive equipment (or be forced to convert to PG&E retail service).

These requirements are not efficient or economically feasible, and while the SFPUC is currently challenging them, it is assumed for this Study that the SFPUC will no longer be able to serve streetlights or other unmetered load throughout the City (other unmetered load includes traffic signals, the distributed antenna system, bus stop lighting, and other small facilities). Instead, PG&E will serve this load and those customers will become retail customers of PG&E, resulting in a significant loss of load for Hetch Hetchy Power beginning in summer 2022 and continuing during the projected Test Year period of this Study. However, the City will continue to own and maintain its streetlights (with some adjustments to the cost due to the new WDT terms) and will only provide electricity to a very small number of streetlights that exist on its own distribution system or which are metered. For the purposes of this Study, the future load of the streetlights is not included in the analysis; however, the costs to maintain them are included as part of the projected revenue requirement (see Section 4). For the purposes of rate design, the streetlight rates for those that continue to be provided electricity by the City will be updated; however, because the revenue is minimal, they have not been included as a customer class in most tables and figures in this Report.

Hetch Hetchy Power – Power Supply

As noted, Hetch Hetchy Power owns generation resources, which provide most of its power supply; however, it also contracts for solar power supply under a PPA and purchases power from the wholesale power market (CAISO) as necessary. Market purchases in particular are needed during certain seasons, as hydroelectric generation is restricted to time periods when water is being released for use by the Water Enterprise. Figure 2-4 provides a summary of the power supply by percentage for the Test Year period.

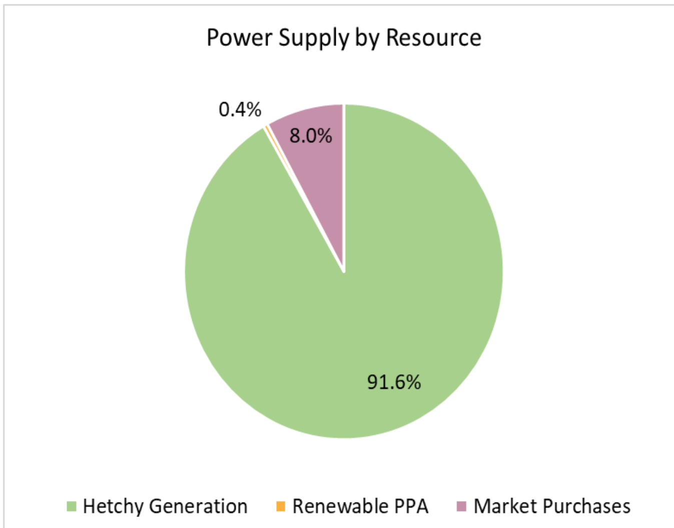


Figure 2-4. Hetch Hetchy Power Supply by Resource for Test Year (FY 2023–2024)

Total energy usage by Hetch Hetchy Power customer class varies by month depending on several factors, including the weather. Figure 2-5 provides a representation of the energy sales by customer class, which includes the SFO as its own load for comparison purposes. The results suggest that generally load for Hetch Hetchy Power is consistent across all months. However, while that is true for the commercial and industrial classes (including SFO), the residential class shows more variability by month.

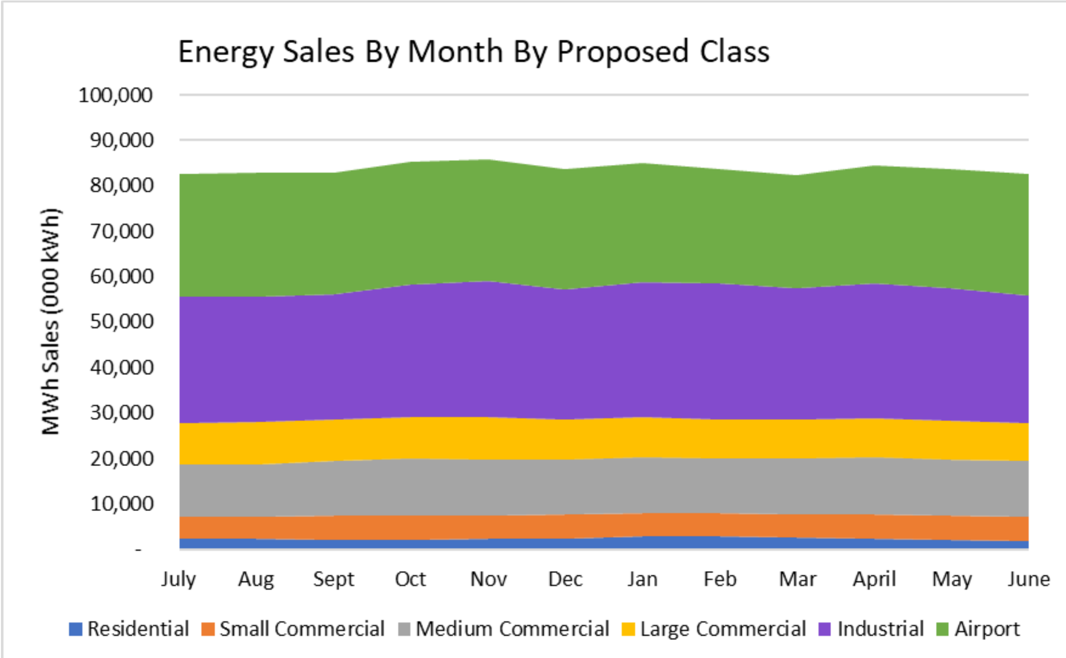


Figure 2-5. Hetch Hetchy Power Energy Sales by Month by Class for Test Year (MWh)

Figure 2-6 provides a representation of the residential energy sales by month for the Test Year, which is not evident in the previous graph due to scale and influence of the larger classes. The residential class load suggests higher energy usage during the winter months, generally from November to April. This is generally due to San Francisco's relatively cool summers requiring minimal air conditioning, with electricity used for heating during the cooler winter months. This usage pattern is expected to continue as the City's environmental policies encourage beneficial electrification and discourage additional natural gas usage, especially in the new residential redevelopment areas developed in coordination with the City.

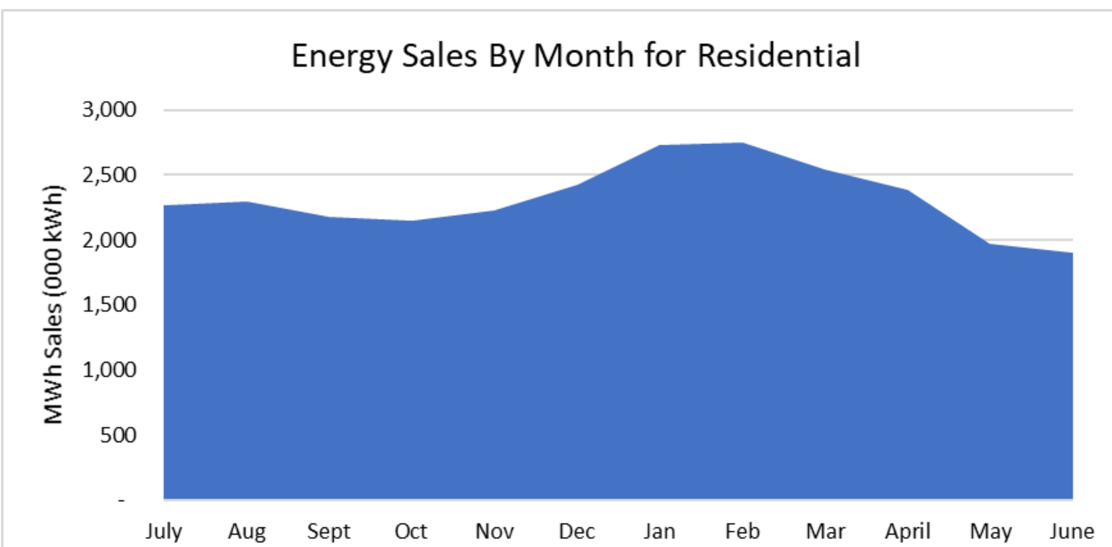


Figure 2-6. Hetch Hetchy Power Energy Sales by Month for Residential for Test Year (MWh)

Further analysis of projected load suggests that Hetch Hetchy Power customer classes use electricity differently during the day. Figure 2-7 provides a summary of the electricity usage pattern for residential customers for an average winter and summer day.

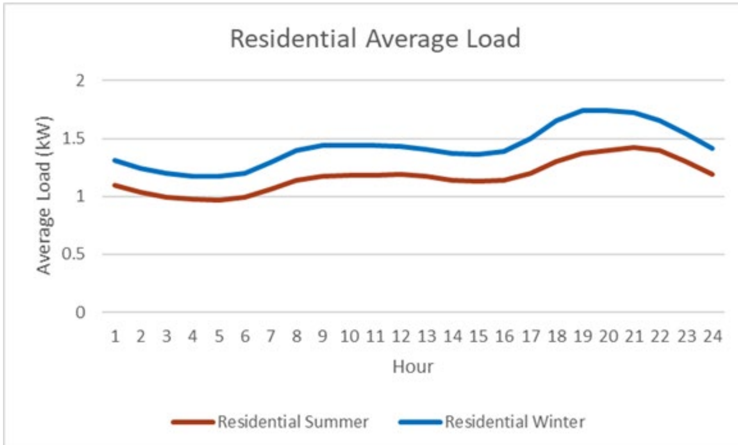


Figure 2-7. Hetch Hetchy Power Average Daily Residential Energy Usage for Summer and Winter (kWh)

Figure 2-8 provides similar average daily load by season for commercial and industrial Hetch Hetchy Power loads. As shown, the analysis conducted on the average daily load indicates that the residential load is generally higher for every hour during the winter compared to summer, whereas the commercial load is higher in the summer (for most hours), and the industrial load is slightly higher during the summer months (although the difference between the seasons for industrial is relatively small). These usage patterns become important in the development of cost-based seasonal and TOU rates for Hetch Hetchy Power customers.

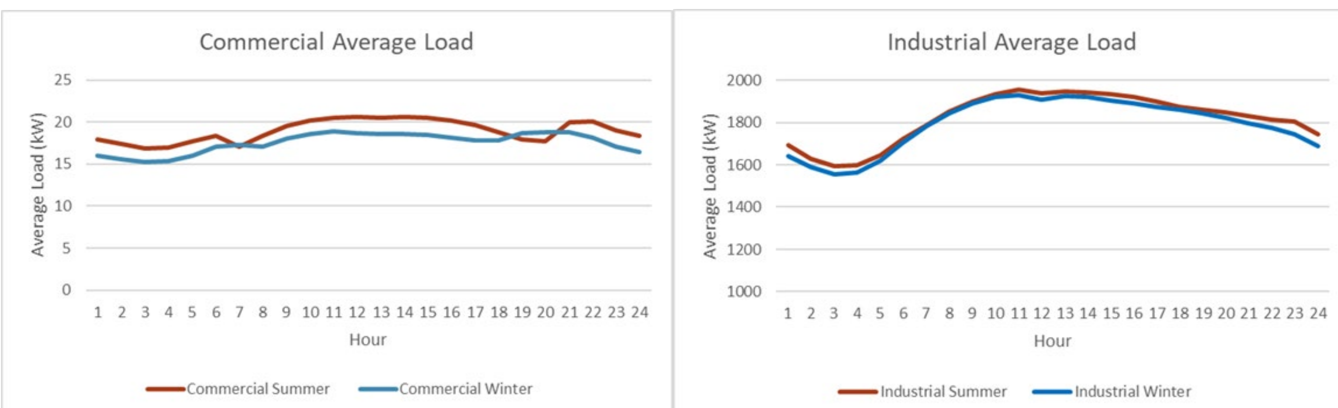


Figure 2-8. Hetch Hetchy Power Average Daily Commercial and Industrial Energy Usage for Summer and Winter (kWh)

Hetch Hetchy Power – Energy Programs

Hetch Hetchy Power offers an array of energy programs for its customers, which includes discounts for low-income customers, energy efficiency programs, services for municipal customers, and one-time programs as approved by the Commission. One such program was recently enacted during the) pandemic, which used funds from the State of California and the federal government to forgive a portion of outstanding debt accrued by customers.

Discount Programs

Long-standing programs include Hetch Hetchy Power's Customer Assistance Program (CAP). Eligible residential customers are those whose income is less than 200% of Federal Poverty Level and who are served by Hetch Hetchy Power. The CAP program offers a 30%-35% discount on each rate component on their bills and applies to both retail and Enterprise residential customers. Cost recovery for the CAP program discount is currently provided by general Hetch Hetchy operating revenues.

Energy Efficiency Programs

Hetch Hetchy Power offers a variety of energy efficiency programs to eligible customers. The GoSolarSF program offers eligible homeowners (based on zip codes and incomes) an opportunity to receive discounts on solar systems and save up to 90% on their electricity bills. EV Charge SF offers Hetch Hetchy Power customers an opportunity to receive financial incentives and technical support to add electric vehicle (EV) chargers and related infrastructure in new or newly constructed buildings. And finally, Energy Efficiency Incentives allow Hetch Hetchy Power commercial, industrial, or municipal customers to receive financial incentives and technical support to reduce energy in new or existing buildings.

Hetch Hetchy Power – Residential Tiered Rates

Hetch Hetchy Power provides service to residential customers under its retail and Enterprise rates. As described in detail in Section 5 of this Report, the residential energy rates are offered as an inclining block structure over three tiers that are seasonally differentiated. This means that the energy rates on a $/kWh basis are higher in each subsequent block. The current tiers are a legacy structure from historic PG&E rate structures for the retail rates and reflect current rate structures for the Enterprise rates.

Hetch Hetchy Power – GUSE Service

Hetch Hetchy Power provides service to municipal entities through two existing rate codes, identified as GUSE and Enterprise. As noted in Section 1, GUSE rates are currently offered as a flat energy-only rate ($/kWh). However, as part of the rate plan recommended for this Study, GUSE rates will be offered in a rate structure similar to their customer class, such that rates will either be a customer and energy rate (a two-part rate) or a customer, energy, and demand rate (three-part rate). GUSE rates are recommended to be seasonally or TOU differentiated, depending on how the comparable class of Hetch Hetchy Power retail rates are offered.

GUSE rates are recommended to increase at a maximum of $0.03/kWh for each year of the recommended rate study (FY 2022–2023, FY 2023–2024). For the purposes of this Study, this limitation on the increase for GUSE customers is calculated on a class average basis (total dollars divided by total kWh for each group of GUSE customers). However, in general, this increase in projected revenue over the Study period is not equivalent to the COS for each class in which the GUSE customers exist. The recommended rate strategy is to eliminate this subsidy over time, and until it is completely phased out, to recover it from the non-GUSE, non-residential customers served by Hetch Hetchy Power so the total revenue requirement is met.

CleanPowerSF Characteristics

CleanPowerSF provides residents and businesses of the City with an alternative power source supplier compared to PG&E. However, as a CCA, CleanPowerSF only provides generation services to its customers; the delivery and outage response aspects of utility operations continue to be provided by PG&E. CleanPowerSF serves the majority of the City with alternative power; customers can either purchase their

"Green" product, which is at least 50% California-certified Renewable and more than 90% greenhouse-gas free energy, or their "SuperGreen" product, which is comprised of 100% California-certified Renewable and greenhouse gas free power.

Figure 2-9 provides a representation of the customers served by CleanPowerSF by customer class. Because CleanPowerSF must follow PG&E rate classes, this Report utilizes the term "general service" for the commercial classes served by CleanPowerSF.

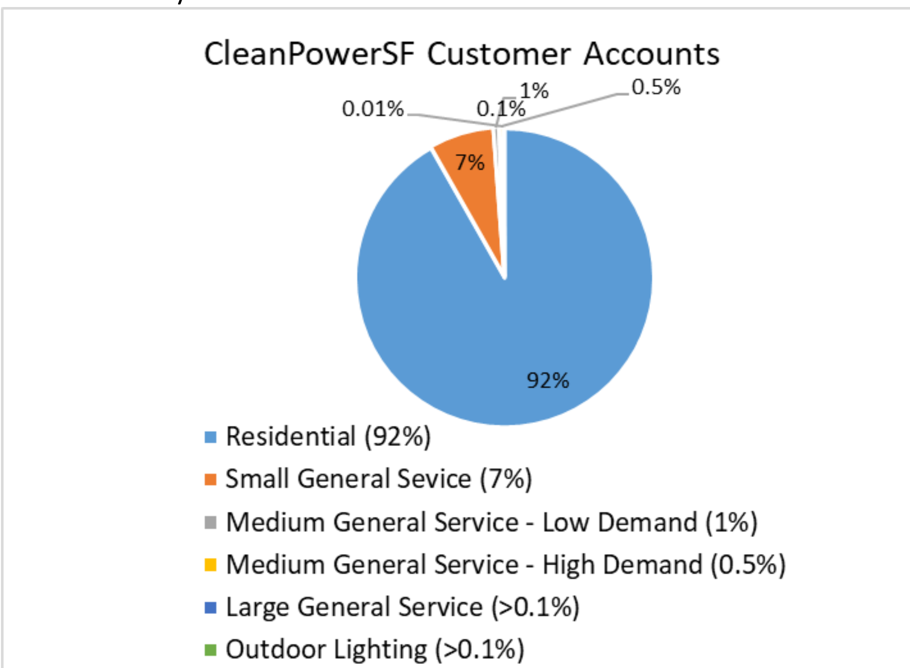


Figure 2-9. CleanPowerSF Customer Account by Percentage for Test Year

As suggested in Figure 2-9, the majority of the CleanPowerSF customers are residential customers in the City (92%), followed by Small General Service (7%), Medium General Service Low Demand (demand less than 499 kW), Medium General Service High Demand (demand greater than 500 kW, but less than 1,000 kw), and Large General Service (demand greater than 1,000 kW). CleanPowerSF also serves some outdoor lighting customers as well. As noted herein, SuperGreen customers pay a premium above the existing and recommended rates and are represented by all of the customer classes.

CleanPowerSF – Power Supply

CleanPowerSF obtains its power supply from a variety of sources, the majority of which is through competitively-bid contracts with power resources (PPAs). CleanPowerSF has entered into PPAs with renewable generation providers which include solar, wind, storage, and geothermal resources. For the purposes of this report, these resources are collectively referred to as "Renewable Energy;" however, as discussed later, they do provide some capacity as well. Additionally, CleanPowerSF purchases bundled renewable energy credits (RECs) and other GHG-free attributes on an as-needed and ongoing basis to augment its power supply needs, which are also included as Renewable Energy. Renewable Energy represents over 50% of CleanPowerSF's total power supply costs.

CleanPowerSF purchases a portion of its energy from the CAISO market, which includes a mix of renewable and non-renewable sources depending on the timing of the purchase, as well as limited amounts associated with contracts in place for non-renewable energy. For the purposes of this report, these power supply resources are referred to as "Energy Open Position." Other power supply expenses include those for purchasing capacity (also referred to as Resource Adequacy, or RA, as discussed later in this report), as well as CAISO fees for services related to scheduling, dispatching, and coordinating CleanPowerSF power supply in generation (referred to here as CAISO Fees). Lastly, CleanPowerSF also budgets a certain amount of funds specifically for contingency purchases. Figure 2-10 provides a summary of the various cost categories related to CleanPowerSF's power supply expenses estimated for the Test Year period by relative percentage.

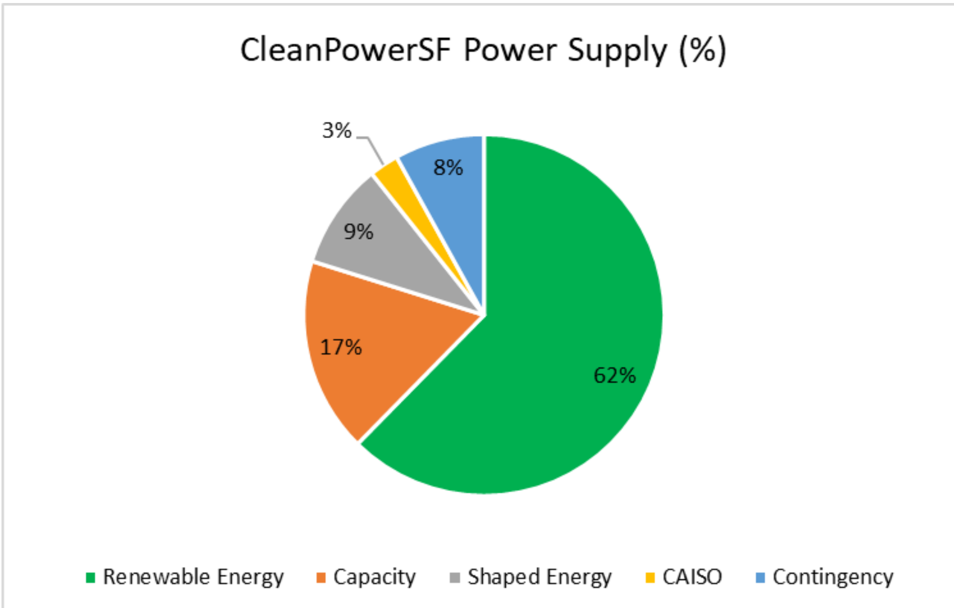


Figure 2-10. CleanPowerSF Power Supply by Category

Figure 2-11 provides a representation of the total sales by class estimated for CleanPowerSF for the Study period.

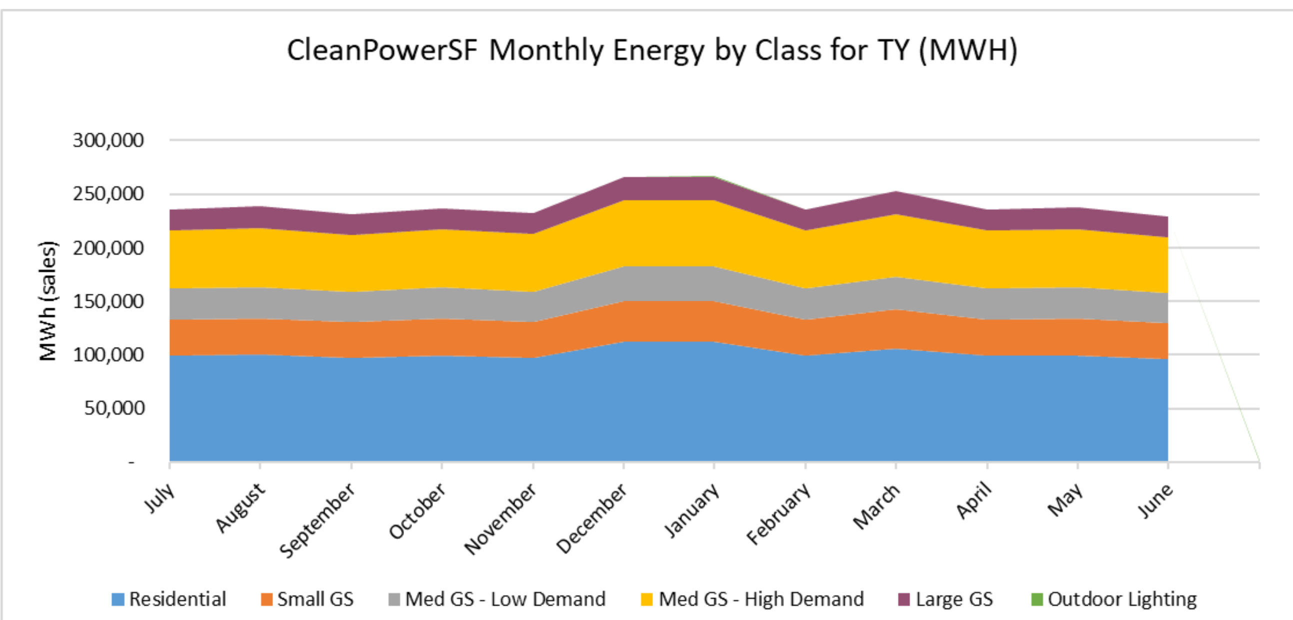


Figure 2-11. CleanPowerSF MWh Sales by Month

Total kWh sales are estimated to be approximately 2.9 million megawatt hours (MWh) for the Test Year period, the majority of which are associated with residential sales. Customer usage on a daily basis differs for the average CleanPowerSF customer from the average Hetch Hetchy Power customer. Figure 2-11 provides a representation of the hourly load profile for CleanPowerSF over a year (for 2019). Hourly peak load was approximately 455 MW during the peak in January 2019. In general, load for CleanPowerSF peaks during the winter months and decreases during the summer months.

Figure 2-12 provides a representation of the average typical daily load profile for the CleanPowerSF system during the winter and summer periods. Figure 2-13 provides similar typical daily load profiles for CleanPowerSF residential and medium general service low demand.

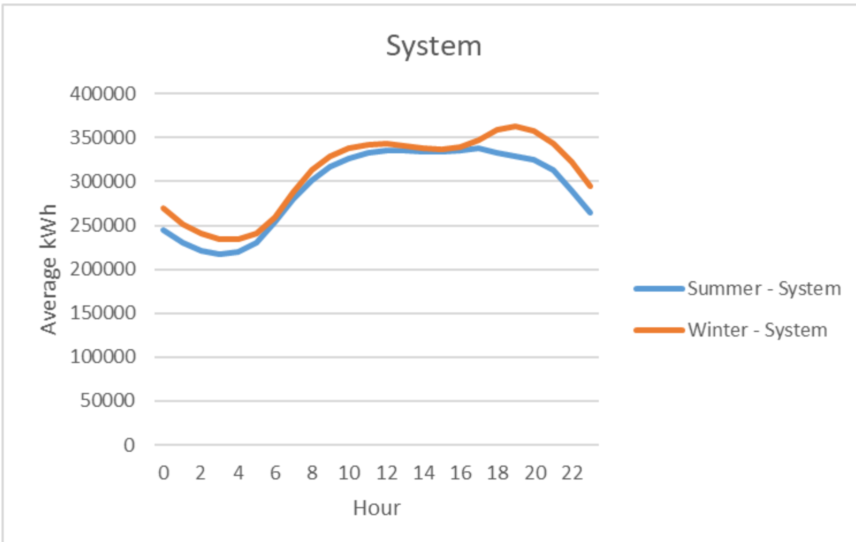


Figure 2-12. CleanPowerSF Average Daily Load Profile for System

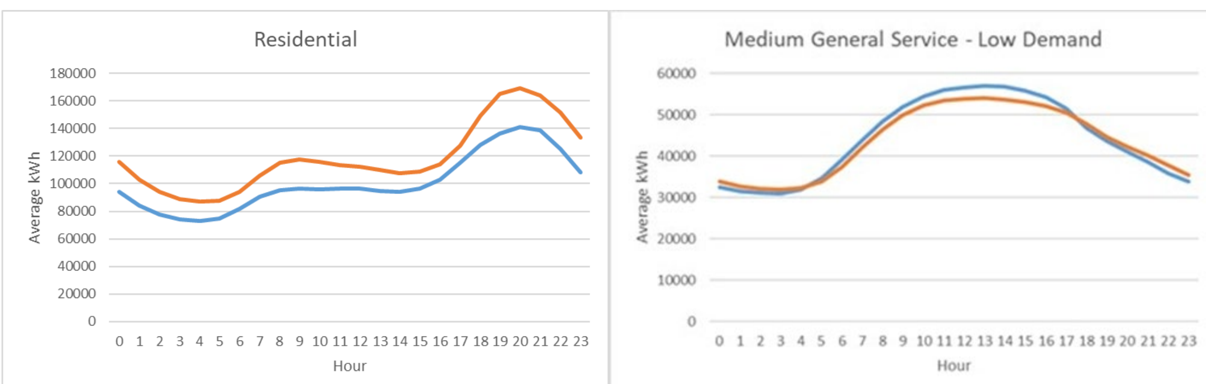


Figure 2-13. CleanPowerSF Average Daily Load Profile for Residential and Medium General Service – Low Demand

CleanPowerSF – Energy Programs

CleanPowerSF also funds energy programs for its customers, including its Local Renewable Energy Program, Peak Day Pricing (PDP) Program, Low-Income Inverters Program, and Heat Pump Water Heater Program partnership with BayREN. The Local Renewable Energy Program includes funds to develop renewable energy projects on SFPUC properties to generate GHG-free power, including solar facilities on reservoirs, and battery storage facilities. Customers who opt into CleanPowerSF's SuperGreen program receive 100% of their energy from renewable sources; revenues from these customers also fund local renewable energy investments. The PDP Program uses internally generated funds to pay commercial customers to reduce demand between 4–9 p.m. in the summer and fall. The Low-Income Inverter program is designed to provide incentives to cover the replacement of aged inverters on distributed solar facilities in the City for qualifying customers. Additionally, CleanPowerSF has partnered with BayREN to offer incentives to participating contractors that install energy-efficient electric heat pump water heaters in CleanPowerSF customers' homes. CleanPowerSF does not provide direct discounts to its generation rate, as that program is implemented by PG&E, is set at a discount to their delivery rates, and is funded by the State of California (CARE program).

Section 3
COST OF SERVICE FOR HETCH HETCHY POWER

Hetch Hetchy Power Introduction/Data Sources

This section provides a description of the cost of service process for Hetch Hetchy Power, which involves the development of the Test Year revenue requirement and the allocation of those costs to the various functions, classification, and ultimately to the customer classes (as provided in Figure 1-2). Supporting the cost of service process are several underlying data sources utilized to create the revenue requirement and the subsequent cost allocation methods. A summary of these data sources is provided below.

Load Data Provided by Advanced Metering Infrastructure

Hetch Hetchy Power has installed Advanced Metering Infrastructure (AMI) equipment at its customer locations, including “smart meters,” since approximately May 2019. AMI meters provide a benefit to both customers and the utility operation by allowing for two-way communication between the meter and the utility. From an operations perspective, AMI allows the utility to manage the flow of electricity on the system in a more precise manner that benefits customers. For example, the utility operations can pinpoint outages almost instantaneously and provide solutions for rerouting power without having to send trucks and crews to the field. Additionally, AMI allows the utility and the customer to understand how power is used on an hourly basis, providing valuable information for the development of rate programs designed to reduce costs, such as TOU rates. Together with the AMI metered customers served at PG&E service point, the majority of Hetch Hetchy Power customers have AMI systems or interval data recorders; however, some of the older customers’ meters have not been upgraded to these new systems as of the date of this Report. The SFPUC provided interval data for CY 2019 customer usage by class. This information was utilized to develop an understanding of how customers use power throughout the year, their contribution to the system peak, and their impacts on system costs, as described herein.

Hetch Hetchy Power Customer Billing Data

Developing accurate billing data for the Hetch Hetchy Power customers was a challenging aspect of this Study. Billing data was used for the 2019 period to capture usage patterns before the impact of COVID-19 on customer behavior, as it is assumed to be a better reflection of electricity usage by class for the Test Year period (future years of FY 2022–2023 and FY 2023–2024). However, utilizing 2019 billing data presented its own set of issues, as SFPUC subsequently implemented a new billing system, making comparisons between the old billing data and the new billing data difficult. Additionally, there have been changes to the customer mix for the Hetch Hetchy Power users since 2019, as new retail load has been added to the system, and the Master Meter residential accounts have been shifted to individual accounts, with the advent of the AMI systems discussed above. Further, several new areas of redevelopment in the City have occurred during the period between 2019 and the Test Year, as well as changes in the total load associated with both the GUSE and Enterprise customers. Efforts by the SFPUC and NewGen during this Study to reconcile the values for purposes of Test Year billing determinants were extensive. However, as indicated before, several of these efforts rely on assumptions regarding the number of customers within a class and how their energy usage may change over time. To the extent that the assumptions utilized are not realized or under- or over-represent actual usage in the future, this may have a material impact on Hetch Hetchy Power revenues and expenses and the projections developed for this Study and presented herein.

SFPUC Ten-Year Financial Plan

Budget data and cost (expense) projections were provided by the SFPUC in their Ten-Year Financial Plan, which were incorporated into the COS analysis and form the basis for the projected revenue requirement for the TY period. The Ten-Year Financial Plan incorporates the SFPUC's proposed budget for FY 2022–2023, with projections for purchased power and related costs (including costs for the WDT and TACs from PG&E) and estimates of labor costs during the five-year planning period. Projected costs also include the amortization of current debt issues for existing projects, as well as anticipated debt issues and use of revenues to fund the projects identified in the Ten-Year Capital Plan over the planning period.

The Ten-Year Plan also included load growth forecasts. This Study followed the forecasts of the Plan, though it was slightly more conservative while still expecting growth. The assumptions going into Hetch Hetchy Power load growth projections accounted for drought and economic recovery, as well as job growth, housing growth, pricing elasticity, and more. For Hetch Hetchy Power load growth specifically, forecasts assumed the San Francisco Municipal Transportation Agency (SFMTA) load growth to grow over the projection period of FY 2022–2023 to FY 2031–2032 due to a bus electrification pilot program and central subway station project. The SFPUC projects total airport loads to grow 4.4% annually on average growth over the ten-year projection period given load growth from new terminals and associated facilities, and other projects from the airport's master plan. Most Hetch Hetchy Power customers are seeing only a slight load growth projection over the ten years of the Plan.

Hetch Hetchy Power Cost of Service Analysis

As noted in Section 1, the revenue requirement refers to the amount of rate-related revenue a utility is projected to need during the Study period. For the purposes of this Study, Hetch Hetchy Power is utilizing a Test Year that represents the average of the two-year period from FY 2022–2023 to FY 2023–2024. The Hetch Hetchy Power Net Revenue Requirement for the Test Year is projected to be approximately $171.8 million. This value is driven by the specific "known and measurable changes" related to the investments projected in the SFPUC's 10-Year Financial Model, including offsetting revenues, as discussed herein. Because the Test Year is a multi-year representation, this value represents the average annual revenue to be collected by Hetch Hetchy Power in its retail rates. For the purposes of recommended Hetch Hetchy Power rate design, provided in Section 5 of this Report, revenues collected over the Study period will vary by year.

Detailed information regarding each component of the Hetch Hetchy Power Revenue Requirement for each year of the Study period is provided in a hyperlink in the Technical Appendix C. A summary of the Test Year Revenue is provided in Table 3-1.

Table 3-1
5-Year Summary Projection of Hetch Hetchy Power Revenue Requirement ($000)

Expense Line	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	Test Year	Percent of Total
O&M Expenses	$100,816	$108,990	$109,545	$113,112	$116,797	$104,903	50%
Power Purchases	$22,972	$22,442	$20,666	$24,252	$24,650	$22,707	11%
Transmission & Distribution Charges	$67,044	$76,087	$81,573	$91,077	$99,214	$71,565	34%
Debt Service	$3,905	$3,459	$10,484	$16,953	$16,923	$3,682	2%
Non-Debt Capital Expenses	$4,923	$7,580	$7,811	$13,029	$20,665	$6,252	3%
Total Expenses	$199,660	$218,558	$230,079	$258,423	$278,249	$209,109	
(Less Other Revenues)	($44,012)	($41,931)	($43,667)	($41,647)	($40,561)	($42,971)	
Deposit to/(Use of) Reserves	$0	$11,237	$11,345	$6,637	$7,015	$5,618	
Total	**$155,648**	**$187,864**	**$197,757**	**$223,412**	**$244,704**	**$171,756**	

Source: SFPUC 10-Year Financial Pro Forma Model and Power Matrix. Note, numbers may not add due to rounding.

O&M expenses consist of labor related to Hetch Hetchy Water (to provide power) and Hetch Hetchy Power (for other power purchases, delivery of power, and customer services and programs) both up-country and down-country expenses (see “Glossary of Terms”), including labor, services of the SFPUC Bureaus, non-personnel services, materials and supplies, equipment, programmatic projects, and other operating expenses. Other O&M costs include programmatic expenses (related to facilities maintenance) and compliance with federal regulations (related to the Western Energy Coordinating Council [WECC] and the National Electric Reliability Council [NERC]), as well as specific maintenance for redevelopment areas and its operations within the City. Hetch Hetchy Power also purchases steam and natural gas on behalf of selected customers and includes those costs in its O&M. However, these costs are directly offset by revenues (included within the Less Other Revenues category [see below]).

As indicated, the combined O&M expenses for Hetch Hetchy Power represent approximately 50% of the total expenses (before adjustments for other revenue and reserves). In addition to generating power from its own resources as identified in Section 1, Hetch Hetchy Power also purchases renewable energy and spot market energy as well as resource adequacy (capacity) and budgets for contingency for power supply. Combined, these power purchases represent approximately 11% of the total expenses during the Test Year period.

Hetch Hetchy Power also incurs charges for power transmission (TAC) as well as charges for use of PG&E’s distribution system (through the WDT). Hetch Hetchy Power characterizes certain other delivery costs (non-volumetric charges) associated with its purchased power within its total transmission and delivery costs. Hetch Hetchy Power is investing in a high voltage transmission and distribution infrastructure project, known as the Bay Corridor Transmission and Distribution (BCTD) project, which is anticipated to reduce costs for Hetch Hetchy Power during the Test Year (anticipated to be in service in FY 2023–2024) by replacing purchased transmission and distribution services for some of the areas where Hetch Hetchy Power customers are concentrated throughout the City. Including the impacts from the BCTD, total transmission and distribution costs represent approximately 34% of the non-adjusted revenue requirement for Hetch Hetchy Power during the Test Year.

Hetch Hetchy Power has issued debt in the past to finance investments in its system. These have included the 2015 Series AB revenue bonds, as well as the issuance of Qualified Energy Conservation Bonds (QECBs), Clean Renewable Energy Bonds (CREBs), and New Clean Renewable Energy Renewable Bonds (NCREBS). Additionally, SFPUC anticipates issuing additional debt to finance ongoing investments. Total debt service for the Test Year period is projected to be approximately $3.7 million. SFPUC also anticipates funding ongoing capital projects with revenue from retail rates (non-debt capital expenditures) of approximately $6.2 million during the Test Year.

Total expenses prior to adjustments for the Test Year are projected to be approximately $209.1 million.

As indicated, Hetch Hetchy Power generates revenues from non-retail services that are utilized to offset or reduce the total revenue requirement to be recovered from retail rates. These represent income from wholesale sales, the delivery of natural gas and steam, and services provided to CleanPowerSF, as well as specific revenues related to several of the programmatic elements included in the revenue requirement above. Additionally, Hetch Hetchy Power generates revenue from cap and trade credits it receives for its generation and from third parties that utilize its infrastructure (collectively referred to as pole attachment fees or as distributed antenna system [DAS] fees). Combined, these revenues are anticipated to be approximately $43 million during the Test Year period.

Other adjustments to the projected revenue requirement include a projected contribution to Hetch Hetchy Power's reserves of approximately $5.7 million for the Test Year (anticipated to occur in FY 2023–2024 with a contribution of approximately $11.2 million). The total of the operational expense less off-setting non-retail revenues plus contributions to reserve funds results in a net revenue requirement of approximately $171.8 million for the Test Year period.

Significant investments to the Hetch Hetchy Power system over the planning period include the BCTD, and improvements to the SFO substations. Additionally, the Ten-Year Capital plan includes improvements for the up-country water and power projects such as the O'Shaughnessy Dam Outlet Works and local power projects such as upgrades to the Power Distribution systems.

Functionalization and Classification

Allocating cost to Hetch Hetchy Power customer classes is achieved through three major processes: 1) functionalization, 2) classification, and 3) allocation. The functionalization and classification of the Test Year Revenue Requirement are discussed in the first part of this Section. The development of the allocation factors for the Test Year Revenue Requirement is discussed in the second portion of this Section.

Functionalization

Although budgeting and accounting systems generally follow functional groups (i.e., production, etc.), certain costs, such as those associated with operating costs (labor), are generally not assigned by accounting and budgetary convention to major function. A COS study usually requires the rearrangement of certain expenditures into functional groups: 1) to be more representative of the expenditure causation, 2) to combine costs that have been incurred for a similar purpose, and 3) to facilitate the allocation of cost responsibility. Thus, the functionalization of certain costs is an industry-accepted rate-making mechanism to apportion such costs to the common utility functions.

Table 3-2 provides a categorization of the COS by function (as a result of the cost allocation process) for Hetch Hetchy Power. As indicated previously, Hetch Hetchy Power provides services that can be functionalized by all four "traditional" utility functional elements, including Power Supply, Transmission, Distribution, and Customer. Additionally, several cost items were directly assigned as explained herein.

Table 3-2
Hetch Hetchy Power – Functionalization of Costs ($000)

Expense Item	Power Supply	Transmission	Distribution	Customer	Direct Assign	2-Year Test Year
O&M Expenses	$35,143	$21,606	$28,317	$13,454	$6,383	$104,903
Power Purchases	$22,707	$0	$0	$0	$0	$22,707
Transmission & Distribution Charges	$6,362	$30,047	$21,632	$0	$13,524	$71,565
Debt Service	$2,728	$267	$0	$688	$0	$3,682
Non-Debt Capital Expenses	$2,838	$914	$2,358	$142	$0	$6,252
Sub-Total Expenses	$69,778	$52,834	$52,306	$14,284	$19,907	$209,109
(Less Other Revenues)	($19,241)	($365)	($3,135)	($323)	($19,907)	($42,971)
Deposit to/(Use of) Reserves	$1,709	$1,774	$1,663	$472	$0	$5,618
Total	$52,246	$54,243	$50,834	$14,433	$0	$171,756
% Total	**30%**	**32%**	**30%**	**8%**	**0%**	**100%**

O&M expenses were functionalized based primarily on labor costs utilizing information regarding up-country and down-country labor as assigned by the SFPUC. Labor costs were reviewed at the individual position level, with managers assigning each position (including positions budgeted but currently vacant) to the programs and functions on which that employee works. If data was available on the purpose of other O&M expenditures—such as consultant services, payments to other government agencies, and programmatic projects—these expenses were also assigned. For more general expenditures where limited data was available, such as materials and supplies, the labor allocator was used. Programmatic expenses have been assigned by labor, compliance-related costs (for the WECC/NERC-related costs), and overall revenue requirement (using the total assigned to each function as a derived allocation method). Additionally, approximately $6.3 million of the expenses within this category were directly assigned (related to the Treasure Island Facilities Maintenance fund).

Altogether, approximately 34% of the O&M costs were allocated to the power supply function, approximately 21% to the transmission function, 21% to the distribution function, and 13% to the customer function (a small portion was directly assigned, as noted below).

Power purchases were assigned to the power supply function and approximately $13.5 million of the power purchases costs are directly assigned, as they are incurred for the gas and steam sales that are directly passed through to customers and are fully offset by equivalent revenues. Transmission and distribution charges were primarily associated with the TAC and WDT charges and assigned to those functions accordingly; however, approximately 9% of the total transmission and distribution charges are related to other power supply purchases and assigned accordingly.

As indicated above, debt service costs include the ongoing amortization of the 2015 Series AB (senior lien revenue bonds) as well as the QECBs, CREBs, and NCREBs (junior lien bonds). These costs are assigned to the function for which the bonds were issued, with the majority of the costs associated with power supply, and a portion associated with transmission and customer functions. Debt service costs for new debt to be issued during the Test Year were separately allocated according to the functions identified in the two-year Capital Improvement Plan (CIP). The two-year CIP was also utilized to allocate costs associated with the revenue-funded capital needs.

Total revenues were then adjusted to account for revenues provided by other sources, as well as projected uses of (or contributions to) reserves. Approximately half of the other revenues were directly assigned (as offsets to the costs also directly assigned). The remainder of the other revenues were allocated based on power supply (wholesale revenues) and overall revenue requirement. Projected use of reserves was allocated based on overall revenue requirement as well.

Power Supply

Hetch Hetchy Power provides its own power supply through its hydroelectric resources located in Yosemite National Park and the surrounding mountains east of San Francisco. Additionally, it purchases energy through one renewable energy PPA, as well as spot market purchases from the CAISO. Table 3-3 provides a summary of the classification/sub-functionalization of the Hetch Hetchy Power supply costs for the Test Year.

Table 3-3
Hetch Hetchy Power – Power Supply ($000)

Expense Item	Hydro	System Dispatching	Purchased Power – Demand	Purchased Power – Energy	RA Costs	Total
Up-country O&M Expenses	$21,063	$5,727	$105	$177	$0	$27,072
Down-country O&M Expenses	$0	$5,599	$1,952	$521	$0	$8,072
Power Purchases	$0	$0	$6,362	$16,239	$6,468	$29,069
Debt Service	$2,728	$0	$0	$0	$0	$2,728
Non-Debt Capital Expenses	$2,838	$0	$0	$0	$0	$2,838
Sub-Total Expenses	$26,629	$11,325	$8,419	$16,937	$6,468	$69,778
(Less Other Revenues)	($1,320)	($115)	($1,311)	($16,495)	$0	($19,241)
Deposit to/(Use of) Reserves	$981	$435	$276	$17	$0	$1,709
Total Expenses	**$26,291**	**$11,644**	**$7,384**	**$459**	**$6,468**	**$52,246**
% Total	**50%**	**22%**	**14%**	**1%**	**12%**	**100%**

Hetch Hetchy Power supply costs are classified into demand and energy, and then further sub-functionalized into hydroelectric (hydro), system dispatching, and purchased power demand (PP-

Demand), as well as purchased power energy and resource adequacy (RA) costs. The expense items include those identified for the revenue requirement; however, the O&M expenses have been further categorized into those associated with the "up-country" operations and those associated with the "down-country" operations, and include programmatic expenses related to facilities maintenance (for hydroelectric systems), as well as other programs that have been allocated based on the total expenses within each sub-function/classification. Because the up-country operations are responsible for the hydroelectric facilities, the majority (78%) of those expenses are assigned to the "hydro" sub-function; however, some of these costs are related to system dispatch and system energy.

System dispatching refers to the alignment of loads and resources and is primarily associated with the labor aspect of Hetch Hetchy Power. Purchased power demand relates to the fixed costs associated with the renewable energy and non-renewable energy other contracts Hetch Hetchy Power has to provide electricity, including requirements to provide RA, as mandated by CAISO. PP-Energy relates to the variable costs associated with electricity generation as well as purchases. The power purchases expense item is split between purchase power—demand and purchased power—energy based on the underlying nature of these costs. Debt service is assigned to the hydro facilities. The power supply portion of revenue-funded capital (non-debt capital) has been assigned to hydro as well. Other revenues are assigned based on the total within each sub-function/classification, with the exception of wholesale energy sales (offsets purchased power energy); cap and trade credit auction revenues, which are used to offset the PP-Demand costs; and the Low Carbon Fuel Standard Credits, which are used to offset the hydro demand costs for the purposes of this Study. The contribution to reserves is assigned based on the totals within each sub-function/classification.

Transmission

Hetch Hetchy Power owns limited transmission facilities that deliver power from their hydro facilities to several sub-stations located in Stanislaus and Alameda counties. Additionally, Hetch Hetchy Power incurs costs to transmit power from its renewable energy PPAs Transmission Access Charges (TAC) as well as spot market purchases from the CAISO. Table 3-4 provides a summary of the classification/sub-functionalization of the Hetch Hetchy Power transmission-related costs for the Test Year.

Table 3-4
Hetch Hetchy Power – Transmission ($000)

Line Item	Substation	Conductor	Transmission Access Charges	Total
Up-country O&M Expenses	$8,913	$10,563	$528	$20,004
Down-country O&M Expenses	$728	$874	$0	$1,602
Power Purchases	$30	$33	$29,985	$30,047
Debt Service	$29	$237	$0	$267
Non-Debt Capital Expenses	$101	$813	$0	$914
Sub-Total Expenses	$9,801	$12,520	$30,513	$52,834
(Less Other Revenues)	($68)	($87)	($211)	($365)
Deposit to/(Use of) Reserves	$329	$420	$1,025	$1,774
Total Expenses	**$10,062**	**$12,853**	**$31,327**	**$54,243**
% Total	**19%**	**24%**	**58%**	**100%**

Similar to the Power Supply cost assignments, Hetch Hetchy Power transmission has been classified/sub-functionalized into substation (transmission level), conductor (wires and associated delivery equipment), and TAC. Programmatic expenses are primarily allocated by labor; however, a small portion are allocated by total transmission expenses and are assigned to up-country and down-country based on information provided by the SFPUC. The majority of the up-country transmission O&M costs are split between the substation and conductor costs. The down-country transmission O&M costs are significantly less than the up-country transmission O&M costs, given the limited transmission assets owned by Hetch Hetchy Power within the City. Power purchases incur transmission-related costs, a portion of which are assigned by labor costs within the organization and therefore were assigned to substations and conductor sub-functions. However, most of these costs are associated with the TAC. Debt service assigned to transmission is allocated based on the projects funded by the debt issue and anticipated use of the proceeds of new debt as provided by the SFPUC. Revenue-funded capital (non-debt capital) follows the allocation for the 2-year capital budget. Other transmission-related revenues, which offset the total revenue requirement for transmission cost, are allocated based on total expenses, as are the anticipated contributions to reserves.

Distribution

Hetch Hetchy Power owns limited distribution facilities that deliver power from the transmission system to customers located in San Francisco and adjacent San Mateo County, including dedicated facilities related to SFO. Hetch Hetchy Power incurs costs to deliver power from the transmission system to its customers primarily through PG&E's WDT charges. Additionally, Hetch Hetchy Power incurs labor and expense-related costs to maintain its limited distribution facilities. More critically, Hetch Hetchy Power incurs significant costs associated with the ownership of its streetlighting facilities in the City. Table 3-5 provides a summary of the classification/sub-functionalization of the Hetch Hetchy Power distribution-related costs for the Test Year.

Table 3-5
Hetch Hetchy Power – Distribution ($000)

Line Item	Dist. Subs.	Cond.	Trans.	Service Drop	Meter	Street Lighting	WDT Charges	Total
Down-country O&M Expenses	$3,039	$2,797	$4,016	$416	$1,548	$16,231	$269	$28,316
Power Purchases	$0	$341	$489	$50	$0	$0	$20,752	$21,632
Debt Service	$0	$0	$0	$0	$0	$0	$0	$0
Non-Debt Capital Expenses	$54	$251	$615	$615	$615	$207	$0	$2,357
Sub-Total Expenses	$3,093	$3,389	$5,120	$1,081	$2,163	$16,438	$21,021	$52,305
(Less Other Revenues)	($21)	($23)	($35)	($7)	($15)	($2,887)	($145)	($3,133)
Deposit to/(Use of) Reserves	$103	$114	$172	$36	$73	$458	$706	$1,662
Total Expenses (1)	**$3,175**	**$3,480**	**$5,257**	**$1,110**	**$2,221**	**$14,009**	**$21,582**	**$50,834**
% Total	**6%**	**7%**	**10%**	**2%**	**4%**	**28%**	**42%**	**100%**

(1) Numbers may not add due to rounding

Hetch Hetchy Power distribution costs are classified and/or sub-functionalized into the various elements of the distribution system, as well as costs incurred for the WDT charges. Distribution system components include substations (distribution), conductors (wires), transformers (which step power down to usage levels commensurate with the customers), service drops (which is the equipment between the transformer and the customer’s meter), and the meter. As indicated previously, Hetch Hetchy Power has installed AMI meters for most of its customers, which allows for two-way communication between the meter and the distribution management system, as well as for unique billing arrangements (such as TOU pricing structures). The up-country O&M expenses for the distribution system are minimal and consist of very limited infrastructure to serve facilities for power generation and transmission infrastructure on U.S. Forest Service land and/or in and around Yosemite National Park. Therefore, those costs have been incorporated into those other functional elements of the up-country operations.

Down-country expenses are allocated based on labor assigned to the various distribution components, with the majority of the costs associated with the streetlighting maintenance costs. Most of the power purchases are allocated to the WDT charges, although some are allocated to elements of the distribution system based on labor. Essentially zero costs for debt service are allocated to the distribution system (they are minimal); however, revenue-funded capital is allocated based on the anticipated expenses associated with the 2-Year CIP. The majority of the other revenues associated with the distribution system include revenues from DAS pole attachment fees, which are used to offset streetlighting expenses. The other elements of the offsetting revenues, as well as the use of reserve accounts, are allocated based on total expenses.

Customer Service/Customer Programs

Hetch Hetchy Power provides customer service and customer accounting (billing and data management systems), as well as significant customer programs. These customer programs include some designated for municipal customers and some for non-municipal customers. These categories provide the basis for the classification/sub-functionalization of the Hetch Hetchy Power customer-related expenses. Table 3-6 provides a summary of the classification/sub-functionalization of the Hetch Hetchy Power customer-related costs for the Test Year.

Table 3-6
Hetch Hetchy Power – Customer Service/Customer Programs ($000)

	Customer Service	Customer Accounting	Customer Programs – Municipal	Customer Programs – Non-Municipal	Total
Down-country O&M Expenses	$2,160	$10,788	$425	$80	$13,454
Power Purchases	$0	$0	$0	$0	$0
Debt Service	$0	$0	$487	$201	$688
Non-Debt Capital Expenses	$0	$0	$101	$41	$142
Total Expenses	$2,160	$10,788	$1,013	$322	$14,284
(Less Other Revenues)	($40)	($198)	($62)	($24)	($323)
Deposit to/(Use of) Reserves	$72	$358	$32	$10	$472
Total Expenses	**$2,192**	**$10,949**	**$983**	**$309**	**$14,433**
% Total	**15%**	**76%**	**7%**	**2%**	**100%**

As indicated above, the up-country operations directly serve a small handful of customers; therefore, those costs were allocated to other functions and are not included above. The down-country O&M costs are allocated based on labor and represent the majority of the Hetch Hetchy Power-related customer costs. Programmatic customer-related expenses within the O&M costs are allocated based on the total expenses, as are the other revenues and use of reserves. Debt services uses the 2-year CIP to allocate to the customer programs, as does the revenue-funded capital.

Customer Class Allocation Factors – Hetch Hetchy Power

General

The previous section developed the assignment of the operational and ongoing investment costs for Hetch Hetchy Power into the various functions or business units provided by the utility. This section discusses the development of the factors utilized to allocate those costs by their electricity usage characteristics and cost causation. As noted in Section 1, utility costs can be classified as demand related, energy related, customer related, revenue related, and direct assignment. The demand-related allocation factors are referred to as "demand" allocation factors and are described below. These factors are utilized to assign fixed costs to customer classes based on the amount of demand they put on the system at certain times. Energy-related allocation factors assign costs based on the combined energy usage of the class. Customer-related allocation factors assign costs to customer classes based on the number of customers within the class and how they utilize the various customer-related programs and services offered by the utility. Revenue-related allocation factors utilize the proportional combined costs of the other allocation factors. Directly assigned costs are allocated directly to specific customer classes.

It is important to note that Hetch Hetchy Power serves a much different mix of customers than that served by CleanPowerSF and that each group utilizes power differently, as indicated in Section 2. Additionally, the cost structure for Hetch Hetchy Power is different from that of CleanPowerSF, including its costs to provide delivery services in addition to power supply and customer-related costs. The Hetch Hetchy Power costs are therefore allocated to the customer classes according to the respective customer characteristics and unique cost allocation factors which have been developed for each class and for each type of cost. The customer classes for Hetch Hetchy Power include Residential, Small Commercial, Medium Commercial, Large Commercial, and Industrial.

Demand Allocation Factors

Demand cost allocation for Hetch Hetchy Power utilized three different methodologies to assign costs to the customer classes. These approaches incorporate the “Coincident Peak” (CP) or the “Non-Coincident Peak” (NCP) of each customer class. These include a 12 CP method (for certain generation demand and transmission-related costs), the Average and Excess Demand (AED) method (referred to as the Hydro Method) for Hetch Hetchy Power resource-related costs, and a 12 NCP method for portions of the distribution demand costs. The 12 CP is the amount of total load from all customers collectively at the same time (coincident with each other and the peak of the system) for all twelve months of the projected Test Year. The 12 NCP is the peak total load from all customers within a class (regardless, or non-coincident, with the other classes or system peak) for all 12 months of the test year. Each method is explained below.

12 Coincident Peak (CP) Method

The CP demand allocation methodology allocates costs based on the customer class contributions to the system CP for each month of the year. Typically, CP allocators are utilized to assign production demand-related costs to customer classes because production demand costs are generally driven by the utility’s need to meet its system peak. A 12 CP is utilized to allocate the System Dispatching and Purchased Power Demand-related costs for Hetch Hetchy Power to the respective customer classes.

Average and Excess Demand/Hydro Method

In addition to the 12 CP method, the Hetch Hetchy Power Hydro-related demand costs (related primarily to up-country labor, as well as existing debt service) are allocated using an AED/Hydro method to allocate to customer classes. The AED/Hydro method utilizes average demand (which is energy) and excess demand (based on the 4 CP, or the four months of the system’s peak) to assign fixed costs to customer classes. The theory behind using the AED/Hydro method is that for certain resources, such as hydroelectric and other generation facilities that continuously run, the facilities are designed for both meeting energy and demand needs. Therefore, the use of a “hybrid” demand cost allocator (which incorporates energy) fits better with the design and use of the generation facility than a pure demand cost allocator. The results of both the 12 CP and AED/Hydro demand cost allocation processes are provided in Table 3-7. As noted, for the purposes of the rate design and cost allocation, the characteristics of the energy usage at SFO have been included with the industrial customers.

Table 3-7
12 CP Cost Allocation

Customer Class	AED/Hydro Allocation % (1)	12 CP Allocation % (1)
Residential	2.7%	2.5%
Small Commercial	6.6%	7.0%
Medium Commercial	14.8%	14.8%
Large Commercial	11.0%	12.0%
Industrial (2)	64.9%	63.7%

(1) Based on Test Year projections provided by SFPUC.
(2) Industrial includes airport (SFO).

The difference between the 12 CP and AED/Hydro demand cost allocation methods is not large; however, the AED/Hydro method tends to move more costs to customer classes with higher energy usage, as expected. This includes the industrial class (including SFO), which is allocated a proportionally higher amount of the costs utilizing the AED/Hydro methodology. Similarly, customer classes with lower energy usage, such as small commercial, medium commerical, and large commercial, are assigned proportionally less costs using the AED/Hydro methodology than the 12 CP methodology. Residential class cost allocation is also slighly higher under the AED/Hydro methodology.

Figure 3-1 provides a graphical representation of the projected contribution to the peak demand (CP) by month for each customer class served by Hetch Hetchy Power for the Test Year, based on historic usage patterns.

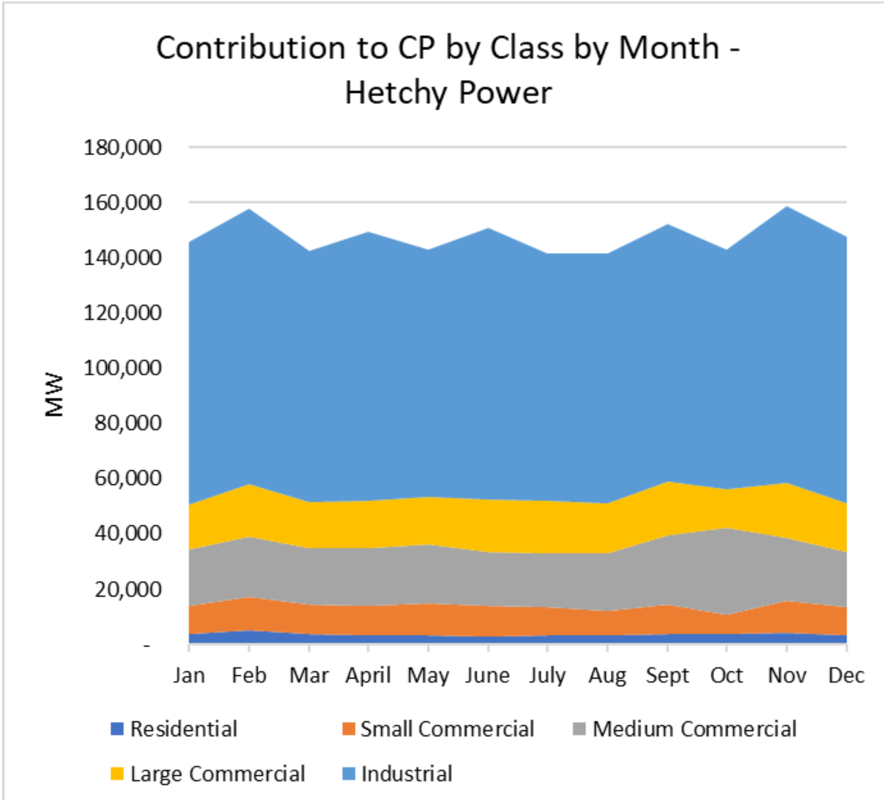


Figure 3-1. Hetch Hetchy Power 12 CP Demand Cost Allocation

As shown in Figure 3-1, while there are a few months of peaks (during winter months) and relatively flat load from July through October (seen primarily in the commercial classes and driven largely by the Industrial load including SFO), the monthly peak demand months for Hetch Hetchy Power appear to be relatively constant throughout the year.

12 Non-Coincident Peak (NCP) Method

The NCP demand allocation method is based on the theory that demand costs are strongly influenced by the highest demand of each customer class, regardless of when that class's peak demand occurs. NCP demand allocators are primarily used to allocate distribution-related costs because the design of these facilities is more consistent with the demand of the classes, rather than the demand of the entire system. This allocation results in the majority of the distribution demand-related costs being allocated to the larger commercial customers (medium, large, and industrial classes).

For the Hetch Hetchy Power system, two different modified 12 NCP methods were utilized to allocate distribution demand-related costs. This includes a 12 NCP for primary and secondary customers, and a 12 NCP method excluding the airport and the anticipated reduction in demand charged from PG&E from the BCTD project on industrial customers. A "pure" 12 NCP method was developed to support the modified versions utilized for this Study, but not as an allocation factor for the COS analysis.

The 12 NCP for primary and secondary customers was used to allocate costs associated with the distribution substations, conductors (wires), and transformers. The 12 NCP excluding the airport and contribution of the BCTD was used to allocate the projected WDT charges for use of the PG&E distribution system, as the excluded customers do not incur WDT costs. The difference between these two methods is a very minor reduction in cost allocation for the industrial customers of the distribution-related costs from the WDT charges. The remainder of the distribution infrastructure-related costs are allocated utilizing customer-related costs. The modified methods exclude the NCP associated with the airport (SFO), because of the manner in which the airport takes power.

Table 3-8
Modified 12 NCP Allocation Methods

Customer Class	12 NCP Prim. Sec. %	12 NCP x SFO/BCTD
Residential	3.5%	4.9%
Small Commercial	8.4%	11.6%
Medium Commercial	16.0%	22.1%
Large Commercial	11.7%	16.2%
Industrial (1)	60.5%	45.2%

(1) Industrial includes SFO for 12 NCP Primary/Secondary allocator. SFO excluded from 12NCP x SFO/BCTD (see text).

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those costs or expenses classified as variable or energy related and assumed to vary directly with the level of kWh sales or generation. The costs classified herein as variable or energy related for Hetch Hetchy Power include the energy-related power purchase costs, as well as the transmission access charges (charged on an energy basis).

Net Energy for load (NEFL) is used to allocate energy-related costs; this is based on customers' consumption of energy in kWh (sales), which have been adjusted for losses. For this analysis, NEFL is used to allocate energy-related production and transmission costs (See Table 3-9). The NEFL is a direct relationship between the costs incurred and the customer classes (in this case, energy-related power purchases and transmission-related charges). As expected, the larger usage customer classes incur the majority of these costs.

Table 3-9
Energy Cost Allocation

Customer Class	NEFL (MWh)	Allocation (%)
Residential	29,243,432	2.8%
Small Commercial	65,698,306	6.4%
Medium Commercial	152,156,332	14.8%
Large Commercial	109,610,877	10.7%
Industrial (1)	673,229,953	65.4%
Total	1,029,938,901	

(1) Industrial class includes airport. See text.

Customer Allocation Factors

Customer costs are defined herein as those costs related to the number of customers. Included in the customer-related costs are the investment (asset) costs required to serve customers (as part of the distribution system), which include the equipment from the transformers to the customer premise (service drop and meter costs). Additionally, labor and other costs associated with customer service and accounting (billing, collecting, and other customer-related functions), as well as customer programs, are allocated using weighted number of customers. The customer allocation factors developed for this Study were based on the projected average number of customers in each class during the Test Year.

The weighted customer allocation factor is based on the number of customers in a particular class times a weighting factor. The weighting factors were developed based on the estimated costs associated with serving non-residential (commercial) customer classes, recognizing that serving these customer classes is more expensive on a per-customer basis. As indicated, Hetch Hetchy Power funds various programs, which have been defined as "municipal" and "non-municipal." Municipal program costs are allocated based on weighted number of customers in each class, excluding residential, as there are municipal customers within each of the non-residential customer classes. Non-municipal program costs are allocated based on weighted number of customers, including residential customers. Table 3-10 provides a summary of the allocation percentages for the weighted customer allocation factor and the weighted customer allocation factor excluding residential customers.

Table 3-10
Customer Cost Allocation

Customer Class	Weighted Customer (%)	Weighted Customer X Res. (%) (1)
Residential	48%	0%
Small Commercial	24%	46%
Medium Commercial	18%	35%
Large Commercial	5%	9%
Industrial (2)	5%	10%

(1) Excluding residential (see text).

(2) Industrial class includes airport. See text.

Adjustments to Allocation Factors

Other adjustments were made to specific customer classes recognizing their unique characteristics, either defined by their usage, contracts, or accounting. A summary of these adjustments is provided below.

High Voltage Customers

As indicated herein, some customers on the Hetch Hetchy Power system take service at a "high-voltage" level. In general, these customers either use energy at a higher voltage or own their own voltage regulating equipment. Customers may use power from the distribution system but take power at primary voltage, which is a higher voltage level than much of the remaining system. Because these customers are not utilizing the entirety of the distribution system (they are only using the "primary" system, not the "secondary" or lower voltage system), they should not be assigned the costs associated with the entire distribution system. Therefore, the cost allocation has been adjusted (see the discussion regarding 12 NCP) for the Large Commercial and Industrial class customers to recognize this reduction in cost causation. However, not all customers within those classes take power at primary voltage. Therefore, the difference in the costs between primary and secondary (and transmission level) has been included in the rate design for these customers, as discussed in Section 5 of this Report.

Streetlighting for Hetch Hetchy Power

Other adjustment factors utilized during the cost allocation process include the use of direct assignment for streetlighting. Hetch Hetchy Power owns and maintains the streetlighting system; however, for the Study, given outstanding litigation, it is assumed energy is provided by PG&E. The cost for the streetlighting system is assigned to each customer class based on projected energy sales for the Test Year, exclusive of sales from retail customers within each class. This does not mean that the costs are not recovered from retail customers, however, just that the assignment of the costs excludes their contribution to the total class sales.

Section 4
COST OF SERVICE RESULTS FOR HETCH HETCHY POWER

Hetch Hetchy Power Allocation and Assignment of Cost of Service

The allocated cost of service results for the Hetch Hetchy Power operations are provided in Table 4-1. The total revenue requirement for the Test Year period is approximately $171.7 million, which has been functionalized, classified, and allocated to the customer classes. The majority of the costs are assigned to the industrial class, which includes SFO operations (approximately 53%), and the remainder are assigned to the residential and commercial classes (small, medium, and large).

Table 4-1
Cost of Service – Hetch Hetchy Power ($000)

	Residential	Small Commercial	Medium Commercial	Large Commercial	Industrial	Total
Power Supply	$1,357	$3,552	$7,722	$6,009	$33,605	$52,246
Transmission	$1,452	$3,613	$8,016	$6,086	$35,075	$54,243
Distribution	$3,650	$5,796	$10,547	$6,723	$24,119	$50,834
Customer	$6,425	$3,644	$2,792	$734	$837	$14,433
Revenue Requirement	$12,884	$16,606	$29,078	$19,553	$93,636	$171,756

Allocation and Assignment of Cost of Service

The results of the cost allocation analysis are presented in Table 4-2, along with a comparison of the cost recovery currently projected for the Test Year.

Table 4-2
Existing Test Year Rate Revenues vs. Test Year Revenue Requirements – Hetch Hetchy Power ($000)

Customer Class	Test Year Existing Rate Revenue	Test Year Revenue Requirement	Difference
Residential	$7,102	$12,884	$5,782
Small Commercial	$12,002	$16,605	$4,603
Medium Commercial	$19,645	$29,078	$9,433
Large Commercial	$14,550	$19,553	$5,003
Industrial (1)	$115,166	$93,636	($21,530)
Total (2)	$168,464	$171,756	$3,292

(1) Includes revenue and revenue requirement for SFO.

(2) Totals may not add due to rounding.

The difference between the Test Year existing rate revenue projections and the Test Year Revenue Requirements helps drive cost recovery by customer class in the rate design process.

Hetch Hetchy Power Seasonal and TOU Periods

Several Hetch Hetchy Power rates are offered as a seasonal TOU option based on historic PG&E rate schedules. For those rates, as indicated below, Hetch Hetchy Power utilizes a summer season of May through October (six months) and a winter season of November through April (six months), which is slightly different than the current four-month summer and eight-month winter seasons for PG&E.

Hetch Hetchy Power also utilizes historic TOU period definitions offered by PG&E for its Enterprise customers. The TOU period for the summer on-peak is 12:00 PM to 6:00 PM, part-peak is 8:30 AM to 12:00 PM and 6:00 PM to 9:30 PM, and off-peak is 9:30 PM to 8:30 AM The winter part-peak period is 8:30 AM to 9:30 PM, and off-peak is 9:30 PM to 8:30 AM. All on-peak and part-peak times are for Monday through Friday, with exception of holidays.

Table 4-3 provides a summary of the seasonal and TOU periods for Hetch Hetchy Power.

Table 4-3
Seasonal and TOU Periods for Hetch Hetchy Power

Season	Hours	Days
Summer (May–October)		
On-Peak	12:00 Noon to 6:00 PM	Monday–Friday (except holidays)
Part-Peak	8:30 AM–12:00 Noon 6:00 PM to 9:30 PM	Monday–Friday (except holidays)
Off-Peak	9:30 PM to 8:30 AM	Monday–Friday (except holidays), All Day Saturday, Sunday, and Holidays
Winter (November–April)		
Part-Peak	8:30 AM to 9:30 PM	Monday–Friday (except holidays)
Off-Peak	9:30 PM to 8:30 AM	Monday–Friday (except holidays), All Day Saturday, Sunday, and Holidays

Hetch Hetchy Power – TOU Periods and Price Differentiation

As part of this Study, NewGen and SFPUC developed an analysis of the power supply costs differential for the Hetch Hetchy Power seasonal and TOU rates. As indicated above, some Hetch Hetchy Power rates currently have a winter and summer rate differential (for energy and demand, as appropriate).

These periods are consistent with historic PG&E seasonal and TOU periods; in recent years PG&E has shifted to different timeframes to reflect the changing nature of California energy markets. At that time, Hetch Hetchy Power elected to keep its current seasonal and TOU periods, as it was not clear whether PG&E's revised times better aligned with Hetch Hetchy Power costs than the current time periods. At this time, we are not recommending a change to the Hetch Hetchy Power seasonal or TOU time periods, as this would represent a significant change to rate schedules that requires more detailed analysis and significant customer outreach. Therefore, all analysis below follows the current periods. The data and methodologies developed in this Study can be used to consider changes to these periods going forward, as desired.

For most utility systems, only the generation function includes pricing that varies by TOU; the transmission, distribution, and customer functions do not vary by time, as they are primarily fixed costs. Therefore, the results of the analysis of the TOU price differentials would be appropriately added to the energy only rate. For energy costs, the analysis utilized the variable prices obtained from the SFPUC as part of their aggregate price per hour, which is influenced by the CAISO power market.

Seasonal & TOU Energy Analysis

The seasonal and TOU energy analysis for Hetch Hetchy Power was determined from the historic hourly load profiles for each customer class for 2019 and the corresponding hourly energy prices from the CAISO. The approach was to utilize the load as a "weighting" mechanism to determine average power supply costs during the appropriate period. For example, commercial customers, in general, peak during the day (for example, office buildings), when CAISO market prices are generally lower than at peak times. By using a weighted average price to determine the relationship between seasonal and TOU periods, the analysis better reflects the underlying cost causation.

As indicated in Section 2, for Hetch Hetchy Power, most of the power supply costs are associated with the hydro power supply resources owned by the City. However, for any given hour during the year, Hetch Hetchy Power is either buying power from the CAISO market to meet its needs or selling excess power into the CAISO market, if available. Table 4-4 provides a summary of how the variability in the market power prices is used as a guide to develop the pricing differential for the time and seasonally differentiated energy rates developed for this Study. The on-peak period for the summer includes the on-peak and part-peak periods, as the current rates structures set these two periods equal to each other, therefore, they are grouped together for purposes of this analysis.

Table 4-4
Hetch Hetchy Power TOU Energy Price Differential Analysis

	Residential	Small Commercial	Medium Commercial	Large Commercial	Industrial
Summer	0.82	0.82	0.82	0.82	0.82
Winter	1.2	1.2	1.2	1.2	1.2
Summer					
On-Peak/Part-Peak	N/A	1.13	1.11	1.11	1.11
Off-Peak	N/A	0.88	0.89	0.89	0.89
Winter					
Part-Peak	N/A	1.05	1.05	1.05	1.05
Off-Peak	N/A	0.95	0.96	0.96	0.96

The results of this analysis suggest that the summer energy costs for Hetch Hetchy Power are generally lower than the winter energy costs. The values in the table represent the relationship to the average price, which is set at a value of 1.0. The average energy value for the total year was divided by the average energy value for the summer, which resulted in a factor of 0.82 (summer costs are 0.82 times the average energy cost). Similarly, for the winter period, the average energy value was determined to be 1.2 times the system average energy costs.

During the summer period, the on-peak/part-peak hours are generally higher cost hours than the off-peak hours for all the applicable Hetch Hetchy Power classes (residential class does not have TOU pricing). The summer pricing differentials for the commercial classes are generally the same; the on-peak costs are approximately 1.11–1.13 times the average price and the off-peak costs are approximately 0.89 times the average price.

Similarly, for the winter periods, the on-peak period is higher than the off-peak period, but less than the difference for the summer (approximately 1.05 times the average price for all commercial classes). The off-peak price for winter is approximately 0.88 times the average price.

Based on discussions with the SFPUC, it was decided to not make any changes to the seasonal price differential in the current rate structures; however, a gradual transition to the TOU rate structures is recommended. Changes to the seasonal rate structures should be evaluated for future rate actions after implementation of this rate plan and in coordination with customer communication efforts.

Retail COS Results Review

This section provides a summary of the COS results by customer class, followed by a summary of the existing rate structures within each class, and the comparison of the COS to the rate structures.

Residential

Table 4-5 provides a summary of Hetch Hetchy Power's residential class COS results developed for this Study for the Test Year.

Table 4-5
Residential Cost of Service

Rate Component	COS	COS – Energy (1)
Customer ($/month)	$156.77	$156.77
Demand ($/kW)	$25.73	
Energy ($/kWh) (2)	$0.0610	$0.1730

(1) Assumes no Demand Charge and bundles demand-related costs within the Energy Charge.

(2) The tiered rates are the same for summer/winter (S/W); however, the characteristics of the tiers change with season. See text for details.

Table 4-5 provides a summary of the rates derived from the COS analysis. This includes a customer cost rate of $156.77/month, a demand cost rate of $25.73/kW, and an energy cost rate of $0.0610/kWh. The COS-based customer cost rate represents the sum of the costs of customer service and accounting, customer programs, and an allocated portion of the distribution system costs on a per customer per month basis. The COS customer cost rate is relatively high because residential customers are the largest customer class by count within Hetch Hetchy Power, but the program has a relatively low number of residential customers compared to most other utilities. As a result, the residential class is allocated a large proportion of customer-related costs, which are then divided over a small number of customers. To the extent that the full customer charge cannot be recovered in the customer rate, these remaining costs would be shifted to the energy rate, requiring a higher energy charge to meet full cost of service.

The demand cost rate represents the cost associated with the fixed costs for power supply, transmission, and the non-customer portion of the distribution system (this includes the investment cost, as well as the fixed costs for operating and maintaining these systems).

For the Residential class, it costs Hetch Hetchy Power approximately $25.73/kW of demand-related costs to serve residential customers; however, residential customers do not incur a demand charge. Therefore, the demand-related costs are included in the existing energy rate. Additionally, to the extent that the recommended rates (Section 5) do not include the entirety of the customer service cost rate of approximately $157/month, these costs are also recovered in the existing energy rates. Hetch Hetchy Power's pure energy cost rate is $0.0610/kWh (not adjusted for tiered costs); however, because of a lower customer charge and no demand charge, the existing energy rate is higher than Hetch Hetchy Power's "pure" energy costs.

Therefore, Table 4-5 includes a column for the COS that shifts the demand costs to the energy rate. The "adjusted COS-based energy rate," which includes appropriate demand costs, has been calculated to be approximately $0.1730/kWh. The recommended residential rates discussed in Section 5 recognize the existing and COS rates, as well as the specific rate proposal.

Residential Rates (Existing)

Table 4-6 provides a summary of Hetch Hetchy Power's existing Retail Residential class rates (R-1). The existing rates and rate structures are provided for each rate code to demonstrate the recommended changes in rates levels and rate structures as a result of this Study. The existing rate includes an $4.58 per month customer service charge and a tiered energy rate. Hetch Hetchy Power's existing energy rates are tiered to encourage conservation; the more energy used by residential customer, the higher the "per unit" rate ($/kWh).

Table 4-6
Existing Residential Rates (R-1)

Rate Component	Existing
Customer ($/month)	$4.58
Demand ($/kW)	-
Energy ($/kWh) (1)	
Tier 1 (0–229 S; 0–278 W)	$0.1778
Tier 2 (229–297 S; 278–361 W)	$0.2021
Tier 3 (>297 S; >361 W)	$0.4137

(1) The tiered rates are the same for summer/winter (S/W); however, the characteristics of the tiers change with season. See text for details.

The tiered energy rate is the same for summer and winter; however, the requirements thresholds for the tier change between the seasons. The summer Tier 1 is monthly energy usage from 0–229 kWh, Tier 2 is for 229–297 kWh, and Tier 3 is for energy used over 297 kWh. The winter Tier 1 is from 0–278 kWh, Tier 2 is for 278–361 kWh, and Tier 3 is for over 361 kWh. The existing tiers reduce the bill impact for customers that use more energy during the six-month winter period (November to April). Because the rates are the same for the tiers, a customer is paying the lower tier rate for more energy (kWh) during the winter than in the summer (residential customers use more electricity in the winter than in the summer, on average).

There are several existing variations on the R-1 rate. R-2 is a low-income discounted rate. R-M provides higher tier thresholds for customers with qualified electrical medical equipment. R-EV provides lower-priced Tier 3 energy for customers with electric vehicle charging in their home. These rates follow similar structures to the R-1 rate, and generally have few customers enrolled.

Enterprise Residential Rates

As noted in Sections 1 and 2, Hetch Hetchy Power currently serves three main customer "groups," each with their own rates and rate structures (GUSE, Enterprise, and Retail). One objective of this Study is to align the Enterprise and GUSE customer rate schedules with their respective retail rates. There are no residential customers served under the GUSE rate structures; however, there are residential Enterprise customers served by Hetch Hetchy Power (under the E1TB and related rate codes). As indicated before, Enterprise customers are currently charged on the applicable PG&E rate.

The E1TB is the standard residential rate code for customers with electric and natural gas utility service. The EL1TB is a low-income rate offering, similar to the retail discount of the R-2 rate discussed above. There are also a series of rates designed for master metered accounts (where a single meter may serve multiple customers, such as at an apartment complex). It should be noted that Hetch Hetchy Power's policy on Master Meter accounts has changed, and they are now installing (and retrofitting) individual meters in place of master meters. However, these accounts are still a significant portion of the residential load served by Hetch Hetchy Power. Rate codes include the EM1TB rate (Residential Master Meter with natural gas and electric service), the EMLTB rate (Residential Master Meter with natural gas and electric service, low-income), the EM1TH rate (Residential Master Meter with all-electric service), and the EMLTH rate (Residential Master Meter with all electric service, low-income).

Table 4-7 provides a summary of the recent rates (changed March 1, 2022) applicable to the E1TB customers served by Hetch Hetchy Power.

Table 4-7
Existing Enterprise Residential Rates (E1TB)

Rate Component	Existing
Customer ($/month)	Min (1)
Energy ($/kWh) (2)	
Tier 1 (0–6.8 S; 0–8.2 W)	$0.3147
Tier 2 (6.8–27.2 S; 8.2–32.8 W)	$0.3945
Tier 3 (> 27.2 S; > 32.8 W)	$0.4932

(1) The E1TB rate does not have a customer service charge ($/month) but is subject to a minimum bill (see text).

(2) The tiered rates are the same for summer/winter (S/W); however, the characteristics of the tiers change with season. Note: these are daily kWh values. See text for details.

As noted in Table 4-7, the tiers are utilized as a pricing signal to encourage customers to reduce energy usage in the summer and winter periods. However, because the E1TB customers are charged on the PG&E Rate schedule, the tiers are set on a daily basis and there is no customer charge. However, there is a "minimum bill provision," which is set at the daily customer charge $0.34810 per day times the days in the month. Similar to the R-1 customers, a customer is paying the lower tier rate for more energy (kWh) during the winter than in the summer (as indicated previously, residential customers use more electricity in the winter than in the summer on an average monthly basis).

Master Meter Rates (EM1TB, EMLTB, EM1TH, EMLTH)

Table 4-8 provides a summary of the master meter rate for residential Enterprise customers served under the EM1TB rate (for electric and natural gas service). The tiers within the EM1TB rate are the same as the E1TB rate structure but have been scaled for the average number of units served. Similar to EM1TB, there is no monthly customer service charge, but there is a minimum bill that is equal to the daily customer charge times the days in the month. The low-income discount is a 30% reduction from the existing rate components and is billed under the EMLTB service. The EM1TH has a similar rate structure (for electric service only), but the tier levels are slightly higher for both the summer and winter periods.

Table 4-8
Enterprise Master Meter Residential Rate (EM1TB)

Rate Component	Existing
Customer ($/month)	Min (1)
Energy ($/kWh)	
Summer (2)	
Tier 1 (0–3.8 kWh daily)	$0.3147
Tier 2 (3.8–15.2 kWh daily)	$0.3945
Tier 3 (> 15.2 kWh daily)	$0.4932
Winter	
Tier 1 (0–4.5 kWh daily)	$0.3147
Tier 2 (4.5–18 kWh daily)	$0.3945
Tier 3 (> 18 kWh daily)	$0.4932

(1) The EM1TB rate does not have a customer service charge ($/month) but is subject to a minimum bill (see text).

(2) The tiered rates are the same for summer/winter (S/W); however, the characteristics of the tiers change with season. Note: these are daily kWh values. See text for details.

Residential Cost Curve

Figure 4-1 provides an illustration of a "cost curve" for Hetch Hetchy Power's residential customer class. A cost curve represents the total costs to serve a customer within a specific rate class over a range of monthly energy usage (using a load factor percent, as described below). The total costs are divided by the total monthly energy usage (in kWh) to calculate an "all-in" cost ($/kWh) to serve customers. A cost curve is a convenient tool to understand how unit costs (all-in $/kWh) for fixed cost industries (such as electric utilities) behave. If the customer is using only very small amounts of energy in a month, the all-in costs are high because of the high fixed costs. However, if the customer is using large amounts of energy in a month, the fixed costs are spread over more energy, so the all-in costs are lower. This is why the cost curves for Hetch Hetchy Power (and generally speaking, any utility), have the characteristic shape of a high "tail" end on the left, then a rapidly decreasing shape that eventually becomes flatter towards the right end.

In the cost curves shown in this Report, the X-axis is displayed as a series of "load factors" from 10% to 100%. For each class, an average customer demand is calculated from usage data provided by the SFPUC, and the energy usage varies by load factor. A load factor is the ratio of the total energy (kWh) divided by the peak load (kW) times the number of hours (hr) in the month (720 hours in a typical month).

For a customer with one kW of demand (1 kW), a 10% load factor uses 72 kWh (72 kWh / (1 kW x 720 hours in month)). A 100% load factor customer (with 1 kW of demand) uses 720 kWh of energy during the month. Load factor is a measurement of how efficiently a customer uses power, as it is the relationship between the maximum hourly demand in any given period (a month) and the amount of energy used during that month.

If a customer's load is constant over the period, the load factor approaches a value of 100%, meaning that in every hour of the period, the customer is using the same amount of power. A high load factor represents efficient use of the system because the utility's investment is fixed to serve the peak demand and the customer is using more energy for each unit of demand it places on the system. If a customer's load is more variable, the load factor is reduced, and the customer is said to be less efficient. Within any customer class, there will be customers with high and low load factors, especially when looking at commercial classes whose loads vary considerably between different customers.

Cost curves are useful in rate design to demonstrate how rates and rate structures compare to a utility's costs. For the example in Figure 4-1, the Existing Rate curve is a representation of Hetch Hetchy Power's existing R-1 rate (the Customer Service charge and the tiered energy charge). This rate curve has been calculated over a series of load factors, using an average demand of approximately 1.6 kW per customer and a blend of the summer and winter tiers. As indicated above, a low load factor customer uses less energy per month, whereas a high load factor customer uses more energy per month, but both customers have a demand of 1.6 kW during the month. Because of the relatively low fixed charge and the relatively high-tiered energy charges for the existing rate, the "all-in" existing rate curve is lower in the front end and slowly gets higher in the tail end, which is the inverse of the cost curve.

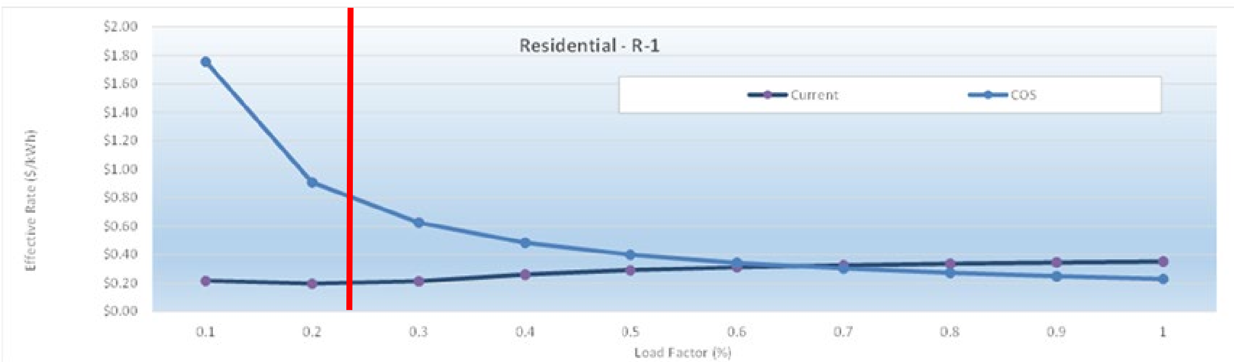


Figure 4-1. Cost Curve and Rate Curve for Residential R-1 Rate

Figure 4-1 suggests that customers that have a lower load factor (meaning they use less energy per unit of demand) should have a higher unit rate ($/kWh). This reflects the relatively high customer costs derived from the COS analysis. As customers increase their load factor (and increase the amount of energy used), the COS curve is reduced as the fixed costs are spread over more energy. However, the current R-1 rate curve suggests that as customers use more energy, the unit rate increases, which is indicative of the tiered rate structure. All else being equal, the comparison of the cost curve and the rate curve suggests that those customers with a load factor of less than approximately 60% are paying less than their costs would suggest, and those with a higher load factor are paying more (on a unit basis). Most residential customer usage is relatively homogeneous (except for those customers with solar panels or extreme loads). For Hetch Hetchy Power, an analysis of 2019 residential customer class usage data suggests an average annual load factor of approximately 23% (see red vertical line in Figure 4-1 at approximately 23% load factor).

Small Commercial

The following provides a summary of the COS analysis results for the Small Commercial customer class, a summary of the existing rates and rate structures, and a comparison of the various rate offerings across different customer usage (cost and rate curve analysis).

Small Commercial COS Results

Table 4-9 provides a summary of the Small Commercial class COS results for the Test Year.

Table 4-9
Small Commercial Cost of Service

Rate Component	COS	COS – Energy (1)
Customer ($/month)	$174.25	$174.25
Demand ($/kW)	$37.10	
Energy ($/kWh)		
Summer Charges	$0.0644	$0.1942
Winter Charges	$0.0644	$0.1942

(1) Assumes no Demand Charge and bundles demand-related costs within the Energy Charge.

The COS analysis suggests a customer cost rate of $174.25/month, a demand cost rate of $37.10/kW, and an energy cost rate of $0.0644/kWh. The COS-based customer cost rate represents the sum of the costs of customer service and accounting, customer programs, and an allocated portion of the distribution system costs on a per customer per month basis. Similar to the residential class, the COS customer cost rate is relatively high because there is a relatively low number of small customers. The demand cost rate represents the cost associated with the fixed costs for power supply, transmission, and the non-customer portion of the distribution system (this includes the investment cost, as well as the fixed costs for operating and maintaining these systems).

It costs Hetch Hetchy Power approximately $37.10/kW of demand-related costs to serve small commercial customers. Hetch Hetchy Power's energy cost rate is $0.0644/kWh (not adjusted for seasonal costs); however, as a result of the lower customer charge and no demand charge currently in effect, the existing energy rate is higher than Hetch Hetchy Power's "pure" energy costs.

Table 4-9 includes a column for the COS that shifts the demand costs to the energy rate. This data is based on the COS analysis and recognizes that small commercial customers are not charged on a demand basis ($/kW). Like all customers, though, small commercial customers do incur demand-related costs; however, they are recovered from the energy rate ($/kWh). Therefore, this table provides an "adjusted COS-based energy rate," which includes appropriate demand costs and has been calculated to be approximately $0.1942/kWh (not adjusted for the seasonal differences).

The recommended rates discussed in Section 5 recognize the existing and COS rates, as well as the specific rate proposal.

GUSE Small Commercial Rate

As indicated above, there are GUSE customers within all of the commercial rate classes served by Hetch Hetchy Power. The current GUSE rate is a flat rate of $0.0988/kWh, which is the same regardless of the commercial customer class in which the GUSE customer exists.

Existing Small Commercial Rates/Rate Structures

Table 4-10 provides a summary of Hetch Hetchy Power's existing retail Small Commercial class rates (C-1). The existing rate includes an $8.99 per month customer service charge for single phase service, $22.49 per month customer service charge for poly phase service, and a seasonal energy rate that is differentiated by summer and winter.

Table 4-10
Existing Small Commercial Rates (C-1)

Rate Component	Existing
Customer ($/month) – Single Phase	$8.99
Customer ($/month) – Poly Phase	$22.49
Energy ($/kWh)	
Summer Charges	$0.2562
Winter Charges	$0.2049

Table 4-11 provides a summary of the existing small commercial rate for single phase (A1S) and poly phase (A1P) Enterprise customers compared to the results of the COS analysis. The small commercial Enterprise customers have a different customer charge depending on the level of service provided: $10.00/month for single phase and $25.00/poly phase, and they have a seasonally differentiated energy rate. The summer energy rate is $0.3364/kWh, and the winter energy rate is $0.2974/kWh.

Table 4-11
Existing Enterprise Small Commercial Rates
(A1S and A1P)

Rate Component	Existing
Customer ($/month) – Single Phase (A1S)	$10.00
Customer ($/month) – Poly Phase (A1P)	$25.00
Energy ($/kWh)	
Summer Charges	$0.3364
Winter Charges	$0.2794

Hetch Hetchy Power offers its current small commercial Enterprise customers a TOU option under its A1-US and A1-UP rates (the "S" and "P" designation are for single and poly phase, the "U" designation is for TOU), as summarized in Table 4-12. These rates are differentiated by single and poly phase customer service charge (identical as those for A1S and A1P). The TOU rates are differentiated by season. The current summer energy rates are $0.3397/kWh for on-peak and part-peak periods, and $0.03490/kWh for off-peak. The current winter energy rates are $0.2921/kWh for part-peak, and $0.2915 for off-peak; there is no on-peak winter period. Summer and winter periods and TOU periods are as previously defined.

Table 4-12
Enterprise Small Commercial Rates (A1US and A1UP)

Rate Component	Existing
Customer ($/month) – Single Phase (A1S)	$10.00
Customer ($/month) – Poly Phase (A1P)	$25.00
Energy ($/kWh)	
Summer Charges	
On-Peak	$0.3397
Part-Peak	$0.3397
Off-Peak	$0.3490
Winter Charges (1)	
Part-Peak	$0.2921
Off-Peak	$0.2915

(1) There is no on-peak period for the winter season for this rate (see text).

Small Commercial Cost Curve

Figure 4-2 provides an illustration of a cost curve for Hetch Hetchy Power's small commercial customer class. As indicated above, a cost curve represents the total costs ($) to serve a customer within a specific rate class over a range of monthly energy usage. Cost curves are useful in rate design to allow a comparison of how rates and rate structures compare to a utility's costs.

Figure 4-2 provides a representation of Hetch Hetchy Power's existing C-1 rate (Retail), along with the GUSE rate (flat) and the Enterprise rate (A-1S). These rate curves have been calculated over a series of load factors assuming an average demand of approximately 10 kW per customer and an even blend of the summer and winter energy usage. The average monthly load factor for the Small Commercial class was determined from 2019 usage data to be approximately 39% (see red vertical line in Figure 4-2 at approximately 39% load factor).

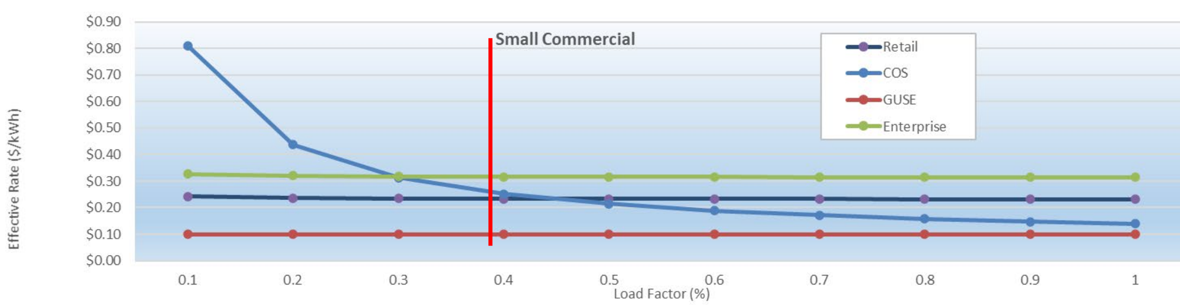


Figure 4-2. Hetch Hetchy Power Cost Curve and Rate Curves for Small Commercial Rates

Figure 4-2 suggests that customers who have a lower load factor (meaning they use less energy per unit of demand) should have a higher unit rate ($/kWh). This reflects the relatively high customer costs derived from the COS analysis. As customers increase their load factor (and increase the amount of energy used), the unit costs are reduced as the fixed costs are spread over more energy. However, the current small commercial rates are generally flat, given the relatively low customer charge and high energy charge for the retail and enterprise customers, and the flat rate for the GUSE customers.

Medium Commercial

The following provides a summary of the COS analysis results for the Medium Commercial customer class, a summary of the existing rates and rate structures, and a comparison of the various rate offerings across different customer usage (cost and rate curve analysis).

Medium Commercial COS Results

Table 4-13 provides a summary of Hetch Hetchy Power's COS-based rates for the Medium Commercial class developed for this Study for the Test Year.

Table 4-13
Medium Commercial Rates Cost of Service

Rate Component	COS
Customer ($/month)	$863.60
Demand ($/kW)	$40.37
Energy ($/kWh) (1)	
Summer Energy Charges	$0.0675
Winter Energy Charges	$0.0675

Table 4-13 provides a summary of the rates derived from the COS analysis. This includes a customer cost rate of $863.90/month, a demand cost rate of $40.37/kW, and an energy cost rate of $0.0675/kWh. The COS-based customer cost rate represents the sum of the costs of customer service and accounting, customer programs, and an allocated portion of the distribution system costs on a per customer per month basis. The demand cost rate represents the cost associated with the fixed costs for power supply, transmission, and the non-customer portion of the distribution system (this includes the investment cost as well as the fixed costs for operating and maintaining these systems). The energy cost rate represents those costs allocated by energy and assigned to the medium commercial class based on their weighted average price (see Section 3). Because the medium commercial rates include a demand charge, there is no need to calculate an all-in energy rate with demand costs, as was the case for the small commercial and residential classes.

Existing Medium Commercial Rates/Rate Structures

Table 4-14 provides a summary of Hetch Hetchy Power's existing retail Medium Commercial class rates. The existing secondary voltage rate includes a $149.92 per month customer service charge, a $14.11/kW demand charge, and a seasonal energy rate that is differentiated by summer ($0.1387/kWh) and winter ($0.1726/kWh).

Table 4-14
Existing Medium Commercial Rates (C-2S)

Rate Component	Existing
Customer ($/month)	$149.92
Demand ($/kW)	$14.11
Energy ($/kWh) (1)	
Summer Energy Charges	$0.1387
Winter Energy Charges	$0.1726

Table 4-15 provides a summary of the current medium commercial Enterprise rate for A10S for secondary voltage service. The Enterprise Medium Commercial rate is also offered for primary service (A10P, not shown below). The Enterprise Medium Commercial Rate (A10S) has a customer charge of $179.90/month, a demand rate of $18.45/kW, and an energy rate that is seasonally adjusted ($0.2337/kWh for summer, $0.1961/kWh for winter).

Table 4-15
Existing Enterprise Medium Commercial Rates (A10S)

Rate Component	Existing
Customer ($/month)	$179.90
Demand ($/kW)	$18.45
Energy ($/kWh)	
Summer Energy Charges	$0.2337
Winter Energy Charges	$0.1961

Table 4-16 provides a summary of the medium commercial rate (A10-US and A10-UP) for secondary and primary voltage TOU Enterprise customers. The medium commercial Enterprise rates have a different demand charge depending on the voltage of service provided and have a seasonally and TOU differentiated energy rate. For secondary voltage service, the summer energy rate for on-peak and part-peak periods is $0.2472/kWh and for off-peak is $0.2204/kWh. The winter energy rate for part-peak is $0.1967/kWh and off-peak is $0.1960/kWh (as indicated for medium commercial customers, there is no on-peak winter period).

Table 4-16
Existing Enterprise Medium Commercial Rates
(A10-US and A10-UP)

Rate Component	A10-US	A10-UP
Customer ($/month)	$179.90	$179.90
Demand ($/kW)	$18.45	$18.14
Summer Energy Charges		
On-Peak	$0.2472	$0.2309
Part-Peak	$0.2472	$0. 2309
Off-Peak	$0.2204	$0.2356
Winter Energy Charges (1)		
Part-Peak	$0.1967	$0.1818
Off-Peak	$0.1960	$0.1811

(1) Winter energy charges do not have an on-peak period (see text).

Medium Commercial Cost Curve

Figure 4-3 provides a representation of Hetch Hetchy Power's existing C-2S rate (Retail), along with the GUSE rate (flat) and the Enterprise rate (A10S). These rate curves have been calculated over a series of load factors, assuming an average demand of approximately 105 kW per customer and an even blend of summer and winter energy usage. The average monthly load factor for the Medium Commercial class was determined from historical (2019) usage data to be approximately 51% (see red vertical line in Figure 4-3 at approximately 51% load factor).

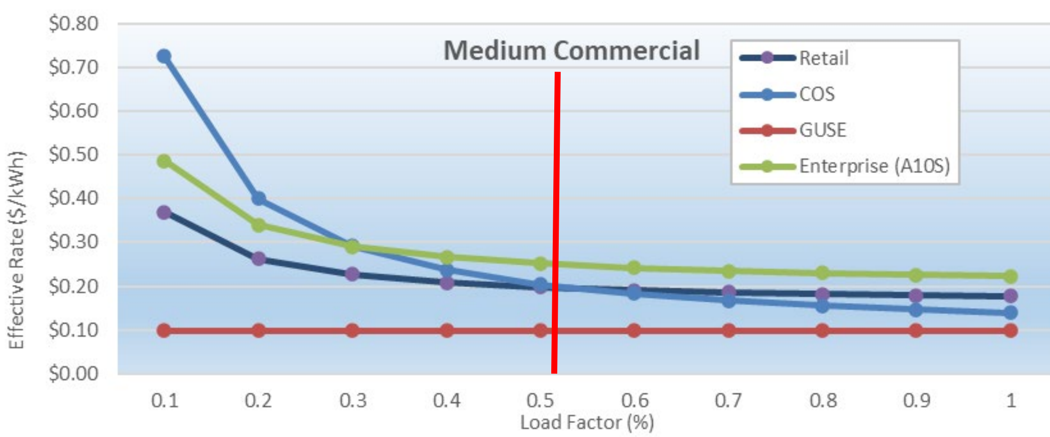


Figure 4-3. Hetch Hetchy Power Cost Curve and Rate Curves for Medium Commercial Rates

Figure 4-3 suggests that customers who have a lower load factor (meaning they use less energy per unit of demand) should have a higher unit rate ($/kWh). This reflects the relatively high customer costs derived from the COS analysis. As customers increase their load factor (and increase the amount of energy used), the unit costs are reduced as the fixed costs are spread over more energy. However, the current medium commercial rates (except for GUSE) have a high customer usage charge and a demand charge, which results in the higher unit costs for lower load factor customers and lower unit costs for high load factor customers.

Large Commercial

The following provides a summary of the COS analysis results for the Large Commercial customer class, a summary of the existing rates and rate structures, and a comparison of the existing various rate offerings across different customer usage (cost and rate curve analysis).

Large Commercial COS Results

Table 4-17 provides a summary of the rates derived from the COS analysis for the Test Year. This includes a customer cost rate of $1,692.22/month, a demand cost rate of $43.46/kW, and an energy cost rate of $0.0649/kWh.

Table 4-17
Large Commercial Rates Cost of Service

Rate Component	COS
Customer ($/month)	$1,692.22
Demand ($/kW)	$43.46
Energy ($/kWh)	$0.0649

Existing Large Commercial Rates/Rate Structures

Table 4-18 provides a summary of Hetch Hetchy Power's existing retail Large Commercial class rates (C-3S, secondary voltage service, and C-3P, primary voltage service) compared to the COS-based rates developed for this Study (for secondary voltage service). The existing rate includes a $754.93 per month customer service charge for secondary voltage and a $1,151.50 per month customer service charge for primary voltage service. The demand charge is differentiated by season as well as TOU, as well as by voltage level. The summer on-peak period for demand is the same as the summer on-peak period for energy for the medium commercial customers as indicated above (12:00 PM to 6:00 PM, Monday through Friday, excluding holidays). The part-peak period for summer demand is the remaining hours (there is no off-peak summer demand period). For the winter period, there is no TOU period for demand.

The secondary voltage summer on-peak demand rate is $12.267/kW, the part-peak rate is $10.008/kW, and the max rate is $22.437/kW. The max rate is applied to the peak demand for either period and is in addition to the demand charges for the on- or part-peak periods. The primary voltage summer on-peak demand rate is $10.440/kW, the part-peak rate is $8.730/kW, and the max rate is $18.576/kW. The winter demand rate is only subject to the max demand rate, which is $22.44/kW for secondary voltage and $18.58/kW for primary voltage.

The energy charges are similarly differentiated by voltage level, season, and TOU. The summer secondary voltage on-peak and part-peak energy rates are $0.1019/kWh and $0.0934/kWh for primary voltage, and the summer off-peak rate is $0.0965/kWh for secondary voltage and $0.0833/kWh for primary voltage. The winter part-peak energy charges are $0.0942/kWh and $0.0860/kWh (secondary and primary), and the off-peak charges are $0.0936/kWh and $0.0854/kWh (secondary and primary). There is no on-peak period for winter energy charges (part-peak is 8:30 AM to 9:30 PM, Monday through Friday, except holidays, and the remainder is off-peak).

Table 4-18
Existing Large Commercial Rates (C-3S, C-3P)

Rate Component	C-3S	C-3P
Customer ($/month)	$754.93	$1,151.50
Demand ($/kW)		
Summer Demand Charges (1)		
On-Peak	$12.267	$10.440
Part-Peak	$10.008	$8.730
Max	$22.437	$18.576
Winter Demand Charges (2)		
Max	$22.44	$18.58
Energy ($/kWh)		
Summer Energy Charges		
On-Peak	$0.1019	$0.0934
Part-Peak	$0.1019	$0.0934
Off-Peak	$0.0965	$0.0883
Winter Energy Charges (3)		
Part-Peak	$0.0942	$0.0860
Off-Peak	$0.0936	$0.0854

(1) Summer demand charges are the sum of the on- and part-peak and max demand for the month.

(2) Winter demand charges are the max demand for the month, regardless of time.

(3) There is no on-peak energy period for winter months (see text).

Table 4-19 provides a summary of the current large commercial Enterprise rates. The Enterprise Large Commercial rates are differentiated by service voltage for the customer charge, demand charge, and energy charge. The secondary voltage customer charge is $902.03/month, and the primary voltage customer charge is $1,372.68/month. The demand charge is seasonal, and TOU is differentiated by on-peak, part-peak, and max rate for the two voltage service levels. The winter demand rate is set by the max rate, which is identical to the max demand rate for the summer period. The energy rate is differentiated by season, TOU, and voltage level. The summer on-peak and part-peak energy rates are identical and are slightly higher for primary voltage customers comparted to secondary voltage customers. The winter part- and on-peak energy rates are similarly structured. As with the retail customers, there is no on-peak winter energy period.

Table 4-19
Existing Enterprise Large Commercial Rates
(E-19S and E-19P)

Rate Component	E-19S	E-19P
Customer ($/month)	$903.76	$1,375.29
Demand ($/kW)		
Summer Demand Charges (1)		
On-Peak	$16.990	$14.460
Part-Peak	$14.280	$12.420
Max	$28.390	$23.730
Winter Demand Charges (2)		
Max	$28.39	$23.730
Summer Energy Charges		
On-Peak	$0.1410	$0.1281
Part-Peak	$0.1410	$0.1281
Off-Peak	$0.1350	$0.1224
Winter Energy Charges (3)		
Part-Peak	$0.1325	$0.1199
Off-Peak	$0.1317	$0.1192

(1) Summer demand charges are the sum of the on- and part-peak and max demand for the month.

(2) Winter demand charges are the max demand for the month, regardless of time.

(3) There is no on-peak energy period for winter months (see text).

Large Commercial Cost Curve

Figure 4-4 provides an illustration of a cost curve for Hetch Hetchy Power's large commercial customer class. As indicated above, a cost curve represents the total costs ($) to serve a customer within a specific rate class over a range of monthly energy usage.

Figure 4-4 provides a representation of Hetch Hetchy Power's existing C-3S rate (retail), along with the GUSE rate (flat) and the Enterprise rate (E19-S). These rate curves have been calculated over a series of load factors, assuming an average demand of approximately 516 kW per customer and an even blend of the summer and winter energy usage. An analysis of 2019 customer usage data suggests a monthly load factor of approximately 54% for the large commercial customer class (see red vertical line in Figure 4-4 at approximately 54% load factor).

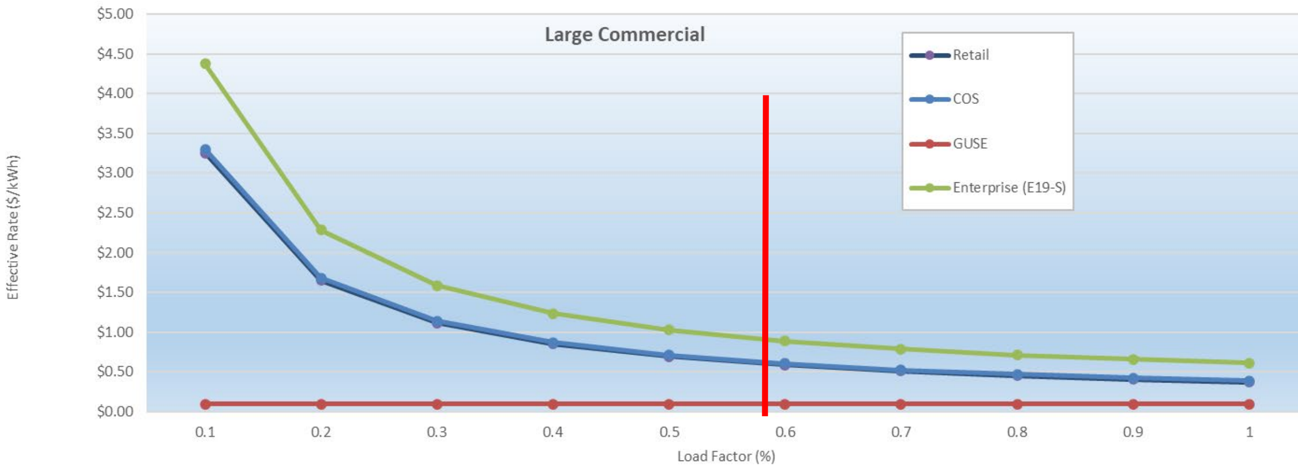


Figure 4-4. Hetch Hetchy Power Cost Curve and Rate Curves for Large Commercial Rates

Figure 4-4 indicates that the current rate structures for large commercial customers (with the exception of the GUSE customers) generally lines up with the cost curves. This is because of the relatively high customer service charges and demand charges that recover the fixed costs, and the relatively lower energy rates recovering the variable costs. This analysis assumes same demand for the on-, part- and maximum periods and that approximately 20% of energy is consumed during on-peak, 24% is consumed during part-peak, and approximately 56% is consumed during off-peak periods for the summer and winter periods, based on analysis of customer usage in this class.

The retail rate structure appears to be slightly lower than the COS analysis for all load factors, and the Enterprise rate structure (for E19-S customers) appears to be higher for all load factor customers on a unit cost basis. This suggests that for these customers the rate structures are similar to COS; however, the rate levels for each component may need to be adjusted to get to COS. For the GUSE customers, who are charged on a flat fee, the unit cost basis is lower than COS for all load factors in this example.

Industrial Customers

The following provides a summary of the COS analysis results for the Industrial customer class, a summary of the existing rates and rate structures, and a comparison of the existing various rate offerings across different customer usage (cost and rate curve analysis).

Industrial COS Results

Table 4-20 provides a summary of the rates derived from the COS analysis for the Industrial rate class (for secondary voltage service). This includes a customer cost rate of $1,685.42/month, a demand cost rate of $37.42/kW, and an energy cost rate of $0.0645/kWh. The analysis for the industrial class includes the costs allocated to the airport (SFO) in Section 3 of this report. Industrial service is also offered at primary level (rate code I-1P), however, SFO is currently served under the Enterprise E-20P (primary) rate code (see below).

Table 4-20
Industrial Rates (I-IS)
Cost of Service

Rate Component	COS
Customer ($/month) – Phase	$1,685.42
Demand ($/kW)	$37.42
Energy ($/kWh)	$0.0645

Existing Industrial Rates/Rate Structures

Table 4-21 provides a summary of Hetch Hetchy Power's existing retail Industrial class rates at secondary (I-1S) and primary voltage (I-1P). The existing primary rate includes a $1,367.57 per month customer service charge and a demand charge that is differentiated by season as well as TOU. The summer on-peak demand rate is $12.384/kW, the part-peak rate is $10.233/kW, and the max rate is $20.106/kW (as with the large commercial customers, the demand rate during the summer is the sum of the three individual rates for each month). The winter demand rate is only subject to the max demand rate, which is $20.11/kW. The energy charges are similarly differentiated by season and TOU. The summer on-peak and part-peak energy rate is $0.0942/kWh, and the off-peak rate is $0.0890/kWh. The winter part-peak rate is $0.0868/kWh, and the off-peak rate is $0.0861/kWh.

Table 4-21
Existing Industrial Rates (I-IS and I-1P)

Rate Component	I-IS (Secondary)	I-IP (Primary)
Customer ($/month) – Phase	$1,370.12	$1,367.57
Demand ($/kW)		
Summer Demand Charges (1)		
On-Peak	$12.44	$12.38
Part-Peak	$9.79	$10.23
Max	$22.14	$20.11
Winter Demand Charges (2)		
Max	$22.14	$20.11
Energy ($/kWh)		
Summer Energy Charges		
On-Peak	$0.0971	$0.0942
Part-Peak	$0.0971	$0.0942
Off-Peak	$0.0918	$0.0890
Winter Energy Charges (3)		
Part-Peak	$0.0895	$0.0868
Off-Peak	$0.0888	$0.0861

(1) Summer demand charges are the sum of the on-peak, part-peak, and max demand for the month.
(2) Winter demand charges are the max demand for the month, regardless of time.
(3) There is no on-peak energy period for winter months (see text).

Table 4-22 provides a summary of the current large commercial Enterprise rates. The Enterprise Large Industrial rates are differentiated by service voltage for the customer charge, demand charge, and energy charge. The secondary customer charge is $1,632.16/month and the primary customer charge is $1,624.03/month. The demand charge is seasonally, and TOU is differentiated by on-peak, part-peak, and max rate. The winter demand rate is set by the max rate, which is identical to the max demand rate for the summer for both secondary and primary voltage customers. The energy rate is differentiated by season and TOU and by voltage. The summer on-peak and part-peak energy rates are identical and are slightly higher for primary service customers compared to secondary service customers. The winter part-peak and off-peak energy rates are slightly lower for secondary voltage level customers compared to primary voltage level customers.

Table 4-22
Existing Enterprise Industrial Rates (E-20S and E-20P)

Rate Component	E-20S (Secondary)	E-20P (Primary)
Customer ($/month)	$1,632.16	$1,624.03
Demand ($/kW)		
Summer Demand Charges (1)		
On-Peak	$117.06	$17.11
Part-Peak	$13.90	$14.56
Max	$28.61	$26.15
Winter Demand Charges (2)		
Max	$28.61	$26.15
Summer Energy Charges		
On-Peak	$0.1340	$0.1293
Part-Peak	$0.1340	$0.1293
Off-Peak	$0.1281	$0.1236
Winter Energy Charges (3)		
Part-Peak	$0.1155	$0.1211
Off-Peak	$0.1248	$0.1204

(1) Summer demand charges are the sum of the on-peak, part-peak, and max demand for the month.

(2) Winter demand charges are the max demand for the month, regardless of time.

(3) There is no on-peak energy period for winter months (see text).

Industrial Cost Curve

Figure 4-5 provides a representation of Hetch Hetchy Power's existing I-IP rate (retail), along with the GUSE rate (flat), the Enterprise rate (E20-S), and the COS rate. These curves have been calculated over a series of load factors, assuming an average demand of approximately 1,788 kW per customer and an even blend of the summer and winter energy usage. The monthly average load factor determined from 2019 load data for the industrial class was approximately 59% (see red vertical line in Figure 4-5 at approximately 59% load factor).

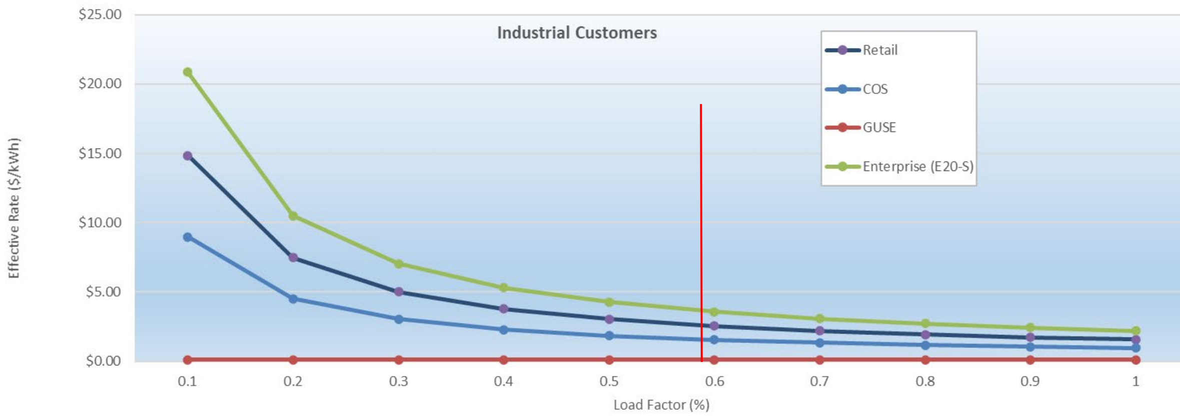


Figure 4-5. Hetch Hetchy Power Cost Curve and Rate Curves for Industrial Rates

Similar to the large commercial customers, Figure 4-5 indicates that the current rate structures for industrial customers (with the exception of the GUSE customers) are generally in alignment with the costs curves. This is because of the relatively high customer service charges and demand charge that recover the fixed costs, and the relatively lower energy rates recovering the variable costs. This analysis assumes that approximately 62% of the energy usage is off-peak, 30% is part-peak, and the remainder is on-peak for the summer and winter periods, based on analysis of usage data for these customers.

The retail rate structure and the Enterprise rate structure (for E-20S customers) is higher than the COS for all load factor customers on a unit cost basis (for this level of usage). This suggests that for these customers the rate structures are similar to COS; however, the rate levels for each component may need to be adjusted to get to COS. For the GUSE customers, who are charged on a flat fee, the unit cost basis is lower than COS for all load factors in this example.

Section 5
RATE RECOMMENDATIONS FOR HETCH HETCHY POWER

Hetch Hetchy Power – Rate Recommendations

Rate design is the end result of a COS study, in which the cost recovery mechanisms (rates and charges) for each customer class are established. Rates and charges are set for each customer class to collectively meet the utility's Revenue Requirement, as well as to address specific policy goals and objectives. For the purposes of this Study, the following rate design objectives were considered during the rate design process, which are discussed in Section 1 of this Report.

Hetch Hetchy Power rates are designed to follow the subsequent principles, which following the SFPUC Ratepayer Assurance Policy:

- Achieve recovery of costs for system
- Equitably allocate costs across and within customer classes
- Encourage efficient use of electricity
- Provide rate stability
- Offer flexibility and options
- Maintain rate competitiveness with PG&E
- Be simple and easy to understand

The recovery of the projected revenue requirement is the primary objective of rate design. This means that the specific components of the rates for each customer class must be paired with their respective projected billing determinants (in the form of energy, demand, and number of customers) to collect sufficient revenues for Hetch Hetchy Power to maintain operations and fund its historic and planned capital investments.

Consolidation of Retail, Municipal Enterprise, and Municipal General (GUSE) Rates

As stated above, a major goal of this study is to consolidate the legacy retail, municipal enterprise, and municipal general (GUSE) rate schedules into more traditional rate schedules by customer class. This change is being implemented in a gradual, phased manner to prevent rate shock to any particular customer class. The recommended two-year rate period changes will move the current set of tariffs significantly closer to this goal and set up Hetch Hetchy Power to achieve this objective within the next five years.

Specifically, the following approach was developed to consolidate and transition the "legacy" rate classes into their traditional rate classes:

1. Assign all GUSE customers to the appropriate customer class.
    a. Create a GUSE rate for each class with the same structure as the retail rate within that class (i.e., the same seasonal periods, energy and demand line items, customer charge, etc.).

b. Calculate the GUSE rate as a discount from the equivalent retail rate schedule in the year, solving for an all-in average $/kWh effective rate that increases by $0.03/kWh annually from the current GUSE rate of $0.0988/kWh.

c. If the GUSE rate for a fiscal year meets or exceeds the cost of service for the customer class, eliminate the rate, and charge these customers the normal retail rate for that customer class.

2. For Enterprise and retail customers, maintain the current rate structures and options available, but transition to cost of service, with some adjustments.

   a. Begin by changing from the current rate to the cost of service rate over two fiscal years. This may require an increase or a decrease to the rate, depending on its current level, but should result in the Enterprise and retail rates being the same or very close to the same in the second year of the rate plan.

   b. Implement a rate cap to limit the all-in average $/kWh rate increase to less than approximately 10% to prevent rate shock. However, this limit is calculated on an average class basis; within the class, rate impact may be greater or less than 10% for individual customers.

3. Because the phase-out of the GUSE subsidy, the continued discounts for low-income residential customers, and the cap on annual rate increases result in under collection of the revenue requirement for certain rate schedules, the resulting under collection amount is distributed to all retail and Enterprise non-residential rate classes.

Other than the steps described above, the recommended rates are generally designed to minimize significant changes to rate structures, as the recommended changes to rate levels as part of the transition to cost of service rates are significant in some instances.

GUSE, Low-Income, Rate Cap Cost Recovery

As indicated previously, there are several GUSE customers that are served by Hetch Hetchy Power within each of the commercial and industrial classes, as indicated in Table 5-1 below. Currently, these customers are served on a flat rate of $0.0988/kWh. However, the recommended change in rates for GUSE customers is to increase their effective rate by $0.03/kWh for FY 2022–2023 and $0.03/kWh for FY 2023–2024, as well as to change their rate structure from a flat rate to a rate structure identical to the retail rate offerings within their class (i.e., energy and customer charge for small commercial, and energy, customer charge, and demand rate for other commercial and industrial customers).

Because GUSE customers are limited in their rate recovery to be at the same effective rate as if they were still on their flat rate (with the increases), collectively they are not recovering sufficient revenue equal to their costs. Therefore, this creates a subsidy between commercial and industrial rate classes for Hetch Hetchy Power. It is important to note that this subsidy has existed since Hetch Hetchy Power has offered these flat rates to its GUSE customers, and the recommended rate changes for this Study are intended to reduce the subsidy over the period of the Test Year. It is expected that within approximately the next five years, each rate class will be charged rates reflecting its full COS.

Additionally, the low-income discounts offered by Hetch Hetchy Power for its residential retail and Enterprise customers also create a subsidy that must be recovered by other classes (non-residential). Also, the approximate 10% cap placed on recommended rate designs for residential, as well as other customer classes, creates an under recovery (as indicted in the methodology discussion above). The GUSE, low-income, and rate cap subsidies are combined and are allocated to the non-residential retail and Enterprise customers based on total energy sales. Further, they are recovered in the applicable energy rate by customer class.

Table 5-1 below provides a summary of the projected revenue deficiency created by the GUSE and residential rate constraints. The recommended changes to energy rates for retail and Enterprise non-residential customer classes include recovery of the projected combined revenue.

Table 5-1
Cost Under Recovery by Test Year ($000)

Rate Constraint	FYE 2023	FYE 2024
GUSE Subsidy (1)	$17,646	$10,095
Residential Subsidy	$4,408	$9,158
Total	$22,054	$19,254

(1) Rate increases for GUSE are projected to reduce the GUSE subsidy in FY 2023–2024 (see text).

As indicated in Table 5-1, the combined rate constraints are projected to result in an under-recovery of approximately $22.0 million in the first year, and $19.3 million in the second year. The low-income rate program combined with the residential rate cap is approximately $4.4 million in the first year and $9.2 million in the second year, as the residential class is anticipated to increase substantially at that time. The GUSE subsidy is approximately $17.6 million during the first year of the rate plan (FY 2022–2023) but is reduced to approximately $7.5 million in the second year (FY 2023–2024) as the rate increase moves these customers closer to their cost of service.

Customer Charges

In some cases, the COS customer charges may be significantly higher than current customer charges. To prevent large shifts in revenue collection along the cost curve, the recommended rates limit the increase in the customer charge. If this results in the customer charge being below cost of service, the remainder of the cost will be recovered through the energy charge for the class.

Seasonal and Time of Use Rates

The recommended rates do not eliminate or add customer charges, demand charges, or time of use differentiation unless that feature was already present in the current rate schedule. Existing seasonal rate differentials are designed to remain the same as the existing rate structures; however, the rate levels have been adjusted. For the TOU periods established for the on-, part-, and off-peak periods for the energy component, the TOU differentials described in Table 4-4 are incorporated into the recommended rates gradually over the two-year period.

Demand Rates

For customer classes with demand rates that are TOU differentiated (Large Commercial and Industrial classes only), the recommended rates maintain the rate differential between the on-peak, part-peak, and maximum demand rates, while moving the demand rates collectively towards their COS values. Currently, the customer pays the maximum demand rate for the peak demand during the month and in addition pays either the on-peak or part-peak demand rate if the maximum demand occurs during that period. The TOU demand rates will remain in place for the two-year period as the changes to the rates are transitioned over that time.

Analysis of Residential Tiers

For the purposes of this Study, an analysis of the residential tiers was conducted to determine if potential changes were warranted. As indicated previously, the existing tiers for the retail rate structures are based on historic tiers offered by PG&E that have not been updated since the rates were introduced. Additionally, the retail Enterprise tiers are consistent with PG&E's current rate structures, as are the rate levels.

This Study reviewed a distribution of existing retail customers' electricity usage during summer and winter periods for 2019. This analysis resulted in recommended tiers for each seasonal period based on the average user and the relative distribution of customer usage within the tiers: usage within Tier 1 represents below-average usage (i.e., the average usage is the division between Tiers 1 and 2), whereas Tier 2 represents above-average usage, and Tier 3 is high usage over two standard deviations from the average (for the purposes of this analysis, customers with usage over 1,000 kWh in a month were excluded). The results of the distribution analysis are presented in Figure 5-1 and 5-2 below.

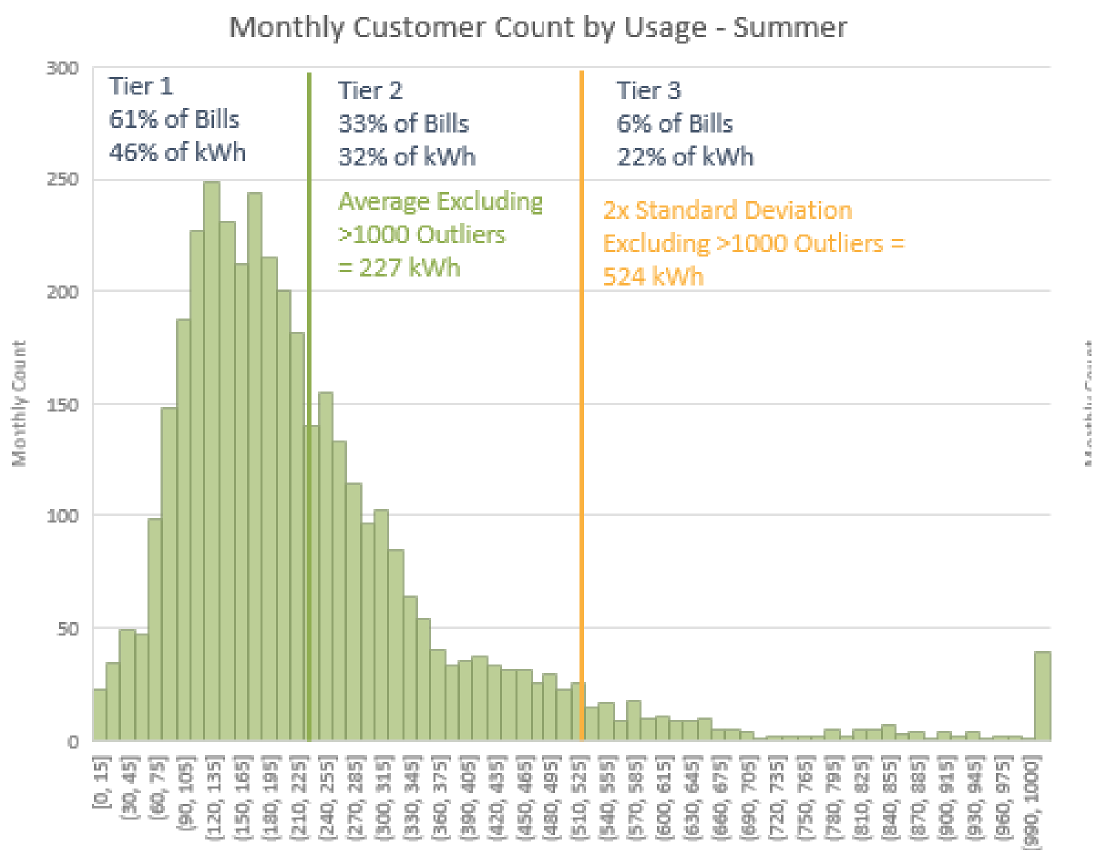


Figure 5-1. Distribution Analysis of Customer Usage for Summer

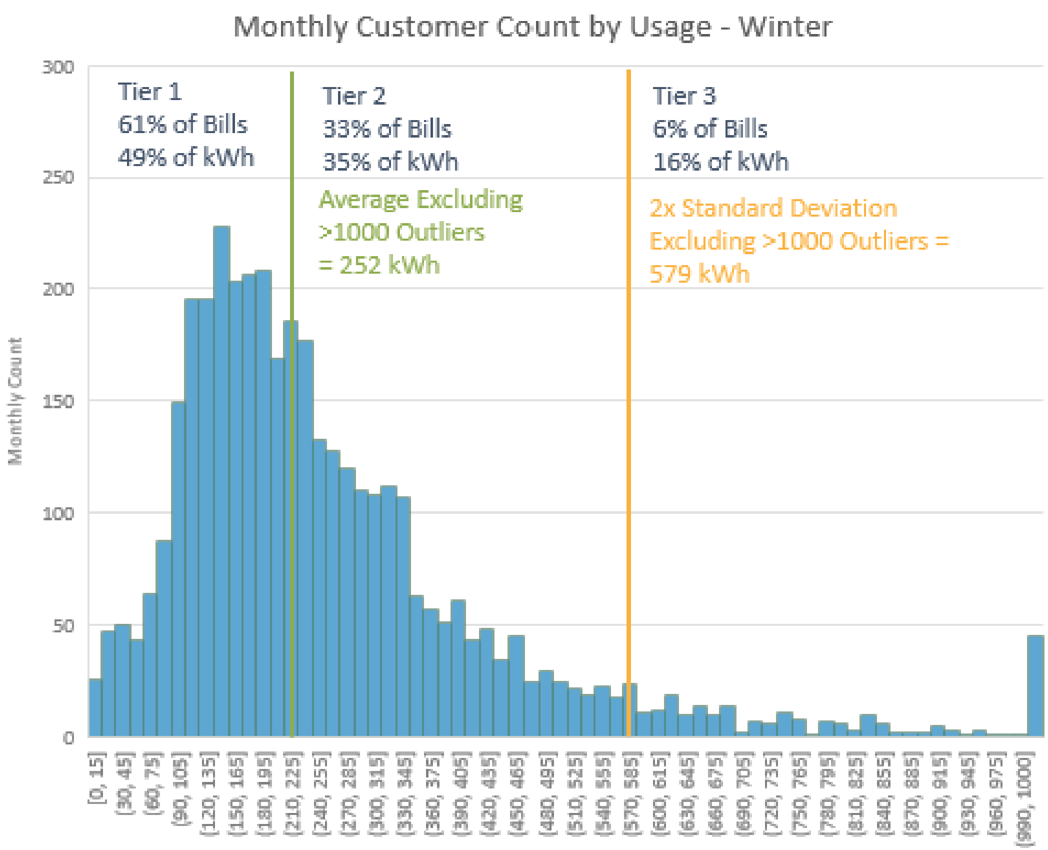


Figure 5-2. Distribution Analysis of Customer Usage for Winter

The analysis described above was conducted for Hetch Hetchy Power customers identified as having both electric and natural gas service. As noted in Section 1, one objective of this Study is to develop recommended rates for customers with electric only heating service (and therefore, no natural gas heating systems). A review of available load information indicated that there is insufficient data to conduct a detailed analysis of current Hetch Hetchy Power customers with all-electric heating service at this time. Therefore, this Study utilized the existing relationship between the PG&E tiers for summer and winter residential users with gas and electric vs all-electric service as a proxy for the usage characteristics for Hetch Hetchy Power all-electric customers.

The results of this analysis suggest a new tiered structure for both R-1 (to become R-1G [natural gas service] and the newly recommended R-1E customers, as indicated in Table 5-2 below.

Table 5-2
Existing and Recommended Tiers – R-1 Gas and Electric and All Electric

Current R-1 Tier (Monthly kWh)		
Tier	Summer	Winter
Tier 1	0–229	0–278
Tier 2	229–297	278–361
Tier 3	> 297	> 361
Recommended Tiers – Gas and Electric (Monthly kWh) (1)		
Tier	Summer	Winter
Tier 1	0–227	0–252
Tier 2	227–524	252–579
Tier 3	> 524	> 579
Recommended Tiers – All Electric (Monthly kWh) (2)		
Tier	Summer	Winter
Tier 1	0–250	0–418
Tier 2	250–578	418–960
Tier 3	> 578	> 960

(1) R-1 with gas and electric service to be recoded as R-1G.

(2) R-1 with electric heating service to be recoded as R-1E.

For residential Enterprise customers, the daily tiers are recommended to be adjusted to be monthly tiers, consistent with the retail rate offerings. For residential master metered Enterprise customers, the tiers have been adjusted to reflect the average number of units served by the master meter (and adjusted for monthly totals).

Discounting Rates for Energy Received at Higher Voltages

Several customers take power at voltage levels above the default secondary voltage service. The rationale for offering a high voltage discount for customers taking service at primary or transmission level voltage is that these customers do not incur the costs associated with the equipment and maintenance necessary for secondary service (generally less than 4 kilovolts [kV]). It is more efficient to transmit electricity at higher voltages (which reduces the energy lost to resistance) and these customers do not require utility investment in step-down converters. To qualify for this adjustment, the customer must supply the appropriate transformation equipment to reduce the incoming voltage for their use, as appropriate.

Recommended changes to the rates for high voltage (transmission, primary) have been adjusted based on the COS, as well as rate policy. Table 5-3 provides the service voltage discounts applied to the COS results for medium commercial, large commercial, and industrial customer classes, as appropriate and included in this Study.

Table 5-3
Service Voltage Discounts

	Discount Compared to Secondary Service	
Rate Class	Primary	Transmission
Medium Commercial	(13%)	N/A
Large Commercial	(10%)	N/A
Industrial	(29%)	(31%)

Recommended Rate Design

This section of the Report provides a summary of the recommended rate design for each year of the Two-Year Rate Plan for each major customer class. Included in this summary is an analysis of the recommended rates, including rate impacts for the selected customer types. Recommended adjustments to the "other" customer classes are discussed at the end of this Section, with specific rates included in Appendix A.

It is important to understand that the recommended rates are not designed to generate the revenue requirements for the customer class due to subsidies created by the rate design options. For residential rates, this includes subsidies for low-income rates, as described above, as well as policy decisions regarding the practicality and feasibility of implementing cost-based rates.

Residential Rates

Table 5-4 provides a summary of the rate schedules and rate classes within the residential rate offerings by Hetch Hetchy Power, the number of customers in each rate code, and whether the recommended rates are included in the body of the report or in Appendix A.

Table 5-4
Hetch Hetchy Power Residential Rate Schedules and Customers

Rate Code	Description	# Customers (TY)	Report/Appendix
R-1	Standard Retail (1), renamed R-1G (1)	155	Report
R-1E	Retail Electric Heating Customer (New Rate Code) (2)	620	Report
R-2	Low-Income	588	Appendix A
R-M	Medical Necessity Assistance Program	7	Appendix A
E1TB	Municipal Enterprise (Gas & Electric)	399	Report
EL1TB	Municipal Enterprise (Gas & Electric) Low Income	90	Appendix A
REV-1	Residential with Electric Vehicle	17	Appendix A
EM1TB (1)	Residential Master Meter (Gas & Electric)	13 / 547	Report
EMLTB	Residential Master Meter (Gas and Electric – Low-Income)	22 / 2,399	Appendix A
EM1TH (2)	Residential Master Meter (Electric Heating)	0	Appendix A
EMLTH	Residential Master Meter (Electric Heating – Low Income)	1 / 51	Appendix A

(1) For Master Meter accounts, the first number is the number of meters, the second number is the number of customers served by each Master Meter.

(2) No current customers are on this rate.

Residential Class Rate Offerings

As indicated in Table 5-4, the Residential class includes rate codes which represent different types of customers within the class. The "Standard Retail" is designated R-1 and represents most of the customers in this class. The R-2 rate is the Low-Income Residential service, which is set at a 30% discount to the R-1 rate. The R-M rate is a medical necessity assistance program with a similar rate structure as the R-1 rate; however, the tiers are set at a higher level (75% increase to those of the R-1 class). The R-2 and R-M recommended rate changes are provided in Appendix A.

The Municipal Enterprise (E1TB) rate is a residential rate for customers in City-owned or developed residences with natural gas and electric service, which is set at the PG&E equivalent rate for this service and has the different tier breaks and a minimum bill requirement. The Municipal Enterprise also has a low-income rate (EL1TB) which is set at a 30% discount to the PG&E rate. Currently, there are no customers served on the electric heating equivalent Municipal Enterprise rate (E1TH), and going forward any new customers will be served on the R-1E rate.

The Residential with Electric Vehicle Rate (REV-1) is a voluntary rate with a similar rate structure as the R-1 rate and is recommended to be adjusted to the tiers similar to those recommended for the R-1E (electric heating) rate. However, in addition to widening the tiers for electric heating, the recommended change for the REV-1 rate is to include an additional 150 kWh in the first tier (and increase the top of the remaining second tier appropriately) to account for estimated average driving needs of electric car owners in the City. This increase in Tier 1 and Tier 2 is recommended to be applied to both the summer and winter rate structures.

The Municipal Enterprise has a series of master meter rates for residential service depending on the type of heating (gas and electric heat is rate code EM1TB, all electric heating is rate code EM1TH), as well as low-income rate offerings for the same (EMLTB for gas and electric heating low-income and EMLTH for all electric low-income). As indicated above, the current Municipal Enterprise rates are set to be the equivalent of the PG&E rate; however, the low-income discount is set at 30% of the otherwise applicable rate.

Recommended Changes for Residential (Summary)

The recommended changes for the residential rate class include an increase in the rates for Tier 1 and Tier 2, however, most rate codes will see a rate decrease in the Tier 3 rate, as well as a change in the existing tiered rate structure. This change includes expanding the amount of energy within the second tier (Tier 2), which increases the threshold for the Tier 3. This change is recommended for both the summer and winter periods

One recommended change to the residential rate structure is a new R-1 electric heating rate offering (R-1E) for the current retail customers. For the winter period, the recommended changes include greatly expanding the energy within the Tier 2 usage. Similarly, the daily tiering for the residential Enterprise rates will be replaced with a similarly scheduled monthly tiering to provide consistency between the rate codes. Additional detail on the specific rate levels for residential customers is provided below. The REV-1 rate tiers are recommended to increase as discussed above.

The recommended customer charge for residential customers is designed to recover approximately 5% of the total revenue requirement for customer cost by the end of FY 2023–2024. The recommended customer service charges are designed to recover half of the increase necessary to get to this value in FY 2022–2023 and the remainder in FY 2023–2024. The dollar value of the recommended customer charge depends on the starting value within each rate code, as described herein.

The low-income discount for the R-2 and Municipal Enterprise customers (EMLTB, EMLTH) creates an under-recovery of revenue relative to their total cost of service. Additionally, several of the rate codes in the residential rate class rates are not recommended to meet their projected cost of service due to the potential for significant rate impacts. Therefore, the projected revenue shortfall from these rates is recovered from other rate classes as Hetch Hetchy Power transitions to full cost of service rates.

Residential R-1 Rates and Bill Impact Analysis

Table 5-5 provides a summary of the recommended rates for the residential rate class for each year of the two-year rate plan and a comparison of the rate components to the existing rate structure.

Table 5-5
Residential Rates (R-1G)
(Existing and Recommended)

Rate Component	Existing	Recommended (1) New Tiers	FYE 2023	FYE 2024
Customer Charge ($/month)	$4.58		$5.91	$7.23
Energy Charge ($/kWh) (2)				
Summer				
Tier 1 (0 kWh–229 kWh)	$0.1778	Tier 1 (0 kWh–227 kWh)	$0.2088	$0.2277
Tier 2 (229 kWh–297 kWh)	$0.2021	Tier 2 (227 kWh–524 kWh)	$0.2506	$0.2732
Tier 3 (Over 297 kWh)	$0.4137	Tier 3 (Over 524 kWh)	$0.3758	$0.4099
Winter		Winter		
Tier 1 (0 kWh–278 kWh)	$0.1778	Tier 1 (0 kWh–252 kWh)	$0.2088	$0.2277
Tier 2 (278 kWh–361 kWh)	$0.2021	Tier 2 (252 kWh–579 kWh)	$0.2506	$0.2732
Tier 3 (Over 361 kWh)	$0.4137	Tier 3 (Over 579 kWh)	$0.3758	$0.4099

(1) Rate changes are effective July 1, 2022 (FYE 2023), and July 1, 2023 (FYE 2024). Rate increases for R-1G customers are limited to approximately 10% per year (see text).

This rate has been renamed to R-1G to reflect the fact that it is intended for customers with natural gas heating, and to distinguish it from the R-1E rate described below for customers with electric heating. As noted, the recommended tiers for both summer and winter periods have been adjusted to reflect the usage characteristics of customers in the R-1G class, including an expansion of the energy within Tier 2 (from 69 kWh to 287 kWh during the summer period), as well as the resulting increase in the Tier 3 threshold.

There are several important changes recommended for the Residential rate schedules. The COS-based rates indicate a customer charge of $156.77 per month, as discussed in Section 4. The recommended customer charge starts at $5.91 per month (FY 2022–2023) and is increased to $7.23 per month for FY 2023–2024.

The recommended energy rates for the residential rate class have been adjusted to align with the policy goals of the new tiers, with the Tier 2 rates set at 120% of the Tier 1 rate, and the Tier 3 rate set at 180% of the Tier 1 rate.

Distribution of Bill Impacts – Residential Customers (R-1G)

Figure 5-3 provides an analysis of the distribution of the impact on an average monthly electricity bill for Hetch Hetchy Power's projected residential customer class for the first year of the rate plan (FY 2022–2023) as determined from customer billing data.

The bill impact will vary based on individual customer usage patterns, as provided in Figure 5-3. However, approximately 300 residential customers are expected to receive an average bill increase of approximately $8 per month under the recommended rates. As evidenced by this graphic, some customers will see an average bill decrease, as some customers will see an average bill increase greater than $8 per month.

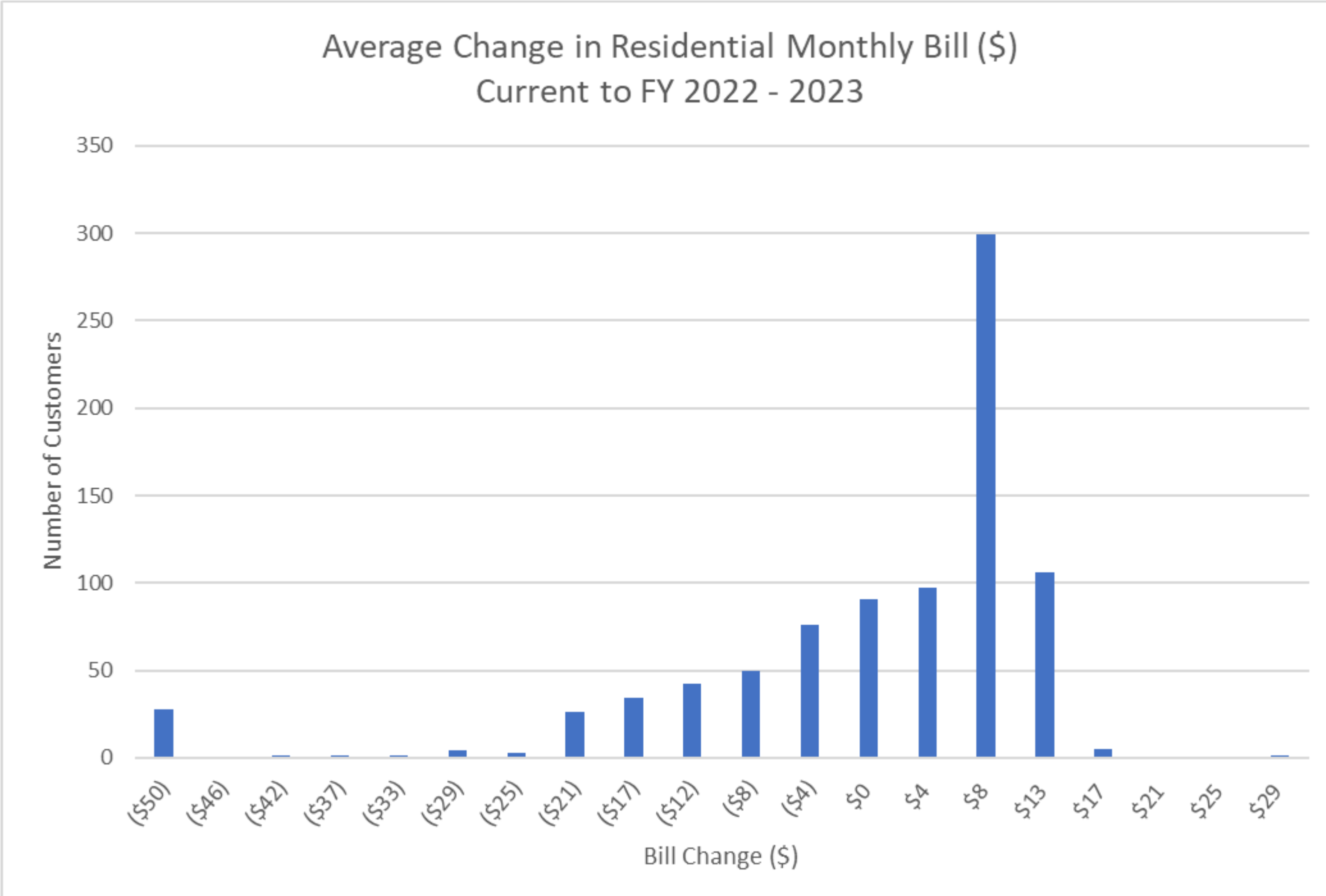


Figure 5-3. Distribution of Recommended Hetch Hetchy Power Residential Monthly Customers Bill Impacts

All Electric Heating Residential Rates (R-1E)

SFPUC proposes to develop a new rate for retail residential customers who have electric heating (no natural gas service to the residence), currently proposed as the R-1E rate. The R-1E rate will have the same recommended customer charge and tiered energy charges as the R-1G rate; however, the energy in each tier will be slightly higher for the summer season and significantly higher for the winter season (See Table 5-2). The recommended changes for FY 2022–2023 and FY 2023–2024 rates for the R-1E rate class, compared to the existing R-1 rate class, are provided in Table 5-6 below.

Table 5-6
Residential Rates (R-1E)
(Existing R-1 and Recommended R-1E)

Rate Component	R-1 Existing	Recommended R-1E (1) New Tiers (2)	FYE 2023	FYE 2024
Customer Charge ($/month)	$4.58		$5.91	$7.23
Energy Charge ($/kWh) (2)				
Summer				
Tier 1 (0 kWh–229 kWh)	$0.1778	Tier 1 (0 kWh–250 kWh)	$0.2088	$0.2277
Tier 2 (229 kWh–297 kWh)	$0.2021	Tier 2 (250 kWh–578 kWh)	$0.2506	$0.2732
Tier 3 (Over 297 kWh)	$0.4137	Tier 3 (Over 578 kWh)	$0.3758	$0.4099
Winter				
Tier 1 (0 kWh–278 kWh)	$0.1778	Tier 1 (0 kWh–418 kWh)	$0.2088	$0.2277
Tier 2 (278 kWh–361 kWh)	$0.2021	Tier 2 (418 kWh–960 kWh)	$0.2506	$0.2732
Tier 3 (Over 361 kWh)	$0.4137	Tier 3 (Over 960 kWh)	$0.3758	$0.4099

(1) Rate changes are effective July 1, 2022 (FYE 2023), and July 1, 2023 (FYE 2024).

(2) Recommended tiers reflect all electric usage for winter period. See text.

The intent of this new rate is to recognize the restriction of new natural gas service for new retail residential customers in the City, which is part of the overall City policy to reduce carbon emissions and increase beneficial electrification. By increasing the size of the tiers for each level of usage, the new R-1E is anticipated to decrease the relative monthly energy bills for all-electric retail customers, similar to those under the current Municipal Enterprise residential all-electric rates (E1TH).

Residential Municipal Enterprise Rates

Changes to the Residential Municipal Enterprise rates (E1TB, EM1TB, EM1TH, and their low-income associated rate codes EL1TB, EMLTB, and EMLTH) include changes to their tiered rate determination (recommended to be monthly, not daily) and to match the retail rate tiers for R-1G and R-1E (for natural gas and electric, and all-electric, respectively) as well as updates to their service charge and rate levels. Table 5-7 provides a summary of the newly recommended monthly tiers and rates for the E1TB customers.

Table 5-7
Enterprise Residential Rates (E1TB)
(Existing and Recommended)

Rate Component	Existing	Recommended (1)		
		New Tiers	FYE 2023	FYE 2024
Customer Charge ($/month)	$0.00	(Monthly Basis)	$3.62	$7.23
Energy Charge ($/kWh) (2)				
Summer				
Tier 1 (0– 6.8 kWh daily)	$0.3147	Tier 1 (0 kWh–227 kWh)	$0.2712	$0.2277
Tier 2 (6.8–27.2 kWh daily)	$0.3945	Tier 2 (227 kWh–524 kWh)	$0.3254	$0.2732
Tier 3 (> 27.2 kWh daily)	$0.4932	Tier 3 (Over 524 kWh)	$0.4881	$0.4099
Winter				
Tier 1 (0–8.2 kWh daily)	$0.3147	Tier 1 (0 kWh–252 kWh)	$0.2712	$0.2277
Tier 2 (8.2–32.8 kWh daily)	$0.3945	Tier 2 (252 kWh–579 kWh)	$0.3254	$0.2732
Tier 3 (> 32.8 kWh daily)	$0.4932	Tier 3 (Over 579 kWh)	$0.4881	$0.4099

(1) Rate changes are effective July 1, 2022 (FYE 2023), and July 1, 2023 (FYE 2024).

(2) Tiers recommended to change in usage volume to be equal to recommended R-1G rate structure and redesigned to be calculated monthly (see text).

Table 5-8 provides a summary of the newly recommended monthly tiers and rates for the EM1TB customers (Enterprise Municipal Master Metered, Natural Gas and Electric Service).

Table 5-8
Enterprise Master Meter Residential Rates (EM1TB – Natural Gas and Electric)
(Existing and Recommended)

Rate Component	Existing	Recommended [1]		
		New Tiers [2]	FYE 2023	FYE 2024
Customer Charge ($/month)	Min [3]	(Monthly Basis)	$3.62	$7.23
Energy Charge ($/kWh) [2]				
Summer				
Tier 1 (0–3.8 kWh daily)	$0.3147	Tier 1 (0 kWh–227 kWh)	$0.2712	$0.2277
Tier 2 (3.8–15.2 kWh daily)	$0.3945	Tier 2 (227 kWh–524 kWh)	$0.3254	$0.2732
Tier 3 (> 15.2 kWh daily)	$0.4932	Tier 3 (Over 524 kWh)	$0.4881	$0.4099
Winter				
Tier 1 (0–4.5 kWh daily)	$0.3147	Tier 1 (0 kWh–252 kWh)	$0.2712	$0.2277
Tier 2 (4.5–18 kWh daily)	$0.3945	Tier 2 (252 kWh–579 kWh)	$0.3254	$0.2732
Tier 3 (> 18 kWh daily)	$0.4932	Tier 3 (Over 579 kWh)	$0.4881	$0.4099

(1) Rate changes are effective July 1, 2022 (FYE 2023), and July 1, 2023 (FYE 2024).

(2) Tiers recommended to change in usage volume to be equal to recommended R-1G rate structure, based on the average number of units within the Master Meter complexes served by Hetch Hetchy Power and redesigned to be calculated on a monthly basis (see text).

(3) Master Meter customers have a minimum charge which is equal to their customer charge. This is recommended to be replaced with a monthly charge.

Small Commercial Rates

Table 5-9 provides a summary of the current rate schedules and rate classes within the small commercial rate offerings by Hetch Hetchy Power, and the number of customers in each rate code. All of the recommended small commercial rate changes are provided in the body of the report.

Table 5-9
Hetch Hetchy Power Small Commercial Rate Schedules and Customers

Rate Code	Description	# Customers	Report/Appendix
C-1 (S, P)	Standard Retail, Single/Polyphase, Municipal Enterprise, Municipal Enterprise TOU	1,322	Report
A1 (S, P)	Municipal Enterprise, Single/Polyphase	214	Report
A1-U (S, P)	Municipal Enterprise TOU, Single/Polyphase	183	Report
M-2 (CG-1)	Municipal General (GUSE) – To be renamed CG-1	832	Report

The Small Commercial customer class is currently defined as those customers who utilize less than 200 kW in a month and can be served by single phase (S) or poly phase (P). The rate classes within the Small Commercial class include the standard retail class (C-1), the rate for which includes a monthly service charge and a seasonal energy charge (summer and winter). The Municipal Enterprise customer rates include single or poly phase (A1S or A1P) and have the same rates as the equivalent PG&E rate for this class. The Municipal Enterprise does have a TOU rate option (A1-US or A1-UP) that includes an on-, part-, and off-peak summer rate and a part-peak and off-peak winter rate. Notably, the Municipal Enterprise rate, in line with PG&E's methodology, is defined as customers who use less than 75 kW in a month, differing from the retail and GUSE definitions. The Municipal General Use (GUSE) rate is the M-2 rate code and is a flat rate (as indicated previously).

The recommended changes to small commercial include a reduction in the maximum demand for these customers from 200 kW in a month to 75 kW in a month to be consistent with other municipal small commercial rate offerings. Those current small commercial customers that have a monthly demand of greater than 75 kW (approximately 11 customers) will be moved into the medium commercial customer class. The summer and winter energy rate differentials will be adjusted according to the analysis conducted for this Study, as will those for the Municipal Enterprise rates. The GUSE rate changes have been approved by budget and are limited to a $0.03/kWh increase in FY 2022–2023 and FY 2023–2024 (each year). Further, the GUSE rate structure will be changed from a flat $/kWh to a service change and an energy charge for these customers, which will be assigned a new rate code (GC-1).

The recommended customer charge for small commercial customers is designed to recover approximately 15% of the total revenue requirement for customer cost by the end of FY 2023–2024. This increase is recommended to be phased in evenly over the two-year rate plan period, similar to the residential rate class phase in.

Table 5-10 provides a summary of the recommended rate adjustments for the retail Small Commercial rate class (C-1) and a comparison of the rate components to the existing rate structure.

Table 5-10
Small Commercial (C-1)
(Existing and Recommended)

Rate Component	Existing	Recommended (1) FYE 2023	Recommended (1) FYE 2024
Customers Single Phase ($/month)	$8.99	$11.65	$14.31
Customers Poly Phase ($/month)	$22.49	$29.14	$35.80
Energy ($/kWh)			
Summer Charges	$0.2562	$0.2743	$0.2973
Winter Charges	$0.2049	$0.2194	$0.2378

(1) Rate changes are effective July 1, 22022, and July 1, 32023.

There are several important changes recommended for the Small Commercial rate schedules. The COS-based rates indicate a customer charge of $174 per month. The recommended customer charge starts at $11.65 per month (FY 2022–2023) and is increased to $14.31 per month for FY 2023–2024 for single phase service. The cost basis relationship between single phase and poly phase is recommended to remain constant in the recommended rate such that the recommended customer charge for poly phase services is $29.14 per month for FY 2022–2023 and $35.80 per month for FY 2023–2024.

The energy charge is recommended to increase to $0.2835/kWh for the C-1 customers in the summer $0.2267 /kWh in the winter in the first phase.

Distribution of Bill Impacts – Small Commercial

Figure 5-4 provides a summary of the distribution of monthly bill impacts for all customers in the small commercial class for the first phase of the recommended rate changes. As indicated, approximately 550 customers will see an average bill increase of approximately $36/month. Some customers are expected to see an average monthly bill decrease whereas some customers are expected to see an average bill increase greater than the average value, depending on usage characteristics.

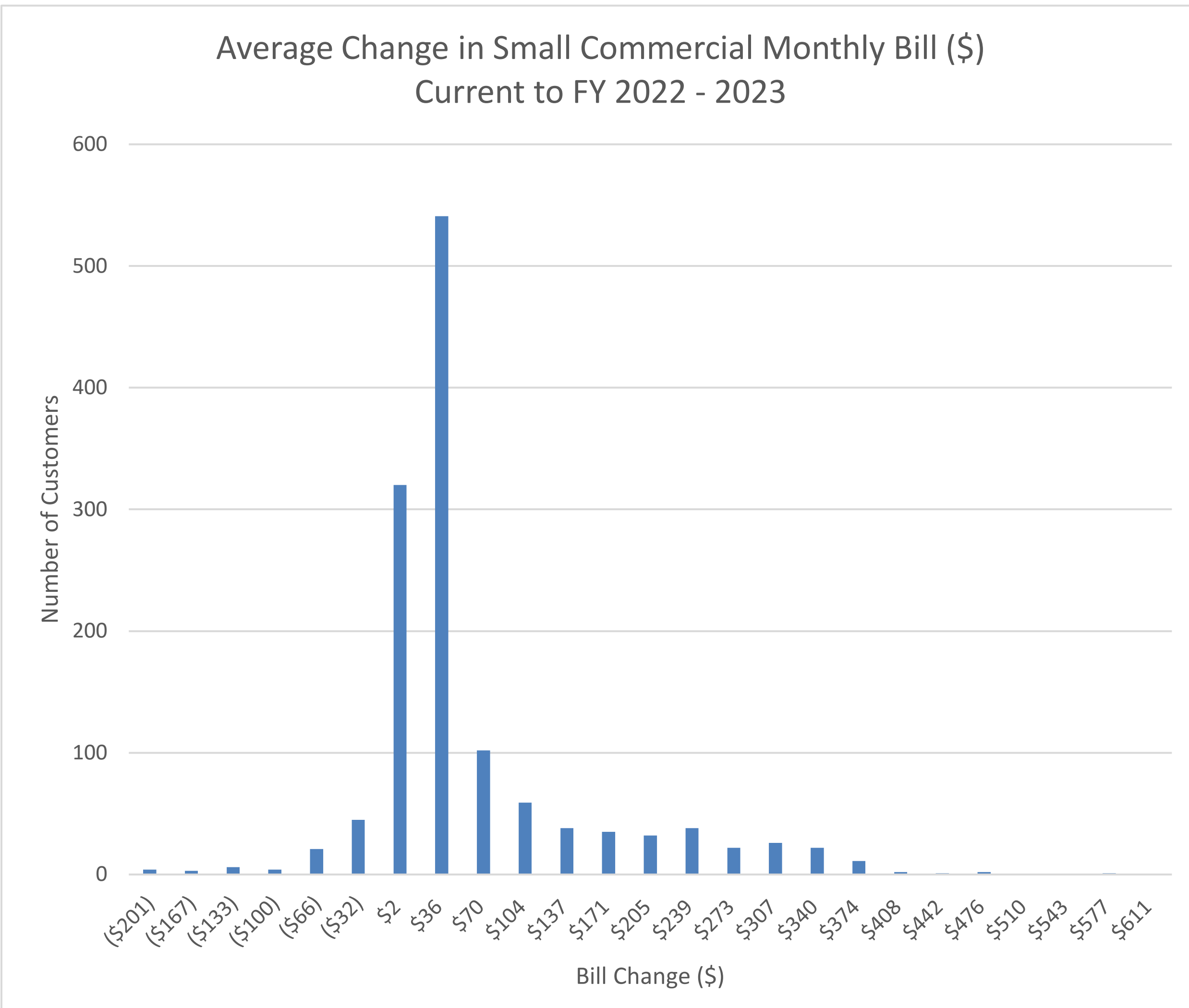


Figure 5-4. Distribution of Small Commercial Customers Monthly Bill Impact ($) for FY 2022–2023

GUSE Small Commercial (M-1, proposed GC-1)

Table 5-11 provides the current and recommended rates for the GUSE Small Commercial customers for single phase (GC-1S) and poly phase (GC-1P) service. Note that the current rate (M-1) is a flat energy rate without a monthly service charge. As noted previously, the "effective rate" (the total projected revenue divided by the total projected energy sales) is limited to an increase of $0.03/kWh for the GUSE customers (for each phase).

Table 5-11
GUSE Small Commercial Rates (GC-1S and GC-1P)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Single Phase	$0.00	$6.00	$8.52
Customer ($/month) – Poly Phase	$0.00	$15.02	$21.31
Energy ($/kWh)			
Summer Charges	$0.0988	$0.1410	$0.1733
Winter Charges	$0.0988	$0.1128	$0.1386

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Municipal Enterprise Small Commercial (A1S, A1P)

Table 5-12 provides the current and recommended rates for the Municipal Enterprise Small Commercial customers for single phase (A1S) and poly phase (A1P) service.

Table 5-12
Enterprise Small Commercial Rates (A1S and A1P)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Single Phase	$10.00	$12.15	$14.31
Customer ($/month) – Poly Phase	$25.00	$30.38	$35.78
Energy ($/kWh) (2)			
Summer Charges	$0.3364	$0.3271	$0.2972
Winter Charges	$0.2794	$0.2616	$0.2377

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

(2) Recommended rate structure includes decrease in summer and increase in winter rate for FY 2023–2024 to reflect costs. See text.

Municipal Enterprise Small Commercial (A1-US, A1-UP)

Table 5-13 provides the current and recommended rates for the Municipal Enterprise Small Commercial customers for TOU service for single phase (A1-US) and poly phase (A1-UP) service.

Table 5-13
Enterprise Small Commercial Rates (A1-US and A1-UP)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Single Phase	$10.00	$12.15	$14.31
Customer ($/month) – Poly Phase	$25.00	$30.38	$35.78
Summer Energy Charges			
On-Peak	$0.3397	$0.3290	$0.2978
Part-Peak	$0.3397	$0.3290	$0.2978
Off-Peak	$0.3149	$0.2832	$0.2332
Winter Energy Charges			
Part-Peak	$0.2921	$0.2947	$0.2790
Off-Peak	$0.2915	$0.2803	$0.2515

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Medium Commercial Rates

Table 5-14 provides a summary of the current rate schedules and rate classes within the medium commercial rate class offerings by Hetch Hetchy Power, the number of customers in each rate code, and whether the recommended rates are included in the body of the report or in Appendix A.

Table 5-14
Hetch Hetchy Power Medium Commercial Rate Schedules and Customers

Rate Code	Description	# Customers	Report/Appendix
C-2 (S, P)	Standard Retail, Secondary/Primary	2	Secondary – Report Primary – Appendix A
A10 (S, P)	Municipal Enterprise, Secondary/Primary	46	Secondary – Report Primary – Appendix A
A10-U (S, P)	Municipal Enterprise TOU, Secondary/Primary	66	Secondary – Report Primary – Appendix A
M-2 (CG-2)	Municipal General (GUSE) – To be renamed CG-2	212	Report

The Medium Commercial customer class is currently defined as those customers who utilize between 200 and 500 kW demand during a month and can be served by secondary voltage (S) or primary voltage (P). The rate classes within the Medium Commercial Class include the standard retail class (C-2), which includes a monthly service charge, a seasonal energy charge, and a demand charge (which is the same for summer and winter periods). The Municipal Enterprise (A10S, A10P) rate class has the same rates as the equivalent PG&E rate class. The Municipal Enterprise TOU does have a TOU rate option (A10-US or A10-UP) that includes on-, part-, and off-peak periods in the summer and part-peak and off-peak in the winter (and no summer or winter differential for the demand rate). The Municipal General Use rate is the same flat rate for all commercial customers.

The recommended customer charge for medium commercial customers is designed to recover approximately 29% of the total revenue requirement for customer cost by the end of FY 2023–2024. This increase is recommended to be phased in evenly over the two-year rate plan period, similar to the residential rate class phase in.

Table 5-15 provides a summary of the recommended rate adjustments for the Medium Commercial, secondary service (C2-S) rate class and a comparison of the rate components to the existing rate structure.

Table 5-15
Medium Commercial Rates (C2-S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer Charge ($/month)	$149.92	$202.51	$255.11
Demand ($/kW)			
Summer	$14.11	$27.76	$41.41
Winter	$14.11	$27.76	$41.41
Energy Charge ($/kWh)			
Summer	$0.1387	$0.1139	$0.0932
Winter	$0.1726	$0.1416	$0.1160

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Distribution of Bill Impacts – Medium Commercial

Figure 5-5 provides a distribution of the average monthly bill impacts to all customers in the Medium Commercial class due to the recommended changes to the rates for the first phase of the two-year rate plan. As indicated, there are approximately five customers who are projected to see a bill decrease of approximately $1,000 or more for the month, based on their usage. There are approximately 120 customers who are expected to see a bill increase of between approximately $500 and $750, and there are a small number of customers who are expected to see a bill increase of greater than $5,000. The reason for this broad distribution of estimated monthly rate impacts is due to the changes in the demand and energy rates recommended and the wide range of usage characteristics within the Medium Commercial class.

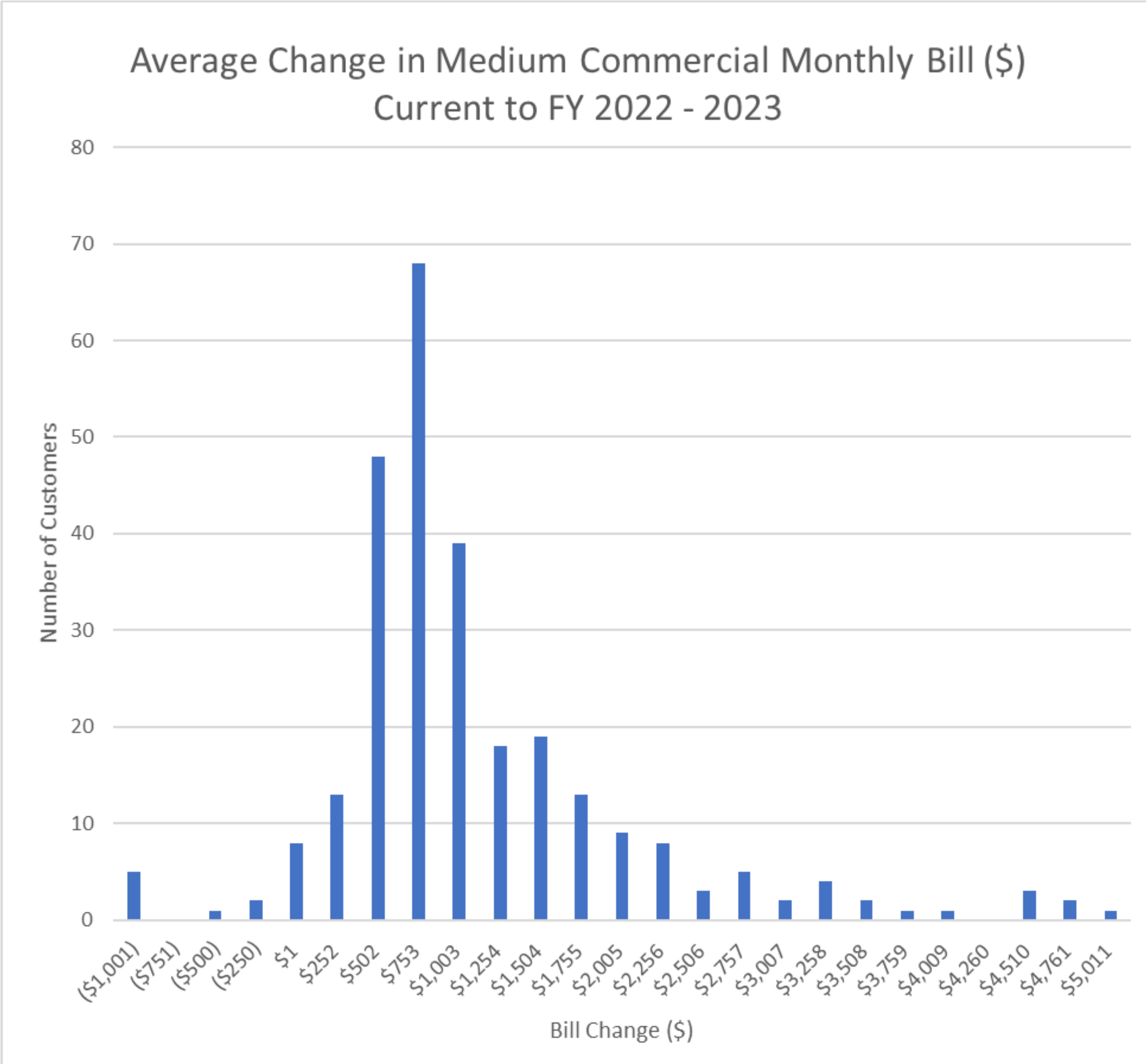


Figure 5-5. Distribution of Medium Commercial Customers Monthly Bill Impact ($) for FY 2022–2023

GUSE Medium Commercial (M-1, proposed GC-2)

Table 5-16 provides the current and recommended rates for the GUSE Medium Commercial customers for secondary (GC-2S), see Appendix A for GC-2P. Note that the current rate (M-1) is a flat energy rate without a monthly service charge.

Table 5-16
GUSE Medium Commercial Rates (GC-2S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$0.00	$132.19	$205.54
Demand ($/kW)			
Summer Charges	$0.00	$18.12	$33.36
Winter Charges	$0.00	$18.12	$33.36
Energy ($/kWh)			
Summer Charges	$0.0988	$0.0683	$0.0569
Winter Charges	$0.0988	$0.0850	$0.0707

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Municipal Enterprise Medium Commercial

Table 5-17 provides the current and recommended rates for the Municipal Enterprise Medium Commercial customers for secondary (A10-S) service. The recommended rate changes for the A10-P customers are provided in Appendix A.

Table 5-17
Enterprise Medium Rates (A10S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$179.90	$217.50	$255.11
Demand Rate ($/kW)	$18.45	$29.93	$41.41
Energy ($/kWh)			
Summer Charges	$0.2337	$0.1611	$0.0925
Winter Charges	$0.1961	$0.2004	$0.1151

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Municipal Enterprise Medium Commercial TOU

Table 5-18 provides the current and recommended rates for the Municipal Enterprise Medium Commercial customers for TOU service for secondary service (A10-US). The recommended changes in rates for the primary (A10-UP) service are provided in Appendix A.

Table 5-18
Enterprise Medium Commercial Rates (A10-US)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$179.55	$217.50	$255.11
Demand Rate ($/kW)	$18.45	$29.93	$41.41
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.2472	$0.1841	$0.1255
Part-Peak	$0.2472	$0.1841	$0.1255
Off-Peak	$0.2204	$0.1593	$0.1003
Winter Charges			
Part-Peak	$0.1967	$0.1541	$0.1182
Off-Peak	$0.1960	$0.1493	$0.1077

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Large Commercial

Table 5-19 provides a summary of the current rate schedules and rate classes within the large commercial rate class offerings by Hetch Hetchy Power and the number of customers in each rate code. Recommended changes to secondary and primary rates for the large commercial class are included in the body of the report.

Table 5-19
Hetch Hetchy Power Large Commercial Rate Schedules and Customers

Rate Code	Description	# Customers	Report/Appendix
C-3 (S, P)	Standard Retail, Secondary/Primary	2	Report
E-19 (S, P)	Municipal Enterprise TOU, Secondary/Primary	46	Report
M-2 (CG-3)	Municipal General (GUSE) – To be renamed CG-3	26	Report

The Large Commercial customer class is currently defined as those customers who utilize between 500 and 1,000 kW demand during a month and can be served by secondary voltage (S) or primary voltage (P). The rate classes within the Large Commercial Class include the standard retail class (C-3), which includes a monthly service charge, a seasonal and TOU energy charge, and a seasonal and TOU demand charge. The energy charge includes an on-peak, part-peak, and off-peak charge in summer and a part-peak and off-peak charge in the winter. The demand rate is applied to an on-peak, part-peak, and max demand during the summer period, and a max demand during the winter period. The Municipal Enterprise (E-19S, E-19P) rate class has the same rates as the current equivalent PG&E rate class. However, seasons and TOU periods are based on historic PG&E rate structures and are the same as those in place for the retail rates (C-3). The Municipal General Use rate is the same flat rate for all commercial customers.

The recommended customer charge for large commercial customers is designed to recover approximately 29% of the total revenue requirement for customer cost by the end of FY 2023–2024. This increase is recommended to be phased in evenly over the two-year rate plan period, similar to the residential rate class phase in.

Table 5-20 provides a summary of the existing and recommended changes for Large Commercial rates for secondary service (C-3S).

Table 5-20
Large Commercial Rates (C-3S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$754.93	$1,207.12	$1,659.31
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$12.27	$16.65	$21.03
Part-Peak	$10.01	$13.58	$17.15
Max	$22.44	$30.45	$38.46
Winter Charges			
Max	$22.44	$30.45	$38.46
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.1019	$0.0897	$0.0783
Part-Peak	$0.1019	$0.0897	$0.0783
Off-Peak	$0.0965	$0.0792	$0.0624
Winter Charges			
Part-Peak	$0.0942	$0.0835	$0.0735
Off-Peak	$0.0936	$0.0802	$0.0674

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Table 5-21 provides a summary of the existing and recommended changes for Large Commercial rates for primary service (C-3P).

Table 5-21
Large Commercial Rates (C-3P)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Primary	$1,151.50	$1,352.55	$1,553.60
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$10.44	$11.80	$13.15
Part-Peak	$8.73	$9.86	$11.00
Max	$18.58	$20.99	$23.40
Winter Charges			
Max	$18.58	$20.99	$23.40
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.0934	$0.0852	$0.0779
Part-Peak	$0.0934	$0.0852	$0.0779
Off-Peak	$0.0883	$0.0749	$0.0620
Winter Charges			
Part-Peak	$0.0860	$0.0792	$0.0732
Off-Peak	$0.0854	$0.0759	$0.0671

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Distribution of Bill Impacts – Large Commercial

Figure 5-6 provides a distribution of the average monthly bill impacts to all customers in the Large Commercial class due to the recommended changes to the rates for the first phase of the two-year rate plan. As indicated, there are approximately ten customers who are projected to see a bill decrease, based on their usage. There are approximately three customers who are expected to see a bill increase of between approximately $1 and $2,700, and there are approximately nine customers who are expected to see a bill increase of greater than $2,500. This is due to the recommended changes in the demand and energy rates and the range of usage characteristics within the Large Commercial class.

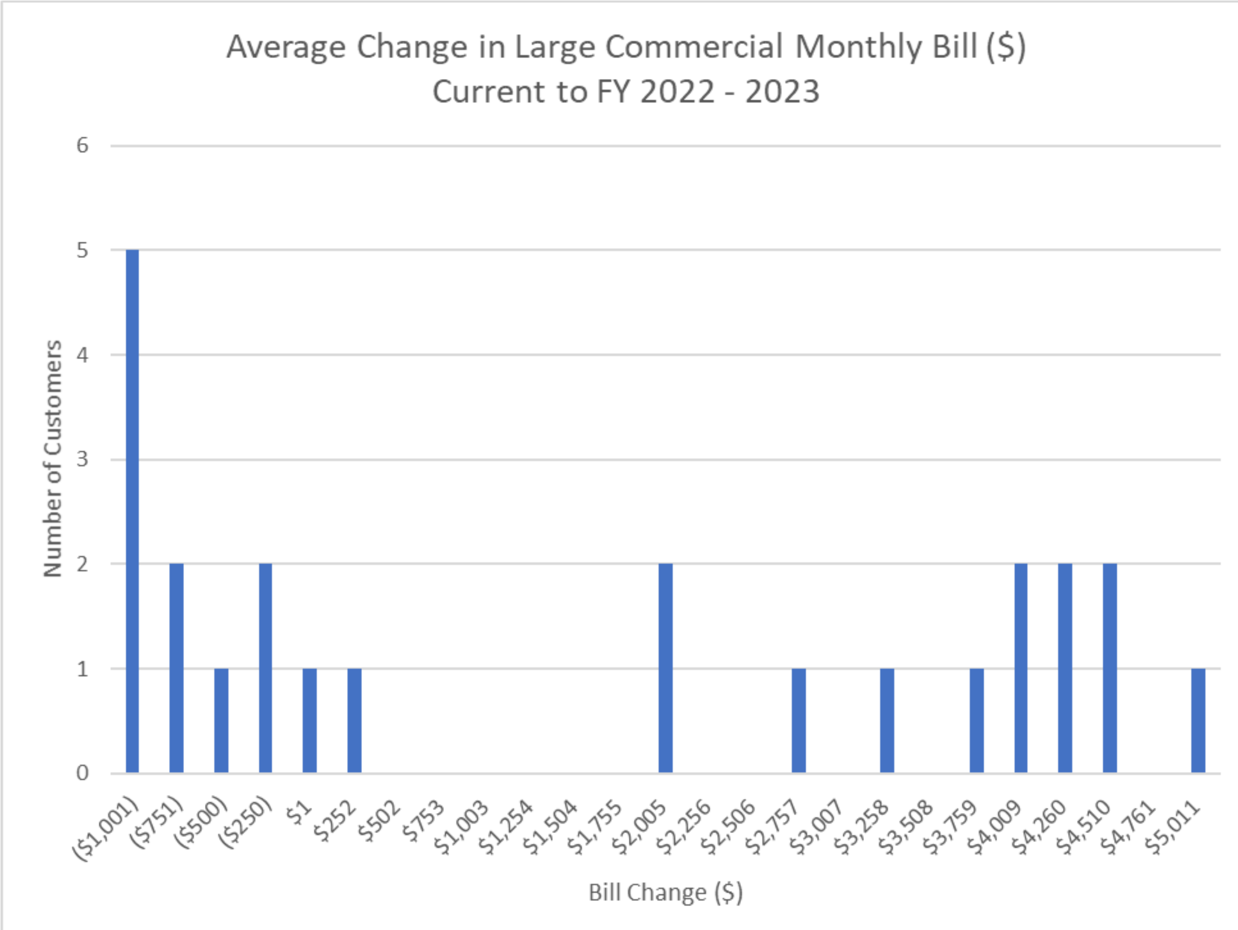


Figure 5-6. Distribution of Large Commercial Customers Monthly Bill Impact ($) for FY 2022–2023

Table 5-22 provides a summary of the existing and recommended changes for Large Commercial GUSE rates (currently M-1, proposed to be GC-3S, secondary).

Table 5-22
Large Commercial GUSE Rates (GC-3S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$0.00	$774.98	$1,235.78
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$0.00	$10.69	$15.66
Part-Peak	$0.00	$8.72	$12.78
Max	$0.00	$19.55	$28.64
Winter Charges			
Max	$0.00	$19.55	$28.64
Energy ($/kWh)			
Summer Charges	$0.0988		
On-Peak		$0.0572	$0.0567
Part-Peak		$0.0572	$0.0567
Off-Peak		$0.0505	$0.0451
Winter Charges	$0.0988		
Part-Peak		$0.0532	$0.0459
Off-Peak		$0.0511	$0.0421

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Table 5-23 provides a summary of the existing and recommended changes for Municipal Enterprise Large Commercial rates for secondary voltage (E-19S).

Table 5-23
Enterprise Large Commercial Rates (E-19S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$903.76	$1,281.54	$1,659.31
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$16.99	$19.01	$21.03
Part-Peak	$14.28	$15.72	$17.15
Max	$28.39	$33.42	$38.46
Winter Charges			
Max	$28.39	$33.42	$38.46
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.1410	$0.1222	$0.0784
Part-Peak	$0.1410	$0.1222	$0.0784
Off-Peak	$0.1350	$0.1101	$0.0624
Winter Charges			
Part-Peak	$0.1325	$0.1148	$0.0736
Off-Peak	$0.1317	$0.1110	$0.0674

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Table 5-24 provides a summary of the existing and recommended changes for Municipal Enterprise Large Commercial rates for primary voltage (E-19P).

Table 5-24
Enterprise Large Commercial Rates (E-19P)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Primary	$1,372.68	$1,464.45	$1,553.60
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$14.46	$13.81	$13.15
Part-Peak	$12.42	$11.71	$11.00
Max	$23.73	$23.56	$23.40
Winter Charges			
Max	$23.73	$23.56	$23.40
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.1281	$0.1156	$0.0779
Part-Peak	$0.1281	$0.1156	$0.0779
Off-Peak	$0.1224	$0.1036	$0.0620
Winter Charges			
Part-Peak	$0.1199	$0.1083	$0.0731
Off-Peak	$0.1192	$0.1045	$0.0670

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Industrial Rates

Table 5-25 provides a summary of the current rate schedules and rate classes within the industrial commercial rate class offerings by Hetch Hetchy Power and the number of customers in each rate code. Recommended changes to the secondary and primary rates for the large commercial class are included in the body of the report, and the transmission rates are provided in Appendix A.

Table 5-25
Hetch Hetchy Power Industrial Rate Schedules and Customers

Rate Code	Description	# Customers	Report/Appendix
1-1 (S, P, T)	Standard Retail, Secondary/Primary/Transmission	3	Primary (Report), Secondary & Transmission (Appendix A)
E-20 (S, P, T)	Municipal Enterprise TOU, Secondary/Primary/Transmission	23	Report
M-2 (CG-4)	Municipal General (GUSE) – To be renamed CG-4	19	Secondary (Report), Primary & Transmission (Appendix A)

The Industrial Commercial customer class is currently defined as those customers who utilize greater than 1,000 kW demand during a month and can be served by secondary (S), primary (P), or transmission (T)-level voltage. The rate classes within the Industrial Class include the standard retail class (I-1), which includes a monthly service charge, a seasonal and TOU energy charge, and a seasonal and TOU demand charge. The energy charge includes an on-peak, part-peak, and off-peak charge in summer and a part-peak and off-peak charge in the winter. The demand rate is applied to an on-peak, part-peak, and max demand during the summer period, and a max demand during the winter period. The Municipal Enterprise (E-20) rate class has the same rates as the equivalent PG&E rate class; however, the structure is identical to the I-1 rate class with regard to the seasonality and time periods of the energy and demand rates. The Municipal General Use rate is the same flat rate for all commercial customers.

Table 5-26 provides a summary of the existing and recommended changes for Industrial primary service rates (I-1P).

Table 5-26
Industrial Rates (I3-P)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Primary	$1,367.57	$1,481.03	$1,594.48
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$12.38	$14.51	$16.63
Part-Peak	$10.23	$11.99	$13.74
Max	$20.11	$23.55	$27.00
Winter Charges			
Max	$23.73	$23.55	$27.00
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.0942	$0.0967	$0.1078
Part-Peak	$0.0942	$0.0967	$0.1078
Off-Peak	$0.0890	$0.0842	$0.0843
Winter Charges			
Part-Peak	$0.0868	$0.0895	$0.1004
Off-Peak	$0.0861	$0.0853	$0.0911

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Table 5-27 provides a summary of the existing and recommended changes for Industrial GUSE rates (currently M-1, proposed to be CG4-S, secondary).

Table 5-27
Industrial GUSE Rates (CG4-S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary (2)	$0.00	$1,141.32	$1,522.94
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$0.00	$10.86	$15.04
Part-Peak	$0.00	$8.55	$11.84
Max	$0.00	$19.33	$26.77
Winter Charges			
Max	$0.00	$19.33	$26.77
Energy ($/kWh)			
Summer Charges	$0.0988		
On-Peak		$0.0675	$0.0753
Part-Peak		$0.0675	$0.0753
Off-Peak		$0.0587	$0.0589
Winter Charges	$0.0988		
Part-Peak		$0.0625	$0.0701
Off-Peak		$0.0596	$0.0636

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

(2) Assumes GUSE Secondary Service.

Table 5-28 provides a summary of the existing and recommended changes for Municipal Enterprise Industrial rates for secondary voltage (E20-S).

Table 5-28
Enterprise Industrial Rates (E20-S)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Secondary	$1,632.16	$1,646.29	$1,660.42
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$17.06	$16.73	$16.39
Part-Peak	$13.90	$13.40	$12.91
Max	$28.61	$28.90	$29.18
Winter Charges			
Max	$28.61	$28.90	$29.18
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.1340	$0.1080	$0.1107
Part-Peak	$0.1340	$0.1080	$0.1107
Off-Peak	$0.1281	$0.0961	$0.0866
Winter Charges			
Part-Peak	$0.1255	$0.1010	$0.1031
Off-Peak	$0.1248	$0.0971	$0.0935

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Table 5-29 provides a summary of the existing and recommended changes for Municipal Enterprise Industrial rates for primary voltage (E-20P).

Table 5-29
Enterprise Industrial (E-20P)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Primary	$1,624.03	$1,609.25	$1,594.48
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$17.11	$16.87	$16.63
Part-Peak	$14.56	$14.15	$13.74
Max	$26.15	$26.58	$27.00
Winter Charges			
Max	$26.15	$26.58	$27.00
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.1293	$0.1083	$0.1077
Part-Peak	$0.1293	$0.1083	$0.1077
Off-Peak	$0.1236	$0.0964	$0.0843
Winter Charges			
Part-Peak	$0.1211	$0.1012	$0.1003
Off-Peak	$0.1204	$0.0973	$0.0910

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Table 5-30 provides a summary of the existing and recommended changes for Municipal Enterprise Industrial rates for transmission voltage (E-20T).

Table 5-30
Enterprise Industrial Rates (E-20T)
(Existing and Recommended Rates) (1)

Rate Component	Existing	FYE 2023	FYE 2024
Customer ($/month) – Transmission	$1,111.18	$1,332.39	$1,553.60
Demand Rate ($/kW)			
Summer Charges			
On-Peak	$15.02	$17.75	$20.48
Part-Peak	$15.02	$17.75	$20.48
Max	$13.55	$16.01	$18.48
Winter Charges			
Max	$13.55	$16.01	$18.48
Energy ($/kWh)			
Summer Charges			
On-Peak	$0.1140	$0.1070	$0.1076
Part-Peak	$0.1140	$0.1070	$0.1076
Off-Peak	$0.1083	$0.0944	$0.0841
Winter Charges			
Part-Peak	$0.1059	$0.0995	$0.1002
Off-Peak	$0.1053	$0.0954	$0.0909

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Distribution of Bill Impacts – Industrial Customers

Figure 5-7 provides a distribution of the average monthly bill impacts to all customers in the Industrial rate class due to the recommended changes to the rates for FY 2022-2023 of the two-year rate plan. As indicated, there are eight customers who are projected to see a bill decrease and approximately 32 customers who are expected to see a bill increase.

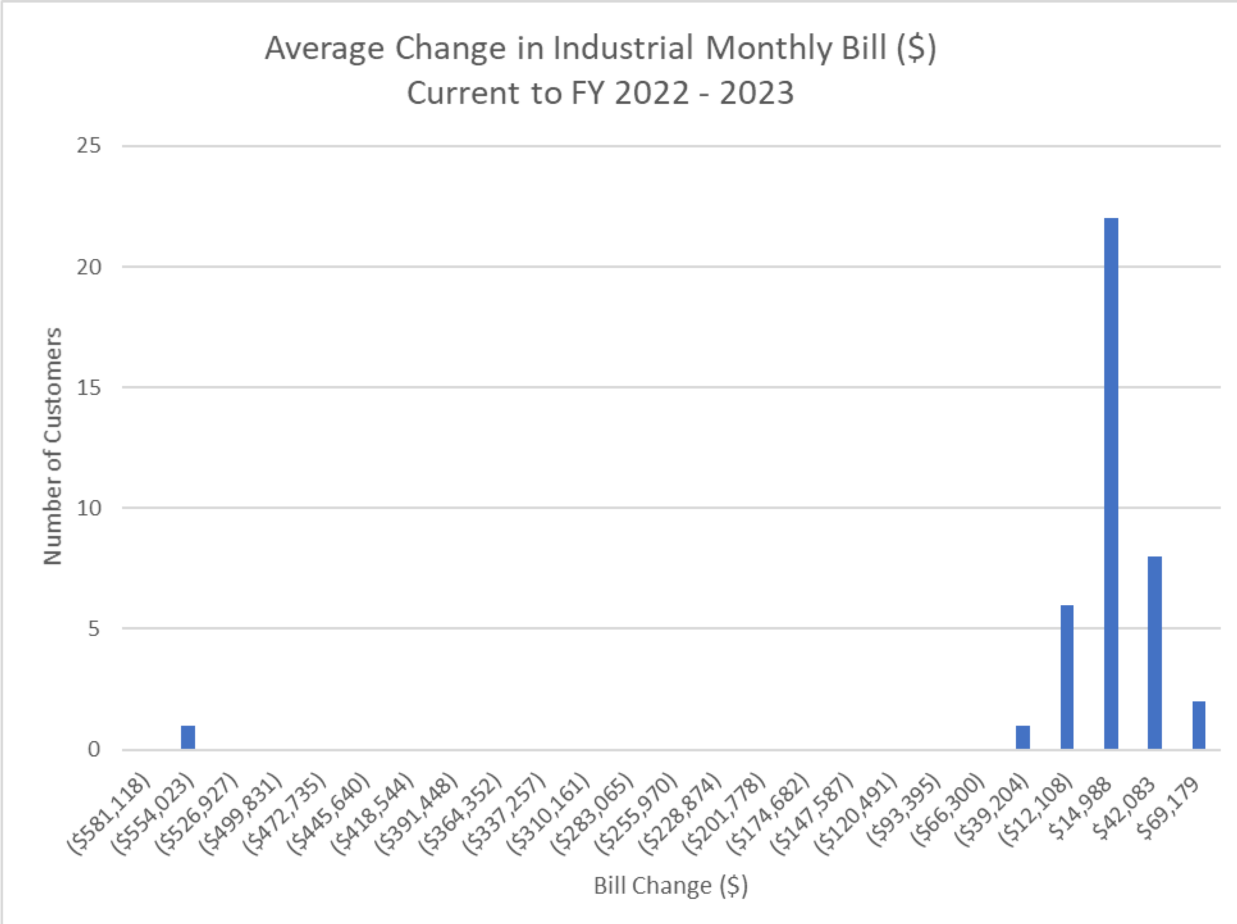


Figure 5-7. Distribution of Average Monthly Bill Impacts Industrial Commercial Customers

Other Rates

Traffic Lights/Street Lights

As indicated in Section 2, most of the unmetered customers, including most streetlighting customers, will not be served electricity by Hetch Hetchy Power in the future. However, there will continue to be a small number (less than 30) metered outdoor lighting and some unmetered customers within areas where Hetch Hetchy Power owns the distribution system. This includes traffic lights (under current rate TC-1, which is an Enterprise PG&E equivalent rate) and streetlights (LS-3 which is an Enterprise PG&E equivalent rate and GUSE, which is a flat rate). The TC-1 and LS-3 rate include customer charges (PG&E's charge is a daily rate, but the SFPUC charges monthly based on a 30-day month) and an energy rate.

For these customers, the recommended rate is a flat all-in energy rate (not seasonally or TOU differentiated), based on the small commercial class average energy rate for the Test Year period (see Table 5-31 below). For GUSE rates, the recommended rate increase is limited to $0.03/kwh per year, as described herein.

Table 5-31
Traffic Lights/Streetlights (TC-1/LS-3/SLG)
(Existing and Recommended Rate) (1)

Rate Component	Current Rate	FYE 2023	FYE 2024
TC-1			
Customer Charge ($/month) (2)	$14.78	$0	$0
Energy ($/kWh)	$0.2528	$0.2592	$0.2656
LS-3			
Customer Charge ($/month) (2)	$7.39	$0	$0
Energy ($/kWh)	$0.2255	$0.2456	$0.2656
SLG Streetlight (GUSE) $/kWh (2)	$0.0988	$0.1288	$0.1588

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

(2) TC-1 and LS-3 current rate are Enterprise rates. Recommended rate is the average all-in COS energy rate for small commercial class for the Test Year. GUSE to increase at $0.03/kWh per year

Individually Metered EV Charging Pilot Rate (EV-1)

The SFPUC is proposing to introduce an individually metered EV charging rate based on the costs associated with the small commercial rate. This rate is designed to recover costs based on a customer charge and energy rate (no demand rate component is recommended). This rate would be charged to a dedicated meter solely for EV charging for a commercial or residential customer. For the purposes of this rate plan, this rate is recommended to be offered as a "pilot" program, designed to collect usage data for analysis and refinement in future years.

The costs for the infrastructure (metering support, connection to existing service), are to be defined as part of this pilot program and are anticipated to be recovered from the customer interested in having a dedicated EV charging system at their location. SFPUC will install the meter. This program has not yet been defined by SFPUC; however, the recommended rate is based on the COS analysis developed for this Study. The recommended energy rate is provided in Table 5-32 and is to be TOU differentiated based on the SFPUC costs with a TOU period of 4–9 PM every day of the week. As this program is further defined and data is load obtained, it is recommended that the SFPUC continue to monitor usage, costs, and cost recovery for this recommended rate offering.

Table 5-32
Commercial EV Charging Rate (C-EV)
(Recommended Pilot Rate)

Rate Component	FYE 2023	FYE 2024
Customer Charge	$8.03	$8.03
Energy ($/kWh) (1)		
Summer		
On-Peak (4–9 PM)	$0.20252	$0.20252
Off-Peak	$0.12961	$0.12961
Winter		
On-Peak (4–9 PM)	$0.28768	$0.28768
Off-Peak	$0.21686	$0.21686

(1) No demand charge is recommended for the C-EV Pilot program; these costs are recovered in the energy rate (see text).

Projected Revenue from Recommended Rates

Hetch Hetchy Power proposes to offer the rates described herein and set for each year of the two-year Test Year period. Table 5-33 provides a summary of the projected revenue requirement by customer class for Year 1 of the Study period and the projected revenues at the recommended rates, and Table 5-34 provides a similar analysis of Year 2 of the Study period.

Table 5-33
Revenue Requirement and Year 1 Projected Revenue by Customer Class ($000)

Class	Year 1 Revenue Requirement (1)	Year 1 Projected Revenue	$ Difference	% Difference
Residential	$9,537	$5,128	($4,408)	(46%)
Small Commercial	$14,885	$11,255	($3,630)	(24%)
Medium Commercial	$27,595	$21,658	($5,937)	(22%)
Large Commercial	$17,896	$15,305	($2,592)	(14%)
Industrial	$85,735	$102,302	$16,567	19%
Total Revenue Requirement	$155,648	$155,648	$0	0%

(1) Numbers may not add due to rounding.

Table 5-34
Revenue Requirement and Year 2 Projected Revenue by Customer Class ($000)

Class	Year 2 Revenue Requirement (1)	Year 2 Projected Revenue	$ Difference	% Difference
Residential	$16,175	$7,017	($9,158)	(57%)
Small Commercial	$18,386	$15,671	($2,715)	(15%)
Medium Commercial	$30,577	$26,507	($4,070)	(13%)
Large Commercial	$21,236	$19,630	($1,605)	(8%)
Industrial	$101,490	$119,039	$17,549	17%
Total Revenue Requirement	$187,864	$187,864	$0	0%

(1) Numbers may not add due to rounding.

The result indicates that the rates recommended herein, assuming the load growth occurs as projected, will provide sufficient revenue in Year 1 and Year 2 to cover the projected costs for the Hetch Hetchy Power system. Revenues for the residential, small, medium, and large commercial classes will continue to under-collect for the two-year rate plan, relative to their costs, primarily due to the GUSE, low-income, residential rate cap rate policies discussed herein. For both Year 1 and Year 2 of the rate plan, the industrial customer class is anticipated to over collect relative to its costs.

Section 6
COST OF SERVICE FOR CLEANPOWERSF

As indicated, the costs and operations related to CleanPowerSF are dramatically different than those associated with the Hetch Hetchy Power entities. CleanPowerSF purchases power on behalf of their customers through a combination of PPAs for renewable and non-renewable resources, such as purchases of market power from CAISO to serve load. Further, CleanPowerSF relies on a third-party vendor (Calpine) to provide billing data (Calpine provides this serve to several CCAs in California and works directly with the incumbent utility, such as PG&E). For this Study, Calpine provided billing data known as the "Item 17 data" and the "TOU Buckets" data set for CleanPowerSF customers, which includes hourly load data by class. Additionally, this Study relied on historic data from CleanPowerSF known as the "MDEF" (Meter Data Exchange Format), which is hourly data summed by customer class and is used to inform the CAISO of the total load necessary to serve customers.

Revenue requirement refers to the amount of rate-related revenue a utility is projected to need during the Study period. For the purposes of this Study, and similar to Hetch Hetchy Power, CleanPowerSF is utilizing a Test Year that represents the average of the two-year period from FY 2022–2023 to FY 2023–2024. The CleanPowerSF Revenue Requirement for the Test Year is approximately $302.4 million. This value is driven by the specific "known and measurable changes" related to the investments projected in the SFPUC's 10-Year Financial Model. Because the Test Year is a multi-year representation, this value represents the average annual revenue to be collected by CleanPowerSF retail rates. For the purposes of CleanPowerSF rate design, provided in Section 7 of this Report, revenues collected over the Study period will vary by year. A summary of the Test Year Revenue Requirements is provided in Table 6-1.

Table 6-1
5-Year Projection of Revenue Requirement by Summary ($000)

Expense Line	FYE 2023	FYE 2024	FYE 2025	FYE 2026	FYE 2027	Test Year Value	Percent of Total
Renewable Energy	$72,929	$77,683	$83,042	$91,183	$93,385	$75,306	25%
Capacity	$43,616	$41,946	$49,544	$60,266	$64,250	$42,781	14%
Shaped Energy	$8,597	$0	$0	$0	$0	$4,298	1%
Energy Open Position	$101,778	$90,583	$81,423	$70,843	$62,852	$96,180	32%
CAISO	$6,430	$6,481	$6,513	$6,546	$6,578	$6,455	2%
Contingency	$17,968	$21,453	$22,052	$22,884	$22,707	$19,710	7%
Operating and Other Costs	$65,923	$49,542	$52,750	$51,443	$54,908	$57,733	19%
Total	$317,240	$287,688	$295,324	$303,164	$304,680	$302,464	

Source: SFPUC 10-Year Financial Pro Forma Model. Note: numbers may not add due to rounding.

As Table 6-1 indicates, the energy open position (market purchases) is the largest expense line item for CleanPowerSF to serve its customers (32% of the Test Year total). CleanPowerSF also invests significantly in PPAs with renewable energy resources, which represent approximately 25% of its total expenses. This investment allows CleanPowerSF to offer its "Green" and "SuperGreen" rate products. Other power supply costs include costs for RA, which is essentially the capacity necessary to support its energy purchases; other CAISO charges; and contingency reserves. Operating and other costs includes labor, program costs, and contributions to reserves (margin). As indicated, CleanPowerSF is pursuing a policy of increasing its cash reserves, which represent a significant increase in revenue requirement (approximately $31 million in contribution in the first year of the Test Year), but which are expected to reduce to approximately $16 million per year at the end of the five-year period. Overall, the deposit to CleanPowerSF cash reserves represents approximately 8% of the Test Year Revenue Requirement.

CleanPowerSF Reserve Policy

The San Francisco Charter Section 8B.125 requires the SFPUC to be a financial steward by establishing:

> rates, fees and charges at levels sufficient to improve or maintain financial condition and bond ratings at or above levels equivalent to highly rated utilities of each enterprise under its jurisdiction, meet requirements and covenants under all bond resolutions and indentures … and provide sufficient resources for the continued financial health (including appropriate reserves), operation, maintenance and repair of each enterprise, consistent with good utility practice.

To meet this requirement most effectively, the SFPUC has adopted financial policies, including those that govern financial reserves, to foster financial stability, support fiscal discipline, and maintain credit ratings at or above levels equivalent to highly rated utilities.

The SFPUC faces several risks to revenue stability, including multi-year rate packages, drought and weather variability, and highly volumetric rates. While CleanPowerSF operates under much of the same legal and policy framework as the SFPUC's other utility services, the program is also reliant on the power supply market and faces competitive pressures that may reduce its flexibility for rate increases. In the case of CleanPowerSF, financial reserves may need to be incrementally higher than in other Enterprises to account for the increased financial pressures and need for rate stabilization faced by power supply market volatility. Moreover, CleanPowerSF's credit impacts not only lending terms, but also third-party power supply contracts, a key tool to mitigate market exposure.

The reserve level is defined by the end of year (EOY) fund balances for CleanPowerSF. The days cash is defined as the EOY Fund Balance divided by the sum of the total supply and operating costs divided by 365 days. Table 6-2 provides the projected target EOY reserve fund balance beginning at the end of FY 2021–2022 and for each year of the Test Year, as well as the calculated days cash on hand (with the recommended rate changes).

Table 6-2
CleanPowerSF Metrics

Metric	FYE 2022	FYE 2023	FYE 2024
EOY Fund Balances	$66,238	$104,855	$119,014
Days of Cash on Hand	93	134	160

Functionalization and Classification

Similar to the process for Hetch Hetchy Power, allocating cost to CleanPowerSF customer classes is achieved through three major processes: 1) functionalization, 2) classification, and 3) allocation.

Functionalization of Test Year Expenditures

Table 6-3 provides a categorization of the COS by function (as a result of the cost allocation process) for CleanPowerSF. As indicated previously, CleanPowerSF provides services that can be functionalized by Power Supply (which includes generation and delivery of power to customers), and Customer (which are defined as those services that are related to the number of customers or are an allocated portion of fixed costs, such as labor).

Table 6-3
Revenue Requirement by Function – CleanPowerSF ($000)

Expense Line	2-Year Test Year	Power Supply	Customer	% of Total Power Supply	% of Total Customer
Renewable Energy (1)	$75,306	$75,306	$0	27%	0%
Capacity	$42,781	$42,781	$0	15%	0%
Shaped Energy	$4,298	$4,298	$0	2%	0%
Energy Open Position (2)	$96,180	$96,180	$0	35%	0%
CAISO	$6,455	$6,455	$0	2%	0%
Contingency	$19,710	$19,710	$0	7%	0%
Operating and Other Costs	$57,733	$33,663	$24,070	12%	100%
Total (3)	$302,464	$278,394	$24,070	100%	100%

(1) Renewable energy resources include PPA's for renewable power.
(2) Energy open position includes purchases for renewable power from CAISO, as discussed in Section 2.
(3) Numbers may not add due to rounding.

As indicated by Table 6-3, the total Test Year expenses for CleanPowerSF are projected to be approximately $302.5 million. The majority of these costs are related to the Power Supply function, driven mostly by the renewable energy, shaped energy, open energy position, contingency (for power purchases) and other power supply costs incurred by CleanPowerSF. Operating costs and other costs (including contributions to reserves) have been allocated between the Power Supply and Customer function based on the underlying nature of the individual cost item.

For example, operating costs consist primarily of labor, either directly associated with CleanPowerSF staff or allocated from other bureaus or other departments (within the SFPUC and/or City organization), as well as non-personnel services, such as professional services, data management fees charged by Calpine (which provides billing and data services), and service fees imposed by PG&E. The latter two fees are charged on a dollars/account/month basis and have been classified as customer-related costs. Further, the contribution to reserves as discussed above has been allocated to the Power Supply and Customer functions based on a revenue requirement derived allocator for this analysis. This means that the sum of the allocators for all the other expense items was used to derive the allocator applied to the contribution to reserves.

Classification – Power Supply

Often the functional costs for a utility operation are further "sub-functionalized" during the classification process. For CleanPowerSF, the Power Supply costs were further allocated based on the underlying nature of each cost. As indicated below, CleanPowerSF purchases power supply to meet the needs of its Green and SuperGreen customers, some of which have different costs.

As shown below, most CleanPowerSF costs are split between Green and SuperGreen to develop an all-in cost of providing energy to each set of customers. For some categories, costs are shared across the two products, in which case they are allocated proportionally in the allocation step. For this Study, costs were classified into the following categories: Green and SuperGreen capacity costs, combined Green and SuperGreen fixed charges, Green and SuperGreen energy (individually), SuperGreen Firming and Shaping costs (to support SuperGreen purchases when those resources are under-generating or not available), and combined Green and SuperGreen other costs.

For the renewable energy purchases, the total costs are allocated between Green and SuperGreen energy based on an analysis of the specific contracts (PPAs), and a portion of those costs are allocated to SuperGreen capacity. Similarly, the capacity costs are also split based on an analysis of the RA costs required for each product. The shaped energy costs are allocated entirely to the Green customers. For the expense line referred to as "energy open position," costs are split between Green and SuperGreen (the energy open position costs for SuperGreen were identified as the "firming and shaping" requirements for that product). The CAISO costs are combined into the "other costs" for both products (and allocated to each as appropriate and discussed below). Contingency costs are allocated to the categories based on the total power supply related costs for each category.

Operating and other costs include labor, non-debt capital expenditures (cash-funded capital), and contribution to reserves. The labor costs are directly assigned to the Green and SuperGreen Fixed Charges (and allocated at a later step). The cash-funded capital is assigned to the SuperGreen Energy, as it is funding for programs related to its "Local Renewable Energy Program." This program is designed to develop projects on SFPUC properties to generate renewable power, including placement of solar resources on City-owned reservoirs and the installation of battery energy storage systems (BESS). The Local Renewable Energy Program is designed to support the SuperGreen product and develop additional local energy resources. Contribution to reserves uses the total revenue requirement for each of the categories to assign costs.

Table 6-4 provides a summary of the results of the sub-functionalization process for the Power Supply costs for CleanPowerSF.

Table 6-4
Power Supply – CleanPowerSF ($000)

Expense Line	Green Capacity	Super Green Capacity	Green & SuperGreen Fixed Charges	Green Energy	Super Green Energy	SuperGreen Firming & Shaping	Green & SuperGreen Other Energy Costs	Total
Renewable Energy (1)	$0	$0	$0	$63,822	$8,075	$0	$0	$71,897
Capacity	$42,774	$3,416	$0	$0	$0	$0	$0	$46,190
Shaped Energy	$0	$0	$0	$4,298	$0	$0	$0	$4,298
Energy Open Position (2)	$0	$0	$0	$95,278	$0	$903	$0	$96,180
CAISO	$0	$0	$0	$0	$0	$0	$6,455	$6,455
Contingency	$3,747	$299	$0	$14,313	$707	$79	$565	$19,710
Operating and Other Costs	$3,795	$303	$13,229	$14,496	$1,188	$80	$573	$33,663
Total (3)	**$50,315**	**$4,018**	**$13,229**	**$192,207**	**$9,970**	**$1,062**	**$7,593**	**$278,394**
% Total	**18%**	**1%**	**5%**	**69%**	**4%**	**0%**	**3%**	**100%**

(1) Renewable energy resources include PPA's for renewable power. A portion of the renewable energy is allocated to SuperGreen Capacity.

(2) Energy open position includes purchases for renewable power from CAISO, as discussed in Section 2.

(3) Numbers may not add due to rounding.

Classification – Customer Service/Customer Programs

For CleanPowerSF, the customer costs for customer service and customer programs were further allocated based on the underlying nature of each cost. These groups include the data management and service fees (payable to Calpine and PG&E for customer data and billing services), customer accounts, services and sales (traditional utility functions for customer costs), energy programs (for investments that serve customers directly), and bad debt (for customer costs that are not recoverable from customers). Specific expenses include those associated with labor and personnel costs for CleanPowerSF; other bureaus of the SFPUC and other departments of the City that provide support (allocated to the customer accounting, service, and sales group); non-personnel services, which include the Calpine and PG&E fees; and other expenses (split between the data management and service fees group, and the customer accounting, service, and sales based on the underlying costs). Uncollectable accounts were directly assigned to bad debt, whereas non-debt capital were directly assigned to energy programs (for investments in these systems). The applicable customer-related contribution to reserves (included in the Operating and Other Costs category) was directly assigned to customer accounting, service, and sales. The total customer-related (customer service/customer programs) costs for the Test Year were determined to be approximately $24 million, as noted in Table 6-5.

Table 6-5
Customer Service/Customer Programs – CleanPowerSF ($000)

Expense Line	Data Management & Service Fees	Cust. Account, Service & Sales	Energy Programs	Bad Debt	Total
Labor/Personnel	$0	$5,039	$0	$0	$5,039
Services of Bureaus	$0	$3,223	$0	$0	$3,223
Non-Personnel Services	$6,549	$1,338	$0	$0	$7,887
Services of Other Departments	$0	$1,630	$0	$0	$1,630
Uncollectible	$0	$0	$0	$3,025	$3,025
Non-Debt Capital Expenditures	$0	$0	$1,451	$0	$1,451
Contribution to Reserves (1)	$0	$1,815	$0	$0	$1,815
Total	**$6,549**	**$13,045**	**$1,451**	**$3,025**	**$24,070**
% Total	**27%**	**54%**	**6%**	**13%**	**100%**

(1) Contribution to reserves is included in the Operating and Other Costs category in the Power Supply Costs and is allocated to customer accounting, service, and sales in the Customer Service/Customer Programs function (see text).

Customer Class Allocation Factors – CleanPowerSF

General

Similar to the process described in Section 3 for Hetch Hetchy Power, the previous section described the assignment of the operational and ongoing investment costs for CleanPowerSF into the various functions or business units provided by the utility. However, as noted in Section 1, the CleanPowerSF functions are limited to Power Supply and Customer Service/Customer Programs (PG&E delivers the power to CleanPowerSF through its PG&E-owned transmission and distribution systems). This section discusses the development of the factors utilized to allocate those costs to CleanPowerSF customers by their underlying usage characteristics and cost causation.

As noted, utility costs can be classified as demand related, energy related, customer related, revenue related, and direct assignment. Demand allocation factors are utilized to assign fixed costs to customer classes based on the amount of demand they put on the system at certain times. Energy-related allocation factors assign costs based on the combined energy usage of the class, and customer-related allocation factors assign costs based on the number of customers within the class. Revenue-related allocation factors utilize the combined costs (as a result of the other allocation factors) to assign costs. Directly assigned costs are allocated directly to the customer classes. For CleanPowerSF, the customer classes include Residential, Small Commercial, Medium General Service Low Demand, Medium General Service High Demand, Large Commercial, and Outdoor Lighting. These customer classes are the equivalent to the classes used for Hetch Hetchy Power but are named differently for CleanPowerSF to align with how PG&E describes its customer classes.

Green and SuperGreen Cost Allocation

As indicated previously, CleanPowerSF offers a voluntary SuperGreen product that offers customers the option of 100% renewable energy. This process includes purchases from dedicated renewable energy resources specially to support the SuperGreen energy needs, as well as other related costs to support the SuperGreen customers. To properly determine the costs associated with the SuperGreen program, an additional analysis was conducted, in essence a "mini cost of service" for SuperGreen only within the COS process developed for the entire CleanPowerSF. In this process, the revenue requirement for CleanPowerSF was allocated to both "Green" and "SuperGreen" utilizing the allocation methods identified below.

This process relied on estimates and projections of costs developed by SFPUC staff. This included assigning Green and SuperGreen capacity, energy and firming and shaping costs directly to the SuperGreen and Green "classes." To be clear, both the Green and SuperGreen customers include the same customer classes (residential, commercial, etc.); however, the load for SuperGreen is less than the load for Green (as the majority of the CleanPowerSF sales are associated with the Green product). In addition, this process included allocating the fixed charges, other power costs, and customer costs to Green and SuperGreen. The resulting total allocated customer class costs for Green and SuperGreen costs were divided by Green and SuperGreen energy sales to determine a comparable embedded generation cost by customer class for each product.

Demand Allocation Factors

Demand allocation refers to the basis on which capacity and other demand-related costs are distributed or assigned (allocated) among the various customer classes for the purposes of determining the revenues required from each class to recover such costs. The demand allocation factors, as developed and used herein, reflect the cost responsibility for each of the various customer classes in relation to the demand-related costs to be allocated. The demand allocation factors were used to apportion the production capacity or demand-related costs among the various customer classes.

For the CleanPowerSF COS analysis, a 12 CP method was utilized. The peak demand is often referred to as the "Coincident Peak" because it is the amount of total load from all customers collectively at the same time (coincident with each other) for all 12 months of the projected Test Year.

12 CP Method

The CP demand allocation methodology allocates costs based on the customer class contributions to the system CP. Typically, CP allocators are utilized to assign production demand-related costs to customer classes because production demand costs are driven by the utility's need to meet its system peak. For the Green capacity costs, the 12 CP Green method was utilized for this Study to allocate those fixed production-related costs (no costs allocated to SuperGreen). For costs identified as both Green and SuperGreen (fixed costs) a 12 CP split method was utilized (which is the 12 CP Green method plus the contributions of the SuperGreen customers). After SuperGreen costs were determined from this process, they were allocated to customer classes. For the SuperGreen capacity costs, a 12 CP SuperGreen method was utilized to assign costs to customer classes based on their projected SuperGreen purchases. The results of the different 12 CP demand cost allocation methodologies (as a percent) are provided in Table 6-6.

For the 12 CP Green method, approximately 45% of the costs are assigned to the residential class and 22% to the Medium General Service High Demand class, followed by the Small General Service, Medium

General Service Low Demand, Large General Service and Outdoor Lighting. This distribution of the allocation is similar for the 12 CP – Split methodology; however, the contribution of the SuperGreen customer is approximately 7% of the total, which reduces the contribution from the other classes. For the 12 CP SuperGreen method, the results are different due to the amount of the projected SuperGreen purchases by class (the Large Commercial class is the largest percent purchaser of SuperGreen products).

Table 6-6
12 CP Cost Allocation for Green Energy

Customer Class	12 CP Green (%)	12 CP – Split (%)	12 CP SuperGreen (%) (1)
Residential	45%	42%	12%
Sm. General Service	16%	14%	3%
Med. General Service – Low Demand	13%	12%	8%
Med. General Service – High Demand	22%	20%	24%
Large General Service	5%	4%	53%
Outdoor Lighting	0.04%	0.04%	0.03%
SuperGreen (2)	0%	7%	0%
Total System	100%	100%	100%

(1) SuperGreen is allocated to customers after its costs are determined by the initial allocation process (see text)

(2) Based on Test Year projections provided by SFPUC.

Energy Allocation Factors

Energy allocation factors are the basis for apportioning those costs or expenses classified as variable or energy related and assumed to vary directly with the level of generation needed to serve the load. Total energy sales (NEFL) are often used to allocate energy-related costs; cost allocations are based on customers' consumption of energy in kWh and accounting for losses by customer class. The costs classified herein as variable or energy related are the Green Energy costs (energy purchases for Green only) and combined Green and SuperGreen Other Energy costs. Similar to the capacity cost allocation process, once the SuperGreen energy costs were determined, they were allocated to classes using the NEFL for projected SuperGreen purchases by class, as well as SuperGreen firming and shaping costs (derived from hourly projections by class of SuperGreen customers for purchases from the CAISO market).

For allocating energy costs, four methods were utilized for this Study: a Weighted Price Green, a NEFL Split, a NEFL SuperGreen, and a SuperGreen Firming and Shaping (the latter two applied to SuperGreen costs only). The Weighted Price Green method was utilized to recognize the differences in the hourly costs for purchases from the market, relative to the load profile of the customer classes. For example, because the residential class uses more energy during the peak periods (generally in the evening hours) when market prices are more expensive, the Weighted Price method assigns more costs to that class than a non-weighted method. The second non-weighted method was utilized to allocate the Other Energy costs, which are related to CAISO charges on a per kWh basis but are not subject to fluctuations in market prices. The second method is referred to as the NEFL Split method as it includes projected NEFL from SuperGreen customers.

The SuperGreen energy allocators are similar to the Green allocators. The NEFL SuperGreen recognizes the SuperGreen energy purchases by customer class. The SuperGreen Firming and Shaping recognizes the costs for each customer class by hour for market purchases to support the SuperGreen product during times when insufficient generation is available from the renewable contract PPA and CleanPowerSF must make purchases from the market.

Table 6-7 provides the summary of the energy methodologies utilized for this Study. As indicated, there is a slight difference between the customer classes between the methods. The Weighted Price places slightly more cost responsibility on the residential class, whereas the non-weighted price method places more cost responsibility on the commercial classes. The outdoor lighting class is not significantly impacted by the weighting methodology, given its relatively low load. For the SuperGreen cost allocators, the NEFL SuperGreen method resulted in the majority of costs going to the Large Commercial class (given its relatively large purchases of SuperGreen product). The SuperGreen Firming and Shaping allocation method has a similar result.

Table 6-7
Energy Cost Allocation Methods

Customer Class	Weighted Price Green Allocation (%)	NEFL Split Allocation (%)	NEFL SuperGreen (%) (1)	SuperGreen Firming and Shaping (%) (2)
Residential	45.0%	41.2%	12.0%	8.2%
Small General Service	15.1%	14.2%	2.6%	2.0%
Medium General Service – Low Demand	12.4%	11.7%	7.9%	6.2%
Medium General Service – High Demand	22.7%	21.1%	24.7%	15.4%
Large General Service	4.7%	4.5%	52.8%	68.1%
Outdoor Lighting	0.1%	<0.1%	<0.1%	<0.1%
SuperGreen Customers	0.0%	7.4%	0.0%	0.0%

(1) Net Energy for Load (NEFL) applies SuperGreen costs to customers based on usage adjusted for losses.

(2) SuperGreen Firming and Shaping applies costs to customers based on energy sales.

Customer Allocation Factors

Customer costs are defined herein as those costs related to the number of customers and how customers utilize various programs and services offered by CleanPowerSF. As indicted above, included in the customer-related costs are the costs associated with data management and services fees (related to metering and billing customers, which is a service provided by PG&E), customer accounting, service, and sales functions, as well as energy programs and bad debt. The customer allocation factors developed for this Study were based on the projected average number of customers in each customer class during the Test Year.

In allocating customer-related costs to the various customer classes, customer allocation factors were utilized that recognized the weighted and un-weighted number of customers by class. The un-weighted factors are simply the number of customers within each class. The weighted customer allocation factor is based on the number of customers in a particular class times a weighting factor. The weighting factors were developed based on the estimated costs associated with serving non-residential customer classes, recognizing that serving these customer classes is generally more expensive on a per-customer basis than residential classes. The non-weighted cost allocation factors were applied to the data management and service fees, which are charged on a per customer basis, regardless of class. The weighted customer cost allocation factors were applied to the customer accounting and service and sales functions. The Energy Programs utilized a derived allocation factor, which recognized that some of the elements of CleanPowerSF Energy Programs were designed to serve residential customers only, whereas some were designed to serve all customer classes. The Bad Debt expense was allocated based on a report developed by the SFPUC that provides the total amount of bad debt by customer class.

Like the capacity and energy allocators, two sets of customer cost allocators were developed for this Study. The first set included Green and SuperGreen (although bad debt was not allocated to SuperGreen customers), and the second set was applied to SuperGreen costs to assign to each customer class. The first set included a Customer Split (number of customers), a Weighted Customer Split, Energy Programs, and Bad Debt. The second set (for SuperGreen costs only) included SuperGreen Customers and Weighted SuperGreen Customers.

A summary of the customer allocation factors by rate class is provided in Table 6-8.

Table 6-8
Allocation of Customer Service/Customer Programs (%)

Customer Class	Customer Split	Weighted C&O Split	Energy Programs	Bad Debt	SuperGreen Customers	Weighted SuperGreen Customers
Residential	89.8%	85.1%	71.6%	47.9%	92.4%	74.9%
Small General Service	6.9%	6.5%	3.2%	18.4%	4.0%	3.3%
Medium Gen Service – Low Demand	0.6%	2.8%	0.3%	13.6%	1.4%	5.8%
Medium Gen Service – High Demand	0.4%	4.0%	0.2%	19.7%	1.8%	14.2%
Large General Service	<0.1%	0.1%	<0.1%	0.5%	0.2%	1.6%
Outdoor Lighting	0.1%	0.1%	<0.1%	<0.1%	0.2%	0.2%
SuperGreen Customers	2.1%	2.4%	24.7%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%

High Voltage Customers

With traditional utilities, customers that take service at high voltage are often provided a discount on their rates. This discount is due to the fact that high voltage customers do not incur as many losses as low voltage customers (due to the nature of moving electricity across various elements of the distribution system), as well as the fact that high voltage customer do not utilize the secondary portion of the distribution system (or even the primary portion if they are served at transmission level voltage). Because CleanPowerSF does not own the delivery portion of the distribution or transmission system serving these customers (it only provides generation service), no additional discount to high voltage customers is warranted. There is a very slight difference in the electricity losses incurred by high voltage customers, which is included in the derivation of the energy allocator and applied accordingly.

Cost of Service Results

Table 6-9 provides a summary of the cost of service analysis conducted for CleanPowerSF for the Green power (default rate product). The total Green costs for the Test Year are approximately $285.1 million and the total SuperGreen costs for the Test Year are approximately $17.4 million for a combined revenue requirement of approximately $302.5 million.

For the Green product, the majority of those costs have been allocated to the residential customer class, presented below. The large commercial class represents the second largest class in terms of cost responsibility. The total values by class represent the revenue requirement for the Test Year for each class and are a driver of the recommended rate design (Section 7).

Table 6-9
CleanPowerSF Cost of Service Results – Green Power Revenue Requirement by Class ($000) (1)

Expense Line	Residential	Small General Service	Medium General Service – Low Demand	Medium General Service – High Demand	Large General Service	Outdoor Lighting	Total Green Power (TY)
Power Supply							
Green Capacity	$22,823	$7,839	$6,328	$10,870	$2,434	$20	$50,315
Green and SuperGreen Fixed Charges	$5,560	$1,910	$1,542	$2,648	$593	$5	$12,257
Green Energy	$86,500	$29,116	$23,865	$43,538	$9,072	$116	$192,207
Green & SuperGreen Other Energy Costs	$3,127	$1,076	$886	$1,601	$338	$4	$7,032
Total Power Supply	$118,010	$39,941	$32,621	$58,658	$12,436	$145	$261,811
Customer							
Data Management & Service Fees	$5,884	$455	$39	$28	$1	$5	$6,412
Cust. Account, Service & Sales	$10,972	$848	$367	$520	$12	$9	$12,728
Energy Programs	$1,038	$47	$4	$3	$0	$0	$1,093
Bad Debt	$1,448	$555	$411	$595	$14	$0	$3,025
Total Customer	$19,342	$1,905	$822	$1,146	$27	$15	$23,257
Total Cost of Service (2)	$137,352	$41,846	$33,443	$59,803	$12,463	$159	$285,068

(1) Excludes costs allocated to SuperGreen customers (see Table 6-10).
(2) Numbers may not add due to rounding.

The cost of service results for the SuperGreen revenue requirement is provided in Table 6-10

Table 6-10
CleanPowerSF Cost of Service Results – SuperGreen Power Total Revenue Requirement ($000)

Expense Line	Residential	Small General Service	Medium General Service – Low Demand	Medium General Service – High Demand	Large General Service	Outdoor Lighting	Total for TY
Power Supply							
Super Green Capacity	$497	$105	$320	$947	$2,148	$1	$4,018
Green and SuperGreen Fixed Charges	$120	$25	$77	$229	$519	$0	$972
Super Green Energy	$1,200	$255	$789	$2,460	$5,262	$4	$9,970
SuperGreen Firming & Shaping	$87	$21	$66	$163	$724	$1	$1,062
Green & SuperGreen Other Energy Costs	$68	$14	$44	$139	$296	$0	$562
Total Power Supply	$1,972	$421	$1,297	$3,938	$8,949	$7	$16,584
Customer							
Data Management & Service Fees	$127	$6	$2	$2	$0	$0	$138
Cust. Account, Service & Sales	$237	$10	$18	$45	$5	$1	$317
Energy Programs	$331	$14	$5	$6	$1	$1	$359
Total Customer	$696	$30	$26	$54	$6	$2	$813
Total Cost of Service (1)	$2,667	$451	$1,322	$3,992	$8,955	$9	$17,396

(1) Numbers may not add due to rounding.

The analysis for the Green and SuperGreen power was developed on an "all-in" effective rate basis, using the total revenue requirement by class divided by the total energy sales by class. The results of this analysis are presented in Table 6-11 below.

Table 6-11
Analysis of Green and SuperGreen COS Results for CleanPowerSF

Expense Line	Residential	Small General Service	Medium General Service – Low Demand	Medium General Service – High Demand	Large General Service	Outdoor Lighting	Total for TY
Cost of Service/Revenue Requirement ($000)							
Green Customer	$137,352	$41,846	$33,443	$59,803	$12,463	$159	$285,068
SuperGreen	$2,667	$451	$1,322	$3,992	$8,955	$9	$17,396
Total	$140,020	$42,297	$34,765	$63,795	$21,418	$168	$302,464
COS $/kWh Sales							
Green Customer COS	$0.1152	$0.1020	$0.0990	$0.0975	$0.0962	$0.1123	$0.1062
SuperGreen COS	$0.1035	$0.0824	$0.0780	$0.0752	$0.0789	$0.0958	$0.0809
Total COS (1)	$0.1150	$0.1017	$0.0980	$0.0957	$0.0881	$0.1113	$0.1043

(1) Numbers may not add due to rounding.

The results in Table 6-11 indicate that for all customer classes, the embedded cost for the SuperGreen product is less expensive on an effective rate ($/kWh) basis than the Green product. This is generally due to the costs associated with the renewable power portfolio assigned to the SuperGreen customers compared to the combination of renewable and non-renewable PPA and market costs for power for the Green customers. As a result, this differential represents a "snapshot in time" for these two customer groups, as SuperGreen customers are benefitting from lower-priced PPAs entered into in the past, while Green customers are currently facing higher costs due to exposure to high-priced energy markets for a portion of their open position.

To develop the rate design for CleanPowerSF (Section 7), the effective rates by class from the COS analysis (the Total COS line on Table 6-11) are utilized. Specific rate elements (energy, capacity, and customer charge) are considered in this process. A summary of the specific COS rate elements is presented by customer class in Table 6-12.

Table 6-12
Average COS Rate, Rate Component by Rate Class (1)

Class	"All-In" Effective Cost of Service ($/kWh)	Customer Charge ($/Customer Month)	Demand Charge ($/kW)	Energy Charge ($/kWh)
Residential	$0.1150	$4.67	$3.18	$0.0747
Small General Service	$0.1017	$5.89	$6.50	$0.0733
Medium General Service Low Demand	$0.0980	$28.72	$8.37	$0.0723
Medium General Service High Demand	$0.0957	$55.53	$9.69	$0.0719
Large General Service	$0.0881	$49.79	$9.59	$0.0645
Outdoor Lighting	$0.1113	$4.50	$9.20	$0.0825

(1) Average rates for Test Year period.

Section 7
EXISTING AND RECOMMENDED RATE DESIGN FOR CLEANPOWERSF

Retail Rate Review

Background information on the existing rates and rate structures of CleanPowerSF's major customer classes is presented below. This includes a comparison of the existing rates to the COS-based rates. Because CleanPowerSF only provides an alternative to the generation portion of the customer bill (PG&E still provides the delivery and billing services), the development of costs curves compared to the rate curves was not developed for this section of the Report. Rather, because CleanPowerSF is in a competitive market (customers can opt out of service from CleanPowerSF and return to PG&E rates), an analysis of the total customer bill for selected customer classes was developed. The analysis of the comparison to PG&E bills was considered for the individual customer class rate recommendations provided in Section 8 of this Report.

Legacy Rates & PG&E Rates

Because CleanPowerSF must offer all rates offered by PG&E to remain competitive and avoid customer confusions, it has many different rate schedules or rate codes. Many of these are "legacy" rates that are closed to new customers—in some cases the rates continue to exist because rooftop solar/net energy metering customers are enrolled on the rate and are being gradually phased to newer rates over a set time period. In other cases, the rate is simply closed to new customers, but existing ones are allowed to remain on it indefinitely (see further discussion in Section 8). In some cases, only a small handful of customers may be enrolled in a given rate offering, making it inappropriate to analyze the cost of service for that rate based on such a small sample size. Moreover, the legacy rates may have different seasonal or TOU periods and/or different rate features (e.g., demand charges) than default rates open to new enrollment.

For simplicity, each rate offering has been grouped into one of the customer classes described in Section 6. Within each customer class, a discussion of the default rate schedule for new customers is presented, as well as any additional rate schedules for which more than 10% of the customer class is enrolled. New rates are recommended for all rate offerings for CleanPowerSF, regardless of the number of customers within the class or if they are open or not to new customers. However, the focus of this analysis and discussion is on the "main" rate schedules, whereas the change to the minor rate schedules are presented in Appendix B.

CleanPowerSF – TOU Periods and Price Differentiation

A similar analysis to the TOU cost analysis conducted for Hetch Hetchy Power was developed for CleanPowerSF. As indicated above, some CleanPowerSF rates currently have a winter and summer rate differential (for energy and demand, as appropriate). For CleanPowerSF, these periods are defined by PG&E, and for current rates, summer is the period from June through September and winter is October through the end of May. Legacy rates have a different seasonal period, with summer being May through October, and winter being November through April. Generally, as with Hetch Hetchy Power, the TOU periods are defined as On-Peak, Part-Peak, and Off-Peak; however, the definition of those periods vary by rate code.

Similar to the analysis conducted for Hetch Hetchy Power, the analysis for CleanPowerSF utilized the historic hourly load profiles for each customer class for 2019 and the corresponding hourly energy prices from the CAISO.

The hourly load profiles for CleanPowerSF by class were utilized as a weighting factor to the power supply costs, which provides a better reflection of the underlying cost causation. As indicated previously, for CleanPowerSF, the majority of the power supply costs are associated with purchases in the CAISO market. Therefore, the variability in the market power prices was developed to evaluate potential changes to the pricing differential for the time and seasonally differentiated energy rates developed for this Study.

Table 7-1 provides a summary of the cost differentials determined by class load for the CleanPowerSF customers.

Table 7-1
TOU Energy Price Differential Analysis – CleanPowerSF

	Residential	Small General Service	Medium General Service – Low Demand	Medium General Service – High Demand	Large General Service
Summer	0.87	0.87	0.87	0.87	0.87
Winter	1.07	1.07	1.07	1.07	1.07
Summer					
On-Peak	1.40	1.25	1.25	1.25	1.25
Off-Peak	0.82	0.80	0.81	0.81	0.81
Winter					
On-Peak	1.29	1.30	1.30	1.30	1.30
Off-Peak	0.87	0.98	0.99	0.99	0.98
Super Off-Peak	N/A	0.38	0.39	0.39	0.38

CleanPowerSF – Seasonal and TOU Energy Periods

The results indicate that for the system, the summer energy costs are generally lower than the winter energy costs. The values in the table represent the relationship to the average price, which is set at a value of 1.0. The average energy value for the total year was divided by the average energy value for the summer, which resulted in a factor of 0.87 (so summer costs are 0.87 times the average energy cost). Similarly, for the winter period, the average energy value was determined to be 1.07 times the system average energy costs.

During the summer period, the on-peak hours are generally higher cost hours than the off-peak hours for all CleanPowerSF classes. For the Residential customer class, the on-peak costs are 1.40 times higher than the average price, whereas the off-peak cost are 0.82 times the average price. The summer pricing differential for the General Service classes are generally the same; the on-peak costs are approximately 1.25 times the average price and the off-peak costs are approximately 0.81 times the average price.

Similarly, for the winter periods, the on-peak period is higher than the off-peak period by approximately 1.30 times the average price for all classes. The off-peak price for the residential class is approximately

0.87 times the average price, and 0.99 times the average price for the general service classes (the residential class does not have a super off-peak period). For the super off-peak winter period, the costs are approximately 0.39 times the average rates.

CleanPowerSF Rate Strategy

The overall rate strategy developed for the rate recommendations presented herein (the rate plan) is to begin to lower the current rates for each rate class and rate code over the two-year period in an incremental manner while ensuring that CleanPowerSF meets its financial metrics. For each rate class, an effective all-in COS rate was developed (as presented in Table 6-12). The intent of the rate plan is to move existing rates towards COS from the existing effective rate for the class by approximately 50% in Year 1 (FY 2022–2023) and to 100% of the COS rate in Year 2 (FY 2023–2024). The effective rate for each class was determined from the sum of the billing determinants times the existing CleanPowerSF rate across the various TOU and seasonal periods (updated March 1, 2022).

Based upon discussions with CleanPowerSF staff, it was decided that it was not in the best interests of the operation or its customers to adjust the pricing differentials between TOU or seasonal periods at this time. Therefore, the recommended rates developed herein continue the pricing differentials established by PG&E for the current and legacy rate offerings, including those by season and TOU periods.

Additionally, it is recommended that CleanPowerSF will not implement a generation-related customer charge for its customers; rather, the customer-related costs will be included in the recommended energy rate. For customers with a demand rate, a similar gradual approach to an effective demand rate was developed for each customer class based on the COS results. The effective demand rate was determined in a similar manner to the effective energy rate; the sum of the billing determinants times the current rate across the various TOU and seasonal periods divided by the billing determinants equals the effective demand rate. NewGen reviewed the current energy rate differentials between transmission, primary and secondary service and determined that they were consistent with the energy losses between these types of voltages. Therefore, the current energy rate differentials are recommended to be maintained as the rates transition towards cost of service based on the effective rate analysis. Similarly, the current demand rate differentials between transmission, primary and secondary voltage service are recommended to be maintained as well.

Residential

The residential class is the largest customer class served by CleanPowerSF. Table 7-2 provides a summary of the rate code and description, shows if the rate code is a legacy rate, and shows if the recommended rates are included within this Report or have been added in Appendix B.

Table 7-2
Residential Rate Codes for CleanPowerSF

Rate Code	Description	Open/Legacy	Report/Appendix
E-TOU-B	Time of Use	Open	Report
E-TOU-C	Time of Use	Open	Report
E-TOU-D	Time of Use	Open	Report
E-1	Flat Energy Charge	Legacy	Report
E-EV	Electric Vehicle	Legacy	Appendix B
E-EV2	Electric Vehicle	Open	Appendix B
E-6	Time of Use	Legacy	Report

E-TOU-B

The E-TOU-B rate is a TOU rate that offers a summer on- and off-peak rate, and winter on- and off-peak rate. The summer period is June through September (as it is for all TOU rates). For the TOU-B rate, the summer and winter peaks are 4:00 PM to 9:00 PM Monday through Friday (excluding holidays). As indicated previously, the recommended rate plan incrementally adjusts the rate to an effective rate for the class over the two-year period (50% in Year 1, 100% in Year 2). Recommended generation rates for the E-TOU-B are presented in Table 7-3.

Table 7-3
CleanPowerSF Residential Rates (E-TOU B)
(Existing and Recommended) (1)

Rate Component	TOU-B	FYE 2023	FYE 2024
Energy			
Summer			
On-Peak	$0.2505	$0.2368	$0.2231
Off-Peak	$0.1274	$0.1205	$0.1135
Winter			
On-Peak	$0.1445	$0.1366	$0.1287
Off-Peak	$0.1057	$0.0999	$0.0942

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

E-TOU-C

The E-TOU-C rate is a TOU rate that offers a summer on- and off-peak rate, and a winter on- and off-peak rate. The summer is period is June through September (as it is for all TOU rates). For the TOU-C rate, the summer and winter peaks are 4:00 PM to 9:00 PM every day including holidays. Recommended generation rates for the E-TOU-C are presented in Table 7-4.

Table 7-4
CleanPowerSF Residential Rates (E-TOU C)
(Existing and Recommended) (1)

Rate Component	TOU-C	FYE 2023	FYE 2024
Energy			
Summer			
On-Peak	$0.1802	$0.1670	$0.1538
Off-Peak	$0.1268	$0.1175	$0.1082
Winter			
On-Peak	$0.1315	$0.1218	$0.1121
Off-Peak	$0.1164	$0.1079	$0.0993

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

E-TOU-D

The E-TOU-D rate is a TOU rate that offers a summer on- and off-peak rate, and winter on- and off-peak rate. The summer period is June through September (as it is for all TOU rates). For the TOU-D rate, the summer and winter peaks are 5:00 PM to 8:00 PM, Monday through Friday, excluding holidays. Recommended generation rates for the E-TOU-D are presented in Table 7-5.

Table 7-5
CleanPowerSF Residential Rates (E-TOU D)
(Existing and Recommended) (1)

Rate Component	TOU-D	FYE 2023	FYE 2024
Summer			
On-Peak	$0.2097	$0.1938	$0.1779
Off-Peak	$0.1047	$0.0968	$0.0888
Winter			
On-Peak	$0.1688	$0.1560	$0.1432
Off-Peak	$0.1337	$0.1236	$0.1134

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

E-1 and E-6

The E-1 rate is a tiered rate, but the CleanPowerSF generation charge for this rate is flat (not differentiated by season or time). The E-6 rate is seasonally and TOU differentiated (summer, winter). The E-6 rate includes an additional time period not included in the E-TOU rates above, which is the summer part-peak (defined as 12:00 PM to 3:00 PM and 8:00 PM to 10:00 PM Monday through Friday, and 5:00 PM to 8:00 PM Saturday and Sunday). The summer on-peak period is 3:00 PM to 8:00 PM Monday through Friday. The winter peak period is 5:00 PM to 8:00 PM Monday through Friday. All other times, including holidays, are off-peak.

E-6 is a legacy rate, meaning that no additional customers are allowed to be placed on this rate schedule (new customers are required to be on a defined TOU rate offering with slightly different periods, such as E-TOU-B, E-TOU-C, and E-TOU-D or on the E-1 rate). The seasons and TOU periods cannot be changed for legacy customers, although they can choose to be served on a different rate. For the legacy rates, the summer period is six months (May through October), and the TOU periods are included in the table below. The existing and recommended rates for the E-1 and E-6 customer class are provided in Table 7-6.

Table 7-6
CleanPowerSF Residential Rates (E-1 and E-6)
(Existing and Recommended) (1)

Rate Component	Existing	FYE 2023	FYE 2024
E-1 (Flat)	$0.1304	$0.1196	$0.1088
E-6 (Seasonal/TOU)			
Summer			
On-Peak – 3:00 PM to 8:00 PM, M–F	$0.2598	$0.2448	$0.2298
Part-Peak – 12 PM to 3:00 PM, 8:00 PM–10:00 PM, M–F, 5:00 PM–8:00 PM, Weekends	$0.1768	$0.1666	$0.1564
Off-Peak – all other times, plus holidays	$0.1067	$0.1005	$0.0943
Winter			
Part-Peak – 5:00 PM–8:00 PM, M–F	$0.1441	$0.1358	$0.1275
Off-Peak – all other times, plus holidays	$0.1103	$0.1039	$0.0976

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Other CleanPowerSF Residential Rates

Other CleanPowerSF residential rates include EV rates (EV-A and EV-B are legacy EV rates, and EV-2A is the current EV rate). EV rates are provided in Appendix B.

Small General Service

The Small General Serve class represents the non-demand metered commercial class for customers that utilize less than 75 kW of demand in a month. Small General Service rates are all seasonally and TOU differentiated; however, the TOU periods are different between the current and legacy rate codes. Additionally, some Small General Service rates have a part-peak period and a super off-peak period in the winter. Table 7-7 provides a summary of the Small General Service rate codes and description, shows if the rate code is a legacy rate code or open (current), and shows if the recommended rates are included within this report or have been included in Appendix B.

Table 7-7
Small General Service Rate Codes for CleanPowerSF

Rate Code	Description	Open/Legacy	Report/Appendix
B-1	Time of Use	Open	Report
B-6	Time of Use	Open	Report
A-6	Time of Use	Legacy	Report
A-1-B	Time of Use	Legacy	Report
A-1-A	Time of Use	Legacy	Report
BEV-1	Electric Vehicle, Low Demand (<100 kW)	Open	Appendix B
B-1-ST	Time of Use/Storage	Open	Appendix B

Small General Service (B-1)

The B-1 rate code is a current rate that has a peak period from 4:00–9:00 PM every day, a part-peak period from 2:00–4:00 PM and 9:00–11:00 PM during the summer (June through September), and a super off-peak period from 9:00 AM to 2:00 PM in March, April, and May. All other times are off-peak. Table 7-8 provides a summary of the existing and recommended changes to the B-1 rate.

Table 7-8
CleanPowerSF Small General Service (B-1)
(Existing and Recommended)

Rate Component	B-1	FYE 2023	FYE 2024
Summer			
Peak	$0.1881	$0.1650	$0.1419
Part-Peak	$0.1389	$0.1218	$0.1047
Off-Peak	$0.1181	$0.1036	$0.0890
Winter			
Peak	$0.1329	$0.1165	$0.1002
Off-Peak	$0.1168	$0.1024	$0.0880
Super Off-Peak	$0.1003	$0.0880	$0.0757

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Small General Service (B-6)

The B-6 rate code is a current rate that does not have a part-peak period; the peak period is from 4:00–9:00 PM every day, and the super off-peak period is from 9:00 AM–2:00 PM in March, April, and May. All other times are off-peak. Table 7-9 provides a summary of the existing and recommended changes to the B-6 rate.

Table 7-9
CleanPowerSF Small General Service (B-6)
(Existing and Recommended) (1)

Rate Component	B-6	FYE 2023	FYE 2024
Summer			
Peak	$0.1903	$0.1703	$0.1503
Off-Peak	$0.1191	$0.1066	$0.0941
Winter			
Peak	$0.1268	$0.1134	$0.1001
Off-Peak	$0.1097	$0.0982	$0.0866
Super Off-Peak	$0.0933	$0.0835	$0.0737

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Small General Service (A-6)

The A-6 rate code is a Small General Service legacy rate that has a summer peak period from 12:00 PM to 6:00 PM, Monday through Friday, except holidays; a part-peak period from 8:30 AM to 12:00 PM and 6:00 PM–9:30 PM, except holidays; and a winter part-peak period from 8:30 AM to 9:30 PM, Monday through Friday, except holidays. All other times are off-peak. Table 7-10 provides a summary of the existing recommended changes to the A-6 rate.

Table 7-10
CleanPowerSF Small General Service (A-6)
(Existing and Recommended) (1)

Rate Component	A-6	FYE 2023	FYE 2024
Summer			
Peak	$0.2100	$0.1861	$0.1622
Part-Peak	$0.1607	$0.1424	$0.1240
Off-Peak	$0.1285	$0.1139	$0.0992
Winter			
Peak	$0.1192	$0.1056	$0.0920
Off-Peak	$0.1184	$0.1049	$0.0914

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Small General Service (A-1-A)

The A-1-A rate code is a Small General Service legacy rate that is seasonally differentiated but does not have TOU periods. The summer period is from May through October, and the winter period is from

November through April. Table 7-11 provides a summary of the existing and recommended changes to the A-1-A rate.

Table 7-11
CleanPowerSF Small General Service (A-1-A)
(Existing and Recommended) (1)

Rate Component	A-1-A	FYE 2023	FYE 2024
Summer	$0.1440	$0.1291	$0.1142
Winter	$0.1038	$0.0931	$0.0823

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

Small General Service (A-1-B)

The A-1-B rate code is a legacy Small General Service rate that has a summer peak period from 8:30 PM to 9:30 PM, Monday through Friday, except holidays, and a winter part-peak period from 8:30 AM to 9:30 PM, Monday through Friday, except holidays. As with the A-1-A rate code, the legacy summer period is from May through October and the winter period is from November through April. All other times are off-peak. Table 7-12 provides a summary of the existing and recommended changes to the A-1-B rate.

Table 7-12
CleanPowerSF Small General Service (A-1-B)
(Existing and Recommended)

Rate Component	A-1-B	FYE 2023	FYE 2024
Summer			
Peak	$0.1473	$0.1339	$0.1205
Part-Peak	$0.1473	$0.1339	$0.1205
Off-Peak	$0.1225	$0.1114	$0.1003
Winter			
Part Peak	$0.1165	$0.1059	$0.0953
Off-Peak	$0.1159	$0.1054	$0.0949

(1) Rate changes are effective July 1, 2022, and July 1, 2023

Other CleanPowerSF Small General Service Rates

CleanPowerSF offers two other Small General Service rates, one for EV charging (BEV-1) and one for (battery) storage (B-1-ST). The BEV-1 rate offers a peak (4:00 to 9:00 PM), off-peak (9:00 PM to 9:00 AM and 2:00 to 4:00 PM), and super off-peak TOU periods (9:00 AM to 2:00 PM), as well as a summer/winter flat rate option. The storage rate includes a super off-peak rate during the winter periods that is approximately 15% less than the off-peak winter rates. The recommended change to these rates is provided in Appendix B.

Medium General Service – Low Demand Rates

CleanPowerSF offers service to Medium General Service customers for those without demand rates (Medium General Service Low Demand) and those with demand rates (Medium General Service High Demand). This section provides a summary of the rate offerings for the Medium General Service Low Demand rates, which are for customers with demand less than 500 kW in each month. The B-10 rate is the current rate offering, whereas the A-10-A and A-10-B are legacy rates, closed to new customers.

The A-10-A rates are seasonally differentiated but are not TOU. The A-10-B are seasonally, and TOU differentiated, but the TOU periods did not change with the most recent changes implemented by PG&E, which are included in the B-10 rate. The B-10 (current) and A-10-B (legacy) have rates that are differentiated by service voltage (either secondary, primary, or transmission level). For the tables provided below, the secondary service rates have been provided; the primary and transmission level rates are provided in Appendix B. The electric vehicle charging rates, BEV-2 (for high demand), is in this customer class as well.

Table 7-13 provides a summary of the Medium General Service Low Demand rate codes and description, shows if the rate code is a legacy rate code, and shows if the recommended rates are included within this report, or have been included in Appendix B.

Table 7-13
Medium General Service Low Demand Rate Codes for CleanPowerSF

Rate Code	Description	Open/Legacy	Report/Appendix
B-10	Time of Use, Secondary, Primary Transmission	Open	Report (Secondary), Appendix B (Primary, Transmission)
A-10-A	Seasonal (Secondary)	Legacy	Report
A-10-B	Time of Use, Secondary, Primary Transmission	Legacy	Report (Secondary), Appendix B (Primary, Transmission
A-15	Summer / Winter Energy	Legacy	Appendix B
BEV-2	Electric Vehicle, TOU, Secondary, Primary	Open	Appendix B

Medium General Service Low Demand (B-10)

The B-10 rate code is a current rate offering that has a peak period from 4:00–9:00 PM every day, a part peak period from 2:00–4:00 PM and 9:00–11:00 PM during the summer (June through September), and a super off-peak period from 9:00 AM–2:00 PM in March, April, and May. All other times are off-peak. Table 7-14 provides a summary of the existing and recommended changes to the B-10 rate.

Table 7-14
CleanPowerSF Medium General Service Low Demand (B-10)
Secondary Service
(Existing and Recommended) (1)

Rate Component	B-10 (2)	FYE 2023	FYE 2024
Summer			
Peak	$0.2153	$0.1808	$0.1463
Part-Peak	$0.1536	$0.1290	$0.1044
Off-Peak	$0.1210	$0.1016	$0.0822
Winter			
Peak	$0.1572	$0.1320	$0.1069
Off-Peak	$0.1217	$0.1022	$0.0827
Super Off-Peak	$0.0854	$0.0717	$0.0580

(1) Rate changes are effective July 1, 2022, and July 1, 2023

(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates.

Medium General Service Low Demand (A-10-A)

The A-10-A rate code is a legacy rate that is seasonally differentiated but does not have TOU periods. The summer period is from May through October and the winter period is from November through April. Table 7-15 provides a summary of the existing and recommended changes to the A-10-A rate for secondary voltage level service.

Table 7-15
CleanPowerSF Medium General Service Low Demand (A-10-A)
Secondary Service
(Existing and Recommended) (1)

Rate Component	A-10-A (2)	FYE 2023	FYE 2024
Summer	$0.1454	$0.1235	$0.1015
Winter	$0.1237	$0.1050	$0.0863

(1) Rate changes are effective July 1, 2022, and July 1, 2023

(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates.

Medium General Service Low Demand (A-10-B)

The A-10-B rate code is a legacy rate offering that has a peak period from 8:30 AM to 9:30 AM, Monday through Friday, except holidays for both the summer and winter periods. All other times are off-peak. Summer is from May through October and winter is from November through April. The rate is offered for secondary, primary, and transmission voltage level service. Table 7-16 provides a summary of the existing and recommended changes to the A-10-B rate for secondary voltage level service.

Table 7-16
CleanPowerSF Medium General Service Low Demand (A-10-B) Secondary Service (Existing and Recommended) [(1)]

Rate Component	A-10-B [(2)]	FYE 2023	FYE 2024
Summer			
Peak	$0.1589	$0.1371	$0.1152
Part-Peak	$0.1589	$0.1371	$0.1152
Off-Peak	$0.1321	$0.1140	$0.0958
Winter			
Peak	$0.1243	$0.1072	$0.0901
Off-Peak	$0.1236	$0.1066	$0.0896

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates.

Other CleanPowerSF Medium General Service Low Demand Rates

Medium general service low demand rates are also offered with a discount for primary (P) or transmission level service (the default service is secondary). The primary rates are B-10-P, A-10-B-P, and A-10-A-P, and the transmission rates are B-10-T, A-10-B-T, and A-10-A-T. Additionally, the EV charging (BEV-2) rate for high demand (greater than 100 kW) is included in this rate class. The BEV-2 rate structure is identical to the BEV-1 rate structure, with peak (4:00 to 9:00 PM), off-peak (9:00 PM to 9:00 AM and 2:00 to 4:00 PM), and super off-peak TOU periods (9:00 AM to 2:00 PM), as well as a summer/winter flat rate option. The BEV-2 rate is offered for both secondary voltage (default) and primary voltage. The recommended rates for these customers are provided in Appendix B.

Medium General Service High Demand

CleanPowerSF offers service to Medium General Service High Demand for customers with demand greater than 500 kW, but less than 1,000 kW in a month. These rates include seasonally, and TOU differentiated demand and energy rates. Rates are also differentiated by service voltage; secondary voltage service rates are provided below, and the primary and transmission voltage service are provided in Appendix B.

Table 7-17 provides a summary of the Medium General Service High Demand rate codes and description, shows if the rate code is a legacy rate code, and shows if the recommended rates are included within this Report or have been included in Appendix B.

Table 7-17
Medium General Service High Demand Rate Codes for CleanPowerSF

Rate Code	Description	Open/Legacy	Report/Appendix
B-19	Time of Use Energy and Demand, Primary, Secondary, Transmission	Open	Report (Secondary), Appendix B (Primary, Transmission
B-19-R	Time of Use Energy and Demand, Primary, Secondary, Transmission, with Solar or Storage	Open	Appendix B
E-19	Time of Use Energy and Demand, Primary, Secondary, Transmission	Legacy	Report (Secondary), Appendix B (Primary, Transmission
E-19-R	Time of Use Energy and Demand, Primary, Secondary, Transmission (Renewable)	Legacy	Appendix B

Medium General Service High Demand (B-19)

The B-19 rate code is a current rate offering that has a peak period from 4:00–9:00 PM every day, a part peak period from 2:00–4:00 PM and 9:00–11:00 PM during the summer (June through September), and a super off-peak period from 9:00 AM–2:00 PM in March, April, and May. All other times are off-peak. This rate is offered for secondary, primary and transmission voltage level service. Rates shown below are for secondary voltage service; primary and transmission voltage service recommended rates are provided in Appendix B. Table 7-18 provides a summary of the existing and recommended changes to the B-19 rate.

Table 7-18
CleanPowerSF Medium General Service High Demand
(B-19, Secondary Service)
(Existing and Recommended Rates) (1)

Rate Component	B-19 (2)	FYE 2023	FYE 2024
Demand ($/kW)			
Summer			
Peak	$18.85	$21.22	$23.58
Part-Peak	$2.74	$3.08	$3.43
Winter			
Peak	$2.24	$2.52	$2.80
Energy ($/kWh)			
Summer			
Peak	$0.1555	$0.1285	$0.1014
Part-Peak	$0.1179	$0.0974	$0.0769
Off-Peak	$0.0913	$0.0754	$0.0595
Winter			
Peak	$0.1316	$0.1087	$0.0858
Off-Peak	$0.0912	$0.0753	$0.0595
Super Off-Peak	$0.0369	$0.0305	$0.0241

(1) Rate changes are effective July 1, 2022, and July 1, 2023

(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates

Medium General Service High Demand (E-19)

The E-19 rate code is a legacy rate that has a summer peak period from 12:00 PM to 6:00 PM, Monday through Friday; a part peak period from 8:30 PM to 12:00 PM and 6:00 PM to 9:30 PM, Monday through Friday, except holidays; and a winter part peak period from 8:30 AM to 9:30 PM, Monday through Friday, except holidays. The legacy summer period is from May through October and the winter period is from November through April. All other times are off-peak. The demand rate is not seasonally differentiated, and the summer on-peak and part-peak demand rates are the same (not TOU differentiated). There is no winter demand rate. Additionally, the summer peak and part-peak energy rates are the same.

Rates shown below are for secondary voltage service; primary and transmission voltage service recommended rates are provided in Appendix B. Table 7-19 provides a summary of the existing and recommended changes to the E-19 rate.

Table 7-19
CleanPowerSF Medium General Service High Demand
(E-19, Secondary Service)
(Existing and Recommended Rates) (1)

Rate Component	E-19 (2)	FYE 2023	FYE 2024
Demand ($/kW) (3)			
Summer			
Peak	$12.31	$10.87	$9.43
Part-Peak	$12.31	$10.87	$9.43
Energy ($/kWh)			
Summer			
Peak	$0.0991	$0.0863	$0.0736
Part-Peak	$0.0991	$0.0863	$0.0736
Off-Peak	$0.0931	$0.0811	$0.0692
Winter			
Peak	$0.0905	$0.0789	$0.0672
Off-Peak	$0.0898	$0.0782	$0.0667

(1) Rate changes are effective July 1, 2022, and July 1, 2023

(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates

(3) E-19 does not offer a winter peak demand rate.

Other CleanPowerSF Medium General Service High Demand Rates

Medium general service high demand service rates are also offered with a discount for primary (P) or transmission level service (the default service is secondary). However, there are no customers on these rates at this time. Additionally, CleanPowerSF offers customers in this rate class a solar rate (designed with an "R," which is the same rate as the secondary "S" rate). The recommended rates for these customers are provided in Appendix B.

Large General Service

CleanPowerSF offers service to Large General Service customers for those with demand greater than 1,000 kW in a month. These rates include seasonally, and TOU differentiated demand and energy rates. Rates are also differentiated by service voltage; secondary voltage service rates are provided below, and the primary and transmission voltage service are provided in Appendix B.

Table 7-20 provides a summary of the Large General Service rate codes and descriptions, the number of customers within the rate code, and whether the rate code is a legacy rate code. Both Large General Service rates are presented in the report.

Table 7-20
Large General Service – High Demand Rate Codes for CleanPowerSF

Rate Code	Description	Open/Legacy	Report/Appendix
B-20	Time of Use Energy and Demand, Primary, Secondary, Transmission	Open	Report (Secondary), Appendix B (Primary), Transmission
E-20	Time of Use Energy and Demand, Primary, Secondary, Transmission	Legacy	Report (Secondary), Appendix B (Primary), Transmission
B-ST	Standby TOU, Reservation Charge	Open	Appendix B
B-20-R	Time of Use Energy, Primary, Secondary, Transmission (Renewable)	Open	Appendix B
E-20-R	Time of Use Energy, Primary, Secondary, Transmission (Renewable)	Legacy	Appendix B

Large General Service (B-20)

The B-20 rate code is a current rate offering that has a peak period from 4:00–9:00 PM every day, a part peak period from 2:00–4:00 PM and 9:00–11:00 PM during the summer (June through September), and a super off-peak period from 9:00 AM–2:00 PM in March, April, and May. All other times are off-peak. This rate is offered for secondary, primary, and transmission voltage level service. Rates shown below are for secondary voltage service; primary and transmission voltage service recommended rates are provided in Appendix B. Table 7-21 provides a summary of the existing and recommended changes to the B-20 rate.

Table 7-21
CleanPowerSF Large General Service – High Demand
(B-20, Secondary Service)
(Existing and Recommended Rates) (1)

Rate Component	B-20 (2)	FYE 2023	FYE 2024
Demand ($/kW)			
Summer			
Peak	$18.32	$20.70	$23.08
Part-Peak	$2.66	$3.01	$3.35
Winter			
Peak	$2.34	$2.64	$2.95
Energy ($/kWh)			
Summer			
Peak	$0.1476	$0.1177	$0.0878
Part-Peak	$0.1139	$0.0908	$0.0677
Off-Peak	$0.0872	$0.0695	$0.0519
Winter			
Peak	$0.1275	$0.1016	$0.0758
Off-Peak	$0.0870	$0.0694	$0.0517
Super Off-Peak	$0.0328	$0.0261	$0.0195

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates

Large General Service (E-20)

The E-20 rate code is a legacy rate a that has summer peak period from 12:00 PM to 6:00 PM, Monday through Friday; a part peak period from 8:30 PM to 12:00 PM and 6:00 PM to 9:30 PM, Monday through Friday, except holidays; and a winter part peak period from 8:30 AM to 9:30 PM, Monday through Friday, except holidays. The legacy summer period is from May through October and the winter period is from November through April. All other times are off-peak. The demand rate is not seasonally differentiated, and the summer on-peak and part-peak demand rates are the same (not TOU differentiated). Additionally, the summer peak and part-peak energy rates are the same.

Rates shown below are for secondary voltage service; primary and transmission voltage service recommended rates are provided in Appendix B. Table 7-22 provides a summary of the existing and recommended changes to the E-20 rate.

Table 7-22
CleanPowerSF Large General Service
(E-20, Secondary Service)
(Existing and Recommended Rates) (1)

Rate Component	E-20 (2)	FYE 2023	FYE 2024
Demand ($/kW)			
Summer			
Peak	$11.80	$10.37	$8.94
Part-Peak	$11.80	$10.37	$8.94
Energy ($/kWh)			
Summer			
Peak	$0.0943	$0.0792	$0.0641
Part-Peak	$0.0943	$0.0792	$0.0641
Off-Peak	$0.0884	$0.0742	$0.0601
Winter			
Part-Peak	$0.0858	$0.0721	$0.0583
Off-Peak	$0.0851	$0.0715	$0.0578

(1) Rate changes are effective July 1, 2022, and July 1, 2023.
(2) Secondary service rates. See Appendix B for Primary and Transmission level service rates

Agricultural Rates

CleanPowerSF offers agricultural rates to approximately 28 customers under the similar structure as PG&E's seasonally and TOU differentiated rate offerings. For the purposes of the COS, these customers are considered in the Large Commercial class. These include the AG-A, AG-B, AG-C, AG-5-A, AG-F-A, AG-F-B, AG-F-C (non-demand, TOU), and the AG-5-B, AG-5-C, AG-1-A, AG-1-B, AG-1-B-P, AG-4-A, AG-4-B, AG-4-B-P, AG-4-C, AG-4-C-P, and AG-4-C-T (demand, TOU). The recommended rates for these customers are provided in Appendix B.

Outdoor Lighting and Traffic Control

CleanPowerSF offers outdoor lighting rates under the LS-1 tariff and traffic control rates under the TC-1 rate tariff. Both rates are energy only and are not seasonally or TOU differentiated. The recommended rates for outdoor lighting and traffic control customers are provided in Appendix B.

Other Rates

Other rates developed for CleanPowerSF include S-EM, S-B-S, S-B-P, S-B-T are provided in Appendix B.

SuperGreen Energy Premium

As indicated previously, CleanPowerSF offers SuperGreen product that is 100% renewable energy. This product is offered at a premium to the standard Green energy product and is charged as an additional per energy rate above the customer's otherwise applicable energy rate. A subtle change is recommended for the SuperGreen energy premium rate. Currently, residential customers are charged an additional $0.01/kWh for the SuperGreen energy, whereas commercial customers are charged between $0.005/kWh and $0.0075/kWh. The recommended changes are to simplify the commercial rate to be $0.005/kWh, as indicated in Table 7-23 below.

Table 7-23
CleanPowerSF SuperGreen Energy Premium
(Existing and Recommended Rates) (1)

SuperGreen Premium ($/kWh)	Current	FYE 2023	FYE 2024
Residential	$0.0100	$0.0100	$0.0100
Small General Service (2)	$0.0075	$0.0050	$0.0050
Med General Service – Low	$0.0050	$0.0050	$0.0050
Med General Service – High	$0.0050	$0.0050	$0.0050
Large General Service (2)	$0.0075	$0.0050	$0.0050

(1) Rate changes are effective July 1, 2022, and July 1, 2023.

(2) Changes recommended for Small and Large General Service (see text).

Section 8
PROJECTED REVENUE/RATE IMPACTS CLEANPOWERSF

This section includes an analysis of the projected revenue for CleanPowerSF by each year of the rate study, as well as the rate impacts from the recommended changes to the CleanPowerSF rates provided in Section 7.

Projected Revenue from Recommended Rates

NewGen recommends that CleanPowerSF offer the rates described herein, set for each year of the two-year Test Year period and applied to the PG&E TOU periods, as appropriate, and for the legacy rate codes as identified. Table 8-1 provides a summary of the projected revenue requirement by customer class for Year 1 of the Study period and the projected revenues at the recommended rates. For FY 2022–2023, the rates are projected to over collect the revenue requirement in total by approximately $7.2 million.

For FY 2023–2024, the rates are projected to essentially meet the projected revenue requirement for that period (Table 8-2). This is because the change to the rates is designed to be phased in evenly over the two-year period. This methodology provides CleanPowerSF a small degree of conservatism to ensure that it meets its financial metrics while providing cost-based rates to its customers.

Table 8-1
Revenue Requirement and Year 1 Projected Revenue by Customer Class ($000)

Class	Year 1 Revenue Requirement	Year 1 Projected Revenue	$ Difference	% Difference
Residential	$146,683	$144,623	($2,060)	(1%)
Small General Service	$44,523	$45,662	$1,139	3%
Medium General Service Low Demand	$36,592	$39,983	$3,391	9%
Medium General Service High Demand	$67,118	$69,544	$2,426	4%
Large General Service	$22,148	$24,424	$2,276	10%
Outdoor Lighting	$177	$159	($18)	(10%)
Total Revenue (1)	$317,240	$324,395	$7,155	2%

(1) Numbers may not add due to rounding.

Table 8-2
Revenue Requirement and Year 2 Projected Revenue by Customer Class ($000)

Class	Year 2 Revenue Requirement	Year 2 Projected Revenue	$ Difference	% Difference
Residential	$133,340	$133,340	$0.4	<0.1%
Small General Service	$40,080	$40,080	($0.3)	<0.1%
Medium General Service Low Demand	$32,943	$32,943	$0.3	<0.1%
Medium General Service High Demand	$60,472	$60,472	($0.1)	<0.1%
Large General Service	$20,693	$20,693	($0.2)	<0.1%
Outdoor Lighting	$160	$160	($0.0)	<0.1%
Total Revenue (1)	$287,688	$287,688	$0	<0.1%

(1) Numbers may not add due to rounding.

Bill Impact Analysis

This section provides a summary of projected bill impacts as a result of the recommended rate changes presented herein by customer class for CleanPowerSF. The average monthly usage for energy (and demand) for each customer class was developed from an analysis of the MDEF data. The generation rate is the average effective rate, which is a weighted average of the rates for TOU, seasonal periods and voltage level, as appropriate, for the total revenue for each rate code divided by the total energy (kWh) or demand (kW, for demand rate classes). Impacts to individual customers will be influenced by when they utilize power (TOU, seasonally) and the voltage level at which they are served.

The PCIA plus FFS for Year 1 is the existing PCIA (effective March 1, 2022, using the 2018 Vintage for all CleanPowerSF customers), and the delivery rate is the published rate for each rate class for PG&E (as of March 2022). The total bill is the sum of the effective generation rate, the PCIA and FFS, and the delivery rate times the energy (or demand) within a month. The change in total bill is calculated similarly using the March 2022 effective generation rate, the PCIA plus the FFS rate and delivery rate (for Year 1 impacts).

Year 2 average bill impacts are provided below the Year 1 average bill impacts. Changes to Year 2 include continued reduction in generation rates towards their COS. PG&E's PCIA is anticipated to increase January 1, 2023, by approximately 68%, which is reflected in the analysis provided below. For the purposes of this analysis, the PG&E delivery rates are anticipated to remain constant on January 1, 2023; however, the exact change to these rates is unknown at this time.

Year 1 Average Bill Impacts

Residential

For the Residential class, an analysis of the bill impacts for the two largest rate codes was developed for the Year 1 changes (E-1 and TOU C). Table 8-3 provides an analysis of customers served on the E-1 rate code. The average usage for this customer class was determined to be 284 kWh for a month. An analysis of a representative "low-use" customer (184 kWh) and a "high-use" customer (484 kWh) is included for comparative purposes. The results indicate a reduction in the average monthly bill from approximately $1.99/month to $5.22/month, depending on usage level.

Table 8-3
Monthly Bill Impact Analysis: Residential E-1 (FYE 2023)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	184	284	484
Generation Rate $/kWh	$0.1196	$0.1196	$0.1196
PCIA + FFS ($/kWh)	$0.0204	$0.0204	$0.0204
Delivery Rate ($/kWh)	$0.1995	$0.1995	$0.1995
Total Bill ($)	$62.47	$96.43	$164.33
Change in Total Bill ($) (1)	($1.99)	($3.06)	($5.22)

(1) Numbers may not add due to rounding.

Table 8-4 provides an analysis of customers served on the TOU C rate code. The results indicate a reduction in the average monthly bill from approximately $0.73/month to $1.93/month, depending on usage level for the month as well as during the TOU periods.

Table 8-4
Monthly Bill Impact Analysis: Residential TOU C (FYE 2023)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	184	284	484
Generation Rate $/kWh	$0.1182	$0.1182	$0.1182
PCIA + FFS ($/kWh)	$0.0204	$0.0204	$0.0204
Delivery Rate ($/kWh)	$0.1995	$0.1995	$0.1995
Total Bill ($)	$62.21	$96.02	$163.64
Change in Total Bill ($) (1)	($0.73)	($1.13)	($1.93)

(1) Numbers may not add due to rounding.

Small General Service

For the Small General Service class, an analysis of the bill impacts for the two largest rate codes was developed for the Year 1 changes (B-1 and A-1-B). Table 8-5 provides an analysis of customers served on the B-1 rate code. The average usage for this customer class was determined to be 1,266 kWh for a month. An analysis of a representative "low-use" customer (766 kWh) and a "high-use" customer (1,766 kWh) is included for comparative purposes. The results indicate a reduction in the average monthly bill from approximately $11.97/month to $27.60/month, depending on usage level, for Year 1.

Table 8-5
Monthly Bill Impact Analysis: Small General Service B-1 (FYE 2023)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	766	1,266	1,766
Generation Rate $/kWh	$0.1115	$0.1115	$0.1115
PCIA + FFS ($/kWh)	$0.0197	$0.0197	$0.0197
Delivery Rate ($/kWh)	$0.1822	$0.1822	$0.1822
Total Bill ($)	$240.09	$396.80	$553.52
Change in Total Bill ($) (1)	($11.97)	($19.79)	($27.60)

(1) Numbers may not add due to rounding.

Table 8-6 provides an analysis of customers served on the A-1-B rate code. The results indicate a reduction in the average monthly bill from approximately $8.15/month to $18.79/month, depending on usage level, for Year 1.

Table 8-6
Monthly Bill Impact Analysis: Small General Service – A-1B (FYE 2023)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	766	1,266	1,766
Generation Rate $/kWh	$0.1065	$0.1065	$0.1065
PCIA + FFS ($/kWh)	$0.0197	$0.0197	$0.0197
Delivery Rate ($/kWh)	$0.1822	$0.1822	$0.1822
Total Bill ($)	$236.27	$390.49	$544.71
Change in Total Bill ($) (1)	($8.15)	($13.47)	($18.79)

(1) Numbers may not add due to rounding.

Medium General Service Low Demand

For the Medium General Service Low Demand class, an analysis of the bill impacts for the two largest rate codes was developed for the Year 1 changes (B-10 and A-10-B). Table 8-7 provides an analysis of customers served on the B-10 rate code. The average usage for this customer class was determined to be 12,024 kWh for a month. An analysis of a representative "low-use" customer (10,024 kWh) and a "high-use" customer (14,024 kWh) is included for comparative purposes. The results indicate a reduction in the average monthly bill from approximately $217/month to $304/month, depending on usage level, for Year 1.

Table 8-7
Bill Impact Analysis: Medium General Service Low Demand (B-10) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	10,024	12,024	14,024
Generation Rate $/kWh	$0.1137	$0.1137	$0.1137
PCIA + FFS ($/kWh)	$0.0211	$0.0211	$0.0211
Delivery Rate ($/kWh)	$0.1385	$0.1385	$0.1385
Total Bill ($)	$2,739	$3,286	$3,832
Change in Total Bill ($) (1)	($217)	($261)	($304)

(1) Numbers may not add due to rounding.

Table 8-8 provides an analysis of customers served on the A-10-B rate code. The results indicate a reduction in the average monthly bill from approximately $175/month to $244/month, depending on usage level, for Year 1.

Table 8-8
Bill Impact Analysis: Medium General Service Low Demand (A-10-B) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	10,024	12,024	14,024
Generation Rate $/kWh	$0.1094	$0.1094	$0.1094
PCIA + FFS ($/kWh)	$0.0211	$0.0211	$0.0211
Delivery Rate ($/kWh)	$0.1385	$0.1385	$0.1385
Total Bill ($)	$2,697	$3,235	$3,773
Change in Total Bill ($)	($175)	($210)	($244)

(1) Numbers may not add due to rounding.

Medium General Service High Demand

For the Medium General Service High Demand class, an analysis of the bill impacts for the B-19 and E-19 was developed for the Year 1 rate changes. Table 8-9 provides an analysis of customers served on the B-19 rate code, which includes seasonally and TOU differentiated demand and energy rates. The energy average usage for this customer class was determined to be 30,865 kWh for a month and the average demand was determined to be 64 kW per month (for an average load factor of approximately 60%). An analysis of a representative "low-use" customer (25,865 kWh and 53 kW demand) and a "high-use" customer (35,865 kWh and 74 kW demand) is included for comparative purposes. The results indicate a reduction in the average monthly bill from approximately $408/month to $566/month, depending on usage level, for Year 1.

Table 8-9
Bill Impact Analysis: Medium General Service High Demand (B-19) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	25,865	30,865	35,865
Monthly Usage (Demand, kW)	60	71	83
Generation Rate $/kWh (Year 1)	$0.0852	$0.0852	$0.0852
Demand Rate $/kW (Year 1)	$8.40	$8.40	$8.40
PCIA + FFS ($/kWh)	$0.0211	$0.0211	$0.0211
Delivery Rate ($/kWh)	$0.1050	$0.1050	$0.1050
Total Bill ($)	$5,968	$7,122	$8,276
Change in Total Bill ($) (1)	($408)	($487)	($566)

(1) Numbers may not add due to rounding.

Table 8-10 provides an analysis of customers served on the A-10-B rate code. The results indicate a reduction in the average monthly bill from approximately $386/month to $536/month, depending on usage level, for Year 1.

Table 8-10
Bill Impact Analysis: Medium General Service High Demand (E-19) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	25,865	30,865	35,865
Monthly Usage (Demand, kW)	60	71	83
Generation Rate $/kWh (Year 1)	$0.0789	$0.0789	$0.0789
Demand Rate $/kW (Year 1)	$10.76	$10.76	$10.76
PCIA + FFS ($/kWh)	$0.0211	$0.0211	$0.0211
Delivery Rate ($/kWh)	$0.1050	$0.1050	$0.1050
Total Bill ($)	$5,947	$7,097	$8,246
Change in Total Bill ($) (1)	($386)	($461)	($536)

(1) Numbers may not add due to rounding.

Large General Service

For the Large General Service class, an analysis of the bill impacts for the B-20 and E-20 was developed for the Year 1 rate changes. Table 8-11 provides an analysis of customers served on the B-20 rate code, which includes seasonally and TOU differentiated demand and energy rates. The energy average usage for this customer class was determined to be 364,747 kWh for a month and the average demand was determined to be 905 kW per month (for an average load factor of approximately 56%). An analysis of a representative "low-use" customer (314,747 kWh and 1,257 kW demand) and a "high-use" customer (414,747 kWh and 1,656 kW demand) is included for comparative purposes. The results indicate a reduction in the average monthly bill from approximately $5,500/month to $7,200/month, depending on usage level, for Year 1.

Table 8-11
Bill Impact Analysis: Large General Service (B-20) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	314,747	364,747	414,747
Monthly Usage (Demand, kW)	781	905	1,029
Generation Rate $/kWh (Year 1)	$0.0779	$0.0779	$0.0779
Demand Rate $/kW (Year 1)	$8.29	$8.29	$8.29
PCIA + FFS ($/kWh)	$0.0198	$0.0198	$0.0198
Delivery Rate ($/kWh)	$0.1100	$0.1100	$0.1100
Total Bill ($)	$71,843	$83,256	$94,669
Change in Total Bill ($) (1)	($5,489)	($6,361)	($7,232)

(1) Numbers may not add due to rounding.

Table 8-12 provides an analysis of customers served on the E-20 rate code. The results indicate a reduction in the average monthly bill from approximately $5,500/month to $7,200/month, depending on usage level, for Year 1.

Table 8-12
Bill Impact Analysis: Large General Service (E-20) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	314,747	364,747	414,747
Monthly Usage (Demand, kW)	781	905	1,029
Generation Rate $/kWh (Year 1)	$0.0718	$0.0718	$0.0718
Demand Rate $/kW (Year 1)	$10.72	$10.72	$10.72
PCIA + FFS ($/kWh)	$0.0198	$0.0198	$0.0198
Delivery Rate ($/kWh)	$0.1100	$0.1100	$0.1100
Total Bill ($)	$71,812	$83,220	$94,628
Change in Total Bill ($) (1)	($5,458)	($6,325)	($7,192)

(1) Numbers may not add due to rounding.

Year 2 Average Bill Impacts

An analysis of the potential impacts to selected customers served by CleanPowerSF was developed for the Year 2 rate changes. For this scenario, it is assumed that the PCIA will increase by approximately 68% on January 1, 2023. A report issued by the California Public Utilities Commission in April 2021 ("Utility Cost and Affordability of the Grid of the Future"), included an appendix with projections of bundled rates for PG&E, which suggested a decrease in the distribution delivery rate. However, for the purposes of this Report, it is assumed that the delivery rate will remain the same for FY 2023-2024.

Residential

For the Residential class, an analysis of the bill impacts for the Year 2 changes (E-1 and TOU C). Table 8-13 provides an analysis of customers served on the E-1 rate code. The results indicate an increase in the average monthly bill from approximately $0.45/month to $1.19/month, depending on usage level.

Table 8-13
Monthly Bill Impact Analysis: Residential E-1 (FYE 2024)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	184	284	484
Generation Rate $/kWh	$0.1088	$0.1088	$0.1088
PCIA + FFS ($/kWh)	$0.0337	$0.0337	$0.0337
Delivery Rate ($/kWh)	$0.1995	$0.1995	$0.1995
Total Bill ($)	$62.93	$97.13	$165.52
Change in Total Bill ($) (1)	$0.45	$0.70	$1.19

(1) Numbers may not add due to rounding.

Table 8-14 provides an analysis of customers served on the TOU C rate code. The results indicate an increase in the average monthly bill from approximately $0.71/month to $1.88/month, depending on usage level for the month as well as during the TOU periods.

Table 8-14
Monthly Bill Impact Analysis: Residential TOU C (FYE 2024)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	184	284	484
Generation Rate $/kWh	$0.1088	$0.1088	$0.1088
PCIA + FFS ($/kWh)	$0.0337	$0.0337	$0.0337
Delivery Rate ($/kWh)	$0.1995	$0.1995	$0.1995
Total Bill ($)	$62.93	$97.13	$165.52
Change in Total Bill ($) (1)	$0.71	$1.10	$1.88

(1) Numbers may not add due to rounding.

Small General Service

For the Small General Service class, an analysis of the bill impacts for the Year 2 changes for B-1 and A-1-B was developed. Table 8-15 provides an analysis of customers served on the B-1 rate code. The average usage for this customer class was determined to be 1,266 kWh for a month. The results indicate a reduction in the average monthly bill from approximately $2.20/month to $5.07/month, depending on usage level, for Year 2.

Table 8-15
Monthly Bill Impact Analysis: Small General Service B-1 (FYE 2024)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	766	1,266	1,766
Generation Rate $/kWh	$0.0959	$0.0959	$0.0959
PCIA + FFS ($/kWh)	$0.0325	$0.0325	$0.0325
Delivery Rate ($/kWh)	$0.1822	$0.1822	$0.1822
Total Bill ($)	$237.89	$393.16	$548.44
Change in Total Bill ($) (1)	($2.20)	($3.64)	($5.07)

(1) Numbers may not add due to rounding.

Table 8-16 provides an analysis of customers served on the A-1-B rate code. The results indicate an increase in the average monthly bill from approximately $1.62/month to $3.74/month, depending on usage level, for Year 2.

Table 8-16
Monthly Bill Impact Analysis: Small General Service – A-1B (FYE 2024)

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	766	1,266	1,766
Generation Rate $/kWh	$0.0959	$0.0959	$0.0959
PCIA + FFS ($/kWh)	$0.0325	$0.0325	$0.0325
Delivery Rate ($/kWh)	$0.1822	$0.1822	$0.1822
Total Bill ($)	$237.89	$393.16	$548.44
Change in Total Bill ($) (1)	$1.62	$2.68	$3.74

(1) Numbers may not add due to rounding.

Medium General Service Low Demand

For the Medium General Service Low Demand class, an analysis of the bill impacts for the Year 2 changes for B-10 and A-10-B was developed. Table 8-17 provides an analysis of customers served on the B-10 rate code. The results indicate a reduction in the average monthly bill from approximately $80/month to $112/month, depending on usage level, for Year 2.

Table 8-17
Bill Impact Analysis: Medium General Service Low Demand (B-10) FYE 2024

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	10,024	12,024	14,024
Generation Rate $/kWh	$0.0920	$0.0920	$0.0920
PCIA + FFS ($/kWh)	$0.0348	$0.0348	$0.0348
Delivery Rate ($/kWh)	$0.1385	$0.1385	$0.1385
Total Bill ($)	$2,659	$3,190	$3,721
Change in Total Bill ($) (1)	($80)	($96)	($112)

(1) Numbers may not add due to rounding.

Table 8-18 provides an analysis of customers served on the A-10-B rate code. The results indicate a reduction in the average monthly bill from approximately $37/month to $52/month, depending on usage level, for Year 2.

Table 8-18
Bill Impact Analysis: Medium General Service Low Demand (A-10-B) FYE 2024

Item	Low Usage	Average Usage	High Usage
Monthly Usage (kWh)	10,024	12,024	14,024
Generation Rate $/kWh	$0.0920	$0.0920	$0.0920
PCIA + FFS ($/kWh)	$0.0348	$0.0348	$0.0348
Delivery Rate ($/kWh)	$0.1385	$0.1385	$0.1385
Total Bill ($)	$2,659	$3,190	$3,721
Change in Total Bill ($)	($37)	($45)	($52)

(1) Numbers may not add due to rounding.

Medium General Service High Demand

For the Medium General Service High Demand class, an analysis of the bill impacts for the B-19 and E-19 was developed for the Year 2 rate changes. Table 8-19 provides an analysis of customers served on the B-19 rate code, which includes seasonally and TOU differentiated demand and energy rates. The results indicate a reduction in the average monthly bill from approximately $53/month to $74/month, depending on usage level, for Year 2.

Table 8-19
Bill Impact Analysis: Medium General Service High Demand (B-19) FYE 2024

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	25,865	30,865	35,865
Monthly Usage (Demand, kW)	60	71	83
Generation Rate $/kWh (Year 2)	$0.0673	$0.0673	$0.0673
Demand Rate $/kW (Year 2)	$9.34	$9.34	$9.34
PCIA + FFS ($/kWh)	$0.0348	$0.0348	$0.0348
Delivery Rate ($/kWh)	$0.1050	$0.1050	$0.1050
Total Bill ($)	$5,915	$7,059	$8,202
Change in Total Bill ($) (1)	($53)	($63)	($74)

(1) Numbers may not add due to rounding.

Table 8-20 provides an analysis of customers served on the A-10-B rate code. The results indicate a reduction in the average monthly bill from approximately $32/month to $44/month, depending on usage level, for Year 1.

Table 8-20
Bill Impact Analysis: Medium General Service High Demand (E-19) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	25,865	30,865	35,865
Monthly Usage (Demand, kW)	60	71	83
Generation Rate $/kWh (Year 2)	$0.0673	$0.0673	$0.0673
Demand Rate $/kW (Year 2)	$9.34	$9.34	$9.34
PCIA + FFS ($/kWh)	$0.0348	$0.0348	$0.0348
Delivery Rate ($/kWh)	$0.1050	$0.1050	$0.1050
Total Bill ($)	$5,915	$7,059	$8,202
Change in Total Bill ($) (1)	($32)	($38)	($44)

(1) Numbers may not add due to rounding.

Large General Service

For the Large General Service class, an analysis of the bill impacts for the B-20 and E-20 was developed for the Year 2 rate changes. Table 8-21 provides an analysis of customers served on the B-20 rate code, which includes seasonally and TOU differentiated demand and energy rates. The results indicate a reduction in the average monthly bill from approximately $1,400/month to $1,900/month, depending on usage level, for Year 1.

Table 8-21
Bill Impact Analysis: Large General Service (B-20) FYE 2024

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	314,747	364,747	414,747
Monthly Usage (Demand, kW)	781	905	1,029
Generation Rate $/kWh (Year 2)	$0.0581	$0.0581	$0.0581
Demand Rate $/kW (Year 2)	$9.25	$9.25	$9.25
PCIA + FFS ($/kWh)	$0.0326	$0.0326	$0.0326
Delivery Rate ($/kWh)	$0.1100	$0.1100	$0.1100
Total Bill ($)	$70,391	$81,573	$92,755
Change in Total Bill ($) (1)	($1,452)	($1,683)	($1,913)

(1) Numbers may not add due to rounding.

Table 8-22 provides an analysis of customers served on the E-20 rate code. The results indicate a reduction in the average monthly bill from approximately $1,400/month to $1,900/month, depending on usage level, for Year 1.

Table 8-22
Bill Impact Analysis: Large General Service (E-20) FYE 2023

Item	Low Usage	Average Usage	High Usage
Monthly Usage (Energy, kWh)	314,747	364,747	414,747
Monthly Usage (Demand, kW)	781	905	1,029
Generation Rate $/kWh (Year 1)	$0.0581	$0.0581	$0.0581
Demand Rate $/kW (Year 1)	$9.2466	$9.2466	$9.2466
PCIA + FFS ($/kWh)	$0.0326	$0.0326	$0.0326
Delivery Rate ($/kWh)	$0.1100	$0.1100	$0.1100
Total Bill ($)	$70,391	$81,573	$92,755
Change in Total Bill ($) (1)	($1,421)	($1,647)	($1,873)

(1) Numbers may not add due to rounding.

Section 9
CONCLUSION/FUTURE RATE CHANGES/RECOMMENDATONS

Conclusion

The process of developing this Study resulted in several findings and recommendations for rate changes for both Hetch Hetchy Power and CleanPowerSF. One conclusion is that while the SFPUC is under a mandate to conduct an independent review of its rates every five years, a shorter rate plan period is warranted. For this Study, the rate plan period is a two-year period, beginning in FY 2022–2023 and ending FY 2022–2024. Further, the recommended two-year rate plan is recommended to implement different rates for each fiscal year: July 1, 2022 (for FY 2022–2023) and July 1, 2023 (for FY 2023–2024), rather than enact one set of rates to cover both fiscal years. However, the results of the analysis, methodologies and models created for this Study can be utilized by SFPUC to inform rates for the five-year period ending FY 2026-2027.

There are several reasons for this recommendation. For Hetch Hetchy Power, the projections for customer growth, especially in the residential customer class, are significant. This growth results in increased costs for services, which is met with changes in rates for customers. If the growth does not materialize in the projected period, revenue projections will need to be adjusted (as will expenses). For CleanPowerSF, the exposure to price volatility in the CAISO market also warrants a two-year phase in to move customers to COS-based rates. By recommending two sets of rate changes over the two-year rate plan period, SFPUC management and staff have the opportunity to review projections for growth, revenue, and expenses, and potentially make adjustments as necessary to their operations to continue to ensure fiscal responsibility.

Other findings of this Study included an analysis of the underlying market power costs that vary throughout the year and within the day. The seasonal variation suggests that CAISO power supply costs for both Hetch Hetchy Power and CleanPowerSF are higher during the winter periods than summer periods. However, current and recommended rate structures are set to have higher costs during the summer than winter. Further, an analysis of power supply costs during the day (TOU) within each operation generally suggests higher costs during on- and part-peak periods than off-peak periods. For Hetch Hetchy Power, the TOU differentials analyzed for this Study have been incorporated into the recommended rates over the two-year rate period. For CleanPowerSF, the existing TOU rate differentials (based on PG&E rate structures) have been maintained in the recommended rates.

For Hetch Hetchy Power, one primary objective of this Study is to move the "legacy" rate groups (retail, GUSE, Enterprise) into traditional rate offerings (residential, commercial, industrial). This goal includes shifting customers within each "group" towards the COS-based rates developed for the industry standard rate offering. This objective will require a transition period; for some customer classes, this transition period is the two-year rate plan (depending on load growth). However, for most customer classes this objective may require additional time to fully achieve. During this transition period, the existing subsidy for GUSE customers will be maintained, but is reduced as those customers' rates approach COS. For residential customers, an effective rate cap of 10% for the class also creates a subsidy during this transition period. A final subsidy related to the low-income rate offering for residential customers is maintained for the rate study period. Over time, these subsidies (with the potential exception of the low-income discount) should be phased out as customers are moved to cost of service; the recommended rates make significant progress towards this goal, but the SFPUC should continue on this path in future years.

For CleanPowerSF, a primary objective of this Study is to provide funding of specific financial reserves for the operation and continued financial stability of the organization. As indicated herein, this includes recommendations for a policy change to increase its targeted days cash on hand to equal 180 days. This specific target is not achieved during the two-year rate plan; however, the recommended rates provide funding for reserves that allow CleanPowerSF to move towards its goal during this period, and to meet the target within three years, as required by the policy.

For both Hetch Hetchy Power and CleanPowerSF, a combined objective of this Study is to separate the rate-related actions for customers served by the SFPUC from the rate actions of PG&E. As indicated, currently CleanPowerSF rates are tied to changes in PG&E rates; rates were changed to match PG&E during the recent rate change on March 1, 2022. Due to the nature of the CCA operation, CleanPowerSF will remain "tied" to PG&E for the billing periods (TOU), as well as future changes in the PCIA. Additionally, CleanPowerSF will need to remain "competitive" with PG&E either on a cost basis or with their rate offerings (such as their SuperGreen product). However, going forward, generation rates for CleanPowerSF will be related to their projected COS and the results of this Study will allow operations to forecast revenue from projected sales based on the rate recommendations.

For Hetch Hetchy Power, the Enterprise and retail rates were historically tied to the rate levels set by PG&E. However, with the rate recommendations, the rates are based on their projected COS by traditional rate class. The recommended rate structures for the Enterprise customers (seasonal, TOU) are tied to their former structures, but are transitioning towards COS during the two-year rate plan.

Future Rate Changes

As indicated, not all of the anticipated objectives of this Study were able to be accomplished during the two-year rate plan developed herein. Specifically, analysis and updates to the Net Energy Metering (NEM) rate program for CleanPowerSF and Hetch Hetchy Power is an area that warrants review, given the changes in the industry regarding NEM reform. Additionally, future rate changes may be warranted for the existing Peak Day pricing programs as well as other demand management programs, which were not reviewed for this Study. As mentioned, time-of-use periods for Hetch Hetchy rates were not changed from their current structures. Further analysis should examine whether different time periods better capture Hetch Hetchy costs and drive customer behavior. Moreover, not all customer classes have TOU rate options and future analysis could consider creating those.

For Hetch Hetchy Power, specific rate elements were identified during this Study that warrant future review and potential changes to the rates, rate structures, and fee programs. Specifically, it was identified that, as noted above, the seasonal rates do not appear to correspond with the seasonal market costs. The winter energy costs (on average) for Hetch Hetchy Power appear to be higher than the summer energy costs (on average), whereas the current (and recommended) rate structures reflect the opposite (summer rates are higher than winter rates). This issue should be examined in future rate studies to determine if the analysis conducted herein holds true over a longer period (this was an annual analysis based on 2019 load and pricing). Any future changes to seasonal rate structures should recognize that a significant communication and outreach effort will be required. This Study did not develop transmission access charges for Hetch Hetchy Power transmission assets or other wholesale power rates, which should be considered in future rate studies. Additionally, this Study did not review costs or application of Hetch Hetchy Power premium or green tariff programs, which should be addressed in future rate offerings.

The SFPUC is considering a review of its existing policies regarding assignment of its up-country and down-country costs (the 45/55% split, see "Glossary of Terms"). Currently, for joint operations, the Water Enterprise is responsible for 45% of operating and capital costs, while the Power Enterprise is responsible for the remaining 55%. Any changes to this methodology would results in changes to the costs allocated to Hetch Hetchy Power and would therefore need to be incorporated into future rate changes, as appropriate.

Hetch Hetchy Power should also continue to evaluate its line extension policy with its projected costs to ensure future development contributes an appropriate share of its costs to the system. Other fee programs to be reviewed for future rate evaluation include the streetlight permit review fees and the low carbon fuel standard credit trading fees.

The resulting recommended rates developed for this Study were prepared for the two-year rate plan as described herein. The period of the analyses covered by this Study extends to FY 2026-2027 (a five-year period). The methodology and models prepared for this Study should be utilized by the SFPUC within the five-year period analyzed to inform retail rates for Hetch Hetchy Power and CleanPowerSF for this period. As indicated herein, the two-year rate plan period was selected due to the anticipated volatility in the wholesale power market (CAISO), which directly impacts the operations costs for CleanPowerSF. Additionally, the two-year rate plan was developed to address the uncertainly regarding projected load growth to be served by Hetch Hetchy Power, which is primarily focused on the residential customer class. However, this Study provides SFPUC with the tools and analyses to evaluate and proposed rate changes for the period from FY 2022-2023 to FY 2026-2027.

Recommendations

Based on the conclusions and supporting analyses presented herein, the following recommendations are a result of this Study:

- The Commission should adopt rates as described and recommended in two-year rate plan and this Report.
- The SFPUC should continue to invest in infrastructure, equipment, and personnel to ensure its ability to meet customer demand for innovation and reliable power supply.
- The SFPUC should continue to monitor and evaluate evolving technologies, systems, and operations to maximize its investments.
- SFPUC should utilize the results of this Study to develop future year rate proposals as necessary.

APPENDIX A: RECOMMENDED HETCH HETCHY POWER RATES

MAY 11, 2022

2022 POWER RATES STUDY FINAL REPORT

Residential	Rate Component	Current Rates	Proposed Phase 1 Rates	Proposed Phase 2 Rates
R-1 Gas and Electric				
	Customer Charge	$4.58	$5.91	$7.23
	Summer Energy			
	Tier 1 (0 kWh - 227 kWh)	$0.1778	$0.2088	$0.2277
	Tier 2 (227 kWh - 524 kWh	$0.2021	$0.2506	$0.2732
	Tier 3 (Over 524 kWh)	$0.4137	$0.3758	$0.4099
	Winter Energy			
	Tier 1 (0 kWh - 252 kWh)	$0.1778	$0.2088	$0.2277
	Tier 2 (252 kWh - 579 kWh	$0.2021	$0.2506	$0.2732
	Tier 3 (Over 579 kWh)	$0.4137	$0.3758	$0.4099
ER-1 Electric Heating				
	Customer Charge	$4.58	$5.91	$7.23
	Summer Energy			
	Tier 1 (0 kWh - 250 kWh)	$0.1778	$0.2088	$0.2277
	Tier 2 (250 kWh - 578 kWh	$0.2021	$0.2506	$0.2732
	Tier 3 (Over 578 kWh)	$0.4137	$0.3758	$0.4099
	Winter Energy			
	Tier 1 (0 kWh - 418 kWh)	$0.1778	$0.2088	$0.2277
	Tier 2 (418 kWh - 960 kWh	$0.2021	$0.2506	$0.2732
	Tier 3 (Over 960 kWh)	$0.4137	$0.3758	$0.4099
R-2 Low Income Gas and Electric				
	Customer Charge	$3.21	$4.14	$5.06
	Summer Energy			
	Tier 1 (0 kWh - 227 kWh)	$0.1245	$0.1462	$0.1594
	Tier 2 (227 kWh - 524 kWh	$0.1415	$0.1754	$0.1913
	Tier 3 (Over 524 kWh)	$0.2896	$0.2631	$0.2869
	Winter Energy			
	Tier 1 (0 kWh - 252 kWh)	$0.1245	$0.1462	$0.1594
	Tier 2 (252 kWh - 579 kWh	$0.1415	$0.1754	$0.1913
	Tier 3 (Over 579 kWh)	$0.2896	$0.2631	$0.2869
ER-2 Low Income Electric Heating				
	Customer Charge	$3.21	$4.14	$5.06
	Summer Energy			
	Tier 1 (0 kWh - 250 kWh)	$0.1245	$0.1462	$0.1594
	Tier 2 (250 kWh - 578 kWh	$0.1415	$0.1754	$0.1913
	Tier 3 (Over 578 kWh)	$0.2896	$0.2631	$0.2869
	Winter Energy			
	Tier 1 (0 kWh - 418 kWh)	$0.1245	$0.1462	$0.1594
	Tier 2 (418 kWh - 960 kWh	$0.1415	$0.1754	$0.1913
	Tier 3 (Over 960 kWh)	$0.2896	$0.2631	$0.2869
REV-1 Experieimetal Electric Vehicle				
	Customer Charge	$4.58	$5.91	$7.23
	Summer Energy			
	Tier 1 (0 kWh - 400 kWh)	$0.1778	$0.2028	$0.2277
	Tier 2 (400 kWh - 728 kWh	$0.2021	$0.2433	$0.2732
	Tier 3 (Over 728 kWh)	$0.3103	$0.3650	$0.4099
	Winter Energy			
	Tier 1 (0 kWh - 568 kWh)	$0.1778	$0.2028	$0.2277
	Tier 2 (568 kWh - 1110 kW	$0.2021	$0.2433	$0.2732
	Tier 3 (Over 1110 kWh)	$0.3103	$0.3650	$0.4099

R-M Medical Necessity Assistance			
Customer Charge	$4.58	$5.91	$7.23
Summer Energy			
Tier 1 (0 kWh - 727 kWh)	$0.1778	$0.2028	$0.2277
Tier 2 (727 kWh - 1024 kW	$0.2021	$0.2433	$0.2732
Tier 3 (Over 1024 kWh)	$0.4137	$0.3650	$0.4099
Winter Energy			
Tier 1 (0 kWh - 752 kWh)	$0.1778	$0.2028	$0.2277
Tier 2 (752 kWh - 1079 kW	$0.2021	$0.2433	$0.2732
Tier 3 (Over 1079 kWh)	$0.4137	$0.3650	$0.4099
ER-M Medical Necessity Assistance Electric Heat			
Customer Charge	$4.58	$5.91	$7.23
Summer Energy			
Tier 1 (0 kWh - 750 kWh)	$0.1778	$0.2088	$0.2277
Tier 2 (750 kWh - 1078 kW	$0.2021	$0.2506	$0.2732
Tier 3 (Over 1078 kWh)	$0.4137	$0.3758	$0.4099
Winter Energy			
Tier 1 (0 kWh - 918 kWh)	$0.1778	$0.2088	$0.2277
Tier 2 (918 kWh - 1460 kW	$0.2021	$0.2506	$0.2732
Tier 3 (Over 1460 kWh)	$0.4137	$0.3758	$0.4099
E1TB Individually Metered Gas and Electric			
Customer Charge	$0.00	$3.62	$7.23
Summer Energy			
Tier 1 (0 kWh - 227 kWh)	$0.3147	$0.2712	$0.2277
Tier 2 (227 kWh - 524 kWh	$0.3945	$0.3254	$0.2732
Tier 3 (Over 524 kWh)	$0.4932	$0.4881	$0.4099
Winter Energy			
Tier 1 (0 kWh - 252 kWh)	$0.3147	$0.2712	$0.2277
Tier 2 (252 kWh - 579 kWh	$0.3945	$0.3254	$0.2732
Tier 3 (Over 579 kWh)	$0.4932	$0.4881	$0.4099
EL1TB Low Income Individually Metered Gas and Electric			
Customer Charge	$0.00	$2.36	$4.70
Summer Energy			
Tier 1 (0 kWh - 227 kWh)	$0.2047	$0.1764	$0.1481
Tier 2 (227 kWh - 524 kWh	$0.2567	$0.2117	$0.1778
Tier 3 (Over 524 kWh)	$0.3208	$0.3176	$0.2666
Winter Energy			
Tier 1 (0 kWh - 252 kWh)	$0.2047	$0.1764	$0.1481
Tier 2 (252 kWh - 579 kWh	$0.2567	$0.2117	$0.1778
Tier 3 (Over 579 kWh)	$0.3208	$0.3176	$0.2666
EM1TB Mastered Metered Gas and Electric Heating			
Customer Charge	$0.00	$3.62	$7.23
Summer Energy			
Tier 1 (0 kWh - 227 kWh)	$0.3147	$0.2712	$0.2277
Tier 2 (227 kWh - 524 kWh	$0.3945	$0.3254	$0.2732
Tier 3 (Over 524 kWh)	$0.4932	$0.4881	$0.4099
Winter Energy			
Tier 1 (0 kWh - 252 kWh)	$0.3147	$0.2712	$0.2277
Tier 2 (252 kWh - 579 kWh	$0.3945	$0.3254	$0.2732
Tier 3 (Over 579 kWh)	$0.4932	$0.4881	$0.4099

EMLTB Low Income Mastered Metered Gas and Electric Heating			
Customer Charge	$0.00	$2.36	$4.70
Summer Energy			
Tier 1 (0 kWh - 227 kWh)	$0.2047	$0.1764	$0.1481
Tier 2 (227 kWh - 524 kWh	$0.2567	$0.2117	$0.1778
Tier 3 (Over 524 kWh)	$0.3208	$0.3176	$0.2666
Winter Energy			
Tier 1 (0 kWh - 252 kWh)	$0.2047	$0.1764	$0.1481
Tier 2 (252 kWh - 579 kWh	$0.2567	$0.2117	$0.1778
Tier 3 (Over 579 kWh)	$0.3208	$0.3176	$0.2666
EMLTH Low Income Mastered Metered Electric Heating			
Customer Charge	$0.00	$2.35	$4.70
Summer Energy			
Tier 1 (0 kWh - 250 kWh)	$0.2047	$0.1764	$0.1481
Tier 2 (250 kWh - 578 kWh	$0.2567	$0.2117	$0.1778
Tier 3 (Over 578 kWh)	$0.3208	$0.3176	$0.2666
Winter Energy			
Tier 1 (0 kWh - 418 kWh)	$0.2047	$0.1764	$0.1481
Tier 2 (418 kWh - 960 kWh	$0.2567	$0.2117	$0.1778
Tier 3 (Over 960 kWh)	$0.3208	$0.3176	$0.2666

Small Commercial				
C-1				
	Customer Charge Single Phase	$8.99	$11.65	$14.31
	Customer Charge Poly Phase	$22.49	$29.14	$35.80
	Summer Energy Charge	$0.2562	$0.2743	$0.2973
	Winter Energy Charge	$0.2049	$0.2194	$0.2378
			1.250319052	1.250304942
GUSE G-1				
	Customer Charge Single Phase	$0.00	$6.00	$8.52
	Customer Charge Poly Phase	$0.00	$15.02	$21.32
	Summer Energy Charge	$0.0988	$0.1410	$0.1733
	Winter Energy Charge	$0.0988	$0.1128	$0.1386
A1S and A1P				
	Customer Charge Single Phase	$10.00	$12.15	$14.31
	Customer Charge Poly Phase	$25.00	$30.38	$35.78
	Summer Energy Charge	$0.3364	$0.3271	$0.2972
	Winter Energy Charge	$0.2794	$0.2616	$0.2377
			1.250334467	1.250326
A1-US and A1-UP				
	Customer Charge Single Phase	$10.00	$12.15	$14.31
	Customer Charge Poly Phase	$25.00	$30.38	$35.78
	Summer Energy Charge			
	On-Peak	$0.3397	$0.3290	$0.2978
	Part Peak	$0.3397	$0.3290	$0.2978
	Off Peak	$0.3149	$0.2832	$0.2332
	Winter Energy Charge			
	On-Peak	$0.0000	$0.000000	$0.00000
	Part Peak	$0.2921	$0.2947	$0.2790
	Off Peak	$0.2915	$0.2803	$0.2515

Medium Commercial				
C-2S				
	Customer Charge	$149.92	$202.52	$255.11
	Summer Energy Charge	$0.1387	$0.1139	$0.0932
	Winter Energy Charge	$0.1726	$0.1416	$0.1160
	Summer Demand Charge	$14.11	$27.76	$41.41
	Winter Demand Charge	$14.11	$27.76	$41.41
		0.803894298	0.803855115	0.803897896
C-2P				
	Customer Charge	$149.92	$194.22	$238.51
	Summer Energy Charge	$0.1302	$0.1075	$0.0891
	Winter Energy Charge	$0.1619	$0.1338	$0.1108
	Summer Demand Charge	$15.89	$25.07	$34.25
	Winter Demand Charge	$13.90	$24.07	$34.25
		0.804398863	0.80388785	0.803898565
GUSE G-2S				
	Customer Charge	$0.00	$132.19	$205.54
	Summer Energy Charge	$0.0988	$0.0683	$0.0569
	Winter Energy Charge	$0.0988	$0.0850	$0.0707
	Summer Demand Charge	$0.00	$18.12	$33.36
	Winter Demand Charge	$0.00	$18.12	$33.36
GUSE G-2P				
	Customer Charge	$0.00	$138.05	$219.56
	Summer Energy Charge	$0.0988	$0.0699	$0.0611
	Winter Energy Charge	$0.0988	$0.0869	$0.0761
	Summer Demand Charge	$0.00	$17.82	$31.52
	Winter Demand Charge	$0.00	$17.11	$31.52
A10-S				
	Customer Charge	$179.90	$217.51	$255.11
	Summer Energy Charge	$0.2337	$0.1611	$0.0925
	Winter Energy Charge	$0.1961	$0.2004	$0.1151
	Summer Demand Charge	$18.45	$29.93	$41.41
	Winter Demand Charge	$18.45	$29.93	$41.41
		1.191819248	0.803893187	0.803856845
A10-P				
	Customer Charge	$179.90	$209.20	$238.51
	Summer Energy Charge	$0.2170	$0.1505	$0.0881
	Winter Energy Charge	$0.1818	$0.1872	$0.1096
	Summer Demand Charge	$18.14	$26.19	$34.25
	Winter Demand Charge	$18.14	$26.19	$34.25
			0.803877584	0.803943045
A10-US				
	Customer Charge	$179.90	$217.51	$255.11
	Summer Energy Charge			
	On-Peak	$0.2472	$0.1841	$0.1255
	Part-Peak	$0.2472	$0.1841	$0.1255
	Off-Peak	$0.2204	$0.1593	$0.1003
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1967	$0.1541	$0.1182
	Off-Peak	$0.1960	$0.1493	$0.1077
	Summer Demand Charge	$18.45	$29.93	$41.41
	Winter Demand Charge	$18.45	$29.93	$41.41

A10-UP				
	Customer Charge	$179.90	$209.21	$238.51
	Summer Energy Charge			
	On-Peak	$0.2309	$0.1730	$0.1198
	Part-Peak	$0.2309	$0.1730	$0.1198
	Off-Peak	$0.2056	$0.1495	$0.0957
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1818	$0.1438	$0.1128
	Off-Peak	$0.1811	$0.1394	$0.1028
	Summer Demand Charge	$18.14	$26.19	$34.25
	Winter Demand Charge	$18.14	$26.19	$34.25

Large Commercial				
C-3S				
	Customer Charge	$754.93	$1,207.12	$1,659.31
	Summer Energy Charge			
	On-Peak	$0.1019	$0.0897	$0.0783
	Part-Peak	$0.1019	$0.0897	$0.0783
	Off-Peak	$0.0965	$0.0792	$0.0624
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.0942	$0.0835	$0.0735
	Off-Peak	$0.0936	$0.0802	$0.0674
	Summer Demand Charge			
	On-Peak	$12.27	$16.65	$21.03
	Part-Peak	$10.01	$13.58	$17.15
	Off-Peak	$0.00	$0.00	$0.00
	Max	$22.44	$30.45	$38.46
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$22.44	$30.45	$38.46
C-3P				
	Customer Charge	$1,151.50	$1,352.55	$1,553.60
	Summer Energy Charge			
	On-Peak	$0.0934	$0.0852	$0.0779
	Part-Peak	$0.0934	$0.0852	$0.0779
	Off-Peak	$0.0883	$0.0749	$0.0620
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.0860	$0.0792	$0.0732
	Off-Peak	$0.0854	$0.0759	$0.0671
	Summer Demand Charge			
	On-Peak	$10.44	$11.80	$13.15
	Part-Peak	$8.73	$9.86	$11.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$18.58	$20.99	$23.40
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$18.58	$20.99	$23.40
GUSE G-3S				
	Customer Charge	$0.00	$774.98	$1,235.78
	Summer Energy Charge			
	On-Peak	$0.0988	$0.0572	$0.0567
	Part-Peak	$0.0988	$0.0572	$0.0567
	Off-Peak	$0.0988	$0.0505	$0.0451
	Winter Energy Charge			
	On-Peak	$0.0988	$0.0000	$0.0000
	Part-Peak	$0.0988	$0.0532	$0.0459
	Off-Peak	$0.0988	$0.0511	$0.0421
	Summer Demand Charge			
	On-Peak	$0.00	$10.69	$15.66
	Part-Peak	$0.00	$8.72	$12.78
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$19.55	$28.64
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$19.55	$28.64

GUSE G-3P				
	Customer Charge	$0.00	$1,065.72	$1,514.89
	Summer Energy Charge			
	On-Peak	$0.0988	$0.0666	$0.0738
	Part-Peak	$0.0988	$0.0666	$0.0738
	Off-Peak	$0.0988	$0.0585	$0.0587
	Winter Energy Charge			
	On-Peak	$0.0988	$0.0000	$0.0000
	Part-Peak	$0.0988	$0.0619	$0.0693
	Off-Peak	$0.0988	$0.0593	$0.0635
	Summer Demand Charge			
	On-Peak	$0.00	$9.29	$12.82
	Part-Peak	$0.00	$7.77	$10.72
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$16.54	$22.81
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$16.54	$22.81
E19-S				
	Customer Charge	$903.76	$1,281.54	$1,659.31
	Summer Energy Charge			
	On-Peak	$0.1410	$0.1222	$0.0784
	Part-Peak	$0.1410	$0.1222	$0.0784
	Off-Peak	$0.1350	$0.1101	$0.0624
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1325	$0.1148	$0.0736
	Off-Peak	$0.1317	$0.1110	$0.0674
	Summer Demand Charge			
	On-Peak	$16.99	$19.01	$21.03
	Part-Peak	$14.28	$15.72	$17.15
	Off-Peak	$0.00	$0.00	$0.00
	Max	$28.39	$33.42	$38.46
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$28.39	$33.42	$38.46
E19-P				
	Customer Charge	$1,375.29	$1,464.45	$1,553.60
	Summer Energy Charge			
	On-Peak	$0.1281	$0.1156	$0.0779
	Part-Peak	$0.1281	$0.1156	$0.0779
	Off-Peak	$0.1224	$0.1036	$0.0620
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1199	$0.1083	$0.0731
	Off-Peak	$0.1192	$0.1045	$0.0670
	Summer Demand Charge			
	On-Peak	$14.46	$13.81	$13.15
	Part-Peak	$12.42	$11.71	$11.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$23.73	$23.56	$23.40
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$23.73	$23.56	$23.40

Industrial				
I-3S				
	Customer Charge	$1,370.12	$1,515.27	$1,660.42
	Summer Energy Charge			
	On-Peak	$0.0971	$0.0998	$0.1110
	Part-Peak	$0.0971	$0.0998	$0.1110
	Off-Peak	$0.0918	$0.0868	$0.0868
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.0895	$0.0924	$0.1034
	Off-Peak	$0.0888	$0.0880	$0.0938
	Summer Demand Charge			
	On-Peak	$12.44	$14.42	$16.39
	Part-Peak	$9.79	$11.35	$12.91
	Off-Peak	$0.00	$0.00	$0.00
	Max	$22.14	$25.66	$29.18
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$22.14	$25.66	$29.18
I-3P				
	Customer Charge	$1,367.57	$1,481.03	$1,594.48
	Summer Energy Charge			
	On-Peak	$0.0942	$0.0967	$0.1078
	Part-Peak	$0.0942	$0.0967	$0.1078
	Off-Peak	$0.0890	$0.0842	$0.0843
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.0868	$0.0895	$0.1004
	Off-Peak	$0.0861	$0.0853	$0.0911
	Summer Demand Charge			
	On-Peak	$12.38	$14.51	$16.63
	Part-Peak	$10.23	$11.99	$13.74
	Off-Peak	$0.00	$0.00	$0.00
	Max	$20.11	$23.55	$27.00
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$20.11	$23.55	$27.00
GUSE CG-4S				
	Customer Charge	$0.00	$1,141.32	$1,522.94
	Summer Energy Charge			
	On-Peak	$0.0988	$0.0675	$0.0753
	Part-Peak	$0.0988	$0.0675	$0.0753
	Off-Peak	$0.0988	$0.0587	$0.0589
	Winter Energy Charge			
	On-Peak	$0.0988	$0.0000	$0.0000
	Part-Peak	$0.0988	$0.0625	$0.0701
	Off-Peak	$0.0988	$0.0596	$0.0636
	Summer Demand Charge			
	On-Peak	$0.00	$10.86	$15.04
	Part-Peak	$0.00	$8.55	$11.84
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$19.33	$26.77
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$19.33	$26.77

GUSE CG-4P				
	Customer Charge	$0.00	$1,161.19	$1,518.50
	Summer Energy Charge			
	On-Peak	$0.0988	$0.0678	$0.0751
	Part-Peak	$0.0988	$0.0678	$0.0751
	Off-Peak	$0.0988	$0.0591	$0.0587
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.0988	$0.0628	$0.0699
	Off-Peak	$0.0988	$0.0599	$0.0634
	Summer Demand Charge			
	On-Peak	$0.00	$11.38	$15.84
	Part-Peak	$0.00	$9.40	$13.09
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$18.47	$25.72
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$0.00	$18.47	$25.72
E-20S				
	Customer Charge	$1,632.16	$1,646.29	$1,660.42
	Summer Energy Charge			
	On-Peak	$0.1340	$0.1080	$0.1107
	Part-Peak	$0.1340	$0.1080	$0.1107
	Off-Peak	$0.1281	$0.0961	$0.0866
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1255	$0.1010	$0.1031
	Off-Peak	$0.1248	$0.0971	$0.0935
	Summer Demand Charge			
	On-Peak	$17.06	$16.73	$16.39
	Part-Peak	$13.90	$13.40	$12.91
	Off-Peak	$0.00	$0.00	$0.00
	Max	$28.61	$28.90	$29.18
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$28.61	$28.90	$29.18
E-20P				
	Customer Charge	$1,624.03	$1,609.25	$1,594.48
	Summer Energy Charge			
	On-Peak	$0.1293	$0.1083	$0.1077
	Part-Peak	$0.1293	$0.1083	$0.1077
	Off-Peak	$0.1236	$0.0964	$0.0843
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1211	$0.1012	$0.1003
	Off-Peak	$0.1204	$0.0973	$0.0910
	Summer Demand Charge			
	On-Peak	$17.11	$16.87	$16.63
	Part-Peak	$14.56	$14.15	$13.74
	Off-Peak	$0.00	$0.00	$0.00
	Max	$26.15	$26.58	$27.00
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$26.15	$26.58	$27.00

E-20T				
	Customer Charge	$1,111.18	$1,332.39	$1,553.60
	Summer Energy Charge			
	On-Peak	$0.1140	$0.1070	$0.1076
	Part-Peak	$0.1140	$0.1070	$0.1076
	Off-Peak	$0.1083	$0.0944	$0.0841
	Winter Energy Charge			
	On-Peak	$0.0000	$0.0000	$0.0000
	Part-Peak	$0.1059	$0.0995	$0.1002
	Off-Peak	$0.1053	$0.0954	$0.0909
	Summer Demand Charge			
	On-Peak	$15.02	$17.75	$20.48
	Part-Peak	$15.02	$17.75	$20.48
	Off-Peak	$0.00	$0.00	$0.00
	Max	$13.55	$16.01	$18.48
	Winter Demand Charge			
	On-Peak	$0.00	$0.00	$0.00
	Part-Peak	$0.00	$0.00	$0.00
	Off-Peak	$0.00	$0.00	$0.00
	Max	$13.55	$16.01	$18.48

Miscellaneous Rates					
Traffic Lighting TC-1					
	Customer Charge		$14.78	$0.00	$0.00
	Energy Charge		0.25282	0.259225	0.26563
Street Lighting TC-1					
	Customer Charge		$7.39	$0.00	$0.00
	Energy Charge		$0.2255	$0.2456	$0.2656
GUSE Street Lighting TC-1					
	Customer Charge		$0.00	$0.00	$0.00
	Energy Charge		0.09877	0.12877	0.15877
Commercial EV Charging Rate					
	Customer Charge	N/A		$14.31	$14.31
	Summer Energy Charge				
	On-Peak	N/A		$0.3237	$0.3237
	Off-Peak	N/A		$0.2072	$0.2072
	Winter Energy Charge				
	On-Peak	N/A		$0.3367	$0.3367
	Off-Peak	N/A		$0.2538	$0.2538

APPENDIX B: RECOMMENDED CLEANPOWERSF RATES

MAY 11, 2022

2022 POWER RATES STUDY FINAL REPORT

Residential			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
E-1			
All	$ 0.1304	$ 0.1196	$ 0.1088
E-6			
Summer			
Peak	$ 0.2598	$ 0.2448	$ 0.2298
Part-Peak	$ 0.1768	$ 0.1666	$ 0.1564
Off-Peak	$ 0.1067	$ 0.1005	$ 0.0943
Winter			
Part-Peak	$ 0.1441	$ 0.1358	$ 0.1275
Off-Peak	$ 0.1103	$ 0.1039	$ 0.0976
E-TOU-B			
Summer			
Peak	$ 0.2505	$ 0.2368	$ 0.2231
Off-Peak	$ 0.1274	$ 0.1205	$ 0.1135
Winter			
Peak	$ 0.1445	$ 0.1366	$ 0.1287
Off-Peak	$ 0.1057	$ 0.0999	$ 0.0942
E-TOU-C			
Summer			
Peak	$ 0.1802	$ 0.1670	$ 0.1538
Off-Peak	$ 0.1268	$ 0.1175	$ 0.1082
Winter			
Peak	$ 0.1315	$ 0.1218	$ 0.1121
Off-Peak	$ 0.1164	$ 0.1079	$ 0.0993
E-TOU-D			
Summer			
Peak	$ 0.2097	$ 0.1938	$ 0.1779
Off-Peak	$ 0.1047	$ 0.0968	$ 0.0888
Winter			
Peak	$ 0.1688	$ 0.1560	$ 0.1432
Off-Peak	$ 0.1337	$ 0.1236	$ 0.1134
E-EV			
Summer			
Peak	$ 0.2917	$ 0.3275	$ 0.3634
Part-Peak	$ 0.1482	$ 0.1664	$ 0.1846
Off-Peak	$ 0.1018	$ 0.1143	$ 0.1269
Winter			
Peak	$ 0.0978	$ 0.1098	$ 0.1218
Part-Peak	$ 0.0729	$ 0.0819	$ 0.0908
Off-Peak	$ 0.0729	$ 0.0819	$ 0.0908
E-EV-2			
Summer			
Peak	$ 0.1977	$ 0.1871	$ 0.1764
Part-Peak	$ 0.1530	$ 0.1448	$ 0.1365
Off-Peak	$ 0.1119	$ 0.1059	$ 0.0998
Winter			
Peak	$ 0.1409	$ 0.1333	$ 0.1257
Part-Peak	$ 0.1284	$ 0.1215	$ 0.1146
Off-Peak	$ 0.1049	$ 0.0993	$ 0.0936

Small General Service			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
B1			
Summer			
Peak	$ 0.1881	$ 0.1650	$ 0.1419
Part-Peak	$ 0.1389	$ 0.1218	$ 0.1047
Off-Peak	$ 0.1181	$ 0.1036	$ 0.0890
Winter			
Peak	$ 0.1329	$ 0.1165	$ 0.1002
Off-Peak	$ 0.1168	$ 0.1024	$ 0.0880
Super Off-Peak	$ 0.1003	$ 0.0880	$ 0.0757
B-6			
Summer			
Peak	$ 0.1903	$ 0.1703	$ 0.1503
Off-Peak	$ 0.1191	$ 0.1066	$ 0.0941
Winter			
Peak	$ 0.1268	$ 0.1134	$ 0.1001
Off-Peak	$ 0.1097	$ 0.0982	$ 0.0866
Super Off-Peak	$ 0.0933	$ 0.0835	$ 0.0737
A-1-A			
Summer	$ 0.1440	$ 0.1291	$ 0.1142
Winter	$ 0.1038	$ 0.0931	$ 0.0823
A-1-B			
Summer			
Peak	$ 0.1473	$ 0.1339	$ 0.1205
Part-Peak	$ 0.1473	$ 0.1339	$ 0.1205
Off-Peak	$ 0.1225	$ 0.1114	$ 0.1003
Winter			
Part-Peak	$ 0.1165	$ 0.1059	$ 0.0953
Off-Peak	$ 0.1159	$ 0.1054	$ 0.0949
A-6			
Summer			
Peak	$ 0.2100	$ 0.1861	$ 0.1622
Part-Peak	$ 0.1607	$ 0.1424	$ 0.1240
Off-Peak	$ 0.1285	$ 0.1139	$ 0.0992
Winter			
Part-Peak	$ 0.1192	$ 0.1056	$ 0.0920
Off-Peak	$ 0.1184	$ 0.1049	$ 0.0914
BEV-1			
Peak	$ 0.2761	$ 0.2295	$ 0.1830
Off-Peak	$ 0.0935	$ 0.0777	$ 0.0620
Super Off-Peak	$ 0.0681	$ 0.0566	$ 0.0451
B-1-ST			
Summer			
Peak	$ 0.1928	$ 0.1791	$ 0.1474
Off-Peak	$ 0.1504	$ 0.1397	$ 0.1149
Super Off-Peak	$ 0.1146	$ 0.1065	$ 0.0876
Winter			
Peak	$ 0.1423	$ 0.1321	$ 0.1087
Part Peak	$ 0.1299	$ 0.1207	$ 0.0993
Off-Peak	$ 0.1079	$ 0.1002	$ 0.0825
Super Off-Peak	$ 0.0915	$ 0.0850	$ 0.0699

Medium General Service - Low Demand			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
B-10			
Summer			
Peak			
Secondary	$ 0.2153	$ 0.1808	$ 0.1463
Primary	$ 0.1979	$ 0.1662	$ 0.1345
Transmission	$ 0.1736	$ 0.1458	$ 0.1180
Part-Peak			
Secondary	$ 0.1536	$ 0.1290	$ 0.1044
Primary	$ 0.1396	$ 0.1172	$ 0.0948
Transmission	$ 0.1169	$ 0.0982	$ 0.0795
Off-Peak			
Secondary	$ 0.1210	$ 0.1016	$ 0.0822
Primary	$ 0.1087	$ 0.0913	$ 0.0739
Transmission	$ 0.0868	$ 0.0729	$ 0.0590
Winter			
Peak			
Secondary	$ 0.1572	$ 0.1320	$ 0.1069
Primary	$ 0.1432	$ 0.1203	$ 0.0973
Transmission	$ 0.1206	$ 0.1013	$ 0.0820
Off-Peak			
Secondary	$ 0.1217	$ 0.1022	$ 0.0827
Primary	$ 0.1096	$ 0.0920	$ 0.0745
Transmission	$ 0.0878	$ 0.0737	$ 0.0596
Super Off-Peak			
Secondary	$ 0.0854	$ 0.0717	$ 0.0580
Primary	$ 0.0732	$ 0.0615	$ 0.0498
Transmission	$ 0.0514	$ 0.0432	$ 0.0349
A-10-A			
Summer			
Secondary	$ 0.1454	$ 0.1235	$ 0.1015
Primary	$ 0.1290	$ 0.1096	$ 0.0901
Transmission	$ 0.1089	$ 0.0925	$ 0.0761
Winter			
Secondary	$ 0.1237	$ 0.1050	$ 0.0863
Primary	$ 0.1102	$ 0.0936	$ 0.0769
Transmission	$ 0.0918	$ 0.0780	$ 0.0641
A-10-B			
Summer			
Peak			
Secondary	$ 0.1589	$ 0.1371	$ 0.1152
Primary	$ 0.1429	$ 0.1233	$ 0.1037
Transmission	$ 0.1241	$ 0.1070	$ 0.0900
Part-Peak			
Secondary	$ 0.1589	$ 0.1371	$ 0.1152
Primary	$ 0.1429	$ 0.1233	$ 0.1037
Transmission	$ 0.1241	$ 0.1070	$ 0.0900
Off-Peak			
Secondary	$ 0.1321	$ 0.1140	$ 0.0958
Primary	$ 0.1176	$ 0.1015	$ 0.0853
Transmission	$ 0.0994	$ 0.0858	$ 0.0721
Winter			
Part-Peak			
Secondary	$ 0.1243	$ 0.1072	$ 0.0901
Primary	$ 0.1102	$ 0.0951	$ 0.0799
Transmission	$ 0.0922	$ 0.0795	$ 0.0669
Off-Peak			
Secondary	$ 0.1236	$ 0.1066	$ 0.0896
Primary	$ 0.1095	$ 0.0945	$ 0.0794
Transmission	$ 0.0916	$ 0.0790	$ 0.0664

A-15			
Summer	$ 0.1392	$ 0.1190	$ 0.0988
Winter	$ 0.1188	$ 0.1016	$ 0.0843
BEV-2 Secondary			
Peak	$ 0.2931	$ 0.2434	$ 0.1937
Off-Peak	$ 0.0898	$ 0.0745	$ 0.0593
Super Off-Peak	$ 0.0644	$ 0.0535	$ 0.0425
BEV-2 Primary			
Peak	$ 0.2828	$ 0.2348	$ 0.1868
Off-Peak	$ 0.0868	$ 0.0721	$ 0.0573
Super Off-Peak	$ 0.0626	$ 0.0520	$ 0.0413

Medium General Service - High Demand			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
B-19			
Summer			
Peak - Demand			
Secondary	$ 18.85	$ 21.22	$ 23.58
Primary	$ 16.15	$ 18.18	$ 20.20
Transmission	$ 12.72	$ 14.32	$ 15.91
Part-Peak Demand			
Secondary	$ 2.74	$ 3.08	$ 3.43
Primary	$ 2.36	$ 2.66	$ 2.95
Transmission	$ 3.18	$ 3.58	$ 3.98
Peak - Energy			
Secondary	$ 0.1555	$ 0.1285	$ 0.1014
Primary	$ 0.1359	$ 0.1123	$ 0.0887
Transmission	$ 0.1234	$ 0.1020	$ 0.0805
Part-Peak - Energy			
Secondary	$ 0.1179	$ 0.0974	$ 0.0769
Primary	$ 0.1073	$ 0.0886	$ 0.0700
Transmission	$ 0.1114	$ 0.0920	$ 0.0727
Off-Peak - Energy			
Secondary	$ 0.0913	$ 0.0754	$ 0.0595
Primary	$ 0.0824	$ 0.0680	$ 0.0537
Transmission	$ 0.0857	$ 0.0708	$ 0.0559
Winter			
Peak - Demand			
Secondary	$ 2.24	$ 2.52	$ 2.80
Primary	$ 1.65	$ 1.86	$ 2.06
Transmission	$ 1.22	$ 1.37	$ 1.53
Peak - Energy			
Secondary	$ 0.1316	$ 0.1087	$ 0.0858
Primary	$ 0.1204	$ 0.0995	$ 0.0785
Transmission	$ 0.1250	$ 0.1033	$ 0.0816
Off-Peak - Energy			
Secondary	$ 0.0912	$ 0.0753	$ 0.0595
Primary	$ 0.0825	$ 0.0682	$ 0.0538
Transmission	$ 0.0861	$ 0.0711	$ 0.0561
Super Off-Peak - Energy			
Secondary	$ 0.0369	$ 0.0305	$ 0.0241
Primary	$ 0.0287	$ 0.0237	$ 0.0187
Transmission	$ 0.0288	$ 0.0238	$ 0.0188
B-19-R			
Summer			
Peak - Energy			
Secondary	$ 0.2806	$ 0.2450	$ 0.2095
Primary	$ 0.2569	$ 0.2244	$ 0.1918
Transmission	$ 0.2236	$ 0.1953	$ 0.1670
Part-Peak - Energy			
Secondary	$ 0.1450	$ 0.1266	$ 0.1083
Primary	$ 0.1334	$ 0.1165	$ 0.0996
Transmission	$ 0.1421	$ 0.1241	$ 0.1061
Off-Peak - Energy			
Secondary	$ 0.1065	$ 0.0930	$ 0.0795
Primary	$ 0.0980	$ 0.0856	$ 0.0732
Transmission	$ 0.1000	$ 0.0873	$ 0.0746
Winter			
Peak - Energy			
Secondary	$ 0.1488	$ 0.1299	$ 0.1111
Primary	$ 0.1358	$ 0.1186	$ 0.1014
Transmission	$ 0.1339	$ 0.1169	$ 0.0999
Off-Peak - Energy			
Secondary	$ 0.1064	$ 0.0930	$ 0.0795
Primary	$ 0.0981	$ 0.0857	$ 0.0733
Transmission	$ 0.1002	$ 0.0875	$ 0.0748
Super Off-Peak - Energy			
Secondary	$ 0.0706	$ 0.0617	$ 0.0527
Primary	$ 0.0623	$ 0.0544	$ 0.0465
Transmission	$ 0.0644	$ 0.0562	$ 0.0481

E-19						
Summer						
Peak - Demand						
Secondary	$	12.31	$	10.87	$	9.43
Primary	$	10.68	$	9.43	$	8.18
Transmission	$	11.80	$	10.42	$	9.04
Part-Park - Demand						
Secondary	$	12.31	$	10.87	$	9.43
Primary	$	10.68	$	9.43	$	8.18
Transmission	$	11.80	$	10.42	$	9.04
Peak - Energy						
Secondary	$	0.0991	$	0.0863	$	0.0736
Primary	$	0.0871	$	0.0759	$	0.0647
Transmission	$	0.0777	$	0.0677	$	0.0577
Part-Peak - Energy						
Secondary	$	0.0991	$	0.0863	$	0.0736
Primary	$	0.0871	$	0.0759	$	0.0647
Transmission	$	0.0777	$	0.0677	$	0.0577
Off-Peak - Energy						
Secondary	$	0.0931	$	0.0811	$	0.0692
Primary	$	0.0813	$	0.0709	$	0.0604
Transmission	$	0.0720	$	0.0628	$	0.0535
Winter						
Part-Peak - Energy						
Secondary	$	0.0905	$	0.0789	$	0.0672
Primary	$	0.0789	$	0.0687	$	0.0586
Transmission	$	0.0696	$	0.0607	$	0.0517
Off-Peak - Energy						
Secondary	$	0.0898	$	0.0782	$	0.0667
Primary	$	0.0782	$	0.0682	$	0.0581
Transmission	$	0.0689	$	0.0601	$	0.0512

Large General Service			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
B-20			
Summer			
Peak - Demand			
Secondary	$ 18.32	$ 20.70	$ 23.08
Primary	$ 20.19	$ 22.81	$ 25.44
Transmission	$ 22.85	$ 25.82	$ 28.79
Part-Peak Demand			
Secondary	$ 2.66	$ 3.01	$ 3.35
Primary	$ 2.77	$ 3.13	$ 3.49
Transmission	$ 5.44	$ 6.15	$ 6.85
Peak - Energy			
Secondary	$ 0.1476	$ 0.1177	$ 0.0878
Primary	$ 0.1439	$ 0.1148	$ 0.0856
Transmission	$ 0.1211	$ 0.0965	$ 0.0720
Part-Peak - Energy			
Secondary	$ 0.1139	$ 0.0908	$ 0.0677
Primary	$ 0.1081	$ 0.0862	$ 0.0643
Transmission	$ 0.0989	$ 0.0789	$ 0.0588
Off-Peak - Energy			
Secondary	$ 0.0872	$ 0.0695	$ 0.0519
Primary	$ 0.0831	$ 0.0662	$ 0.0494
Transmission	$ 0.0743	$ 0.0592	$ 0.0442
Winter			
Peak - Demand			
Secondary	$ 2.34	$ 2.64	$ 2.95
Primary	$ 2.32	$ 2.62	$ 2.92
Transmission	$ 3.05	$ 3.45	$ 3.84
Peak - Energy			
Secondary	$ 0.1275	$ 0.1016	$ 0.0758
Primary	$ 0.1211	$ 0.0966	$ 0.0720
Transmission	$ 0.1200	$ 0.0957	$ 0.0713
Off-Peak - Energy			
Secondary	$ 0.0870	$ 0.0694	$ 0.0517
Primary	$ 0.0831	$ 0.0663	$ 0.0494
Transmission	$ 0.0698	$ 0.0556	$ 0.0415
Super Off-Peak - Energy			
Secondary	$ 0.0328	$ 0.0261	$ 0.0195
Primary	$ 0.0292	$ 0.0233	$ 0.0174
Transmission	$ 0.0196	$ 0.0157	$ 0.0117

E20						
Summer						
Peak - Demand						
Secondary	$	11.80	$	10.37	$	8.94
Primary	$	12.61	$	11.08	$	9.56
Transmission	$	15.02	$	13.20	$	11.38
Part-Park - Demand						
Secondary	$	11.80	$	10.37	$	8.94
Primary	$	12.61	$	11.08	$	9.56
Transmission	$	15.02	$	13.20	$	11.38
Peak - Energy						
Secondary	$	0.0943	$	0.0792	$	0.0641
Primary	$	0.0910	$	0.0765	$	0.0619
Transmission	$	0.0782	$	0.0657	$	0.0532
Part-Peak - Energy						
Secondary	$	0.0943	$	0.0792	$	0.0641
Primary	$	0.0910	$	0.0765	$	0.0619
Transmission	$	0.0782	$	0.0657	$	0.0532
Off-Peak - Energy						
Secondary	$	0.0884	$	0.0742	$	0.0601
Primary	$	0.0853	$	0.0716	$	0.0580
Transmission	$	0.0725	$	0.0609	$	0.0493
Winter						
Part-Peak - Energy						
Secondary	$	0.0858	$	0.0721	$	0.0583
Primary	$	0.0828	$	0.0695	$	0.0563
Transmission	$	0.0701	$	0.0589	$	0.0477
Off-Peak - Energy						
Secondary	$	0.0851	$	0.0715	$	0.0578
Primary	$	0.0821	$	0.0690	$	0.0558
Transmission	$	0.0694	$	0.0583	$	0.0472

Rate Code	Current Rate	FY23 Rate	FY24 Rate
B-ST			
Summer			
Peak - Energy			
Secondary	$ 0.1354	$ 0.1137	$ 0.0920
Primary	$ 0.1354	$ 0.1137	$ 0.0920
Transmission	$ 0.1175	$ 0.0987	$ 0.0799
Part-Peak - Energy			
Secondary	$ 0.1196	$ 0.1005	$ 0.0813
Primary	$ 0.1196	$ 0.1005	$ 0.0813
Transmission	$ 0.1024	$ 0.0860	$ 0.0696
Off-Peak - Energy			
Secondary	$ 0.1021	$ 0.0858	$ 0.0694
Primary	$ 0.1021	$ 0.0858	$ 0.0694
Transmission	$ 0.0855	$ 0.0718	$ 0.0581
Winter			
Peak - Energy			
Secondary	$ 0.1291	$ 0.1084	$ 0.0878
Primary	$ 0.1291	$ 0.1084	$ 0.0878
Transmission	$ 0.1116	$ 0.0937	$ 0.0759
Off-Peak - Energy			
Secondary	$ 0.1036	$ 0.0870	$ 0.0704
Primary	$ 0.1036	$ 0.0870	$ 0.0704
Transmission	$ 0.0871	$ 0.0732	$ 0.0592
Super Off-Peak - Energy			
Secondary	$ 0.0471	$ 0.0395	$ 0.0320
Primary	$ 0.0471	$ 0.0395	$ 0.0320
Transmission	$ 0.0311	$ 0.0261	$ 0.0212
Reservation Charge			
Secondary	$ 0.4000	$ 0.4000	$ 0.4000
Primary	$ 0.4000	$ 0.4000	$ 0.4000
Transmission	$ 0.2300	$ 0.2300	$ 0.2300

Agriculture Tariff			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
AG-A			
Summer			
Peak	$ 0.2369	$ 0.2179	$ 0.1989
Off-Peak	$ 0.1172	$ 0.1078	$ 0.0984
Winter			
Peak	$ 0.1139	$ 0.1048	$ 0.0956
Off-Peak	$ 0.0874	$ 0.0804	$ 0.0734
AG-B			
Summer			
Peak	$ 0.2546	$ 0.2194	$ 0.1842
Off-Peak	$ 0.1315	$ 0.1133	$ 0.0951
Winter			
Peak	$ 0.1262	$ 0.1087	$ 0.0913
Off-Peak	$ 0.1000	$ 0.0861	$ 0.0723
AG-C			
Summer			
Peak - Demand	$ 15.38	$ 12.31	$ 9.25
Peak - Energy	$ 0.1173	$ 0.1000	$ 0.0827
Off-Peak	$ 0.0878	$ 0.0748	$ 0.0619
Winter			
Peak	$ 0.1026	$ 0.0875	$ 0.0724
Off-Peak	$ 0.0771	$ 0.0657	$ 0.0544
AG-5-A			
Max Demand	$ 5.51	$ 7.97	$ 10.43
Summer			
Peak	$ 0.1211	$ 0.1154	$ 0.1097
Off-Peak	$ 0.1023	$ 0.0975	$ 0.0927
Winter			
Part-Peak	$ 0.0933	$ 0.0889	$ 0.0846
Off-Peak	$ 0.0926	$ 0.0883	$ 0.0839
AG-5-B-S			
Max Demand	$ 6.99	$ 10.11	$ 13.23
Summer			
Peak - Demand	$ 2.1800	$ 3.1533	$ 4.1266
Peak - Energy	$ 0.1149	$ 0.0945	$ 0.0742
Off-Peak	$ 0.0907	$ 0.0747	$ 0.0586
Winter			
Part-Peak	$ 0.0868	$ 0.0715	$ 0.0561
Off-Peak	$ 0.0861	$ 0.0709	$ 0.0556
AG-5-B-P			
Max Demand	$ 4.79	$ 6.93	$ 9.07
Summer			
Peak - Demand	$ 2.1800	$ 3.1533	$ 4.1266
Peak - Energy	$ 0.1149	$ 0.0945	$ 0.0742
Off-Peak	$ 0.0907	$ 0.0747	$ 0.0586
Winter			
Part-Peak	$ 0.0868	$ 0.0715	$ 0.0561
Off-Peak	$ 0.0861	$ 0.0709	$ 0.0556
AG-5-B-T			
Max Demand	$ 3.18	$ 4.60	$ 6.02
Summer			
Peak - Demand	$ 2.1800	$ 3.1533	$ 4.1266
Peak - Energy	$ 0.1149	$ 0.0945	$ 0.0742
Off-Peak	$ 0.0907	$ 0.0747	$ 0.0586
Winter			
Part-Peak	$ 0.0868	$ 0.0715	$ 0.0561
Off-Peak	$ 0.0861	$ 0.0709	$ 0.0556

AG-5-C-S			
Summer			
Peak - Demand	$ 9.79	$ 10.12	$ 10.46
Part-Peak - Demand	$ 7.82	$ 8.09	$ 8.35
Peak - Energy	$ 0.0894	$ 0.0798	$ 0.0701
Part-Peak - Energy	$ 0.0768	$ 0.0685	$ 0.0602
Off-Peak	$ 0.0721	$ 0.0643	$ 0.0565
Winter			
Part-Peak	$ 0.0741	$ 0.0661	$ 0.0581
Off-Peak	$ 0.0734	$ 0.0654	$ 0.0575
AG-5-C-P			
Summer			
Peak - Demand	$ 8.98	$ 9.29	$ 9.59
Part-Peak - Demand	$ 7.82	$ 8.09	$ 8.35
Peak - Energy	$ 0.0894	$ 0.0798	$ 0.0701
Part-Peak - Energy	$ 0.0768	$ 0.0685	$ 0.0602
Off-Peak	$ 0.0721	$ 0.0643	$ 0.0565
Winter			
Part-Peak	$ 0.0741	$ 0.0661	$ 0.0581
Off-Peak	$ 0.0734	$ 0.0654	$ 0.0575
AG-5-C-T			
Summer			
Peak - Demand	$ 8.28	$ 8.56	$ 8.84
Part-Peak - Demand	$ 7.82	$ 8.09	$ 8.35
Peak - Energy	$ 0.0894	$ 0.0798	$ 0.0701
Part-Peak - Energy	$ 0.0768	$ 0.0685	$ 0.0602
Off-Peak	$ 0.0721	$ 0.0643	$ 0.0565
Winter			
Part-Peak	$ 0.0741	$ 0.0661	$ 0.0581
Off-Peak	$ 0.0734	$ 0.0654	$ 0.0575

Lighting			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
LS-1			
Energy Charge	$ 0.1038	$ 0.1042	$ 0.1045
TC-1			
Energy Charge	$ 0.1143	$ 0.1098	$ 0.1053

Other Rates			
Rate Code	Current Rate	FY23 Rate	FY24 Rate
S-EM			
Reservation Charge	0.61	$ 0.61	$ 0.61
All-Hours	0.13	$ 0.12	$ 0.11
S-B-S			
Summer			
Peak	$ 0.14310	$ 0.15205	$ 0.16099
Part-Peak	$ 0.11807	$ 0.12545	$ 0.13283
Off-Peak	$ 0.08530	$ 0.09063	$ 0.09597
Reservation	$ 0.61	$ 0.61	$ 0.61
Winter			
Peak	$ -	$ -	$ -
Off-Peak	$ 0.12206	$ 0.12969	$ 0.13732
Super Off-Peak	$ 0.09667	$ 0.10271	$ 0.10876
Reservation	$ 0.61	$ 0.61	$ 0.61
S-B-P			
Summer			
Peak	$ 0.14310	$ 0.15205	$ 0.16099
Part-Peak	$ 0.11807	$ 0.12545	$ 0.13283
Off-Peak	$ 0.08530	$ 0.09063	$ 0.09597
Reservation	$ 0.61	$ 0.61	$ 0.61
Winter			
Peak	$ -	$ -	$ -
Off-Peak	$ 0.12206	$ 0.12969	$ 0.13732
Super Off-Peak	$ 0.09667	$ 0.10271	$ 0.10876
Reservation	$ 0.61	$ 0.61	$ 0.61
S-B-T			
Summer			
Peak	$ 0.11380	$ 0.13794	$ 0.16208
Part-Peak	$ 0.09364	$ 0.11350	$ 0.13337
Off-Peak	$ 0.06696	$ 0.08116	$ 0.09537
Reservation	$ 0.49	$ 0.49	$ 0.49
Winter			
Peak	$ -	$ -	$ -
Off-Peak	$ 0.09681	$ 0.11735	$ 0.13788
Super Off-Peak	$ 0.07632	$ 0.09251	$ 0.10870
Reservation	$ 0.49	$ 0.49	$ 0.49
E-19-R-S			
Summer			
Peak	$ 0.16769	$ 0.14665	$ 0.12561
Part-Peak	$ 0.15032	$ 0.13146	$ 0.11260
Off-Peak	$ 0.12101	$ 0.10583	$ 0.09065
Winter			
Part-Peak	$ 0.11842	$ 0.10356	$ 0.08871
Off-Peak	$ 0.11771	$ 0.10294	$ 0.08817
E-19-R-P			
Summer			
Peak	$ 0.15117	$ 0.13810	$ 0.12503
Part-Peak	$ 0.13573	$ 0.12400	$ 0.11226
Off-Peak	$ 0.10977	$ 0.10028	$ 0.09079
Winter			
Part-Peak	$ 0.10730	$ 0.09802	$ 0.08875
Off-Peak	$ 0.10663	$ 0.09741	$ 0.08819

E-19-R-T						
Summer						
Peak	$	0.14637	$	0.13373	$	0.12109
Part-Peak	$	0.13277	$	0.12131	$	0.10984
Off-Peak	$	0.11007	$	0.10057	$	0.09106
Winter						
Part-Peak	$	0.10764	$	0.09835	$	0.08905
Off-Peak	$	0.10698	$	0.09774	$	0.08850
B-20-R-S						
Summer						
Peak	$	0.26786	$	0.23404	$	0.20021
Part-Peak	$	0.13511	$	0.11805	$	0.10099
Off-Peak	$	0.09765	$	0.08532	$	0.07299
Winter						
Peak	$	0.09751	$	0.08520	$	0.07288
Off-Peak	$	0.06176	$	0.05396	$	0.04616
Super Off-Peak	$	0.11341	$	0.09909	$	0.08477
B-20-R-P						
Summer						
Peak	$	0.25889	$	0.22911	$	0.19933
Part-Peak	$	0.13000	$	0.11505	$	0.10009
Off-Peak	$	0.09529	$	0.08433	$	0.07337
Winter						
Peak	$	0.13541	$	0.11983	$	0.10426
Off-Peak	$	0.09534	$	0.08437	$	0.07341
Super Off-Peak	$	0.05959	$	0.05274	$	0.04588
B-20-R-T						
Summer						
Peak	$	0.25785	$	0.23245	$	0.20706
Part-Peak	$	0.13922	$	0.12551	$	0.11180
Off-Peak	$	0.08897	$	0.08021	$	0.07144
Winter						
Peak	$	0.13907	$	0.12537	$	0.11168
Off-Peak	$	0.08605	$	0.07757	$	0.06910
Super Off-Peak	$	0.05325	$	0.04801	$	0.04276
E-20-R-S						
Summer						
Peak	$	0.15215	$	0.13500	$	0.11786
Part-Peak	$	0.13718	$	0.12172	$	0.10626
Off-Peak	$	0.11014	$	0.09773	$	0.08532
Winter						
Part-Peak	$	0.10755	$	0.09543	$	0.08331
Off-Peak	$	0.10684	$	0.09480	$	0.08276
E-20-R-P						
Summer						
Peak	$	0.15303	$	0.13694	$	0.12085
Part-Peak	$	0.13556	$	0.12131	$	0.10706
Off-Peak	$	0.10782	$	0.09648	$	0.08515
Winter						
Part-Peak	$	0.10535	$	0.09427	$	0.08320
Off-Peak	$	0.10468	$	0.09367	$	0.08267
E-20-R-T						
Summer						
Peak	$	0.14750	$	0.13493	$	0.12236
Part-Peak	$	0.13006	$	0.11898	$	0.10789
Off-Peak	$	0.10264	$	0.09389	$	0.08514
Winter						
Part-Peak	$	0.10021	$	0.09167	$	0.08313
Off-Peak	$	0.09955	$	0.09107	$	0.08258

AG-F-A			
Summer			
Peak	$ 0.20244	$ 0.18523	$ 0.16802
Off-Peak	$ 0.12530	$ 0.11465	$ 0.10400
Winter			
Peak	$ 0.11510	$ 0.10532	$ 0.09553
Off-Peak	$ 0.08865	$ 0.08111	$ 0.07358
AG-F-B			
Summer			
Peak	$ 0.22189	$ 0.19008	$ 0.15826
Off-Peak	$ 0.14058	$ 0.12042	$ 0.10027
Winter			
Peak	$ 0.12852	$ 0.11009	$ 0.09167
Off-Peak	$ 0.10207	$ 0.08744	$ 0.07280
AG-F-C			
Summer			
Max Demand	$ 15.38	$ 12.31	$ 9.25
Peak	$ 0.13802	$ 0.11086	$ 0.08370
Off-Peak	$ 0.10801	$ 0.08675	$ 0.06550
Winter			
Peak	$ 0.12360	$ 0.09928	$ 0.07495
Off-Peak	$ 0.09715	$ 0.07803	$ 0.05891
AG-1-A			
Summer			
Connected Load	$ 2.54	$ 2.54	$ 2.54
All Hours	$ 0.10106	$ 0.09748	$ 0.09390
Winter			
All Hours	$ 0.08775	$ 0.08464	$ 0.08154
AG-1-B			
Summer			
Max Demand	$ 3.97	$ 6.61	$ 9.25
All Hours	$ 0.11301	$ 0.09562	$ 0.07822
Winter			
All Hours	$ 0.08052	$ 0.06813	$ 0.05573
AG-1-B-P			
Summer			
Max Demand	3.97	$ 6.61	$ 9.25
All Hours	$ 0.11301	$ 0.09562	$ 0.07822
Winter			
All Hours	$ 0.08052	$ 0.06813	$ 0.05573
AG-4-A			
Summer			
Connected Load	$ 2.00	$ 2.00	$ 2.00
Peak	$ 0.11905	$ 0.11892	$ 0.11879
Off-Peak	$ 0.09647	$ 0.09637	$ 0.09626
Winter			
Part-Peak	$ 0.08541	$ 0.08532	$ 0.08523
Off-Peak	$ 0.08470	$ 0.08461	$ 0.08452
AG-4-B			
Summer			
Peak - Demand	$ 0.98	$ 1.52	$ 2.06
All Hours - Demand	$ 3.64	$ 5.64	$ 7.64
Peak	$ 0.11842	$ 0.09635	$ 0.07428
Off-Peak	$ 0.10566	$ 0.08597	$ 0.06628
Winter			
Part-Peak	$ 0.09667	$ 0.07865	$ 0.06064
Off-Peak	$ 0.09598	$ 0.07809	$ 0.06021

AG-4-B-P						
Summer						
Peak - Demand	$	0.98	$	1.78	$	2.59
All Hours - Demand	$	2.74	$	4.99	$	7.23
Peak	$	0.11842	$	0.09635	$	0.07428
Off-Peak	$	0.10566	$	0.08597	$	0.06628
Winter						
Part-Peak	$	0.09667	$	0.07865	$	0.06064
Off-Peak	$	0.09598	$	0.07809	$	0.06021
AG-4-C						
Summer						
Peak - Demand	$	4.83	$	7.82	$	10.80
Part-Peak - Demand	$	3.62	$	5.86	$	8.10
Peak	$	0.09529	$	0.08766	$	0.08002
Part-Peak	$	0.08018	$	0.07376	$	0.06733
Off-Peak	$	0.07468	$	0.06870	$	0.06272
Winter						
Part-Peak	$	0.07480	$	0.06881	$	0.06282
Off-Peak	$	0.07409	$	0.06815	$	0.06222
AG-4-C-P						
Summer						
Peak - Demand	$	4.45	$	7.40	$	10.36
Part-Peak - Demand	$	3.62	$	6.02	$	8.43
Peak	$	0.09529	$	0.08766	$	0.08002
Part-Peak	$	0.08018	$	0.07376	$	0.06733
Off-Peak	$	0.07468	$	0.06870	$	0.06272
Winter						
Part-Peak	$	0.07480	$	0.06881	$	0.06282
Off-Peak	$	0.07409	$	0.06815	$	0.06222
AG-4-C-T						
Summer						
Peak - Demand	$	4.15	$	7.06	$	9.98
Part-Peak - Demand	$	3.62	$	6.16	$	8.71
Peak	$	0.09529	$	0.08766	$	0.08002
Part-Peak	$	0.08018	$	0.07376	$	0.06733
Off-Peak	$	0.07468	$	0.06870	$	0.06272
Winter						
Part-Peak	$	0.07480	$	0.06881	$	0.06282
Off-Peak	$	0.07409	$	0.06815	$	0.06222

APPENDIX C: TECHNICAL APPENDIX

MAY 11, 2022

2022 POWER RATES STUDY FINAL REPORT

Technical Appendix:
https://www.sfpuc.org/sites/default/files/accounts-and-services/PowerRatesStudyAppC_2022.pdf

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