Application: 24-02-012
(U 39 E)
Exhibit No.: ____________
Date: May 31, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

APPLICATION FOR COMPLIANCE REVIEW OF UTILITY-OWNED GENERATION OPERATIONS, PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES, ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES, CONTRACT ADMINISTRATION, ECONOMIC DISPATCH OF ELECTRIC RESOURCES, UTILITY-OWNED GENERATION FUEL PROCUREMENT, AND OTHER ACTIVITIES FOR THE PERIOD JANUARY 1 THROUGH DECEMBER 31, 2023

AMENDED TESTIMONY

PUBLIC VERSION

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UTILITY-OWNED GENERATION: HYDROELECTRIC

A. Introduction

In compliance with Decision (D.) 14-01-011, this chapter addresses the operation of Pacific Gas and Electric Company's (PG&E or the Company) utility-owned hydroelectric facilities, and outages that occurred at these facilities during the 2023 record year.

PG&E's utility-owned hydroelectric portfolio was operated in a reasonable manner during the record period. At year-end 2023 PG&E's hydro-generating portfolio consisted of 61 powerhouses with 99 generating units. The system operates under 21 Federal Energy Regulatory Commission (FERC) licenses, which govern the operation of 95 of the generating units at 59 powerhouses. Four generating units are at two non-FERC jurisdictional powerhouses. PG&E's hydro-generating portfolio has an aggregate nameplate capacity of 3,845 megawatts (MW) and produces an average of about 10 terawatt-hours of energy in a normal precipitation year.

PG&E's 61 hydro powerhouses are located on 13 rivers and four tributaries of the Sierra Nevada, Cascade and Coastal Mountain ranges. This is a unique set of facilities that was built between 1900 and 1986. Most of the dams and powerhouses have been in service for well over 50 years, and some of the water collection and transport systems were used for gold mining and consumptive water prior to the development of the hydro-generating facilities.

The system collectively includes the following ancillary support facilities: 97 reservoirs, 69 diversions, 165 dams, over 400 miles of water conveyance (canals, flumes, penstocks, siphons, tunnels, low head pipes, and natural waterways), and approximately 140,000 acres of fee-owned land. It also includes switchyards, switching centers that remotely control generation facilities, administrative buildings, fleet, multiple modes of communication, materials and supplies inventories, office equipment, and other miscellaneous instrumentation and monitoring equipment. PG&E's authority to divert and store water for Power Generation (PG) is based on 87 water right licenses or interim permits, and 147 Statements of Water Diversion and Use.

PG&E's hydro plants produce low cost and clean energy, high value ancillary services and peaking capacity to meet customers' needs. PG&E has demonstrated its ability to optimize these generation facilities through efficient use of water resources and continuing environmental stewardship.

PG&E's system of dams, reservoirs, and water collection facilities enables PG&E to store runoff and aquifer flows and then subsequently use the water to generate power when customers need it most. This "shaping" of the available generation is performed both seasonally (for example, by storing more water in the spring and releasing water from the reservoirs during high value hot summer days) and day-to-day (for example, generating more during hours of peak system demand—typically weekday late-afternoons and evenings—and less at night and on weekends). In general, the highest value of PG&E-owned generation is likely to be when demand is greatest and intermittent renewables are not available, and hydro generation can contribute significantly toward offsetting the cost of power purchased for PG&E bundled customers during higher priced hours.

Hydroelectric generating units typically start up quickly, have fast ramp rates, and can easily, quickly, and economically vary output in response to changing customer loads and system conditions. In addition, hydro-generating units can operate at no load or low load with much higher efficiency than the alternative fossil fueled peaking plants. Finally, because a large portion of California's non fossil-fueled electricity resources consist of non-dispatchable energy sources such as wind, solar, nuclear, and regulatory "must-take" generation, the California Independent System Operator (CAISO) relies on PG&E's hydro resources to satisfy a significant portion of its operating reserve requirements.

B. Overview of PG&E's Hydroelectric System

1. Hydro System Characteristics

Hydroelectric generation converts the potential energy contained in falling water to electricity. In general, water from precipitation runoff and aquifer flows is collected at a high elevation and through various water collection, storage and conveyance systems is delivered to the powerhouse penstock where it drops to the powerhouse elevation. The water, under pressure from the elevation drop, is directed through or against the turbine runner causing the turbine and coupled generator to rotate and produce electricity. The major system components consist of:

- Water Collection Facilities – Reservoirs and dams including stream diversions;
- Water Conveyance Facilities – Tunnels, canals, flumes, natural waterways, conduits, and penstocks utilized to direct the water from collection points to the powerhouse;
- Powerhouses – Structures containing the turbines, generators and associated equipment used to produce electricity; and
- Auxiliary Equipment – Transmission lines and associated switchyard equipment to transmit the electricity to the grid.

PG&E's hydro-generation portfolio can be segregated into three categories based on the characteristics of the water supply to the powerhouse:

- Run-of-the-River Powerhouses – These powerhouses generally have little or no water storage facilities and rely on stream/river diversions, with small impoundments, to direct the water into the water conveyance system. The powerhouse is operated based on the flow available to be diverted from the river. Once diverted, the water travels through various water conveyance facilities, such as canals, flumes, tunnels, natural waterways, and conduits to the penstock;
- Reservoir Storage Powerhouses – Powerhouses that have significant water storage facilities are not limited to run based on the available river flow but can store runoff and aquifer flows and then subsequently use the water to generate power when customers need it most. Generally, these powerhouses have less water conveyance assets either because they are located close to the dams or have a single large tunnel delivering water to the penstock(s). Because of their large impoundments and hydro's ability to quickly come online and ramp up to full capacity, these powerhouses can be used for peaking during high demand power periods; and
- Pumped Storage Powerhouse – PG&E has one pumped storage powerhouse, Helms Pumped Storage Facility (Helms). Helms is a

reservoir storage powerhouse, situated between an upper reservoir, Courtright Lake, and a lower reservoir, Lake Wishon, with three generators that can be reversed to act as pumps. During hours when energy prices are lower, the pumping mode is utilized to pump water back up to Courtright Lake to be reused during the next cycle. The ability to pump the water back up to the storage reservoir allows the water resource to be reused during peak demand hours. Helms also provides renewable integration benefits such as regulation up and down, load following, operating reserves (backup), shaping, and management of system over-generation conditions that result from excess renewables generation during off-peak and partial-peak periods.

2. Hydro Operations and Maintenance Organization

PG&E's PG organization is responsible for managing the hydro-generating portfolio. The Hydro Operations and Maintenance (O&M) organization is responsible for facility O&M and works side by side with the other PG and PG&E Energy Supply support organizations to provide safe, reliable, cost-effective, and environmentally responsible generation. Hydro O&M is organized geographically into six areas. These areas consist of logical groupings of facilities that enable efficient oversight, control, and management of O&M. The powerhouses are operated from seven switching centers located throughout the system. Six of the switching centers are located at powerhouses and one is in Fresno. A full listing of powerhouses and individual units is included in Chapter 2, Attachment A.

The Hydro Areas (from North to South) and the PG support organizations are described below, and the information is then summarized in Table 2-1.

a. Shasta Area

The Shasta Area manages 16 powerhouses with 27 generating units and has an installed capacity of 808.3 MW. The powerhouses have in-service dates spanning from 1903 to 1981. The facilities are situated on six different watersheds in Shasta and Tehama counties. There are two switching centers in Shasta, located at Pit 3 Powerhouse and Pit 5 Powerhouse. The Shasta Area headquarters is located in Burney with a satellite headquarters in Manton.

b. DeSabla Area

The DeSabla Area manages 15 powerhouses with 27 generating units and has an installed capacity of 785.7 MW. The powerhouses have in-service dates spanning from 1900 to 1985. The facilities are situated on five different watersheds in Plumas and Butte counties, and on one watershed located in Mendocino County. There is one switching center in DeSabla located at Rock Creek Powerhouse. The DeSabla Area headquarters is located at Rodgers Flat (near Oroville) with satellite headquarters at Camp One (near Paradise) and Potter Valley (near Ukiah).

c. Drum Area

The Drum Area manages 11 powerhouses with 14 generating units and has an installed capacity of 183.4 MW. The powerhouses have in-service dates spanning from 1902 to 1986. The facilities are situated on three different watersheds in Nevada, Placer, and El Dorado counties. There are two switching centers in the Drum Area located at Drum Powerhouse and Wise Powerhouse. The Drum Area headquarters is located in Auburn and satellite headquarters at Alta.

d. Motherlode Area

The Motherlode Area manages 7 powerhouses with 11 generating units and has an installed capacity of 314.5 MW. The powerhouses have in-service dates spanning from 1902 to 1986. The facilities are situated on three different watersheds in Amador, Tuolumne, and Merced counties. There is one switching center in the Motherlode Area located at Tiger Creek Powerhouse. The Motherlode Area has satellite headquarters Angels Camp, Tiger Creek (near Jackson), and Sonora.

e. Kings-Crane Valley Area

The Kings-Crane Valley Area manages 11 powerhouses with 18 generating units and has an installed capacity of 541.1 MW. The powerhouses have in-service dates spanning from 1910 to 1983. The facilities are situated on six different watersheds in Madera, Fresno, Tulare, and Kern counties. The Kings-Crane Valley switching center is located at the Fresno Operating Center. The Kings-Crane Valley Area headquarters is located in Auberry with a satellite headquarters at Balch Camp (east of Clovis).

f. Helms Pumped Storage Facility

This Area consists of the Helms facility with three pump-generator units and an installed capacity of 1,212 MW. Helms was placed in service in 1984. Helms is in Fresno County and has a headquarters facility at the project site.

TABLE 2-1
HYDRO GENERATION AREA DETAILS

Line No.	Area	No. of Powerhouses	No. of Units1	MW	No. of FERC Licenses	No. of Dams
1	Shasta	16	27	808.3	6	44
2	DeSabla	15	27	785.7	6	33
3	Drum	11	14	183.4	1	44
4	Motherlode	7	11	314.5	3	25
5	Kings Crane Valley	11	18	541.1	4	13
6	Helms	1	3	1,212.0	1	6
7	Total	61	99	3,845.0	21	165

g. Support Organizations

The Hydro O&M organization works side-by-side with both PG support organizations and centralized PG&E support organizations to provide safe, reliable, cost-effective generation to California in an environmentally responsible manner. These support organizations provide oversight, direction, and support to ensure that critical resources, personnel, and technical information and advice are available to support O&M for effective operations and maintenance of the hydro fleet.

1) Portfolio Strategy

The PG Portfolio Strategy organization is led by a director and includes several functions:

- Optimization of the composition of the generation fleet;

- Compliance and commitments which includes FERC relicensing and licensing compliance as well as optimizing the cost and benefit to the State, public, and shareholders by working with regulatory agencies such as FERC, Division of Safety of Dams (DSOD);
- Business planning and regulatory reporting which includes identifying, prioritizing, and planning PG's work;
- Monitoring customer value (costs and benefits) of PG&E's utility-owned generation to identify and recommend potential changes to the portfolio;
- Implementing approved divestiture strategies on less economic PG assets to reduce cost to PG&E's customers including overseeing regulatory approvals from the California Public Utilities Commission (CPUC) and FERC;
- Providing analysis and regulatory support for other potential portfolio optimization strategies, such as decommissioning and alternative ratemaking proposals;
- Serving as a liaison for PG&E's Land Conservation Commitment efforts among various PG&E departments and the Stewardship Council;
- Managing the business operations function for PG which combines several functions into an integrated department that provides strategic, and tactical (operational and financial) services; and
- Regulatory reporting which includes preparation and filing of all required documentation for various regulatory proceedings which includes responding to data requests and preparing work papers and testimony.

2) Geosciences

The Geosciences organization is led by a director and is responsible for providing services company wide including the following PG services:

- On-call emergency evaluations and mitigation for seismic events, landslide, erosion, and foundation issues for all company lines of business;
- Support for the Hydro Facility Safety Program including fault studies, penstock geotechnical assessments, dam seepage and liquefaction analysis, and spillway assessments;
- Support for the Company Emergency Response Program, Emergency Operations Center, earthquake exercises, post-event reconnaissance, and emergency training;
- Wildfire burn area debris flow hazard modeling and alerting;
- Geotechnical design and construction review; and
- Climate team research studies and planning support.

3) Corrective Action Program

The Corrective Action Program (CAP) program is led by a manager and is responsible for the Electric Operations CAP program, which includes PG. The Electric Operations CAP group is focused on continuously monitoring the performance of the organization and facilitating the timely and accurate use of CAP across the line of business. The team is responsible for monitoring declines in performance, addressing gaps to standards using evaluation tools (such as cause analysis) to support the safety of our employees and the public and the continued reliable operation of our assets. The CAP Program is further described under Section C.5.e.

4) Asset Excellence

The Asset Excellence department is led by a director and consists of an Asset Management (AM) program that is ISO 55001[1] certified. The department focuses on systemwide condition assessment of PG system equipment and proposes projects and/or

[1] ISO 55000 is an internationally recognized AM System standard that details out the requirements for a business to ensure it is maximizing the value of its assets and minimizing its risks. ISO 55000 standards are aligned with the concept of risk and data informed investment decision making and requires a significant improvement in the way PG treats and maintains its data.

changes to operations and/or maintenance practices to ensure that PG's long-term investment plan reduces risk and maintains the safety and reliability of the hydro portfolio.

PG met its commitment of achieving ISO 55001 certification of its Dams by 2022 and also achieved certification on its entire portfolio, which includes, Hydro Powerhouses, Civil Infrastructure, Fossil, Solar, Battery Storage, Physical Data, and Data assets.

The Asset Excellence department includes the Facility Safety Program for dams and water conveyance facilities to assure compliance with FERC and California Department of Water Resources DSOD regulations.

The Asset Excellence department is supported by a team that develops and implements analytical risk modeling processes and techniques to achieve effective risk management, reduction, and mitigation.

5) Engineering and Technical Services

Engineering and Technical Services department is led by a director and provides engineering technical services, and asset security to PG operations, projects, and public safety work.

Engineering provides engineering services for projects and support of routine hydro O&M work. Engineering uses a number of contractors to augment its workforce, in order to execute on planned work. It ensures that PG is focused on public and employee safety, continuously improving processes, delivering high quality work, and ensuring compliance with all standards and procedures that govern the PG business.

PG&E's Technical Services organization provides direct support to the O&M North and O&M South for the safe, reliable, compliant, efficient operation of PG&E's hydro units. O&M Specialists in the Technical Services organization act as consultants offering expertise in methods and procedures to help assure compliance with operating and maintenance standards.

The department includes the PG Security Program which ensures asset protection and public safety.

6) Outage Management and Project Management

Outage management and Project Management is led by a director and includes outage management, inspection services, and contract services. This team manages project work in addition to supporting routine O&M operations and uses a number of contractors to augment its workforce, particularly in the construction functions, in order to execute on planned work.

Outage Management coordinates outage work scope and schedules among various groups performing project and routine maintenance work. Inspection Services inspects contract construction and equipment installation associated with PG projects.

Project Management provides project management services to PG projects including the development, initial scoping, scheduling, resource planning, and cost estimating for all the major projects included in the long-term plan. Project Management ensures that resources are balanced to improve the implementation of the portfolio of projects in the plan. Project work includes both capital and expense projects. Project Management uses several contractors to augment its workforce, in order to execute on planned work.

Contract Services provides various procurement services including specification development, requests for proposal, bid evaluation, and contract administration support for hydro maintenance and project work.

7) Hydro Construction

Hydro Construction is a mobile construction organization led by a director that handles major maintenance and construction projects throughout the hydro system. With both a civil construction group and an electrical-mechanical group, this organization constructs and/or makes major repairs on a wide variety of hydro facilities.

C. Hydro Portfolio Management

1. Overview

The PG&E hydro portfolio is a complex system composed of many facilities with interrelated operational parameters. Many powerhouses are in "river-chains" where the water is most optimally used sequentially through the powerhouses as it moves downriver. This requires coordinated operations to assure each powerhouse is online to utilize the water flow as it arrives, without spilling past the powerhouse. Operation of the hydro portfolio also must comply with FERC license conditions mandating minimum and maximum flows and ramping rates on the river. Management of this complex portfolio relies on the integration of information and expertise from multiple organizations.

PG&E is committed to providing safe utility service to its customers. As part of this commitment, PG&E reviews its operations, including operation of its hydro facilities, to identify and mitigate, to the extent possible, potential safety risks to the public, PG&E's workforce, and its contractors. As it operates and maintains its hydro generation facilities, PG&E follows internal controls to ensure public, workplace, and contractor safety. PG&E's Employee Code of Conduct specifies that the safety of the public, employees, and contractors are PG&E's highest priority. PG&E's commitment to a safety-first culture is reinforced with its Safety Principles, Safety Commitment, Personal Safety Commitment, and Keys to Life. These tools were developed in collaboration with PG&E employees, leaders, and union leadership and are intended to provide clarity and support as employees strive to take personal ownership of safety at PG&E. Additionally, PG&E obtains all applicable regulatory approvals from governmental authorities with jurisdiction to enforce laws related to worker health and safety, impacts to the environment, and public health and welfare.

As part of PG&E's Safety Commitment, PG&E follows recognized best practices in the industry. PG&E operates each of its generation facilities in compliance with all local, state, and federal permit and operating requirements such as state and federal Occupational Safety and Health Administration requirements and the CPUC's General Order 167. As discussed below, PG&E does this by using internal controls to help manage the O&M of its generation facilities.

PG employees develop action plans each year related to key performance indicators in the areas of safety and reliability. The action plans focus on various items such as forced outage and planned outage (PO) performance, approaches to reduce or eliminate recordable injuries and motor vehicle incidents, and safe dam operations.

With regard to public safety, PG&E continues to develop and implement a comprehensive public safety program that includes: (1) public education, outreach, and partnership with key agencies; (2) improved warning and hazard signage at hydro facilities; (3) enhanced emergency response preparedness, training, drills, and coordination with emergency response organizations; and (4) safer access to hydro facilities and lands, including trail access, physical barriers, and canal escape routes.

Fundamental to a strong safety culture is a leadership team that believes every job can be performed safely and seeks to eliminate barriers to safe operations. Equally important is the establishment of an empowered grassroots safety team that can act to encourage safe work practices among peers. PG's grassroots team is led by bargaining unit employees from across the organization who work to include safety best practices in all the work they do. These employees are closest to the day-to-day work of providing safe, reliable, and affordable energy for PG&E's customers and are best positioned to implement changes that can improve safety performance.

2. Operational Planning

a. Environmental/Regulatory Considerations Affecting Operations

PG&E's operation of its hydro system is governed by the 22 Operating Licenses issued by FERC, which contain over 500 discrete operating conditions. PG&E safely and reliably operates the system in compliance with all FERC license conditions and all local, state, and federal regulations. In addition, operations are constrained by many conditions imposed by United States Forest Service agreements, DSOD regulations, contractual obligations, water diversion rights and other regulations. PG&E's hydro projects deliver water at over 50 locations for consumption by over 30 different user groups under water delivery agreements that contain additional constraints on how the projects are operated. There are defined minimum and maximum flow requirements in most river reaches below PG&E's reservoirs and powerhouses. Any changes in the flows must be performed in compliance with prescribed ramp rates. Reservoirs have both minimum and maximum storage requirements which vary depending upon the time of year.

b. Management of Water Resources

Water is the fuel for the hydro powerhouses and efficient management of water is a very important element of hydro generation operation. The Water Management (WM) organization forecasts runoff and provides guidance for scheduling hydroelectric resources consistent with all regulatory rules, agreements, contracts, environmental regulations, and recreational needs.

WM scheduling consultants employ sophisticated computer modeling programs to forecast runoff. These programs use inputs from the current hydrologic state of the watershed (snowpack, current runoff, and aquifer outflows), an updated 10-day weather forecast, and the long-range weather forecast, with appropriate probability factors, to compile the monthly and daily runoff forecasts used to develop optimized monthly water release schedules. The monthly water release schedules are used by PG&E's Short-Term Electric Supply (STES) organization and Hydro O&M to operate the reservoirs, water conveyance systems and powerhouses.

c. Outage Planning

PG&E has formal outage planning and scheduling processes for its generation assets. Management control over the planning and scheduling of outages is key to prudent management of PG&E's generation facilities. The planning and scheduling processes include management approval points for the base yearly outage schedule and for any changes to the schedule. Scheduled outages are classified as (1) PO and (2) Maintenance Outages (MO).

1) Planned Outages

PO are part of the normal course of maintaining a generating facility. Due to the age of PG&E's hydro portfolio assets and the complexity of the water collection and conveyance systems, and to assure that these generating facilities are reliable during periods of high electric demand, most hydro units are scheduled for one PO each year. These POs are typically scheduled during periods of lower electric demand when market prices are lower.

The purpose of the annual PO is to accomplish recurring routine maintenance work, equipment repairs that can only be performed during an outage, minor project work and condition assessment. Typical annual maintenance tasks include time-based equipment overhauls; time-based equipment inspections; North American Electric Reliability Corporation (NERC) compliance testing; turbine component lubrication, adjustment, and repairs; generator inspection and repairs; relay performance tests; annual auto tests; and condition assessment measurements and readings. The need for scheduled maintenance is well documented in PG&E's past general rate case applications. If major capital projects requiring an outage are planned, the annual outages are modified to accommodate that work.

Scheduling POs is an iterative process spanning several years with input from many stakeholders and quarterly submissions to the CAISO. As described in Section C.5.f., the processes for planning and scheduling annual POs ensure that POs are scheduled sufficiently in advance, have an adequate duration for planning and preparation, have controls in place to manage changes, and have reasonable management oversight to assure that units are promptly returned to service.

2) Maintenance Outages

MOs are taken in response to an emerging need for maintenance that can be deferred beyond the end of the next weekend but cannot be deferred until the next PO. Typical work performed during MOs include replacing generator brushes;

cleaning brush rigging; performing auto tests; troubleshooting tests; transmission line work; monthly routine minor maintenance; monthly gate travel tests; and out-of-tolerance equipment adjustments.

To assure proper planning and preparation, MOs for more routine activities are scheduled much further in advance to assure proper planning and preparation. Every attempt is made to include all maintenance items in the annual PO for each unit, but some systems and equipment must be serviced or tested more frequently.

3. Conventional Hydro Portfolio Operation

PG&E’s 61 conventional powerhouses are operated from five around-the-clock switching centers. Four of the switching centers are at powerhouses and one is in Fresno. Switching center operators receive day-ahead dispatch instructions from PG&E’s STES organization. Operators review the day-ahead schedules and verify that they are attainable. Any operational constraints that may interfere with running the unit to the dispatch schedule are reviewed with STES, and if necessary, the dispatch schedule is adjusted. The conventional hydro powerhouses are operated in accordance with the final dispatch directions provided by STES.

During daily operations, there is close communication between the operators and STES’s real-time energy desk. Through the Supervisory Control and Data Acquisition (SCADA) system, operators remotely start, vary the loading, and stop units in accordance with dispatch instructions. They continuously monitor and adjust the operations of the units at the powerhouses, the canal flows and levels, the reservoir levels, the instream flow releases and other operating parameters. Any operational issues that require a unit to deviate from the dispatch schedule are communicated to the Real-Time Desk (RTD), and operators adjust operations in accordance with the directions received back from the RTD.

Roving operators visit remote, unmanned powerhouses to perform station reads and operational checks that cannot be performed through SCADA. They also perform minor maintenance and adjustments, such as lubricating equipment, checking oil reservoirs on equipment, and cleaning strainers. Roving operators are also dispatched to perform remote unit start-ups that cannot be handled through the SCADA system. At the four powerhouses housing switching centers, the switching center operators perform the duties of the roving operators for those local units.

Water system operators manage the water delivery systems that feed the powerhouses, adjust the reservoir, and canal operations for instream flow releases and water deliveries to third parties. In concert with the switching center operators monitoring SCADA, the water system operators assure safe canal flows and reservoir levels while meeting dispatch requirements.

4. Helms Pumped Storage Operation

Helms is operated around-the-clock from a control room in the powerhouse. Similar to conventional powerhouse dispatch described above, the Helms operators receive day-ahead generating and pumping instructions from STES. Operators review the day-ahead schedules and verify that they are attainable. Any operational constraints that may interfere with running the unit to the dispatch schedule, either in generating or pumping mode, are reviewed with STES and if necessary, the dispatch instructions are adjusted. Helms is operated in accordance with the final dispatch directions provided by STES.

The CAISO relies on Helms for grid stability. As a result, the dispatch of Helms units may change many times throughout the day. Helms operators, the Fresno Operating Center, and the STES RTD stay in constant communication and operators adjust operations in accordance with instructions from the RTD.

Helms operators, similar to roving operators described in Section C.3., complete the system reads and operational checks that cannot be performed through SCADA and perform minor maintenance and adjustments in the powerhouse.

5. Internal Controls

PG&E directs, manages, and monitors its resources using internal controls—processes reflecting the organization's structure, work and authority flows, people, and management information systems.

The internal controls in place to manage the O&M of the hydro facilities include: (1) guidance documents; (2) operating plans; (3) operations reviews; (4) an event reporting system; (5) a CAP; (6) outage planning and scheduling processes; (7) a project management process; and (8) a design change process. Each of these controls is discussed below.

a. Guidance Documents

The guidance documents applicable to hydro operations include PG&E Policy, PG&E Utility Standard Practices, PG&E Utility Procedures, and PG-specific guidance documents. PG-specific guidance documents include Standards, Procedures and Bulletins. These guidance documents cover virtually all aspects of safety, operations, maintenance, planning, environmental compliance, regulatory compliance, emergency response, work management, inspection, testing and other areas. Each guidance document describes the purpose of the document, the details of the actions and/or processes covered by the document, management roles and responsibilities, and the date the document became effective.

b. Operating Plans

The hydro switching centers have operating plans to assure that the powerhouses are operated in conformance with license conditions and all other local, state, and federal regulations. There are also specific operating plans developed for operating the powerhouses in the extreme conditions of summer and winter. The plans specify how operation of the facilities is adjusted to take into account the impacts of the seasons. For example, the summer plan addresses operational issues related to excessive heat and increased public recreation in, around and downstream of PG&E facilities. The winter plan addresses operational issues related to heavy rainfall, increased river and stream runoff and snow conditions.

c. Operations Reviews

Operations reviews are periodically performed at hydro powerhouses and switching centers by the Technical Services organization. The purpose of an operations review is to ensure PG&E's generation facilities are operated in a safe and efficient manner and that they are in compliance with standard operating and clearance procedures.

An operations review evaluates the overall operation of a powerhouse against a variety of PG's guidance documents to assure that standard operating practices are being followed and the powerhouse is in full regulatory and environmental compliance. The results of the review are shared with management and any identified findings or issues require a response and correction.

d. CAP

The CAP is designed to document and track corrective actions (CA) and commitments. The CAP includes problem identification, cause determination, reporting, development of CAs and CA implementation tracking.

PG&E's PG organization has implemented a CAP that utilizes SAP notifications and orders to track and document the following: actions that are necessary or have been taken in response to audit and/or inspection findings, deviations identified in incident reports, regulatory non-compliance issues, engineering deviations, and other systemwide issues.

e. Outage Planning and Scheduling Processes

The hydro outage schedule is developed to plan and communicate when various powerhouse units will be unavailable due to maintenance or project work. Shown on the schedule are PO consisting of maintenance tasks and project-specific outages and combination outages encompassing both project and maintenance tasks as described in section 2.c.1 above. The hydro outage schedule for a given outage year is developed through an iterative process, over several years, as projects and maintenance tasks are identified by field employees, management, project managers, and others. Except for outages with scopes of work demanding long durations or units that have little or no water to run, few outages are planned during the peak summer generation season. Also, every effort is made to limit the number and duration of outages in the off-peak shoulder months.

The yearly outage schedule is not a static document. The schedule is fluid and adaptable to changing requirements. PG&E's STES organization, the CAISO, and others use the schedule to make plans regarding resource allocation, replacement power and restrictions on the system. Therefore, changes in the schedule, particularly in the short term, are discouraged. Due to the dynamic nature of the system, changes will inevitably be required. Changes to the schedule may be required due to weather conditions, resource constraints, changes in project scope or schedule, and/or emergent work. Depending on the proximity to the outage start date, changes to the scope and schedule require different levels of management review and approval. Before outage changes are approved, consideration is given to the impacts of the change on equipment reliability, replacement power costs, water deliveries, possible by-pass spills, resources and impacts to other scheduled outages.

For an individual outage, an outage management plan is developed prior to the start of the outage. Depending on the size and duration of the outage, an outage management plan can be as simple as a list of work orders extracted from the SAP Work Management (SAP WM) system, or as complex as a critical path, resource-loaded work execution plan detailing each task for a project as well as preventative and corrective maintenance work orders. The development of an outage management plan can be broken down into three distinct, but interrelated, processes: (1) Planning and Scoping; (2) Scheduling; and (3) Outage Execution.

1) Planning and Scoping

The planning and scoping process determines the work to be executed during the outage. This includes preventative maintenance work orders, corrective work orders for repairs on equipment and/or facilities and project-specific asset replacements or major refurbishments. The required resources to execute the work and the duration of all work activities are identified during this process.

PG manages preventative and corrective work utilizing SAP WM. Preventative maintenance work orders, sometimes referred to as recurring work, encompass routine maintenance work performed at established intervals. Corrective work orders, sometimes referred to as trouble tags, refer to work identified to correct an issue that is limiting the ability of the equipment or facility to efficiently perform its design function. The SAP WM system is the electronic repository where preventative and corrective work is identified, tracked, organized, and managed. The system utilizes maintenance libraries to generate recurring work orders against a piece of equipment at the appropriate frequency as specified by PG&E. Corrective work orders are created in the system by the crews or individuals identifying the problem.

The planning and scoping process begins two to three years prior to the outage and continues until outage execution.

2) Scheduling

The scheduling process determines the start and duration of the outage. Outage timing and durations are influenced by: capital and maintenance work to be performed, system operation constraints, powerhouse elevation, time of year, weather conditions, water storage requirements, downstream water user requirements, size of unit, labor resources available to perform work, configuration of hydro system (close coupled to dam or long water delivery system), effects on other powerhouses, CAISO constraints, transmission system issues, distribution system issues, and FERC license conditions.

Table 2-2 below provides the timeline for the outage scheduling process.

TABLE 2-2
OUTAGE SCHEDULING PROCESS

Steps	Timing	Process Description
1.	3 to 5 Years Prior to Outage Year	A preliminary annual outage schedule for the outage year is prepared 3 to 5 years in advance. This preliminary schedule is created using outages identified from PG's long term investment plan as well as historical outage durations and timing data for each watershed, powerhouse, and unit. There is no formal approval of this preliminary schedule. The local O&M supervisors review the preliminary schedule and recommend changes.
2.	1 to 2 Years Prior to Outage Year	Each annual outage on the schedule is adjusted/revised over the next 1 to 2 years as more information becomes available about routine maintenance tasks, non-routine maintenance requirements, and/or project work that must be performed during the outage. During this preliminary phase, requested changes are made to the schedule and reviewed by PG&E Generation Supervisors for powerhouses under their control.
3.	3 Months Prior to the Start of the Outage Year	On a quarterly basis, PG&E submits to the CAISO a PO schedule that details the outages planned for the following 15 months. In October of the year prior to the outage year, the PO schedule is submitted to the CAISO to set the base outage schedule. After this submission, any requests for changes to individual outages are submitted to the responsible Area Manager and/or Hydro O&M Director and/or Vice President (VP) for approval. The level of management approval is dictated by the proximity of the request to the outage start date. These internal approvals are required before the changes are submitted to the CAISO.
4.	Changes During an Outage	Changes to the duration of an outage can occur during an outage due to emerging work, unforeseen problems, or other issues. Requests for outage extensions require the approval of the Hydro O&M Director. Outage extensions that occur during the outage require notification to the PG VP or Hydro O&M Director. The level of management notification is dictated by the unit capacity.

3) Outage Execution

The outage execution process includes performing the work planned for the outage, complying with the many sub-processes for notifications and approvals between the outage stakeholders, and lessons learned. Activities include:

- Notifications to and approvals from the CAISO to separate the unit(s) from the grid;
- Clearance procedures covering the steps required to electrically, hydraulically, and mechanically clear the units and facilities (i.e., put them in a safe condition) for the outage work to proceed;

- Notifications and approvals for any changes in the outage due to emerging work or changed conditions;
- Restoration procedures to restore the unit to service when the outage work is completed. This includes complying with the steps in the switch log and any start-up procedure for new or refurbished equipment;
- Notifications to and approvals from the CAISO to restore the unit to service and connect to the grid at the completion of the outage; and
- Collection of lessons learned at the completion of the outage for incorporation into processes and procedures.

Table 2-3 provides the timeline for the outage execution process.

TABLE 2-3
OUTAGE EXECUTION PROCESS

Steps	Timing	Process Description
1.	Prior to Outage Start Date	An Application for Work (AFW) covering the PO is submitted to the STES organization's Outage Coordinator. Once the AFW has been reviewed and approved internally, it is submitted to the CAISO through the Outage Management System (OMS) for preliminary approval. Switching Center Operators write detailed step-by-step switching logs for clearing the units. These logs detail all the clearance points for the outage and the tasks that need to be performed, and the order in which they must be performed, to make the unit or facility safe for outage work to begin.
2.	Outage Start Date	The STES organization's RTD, working off the list of preliminary approved outages, contacts the CAISO for final approval that the unit can be separated from the grid and communicates that approval to the Switching Center Operators. Once approval has been obtained, an operator, working in concert with the Switching Center, executes the steps in the Switching Log to clear the unit or facility.
3.	During the Outage	PG&E employees and/or contractor resources are utilized to execute the prioritized maintenance work and any project work in accordance with the outage plan and in compliance with PG&E standards. Emerging work that is identified during the outage is evaluated and prioritized against other ongoing work. If it is determined that the emerging work must be completed during the current outage, the work is added to the outage plan. Adding emergent work to the outage plan is often necessary to prevent a future forced outage. If emerging work requires an outage extension, approval of the Hydro O&M Director is required. Notification of an outage extension is communicated to the CAISO through the OMS. Both the Switching Log for restoring the unit and a start-up procedure, covering all the requirements for testing newly installed equipment, are written.
4.	Return to Service Date	When all outage work has been completed, the process of restoring the unit to service begins. This entails a series of standard unit tests that must be performed before the unit can be released for service and a start-up procedure if there is newly installed equipment. Once complete, an operator, working in concert with the Switching Center, executes the steps in the Switching Log to restore the unit to service. The Switching Center Operators contact the RTD when the unit has been restored and the RTD notifies the CAISO through the OMS that the unit has been restored to service. At the completion of the outage, the information gathered while performing the maintenance work during the outage is utilized to update maintenance libraries in SAP WM and refine the details and timing of future maintenance tasks.

The three processes detailed above are highly interrelated. Outage scheduling is dependent on planning and scoping. As the defined outage scope changes, the outage schedule is continuously reviewed and updated based on that changed scope. Conversely, if outside influences require the outage timing or duration to change, the scope of work is reviewed and adjusted to fit the revised timeframe. During outage execution, emerging work may require an outage extension, which could, in turn, impact the planning and scheduling of outages on other units or facilities.

f. Project Management Process

Project work is controlled through the project management process. Each project has an assigned Project Manager who has responsibility for the project scope, cost, and schedule, and who coordinates and manages the project from inception to closeout. Project management procedures and tools are in place to provide PG project managers and job leaders guidelines for successfully achieving the project objective of each project they manage. These procedures are intended to be applicable to all types, sizes, and phases of PG projects, and are anticipated to improve the consistency and quality of project management throughout PG. Project Managers report regularly to management.

g. Design Change Process

Design changes are controlled through the design change process. The design change process is the process for proposing, evaluating, and implementing changes to the design of structures, systems, and equipment at PG&E's hydro-generating facilities. It includes the process for requesting design changes; reviewing and approving design change requests; implementing design changes; closing out design changes; and revising design change notices.

D. Operational Results

PG&E operates its diverse hydro system as a portfolio. The following section discusses the operational results for the hydro portfolio. The operational results achieved by PG&E's hydro portfolio demonstrate that PG&E's hydro resources were operated in a reasonable manner during the record period.

1. Energy Production

The energy production at hydro generation facilities is dependent on the available water supplies in any given year. Just as natural gas is fuel for a fossil fuel generating station, water from precipitation, snowmelt, and aquifer outflows is the fuel for hydro-generating facilities. Water availability in any given year is dependent on several factors including meteorological conditions, snowpack, aquifer outflows, the amount of water storage carryover in reservoirs from the previous year, and FERC license conditions. The changing meteorological conditions each year and the ongoing changes in aquifer outflows result in a yearly variation in the fuel supply directly impacting energy output each year.

As FERC-jurisdictional hydro projects, many of PG&E's projects have strict and complex license requirements. To comply with these demands on water resources (such as stream flows for fish, frogs and other species, recreation (including white water rafting), consumptive water uses, and other purposes), some of the water bypasses the generating assets and is lost for the production of energy.

The primary drivers of energy production from hydro generation in any given year are the quality of the water year and the snowpack. PG&E's hydro generating assets' total generation for the portfolio for 2023 record year was 8,509 gigawatt-hours of energy. This is significantly lower than historical long-term averages and primarily driven by drought.

2. Outages

PG&E's hydro generation facilities experienced scheduled outages and forced outages during the record period.

Scheduled outages include PO and MO as described in Section C.2.c above. Forced outages occur when equipment suddenly fails and the unit immediately trips offline, or when the repair need is so urgent that the unit must be forced out of service by an operator before the end of the next weekend. A forced outage is triggered in two ways: (1) the unit is forced out of service by the plant operator or (2) the unit is automatically tripped offline by a protective device.

Consistent with previous Energy Resource Recovery Account (ERRA) Compliance proceedings, PG&E presents general information regarding scheduled outages and specific information regarding each forced outage at facilities 25 MW or greater lasting longer than 24 hours.[2]

One of the key industry metrics used to gauge the operating performance of generating units is the Forced Outage Factor (FOF). FOF is a ratio of the hours a unit is forced out of operation to the total hours in the operation period (i.e., month or year). The hydro portfolio 2023 FOF was 4.23 percent as compared to the industry benchmark of 3.81 percent driven primarily by the Belden forced outage which is discussed in more detail in section 2.B.2. If not for this single event, the FOF would have been 2.48 percent which is significantly better than the industry benchmark.[3] Table 2-4 includes the hydro portfolio FOF for the past five years compared to the industry benchmark.

TABLE 2-4
HYDRO PORTFOLIO FOF

Line No.	Year	PG&E FOF (%)	Benchmark FOF (%)
1	2019	2.41	3.03
2	2020	2.06	3.22
3	2021	2.98[(a)]	3.08
4	2022	3.47[(b)]	3.51
5	2023	4.23[(c)]	3.81

(a) Excludes storm and wildfire-related outages.
(b) Excludes the PO time for Pit 7 transformer replacement (refer to filed 2022 ERRA testimony).
(c) Excludes storm related outages.

2 PG&E has provided additional, detailed information concerning the outages that occurred during the record period to the Public Advocates Office at the California Public Utilities Commission at the CPUC in response to Cal Advocates' Master Data Request.

3 The industry benchmark for 2023 is the 2018-2022 NERC Generator Availability Data System Generating Unit Statistical Brochure 4. The brochure and derivation of the forced outage benchmark is included in PG&E's workpapers.

a. Scheduled Outages

PG&E’s hydro portfolio had 111 scheduled outages 24 hours or greater in duration on units greater than 25 MW during the record period. Of this total, 81 were POs and 30 were MOs.[4] This is an average of just over one scheduled outage per unit across the hydro portfolio.

b. Forced Outages

The average age of PG&E’s 99-unit hydro portfolio is approximately 83 years. 86 units are more than 50 years old, and 37 units are more than 100 years old, so it is reasonable to expect some forced outages of PG&E’s hydro units. Some of these outages are related to unanticipated equipment malfunctions while others are related to external events such as lightning strikes, wildfire, storm-induced transmission line interruptions, or debris in the water.

During forced outages, PG&E’s primary goal is to bring the unit back on-line safely. For outages resulting from equipment failure, PG&E examines components associated with the specific equipment that failed to determine whether modifications or repairs should be made to those components, either at the unit where the outage occurred or at other units with similar components. While this might extend the time before a unit is returned to service, it can potentially avoid a future forced outage.

During the record period, there were 51 forced outages with durations longer than 24 hours occurring at 31 different units with a powerhouse capacity of 25 MW or greater. PG&E has grouped these into two categories: (1) Forced Outages related to wildfires or storms and (2) Forced Outages Unrelated to wildfires or storms.

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4 A description of the general nature and scope of PO and MO is provided in Section C.2.c. above.

1) Forced Outages Related to Wildfires or Storms

During the record period, there were 14 forced outages resulting from storms and none from wildfires. Table 2-5 below lists these forced outage events.[5]

TABLE 2-5
2023 HYDRO FORCED OUTAGES – STORM RELATED FORCED OUTAGES

Line No.	Unit Name	Actual Started	Actual Ended	Actual Duration (Days)
1	BALCH PH 2 UNIT 2	1/9/23 13:50	1/11/23 11:44	1.91
2	BALCH PH 2 UNIT 2	3/10/23 7:23	3/12/23 17:06	2.40
3	BALCH PH 2 UNIT 3	1/9/23 13:51	1/11/23 11:47	1.91
4	DRUM POWERHOUSE #1, UNIT #3	2/27/23 23:59	3/6/23 15:37	6.65
5	ELECTRA POWERHOUSE UNIT #1	12/31/22 8:45	1/1/23 16:40	1.33
6	ELECTRA POWERHOUSE UNIT #2	12/31/22 10:33	1/1/23 16:40	1.25
7	KERCKHOFF PH 2 UNIT 1	1/1/23 0:04	1/12/23 10:22	11.43
8	KERCKHOFF PH 2 UNIT 1	1/12/23 15:00	1/23/23 12:30	10.90
9	KERCKHOFF PH 2 UNIT 1	3/9/23 8:29	3/27/23 9:26	18.04
10	POE POWERHOUSE UNIT #1	12/31/22 8:17	1/3/23 19:12	3.45
11	POE POWERHOUSE UNIT #2	12/31/22 6:53	1/3/23 22:10	3.64
12	SALT SPRINGS PH UNIT #2	9/21/23 6:03	9/25/23 11:32	4.23
13	TIGER CREEK PH UNIT #1	6/6/23 22:54	6/15/23 11:33	8.53
14	TIGER CREEK PH UNIT #2	6/6/23 22:54	6/15/23 10:52	8.50

2) Forced Outages Unrelated Storms

During the record period, there were 37 forced outages unrelated to wildfire or storms. Table 2-6 below summarizes the events followed by a detailed description of each event.

5 PG&E's Prepared Testimony, as submitted on February 28, 2024, stated that there were 15 forced outages resulting from storms. PG&E subsequently discovered that one of these outages—the HAAS PH Unit 2 outage—was incorrectly coded as a forced outage. This event should have been coded as a PO per the NERC Generating Availability Data System (GADS) reporting definition since it was an event that occurred as part of a PO that was extended due to snow/weather impacting the jobsite.

TABLE 2-6
2023 HYDRO FORCED OUTAGES-UNRELATED TO STORMS

Line No.	Unit Name	Actual Started	Actual Ended	Actual Duration (Days)
1	BALCH PH 1 UNIT 1	9/19/23 14:24	9/22/23 8:36	2.76
2	BALCH PH 2 UNIT 3	3/10/23 3:19	3/12/23 17:17	2.58
3	BELDEN POWERHOUSE	6/19/23 17:23		
4	BUCKS CREEK PH UNIT #1	8/31/23 23:59	9/11/23 18:00	10.75
5	BUTT VALLEY POWERHOUSE	1/4/23 10:06	1/16/23 13:12	12.13
6	BUTT VALLEY POWERHOUSE	3/15/23 2:30	4/5/23 12:00	21.40
7	CARIBOU #1 POWERHOUSE UNIT #1	7/26/23 19:10	11/30/23 16:33	126.89
8	CARIBOU #2 POWERHOUSE UNIT #5	6/12/23 5:48	11/27/23 8:17	168.10
9	DRUM POWERHOUSE #1, UNIT #2	12/6/23 6:20	12/7/23 12:19	1.25
10	DRUM POWERHOUSE #1, UNIT #2	12/11/23 7:00	12/13/23 14:33	2.31
11	DRUM POWERHOUSE #1, UNIT #3	10/2/23 12:50	10/5/23 15:03	3.09
12	DRUM POWERHOUSE #1, UNIT #4	8/30/23 15:15	9/8/23 15:47	9.02
13	DRUM POWERHOUSE #1, UNIT #4	4/11/23 18:11	4/27/23 12:45	15.77
14	DRUM POWERHOUSE #1, UNIT #4	10/2/23 12:50	10/5/23 15:03	3.09
15	HAAS PH UNIT 1	10/2/23 17:07	10/3/23 17:26	1.01
16	HAAS PH UNIT 2	4/28/23 13:12	4/29/23 16:08	1.12
17	HAAS PH UNIT 2	11/15/23 17:10	11/17/23 13:09	1.83
18	HELMS POWERHOUSE UNIT 1	8/21/23 10:05	8/22/23 17:33	1.31
19	HELMS POWERHOUSE UNIT 1	7/25/23 14:52	7/26/23 18:48	1.16
20	HELMS POWERHOUSE UNIT 2	10/9/23 22:58	10/11/23 17:33	1.77
21	HELMS POWERHOUSE UNIT 2	7/13/23 0:24	7/14/23 7:52	1.31
22	HELMS POWERHOUSE UNIT 2	7/28/23 0:01	7/29/23 10:22	1.43
24	HELMS POWERHOUSE UNIT 2	12/23/23 6:43	12/24/23 18:27	1.49
25	HELMS POWERHOUSE UNIT 3	6/11/23 11:39	6/15/23 17:14	4.23
26	HELMS POWERHOUSE UNIT 3	1/9/23 23:19	1/13/23 15:08	3.66
27	JAMES B. BLACK PH UNIT #1	1/29/23 3:23	2/6/23 18:32	8.63
28	KERCKHOFF PH 2 UNIT 1	4/24/23 11:23	4/27/23 18:00	3.28
29	KINGS RIVER PH UNIT 1	3/10/23 7:13	3/11/23 17:17	1.42
30	KINGS RIVER PH UNIT 1	3/12/23 1:33	3/13/23 7:05	1.23
31	PIT PH 1 UNIT 1	10/24/22 10:48	6/5/23 19:00	186.79
32	PIT PH 3 UNIT 3	7/14/23 18:58	7/18/23 18:06	3.96
33	PIT PH 4 UNIT 1	3/28/23 8:21	3/29/23 19:35	1.47
34	PIT PH 4 UNIT 2	3/28/23 8:21	3/29/23 19:34	1.47
35	PIT PH 5 UNIT 4	12/6/23 21:34	12/7/23 23:59	1.10
36	SALT SPRINGS PH UNIT #2	12/14/23 22:40	12/22/23 14:27	7.66
37	TIGER CREEK PH UNIT #1	1/17/23 13:38	1/18/23 16:03	1.10
38	TIGER CREEK PH UNIT #2	1/17/23 15:07	1/18/23 16:32	1.06

a) Balch Powerhouse

On Sep 19, 2023, at 12:24 p.m., Balch 1 Unit 1 was forced out of service during startup following a MO upon observation that the slinger rings had come apart. Repairs were made to the slinger ring and the unit was returned to service on Sep 22, 2023 at 8:36 a.m.

On March 10, 2023, at 3:19 a.m., Balch 2 Unit 3 tripped offline due to low cooling water. Immediate access to the powerhouse was restricted due to a severe storm which caused landslides blocking the road access to the powerhouse. Upon regaining access to the powerhouse, investigation of the unit trip determined that very muddy water resulting from the storms had plugged the cooling water intake screens. The intake screens were backflushed, and the unit was tested and returned to service on March 12, 2023 at 5:17 p.m.

b) Belden Powerhouse

On June 19 at 5:23 p.m., Belden tripped offline due to high bearing temperature immediately after returning from a MO. Upon investigation, it was determined the thrust bearing had wiped.[6] The unit was disassembled and the wiped thrust bearing was sent to a third-party vendor for refurbishment. The bearing was returned to the site and the unit was undergoing reassembly at the end of 2023. A cause evaluation is also underway for this event.

Given that the unit remains out of service at the end of 2023, PG&E seeks review of this outage in the 2024 ERRA Compliance proceeding.

c) Bucks Powerhouse

On August 31, 2023, at 11:59 p.m., Bucks Creek Unit 1 was forced out of service during a planned substation outage as a result of an oil sample testing that indicated bearing oil ring wear and electrical discharge damage. Upon investigation, the bearing condition supported oil ring wear and evidence of electrical discharge. Engineering determined additional disassembly was required to verify the bearing was not damaged. Upon disassembly, the bearing was confirmed not to be damaged. The bearing seal and oil ring were repaired and

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6 A bearing wipe occurs when the temperature in the bearing becomes high enough that the overlay babbitt material is melted or displaced.

the electrical discharge was removed. The unit was tested and returned to service on September 11, 2023 at 6:00pm.

d) Butt Valley Powerhouse

On January 4, 2023 at 10:06 a.m., Butt Valley Unit tripped offline on 115 kilovolt (kV) line under voltage, stator ground, and neutral/ground over voltage. Visual inspection of the generator stator/rotor/outdoor switchgear/isophase bus was conducted followed by various electrical testing. Testing revealed that one of the phases on the 13.8 kV isophase disconnects had lower resistance to ground than the other phases. The insulators were cleaned and values all increased to acceptable levels. Additionally, an isophase to rigid bus transition bushing on one of the phases was cracked creating a short to ground. New bushings were procured from the PG&E Emeryville warehouse and were tested by a third party contractor, with acceptable results. Bushings were replaced and the unit was tested and returned to service on January 16, 2023 at 1:12 p.m.

On March 15, 2023 at 2:30 p.m., Butt Valley tripped on numerous alarms. An operator responded to the powerhouse and found water running in two conduits feeding the station service switchgear and water dripping from the ceiling in the control room. The water dripping from the control room ceiling was dripping on the control board, communication, and SCADA equipment. The water intrusion was caused by an atmospheric heavy rain on snow event causing water to run off the side of a mountain directly into electrical pull boxes located in the switchyard. The electrical pull boxes filled with water allowing water to flow through the conduits and into the powerhouse. Water was immediately diverted away from the powerhouse and switchyard. Pumps were brought to the powerhouse and installed to manage any additional leakage in the pull boxes. Crews sealed the conduits inside the powerhouse that route from outdoor pull boxes and conduits in the outside pull boxes. Once the water intrusion was stopped, the pooled water on the floor was cleaned up. Dehumidifiers, fans, and heaters were set up in the powerhouse and control room to perform the dry out process. Extensive electrical equipment testing was performed. All damaged equipment was replaced and all equipment tests were completed successfully. The unit was returned to service on April 5, 2023 at 12:00 p.m.

e) Caribou 1 Powerhouse

On July 26 2023, at 7:10 p.m., Caribou 1 Unit 1 was forced out of service upon an operator hearing a loud noise on the generator deck from the Caribou Switching Center control room and saw flashing coming from the generator stator housing. Upon investigation, a failed generator field pole connection between two generator field poles appeared to have arc'ed. Electrical testing was performed which showed no damage to the stator and no electrical damage to the rotor poles. Further investigation found all rotor pole field connections were subject to fail in the same manner. A repair plan was developed with the contractor who refurbished and installed the rotor poles during a 2021/2022 unit refurbishment PO. The poles were sent to the original equipment manufacturer (OEM) for refurbishment. The refurbished poles were returned to the site and the unit was reassembled. The unit was tested and returned to service on November 30, 2023 at 4:33 p.m.

A cause evaluation is underway for this event. Given that cause evaluation is still in progress, PG&E seeks review of this outage in the 2024 ERRA Compliance proceeding.

f) Caribou 2 Powerhouse

Caribou 2 Unit 5 was in a PO for a generator rewind that started on May 15th, 2023. On June 11, 2023 a severe thunderstorm moved through the Feather River Canyon in Plumas County, California bringing heavy winds and significant rainfall. On June 12, 2023, at 5:48 a.m., PG&E operations and maintenance crew discovered a rockslide on Caribou Road that resulted from the storm. Work stopped on the project due to inaccessibility to the powerhouse. The outage was transitioned form a PO to forced outage on June 12, 2023. Caribou Road became available for crews with only limited restrictions on November 27, 2023 at 8:17 a.m., at which time the event was changed back to a PO.

g) Drum Powerhouse

On December 6, 2023 at 6:20 a.m., Drum 1 Unit 2 was manually shutdown for inspection of possible ball joint leather seal failure. Inspection was performed and discovered ball joint leather seal needed to be replaced. A repair plan was developed to replace the leather seal the following week. The unit was still operable with the bad seal. The unit was tested and returned to service the next day at 12:19 p.m. The leather seal was replaced the following week during a PO.

On December 11, 2023 at 5:00 p.m., Drum 1 Unit 2 was in reserve shutdown and transitioned to a forced outage to replace the ball joint leather. The ball joint leather was replaced and the unit was tested and returned to service at December 13, 2023 at 2:33 p.m.

On April 11, 2023, at 6:11 p.m., Drum 1 Unit 4 was forced out of service due to high bearing temperature alarm. Upon inspection it was determined the generator bearing had wiped. The unit was disassembled, and the bearing was removed. The bearing was scraped and inspected prior to reinstallation. The bearing was installed, and the unit was reassembled. The unit was tested and returned to service on April 27, 2023 at 12:45 p.m.

On August 30, 2023, at 3:15 p.m. Drum 1 Unit 4 was manually shutdown due to a noise coming from the brush rigging and generator bearing. It was suspected there was potential crack in the shaft so the unit was disassembled for thorough testing The bearing was removed and inspected, and the brush rigging was fully inspected. Electrical testing was completed with no issues found. Confirmed no crack in the shaft. The unit was reassembled, tested, and returned to service on September 8, 2023 at 3:47 p.m.

On October 2, 2023, at 12:50 p.m., Drum 1 Unit 3 and 4 were forced out of service due to a broken penstock saddle drain valve.[7] The penstock was drained and cleared to inspect the drain valve. Upon inspection it was discovered the valve mechanism was broken. A new replacement valve was procured. The valve was replaced, and the units were tested and returned to service on October 5, 2023, at 3:03 p.m.

h) Haas Powerhouse

On October 2, 2023, at 5:07 p.m., Haas unit 1 tripped offline due to low/high turbine bearing oil level indication. A visual inspection of the unit, bearing oil level, associated auxiliary equipment and powerhouse tailrace resulted in no findings of abnormal oil levels, oil leakage or other abnormal conditions. Additional testing and inspection found no issues and the unit was returned to service the next day at 4:26 p.m.

On April 28, 2023, at 1:12 p.m., Haas unit 2 was forced out of service due to sparking collector ring brushes. Upon investigation it was determined the brushes had worn down, causing the brushes to spark. The brushes were replaced and the collector ring was honed. The unit was tested and returned to service the next day at 4:08 p.m.

On November 15, 2023, at 5:10 p.m., Haas unit 2 was forced out of service due to inability to close the penstock shutoff valve.[8] Upon investigation it was determined there was a bad cell in the station batteries that provide power to the shutoff valve preventing the valve from closing. A cell was added to the batteries and the penstock shutoff valve was

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7 Units 3 and 4 share the same penstock.

8 Critical valve for controlling the flow of water into the penstock. The penstock carries and regulates the follow of water coming into the powerhouse.

tested for operability with no issues found. The unit was tested and returned to service on November 17, 2023, at 1:09 p.m.

i) Helms Powerhouse

On July 25, 2023 at 2:52 p.m., Helms Unit 1 was forced out of service during routine switching at the Helms Switchyard. Oil was observed to be leaking from the Coupling capacitor voltage transformer (CCVT)[9] on the Helms #1 230 kV bus. The CCVT was taken out of service immediately to prevent a catastrophic failure. All six CCVTs on the Helms #1 and #2 230 kV buses were inspected and two CCVTs were replaced. The unit was tested and returned to service the next day at 6:48 p.m.

On August 21, 2023 at 10:05 a.m., Helms Unit 1 was forced out of service due to a starting motor collector ring stud that was found to be flashed over. The collector rings were inspected and a repair plan was developed. The damage to the collector ring stud only affected the ability to operate in pump mode allowing the unit to return to service and the collector rings to be repaired during the next PO. The unit was tested and returned to service the next day at 5:33 p.m. with the pump mode unavailable. The collector rings were repaired during a planned MO in December. Pump mode was restored on December 17, at 9:43 a.m.

On July 13, 2023 at 12:24 a.m., Helms Unit 2 was forced out of service due to spurious closure of circuit breaker CB-280 in the Helms switchyard. Thorough electrical testing was conducted to determine the cause. It was determined that there was water intrusion and degradation of the terminal blocks at the wire terminal boxes located in the powerhouse. The terminal boxes were cleaned, repaired, and thoroughly tested. The unit was tested and returned to service the next day at 7:52 a.m.

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[9] CCVTs used for providing voltage to the inputs of meters and relays.

On July 28, 2023 at 12:01 a.m., Helms Unit 2 was forced out again due to inadvertent closure of circuit breaker CB 280. Testing and inspection of the breaker found no issues. Additional sync check relay logic was added at to the breaker control scheme to prevent inadvertent closures. The unit was tested and returned to service the next day at 10:22 p.m. CB 280 is scheduled to be rebuilt and tested further during a PO in 2024. Additionally, there is a multi-year project underway to replace the control wiring for all three units from the powerhouse to the switchyard. The project is scheduled to be completed in 2026.

On October 9, 2023 at 10:58 p.m., Helms Unit 2, failed to start in Pump Mode due to the turbine shutoff valve (TSV) remaining in the open position. Upon inspection of the TSV, water was observed coming out of the lubrication visual check points (ports) on the TSV trunnion. Lubricant was applied to displace the water. Additionally, a broken swivel grease fitting was discovered on the grease line going to the TSV. The swivel fitting was replaced with a manual grease fitting temporarily installed to allow the unit to return to service. The repairs were completed and the TSV was confirmed to be adequately greased and the TSV functional testing was then completed. The unit was tested and returned to service on October 11, 2023 at 5:33 p.m. In addition to the repair work, the TSV is scheduled to be replaced during a PO in 2026.

On December 23, 2023 at 6:43 a.m., Helms Unit 2 was forced out due to an arc flash in the 480V station service bus. Upon investigation it was suspected that water intrusion caused the event. The station service transformer bank and bus were isolated allowing the unit to be returned to service while testing and repairs of the bank and bus occurred. The station service transformer was tested with no issues found. The unit was tested and returned to service the next day at 5:27 p.m. Station service bank and the associated bus remained out of service at the end of 2023 while repairs were being completed.

On January 9, 2023 at 11:19 p.m., Helms Unit 3 tripped on circuit breaker CB 290 breaker alarm during a station service transfer. Testing and inspection of the breaker found no issues. The unit was tested and returned to service on January 13, 2023 at 3:08 p.m. CB 290 is scheduled to be rebuilt and tested further in 2025. Additionally, there is a multi-year project underway to replace the control wiring for all three units from the powerhouse to the switchyard. The project is scheduled to be completed in 2026.

On June 11, 2023 at 11:39 a.m., Helms Unit 3 was tripped offline on low pressure air following no TSV movement during pump start. Upon investigation, a water valve was found to not be operating properly. The valve was removed, repaired, and re-installed. The unit was tested and returned to service on June 14, 2023 at 5:14 p.m.

j) James B Black Powerhouse

On January 29, 2023 at 3:23 a.m., James Black tripped offline due to high turbine bearing oil level. Upon visual inspection of the turbine bearing oil level, the oil appeared milky. An oil sample was taken and it was confirmed water was in the oil. Upon further investigation, it was determined the cooling coil had three pin hole leaks. The leaks were repaired and the unit was tested and returned back to service on February 6, 2023 at 6:32 p.m.

k) Kerckhoff 2 Powerhouse

On April 24, 2023 at 11:23 a.m., Kerckhoff 2 Powerhouse Unit 1 was forced out of service due to oil leaking in the wicket gate servo packing area. Upon investigation it was determined the wicket gate servo shaft packing had failed. With input from the OEM, the wicket gate servo packing was adjusted in order to adequately control the leak off and allow the unit to be returned to service while new packing was procured from the OEM. The unit was tested and returned to service on April 27, 2023 at 6:00 p.m. New packing has been received from the OEM and is scheduled to be replaced during a PO in 2024.

l) Kings River Powerhouse

On March 10, 2023 at 7:13 a.m., Kings River Powerhouse Unit 1 tripped offline due to generator winding over temperature. The trip was caused by a failed Resistance Temperature Detector (RTD). The faulty RTD was removed from service since there was redundant RTD that could provide sufficient data for protection. The unit was tested and returned to service the next day at 5:17 p.m.

On March 12, 2023 at 1:33 a.m., Kings River Powerhouse unit 1 tripped offline due to bearing high temperature. Immediate access to the powerhouse was restricted due to a severe storm which caused landslides blocking the road access to the powerhouse. Upon regaining access to the powerhouse, it was determined that the high bearing temperature was due to loss of cooling water. Very muddy water resulting from the storms had plugged the cooling water intake screens. The intake screens were back-flushed and the cooling water was restored. The unit was tested and returned to service the next day at 7:05 a.m.

m) Pit 1 Powerhouse

On October 24, 2022, at 10:48 a.m., Pit 1 Unit 1 was forced out of service due to lower guide bearing high temperature indication. Upon investigation, it was determined the lower guide bearing had wiped.[10] The lower guide bearing and upper guide bearing oil tubs were disassembled and cleaned. The associated oil piping was cleaned and flushed to remove any debris from the system. The lower guide bearing was sent to a third-party vendor for refurbishment. The refurbished bearing

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[10] Material is melted or displaced.

was returned to the site and the unit was reassembled. The unit was returned to service on June 5, 2023 at 7:00 p.m.

A cause evaluation was completed for this event which determined that insufficient clearance between the lower guide bearing and the shaft led directly to the bearing wipe. The following CAs were identified and completed:

- Develop a procedure for work on tapered split shell bearings; and
- Update work standard PG-2902S "PG Engineering Requirements Hydro Projects" that outlines required information within a project scope of work before proceeding with any project.

n) Pit 3 Powerhouse

- On July 14, 2023, at 6:58 p.m., Pit 3 Unit 3 was forced offline due to excessive leakage from the penstock expansion joint packing ring. Attempts to seal the leakage while the unit remained in service were unsuccessful. The unit was shut down and the penstock was dewatered and the deteriorated packing was replaced. The penstock was watered up and the unit was brought online under close observation before the unit was tested and returned to service on July 18, 2023, at 6:06 p.m.

o) Pit 4 Powerhouse

On March 28, 2023, at 8:21 a.m., Pit 4 Unit 1 and 2 tripped offline due to trouble on the Pit 5 – Round Mountain 230 kV transmission line. Following the line fault clearance, the units were tested and returned to service the next day at 7:35 p.m. and 7:34 p.m. respectively.

p) Pit 5 Powerhouse

On December 6, 2023, at 9:34 p.m., Pit 5 Unit 4 was forced out of service to replace a blown fuse on the 480-volt bus main station service control power. The fuse was replaced and station service tested normal. The unit was tested and returned the next day at 11:59 p.m.

q) Salt Springs Powerhouse

On December 14, 2023, at 10:40 p.m., Salt Springs Unit 2 tripped offline on low cooling water flow. Upon investigation it was determined the tailrace pump had failed which was providing cooling water flow. The pump was replaced and the cooling water flow was restored to Unit 2. The unit was tested and returned service on December 22, 2023 at 2:27 p.m.

r) Tiger Creek Powerhouse

On January 17, 2023, at 1:38 p.m. and 3:07 p.m., Tiger Creek Unit 1 and Unit 2 were forced out of service due to blown fuses on the station service breakers. The fuses were replaced, and the breakers were tested with no issues found. The units were tested and returned service the next day at 4:03 p.m. and 4:30 p.m., respectively.

E. Compliance Items

1. Transformer Inspection Program Standards

D.18-05-004, Ordering Paragraph (OP) 6 directed PG&E to include a report, in future ERRA Compliance applications, describing national industry standards of similar transformer inspection program tests, including standards for inspection periods. The following testimony and the workpapers supporting this chapter provide the required report.

PG&E instituted a transformer inspection program in December 2015. This program follows industry recommendations regarding specific inspection intervals from the International Council on Large Electric Systems (CIGRE) Working Group and associated feedback from the product of an AM partnership, Hydropower Asset Management Partnership (HydroAMP).[11] This program also incorporates key findings from studies

[11] In 2001, the Bureau of Reclamation, Hydro-Québec, the Army Corps of Engineers' Hydroelectric Design Center, and Bonneville Power Administration began collaborating on a hydroelectric equipment condition assessment technique that was later named HydroAMP.

done by the Centre for Energy Advancement through Technological Innovation (CEATI) and CIGRE international workgroups. While CEATI and CIGRE have observed significant differences on maintenance activities and their intervals across the utility industry, PG&E has adopted best practices and recommendations to design and validate its transformer program. In 2018, in response to D.18-05-004, OP 6, PG&E worked with Doble, an industry leader in transformer assessment, to survey seven companies to understand if other PG companies have coalesced around a specific set of standards. The transformer program inspections continue to be executed based on the results of the survey from 2019 and in line with industry best practices.

2. Transformer Inspection Program Status

D.18-05-004, OP 6 directed PG&E to report the dates and results of all inspections performed under the new transformer inspection program in its future ERRA Compliance filings, including descriptions of the results of all visual inspections. The following testimony and the workpapers supporting this chapter provide the required inspection results.

As discussed in Section E.1. above, PG&E instituted a transformer inspection program in December 2015 following industry recommendations from CIGRE and HydroAMP. PG's guidance documents for its transformer inspection program include a High Voltage Transformer Condition Evaluation Standard and three procedures: (1) High Voltage Transformer Tier 1 Inspection and Measurement; (2) High Voltage Transformer Tier 2 Oil Test and Investigation; and (3) High Voltage Transformer Tier 3 Electrical Testing and Inspection.

PG&E has 103 transformers under this program as shown in Table 2-7 by hydro area and fossil plant.

TABLE 2-7
NUMBER OF TRANSFORMERS IN THE TRANSFORMER INSPECTION PROGRAM

Line No.	Hydro Area or Fossil Facility	Number of Transformers
1	Central	21
2	DeSabla	22
3	Helms	10
4	Kings Crane	12
5	Shasta	24
6	Humboldt Bay GS	3
7	Colusa GS	6
8	Gateway GS	5
9	Total	103

The transformer inspection program results are included in the workpapers supporting this chapter.

F. Conclusion

In compliance with D.14-01-011, this chapter addressed the operation of PG&E’s utility-owned hydroelectric facilities, and outages that occurred at these facilities during the 2023 record year. It demonstrates that PG&E’s utility-owned hydroelectric portfolio was operated in a reasonable manner during the record period.

PG&E has a comprehensive management structure, with numerous internal controls, to prudently oversee the operation of a large, geographically dispersed, and complex hydro system. Scheduled outages were planned sufficiently in advance to allow adequate preparation time and were efficiently executed to assure prompt return to service.

PG&E’s hydro resources were operated in a reasonable manner as demonstrated by the 2023 record year FOF results. Additionally, PG&E assets larger than 25 MW are significantly better than the industry average. PG&E acted reasonably in resolving forced outages in a timely manner.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

SUMMARY OF PORTFOLIO ALLOCATION

BALANCING ACCOUNT ENTRIES FOR THE RECORD PERIOD

PACIFIC GAS AND ELECTRIC COMPANY
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BALANCING ACCOUNT ENTRIES FOR THE RECORD PERIOD

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SUMMARY OF PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES FOR THE RECORD PERIOD

A. Introduction

This chapter presents the accounting entries made to Pacific Gas and Electric Company's (PG&E) Portfolio Allocation Balancing Account (PABA) for the period January 1 through December 31, 2023 (record period). Section B describes the background and structure of PABA, Section C describes the activity recorded to PABA, and Section D shows a variance analysis of the forecasted costs compared to the actual 2023 amounts recorded in PABA. This testimony demonstrates that the entries recorded to the PABA comply with California Public Utilities Commission (Commission) rules and decisions.

B. Background and PABA Structure

Decision (D.) 18-10-019 issued in the Power Charge Indifference Amount (PCIA) Rulemaking 17-06-026 significantly modified the accounting for the PCIA by requiring that PCIA revenues from customers and costs be trued-up on an annual basis. To do so, D.18-10-019, Ordering Paragraph (OP) 8, required each utility to modify its Energy Resource Recovery Account (ERRA) and any other balancing accounts, as necessary, to be consistent with the PABA vintage subaccount structure adopted in the decision. PG&E Advice Letter (AL) 5440-E implemented these changes and was approved with an effective date of January 1, 2019. PG&E implemented the changes authorized in AL 5440-E during the June 2019 business close.

In D.19-10-001, the Commission established the methodology to true-up the Market Price Benchmarks (MPB) for Renewable Portfolio Standard (RPS) and Resource Adequacy (RA) attribute values from the forecast values. The final 2023 MPB values were incorporated into the PABA during the October close to reflect final actual attribute values for the retained RPS and RA attributes.

The purpose of the PABA is to recover the above-market costs for all generation resources eligible for recovery through the PCIA.[1] The PCIA is recovered from both bundled and departing load customers. Above market costs include the categories of activity detailed in Section C below.

The PCIA assigns cost responsibility for vintages of generation resources based upon when the customer departed bundled service. Consistent with developing PCIA rates in the annual ERRA Forecast proceedings, PCIA-eligible generation resources are generally assigned to vintages based on the year the resource commitment is made (i.e., contract execution date, legacy Utility-Owned Generation (UOG) or construction/acquisition date for other UOG after 2002).[2] As a result, the PABA is comprised of subaccounts for each year's vintage portfolio that records the costs and revenues associated with the categories of activity described above for all generation resources executed or approved by the Commission for cost recovery that year.

C. Activity Recorded to the PABA

Activity recorded in the PABA includes the following categories: Revenues from Customers, RPS Activity,[3] RA Activity,[4] System RA Value Transferred to the System Reliability Incremental Procurement Subaccount of New System Generation Balancing Account (NSGBA), Adopted UOG Revenue Requirements, CAISO Related Charges and Revenues, Fuel Costs, Contract Costs, Greenhouse Gas (GHG) Costs, Green Tariff Shared Renewables (GTSR)

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1 See PG&E's approved Electric Preliminary Statement Part HS tariff (hyperlink at: https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_HS.pdf.

2 Please see further discussion on definition of UOG vintages in Section C.5 below.

3 Within PABA, RPS and RA are categorized together as Sold RPS and RA and Retained RPS and RA. PG&E organized this chapter to more clearly demonstrate how each RA and RPS product is accounted as Sold, Unsold, and Retained.

4 *Id.*

PCIA Program Charges,[5] and Miscellaneous Costs.[6] These entries are further described below.

1. Revenues from Customers

As required by Generally Accepted Accounting Principles, PG&E recognizes customer revenue for any balancing account based on when the revenue is earned, not when it is billed to customers. As a result, the revenues recorded to PABA in any given month include revenues billed to customers for usage during the current month <u>and</u> an estimate of revenues earned from providing electricity to customers that has not yet been billed to customers, referred to as unbilled revenue.

Because customer billing cycles vary throughout the month, the amount of revenue on a customer's bill reflects both a portion of usage from the current month, as well as a portion of usage from the prior month. For example, if a customer is billed on the 16th of each month, the March 16th bill will reflect the following:

- Current month usage for March 1st through March 16th;
- Prior month usage for February 17th through February 28th; and
- To estimate the remaining unbilled revenue for March, PG&E's process is based upon the sum of unbilled usage by customer billing cycle multiplied by the average billed rate for that cycle, with no delineation between bundled or departed load. This approach to estimating total unbilled revenue is based on summarized unbilled customer usage and average rates from PG&E's billing system. This reflects a reasonable estimate of total revenue attributable to the calendar month.

The total unbilled revenue for all billing cycles is then allocated first to balancing accounts that have a rate on Electric Preliminary Statement

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5 2020 ERRA Compliance Settlement Agreement (SA) (A-21-03-008) and AL 6297-E approved on January 1, 2022 to record the transfer of PCIA program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT and E-ECR to PABA.

6 Interest is also recorded in PABA that is based on the on the average balance in the account at the beginning of the month and the balance after the accounting procedures for the current month are recorded times one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.

Part I,[7] which is determined by multiplying the rate by the total unbilled usage. The Preliminary Statement I states the specific rate for a balancing account that is part of the rate component used for revenue allocation for a specific rate component by balancing account.[8] The remaining unbilled revenue is then allocated to balancing accounts that record revenues but do not have a rate on Preliminary Statement I based on actual billed revenues for that balancing account over the sum of actual revenues for balancing accounts that do not have a rate on Preliminary Statement I. This approach to estimating unbilled revenue by balancing account does not rely upon detailed unbilled usage by customer type (bundled or departed customers) or specific rates by function associated with a specific balancing account, such as the PABA. Importantly, continuing with the example from above, the estimated unbilled revenue for March 17th through March 31st is reversed the following month and replaced with the actual amount billed to the customer.

Additionally, PCIA billed revenues from departed load customers and the PCIA portion of bundled customer's generation revenue is recorded to the PABA vintage subaccounts using incremental PCIA rates applicable to each vintage subaccount. The incremental PCIA rates recover the net resource costs recorded to the PABA vintages. Customers' billed vintage specific PCIA rates reflect the cumulative incremental rates for each vintage. PG&E uses a power query revenue model that facilitates the disaggregation of the cumulative PCIA revenues, by customer vintage, into incremental

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7 PCIA rates are stated on the Preliminary Statement Part I. However, the rates on the Preliminary Statement Part I are not used to calculate the unbilled revenue like the balancing accounts that have rates on Preliminary Statement Part I. To use the rate on Preliminary Statement Part I for unbilled revenue calculation, the rate must be able to be applied to a system-wide or customer class volume. PG&E does not have enough information to separately forecast unbilled usage for individual customer types such as departed load, nor by customer vintage. In that case, the allocation methodology for the remaining unbilled revenues as described below is used. After determining the unbilled revenue for PCIA by bundled, Direct Access and Community Choice Aggregation Customers, the unbilled revenue is then allocated in vintage over total billed revenue for the customer type.

8 This first step in allocating unbilled revenue to balancing accounts using Preliminary Statement I rates is the same as how billed revenues are allocated to balancing accounts.

PCIA revenues, by bundled and departing load and vintage subaccounts. The power query model also uses customer revenue and usage information from PG&E's revenue reporting system, which is based on PG&E's Billing System.

Lastly, the transfer of net PCIA revenues for bundled customers served under the DAC-GT and CS-GT tariffs to the respective DAC-GT and CS-GT subaccounts in the PCCBA are found in accounting procedure 5.d. and 5.e.[9]

2. RPS Activity

In D.19-10-001 the Commission directed the utilities to value sold, unsold, and retained RPS products as follows: (1) sold RPS (actual transacted volumes) at the actual transacted prices, (2) unsold RPS (actual unsold volume) at $0; and (3) retained RPS (volume used for Investor-Owned Utility (IOU) compliance from PCIA-eligible portfolio) at the Final RPS Adder, or benchmark price.[10]

Furthermore, effective January 2023, PG&E implemented the Voluntary Market Allocation (VAMO) framework as adopted in D.21-05-030 and D.22-11-021.The VAMO framework was designed to optimize the distribution of the RPS portfolio of all California IOUs. VAMO, as implemented by these decisions, is composed of two parts: (1) voluntary allocations (VA) and (2) market offer (MO). Voluntary Allocations comprise "a slice" of an investor-owned utility's entire PCIA-eligible RPS portfolio made available to eligible LSEs to accept. PG&E records the allocated portion of its RPS portfolio that was voluntarily accepted by other LSEs for use and reimbursement at the Final RPS Adder, or benchmark price, pursuant to signed contracts. Market Offer, which is the remaining portion of the portfolio eligible to be sold on the market in a mandated offering process at contract prices. Pursuant to the adopting decisions, any RPS-eligible resources subject to the VAMO framework but not allocated or sold would be shown as unsold. Impacts to PABA are described under the Sold and Retained RPS subsections below.

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9 AL 5763-E/E-A approved the proposal to separately record interim resources net costs entries by type for DAC-GT and to reflect that the transfer of certain net cost entries supporting these programs will be from the PABA.

10 D.19-10-001, Table III: RPS Value True Up (Price and Quantity).

Table 12-1 summarizes the value of Sold, Unsold, Retained RPS, and Minimum Retained RPS recorded to the PABA. The sold RPS represent all RPS sales transacted for 2023 deliveries through PG&E's Bundled RPS Sales Solicitations (including VAMO contracts signed with counterparties) and settled during the record period[11] as well as Renewable Energy Credits (REC) delivered in 2022 but invoiced in 2023. These entries totaled to a value of 5,454 gigawatt-hour (GWh) at the transacted price. During the record period, PG&E recorded 3,303 GWh unsold RPS to PABA[12]. The retained RPS for PCIA-eligible resources represent the total 2023 PCIA-eligible generation, less the sold RPS quantity, less the unsold RPS quantity, totaling a value of [redacted] at the RPS Adder, or benchmark price of $30.30 per MWh.

Lastly, as acknowledged in PG&E's 2023 ERRA Forecast Application, the VAMO process could result in PG&E's net physical RPS position being less than the annual target established in D.19-06-023. PG&E proposed the Minimum Retained RPS methodology to determine how many additional RECs bundled customers need to retain in ERRA such that the total amount of procured bundled RECs met the annual RPS target as part of the PCIA revenue requirement calculation and how the value of any additional RECs need to satisfy this ratemaking requirement for bundled customers will be allocated across PCIA vintages. PG&E's Minimum Retained RPS process was adopted in D.22-12-044. As identified in its Fall Update in A.23-05-012, PG&E identified that it would record an entry at the 2023 RPS Adder for a total of [redacted] to meet this net short position for 2023.

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11 REC volumes are associated with 2023 deliveries recorded through the December 2023 close and do not include any true-ups found in periods after December 2023.

12 Unsold RECs are valued at $0 and therefore are not shown directly in the PABA Subledger, which follows transactions or authorized amounts with financial values collected from or returned to customers.

TABLE 12-1
RPS ATTRIBUTE VALUE FOR PABA

Line No.		Value ($ per MWh)	GWh	$ millions
1	Sold RPS (Valued at Transacted Price)	[redacted]		
2	Unsold RPS (Valued at $0)	–	3,303	–
3	Retained RPS (Valued at RPS Adder)	$30.30	[redacted]	
4	Minimum Retained RPS	$30.30		

a. Sold RPS

PG&E sold RPS volumes for 2023 deliveries, in adherence with the Commission-approved Sales Framework in its 2017 RPS Plan and its 2018 RPS Plan.[13] The total sales for 2023 deliveries equate to [redacted] of PCIA-recoverable resources through PG&E's Bundled RPS Sales Solicitations, including the VAMO contracts with counterparties. However, as sales are not invoiced and settled until after Western Renewable Energy Generation Information System (WREGIS) certification of RECs, they are subject to an approximately 2 to 3-month lag[14]. Transactions related to PCIA-recoverable resources delivered in 2023 that were also recorded to PABA during 2023 totaled approximately [redacted] and were recorded in PABA as sold RPS at transaction prices ranging from [redacted], totaling to a notional value of [redacted] for 2023 deliveries.

The total value of these deliveries plus adjustments for 2022 deliveries invoiced during 2023 equals a total of $190 million as recorded in Accounting Procedure 5.f. of Preliminary Statement HS.

b. Unsold RPS

Pursuant to D.20-02-047, PG&E is including Unsold RPS for 2023 as a tracking framework within PABA. As of the December 2023 Close, PG&E had valued 3,303 GWh of RPS as unsold, as illustrated in Table 12-1.

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[13] The RPS sales framework was approved in D.19-12-042.

[14] WREGIS lags in validating RECs has varied from 2 months to over 5 months during the course of 2023 and is subject to change.

c. 2023 Retained RPS

PG&E's retained RPS volumes for 2023 deliveries are calculated by taking the total 2023 RPS generation, less the quantity sold, less the unsold RPS for 2023 deliveries. This calculation equates to [redacted] (total PCIA-eligible 2023 generation) – [redacted] (total RPS sales for PCIA-eligible 2023 deliveries) – 3,303 GWh (unsold RPS sales for 2023 deliveries in the 2023 Bundled RPS Sale Solicitation) or [redacted] of PCIA-eligible retained RPS (including PG&E's accepted VAMO volumes for 2023). As required by D.19-10-001, PG&E records retained RPS volumes at the Final RPS Adder benchmark price published by Energy Division and recorded a total value of [redacted] for these 2023 deliveries. In addition, during the record period PG&E also recorded [redacted] in the prior period related to adjustments for 2019 through 2022 deliveries.[15]

In addition, as acknowledged in D.22-12-044, the VAMO process could result in PG&E's net physical RPS position being less than the annual target established in D.19-06-023. As a result, effective January 2023, PG&E began recording a monthly minimum RPS entry based on PG&E's determination of how many additional RPS units will be needed to meet the ratemaking requirement for bundled customers to be allocated across the PCIA vintages. The minimum RPS units are valued at the latest market price benchmark.

The total value of these adjustments plus 2023 deliveries equals $351 million as recorded in Accounting Procedures 5.h. and 5.i. of Preliminary Statement HS.

Lastly, the authorized VAMO memorandum account balance was transferred to PABA for recovery of the 2021 and 2022 incremental costs incurred and the staffing and information technology system needed for administering the RPS VAMO process, as approved in D.22-12-044, Ordering Paragraph 1(b). This amount is included in the authorized transfers discussed in the Miscellaneous Costs section.

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15 During the record period, PG&E recorded approximately [redacted] in true-ups for 2022 in the normal course of business.

d. Allocation of Retained REC Value and Sold RECs to PABA Vintages

The 2023 Retained and Sold RECs subject to the VAMO framework and recorded in the PABA were allocated to the vintages based on the accepted allocations for the PCIA-eligible RPS portfolio made available. For the remaining RECs retained for bundled compliance (not subject to the VAMO framework), PG&E assigned these transactions to the appropriate vintage of the resource. For REC sales not subject to VAMO,[16] PG&E allocated these to vintages based on the adopted 2023 ERRA Forecast portfolio position.[17] Specifically, the allocation factors were developed using the forecasted GWhs of eligible RPS energy assigned to each vintage.[18] The 2023 allocation rate for Retained RECs was approved on December 2022 and was scheduled to be effective on January 2023. The table below shows the 2023 REC allocation factors used to allocate recorded retained REC amounts and proceeds associated with RECs sold to third parties.

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16 Total entries for non-VAMO sales comprised [redacted] of 2023 invoices related to 2022 activity in Preliminary Statement HS, tariff line 5.h.

17 As Unsold RECs have a $0 value, they are not directly recorded into the PABA.

18 The forecasted GWhs were extracted from PG&E's Joint IOU Common Template workpaper supporting the 2023 Update to Prepared Testimony filed during the Fall Update in A.22-05-029 and supporting D.22-12-044.

TABLE 12-2
2023 REC ALLOCATION FACTORS BY PABA SUBACCOUNT EFFECTIVE JAN-23 TO DEC-23

Line No.		Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
1	GWh	710.70	2,347.92	1,897.48	615.57	721.98	450.26	53.55	85.76	26.35	100.72	0.00	0.00	0.00	24.89	0.00	7,035.18
2	Percent of Total GWh	10.10%	33.37%	26.97%	8.75%	10.26%	6.40%	0.76%	1.22%	0.37%	1.43%	0.00%	0.00%	0.00%	0.35%	0.00%	100%

3. RA Activity

As part of the RA program codified in Section 380 of the Public Utilities Code and CAISO Tariff provisions related to RA, PG&E complies with RA requirements related to system capacity requirements, local capacity requirements, and flexible capacity requirements. For a discussion of the RA procurement activities undertaken by PG&E pursuant to its Conformed 2014 Bundled Procurement Plan (BPP) and Commission directives during the January 1 through December 31, 2023 record period, please see Chapter 8.

In D.18-10-019, the Commission adopted the California Large Energy Consumer Association's proposal to reflect system, local, and flexible RA in the PCIA as follows:

- RA that provides both system and flexible capacity shall be counted as flexible RA capacity;
- RA that provides both system and local capacity shall be counted as local RA capacity; and
- RA that provides all three types of RA capacity shall be counted as local RA capacity.

In D.19-10-001, the Commission directed the utilities to value retained, sold, and unsold RA products as follows: (1) sold RA (actual transacted volumes) at the actual transacted prices; (2) unsold RA (volume offered for sale but not sold or used by the IOU) at $0; and (3) retained RA (volume used for IOU compliance and retained for IOU use) at the Final RA Adder, or MPB.[19]

The following sections describe how PG&E's RA activities described in Chapter 8 during the 2023 record period are accounted for in the PABA account.

a. Sold RA

PG&E offered to sell 2023 RA volumes in accordance with Appendix S of its BPP, as described in Chapter 8. Table 12-3 summarizes the notional volumes sold and recorded to PABA for the Record Period.

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[19] D.19-10-001, Table IV: RA Value True Up (Price and Quantity).

TABLE 12-3
SOLD RA VOLUMES

Line No.		Volume (megawatt (MW)-Year)
1	Local	[redacted]
2	Flex	
3	System	
4	Total	

The total value of sold RA recorded to PABA amounts to $122 million for the record period.[20]

b. Unsold RA

PG&E's unsold RA volumes for 2023 deliveries represent RA amounts that were offered for sale, but were not sold or used by the IOU, as described in Chapter 8. PG&E documents the volumes of RA offered for sale in the Quarterly Compliance Report (QCR), which includes showing that it is consistent with Appendix S of its BPP.[21] PG&E had [redacted] of unsold RA volumes related to PCIA-eligible resources.

D.18-10-019 directed the IOUs to value all RPS and RA attributes in the PCIA-eligible portfolio, regardless of whether they were retained for compliance or they were unsold, at the forecast MPB for the attribute until a decision was issued in Phase 2 of PCIA Order Instituting Rulemaking. In D.19-10-001, the Commission ruled that all unsold RA product shall be valued at zero.[22]

c. 2023 Retained RA

As described in Chapter 8, the volume of retained RA is based on the resources used for PG&E's compliance and retained for IOU use. As required by D.19-10-001, PG&E records retained RA volumes at the

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20 2023 Sold RA value recorded to Accounting Procedure 5.g. of Preliminary Statement Part HS includes any adjustments for true-ups to prior periods.

21 PG&E's 2023 QCRs were submitted to the Commission in the following ALs: (1) AL 6927-E (Quarter 1), (2) AL 7001-E (Quarter 2), (3) AL 7059-E (Quarter 3); and (4) AL 7159-E (Quarter 4).

22 D.19-10-001, OP 3.e.

Forecast RA Adder throughout the year, which is trued up using the Final RA Adder, as calculated by Energy Division. Table 12-4 summarizes the Final RA Adder by RA type and the total retained RA volumes.

TABLE 12-4
RETAINED RA VALUE

Line No.		Final Adder ($/kW-Month)	Total Retained RA (MW-Year)	Notional Value ($ millions)
1	Local – PG&E	$8.38	[redacted]	[redacted]
2	Local – SCE	$7.79	[redacted]	[redacted]
3	Local – SDG&E	$9.77	[redacted]	[redacted]
4	Flex	$7.82	[redacted]	[redacted]
5	System	$14.37	[redacted]	[redacted]

d. Allocation of Retained RA Value and Sold RA to PABA Vintages

The 2023 retained and sold RA recorded in the PABA were allocated pro-rata to the vintages based on the adopted 2023 ERRA Forecast portfolio position. Specifically, the allocation factors were developed using the forecasted Net Qualifying Capacity (NQC) assigned to each vintage for each RA type.[23] The 2023 allocation rate for Retained RA was approved in December 2022 and was scheduled to be effective in January 2023. Table 12-5 below shows the 2023 RA allocation factors used to allocate recorded retained RA amounts and revenues associated with RA sold to third parties.

[23] The forecasted NQCs were extracted from PG&Es Joint IOU Common Template workpaper supporting the 2023 Update to Prepared Testimony filed during the Fall Update in A.22-05-029 and supporting D.22-12-044.

TABLE 12-5
2023 RA ALLOCATION FACTORS BY RA TYPE AND PABA SUBACCOUNT EFFECTIVE JAN-23 TO DEC-23

Line No.		Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total
1	Local																
2	NQC (MW-Year)	1,904.14	1,564.69	112.41	31.41	210.34	2.52	1.52	4.88	0.00	60.77	0.00	332.64	9.17	1.84	0.00	4,236.30
3	Percent of Total	44.95%	36.94%	2.65%	0.74%	4.97%	0.06%	0.04%	0.12%	0.00%	1.43%	0.00%	7.85%	0.22%	0.04%	0.00%	100.00%
4	Flex																
5	NQC (MW-Year)	367.80	919.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	562.98	0.00	657.50	0.00	2,508.02
6	Percent of Total	14.66%	36.67%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	22.45%	0.00%	26.22%	0.00%	100.00%
7	System																
8	NQC (MW-Year)	1,783.15	209.34	44.85	24.36	55.11	17.74	1.14	2.54	1.68	5.84	0.00	0.00	0.00	0.24	0.00	2,145.99
9	Percent of Total	83.09%	9.75%	2.09%	1.14%	2.57%	0.83%	0.05%	0.12%	0.08%	0.27%	0.00%	0.00%	0.00%	0.01%	0.00%	100.00%

4. System RA Value Transferred to the System Reliability Incremental Procurement Subaccount

D.21-03-056 directs PG&E to prepare for potential extreme weather by increasing the peak and net peak supply to prevent the need for rotating outages. The Commission authorized recovery of the costs associated with increasing peak and net peak supply through the CAM methodology, which is recorded in the NSGBA. However, one type of transaction associated with increasing peak and net peak supply is recorded to PABA: Excess RA capacity value transferred to the System Reliability Incremental Procurement (Reliability OIR), a subaccount of the NSGBA. This program is used to meet the system reliability incremental procurement targets, or for new long-term procurement that meets the 2021 and 2022 emergency procurement requirements pursuant to D.21-03-056. Transfers from PG&E's existing portfolio to the Reliability OIR, after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 16 percent planning reserve margin, are found in accounting procedure 5.I.[24] Transfers from PG&E's PCIA resource portfolio results in a credit to PABA and a debit to NSGBA[25]. PG&E transferred a total of 358 MW of excess capacity in 2023.

5. Adopted UOG Revenue Requirements

As affirmed in D.18-10-019,[26] the adopted PCIA-eligible UOG revenue requirement has been assigned to PABA vintage subaccounts based whether the resources are legacy UOG or were built or acquired after

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[24] AL 6222-E approved on December 28, 2020. PG&E expects the need for longer term procurement to meet bundled service customer's load given the recent proposed decision and alternate proposed decision issued in the Integrated Resource Plan Rulemaking, R.20-05-003.

[25] During 2023, Diablo Canyon was used as the available resource with excess capacity to help meet the system reliability incremental procurement targets. However, this process could apply to any relevant PCIA resource.

[26] D.18-10-019, pp. 51-59 and Conclusion of Law 12 and 13.

2002.[27] Legacy UOG includes PG&E's hydroelectric facilities and Diablo Canyon Power Plant (DCPP). Facilities constructed after 2002 include PG&E's Colusa, Gateway, and Humboldt Power Plants, PG&E's solar facilities and two fuel cells.[28] The vintage for facilities built after 2002 is based on the facilities' construction start date. The first annual vintage subaccount is 2009, so resources built between 2002 and 2008 are assigned to UOG Legacy vintage and remaining resources are assigned to the 2009 and later vintages.

The Commission approved UOG construction start date as an attribute that would define UOG vintage for cost recovery purposes. PG&E has developed a formal definition of "UOG construction start date" and supporting documentation to enable a standardized process to assign vintages to UOG facilities and communicated to all stakeholders for use in the UOG vintaging process:

> For the purpose of determining the "Construction Start Date" for PCIA-eligible utility-owned (UO) generation resources and storage resources, PG&E shall use the later of: (1) the first date that expenditures are recorded to SAP Project Order(s) established for the resource that are associated with site-specific construction work and that will be capitalized once the project reaches commercial operation, or (2) the date the Commission approves the new generation resource for cost recovery. Alternatively, if the Commission decision directing procurement assigns a resource vintage prior to selection of the resource, the Commission-assigned vintage will supersede vintaging the resource based on a construction start date.[29]

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27 The adopted UOG revenue requirement also includes Electric Supply Administration (ESA) costs, which is embedded in the adopted generation base revenue requirement approved in PG&E's General Rate Case. ESA costs allocated to the electric generation balancing accounts was adjusted to exclude Core Gas Supply costs. A portion of the ESA costs are then proportionally allocated to the PABA vintage subaccounts.

28 Fuel cells were decommissioned during 2021. However, PG&E's UOG revenue requirements are on a forecast levelized basis through 2022. These are flagged for any residual allocations for the final period of the GRC rate case period.

29 In reviewing all UOG facility assignments during and internal audit initiated during 2020, PG&E determined four resources that were given later PCIA vintages than otherwise allowable under this definition. Two of these resources were pre-2009 and would require no change to entries into PABA. PG&E Huron was given a 2011 vintage instead of 2010, while PG&E Guernsey was given a 2012 vintage instead of 2011. As explained in PG&E's 2021 ERRA Compliance Filing, formal grandfathering of the other two resources was recommended.

Under this formal definition, no PCIA-eligible UOG facilities were approved by the Commission and no site-specific construction started during the Record Period of 2023.

Other electric generation amounts approved by the Commission to be recovered through the PABA include: (1) approved pension contribution revenue requirement associated with the UOG revenue requirement; (2) adjustments to PG&E's UOG revenue requirement (e.g., cost of capital and tax reform); (3) gain or loss on sale of electric generation non-depreciable assets, including removal of assets sold that are embedded in the generation base revenue requirement; (4) DCPP employee retention program and license renewal costs; and (5) transfer of generation related amounts from other accounts. The following table summarizes how the adopted UOG amounts recorded in the PABA are assigned/allocated to the vintages.[30]

TABLE 12-6
ADOPTED UOG ASSIGNMENT/ALLOCATION TO PABA

UOG Item		Assignment/Allocation
Pension		Allocated to UOG facilities and ESA based on adopted 2020 General Rate Case (GRC). Electric Generation Results of Operations (RO) labor expenses for each facility.
UOG Revenue Requirement	Facility: Hydro and Nuclear	UOG Legacy
	Fossil: Gateway, Colusa, Humboldt	2009 Vintage
	Fuel Cell	2020 Vintage
	Solar Photovoltaic	2010 - 2012 Vintages
	ESA*	Allocated among PABA, ERRA, and NSGBA based on adopted 2020 RRQ for each account. Amount assigned to PABA is further allocated based on the adopted 2020 RRQ (Advice 5781-E, Appendix B)
	Cost of Capital Adjustment	Allocated to UOG facilities and ESA based on adopted 2020 General Rate Case (GRC). Electric Generation Results of Operations (RO) Ratebase.
	Ex Parte Penalty	Amounts are based on a Settlement Agreement approved by the Commission in 2018 related to the Ex Parte investigations.
Gain/Loss on sale of asset		Assigned to same vintages as asset sold
DCPP Employee Retention and License Renewal		UOG Legacy

* Excludes Core Gas Supply amounts assigned to ERRA for recovery.

30 The vintage assignments found in Table 12-6 are consistent with the final UOG Resource vintage determination described in Section C.5 above.

6. CAISO Related Charges and Revenues

As described in Chapter 10, PG&E incurs procurement costs and receives revenues for various interactions through its participation in the CAISO market. PG&E incurs costs for the following activities: day ahead (DA) and real-time purchases, grid management charges, Federal Energy Regulatory Commission Fees, and other miscellaneous CAISO charges. PG&E receives revenues related to DA and real-time sales, scheduling coordinator fees, and congestion revenue rights. Section 37 sanctions are excluded from the CAISO Settlement Charges/(Revenues) which include failure on a timely basis to report generator outages, submit meter data and/or provide other information required by CAISO Tariff. PG&E assigns these CAISO related charges and revenues to PABA vintages based upon the vintage the contract or UOG resource is assigned.

During 2023, PG&E transferred net CAISO Revenues related to DAC-GT interim renewable resources out of PABA for vintages 2012, 2013 and 2015 to support the DAC-GT Program; this entry is included in accounting procedure 5.t.[31] In addition, PABA transfers of net CAISO Revenues related to true-up 2022 and 2023 GTSR interim renewable resources out of PABA for vintages 2012 to 2015 to support the GTSR program to ERRA are also included in accounting procedure 5.t.[32]

The total amount recorded in the PABA for the recorded period is a credit of $3,002 million.[33] Further details on the types of charges, PG&E activities in the CAISO Market, and the basis for assigning to vintages is included in Chapter 10.

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[31] AL 5763-E/E-A approved on December 21, 2020 to separately record interim resources net costs entries by type for DAC-GT and to reflect that the transfer of certain net cost entries supporting DAC-GT and CS-GT will be from the PABA.

[32] AL 6677-E approved on November 16, 2022 to separately record interim resources net costs entries for GTSR and to reflect that the transfer from PABA to ERRA.

[33] This amount includes all CAISO settlement amounts recorded during 2023 accounting closes through December 31, 2023. CAISO settlement amounts reflected in Chapter 10 includes all settlement data for 2023 trade months, including those recorded during January 2024 accounting close.

7. Fuel Costs

As described in Chapter 6, costs of fuel used to supply UOG facilities and tolling contracts are recoverable in PABA and are allocated to the same vintages that the UOG facilities and contracts are assigned. Total gas costs are allocated based on fuel used by each UOG facility and tolling contract as a percentage of the total fuel used for each month. Fuel costs assigned to UOG facilities are recorded in PABA pursuant to accounting procedure 5.w. and fuel costs assigned to tolling contracts are recorded in the same accounting procedure that the contract costs are recorded in PABA. For example, if the contract costs are recorded in PABA pursuant to accounting procedure 5.ac., then the fuel costs are also recorded in that same tariff line item.

PG&E also records other non-gas fuel and related transportation and miscellaneous costs according to other accounting procedures in this section of Preliminary Statement HS, including distillate fuel, hydroelectric fuel, and nuclear fuel and associated carrying costs.

8. Contract Costs

As described in Chapter 9 and stated in the accounting procedures of PG&E's approved PABA preliminary statement, the majority of PCIA-eligible contract costs were assigned to vintages in the PABA based on the year the resource commitment was made, which in the case of procurement contracts is contract execution date. The above-market costs associated with Modified CAM Energy Storage contracts that are procured on behalf of bundled customers shall be assigned to 2019 vintage and will be recovered from bundled and departing load customers of non-IOU LSEs through the PCIA in which the contract costs will be allocated between PABA, MCAMBA and NSGBA (93.7%, 6.1% and 0.2% respectively).[34] The transfers of the DAC-GT interim renewable resources related to Renewable Bilateral costs associated with participating in WREGIS are in PABA for vintages 2012,

[34] D.22-05-015, OP4, D.19-11-016

2013 and 2015 to support the DAC-GT Program and is found in accounting procedure 5.ad.[35]

In addition, new Qualifying Facility Standard Offer Contract obligations authorized pursuant to D.20-05-005 were previously recorded into a non-vintage subaccount. PG&E proposed to move these costs from the non-vintage subaccount in PABA to the PPCBA as part of its 2022 ERRA Forecast Application (A.21-06-001). In D.22-02-002, the Commission approved this proposal, and upon disposition of AL 6524-E, PG&E transferred the costs to a new PPCBA subaccount and disposed of the nonvintage subaccount and related Standard Offer Contract tariff line item.

9. GHG Costs

In OP 10 of D.12-04-046, PG&E was granted authority to recover the costs incurred for GHG compliance instrument transactions through ERRA. D.18-10-019, OP 8 modified D.12-04-046 and required each utility to modify its ERRA and any other balancing accounts, as necessary, to be consistent with the PABA vintage subaccount structure adopted in the decision. This change was implemented via AL 5440-E and granted PG&E the authority to recover the costs incurred for GHG compliance instrument transactions through PABA pursuant to accounting procedure 5.ag. that was effective as of January 1, 2019.[36]

In addition, pursuant to D.20-12-005, PG&E was authorized to recover the GHG carrying costs through the ERRA and Annual Gas True-up proceedings.[37] These costs were first recorded to the PABA, as recorded under “GHG Costs” in tariff line item 5.ag. upon approval of 2022 ERRA Forecast decision, beginning in 2022.[38]

PG&E incurs both direct GHG costs and financially settled GHG costs. Direct GHG costs are those costs related to PG&E’s physical procurement

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35 AL 5763-E/E-A approved on 12/21/2020 to separately record interim resources net costs entries by type for DAC-GT and CS-GT and to reflect that the transfer of certain net cost entries supporting these programs will be from the PABA.

36 Any applicable broker fees are included in this line item. PG&E is authorized to use brokers for GHG procurement in its BPP.

37 Issued by the Commission on December 11, 2020.

38 PG&E filed AL 6175-E for minor tariff revisions and to notify the Commission that it would present such carrying costs in its 2022 ERRA Forecast Application.

of GHG compliance instruments consistent with its BPP authority, whereas financially settled GHG costs are obligations that can be financially settled as described in Section 8.b. below.

In addition, D.20-05-004 ordered Southern California Edison Company (SCE) to work in conjunction with other IOUs and the Public Advocates Office to address balancing account treatment of direct GHG costs and to provide transparency where these costs are recovered. The decision directed SCE to file a Petition for Modification to modify D.19-04-016 addressing the improvement of recording and presenting the Direct GHG costs in their respective balancing accounts, in a manner consistent with their associated resource costs. For example, GHG costs for PCIA-eligible resources will be recorded in PABA, Cost Allocation Mechanism-eligible resources will be recorded in NSGBA, and bundled-only resources will be recorded in ERRA. Accordingly, a new GHG Balancing Account Table was added to Attachment A to show the total GHG costs recorded to each balancing account during the record year.

a. PG&E's Process for Recording Direct GHG Costs

As explained below, the costs associated with PG&E's purchases of GHG compliance instruments in a given year will not match with the costs recorded in the PABA for the same year. If PG&E were to participate in the quarterly Air Resources Board (ARB) auction, those compliance instruments would be recorded to PG&E's inventory when auction results are released. GHG compliance instruments and offset credits purchased from other third-party sellers are recorded to PG&E's inventory when they are received. Each month, GHG emissions costs are recorded in PABA based on the accrual method of accounting using the best available volume of emissions and Weighted Average Cost (WAC) price at the time the emissions costs are recorded. Physical compliance obligation costs are calculated as the WAC price of Eligible Compliance Instruments held in inventory at the end of a month multiplied by the quantity of emissions generated in that month. The accrual amount will continue to be trued-up in subsequent months as new or additional information becomes available for emission quantities and for WAC price changes.[39]

PG&E's current methodology for calculating the WAC is consistent with D.19-04-016.[40] The WAC is calculated for each specified compliance period. When compliance instruments are purchased, they are held in Inventory at the purchase price. When compliance instruments are added, the Inventory increases, and the WAC price may change. The cost of inventory also increases when there are payments in fees or premiums related to the compliance instruments. The WAC is calculated as the total cost, inclusive of fees and premiums, of eligible compliance instruments in inventory, divided by the total quantity of eligible compliance instruments in inventory. Compliance instruments held in inventory are segregated by their eligible compliance periods (based on the vintage year). This methodology is done in accordance with generally accepted accounting practices.

The accounting expense is then determined by comparing the total change in the expected gross emissions expense inception to date less the total cumulative recorded emissions expense inception to date. The emissions expense is based on the current WAC of inventory (\$/mtCO_2e) multiplied by emissions volumes (\$/mtCO_2e). GHG costs are associated with PG&E's fossil fuel UOG facilities and therefore assigned to the same vintage in PABA as those facilities.

b. PG&E's Process for Recording Financially Settled GHG Emissions Costs

As noted in Chapter 7, GHG Compliance Instrument Procurement, some PG&E tolling contracts allow PG&E to elect financial settlement of GHG emissions obligations.[41] In these cases, GHG emission costs are

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39 When the cost, or debit, is recorded in the PABA, a corresponding entry, a credit, is recorded to a liability account, reflecting PG&E's liability to surrender GHG compliance instruments to the ARB. The inventory and liability accounts are reduced when the GHG compliance instruments have been surrendered to the ARB and/or transferred to a third party.

40 Issued by the Commission on April 25, 2019.

41 See Chapter 7, Section C.1.

embedded within the contract payments made to the counterparty and therefore recorded in the same balancing account and accounting procedure as the contract costs. For example, financially settled tolling agreement costs for both the contract and GHG emissions payments made to the counterparty that are recorded in the PABA are recorded in accounting procedure 5.ac for bilateral contracts.

10. GTSR PCIA Program Charges

PG&E is authorized to transfer PCIA related Program Charge expense associated with the GTSR Program dedicated resources for customers taking service for the GT and ECR subaccounts from the PABA to the GTSRBA.[42] During the record period PG&E recorded $0.3 million in PCIA Program Charge credit in procedure 5.ah for GTSR program charges. In addition, PG&E is authorized to transfer interim pool resources' contract expenses in PABA for vintages 2012 to 2015 to GTSRBA, which can be found in accounting procedure 5.aj.[43] During the record period PG&E recorded $19.9 million to transfer 2023 and true-up 2022 interim pool resources' contract costs associated with the GTSR Program from PABA to GTSRBA.

11. Miscellaneous Costs

PG&E is authorized to recover indirect costs that support PG&E's management of its procurement/generation resource portfolio.[44] These costs include credit and collateral and third-party independent evaluator reviews.[45] Additionally, PG&E is authorized to transfer amounts to recover the transfer or repayment of the under-collection due to the PCIA revenue shortfall from the applicable PABA subaccount to the PCIA Undercollection

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[42] 2020 ERRA Compliance SA (A.21-03-008) and AL 6297-E approved on 1/1/2022 to record the transfer of PCIA program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT and E-ECR to PABA.

[43] AL 6677-E approved on 11/16/2022 to separately record interim resources contract expenses for GTSR and to reflect that the transfer from PABA to GTSRBA.

[44] See PG&E's approved PABA tariff, Electric Preliminary Statement Part HS.

[45] As approved in Advice 5440-E, hedging costs, Net Energy Metering payments and Energy Storage Evaluation Program funding remain in ERRA for recovery from bundled customers.

Balancing Account (PUBA).[46] Finally, PG&E is authorized to transfer amounts to or from other accounts as authorized by the Commission.[47]

In Advice 5440-E, the Commission approved allocating credit and collateral and WREGIS certificate fees among PABA, ERRA, and the NSGBA based on the adopted revenue requirements for each of the accounts.[48] Independent evaluator expenses are assigned to PABA, ERRA, NSGBA, or MCAMBA based on the account from which the generation resource being evaluated is recorded and recovered. However, if the expenses are not associated with a specific resource, which is generally the case, the expenses are allocated to ERRA and PABA vintages the same as credit and collateral and WREGIS expenses.

In compliance with D.18-10-019 and D.20-02-047,[49] PABA began recording the transfer of the under-collection due to the PCIA revenue shortfall from PABA to PUBA. This amount is equal to the difference between the uncapped vintaged PCIA rate by customer class minus the capped vintage PCIA rate by customer class applicable to departing load customers (net of Revenue Fees and Uncollectibles) multiplied by the departing load's usage by customer class for each vintage. Subsequently, D.20-12-038 authorized an incremental rate adder to departed load PCIA rates to repay the forecast 2020 undercollection over three years from 2021 through 2023. These incremental rates are being transferred from PABA to PUBA to recognize the reduction in the outstanding undercollection due to PCIA capped rates. This was slightly offset to the extent that rebates and rebills of prior years occurred throughout the record period.

Finally, transfer of amounts from other accounts to the PABA are generally assigned to the same vintage as the associated base generation

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46 See PG&E's approved PABA tariff, Electric Preliminary Statement Part HS, Accounting Procedure 5.am.

47 For example, in the 2023 Annual Electric True-up (AL 6805-E) the Commission authorized PG&E to transfer various 2022 year-end amounts totaling to $112.4 million to PABA. In D.22-01-023 of R.17-06-026, the Commission authorized PG&E to transfer each year-end ERRA balance to the most-recent vintage subaccount of PABA; during January 2023, PG&E transferred the 2022 ERRA balance of $584.8 million to PABA.

48 AL 5527-E, Appendix A and Appendix C. Note that amounts allocated to the NSGBA are approved to be recorded in the ERRA.

49 Entries implemented pursuant to ALs 5624-E and 5781-E.

costs. For example, refunds transferred from the DOE Litigation Balancing Account, are assigned to the same PABA vintage as DCPP costs, which are recorded in the UOG Legacy vintage.

D. Variance Analysis

In Table 12-7, PG&E provides a summary of the PABA portfolio costs recorded in the current record period compared to the forecast included in its 2023 ERRA Forecast Fall Update Application, approved by the Commission in D.22-12-044.

TABLE 12-7
2023 ACTUAL RECORDED COSTS COMPARED TO APPROVED FORECAST

Line No.	Description	Recorded (PABA) Millions of Dollars	Forecast Millions of Dollars	Variance Millions of Dollars
1	Fuel Cost for UOG Facilities	[redacted]	[redacted]	[redacted]
2	UOG Costs (GRC Costs)	[redacted]	[redacted]	[redacted]
3	CAISO Cost	[redacted]	[redacted]	[redacted]
4	Contract & GHG Costs	[redacted]	[redacted]	[redacted]
5	Renewable Portfolio Standard-Eligible Contracts	[redacted]	[redacted]	[redacted]
6a	Retained RPS	[redacted]	[redacted]	[redacted]
6b	Retained RA	[redacted]	[redacted]	[redacted]
7	Green Tariff Shared Renewables (GTSR) PCIA Program Charges	[redacted]	[redacted]	[redacted]
8	Miscellaneous Costs	[redacted]	[redacted]	[redacted]
9	Total Procurement Costs in ERRA Forecast Proceeding	[redacted]	[redacted]	[redacted]

As Table 12-7 indicates, PG&E's procurement costs recorded across the portfolio were $810.8 million higher than forecasted, primarily due to lower-than-forecast net CAISO market revenues due to lower market electricity prices and a decrease in expected total generation, lower than expected contract costs, and higher Retained RPS offset by lower-than-forecast RPS-eligible contracts. RPS costs are lower than forecast due to the energy revenue component of RPS and other energy sale contracts being incorporated in the contract forecast while the recorded benefit is under CAISO market revenues. RPS costs are still lower than forecast due to higher than forecast RPS-eligible energy due to lower CAISO market electricity prices for contracts, greater generation from variable priced wind resources, and higher-than expected RPS sales. In addition, the 2023 and true-up of 2022 Interim

Resources Contract Costs associated with the shortfall of the GTSR Program moved from PABA (vintages 2012-2015) to GTSRBA, and 2023 and true-up of 2022 Interim Resources CAISO Market Revenues moved from PABA (vintages 2012-2015) to ERRA, which was not forecasted.

A more detailed variance analysis of forecasted and actual amounts is included in PG&E's confidential workpapers for Chapter 12.

E. Conclusion

PG&E has complied with the Commission's directives and has appropriately recorded entries to the PABA. PG&E requests that upon verification and review of the costs and revenues recorded in the PABA, the Commission find the recorded entries in PABA for the record period are appropriate, correctly stated, and in compliance with Commission decisions.

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
Customer Billed Revenue															
5.a.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from bundled customers	[redacted]												(319,047,897.54)
5.b.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from DA customers													(19,715,818.77)
5.c.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from CCA customers													(92,877,328.85)
		Revenues Net of RF&U													(431,641,045.16)
5.d.	DR/CR	A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Disadvantaged Communities Green Tariff (DAC-GT) rate schedule and PCIA billed under DAC-GT customer's otherwise applicable rate tariff.													-
5.e.	DR/CR	A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Community Solar Green Tariff (CS-GT) rate schedule and PCIA billed under DAC-GT customer's otherwise applicable rate tariff.													-

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
Actual Sold Renewable Portfolio Standard (RPS) & Resource Adequacy (RA) Transaction															
5.f.	CR	A credit entry equal to revenues received for Actual Sold RPS (REC) transactions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(190,464,643.34)
5.g.	CR	A credit entry equal to revenues received for Actual Sold RA transactions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(105,715,680.74)
Retained RPS & Retained RA Value			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
5.h.	CR	A credit entry equal to the Retained RPS Value, determined using the most current Commission-adopted RPS Adder multiplied by Actual Retained RPS quantities. A corresponding debit entry equal to the Retained RPS Value is recorded in ERRA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(184,637,507.75)
5.i.	DR/CR	A debit or credit entry to true-up the Retained RPS Value, determined using the Forecast RPS Adder to the Actual Retained RPS Value using the Final RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RPS Value is recorded in ERRA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(166,033,720.56)

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.j.	**CR**	A credit entry equal to the Retained RA Value, determined using the most current Commission-adopted RA Adder, multiplied by the Actual Retained RA quantities. A corresponding debit entry equal to the Retained RA Value is recorded in ERRA.	[redacted]												(714,112,662.70)
5.k.	**DR/CR**	A debit or credit entry to true-up the Retained RA Value, determined using the Forecast RA Adder to the Retained RA Value using the Final RA Adder. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in ERRA.													(212,924,138.50)
System RA Value Transferred to the System Reliability Incremental Procurement Subaccount															

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.l.	CR	A credit entry equal to the value of RA capacity that is excess or unsold RA capacity that is transferred to the System Reliability Incremental Procurement Subaccount of NSGBA and used to meet the updated system reliability incremental procurement targets pursuant to D.21-12-015, after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 15% planning reserve margin. The credit entry will use the most current market price benchmark for system RA approved int he Annual ERRA Forecast, which is used to calculate the value of RA capacity in the PCIA calculation.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(5,149,776.90)
UOG Costs			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
5.m.	DR	A debit entry equal to one-twelfth of the electric generation portion of revenue requirement associated with the CPUC authorized pension contribution amount	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	33,816,954.99

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description		FY 2023 YTD
5.n.	DR	A debit entry equal to the annual authorized revenue requirements associated with PG&E's owned generation divided by twelve, excluding PCIA-eligible UOG resource costs that have been procured by Central Procurement (CPE) for recovery through the New System Generation Charge (NSGC) & recorded to the Centralized Local Procurement Subaccount (CLPSA) of the New System Generating Balancing Account (NSGBA).	[redacted]	2,141,922,055.33
5.o.	DR/CR	A debit or credit entry, as appropriate, to record ESA costs associated with PCIA eligible generation resources portfolio/ procurement activity (which is embedded in the annual authorized revenue requirements associated with PG&E's owned generation)	[redacted]	21,437,338.98
5.p.	DR/CR	A debit or credit entry, as appropriate, to record the gain or loss on the sale of an electric generation non-depreciable asset, as approved by the CPUC	[redacted]	30,517,086.55

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.q.	DR	A debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant Employee Retention Program (see corresponding entry in the Employee Retention Subaccount of the Diablo Canyon Retirement Balancing Account (DCRBA) per Preliminary Statement HK, 5b.1)	[redacted]												49,755,351.60
5.r.	DR	A debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant license renewal costs													2,325,000.00
5.s.	DR	A debit entry equal to one-twelfth (or amortization period approved) of the power generation portion of the interim rate relief as authorized by the CPUC in Decision 19-04-039 on April 25, 2019, or future interim rate relief Decisions as authorized by the Commission -2022 WMCE CEMA Interim Rate Recovery (A.22-12-009) approved in June 2023.													(0.00)

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
ISO Related Charges/ Revenues															-
5.t.	DR/CR	A debit or credit entry equal to the net charges or revenues for energy associated with generating resources recovered in PABA, which excludes net charges or revenues for energy associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC & recorded to the CLPSA of the NSGBA, and excludes charges and energy revenues associated with interim pool renewable resources that support the DAC-GT program.	[redacted]												(2,964,331,354.84)
5.u.	DR/CR	A debit or credit entry equal to the net charges or revenues for miscellaneous CAISO charges/credits associated with generating resources recovered in PABA, which excludes net charges or revenue for miscellaneous CAISO charges/credits associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]												(11,750,704.26)

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.v.	DR/CR	A debit or credit entry equal to the net charges or revenues for ancillary services associated with generating resources recovered in PABA, excluding net charges or revenues for ancillary services associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]												(25,928,279.17)
Fuel Costs															-
5.w.	DR	A debit entry equal to natural gas fuel and related transportation and miscellaneous expenses for PCIA eligible UOG resources and contracts, excluding expenses in this category that have been allocated to PCIA-eligible UOG and contract resources that have been procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA.													561,602,039.60

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.x.	DR	A debit entry equal to distillate fuel and related transportation and miscellaneous expenses used at PG&E's fossil plants as a back-up, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]												1,049,890.09
5.y.	DR	A debit entry equal to the hydroelectric fuel and related transportation and miscellaneous expenses, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. The fuel expenses include water purchase costs for the hydroelectric plants.	[redacted]												2,619,277.22
5.z.	DR	A debit entry equal to nuclear fuel and miscellaneous expenses for the Diablo Canyon Nuclear Power Plant.	[redacted]												106,590,909.93

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.aa.	**DR**	A debit entry for nuclear fuel carrying costs equal to the interest on the monthly nuclear fuel inventory at the beginning of the month and one-half the balance of the current month's activity, multiplied at a rate equal to one-twelfth of the rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.	[redacted]												12,156,378.72
Contract Costs			[redacted]												-
5.ab.	**DR**	A debit entry to total costs associated with QF obligations that are not eligible for recovery as an ongoing CTC, which excludes non-CTC QF costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]												-
5.ac.	**DR**	A debit entry equal to bilateral contract obligations, which excludes bilateral costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA	[redacted]												460,559,409.70

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.ad.	**DR/CR**	A debit or credit entry equal to renewable contract obligations, and fees associated with participating in WREGIS, net of interim renewable resource costs supporting the DAC-GT Program, and net of WREGIS fees supporting the DAC-GT and the CS-GT Programs.	[redacted]												1,876,512,276.04
5.ae.	**DR**	A debit entry equal to the capacity and energy costs for QF/non-CHP Program contracts, which excludes QF/Non-CHP costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.													(828,550.00)
5.af.	**DR/CR**	A debit or credit entry equal to the cost or revenue associated with combined heat and power systems authorized in D.09-12-042, D.10-12-055 and D.11-04-033, and defined in PG&E's tariffs E-CHP, E-CHPS, and E-CHPSA, which excludes combined heat and power costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.													2,451,470.90

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
GHG Costs															-
5.ag.	DR	A debit entry equal to the greenhouse gas costs related to PG&E's generating facilities and physically settled compliance instruments associated with contracts, including carrying costs, which excludes GHG costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]												68,889,666.83
Green Tariff Shared Renewables (GTSR) Program Entries			[redacted]												-
5.ah.	DR/CR	A credit or debit to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-GT customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs.	[redacted]												254,034.55

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.ai.	**DR/CR**	A credit or debit entry to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-ECR, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-ECR customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs.	[redacted]												-

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.aj.	DR/CR	A debit or credit entry to reflect: (1) the transfer of the interim pool resource's contract expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the interim pool weighted average costs, multiplied by the portion of kWh delivered under the program to E-GT customers that the vintage's interim pool resources can support for the month or (2) entry to reflect any subsequent true-up of the weighted average price and generation volumes of the interim pool resources used to support the E-GT customers' subscription level to final actual costs and generation amounts available to support the program.	[redacted]												(19,871,229.54)
Miscellaneous Costs															
5.ak.	DR/CR	A debit or credit entry equal to pre-payments and credit and collateral payments, including all associated fees, for procurement purchase and, if applicable, reimbursements of prepayments, credit and collateral payments.													(46,053.40)

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.al.	DR	A debit entry equal to any other power costs associated with procurement.	[redacted]												1,425,468.02
5.am.	DR/CR	A credit/debit entry to transfer/repay the undercollection due to the PCIA revenue shortfall from the applicable PABA subaccount to the PUBA. The PCIA revenue shortfall is equal to the difference between the uncapped vintage PCIA rate by customer class minus the capped vintaged PCIA rate by customer class applicable to departing load customers, net of RF&U, multiplied by the departing load's usage by customer class for each vintage. The PCIA revenue shortfall is mapped to the PABA vintage subaccounts based on incremental revenue shortfall rates. Corresponding debit/credit entries will be recorded in PCIA Undercollection Balancing Account (PUBA), Electric Preliminary Statement Part HZ, based on the cumulative revenue shortfall rates, by customer vintage.													85,318,766.50

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2023
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	FY 2023 YTD
5.an.	DR/CR	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC.	[redacted]												708,342,707.92
		Total Monthly Activity Before Interest	**450,638,971.97**	**130,659,133.32**	**(60,131,600.21)**	**84,223,620.76**	**207,481,478.82**	**240,001,772.97**	**221,198,493.09**	**(54,953,445.06)**	**135,442,452.00**	**(341,213,539.89)**	**92,906,479.64**	**27,856,919.17**	**1,134,110,736.59**
5.ao.	DR/CR	An entry equal to the interest on the average balance of the account at the beginning of the month and the balance after the entries above, at a rate equal to one-twelfth the interest rate of the three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.	[redacted]												21,681,942.28
		Beginning Balance	**(333,829,165.83)**	**116,975,824.24**	**248,336,962.33**	**189,064,439.67**	**274,197,946.62**	**483,217,652.82**	**725,783,104.57**	**950,606,879.18**	**899,332,883.43**	**1,038,844,113.84**	**693,900,625.00**	**790,027,833.11**	**(333,829,165.83)**
		PABA Ending Balance	**116,975,824.24**	**248,336,962.33**	**189,064,439.67**	**274,197,946.62**	**483,217,652.82**	**725,783,104.57**	**950,606,879.18**	**899,332,883.43**	**1,038,844,113.84**	**693,900,625.00**	**790,027,833.11**	**821,963,513.05**	**821,963,513.05**
PCIA Subaccount															
6.a.	DR	A debit entry equal to imputed PCIA revenue based on the PCIA rate as adopted by the Commission;	[redacted]												-
6.b.	DR/CR	A credit or debit entry equal to the recorded PCIA revenues; and	[redacted]												-
6.c.	DR/CR	A credit or debit entry to transfer the balance as authorized by the Commission.	[redacted]												-
		Beginning Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
		PCIA Subaccount Ending Balance	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
		TOTAL PABA ENDING BALANCE	**116,975,824.24**	**248,336,962.33**	**189,064,439.67**	**274,197,946.62**	**483,217,652.82**	**725,783,104.57**	**950,606,879.18**	**899,332,883.43**	**1,038,844,113.84**	**693,900,625.00**	**790,027,833.11**	**821,963,513.05**	**821,963,513.05**

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
Revenues from Customers (net billed)			996,726,541.91	(1,012,847,233.82)	(209,903,875.34)	8,874,395.88	69,697,771.28	(29,087,309.25)	(1,251,549.07)	3,001,627.76	3,879,186.67	19,336,793.94	5,369,549.17	19,537,247.07	50,942,570.78	57,105,645.46	(413,022,407.60)	(431,641,045.16)
5.a.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from bundled customers	[redacted]															
5.b.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from DA customers																
5.c.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from CCA customers																
		Revenues (Net of RF&U)																
5.d.	DR/CR	A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Disadvantaged Communities Green Tariff (DAC-GT) rate schedule and PCIA billed under DAC-GT customer's otherwise applicable rate tariff.																
5.e.	DR/CR	A debit or credit entry equal to the difference between the vintaged PCIA revenues attributed to bundled customers served under the Community Solar Green Tariff (CS-GT) rate schedule and PCIA billed under CS-GT customer's otherwise applicable rate tariff.																
Actual Sold Renewable Portfolio Standard (RPS) Transaction			-	(91,030,749.30)	(50,651,547.47)	(14,967,907.90)	(19,265,188.10)	(10,278,836.31)	(896,981.52)	(1,653,566.23)	(313,545.92)	(1,406,320.58)	-	-	-	-	-	(190,464,643.34)
5.f.	CR	A credit entry equal to actual revenues for REC sales.	[redacted]															
Actual Sold Resource Adequacy (RA) Transaction			(46,029,059.43)	(30,651,854.39)	(1,792,015.62)	(688,634.85)	(2,969,381.90)	(238,298.62)	(30,850.43)	(86,096.72)	(32,988.70)	(748,359.16)	-	(15,079,421.29)	(103,710.48)	(7,265,009.14)	-	(105,715,680.74)
5.g.	CR	A credit entry equal to actual revenues for RA sales.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
Retained Renewable Portfolio Standard (RPS) Value			(214,784.55)	(86,303,438.67)	(51,191,827.62)	(17,970,281.46)	(22,577,609.56)	(15,361,650.91)	(3,683,317.47)	(6,905,085.49)	(520,890.53)	(2,341,854.98)	-	(186.74)	(31.61)	(106,237,222.06)	(37,363,046.68)	(350,671,228.31)
5.h.	**CR**	A credit entry equal to the Retained RPS Value, determined using the most current Commission-adopted RPS Adder multiplied by Actual Retained RPS quantities. A corresponding debit entry equal to the Retained RPS Value is recorded in ERRA.	[redacted]															
5.i.	**DR/CR**	A debit or credit entry to true-up the Retained RPS Value, determined using the Forecast RPS Adder to the Actual Retained RPS Value using the Final RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RPS Value is recorded in ERRA.	[redacted]															
Retained Resource Adequacy (RA) Value			(543,086,709.46)	(220,886,746.22)	(19,608,928.36)	(7,783,656.66)	(31,075,925.53)	(3,699,770.24)	(368,414.53)	(967,079.98)	(327,567.77)	(7,014,652.30)	-	(48,862,400.22)	(886,340.28)	(20,814,758.86)	(21,653,850.80)	(927,036,801.20)

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.j.	**CR**	A credit entry equal to the Retained RA Value, determined using the most current Commission-adopted RA Adder, multiplied by the Actual Retained RA quantities. A corresponding debit entry equal to the Retained RA Value is recorded in ERRA.	[redacted]															
5.k.	**DR/CR**	A debit or credit entry to true-up the Retained RA Value, determined using the Forecast RA Adder to the Retained RA Value using the Final RA Adder. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in ERRA.																
System RA Value Transferred to the System Reliability Incremental Procurement Subaccount			(5,149,776.90)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(5,149,776.90)

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.l.	**CR**	A credit entry equal to the value of RA capacity that is excess or unsold RA capacity that is transferred to the System Reliability Incremental Procurement Subaccount of NSGBA and used to meet the system reliability incremental procurement targets pursuant to D.21-03-056, after having made reasonable attempts to sell excess capacity to other load-serving entities to meet their 15% planning reserve margin. The credit entry will use the most current market price benchmark for system RA approved int he Annual ERRA Forecast, which is used to calculate the value of RA capacity in the PCIA calculation.	[redacted]															
UOG Costs			1,985,388,757.74	234,273,819.74	22,815,227.76	16,433,854.99	21,260,435.83	(143,275.98)	(64,757.84)	(115,166.52)	(3,314.06)	(9,938.38)	(4,616.35)	(6,557.48)	(2,039.27)	(40,041.53)	(8,601.21)	2,279,773,787.44

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.m.	**DR**	A debit entry equal to one-twelfth of the electric generation portion of revenue requirement associated with the CPUC authorized pension contribution amount, transferred from UGBA.	[redacted]															
5.n.	**DR**	A debit entry equal to the annual authorized revenue requirements associated with PG&E's owned generation divided by twelve , transferred from UGBA.	[redacted]															
5.o.	**DR/CR**	A debit or credit entry, as appropriate, to record ESA costs associated with PCIA eligible generation resources portfolio/ procurement activity (which is embedded in the annual authorized revenue requirements associated with PG&E's owned generation), transferred from UGBA	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.p.	**DR/CR**	a debit or credit entry, as appropriate, to record the gain or loss on the sale of an electric generation non-depreciable asset, as approved by the CPUC, transferred from UGBA	[redacted]															
5.q.	**DR**	a debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant Employee Retention Program (see corresponding entry in the Employee Retention Subaccount of the Diablo Canyon Retirement Balancing Account (DCRBA) per Preliminary Statement HK, 5b.1), transferred from UGBA	[redacted]															
5.r.	**DR**	a debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant license renewal costs, transferred from UGBA	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.s.	**DR**	A debit entry equal to one-twelfth (or amortization period approved) of the power generation portion of the interim rate relief as authorized by the CPUC in Decision 19-04-039 on April 25, 2019 & 2022 WMCE CEMA Interim Rate Recovery (A.22-12-009) approved in June 2023.	[redacted]															
ISO Related Charges/ Revenues			(2,279,469,211.86)	(451,367,618.28)	(99,587,915.20)	(45,597,913.38)	(77,148,099.74)	(32,034,035.01)	(4,101,006.02)	(6,032,176.35)	(1,254,755.75)	(4,183,019.09)	0.00	-	-	(1,390,269.31)	155,681.70	(3,002,010,338.27)

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.t.	**DR/CR**	A debit or credit entry equal to the net charges or revenues for energy associated with generating resources recovered in PABA, which excludes net charges or revenues for energy associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC & recorded to the CLPSA of the NSGBA, and excludes charges and energy revenues associated with interim pool renewable resources that support the DAC-GT program.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.u.	**DR/CR**	A debit or credit entry equal to the net charges or revenues for miscellaneous CAISO charges/credits associated with generating resources recovered in PABA, which excludes net charges or revenue for miscellaneous CAISO charges/credits associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.v.	**DR/CR**	A debit or credit entry equal to the net charges or revenues for ancillary services associated with generating resources recovered in PABA, excluding net charges or revenues for ancillary services associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															
Fuel Costs			122,416,455.96	562,719,645.06	(1,117,605.46)	-	-	-	-	-	-	-	-	-	-	-	-	684,018,495.57

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.w.	**DR**	A debit entry equal to natural gas fuel and related transportation and miscellaneous expenses for PCIA eligible UOG resources and contracts, excluding expenses in this category that have been allocated to PCIA-eligible UOG and contract resources that have been procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															
5.x.	**DR**	A debit entry equal to distillate fuel and related transportation and miscellaneous expenses used at PG&E's fossil plants as a back-up, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA.																

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.y.	**DR**	A debit entry equal to the hydroelectric fuel and related transportation and miscellaneous expenses, excluding expenses in this category that can be allocated to PCIA-eligible UOG and contract resources procured by the CPE for recovery through the NSGC and recorded to the CLPSA of the NSGBA. The fuel expenses include water purchase costs for the hydroelectric plants.	[redacted]															
5.z.	**DR**	A debit entry equal to nuclear fuel and miscellaneous expenses for the Diablo Canyon Nuclear Power Plant.																

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.aa.	**DR**	A debit entry for nuclear fuel carrying costs equal to the interest on the monthly nuclear fuel inventory at the beginning of the month and one-half the balance of the current month's activity, multiplied at a rate equal to one-twelfth of the rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor.	[redacted]															
Contract Costs			8,351,260.11	1,409,873,186.55	458,342,016.79	129,214,491.18	158,965,524.14	70,419,699.18	11,633,530.42	20,345,954.00	2,591,088.34	6,237,193.02	-	39,118,279.57	-	22,265,583.42	1,336,799.91	2,338,694,606.64
5.ab.	**DR**	A debit entry to total costs associated with QF obligations that are not eligible for recovery as an ongoing CTC, which excludes non-CTC QF costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.ac.	**DR**	A debit entry equal to bilateral contract obligations, which excludes bilateral costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA	[redacted]															
5.ad.	**DR/CR**	A debit or credit entry equal to renewable contract obligations, and fees associated with participating in WREGIS, net of interim renewable resource costs supporting the DAC-GT Program, and net of WREGIS fees supporting the DAC-GT and the CS-GT Programs.																

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.ae.	**DR**	A debit entry equal to the capacity and energy costs for QF/non-CHP Program contracts, which excludes QF/Non-CHP costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.af.	**DR/CR**	A debit or credit entry equal to the cost or revenue associated with combined heat and power systems authorized in D.09-12-042, D.10-12-055 and D.11-04-033, and defined in PG&E's tariffs E-CHP, E-CHPS, and E-CHPSA, which excludes combined heat and power costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															
GHG Costs			68,889,666.83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68,889,666.83

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.ag.	**DR**	A debit entry equal to the greenhouse gas costs related to PG&E's generating facilities and physically settled compliance instruments associated with contracts, which excludes GHG costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]															
Green Tariff Shared Renewables (GTSR) Program Entries			-	-	-	-	(1,509,532.46)	(7,281,986.72)	(4,110,504.21)	(6,981,298.72)	(2,168.57)	(4,582.68)	(21,468.56)	(14,239.77)	256,356.38	40,578.79	11,651.53	(19,617,194.99)

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.ah.	**DR/CR**	A credit or debit to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-GT customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.ai.	**DR/CR**	A credit or debit entry to reflect the transfer of PCIA Program Charge expense associated with the GTSR Program for customers taking service under Schedule E-ECR, equal to the PCIA Program Charge rate, multiplied by the kWh delivered under the program to the E-ECR customers for the month, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs.	[redacted]															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.aj.	**DR/CR**	A debit or credit entry to reflect: (1) the transfer of the interim pool resource's contract expense associated with the GTSR Program for customers taking service under Schedule E-GT, equal to the interim pool weighted average costs, multiplied by the portion of kWh delivered under the program to E-GT customers that the vintage's interim pool resources can support for the month or (2) entry to reflect any subsequent true-up of the weighted average price and generation volumes of the interim pool resources used to support the E-GT customers' subscription level to final actual costs and generation amounts available to support the program.	[redacted]															
Miscellaneous Costs (Collateral, Other Procurement Costs & Transfer Amts to Other Accounts)			81,994,942.35	134,483,555.73	38,780,436.84	(24,471,658.59)	(56,156,563.02)	54,371,395.33	4,283,442.80	474,739.21	(1,954,301.71)	(4,016,535.17)	(3,209,026.00)	6,861,748.55	(83,242,546.78)	(110,917.39)	646,952,176.88	795,040,889.04

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
5.ak.	**DR/CR**	A debit or credit entry equal to pre-payments and credit and collateral payments, including all associated fees, for procurement purchase and, if applicable, reimbursements of prepayments, credit and collateral payments.	[redacted]															
5.al.	**DR**	A debit entry equal to any other power costs associated with procurement.	[redacted]															

5.am.	**DR/CR**	A credit/debit entry to transfer/repay the undercollection due to the PCIA revenue shortfall from the applicable PABA subaccount to the PUBA. The PCIA revenue shortfall is equal to the difference between the uncapped vintage PCIA rate by customer class minus the capped vintaged PCIA rate by customer class applicable to departing load customers, net of RF&U, multiplied by the departing load's usage by customer class for each vintage. The PCIA revenue shortfall is mapped to the PABA vintage subaccounts based on incremental revenue shortfall rates. Corresponding debit/credit entries will be recorded in PCIA Undercollection Balancing Account (PUBA), Electric Preliminary Statement Part HZ, based on the cumulative revenue shortfall rates, by customer vintage.	[redacted]
5.an.	**DR/CR**	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC.	[redacted]

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
		Total Monthly Activity Before Interest	389,818,082.70	448,262,566.41	86,083,966.32	43,042,689.20	39,221,430.95	26,665,931.46	1,409,592.14	1,081,850.97	2,060,742.01	5,848,724.63	2,134,438.26	1,554,469.68	(33,035,741.26)	(56,446,410.63)	176,408,403.73	1,134,110,736.59
Interest			(48,343,597.89)	46,205,057.31	3,336,839.91	1,417,058.93	505,901.25	198,270.04	(71,174.18)	(158,109.69)	69,635.86	(54,314.34)	(78,895.82)	1,268,302.58	(1,632,839.75)	(713,059.00)	19,732,867.08	21,681,942.28
5.ao.	**DR/CR**	An entry equal to the interest on the average balance of the account at the beginning of the month and the balance after the entries above, at a rate equal to one-twelfth the interest rate of the three-month Commercial Paper for the previous month, as rep	[redacted]															
		Beginning Balance	**(960,148,606.33)**	**560,414,506.56**	**32,091,702.42**	**8,383,066.32**	**(2,764,386.41)**	**(10,583,359.06)**	**(2,805,546.24)**	**(4,958,433.29)**	**271,615.96**	**(5,221,946.76)**	**(2,602,051.35)**	**13,921,230.45**	**21,466,408.22**	**18,723,775.03**	**(17,141.33)**	**(333,829,165.83)**
		PABA Ending Balance	**(618,674,121.49)**	**1,054,882,130.28**	**121,512,508.65**	**52,842,814.45**	**36,962,945.79**	**16,280,842.43**	**(1,467,128.28)**	**(4,034,692.02)**	**2,401,993.83**	**572,463.53**	**(546,508.91)**	**16,744,002.72**	**(13,202,172.79)**	**(38,435,694.60)**	**196,124,129.47**	**821,963,513.05**
PCIA Subaccount			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6.a.	**DR**	A debit entry equal to imputed PCIA revenue based on the PCIA rate as adopted by the Commission;	[redacted]															
6.b.	**DR/CR**	A credit or debit entry equal to the recorded PCIA revenues; and																
6.c.	**DR/CR**	A credit or debit entry to transfer the balance as authorized by the Commission.																
		PCIA Subaccount Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Beginning balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2023
(YEAR-TO-DATE BY VINTAGE)
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	UOG Legacy	2009 Vintage	2010 Vintage	2011 Vintage	2012 Vintage	2013 Vintage	2014 Vintage	2015 Vintage	2016 Vintage	2017 Vintage	2018 Vintage	2019 Vintage	2020 Vintage	2021 Vintage	2022 Vintage	Total all Vintages for Current Month
		PCIA Subaccount Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		TOTAL PABA ENDING BALANCE	(618,674,121.49)	1,054,882,130.28	121,512,508.65	52,842,814.45	36,962,945.79	16,280,842.43	(1,467,128.28)	(4,034,692.02)	2,401,993.83	572,463.53	(546,508.91)	16,744,002.72	(13,202,172.79)	(38,435,694.60)	196,124,129.47	821,963,513.05