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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, 2020

PREPARED TESTIMONY

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
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TABLE OF ACRONYMS

Line No.	Acronym	Description
1	A.	Application
2	A/S	Ancillary Services
3	AB	Assembly Bill
4	A/C	Air Conditioning
5	AC	Alternating Current or Alternate Current
6	ACE	Apparent Cause Evaluation
7	AET	Annual Electric True-Up
8	AFW	Application for Work
9	AHC	American Hydro Company
10	AL	Advice Letter
11	AMP	Aggregator Managed Portfolio
12	ANSI	American National Standards Institute
13	AQI	Air Quality Index
14	ARB	Air Resources Board
15	ATS	Applied Technology Services
16	BAAQMD	Bay Area Air Quality Management District (only mentioned once in Chapter 3)
17	BAV	best available volume of emissions
18	BCR	Bid Cost Recovery
19	BioMASSMA	Biomass Memorandum Account
20	BioMAT	Bioenergy Market Adjusting Tariff
21	BioRAMMA	Bioenergy Renewable Auction Mechanism Memorandum Account
22	BPP	Bundled Procurement Plan
23	Btu	British Thermal Unit
24	Burney	Burney Forest Products
25	CAISO	California Independent System Operator
26	Cal Advocates	Public Advocates Office at the California Public Utilities Commission
27	CAM	Cost Allocation Mechanism
28	CAN	Control Area Network (only mentioned once in Chapter 3)
29	CAP	Corrective Action Program
30	CARB	California Air Resources Board
31	CARE	California Alternate Rates for Energy
32	CBP	Capacity Bidding Program

TABLE OF ACRONYMS
(CONTINUED)

Line No.	Acronym	Description
33	CCA	Community Choice Aggregator
34	CCCSIP	Central California Coast Seismic Imaging Project
35	CCM	cylinder control module
36	CCGT	Combined cycle gas turbine
37	CCSN	Central Coastal Seismic Network
38	CDWR	California Department of Water Resources
39	CEATI	Centre for Energy Advancement through Technological Innovation
40	CEC	California Energy Commission
41	CED	ConEdison Development
42	CECM	Consolidated Energy Contract Management
43	CEMS	Continuous Emission Monitoring system (only mentioned once in Chapter 3)
44	CFR	Code of Federal Regulations
45	CFCU	Containment Fan Cooler Unit
46	CGS	California Geological Survey
47	CHP	Combined Heat and Power
48	CIDI	Customer Inquiry, Dispute and Information
49	CIGRE	International Council on Large Electric Systems
50	CIP	Critical Infrastructure Protection (only mentioned once in Chapter 3)
51	CM	Contract Management
52	CNO	Chief Nuclear Officer
53	CO	carbon monoxide
54	CO_2	carbon dioxide
55	CO_2e	carbon dioxide equivalent
56	COD	Commercial Operation Date
57	COL	Conclusion of Law
58	Colusa	Colusa Generating Station
59	Commission	California Public Utilities Commission
60	Courtright	Courtright Forebay Reservoir Storage
61	CPUC	California Public Utilities Commission
62	CRADA	Cooperative Research and Development Agreement
63	CR	credit
64	CRR	Congestion Revenue Rights

TABLE OF ACRONYMS
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Line No.	Acronym	Description
65	CS-GT	Community Solar Green Tariff
66	CSA	Capacity Storage Agreement
67	CSIAL	Customer-Side Implementation Advice Letter
68	CSR	Customer Service Representative
69	CSU	California State University
70	CSU East Bay or CSUEB	California State University, East Bay
71	CT	Combustion Turbine
72	CTC	Competition Transition Charge
73	D2	Documentum
74	D.	Decision
75	DAC	Disadvantaged Communities
76	DAC SASH	Disadvantaged Community – Single-Family Affordable Solar Housing
77	DAC-GT	Disadvantaged Community Green Tariff
78	DACSASHBA	Disadvantaged Community – Single-Family Affordable Solar Housing Balancing Account
79	DACSASHMA	Disadvantaged Community – Single Family Affordable Solar Housing Memorandum Account
80	DC	Direct Current
81	DCPP	Diablo Canyon Nuclear Power Plant
82	DCSSBA	Diablo Canyon Seismic Studies Balancing Account
83	DUNC	degraded, un-analyzed or non-conforming
84	DLAP	Default Load Aggregation Point
85	DR	debit
86	DR	Demand Response
87	DSOD	Division of Safety of Dams
88	ECMS	Energy Contract Management and Settlements
89	ECP	Employee Concerns Program
90	ECR	enhanced community renewables
91	EDG	Emergency Diesel Generator
92	EDMS	Electronic Document Management System
93	EEI	Edison Electric Institute
94	EIM	Energy Imbalance Market
95	ERRA	Energy Resource Recovery Account

TABLE OF ACRONYMS
(CONTINUED)

Line No.	Acronym	Description
96	EN	Energy Bid
97	EPI	Electricity Price Index
98	ESA	Energy Storage Agreement
99	ESTAR	Electric Settlements Tool for Analysis and Reporting
100	EUP	Enriched Uranium Product
101	°F	Degree Fahrenheit (can be used lowercase)
102	FCE	FuelCell Energy
103	FERA	Family Electric Rate Assistance
104	FERC	Federal Energy Regulatory Commission
105	FF&U	Franchise Fees and Uncollectibles
106	FLR	Forced Loss Rate
107	FMM	Fifteen-Minute Market
108	FNM	Full Network Model
109	FIT	Feed-In Tariff
110	FOF	Finding of Fact
111	FOF	Forced Outage Factor
112	Gateway	Gateway Generating Station
113	GCOD	Guaranteed Commercial Operation Date
114	GE	General Electric
115	GEP	Guaranteed Energy Production
116	GFN	Good Faith Negotiation
117	GHG	Greenhouse Gas
118	GMC	Ground Motion Characterization
119	GMC	Grid Management Charges
120	GO	General Order
121	GRC	General Rate Case
122	GRIT	Generation Risk Information Tool
123	GSP	Gas Supply Plan
124	GT	Gas Turbines
125	GTSR	Green Tariff Shared Renewables
126	GTSRBA	Green Tariff Shared Renewables Balancing Account
127	GTSRMA	Green Tariff Shared Renewables Memorandum Account
128	GWh	gigawatt-hour

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(CONTINUED)

Line No.	Acronym	Description
129	HANG2	Hassayampa to North Gila
130	HBGS	Humboldt Bay Generation Station
131	Helm	Helms Pumped Storage Plant
132	HEP	high-energy piping
133	HRSG	Heat Recovery Steam Generator
134	Humboldt	Humboldt Bay Generating Station
135	HydroAMP	Hydropower Asset Management Partnership
136	I&C	Instrumentation and Control
137	ICE	Intercontinental Exchange
138	ID&WA	Irrigation District and Water Agency
139	IDWA	Irrigation District Water Associations
140	IEDD	Initial Expected Delivery Date
141	IFM	Integrated Forward Market
142	IMHR	Implied Market Heat Rate
143	ILRT	Integrated Leak Rate Test
144	IPRP	Independent Peer Review Panel
145	IOU	Investor-Owned Utility
146	IT	Information Technology
147	KRCC	Kern River Cogeneration Company
148	kV	kilovolt
149	kW	kilowatt
150	kWh	kilowatt-hour
151	LCA	Local Capacity Areas
152	LCD	Least-Cost Dispatch
153	LESS	low energy seismic survey
154	LIFO	Last-In First Out
155	LMP	Locational Marginal Price
156	LMPM	Local Market Power Mitigation
157	LSE	Load Serving Entities
158	LTSA	Long-Term Service Agreement
159	LTSP	Long Term Seismic Program
160	MAPE	Mean Absolute Percentage Error
161	MBCPA	Monterey Bay Community Power Authority

TABLE OF ACRONYMS
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Line No.	Acronym	Description
162	MCC	maximum cumulative capacity
163	MCFC	Molten Carbonate Fuel Cell
164	MDC	Maximum Dependable Capacity
165	MMA	Major Maintenance Adder
166	MMBtu	Millions of British Thermal Units
167	mmt	million metric ton
168	MO	Maintenance Outages
169	MPR	Market Price Referent
170	MRTU	Market Redesign and Technology Upgrade
171	MSG	Multi-Stage Generation
172	MTCBA	Modified Transition Cost Balancing Account
173	$mtCO_2e$	metric tons of carbon dioxide equivalent
174	MW	megawatt
175	MWh	megawatt-hour
176	NCPA	Northern California Power Agency
177	NDA	Non-Disclosure Agreement
178	NERC	North American Electric Reliability Corporation
179	NGR	Non-Generator Resource
180	NO_x	Nitrogen Oxide
181	NQA	Nuclear Quality Assurance
182	NQC	Net Qualifying Capacity
183	NRC	Nuclear Regulatory Commission
184	NSGBA	New System Generation Balancing Account
185	NTTF	Near-Term Task Force
186	O&M	Operations and Maintenance
187	OBS	Ocean Bottom Seismometer
188	OEM	Original Equipment Manufacturer
189	OIR	Order Instituting Rulemaking
190	OMS	Outage Management System
191	OP	Ordering Paragraph
192	OP7860	Operation Procedure 7860
193	ORA	Office of Ratepayer Advocates
194	PCIA	Power Charge Indifference Adjustment

TABLE OF ACRONYMS
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Line No.	Acronym	Description
195	PDR	Proxy Demand Response
196	PDS	Project Development Security
197	PEER	Pacific Earthquake Engineering Research
198	PG&E	Pacific Gas and Electric Company
199	PHC	Plant Health Committee
200	PLC	programmable logic controller
201	PMG	permanent magnet generator
202	PO	Planned Outages
203	PPA	Power Purchase Agreement
204	PRG	Procurement Review Group
205	PRT	Pattern Recognition Technologies
206	PRV	pressure relief valve
207	PSMP	Protection System Maintenance and Testing Program
208	Pub. Util. Code	Public Utilities Code
209	PPCBA	Public Purpose Charge Balancing Account
210	PURPA	Public Utility Regulatory Policies Act
211	PV	Photovoltaic
212	QA	Quality Assurance
213	QC	qualifying capacity
214	QCR	Quarterly Compliance Report
215	QF	Qualifying Facility
216	QF/CHP	Qualifying Facility and Combined Heat and Power
217	QIC	Qualifying Facilities Information Center
218	QV	Quality Verification
219	RA	Resource Adequacy
220	RAM	Renewable Auction Mechanism
221	RDRR	Reliability Demand Response Resources
222	REC	Renewable Energy Credits
223	REC	Renewable Energy Certificate
224	REM	Regulation Energy Management
225	ReMAT	Renewable Market Adjusting Tariff
226	Res.	Resolution (when used in conjunction with a number)
227	RF&U	Revenue Fees and Uncollectibles

TABLE OF ACRONYMS
(CONTINUED)

Line No.	Acronym	Description
228	RFO	Request for Offers
229	RFP	Request for Proposal
230	RMSE	Root Mean Square Error
231	RPS	Renewable Portfolio Standard
232	RPSCMA	Renewable Portfolio Standard Cost Memorandum Account
233	RTD	Real-Time Dispatch
234	RTM	Real-Time Market
235	RUC	Residual Unit Commitment
236	R.	Rulemaking
237	SAP WM	SAP Work Management
238	SB	Senate Bill
239	SC	Scheduling Coordinator
240	SCADA	Supervisory Control and Data Acquisition
241	SCE	Southern California Edison Company
242	SCEC	Southern California Earthquake Center
243	SCR	Selective Catalytic Reduction
244	SCUC	Security Constrained Unit Commitment
245	SDG&E	San Diego Gas & Electric Company
246	SEL	Schweitzer Engineering Laboratories
247	SFSU	San Francisco State University
248	SFWPA	South Feather Water and Power Agency
249	SGDP	Smart Grid Demonstration Program
250	SJCE	San Jose Clean Energy (SJCE)
251	SL4	Severity Level 4
252	SLIC	Scheduling and Logging ISO California
253	SMUD	Sacramento Municipal Utility District
254	SOC	State of Charge
255	SOC4	Standard of Conduct 4
256	SOFC	Solid Oxide Fuel Cell
257	SPPC	Sierra Pacific Power Company
258	SPS	Special Protection Scheme
259	SQS	Safety, Quality and Standards
260	SS	Self-Scheduling

TABLE OF ACRONYMS
(CONTINUED)

Line No.	Acronym	Description
261	ST	Steam Turbine
262	STARS	STARS Alliance, LLC
263	STARS	Strategic Teaming and Resource Sharing
264	SWU	Separate Working Unit
265	STES	Short Term Electric Supply
266	Sub-LAP	Sub-Load Aggregation Point
267	SVCEA	Silicon Valley Clean Energy Authority
268	T3	Task Tracking Tool
269	TEA	The Energy Authority, Inc.
270	TMNBC	Tree Mortality Non-Bypassable Charge
271	TSV	Turbine Shutoff Valve
272	UEG	Utility Electric Generation
273	UGBA	Utility Generation Balancing Account
274	UOG	Utility-Owned Generation
275	USGS	U.S. Geological Survey
276	V	Volt
277	VCE	Valley Clean Energy
278	VOC	Volatile Organic Compound
279	VOM	Variable Operating and Maintenance Cost
280	VP	Vice President
281	WAC	Weighted Average Cost
282	WM	Water Management
283	WM	Work Management
284	WRCC	Western Regional Climate Center
285	WREGIS	Western Renewable Energy Generation Information System
286	YCWA	Yuba County Water Agency

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

LEAST-COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
LEAST-COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE

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LEAST-COST DISPATCH AND ECONOMICALLY-TRIGGERED DEMAND RESPONSE

A. Introduction

This chapter describes the Least-Cost Dispatch (LCD) practices and procedures Pacific Gas and Electric Company (PG&E or the Utility) employed during the January 1 through December 31, 2020 record period. The testimony and workpapers, taken together, provide a qualitative and quantitative demonstration of LCD for each day during the record period.

During the record period, PG&E complied with the California Public Utilities Commission's (CPUC or Commission) Standard of Conduct 4 (SOC4), relevant Commission decisions, and PG&E's conformed Bundled Procurement Plan (BPP).[1] SOC4 and the related CPUC decisions mandate that:

> [T]he utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.[2]

The format of this chapter and the associated workpapers is intended to conform with the requirements in Decision (D.) 15-05-006, as modified by D.15-12-015, which adopted a methodology for making an LCD showing in Energy Resource Recovery Account (ERRA) Compliance proceedings (LCD Decisions).

In addition, pursuant to the 2014 and 2015 ERRA Settlement Agreements between PG&E and the Public Advocates Office at the California Public Utilities Commission (Cal Advocates),[3] this chapter also addresses agreed-upon

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1 D.15-10-031 adopted the investor-owned utilities' proposed BPPs, with modifications, and required PG&E to submit a conformed copy of its BPP, which was approved June 15, 2016. Since then, PG&E has updated the BPP as needed when market conditions or electric portfolio changes necessitate modifying the BPP.

2 See D.02-10-062, p. 74. This responsibility was clarified in D.14-05-023, Finding of Fact (FOF) 15, stating that while the regulated utilities are responsible for bidding and scheduling its generation resources in a least-cost manner, it is the California Independent System Operator (CAISO) who performs actual generation dispatch. (D.14-05-023, p. 19).

3 PG&E entered into these settlement agreements with the Office of Ratepayer Advocates (ORA). Subsequently, ORA changed its name to the Cal Advocates.

additions to the testimony and workpapers.[4] These agreed upon additions are the following:

Testimony/ Workpaper Section	2014 and 2015 ERRA Settlement Requirements for LCD
B.3.b.1.d.; Workpaper 6	An evaluation of PG&E's price forecast accuracy for all days during the record period
B.3.b.4.; Workpaper 1	A description of the decision-making process that PG&E performs to determine whether proxy or registered costs are selected for resources
B.3.b.8.; Workpaper 2	Explanations of instances in which bids were not submitted for thermal resources
B.3.b.12. Bid Sheets	Explanation of renewable resource opportunity costs and curtailments
C	Inclusion of PG&E's dispatch of Demand Response (DR) programs that have an economic trigger and evaluation of metrics

Section B of this chapter addresses LCD, and Section C addresses economically-triggered DR.

B. Least-Cost Dispatch

1. Structure of LCD Section

PG&E will demonstrate in this section and in the accompanying workpapers that during the record period it correctly performed LCD. The format of PG&E's testimony and workpapers is based on the LCD Decisions and consists of the following:

Section	Subject
B.2.	Overview of LCD in the CAISO markets
B.3.	PG&E's Bidding and Scheduling Processes
B.4.	Summary Reports/Tables – Annual Exception Rates
B.5.	LCD Bidding and Scheduling Cost Impacts
B.6.	Background Summary Table
B.7.	2020 Market and Business Process Changes
B.8.	LCD Summary

PG&E is also providing detailed workpapers that are formatted consistent with, and provide the information required by, the LCD Decisions.

[4] See D.16-12-045, *Decision on PG&E 2014 ERRA Compliance Review* (Issued December 20, 2016) and D.17-03-021, *Decision Addressing Settlement Between PG&E and ORA* (Issued March 28, 2017).

2. Overview of LCD in the CAISO Markets

During the record period, PG&E managed its portfolio of contracted and utility-owned resources consistent with SOC4, relevant Commission decisions, and its BPP.

SOC4 was initially adopted by the Commission in 2002. At that time, all CAISO generation resource schedules were either directly matched by the utilities to their customer loads or energy was procured and matched to forecast customer loads via bilateral trades. However, as the Commission explained in D.11-10-002, FOF 1:

> [O]n April 1, 2009, the CAISO began implementation of [MRTU], which substantially changed the LCD processes of SCE and other utilities.

As the Commission has noted, since 2009:

> [T]he regulated energy utility is responsible for scheduling and bidding its generation to the CAISO, but once that is done, it is the CAISO's responsibility to dispatch the generation.[5]

Since April 1, 2009, the CAISO has operated the day-ahead market (DAM) and real-time markets (RTM), enabling market participants to offer or procure energy and Ancillary Services (A/S) in the CAISO control area. The CAISO markets perform optimization (i.e., LCD) for all resources bid or self-scheduled[6] into the markets based on information provided by market participants, CAISO transmission information, and information regarding system conditions that is not available to market participants. The Full Network Model (FNM) used in the CAISO markets contains approximately 10,000 pricing nodes. The FNM is used to identify potential local area reliability concerns and resolve them day-ahead in the Integrated Forward Market (IFM) and Residual Unit Commitment (RUC) processes (further detail below), as well as in the RTMs.

The CAISO's optimization by each of its markets results in supply clearing against demand at least cost. The results are based on the submitted hourly bids and the costs of getting energy from supply nodes to

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5 D.14-05-023, FOF 15.

6 Self-schedules are interpreted by the CAISO markets as price-taking supply or demand. Price-taking supply is supply that is willing to accept any price to inject energy into the grid. Price-taking demand self-schedules, which can only be submitted by Load Serving Entities (LSE) in the day-ahead market, indicate a willingness to pay any price to clear demand in that market.

demand nodes in the CAISO grid. Market prices at each node are determined on a day-ahead basis for each hour of the day, and in real-time for each 15- and 5-minute interval, and indicate the incremental cost of an additional unit of energy at each location in the CAISO grid (Locational Marginal Price (LMP)).[7]

The structure and design of each of the CAISO markets, day-ahead and real-time, are described in more detail below.

a. Day-Ahead Market

The CAISO DAM process, the IFM, provides market participants with the opportunity to buy and sell energy for the following day. In the IFM, the CAISO clears the offers to buy and sell energy based on the physical characteristics and locations of available resources and bid-in demand, for each of the 24 hours of the following day, and establishes LMPs for each of the approximately 10,000 nodes within the CAISO system. The CAISO also uses the IFM to procure A/S (regulation up, regulation down, spinning reserve and non-spinning reserve) to ensure system reliability for the next day. Energy and A/S procurement are performed simultaneously using the CAISO's Security Constrained Unit Commitment algorithm, which minimizes total costs based on submitted bids, the CAISO's A/S requirements, and the constraints on power flows imposed by the control area's large and complex transmission network.

The CAISO's market model recognizes load pockets that may be exposed to local market power. The CAISO performs a Local Market Power Mitigation (LMPM) process that identifies suppliers with local market power and mitigates their supply bids to competitive default bid levels.

Because not all forecast load will necessarily clear in the IFM, the CAISO performs a second phase of the DAM process, RUC, after the IFM to ensure that sufficient capacity has an obligation to bid into Real Time to meet the CAISO's own forecast of CAISO area load.

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7 The LMP is the marginal cost of supplying, at least cost, the next increment of electric demand at a specific node on the electric power network. This takes into account supply (generation/import) bids, demand (load/export) offers and the physical network of the transmission system.

LCD requires PG&E to bid or schedule its generation portfolio such that it is generally dispatched to serve load if the variable operating costs of the resources are lower than the alternative CAISO market cost of energy. PG&E meets this requirement by offering PG&E owned and contracted resources into the DAM at incremental cost,[8] with the resulting awards of schedules determined by the CAISO without regard to whether the scheduled resources are PG&E controlled or from the other market participants.

The CAISO should dispatch resources such that those with lowest incremental costs are scheduled to meet loads at least cost.[9]

b. Real-Time Markets

The RTM is comprised of several overlapping market processes, producing financially and/or physically binding awards and prices that are used for energy and A/S settlements.

The Hour-Ahead Scheduling Process is an hour-ahead, non-binding process that runs every hour to yield feasible block schedules for imports and exports (permitting “tagging,” i.e., scheduling of supporting transmission capacity across multiple balancing authorities) and advisory (non-binding) price and schedule results.

The Fifteen-Minute Market (FMM) process was introduced with Federal Energy Regulatory Commission (FERC) Order 764 implementation in 2014. The FMM process runs for successive 15-minute intervals with updated CAISO forecasts of system load and intermittent resource generation and yields schedules and financially binding prices for all CAISO products. As in the DAM, the LMPM process is run prior to each FMM run. Differences between the day-ahead awards and FMM awards are settled at the FMM prices.

Finally, the 5-minute Real-Time Dispatch (RTD) process runs with updated CAISO 5-minute load and intermittent resource forecasts, to yield 5-minute prices and physically binding energy dispatches for all

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8 Incremental cost refers to the variable costs of providing energy (which includes opportunity cost) but does not include fixed costs.

9 The CAISO ultimately clears all control area demand physically in the RTMs: This is fundamental to its mandate to serve California’s electricity needs reliably.

resources internal to the CAISO's Balancing Authority Area. Differences between the FMM awards and RTD awards are settled at the RTD prices. Imbalances between RTD awards and actual deliveries are priced at the RTD prices in each 5-minute interval.

3. PG&E's Bidding and Scheduling Processes

a. LCD Guidelines and Principles

1) LCD Principles

As explained in the Commission-approved BPP that was in effect during the record period, PG&E has adopted the following seven principles to guide its procurement and LCD activities:[10]

1) PG&E aims to minimize the total cost of energy required to meet load and A/S requirements, subject to regulatory, legal, operational, contractual, and financial requirements.
2) PG&E's scheduling and bidding process considers all regulatory, legal, safety, operational, contractual and financial requirements. Subject to these requirements, the scheduling and bidding process aims to provide the CAISO flexibility in dispatching the resources across the DAM and RTM.
3) PG&E supports LCD by explicitly considering the incremental costs of all resources available to it in scheduling or bidding decisions.
4) PG&E integrates any local area reliability requirements, day-ahead scheduling requirements, and deliverability requirements into its scheduling or bidding decisions.
5) The CAISO markets perform LCD for all resources bid/scheduled into the markets based on information provided by all market participants, transmission information that is solely available to the CAISO, and information regarding system conditions that is solely available to the CAISO.
6) The parameters and forecasts that PG&E uses as inputs to the CAISO LCD process include: PG&E and CAISO load forecasts;

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10 See also BPP, Appendix K.

market price forecasts; incremental heat rates; and Master File parameters. These parameters and forecasts are used in the calculation of submitted bids and/or schedules.

7) LCD results are subject to forecast and market uncertainties, including those associated with actual customer loads, behavior of other market participants, actual energy deliveries from non-dispatchable and intermittent resources, non-public transmission constraints, and CAISO reliability-based discretionary decisions.

PG&E followed the principles described above during the record period. The principles described above remain essential for achieving LCD and meeting all safety, regulatory, legal, operational, and financial requirements associated with PG&E's portfolio.

PG&E bids resources with bidding rights into the CAISO markets based on their incremental costs or opportunity costs.[11] By bidding its resources into the CAISO markets at their incremental or opportunity costs, PG&E enables total procurement to meet customer demand in the CAISO markets at least cost. Resources with contractual or physical constraints that limit their ability to be bid may be fully or partially self-scheduled into the CAISO markets.

2) Incremental Costs

PG&E schedules[12] or bids resources that have dispatch flexibility into the CAISO markets at the incremental cost of providing energy, considering the variable resource operating cost and the most current market price forecast. Resource costs that increase or decrease with resource output are properly treated as incremental costs. Fixed costs that are not affected by how resources are dispatched, such as past capital investment costs or contract capacity payments, are treated as sunk costs and therefore not incorporated into energy bids. For resources with energy or

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[11] For those resources with energy, curtailment, or starts limitations, the opportunity cost reflects the value of not being able to use the resource's flexibility in a future time period.

[12] Schedules commonly refer to self-schedules whereas bids refer to price-quantity offers to sell or buy in the CAISO markets.

starts constraints, incremental costs may also include the opportunity cost of not having use of the resource in the future.

Incremental costs are categorized as: (1) start-up costs; (2) minimum load costs; and (3) incremental energy costs. Start-up costs are the costs to start a resource and bring it to its minimum operating level; for Multi-Stage Generation (MSG)[13] resources, “state transition costs” are similar to startup costs and represent the start-up of resource sub-units. An additional opportunity cost component may be added to start-up costs when a limit on cycling (starts and shutdowns) is expected to be binding over a period of months or years.

Minimum load cost is the cost to operate a resource at its minimum operating level for one hour.

Minimum load, start-up, and transition costs may include fuel costs and Greenhouse Gas (GHG) costs as well as variable operations and maintenance (VOM) costs, and documented Major Maintenance Adder costs of inspections and overhauls that are incurred, or other contract provisions, based on run hours or cycles.

Incremental energy bid costs include those incremental or opportunity costs that vary directly with the generation of each additional megawatt-hour (MWh) above the minimum operating point. For example, fuel costs, GHG costs, and VOM costs vary directly with energy output.

Bids for resources with no explicit fuel cost, such as hydroelectric plants, are based on their opportunity costs, which are equivalent to fuel costs in their effect on bids. For Hydroelectric Generation (Hydro) resources, the opportunity cost is the future value of water. It may be more prudent and lower cost in the long run to defer hydro generation to higher value future periods, rather than using it in the current day and receiving a price below its opportunity cost.

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13 MSG resources are described in further detail in the “Thermal Resource Bidding and Scheduling” section of this chapter.

In addition to its large (in number, total capacity, and total energy) portfolio of utility-owned resources, PG&E also bids and schedules resources under various types of contracts. Incremental costs of contracts are based on contract terms, reflecting the actual costs or opportunity cost of dispatch. Incremental costs of these different resource types are further discussed below.

3) Self-Scheduling

A portion of PG&E's supply portfolio is must-take[14] or must-run,[15] due to safety, environmental and license constraints, regulatory requirements, contract terms (e.g., certain renewable resources and Qualifying Facility (QF) resources) or because it is inherently non-dispatchable (e.g., run-of-river hydro with no reservoir controls). Because such generation is inflexible, PG&E self-schedules must-take supply in the DAM based on PG&E's forecast of their generation, and then modifies these self-schedules in real-time if the forecast of generation changes.

A relatively small number of PG&E's contracts, tolling agreements, and the Puget Exchange have dispatch flexibility on an earlier contractual timeline from the CAISO markets and therefore cannot be bid into the CAISO market and must be self-scheduled by PG&E. The best price forecast available at the time of the

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14 Regulatory Must-Take Generation is defined as generation from the following resources that the relevant Scheduling Coordinator (SC) schedules directly with the CAISO as Regulatory Must-Take Generation: (1) Generation from Generating Units subject to (a) an Existing QF Contract or an Amended QF Contract, or (b) a QF Power Purchase Agreement (PPA) for a QF 20 megawatts (MW) or smaller, pursuant to a mandatory purchase obligation as defined by federal law; (2) Generation delivered from a Combined Heat and Power (CHP) Resource needed to serve its host thermal requirements up to RMTMax in any hour; and (3) Generation from nuclear units. See CAISO Conformed Tariff, August 1, 2020.

15 Regulatory Must-Run Generation is defined as Hydro Spill Generation and Generation which is required to run by applicable federal or California laws, regulations, or other governing jurisdictional authority. See CAISO Conformed Tariff, August 1, 2020. Such requirements include, but are not limited to, hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements, or the requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by federal or California law or Local Regulatory Authority.

scheduling decision is used in PG&E optimization program runs to determine the highest value self-schedules for these resources.

In addition to must-take and must-run resources and bilateral contracts which are self-scheduled, other resources are periodically or partially self-scheduled for particular purposes. Self-schedules may be used when testing is to be performed on resources, or when resources such as hydro plants need to be run above their minimum operating limits to ensure that water is used according to operating constraints. Resources may also be "self-committed," which refers to instances in which a resource is self-scheduled at minimum, and its remaining available capacity is bid economically into the markets.

4) Operational Constraints

In addition to meeting load obligations at minimum cost, PG&E also incorporates safety, operational, physical, legal, regulatory, and environmental constraints into bidding and scheduling decisions.

One category of operational constraints is those imposed by FERC licenses on the operations of PG&E's hydroelectric system. For example, FERC licenses may include requirements for fish and wildlife maintenance (e.g., flows for fish habitat and water quality that bypass generators and thus produce no electricity), recreation (e.g., seasonal minimum reservoir water levels), and safety (e.g., constraints on reservoir drawdowns). Such considerations may not be readily apparent in a cost-only analysis of PG&E's bidding and scheduling decisions.

b. 2020 LCD Business Process Overview

PG&E's daily LCD business processes use forecasts of loads and prices to perform LCD via the bidding of customer demand and PG&E supply. After the market run, PG&E performs routine validation and analysis of market results. PG&E's processes are described in the following sections.

1) Load and Price Forecasts

In this section we describe PG&E's load and price forecasts.

a) Load Forecast Process

The short-term area load forecast utilized in PG&E's LCD process is provided by a vendor, Pattern Recognition Technologies (PRT).[16] The inputs to the short-term load forecast include actual historical loads for the PG&E system based on Supervisory Control and Data Acquisition system, and actual and forecast temperatures for six representative weather stations in the PG&E service territory, provided by external weather forecast vendors to PRT. PG&E reviews data provided to the vendor and, on rare occasions, modifies inputs to the vendor model to correct for data quality problems.

The "7-day" hourly PG&E area load forecast provided by the vendor is adjusted to produce a forecast of PG&E's bundled customer load. The PG&E area load forecast is adjusted by subtracting estimates of transmission losses, municipal loads, and forecasts of Direct Access and Community Choice Aggregation loads in the PG&E area. PG&E uses this 7-day short-term forecast of bundled customer load in creating load bids for each of the next six days. PG&E may further modify the vendor forecast under special circumstances (i.e., holiday periods) that are not modelled adequately by the forecast model.

b) Evaluation of Load Forecast Accuracy

The most common metric used to evaluate the relative quality of load forecasts in the utility industry is Mean Absolute Percentage Error (MAPE). This metric measures both the magnitude and frequency of errors, and is similar to the Root Mean Square Error metric except that it puts a higher weight on larger errors. The metric is expressed as a percentage of actual hourly load.

Average daily MAPE of the short-term area load forecast was less than three percent during the record period. PG&E

16 PRT is also known as Enverus.

analyzes the short-term area load forecast on a daily basis and contacts the vendor when necessary.

c) Price Forecast Process

PG&E uses an hourly next-day price forecast and a long-term price forecast to inform bidding and scheduling in the DAM.

The short-term price forecast is used for load bids and for resources where a daily price forecast is used to optimize bids. During the 2020 record period, PG&E utilized a neural-network based price short-term forecast model provided by PRT. PG&E regularly reviews the reasonableness of the daily forecasts produced by the vendor.

A longer-term price forecast produced by PG&E's Credit and Risk Department, ranging from several days up to two years, is used for resources with potential opportunity costs beyond the next day. The longer-term price forecast is needed to estimate the relative value of dispatching the resources next day versus at later points in time.

d) Evaluation of Price Forecast Accuracy

PG&E reviews the accuracy of the PRT price forecast. The day-ahead PG&E Default Load Aggregation Point price forecast error during the record period using the metric of mean average percentage error, or MAPE, was 13.5 percent.[17] This MAPE value and Workpaper 6 offer PG&E's evaluation of its day-ahead price forecast accuracy, as requested by Cal Advocates in the 2014 ERRA Settlement.

2) Load Bidding

The CAISO DAM offers LSEs, such as PG&E, the capability to bid some or all of their forecast loads into a DAM.

PG&E evaluates the relative costs of serving customer loads in the DAM versus the RTM, based on actual past market outcomes.

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17 Daily MAPE = $\frac{1}{24} * \sum_{t=1}^{24} \frac{|\text{Forecasted Price}_t - \text{Cleared Price}_t|}{\text{Daily Average Cleared Price}}$.

[redacted]

3) Thermal Resource Bidding and Scheduling

The portfolio of dispatchable thermal power plants for which PG&E creates bids (all using natural gas as their primary, if not exclusive, fuel) are either owned by PG&E or contracted from counterparties through tolling agreements.

D.02-12-069 provides that:

> [P]rohibited utility conduct under this standard includes any action that results in preference to utility-retained generation resources or the utility's own negotiated contracts.[18]

PG&E makes no distinction between its own resources and contracted resources in its bidding practices: All resources are bid or self-scheduled into the CAISO markets based on their incremental costs, recognizing safety, regulatory, legal, operational, and financial requirements.

PG&E-owned plants and tolling agreement plants that can be bid into the CAISO markets are bid at incremental cost consistent with operational and contract constraints, as described in Section 3.a.2. The incremental cost of energy consists of incremental fuel costs and any other costs that vary with output between the minimum and maximum points of a plant's operating range.

The incremental cost of minimum load is similarly estimated as the minimum load fuel cost and any other costs that are incurred in every hour that the plant runs (for example, hourly operating charges included or imputed in plant long-term service agreements).

The incremental cost of starting a plant (or in the case of a multi-unit plant, starting a unit at the plant) is estimated as the fuel and other inputs required for a start along with other costs incurred

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18 D.02-12-069, pp. 62-63.

for every start (such as start charges included or imputed in plant long-term service agreements).

In its portfolio, PG&E has a number of MSG resources, which are resources that have multiple operating configurations that can be characterized as having distinct operating parameters. Often these resources require time and/or incur costs to move from one configuration operating range to another. For example, combined cycle gas turbine (CCGT) plants consist of a steam turbine (ST) and multiple gas turbines (GT) run in combination so that GT waste heat can be used to power the ST. Dispatch of CCGT plants therefore requires consideration of the cycling (startup and shutdown) of individual turbines. The CAISO has developed the MSG resource model to better represent dispatch of MSGs.

4) Description of Proxy/Registered Cost Determination for Thermal Resources

In the 2014 ERRA settlement, PG&E agreed to provide documentation for evaluating the proxy versus registered cost determination for thermal resources.

Starting April 1, 2019, CAISO retired the registered cost option with an exception only for the resources that have less than 12 months of 15-minute LMP data. Since none of the thermal resources in the PG&E's portfolio was eligible for the exception, all were required to use the proxy cost option starting April 1, 2019. Because of this CAISO rule change, PG&E did not perform any proxy/registered cost determinations for thermal resources during the record period for 2020.

5) Hydro Resource Bidding and Scheduling

In this section we describe PG&E's hydro resource bidding and scheduling processes. PG&E manages its hydro fleet through bidding and scheduling practices that depend on the constraints of each particular hydro facility and amount of water available.

In general, hydro generation is energy-limited due to the limited availability of water. While water in reservoirs from natural inflows may be considered a zero-cost fuel (except in the case of pumped storage hydro, which is further discussed below), the availability of this zero-cost water may be limited.

Hydro resources have their highest value to customers when this limited amount of water is utilized during high market prices. To the extent that the availability of water can be controlled, it is prudent to store water to generate when the power is most valuable (i.e., those times with the highest prices in the CAISO's DAM and RTM). Thus, in order to perform least-cost hydroelectric dispatch and target high market prices, PG&E bids and schedules hydro resources based on their estimated opportunity costs (which reflect their energy limitations and forecasts of the future value of water).

Opportunity costs are evaluated based on comparison to historical periods or forecasts of future periods to estimate the risk of high-market prices or capacity shortage. In addition, the energy and capacity markets provide short-term price signals, in the form of high energy or A/S prices, that also help identify high-risk, high-value periods. Prudent dispatch of PG&E's hydroelectric resources necessitates that uncertainties in future hydrological system conditions (stream flows, precipitation, temperatures, etc.) and uncertainties in the future value of energy and A/S be incorporated into planning models.

PG&E's operation of energy-limited resources, such as hydro, involves decisions that may span multiple months and years. Hydro conditions, reservoir target levels, market conditions, and scheduled plant outages affect the optimization of hydro operations in the "short term," meaning two years or less. For watersheds with sufficient storage, a two year optimization cycle is used because using either too much or too little water from the large reservoirs in PG&E's hydro system may leave the system vulnerable to either drought or storm conditions in the following year.

In general, PG&E bids dispatchable hydro by submitting limits for each resource on total energy available for dispatch in the DAM. CAISO allows hydro resources to submit limits on total energy dispatched in a single day. PG&E sets hydro limits based on a resource's opportunity cost with bid prices that enable the CAISO to optimize the resource's dispatch over an operating day.

In addition to those resources with bid limits that reflect opportunity costs, depending on operating constraints (such as safety, FERC license requirements, recreational use requirements, or environmental restrictions), some hydro generation may be self-scheduled or bid at a price close to zero to indicate that some flow through the watersheds is not controllable, except possibly by diverting it from particular plants ("spilling" the water) and thus losing any opportunity to generate with it at these plants.

a) Hydro Modeling

Mid-term hydro planning models generate forecasts of optimal water plans for each of PG&E's watersheds using assumptions about forward prices, considering safety, physical, operational, and license constraints. The models produce target reservoir storages and end-of-month water values over the entire water planning horizon, as well as nominal hydro generation schedules at each PG&E powerhouse. The most recently generated water plans provide guidance in planning the storage and drafting of reservoirs, maintenance of hydro powerhouses, and assumptions about availability of hydro generation and A/S over the model's horizon.

The inputs to PG&E's mid-term hydro planning models include:

- Static characteristics of generators, reservoirs and canals and the network configurations of the watersheds;
- Energy and A/S price forecasts;
- Reservoir inflow forecasts;
- Outage schedules of generators (and at Helms Pumped Storage Plant (Helms), the pumps);
- Reservoir storage initial volumes; and
- Other reservoir operational constraints.

The nearest term outputs of the mid-term hydro planning models are their end-of-month target reservoir storage levels and marginal water values for the current and following months of the model's optimization horizon. Outputs of the mid-term hydro planning model include:

- Hourly MW schedules for all represented plants;
- Hourly A/S schedules for A/S capable plants;
- Forecast energy and A/S revenues;
- Forecast water releases from reservoirs and resulting storage levels;
- Flows on all canals/waterways; and
- Forecasted water values.

b) Implementation and Use of Modeling Results

The outputs of the mid-term hydro planning model are used as starting points in shorter-term hydro optimization. PG&E uses a combination of network optimization models and water balance spreadsheet models to forecast week-ahead powerhouse operations at each dispatchable powerhouse. Thus, the network optimization and water balance models forecast bids or schedules of hydro resources based on the most current information on end-of-month reservoir targets, water values, actual hydro conditions, and forecast CAISO market energy and A/S prices.

Multi-day hydro operations forecasts are translated into next-day preferred operating schedules and/or total energy available for each powerhouse.

Per the 2015 ERRA Settlement, PG&E contracted for an independent review of PG&E's hydro resource bidding and scheduling processes. The independent reviewer's conclusions were as follows:

> The hydropower modelling system I observed at PG&E does as well or better at meeting PG&E's needs when compared to other utilities with complicated hydropower systems. The use of a (sic) hourly time-step within the so-called "monthly" PLEXOS provides a good description of likely reserve resources given forecasted mean monthly

flows and mean hourly energy and regulation reserve prices.[19]

6) Hydro Self-Scheduling Decisions

In this section, PG&E includes a description of the rationales for hydro self-schedules during the record period to provide additional information on the operational constraints in the hydro LCD process as requested by Cal Advocates in the ERRA 2014 Settlement. Self-scheduling is done for one of the following three reasons:

a) Self-Scheduling Required During and After Storms

Under certain storm conditions, much or all of PG&E's hydroelectric system can become effectively "run of river" hydro, meaning that it cannot be controlled by dispatch decisions. Under such conditions, PG&E's hydro is self-scheduled.

b) Self-Scheduling in Other Conditions With Limited Operating Flexibility

Constraints on the hydroelectric system for irrigation, recreation, environmental, or safety reasons may be expressed in terms of minimum flows or minimum releases from reservoirs. Such constraints may require flows through powerhouses that exceed the rated minimum flows, thus requiring self-schedules at levels above minimum generating level for specific hydro resources. Additionally, limited capacities of small forebay reservoirs may require minimum guaranteed powerhouse flows, implemented as self-schedules, to ensure the safe operation of those small reservoirs.

c) Self-Commitment to Indicate Preferred Ancillary Service Providing Resources

Hydroelectric resources supply a significant amount of PG&E's supply of A/S, including regulation and spinning reserves. In cases where experience shows that price signals alone may result in excessive cycling of resources to provide A/S, PG&E may elect to self-schedule particular hydro

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[19] See Exhibit (PG&E-2), Attachment A, p. 1-AtchA-4, in PG&E's 2017 ERRA Compliance Application (Application 18-02-015).

resources to ensure that A/S are provided in the most efficient and effective way.

7) Helms Pumped Storage Plant Bidding and Scheduling

Helms is located on the Kings River watershed, situated between an upper reservoir, Courtright Lake, and lower reservoir, Lake Wishon. Helms has three generators that can be reversed to act as pumps, and has an installed generation capacity of 1,218 MW and a pump capacity of 1,020 MW. Like any other PG&E hydro resource, Helms is subject to physical operating constraints and hydrological uncertainties.[20] Unlike other hydro resources, Helms has the capability of increasing its forebay reservoir storage (Courtright) by pumping water from the Lake Wishon uphill to Courtright. Pumping water uphill requires purchase of electricity from the CAISO markets and serves as future fuel source in addition in addition to natural inflows (limited by the cycling capability and reservoir capacities of the plant).

LCD of Helms requires evaluation of the opportunity cost of stored water and, in addition, requires that pumping be evaluated based on the benefits of incremental generation and reduced downstream spill. LCD of Helms also requires evaluation of how best to use the generating capacity of the plant, which can provide A/S as well as energy. Because A/S generally have highest value in the same periods that energy has highest value, total costs to customers are minimized when the Helms schedule has maximum value considering both energy and A/S. The plant may therefore not be dispatched to its maximum generation output in the market, so that its remaining capacity may provide high value A/S.

The mid-term hydro planning optimization model is used to determine reservoir storage targets and water values for Courtright (forebay) and Wishon (afterbay) reservoirs on a monthly basis through the end of the year following the current year. Reservoir

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[20] For more information on Helms in the context of PG&E's Hydroelectric System and PG&E's Portfolio Management, see "Chapter 2: Utility-Owned Generation: Hydroelectric."

planning for Helms differs from that on other watersheds in that inflows to the afterbay can be pumped to the forebay for later use; and mid-term planning model outputs therefore include a pumping plan over the horizon of the model.

Short-term hydro planning for Helms is based on the mid-term month-end reservoir targets and water values, as it is for other watersheds. Adjustments within the month are made based on realized inflows and operations as well as short-term price forecasting. The resulting preferred operating schedules for Helms may include some pumping and some combination of generation and A/S. Additional pumping may be economic in the short term if additional generation and A/S (above the forecast/preferred schedule) is valuable enough; likewise, additional generation and/or A/S may be economic in the short term if additional pumping is at low enough cost (the LMP paid for pumping energy). This incremental ability to pump and generate or provide A/S is included in the bids submitted for Helms to the CAISO markets.

8) Battery Storage Bidding and Scheduling

PG&E’s two small utility-scale batteries were bid during the record period based on an optimization model similar to that of hydro optimization, with more restrictive storage limits and treating stored energy as fuel. Overall, the purpose of operating the batteries in the market combined the objectives of (1) maximizing revenues from the resources under a known strategy (e.g., bidding the resources into the regulation markets) and (2) testing new approaches that might yield new sources of value or have application to future operations of batteries in the CAISO markets (e.g., representing customer-side uses of the batteries or distribution-level operating restrictions).

The incremental cost of providing either energy or A/S from PG&E’s batteries was calculated based on the cost of maintaining the battery’s State of Charge (SOC) at a level permitting provision of energy or A/S, considering the charging efficiency. Charging energy was procured from the CAISO markets in the lowest cost or lowest value hours.

During the record period, PG&E continued to bid its dispatchable storage batteries to test CAISO software capabilities and limitations and to identify feasible charge/discharge cycles, and otherwise to maximize net market revenues derived from market operations to reduce PG&E customer costs.

The batteries participate in the CAISO markets through the Non-Generator Resource market model, which allows a combination of energy bids and A/S bids. This model constrains charge and discharge to keep the battery between minimum and maximum SOC limits. The incremental cost of battery discharge is based on the battery's cycling efficiency and cost of charging.

9) Thermal Resource Bid Non-Submission

In this section, PG&E provides a description of the thermal resource bid non-submissions during the record period. "Thermal resource bid non-submission" here means non-submission of bids in periods when a resource is available, i.e., not explicitly limited by a clearance in the CAISO's Outage Management System (OMS). Resources on outage are not included here. Workpaper 2 provides additional detailed explanations for instances in which bids were not submitted for thermal resources. Taken together, this section and the workpapers offer complete documentation of thermal bid non-submission decisions as requested by Cal Advocates in the 2014 ERRA Settlement.

Gas-fired and other fossil fuel thermal plants are in general subject to limits (e.g., emissions limits) that translate into limits on startups and shutdowns over each year and over sub-periods, potentially even daily sub-periods, of the year. To stay within the limits and to guarantee the availability of some thermal resources to serve customers in the periods of the year with expected highest need, PG&E may not bid some or all of the resource capacity in other periods of the year, subject to meeting all Resource Adequacy (RA) and other contractual or reliability constraints on the resource.

10) Bilateral Market Transactions

Bilateral transactions in the CAISO DAMs take two forms: (1) financial bilateral transactions, known as "inter-SC trades" or "bi-lateral swaps," which trade the difference between a fixed price and the CAISO's day-ahead IFM prices at a given location without involving any delivery of energy to the grid; and (2) bilateral physical transactions at the intertie points (also known as scheduling points), which require physical scheduling of an import or export and are settled in the CAISO DAM just as other supplies or demands are settled.

Day-ahead financial bilateral transactions (i.e., within the CAISO balancing area) and bilateral physical transactions (i.e., at CAISO interties) were used to settle existing energy procurement contracts. During the record period, PG&E closed its financial and physical positions through in the CAISO markets, with the important exceptions of imports from, and exports to, outside of the CAISO control area.

Imports and exports require physical scheduling into the CAISO markets, "tagging" to match schedules across balancing authority control areas, and a separate bilateral financial settlement with counterparties outside of the CAISO control area. PG&E imports included energy associated with renewable contracts, energy required to meet RA targets, and the long-term Puget Exchange contract.

11) Must-Take Resources and Contracts

Must-take resources, unlike dispatchable resources, have no economic flexibility in the delivery of energy; whatever energy they produce must be taken by the transmission grid. Must-take resources include:

1) QFs: PG&E's QF PPAs allow QFs to decide what level of generation to provide;
2) CHP: Contracts allow certain CHP resources to determine the level of supply they will provide;
3) Renewable energy contracts and resources without bidding rights for economic dispatch;

4) Diablo Canyon Power Plant;

5) Existing/Legacy Contracts: PG&E had obligations to purchase or exchange power under existing contracts. These purchases and exchanges were settled as financial bilateral transactions (inter-SC trades); and

6) Must-Run Hydro Generation: Certain power plants have environmental, licensing or physical requirements that require continuous operations.

12) Economic Bidding of Renewable Resources

During the record period, PG&E's portfolio included utility owned and contracted renewable resources with dispatch capabilities and economic bidding rights. Economic bidding of these resources captures the incremental and opportunity costs associated with the contractual and operational constraints of these resources. [redacted]

In all cases of economic bidding of renewable resources, [redacted]

[redacted]

Economic curtailment of renewables occurs when market prices fall to, or below, [redacted]. Thus, the market, not PG&E, ultimately determines when these resources are economically curtailed.

13) Bid/Award Validation

PG&E reviews the results of each day's CAISO DAM. Market results in the form of resource schedules are evaluated for reasonableness based on expected outcomes of PG&E's forecast of generation. PG&E investigates any unexpected market results and follows-up with the CAISO when necessary.

Forecasts inherently do not perfectly match actual results. PG&E reviews the performance of its forecasts to assess the potential to increase the quality of forecast results.

If day-ahead schedules are not physically deliverable, PG&E adjusts them in real-time and performs an analysis to determine the reason for any infeasibility. In addition to correcting infeasible schedules (i.e., re-scheduling or rebidding in the RTMs), corrective action is taken when possible with respect to future days' bidding and scheduling.

When total market revenues earned over the course of a day based on the awards by the CAISO do not cover the generating unit's bid in costs, units are eligible to receive Bid Cost Recovery (BCR) payments. PG&E validates that expected BCR is received in these cases, or if not, that PG&E communicates its concerns and/or disputes of BCR calculations to CAISO.

When issues with market results are identified, whether immediately after publication of DAM results or at any later point in time, management is informed and, when appropriate, a ticket is registered with the CAISO's Issues Management System (also known as Customer Inquiry, Dispute and Information (CIDI)) for resolution. Persistent issues not remedied through normal CIDI ticket resolution or settlement dispute resolution may be identified for resolution either by changes in bidding and scheduling strategy or through CAISO market design or regulatory channels.

4. Summary Reports/Tables Annual Exception Rates

Table 1-1 below is an index which maps LCD data requirements with PG&E's demonstration.

TABLE 1-1
INDEX OF LCD DATA REQUIREMENTS[a] AND PG&E'S RESPONSES

Line No.	CPUC/Cal Advocates Metric	PG&E's Response
1	Commitment Cost Decisions	Testimony: Section B.3.b.4.; B.4.c. Workpaper: 1
2	Bid Cost Calculations	Testimony: Section B.3.a.2.; B.4.a. Workpaper: 2
3	Self-Commitment	Testimony: Section B.4.b. Workpaper: 3
4	Dispatchable Hydro Resources	Testimony: Section B.3.b.5. Workpaper: 4
5	Background Summary	Testimony: Section B.5. Workpaper: 5
6	Highest Energy Value Days	Workpaper: 6
7	Load Bid	Testimony: Section B.3.b.2. Workpaper: 7
8	Business Processes and Software Documentation	Workpaper: 8
9	Evaluation of PG&E's Price Forecast Accuracy	Testimony: Section B.3.b.1 Workpaper: 6
10	Decision Making Process for Proxy vs. Registered Costs	Testimony: Section B.3.b.4; B.4.c. Workpaper: 1
11	Explanation of Thermal Bids Not Submitted	Testimony: Section B.3.b.9. Workpaper: 2

(a) Per the LCD Decisions and the 2014 ERRA Settlement.

Additionally, consistent with the LCD Decisions, PG&E is providing the tables below which summarize exception rates for incremental cost bid calculations, self-commitment decisions, and Master File data changes. Tables 1-2 and 1-3 include exceptions for the record period. PG&E has work procedures and systems that are intended to detect and prevent internal errors before the fact, and such procedures and systems are subject to continuous improvement.

a. Incremental Cost Bid Calculation Exceptions

All bids submitted to the CAISO are reported in PG&E's confidential workpapers for Chapter 1 under the folder "Bid Sheets." There are individual files for each resource with a tab for Energy, A/S, and RUC bids. In the Workpaper 2 folder for dispatchable thermal resources, the actual incremental bid cost submitted to the CAISO is compared against the calculated cost, using incremental heat rates, VOM cost adders, GHG costs, and natural gas prices. In 2020, 687,526 bids were submitted to the CAISO for gas-fired dispatchable resources, of which 0.28 percent of the submitted bids were found to have a variance greater than $0.10/MWh (Workpaper 2).

Table 1-2 below summarizes the variances for dispatchable thermal resources during the record period. None of the variances resulted in potential cost impacts.

TABLE 1-2
INCREMENTAL BID COST CALCULATION VARIANCE – ANNUAL SUMMARY

Line No.	Description	No. of Significant Variances (in Hours) > $0.10	% of Total Bid Hour Count	Potential Cost Impact $
1	User Error	1920	0.28%	$0
2	External to PG&E	–	–	–
3	Total	1920	0.28%	$0

Note: Reference - Workpaper 2: Bid Cost Calculation: Table 2.1 – Annual Bid Cost Calculation Variance – Annual 2020.

See Workpaper 2, Bid Cost Calculation, for additional details.

b. Self-Commitment Decision Exceptions

The reasons for self-commitment during the record period are described in Section B.3. above, "PG&E's Bidding and Scheduling Processes."

Table 1-3 below summarizes exceptions associated with daily self-commitment decisions for dispatchable thermal resources for the record period.

TABLE 1-3
SELF-COMMITMENT DECISION VARIANCE – ANNUAL SUMMARY

Line No.	Reason Code	Description	Total Count (Hour)	Total MWh Energy Self-Committed
1	User Error		12	581.7
2	Total		12	581.7

Note: Reference- Workpaper 3: Self Commitment: Table 3.1 – Self Commitment – Annual Report.

During the record period, there was a one-time IT error that resulted in the self-commitment of 2 units. These instances did not result in any cost impacts. All other instances of self-commitment were for non-discretionary purposes (e.g., testing). Refer to Workpaper 3: Self Commitment for additional details.

c. Master File Data Change Exceptions

The Master File describes the detailed characteristics of resources. This section has historically summarized exceptions on proxy versus registered costs. As described in Section 7a, CAISO policies have evolved such that all units were required to use the Proxy cost option for the record period. PG&E did not perform any proxy/registered cost determinations for thermal resources during the record period for 2020.

TABLE 1-4
PROXY VS. REGISTERED COST EXCEPTIONS – ANNUAL SUMMARY

Line No.		No. of Times Proxy Used	No. of Times Registered Used	No. of Incorrect Submissions	Potential Cost Impact
1	Startup	–	–	–	–
2	Min Load	–	–	–	–
3	Total	–	–	–	–
4	Percent of Total Startup and Min Load Submissions	–	–	–	–

Note: Reference: Workpaper 1: Commitment Cost Decisions (xlsx); Table 1.1 – Annual Summary.

5. LCD Bidding, and Scheduling Cost Impacts

The dynamic management of LCD for an increasingly complex supply portfolio creates inevitable challenges to perfect execution. The Commission has made clear that the Utility is not to be held to a "perfection" standard with respect to LCD. PG&E bids and schedules a large portfolio of about 340 resources, each of which may have individual operational and contract parameters. PG&E demonstrates in this testimony and the supporting workpapers that it bids and schedules resources and procures energy for customers to LCD standards. During the record period, PG&E submitted over 2,351,000 hourly Day-Ahead bids and self-schedules for CAISO day-ahead revenues of over $1.64 billion. The potential cost impact of scheduling errors described below in this testimony totaled $112,629 or 0.007 percent of day-ahead revenue. The total affected bids of scheduling errors with cost impact totaled 653 hours, or 0.028 percent of total day-ahead bids. PG&E considers this error rate and cost impacts described in this testimony to demonstrate that PG&E was a prudent and reasonable manager, especially seen in the context of the overall gains to customers of its LCD processes. In addition, PG&E has instituted rigorous checks to monitor errors and has subjected our internal processes to continuous scrutiny.

During the record period, there were three bidding, and scheduling, events with estimated cost impacts as outlined below:

TABLE 1-5
BIDDING, AND SCHEDULING EVENTS WITH IMPACT

Event No.	[redacted]	Cost Impact
1		$1,700
2		$1,260
3		$109,669

[redacted]

Additionally, PG&E, in its role as a SC, conveyed to Panoche Energy Center a manual real-time CAISO exceptional dispatch order that was intended for a different unit on August 15, 2020. This dispatch instruction, which caused Panoche to ramp down and decrease its output for approximately 30 minutes, was corrected immediately on discovery. [redacted]

[redacted]

In response to these events, PG&E improved processes/tools and conducted training to help prevent similar events from occurring again. These improvements that mitigate reoccurrence of similar scheduling errors included: implementation of additional validation checks, updates to bidding software, and other database upgrades.

6. Background Summary Table

Table 1-6 below provides a summary of schedule and dispatch data for the record period, corresponding to the requirement in the LCD Decisions. The table reflects an annual summary by resource type (and divided into dispatchable and non-dispatchable resources) for capacity, day-ahead self-schedule awards and DAM awards.

TABLE 1-6
BACKGROUND SUMMARY – ANNUAL REPORT

Line No.	Dispatchable	[redacted]
1	CHP	
2	HYDRO	
3	PDR	
4	RENEWABLE	
5	SOLAR	
6	STORAGE	
7	THERMAL	
8	WIND	
9	Dispatchable Total	

(a) Capacity (MWh) for non-PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours in a day during the applicable time period.

Capacity (MWh) for PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours bid during the applicable time period.

(b) Total Unavailable Capacity for non-PDR resources represents the total capacity unavailable due to planned or forced outages reported in OMS.

(c) The renewable category consists mainly of biomass, biogas, and geothermal resources.

Reference: Workpaper 5: Background Summary (xlsx); Table 5.1 – Annual Report.

TABLE 1-6
BACKGROUND SUMMARY – ANNUAL REPORT
(CONTINUED)

Line No.	Non-Dispatchable	[redacted]
1	CHP	
2	FIT	
3	Hydro	
4	Nuclear	
5	QF	
6	Renewable	
7	Solar	
8	Wind	
9	Non-Dispatchable Total	
10	Grand Total	

(a) Capacity (MWh) for non-PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours in a day during the applicable time period.

Capacity (MWh) for PDR resources is calculated using the resources' P-Max MW multiplied by the number of hours bid during the applicable time period.

(b) Total Unavailable Capacity for non-PDR resources represents the total capacity unavailable due to planned or forced outages reported in OMS.

7. 2020 Market and Business Process Changes

PG&E participates in CPUC proceedings and CAISO initiatives on changes to market design and implementation and then integrates any changes into internal processes. During the record period, there were no new major market initiatives, business process changes, or LCD-related modeling and process changes. As discussed in Section B.3.b.4), the CAISO's Commitment Cost Enhancements Phase 3 initiative implemented on April 1, 2019 eliminated the need for PG&E to make a Proxy/Registered cost determination for thermal resources during the record period. The market change eliminates the need for Workpaper 1 – Commitment Cost Decisions.

C. Economically-Triggered DR Programs

1. Introduction

This section addresses PG&E's dispatch of DR programs with an economic trigger during the record period, as directed by the LCD Decisions. Specifically, these decisions require PG&E to include in this application metrics proposed by Cal Advocates concerning the dispatch of

DR programs with economic triggers. For purposes of this section, the term “dispatch” refers to times when PG&E activates a DR program to reduce load.

PG&E utilized its DR portfolio during the record period to provide load reductions that enhanced reliability and reduced peak demand and associated prices. Economically-triggered DR programs were represented as Proxy Demand Response (PDR) resources in PG&E’s portfolio and bid into the CAISO DAM based on calculated availabilities and dispatch trigger prices. In cases where forecast prices indicated that a PDR resource would exceed its maximum call days in a given month, an opportunity cost was added to the dispatch trigger price with the aim of maximizing the realized value of call days. Because PG&E’s economically-triggered DR programs cannot be dispatched in the RTMs, all PDR resources were registered as “day-ahead only” in the Master File, and received no further dispatch instructions in the RTMs.

During the record period, a total of 63 PDR resources were bid into the CAISO markets between May 1 through October 31, 2020 (the period when PDR was active). These resources represented subsets of customers enrolled in the Capacity Bidding Program (CBP) and SmartAC™[21] DR programs that were determined capable to respond when directed to do so.

For the record period, dispatch of DR resources was well-aligned with periods of high load and high prices. Instances in which either bidding procedures were not followed, or resources were not dispatched when awarded, increased in 2020 due to: the Coronavirus pandemic and related California stay-at-home orders, opportunity costs associated with “customer fatigue” affecting the frequency of program calls, and/or Public Safety Power Shut-off (PSPS) events.

The remainder of this section consists of the following subsections:

- <u>A description of the CBP and a summary of its dispatch during the record period</u>. This section describes the program parameters and includes information about when the program’s trigger conditions were

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21 The name SmartAC is a registered trademark of PG&E. All further references to the program in PG&E’s testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

met and resources dispatched. Also included is an explanation of non-dispatch decisions, including the instances when CBP triggers were met but resources were not dispatched, and a description of PG&E's opportunity cost methodology.

- <u>A description of the SmartAC Program and a summary of its dispatch during the record period</u>. In 2020, SmartAC continued to be integrated into the CAISO day-ahead energy market as a PDR. This section discusses SmartAC Program changes, including bidding strategy, information about the program's trigger conditions and forecasts, and when the programs were dispatched. Also included is an explanation of non-dispatch decisions, including the instances when SmartAC conditions were met but resources were not dispatched for various reasons. Further details can be found in section three.

2. Economically-Dispatched DR Summary

Table 1-7 below provides specific references to testimony or attachments to this chapter that address Cal Advocates' metrics.

TABLE 1-7
INDEX OF CAL ADVOCATES' METRICS AND PG&E'S RESPONSES

Line No.	Cal Advocates' Metric	PG&E's Response
1	1A	Section 2.b.1)., Attachment 1A
2	1B	Attachment 1A
3	1C	Section 2.b.3)., Attachment 1A
4	2	Section 2.b.2)., Attachment 1B
5	3A	Attachment 1C
6	3B	Attachment 1C
7	3C	Attachment 1C
8	4	Section 2.b.3)., Attachment 1A
9	5	Section 2.b.3).
10	6A	Section 2.b.4).
11	6B	Section 2.b.4).
12	6C	Section 2.b.4).
13	7	Section 2.b.3).

3. Capacity Bidding Program

a. Description

The CBP is a voluntary DR program that offers customers capacity and energy payments for being on standby to reduce energy consumption when requested by PG&E. Since 2018, CBP resources have been integrated into the CAISO DAM as PDRs. The PDR models the physical characteristics of a resource supplied to the CAISO and is the basis for bidding, awards, dispatch, outages, and settlements. Customers enroll through a third-party aggregator for participation in a Day-Ahead notification product. CBP operates from May through October.

CBP offers three program options: (1) Prescribed, (2) Elect, and (3) Elect Plus.

The *Prescribed option* program hours are 1-9 p.m., Monday through Friday, with a maximum of five events and 30 hours per month.

PG&E may trigger a CBP Prescribed Event for one or more Sub-Load Aggregation Points (Sub-LAP) when: (1) the CAISO DAM price exceeds $95/MWh; (2) PG&E receives a market award or dispatch instruction from the CAISO for a PDR that's part of CBP; (3) when PG&E, in its sole opinion, forecasts that generation resources or electric system capacity may not be adequate; or (4) forecasted temperature for a Sub-LAP exceeds the temperature threshold for the Sub-LAP.

The *Elect option* program hours are 1-9 p.m., Monday through Friday, with a maximum of five events and 30 hours per month, though Elect participants can choose to participate in additional events or hours at their discretion. The Elect option also gives aggregators the ability to choose the price at which their PDRs are bid into the DAM.

The *Elect Plus option* allows participation in the CAISO market for additional hours outside the standard program hours, and like the Elect option, gives aggregators the ability to choose the price at which their PDRs are bid into the DAM.

The maximum number of hours a customer may be dispatched under any of these options is 30 hours per month.

b. Annual Summary of Results

All CBP events during the record period were dispatched as the result of PDR market awards, except for four test events. PDRs enrolled in the CBP are subject to a test event when they have not received a market award in a given month and the DAM price exceeds the tariff trigger price of $95 per MWh.

1) Times and Duration of Program Dispatches

During the record period, PG&E dispatched CBP resources on 28 occasions for a total of 60 event hours compared to 13 occasions and 20 event hours in 2019, and 47 occasions and 114 event hours in 2018. The increase in dispatch frequency and dispatch duration between 2019 and 2020 is attributable to significant heat storms California faced in the Fall season and the market awards CBP resources received.

Table 1-8 below provides additional detail and a comparison of CBP event count and frequency for 2013 through 2020.

TABLE 1-8
CBP DR PROGRAM DISPATCH

		CBP	
Line No.	Year	Day-Ahead Total Events/Hours	Day-Of Total Events/Hours
1	2013	5/20	5/19
2	2014	11/41	15/60
3	2015	16/63	18/72
4	2016	16/58	19/69
5	2017	22/67	25/71
6	2018	47/114	0/0
7	2019	13/20	0/0
8	2020	28/60	0/0

Attachment 1A provides a summary of: (a) the times and duration that all programs were dispatched; (b) all cases where CBP trigger conditions were forecast to be met and all cases where these trigger conditions were actually met; and (c) a list of occurrences when DR resources met program triggers, but were not dispatched, along with an explanation of the reason for non-dispatch.

2) Satisfaction of DR Program Trigger Conditions

Table 1-9 below summarizes the annual number of hours CBP was dispatched in each Sub-LAP, compared to the annual number of hours that CBP was available. Also included is the annual number of events dispatched compared to the maximum number of events allowed.[22]

TABLE 1-9
ANNUAL CBP HOURS DISPATCHED

Line No.	Load Zone	Number of Hours Day-Ahead Trigger Was Met	Total Day-Ahead Event Hours Dispatched	Number of Day-Ahead Events
1	PGCC	19	19	9
2	PGEB	20	20	9
3	PGF1	18	18	9
4	PGFG	23	23	9
5	PGHB	7	7	5
6	PGKN	15	15	7
7	PGNB	21	21	9
8	PGNC	–	–	–
9	PGNP	49	49	22
10	PGP2	62	62	23
11	PGSB	52	52	19
12	PGSF	23	23	11
13	PGSI	26	26	11
14	PGST	18	18	9
15	PGZP	18	16	8

Attachment 1B provides monthly tables showing the number of hours when PG&E forecasted that trigger criteria would be reached, hours in which trigger conditions were reached in the same time period, actual hours dispatched, and the number of events dispatched.

3) Non-Dispatch Occurrences

a) Summary

The number of hours when triggers were met but resources were not dispatched were minimal during the record period. As a result of the integration of CBP resources as PDRs in the CAISO day-ahead energy market, bidding strategies incorporated operational constraints and opportunity costs. Additionally, the Elect and Elect Plus Program options allow CBP aggregators to make resources available beyond the limits

[22] The maximum number of events was established in Resolution E-4819 and implemented on June 1, 2017.

on number of events hours, and consecutive days. The details are discussed below.

TABLE 1-10
CPB HOURS IN WHICH TRIGGER MET, BUT RESOURCE NOT DISPATCHED

Line No.	Load Zone	Day-Ahead Hours
1	PGCC	–
2	PGEB	–
3	PGF1	–
4	PGFG	–
5	PGHB	–
6	PGKN	–
7	PGNB	–
8	PGNC	–
9	PGNP	5
10	PGP2	10
11	PGSB	10
12	PGSF	–
13	PGSI	–
14	PGST	–
15	PGZP	–

Attachment 1C provides a detailed summary of total energy actually dispatched as a proportion of maximum available energy for each DR program. This comparison provides both percentage and nominal MWh terms.

b) Explanation of the Basis for a Decision Not to Dispatch

The integration of CBP as PDR in the DAM resulted in program dispatches triggered by market awards (four dispatches were test events). Operational constraints and opportunity cost now are incorporated into the PDR bidding strategy for the Prescribed option. For example, PG&E monitors the dispatches for each PDR to ensure the 5-event and 30-hour monthly maximums, as well as the three consecutive event days, are observed. When the limits have are reached, the PDR is not bid into the market unless it is nominated in the Elect or Elect+ option and the aggregator opts to voluntarily exceed the limits. Similarly, when forecast prices indicate that a PDR resource would exceed its five event maximum in a given month, an opportunity cost was added to the dispatch trigger price to maximize the value of call days.

The result of considering operational constraints and opportunity cost in the bidding strategy is a significant reduction in cases of when the program trigger is met, but the program is not dispatched. There were six occasions, totaling 12 hours, during the record period where CBP resources received market awards but were not dispatched due to operational constraints.

The Elect and Elect Plus participation options reduce the number of dispatch exceptions. These options provide CBP aggregators the ability to decide what operational constraints and opportunity cost considerations apply to their portfolio. The aggregators determine how many hours per month, events per month, and consecutive days their resources are available. They develop their bidding strategy and PG&E submits the bids as provided. When the bids result in a market award, PG&E dispatches the resources accordingly.

In the 2014 ERRA Settlement, PG&E agreed to provide definitions of "operational constraints" and "opportunity cost" which are used as reasons for not dispatching DR programs when economic triggers are met.[23] These definitions are provided in Sections C.2.b.3)b)i. and C.2.b.3)b)ii. below, respectively. PG&E also agreed to provide guidelines for situations in which "customer fatigue" may occur. This is included in Section C.2.b.3) b) ii.

On two occasions, totaling three hours, CBP resources received market awards but were not dispatched due to technical difficulties with PG&E notification and dispatch systems.

i) Operational Constraints Related to DR Dispatch

PG&E defines a DR "operational constraint" as a constraint based on limitations included in the DR tariff(s). These include the monthly "total hour" and "number of

[23] 2014 ERRA Settlement, 3.2, 3.6.

events", and the hour per-call basis. For example, the CBP Prescribed option is limited to 30 hours per month and five events per month.[24] As mentioned above, PG&E accounts for these constraints in the bidding strategy.

ii) Opportunity Costs as Related to DR Dispatch

Generally, "opportunity cost" is the potential lost future value associated with calling a DR program at a certain point in time and, therefore, eliminating the option to use it at a future time. Opportunity costs arise from two issues.

First, there are maximum hour limits and number of times a PDR participating in the Prescribed option may be called in the DR program season, so dispatching a resource today may result in the resource not being available during a future time of need.

The second issue that creates opportunity cost is "customer fatigue," which is a reduction in participation rates after multiple calls due to the customer perceiving the costs of participating exceeding the benefits of participating.

Some of PG&E's largest DR customers have provided consistent feedback to PG&E that dispatch frequency has seriously impacted their business operations and requested that dispatch only occur if necessary. As a result, PG&E generally does not dispatch DR events for more than three days in a row, which was agreed to in the 2014 ERRA Settlement and included in the CBP tariff.

iii) PSPS Related to DR Dispatch

During the record period, PG&E considered the impact of PSPS events in order to minimize any confusion that could result from customers receiving multiple and potentially contradictory messages (e.g., receiving both notice of an impending PSPS event, and instructions to drop

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[24] The CBP tariff specifies that the program is only available during the summer (May-October) DR season. This also would be considered an operational constraint when compared to year-round DR programs.

load, should a DR event be dispatched concurrently with the PSPS event). Furthermore, customers experiencing an involuntary outage would provide no incremental load reduction.

The impact of PSPS events was decreased in 2020 by the development of procedures whereby the DR team received a list of the exact customers who would be affected by a pending PSPS event. When the number of impacted customers was relatively small, said customers could be manually withheld from PDR bids. On occasions when the number of impacted customers was relatively large, or the DR team did not have advanced visibility into which specific CBP customers would be impacted (mainly during the first few weeks of the DR season), PG&E elected to withhold day-ahead bids for entire PDR resources in Sub-LAPs receiving a Utility Fire Potential Index (FPI) rating of “R5” or “R5-Plus” when a PSPS event was imminent.

There were no occasions during the record period where a resource received a market award and was also affected by a PSPS event.

4) Dispatch Day Selection

For the record period, PG&E’s CBP event dispatch helped to minimize its overall portfolio costs. As demonstrated in Table 1-11 below, PG&E employed its DR resources during highly valuable hours.

TABLE 1-11
AVERAGE LMP FOR FORECASTED TRIGGER EVENT DAYS AND ACTUAL DISPATCH DAYS

Line No.	Average Hourly Price During Actual Dispatch Events ($/MWh) (A)	Average Hourly Potential Price During All Times When Trigger Conditions Were Forecasted (Dispatched or Not) ($/MWh) (B)	$ (A) – (B)	(A)/(B) (%)
1	[redacted]			

As indicated in Table 1-11, the average hourly LMP for CBP events actually dispatched in the record period was [redacted]/MWh, whereas the average hourly potential LMP from all time periods when CBP triggers were forecasted to be met by PG&E was [redacted]/MWh. The variability between the two price figures can in part be attributed to instances where the trigger for an event was met, but was not ultimately dispatched due to operational constraints.

4. SmartAC

a. Description

PG&E's SmartAC Program is a voluntary DR program available to residential customers. PG&E installs a load control device at a customer's premises that can temporarily disengage the customer's primary central Air Conditioning (A/C) unit or raise the temperature at the thermostat when the device is remotely activated. SmartAC is both a reliability program used during emergencies and an economic program based on wholesale energy prices. It can be dispatched by: (1) order of the CAISO a) after the dispatch of Condition 2 Reliability Must-Run units and prior to canvasing other entities and Balancing Authorities for available Manual Dispatch Energy/Capacity on interties, or b) otherwise based on its forecasted system conditions and operating procedures; or c) during emergency or near-emergency situations; (2) at the discretion of PG&E's energy operations center in response to a CAISO economic award in the wholesale market or high wholesale energy prices; or (3) during program testing.

SmartAC is available for dispatch from May 1 through October 31, consistent with times of high A/C usage. It is available for emergencies seven days a week and economic dispatch is targeted for Monday through Friday. The program was originally designed to permit a maximum of 100 hours of cycling per customer per year. Historically, however, few emergency events happened, and with CAISO wholesale market integration in 2018, economic dispatch has been targeted at 20 hours per service account annually. This target number of hours was identified based on PG&E's own testing, and information shared by

Southern California Edison Company and their experience with their AC cycling program. Both sources indicated that cycling in excess of 20-25 hours leads to higher customer attrition rates.

As mentioned above, SmartAC continued to be integrated as a PDR in the CAISO DAM in 2020. The SmartAC bidding strategy reflects the dual nature of the program as both a reliability program and an economic program.

[redacted]

TABLE 1-12
SMART AC SUB-LAP TEMPERATURE THRESHOLDS

Line No.	Load Zone	Forecast High Temperature
1	PGCC	94
2	PGEB	101
3	PGF1	106
4	PGFG	98
5	PGHB	104
6	PGKN	106
7	PGNB	94
8	PGNC	104
9	PGNP	107
10	PGP2	94
11	PGSB	94
12	PGSF	87
13	PGSI	103
14	PGST	104
15	PGZP	106

[redacted]

[redacted] The exceptions to this procedure in 2020 were the result of California’s Stay-at-Home order which was issued on March 19, 2020 and PSPS events, which are explained in Section b)3).

b. Annual Summary of Results

1) Times and Duration of Program Dispatches

During the record period, PG&E dispatched SmartAC resources on fifteen occasions. All events were dispatched as a result of market awards or a CAISO emergency apart from one test event.

TABLE 1-13
SMARTAC PROGRAM DISPATCH

Line No.	Year	Day-Ahead Total Events/Hours
1	2018	9/32
2	2019	10/32
3	2020	15/40.367

Attachment 1A provides a summary of: (a) the times and duration that programs were dispatched; (b) all cases where trigger conditions were forecast to be met and all cases where these trigger conditions were actually met; and (c) a list of occurrences when DR resources met program triggers, but were not dispatched, along with an explanation of the reason for non-dispatch.

2) Satisfaction of DR Program Trigger Conditions

Table 1-14 summarizes the annual number of hours SmartAC was dispatched in each Sub-LAP, compared to the annual number of hours that it was available.

TABLE 1-14
ANNUAL SMARTAC PROGRAM HOURS DISPATCHED

Line No.	Load Zone	Hours Trigger Was Forecast to be Met	Hours Day-Ahead Trigger Was Met	Hours Day-Ahead Event Dispatched	Number of Day-Ahead Events	Maximum Allowable Event Hours/Year
1	PGCC	18	18	18	9	100
2	PGEB	20	20	20	9	100
3	PGF1	19	19	19	9	100
4	PGFG	16	16	14	6	100
5	PGHB	–	–	–	–	100
6	PGKN	18	18	18	8	100
7	PGNB	20	20	20	9	100
8	PGNC	20	20	20	9	100
9	PGNP	18	18	16	7	100
10	PGP2	20	20	20	9	100
11	PGSB	14	14	14	6	100
12	PGSF	–	–	–	–	100
13	PGSI	21	21	20	10	100
14	PGST	20	20	20	9	100
15	PGZP	18	18	18	8	100

Attachment 1B provides monthly tables showing the number of hours when PG&E forecasted that trigger criteria would be reached, hours in which trigger conditions were reached in the same time period, actual hours dispatched, and the number of events dispatched.

3) Non-Dispatch Occurrences

[redacted] The exceptions to this procedure in 2020 were the result of California's Stay-at-Home order which was issued on March 19, 2020 and PSPS events.

PG&E did not dispatch the SmartAC Program from May to July 2020 due to concerns about the impact of decreasing A/C in homes where customers were mandated to remain. During this period, typically suggested customer mitigations were not available; malls, theatres and cooling centers were closed. In July, after consulting with CPUC staff, PG&E resumed lowering the bids for the SmartAC Program.

As in the case of CBP PDRs, the impact of PSPS events on SmartAC PDRs was decreased in 2020 due to process and data improvements. When access to the list of PSPS-impacted customers was available, and the number of impacted customers was relatively small, said customers could be manually withheld from DR events during the PSPS period. If manual omission was not feasible due to quantity of impacted customer, an outage was declared in that Sub-LAP. On occasions when the DR team did not have advanced visibility into which specific SmartAC customers would be impacted (mainly during the first few weeks of the DR season), PG&E elected to withhold day-ahead bids for entire PDR resources in Sub-LAPs receiving a Utility FPI rating of "R5" or "R5 Plus" when a PSPS event was imminent.

TABLE 1-15
SMARTAC PROGRAM HOURS IN WHICH TRIGGER MET BUT RESOURCE NOT DISPATCHED

Line No.	Load Zone	Day-Ahead Hours
1	PGCC	–
2	PGEB	–
3	PGF1	–
4	PGFG	2
5	PGHB	–
6	PGKN	–
7	PGNB	–
8	PGNC	–
9	PGNP	2
10	PGP2	–
11	PGSB	–
12	PGSF	–
13	PGSI	1
14	PGST	–
15	PGZP	–

4) Dispatch Day Selection

For the record period, PG&E's SmartAC Program event dispatches helped to minimize its overall portfolio costs. As demonstrated in Table 1-16 below, PG&E employed its DR resources during highly-valuable hours.

TABLE 1-16
AVERAGE LMP FOR
SMARTAC FORECASTED TRIGGER EVENT DAYS
AND ACTUAL DISPATCH DAYS

Line No.	Average Hourly Price During Actual Dispatch Events ($/MWh)	Average Hourly Potential Price During All Times When Trigger Conditions Were Forecasted (Dispatched or Not) ($/MWh)	$ (A) – (B)	(A)/(B) (%)
	(A)	(B)		
1	[redacted]			

As indicated in Table 1-16, the average hourly LMP for SmartAC events actually dispatched in the record period was $217.16/MWh, whereas the average hourly potential LMP from all time periods when SmartAC triggers were forecasted to be met was $220.05/MWh. The variability between the two price figures can in part be attributed to non-dispatch occurrences—as outlined above.

5. Economically-Dispatched DR Summary

PG&E utilized CBP and SmartAC to provide load reductions that enhanced reliability and reduced peak demand and associated prices. DR resources were well-aligned with high load and price time periods. While PG&E did not dispatch its DR resources each time an economic trigger was met, instances of non-dispatch were due to operational constraints of the programs or due to opportunity costs associated with customer impact as outlined earlier.

D. Conclusion

In compliance with the LCD Decisions and 2014 and 2015 ERRA Settlements, this chapter and the associated work papers have demonstrated that PG&E:

- Achieved LCD during the record period; and
- Reasonably utilized, integrated and improved the dispatch for economic DR resources during the record period.

PG&E has fully complied with the Commission decisions addressing LCD practices during the record period, and has provided testimony and workpapers that are consistent with the LCD Decisions to satisfy PG&E's *prima facie* burden of proof to demonstrate that it achieved LCD. This testimony and the confidential workpapers for Chapter 1 demonstrate that PG&E dispatched its resources in a manner consistent with LCD requirements during the record period.

PG&E also utilized its DR portfolio during the record period to provide load reductions that enhanced reliability and reduced peak demand and associated prices. In addition, PG&E has provided the information and metrics required by the LCD Decisions for LCD and its economically-triggered DR Programs. Finally, where applicable, the Chapter 1 testimony and workpapers satisfy the requirements of the 2014 and 2015 ERRA Settlements.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT A

SUMMARY OF TRIGGERED DISPATCH FROM DEMAND RESPONSE PROGRAMS

Attachment A - Triggers Met - DR Program Dispatched

Date Trigger Condition Was Forecast to be Met	Type of Trigger	Program	Location	Forecast Start Time	Forecast End Time	Dispatch Start Time	Dispatch End Time	Forecast Event Hours	Trigger Was Met?	Resource Dispatched?	If No, Explain	Program Not Dispatched	Dispatched/Hours Non-dispatch	Capacity of Program Available	ed Available Load For the	Actual Load Achieved	Duration of Dispatch
6/3/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSF	17:00	20:00	17:00	20:00	3	Y	Y			3	[redacted]			3
7/13/2020	Market Award	Capacity Bidding Program	Market Resources in PGHB	20:00	21:00	20:00	21:00	1	Y	Y			1				1
7/28/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2, PGSB	19:00	20:00	19:00	20:00	1	Y	Y			1				1
7/29/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGP2	18:00	20:00	18:00	20:00	2	Y	Y			2				2
7/30/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2, PGSB	19:00	20:00	19:00	20:00	1	Y	Y			1				1
7/30/2020	PG&E Test	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGFG, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST	18:00	20:00	18:00	20:00	2	Y	Y			2				2
7/31/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2	18:00	20:00	18:00	20:00	2	Y	Y			2				2
7/31/2020	PG&E Test	Capacity Bidding Program	Market Resources in PGF1, PGKN, PGZP	19:00	20:00	19:00	20:00	1	Y	Y			1				1
8/11/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP	19:00	20:00	19:00	20:00	1	Y	Y			1				1
8/13/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB	18:00	20:00	18:00	20:00	2	Y	Y			2				2
8/14/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP	17:00	21:00	17:00	21:00	4	Y	Y			4				4
8/17/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP	17:00	21:00	17:00	21:00	4	Y	Y			4				4
8/18/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST	16:00	21:00	16:00	21:00	5	Y	Y			5				5
8/19/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP	18:00	20:00	18:00	20:00	2	Y	Y			2				2
8/20/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2	18:00	19:00	18:00	19:00	1	Y	Y			1				1
8/24/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2	18:00	19:00	18:00	19:00	1	Y	Y			1				1
8/25/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2	18:00	20:00	18:00	20:00	2	Y	Y			2				2
9/8/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB, PGSF, PGSI, PGZP	18:00	20:00	18:00	20:00	2	Y	Y			2				2
9/9/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB	18:00	19:00	18:00	19:00	1	Y	Y			1				1
9/14/2020	Market Award	Capacity Bidding Program	Market Resources in PGHB	14:00	15:00	14:00	15:00	1	Y	Y			1				1
9/28/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2, PGSB	17:00	20:00	17:00	20:00	3	Y	Y			3				3
9/29/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB	17:00	20:00	17:00	20:00	3	Y	Y			3				3
9/30/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP	16:00	20:00	16:00	20:00	4	Y	Y			4				4
9/30/2020	PG&E Test	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSI, PGST, PGZP	17:00	19:00	17:00	19:00	2	Y	Y			2				2
10/1/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP	16:00	20:00	16:00	20:00	4	Y	Y			4				4
10/13/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB	18:00	19:00	18:00	19:00	1	Y	Y			1				1
10/14/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB	17:00	19:00	17:00	19:00	2	Y	Y			2				2
10/15/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST	17:00	19:00	17:00	19:00	2	Y	Y			2				2
10/16/2020	Market Award	Capacity Bidding Program	Market Resources in PGCC, PGEB, PGF1, PGFG, PGHB, PGKN, PGNB, PGNP, PGP2, PGSB, PGSF, PGSI, PGST, PGZP	17:00	19:00	17:00	19:00	2	Y	Y			2				2
10/20/2020	Market Award	Capacity Bidding Program	Market Resources in PGSB	17:00	18:00	17:00	18:00	1	Y	Y			1				1
10/21/2020	PG&E Test	Capacity Bidding Program	Market Resources in PGNP, PGSI	18:00	19:00	18:00	19:00	1	Y	Y			1				1
8/14/2020	Market Award / CAISO E	SmartAC	Market Resources in PGNP, PGST, PGKN, PGZP, PGNC, PGNB, PGEB, PGP2, PGSI, PGF1, PGCC, PGFG, PGSB	16:00	20:22	16:00	20:22	4.367	Y	Y			4.367				4.367
8/15/2020	Market Award	SmartAC	Market Resources in PGCC, PGEB, PGF1, PGKN, PGNC, PGNP, PGP2, PGST, PGZP, PGNB, PGSI	16:00	19:00	16:00	19:00	3	Y	Y			3				3
8/17/2020	Market Award	SmartAC	Market Resources in PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGSI, PGST, PGZP	16:00	18:00	16:00	18:00	2	Y	Y			2				2
8/18/2020	PG&E Test	SmartAC	Market Resources in PGCC, PGST, PGSI, PGP2, PGFG, PGNB, PGEB, PGNP, PGKN, PGZP, PGF1, PGNC	16:00	19:00	16:00	19:00	3	Y	Y			3				3
8/19/2020	Market Award	SmartAC	Market Resources in PGEB, PGF1, PGKN, PGNB, PGP2, PGSI, PGST, PGZP, PGCC, PGNC	16:00	20:00	16:00	20:00	4	Y	Y			4				4
9/5/2020	Market Award	SmartAC	Market Resources in PGEB, PGF1, PGSI	16:00	18:00	16:00	18:00	2	Y	Y			2				2
9/6/2020	Market Award	SmartAC	Market Resources in PGCC, PGEB, PGKN, PGNB, PGNC, PGNP, PGP2, PGSI, PGST, PGZP, PGF1	15:00	20:00	15:00	20:00	5	Y	Y			5				5
9/7/2020	Market Award	SmartAC	Market Resources in PGEB, PGF1, PGKN, PGNB, PGNC, PGNP, PGSI, PGST, PGZP	16:00	18:00	16:00	18:00	2	Y	Y			2				2
9/8/2020	Market Award	SmartAC	Market Resources in PGNB, PGST	16:00	18:00	16:00	18:00	2	Y	Y			2				2
9/27/2020	Market Award	SmartAC	Market Resources in PGP2, PGSB, PGCC	16:00	18:00	16:00	18:00	2	Y	Y			2				2
9/28/2020	Market Award	SmartAC	Market Resources in PGCC, PGFG, PGNC, PGP2, PGSB	16:00	18:00	16:00	18:00	2	Y	Y			2				2
9/30/2020	Market Award	SmartAC	Market Resources in PGSI	17:00	18:00	17:00	18:00	1	Y	Y			1				1
10/1/2020	Market Award	SmartAC	Market Resources in PGFG	15:00	17:00	15:00	17:00	2	Y	Y			2				2
10/15/2020	Market Award	SmartAC	Market Resources in PGFG, PGP2, PGCC, PGSB	17:00	20:00	17:00	20:00	3	Y	Y			3				3
10/16/2020	Market Award	SmartAC	Market Resources in PGSB, PGFG	16:00	19:00	16:00	19:00	3	Y	Y			3				3

Attachment A - Triggers Met - DR Program Not Dispatched

Date Trigger Condition Was Forecast to be Met	Type of Trigger	Program	Location	Forecast Start Time	Forecast End Time	Dispatch Start Time	Dispatch End Time	Forecast Event Hours	Trigger Was Met?	Resource Dispatched?	If No, Explain	Program Not Dispatched	Dispatched/Hours Non-dispatch	Capacity of Program Available	ed Available Load For the	Actual Load Achieved	Duration of Dispatch
7/27/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2	19:00	20:00			1	Y	N	The deadline was missed for dispatch	Y	1	[redacted]	[redacted]	0.00	
8/20/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2	18:00	19:00			1	Y	N	Tariff monthly event cap was met	Y	1	[redacted]	[redacted]	0.00	
8/24/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2, PGSB	18:00	20:00			2	Y	N	Tariff monthly event cap was met	Y	2	[redacted]	[redacted]	0.00	
8/25/2020	Market Award	Capacity Bidding Program	Market Resources in PGP2, PGSB	18:00	20:00			2	Y	N	Tariff monthly event cap was met	Y	2	[redacted]	[redacted]	0.00	
10/6/2020	Market Award	Capacity Bidding Program	Market Resources in PGSB	17:00	19:00			2	Y	N	Advisory Schedule received after dispatch deadline	Y	2	[redacted]	[redacted]	0.00	
10/16/2020	Market Award	Capacity Bidding Program	Market Resources in PGNP, PGP2, PGSB	16:00	20:00			4	Y	N	Resources had 3 consecutive events	Y	4	[redacted]	[redacted]	0.00	
9/27/2020	Market Award	SmartAC	Market Resources in PGFG	16:00	18:00			2	Y	N	PGFG customers were involved in a PSPS event and SmartAC did not want to limit their AC	Y	2	[redacted]	[redacted]	0.00	
9/28/2020	Market Award	SmartAC	Market Resources in PGSI	16:00	17:00			1	Y	N	PGSI customers were involved in a PSPS event and SmartAC did not want to limit their AC u	Y	1	[redacted]	[redacted]	0.00	
10/16/2020	Market Award	SmartAC	Market Resources in PGNP	17:00	19:00			2	Y	N	Due to operations mistake, an incorrect resource received a market award. However, the r	Y	2	[redacted]	[redacted]	0.00	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT B

SUMMARY OF 2020 CAPACITY BIDDING PROGRAM EVENTS

Attachment B. Number of hours when PG&E forecasted that trigger criteria would be Met, actual hours Met, and actual hours dispatched

Capacity Bidding Program/Day-Ahead

May

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	0	0	0	0
PGEB	0	0	0	0
PGF1	0	0	0	0
PGFG	0	0	0	0
PGHB	0	0	0	0
PGKN	0	0	0	0
PGNB	0	0	0	0
PGNC	0	0	0	0
PGNP	0	0	0	0
PGP2	0	0	0	0
PGSB	0	0	0	0
PGSF	0	0	0	0
PGSI	0	0	0	0
PGST	0	0	0	0
PGZP	0	0	0	0

June

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	0	0	0	0
PGEB	0	0	0	0
PGF1	0	0	0	0
PGFG	0	0	0	0
PGHB	0	0	0	0
PGKN	0	0	0	0
PGNB	0	0	0	0
PGNC	-	-	-	-
PGNP	1	1	1	1
PGP2	3	3	3	1
PGSB	0	0	0	0
PGSF	1	1	1	1
PGSI	0	0	0	0
PGST	0	0	0	0
PGZP	0	0	0	0

July

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	1	1	1	1
PGEB	1	1	1	1
PGF1	1	1	1	1
PGFG	1	1	1	1
PGHB	1	1	1	1
PGKN	1	1	1	1
PGNB	1	1	1	1
PGNC	-	-	-	-
PGNP	4	4	3	3
PGP2	7	7	6	4
PGSB	3	3	3	3
PGSF	1	1	1	1
PGSI	2	2	2	1
PGST	2	2	2	1
PGZP	1	1	1	1

August

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	11	11	11	4
PGEB	11	11	11	4
PGF1	11	11	11	4
PGFG	14	14	14	4
PGHB	2	2	2	1
PGKN	9	9	9	3
PGNB	12	12	12	4
PGNC	-	-	-	-
PGNP	20	20	20	8
PGP2	25	25	20	8
PGSB	20	20	16	5
PGSF	13	13	13	4
PGSI	14	14	14	4
PGST	8	8	8	4
PGZP	9	9	9	3

September

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	2	2	2	1
PGEB	2	2	2	1
PGF1	2	2	2	1
PGFG	2	2	2	1
PGHB	3	3	3	2
PGKN	2	2	2	1
PGNB	2	2	2	1
PGNC	-	-	-	-
PGNP	8	8	8	4
PGP2	13	13	13	5
PGSB	13	13	13	5
PGSF	2	2	2	2
PGSI	3	3	3	2
PGST	2	2	2	1
PGZP	3	3	3	2

October

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	5	5	5	3
PGEB	6	6	6	3
PGF1	4	4	4	3
PGFG	6	6	6	3
PGHB	1	1	1	1
PGKN	3	3	3	2
PGNB	6	6	6	3
PGNC	-	-	-	-
PGNP	16	16	12	6
PGP2	14	14	10	5
PGSB	16	16	10	6
PGSF	6	6	6	3
PGSI	7	7	7	4
PGST	6	6	6	3
PGZP	3	3	3	2

Annual

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	19	19	19	9
PGEB	20	20	20	9
PGF1	18	18	18	9
PGFG	23	23	23	9
PGHB	7	7	7	5
PGKN	15	15	15	7
PGNB	21	21	21	9
PGNC	-	-	-	-
PGNP	49	49	44	22
PGP2	62	62	52	23
PGSB	52	52	42	19
PGSF	23	23	23	11
PGSI	26	26	26	11
PGST	18	18	18	9
PGZP	16	16	16	8

Attachment B. Number of hours when PG&E forecasted that trigger criteria would be Met, actual hours Met, and actual hours dispatched

Smart AC Program/Day-Ahead

May

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	0	0	0	0
PGEB	0	0	0	0
PGF1	0	0	0	0
PGFG	0	0	0	0
PGHB	0	0	0	0
PGKN	0	0	0	0
PGNB	0	0	0	0
PGNC	0	0	0	0
PGNP	0	0	0	0
PGP2	0	0	0	0
PGSB	0	0	0	0
PGSF	0	0	0	0
PGSI	0	0	0	0
PGST	0	0	0	0
PGZP	0	0	0	0

June

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	0	0	0	0
PGEB	0	0	0	0
PGF1	0	0	0	0
PGFG	0	0	0	0
PGHB	0	0	0	0
PGKN	0	0	0	0
PGNB	0	0	0	0
PGNC	0	0	0	0
PGNP	0	0	0	0
PGP2	0	0	0	0
PGSB	0	0	0	0
PGSF	0	0	0	0
PGSI	0	0	0	0
PGST	0	0	0	0
PGZP	0	0	0	0

July

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	0	0	0	0
PGEB	0	0	0	0
PGF1	0	0	0	0
PGFG	0	0	0	0
PGHB	0	0	0	0
PGKN	0	0	0	0
PGNB	0	0	0	0
PGNC	0	0	0	0
PGNP	0	0	0	0
PGP2	0	0	0	0
PGSB	0	0	0	0
PGSF	0	0	0	0
PGSI	0	0	0	0
PGST	0	0	0	0
PGZP	0	0	0	0

August

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	9	9	9	5
PGEB	13	13	13	6
PGF1	12	12	12	6
PGFG	6	6	6	2
PGHB	0	0	0	0
PGKN	13	13	13	6
PGNB	13	13	13	6
PGNC	13	13	13	6
PGNP	11	11	11	5
PGP2	11	11	11	5
PGSB	6	6	6	2
PGSF	0	0	0	0
PGSI	12	12	12	6
PGST	13	13	13	6
PGZP	13	13	13	6

September

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	7	7	7	3
PGEB	7	7	7	3
PGF1	7	7	7	3
PGFG	4	4	2	1
PGHB	0	0	0	0
PGKN	5	5	5	2
PGNB	7	7	7	3
PGNC	7	7	7	3
PGNP	5	5	5	2
PGP2	7	7	7	3
PGSB	4	4	4	2
PGSF	0	0	0	0
PGSI	9	9	8	4
PGST	7	7	7	3
PGZP	5	5	5	2

October

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	2	2	2	1
PGEB	0	0	0	0
PGF1	0	0	0	0
PGFG	6	6	6	3
PGHB	0	0	0	0
PGKN	0	0	0	0
PGNB	0	0	0	0
PGNC	0	0	0	0
PGNP	2	2	0	0
PGP2	2	2	2	1
PGSB	4	4	4	2
PGSF	0	0	0	0
PGSI	0	0	0	0
PGST	0	0	0	0
PGZP	0	0	0	0

Annual

Load Zone	Forecasted	Met	Actual Hours Dispatched	Number of Events Dispatched
PGCC	18	18	18	9
PGEB	20	20	20	9
PGF1	19	19	19	9
PGFG	16	16	14	6
PGHB	0	0	0	0
PGKN	18	18	18	8
PGNB	20	20	20	9
PGNC	20	20	20	9
PGNP	18	18	16	7
PGP2	20	20	20	9
PGSB	14	14	14	6
PGSF	0	0	0	0
PGSI	21	21	20	10
PGST	20	20	20	9
PGZP	18	18	18	8

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ATTACHMENT C

SUMMARY OF TOTAL ENERGY DISPATCHED FROM DEMAND RESPONSE PROGRAMS

Attachment C. Number of hours dispatched, energy dispatched and maximum energy available

Capacity Bidding Program/Day-Ahead

May

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 30 hrs)	(c) = (a)/(b) %
PGCC	0	[redacted]		0%
PGEB	0			0%
PGF1	0			0%
PGFG	0			0%
PGHB*	-			-
PGKN	0			0%
PGNB	0			0%
PGNC*	-			-
PGNP	0			0%
PGP2	0			0%
PGSB	0			0%
PGSF	0			0%
PGSI	0			0%
PGST	0			0%
PGZP	0			0%

* No participating customers

June

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 30 hrs)	(c) = (a)/(b) %
PGCC	0	[redacted]		0%
PGEB	0			0%
PGF1	0			0%
PGFG	0			0%
PGHB*	-			-
PGKN	0			0%
PGNB	0			0%
PGNC*	-			-
PGNP	1			3%
PGP2	3			10%
PGSB	0			0%
PGSF	1			3%
PGSI	0			0%
PGST	0			0%
PGZP	0			0%

* No participating customers

July

Load Zone	Actual Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 30 hrs)	(c) = (a)/(b) %
PGCC	1	[redacted]		3%
PGEB	1			3%
PGF1	1			3%
PGFG	1			3%
PGHB	1			3%
PGKN	1			3%
PGNB	1			3%
PGNC*	-			-
PGNP	3			10%
PGP2	6			20%
PGSB	3			10%
PGSF	1			3%
PGSI	2			7%
PGST	2			7%
PGZP	1			3%

* No participating customers

August

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 30 hrs)	(c) = (a)/(b) %
PGCC	11	[redacted]		37%
PGEB	11			37%
PGF1	11			37%
PGFG	14			47%
PGHB	2			7%
PGKN	9			30%
PGNB	12			40%
PGNC*	-			-
PGNP	20			67%
PGP2	20			67%
PGSB	16			53%
PGSF	13			43%
PGSI	14			47%
PGST	8			27%
PGZP	9			30%

* No participating customers

September

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 30 hrs)	(c) = (a)/(b) %
PGCC	2	[redacted]		7%
PGEB	2			7%
PGF1	2			7%
PGFG	2			7%
PGHB	3			10%
PGKN	2			7%
PGNB	2			7%
PGNC*	-			-
PGNP	8			27%
PGP2	13			43%
PGSB	13			43%
PGSF	2			7%
PGSI	3			10%
PGST	2			7%
PGZP	3			10%

* No participating customers

October

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 30 hrs)	(c) = (a)/(b) %
PGCC	5	[redacted]		17%
PGEB	6			20%
PGF1	4			13%
PGFG	6			20%
PGHB	1			3%
PGKN	3			10%
PGNB	6			20%
PGNC*	-			-
PGNP	12			40%
PGP2	10			33%
PGSB	10			33%
PGSF	6			20%
PGSI	7			23%
PGST	6			20%
PGZP	3			10%

* No participating customers

Annual

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available	(c) = (a)/(b) %
PGCC	19	[redacted]		13%
PGEB	20			11%
PGF1	18			11%
PGFG	23			15%
PGHB	7			6%
PGKN	15			9%
PGNB	21			15%
PGNC*				-
PGNP	44			29%
PGP2	52			33%
PGSB	42			25%
PGSF	23			13%
PGSI	26			15%
PGST	18			11%
PGZP	16			10%

* No participating customers

Attachment C. Number of hours dispatched, energy dispatched and maximum energy available

Smart AC Program/Day-Ahead

May

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	0	[redacted]		0%
PGEB	0			0%
PGF1	0			0%
PGFG*	-			-
PGHB*	-			-
PGKN	0			0%
PGNB	0			0%
PGNC*	-			-
PGNP	0			0%
PGP2	0			0%
PGSB	0			0%
PGSF*	-			-
PGSI	0			0%
PGST	0			0%
PGZP	0			0%

* No participating customers

June

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	0	[redacted]		0%
PGEB	0			0%
PGF1	0			0%
PGFG*	-			-
PGHB*	-			-
PGKN	0			0%
PGNB	0			0%
PGNC	0			0%
PGNP	0			0%
PGP2	0			0%
PGSB	0			0%
PGSF*	-			-
PGSI	0			0%
PGST	0			0%
PGZP	0			0%

* No participating customers

July

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	0	[redacted]		0%
PGEB	0			0%
PGF1	0			0%
PGFG*	-			-
PGHB*	-			-
PGKN	0			0%
PGNB	0			0%
PGNC	0			0%
PGNP	0			0%
PGP2	0			0%
PGSB	0			0%
PGSF*	-			-
PGSI	0			0%
PGST	0			0%
PGZP	0			0%

* No participating customers

August

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	5	[redacted]		25%
PGEB	8			40%
PGF1	8			40%
PGFG*	-			-
PGHB*	-			-
PGKN	8			40%
PGNB	8			40%
PGNC	9			45%
PGNP	6			30%
PGP2	6			30%
PGSB	0			0%
PGSF*	-			-
PGSI	8			40%
PGST	8			40%
PGZP	8			40%

* No participating customers

September

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	7	[redacted]		35%
PGEB	7			35%
PGF1	7			35%
PGFG	4			20%
PGHB*	-			-
PGKN	5			25%
PGNB	7			35%
PGNC	7			35%
PGNP	5			25%
PGP2	7			35%
PGSB	4			20%
PGSF*	-			-
PGSI	9			45%
PGST	7			35%
PGZP	5			25%

* No participating customers

October

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	2	[redacted]		0%
PGEB	0			0%
PGF1	0			0%
PGFG	6			30%
PGHB*	-			-
PGKN	0			0%
PGNB	0			0%
PGNC	0			0%
PGNP	2			10%
PGP2	2			10%
PGSB	4			20%
PGSF*	-			-
PGSI	0			0%
PGST	0			0%
PGZP	0			0%

* No participating customers

Annual

Load Zone	Hours Dispatched	(a) Total Energy Dispatched (MWh)	(b) Maximum Energy Available (Avg MW X 20 hrs)	(c) = (a)/(b) %
PGCC	14	[redacted]		10%
PGEB	15			17%
PGF1	15			16%
PGFG	10			24%
PGHB*				-
PGKN	13			15%
PGNB	15			14%
PGNC	16			20%
PGNP	13			15%
PGP2	15			13%
PGSB	8			4%
PGSF*				-
PGSI	17			19%
PGST	15			18%
PGZP	13			15%

* No participating customers

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

UTILITY-OWNED GENERATION: HYDROELECTRIC

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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 2020 record year.

PG&E's utility-owned hydroelectric portfolio was operated in a reasonable manner during the record period. At year-end 2020 PG&E's hydro-generating portfolio consisted of 64 powerhouses with 103 generating units. The system operates under 23 Federal Energy Regulatory Commission (FERC) licenses, which govern the operation of 99 of the generating units at 62 powerhouses. Four generating units are at two non-FERC jurisdictional powerhouses. PG&E's hydro-generating portfolio has an aggregate nameplate capacity of 3,867.1 megawatts (MW) and produces an average of about 10 terawatt-hours of energy in a normal precipitation year.

PG&E's 64 hydro powerhouses are located on 15 rivers and four tributaries of the Sierra Nevada, Cascade and Coastal mountain ranges. This is a unique set of facilities that was built between 1898 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 these hydro-generating facilities.

The system collectively includes the following ancillary support facilities: 98 reservoirs, 72 diversions, 168 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 is based on 86 water right licenses or interim permits, and 158 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 that has to be purchased for PG&E bundled customers during these 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 large 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.
- 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 (O&M) Organization

PG&E's Power Generation organization is responsible for managing the hydro-generating portfolio. The Hydro O&M organization is responsible for facility O&M and works side by side with the other Power Generation and PG&E Energy Supply support organizations to provide safe, reliable, cost-effective and environmentally responsible generation. Hydro O&M is organized geographically into five 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 located in Fresno. A full listing of powerhouses and individual units is included in Attachment 2A.

The Hydro Areas (from North to South) and the Power Generation 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. Central Area

The Central Area manages 20 powerhouses with 27 generating units and has an installed capacity of 510.6 MW. The powerhouses have in-service dates spanning from 1902 to 1986. The facilities are situated on eight different watersheds in Nevada, Placer, El Dorado, Amador, Tuolumne and Merced counties. There are three switching centers in the Central Area located at Drum Powerhouse, Wise Powerhouse and Tiger Creek Powerhouse. The Central Area headquarters is located in Auburn with satellite headquarters at Alta, Angels Camp, Tiger Creek (near Jackson) and Sonora.

d. Kings-Crane Valley Area

The Kings-Crane Valley Area manages 12 powerhouses with 19 generating units and has an installed capacity of 551 MW. The powerhouses have in-service dates spanning from 1906 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).

e. 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 located 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 Units	MW	No. of FERC Licenses	No. of Dams
1	Shasta	16	27	808.3	6	44
2	DeSabla	15	27	785.7	6	32
3	Central	20	27	510.6	5	70
4	Kings Crane Valley	12	19	550.5	5	16
5	Helms	1	3	1,212.0	1	6
6	Total	64	103	3,867.1	23	168

f. Support Organizations

The Hydro O&M organization works side-by-side with Power Generation support organizations to provide safe, reliable, cost-effective generation to California in an environmentally responsible manner.

Support organizations consists of the Generation Business and Technical Services organization and centralized departments within Power Generation. The Generation Business and Technical Services organization is an independent organization from Power Generation that supports both Nuclear and Power Generation. The centralized departments within Power Generation work closely with the Hydro O&M organization. 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) Generation Business and Technical Services

The Generation Business and Technical Services organization provides the following services and expertise.

a) **Risk and Compliance**

The Risk and Compliance organization is led by a director and is responsible for the risk and compliance functions for both nuclear and non-nuclear generation. The team develops and implements analytical risk modeling processes and techniques to achieve effective risk management, reduction and mitigation. They manage compliance and commitments to optimize the cost and benefit to the State, public and shareholders by working with regulatory agencies such as the: Nuclear Regulatory Commission, FERC, Division of Safety of Dams (DSOD), among many others. The group also manages the Nuclear Cybersecurity Program and the Power Generation Security Program to ensure asset protection and public safety.

b) **Portfolio Strategy**

The Power Generation Portfolio Strategy organization is led by a director and is responsible for optimizing the composition of the generation fleet, FERC relicensing, and managing license compliance to meet the Company's goals on affordability, reliability, compliance and supply. This team monitors the customer value (costs and benefits) of PG&E's utility-owned generation to identify and recommend potential changes to the portfolio. In addition, this team is responsible for implementing approved divestiture strategies including overseeing regulatory approvals from the California Public Utilities Commission (CPUC or the Commission) and FERC. This team provides analysis and regulatory support for other potential portfolio optimization strategies, such as decommissioning and alternative ratemaking proposals. This team also serves as a liaison for PG&E's Land Conservation Commitment efforts among various PG&E departments and the Stewardship Council.

c) Business Operations

The Business Operations organization is led by a director and is responsible for business planning and regulatory reporting which includes identifying, prioritizing, and planning Power Generation's work. Business Operations combines several functions into an integrated department that provides strategic, and tactical (operational and financial) services. Regulatory reporting includes preparation and filing of all required documentation for various regulatory proceedings which includes responding to data request and preparing work papers and testimony.

d) Geosciences

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

- Lead for seismic studies for Diablo Canyon Power Plant including management of the Long-Term Seismic Program which is an operational license commitment;
- On-call emergency evaluations and mitigation for seismic events, landslide, erosion, and foundation issues for all company Lines of Businesses;
- Support for the Hydro Facility Safety Program including fault studies, penstock geotechnical assessments, dam seepage and liquefaction analysis, 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;
- Gas Department pipeline geohazards program and pipeline replacement project support;
- Electric Transmission tower evaluations and support projects; and
- Climate team research studies and planning support.

e) Process Improvement and Corrective Action Program (CAP)

The Process Improvement and CAP is led by a director and is responsible for process improvement and Power Generation's CAP program. The Generation 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 through the use of 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.

2) Centralized Departments within Power Generation

The centralized departments within Power Generation provide the following services and expertise.

a) Asset Excellence

The Asset Excellence department is led by a director and consists of an Asset Management (AM) program that focuses on systemwide condition assessment of the hydro system equipment and proposes projects and/or changes to operations and/or maintenance practices to ensure that Power Generation's long-term investment plan reduces risk and maintains the safety and reliability of the hydro portfolio. The department is working towards achieving ISO 55001 certification for the AM program.

b) Engineering, Project Management, and Technical Services

Engineering, Project Management, and Technical Services department is led by a director and provides engineering, project management, and technical services to Power Generation operations, projects and public safety work.

Engineering provides engineering services for projects and support of routine hydro O&M work. This includes the Facility

Safety Program for dams and water conveyance facilities to assure compliance with FERC and California Department of Water Resources DSOD regulations. Engineering uses a number of contractors to augment its workforce, in order to execute on planned work. It ensures that Power Generation 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 Power Generation business.

Project Management provides project management services to Power Generation 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 a number of contractors to augment its workforce, in order to execute on planned work.

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.

c) Project Execution

Project Execution is led by a director and includes outage management, inspection services, contract services, and construction services. This team manages project work in addition to supporting routine O&M operations. Project Execution 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 Power Generation projects.

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

Construction is a mobile construction organization 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.

Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as training and qualifications, contractor safety, human performance, approaches to reduce or eliminate recordable injuries and motor vehicle incidents, approaches to sharing safety best practices, and actions to improve the safety culture of the organization.

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 grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots 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 23 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) Planned Outages (PO) and (2) Maintenance Outages (MO).

1) PO

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 PO 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) MO

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 63 conventional powerhouses are operated from seven around-the-clock switching centers. Six 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 six 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 and make adjustments in 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 Power Generation-specific guidance documents. Power Generation-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 Power Generation'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. Event Reporting System

The event reporting system documents and resolves problems related to forced outages or curtailments to generating units. By thoroughly analyzing significant problem events that occur in the operation and maintenance of PG&E's facilities, PG&E can report to various regulatory agencies as required, identify, understand and correct causal factors, and communicate and apply lessons learned to other facilities and personnel.

e. 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 Power Generation 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.

f. 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 annual MO, project-specific outages and combination outages encompassing both project and maintenance tasks. 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.

Power Generation 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.	2 to 3 Years Prior to Outage Year	A preliminary annual outage schedule for the outage year is prepared 2 to 3 years in advance. This preliminary schedule is created using 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 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.

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.
- 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.

g. 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 Power Generation 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 Power Generation projects, and are anticipated to improve the consistency and quality of project management throughout Power Generation. Project Managers report regularly to management.

h. 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 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 that directly impacts the energy output each year.

As FERC-jurisdictional hydro projects, many of PG&E's projects have recently completed relicensing efforts, resulting in increasingly 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.

PG&E's hydro generating assets produced significant amounts of electricity during the 2020 record period. The total generation for the portfolio for the 2020 record year was 5,931 gigawatt-hours 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.

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 automatically trips offline by a protective device.

Consistent with previous Energy Resource Recovery Account (ERRA) compliance proceedings, PG&E presents general information regarding scheduled outages that were 24 hours or more in duration, and specific information regarding each forced outage that was longer than 24 hours in duration, for facilities that are 25 MW or greater in size.[1]

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 2020 FOF was 2.08 percent which is better than the industry benchmark of 3.22 percent.[2] 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	FOF (%)	Benchmark FOF (%)
1	2016	1.36	3.10
2	2017	1.86[(a)]	3.08
3	2018	3.22[(a)]	2.91
4	2019	2.41	3.03
5	2020	2.08	3.22

(a) Excludes storm-related outages.

a. Scheduled Outages

PG&E's hydro portfolio had 108 scheduled outages 24 hours or greater in duration during the record period. Of this total, 69 were PO

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

2 The industry benchmark for 2020 is the 2015-2019 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.

and 39 were MO.[3] This is an average of just under one scheduled outage per unit across the hydro portfolio.

b. Forced Outages

The average age of PG&E's 103-unit hydro portfolio is approximately 81 years. 89 units are more than 50 years old and 29 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. PG&E also 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 53 forced outages with durations longer than 24 hours occurring at 32 different units with a powerhouse capacity of 25 MW or greater. The forced outages have been grouped into two categories: (1) Forced Outages Related to Wildfire Evacuations and Public Safety Power Shutoff (PSPS) Events and (2) Forced Outages Unrelated to Storm/Flood Events and PSPS Events.

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3 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 Wildfire Evacuations and PSPS Events

During the record period, there were 37 forced outages related to PSPS events[4] and wildfire related evacuations. The first PSPS event occurred between September 7, 2020 and September 10, 2020. The second event occurred between September 27, 2020 and September 29, 2020. The third event occurred between October 14, 2020 and October 17, 2020. The fourth event occurred between October 21, 2020 and October 23, 2020. The fifth event occurred between October 25, 2020 and October 28, 2020. Table 2-5 below lists the forced outage events that occurred due to Wildfire Evacuations and PSPS Events. The three non-PSPS events were:

a) Kerckhoff 2 Powerhouse

On Sep 8, 2020 at 3:10 p.m., Kerckhoff was forced out of service due to approaching Creek Fire that started on September 4, 2020. When deemed safe, the unit was returned to service on September 28, 2020 at 7:03 p.m.

b) Rock Creek Powerhouse

On September 27, 2020 at 3:10 p.m., Rock Creek Unit 1 and 2 were forced out of service due to approaching North Complex Fire that started on August 17, 2020. When deemed safe, the units were returned to service on October 6, 2020 at 7:03 p.m.

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4 "Public Safety Power Shutoff" or "PSPS"' events occur when PG&E turns off electricity for public safety when gusty winds and dry conditions, combined with a heightened fire risk, are forecasted. The specific area and number of affected customers will depend on forecasted weather conditions and which circuits and generating units PG&E needs to turn off for public safety.

TABLE 2-5
2020 HYDRO FORCED OUTAGES – PSPS AND WILDFIRE EVACUATIONS

Line No.	Unit Name	Actual Started	Actual Ended	Actual Duration (Days)	Description
1	KERCKHOFF PH 2 UNIT 1	9/8/20 1:29 PM	9/28/20 11:39 AM	20.92	Creek Fire
2	ROCK CREEK POWERHOUSE UNIT #2	9/27/20 11:40 PM	10/6/20 7:37 AM	9.33	North Complex Fire
3	ROCK CREEK POWERHOUSE UNIT #1	9/28/20 12:00 AM	10/6/20 7:28 AM	9.31	North Complex Fire
4	BUTT VALLEY POWERHOUSE	9/7/20 9:21 PM	9/10/20 12:18 PM	3.62	PSPS Event 1
5	CARIBOU #2 POWERHOUSE UNIT #5	9/7/20 10:23 PM	9/9/20 5:14 PM	2.79	PSPS Event 1
6	CARIBOU #2 POWERHOUSE UNIT #4	9/7/20 10:31 PM	9/9/20 5:11 PM	2.78	PSPS Event 1
7	PIT PH 3 UNIT 1	9/7/20 10:42 PM	9/9/20 3:04 PM	2.68	PSPS Event 1
8	PIT PH 3 UNIT 2	9/7/20 10:42 PM	9/9/20 3:09 PM	2.69	PSPS Event 1
9	PIT PH 3 UNIT 3	9/7/20 10:42 PM	9/9/20 3:01 PM	2.68	PSPS Event 1
10	CARIBOU #1 POWERHOUSE UNIT #1	9/7/20 10:43 PM	9/9/20 6:03 PM	2.81	PSPS Event 1
11	CARIBOU #1 POWERHOUSE UNIT #2	9/7/20 10:46 PM	9/9/20 5:20 PM	2.77	PSPS Event 1
12	CARIBOU #1 POWERHOUSE UNIT #3	9/7/20 10:49 PM	9/9/20 5:19 PM	2.77	PSPS Event 1
13	BELDEN POWERHOUSE	9/7/20 11:08 PM	9/9/20 6:51 PM	2.82	PSPS Event 1
14	PIT PH 1 UNIT 2	9/8/20 1:32 AM	9/9/20 2:35 PM	2.54	PSPS Event 1
15	DRUM POWERHOUSE #2, UNIT #5	9/8/20 2:13 AM	9/9/20 1:02 PM	2.45	PSPS Event 1
16	DRUM POWERHOUSE #1, UNIT #1	9/8/20 2:28 AM	9/9/20 10:37 AM	2.34	PSPS Event 1
17	DRUM POWERHOUSE #1, UNIT #2	9/8/20 2:28 AM	9/9/20 10:37 AM	2.34	PSPS Event 1
18	DRUM POWERHOUSE #1, UNIT #3	9/8/20 2:28 AM	9/9/20 10:37 AM	2.34	PSPS Event 1
19	DRUM POWERHOUSE #1, UNIT #4	9/8/20 2:28 AM	9/9/20 10:37 AM	2.34	PSPS Event 1
20	BUTT VALLEY POWERHOUSE	9/26/20 6:11 PM	9/29/20 8:52 AM	3.61	PSPS Event 2
21	CARIBOU #2 POWERHOUSE UNIT #5	9/26/20 6:11 PM	9/29/20 12:55 PM	3.78	PSPS Event 2
22	CARIBOU #2 POWERHOUSE UNIT #4	9/26/20 10:31 PM	9/29/20 12:52 PM	3.60	PSPS Event 2
23	BUTT VALLEY POWERHOUSE	10/14/20 11:18 AM	10/16/20 4:05 PM	3.20	PSPS Event 3
24	BUTT VALLEY POWERHOUSE	10/21/20 11:33 AM	10/23/20 12:57 PM	3.06	PSPS Event 3
25	CARIBOU #2 POWERHOUSE UNIT #4	10/21/20 2:35 PM	10/23/20 1:07 PM	2.94	PSPS Event 3
26	CARIBOU #2 POWERHOUSE UNIT #5	10/21/20 2:35 PM	10/23/20 1:07 PM	2.94	PSPS Event 5
27	KERCKHOFF PH 2 UNIT 1	10/24/20 1:17 PM	10/27/20 10:00 AM	3.86	PSPS Event 4
28	BUTT VALLEY POWERHOUSE	10/25/20 8:55 AM	10/27/20 8:56 PM	3.50	PSPS Event 4
29	CARIBOU #2 POWERHOUSE UNIT #4	10/25/20 12:08 PM	10/27/20 2:27 PM	3.10	PSPS Event 4
30	CARIBOU #2 POWERHOUSE UNIT #5	10/25/20 12:08 PM	10/27/20 10:00 PM	3.41	PSPS Event 5
31	BELDEN POWERHOUSE	10/25/20 2:21 PM	10/27/20 10:00 PM	3.32	PSPS Event 5
32	SALT SPRINGS PH UNIT #1	10/25/20 3:01 PM	10/27/20 4:40 PM	3.07	PSPS Event 5
33	DRUM POWERHOUSE #1, UNIT #1	10/25/20 4:49 PM	10/27/20 3:50 PM	2.96	PSPS Event 5
34	DRUM POWERHOUSE #1, UNIT #2	10/25/20 4:49 PM	10/27/20 3:50 PM	2.96	PSPS Event 5
35	DRUM POWERHOUSE #1, UNIT #3	10/25/20 4:49 PM	10/27/20 3:50 PM	2.96	PSPS Event 5
36	DRUM POWERHOUSE #1, UNIT #4	10/25/20 4:49 PM	10/27/20 3:50 PM	2.96	PSPS Event 5
37	DRUM POWERHOUSE #2, UNIT #5	10/25/20 4:49 PM	10/27/20 3:53 PM	2.96	PSPS Event 5

2) Forced Outages Unrelated to Wildfires and PSPSs

During the record period, there were 16 forced outages unrelated to PSPS events or wildfire evacuations. Table 2-6 below summarizes the 16 events followed by a detailed description of each event.

TABLE 2-6
2020 HYDRO FORCED OUTAGES

Line No.	Unit Name	Actual Started	Actual Ended	Actual Duration (Days)
1	BUCKS CREEK PH UNIT #2	2/7/20 2:12 PM	2/10/20 9:02 AM	3.78
2	CARIBOU #1 POWERHOUSE UNIT #1	12/4/20 9:26 AM	12/5/20 2:38 PM	2.22
3	CARIBOU #1 POWERHOUSE UNIT #3	6/22/20 5:57 AM	6/23/20 11:32 AM	2.23
4	CARIBOU #2 POWERHOUSE UNIT #4	12/8/20 6:52 PM	12/10/20 11:30 AM	2.69
5	HAAS PH UNIT 1	2/16/20 3:28 AM	2/17/20 4:00 PM	2.52
6	HAAS PH UNIT 2	2/16/20 3:28 AM	2/17/20 5:54 PM	2.60
7	HELMS POWERHOUSE UNIT 3	3/11/20 7:08 AM	3/12/20 8:00 PM	2.54
8	PIT PH 3 UNIT 1	1/6/20 3:45 PM	1/8/20 3:49 PM	3.00
9	PIT PH 5 UNIT 2	2/11/20 12:03 PM	2/14/20 2:12 PM	4.09
10	PIT PH 6 UNIT 1	8/16/20 11:59 PM	9/5/20 4:19 PM	20.68
11	PIT PH 6 UNIT 2	8/16/20 11:59 PM	9/5/20 6:45 PM	20.78
12	PIT PH 7 UNIT 2	6/20/20 11:59 PM	8/15/20 4:30 PM	56.69
13	POE POWERHOUSE UNIT #1	5/3/20 7:05 PM	5/10/20 2:02 PM	7.79
14	SALT SPRINGS PH UNIT #1	01/20/20 8:17 AM	3/22/20 0:01 AM	62.66
15	SALT SPRINGS PH UNIT #1	10/13/20 7:57 AM	10/16/20 2:13 PM	4.26
16	SALT SPRINGS PH UNIT #2	2/6/20 11:46 AM	2/8/20 1:43 PM	3.08

a) Bucks Powerhouse

On February 7, 2020, at 2:12 p.m., Bucks Unit 2 was forced out of service due to water discovered in the bearing oil. Upon investigation, it was determined there were issues with the bearing oil cooling water system. Repairs were made to the heat exchanger until the bearing oil cooling water system was replaced during the PO scheduled in the Fall of 2020. The contaminated oil was replaced, the unit was tested and returned to service on February 10, 2020, at 9:02 a.m.

b) Caribou 1 Powerhouse

On June 22, 2020 at 5:57 a.m., Caribou 1 Unit 3 was forced out of service due to a governor major fault alarm while the unit was on reserve shutdown. Upon investigation, PG&E identified a loose communication cable in the governor cabinet as well as a failed pressure switch. The communication cable was secured, and the pressure switch was replaced. The unit was returned to service the next day at 11:32 a.m.

On December 4, 2020 at 9:26 a.m., Caribou 1 Unit 1 was forced out of service due to a turbine deflector issue.

Investigation determined a faulty sensor on the deflector. The sensor was replaced and the unit was returned to service the next day at 2:38 p.m.

c) Caribou 2 Powerhouse

On December 8, 2020 at 3:52 p.m., Caribou 2 Unit 4 was forced out of service after being returned from a PO. The unit was unstable and experiencing wide swings in voltage and amps so the unit was forced out for troubleshooting. Upon investigation, PG&E technicians discovered a blown fuse on a potential transformer. No additional instabilities with control were observed after replacement of the fuse. The unit was returned to service on December 10, 11:30 a.m.

d) Haas Powerhouse

On February 16, 2020 at 3:28 a.m., Haas Unit 1 and Unit 2 tripped offline on due to a high voltage on the 230 kilovolt transmission line. Investigation by hydro technicians, transmission, and system protection was required to ensure the units could be put back online without causing damage due to the transmission voltage spike. Unit 1 was returned the next day at 4:00 p.m and Unit 2 at 5:54 p.m.

e) Helms Powerhouse

On March 11, 2020, at 7:08 a.m., Helms Unit 1 was forced out of service from reserve shutdown to investigate a ticking noise near the generator brake area. Upon investigation, segments of the generator rotor brake ring had become loose. The locking mechanism for the brake ring segments was repaired and the brake ring was re-secured. The unit was returned to service the next day at 8:00 p.m.

f) Pit 3 Powerhouse

On January 6, 2020 at 3:45 p.m., Pit 3 Unit 3 was forced out of service due to a failure of the turbine main shaft driven oil pump. The pump was repaired, and the unit was returned to service on January 8, 2020 3:49 p.m.

g) Pit 5 Powerhouse

On February 11, 2020 at 12:03 p.m., Pit 5, Unit 2 tripped offline while PG&E personnel were conducting bearing and governor oil sample collection. PG&E personnel were removing a plug from a mini-ball valve at a non-standard location and the internal valve bushing inadvertently came out with the plug resulting in an oil release and tripping the unit offline. The unit remained out of service for repair and cleanup of the Unit 2 governor system. The unit was tested and returned to service on February 14, 2020 at 2:12 p.m.

A cause evaluation was completed for this forced outage and is included as a workpaper. Nine CAs were identified in the CE of which seven have been completed. The two remaining CAs, which are listed below, are scheduled to be completed in the Fall of 2021 during the next PO.

- CA - 4: installation of dedicated oil sampling ports at Pit 5
- CA - 5B: create notifications in work management system for installation of dedicated sampling ports in other powerhouses.

h) Pit 6 Powerhouse

On August 18, 2020 at 11:59 p.m., Pit 6 Unit 1 and 2 were transitioned from a PO to a forced outage on the day the PO was originally scheduled to end. This was the result of COVID-19-related resource constraints resulting from the extension of the Pit 7 PO described below. Pit 6 and Pit 7 are powerhouses on the same river system and share the same O&M and construction resources. Originally, the PO were scheduled sequentially so that resources could be optimized and PO durations could be as short as possible. However, due to the emergent need to extend the Pit 7 PO due to COVID-19 pandemic related equipment delivery delays, the Pit 6 and Pit 7 outages had to be supported in parallel. The Pit 6 PO could not be rescheduled to a later time due to the urgency of replacing the transformer banks, the risk of attempting to store the transformer banks, logistical challenges, and identifying an outage window which would minimize market impact, meet license conditions, and not disrupt other PO work with shared resources. As a result, Pit 6 returned to service on September 5, 2020 upon completion of the replacement of the transformer banks.

i) Pit 7 Powerhouse

On June 20, 2020 at 11:59 p.m., Pit 7 Unit 2 was transitioned to a forced outage from a PO as result of major generator equipment delivery delays stemming from the COVID-19 pandemic. The equipment manufacturer, ABB, had originally scheduled the new generator field poles to be delivered to the powerhouse on May 1, 2020. ABB subsequently informed PG&E that the Canadian government had extended their shutdown of non-essential work from April 13, 2020 to May 1, 2020 which delayed the delivery of the poles to May 22, 2020. This resulted in a significant construction schedule delays and work sequence inefficiencies. The scope of work for the PO was completed and the unit returned to service on August 15, 2020 at 4:30 p.m.

j) Poe Powerhouse

On May 3, 2020, at 7:05 p.m., Poe Unit 1 tripped offline due to a failed lighting arrester on the main transformer bank. Upon engineering investigation of the other two lightning arrestors, all three lighting arresters required replacement. New lightning arrestors were procured, installed, and tested. The unit was returned on May 10 at 2:02 p.m.

k) Salt Springs Powerhouse

On January 20, 2020 at 8:17 a.m., Salt Springs Unit 1 was forced out of service due to lack of water due to seasonal water constraints which are often a part of the normal operations of hydro plants. When seasonal water constraints improved and sufficient water was available to run the unit, the unit was returned to service on March 22, 2020 at 12:01 a.m.

On February 6, 2020 at 11:46 p.m., Salt Springs Unit 2 was forced out of service due to a broken sight glass on the governor accumulator tank. The broken sight glass was replaced, and the unit was returned to service on February 8, 2020 at 1:43 p.m.

On October 13, 2020 at 7:57 p.m., Salt Springs Unit 1 tripped offline due to a low oil flow alarm for bearing lube oil. Upon investigation, a coupling on the shaft driven oil pump had failed. The pump was repaired, and the unit was returned to service on October 16, 2020 at 2:13 p.m.

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 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),[5] regarding specific intervals. This program incorporates key findings from studies 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

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[5] 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.

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 power generation 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 practice.

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. Power Generation'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 101 transformers under this program as shown in Table 2-6 by hydro area and fossil plant.

TABLE 2-6
NUMBER OF TRANSFORMERS IN THE TRANSFORMER INSPECTION PROGRAM

Line No.	Hydro Area or Fossil Facility	Number of Transformers
1	Central	20
2	DeSabla	21
3	Helms	10
4	Kings Crane	15
5	Shasta	23
6	Humboldt Bay GS	1
7	Colusa GS	3
8	Gateway GS	3
9	Total	96

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

3. May 2018 Belden Forced Outage

D.20-02-006, OP 6 adopted the Settlement Agreement Between PG&E (U 39 E), the Cal Advocates at the Commission, and Joint Community Choice Aggregators in PG&E's 2018 ERRA Compliance Proceeding. PG&E agreed in that settlement to report on the progress of its implementation of all CAs in its next ERRA Compliance Application, including those indicated in the Belden Thrust Bearing Wipe Cause Evaluation Report and the Auto Testing Frequency and Over Speed Testing slide presentation, dated December 10, 2018. PG&E provides an update on the progress of its implementation of the Belden CAs below.

Below is the status of the CAs identified on page 4 of the Belden Thrust Bearing Wipe Cause Evaluation Report. All CAs have been completed.

CA#	CA Description	Status
CA-1	Engineering to up size the heat exchanger and remove the old cooling coils from the upper bearing tub.	Complete
CA-2	Upgrade Lift System to be in line with current industry standards.	Complete
CA-3	Evaluate the mechanical overspeed device for a more reliable system.	Complete
CA-4	Clean and flush the bearing oil system.	Complete
CA-5	Tailboard Project Execution group on the findings from TCB as founds report titled “Belden Emergency Bearing Inspection Conditions”.	Complete

Below is the status of the correction actions identified on page 5 of the Auto Testing Frequency and Over Speed Testing slide presentation dated December 10, 2018.

Description	Status Update
Decrease frequency of auto testing by revision of PG 1617S and PG 2216S. Establish method for crediting alarms during operation of the unit	Completed PG-1617S was published on 8/18/2020 PG-2216S was published on 4/16/2020
Revise PG 2323P 01 requirement for inspection of pole wedges to 165% of synchronous speed	Completed PG 2323P-01 was published on 8/15/2019
Lower Over Speed device (12E and 12M) set points. Revised to NTE 150% and 155% of synchronous speed in PG 1617S	Completed PG-1617S was updated to reflect this change.
Install pilot(s) for electronic speed sensing to evaluate effectiveness	Design standard complete - Q4 2020 Site(s) selected & installation commences - 2021 Timing of completion of installation at selected site(s) is coordinated with other PO work

Complete bearing cooling design reviews for at risk machines (high load rejection speeds). Establish adequacy of existing systems	Belden heat exchanger was sized adequately for the intended full load design and operating parameters. PG 2216S has been updated to eliminate the need to perform extended duration overspeed testing on units with electrical overspeed devices to verify overspeed protection device setpoint.
Fully implement Bearing Initiative activities related to recording as left clearances	20 engineering packages completed and additional 10 targeted in 2021. This action has been incorporated into a broader initiative (reliability action plan).
Harvest rotor rim materials to conduct fatigue testing and quantify risk	After further review, this mitigation is no longer recommended

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 2020 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 2020 record year FOF results being better than the industry average when considering the total portfolio. 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 2

ATTACHMENT A

PG&E POWERHOUSES AND GENERATING UNITS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
UTILITY OWNED GENERATION: HYDROELECTRIC
Attachment A Table of Hydro Generating Units at 2020 End of Year

Line No.	Powerhouse Name and Unit	Basic type and / or configuration	Management Area	Specific physical location	Capacity	Date in service
1	ALTA POWERHOUSE UNIT #1	Conv Hydro	Central	Alta, CA	1.0	11/7/1902
2	BALCH PH 1 UNIT 1	Conv Hydro	Kings Crane Valley	Balch Camp, CA	34.0	2/20/1927
3	BALCH PH 2 UNIT 2	Conv Hydro	Kings Crane Valley	Balch Camp, CA	52.5	11/26/1958
4	BALCH PH 2 UNIT 3	Conv Hydro	Kings Crane Valley	Balch Camp, CA	52.5	11/26/1958
5	BELDEN POWERHOUSE	Conv Hydro	DeSabla	Belden, CA	125.0	9/14/1969
6	BUCKS CREEK PH UNIT #1	Conv Hydro	DeSabla	Storrie, CA	33.0	3/4/1928
7	BUCKS CREEK PH UNIT #2	Conv Hydro	DeSabla	Storrie, CA	32.0	3/4/1928
8	BUTT VALLEY POWERHOUSE	Conv Hydro	DeSabla	Belden, CA	41.0	12/31/1958
9	CARIBOU #1 POWERHOUSE UNIT #1	Conv Hydro	DeSabla	Belden, CA	25.0	5/6/1921
10	CARIBOU #1 POWERHOUSE UNIT #2	Conv Hydro	DeSabla	Belden, CA	25.0	5/6/1921
11	CARIBOU #1 POWERHOUSE UNIT #3	Conv Hydro	DeSabla	Belden, CA	25.0	5/6/1921
12	CARIBOU #2 POWERHOUSE UNIT #4	Conv Hydro	DeSabla	Belden, CA	60.0	11/9/1958
13	CARIBOU #2 POWERHOUSE UNIT #5	Conv Hydro	DeSabla	Belden, CA	60.0	11/9/1958
14	CENTERVILLE PH UNIT NO.1	Conv Hydro	DeSabla	Chico, CA	5.5	5/1/1900
15	CENTERVILLE PH UNIT NO.2	Conv Hydro	DeSabla	Chico, CA	0.9	5/1/1900
16	CHILI BAR POWERHOUSE UNIT #1	Conv Hydro	Central	Placerville, CA	7.0	3/22/1965
17	COLEMAN PH UNIT NO.1	Conv Hydro	Shasta	Anderson, CA	13.0	6/19/1979
18	COW CREEK PH UNIT NO.1	Conv Hydro	Shasta	Millville, CA	0.9	1/1/1907
19	COW CREEK PH UNIT NO.2	Conv Hydro	Shasta	Millville, CA	0.9	1/1/1907
20	CRANE VALLEY PH UNIT 1	Conv Hydro	Kings Crane Valley	North Fork, CA	0.9	7/4/1919
21	CRESTA POWERHOUSE UNIT #1	Conv Hydro	DeSabla	Storrie, CA	35.0	11/23/1949
22	CRESTA POWERHOUSE UNIT #2	Conv Hydro	DeSabla	Storrie, CA	35.0	1/15/1950
23	DE SABLA PH UNIT NO.1	Conv Hydro	DeSabla	Magalia, CA	18.5	2/28/1963
24	DEER CREEK PH UNIT #1	Conv Hydro	Central	Nevada City, CA	5.7	5/6/1908
25	DRUM POWERHOUSE #1, UNIT #1	Conv Hydro	Central	Alta, CA	13.2	11/26/1913
26	DRUM POWERHOUSE #1, UNIT #2	Conv Hydro	Central	Alta, CA	13.2	11/26/1913
27	DRUM POWERHOUSE #1, UNIT #3	Conv Hydro	Central	Alta, CA	13.1	11/26/1913
28	DRUM POWERHOUSE #1, UNIT #4	Conv Hydro	Central	Alta, CA	14.5	11/26/1913
29	DRUM POWERHOUSE #2, UNIT #5	Conv Hydro	Central	Alta, CA	49.5	12/18/1965
30	DUTCH FLAT POWERHOUSE UNIT #1	Conv Hydro	Central	Alta, CA	22.0	3/29/1943
31	ELECTRA POWERHOUSE UNIT #1	Conv Hydro	Central	Jackson, CA	31.0	6/29/1948
32	ELECTRA POWERHOUSE UNIT #2	Conv Hydro	Central	Jackson, CA	31.0	6/29/1948
33	ELECTRA POWERHOUSE UNIT #3	Conv Hydro	Central	Jackson, CA	36.0	6/29/1948
34	HAAS PH UNIT 1	Conv Hydro	Kings Crane Valley	Balch Camp, CA	72.0	12/23/1958
35	HAAS PH UNIT 2	Conv Hydro	Kings Crane Valley	Balch Camp, CA	72.0	12/23/1958
36	HALSEY POWERHOUSE UNIT #1	Conv Hydro	Central	Auburn, CA	11.0	12/6/1916
37	HAMILTON BRANCH PH UNIT #1	Conv Hydro	DeSabla	Penninsula Village, CA	2.4	1/1/1921
38	HAMILTON BRANCH PH UNIT #2	Conv Hydro	DeSabla	Penninsula Village, CA	2.4	1/2/1921
39	HAT CREEK PH 1 UNIT 1	Conv Hydro	Shasta	Burney, CA	8.5	8/22/1921
40	HAT CREEK PH 2 UNIT 1	Conv Hydro	Shasta	Burney, CA	8.5	9/28/1921
41	HELMS POWERHOUSE UNIT 1	Pumped Storage	Helms	Shaver Lake, CA	404.0	6/30/1984
42	HELMS POWERHOUSE UNIT 2	Pumped Storage	Helms	Shaver Lake, CA	404.0	6/30/1984
43	HELMS POWERHOUSE UNIT 3	Pumped Storage	Helms	Shaver Lake, CA	404.0	6/30/1984
44	INSKIP PH UNIT NO.1	Conv Hydro	Shasta	Manton, CA	8.0	10/9/1979
45	JAMES B. BLACK PH UNIT #1	Conv Hydro	Shasta	Big Bend, CA	86.0	2/17/1966
46	JAMES B. BLACK PH UNIT #2	Conv Hydro	Shasta	Big Bend, CA	86.0	12/17/1965
47	KERCKHOFF PH 1 UNIT 1	Conv Hydro	Kings Crane Valley	Auberry, CA	12.6	8/6/1920
48	KERCKHOFF PH 1 UNIT 3	Conv Hydro	Kings Crane Valley	Auberry, CA	12.8	8/6/1920
49	KERCKHOFF PH 2 UNIT 1	Conv Hydro	Kings Crane Valley	Auberry, CA	155.0	5/6/1983
50	KILARC PH UNIT NO.1	Conv Hydro	Shasta	Whitmore, CA	1.6	10/1/1903
51	KINGS RIVER PH UNIT 1	Conv Hydro	Kings Crane Valley	Balch Camp, CA	52.0	3/7/1962

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Attachment A Table of Hydro Generating Units at 2020 End of Year

Line No.	Powerhouse Name and Unit	Basic type and / or configuration	Management Area	Specific physical location	Capacity	Date in service
52	LIME SADDLE PH UNIT NO.1	Conv Hydro	DeSabla	Oroville, CA	1.0	8/1/1906
53	LIME SADDLE PH UNIT NO.2	Conv Hydro	DeSabla	Oroville, CA	1.0	8/1/1906
54	NEWCASTLE POWERHOUSE UNIT #1	Conv Hydro	Central	Auburn, CA	11.5	10/28/1986
55	OAK FLAT POWERHOUSE UNIT #1	Conv Hydro	DeSabla	Belden, CA	1.3	11/2/1985
56	PHOENIX POWERHOUSE UNIT #1	Conv Hydro	Central	Sonora, CA	2.0	2/20/1940
57	PIT PH 1 UNIT 1	Conv Hydro	Shasta	Burney, CA	30.5	2/28/1922
58	PIT PH 1 UNIT 2	Conv Hydro	Shasta	Burney, CA	30.5	2/28/1922
59	PIT PH 3 UNIT 1	Conv Hydro	Shasta	Burney, CA	23.3	7/15/1925
60	PIT PH 3 UNIT 2	Conv Hydro	Shasta	Burney, CA	23.3	7/15/1925
61	PIT PH 3 UNIT 3	Conv Hydro	Shasta	Burney, CA	23.4	7/15/1925
62	PIT PH 4 UNIT 1	Conv Hydro	Shasta	Big Bend, CA	47.5	10/1/1955
63	PIT PH 4 UNIT 2	Conv Hydro	Shasta	Big Bend, CA	47.5	10/1/1955
64	PIT PH 5 UNIT 1	Conv Hydro	Shasta	Big Bend, CA	40.0	4/29/1944
65	PIT PH 5 UNIT 2	Conv Hydro	Shasta	Big Bend, CA	40.0	4/29/1944
66	PIT PH 5 UNIT 3	Conv Hydro	Shasta	Big Bend, CA	40.0	4/29/1944
67	PIT PH 5 UNIT 4	Conv Hydro	Shasta	Big Bend, CA	40.0	4/29/1944
68	PIT PH 6 UNIT 1	Conv Hydro	Shasta	Montgomery Creek, CA	40.0	8/14/1965
69	PIT PH 6 UNIT 2	Conv Hydro	Shasta	Montgomery Creek, CA	40.0	8/14/1965
70	PIT PH 7 UNIT 1	Conv Hydro	Shasta	Montgomery Creek, CA	56.0	9/10/1965
71	PIT PH 7 UNIT 2	Conv Hydro	Shasta	Montgomery Creek, CA	56.0	9/10/1965
72	POE POWERHOUSE UNIT #1	Conv Hydro	DeSabla	Storrie, CA	60.0	10/26/1958
73	POE POWERHOUSE UNIT #2	Conv Hydro	DeSabla	Storrie, CA	60.0	10/26/1958
74	POTTER VALLEY UNIT 1	Conv Hydro	DeSabla	Potter Valley, CA	4.5	4/1/1908
75	POTTER VALLEY UNIT 3	Conv Hydro	DeSabla	Potter Valley, CA	2.0	4/1/1908
76	POTTER VALLEY UNIT 4	Conv Hydro	DeSabla	Potter Valley, CA	2.7	4/1/1908
77	ROCK CREEK POWERHOUSE UNIT #1	Conv Hydro	DeSabla	Storrie, CA	63.0	3/1/1950
78	ROCK CREEK POWERHOUSE UNIT #2	Conv Hydro	DeSabla	Storrie, CA	63.0	3/16/1950
79	SALT SPRINGS PH UNIT #1	Conv Hydro	Central	Pioneer, CA	11.0	6/15/1931
80	SALT SPRINGS PH UNIT #2	Conv Hydro	Central	Pioneer, CA	33.0	4/24/1953
81	SAN JOAQUIN 1A PH UNIT 1	Conv Hydro	Kings Crane Valley	North Fork, CA	0.4	3/12/1919
82	SAN JOAQUIN 2 PH UNIT 1	Conv Hydro	Kings Crane Valley	North Fork, CA	3.2	9/29/1917
83	SAN JOAQUIN 3 PH UNIT 1	Conv Hydro	Kings Crane Valley	North Fork, CA	4.2	8/17/1923
84	SOUTH PH UNIT NO.1	Conv Hydro	Shasta	Manton, CA	7.0	12/8/1979
85	SPAULDING PH #1, UNIT #1	Conv Hydro	Central	Emigrant Gap, CA	7.0	5/8/1928
86	SPAULDING PH #2, UNIT #1	Conv Hydro	Central	Emigrant Gap, CA	4.4	7/16/1928
87	SPAULDING PH #3, UNIT #1	Conv Hydro	Central	Emigrant Gap, CA	5.8	2/21/1929
88	SPRING GAP POWERHOUSE UNIT #1	Conv Hydro	Central	Long Barn, CA	7.0	9/16/1921
89	STANISLAUS POWERHOUSE UNIT #1	Conv Hydro	Central	Vallecito, CA	91.0	3/11/1963
90	TIGER CREEK PH UNIT #1	Conv Hydro	Central	Pioneer, CA	29.0	8/1/1931
91	TIGER CREEK PH UNIT #2	Conv Hydro	Central	Pioneer, CA	29.0	8/1/1931
92	TOADTOWN PH UNIT NO.1	Conv Hydro	DeSabla	Mogalia, CA	1.5	4/22/1986
93	TULE RIVER PH UNIT 1	Conv Hydro	Kings Crane Valley	Springville, CA	3.2	1/21/1914
94	TULE RIVER PH UNIT 2	Conv Hydro	Kings Crane Valley	Springville, CA	3.2	1/21/1914
95	VOLTA 1 PH UNIT NO.1	Conv Hydro	Shasta	Manton, CA	9.0	4/4/1980
96	VOLTA 2 PH UNIT NO.2	Conv Hydro	Shasta	Manton, CA	0.9	10/30/1981
97	WEST POINT PH UNIT #1	Conv Hydro	Central	Pioneer, CA	14.5	11/21/1948
98	WISE POWERHOUSE #1, UNIT #1	Conv Hydro	Central	Auburn, CA	14.0	3/4/1917
99	WISE POWERHOUSE #2, UNIT #1	Conv Hydro	Central	Auburn, CA	3.2	12/12/1986
100	WISHON PH 1 UNIT 1	Conv Hydro	Kings Crane Valley	North Fork, CA	5.0	9/20/1910
101	WISHON PH 1 UNIT 2	Conv Hydro	Kings Crane Valley	North Fork, CA	5.0	9/20/1910
102	WISHON PH 1 UNIT 3	Conv Hydro	Kings Crane Valley	North Fork, CA	5.0	9/20/1910
103	WISHON PH 1 UNIT 4	Conv Hydro	Kings Crane Valley	North Fork, CA	5.0	9/20/1910
					3,867.1	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

UTILITY-OWNED GENERATION:

FOSSIL AND OTHER GENERATION

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CHAPTER 3
UTILITY-OWNED GENERATION:
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CHAPTER 3
UTILITY-OWNED GENERATION:
FOSSIL AND OTHER GENERATION

A. Introduction

In compliance with Decision (D.) 14-01-011, this chapter addresses the operation of Pacific Gas and Electric Company's (PG&E) utility-owned fossil-fuel, fuel cell, and photovoltaic (PV) facilities during the 2020 record year. PG&E's utility-owned fossil-fuel, fuel cell, and PV portfolio was operated in a reasonable manner during the record period.

During the record period, PG&E owned, operated and maintained three fossil-fuel generating stations, two fuel cell facilities, and 10 ground-mounted PV solar stations.[1] The three fossil-fuel generating stations are Gateway Generating Station (GGS), Colusa Generating Station (CGS), and Humboldt Bay Generating Station (HBGS). These three generating facilities have a combined maximum normal operating capacity of 1,400 megawatts (MW).

PG&E's small fuel cell facilities are the California State University East Bay (CSU East Bay) Fuel Cell Facility and the San Francisco State University (SFSU) Fuel Cell Facility. The fuel cells were in service periodically throughout the record period. These fuel cells were installed pursuant to PG&E's application to install fuel cells on state-owned property approved in D.10-04-028.

The 10 ground-mounted PV generating stations are Vaca Dixon, Westside, Stroud, Five Points, Huron, Cantua, Giffen, Gates, West Gates, and Guernsey Solar Stations. These facilities were built as part of the Utility-Owned Generation (UOG) portion of PG&E's 5-year solar PV Program approved in D.10-04-052. All of PG&E's solar stations entered into commercial operations prior to the record period.

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[1] PG&E also owns three small PV facilities in San Francisco that entered commercial operations in 2007. Because these facilities total less than 300 kilowatts (kW), PG&E has not addressed them in this testimony.

1. Fossil-Fuel Generating Stations

a. GGS

Gateway is a 530 MW combined cycle power plant consisting of two General Electric (GE) Frame 7FA combustion turbine (CT)-generators, each with its own Vogt-NEM heat recovery steam generator (HRSG), and a single GE steam turbine (ST)-generator. In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an air-cooled condenser. Air emissions are controlled with Dry Low Nitrogen Oxide (NO_x) combustion coupled with Selective Catalytic Reduction (SCR) systems. For each HRSG, two catalyst systems are used to reduce NO_x, (CO), and Volatile Organic Compound (VOC) production. Additionally, Gateway is equipped with a capacity enhancing technology to improve output during peak generation periods. Duct burners are used to increase steam production in the HRSGs resulting in increased ST output. The duct burners allow Gateway to increase its output by approximately 50 MW above the 530 MW nominal capacity.

b. CGS

Colusa is a 530 MW combined cycle power plant consisting of two GE Frame 7FA CTs, each with its own HRSG, and a single GE ST. In this standard 2 × 1 configuration, each CT generates power and exhausts directly into its own HRSG where the exhaust heat is captured and generates steam for use in the ST. The exhaust steam leaves the turbine and is condensed for reuse in an air-cooled condenser. Air emissions are controlled with Dry Low NO_x combustion coupled with SCR systems. For each HRSG, two catalyst systems are used to reduce NO_x, CO and VOC production. Additionally, Colusa is equipped with a capacity enhancing technology to improve output during peak generation periods. Duct burners are used to increase steam production in the HRSGs resulting in increased ST output. The duct burners allow Colusa to increase its output by approximately 127 MW above the 530 MW nominal capacity.

c. HBGS

Humboldt is a 163 MW reciprocating engine power plant consisting of 10 Wartsila 18V50 DF natural gas-fired reciprocating units.[2] Each unit has 18 cylinders, each with a bore of 50 centimeters, and operates at 514 revolutions per minute. Each unit is designed to run on natural gas with 1 percent of total fuel input provided by low sulfur distillate as the pilot fuel. The units are also designed to run on low sulfur distillate or biodiesel. Each unit is equipped with a separate independent closed loop cooling system. Emission control is accomplished with SCR. Similar to Gateway and Colusa, two catalyst systems are used to reduce NO_x, CO, and VOC production.

2. Fuel Cell Facilities

a. CSU East Bay Fuel Cell Facility

The CSU East Bay Fuel Cell facility is a 1.4 MW facility located on the campus of CSU East Bay in Hayward, California. There is one fuel cell at this facility. This fuel cell uses Molten Carbonate Fuel Cell (MCFC) technology and was manufactured by FuelCell Energy (FCE). This facility provides electricity to PG&E's electrical grid and waste heat for the university's use.

A fuel cell is an electrochemical conversion process that produces electricity from fuel and an oxidant, which react in the presence of an electrolyte. Molten carbonate is used as the electrolyte in a MCFC. The MCFC technology reforms hydrogen from natural gas to power the fuel cell. Within the MCFC stack, an electrochemical reaction occurs between the hydrogen (the fuel) and oxygen (the oxidant) to generate Direct Current (DC) electricity, heat and water. The DC electricity is converted by an inverter into Alternating Current (AC) for supplying the PG&E electrical grid.

[2] For HBGS, each engine is also referred to as a unit.

b. SFSU Fuel Cell Facility

The SFSU Fuel Cell facility is a 1.6 MW facility located on the campus of SFSU in San Francisco, California. There are two fuel cells at this facility. The first fuel cell, like CSU East Bay, is rated at 1.4 MW, uses MCFC technology, and was manufactured by FCE. This fuel cell provides electricity to PG&E's electrical grid and provides waste heat for the university's use. The second fuel cell is rated at 200 kW, uses Solid Oxide Fuel Cell (SOFC) technology, and was manufactured by Bloom Energy (Bloom). The Bloom fuel cell provides electricity to PG&E's electrical grid.

The SOFC technology converts natural gas into a hydrogen rich gas and then, using silica as the electrolyte, induces an electrochemical reaction between the hydrogen (the fuel) and oxygen (the oxidant) to generate DC electricity. The DC electricity is fed to an inverter, which converts the DC power to AC for supplying the PG&E electrical grid. The SOFC utilizes the heat that is generated internally to improve electric efficiency.

3. Solar Stations

a. Vaca Dixon Solar Station

Vaca Dixon is a 2 MW PV solar station located in Vacaville, California, on a 16-acre site. The solar station includes 9,672 solar modules that provide DC energy; five inverters that convert the DC energy to AC; one transformer that increases the voltage from 480 volts (V) to 12.47 kilovolts (kV); and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

b. Westside Solar Station

Westside is a 15 MW PV solar station located near Five Points, California, on a 200-acre site. The solar station includes over 66,000 solar modules that provide DC energy; 30 inverters that convert the DC energy to AC; 15 transformers that increase the voltage from 440 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

c. Stroud Solar Station

Stroud is a 20 MW PV solar station located near Helm, California, on a 201-acre site. The solar station includes 88,000 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 20 transformers that increase the voltage from 440 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

d. Five Points Solar Station

Five Points is a 15 MW PV solar station located near Five Points, California, on a 162-acre site. The solar station includes over 75,000 solar modules that provide DC energy; 24 inverters that convert the DC energy to AC; 12 transformers that increase the voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

e. Huron Solar Station (HSS)

Huron is a 20 MW PV solar station located near Huron, California, on a 145-acre site. The solar station includes over 90,000 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 10 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

f. Cantua Solar Station

Cantua is a 20 MW PV solar station located near Cantua Creek, California, on a 171-acre site. The solar station includes approximately 110,000 solar modules that provide DC energy; 32 inverters that convert the DC energy to AC; 16 transformers that increase the voltage from 320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

g. Giffen Solar Station

Giffen is a 10 MW PV solar station located near Cantua Creek, California, on a 97-acre site. The solar station includes close to 55,000 solar modules that provide DC energy; 16 inverters that convert the DC energy to AC; 8 transformers that increase the voltage from

320 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

h. Gates Solar Station

Gates is a 20 MW PV solar station located on a 120-acre site, adjacent to the HSS near Huron, California. The solar station includes 91,490 solar modules that provide DC energy; 28 inverters that convert the DC energy to AC; 31 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear.

i. West Gates Solar Station

West Gates is a 10 MW PV solar station located on a 60-acre site, near Huron, California. The solar station includes over 45,752 solar modules that provide DC energy; 14 inverters that convert the DC energy to AC; 14 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment, such as a communications enclosure, two weather stations, and electrical switchgear.

j. Guernsey Solar Station

Guernsey is a 20 MW PV solar station located on a 120-acre site, near Hanford, California. The solar station includes: 89,400 solar modules that provide DC energy; 40 inverters that convert the DC energy to AC; 11 transformers that increase the voltage from 420 V to 12.47 kV; and other equipment such as a communications enclosure, two weather stations, and electrical switchgear. Guernsey also includes single axis trackers that move the solar modules to optimize their position with the sun.

B. Fossil and Solar Operations and Maintenance (O&M) Organization

The Fossil and Solar O&M organization is responsible for managing PG&E’s fossil, solar PV and fuel cell generating assets to provide safe, reliable, cost-effective and environmentally responsible generation. Most of the fossil portion of the O&M organization is located at the three generating stations. Most of the PV and fuel cell portion of the organization is located at two separate locations—Antioch and Caruthers. The remainder of the fossil, solar PV and fuel cell O&M staff is headquartered in San Francisco.

PG&E utilizes contract services for much of the major maintenance work at its fossil-fuel generating stations and PV and fuel cell facilities. For Gateway and Colusa; Long-Term Service Agreements (LTSA)[3] for the CTs and STs are provided by GE, the Original Equipment Manufacturer (OEM) for the CTs and STs. Also, PG&E has entered into O&M agreements with the fuel cells' OEMs.

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 fossil and other generation 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 fossil and other 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 California Public Utilities Commission's (CPUC) General Order (GO) 167. As discussed below, PG&E does this by using internal controls to help manage the O&M of its generation facilities.

With regard to employee safety, Power Generation employees develop a safety action plan each year. This action plan focuses on various items such as training and qualifications, contractor safety, human performance, approaches to reduce or eliminate recordable injuries and motor vehicle incidents, approaches

[3] LTSAs are also known as Contractual Services Agreements.

to sharing safety best practices, and actions to improve the safety culture of the organization.

With regard to public safety, PG&E continues to develop and implement a comprehensive public safety program that includes public education, outreach and partnership with key agencies, and enhanced emergency response preparedness, training, drills and coordination with emergency response organizations.

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 grass roots safety team that can act to encourage safe work practices among peers. Power Generation's grass roots 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.

The Fossil O&M organization works side-by-side with Power Generation support organizations to provide safe, reliable, cost-effective generation to California in an environmentally responsible manner.

Support organizations consists of the Generation Business and Technical Services organization and centralized departments within Power Generation. The Generation Business and Technical Services organization is an independent organization from Power Generation that supports both Nuclear and Power Generation. The centralized departments within Power Generation work closely with the Fossil and Solar O&M organization. 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 fossil and solar fleet.

C. Generation Business and Technical Services

The Generation Business and Technical Services organization provides the following services and expertise.

1. Risk and Compliance

The Risk and Compliance organization is led by a director and is responsible for the risk and compliance functions for both nuclear and non-nuclear generation. The team develops and implements analytical risk modeling processes and techniques to achieve effective risk management, reduction and mitigation. They manage compliance and commitments to optimize the cost and benefit to the State, public and shareholders by working with regulatory agencies such as the: (1) Nuclear Regulatory Commission, (2) Federal Energy Regulatory Commission (FERC), (3) Division of Safety of Dams, among many others. The group also manages the Nuclear Cybersecurity Program and the Power Generation Security Program to ensure asset protection and public safety.

2. Portfolio Strategy

The Power Generation Portfolio Strategy organization is led by a director and is responsible for optimizing the composition of the generation fleet, FERC relicensing, and managing license compliance to meet the Company's goals on affordability, reliability, compliance and supply. This team monitors the customer value (costs and benefits) of PG&E's utility-owned generation to identify and recommend potential changes to the portfolio. In addition, this team is responsible for implementing approved divestiture strategies including overseeing regulatory approvals from the CPUC and FERC. This team provides analysis and regulatory support for other potential portfolio optimization strategies, such as decommissioning and alternative ratemaking proposals. This team also serves as a liaison for PG&E's Land Conservation Commitment efforts among various PG&E departments and the Stewardship Council.

3. Business Operations

The Business Operations organization is led by a director and is responsible for business planning and regulatory reporting which includes identifying, prioritizing, and planning Power Generation's work. Business Operations combines several functions into an integrated department that provides strategic, and tactical (operational and financial) services. Regulatory reporting includes preparation and filing of all required documentation for various regulatory proceedings which includes responding to data request and preparing work papers and testimony.

4. Geosciences

The Geosciences organization is led by a director and is responsible for providing services company wide.

5. Process Improvement (PI) and Corrective Action Program (CAP)

The PI and CAP is led by a director and is responsible for process improvement and Power Generation's CAP program. The Generation 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 through the use of 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.4.

D. Centralized Departments within Power Generation

The centralized departments within Power Generation provide the following services and expertise.

1. Asset Excellence

The Asset Excellence department is led by a director and consists of an asset management program that focuses on systemwide condition assessment of the equipment and proposes projects and/or changes to operations and/or maintenance practices to ensure that Power Generation's long-term investment plan reduces risk and maintains the safety and reliability of the hydro portfolio. The department is working towards achieving ISO 55001 certification for the Asset Management program.

2. Engineering, Project Management, and Technical Services

Engineering, Project Management, and Technical Services department is led by a director and provides engineering, project management, and technical services to Power Generation operations, projects and public safety work.

3. Project Execution

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

E. Other Support Organizations

PG&E's Environmental Services organization also provides direct support to the Fossil and Solar O&M organization, with a focus on regulatory compliance. Environmental consultants are located at each of the fossil-fuel generating stations and at or near the PV and fuel cell facilities and support the facility staff.

F. Internal Controls

PG&E directs, monitors, and measures its resources using processes that take into consideration the organization's structure, work and authority flows, people and management information systems. Internal controls help PG&E comply with GO 167.

GO 167 sets forth standards that govern the O&M of power plants. The purpose of GO 167 is:

> …to implement and enforce standards for the maintenance and operation of electric generating facilities and power plants so as to maintain and protect the public health and safety of California residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy.[4]

The standards set forth in GO 167 include operation standards, maintenance standards, and logbook standards. PG&E accomplishes compliance with GO 167 through the use of various internal controls, and through audits by the CPUC. GO 167 was set in place post energy crisis by the CPUC as a way to enforce prudent practices in the availability of the fossil fleet for California.

PG&E has many internal controls in place to manage the O&M of its generation assets, including: (1) guidance documents; (2) operations reviews;

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4 CPUC, GO 167, Section 1.0 Purpose.

(3) an event reporting system; (4) a CAP; (5) an outage planning and scheduling process; and (6) a design change process. Each of these controls is discussed below.

1. Guidance Documents

The guidance documents applicable to PG&E's fossil and solar operations include PG&E Policy, PG&E Utility Standard Practices, PG&E Utility Procedures, and Power Generation-specific guidance documents. Power Generation-specific guidance documents include Standards, Procedures and Bulletins. In addition, the fossil-fuel generating stations and fuel cell and PV facilities have site-specific procedures. 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's roles and responsibilities, and the date the document became effective.

2. Operations Reviews

Operations reviews are performed by the Technical Services organization at the three fossil-fuel generating stations each year and periodically at remote facilities such as the solar stations and fuel cells. 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.

By thoroughly reviewing fossil and solar operations, PG&E can identify possible precursors to more serious problems. Plant managers are provided a report on the overall operational health of their generating stations, with recommendations based on safety, best operating practices, latest operating technologies, training, and reducing the overall cost of production. The recommendations are then implemented on a priority basis within a reasonable time frame. This control enhances PG&E's ability to improve operations by promoting safe operating practices and verifying compliance with emergency and standard operating and clearance procedures. In 2020, operations reviews were completed for Colusa and Caruthers.

3. Event Reporting System

The event reporting system documents and resolves problems related to forced outages or curtailments to generating units. By thoroughly analyzing significant problem events that occur in the O&M of PG&E's facilities, PG&E can report to various regulatory agencies as required, identify possible precursors to repetitive or more serious problems, identify, understand and correct causal factors, and communicate lessons learned to other facilities and personnel.

4. CAP

The CAP documents and tracks corrective actions and commitments. The CAP includes problem identification, cause determination, reporting, development of corrective actions and corrective action implementation tracking.

The CAP for PG&E's Power Generation organization utilizes SAP notifications and orders to track and document 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.

5. Outage Planning and Scheduling Processes

The outage schedule is developed to plan and communicate when various generating stations will be unavailable due to maintenance or project work. Annual maintenance outages, project-specific outages and combination outages encompassing both project and maintenance tasks are shown on the schedule. The 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. Typically, no 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 Energy Policy and

Procurement organization, the California Independent System Operator (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 inevitably will be required. Changes to the schedule may be required due to: (1) weather conditions, (2) resource constraints, (3) changes in project scope or schedule, (4) and/or emergent work. Depending on the proximity to the outage start date, changes to the scope and schedule require different levels of review and approval. Before outage changes are approved, consideration is given to the impacts of the change on: (1) equipment reliability, (2) replacement power costs, (3) resources and other scheduled outages.

An outage plan is developed prior to the start of the outage. Depending on the size and duration of the outage, an outage plan can be as simple as a list of work orders extracted from the SAP Work Management System (SAP/WMS), 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 plan can be broken down into three distinct, but interrelated, processes: (1) planning and scoping; (2) scheduling; and (3) outage execution.

a. 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 durations of all work activities are identified during this process.

PG&E manages preventative and maintenance work using SAP/WMS. 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/WMS 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 occurs over a 2- to 3-year period leading up to the outage start date.

b. Scheduling

The scheduling process determines the start and duration of an outage. Outage timing and durations are influenced by: (1) capital and maintenance work to be performed; (2) system operation constraints; (3) time of year; (4) labor resources available to perform work; (5) CAISO constraints, and transmission system issues.

The scheduling process occurs in conjunction with the scoping and planning process over a 2- to 3-year timeframe. A base preliminary outage schedule is developed from historical outage durations and timing, and OEM recommended frequency based on service hours and/or the number of equipment starts/stops. This schedule is refined over time as the scoping and planning process provides updated information regarding the work to be performed during the outages.

In October of the year prior to the outage year, the planned outage 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 plant manager and/or fossil O&M director 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.

c. Outage Execution

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

- Notifications to and approvals from the CAISO to separate the unit(s) from the grid;
- Energy isolation 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 energy isolation procedure and any start-up procedure for new or re-furbished equipment; and
- Notifications to and approvals from the CAISO to restore the unit to service and connect to the grid at the completion of the outage.

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 to determine if it can be adjusted to fit the revised timeframe, or if the outage scheduling needs to be moved. 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.

6. Design Change Process

Design changes are controlled through the design change process. The design change process is the process for proposing, evaluating, obtaining approval, and implementing changes to the design of structures, systems, and equipment at PG&E's 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.

G. Operational Results

This section examines the operational results during the 2020 record period by reviewing the energy production, fuel usage, and reliability of the fossil-fuel generating stations and the energy production and fuel usage of the PV facilities. The 2020 outages are also presented for facilities larger than 25 MW.

1. Energy Production

The output of Gateway, Colusa, and Humboldt varies throughout the day in response to CAISO market awards and dispatch instructions.

During 2020, PG&E's fuel cells were typically self-scheduled in the CAISO markets to run at maximum production. The fuel cells operate at extremely high temperatures (in excess of 1,200 degrees Fahrenheit (F)). When a fuel cell's output is cycled, the temperature of the fuel cell stack cycles. Since the useful life of a fuel cell stack is reduced with each thermal cycle, PG&E minimizes thermal cycles by running the fuel cells as base load resources.

PG&E's fossil fuel generating stations provided approximately 6,377 gigawatt hours (GWh) of energy during the 2020 record period. To generate this amount of energy, the fossil fuel generating stations burned 46,924,287 millions of British Thermal Units (MMBtu) of natural gas and 31,087 MMBtu of distillate fuel. The resulting net plant heat rate for the fossil fuel generating stations in 2020 was 7,363 British thermal units per kilowatt hour (Btu/kWh) as shown in Table 3-1 below.[5]

TABLE 3-1
FOSSIL GENERATION 2020 ENERGY PRODUCTION

Line No.	Station	Net Generation (GWh)	Fuel Usage (MMBtu)	Average Net Heat Rate (Btu/kWh)
1	Gateway	2,855	20,779,864	7,278
2	Colusa	3,038	21,906,341	7,211
3	Humboldt	484	4,269,168	8,821
4	Total	6,377	46,955,373	7,363

5 Net plant heat rate is equal to the amount of fuel consumed (British Thermal Units) divided by the net generation (kilowatt-hours).

During 2020, PG&E's PV generating facilities were included in the CAISO market in accordance with the appropriate CAISO tariff provisions relating to these types of intermittent renewable facilities, and as a result were typically operated at maximum production.[6] PG&E's PV generating facilities provided approximately 277 GWh of energy during the 2020 record period.

D.10-04-052 approving PG&E's 5-year solar PV Program links recovery of O&M costs for PG&E-owned PV facilities to the performance of the PV facilities. If the average performance of PG&E's PV UOG systems falls below 80 percent of expected output, it will weigh heavily in favor of disallowing or refunding some of the O&M costs to ratepayers.[7] The PV facilities operated at 85.6 percent of expected output during the 2020 record period. PG&E reduced power output on (curtailed) many of its PV generation facilities during 2020 (at the request of the CAISO and for economic dispatch purposes). Had PG&E not reduced output as directed, PG&E's PV facilities would have operated at 88.8 percent of the expected output during the 2020 record period.

2. Outages

PG&E's fossil-fuel generating stations experienced scheduled outages and forced outages during the record period.

Scheduled outages include planned outages and maintenance outages. Planned outages are typically scheduled prior to the start of the year. PG&E's combined cycle plants, Gateway and Colusa, typically schedule planned outages in the spring of each year to address preventive and corrective maintenance issues. Maintenance outages are scheduled when needed throughout the year to perform testing or routine maintenance, or to perform non-emergency repairs when an outage can be deferred beyond the end of the next weekend, but cannot be performed while the unit is operational and must be performed before the next planned outage. Humboldt schedules planned outages for larger scope and duration routine

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6 Nine of PG&E's PV generation facilities are capable of being curtailed for economic dispatch purposes.

7 D.10-04-052, Ordering Paragraph 7.

unit maintenance based on service hours. Humboldt schedules maintenance outages for smaller scope and duration routine unit maintenance based on service hours as well.

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 automatically trips offline by a protective device.

Consistent with previous Energy Resource Recovery Account (ERRA) compliance proceedings, PG&E provides general information regarding scheduled outages that were 24 hours or more in duration, and specific information regarding each forced outage longer than 24 hours in duration, for facilities that are 25 MW or greater in size.[8]

During forced outages, PG&E primary goal is to bring the unit back on line safely and expediently. PG&E also examines components associated with the specific equipment failure. This examination helps inform PG&E as to 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 may extend the time before a unit is returned to service, it can potentially avoid a future forced outage.

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 fossil portfolio 2020 FOF was 0.46 percent, better than the industry benchmark of 1.73 percent.[9] Table 3-2 includes the fossil portfolio FOF for the past five years compared to the industry benchmark.

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8 PG&E has provided additional, detailed information concerning the outages that occurred during the record period to the Public Advocates Office (Cal Advocates) at the CPUC in response to Cal Advocates’ Master Data Request.

9 The 2020 industry benchmark is the 2015-2019 North American Electric Reliability Corporation (NERC) Generating Availability Data System Generating Unit Statistical Brochure. It is included in PG&E’s workpapers.

TABLE 3-2
FOSSIL PORTFOLIO FOF

Line No.	Year	FOF (%)	Benchmark FOF (%)
1	2016	0.31	1.87
2	2017	0.55	1.80
3	2018	1.21	1.72
4	2019	1.63	1.70
5	2020	0.46	1.73

a. GGS

1) Scheduled Outages

Gateway executed two planned outages and one maintenance outage in 2020 lasting 24 hours or more in duration.

2) Forced Outages

Gateway experienced no forced outage in 2020 lasting longer than 24 hours.

b. CGS

1) Scheduled Outages

Colusa executed one planned outage and no maintenance outages in 2020 lasting 24 hours or more in duration.

2) Forced Outages

Colusa experienced no forced outage in 2020 lasting longer than 24 hours.

c. HBGS

1) Scheduled Outages

The preventative maintenance schedule at Humboldt is based on service hours of each unit. Maintenance is necessary for each unit at: 1,000, 2,000, 4,000, 6,000, 8,000, 12,000, 18,000, and 24,000-hour intervals. The 18,000 (and associated multiples thereafter) hour overhauls are the most extensive and take the most time to plan for and complete. As mentioned earlier, Humboldt schedules planned outages for larger scope and duration unit maintenance, and schedules maintenance outages for smaller scope and duration unit maintenance. Since Humboldt is a 10-unit facility, another unit is typically available to back up a unit that is out of service for an outage.

Humboldt experienced three planned outages in 2020 lasting 24 hours or more in duration. Humboldt experienced 29 maintenance outages lasting 24 hours or longer in 2020.

2) Forced Outages

Humboldt experienced two forced outages lasting longer than 24 hours in 2020.

TABLE 3-3
2020 HUMBODLT FORCED OUTAGES

Line No.		Start	End	Duration (Days)
1	Humboldt Bay GS Unit 05	10/2/20 14:30	12/08/2020 17:00	67.1
2	Humboldt Bay GS Unit 05	12/08/20 17:00	1/1/2021 10:49	23.3

a) Unit 5

On October 2, 2020, at 2:30 p.m., Unit 5 was forced out of service due to engine control issues. While online, Unit 5 experienced a loss of communication between the control system and Unit 5 that caused the engine to fire erratically. The Unit 5 forced outage occurred during a Unit 4 planned outage so room in the HBGS engine hall was limited making the coordination of the repair even more difficult.

A Wartsila (OEM) Technician was sent to the plant to assess damage, assist in inspection, and recommend corrective actions to be taken to get the unit safely back to service.

After disassembling the unit and evaluating the damage, it was determined that the unit had experienced extensive damage and required a complete over-haul. Several parts were shipped out for repair and some new parts were ordered and shipped to the plant for replacement, including the following:

- Heads were removed and sent to Wartsila’s shop for rebuild;

- New Liners in engine were ordered;
- Pistons were removed and crowns were ordered for replacement; and
- Several other engine parts required replacement as recommended by the Wartsila Technician.

As parts were received back on site, the unit was re-assembled. However, before reassembly of Unit 5 could be completed, HBGS went into sequestration due to several station personnel testing positive for Coronavirus (COVID-19). This further reduced the staff to work on Unit 5. Additional contractors and resources were not allowed to come on site to alleviate the resource constraint due to COVID-19 and the sequestration. This occurred while the Unit 4 planned outage was still underway. The onsite staff was supporting the return to service of Unit 5, the Unit 4 planned outage, and maintaining and operating the 8 other engines at the station.

As a result, the Unit 5 forced outage event ended on December 08, 2020 at 5:00 p.m. and a new forced outage event was initiated with a pandemic cause code due to decreased manpower to support Unit 5 as a result of COVID-19. The unit was reassembled, tested and returned to service on January 1, 10:49 a.m.

H. Compliance and Settlement Items

1. HBGS Relay Replacement Status and Test Report Documentation

a. HBGS Humboldt Protective Relay Replacements

In the 2017 ERRA Compliance Proceeding, PG&E and Cal Advocates entered into a settlement agreement in which PG&E agreed to report on the status of the differential current relay replacements at HBGS in the ERRA Compliance Application for the following year in which the replacements are complete.

Following the 2017 differential current protective relay failure at Humboldt Generating Station, PG&E determined that the best course of action would be to replace the Schneider Electric relays with Schweitzer

Engineering Laboratories (SEL) relays. The SEL relays are PG&E standard and are also utilized industry-wide as the best in class for digital protective relay circuits. PG&E replaced the 10-generator differential current protective relays at HBGS in 2020. With the replacement of the relays in 2020, PG&E has met the requirement to report on the status of the differential current relay replacements at HBGS and will no longer report on this status in future ERRA Compliance proceedings.

b. Compliance Tracking Software Implementation

In the 2017 ERRA Compliance Proceeding, PG&E and Cal Advocates entered into a settlement agreement in which PG&E agreed to report on the updates and capabilities of its Information Technology systems that document relay test reports, such as the Powerbase software, in the 2018 ERRA Compliance proceeding.

PG&E continues to have a very thorough process in place to assure that it complies with the NERC standards including NERC Reliability Standard PRC 005 6, "Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance." PG&E has prudently designed its Protection System Maintenance Program (PSMP) (including TD-3323S Protective Equipment Maintenance Requirements) to require testing of both the relay component test and the relay scheme functional test every six calendar years. Included in PG&E's PSMP are testing forms that are used to document test results. PG&E's Power Generation Department uses electronic means for the designated person in charge to document the review and approval of the test reports.

Powerbase has been implemented within Power Generation in 2020 as the only tool for storing testing and maintenance records for protective relay protection pertaining to the bulk energy system. Powerbase allows for electronic routing of maintenance records through the appropriate chain of command for review and approval.

PG&E Power Generation Standards 1617S-A (Western Electricity Coordinating Council (WECC) devices) and 1617S-B (non-WECC devices) have been revised to explicitly state that the tracking of maintenance and testing will be in Powerbase. The updated revisions include document location and approval methodology which currently rely on implicit SAP approval. The revised guidance documents have been rolled out within Power Generation and training is underway with expected completion in 2021. With the replacement of the relays in 2020, PG&E has met the requirement to report on the updates and capabilities of its Information Technology systems that document relay test reports, such as the Powerbase software, and will no longer report on this topic in future ERRA Compliance proceedings.

I. Conclusion

In compliance with D.14-01-011, this chapter addresses the operation of PG&E's utility-owned fossil-fuel, fuel cell, and PV facilities, and outages that occurred at these facilities during the 2020 record year. It demonstrates that PG&E's utility-owned fossil-fuel and PV portfolio was operated in a reasonable manner during the record period.

PG&E has in place a comprehensive management structure, with adequate internal controls, to prudently oversee the operation of its fossil-fuel generating stations and PV facilities. PG&E's compliance with the operations standards, maintenance standards, and logbook standards set forth in GO 167 are further evidence that PG&E's fossil and solar portfolio was operated in a reasonable manner. In addition, scheduled outages were planned sufficiently in advance to allow adequate preparation time and were executed efficiently to assure prompt return to service.

PG&E's fossil portfolio was operated in a reasonable manner as demonstrated by the 2020 record year FOF results being better than the industry average and by the minimal number of forced outages. PG&E acted reasonably in resolving forced outages in a timely manner.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

UTILITY-OWNED GENERATION: NUCLEAR

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UTILITY-OWNED GENERATION: NUCLEAR

A. Introduction

In compliance with Decision (D.) 14-01-011, this chapter addresses the operation of Pacific Gas and Electric Company's (PG&E) utility-owned nuclear facility, and outages that occurred at this facility during the 2020 record year.

PG&E's utility-owned nuclear facility was operated in a reasonable manner during the record period. During the record period, PG&E owned, operated and maintained one nuclear generating facility, the Diablo Canyon Power Plant (DCPP), located nine miles northwest of Avila Beach in San Luis Obispo County. DCPP consists of twin pressurized water reactors, Units 1 and 2, rated at a nominal 1,122 megawatts (MW) and 1,118 MW, respectively.

All nuclear activities are regulated and overseen daily by the Nuclear Regulatory Commission (NRC) to ensure that the facility is operated within federal regulations.

B. DCPP's Operations Organization

PG&E's Generation organization is led by the Senior Vice President (SVP) of Generation and Chief Nuclear Officer (CNO) and provides oversight to all the company's Utility-Owned Generation. The Site Vice President (VP) reports to the SVP and has responsibility for all activities necessary for safe operation of the station. The Station Director, the Senior Director, Engineering, Technical and Emergency Services, and the Director of Organizational Effectiveness and Learning Services report to the Site VP. The VP of Business and Technical Services, the Director of Quality Verification (QV), and the Manager of Employee Concerns Program (ECP) report directly to the SVP of Generation and CNO.

The Station Director is responsible for operations, maintenance, and nuclear work management. Operations Services, Maintenance Services, Nuclear Work Management, Chemistry and Radiation Protection report to the Station Director. The Senior Director, Engineering, Technical and Emergency Services, is responsible for providing engineering and design services, project management, security, and the emergency response program. The VP of Business and Technical Services is responsible for business planning, regulatory and risk programs, and performance improvement. The Director of QV is responsible for independent oversight of nuclear activities. Finally, the Manager of ECP administers the ECP required by NRC regulations.

C. DCPP System Management

Plant safety is essential to the successful operation of a nuclear power station. Nuclear plants that focus on cost and production at the expense of safety may be required by the NRC to shut down for extended periods of time to correct safety problems. PG&E has remained focused on plant safety and equipment reliability by pursuing critical projects in expense and capital, even as it pursues cost control efforts. Due to PG&E's effective balancing of plant safety and reliability, DCPP has performed well with reliability maintained at extremely high levels to the benefit of PG&E's customers.

PG&E has many internal controls in place to manage the operations and maintenance of DCPP. These controls include: (1) procedures; (2) a Corrective Action Program (CAP); (3) an outage planning and scheduling process; (4) a project management process; and (5) a Quality Assurance (QA) Program. Each of these controls is discussed below.

1. Procedures

Procedures cover virtually all aspects of safety, operations, maintenance, planning, environmental compliance, regulatory compliance, emergency planning, work management, inspection, testing, and other areas. Each procedure describes the purpose of the document, the details of the actions and/or processes covered by the document, management's roles and responsibilities, and the date the document became effective.

2. Corrective Action Program

The CAP is the main process that DCPP uses to identify, analyze, and resolve plant problems and is required by the regulations of the NRC.[1] Elements of the program include: issue identification, issue significance reviews, various levels of cause analysis up to root cause analysis, corrective action development and implementation, and performance

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1 See 10 Code of Federal Regulations (CFR) 50, Appendix B.

trending and monitoring. The program is used to develop corrective action to prevent recurrence of problems.

3. Outage Planning and Scheduling Process

As discussed in Section D.2 below, nuclear generating units must be shut down periodically to be refueled. Planning the duration of each refueling outage is a complex task. Every refueling outage has work activities that are similar in scope and length including: (1) shutdown and cool down of the reactor; (2) disassembly of the reactor vessel; (3) fuel replacement; and (4) re-assembly of the reactor vessel, followed by heatup and startup of the plant. During these refueling periods, schedule maintenance is conducted, surveillance tests[2] are performed, and plant modifications are completed. Because DCPP Units 1 and 2 do not routinely shut down at other times, a great deal of maintenance is planned for these refueling outages.

The DCPP refueling outage planning process is governed by a system of milestones. The outage is broken down into individual steps to allow a logical process for developing a schedule and monitoring outage preparation activities. Each outage has a set of milestones and due dates. The milestones are consistent from outage to outage. Nuclear Work Management and senior leadership monitor completion of the milestones to ensure the organization is prepared for the upcoming outage.

The outage preparation milestones begin with a review of the long-range outage plan by Nuclear Work Management, approximately 24 months prior to the outage start date. Other significant milestones include outage scope freeze at approximately 12 months prior to outage start and issuance of the initial schedule at approximately 11 months prior to outage start. The initial schedule undergoes two additional revisions prior to the outage start to incorporate activity logic ties and resource availability. An additional review of the outage safety plan and the outage safety schedule is performed by the Plant Staff Review Committee one month prior to outage start. The final schedule is issued two weeks prior to the outage start.

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[2] Surveillance tests are tests required by the NRC-approved technical specifications.

The initial start time for future outages is developed years in advance of the outage start through a coordinated effort between Nuclear Work Management and Engineering Services. Outage start dates are typically in the spring or fall to support operation during the summer months and are coordinated with reactor fuel core cycle length (currently from 18-20 months on each unit). This planning minimizes years in which an outage occurs on both Units 1 and 2. The outage initial start date is then coordinated through PG&E's Energy Policy and Procurement organization, well in advance of the actual outage start date.

All key steps necessary to determine the duration of a refueling outage are developed through the milestone process discussed above. In the outage schedule, some "float" hours are included to accommodate any minor issues that arise during the outage. The float hours are intended to assure that the unit is returned to service as planned in the outage schedule.

Nuclear Work Management, through the milestone structure, identifies most of the outage design scope (including both major and minor items) approximately 22 months prior to the outage start. This scope is reviewed and approved by station leadership and is finalized 20 months prior to the outage start. Required preventive maintenance items are identified and approved by Engineering Services 15 months prior to the outage start. Preventive maintenance items are items that are needed on a recurring frequency to ensure a safe and reliable plant. Examples of preventive maintenance include motor overhauls, valve refurbishments and instrument calibrations.

Once the outage scope milestone is completed, there is a process for incorporating late scope additions and scope deletions. For significant scope items or challenges to the scope, approval by a Readiness Review Board, consisting of upper management and chaired by the Station Director, is required. These items are presented to the board and either approved as scope addition or rejected. This process is utilized for all refueling outages at DCPP and was accordingly used to develop and modify the outage scope for the 2020 Unit 1 1R22 refueling outage discussed in Section D.2 below.

4. Project Management

Project work is controlled through the project management process. Projects are assigned a Project Manager who has responsibility for the project scope, cost and schedule, and coordinates and manages the project from inception to closeout. Project management procedures and tools are in place to provide Nuclear Generation Project Managers with guidelines for successfully achieving the project objective of each project they manage. These procedures are intended to be applicable to all project types, sizes and phases, and are anticipated to improve the consistency and quality of project management throughout Nuclear Generation. Project Managers are responsible for regular project reporting to management.

5. QA Program

QA audits, assessments, reviews and inspections are required by the NRC. These processes evaluate plant activities to ensure they are being performed in accordance with NRC QA program requirements and other recognized industry standards. Quality oversight activities at DCPP are performed in accordance with the following regulations: 10 CFR 50, Appendix B; NRC Regulatory Guide 1.33 (that endorses American National Standards Institute (ANSI) N18.7); NRC Regulatory Guide 1.44 (that endorses ANSI N45.2.12); NRC Regulatory Guide 1.58 (that endorses ANSI N45.2.6); and NRC Regulatory Guide 1.123 (that endorses ANSI N45.2.13).

QV has overall responsibility for independent quality oversight of DCPP: plant operations, maintenance, radiation protection, chemistry, emergency planning, environmental protection plan, fitness for duty, engineering, design, procurement, outage management, work control, and strategic projects. The work performed by the QV section includes: independent QA audits, assessments, reviews, quality control inspections, welding non-destructive examinations, source assessments, and supplier audits.

D. Operational Results

1. Capacity Factor and Energy Production

DCPP is consistently operated at 100 percent (or full) power level. Regular cycling of DCPP is not performed. This is consistent with the operation of most nuclear power plants in the United States, which are operated as baseload units. When a plant is taken off-line for any reason, regulatory-required testing must be performed before the plant can be returned to service, which extends the time period to return to service beyond the time required to conduct repairs.

There are a number of factors that can affect the megawatt-hour (MWh) output of a nuclear facility, such as: scheduled refueling outages, routine turbine generator valve testing, ocean cooling water temperature, ocean cooling water system tunnel cleaning, curtailments, and forced outages. The capacity factor[3] and net generation[4] for the record period for DCPP Units 1 and 2 are shown below in Table 4-1.

TABLE 4-1
NUCLEAR GENERATION 2020 ENERGY PRODUCTION

Line No.	DCPP Unit	Capacity Factor	Net Generation (MWh)[(a)]
1	1	90.4%	8,910,573
2	2	75.1%	7,373,850

(a) Net generation values include preliminary California Independent System Operator (CAISO) data for October, November, and December. Final 2020 generation values will be available in April 2021.

Electric power industry generation unit performance calculations are based on "Maximum Dependable Capacity" (MDC). This value is determined for each generating unit based on extensive unit operational testing and engineering analysis by the plant staff. MDC is the maximum amount of power a unit can produce during average worst case natural operating conditions.[5]

3 Capacity factor is a measure of actual generation compared to potential generation (based on operating a unit 24 hours a day every day of the reporting period and established Net MDC values of 1,122 MW for Unit 1 and 1,118 MW for Unit 2).

4 Net generation (MWh) is equal to gross generation minus the amount of energy consumed by the plant, as reported by PG&E to the CAISO.

5 The NRC's definition of MDC can be found at: https://www.nrc.gov/reading-rm/basic-ref/glossary/maximum-dependable-capacity-gross.html.

The MDC values for DCPP Units 1 and 2 are 1,122 MW and 1,118 MW, respectively. As shown in Table 4-1 above, the 2020 capacity factors for Unit 1 and Unit 2 were 90.4 percent and 75.1 percent, respectively. In 2020, Unit 1 had a planned Refueling Outage (1R22), while Unit 2 experienced several unplanned maintenance outages (MO) to repair the generator, resulting in a lower capacity factor for Unit 2 than for Unit 1.

Combined, DCPP Units 1 and 2 generated 16,284,423 MWh of energy with an average capacity factor of 82.8 percent (for the record period) against a planned target of 93.4 percent.[6] The 2019 industry average annual capacity factor was 93.4 percent (2020 industry results are not yet available).[7] DCPP's performance was the result of one short-duration Unit 2 forced outage to repair a control rod malfunction, three Unit 2 forced outages to perform generator cooling system repairs during the record period, and completion of the planned Unit 1 1R22 Refueling Outage within the business plan duration of 33 days.

On October 3, 2020 Unit 1 completed its 3rd consecutive on-line continuous operation run between refueling outages. This industry leading continuous safe operation resulted in reliable electric production for PG&E customers.

As demonstrated above, DCPP's performance resulted in safe and reliable generation for PG&E's customers. In addition, completion of the Unit 1 1R22 Refueling Outage within the business plan duration of 33 days was a significant contributor to overall safety and performance results.

2. Outages

Nuclear generating facilities can experience generation losses due to: (1) refueling (planned) outages; (2) MOs; (3) forced outages; and (4) curtailments. Refueling outages and MOs are both classified as scheduled outages. Each of these types of outages is discussed below.

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6 The 93.4 percent planned target capacity factor accounted for the scheduled Unit 1 1R22 Refueling Outage.

7 Industry capacity factor from the U.S. Energy Information Administration, Electric Power Monthly (with data for September 2020), Table 6.7.B https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_b.

Nuclear generating units are unique in that they must be shut down periodically to be refueled. The consumption of this set amount of fuel is what establishes the operating duration of a fuel cycle and scheduling of a refueling outage. Nuclear units schedule necessary maintenance and projects within the refueling outages. After a nuclear unit is refueled it can then be operated until the next refueling outage. The planned duration of a refueling outage is established based on the duration required to refuel the reactor, the scope of maintenance required for the specific outage, and the scope of projects required to be implemented for regulatory or plant improvement activities.

MOs are scheduled when needed throughout the year to perform testing, routine maintenance, or non-emergency repairs when the repairs can be deferred beyond the end of the next weekend but require a capacity reduction before the next scheduled refueling outage.

Forced outages are generally the result of equipment malfunctions or unexpected ocean conditions that restrict the plant’s ocean cooling water intake system. When a forced outage occurs, the primary objective is to repair the item that led to the outage or protect plant equipment from damage resulting from restricted ocean cooling water flow. While minimizing the outage period is important, a certain amount of work is required for every forced shutdown. This includes surveillance testing, as well as complying with all regulatory requirements and emergent maintenance requirements that cannot be deferred to a later period.

A curtailment is when a unit is not operating at 100 percent capacity. A curtailment could be the result of required surveillance testing that must be performed at a power level less than 100 percent, routine maintenance that requires a unit to be at less than 100 percent, such as cleaning of the ocean cooling water system to remove biological growth, emergent maintenance items that require the unit to be at a reduced power level, or an operational decision to reduce power due to external influences such as significant swells that could impact the ability of a unit to remain operational.

Further detail concerning refueling outages, MOs, and forced outages that occurred during the record period for DCPP Units 1 and 2 is discussed below. Consistent with previous Energy Resource Recovery Account

(ERRA) compliance proceedings, PG&E is providing general information regarding Scheduled Outages that were 24 hours or more in duration, and specific information regarding each Forced Outage that was longer than 24 hours in duration. PG&E has provided additional, detailed information concerning the outages that occurred during the record period in response to the Public Advocates Office at the California Public Utilities Commission Master Data Request.

a. Unit 1

During 2020, Unit 1 conducted a planned 1R22 Refueling Outage from October 3, 2020 at 21:00 through November 2, 2020 at 19:40. This outage was planned for 33 days. The actual Unit 1 1R22 outage duration was 29.99 days, completing 3 days ahead of the plan. This outage included successfully completing infrequent major work scopes of the required steam generator tube inspections and inspection of the third low pressure steam turbine. Outside of the planned Unit 1 refueling outage Unit 1 operated safely with no unplanned outages.

b. Unit 2

During 2020, Unit 2 experienced an unplanned forced outage from February 13, 2020 at 15:18 to February 16, 2020 at 06:20. The 63.0-hour outage occurred because four control rods became misaligned greater than 12 steps, requiring a plant shutdown in accordance with the DCPP operating license requirements. The root cause was determined to be an original-construction factory-supplied improper crimp of a wire to a ring lug termination that had degraded over 40 years, resulting in a high resistance connection and intermittent logic failures on the control card. The control system safety function of being able to insert or trip the control rods was not affected by this condition.

Also, during the record period, Unit 2 experienced several forced outages related to malfunctions within the main generator associated with excessive vibrations. Additional inspections and replacement of a redesigned component of the generator are expected to occur during Unit 2's spring 2021 refueling outage. Given the ongoing effort to address and finally resolve these operational issues and the preliminary status of root cause evaluations, these outages should be reviewed in the 2021 ERRA Compliance proceeding.

c. Violations From the NRC

There were no NRC violations in 2020 that resulted in an outage extension or unplanned outage. PG&E received three plant operations Green Non-Cited Violations (NCV), one green finding, and one Documented minor violation in 2020. Green Findings, NCVs and Documented Minor violations were all very low safety significance as determined by the NRC, and therefore required no response to the NRC.

A summary of the violations and actions taken are listed in the table below:

TABLE 4-2
SUMMARY OF NRC VIOLATIONS

Line No.	Inspection Report	Violation Description/Summary	Corrective Actions
1	2020-001	Green NCV. On 11/29/19 with Unit 2 in Mode 4, both Containment Spray pumps were made inoperable by opening the associated knife switches. With Unit 2 in preparations for transition to Mode 5 the Containment Spray pumps were disabled to optimize manpower resources. It was later recognized that this action was performed too early as Containment Spray Pumps are required to be operable in Modes 1-4.	The following actions have been taken: Coaching and counseling, including removal of qualification and remediation, was performed for the individual involved.
2	2020-001	Documented Minor Violation. On March 26, 2020, DCPP made a change to surveillance frequency requirement SR 0.2 of the "applicability" section of the Equipment Control Guidelines (ECG). DCPP incorrectly determined that the 10 CFR 50.59 change process did not apply because the change to the generic ECG SR 0.2 applicability was a maintenance activity and therefore covered under the requirements of 10 CFR 50.65(a)(4); therefore, a screen to determine if a more detailed evaluation or NRC prior approval was required was not conducted.	The following actions have been taken: The re-performed licensing basis impact evaluation concluded that the proposed activity was NOT maintenance and that the 50.59 process applied. The 50.59 Screen concluded there was no adverse impact on design functions, no adverse impact on how those design functions are performed or controlled, no impact on methodologies, and no impact on tests/experiments. As such, a 50.59 Evaluation was not required.

TABLE 4-2
SUMMARY OF NRC VIOLATIONS
(CONTINUED)

Line No.	Inspection Report	Violation Description/Summary	Corrective Actions
3	2020-003	Green NCV. During the Diesel Generator 1-1 MO Window, the NRC identified a portion of scaffolding located in very close to a safety-related airline. While the scaffold construction and evaluation followed current procedures, additional evaluation, beyond what is in the procedure, had to be performed to demonstrate that the scaffold was seismically qualified when the qualification was questioned.	The following actions have been taken: The scaffold procedure, AD7.ID5, is being revised to require the formal evaluation described in the Seismically Induced Systems Interaction (SISI) manual, as well as clarify the intent of getting a SISI inspection as a last resort if clearances are unable to be met due to field conditions by the scaffold crew.
4	2020-003	Green Finding. On 7/23/20, with Unit 2 in Mode 3, a through wall leak was discovered on a section of insulated Auxiliary Feedwater discharge piping locate in the pipe rack. Subsequent investigations determined that in 2009 and 2010, industry operating experience that was regarding under-insulation corrosion was dispositioned by DCPP. Neither one of them concluded additional action was necessary. These operating experience items were not evaluated in accordance with the operating experience procedure, OM4.ID3.	The following actions have been taken: Pipe was repaired, non-essential insulation will be removed from auxiliary feedwater discharge piping, and corroded piping restored to provide sufficient margin to piping code limits through the end of plant operation. Operating experience procedure OM4.ID3 was revised to obtain subject matter expertise when performing evaluations, and engineering inspection procedures will be revised to assess for corrosion-under-insulation where insulation damage is identified.
5	2020-004	Green NCV. During the Unit 1 refueling outage 22, operators failed to adequately check a drain valve was in the closed position as required by the clearance order, resulting in about 300 gallons of water discharging into containment sumps.	The following actions have been taken: The valve was properly closed and the area cleaned, responsible operators qualifications were suspended until remediated on valve positioning standards, a stand-down was held with the day and night operating crews to discuss the event and techniques to avoid similar errors, on improving communications and briefings for clearance activities, and detailing how to deal with difficult-to-manipulate valves.

E. Conclusion

In compliance with D.14-01-011, this chapter addresses the operation of PG&E's utility-owned nuclear facility, and outages that occurred at this facility during the 2020 record year. It demonstrates that DCPP 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 DCPP. The 2020 year-end DCPP total plant capacity factor of 82.8 percent was below the 2020 target of 93.4 percent due to the Unit 2 unplanned MOs required to conduct generator repairs. The Unit 2 unplanned MOs could not have been foreseen and prevented by testing and monitoring practiced by the nuclear generation industry. Finally, the Unit 1 planned 1R22 Refueling Outage was planned sufficiently in advance to allow adequate preparation and was efficiently executed to assure prompt return to service in accordance with the business plan.

In sum, DCPP was operated in a reasonable manner in 2020 as demonstrated by PG&E’s on time completion of the Unit 1 planned 1R22 Refueling Outage, and the absence of forced outages that could have been foreseen and prevented by testing and monitoring practiced by the nuclear generation industry.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – GREEN TARIFF BALANCING ACCOUNT AND THE COMMUNITY SOLAR GREEN TARIFF BALANCING ACCOUNT

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A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents for review its funding and administrative costs recorded to the Disadvantaged Community – Green Tariff (DAC-GT) subaccount and Community Solar – Green Tariff (CS-GT) subaccount of the Public Policy Charge Balancing Account (PPCBA) during 2020 the record period, as directed by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 18-06-027, the *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*. D.18-06-027 implements Assembly Bill 327, which required the Commission to develop alternatives to increase the adoption and growth of renewable generation in Disadvantaged Communities (DAC).

B. Disadvantaged Community – Green Tariff Balancing Account

1. Overview

The DAC-GT Program is available to customers who live in DAC and meet the income eligibility requirements for the California Alternate Rates for Energy (CARE) and Family Electric Rate Assistance (FERA) programs. DAC-GT will provide a 20 percent discount to CARE or FERA-eligible residential customers located in DACs which is applied to their total electric bill. The DAC-GT Program allows eligible customers to choose clean energy options without the need to own their home and without the cost of installing their own distributed renewable generation. PG&E will procure renewable generation up to the program participation cap of 54.72 megawatt (MW).[1] The program is funded through greenhouse gas (GHG) allowance proceeds. If such funds are exhausted, the programs will then be funded

[1] Per Resolution (Res.) E-4999, PG&E's DAC-GT program cap of 70 MW was modified to 54.82 MW. See p. 13.

through Public Purpose Program funds.[2] PG&E's procurement team is holding semi-annual DAC Request for Offers to procure the full program capacity, as is required by CPUC Res.E-4999.[3] PG&E procured 4.65 MW for the DAC-GT Program in the spring of 2020 and PG&E is currently working to execute contracts resulting from solicitation in the fall of 2020 by early February. The DAC-GT program is fully subscribed up to the program participation cap, with the program funds disbursed to provide the discount to program enrollees. PG&E is providing renewable energy to customers in the interim with eligible resources from Renewable Portfolio Standard or other existing PG&E solar resources.[4]

2. Balancing Account Implementation

In accordance with D.18-06-027, PG&E filed Advice Letter (AL) 5351-E "Disadvantaged Communities Green Tariff and CS-GT Programs Balancing Account Implementation Advice Letter," which was approved on January 24, 2019, with an effective date of September 6, 2018. This AL established the PPCBA with two subaccounts to track the costs and revenues associated with the DAC-GT and CS-GT programs.[5]

Subsequently, PG&E's filed AL 5763-E, "Revisions to the Disadvantaged Communities Green Tariff Programs' Subaccounts in the Public Policy Charge Balancing Account" on February 14, 2020, and filed further revisions in AL 5763-E-A on November 17, 2020. ALs 5763-E and 5763-E-A were approved on December 21, 2020, with an effective date of December 17, 2020. These ALs update AL 5351-E, and address changes requested by the Energy Division of the CPUC to reconcile

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[2] Res.E-4999, p. 14, Table 1.

[3] Res.E-4999, Ordering Paragraph 8, p. 69.

[4] D.20-07-008 directed PG&E to auto-enroll eligible DAC-GT customers that were at highest risk of disconnection.

[5] Hereafter the two subaccounts are interchangeably referred to as balancing accounts as follows: DAC-GT subaccount of the PPCBA may be referred to as the DAC-GT Balancing Account, or DACGTBA; the CS-GT subaccount of the PPCBA may be referred to as the CS-GT Balancing Account, or CSGTBA.

accounting treatment for the DAC-GT and CS-GT programs among the three Investor-Owned Utilities.[6]

During this time of alignment, PG&E initially held off on recording entries to the two balancing accounts, while awaiting approval of ALs 5763-E and 5763-E-A. However, as program costs became more material, PG&E recorded approved 2019 and 2020 program costs and GHG Proceeds into the balancing accounts. For this reason, 2019 and 2020 program activities were recorded during the 2020 recorded period and are presented in this testimony.

3. Funding of the DAC-GT Program and Transfer to Balancing Account

In the 2019 Energy Resource Recovery Account (ERRA) Forecast Proceeding (Application (A.) 18-06-001), PG&E presented a set aside from GHG allowance proceeds for the DAC-GT Program in combination with the CS-GT Program. The total amount authorized by D.19-02-023 includes $14.5 million for both programs combined for the 2019 record period. PG&E used the approved program capacity for each program to allocate this amount between the two programs. Accordingly, $11.5 million was transferred from the GHG Revenue Balancing Account to the DACGTBA during 2020, as approved by D.19-02-023.

In the 2020 ERRA Forecast Proceeding (A.19-06-001), PG&E presented a set aside of $2.0 million from GHG allowance proceeds for use in the DAC-GT Program for the 2020 record period. In February, the Commission approved this use of GHG allowance proceeds for the DAC-GT Program. Accordingly, $2.0 million was transferred from the GHG Revenue Balancing Account to the DACGTBA during 2020, as approved by D.20-02-047.

4. Revenue Shortfalls

As mentioned in Section B.1 above, the DAC-GT Program provides a 20 percent discount to CARE or FERA-eligible residential customers located in DACs which is applied to their total electric bill. The 20 percent discount provided to the customer in support of the program will be shown on the

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6 Changes include a harmonization of incremental renewable generation and generation-related program costs used to support the DAC-GT and CS-GT tariffs with the approach Southern California Edison Company and San Diego Gas & Electric Company had implemented.

customer's bills and the revenue shortfall associated with the discount is recorded as an expense to the DAC-GT subsidiary account in the PPCBA. During 2020 the DAC-GT Balancing Account recorded $745 thousand in revenue shortfalls.

5. Expenses of the DAC-GT Program Recorded to the Balancing Account

An overview of the expenses and balancing account interest recorded in 2020 to the DAC-GT are shown in Table 5-1 below.

TABLE 5-1
DAC-GT EXPENSE ACTIVITY

Line No.	Tariff Line Item	Debit (DR)/ Credit(CR)	Description	2019 Amount	2020 Amount
1	5.A.h.	DR	Revenue Shortfall Based on 20 percent Discount		$744,979
2	5.A.k.	DR	Administrative Costs		
			DAC-GT Information Technology (IT) (IT/Billing System)	$1,161,165	$922,830
			Program Management	97,022	96,239
			Contact Center Operations		9,210
			Energy Procurement	25,001	68,756
			Subtotal of Administrative Costs	$1,283,188	$1,097,035
3	5.A.l.	DR	Marketing	8,836	1,365
4			Total DAC-GT Expense Activity[(a)]	$1,292,025	$1,843,379

(a) Includes all administrative, marketing, and other program expenses excluding balancing account interest.

PG&E incurred $1.8 million in expenses to the DACGTBA during 2020. In addition, PG&E recorded $1.3 million in expenses to the DACGTBA during 2020 related to 2019 activities. Activities associated with these expenses included:

- Administrative expenses associated with implementation and operation which may include costs associated, but not limited to include:
  - IT-related system modifications;
  - Customer Communications Center training and job aids;
  - Program Management;
  - Enrollment process; and
- Marketing expense for the program.

For the administrative expenses incurred from the inception of the program through the end of the record period PG&E recorded $2.4 million to the DACGTBA. For marketing expenses incurred from the inception of the program through the end of the record period, PG&E recorded approximately $10,000 to the DACGTBA. In addition, PG&E recorded approximately $12,000 in balancing account interest during the record period, which represents the 3-month commercial paper rate for the prior month as found on Statistical Release H-15.

C. Community Solar – Green Tariff Balancing Account

1. Overview

The CS-GT Program is structured similarly to the DAC-GT Program, but is intended to drive more local engagement in community-developed solar projects. To achieve this goal, there are customer eligibility and program rules that are intended to create a closer relationship between the customer and the solar project. Notably, the solar generation project supporting the program must be located within 5 miles of the participating customers' community (or within 40 miles if the participant lives in a San Joaquin Valley pilot community) and the program requires demonstration of community involvement and interest, facilitated through a local "sponsor." Participation in the CS-GT Program is limited to CARE or FERA eligible customers for the first 50 percent of the project capacity. Once 50 percent or greater of the project is subscribed to low-income customers, CS-GT projects may allow non-CARE or FERA eligible customers or the "sponsor" to participate in the program discount. The CS-GT offers the same 20 percent discount to participating customers as the DAC-GT Program and has a program cap of 14.2 MW for PG&E.[7]

PG&E procured 6 MW for the CS-GT program in the spring 2020 DAC solicitation and is currently working to execute contracts resulting from the fall 2020 DAC solicitation. No customers are currently enrolled in the CS-GT Program and are not expected to be enrolled until the first CS-GT projects come online in 2022 at the earliest.

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[7] Res.E-4999, p. 14, Table 1. Per Res.E-4999, PG&E's CS-GT Program cap of 18 MW was modified to 14.20 MW.

2. **Funding of the CS-GT Program and Transfer to Balancing Account**

In the 2019 ERRA Forecast Proceeding (A.18-06-001), PG&E presented a set-aside from GHG allowance proceeds for the CS-GT Program, in combination with the DAC-GT Program—as described in Section B.2 above. The allocated 2019 amount for CS-GT programs that PG&E transferred from the GHG Revenue Balancing Account to the CSGTBA during 2020 was $3.0 million, as approved by D.19-02-023.[8]

In the 2020 ERRA Forecast Proceeding (A.19-06-001), PG&E presented a set-aside of $3.1 million from GHG allowance proceeds for use in the CS-GT Program for the 2020 record period. The Commission approved this use of GHG allowance proceeds for the CS-GT Program in D.20-02-047. Accordingly, PG&E transferred $3.1 million from the GHG Revenue Balancing Account to the CSGTBA during 2020.

3. **Expenses of the CS-GT Program Recorded to the Balancing Account**

An overview of the expenses recorded in 2020 to the CS-GT are shown in Table 5-2 below.

TABLE 5-2
CS-GT EXPENSE ACTIVITY

Line No.	Tariff Line Item	DR/CR	Description	2019 Amount	2020 Amount
1	5.B.i.	DR	Administrative Costs		
			CS-GT IT (IT/Billing System)	$96,515	$744,805
			Program Management	26,747	112,295
			Energy Procurement	44,810	48,101
			Subtotal of Administrative Costs	$168,072	$905,201
2	5.B.j.	DR	Marketing	7,406	1,007
3			Total CS-GT Expense Activity[(a)]	$175,477	$906,208

(a) Includes all administrative, marketing, and other program expenses excluding balancing account interest.

8 As noted in Section B.2 above, PG&E delayed implementation of its DAC-GT and CS-GT accounts while awaiting approval of AL 5763-E. However, during 2020 PG&E recorded approved 2019 and 2020 balancing account activity.

PG&E incurred $906 thousand in expenses to the CSGTBA during 2020. In addition, PG&E recorded $175 thousand in expenses to the CSGTBA during 2020 related to 2019 activities. Activities associated with these expenses included:

- Administrative expenses associated with implementation and operation which may include costs associated but not limited to include:
  - IT-related system modifications;
  - Customer Communications Center training and job aids;
  - Program Management;
  - Enrollment process; and
- Marketing expense for the program.

For the administrative expenses incurred from the inception of the program through the end of the record period, PG&E recorded $1.1 million to the CSGTBA. For marketing expenses incurred from the inception of the program through the end of the record period, PG&E recorded approximately $8,000 to the CSGTBA. In addition, PG&E recorded approximately $1,000 in balancing account interest income during the record period, which represents the 3-month commercial paper rate for the prior month as found on Statistical Release H-15.

D. Conclusion

In this chapter, PG&E described its funding and recorded expenses for the DAC-GT and CS-GT programs. PG&E requests that the Commission find the amounts recorded to the DACGTBA and CSGTBA accounts was in compliance with the Commission's directives.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

GENERATION FUEL COSTS AND

ELECTRIC PORTFOLIO HEDGING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
GENERATION FUEL COSTS AND
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
GENERATION FUEL COSTS AND ELECTRIC PORTFOLIO HEDGING

A. Introduction

This chapter reviews actions taken by Pacific Gas and Electric Company (PG&E) regarding generation fuel procurement for:

- PG&E-owned conventional generation;
- PG&E tolling agreements;
- Hydroelectric; and
- Diablo Canyon Power Plant (DCPP).

PG&E engaged in fuel procurement activities in a manner consistent with: its California Public Utilities Commission (CPUC or Commission)-approved procurement plans; Nuclear Fuel Procurement Plan; and Commission decisions addressing procurement.

In addition, consistent with Decision (D.) 12-05-010, Ordering Paragraph (OP) 3, PG&E is also providing in this chapter a report concerning its activities and operating costs associated with the STARS Alliance, LLC (STARS Alliance).

Finally, this chapter reviews PG&E's implementation of its Commission-approved Electric Portfolio Hedging Plan (Hedging Plan) during the record period from January 1 to December 31, 2020. Consistent with D.11-07-039, OP 3, PG&E is also providing in this chapter a high-level discussion of its internal procedures and controls for ensuring compliance with its Hedging Plan.

B. Gas Procurement

1. Portfolio Overview

PG&E manages natural gas procurement for its portfolio of gas-fired generators, including power plants owned by PG&E and generators contracted to PG&E under tolling agreements. PG&E describes its gas procurement activities in the section below.

2. Natural Gas Procurement

a. PG&E Generation

PG&E owned six generating facilities in commercial operation during the record period that primarily use natural gas as a fuel source: Humboldt Bay Generating Station (Humboldt), Gateway Generating Station (Gateway), Colusa Generating Station (Colusa), and three fuel cell generating units (one at California State University, East Bay (CSUEB Fuel Cell) and two at San Francisco State University (SFSU Fuel Cells). Humboldt primarily burns natural gas[1] and is capable of burning distillate fuel oil during gas curtailments or emergencies. These facilities are listed in Table 6-1 below.

TABLE 6-1
PG&E-OWNED GENERATION FACILITIES

Line No.	Name	Location	Capacity (megawatts (MW))	Technology	Heat Rate (Millions of British Thermal Units (MMBtu)/ megawatt-hours (MWh))
1	Gateway	Antioch, CA	530	Combined Cycle Gas Turbine	7.2
2	Colusa	Maxwell, CA	530	Combined Cycle Gas Turbine	7.2
3	Humboldt	Eureka, CA	163	Reciprocating Engines	9.1
4	CSUEB Fuel Cell	Hayward, CA	1.4	Fuel Cell	8.0[a]
5	SFSU Fuel Cells	San Francisco, CA	0.2	Fuel Cell	6.6[a]
6	SFSU Fuel Cells	San Francisco, CA	1.4	Fuel Cell	8.0[a]

(a) Manufacturers' estimated heat rate.

b. PG&E Tolling Agreements

In addition to the gas-fired generating facilities it owns, PG&E's electric portfolio includes numerous tolling agreements for gas-fired generators. A tolling agreement is an agreement for generating capacity and electric energy where the buyer delivers fuel to the seller and the

1 When burning natural gas, the units at Humboldt require a small amount of distillate fuel for ignition.

seller delivers electric energy to the buyer.[2] In this case, PG&E (as buyer) delivers natural gas to the owner of the generating facility (the seller) and in exchange receives energy and other services. PG&E dispatches these tolled facilities according to least-cost dispatch principles. These agreements are listed in Table 6-2.

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[2] Tolling agreements are structured arrangements that can include a variety of services including capacity, energy, and ancillary services.

TABLE 6-2
PG&E'S TOLLING AGREEMENTS IN 2020

Line No.	Name	Location	Counterparty	Capacity (MW)	Technology	Heat Rate (MMBtu/MWh)
1	Badger Creek Limited	Bakersfield	Badger Creek Limited	42	Simple Cycle Combustion Turbine (CT)	9.4 – 10.5
2	Bear Mountain Limited	Bakersfield	Bear Mountain Limited	42	Simple Cycle CT	9.4 – 10.5
3	Calpine Peakers	Various	Calpine Energy Services, L.P.	495	Simple Cycle CT	10.5 - 12.8
4	Chalk Cliff Limited	Taft	Chalk Cliff Limited	42	Simple Cycle CT	9.4 – 10.5
5	Double C Limited	Bakersfield	Double C Limited	47	Simple Cycle CT	10.3
6	GWF Energy Hanford	Hanford	GWF Energy LLC	96	Simple Cycle CT	10.1 – 12.9
7	GWF Energy Henrietta	Henrietta	GWF Energy LLC	96	Simple Cycle CT	10.1 – 12.9
8	GWF Tracy	Tracy	GWF Energy LLC	323	Combined Cycle	7.8 – 8.5
9	High Sierra Limited	Bakersfield	High Sierra Limited	47	Simple Cycle CT	10.3
10	Kern Front Limited	Bakersfield	Kern Front Limited	47	Simple Cycle CT	10.3
11	Live Oak Limited	Bakersfield	Live Oak Limited	42	Simple Cycle CT	9.4 – 10.5
12	Los Esteros Critical Energy Facility	San Jose	Los Esteros Critical Energy Facility, LLC	294	Combined Cycle	8.0 – 9.4
13	Mariposa	Byron	Mariposa Energy	194	Simple Cycle CT	9.9 – 11.7
14	Marsh Landing Generating Station	Antioch	NRG Marsh Landing, LLC	801	Simple Cycle CT	10.2 – 12.8
15	McKittrick Limited	McKittrick	McKittrick Limited	42	Simple Cycle CT	9.4 – 10.5
16	O.L.S. Energy-Agnews, Inc.	San Jose	O.L.S. Energy-Agnews	28	Combined Cycle	8.8
17	Oroville Cogen	Oroville	Oroville Cogeneration, L.P.	8	Reciprocating Engine	14.0 – 15.0
18	Panoche Energy Center	Firebaugh	Panoche Energy Center, LLC	399	Simple Cycle CT	9.3 – 13.8
19	Russell City Energy Center	Hayward	Russell City Energy Company, LLC	601	Combined Cycle	7.2 – 8.0
20	Starwood Power Midway	Firebaugh	Starwood Power-Midway, LLC	118	Simple Cycle CT	10.7–12.0

c. PG&E's Gas Supply Transactions Are Fully Compliant With Commission Guidance

PG&E's Bundled Procurement Plan (BPP) establishes upfront achievable standards and criteria for PG&E's procurement activities and the recovery of procurement costs.[3]

With respect to natural gas procurement activities, these standards and criteria include approved products, approved procurement methods, approved procurement limits, and specify when consultation with the Procurement Review Group (PRG) is required.

In 2020, PG&E's gas procurement activities met these standards and criteria. A high-level review of compliance is provided in this section and a detailed demonstration is provided in each of PG&E's 2020 Quarterly Compliance Reports (QCR), which are included in PG&E's workpapers to PG&E's Prepared Testimony. The confidential attachments to the QCRs detail all of PG&E's transactions for physical gas supply, including product type and method of transaction.

1) PG&E Transacted Using Approved Products for Purchase or Sale

All of PG&E's electric portfolio transactions for natural gas in 2020 were for products approved in PG&E's 2014 BPP.[4] These products are found in Table A-3, Sheet 43 of PG&E's 2014 BPP. PG&E utilized the following products in 2020:

- Natural Gas Physical Supply (Spot and Term);
- Gas Storage, including parking and lending; and
- Gas Transportation.

Table 6B-1 in Attachment B details total costs allocated to and volumes burned at each generator in PG&E's portfolio. Attachments to PG&E's 2020 QCRs detail each transaction, including product type.[5]

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[3] 2014 BPP, Sheet 1.

[4] PG&E's 2014 BPP, which was approved in D.15-10-031, is included as part of PG&E's Chapter 6 confidential workpapers.

[5] The 2020 QCRs are included as part of PG&E's confidential workpapers.

2) **PG&E Transacted Using Approved Procurement Processes**

All of PG&E's electric portfolio transactions for natural gas in 2020 used procurement processes and methods approved in PG&E's 2014 BPP. These procurement processes are found in Table B-1, Sheet 56 of PG&E's 2014 BPP. All of the transaction processes PG&E used in 2020 are listed below:

- Bilateral Transactions, short-term (three months or less);
- Transparent Exchanges, including brokers; and
- Electronic Solicitations.

For day-ahead transactions—for gas deliveries the next business day, or next few business days (in the event of a weekend or holiday)—electronic solicitations, bilateral and transparent exchange transactions were the most common procurement process used by PG&E. For longer-term transactions, most were conducted via transparent exchanges and electronic solicitations. The 2014 BPP defines an electronic solicitation as any competitive process where products are requested from the market[6] including e-mail, instant message, auction platforms, telephone survey and may also be informed by market prices on transparent exchanges and from brokers. Attachments to PG&E's 2020 QCRs detail each physical gas transaction, including its procurement method.

3) **PG&E Transacted Within BPP Procurement Limits**

PG&E's compliance with the 2014 BPP Pipeline Capacity Procurement Limits[7] is demonstrated in Table 6B-2 and compliance with the Natural Gas Storage Procurement Limits[8] is demonstrated in Table 6B-3.

4) **PG&E Consulted With Its PRG as Required**

PG&E is required to consult its PRG for transactions with delivery periods greater than three months. For certain transactions, PG&E may preview the plan or strategy prior to

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[6] 2014 BPP, Sheet 51.

[7] 2014 BPP, Appendix C, Section B.2., Sheets 75-76.

[8] 2014 BPP, Appendix C, Section B.3., Sheets 76-77.

execution, and then share the transactions executed at the next quarterly PRG meeting.[9] PG&E made all required consultations with its PRG as follows:

1) December 17, 2019, for the first quarter of 2020 (January 1-March 31, 2020);
2) March 17, 2020, for the second quarter of 2020 (April 1-June 30, 2020);
3) June 30, 2020 for the third quarter of 2020 (July 1-September 30, 2020); and
4) September 15, 2020, for the fourth quarter of 2020 (October 1-December 31, 2020).

In these quarterly consultations, PG&E also shared with the PRG, as required by D.15-10-031, any transactions executed according to the previously shared strategy or plan. A copy of each PRG presentation is included in the confidential attachments to the QCR, which are included as workpapers for PG&E's Prepared Testimony.

d. Compliance With Ruby Pipeline Decision Requirements

In its decision approving the Ruby Pipeline contract, the Commission required that:

> [w]henever PG&E seeks Commission approval to recover Ruby Pipeline costs, PG&E shall certify that it is paying the lowest rate available under the Precedent Agreement. This certification may take the form of (a) a sworn declaration signed by an officer of PG&E or Ruby under penalty of perjury, or (b) any other form deemed acceptable by the Commission.[10]

To comply with this requirement, PG&E is providing as Attachment 6A to this chapter a letter from an officer of Ruby Pipeline confirming that the "Most Favored Nations" provision in the PG&E transportation contract with Ruby was not triggered with any other shipper(s) in 2020, that is, PG&E received the lowest rate available to a firm shipper with a term of one year or longer.

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9 D.15-10-031, OP 1h.

10 D.08-11-032, OP 3.

C. Distillate Expenses

In addition to natural gas, PG&E also purchases distillate as a pilot and backup fuel at Humboldt. Humboldt consists of 10 reciprocating engines, 16.3 MW each, that burn a mix of natural gas as primary fuel and distillate as pilot fuel. During times of limited natural gas delivery to the Humboldt area, the units are able to burn 100 percent distillate. During the record period, PG&E consumed distillate fuel for Humboldt at a total cost of $139,914. The calculation is performed on industry acceptable practice of Last-In First-Out (LIFO) basis. The LIFO method was first approved by the Commission in Advice Letter (AL) 1153-E associated with the Energy Cost Adjustment Clause (precursor to Energy Resource Recovery Account (ERRA)) balancing account.

D. Water Purchased for Power

PG&E makes payments to various entities to obtain water for use in PG&E's hydro generation powerhouses, supplementing what is available from normal inflows. These include water purchases and headwater payments. In addition, PG&E pays water rights fees to the State Water Resources Control Board. PG&E made water-for-power payments totaling $2,435,041 during the record period. Generation benefits are not necessarily coincident within the time period when the payments are made. For example, payment for a water diversion or purchase may occur months after the water was obtained or used.

E. Nuclear Fuel Expenses

The framework for PG&E's 2020 nuclear fuel procurement activity is articulated in the Nuclear Fuel Procurement Plan included in PG&E's 2014 BPP, Appendix F as amended in AL 5202-E. Nuclear fuel expenses are based on the amortization of the costs of the in-core fuel, the actual cycle burn-up rate for the re-load, and DCPP's monthly generation. Each fuel re-load includes: the costs of uranium; conversion services; enrichment services; fabrication; and state and local use taxes, with the total costs dependent on the specific core design. Table 6-3 reflects component coverage targets in PG&E's 2014 BPP.

TABLE 6-3
SUMMARY OF PG&E'S 2014 BPP NUCLEAR FUEL COMPONENT COVERAGE TARGETS

[redacted]

Table 6-4[11] reflects PG&E's strategic inventory coverage targets.

TABLE 6-4
SUMMARY OF PG&E'S NUCLEAR FUEL STRATEGIC INVENTORY COVERAGE TARGETS

[redacted]

For the period of January 1 through December 31, 2020, DCPP's recorded nuclear fuel expenses were [redacted].

During the period January 1 through December 31, 2020, DCPP's Unit 1 completed its 22nd cycle of operation, underwent a 29-day refueling outage, and started its 23rd cycle of operation upon completion of the planned outage. The average annual capacity factor for Unit 1 during 2020 was 91.0 percent. The total Unit 1 nuclear fuel expense for 2020 was [redacted].

During the period January 1 through December 31, 2020, DCPP's Unit 2 operated in its 22nd cycle of operation. The average annual capacity factor for

[11] Strategic Inventory percentage is [redacted].

Unit 2 during 2020 was 74.7 percent. The total Unit 2 nuclear fuel expense for 2020 was [redacted].

Miscellaneous fuel expenses for the record period include costs associated with a new loss-of-coolant analysis which will be required to satisfy changing regulations by the Nuclear Regulatory Commission. Nuclear Fuel Contracts executed during the record period are included in Table 6B-6. The transactions were consistent with the Commission-approved Nuclear Fuel Procurement Plan.

Pursuant to D.05-09-006, PG&E agreed to provide certain information on Fuelco activities and operating costs to the Commission in the annual ERRA compliance review proceeding. D.05-09-006 also directed PG&E to expand its annual report on interactions with Fuelco to include any activities undertaken outside the scope of Fuelco's general purposes to monitor the full impact on ratepayers of PG&E's participation in Fuelco. The required data is provided in Tables 6B-4 and 6B-5. The current composition of Fuelco includes Ameren Missouri and PG&E, with expenses shared on an equal 50 percent basis.

F. Nuclear Fuel Carrying Costs

Nuclear fuel inventory carrying costs are recovered through Portfolio Allocation Balance Account at the short-term interest rate. The nuclear fuel inventory carrying costs for 2020 are [redacted].

G. STARS Alliance

OP 3 of D.12-05-010 directed PG&E to provide a report concerning its activities and operating costs associated with PG&E's participation in the STARS Alliance. The objective of the STARS Alliance is to increase efficiency and to reduce costs related to the operation of the members' nuclear power generation facilities. The other anticipated benefits include more efficiently coordinating the purchase and location of assets necessary to ensure purchasing power and effective responses to potential disruption in operations, and collectively to achieve the safest and most efficient generation of electricity from nuclear units.

PG&E provides as Attachment C-1 the Annual Report of Utility on the Activities of the STARS Alliance for the recorded and budget year 2020 in the format required by the Commission in D.12-05-010, Appendix A.

Attachment C-2 also specifies the Utility Savings/Avoided Costs by STARS Team/Project as required by D.12-05-010. The cost of the STARS Alliance allocated to PG&E was $378,673, with the preliminary savings/avoided costs of $24,199,920 for all four STARS Alliance members. Based on the results for 2020, if not for PG&E's participation in the STARS Alliance, the costs to operate DCPP would have been higher. Treatment of cost recovery and avoided cost aspects of PG&E's participation in the STARS Alliance is subject to review in PG&E's General Rate Case proceeding.

H. Electric Portfolio Hedging

1. Background

PG&E's 2014 BPP Hedging Plan was approved on October 22, 2015. PG&E continued implementing this plan during 2020. PG&E demonstrates compliance with its Hedging Plan in this section.

2. All Transactions Complied With Approved Products and Approved Transaction Processes

During 2020, all PG&E financial transactions used only approved products (2014 BPP, Appendix A, Table A-1 for electric products and Table A-4 for gas products), and approved procurement processes (2014 BPP, Appendix B, Table B-1). Each transaction and its approved product type and transaction process is included in PG&E's QCR filings, and also summarized in Tables 6B-7 through 6B-10.

3. PG&E Consulted With the PRG as Required

PG&E consulted its PRG prior to executing hedging transactions beyond three months in duration. PG&E reviewed with the PRG its planned and exceptional execution of hedges on:

1) November, 2019, for hedging activities in the through first quarter of 2020 (December 1, 2020-March 31, 2020);
2) March 17, 2020, for hedging activities in the second quarter of 2020 (April 1-June 30, 2020);
3) June 30, 2020, for hedging activities in the third quarter of 2020 (July 1-September 30, 2020); and
4) October 20, 2020, for hedging activities in the fourth quarter of 2020 (October 1-December 31, 2020).

In each of these quarterly consultations, PG&E also shared with the PRG, as required by D.15-10-031, any transactions executed according to the previously shared strategy or plan. A copy of each PRG presentation is included in the confidential attachments to the QCR, which are included as workpapers for PG&E's Prepared Testimony.

4. Transaction Compliance Reports

Transaction Compliance Reports, which are included in Attachment L of each QCR, demonstrate that each financial transaction complies with each of the applicable provisions of the Hedging Plan, and also with the 2014 BPP procurement limits. The Hedging Plan includes seven provisions that can apply to each transaction, depending on the type of product transacted. The compliance reports demonstrate how the transaction complied with each of these provisions.

5. PG&E Managed Its Hedging Position in Compliance With Its Hedging Plan

As detailed in Section C.2. of the Hedging Plan,[12] PG&E's compliance with the Plan, as measured against the Hedging Targets, is judged at the end of [redacted][13] [redacted]

[redacted][14]

PG&E filed AL 5704-E to explain how PG&E will temporarily manage its position consistent with the Hedge Plan. AL 5704-E was approved by the Energy Division and effective December 9, 2019.

Table 6B-11 shows PG&E's electric portfolio financial position [redacted], and demonstrates that PG&E's hedging positions, as measured against the Hedging Targets, complied with the Hedging Plan and

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[12] PG&E's Hedging Plan is Appendix E of the 2014 BPP.

[13] PG&E's 2014 BPP Hedging Plan, Section C.2., Hedging Targets.

[14] *Id.*

AL 5704-E. The footnote with Table 6B-11 describes the actions PG&E took, by delivery period, to comply with its Hedge Plan. [redacted]

6. PG&E Transacted Within BPP Procurement Limits

PG&E's 2014 BPP includes limits on electric energy and natural gas procurement.[16] These limits apply to all fixed-price energy and gas contracts beyond prompt month. Figures 6B-1 and 6B-2 demonstrate PG&E compliance with these limits at the end of 2020. The compliance reports included in each QCR demonstrate compliance for every transaction.

I. Internal Procedures and Controls

Consistent with D.11-07-039, OP 3, PG&E provides the following high-level discussion of its internal procedures and controls for ensuring compliance with its Hedging Plan. PG&E employs the following system of internal procedures and controls to ensure compliance:

1) Segregation of Duties;
2) Risk Management Policies;
3) Prescriptive Hedging Strategies; and
4) Controls Framework.

1. Segregation of Duties

PG&E separates the duties of executing, monitoring and tracking, and settling hedging transactions among its Front Office, Middle Office and Back Office. The Middle Office reports to the Chief Risk Officer, while the

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15 In 2020, [redacted] on a Saturday.

16 2014 BPP, Appendix C, Sections A.2. and B.1., Sheets 68-75.

Front Office and Back Office report to the Senior Vice President, Energy Policy and Procurement.

The Front Office is responsible for negotiating and executing transactions that comply with the Hedging Plan and internal controls; and ensuring the terms of the transaction are captured in PG&E's trade capture system.

The Middle Office reviews each transaction for completeness and accuracy and also establishes and manages several of the trading controls in the Controls Framework. The Middle Office also reports the status of hedging programs and portfolio risk measures to PG&E senior management.

The Back Office confirms non-cleared transactions with counterparties and settles transactions after delivery or expiration. The Back Office is also responsible for managing existing contracts.

2. Risk Management Policies

PG&E maintains Risk Management Policies and Standards that provide guidelines to the PG&E Front, Middle and Back Offices on management and control of risks associated with fluctuations in electricity and gas prices and counterparty credit exposure. PG&E's Corporation Risk Policy Committee and Utility Risk Management Committee are delegated, from the Board of Directors, the responsibility for ensuring that PG&E management adheres to the Risk Policies and Standards. PG&E's Middle Office monitors compliance with these policies and standards and regularly measures and reports market and portfolio risk to the committees.

3. Prescriptive Hedging Plan

PG&E's Hedging Plan is prescriptive, that is, it specifies which positions are to be hedged, which products are to be used, and the timeline for execution. The Hedging Plan is periodically updated and changes are implemented after final CPUC approval is received, and after internal processes are modified to ensure that the updated Hedging Plan can be monitored for consistency with the CPUC-approved plan and internal governance requirements.

4. Controls Framework

The Controls Framework is centered on assuring data quality and completeness, guiding trading activities with an electronic model, and monitoring trader activity relative to authorized plans and counterparty credit limits. Controls are separated into six categories:

1) Electronic Model – PG&E uses an electronic model to guide its financial traders in implementing the Hedging Plan. The model includes the long- and short positions in PG&E's portfolio and applies each of the provisions of the Hedging Plan to these positions to determine for the current trading month which products should be traded and the quantity of each product. The model is refreshed overnight after each trading day to ensure the portfolio positions are current. The model is developed by the Middle Office in consultation with the Front Office and is validated for accuracy by a separate, independent team of qualified analysts also in the Middle Office.
2) Trade Limits – PG&E sets limits on its Front Office trading activities to help ensure that its traders comply with its approved Hedging Plan. PG&E breaks down the annual Hedging Plan trading limits approved by its risk committees into monthly limits for monitoring trading activities.
3) Trade Preview – Prior to execution, PG&E traders preview all trades in an electronic blotter system that tests each trade against their monthly trade limits and counterparty credit limits. PG&E traders are not allowed to execute trades that are not pre-approved by this system.
4) Trade Capture – PG&E traders are required to enter all completed transactions into a trade capture system on the day the transaction is executed. PG&E's Middle Office reviews all trades to ensure that they are captured accurately in the trade capture system.
5) Transaction Monitoring – PG&E's risk management system provides reports that monitor compliance with the risk management policies and trading limits. In addition, the system tracks counterparty-credit exposure.
6) Compliance Reports – PG&E developed an automated compliance report that demonstrates compliance of its electric and gas financial hedge trades. The report demonstrates that all the trades executed on

a specified trading day comply with each provision of PG&E's Hedging Plan.

J. Conclusion

The preceding discussion demonstrates that PG&E procured fuel for its utility-owned generation facilities and tolling agreements, acquired water for hydroelectric generation, and procured nuclear fuel for DCPP consistent with the 2014 BPP and Commission decisions addressing procurement. In addition, the preceding discussion demonstrates that PG&E's electric portfolio hedging activities complied with its Hedging Plan and the 2014 BPP.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT A

LETTER FROM RUBY PIPELINE OFFICER CERTIFYING PG&E'S "MOST FAVORED NATIONS" (LOWEST RATE) STATUS

RUBY PIPELINE LLC

January 27, 2021

VIA ELECTRONIC MAIL – JPU1@pge.com

Mr. John Ulloa
PACIFIC GAS AND ELECTRIC COMPANY
Mail Code B25F
P.O. Box 770000
San Francisco, CA 94177-0001

Re: Firm Transportation Service Agreements on Ruby Pipeline

Dear Mr. Ulloa:

In response to your request, Ruby Pipeline, L.L.C. herby certifies that during the calendar year 2020, the "Most Favored Nations" rate protection provision in the Firm Transportation Service Agreements of Pacific Gas and Electric Company (FTSA Nos. 61009000 and 61014000) have not been triggered by an agreement with any other shipper(s) on the Ruby Pipeline.

Sincerely,

Will W. Brown

Will W. Brown
Vice President, Ruby Pipeline

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT B

GENERATION FUEL COSTS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
ATTACHMENT B
GENERATION FUEL COSTS

TABLE 6B-1
SUMMARY OF 2020 PG&E GAS DELIVERIES BY FACILITY OR TOLLING AGREEMENT

Line No.	Generating Facility	Volume[a] (Millions British Thermal Units (MMBtu))	Total Cost[b] ($ Millions)
1	Oroville Cogeneration	[redacted]	[redacted]
2	OLS Energy Agnews	[redacted]	[redacted]
3	Pacific Gas and Electric Company (PG&E) – Gateway	[redacted]	[redacted]
4	PG&E – Humboldt	[redacted]	[redacted]
5	PG&E Colusa – Maxwell	[redacted]	[redacted]
6	Calpine Creed Energy Center	[redacted]	[redacted]
7	Calpine Goose Haven Energy Center	[redacted]	[redacted]
8	Calpine Gilroy Energy Center at Lambie	[redacted]	[redacted]
9	Calpine Gilroy Energy Center	[redacted]	[redacted]
10	Calpine Los Esteros	[redacted]	[redacted]
11	GWF Tracy	[redacted]	[redacted]
12	Panoche Energy Center	[redacted]	[redacted]
13	Starwood Power-Midway	[redacted]	[redacted]
14	PG&E Power Generation – Hayward	[redacted]	[redacted]
15	PG&E Power Generation – San Francisco	[redacted]	[redacted]
16	Mariposa Energy	[redacted]	[redacted]
17	GenOn Marsh Landing	[redacted]	[redacted]
18	Calpine Russell City	[redacted]	[redacted]
19	GWF Energy Hanford	[redacted]	[redacted]
20	GWF Energy Henrietta	[redacted]	[redacted]
21	Double C Limited	[redacted]	[redacted]
22	High Sierra Limited	[redacted]	[redacted]
23	Kern Front Limited	[redacted]	[redacted]
24	Badger Creek	[redacted]	[redacted]
25	Bear Mountain	[redacted]	[redacted]
26	Chalk Cliff	[redacted]	[redacted]
27	Live-Oak	[redacted]	[redacted]
28	McKittrick	[redacted]	[redacted]
29	Total	[redacted]	[redacted]
30	Total Unit Cost ($/MMBtu)	[redacted]	[redacted]

(a) Some values for volume appear as zero due to rounding.

(b) Total costs include gas commodity, storage and transport related costs included in Portfolio Allocation Balancing Account and New System Generation Balancing Account.

TABLE 6B-2
2020 DEMONSTRATION OF COMPLIANCE WITH
2014 BUNDLED PROCUREMENT PLAN (BPP) PIPELINE CAPACITY PROCUREMENT LIMITS[(a)]

Line No.	Year	Actual Capacity (MMBtu/day)	Limits[(b)] (MMBtu/day)
1	2020	[redacted]	
2	2021		
3	2022		
4	2023		
5	2024		

(a) PG&E's actual pipeline capacity holdings were all less than the 2014 BPP limits therefore PG&E was compliant with the Pipeline Capacity Procurement Limits in 2020.
(b) 2014 BPP, Appendix C, Table C-10, Sheet 76.

TABLE 6B-3
2020 DEMONSTRATION OF COMPLIANCE WITH
2014 BPP STORAGE CAPACITY PROCUREMENT LIMITS[(a)]

Line No.	Year	Actual Withdrawal Capacity (MMBtu/day)	Withdrawal Capacity Limit[(b)] (MMBtu/day)	Actual Injection Capacity (MMBtu/day)	Injection Capacity Limit[(b)] (MMBtu/day)	Actual Inventory (million MMBtu)	Inventory Limit[(b)] (million MMBtu)
1	2020	[redacted]					
2	2021						
3	2022						
4	2023						
5	2024						

(a) PG&E's actual Withdrawal, Injection, and Inventory capacity holdings were all less than the 2014 BPP limits therefore PG&E was compliant with the Storage Capacity Procurement Limits in 2020.
(b) 2014 BPP, Appendix C, Table C-12, Sheet 77.
(c) [redacted]
(d) [redacted]

TABLE 6B-4
ANNUAL REPORT OF PACIFIC ENERGY FUELS COMPANY (PEFCO)
ON THE ACTIVITIES OF FUELCO, LLC
ADMINISTRATIVE COSTS ASSOCIATED WITH THE PROCUREMENT
OF NUCLEAR FUEL AND FUEL-RELATED PRODUCTS OR SERVICES

Line No.	Description	Recorded Year 2020	Budget Year 2020
1	Total Common Costs[a]		
2	Out of Pocket ($)	[redacted]	
3	Labor ($)		
4	Total Fuelco ($)		
5	PG&E/PEFCO Share (%)		
6	PG&E/PEFCO Share ($)		
7	Special Project Costs[b] ($)		
8	Out of Pocket[b] ($)		
9	Labor ($)		
10	Total Fuelco ($)		
11	PG&E (%)[c]		
12	PG&E ($)[c]		
13	Total PG&E Share ($)		

(a) Currently expensed on Fuelco books.
(b) 2021 subscriptions capitalized as deferred charges on Fuelco books.
(c) Reflects composite participation in one or more projects.

TABLE 6B-5
NUCLEAR FUEL AND
FUEL-RELATED PRODUCTS OR SERVICES
PROCURED BY PG&E/PEFCO THROUGH FUELCO (RECORD YEAR 2020)
(TOTAL COST – MILLIONS OF DOLLARS)

Line No.	Contract	Delivery Date	Product	Unit Price ($)	Total Cost	Contract Duration	Fuelco Title (Y/N)	Market Unit Price ($) At Contract(a),(c)	Current Market Unit Price ($)(b)
1	[redacted]								
2									
3									
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									

(a) The historic month-end spot prices for the contract execution date as reported in the 2020 year-end publications for Trade Tech LLC, Nuclear Review, Ux Consulting, Quarterly Market Report – Conversion Market Outlook, Ux Consulting, Quarterly Market Report – Uranium Market Outlook, or Ux Consulting, Quarterly Market Report – Enrichment Market Outlook. Not applicable to fabrication, brokerage, location swap or regulatory fees.

(b) A simple arithmetic average of the spot prices reported in the year-end publications of Trade Tech LLC, Nuclear Market Review dated December 31, 2020, and Ux Consulting, Ux Weekly dated December 28, 2020. Not applicable to fabrication, brokerage, location swap or regulatory fees.

(c) EUP market prices determined for the same SWU, enrichment and tails as the 2020 delivery using UxC historical pricing.

TABLE 6B-6
NUCLEAR FUEL CONTRACTS EXECUTED IN 2020
(WITH DELIVERIES BEYOND 2020)
(MILLIONS OF DOLLARS)

Line No.	Contract No.	Execution Date	Term of Services	Services	Amount
1	[redacted]				

(a) [redacted]

TABLE 6B-7
SUMMARY OF PG&E ELECTRIC PORTFOLIO
GAS FINANCIALTRANSACTIONS
LISTED BY 2014 BPP APPROVED PRODUCT

Line No.	Product	2014 BPP Table A-4 Line Number	Volume (MMBtu)	Notional Value ($ Millions)	Number of Trades
1	Natural Gas Futures	2	[redacted]		
2	Natural Gas Futures (Basis)	2			
3	Natural Gas Futures (Swing & Index)	2			
4	Financial Options (Calls) and Swaptions	3			
5	Total Transacted				

TABLE 6B-8
SUMMARY OF PG&E ELECTRIC PORTFOLIO
GAS FINANCIAL TRANSACTIONS
LISTED BY 2014 BPP APPROVED TRANSACTION PROCESS

Line No.	Product	2014 BPP Table B-1 Item Number	Volume (MMBtu)	Notional Value ($ Millions)	Number of Trades
1	Transparent Exchanges (Electronic Trading)	6	[redacted]		
2	Transparent Exchanges (Voice Brokers)	6			
3	Electronic Solicitations (IM or Voice)	10			
4	Total Transacted				

TABLE 6B-9
SUMMARY OF PG&E ELECTRIC PORTFOLIO
ELECTRICITY FINANCIAL TRANSACTIONS
LISTED BY 2014 BPP APPROVED PRODUCT

Line No.	Product	2014 BPP Table A-1 Line Number	Volume (GWh)	Notional Value ($ Millions)	Number of Trades
1	Electricity Futures	13	[redacted]		
2	Electricity Options	7			
3	Total Transacted				

TABLE 6B-10
SUMMARY OF PG&E ELECTRIC PORTFOLIO
ELECTRICITY FINANCIAL TRANSACTIONS
LISTED BY 2014 BPP APPROVED TRANSACTION PROCESS

Line No.	Product	2014 BPP Table B-1 Item Number	Volume (GWh)	Notional Value ($ Millions)	Number of Trades
1	Transparent Exchanges (Electronic Trading Exchange)	6	[redacted]		
2	Transparent Exchanges (Voice and On-Line Brokers)	6			
3	Electronic Solicitations	10			
4	Total Transacted				

TABLE 6B-11
COMPLIANCE WITH 2014 BPP HEDGING TARGETS
(MILLIONS OF DOLLARS)

Line No.	Position
	[redacted]
1	
2	
3	
4	
5	

Notes: Table 6B-11 provides PG&E's electric portfolio position at the end of the Plan Year, on [redacted]

FIGURE 6B-1
DEMONSTRATION OF COMPLIANCE
WITH 2014 BPP ELECTRICAL ENERGY PROCUREMENT LIMITS

[redacted]

Note: [redacted]

FIGURE 6B-2
DEMONSTRATION OF COMPLIANCE
WITH 2014 BPP NATURAL GAS PROCUREMENT LIMITS

[redacted]

Note: [redacted]

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

ATTACHMENT C

ANNUAL REPORT OF UTILITY ON THE ACTIVITIES OF STARS ALLIANCE, LLC; UTILITY SAVINGS/AVOIDED COSTS BY STARS TEAM/PROJECT; AND INDEPENDENT AUDITOR'S REPORT AND FINANCIAL STATEMENTS

ATTACHMENT C

ANNUAL REPORT OF UTILITY ON THE ACTIVITIES OF STARS ALLIANCE, LLC
RECORDED YEAR 2020 AND BUDGET YEAR 2020

(All Data in Whole Numbers)

	Recorded Year 2020		**Budget Year 2020**	
Total Common Costs (1)				
Labor, Benefits, & Bonus	$	378,673	$	400,000
Travel Expenses	$	70,452	$	535,000
Non-travel Meals	$	16,866	$	40,000
Sub-Total Labor, Benefits & Bonus	$	465,991	$	975,000
Contractor Support	$	292,239	$	354,000
Legal	$	134,962	$	95,000
Office Supplies & Expenses	$	149,157	$	146,000
Building Lease/Utilities	$	265,403	$	260,000
Communications	$	28,480	$	34,000
Insurance	$	6,850	$	15,000
Infrastructure	$	87,610	$	93,000
Office Furniture & Equipment	$	15,347	$	20,000
Computer Equipment	$	42,313	$	50,000
Total STARS Alliance	**$**	**1,488,352**	**$**	**2,042,000**
Utility Share (%)		25%		25%
Utility Share ($)	**$**	**372,088**	**$**	**510,500**
Total Utility Share	**$**	**372,088**	**$**	**510,500**

(1) Currently expensed on STARS Alliance books.

UTILITY SAVINGS / AVOIDED COSTS BY STARS TEAM / PROJECT

(All Data in Whole Numbers)

	STARS Total	
Supply Chain (STARS Contracts) (preliminary)	$	18,338,186
Rebates (preliminary)	$	5,861,734
Total Savings / Avoided Costs (preliminary)	**$**	**24,199,920**

- Teams / Projects may change annually based upon the needs of the Utility and STARS Alliance

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

GREENHOUSE GAS COMPLIANCE

INSTRUMENT PROCUREMENT

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GREENHOUSE GAS COMPLIANCE
INSTRUMENT PROCUREMENT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
GREENHOUSE GAS COMPLIANCE
INSTRUMENT PROCUREMENT

A. Introduction

The California Air Resources Board (CARB) Cap-and-Trade regulation established requirements for emissions reporting and compliance demonstrations by covered entities. As a covered entity and to fulfill certain contractual requirements, Pacific Gas and Electric Company (PG&E) needs to procure greenhouse gas (GHG) compliance instruments to satisfy its compliance obligation.

This chapter describes the GHG compliance instrument procurement activities undertaken by PG&E, pursuant to its 2014 Bundled Procurement Plan (BPP) during the January 1 through December 31, 2020 record period.[1] PG&E's 2014 BPP addresses the means, strategies, and limits applicable to PG&E's GHG compliance instrument procurement.

This testimony and supporting workpapers demonstrate that PG&E's 2020 GHG compliance instrument procurement activities complied with the requirements established in the 2014 BPP. This testimony also describes PG&E's bundled electric GHG procurement regulatory framework to illustrate those requirements impacting PG&E's management of its GHG procurement plan. Specifically:

- Section B describes the regulatory authority impacting PG&E's GHG procurement, including: (1) an overview of the CARB Cap-and-Trade Program to regulate GHG emissions; (2) a description of CARB requirements to calculate GHG emissions for covered entities in the electric generation sector; and (3) a summary of the regulatory authority the

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1 The 2014 BPP was approved by the Commission in Decision (D.) 15-10-031. PG&E has since filed updates to its 2014 BPP Appendix G. Advice Letter (AL) 5469-E filed on January 16, 2019, [redacted]. AL 5473-E filed on January 25, 2019 and approved in Resolution (Res.) E-4998, modified Appendix G so that [redacted]. Pursuant to the requirements of Res.E-4998, PG&E filed its Conformed 2014 BPP Appendix G in AL 5579-E on July 1, 2019. Additionally, PG&E updates its BPP GHG procurement limits annually.

California Public Utilities Commission (Commission) provides to PG&E to procure GHG compliance instruments on behalf of its bundled electric portfolio.

- Section C describes the resources that comprised PG&E's direct physical obligation to procure compliance instruments during the record period, including Utility-Owned Generation (UOG), imported electricity, and any PG&E contracts with physical settlement of GHG compliance instruments. This section also describes the means by which PG&E procured GHG compliance instruments, including a showing of PG&E's GHG procurement activities during the record period related to PG&E's direct physical obligation, including analysis on financial versus physical settlement of tolling agreements, as established in the *Settlement Agreement Between Pacific Gas and Electric Company (U 39 E) and The Public Advocates Office at the Public Utilities Commission* (2017 ERRA Compliance Settlement Agreement) approved in D.19-02-005.
- Section D shows that PG&E complied with the requirements set forth in the 2014 BPP to procure GHG compliance instruments, including limits on GHG compliance instrument procurement.

Together, this testimony and the supporting workpapers demonstrate that PG&E's 2020 GHG compliance instrument procurement activities complied with its 2014 BPP.[2]

B. Background Information

This section describes CARB and Commission requirements relevant to PG&E's GHG compliance instrument procurement for the bundled electric portfolio. This section also establishes that GHG procurement activities are reviewed for compliance with the 2014 BPP in this proceeding.

1. Assembly Bill (AB) 32 Cap-and-Trade Program

AB 32 is California's landmark GHG legislation that requires the reduction of statewide GHG emissions to 1990 levels by 2020. To this end, the CARB promulgated a statewide Cap-and-Trade regulation that established a market-based price for GHG emissions. AB 398 extended the Cap-and-Trade Program through 2030 in order to reach the statewide goal

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2 See 2014 BPP, Appendices C and G.

set in Executive Order B-30-15 and Senate Bill 32 of reducing GHG emissions to at least 40 percent below 1990 levels by 2030.

For the electric generation sector, covered entities include operators of any facility that annually emits at least 25,000 metric tons of carbon dioxide equivalents ($mtCO_{2e}$).[3] Covered entities are required to obtain and surrender compliance instruments equivalent to the GHG emissions for each such facility. Importers of electricity into California are also responsible for obtaining and surrendering compliance instruments for GHG emissions deemed to be associated with electricity imports for purposes of compliance with Cap-and-Trade.

There are two types of compliance instruments: (1) allowances, which are limited tradable authorizations created by CARB to emit up to 1 $mtCO_{2e}$; and (2) offset credits, which are tradable compliance instruments issued by CARB that represent verified reductions of 1 $mtCO_{2e}$ from projects whose emissions or avoided emissions are not from a source covered under the Cap-and-Trade Program. For compliance purposes, an offset credit and an allowance have limited differences. Allowances have a unique vintage year and each vintage may be used in the vintage year issued or in future years, but future vintage allowances may not be used to satisfy any compliance obligations prior to the vintage year. For example, 2019 vintage allowances can be used to fulfill 2019 or 2020 obligations, but not 2016 obligations. Unlike an allowance, an offset credit is not limited by vintage and can be utilized for any surrender year. However, an entity can only use offset credits to meet up to 8 percent of its compliance obligation under the Cap-and-Trade regulation through 2020. In addition, CARB's Cap-and-Trade regulation allows CARB to invalidate an offset credit for errors, regulatory violations, or fraud.[4]

2. Electric Sector GHG Emissions

For the electric generation sector, CARB requires specific methodologies to calculate emissions from electricity generating facilities

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3 Units of GHG are typically measured in terms of $mtCO_{2e}$.

4 In event of invalidation, CARB requires the party holding the offset to replace within six months of notification.

located in the state of California (in-state facilities) and a separate methodology is required to calculate emissions for electricity imported into the state of California (imported electricity). For in-state electric generation facilities, carbon dioxide equivalent (CO_{2e}) compliance obligations are calculated based upon the combustion of fossil fuel used, and not the electrical energy produced. PG&E's UOG facilities and all facilities associated with its tolling contracts are entirely located in the state of California. For imported electricity, CO_2e emissions are calculated based on the electrical energy imported. The compliance obligation associated with imported electricity emissions may be further reduced through adjustments for certain renewables procurement and qualified exports.

3. PG&E's GHG Compliance Instrument Procurement Authority

On April 19, 2012, the Commission issued D.12-04-046, authorizing PG&E to procure GHG compliance instruments and requiring PG&E to update its 2010 BPP to incorporate the modifications made in that decision, including annual procurement limits. Following that decision, PG&E amended its 2010 BPP to include a GHG Procurement Plan approved by the Commission in late 2012.[5] PG&E's GHG Procurement Plan was subsequently modified in 2014 to reflect changes in regulatory and market conditions.[6] In October 2015, the Commission issued D.15-10-031, approving PG&E's 2014 BPP, which included an amended GHG Procurement Plan and GHG Procurement Limits.

In January 2019, PG&E filed AL 5469-E, which [redacted] due to impaired credit ratings and ability to transact. PG&E followed up this filing with AL 5473-E, which included comprehensive modifications to the GHG Procurement Plan in its 2014 BPP Appendix G, and which the Commission approved via Res.E-4998. In July 2019, following the Commission's resolution, PG&E filed its Conformed 2014 BPP

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5 In October 2012, the Commission issued Res.E-4544, approving PG&E's 2010 BPP, authorizing PG&E to procure allowances and offsets.

6 In December 2013, PG&E filed AL 4331-E concerning updates to its GHG Plan to reflect updated market and regulatory conditions. Res.E-4660 approved certain changes requested by AL 4331-E, and PG&E filed AL 4499-E to comply with the resolution. AL 4499-E was approved on October 15, 2014.

Appendix G via AL 5579-E and [redacted] under the modified GHG Procurement Plan.

PG&E's 2014 BPP addresses the GHG-related procurement authority necessary for PG&E to comply with the obligations associated with the Cap-and-Trade Program. As a covered entity and to fulfill certain contractual requirements, PG&E needs to procure GHG compliance instruments to satisfy its compliance obligation. PG&E's 2014 BPP further addresses the means, strategies, and limits applicable to PG&E's GHG compliance instrument procurement, including annual GHG Procurement Limits.

C. PG&E's GHG Procurement Activity During the Record Period

Section C details the resources in PG&E's bundled electric portfolio that require PG&E to engage in the GHG compliance instrument procurement activities reviewed in this proceeding. This section also details PG&E's procurement activity and internal analyses required by the 2017 ERRA Compliance Settlement Agreement and describes the actions PG&E took to comply with its 2014 BPP during that procurement.

1. Facilities Comprising PG&E's Direct GHG Costs

To comply with the Cap-and-Trade program, PG&E must procure compliance instruments for GHG emissions obligations associated with qualifying UOG, import electricity, and contracted tolling facilities.

During the record period, PG&E only needed to procure compliance instruments for anticipated GHG obligations related to three of its UOG electric generation facilities: (1) Colusa Generating Station; (2) Gateway Generation Station; and (3) Humboldt Bay Generation Station. For emissions obligations associated with import energy, please see explanation in Section B above.

PG&E's tolling contracts allow PG&E to compensate tolling counterparties for their emissions obligations either through the physical transfer of compliance instruments or through financial settlement. During the record period, PG&E [redacted]

[redacted], pursuant to the Conformed 2014 BPP Appendix G. PG&E's Conformed 2014 BPP Appendix G establishes that PG&E will [redacted][7]

Even though the decision [redacted] is established in the 2014 BPP, PG&E continues to perform an analysis of GHG portfolio costs to compare financial settlement versus physical settlement for its tolling contracts at least twice a year. As required by the 2017 ERRA Compliance Settlement Agreement, which was approved by the Commission in D.19-02-005, this analysis for the record year is provided in the Confidential Workpapers to this chapter.

PG&E also presents its Bundled Electric GHG Position to the Procurement Review Group (PRG) each quarter, which includes the forecasted GHG Position, including PG&E's intention to continue [redacted] of GHG obligations.

2. PG&E's GHG Procurement Activity

Emissions allowances are issued by CARB, and CARB sells allowances through quarterly auctions. CARB also issues offset credits pursuant to specific protocols set forth in the Cap-and-Trade Regulation. In addition, compliance instruments are available for purchase bilaterally, or through the market. [redacted]

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[7] See AL 5579-E filed on and made effective July 1, 2019.

TABLE 7-1
TRANSACTIONS EXECUTED DURING RECORD PERIOD

[redacted]

TABLE 7-2
PG&E'S PROCURED GHG COMPLIANCE INSTRUMENTS IN THE 2020 RECORD PERIOD

Line No.	Procured GHG Compliance Instruments	Quantity ($MTCO_{2e}$)	Cost ($)	Average Cost per Compliance Instrument (Calculated)
1	Allowances Procured from CARB Auctions	[redacted]		
2	Offsets Procured from Third Parties			
3	Instruments with Future Vintages procured in the Record Period (Do not qualify for the current Cap-and-Trade compliance year of 2020)			
4	Total Instruments Procured that qualify for the current Cap-and-Trade compliance year of 2020			
5	Total Instruments Procured in 2020			

3. PG&E's GHG CARB Auction Procurement Activity

CARB holds quarterly auctions of current vintage and future vintage allowances. The current vintage auction may include allowances of any vintage that can be used in the current year. During the record period, CARB made available current vintage allowances (i.e., 2020 vintage and unsold earlier vintage allowances) and future vintage (i.e., 2023) allowances. Each quarterly auction has a published settlement price. Annually, CARB sets a floor price for its auctions. In 2020, the floor price was $16.68 per allowance.[8]

[redacted][9] [redacted]

8 https://ww3.arb.ca.gov/cc/capandtrade/auction/auction.htm.

9 [redacted]

[redacted]

4. PG&E's GHG Market Transactions Procurement Activity

[redacted]

5. Other Matters

In addition to the matters described above, this section describes other GHG procurement activity matters that occurred during the record period.

a. BP Products

[redacted]

D. PG&E Complied with the GHG Procurement Plan

This Section D demonstrates that PG&E's procurement complied with its 2014 BPP. This section also demonstrates that PG&E's GHG procurement activities complied with the limits established in the 2014 BPP.

1. 2014 BPP GHG Procurement Strategy

PG&E's 2014 BPP includes PG&E's GHG procurement strategy.[10] The strategy defines how PG&E will participate in the GHG market to procure necessary compliance instruments to comply with the Cap-and-Trade Program and meet any physical contractual obligations.

[redacted]

2. Procurement Limits for GHG Products

The 2014 BPP includes GHG Purchase Limits.[11] The GHG Purchase Limit establishes the maximum amount of GHG products PG&E may purchase in the current year to fulfill its "direct compliance obligation," defined as the tons of emissions for which PG&E has an obligation to retire allowances in the current year on its own behalf as a regulated entity under CARB's Cap-and-Trade Program, and/or is otherwise obligated to procure for a third party. A "purchase" is defined as taking title of the GHG product (i.e., allowance or offset) when it is delivered. Thus, forward purchases count against the procurement limit when the product is delivered, which may not be the same year the transaction is executed.

Table 7-3 demonstrates that PG&E transacted within its 2020 GHG Purchase Limit established by its 2014 BPP. PG&E's GHG Purchase Limit

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10 See Conformed 2014 BPP Appendix G, Section D, Sheets 132-138.

11 See 2014 BPP, Appendix C, Section C, Sheets 77-81 (regarding GHG procurement limits).

is calculated as set forth in D.12-04-046 and in the 2014 BPP.[12] PG&E's [redacted].

TABLE 7-3
2020 GHG PRODUCTS PURCHASED BY PG&E COMPARED TO GHG LIMIT
MILLION $MTCO_{2E}$

[redacted]

The quarterly PRG presentations concerning GHG compliance instrument procurement and attachments included in each Quarterly Compliance Report (QCR) also demonstrate that PG&E complied with its GHG Purchase Limit.[13] These documents are included as confidential workpapers to support PG&E's Prepared Testimony in this proceeding.

E. Conclusion

This chapter, as well as information included in PG&E's workpapers to this chapter, demonstrates that during the 2020 record period, PG&E's procurement of GHG compliance instruments complied with the requirements the 2014 BPP because PG&E utilized the means, strategies and limits described therein.

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[12] 2014 BPP, Sheets 79-81.

[13] See Fourth Quarter 2020 Bundled Electric GHG Position Update, p. 8, included with Fourth Quarter QCR GHG Workpapers.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

RESOURCE ADEQUACY

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RESOURCE ADEQUACY

A. Introduction and Bundled Procurement Plan Background

Pacific Gas and Electric Company's (PG&E) Bundled Procurement Plan (BPP) contains several provisions for how PG&E is required to conduct its procurement and sales of Resource Adequacy (RA) products in order to meet the reliability compliance requirements established in Public Utilities Code Section 380 and implemented by the California Public Utilities Commission (CPUC or Commission) (RA Program) and respective California Independent System Operator (CAISO) Tariff provisions.

This chapter describes the RA procurement and sale efforts (RA Activities) undertaken by PG&E, pursuant to its Conformed 2014 BPP and the Commission directives during the January 1 through December 31, 2020 record period. PG&E's RA Activities were impacted by changes during the record period in the CPUC RA Program. Accordingly, PG&E updated PG&E's sales framework[1] in its Conformed 2014 BPP over the course of calendar year 2020.[2]

- Section B provides background information on RA requirements including: (1) existing CPUC RA requirements at the time of the last Energy Resource Recovery Account (ERRA) compliance proceeding; (2) new CPUC RA requirements as of the filing of this testimony; and (3) CAISO Reliability Requirements.
- Section C describes PG&E's RA Activities during the record period, including: (1) RA position; (2) RA purchases; (3) RA sales; (4) RA contract management; and (5) Tree Mortality Procurement Program.
- Section D demonstrates the reasonableness of one RA transaction and requests Commission approval.
- Section E documents how PG&E complied with the Portfolio Allocation Balancing Account (PABA) revenue and cost recording required in the

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1 Pursuant to the requirements of Resolution (Res.) E-4998, PG&E filed its Appendix S in Advice Letter (AL)-5579 on July 1, 2019.

2 PG&E filed updates to Appendix S in 2020 via ALs 5807-E, 5884-E, 5905-E, and 5968-E.

Power Charge Indifference Adjustment (PCIA) Phase 1 Decision ((D.) 18-10-019).

Together, this testimony and the supporting workpapers demonstrate PG&E's 2020 RA Activities complied with its Conformed 2014 BPP.[3]

B. Background Information

1. Existing RA Requirements

The CPUC's RA Program, adopted in 2004, was developed in response to the 2000-2001 California energy crisis. The program is designed to ensure reliable electric service in California by requiring all CPUC jurisdictional Load Serving Entities (LSE) to have enough capacity to meet the CPUC RA Program requirements. The CPUC's RA Program contains three distinct requirements: System RA requirements, Local RA requirements, and Flexible RA requirements. System RA requirements are determined based on each LSE's California Energy Commission (CEC) adjusted forecast plus a 15 percent planning reserve margin. Local RA requirements are determined based on an annual CAISO study using a 1-10 weather year and an N-1-1 contingency. Flexible RA requirements are based on an annual CAISO study that currently looks at the largest three-hour ramp for each month needed to run the system reliably. There are two types of filings used to comply with the CPUC's RA Program; annual filings (filed annually on October 31[4] for the coming year) and monthly filings (filed 45 days prior to the compliance month). The CPUC sets the annual and monthly System, Local, and Flexible RA requirements for CPUC-jurisdictional LSEs based on inputs from the CEC and CAISO.

The CPUC RA Program annual filing requires LSEs to make annual System, Local, and Flexible RA compliance showings for the coming year. For the System showing, LSEs must demonstrate they have procured at least 90 percent of their System RA obligation for the five summer months from May through September. For the Local showing, LSEs must demonstrate that they have procured 100 percent of their Local RA

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[3] See 2014 BPP, Appendices C and S.

[4] Pursuant to Rule 1.15 of the CPUC Rules of Practices and Procedure, if the due date falls on a Saturday, Sunday, or holiday, it is extended to the following business day.

obligation for all 12 months. LSEs are also required to demonstrate that they have procured at least 90 percent of their Flexible RA requirement for all 12 months.

For the monthly filings, LSEs must demonstrate they have procured 100 percent of their monthly System and Flexible RA obligation. LSEs must also demonstrate they have met 100 percent of their revised (due to load migration) Local RA obligation.

2. New RA Requirements

In 2020, the CPUC adopted several major changes to the RA Program that impacted PG&E's 2020 portfolio management activities.

First, D.20-06-002, issued on June 17, 2020, adopted a hybrid procurement framework for Local RA resources for LSEs within PG&E's and Southern California Edison Company's distribution service areas. D.20-06-002 also established PG&E and SCE as central procurement entities for Local RA resources on behalf of all LSEs within their respective distribution service areas beginning with the 2023 RA compliance year. All LSEs, including PG&E, would continue to meet Local RA requirements for the 2021 and 2022 RA compliance years pursuant to D.20-06-002.

Second, D.20-06-028, issued on July 6, 2020, superseded D.19-10-021, issued on October 17, 2019, and adopted additional requirements for import energy contracts to count towards an LSE's System RA requirements. Import RA shall now be categorized as either (a) resource specific or (b) non resource-specific. In order to be resource-specific, the import RA must be pseudo-tied or dynamically scheduled. If the import RA is non-resource specific, it is required to self-schedule or economically bid between -$150/megawatt-hour (MWh) and $0/MWh during the RAAIM assessment hours in the day-ahead and real-time markets, consistent with the maximum cumulative capacity (MCC) bucket criteria and have no economic curtailment provisions. Additionally, the import RA contract must state that the energy will be delivered and sold to the LSE and is not sourced from resources internal to CAISO.[5]

Finally, D.20-06-031, issued on June 30, 2020, adopted the Alternative Compliance Mechanism (ACM) for Local RA. Local RA must be procured in each of the seven Local Capacity Areas (LCA).[6] However, the ACM can be utilized by an LSE in PG&E's service area to fulfill its Local RA obligations in six disaggregated LCAs (called the "Other PG&E" LCA) if the LSE demonstrates its collective procurement in the six disaggregated Other PG&E LCAs meets its collective requirement for the Other PG&E Area LCAs. In addition, an LSE must make the required demonstration as part of the current Local RA waiver process through a Tier 2 Advice Letter for its disaggregated Other PG&E LCA requirements. D.20-06-031 also adopted additional refinements to the RA Program, including: adopting a shaped penalty price structure for System RA requirements for summer and non-summer months; adopting revisions to the MCC buckets; and adopting an exceedance-based qualifying capacity (QC) methodology for dispatchable hydroelectric resources as an optional methodology. Notably, D.20-06-031 adopted the 2021-2022 Local RA requirements for all local areas, other than the Greater Bay Area LCA. For the Greater Bay Area LCA, the 2020 Local RA requirements were adopted to apply to the 2022 local RA requirements.

3. CAISO Reliability Requirements

In addition to the requirements set by the CPUC, the CAISO includes RA provisions in its Tariff.[7] Working in conjunction with the RA requirements adopted by the CPUC and other provisions of California law applicable to non-CPUC jurisdictional LSEs, the RA provisions in the CAISO Tariff are intended to establish a process that ensures capacity is available

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[5] D.20-06-028 Ordering Paragraph 8 allows for an attestation to be used to fulfill the contract language requirement.

[6] The seven LCAs in PG&E's Service Territory include Greater Bay Area and the six LCAs previously aggregated as "PG&E Other": Humboldt, Fresno, Kern, North Coast/North Bay, Sierra, and Stockton.

[7] CAISO Tariff, Section 40, Section 9, and Section 43A represent the primary Reliability Requirements in the CAISO Tariff.

when and where it is needed to reliably operate the CAISO grid. Accordingly, the CAISO tracks how each LSE is complying with its RA requirements. If an LSE does not meet its specific requirements, the CAISO may allocate costs of CAISO backstop procurement to the deficient LSE.[8] The CAISO also enforces non-availability charges on resources that do not perform consistent with CAISO's expectation.[9]

C. PG&E's RA Activity During the Record Period

1. RA Position

PG&E manages the RA position to address a few key objectives: (1) to comply with the CPUC RA Program and the CAISO reliability requirements; (2) to enable sales of capacity where appropriate; and (3) to manage its responsibility as a scheduling coordinator. In order to effectively achieve these position management objectives, PG&E manages resources and coordinates with regulators (i.e., CEC, CPUC, and CAISO) to make sure these objectives are achieved.

System, Local, and Flexible RA requirements for each LSE are provided by the CPUC in September each year, including Demand Response and Cost Allocation Mechanism allocations. This means PG&E does not have a fixed and certain RA Compliance obligation amount until the September preceding the compliance year. Starting for RA Compliance year 2020, per the RA requirements under D.19-02-022, CPUC-jurisdictional LSEs are allocated Local RA compliance obligations in each of the local capacity areas within the service territory in which they serve load (rather than meeting a Local RA compliance obligation using capacity from any local capacity area). In addition to CPUC compliance requirements, the CAISO releases the Net Qualifying Capacity (NQC) and Effective Flexible Capacity (EFC), which provides the quantity of MW a resource can count for RA compliance, each October. This means PG&E does not have a fixed and certain total resource amount of RA in its portfolio until the October preceding the compliance year. PG&E's RA Position is materially impacted by the RA Compliance obligation and CAISO NQC and EFC amounts and

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8 CAISO Tariff Section 43A.8.

9 CAISO Tariff Section 40.9.

the associated distribution timelines. While requirements and resources are put in place late in the year, PG&E manages its position using the best information available at the time.

PG&E also manages its RA position to address all the compliance requirements across the regulators. For instance, for System RA position, the CPUC compliance rules do not account for forecasted planned outages, whereas CAISO rules require PG&E to manage the System RA position to account for these outages. For Local RA position management, the CPUC requires only August NQCs be used for resource capacity counting in every month of the year, whereas the CAISO requires each monthly NQC be used for resource capacity counting. A complex series of requirements across regulators, challenging timelines for receiving critical compliance obligation information, and fluctuations in RA resource qualifying capacity amounts all have an impact on PG&E's RA position.

PG&E managed position in the record period in compliance with the Conformed 2014 BPP with the intent to achieve the key objectives.

2. RA Purchases

PG&E purchased RA to meet its RA compliance obligations during the record period taking into consideration the regulatory changes to Local RA compliance requirements and operational impacts to its portfolio. These transactions were compliant with the BPP and were reported in each 2020 Quarterly Compliance Report (QCR).[10]

3. RA Sales

a. Compliance with Appendix S – Sales Framework

PG&E's Appendix S – Sales Framework includes parameters within which PG&E will conduct sales, offer volumes for sale, and evaluate offers received from counterparties. PG&E's RA sales in 2020 are documented in the relevant QCRs.

1) Product Volume

Appendix S sets forth formulas related to System, Local and Flexible RA and import capacity counting rights that must be used to

[10] The 2020 QCRs are included as workpapers.

determine volumes of RA available for sale as of the date a calculation is performed. The BPP does not obligate PG&E to offer any volumes of RA determined to be available pursuant to the formulas set forth in Appendix S, except through the CAISO capacity procurement mechanism competitive solicitation process.

In compliance with Appendix S, PG&E used the required formulas to determine the volume of RA available for sale at various times. PG&E demonstrates the amount of RA determined to be available for sale at various times in its Portfolio Breakdown in the QCR Appendix E. PG&E offered the volumes of RA determined to be available for sale pursuant to the formulas set forth in Appendix S into the CAISO capacity procurement mechanism competitive solicitation process and, while not required by the BPP, also offered all such volumes of RA to the market.

2) Sales Method

Appendix S describes the PG&E solicitation schedule to sell RA products. PG&E held the following solicitations in accordance with Appendix S. These solicitations were reported in the QCR.

Consistent with Appendix S of its BPP, PG&E held a Q2 Balance of Year 2020 solicitation in January 2020, a Q3 Balance of Year Solicitation in April 2020, a Q4 Balance of Year 2020 solicitation in July 2020, a multi-year RA sales solicitation in the third quarter of 2020, and a February through Balance of Year 2021 solicitation in November 2020.

For the Annual Multi-year (2021-2022) solicitation, to make as much capacity available to the market as early as possible, PG&E continued a two-phased approach to the solicitation. In the first phase, PG&E's capacity was made available shortly after the initial RA Compliance obligations were issued by the CPUC in July. During the second phase, PG&E's capacity was made available shortly after the final RA Compliance obligations were issued by the CPUC. In addition, the CAISO issued its draft NQC and EFC lists prior to the second phase of the solicitation. The issuance of the NQC and EFC lists provided greater certainty to the market on RA values for resources that can be counted towards an LSE's RA obligations. This two-phased approach was developed in consultation with the CPUC's Energy Division, communicated through the service list of Rulemaking 17-09-020.

3) Price Supply Curve

D.19-10-001 found that:

> An investor-owned utility may decide not to sell RA below [a] floor price because the possible California Independent System Operator penalties for doing so could require the IOU to recover costs in excess of the floor price from both bundled service and departing load customers.[11]

In accordance with this finding, Appendix S approves a methodology for PG&E to calculate a price supply curve to determine floor prices. PG&E's floor price evaluates possible CAISO penalties a generating unit may receive, calculated as a function of the probability of a generating unit receiving a penalty and the associated penalty cost. PG&E applied this approved supply curve methodology when evaluating bids to purchase RA from PG&E during the record period for which Appendix S became effective.

4. RA Contract Management

The executed volumes and prices from the solicitations and bilateral contracts is reported in the QCR Attachment E and H. These transactions can be found in Table 8-2. PG&E's RA sales contracts are structured such that unit-specified RA is not identified until necessary for its delivery date. PG&E provides counterparties with unit specific resource information in advance of the filing deadline for the CAISO's Supply Plan. PG&E uses this approach to enable flexibility to manage any unexpected resource outages, load migration, or other issues that may arise. Other routine amendments were made throughout the record period, as shown in Table 8-3 at the end of this chapter.

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11 D.19-10-001 Findings of Fact 29.

5. Tree Mortality

In compliance with Res.E-4805 and D.18-12-003 regarding the Tree Mortality Non-Bypassable Charge (TMNBC), PG&E issued solicitations to sell Tree Mortality RA products. PG&E's ALs 4954-E and 5478-E address the means and strategies applicable to PG&E's Tree Mortality RA sales.

Tree Mortality RA sales transactions are governed by AL 5478-E Appendix C. PG&E did not issue any solicitations for RA from Tree Mortality resources during the 2020 record period.

D. Request for Approval of RA Sale

PG&E initially attempted to negotiate a bilateral transaction with SCE to acquire Local RA needed to meet PG&Es Local RA compliance requirements. PG&E came to understand from the counterparty the only way to purchase the Local RA necessary for PG&E to meet its compliance requirements was to simultaneously sell System RA and import allocation rights to SCE. PG&E's submission in a third-party Request for Proposal (RFP) (SCE's Q4 RFP) to sell RA represents a transaction that falls outside of PG&E's Appendix S in the BPP, which states that PG&E will not sell RA products through other market participants' solicitations. PG&E determined that participating in SCE's RFO was a reasonable and prudent course of action to ensure it could purchase its Local RA requirements for the 2021 Annual Compliance Filing submitted November 2, 2020. PG&E asks the Commission to find that PG&E's actions were reasonable by recognizing the need for executing the sales transactions in concert with the purchase transactions was designed to permit PG&E to comply with its Local RA requirements and approve the sales transactions.

E. Accounting for RA Per PCIA D.18-10-019 and D.19-10-001

PG&E commits resources to meet its System, Local and Flexible RA obligations in accordance with the rules of its regulatory agencies. PG&E selects resources to fulfill RA sales agreements and for its own compliance.

PG&E determines the volume of RA "Retained" for Investor-Owned Utility compliance and RA "Sold" to counterparties after offering all volumes for sale according to the 2014 Conformed BPP Appendix S methodology and uses this information for purposes of calculating the PABA true-up as follows, pursuant to D.19-10-001:

PG&E tracks the amount of MWs of RA from each resource that was Sold or Retained. For PG&E's own compliance and RA sales to counterparties, RA Retained or Sold amounts are finalized when a resource is included in PG&E's Supply Plan to the CAISO. Each MW of RA from each resource that is included on the Supply Plan is assigned to an LSE. When the resource capacity is assigned to PG&E, it is considered "Retained" RA. When a resource is assigned to another LSE, the RA is considered Sold RA. The sales price and quantity for each Sold RA transaction are recorded in PABA.

The Retained or Sold volumes and prices associated with a resource is booked to PABA only if that resource is a PCIA-eligible resource. If the resource is a Qualifying Facility that is recovered through Ongoing Competition Transition Charge (CTC), its retained value or sales value would be recorded under the Modified Transition Cost Balancing Account. Similarly, RA associated with TMNBC resources would be recorded as retained or sold under the TMNBC. If the sales are associated with generation and storage resources that are not otherwise recovered through the CTC, the PCIA, or the TMNBC, the sales are recorded under ERRA.

After determining the total amount of Retained and Sold RA including offering all volumes for sale according to the 2014 Conformed BPP Appendix S methodology, PG&E calculates the Unsold RA. To do so, PG&E deducts the total amount of Retained and Sold RA from the cumulative NQC of PG&E's portfolio to establish how many MW of RA remain unsold. During the Record Period, PG&E offered all volumes of RA for sale according to the 2014 Conformed BPP Appendix S methodology but was not able to sell all available RA for each month in 2020. This information is recorded in Appendix E of the QCRs.

F. Conclusion

This chapter, as well as information included in PG&E's workpapers to this chapter, demonstrates that during the 2020 record period, PG&E's procurement and sale of RA products complied with the requirements of the 2014 Conformed BPP because PG&E utilized the means, strategies, and limits described therein.

TABLE 8-1
PG&E RA SOLICITATION SCHEDULE PURSUANT TO APPENDIX S OF BPP

Line No.	Solicitation	Delivery Term	Products	Anticipated Date
1	Q2 through Balance of Year 2020	Monthly, through December 2020	System RA with/without Flex Local RA with/without Flex Import Capacity Counting Rights RA Swaps	January 2020
2	Q3 through Balance of Year 2020	Monthly, through December 2020	System RA with/without Flex Local RA with/without Flex Import Capacity Counting Rights RA Swaps	April 2020
1	Q4 through Balance of Year 2020	Monthly, through December 2020	System RA with/without Flex Local RA with/without Flex Import Capacity Counting Rights	July/August 2020
2	Annual Multiyear (2021 – 2022)	Monthly, January through December (2021 – 2022)	System RA with/without Flex Local RA with/without Flex Import Capacity Counting Rights	Q3 2020
3	February through Balance of Year 2021	Monthly, February through December 2021	System RA with/without Flex Local RA with/without Flex Import Capacity Counting Rights	November 2020

TABLE 8-2
RA EXECUTED DURING RECORD PERIOD 2020

Line No.	Date	PG&E Log Number	Project Name
1	1/10/2020	33B235S09	Marin Clean Energy – Purchase
2	1/13/2020	33B230S04	Silicon Valley Clean Energy Authority – Purchase
3	1/13/2020	33B230S05	Silicon Valley Clean Energy Authority – Sale
4	1/24/2020	33B232S05	Peninsula Clean Energy Authority – Sale
5	1/24/2020	33B232S06	Peninsula Clean Energy Authority – Purchase
6	1/28/2020	33B236S01	Central Coast Community Energy – Sale
7	1/28/2020	33B236S02	Central Coast Community Energy – Purchase
8	1/28/2020	33B238S05	East Bay Community Energy Authority – Sale
9	1/28/2020	33B238S07	East Bay Community Energy Authority – Sale
10	1/28/2020	33B240S04	Clean Power Alliance of Southern California – Sale
11	1/28/2020	33B243S03	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
12	1/28/2020	33B247S03	City of San Jose (San Jose Clean Energy) – Sale
13	1/28/2020	33B247S04	City of San Jose (San Jose Clean Energy) – Purchase
14	1/29/2020	33B238S06	East Bay Community Energy Authority – Purchase
15	1/31/2020	33B037S01	NextEra Energy Marketing, LLC – Sale
16	2/5/2020	33B022S05	Shell Energy North America (US), L.P. – Sale
17	2/19/2020	33B230S06	Silicon Valley Clean Energy Authority – Purchase
18	3/9/2020	33B240S05	Clean Power Alliance of Southern California – Sale
19	3/23/2020	33B232S07	Peninsula Clean Energy Authority – Purchase
20	4/15/2020	33B217S06	Southern California Edison Company – Purchase
21	5/4/2020	33B232S09	Peninsula Clean Energy Authority – Sale
22	5/5/2020	33B236S03	Central Coast Community Energy – Sale
23	5/5/2020	33B238S08	East Bay Community Energy Authority – Sale
24	5/5/2020	33B238S09	East Bay Community Energy Authority – Purchase
25	5/5/2020	33B238S10	East Bay Community Energy Authority – Sale
26	5/5/2020	33B238U01	East Bay Community Energy Authority – Purchase
27	5/5/2020	33B247S05	City of San Jose (San Jose Clean Energy) – Sale
28	5/5/2020	33B250S03	City County Of San Francisco – Sale
29	5/6/2020	33B243S04	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
30	5/6/2020	33B243S05	CCSF, acting by and thru its PUC, CleanPowerSF – Purchase
31	5/13/2020	33B113S04	3 Phases Renewables, Inc. – Purchase
32	5/13/2020	33B232S08	Peninsula Clean Energy Authority – Purchase

TABLE 8-2
RA EXECUTED DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name
33	5/14/2020	33B235S10	Marin Clean Energy – Purchase
34	5/14/2020	33B241S02	Direct Energy Business Marketing, LLC – Purchase
35	5/27/2020	33B200S02	EDF Trading North America, LLC – Purchase
36	6/15/2020	33B238S11	East Bay Community Energy Authority – Purchase
37	6/23/2020	33B113S05	3 Phases Renewables, Inc. – Sale
38	6/29/2020	33B240S06	Clean Power Alliance of Southern California – Sale
39	7/9/2020	33B247S06	City of San Jose (San Jose Clean Energy) – Sale
40	7/14/2020	33B238S12	East Bay Community Energy Authority – Sale
41	7/15/2020	33B256S01	San Diego Gas And Electric – Sale
42	7/16/2020	33B200S03	EDF Trading North America, LLC – Sale
43	7/17/2020	33B029S01	Calpine Energy Services, L.P. – Sale
44	7/17/2020	33B217S07	Southern California Edison Company – Purchase
45	7/17/2020	33B241S03	Direct Energy Business Marketing, LLC – Sale
46	7/17/2020	33B241S04	Direct Energy Business Marketing, LLC – Sale
47	7/30/2020	33B243S06	CCSF, acting by and thru its PUC, CleanPowerSF – Purchase
48	7/30/2020	33B243S07	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
49	8/5/2020	33B113S06	3 Phases Renewables, Inc. – Sale
50	8/5/2020	33B113S07	3 Phases Renewables, Inc. – Purchase
51	8/5/2020	33B243S08	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
52	8/5/2020	33B243S09	CCSF, acting by and thru its PUC, CleanPowerSF – Purchase
53	8/13/2020	33B235U01	Marin Clean Energy – Purchase
54	8/13/2020	33B235U02	Marin Clean Energy – Sale
55	9/14/2020	33B230T01	Silicon Valley Clean Energy Authority – Purchase
56	9/14/2020	33B230T02	Silicon Valley Clean Energy Authority – Sale
57	9/14/2020	33B232U01	Peninsula Clean Energy Authority – Sale
58	9/15/2020	33B226U01	Sonoma Clean Power Authority – Sale
59	9/15/2020	33B238T01	East Bay Community Energy Authority – Sale
60	9/15/2020	33B251T04	Exelon Generation Company, LLC – Sale
61	9/16/2020	33B236U02	Central Coast Community Energy – Sale
62	9/16/2020	33B238U02	East Bay Community Energy Authority – Sale
63	9/17/2020	33B029U03	Calpine Energy Services, L.P. – Purchase
64	9/17/2020	33B029U04	Calpine Energy Services, L.P. – Sale
65	9/17/2020	33B247T01	City of San Jose (San Jose Clean Energy) – Sale

TABLE 8-2
RA EXECUTED DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name
66	9/17/2020	33B247T02	City of San Jose (San Jose Clean Energy) – Purchase
67	9/17/2020	33B247T03	City of San Jose (San Jose Clean Energy) – Sale
68	9/22/2020	33B243U01	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
69	10/20/2020	33B113U01	3 Phases Renewables, Inc. – Sale
70	10/20/2020	33B230U01	Silicon Valley Clean Energy Authority – Sale
71	10/20/2020	33B232T01	Peninsula Clean Energy Authority – Sale
72	10/20/2020	33B235U03	Marin Clean Energy – Sale
73	10/20/2020	33B235U04	Marin Clean Energy – Purchase
74	10/20/2020	33B236T02	Central Coast Community Energy – Sale
75	10/20/2020	33B238U03	East Bay Community Energy Authority – Sale
76	10/20/2020	33B243T01	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
77	10/20/2020	33B245T01	Pioneer Community Energy – Sale
78	10/20/2020	33B245U01	Pioneer Community Energy – Purchase
79	10/20/2020	33B250T01	City County Of San Francisco – Sale
80	10/21/2020	33B247T04	City of San Jose (San Jose Clean Energy) – Sale
81	10/21/2020	33B247T05	City of San Jose (San Jose Clean Energy) – Purchase
82	10/21/2020	33B247T06	City of San Jose (San Jose Clean Energy) – Sale
83	10/21/2020	33B251T05	Exelon Generation Company, LLC – Sale
84	10/23/2020	33B235U05	Marin Clean Energy – Sale
85	10/23/2020	33B235U06	Marin Clean Energy – Purchase
86	10/27/2020	33B232U02	Peninsula Clean Energy Authority – Sale
87	10/28/2020	33B113T01	3 Phases Renewables, Inc. – Purchase
88	10/28/2020	33B113T02	3 Phases Renewables, Inc. – Sale
89	10/29/2020	33B217T05	Southern California Edison Company – Purchase
90	10/29/2020	33B217T06	Southern California Edison Company – Purchase
91	10/29/2020	33B217T07	Southern California Edison Company – Purchase
92	10/29/2020	33B217T08	Southern California Edison Company – Purchase
93	10/29/2020	33B217T09	Southern California Edison Company – Sale
94	10/29/2020	33B217T10	Southern California Edison Company – Sale
95	10/30/2020	33B262T01	Sierra Energy Storage, LLC – Purchase
96	10/30/2020	33B263T01	Dynegy Marketing and Trade, LLC – Purchase
97	11/20/2020	33B029S02	Calpine Energy Services, L.P. – Sale
98	12/3/2020	33B113T03	3 Phases Renewables, Inc – Purchase

TABLE 8-2
RA EXECUTED DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name
99	12/11/2020	33B243T02	CCSF, acting by and thru its PUC, CleanPowerSF – Purchase
100	12/11/2020	33B243T03	CCSF, acting by and thru its PUC, CleanPowerSF – Sale
101	12/11/2020	33B250T02	City County Of San Francisco – Sale
102	12/14/2020	33B238T02	East Bay Community Energy Authority – Purchase
103	12/14/2020	33B238T03	East Bay Community Energy Authority – Sale
104	12/17/2020	33B232T02	Peninsula Clean Energy Authority – Sale
105	12/31/2020	33B240T01	Clean Power Alliance of Southern California –d Purchase

TABLE 8-3
RA CONTRACT AMENDMENTS DURING RECORD PERIOD 2020

Line No.	Date	PG&E Log Number	Project Name	Transaction Type	Description
1	3/24/2020	33B240S05	Clean Power Alliance of Southern California	Routine Amendment to Existing Agreement	Routine amendment clarifies delivery point and extends deadline for PG&E's delivery of product.
2	8/24/2020	33B217U01	Southern California Edison Company	Amendment to Existing Agreement	Amendment removes Flexible Capacity from the product.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

CONTRACT ADMINISTRATION

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CONTRACT ADMINISTRATION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
CONTRACT ADMINISTRATION

A. Introduction

Pacific Gas and Electric Company's (PG&E) Energy Contract Management and Settlements (ECMS) Department administers PG&E's energy procurement contracts and payments with counterparties.

During the record period, PG&E complied with the California Public Utilities Commission's (CPUC or Commission) Standard of Conduct 4 (SOC4), adopted in Decision (D.) 02-10-062 and elaborated on in D.02-12-069, D.02-12-074, D.03-06-076, and D.05-01-054, regarding prudent contract administration. This chapter describes PG&E's contract administration practices, changes that occurred to the contracts administered, and the results achieved regarding contract administration during the record period. The monthly energy purchases and costs incurred during the record period are shown in Table 9-4 at the end of this chapter.

In this chapter, PG&E will demonstrate that it complied with SOC4 with regards to prudent contract administration during the record period by providing:

1) An overview of ECMS processes, including contract administration during the developing and operational phases of a contract, with descriptions of tools, systems and controls. Additional information about ECMS processes, tools, systems and controls is provided in PG&E's workpapers for Chapter 9.
2) A summary of contract administration activities that occurred during the record period including: (1) programs and solicitations; (2) contracts executed; (3) project development and construction monitoring; (4) contracts that began delivery; (5) contract amendments, consents to assignment and other transactions; (6) force majeure claims; (7) disputes; (8) contracts that expired or terminated; (9) other matters; and (10) amendments and transactions requiring approval.

B. Contract Management (CM) and Electric Settlement Process

1. Overview

Once a contract or transaction is executed, administration and settlement of the contract or transaction becomes the responsibility of ECMS. ECMS uses a number of tools, systems, and controls to administer contracts, and follows processes and procedures to ensure that transactions, new contracts, and amendments to existing contracts are implemented and administered consistent with the terms and conditions contained in each agreement. In general, ECMS processes involve the following, which are described in more detail in the sections below:

- Contract review, interpretation, and administration;
- Active compliance monitoring;
- Construction monitoring and performance testing;
- Settlement and payment;
- Dispute resolution; and
- Tools, systems, and controls.

2. Contract Review, Interpretation and Administration

Prior to contract execution, CM Analysts conduct a thorough review of each proposed transaction. During this review, the CM Analysts work with the assigned Settlements Analyst and Commercial Lead for the transaction to ensure that agreements can be administered by ECMS. The ECMS Director approves proposed transactions on behalf of ECMS after review by ECMS Staff.

Once a contract is executed, assigned CM Analysts review the contract and enter contract milestones, requirements, and tasks in the Task Tracking Tool (T3) and review data entries in the Consolidated Energy Contract Management (CECM) Database. CM Analysts meet with key internal groups to review these documents, respond to questions, and obtain uniform understanding of the terms of each transaction. CM Analysts also work with the assigned Settlements Analyst to review payment provisions in the contract.

In addition to this contract review, ECMS reviews and interprets the contract throughout its term in response to specific questions from other PG&E business groups or as issues arise. CM Analysts also provide support and guidance to the business groups on the use of ECMS tools and systems.

3. Active Compliance Monitoring

PG&E ensures compliance with contract terms by monitoring contract requirements throughout the contract lifecycle. Such activities involve tracking contract milestones and deadlines, reviewing documentation, ensuring that PG&E and the contract counterparties comply with contract provisions, and monitoring performance for projects that are already delivering contracted products to PG&E. PG&E also monitors Renewable Portfolio Standard (RPS) contracts consistent with the Commission's request that each utility ensure that Renewable Energy purchases are from an Eligible Renewable Energy Resource, as defined in California Public Utilities Code Section 399.12.

During the record period, ECMS and other groups in Energy Policy and Procurement (EPP) conducted the following active monitoring activities in relation to renewable generation from RPS contracts:

- Regularly reviewed the California Energy Commission (CEC) website and verified that the counterparty's facility was pre-certified as a renewable resource before the facility began delivering electricity to PG&E and remains certified throughout the delivery term.
- Verified that the counterparty has an active account set up in the Western Renewable Energy Generation Information System (WREGIS).
- Reviewed and verified that metered volumes generated by RPS-certified facilities matched the Renewable Energy Certificate (REC) quantities received through WREGIS. PG&E worked with counterparties and WREGIS to identify why any REC deficits occurred and resolved those REC deficits. If REC deficits were unresolved, then PG&E adjusted invoices, as applicable, under the Power Purchase Agreements (PPA).
- Required an attestation included in each counterparty's monthly invoice that the facility is: (1) certified by the CEC as a California RPS-eligible resource; and (2) registered with WREGIS as a Generating Unit (as defined in the WREGIS Operating Rules).

4. Construction Monitoring and Performance Testing

a. Construction Monitoring and Safety

CM monitors the projects under development, generally from contract execution through commercial operation. Typically, a contract requires the counterparty to provide written progress reports on the project's development status to PG&E on a monthly or quarterly basis. The assigned CM Analyst reviews these reports, consulting with a PG&E Engineer when necessary. When further information is required, a follow-up conference call with counterparty personnel and/or a site inspection may be conducted.

During construction monitoring, PG&E reviews and tracks development activities, including: site control; permitting; interconnection; financing; construction; and safety. Local, state, and federal agencies that have review and approval authority over the generation facilities are responsible for enforcing safety, environmental, and other regulations for the project, including decommissioning.

Safety is also addressed as part of a generator's interconnection process, which requires testing for safety and reliability of the interconnected generation. PG&E's general practice is to declare that a facility has commenced deliveries under the contract only after the interconnecting utility and the California Independent System Operator (CAISO) have concluded such testing and given permission to commence commercial operations.

b. Performance Testing

Some contracts require the counterparty to periodically demonstrate the performance capabilities of the applicable generating station(s) through testing. Engineers witness performance tests of counterparties' generating stations. Performance testing typically determines a facility's full-load generating capacity and heat rate. Performance test-related activities include developing test procedures, witnessing tests, and reviewing and approving test reports/results. The test results are reported to various organizations within PG&E.

5. Settlement and Payment

The Electric Settlements section within ECMS is responsible for ensuring the proper settlement of all contracts in PG&E's electric portfolio, including, but not limited to: RPS; Tolling; Qualifying Facility (QF) Must-Take; QF and Combined Heat and Power (CHP) Settlement; Feed-In Tariff (FIT); Irrigation District and Water Agency (ID&WA) legacy contracts; and Power Trading Master agreements.

The purpose of the settlement process is to ensure that all contract payments are in accordance with the terms and conditions of each contract, and that these costs are fully documented and properly reported in PG&E's financial systems. The settlement process includes: collecting and validating generation, generator scheduling, and outage data; collecting pricing from market indices; calculating and composing invoices; and preparing payment data for the Accounts Payable Department. Settlement data is collected from various sources, including: PG&E's metering systems; the CAISO; other PG&E departments; various price indices; and the generators themselves. The settlements cycle generally takes up to 25 calendar days to process all invoices through calculation, approval, and payment.

After each month's settlement activities are complete, Electric Settlements prepares additional financial and other reports. Electric Settlements also oversees process improvements on other information systems in EPP so that the tools are maintained to keep pace with additional contract requirements. Additional responsibilities include: maintaining and testing EPP's internal controls in accordance with Sarbanes-Oxley requirements; and acting as the liaison to PG&E's Corporate Accounting Department concerning energy-related disclosures for compliance reporting purposes.

Electric Settlements currently has four distinct areas of responsibility: (1) RPS Settlements; (2) Tolling Settlements; (3) QF/CHP and FIT Settlements; and (4) and CAISO Settlements and Reporting. These functions and the tools that support these functions are described below:

- **RPS Settlements:** This group is responsible for invoice validation and payment processing of all RPS contracts, bilateral purchase and sales contracts which include Power Trading Master agreements (including all electric financial instruments).

- **Tolling Settlements:** This group is responsible for the invoice validation and payment processing of all conventional natural gas tolling contracts.
- **QF/CHP and FIT Settlements:** This group is responsible for administering and settling the QF Must-Take agreements, ID&WA legacy contract, and form agreements that arose from the QF/CHP Settlement and were approved by the CPUC in D.10-12-035. In addition, this group settles the FIT agreements promulgated by California Assembly Bill (AB) 1969, AB 1613, Senate Bill (SB) 32 Renewable Market Adjusting Tariff (ReMAT), and SB 1122 Bioenergy Market Adjusting Tariff (BioMAT), as well as the quarterly Greenhouse Gas (GHG) invoices from the California Air Resources Board.
- **CAISO Settlements and Reporting:** This group is responsible for validation, settlement and reporting of procurement costs and generation revenues associated with PG&E’s participation in the CAISO electricity markets as described in Chapter 10. This group also provides reporting data and analysis to internal organizations for the monthly Corporate Accounting close, the Controller’s Gross Margin Analysis, WREGIS data submittal, RPS reports, the 10-Q/10-K processes, GHG and various internal and external requests using the following tools:
  - **OpenLink Endur:** The OpenLink Endur system provides a module for managing, invoicing, and reporting all power trading and contract settlement activities. Electric Settlements uses the Endur system to import meter data and outages from upstream systems, and review generation data and to invoice transactions.
  - **Electric Settlements Tool for Analysis and Reporting (ESTAR):** ESTAR is used to collect and manage unit-specific temperature and gas meter data to calculate the gas balancing true-up adjustments for Tolling Agreements. Upon full implementation, ESTAR calculations will link with the Endur system.

For a detailed description of the processes that Settlements uses, refer to the confidential workpapers that accompany this chapter (see "Electric Settlements' Payment Guide").

6. Dispute Resolution

ECMS manages disputes that arise in connection with the contracts. Initially, PG&E attempts to resolve conflicts through discussions. If the issue cannot be resolved through initial discussions, ECMS may conduct negotiations directly with the counterparty to resolve the dispute, as prescribed by the contract. If such discussions and negotiations are unsuccessful and formal mediation or arbitration becomes necessary, PG&E develops and pursues resolution strategies consistent with the best interests of customers. ECMS supports and participates in these stages of dispute resolution and works with PG&E's Law Department and other internal stakeholders, as applicable, until a final resolution is achieved. These activities include support for discovery and developing positions and proposals for dispute resolution.

7. Tools, Systems and Controls

ECMS uses a number of tools and systems that serve as controls in the CM and electric settlements process. These tools and systems help ensure that contracts are administered according to their terms and conditions, and that there is continuity in ECMS for the entire length of the contract term, which is important given that many of PG&E's contracts have terms of 20 years or more.

Furthermore, these tools, systems and controls play a key role in helping ECMS document, maintain and report contract information for the purpose of providing data to both internal and external stakeholders.

Upon execution of a contract, an assigned lead creates or updates records within ECMS' tools and systems. The lead requests that the assigned CM Analysts review their entries for completeness. For contract data that changes (e.g., project status), ECMS, along with other PG&E departments (e.g., EPP, Market and Credit Risk Management, etc.), review the data for consistency.

The primary tools, systems and controls used by ECMS are described below:

- **Master Contract List:** A complete listing of all contracts administered by ECMS. The list: (1) is used only by internal stakeholders (e.g., EPP, Law, Internal Audit, etc.); (2) contains links to documents stored in the electronic document management system, Documentum (D2) (described below); and (3) includes the assigned CM Analyst and Settlements Analyst for each contract.
- **D2:** A web-based electronic document management system, offering secure document storage and retrieval, that contains documents pertaining to our contracts. These documents include executed contract documents and significant correspondence.
- **CECM Database:** A database containing information about contracts executed by EPP including, but not limited to: Western System Power Pool and Edison Electric Institute (EEI) master enabling agreements and associated confirmations; and tolling, renewable, energy storage, QF, CHP and other must-take contracts. The CECM Database contains information such as: type of energy products; critical milestones; regulatory and permitting status; and pricing and credit information (as applicable). The CECM Database allows for a more accurate and efficient compilation of information for various internal and external reports, such as the Transaction Tracking List (described below), and various regulatory reports (e.g., CPUC Energy Division Monthly RPS Database Report).
- **T3:** A tracking system within the CECM Database that uses the contractual milestone dates managed in the CECM Database to provide reminders for CM tasks. Task notifications can be configured to automatically escalate to CM Analysts and management in order for action to be taken in advance of contractual deadlines, ensuring tasks and obligations are monitored through their resolution.
- **Transaction Tracking List:** A chronological listing of executed contracts, as well as subsequent transactions (e.g., amendments, letter agreements, etc.), including a short description of the transaction. The Transaction Tracking List is a tool used in preparing recurring reports

and data requests as it tracks contract execution dates, advice letter (AL) filing dates, and CPUC approvals for relevant agreements.

- **Scheduling Protocols:** Contract-specific reports summarizing basic contract information, such as contract quantity, delivery point, contact information, scheduling terms, and operational parameters for PG&E's contracted generation.
- **CM Intranet Site (SharePoint):** An intranet site, maintained and controlled by ECMS, which facilitates the sharing of contract information with other stakeholders within PG&E. The following tools and systems reside on or can be accessed from the CM SharePoint site: Master Contract List; D2; Transaction Tracking List.

C. Contract Administration During the Record Period

This section discusses the administration of contracts that were in or added to PG&E's portfolio during the record period, and any significant changes to these contracts that occurred.

1. Procurement Programs and Solicitations

This section describes PG&E solicitations for generation-services procurement programs which had significant activity during the record period.

a. ReMAT

Pursuant to D.12-05-035 and D.13-05-034, PG&E was allocated 218.8 megawatts (MW) of the 750 MW total statewide goal to procure from small distributed generation qualifying as "eligible renewable energy resources." The ReMAT program, which succeeded the AB 1969 FIT[1] program, currently has 28.811 MW of total capacity from executed, non-terminated ReMAT PPAs.

During the record period, PG&E did not hold any bi-monthly auctions for the ReMAT program or execute new ReMAT PPAs, in accordance with the directive received from the CPUC in the letter dated December 15, 2017, regarding Winding Creek Solar LLC v.

[1] AB 1969/FIF represent standard contracts for both Public Water and Wastewater Facilities (E-PWF) and Small Renewable Generators (E-SRG), with nameplate capacities of 1.5 MW or less.

Michael Peevey, et al. On October 16, 2020 the CPUC issued D.20-10-005 to resume and modify the ReMAT program. PG&E filed AL 5994-E and AL 5994-E-A in accordance with the Decision, which was pending approval from the CPUC as of the end of the record period.

b. BioMAT

Pursuant to D.14-12-081, D.15-09-004, and Resolution (Res.) E-4922,[2] PG&E issued bi-monthly auctions during the record period for the BioMAT program Category 1 (biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion) and Category 2 (biogas or biomass from dairy and other agricultural bioenergy), and monthly auctions for Category 3 (biogas or biomass using byproducts of sustainable forest management). PG&E was allocated 111 MW of the 250 MW total Investor-Owned Utility (IOU) procurement target from bioenergy resources. During the record period, PG&E executed two BioMAT PPAs for a total of 6 MW. The BioMAT program currently has 33.369 MW of contracted BioMAT capacity.

c. BioRAM

Pursuant to SB 901 and Res.E-4977, PG&E executed new contracts with two existing BioRAM counterparties during the record period. Additionally, PG&E reached out to biomass facilities eligible for a BioRAM contract pursuant to Res.E-4977, resulting in one executed BioRAM contract. PG&E filed ALs for each respective agreement. At the time of this filing, two are still pending CPUC approval.

d. Carbon Free Energy Sales

Pursuant to Res.E-5046, during the record period, PG&E engaged in sales of its 2020 Carbon Free Energy produced from large hydroelectric and nuclear resources to eligible Load Serving Entities (LSE). In these sales, PG&E offered each eligible LSE a quantity of 2020 Carbon Free Energy based on an allocation of the eligible LSE's corresponding customers' proportional share of forecasted monthly load

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[2] Res.E-4922 ordered the IOUs to continue to hold BioMAT program periods, accept new BioMAT applications, and execute BioMAT contracts.

set forth in PG&E's Energy Resource Recovery Account (ERRA) Forecast Application.

The sales were in compliance with AL 5705-E, which added Appendix P Carbon Free Energy to the Bundled Procurement Plan, and which was approved in Res.E-5046. Information regarding PG&E's sales of Carbon Free Energy, including associated tables, are contained in this Chapter 9.

e. Disadvantaged Communities Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT)

Pursuant to D.18-06-027, D.18-10-007, and Res.E-4999, PG&E held two solicitations during the record period for the DAC program. Information regarding the solicitations are contained in Chapter 5 (Review Entries Recorded in the DAC-GT Balancing Account and the DAC – CS-GT Balancing Account) and information regarding the administration of DAC contracts, including associated tables, are contained in this Chapter 9.

f. Green Tariff Shared Renewable (GTSR) – Regional Renewable Choice (RRC)

Pursuant to D.15-01-051 and D.16-05-006, PG&E held a solicitation during the record period for the RRC program. Information regarding the solicitation is contained in Chapter 11 (Review Entries Recorded in the GTSR Memorandum Account and the GTSR Balancing Account) and information regarding the administration of RRC contracts, including associated tables, are contained in this Chapter 9.

g. New Public Utility Regulatory Policies Act (PURPA) Standard Offer Contract (SOC)

In 2010, California's IOUs and ratepayer/consumer advocate groups filed a Settlement Agreement for approval at the CPUC. The QF/CHP Settlement Agreement created a new QF/CHP Program, intended to provide environmental benefits for California, encourage cost-effective and efficient CHP development, and provide a stable procurement framework for QF and CHP facilities. The Settlement Agreement was approved by the CPUC in December 2010 in D.10-12-035, and became effective on November 23, 2011. Among the pro-forma PPAs approved in the Settlement Agreement was a PURPA PPA for facilities of 20 MW or less. The QF/CHP Settlement expired on December 31, 2020.

Pursuant to D.20-05-006, the California IOUs developed a new PURPA SOC, which was approved by the CPUC on November 19, 2020 in Res.E-5104, with modifications. On November 30, 2020 PG&E filed AL 6013-E with the requested modifications, which was approved by the CPUC on December 22, 2020. During the record period, PG&E did not execute any contracts using the new SOC.

h. Renewable Energy Sales (Short Term and Long Term REC Sales)

Pursuant to D.19-12-042, PG&E held two solicitations to sell renewable energy and corresponding RECs through the Bundled RPS Energy Sale Solicitation in April 2020 and December 2020. The sales contracts were in compliance with PG&E's 2019 RPS Plan and followed the strategy described in the Sales Framework in Appendix F of the 2019 RPS Plan.

Pursuant to D.18-12-003, PG&E held a solicitation in November 2020 to sell renewable energy and corresponding RECs from the tree mortality-related procurement contracts required by Res.E-4470. The solicitation was in compliance with PG&E's AL 5478-E, which was approved by the CPUC on May 23, 2019.

i. Resource Adequacy (RA)

PG&E participates in the RA program as established by D.04-10-035, D.05-10-042, D.06-06-064, and D.14-06-050. In recent years there have been multiple changes to the RA program including those adopted in D.19-02-022, D.20-06-002, D.20-06-028, and D.20-06-031. In accordance with the RA program, PG&E engaged in various RA procurement activities throughout the year. Information regarding RA solicitations and administration of RA contracts, including associated tables, are contained in Chapter 8 (RA).

j. System Reliability Request for Offers (RFO)

Pursuant to D.19-11-016 in the Integrated Resources Planning (IRP) proceeding, PG&E was allocated 716.9 MW of system level qualifying

RA capacity to come online between August 1, 2021, and August 1, 2023. The Decision requires PG&E to procure and have online, 50 percent (358.45 MW) of the target by August 1, 2021. To meet the CPUC's resolution, PG&E will execute Agreements in two phases, Phase 1 for projects that intend to meet the August 1, 2021 online date and Phase 2 for projects that intend to come online after August 1, 2021 and before August 1, 2023. As discussed in PG&E's prepared testimony in Rulemaking 19-09-009, in December 2019 PG&E issued a RFOs, in the initial phase seeking offers to procure energy resources that are capable of providing Distributed Generation Enabled Microgrid Services in addition to RA capacity to meet IRP goals. No contracts were executed out of this solicitation.

On February 28, 2020, PG&E issued the 2020 System Reliability RFO – Phase 1 seeking offers for the purchase of eligible system RA to come online by August 1, 2021. On July 10, 2020, PG&E issued the 2020 System Reliability RFOs Phase 2 seeking offers for the purchase of resources that provide RA or load reductions that meet the objectives of D.19-11-016. During the record period, PG&E executed seven contracts resulting from the Phase 1 RFO and six contracts resulting from the Phase 2 RFO, totaling 810 MW of capacity.

2. Contracts Executed

The list below summarizes the number of contracts executed during the record period. A detailed listing of the contracts executed during the record period can be found in Table 9-5 at the end of this chapter, except for RA contracts, which are addressed in Chapter 8 (RA Procurement).

TABLE 9-1
CONTRACTS EXECUTED

Line No.	Type of Contract	Number of Contracts Executed
1	BioMAT	2
2	Carbon Free Energy Sale	19
3	CS-GT	3
4	DAC-GT	2
5	EEI Master	12
6	Energy Storage	13
7	GTSR - PG&E RRC	2
8	QF/CHP Settlement Agreement[(a)]	2
9	RPS	3
10	RPS Energy REC Sale	3
11	RA	105
12	Shape & Firm[(b)]	1
13	Total	167

(a) Pro-forma contracts approved as part of the QF/CHP Program Settlement Agreement (D.10-12-035).

(b) Shape and Firm are contracts with entities which accept energy deliveries from variable resources and provide to PG&E a corresponding amount of energy in firm, scheduled deliveries.

3. Project Development and Construction Monitoring Results

CM monitors projects under development and tracks contract milestones. During the record period, several counterparties exercised permitted extensions of contract milestones or missed key contract milestones, as reported in Tables 9-6 and 9-7 at the end of this chapter.

4. Contracts That Began Delivery

The list below summarizes the number of contracts that began delivering during the record period. A detailed listing of the contracts that began delivering during the record period can be found in Table 9-8 located at the end of this chapter.

TABLE 9-2
CONTRACTS THAT BEGAN DELIVERY

Line No.	Type of Contract	Number of Contracts That Began Delivery	Total Contract Size (MW)
1	BioMAT	1	1
2	Carbon Free Energy (Sale)	19	–
3	QF/CHP Settlement Agreement	3	7.975
4	RPS	1	50
6	RPS Energy REC Sale	5	–
7	Total	29	58.975

5. Contract Amendments, Consents to Assignment and Other Transactions

Contracts that had amendments, Consent to Assignments, and other similar agreements executed during the record period are listed in Table 9-9 located at the end of this chapter.

6. Force Majeure Claims

A force majeure is an instance when unforeseeable circumstances occur that prevent one or both parties from fulfilling obligations under the contract. PG&E responds to force majeure claims by reviewing the contract as well as the facts surrounding the force majeure claim. The force majeure claims addressed during the record period are listed in Table 9-10 located at the end of this chapter.

7. Disputes

This section describes matters in which PG&E and a counterparty engaged in a dispute resolution process provided for under the agreement (listed in order by the date the dispute was initiated).

a. Global Ampersand, LLC, El Nido Biomass Facility and Chowchilla Biomass Facility (PG&E Log Nos. 33R016 and 33R017)

On November 16, 2017, Global Ampersand, LLC (Global) initiated the dispute resolution process for the El Nido Biomass Facility and the Chowchilla Biomass Facility, regarding multiple payment issues related to scheduling and outage notification. During the record period, the parties reached a tentative agreement on terms to resolve the dispute.

This dispute is ongoing and has not been resolved at the time of this filing.

b. South Feather Water and Power Agency (SFWPA), Sly Creek, Kelly Ridge, Woodleaf, Forbestown (PG&E Log Nos. 33R074 and 33B103)

On November 12, 2019, SFWPA initiated the dispute resolution process regarding provisions in the PPA that extend the PPA Delivery Term as a result of a prolonged outage at the Kelly Ridge facility. PG&E and SFWPA engaged in management negotiations during the record period, and both parties remain actively engaged in discussions. This dispute is ongoing and has not been resolved at the time of this filing.

c. Henrietta D Energy Storage LLC, Henrietta D Energy Storage (PG&E Log No. 40S004)

On November 23, 2015, PG&E and Henrietta executed an Energy Storage Agreement (ESA) for a 10 MW Zinc Hybrid battery storage project with an Expected Initial Delivery Date of May 1, 2020. During a project status call in 2018, Henrietta described a charging restriction issue under Henrietta's Small Generator Interconnection Agreement that would prevent the facility from performing pursuant to the contract. Parties discussed this issue extensively, but Seller was unable resolve this issue.

On October 21, 2019, Henrietta filed a claim in PG&E's Chapter 11 bankruptcy (BK) proceeding seeking: (i) termination of the ESA, (ii) the return of Project Development Security of $600,000; and (iii) an additional $550,000+ for development costs. Subsequently on January 23, 2020, Henrietta initiated the dispute resolution process under the ESA. In 2020, the parties participated in management and executive negotiations. The parties agreed to resolve the claim and dispute by executing a Settlement Agreement on July 29, 2020, wherein the parties agreed [redacted]. This dispute is closed.

d. City and County of San Francisco (CCSF), Acting by and Through Its San Francisco Public Utilities Commission (SFPUC), CleanPowerSF and CCSF, Acting by and Through Its SFPUC, Power Enterprise (PG&E Log Nos. 33B243 and 33B250)

On August 12, 2020, CCSF, acting by and through its SF PUC, CleanPowerSF, and CCSF, acting by and through its SF PUC, Power Enterprise, issued a dispute with PG&E. The dispute claimed that interest amounts accrued on late payments by CCSF, related to five delivering RA Confirmations, were incurred due to PG&E's delinquency in paying CCSF business and tax payment obligations. PG&E determined that the issues raised by CCSF did not fall within the terms and conditions of the RA transaction. On August 24, 2020, ECMS held a teleconference meeting with CCSF to discuss the dispute and parties' respective positions. Following the discussion, PG&E received payment in full. On September 11, 2020, PG&E issued a response to CCSF's dispute acknowledging receipt of CCSF's payment of the interest amounts. This dispute is closed.

e. mNOC AERS LLC, Micronoc 10 MW Behind the Meter (BTM) Aggregate Energy Storage System (ESS) (PG&E Log No. 40S012)

On December 31, 2020, mNOC AERS LLC (mNOC) initiated the dispute resolution process for the Micronoc 10 MW BTM Aggregate ESS, regarding PG&E's denial of mNOC's Force Majeure claim under the agreement. This dispute is ongoing and has not been resolved at the time of this filing.

8. Contracts That Expired or Terminated

The list below summarizes the number of contracts that expired or were terminated during the record period. A detailed listing of the contracts that expired or were terminated during the record period can be found in Table 9-11 at the end of this chapter.

TABLE 9-3
CONTRACTS THAT EXPIRED OR TERMINATED

Line No.	Type of Contract	Number of Contracts Expired	Number of Contracts Terminated
1	AB1969	3	–
2	BioMAT	–	5
3	Energy Storage	–	1
4	QF/CHP Settlement Agreement	1	–
5	QF	8	1
6	RPS	1	–
7	RPS Energy REC Sales	24	–
8	Shape & Firm	1	–
9	Tolling	6	–
10	Total	44	7

D. Other Matters

In addition to the activity described above, this section describes other matters that occurred during the record period.

1. Vantage Wind Energy LLC (PG&E Log No. 33R083)

The Vantage Winds PPA contains a cost sharing mechanism for transmission-related costs in the event such costs exceed a specified threshold for a given Contract Year. In 2019, PG&E discovered that it had not been applying this cost sharing mechanism since October 2010, the beginning of the delivery term.

During the record period, the parties have been engaged in discussions regarding past transmission-related costs prior to Contract Year 2018-2019. The amounts pertaining to the past transmission-related costs are still being sought by PG&E from Powerex, the former Shaping and Firming agent. Powerex has cited delays in providing the amounts due to Coronavirus (COVID-19) restrictions.

2. Villa Sorriso Solar (PG&E Log No. 04S142)

Villa Sorriso Solar is a 7.2 kilowatt solar facility with a QF contract. In June of 2019, PG&E discovered that due to a meter configuration issue, PG&E had been basing energy payments for the facility on load data rather than generation data since 2014. This resulted in a total overpayment of [redacted] over this period. During the record period, the customer agreed to settle and reimburse PG&E in the amount of [redacted] to resolve the matter. This issue is closed.

3. PG&E Bankruptcy

On June 20, 2020, the United States BK Court for the Northern District of California confirmed PG&E's Plan of Reorganization (Plan) to emerge from BK under Chapter 11 of title 11 of the United States Code (BK Code). The BK Court's confirmation followed the CPUC approval of PG&E's Plan on May 28, 2020 in the Plan of Reorganization Order Instituting Investigation (I) proceeding (I.10-09-016). PG&E implemented the Plan on July 1, 2020, emerging from BK. Under the Plan, PG&E assumed all PPAs and renewable energy PPAs. The amounts owed to, among other parties, PG&E's lenders, employees, vendors, suppliers, and contract counterparties related to the period prior to PG&E's filing for Chapter 11 BK on January 20, 2019 (the Petition Date) are being paid pursuant to the Plan. Actual payments are made as the company completes the process of reconciling each claim or determining the appropriate contract cure amount for unpaid deliveries of energy or capacity under the contract for the period prior to the Petition Date.

During the record period, PG&E entered into ten settlement agreements associated with 16 contracts to resolve various issues including, but not limited to, claims or contract cure amounts for unpaid deliveries of energy or capacity under the contract, among other things, for the period prior to the Petition Date. Below is a list of contracts where PG&E executed settlement agreements to resolve claims or contract cure amount for unpaid deliveries of energy or capacity under the contract. PG&E also entered into a settlement agreement with Henrietta D Energy Storage LLC, described above.

- Shiloh IV Wind Project (33R167);
- Greenleaf Energy Unit #1, LLC (12C020);
- Klondike Wind Power III Project (33R030);
- Yuba City Cogen Partners (12C026);
- Snow Mountain Hydro LLC (Cove) (13H013);
- Snow Mountain Hydro LLC (Burney Creek) (13H016);
- Snow Mountain Hydro LLC (Ponderosa Bailey Creek) (13H035);
- Snow Mountain Hydro (Lost Creek 1) (33R101AB);
- Snow Mountain Hydro (Lost Creek 2) (33R102AB);

- Calpine Russell City Energy Center (33B075);
- Calpine Los Esteros Upgrade (33B099);
- Geysers (33R093);
- O.L.S. Energy – Agnews, Inc. (33B208);
- Calpine Peakers Replacement & Extension (33B097);
- Calpine King City Cogen (18C006); and
- Aera Energy LLC (South Belridge) (25C049QAA).

E. Request for Approval of Amendments and Transactions

PG&E requests that the Commission approve the following contract amendments and transactions that occurred during the record period. PG&E is not requesting express approval of each amendment and transaction entered into during the record period because many amendments and transactions are routine and/or administrative in nature and are approved as a part of PG&E's contract administration or were otherwise submitted to the Commission for review and approval in separate applications or ALs. Copies of the amendments and transactions for which PG&E is seeking approval in this Application, described in this Section E, are included in PG&E's confidential workpapers for this chapter.

1. CAISO System Emergency Transactions

PG&E is requesting Commission review and approval in this ERRA filing of 23 transactions associated with nine contracts listed below.

- Mesquite Solar 1 (33R144);
- SPI Biomass Portfolio/Sierra Pacific Industries (33R254);
- Wheelabrator Shasta Energy Company Inc. (33R406);
- Western Power and Steam II (25C138QPA);
- Frito Lay Cogen (25C063QPA2);
- Chevron U.S.A. (Coalinga) (25C055);
- Chevron U.S.A. (Cymric) (25C003);
- Chevron U.S.A. (Taft/Cadet) (25C002); and
- Chevron U.S.A. (SE Kern River) (25C246).

In August 2020, the CAISO identified an immediate need for additional capacity due to the extreme heat event that occurred that month and led to the shedding of customer load throughout California. In response to the identified need, PG&E sought incremental capacity from existing suppliers and entered into short-term agreements with multiple counterparties. The resulting transactions covered various periods of time from August 17, 2020 through October 31, 2020, enabling PG&E to access incremental capacity that was needed to help maintain reliability.

2. Crockett Cogeneration Co. (PG&E Log No. 01C045)

PG&E is requesting Commission review and approval in this ERRA filing of two transactions with Crockett Cogeneration (Log No. 01C045).

PG&E identified an opportunity to decrease the cost of its generation portfolio by reducing the output from Crockett Cogeneration facility during November 2020 and December 2020 and executed a letter agreement on October 23, 2020. A second amendment was executed on December 23, 2020 to decrease the cost of PG&E's generation portfolio by reducing the output from Crockett Cogeneration facility during January 2021 and February 2021. The projected savings are a result of limiting energy deliveries from Crockett to higher value hours in the curtailed periods compared to the anticipated Short Run Avoided Cost price that is paid to Crockett under the underlying agreement.

F. Conclusion

The above testimony describes PG&E's contract administration practices, changes that occurred to the contracts administered, and the results achieved with regard to contract administration during the record period, and demonstrates that PG&E's contract administration during the record period was reasonable and in compliance with SOC4.

TABLE 9-4
ENERGY PURCHASES AND COSTS[1]
JANUARY 1, 2020 THROUGH DECEMBER 31, 2020

Line No.	Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
1	Renewable Generation													
2	Total Energy (MWh)	[redacted]												10,144,659
3	Total Payments ($)													$2,155,894,756
4	Qualifying Facility and CHP Generation													
5	Total Energy (MWh)													1,866,237
6	Total Payments ($)													$141,442,856
7	Conventional Generation[2]													
8	Total Energy (MWh)													4,079,267
9	Total Payments ($)													$713,969,856
10	Other Must-Takes													
11	Total Energy (MWh)													49,144
12	Total Payments ($)													$980,144
	Resource Adequacy[3]													
13	Total Energy (MWh)													0
14	Total Payments ($)													($55,156,537)
15	Total Energy (MWh)													16,139,307
16	Total Payments ($)													$2,957,131,075

[1] Energy Purchase and Cost figures provided in this table are intended for illustrative purposes only, and may reflect simplifications and adjustments. See Chapters 12 and 13 of this testimony for more information on PABA and ERRA entries during the record period.

[2] January and February volumes are negative amounts due to Carbon Free Sales reported during those months.

[3] Sales represented as negative payments.

TABLE 9-5
CONTRACT ADMINISTRATION
CONTRACTS EXECUTED DURING RECORD PERIOD 2020[(a)(b)]

Line No.	Date	PG&E Log Number	Project Name	Capacity (MW)	Contract Type
1	2/6/2020	33R481BIO	Collins Pine Company	3	BioMAT
2	2/7/2020	33R482	Silicon Valley Clean Energy Authority	0	RPS Energy REC Sales
3	2/27/2020	12H010QPA	Deadwood Creek	2	QF/CHP Settlement Agreement
4	3/26/2020	33R083TR02	Morgan Stanley (S&F for Vantage Wind)	0	Shape & Firm
5	3/26/2020	33B252	Morgan Stanley Capital Group Inc.	0	EEI Master
6	5/12/2020	33R483	Burney Forest Products	29	RPS
7	5/12/2020	40S015	Diablo Energy Storage, LLC	50	Energy Storage
8	5/12/2020	40S016	Diablo Energy Storage, LLC	50	Energy Storage
9	5/12/2020	40S017	Diablo Energy Storage, LLC	50	Energy Storage
10	5/12/2020	40S018	Coso Battery Storage, LLC	60	Energy Storage
11	5/12/2020	40S019	Dynegy Marketing and Trade, LLC	100	Energy Storage
12	5/12/2020	40S020	Gateway Energy Storage, LLC	50	Energy Storage
13	5/13/2020	40S021	Blythe Energy Storage 110, LLC	63	Energy Storage
14	5/24/2020	33R484	Wheelabrator Shasta Energy Co, Inc	34	RPS
15	6/8/2020	33R485	Silicon Valley Clean Energy Authority	0	RPS Energy REC Sales
16	6/15/2020	33B022CA01	Shell Energy North America (US), L.P.	0	Carbon Free Energy (Sale)
17	6/15/2020	33B202CA01	Commercial Energy of Montana	0	Carbon Free Energy (Sale)
18	6/15/2020	33B211CA01	Calpine Energy Solutions, LLC	0	Carbon Free Energy (Sale)
19	6/15/2020	33B230CA01	Silicon Valley Community Energy Authority	0	Carbon Free Energy (Sale)
20	6/15/2020	33B232CA01	Peninsula Clean Energy Authority	0	Carbon Free Energy (Sale)
21	6/15/2020	33B235CA01	Marin Clean Energy	0	Carbon Free Energy (Sale)
22	6/15/2020	33B236CA02	Central Coast Community Energy	0	Carbon Free Energy (Sale)
23	6/15/2020	33B238CA02	East Bay Community Energy Authority	0	Carbon Free Energy (Sale)

TABLE 9-5
CONTRACT ADMINISTRATION
CONTRACTS EXECUTED DURING RECORD PERIOD 2020[(a)(b)]
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Capacity (MW)	Contract Type
24	6/15/2020	33B243CA01	CleanPowerSF	0	Carbon Free Energy (Sale)
25	6/15/2020	33B247CA01	City of San Jose (San Jose Clean Energy)	0	Carbon Free Energy (Sale)
26	6/18/2020	33B253	BMW of North America, LLC	0	EEI Master
27	7/1/2020	33B255	Direct Energy Business, LLC	0	EEI Master
28	7/1/2020	33B226CA01	Sonoma Clean Power Authority	0	Carbon Free Energy (Sale)
29	7/1/2020	33B245CA01	Pioneer Community Energy	0	Carbon Free Energy (Sale)
30	7/1/2020	33B255CA01	Direct Energy Business LLC	0	Carbon Free Energy (Sale)
31	7/6/2020	33R486	BMW of North America, LLC	0	RPS Energy REC Sales
32	7/8/2020	33B254	Valley Clean Energy Alliance	0	EEI Master
33	7/10/2020	33B257	City Of King dba King City Community Power	0	EEI Master
34	7/10/2020	33B258	Tiger Natural Gas, Inc.	0	EEI Master
35	7/10/2020	33B259	Redwood Coast Energy Authority	0	EEI Master
36	7/10/2020	33B261	The Regents of the University of California	0	EEI Master
37	7/10/2020	33B239CA01	Pilot Power Group, Inc.	0	Carbon Free Energy (Sale)
38	7/10/2020	33B254CA01	Valley Clean Energy Alliance	0	Carbon Free Energy (Sale)
39	7/10/2020	33B257CA01	City Of King dba King City Community Power	0	Carbon Free Energy (Sale)
40	7/10/2020	33B258CA01	Tiger Natural Gas, Inc.	0	Carbon Free Energy (Sale)
41	7/10/2020	33B259CA01	Redwood Coast Energy Authority	0	Carbon Free Energy (Sale)
42	7/10/2020	33B261CA01	The Regents of the University of California	0	Carbon Free Energy (Sale)
43	7/15/2020	33B256	San Diego Gas And Electric	0	EEI Master
44	8/26/2020	33R487BIO	WCW Generator 1	3	BioMAT
45	8/28/2020	25H149QPA	Orange Cove Irrigation Dist.	0.475	QF/CHP Settlement Agreement

TABLE 9-5
CONTRACT ADMINISTRATION
CONTRACTS EXECUTED DURING RECORD PERIOD 2020[a][b]
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Capacity (MW)	Contract Type
46	9/16/2020	33B260	RDAF Energy Solutions, LLC	0	EEI Master
47	9/30/2020	33R488	Beard	2.25	CS-GT
48	9/30/2020	33R489	Rocha	2	CS-GT
49	9/30/2020	33R490	Gonzalez	1.75	CS-GT
50	9/30/2020	33R491	Highway 43	2.25	DAC-GT
51	9/30/2020	33R492	Kern Sunset	2.4	DAC-GT
52	10/21/2020	33R493	Woodland Biomass	25	RPS
53	10/30/2020	33B262	Sierra Energy Storage, LLC	0	EEI Master
54	10/30/2020	33B263	Dynegy Marketing and Trade, LLC	0	EEI Master
55	11/2/2020	33R494	Ava Elizabeth	1.592	GTSR - PG&E RCC
56	11/2/2020	33R495	ForeFront C2	2.062	GTSR - PG&E RCC
57	12/10/2020	40S022	Daggett Solar Power 2 LLC	46	Energy Storage
58	12/10/2020	40S023	Daggett Solar Power 3 LLC	15	Energy Storage
59	12/10/2020	40S024	LeConte Energy Storage, LLC	15	Energy Storage
60	12/10/2020	40S025	North Central Valley Energy Storage, LLC	132	Energy Storage
61	12/10/2020	40S026	Nexus Renewables U.S. Inc.	27	Energy Storage
62	12/10/2020	40S027	Lancaster Area Battery Storage, LLC	127	Energy Storage

(a) See Chapter 8 for testimony regarding RA procurement.
(b) See Chapter 7 for testimony regarding GHG Compliance Instrument Procurement.

TABLE 9-6
CONTRACT ADMINISTRATION
PERMITTED EXTENSIONS DURING RECORD PERIOD 2020

Line No.	Date of Request	PG&E Log Number	Project Name	Contract Type	Description
1	8/18/2020	33R459BIO	Diamond H Dairy Power	BioMAT	GCOD[a] was extended from 10/22/2020 to 4/22/2021.

(a) Guaranteed Commercial Operation Date (GCOD).

TABLE 9-7
CONTRACT ADMINISTRATION
MISSED MILESTONES DURING RECORD PERIOD 2020

Line No.	Original Milestone Date	PG&E Log Number	Project Name	Contract Type	Milestone	Date of Event	Description
1	6/12/2020	33R435BIO	Van Der Kooi Dairy Digester	BioMAT	Guaranteed COD	6/30/2020 Early Termination Date	[redacted]
2	6/12/2020	33R441BIO	Napa Recycling Biomass Plant	BioMAT	Guaranteed COD	6/29/2020 Early Termination Date	[redacted]

TABLE 9-8
CONTRACT ADMINISTRATION
CONTRACTS THAT BEGAN DELIVERING DURING RECORD PERIOD 2020

Line No.	Date	PG&E Log Number	Project Name	Capacity (MW)	Contract Type
1	1/1/2020	13H024QPA	Olsen Power Partners	5.5	QF/CHP Settlement Agreement
2	1/1/2020	33R461	Central Coast Community Energy	0	RPS Energy REC Sales
3	1/1/2020	33R464	Silicon Valley Clean Energy Authority	0	RPS Energy REC Sales
4	1/1/2020	33R471	Clean Power Alliance of Southern California	0	RPS Energy REC Sales
5	3/1/2020	12H010QPA	Deadwood Creek	2	QF/CHP Settlement Agreement
6	5/4/2020	33R482	Silicon Valley Clean Energy Authority	0	RPS Energy REC Sales
7	6/1/2020	33R343	Midway Solar Farm I (a)	50	RPS
8	6/15/2020	33B022CA01	Shell Energy North America (US), L.P.	0	Carbon Free Energy (Sale)
9	6/15/2020	33B202CA01	Commercial Energy of Montana	0	Carbon Free Energy (Sale)
10	6/15/2020	33B211CA01	Calpine Energy Solutions, LLC	0	Carbon Free Energy (Sale)
11	6/15/2020	33B230CA01	Silicon Valley Community Energy Authority	0	Carbon Free Energy (Sale)
12	6/15/2020	33B232CA01	Peninsula Clean Energy Authority	0	Carbon Free Energy (Sale)
13	6/15/2020	33B235CA01	Marin Clean Energy	0	Carbon Free Energy (Sale)
14	6/15/2020	33B236CA02	Central Coast Community Energy	0	Carbon Free Energy (Sale)
15	6/15/2020	33B238CA02	East Bay Community Energy Authority	0	Carbon Free Energy (Sale)
16	6/15/2020	33B243CA01	CleanPowerSF	0	Carbon Free Energy (Sale)
17	6/15/2020	33B247CA01	City of San Jose (San Jose Clean Energy)	0	Carbon Free Energy (Sale)
18	6/22/2020	33R442BIO	Still Water Power	1	BioMAT
19	7/1/2020	33B226CA01	Sonoma Clean Power Authority	0	Carbon Free Energy (Sale)
20	7/1/2020	33B245CA01	Pioneer Community Energy	0	Carbon Free Energy (Sale)

TABLE 9-8
CONTRACT ADMINISTRATION
CONTRACTS THAT BEGAN DELIVERING DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Capacity (MW)	Contract Type
21	7/1/2020	33B255CA01	Direct Energy Business LLC	0	Carbon Free Energy (Sale)
22	8/1/2020	33B239CA01	Pilot Power Group, Inc.	0	Carbon Free Energy (Sale)
23	8/1/2020	33B254CA01	Valley Clean Energy Alliance	0	Carbon Free Energy (Sale)
24	8/1/2020	33B257CA01	City Of King dba King City Community Power	0	Carbon Free Energy (Sale)
25	8/1/2020	33B258CA01	Tiger Natural Gas, Inc.	0	Carbon Free Energy (Sale)
26	8/1/2020	33B259CA01	Redwood Coast Energy Authority	0	Carbon Free Energy (Sale)
27	8/1/2020	33B261CA01	The Regents of the University of California	0	Carbon Free Energy (Sale)
28	9/1/2020	25H149QPA	Orange Cove Irrigation Dist.	0.475	QF/CHP Settlement Agreement
29	9/12/2020	33R486	BMW of North America, LLC	0	RPS Energy REC Sales

(a) The project began deliveries prior to the record period but started the delivery term during the record period.

TABLE 9-9
CONTRACT ADMINISTRATION
CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2020

Line No.	Date	PG&E Log Number	Project Name	Transaction Type	Transaction Description
1	2/4/2020	33B093	Marsh Landing	Routine Amendment to Existing Agreement	Routine amendment clarifies impact of Marsh Landing's Black Start Agreement with CAISO on PG&E's existing PPA with Marsh Landing.
2	2/21/2020	40S014	Hummingbird Energy Storage, LLC	Consent to Assignment - Financing	Consent to assignment for project financing.
3	4/9/2020	33R279	Alamo Solar, LLC	Routine Amendment to Existing Agreement	Routine amendment establishes utilizing the CAISO forecast for calculating deemed delivered energy.
4	6/8/2020	33B230	Silicon Valley Clean Energy Authority	Routine Amendment to Existing Agreement	Routine amendment adds POLR language to Paragraph 10 of EEI.
5	8/6/2020	33R406	Wheelabrator Shasta	Amendment to Existing Agreement	Amendment implements certain requirements under Res.E-4977, including the monthly opt-out for feedstock requirements, updates definitions, and modifies various reporting obligations.
6	8/17/2020	33R144	Mesquite Solar 1	Short-Term Incremental Deliveries for System Reliability Needs	Short-term agreement for additional energy deliveries in response to CAISO request.
7	8/20/2020	33R254	SPI Biomass Portfolio	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
8	8/24/2020	33R406	Wheelabrator Shasta	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
9	9/4/2020	25C002	Chevron U.S.A. (Taft/Cadet)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
10	9/4/2020	25C003	Chevron U.S.A. (Cymric)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
11	9/4/2020	25C055	Chevron U.S.A. (Coalinga)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
12	9/4/2020	25C063QPA2	Frito Lay Cogen	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
13	9/4/2020	25C138QPA	Western Power and Steam II	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
14	9/4/2020	33R254	SPI Biomass Portfolio	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
15	9/4/2020	33R406	Wheelabrator Shasta	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
16	9/8/2020	33R342RM	Water Wheel Ranch	Consent to Assignment - General Consent	Consent to assignment from Water Wheel Ranch Power Project to Water Wheel Ranch LLC.
17	9/11/2020	40S015	Diablo Energy Storage, LLC	Routine Amendment to Existing Agreement	Routine amendment increases the number of days required to achieve CPUC Approval.
18	9/11/2020	40S016	Diablo Energy Storage, LLC	Routine Amendment to Existing Agreement	Routine amendment increases the number of days required to achieve CPUC Approval.

TABLE 9-9
CONTRACT ADMINISTRATION
CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Transaction Type	Transaction Description
19	9/11/2020	40S017	Diablo Energy Storage, LLC	Routine Amendment to Existing Agreement	Routine amendment increases the number of days required to achieve CPUC Approval.
20	9/11/2020	40S018	Coso Battery Storage, LLC	Routine Amendment to Existing Agreement	Routine amendment increases the number of days required to achieve CPUC Approval.
21	9/11/2020	40S020	Gateway Energy Storage, LLC	Routine Amendment to Existing Agreement	Routine amendment increases the number of days required to achieve CPUC Approval.
22	9/16/2020	25C138QPA	Western Power and Steam II	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
23	9/17/2020	33R406	Wheelabrator Shasta	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
24	9/18/2020	25C002	Chevron U.S.A. (Taft/Cadet)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
25	9/18/2020	25C003	Chevron U.S.A. (Cymric)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
26	9/18/2020	25C055	Chevron U.S.A. (Coalinga)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
27	9/18/2020	33R254	SPI Biomass Portfolio	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
28	9/21/2020	33R093	Geysers	Consent to Assignment - Financing	Consent to assignment for project financing.
29	9/22/2020	25C246	Chevron U.S.A. (SE Kern River)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
30	9/24/2020	33R479BIO	Abel Road Bioenergy	Consent to Assignment - Financing	Consent to assignment for project financing.
31	9/29/2020	33R078	Alpine Solar Project	Consent to Assignment - Financing Amendment	Amendment to the consent to assignment for project financing.
32	10/5/2020	25C138QPA	Western Power and Steam II	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
33	10/5/2020	33R254	SPI Biomass Portfolio	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
34	10/13/2020	25C002	Chevron U.S.A. (Taft/Cadet)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
35	10/13/2020	25C003	Chevron U.S.A. (Cymric)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
36	10/13/2020	25C055	Chevron U.S.A. (Coalinga)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.

TABLE 9-9
CONTRACT ADMINISTRATION
CONTRACT AMENDMENTS AND CONSENTS TO ASSIGNMENT DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Transaction Type	Transaction Description
37	10/13/2020	25C246	Chevron U.S.A. (SE Kern River)	Short-Term Incremental Deliveries for System Reliability Needs	Short-term letter agreement for additional energy deliveries in response to CAISO request.
38	10/15/2020	04H134	Yellowjacket Venture, LLC	Consent to Assignment - General Consent	Consent to assignment from John Neerhout, Jr. to Yellowjacket Venture, LLC.
39	10/21/2020	40S021	Blythe Energy Storage 110, LLC	Routine Amendment to Existing Agreement	Routine amendment increases the number of days required to achieve CPUC Approval.
40	10/23/2020	01C045	Crockett Cogeneration	Amendment to Existing Agreement	Amendment curtails energy and capacity deliveries outside of RA Measurement Hours for November and December 2020.
41	11/5/2020	33B230CA01	Silicon Valley Community Energy Authority	Routine Amendment to Existing Agreement	Routine amendment corrects a typographical error in delivery term.
42	11/6/2020	33R154AB	La Joya Del Sol #1	Consent to Assignment - Financing	Consent to assignment for project financing.
43	11/9/2020	33R343	Midway Solar Farm I	Routine Amendment to Existing Agreement	Routine amendment allows for temporary metering arrangement.
44	11/13/2020	33B075	Calpine Russell City Energy Center	Routine Amendment to Existing Agreement	Routine amendment deletes Section 14.2(c)(iv) re: Seller's joint tax filing.
45	11/16/2020	33B236CA02	Central Coast Community Energy	Routine Amendment to Existing Agreement	Routine amendment corrects a typographical error in delivery term.
46	12/17/2020	33R162	Orion Solar	Consent to Assignment - Financing	Consent to assignment for project financing.
47	12/23/2020	01C045	Crockett Cogeneration	Amendment to Existing Agreement	Amendment curtails energy and capacity deliveries outside of RA Measurement Hours for January and February 2021.
48	12/29/2020	33R163	North Sky River Energy Center	Consent to Assignment - Financing	Consent to assignment for project financing.

TABLE 9-10
CONTRACT ADMINISTRATION
FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2020

Line No.	Date of Claim	PG&E Log Number	Project Name	Contract Type	Date Closed	Description
1	6/18/2019	33R064	Ivanpah Unit 3	RPS	8/12/2020	[redacted]
2	8/15/2019	33R384	Bayshore Solar B	RPS	12/30/2020	[redacted]
3	10/23/2019	33R093	Geysers	RPS	3/19/2020	[redacted]
4	10/24/2019	33R093	Geysers	RPS	3/19/2020	[redacted]
5	11/20/2019	33R093	Geysers	RPS	3/19/2020	[redacted]
6	12/23/2019	33R093	Geysers	RPS	1/15/2020	[redacted]
7	2/5/2020	40S013	Moss Landing Energy Storage	Storage	11/18/2020	[redacted]
8	3/19/2020	40S013	Moss Landing Energy Storage	Storage	11/18/2020	[redacted]
9	3/23/2020	40S014	Hummingbird Energy Storage	Storage	Pending	[redacted]

TABLE 9-10
CONTRACT ADMINISTRATION
FORCE MAJEURE CLAIMS DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date of Claim	PG&E Log Number	Project Name	Contract Type	Date Closed	Description
10	7/16/2020	40S012	Micronoc 10 MW BTM Aggregate ESS	Storage	12/29/2020	[redacted]
11	7/23/2020	40S019	Moss 100	Storage	Pending	
12	8/31/2020	40S019	Moss 100	Storage	Pending	
13	9/19/2020	33R063	Ivanpah Unit 1	RPS	Pending	
14	9/19/2020	33R064	Ivanpah Unit 3	RPS	Pending	
15	9/28/2020	33R093	Geysers	RPS	Pending	
16	10/14/2020	33R093	Geysers	RPS	10/21/2020	
17	10/20/2020	33R337RM	Clover Flat LFG	ReMAT	Pending	
18	10/21/2020	33R093	Geysers	RPS	11/2/2020	
19	10/24/2020	33R093	Geysers	RPS	Pending	

TABLE 9-11
CONTRACT ADMINISTRATION
CONTRACTS THAT EXPIRED OR TERMINATED DURING RECORD PERIOD 2020

Line No.	Date	PG&E Log Number	Project Name	Contract Type	Description
1	1/4/2020	33R468BIO	Avalon Dairy Digester	BioMAT	Termination
2	1/28/2020	12H010	Deadwood Creek	QF	Expiration
3	2/9/2020	25C092	Fresno Cogeneration Partners, L.P.	QF	Expiration
4	2/19/2020	13H013	Snow Mountain Hydro (Cove)	QF	Expiration
5	2/24/2020	13H035	Snow Mountain Hydro (Ponderosa Bailey Creek)	QF	Expiration
6	2/29/2020	33R075	Woodland Biomass	RPS	Expiration
7	3/27/2020	13H016	Snow Mountain Hydro (Burney Creek)	QF	Expiration
8	4/22/2020	33R467BIO	WCW Generator 1	BioMAT	Termination
9	4/30/2020	33R096AB	Combie South	AB1969	Expiration
10	5/31/2020	33R141AB	NID - Scotts Flat	AB1969	Expiration
11	6/29/2020	33R441BIO	Napa Recycling Biomass Plant	BioMAT	Termination
12	6/30/2020	33R435BIO	Van Der Kooi Dairy Digester	BioMAT	Termination
13	7/29/2020	40S004	Henrietta D Energy Storage	Energy Storage	Termination
14	8/18/2020	25H150	Kings River Hydro Co.	QF	Expiration
15	8/22/2020	25H149	Orange Cove Irrigation Dist.	QF	Expiration
16	8/31/2020	15H005QPA	EIF Haypress, LLC	QF/CHP Settlement Agreement	Expiration
17	9/11/2020	01C108	Eco Services Operations LLC	QF	Expiration
18	10/3/2020	33R095	Powerex (S&F for Vantage Wind)	Shape & Firm	Expiration
19	10/13/2020	33R466BIO	Lone Oak Dairy Digester	BioMAT	Termination
20	10/14/2020	33B116	Oroville Cogeneration, L.P.	Tolling	Expiration
21	11/1/2020	33R146AB	Blake's Landing	AB1969	Expiration
22	11/30/2020	33B105QSA	Double C Limited	Tolling	Expiration
23	11/30/2020	33B106QSA	High Sierra Limited	Tolling	Expiration
24	11/30/2020	33B107QSA	Kern Front Limited	Tolling	Expiration
25	12/5/2020	01W119	Donald R. Chenoweth	QF	Termination
26	12/31/2020	33B118	Kern River Cogen Company (KRCC)	Tolling	Expiration
27	12/31/2020	33B126	Midway Sunset Cogeneration Company	Tolling	Expiration

TABLE 9-11
CONTRACT ADMINISTRATION
CONTRACTS THAT EXPIRED OR TERMINATED DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Contract Type	Description
28	12/31/2020	33R426	3 Phases Renewables, Inc.	RPS Energy REC Sales	Expiration
29	12/31/2020	33R427	Direct Energy Business Marketing, LLC	RPS Energy REC Sales	Expiration
30	12/31/2020	33R428	Exelon Generation Company, LLC	RPS Energy REC Sales	Expiration
31	12/31/2020	33R429	Shell Energy North America (US), L.P.	RPS Energy REC Sales	Expiration
32	12/31/2020	33R443	Central Coast Community Energy	RPS Energy REC Sales	Expiration
33	12/31/2020	33R451	Shell Energy North America (US), L.P.	RPS Energy REC Sales	Expiration
34	12/31/2020	33R453	Direct Energy Business Marketing, LLC	RPS Energy REC Sales	Expiration
35	12/31/2020	33R454	Clean Power Alliance of Southern California	RPS Energy REC Sales	Expiration
36	12/31/2020	33R455	Central Coast Community Energy	RPS Energy REC Sales	Expiration
37	12/31/2020	33R456	Calpine Energy Services, L.P.	RPS Energy REC Sales	Expiration
38	12/31/2020	33R457	Powerex Energy Corp.	RPS Energy REC Sales	Expiration
39	12/31/2020	33R460	Sacramento Municipal Utility District	RPS Energy REC Sales	Expiration
40	12/31/2020	33R461	Central Coast Community Energy	RPS Energy REC Sales	Expiration
41	12/31/2020	33R462	Shell Energy North America (US), L.P.	RPS Energy REC Sales	Expiration
42	12/31/2020	33R463	East Bay Community Energy Authority	RPS Energy REC Sales	Expiration
43	12/31/2020	33R464	Silicon Valley Clean Energy Authority	RPS Energy REC Sales	Expiration
44	12/31/2020	33R465	Direct Energy Business Marketing, LLC	RPS Energy REC Sales	Expiration
45	12/31/2020	33R471	Clean Power Alliance of Southern California	RPS Energy REC Sales	Expiration
46	12/31/2020	33R473	City of San Jose (San Jose Clean Energy)	RPS Energy REC Sales	Expiration

TABLE 9-11
CONTRACT ADMINISTRATION
CONTRACTS THAT EXPIRED OR TERMINATED DURING RECORD PERIOD 2020
(CONTINUED)

Line No.	Date	PG&E Log Number	Project Name	Contract Type	Description
47	12/31/2020	33R474	Peninsula Clean Energy Authority	RPS Energy REC Sales	Expiration
48	12/31/2020	33R476	Powerex Energy Corp.	RPS Energy REC Sales	Expiration
49	12/31/2020	33R477	Exelon Generation Company, LLC	RPS Energy REC Sales	Expiration
50	12/31/2020	33R478	Marin Clean Energy	RPS Energy REC Sales	Expiration
51	12/31/2020	33R482	Silicon Valley Clean Energy Authority	RPS Energy REC Sales	Expiration

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CHAPTER 10

CAISO SETTLEMENTS AND MONITORING

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CAISO SETTLEMENTS AND MONITORING

A. Introduction

This chapter describes the procurement costs and revenues associated with Pacific Gas and Electric Company's (PG&E) participation in the California Independent System Operator (CAISO) electricity markets, both Day Ahead (DA) and Real Time (RT) in 2020.

PG&E receives revenue for electric generation provided to the CAISO markets and is charged for demand representing PG&E's bundled customer load. The costs and revenues described here reflect the portion of PG&E's electric supply portfolio for which PG&E is the Scheduling Coordinator (SC). SCs are entities authorized by the CAISO to schedule and bid power on behalf of CAISO market participants. SCs also make and receive market payments and can validate and dispute market charges with the CAISO. The CAISO Settlements Department is responsible for fulfilling this payment and validation role within PG&E. The CAISO utilizes over 200 charge codes to settle its markets and the various instruments and products associated with those markets. The CAISO publishes multiple iterations of settlement statements that market participants can download and validate prior to invoicing. Settlement statements are published for each trade date. SCs can dispute these statements if errors are discovered.

As discussed in Chapter 9, PG&E filed for protection under Chapter 11 of Title 11 of the United States Code (Bankruptcy Code) on January 29, 2019 (Petition Date). In connection with the first day relief granted by the Bankruptcy Court, PG&E received limited authority to pay Prepetition Claims[1] arising from exchange obligations, including those owed to CAISO in 2020 prior to PG&E's emergence from Chapter 11 on July 1, 2020.

B. Balancing Account Allocation of 2020 CAISO Settlement Data

Beginning in 2019 and continuing through 2020, PG&E modified its balancing accounts and created the Portfolio Allocation Balancing Account

[1] Prepetition Claims are obligations which related to the period prior to the Petition Date.

(PABA) to comply with Decision (D.) 18-10-019, as discussed in Chapter 12. PG&E used the implementation of PABA in 2019 as an opportunity to separate settlement data for 2 other balancing accounts, in addition to PABA, that were reported under Energy Resource Recovery Account (ERRA) prior to 2019. These include: (1) Modified Transition Cost Balancing Account (MTCBA), (2) Green Tariff Shared Renewables Balancing Account (GTSRBA) and (3) Bioenergy Market Adjustment Tariff (BioMAT) Non-Bypassable Charge Balancing Account (BNBCBA). The Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA) data are included in the "ERRA Grid" worksheet in the Chapter 10 workpapers under the column headings Bioenergy Renewable Auction Mechanism Memorandum Account and BioMass Memorandum Account.

CAISO settlement data for market participants contain unique identifiers called Resource IDs. These allow PG&E to recognize retail load, third party generation and Utility Owned Generation (UOG) revenues and charges on a resource level in order to determine which balancing account the settlement data is assigned for reporting and cost recovery purposes.

Chapter 10 includes the latest settlement statement data published by CAISO for 2020 trade months recorded as of January 2021. There are no estimates or amounts included for periods prior to 2020. The T+9M settlement statements were included for trade months January through March, T+55B statements for trade months April through October, and T+12B statements for November and December. Each month includes the same statement version for each day of the month and is updated when CAISO publishes any revised statement versions for all trading days of the month. In contrast, the 2020 CAISO settlement amounts reflected in Chapters 12 and 13 are based upon entries recorded during 2020 through the December 2020 accounting close and include December estimated data and resettlement values for pre-2020 trade months recorded in 2020.

Total PG&E revenues and charges from CAISO netted to a credit of ($272,941,116) in 2020. These amounts were allocated and reported by balancing account as follows:

TABLE 10-1
2020 CAISO SETTLEMENT CHARGES/(REVENUES) BY BALANCING ACCOUNT

Table 10 - 2020 CAISO Settlement Charges/(Revenues) by Balancing Account

	TOTAL	ERRA	PABA	MTCBA	TMNCBA	GTSRBA	BioMAT
Day-Ahead Market	($381,584,617)	$1,286,781,564	($1,577,092,470)	($71,914,861)	($15,898,578)	($2,988,037)	($472,236)
Real-Time Market	$102,050,427	$77,575,275	$23,614,086	$461,106	$0	$276,594	$123,366
Congestion Revenue Rights	($34,751,878)	($34,751,878)	$0	$0	$0	$0	$0
Grid Management Charges	$40,537,888	$18,800,856	$20,800,983	$865,281	$0	$66,834	$3,935
FERC Fees	$3,402,971	$3,402,971	$0	$0	$0	$0	$0
Other	($2,595,906)	$67,836,901	($69,644,597)	($808,982)	$0	$19,173	$1,599
TOTAL	($272,941,116)	$1,419,645,688	($1,602,321,998)	($71,397,455)	($15,898,578)	($2,625,437)	($343,335)

Power costs recorded in ERRA are applicable solely to PG&E's bundled customers while power costs incurred on behalf of both bundled and departing load customers are recorded and recovered in PABA. The purpose of the MTCBA is to recover net above market costs associated with Ongoing Competition Transition Charge eligible generation. TMNBCBA recovers the net electric procurement costs of Power Purchase Agreements (PPA) related to Tree Mortality in compliance with Senate Bill (SB) 859 and Resolutions E-4770 and E-4806 as defined in D.18-12-003. The GTSRBA tracks revenues received and actual expenses incurred to procure renewable generation resources for customers participating in Green Tariff Shared Renewables programs. Finally, the BNBCBA records the net costs of BioMAT contracts in compliance with SB 1122, as revised in D.20-08-043.

1. CAISO Market Costs

The charges and revenues that result from the CAISO's market activity are described in this section.

a. DA Market

The CAISO runs a DA Market for energy and Ancillary Service (A/S), referred to as the Integrated Forward Market (IFM). PG&E's electric supply portfolio receives revenues for awarded energy and A/S capacity through these markets. PG&E is also charged for the amount of demand scheduled and bid on behalf of PG&E's bundled load. In addition to the energy and A/S markets, the CAISO runs a Residual Unit Commitment (RUC) process after the IFM. If needed, the CAISO procures additional capacity through this process. Based on the CAISO's procurement through the IFM and RUC, it may be necessary to collect additional funds, or market uplifts, from market participants based on their net market positions. These uplift charges are often based on the amount of demand a market participant has in the CAISO markets. This amount includes charges for energy purchased for PG&E's bundled customer load, A/S portfolio obligations, and market uplifts needed to maintain cash neutrality for the CAISO. These charges are offset by revenues for awarded energy and A/S schedules for PG&E's portfolio generation.

b. Real-Time Market (RTM)

The CAISO's RTM includes the costs and revenues related to the dispatch of energy, unscheduled bundled customer load and procurement of A/S. The RTM is comprised of 5-minute dispatch and settlement and the Fifteen-Minute Market (FMM) resulting from the implementation of Federal Energy Regulatory Commission (FERC) Order 764 beginning in 2014. Also included are the financial settlements related to intertie awards, for both imports and exports, which are generated through the Hour-Ahead Scheduling Process and the FMM. The dispatch of energy in RT is settled through the use of imbalance energy charge codes. Dispatches are paid or charged through the Instructed Imbalance Charge Code mechanism, while deviations from schedule or dispatch are settled through the Uninstructed Imbalance Charge Code mechanism. Similar to the DA Markets, market uplifts are utilized to fund any revenue shortfalls in the RTM.

c. Congestion Revenue Rights

Congestion Revenue Rights (CRR) are financial instruments that allow the holder to hedge congestion costs in the IFM. CRRs are defined between any two nodes in the CAISO transmission network model. The revenue (or shortfall) associated with a CRR on a path is the difference between the congestion component of the source Locational Marginal Price (LMP) and the congestion component of the sink LMP. CRRs, with their associated cash flows, enable Load Serving Entities (LSE), such as PG&E, to mitigate potential congestion costs associated with the price the CAISO charges to serve LSE loads. CRRs are acquired through a yearly and monthly allocation and auction process.

d. Grid Management Charges

Grid Management Charges (GMC) are comprised of daily and monthly charges which are assessed to market participants for the purpose of recovering all CAISO operating costs. The CAISO currently has incorporated three cost service-based GMCs, a fixed Transmission Ownership Rights GMC, as well as four transactional and administrative GMCs. The cost services GMC consist of: (1) a Market Services Charge; (2) a System Operations Charge; and (3) a CRR Services Charge. The five transactional and administrative fees consist of: (1) a Bid Segment Fee; (2) a CRR Transaction Fee; (3) an Inter-SC Trade Transaction Fee; (4) a SC ID Charge and (5) a RC Services Charge. All of these GMCs represent the various ways market participants interact with the CAISO on a day-to-day basis.

e. FERC Fees

FERC fees are allocated to CAISO market participants in accordance with the CAISO Tariff. The fees represent estimated and actual FERC operating costs for its electric regulatory program. The CAISO allocates the fees to each market participant based on their use of the CAISO grid.

f. Other

Other charges and credits include Unaccounted for Energy, Bid Cost Recovery, Convergence Bidding, A/S, DA IFM Credit Allocation, RT Imbalance Energy Offset, Resource Adequacy Availability Incentive Mechanism (RAAIM) and other miscellaneous categories.

C. Miscellaneous

1. CAISO Tariff Section 37 Sanction Charges

CAISO Tariff Section 37 Rules of Conduct set forth the guiding principles for participation in the markets administered by the CAISO. Under these rules, sanction charges can be assessed as the result of market participants' failure to respond to CAISO requests for data or perform certain functions across a potential range of areas.[2] Incidents that can trigger a sanction include failure on a timely basis to report generator outages, submit meter data and/or provide other information required by the CAISO Tariff. Responsibility to comply with CAISO Section 37 requests can rest with third party generators.[3]

During the record period PG&E was assessed charges totaling $717,000 related to non-compliance with CAISO Tariff Section Rules of Conduct associated with either its load (non-demand response), generation, or storage portfolio:

- $469,500 in sanction charges was attributed to 26 contracted generating resources failing to complete transmission modeling data requests or to resolve telemetry communication issues by the CAISO mandated deadlines. PG&E, as SC for these 26 contracted generators, received the sanction charges via CAISO invoices, however, these costs are the responsibility of the generators per their PPA with PG&E. As such, PG&E passed through all of the $469,500 in charges to the 26 generators as offsets to their monthly contract settlement payments in 2020;
- $43,500 in sanction charges was related to UOG resources due to the late submission of transmission modeling data or telemetry communication. These costs are included in PABA;
- $202,000 in sanction charges was due to the filing of inaccurate settlement quality meter data for PG&E retail load from November 30, 2018 to June 24, 2019. In 2019, PG&E enhanced its meter data validation process and identified 37 meters, out of the over five million meters, that were misconfigured. PG&E notified the CAISO and submitted corrected meter data for the time period April 17, 2019 to June 24, 2019 based on the timeline as allowed under the CAISO Tariff. The CAISO penalty costs are included in ERRA; and

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2 See CAISO Tariff Section 37 – Rules of Conduct (Rev. 9-9-20).

3 CAISO Tariff Section 37.9.3.3 – Other Responsible Party.

- $2,000 was related to the late submission of monthly Resource Adequacy (RA) and supply plans to CAISO. These costs are included in ERRA.

2. CAISO RAAIM Non-Availability Charges associated with RA Compliance Showing

CAISO Tariff Section 40.9 RAAIM set forth the assessment of availability of resources during a set of pre-defined availability assessment hours. Under this mechanism, RA resources receive incentive payments if capacity availability is above the monthly Availability Standard and incur non-availability charges if capacity availability is below the monthly Availability Standard.[4] During the January 2019 through February 2020 RA compliance period, PG&E inadvertently committed capacity from one PPA resource in the amount above the contract quantity in PG&E's RA compliance showing (excess of 0.40 MW each month). This error was due to an internal source spreadsheet that contained a higher monthly capacity amount which was based on the CAISO's Net Qualifying Capacity, rather than the PPA contract quantity. As a result, PG&E incurred a total of $27,507 in non-availability charges ($24,585 for January – December 2019; $2,922 for January and February 2020). These non-availability charges were not passed through to the responsible third-party generator since the error was caused by PG&E's internal source data. PG&E has since corrected the source spreadsheet for the remaining months of 2020 (March – December). These non-availability charges are included in PABA.

D. Conclusion

The above testimony describes the CAISO costs that were incurred during the record period and demonstrates that these costs were reasonable and prudently incurred.

4 See CAISO Tariff Section 40.9.3 – Availability Assessment

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CHAPTER 11

REVIEW ENTRIES RECORDED IN THE GREEN TARIFF SHARED RENEWABLES MEMORANDUM ACCOUNT AND THE GREEN TARIFF SHARED RENEWABLES BALANCING ACCOUNT

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A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its 2020 recorded Green Tariff Shared Renewables (GTSR) administrative and marketing costs for reasonableness review, as directed by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 15-01-051, the *Decision Approving Green Tariff Shared Renewables Program for San Diego Gas & Electric Company, Pacific Gas and Electric Company, and Southern California Edison Company Pursuant to Senate Bill 43*. In addition, PG&E is presenting costs and revenues recorded to the Green Tariff Shared Renewables Balancing Account (GTSRBA) for review to ensure compliance with applicable tariffs[1] and Commission directives, as required in D.15-01-051.[2]

Senate Bill (SB) 43 requires the three large electrical utilities to implement the GTSR Program. SB 43 further requires that participating customers pay the administrative and marketing costs of the GTSR Program.[3] The Investor-Owned Utilities (IOU) are collecting administrative costs, as well as marketing costs, from GTSR customers through specific charges.

In D.15-01-051, the Commission required that administrative and marketing costs be tracked in a memorandum account and be subject to reasonableness review in each IOU's annual Energy Resource Recovery Account (ERRA) compliance review. Costs that are found not to be reasonable cannot be

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1 GTSRBA – Electric Preliminary Statement GR: http://www.pge.com/tariffs/tm2/pdf/ELEC_PRELIM_GR.pdf.

2 D.15-01-051, Finding of Fact (FOF) 137: Coordinating review of true-up of GTSR charges and credits with the ERRA process will provide greater certainty that entries to the GTSR accounts are stated correctly and are consistent with Commission decisions and Conclusion of Law (COL) 59: It is appropriate for an IOU to provide a summary and true-up of costs and revenues against charges and credits applied to GTSR customers on an annual basis, either through the IOU's annual ERRA process or in a separate application.

3 D.15-01-051, p. 108.

collected from customers participating in the program and will be borne by shareholders. Program startup costs that are found to be reasonable can be amortized.[4]

In D.15-10-051, the CPUC approved two program offerings under the GTSR: (1) a "green tariff" (which PG&E began offering to customers in January 2016 under the program name "PG&E's Solar Choice"); and (2) an "enhanced community renewables" (ECR) offering—which PG&E opened for developer participation in November 2015 and is called "Regional Renewable Choice." In D.16-05-006, the *Decision Addressing Participation of Enhanced Community Renewables Projects in the Renewable Auction Mechanism and Other Refinements to the Green Tariff Shared Renewables Program*, the Commission provided further refinements to both programs.

B. Green Tariff Shared Renewables Memorandum Account

1. Description of Costs Incurred

In 2020, PG&E incurred $1,447,944 in expenses in order to implement and manage the GTSR Program. These expenses can be broken down into five major categories: (1) program management; (2) Information Technology (IT)/billing system; (3) energy procurement; (4) contact center operations; and (5) outreach. The recorded expenses, by category, are shown in Table 11-1. The expenses were recorded into a memorandum account in accordance with D.15-01-051.[5] PG&E implemented careful tracking of administrative and marketing costs through the use of internal order numbers in order to maintain non-participant indifference of such costs.[6]

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4 D.15-01-051, p. 113.

5 D.15-01-051, COL 58, p. 178.

6 PG&E is providing workpapers for this chapter which provide additional detail.

TABLE 11-1
GTSR MEMO ACCOUNT 2020 RECORDED COSTS

Line No.	Description	Amount
1	Program Management	$205,596
2	IT/Billing System	1,054,679
3	Energy Procurement	106,008
4	Contact Center Operations	23,250
5	Outreach	58,411
6	Total	$1,447,944

2. Program Management

PG&E incurred $205,596 in 2020 in program management labor and expenses to administer the GTSR Program. The activities associated with this work included ensuring compliance with all regulatory requirements, implementing customer-facing changes to rates and tariffs, overseeing the contact center and billing operations functions, addressing customer inquiries, and filing required reports. The program management function also managed the external advisory board and ran two advisory board meetings in 2020.

This category of expenses also included project management functions, such as developing budgets and detailed schedules, establishing internal reports, and managing regular team meetings. It includes financial planning and analysis for the program, as well as incidental administrative charges, such as the Green-e Energy certification fee. Finally, strategic planning for long-term program sustainability and Information Technology (IT) management activities are captured in this category.

3. IT/Billing System Work

PG&E incurred $1,054,679 in 2020 in expenses associated with implementing and maintaining the IT and billing system work for the GTSR Program. In 2020, the work entailed significant IT development to complete the bulk of the development of an IT platform and billing functionality for the ECR portion of the GTSR program. PG&E refers to this program by its customer-facing name: Regional Renewable Choice.

The back-end billing system functionality enables: determination of customer eligibility; enrollment and de-enrollment; calculation of appropriate charges; bill presentment; and all associated revenue accounting and reporting. The functionality also enables Customer Service Representatives (CSR) to view customized bill impacts for customers, and provides CSRs the ability to enroll and de-enroll customers. Finally, the customer-facing website and energy portal enable customers to self-serve at a lower cost to the program by viewing the same customized bill impact information online, and to enroll in or de-enroll from the program directly.

In addition to the IT work done on PG&E's billing system and customer-facing website, significant work went into completing a Salesforce-based IT platform for program managers to manage projects and developers, as well as provide insights to developers about their projects and customers. The complex eligibility requirements of the ECR program, such as the ongoing 1/6 residential load requirement, coupled with the reality that customers will come and go over the life of a solar project, necessitated this platform. IT work for the ECR program was largely completed in 2020 and expenditures in 2021 and subsequent years are expected to decrease significantly.

Some additional IT work for the Solar Choice program was necessitated due to decreasing program costs and possible enrollment in the program up to the program cap. This work is being completed to make sure PG&E maintains enrollment within the capacity limits set by the CPUC as well as manage a waitlist to manage customers after the cap has been reached. This work began in Q4 2020 and is expected to continue through mid-2021.

4. Energy Procurement

PG&E incurred $106,008 in energy procurement expenses associated with administration of the GTSR program in 2020. This work included completion of the Winter 2018 ECR solicitation, running a Fall 2020 ECR solicitation, and additional miscellaneous program support, including strategic planning for Green Tariff/Solar Choice procurement.

Energy procurement work also included the management of existing contracts, settlements, and reporting work, as well as renewable energy credit tracking, reporting, and retirement.

5. Contact Center Operations

PG&E incurred $23,250 in contact center operations expenses in 2020. These included supporting customer inquiries, enrollment and de-enrollment in the GTSR Program through the contact centers. It also included maintenance of contact center tools and resources, such as the Interactive Voice Response system and the CSR tools, to better support customers in learning about or enrolling in the program.

6. Outreach

PG&E incurred $58,411 in contract and labor costs in development of outreach strategies and tactical plans in 2020. This included development and deployment of acquisition and retention tactics: digital advertisements, e-mails, direct mail, small and large commercial business sales support, website, and integrating the solar choice message within other relevant communications.

C. Green Tariff Shared Renewables Balancing Account

1. Background

As discussed above, the Commission approved D.15-01-051, implementing the GTSR Program in January 2015. PG&E's program includes two GTSR electric rate schedules: Schedule-EGT (Green Tariff Program) and Schedule E-ECR (ECR Program). Under E-GT, customers purchase energy supplies via a portfolio of new solar photovoltaic generation facilities sized 0.5 to 20 megawatts located within PG&E's service area and under contract with PG&E. In 2020, no customers took service under the E-ECR tariff. Consistent with the legislative requirement that non-participating customers remain indifferent to the GTSR Program, the Commission determined that each IOU is required to establish a balancing account to track the costs and revenues of the program.[7]

The purpose of the GTSRBA is to track revenues received and actual expenses incurred to procure renewable generation resources for customers participating in the GTSR Program, taking service under the Green Tariff

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[7] D.15-01-051, p. 129; FOF 145, "A balancing account will allow the IOU to track revenue under and over collection of GTSR costs using balancing account ratemaking standards."

Rate (Schedule E-GT) and the ECR (Schedule E-ECR). During the record period, customers only took service under the E-GT option. An overview the Green Tariff Shared Renewables Memorandum Account and GTSRBA are shown in Table 11-2 below.

TABLE 11-2
MEMORANDUM AND BALANCING ACCOUNTS

	GTSR Memorandum Account	GTSR Balancing Account	Generation Revenue and Energy Resource Recovery Account (ERRA)
Credit	***Revenues***: - GT/ECR Admin. - GT Marketing - ECR Marketing	***Revenues:*** - Solar Generation (GT only) - Program Charge – less A&M ***Expense*** - GT Solar Resource backstop	***Expense:*** - Solar Generation (GT only) * Interim Pool Only - Program Charge – less A&M
Debit	***Expenses:*** - GT/ECR Admin - GT Marketing - ECR Marketing	***Expenses:*** - Solar Generation (GT only) * Interim Pool and/or * GT Solar Resources - Program Charge – less A&M	***Generation Revenue***: - Class Average Gen. Credit ***Expense:*** ***GT Resources*** - GT Solar Resource backstop ***ECR Resources:*** - unsubscribed ECR energy

On December 6, 2018, PG&E submitted Advice Letter 5439-E, requesting revisions to the GTSRBA preliminary statement. The advice letter proposed modification of the GTSRBA to include separate subaccounts for the Green Tariff Program versus the ECR Program so that activity for the two programs can be recorded to its own unique subaccount. The advice letter was approved on March 28, 2020 with an effective date of January 9, 2020.

2. Rate Design Overview

Table 11-3 below provides the framework for how the credit and charge components are included in the E-GT tariff option, by illustrating where each of the components is reflected in the rates shown in the tariff and how the tariff rates are presented on customers' bills. As shown in the tables below, the rate components will roll-up to either to the Solar Charge, Power Charge

Indifference Adjustment (PCIA) Program Charge or the Program Charge-Other (generation-related).

TABLE 11-3
ALLOCATION OF CHARGES AND CREDITS

<table>
<tr><th>Component</th><th>Charges</th><th>Credits</th><th>Tariff Presentation</th><th>Bill Presentation</th></tr>
<tr><td>Solar Generation</td><td></td><td rowspan="3"></td><td rowspan="3">Solar Charge</td><td rowspan="3">Solar Charge</td></tr>
<tr><td>– GT Interim Pool</td><td>✓</td></tr>
<tr><td>– GT Solar Resource</td><td>✓</td></tr>
<tr><td>Power Charge Indifference Adjustment (PCIA)</td><td>✓</td><td></td><td>Program Charge - PCIA</td><td>Program Charge - PCIA</td></tr>
<tr><td>Renewable Integration</td><td>✓</td><td></td><td rowspan="7">Program Charge - Other (Gen-Related)</td><td rowspan="8">Program Charge</td></tr>
<tr><td>Resource Adequacy</td><td>✓</td><td></td></tr>
<tr><td>Grid Management Charges</td><td>✓</td><td></td></tr>
<tr><td>WREGIS Fees</td><td>✓</td><td></td></tr>
<tr><td>Solar Value Adjustments</td><td rowspan="3"></td><td></td></tr>
<tr><td>- Time of Use</td><td>✓</td></tr>
<tr><td>- Resource Adequacy</td><td>✓</td></tr>
<tr><td>Program Administration and Marketing</td><td>✓</td><td></td><td>Program Charge - (Marketing & Admin)</td></tr>
<tr><td>Class Average Generation Credit</td><td></td><td>✓</td><td>Generation Credit</td><td>Generation Credit</td></tr>
</table>

Revenues billed under the E-GT option are credited to the GTSRBA E-GT subaccount. Specifically, billed revenues to be credited to the account are as follows:

- Solar Generation
- Program Charge – PCIA
- Program Charge – Other

Expenses for the E-GT option recorded to the GTRSBA E-GT Subaccount include solar generation expenses, the PCIA Program Charge, and a Program Charge for the other expenses (generation-related), net of marketing and administration costs. In 2020, the E-GT Program was served exclusively with dedicated resources which were operational in 2020. The costs of these resources were recorded directly to the GTSRBA.

Expenses for the generation-related program charge were credited from ERRA and debited to the GTSRBA based on the generation- related program charge, less allowance for Franchise Fees and Uncollectibles accounts expense, multiplied by customer usage, in kilowatt-hour.

The class average generation revenue credit on customer bills was allocated to the generation balancing accounts based on PG&E's Preliminary Statement I allocations. The generation revenue credits will offset the otherwise applicable schedule's generation revenues, recorded to the generation accounts.

3. Balancing Account Entries for the Record Period

Table 11-4 summarizes the balancing account entries for the record period. As described above, the billed revenues and expense recorded to the account follow the categories illustrated in Table 11-3 above, for both billed revenues and expenses incurred. In addition to recording expenses to the account, in December 2020, PG&E recorded a backstop entry to transfer the costs from the GTSRBA associated with the GTSR Program's dedicated resource deliveries that were in excess of the subscription levels for 2019 to ERRA. An additional adjusting entry to true-up the Resource Adequacy (RA) charge using the final RA adder issued in PG&E's ERRA Forecast proceeding was implemented during the December close and the results are reflected in the GTSRBA ending balance.

D. Conclusion

In this chapter, PG&E described its 2020 recorded administrative and outreach expenses for the GTSR Program. PG&E's workpapers include more detailed information regarding the specific, recorded administrative and outreach expenses. PG&E requests that the Commission review and approve that PG&E's 2020 recorded administrative and outreach expenses are reasonable.

Additionally, this chapter presents PG&E's entries to the GTSRBA for compliance review. PG&E requests that the Commission find the entries were made to the GTSRBA in compliance with the applicable tariffs and Commission directives.

TABLE 11-4
BALANCING ACCOUNT ENTRIES

GREEN TARIFF SHARED RENEWABLES BALANCING ACCOUNT

Tariff Line Item	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
5.A	**GT Subaccount**													
Billed Revenues - Net, excluding the allowance for RF&U accounts expense														
	The following revenue entries shall be made each month:													
5.A.1	E-GT Solar Charge Revenue	(422,286)	(377,307)	(304,345)	(403,593)	(360,841)	(443,373)	(563,898)	(516,456)	(470,713)	(336,235)	(600,823)	(380,430)	(5,180,299)
5.A.2	E-GT Program Charge Revenue, including PCIA and excluding A&M	(214,730)	(195,991)	(153,365)	(212,287)	(167,267)	(267,632)	(352,282)	(315,601)	(290,408)	(211,995)	(362,544)	(350,606)	(3,094,705)
	Net Revenues - GT Subaccount	(637,016)	(573,298)	(457,710)	(615,880)	(528,108)	(711,004)	(916,180)	(832,057)	(761,121)	(548,230)	(963,366)	(731,036)	(8,275,004)
Expenses - Solar Charge and Program Charge (includes PCIA)														
	The following expense entries shall be made each month:													
5.A.3	Interim Pool Solar Generation Expense	[redacted]												
5.A.4	GTSR Dedicated Resource Expense													
5.A.5	Program Charge expense, including PCIA and excluding A&M													
	Net Expenses - GT Subaccount	546,359	824,191	732,219	861,692	1,157,630	1,144,040	1,657,406	1,335,742	1,023,594	819,480	786,420	630,496	11,519,268
	Net Activity before interest - GT Subaccount	(90,657)	250,893	274,510	245,812	629,522	433,036	741,226	503,686	262,473	271,251	(176,947)	(100,540)	3,244,264
5.A.6	Interest	328	410	747	1,003	1,041	422	359	352	340	367	341	210	5,918
Expense True-up Entries														
	The following entries will be made annually as data becomes available:													
5.A.7	Interim Pool Solar Generation Expense True-up													
5.A.8	Program Charge expense True-up													
	Net Activity - GT Subaccount	(90,329)	251,303	275,257	246,815	630,562	433,457	741,585	504,038	262,813	271,617	(176,606)	(100,330)	3,250,183
	Beginning Balance	276,572	186,243	437,546	712,803	959,618	1,590,180	2,023,638	2,765,223	3,269,260	3,532,074	3,803,691	3,627,085	276,572
	Ending Balance - GT Subaccount	186,243	437,546	712,803	959,618	1,590,180	2,023,638	2,765,223	3,269,260	3,532,074	3,803,691	3,627,085	3,526,755	3,526,755
6	**DISPOSITION**													
6.a	Disposition of the GTSRBA balance attributable to oversupply of dedicated resources												(3,284,413)	(3,284,413)
6.b	Disposition of the GTSRBA balance excluding amounts attributable oversupply of dedicated resources through: (a) the advice letter process or (b) through an Application.													
	GTSRBA Beginning Balance	-	186,243	623,789	1,336,592	2,296,210	3,886,390	5,910,027	8,675,250	11,944,510	15,476,584	19,280,275	22,907,360	-
	GTSRBA Ending Balance	186,243	623,789	1,336,592	2,296,210	3,886,390	5,910,027	8,675,250	11,944,510	15,476,584	19,280,275	22,907,360	23,149,702	242,342

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

SUMMARY OF PORTFOLIO ALLOCATION BALANCING ACCOUNT ENTRIES FOR THE RECORD PERIOD

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CHAPTER 12
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, 2020 (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 2020 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 2020 MPB values were incorporated into the PABA during the November 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). 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,[2] RA Activity,[3] Adopted UOG Revenue Requirements, California Independent System Operator (CAISO) Related Charges and Revenues, Fuel Costs, Contract Costs, Greenhouse Gas (GHG) Costs, and Miscellaneous Costs.[4] 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

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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] 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.

[3] *Id.*

[4] 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.

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.
- 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 Part I,[5] 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

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5 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.

specific rate component by balancing account.[6] 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 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.

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

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6 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.

Investor-Owned Utility (IOU) compliance from PCIA-eligible portfolio) at the Final RPS Adder, or benchmark price.[7]

Table 12-1 summarizes the value of Sold, Unsold, and Retained RPS recorded to the PABA. The sold RPS represent all RPS sales transacted for 2020 deliveries through PG&E's Bundled RPS Sales Solicitations and settled during the record period,[8] totaling a value of 7,442 gigawatt-hour (GWh) at the transacted price. During the record period, PG&E did not record any unsold Renewable Energy Credits (REC) to PABA. Lastly, the retained RECs represent the total 2020 generation, less the sold RPS quantity, less the unsold RPS quantity,[9] totaling a value of [redacted] at the RPS Adder, or benchmark price of $15.10 per MWh.

TABLE 12-1
RPS ATTRIBUTE VALUE FOR PABA

Line No.		Value ($ per MWh)	GWh	$ millions
1	Sold RPS (Valued at Transacted Price)	[redacted]	7,442	[redacted]
2	Unsold RPS (Valued at $0)	$0	0	$0
3	Retained RPS (Valued at RPS Adder)	$15.10	[redacted]	

a. Sold RPS

PG&E sold RPS volumes for 2020 deliveries, in adherence with the Commission-approved Sales Framework in its 2017 RPS Plan and its 2018 RPS Plan.[10] The total sales for 2020 deliveries equate to 7,690 GWh.[11] Transactions related to PCIA-recoverable resources totaled 7,442 GWh and were recorded in PABA as sold RPS at the transaction price ranging from [redacted], totaling notional value of [redacted] for 2020 deliveries. In addition, during the record period PG&E also recorded [redacted] in prior period adjustments for 2018

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

8 REC volumes are associated with 2020 deliveries recorded through the December 2020 close and do not include any true-ups found in periods after December 2020.

9 As noted above, PG&E did not record any unsold volumes during 2020.

10 The RPS sales framework was approved in D.19-12-042.

11 This amount is the total sold volumes related to all resources regardless of recovery mechanism. Of this amount, 248 GWh of sold volumes were recorded in the Tree Mortality Non-Bypassable Charge Balancing Account.

and 2019 deliveries.[12] The total value of these adjustments plus 2020 deliveries equals a total of $112 million as recorded in Accounting Procedure 5.f. of Preliminary Statement HS.

b. Unsold RPS

Pursuant to D.20-02-047, PG&E is not including actual Unsold RPS for 2020 as a tracking framework within PABA has yet to be developed to determine 'whether retired RECs in PABA were "unsold" or "retained for compliance.

c. 2020 Retained RPS

PG&E's retained RPS volumes for 2020 deliveries is calculated by taking the total 2020 RPS generation, less the quantity sold, less the unsold RPS for 2020 deliveries. This calculation equates to [redacted] (total 2020 generation) – 7,690 GWh (total RPS sales for 2020 deliveries) – 0 GWh (unsold RPS sales for 2020 deliveries in the 2020 Bundled RPS Sale Solicitation) or 11,942 GWh of retained RPS. Of this amount, 11,709 GWh were retained from PCIA-eligible resources and recorded to the PABA[13]. 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 2020 deliveries. In addition, during the record period PG&E also recorded [redacted] in prior period adjustments for 2019 deliveries.[14] The total value of these adjustments plus 2020 deliveries equals a total of $274 million as recorded in Accounting Procedures 5.h. and 5.i. of Preliminary Statement HS.

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[12] During the record period, PG&E recorded a $16 million reclassification of 2018 REC Sales from PABA to ERRA as explained in PG&E's 2019 ERRA Compliance Rebuttal Testimony. In addition, PG&E recorded a [redacted] true-up for 2019 deliveries in the normal course of business.

[13] REC volumes are associated with 2020 deliveries recorded through the December 2020 close and do not include any true-ups found in periods after December 2020.

[14] During the record period, PG&E recorded a $93 million adjustment for its 2019 unsold adjustments as required by D.20-02-047 and explained in PG&E's 2019 ERRA Compliance Rebuttal Testimony. In addition, PG&E recorded a [redacted] true-up for 2019 deliveries in the normal course of business.

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

The 2020 Retained and Sold RECs recorded in the PABA were allocated to the vintages based on the adopted 2020 ERRA Forecast portfolio position.[15] Specifically, the allocation factors were developed using the forecasted GWhs of eligible RPS energy assigned to each vintage.[16] The table below shows the 2020 REC allocation factors used to allocate recorded retained REC amounts and proceeds associated with RECs sold to third parties.

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

[16] The forecasted GWhs were extracted from PG&E's Joint IOU Common Template workpaper supporting the 2020 Update to Prepared Testimony filed on November in 2019 in Application (A.) 19-06-001, and supporting D.20-02-047.

TABLE 12-2
2020 REC ALLOCATION FACTORS BY PABA SUBACCOUNT

Line No.		Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
1	GWh	909.05	9,766.52	4,525.01	1,369.33	1,494.19	1,126.99	17.70	377.36	194.27	52.64	51.05	13.32	0.48	19,897.90
2	Percent of Total GWh	4.57%	49.08%	22.74%	6.88%	7.51%	5.66%	0.09%	1.90%	0.98%	0.26%	0.26%	0.07%	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, 2020 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.[17]

The following sections describe how PG&E's RA activities described in Chapter 8 during the 2020 record period are accounted for in the PABA account.

a. Sold RA

PG&E offered to sell 2020 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.

[17] 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 $87 million for the record period.[18]

b. Unsold RA

PG&E's unsold RA volumes for 2020 deliveries represents 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.[19] In total, [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.[20]

c. 2020 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 Forecast RA Adder throughout the year, which is trued up using the

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18 2020 Sold RA value recorded to Accounting Procedure 5.e. of Preliminary Statement Part HS includes any adjustments for true-ups to prior periods.

19 PG&E's 2020 QCRs were submitted to the Commission in the following ALs: (1) AL 5815-E (Quarter 1), (2) AL 5897-E (Quarter 2), (3) AL 5986-E (Quarter 3); and (4) AL 6069-E (Quarter 4).

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

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	$5.02	[redacted]	
2	Local – SCE	$4.84		
3	Flex	$4.65		
4	System	$5.20		

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

The 2020 retained and sold RA recorded in the PABA were allocated pro-rata to the vintages based on the adopted 2020 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.[21] Table 12-5 below shows the 2020 RA allocation factors used to allocate recorded retained RA amounts and revenues associated with RA sold to third parties.

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21 The forecasted NQCs were extracted from PG&Es Joint IOU Common Template workpaper supporting the 2020 Update to Prepared Testimony filed in November 2019 in A.19-06-001 and supporting D.20-02-047.

TABLE 12-5
2020 RA ALLOCATION FACTORS BY RA TYPE AND PABA SUBACCOUNT

Line No.		Legacy UOG	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
1	**Local**														
2	NQC (MW-Year)	46,489.49	20,688.08	1,484.49	2,588.58	1,409.09	105.39	14.71	83.42	661.18	37.36	0.00	87.33	0.00	73,649.12
3	Percent of Total	63.12%	28.09%	2.02%	3.51%	1.91%	0.14%	0.02%	0.11%	0.90%	0.05%	0.00%	0.12%	0.00%	100.00%
4	**Flex**														
5	NQC (MW-Year)	15,602.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15,602.98
6	Percent of Total	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
7	**System**														
8	NQC (MW-Year)	40,310.87	1,833.49	1,375.14	662.33	1,160.68	552.07	2.59	65.55	0.00	16.37	0.00	218.36	0.00	46,197.45
9	Percent of Total	87.26%	3.97%	2.98%	1.43%	2.51%	1.20%	0.01%	0.14%	0.00%	0.04%	0.00%	0.47%	0.00%	100.00%

4. Adopted UOG Revenue Requirements

As affirmed in D.18-10-019,[22] 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 2002.[23] 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. 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.

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 renewable 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.

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

23 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.

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.

Finally, the power generation portion of the adopted Catastrophic Event Memorandum Account interim rate relief recorded in PABA are related to PG&E's hydroelectric generation facilities and therefore assigned to the UOG Legacy vintage.

5. CAISO Related Charges and Revenues

As described in Chapter 10, PG&E both 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. PG&E assigns these CAISO related charges and revenues to PABA vintages based upon the vintage the contract or UOG resource is assigned.

The total amount recorded in the PABA for the recorded period is a credit of $1,646.9 million.[24] Further details on the types of charges, PG&E

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[24] This amount includes all CAISO settlement amounts recorded during 2020 accounting closes through December 31, 2020. CAISO settlement amounts reflected in Chapter 10 includes all settlement data for 2020 trade months, including those recorded during January 2021 accounting close.

activities in the CAISO Market, and the basis for assigning to vintages is included in Chapter 10.

6. Fuel Costs

Costs of fuel used to supply UOG facilities and tolling contracts are recoverable in PABA and are allocated to the same vintages the UOG facilities and contracts are assigned. Total gas costs are allocated based on fuel used for 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.v. 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.

7. Contract Costs

As 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. In addition, new Qualifying Facility Standard Offer Contract obligations authorized pursuant to D.20-05-005 are recorded to a new non-vintage subaccount, as found in accounting procedure 5.aa.

8. 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.18-10-09, OP 8 modified D.12-04-046, 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 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.[25]

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 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, the Commission issued D.20-05-004 in May 2020 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 the manner consistent as 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 New System Generation Balancing Account (NSGBA), and bundled-only resources will be recorded in ERRA. Thus, a new GHG Balancing Account Table will be added to show the total GHG costs recorded to each balancing account during the record year.

a. PG&E's Process for Recording of 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

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

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.[26]

PG&E's current methodology for calculating the WAC is consistent with D.19-04-016.[27] 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.

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26 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.

27 Issued by the Commission on April 25, 2019.

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.[28] In these cases, GHG emission costs are 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.

9. Miscellaneous Costs

PG&E is authorized to recover indirect costs that support PG&E's management of its procurement/generation resource portfolio.[29] These costs include credit and collateral and third-party independent evaluator reviews.[30] 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 Balancing Account (PUBA).[31] Finally, PG&E is authorized to or from other accounts as authorized by the Commission.[32]

In Advice 5440-E, the Commission approved allocating credit and collateral and Western Renewable Energy Generation Information System (WREGIS) certificate fees among PABA, ERRA, and the NSGBA based on

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28 See Chapter 7, Section C.1., p. 7-5.

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

30 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.

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

32 For example, in D.20-12-038 the Commission authorized PG&E to transfer the 2020 ending balance of ERRA (excluding the PCIA Financing Subaccount), to PABA vintages 2019 and 2020. PG&E recorded this entry in December 2020.

the adopted revenue requirements for each of the accounts.[33] Independent evaluator expenses are assigned to PABA, ERRA, or NSGBA based on the account 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 PABA vintages the same as credit and collateral and WREGIS expenses. In compliance with D.18-10-019 and D.20-02-047,[34] 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. Finally, transfer of amounts from other accounts to the PABA are generally assigned to the same vintage as the associated base generation costs. For example, costs recorded in the Diablo Canyon Seismic Studies 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 2020 ERRA Forecast November Update Application, approved by the Commission in D.20-02-047.

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

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

TABLE 12-7
2020 ACTUAL RECORDED COSTS COMPARED TO APPROVED FORECAST

Line #	Description	Recorded (PABA)	Forecast	Variance
		$M	$M	$M
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 RPS (D.20-02-047)	[redacted]	[redacted]	[redacted]
6c	Retained RA	[redacted]	[redacted]	[redacted]
7	Miscellaneous Costs	[redacted]	[redacted]	[redacted]
8	**Total Procurement Costs in ERRA Forecast Proceeding**	[redacted]	[redacted]	[redacted]

As Table 12-8 indicates, PG&E’s procurement costs recorded across the portfolio were $158.8 million higher than forecasted, primarily due to higher-than-forecast RPS-eligible contracts, as offset by higher than forecast retained RPS and retained RA, as well as lower than forecast fuel costs for UOG facilities. RPS costs are higher 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. Excluding this adjustment, RPS costs are still higher than forecast due to lower than forecast RPS-eligible energy. Higher than forecast retained RPS is primarily due to recording and adjustment to reverse 2019 Unsold RPS Attributes pursuant to D.20-02-047. Higher than forecast retained RA amounts is due to a higher than final RA benchmark than forecast, partially offset by higher than forecast unsold RA volumes. Finally, fuel costs for UOG facilities and tolling contracts were lower than expected due to lower than expected demand for generation from PG&E’s dispatchable gas-fired plants.

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, 2020

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
Customer Billed Revenue															
5.a.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from bundled customers	[redacted]												(1,281,879,386)
5.b.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from DA customers	[redacted]												(88,004,829)
5.c.	CR	A credit entry equal to PCIA revenues attributable to the Vintage from CCA customers	[redacted]												(995,185,123)
		Revenues Net of RF&U	[redacted]												(2,365,069,339)
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]												(112,136,220)
5.g.	CR	A credit entry equal to revenues received for Actual Sold RA transactions	[redacted]												(87,278,734)
Retained RPS & Retained RA Value															
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]												(299,563,477)
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]												25,624,365
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]												(470,641,516)
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.	[redacted]												(65,897,501)
UOG Costs															
5.l.	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]												47,000,621
5.m.	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]												2,083,579,285
5.m.	DR	**Cost of Capital Adjustment** - 2020 - ***non ESA***	[redacted]												5,526,459
5.m.	DR	**Cost of Capital** - 2020 Incremental (July to Dec 2020) - ***non ESA***	[redacted]												(11,838,174)
5.m.	CR	**UOG Tax Reform**: 2018 & 2019 Electric Generation (EG) & Merced Falls RRQ reductions to reflect the effects of the 2017 Tax Act per D.19-08-023 (issued on 8/15/19) and per AL 4142-G/5636-E (approved on 10/17/19) - **non ESA**	[redacted]												(79,307,413)
5.m.	CR	**2020 Ex Parte Penalty for Elec Gen,** net of RF&U: 2020	[redacted]												(436,260)
5.m.	CR	**2020 Ex Parte II Penalty for Elec Gen,** net of RF&U: 2020	[redacted]												(80,800)
5.n.	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]												77,347,437
5.n.	DR	**Cost of Capital Adjustment** - 2020 - ***ESA***	[redacted]												125,305
5.n.	DR	**Cost of Capital** - 2020 Incremental (July to Dec 2020) - ***ESA***	[redacted]												(268,213)
5.n.	CR	**UOG Tax Reform**: 2018 & 2019 Electric Generation (EG) & Merced Falls RRQ reductions to reflect the effects of the 2017 Tax Act per D.19-08-023 (issued on 8/15/19) and per AL 4142-G/5636-E (approved on 10/17/19) - ***ESA***	[redacted]												(3,195,653)

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2020
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
UOG Costs															
5.o.	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]												9,502,647
5.p.	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]												50,207,754
5.p.	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) - **Adj RF&U for DCPP Retention RRQ from June 2019 to Oct 2020)**	[redacted]												(922,130)
5.q.	DR	A debit entry equal to one-twelfth of the annual authorized revenue requirement for the Diablo Canyon Power Plant license renewal costs	[redacted]												2,325,000
5.r.	DR	A debit entry equal to one-twelfth (or amortization period approved) of the power generation portion of the Catastrophic Event Memorandum Account (CEMA) interim rate relief for costs incurred in 2016 and 2017, as authorized by the CPUC in Decision 19-04-039 on April 25, 2019.	[redacted]												7,354,490
ISO Related Charges/ Revenues															
5.s.	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]												(1,595,195,485)
5.t.	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]												7,784,708
5.u.	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 throught the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]												(59,514,799)
Fuel Costs															
5.v.	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 alloated 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]												185,128,922
5.w.	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]												139,914
5.x.	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]												2,435,041
5.y.	DR	A debit entry equal to nuclear fuel and miscellaneous expenses for the Diablo Canyon Nuclear Power Plant.	[redacted]												110,484,614
5.z.	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]												2,358,292

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2020
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
Contract Costs															
5.aa.	DR	A debit entry equal to total costs associated with New QF SOC obligations authorized pursuant to D.20-05-005, which excludes New QF SOC 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]												79,885
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]												798,353
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]												584,418,521
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 feees supporting the DAC-GT and the CS-GT Programs.	[redacted]												2,226,860,074
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 recordeed to the CLPSA of the NSGBA.	[redacted]												296,940
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 recordeed to the CLPSA of the NSGBA.	[redacted]												1,427,303
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,which excludes GHG costs associated with PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recordeed to the CLPSA of the NSGBA.	[redacted]												37,602,471
Miscellaneous Costs															
5.ah.	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]												6,306,829
5.ai.	DR	A debit entry equal to any other power costs associated with procurement.	[redacted]												1,274,460
5.aj.	DR/CR	A credit/debit entry to transfer/repay the undercollection due to the PCIA revenue shortall from the applicable PABA subaccount to the PUBA. The PCIA revenue shortfall is equal to the difference bertween the uncapped vintage PCIA rate by customer calss 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 cumulativve revenue shortfall rates, by customer vintage.	[redacted]												(244,436,432)
5.ak.	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]												(606,321,795)
		Total Monthly Activity Before Interest	33,377,470	78,447,958	584,698	(36,331,867)	58,103,743	1,316,188	94,203,300	(153,799,551)	(38,842,451)	(30,617,866)	(48,454,075)	(484,101,800)	(526,114,251)

TABLE 12-8
FOR THE YEAR ENDING DECEMBER 31, 2020
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
5.am.	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]												5,642,644
5.am.	DR/CR	Prior Period Interest													(1,933,992)
		Beginning Balance	**713,711,384**	**748,057,798**	**827,648,574**	**829,092,615**	**793,780,189**	**852,587,394**	**853,924,983**	**948,263,483**	**793,165,985**	**754,400,761**	**723,856,526**	**675,381,008**	**713,711,384**
		PABA Ending Balance	**748,057,798**	**827,648,574**	**829,092,615**	**793,780,189**	**852,587,394**	**853,924,983**	**948,263,483**	**793,165,985**	**754,400,761**	**723,856,526**	**675,381,008**	**191,305,785**	**191,305,785**
PCIA Subaccount															
6.a.	DR	A debit entry equal to imputed PCIA revenue based on the PCIA rate as adopted by the Commission;	[redacted]												0
6.b.	DR/CR	A credit or debit entry equal to the recorded PCIA revenues; and													(38,300,488)
6.c.	DR/CR	A credit or debit entry to transfer the balance as authorized by the Commission.													0
		Beginning Balance	**38,300,488**	**38,300,488**	**38,300,488**	**38,300,488**	**38,300,488**	**38,300,488**	**219,088,415**	**219,088,415**	**180,787,927**	**180,787,927**	**180,787,927**	**180,787,927**	**38,300,488**
		PCIA Subaccount Ending Balance	**38,300,488**	**38,300,488**	**38,300,488**	**38,300,488**	**38,300,488**	**219,088,415**	**219,088,415**	**180,787,927**	**180,787,927**	**180,787,927**	**180,787,927**	**(0)**	**(0)**
		TOTAL PABA ENDING BALANCE	**786,358,286**	**865,949,062**	**867,393,103**	**832,080,677**	**890,887,882**	**1,073,013,398**	**1,167,351,898**	**973,953,912**	**935,188,688**	**904,644,453**	**856,168,935**	**191,305,785**	**191,305,785**

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2020
(YEAR-TO-DATE BY VINTAGE)

Tariff Line Item	DR/CR	Tariff Description	Non-Vintage Subaccount	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	Total all Vintages for Current Month
Revenues from Customers (net billed)			0	(614,501,823)	(1,241,422,620)	(311,634,771)	(123,322,084)	(60,415,659)	(65,180,677)	(11,406,396)	(40,156)	16,867,882	16,806,313	17,730,790	11,576,277	(126,415)	(2,365,069,339)
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)															
Actual Sold Renewable Portfolio Standard (RPS) Transaction			0	(6,179,375)	(53,248,157)	(26,199,485)	(7,561,335)	(8,086,240)	(6,882,599)	(94,987)	(2,114,083)	(1,032,360)	(322,046)	(327,141)	(85,347)	(3,065)	(112,136,220)
5.f.	CR	A credit entry equal to actual revenues for REC sales.	[redacted]														
Actual Sold Resource Adequacy (RA) Transaction			0	(46,493,619)	(34,416,710)	(1,931,406)	(2,143,849)	(1,664,645)	(454,062)	(11,627)	(98,246)	(421,879)	(36,071)	(2,712)	396,091	0	(87,278,734)
5.g.	CR	A credit entry equal to actual revenues for RA sales.	[redacted]														
Retained Renewable Portfolio Standard (RPS) Value			0	(13,956,345)	(137,503,603)	(55,825,600)	(18,931,701)	(22,519,045)	(15,461,329)	(260,179)	(5,038,144)	(2,951,762)	(712,921)	(655,892)	(118,341)	(4,251)	(273,939,112)
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.															
Retained Resource Adequacy (RA) Value			0	(396,430,794)	(96,382,270)	(11,904,016)	(13,442,562)	(10,682,759)	(2,754,419)	(71,676)	(618,183)	(2,729,154)	(221,251)	4,554	(1,306,487)	0	(536,539,016)
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.															
UOG Costs			0	1,838,590,114	263,196,392	37,868,285	23,136,426	23,055,120	408,488	42,940	19,273	279,414	128,807	195,553	(439)	(21)	2,186,920,353
5.l.	DR	A debit entry equal to one-tw elfth of the electric generation portion of revenue requirement associated w ith the CPUC authorized pension contribution amount, transferred from UGBA.	[redacted]														
5.m.	DR	A debit entry equal to the annual authorized revenue requirements associated w ith PG&E's ow ned generation divided by tw elve , transferred from UGBA.															
5.n.	DR/CR	A debit or credit entry, as appropriate, to record ESA costs associated w ith PCIA eligible generation resources portfolio/ procurement activity (w hich is embedded in the annual authorized revenue requirements associated w ith PG&E's ow ned generation), transferred from UGBA															
5.o.	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															
5.p.	DR	a debit entry equal to one-tw elfth of the annual authorized revenue requirement for the Diablo Canyon Pow er 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															
5.q.	DR	a debit entry equal to one-tw elfth of the annual authorized revenue requirement for the Diablo Canyon Pow er Plant license renew al costs, transferred from UGBA															
5.r.	DR	A debit entry equal to one-tw elfth (or amortization period approved) of the pow er generation portion of the Catastrophic Event Memorandum Account (CEMA) interim rate relief for costs incurred in 2016 and 2017, as authorized by the CPUC in Decision 19-04-039 on April 25, 2019.															

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2020
YEAR-TO-DATE BY VINTAGE
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Non-Vintage Subaccount	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	Total all Vintages for Current Month
ISO Related Charges/ Revenues			(286,435)	(1,031,520,580)	(441,682,788)	(68,422,797)	(30,612,240)	(39,312,638)	(21,684,669)	(1,417,477)	(7,132,028)	(2,746,568)	(1,176,679)	(930,677)	0	0	(1,646,925,576)
5.s.	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]														
5.t.	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]														
5.u.	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 throught the NSGC and recorded to the CLPSA of the NSGBA.	[redacted]														
Fuel Costs			0	115,417,861	185,195,559	(66,637)	0	0	0	0	0	0	0	0	0	0	300,546,783
5.v.	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 alloated 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.w.	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]														
5.x.	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.y.	DR	A debit entry equal to nuclear fuel and miscellaneous expenses for the Diablo Canyon Nuclear Power Plant.	[redacted]														
5.z.	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			479,751	0	1,861,527,563	493,425,240	155,189,685	168,462,877	75,848,732	2,506,611	20,843,961	17,977,500	4,984,253	3,572,949	9,061,953	0	2,813,881,077
5.aa.	DR	A debit entry equal to total costs associated with New QF SOC obligations authorized pursuant to D.20-05-005, which excludes New QF SOC 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.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]														
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 feees supporting the DAC-GT and the CS-GT Programs.	[redacted]														
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 recordeed to the CLPSA of the NSGBA.	[redacted]														
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 recordeed to the CLPSA of the NSGBA.	[redacted]														

TABLE 12-8A
FOR THE YEAR ENDING DECEMBER 31, 2020
YEAR-TO-DATE BY VINTAGE
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Non-Vintage Subaccount	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	Total all Vintages for Current Month
GHG Costs			0	37,602,471	0	0	0	0	0	0	0	0	0	0	0	0	37,602,471
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 w ith contracts,w hich excludes GHG costs associated w ith PCIA-eligible resources procured by the Central Procurement Entity for recovery through the NSGC and recordeed to the CLPSA of the NSGBA.	[redacted]														
Miscellaneous Costs (Collateral, Other Procurement Costs & Transfer Amts to Other Accounts			0	(2,693,437)	(181,624,580)	(84,437,926)	7,444,342	(35,952,722)	29,437,488	7,591,254	(5,064,916)	629,178	(25,847,141)	(18,237,629)	(7,973,501)	(526,447,348)	(843,176,938)
5.ah.	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.ai.	DR	A debit entry equal to any other pow er costs associated w ith procurement.															
5.aj.	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 betw een the uncapped vintage PCIA rate by customer calss 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 w ill be recorded in PCIA Undercollection Balancing Account (PUBA), Electric Preliminary Statement Part HZ, based on the cumulative revenue shortfall rates, by customer vintage.															
5.ak.	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.															
		Total Monthly Activity Before Interest	193,316	(120,165,526)	123,638,786	(29,129,113)	(10,243,318)	12,884,289	(6,723,047)	(3,121,536)	757,478	25,872,252	(6,396,735)	1,349,794	11,550,207	(526,581,100)	(526,114,251)
Interest			2,549	(1,162,511)	3,156,757	1,406,327	348,385	372,605	142,082	42,120	96,096	(31,333)	(32,356)	(46,704)	(345,117)	(240,249)	3,708,652
5.am.	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-tw elfth the interest rate of the three-month Commercial Paper for the previous month, as rep	[redacted]														
		Beginning Balance	**0**	**(101,809,463)**	**490,853,531**	**203,635,057**	**56,029,779**	**57,148,748**	**27,417,585**	**6,735,196**	**14,667,745**	**(4,825,158)**	**2,455,022**	**481,525**	**(39,078,183)**	**0**	**713,711,384**
		PABA Ending Balance	**195,865**	**(223,137,500)**	**617,649,074**	**175,912,271**	**46,134,846**	**70,405,642**	**20,836,621**	**3,655,781**	**15,521,319**	**21,015,761**	**(3,974,069)**	**1,784,616**	**(27,873,092)**	**(526,821,349)**	**191,305,785**
PCIA Subaccount			0	0	(27,429,687)	(7,696,624)	(1,127,187)	(1,640,545)	(1,167,735)	1,946,264	(537,779)	1,260,078	(6,374,252)	7,126,878	(2,659,899)		(38,300,488)
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	**0**	**0**	**(27,429,687)**	**(7,696,624)**	**(1,127,187)**	**(1,640,545)**	**(1,167,735)**	**1,946,264**	**(537,779)**	**1,260,078**	**(6,374,252)**	**7,126,878**	**(2,659,899)**	**0**	**(38,300,488)**
		Beginning balance	**0**	**0**	**27,429,687**	**7,696,624**	**1,127,187**	**1,640,545**	**1,167,735**	**(1,946,264)**	**537,779**	**(1,260,078)**	**6,374,252**	**(7,126,878)**	**2,659,899**	**0**	**38,300,488**
		PCIA Subaccount Ending Balance	**0**	**0**	**(0)**	**(0)**	**(0)**	**(0)**	**0**	**0**	**(0)**	**(0)**	**0**	**0**	**0**	**0**	**(0)**
		TOTAL PABA ENDING BALANCE	**195,865**	**(223,137,500)**	**617,649,074**	**175,912,271**	**46,134,846**	**70,405,642**	**20,836,621**	**3,655,781**	**15,521,319**	**21,015,761**	**(3,974,069)**	**1,784,616**	**(27,873,092)**	**(526,821,349)**	**191,305,785**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

ATTACHMENT A

FINAL JOINT PROPOSAL ON POTENTIAL VERIFICATION METHOD FOR PG&E'S GREENHOUSE GAS EMISSIONS AND WEIGHTED AVERAGE COSTS (WAC) FOR FUTURE ERRA COMPLIANCE FILING

PACIFIC GAS AND ELECTRIC COMPANY
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A. Definitions of Terms Based on Decision (D.) 14-10-033

1) Recorded Direct GHG Costs:

The recorded direct Greenhouse Gas (GHG) costs include two variables: (a) total direct emissions, and (b) costs of compliance instruments purchased to satisfy this liability. Recorded year direct GHG costs represent the actual costs for Utility-Owned Generation (UOG) and imports, tolls and other contracts for which the utility has responsibility for cap-and trade costs.[1,2]

2) Recorded:

We use the term "recorded" to describe both the actual cost and revenue amounts recorded, and the estimate of indirect GHG costs embedded in electricity prices.[3]

3) Direct Emissions:

Direct emissions should be calculated on an annual basis based on monthly dispatched resources using methodologies consistent with the Auction Rate Bond regulations for measuring GHG emissions.[4]

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1 D.14-10-033, p.18.

2 D.14-10-033, p.18. Also, Footnote 24, states: "The specific terms of a utility's contract may specify whether the utility provides physical compensation (a transfer of compliance instruments) or financial compensation (payment to the entity for the cost of the applicable compliance instruments) for the cap-and-trade costs. Physical settlement is a direct cost, but the utilities can choose to report financially settled tolling agreements as direct or indirect costs. Financially settled Qualifying Facility (QF) contracts where the financial obligation is embedded in the market price of energy purchases or within the specific contract terms for energy payment may be categorized as indirect GHG costs." D.14-10-033, p. 18.

3 D.14-10-033, Footnote 10, p. 8.

4 D.14-10-033, p. 18.

B. PG&E's Proposed Definitions of Terms

1) "December Close" means represents the best available information/data (i.e., Weighted Average Costs (WAC), emissions volumes, etc.) for the entire Record Year as of the month ended December, as available during the month end accounting close.

2) "Direct Physical GHG Costs" means those actual costs resulting from Pacific Gas and Electric Company's (PG&E) need to procure GHG compliance instruments in connection with: (1) UOG facilities; (2) certain tolling agreements where PG&E elects to physically settle contractual GHG obligations; and (3) electricity imports. Direct Physical GHG Costs are recorded to the Portfolio Allocation Balancing Account (PABA) Balancing Account Line Item 5.ag.

3) "Direct Physical GHG Emissions" are GHG emissions associated with (1) UOG facilities; (2) certain tolling agreements where PG&E elects to physically settle contractual GHG obligations; and (3) electricity imports.

4) "Financial GHG Costs" are GHG costs associated with PG&E's tolling agreements and other contracts for which PG&E elects to financially settle contractual GHG obligations or contract with financial settlement specifically for GHG costs. Financial GHG Costs are recorded to PABA Balancing Account Line Items other than Line Item 5.ag.

5) "Financially Settled GHG Emissions" are GHG emissions associated with PG&E's tolling agreements and other contracts for which PG&E elects to financially settle contractual GHG obligations or contracts with financial settlement specifically for GHG costs.

6) "PG&E's Electric Portfolio" includes those UOG or electric generation facilities contracted to PG&E. PG&E's Electric Portfolio does not include resources use to serve PG&E's natural gas utility customers.

7) "Record Year" refers to the calendar year addressed in an Energy Resource Recovery Account (ERRA) Compliance Application.

Attachments A and B physically-settled obligations presented in Attachments A and B are reported based on the best available volume of emissions and Weighted Average Cost price at the time the emissions costs are recorded. Financially-settled obligations, which is included as part of

Attachment B, reported amounts represent emissions based on actual plant output which may be recorded after the December close.

1) To support PG&E's WAC and Direct Physical GHG Costs for the Record Year, PG&E will submit tables in substantially the form of Attachment A as a workpaper to its ERRA Compliance Application.

The purpose of Attachment A, Table 1, is to calculate the WAC of compliance instruments of PG&E's Electric Portfolio.[5] WAC is not impacted by financial settlement of contractual GHG obligations. Attachment A, Table 1 will be submitted as an active spreadsheet showing all calculations and formulas used.

The purpose of Attachment A, Table 2 is to support the applied WAC for monthly Direct Physical GHG Costs of PG&E's Electric Portfolio. Attachment A, Table 2 will be partially submitted as an active spreadsheet showing all calculations and formulas used.

PG&E's official system of record to calculate the WAC of compliance instruments is Endur. While PG&E can replicate calculations performed in Endur to produce the WAC, numbers calculated in the spreadsheet provided may vary from the official record due to rounding in the Endur system versus the spreadsheet.

In May 2020, D.20-05-004 issued by the California Public Utilities Commission on May 15, 2020 ordered Southern California Edison Company (SCE) to convene a working group with PG&E, SDG&E, and the Public Advocates Office to address balancing account treatment of direct GHG costs. This modification would require that utilities provide a GHG Balancing Account Table to show their recorded GHG costs to the balancing account

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5 For definition of recorded direct GHG costs, Refer to section 4.2.1 and Footnote 24 of D.14-10-033, page 18. D.14-10-033 (page 18) states: "Recorded Direct GHG costs represent the actual costs for utility owned generation and imports, tolls and other contracts for which the utility has responsibility for cap-and-trade costs." Footnote 24 of the Decision states: "The specific terms of a utility's contract may specify whether the utility provides physical compensation (a transfer of compliance instruments) or financial compensation (payment to the entity for the cost of the applicable compliance instruments) for the cap-and-trade costs. Physical settlement is a direct cost, but the utilities can choose to report financially settled tolling agreements as direct or indirect costs. Financially settled QF contracts where the financial obligation is embedded in the market price of energy purchases or within the specific contract terms for energy payment may be categorized as indirect GHG costs."

to which cost recovery for the underlying procurement resource is approved. SCE will be filing a Petition for Modification to propose slight modification to the Attachment A which will supersede in its entirety the version of Attachment C contained in D.14-10-033, as corrected by D.14-10-055, D.15-01-024, and D.19-04-016 (see Table 3 for an example of the new template.)

2) To support PG&E's recorded monthly Direct Physical GHG Costs and Financial GHG Costs as of the Record Year's December Close, PG&E will submit a table in substantially the form of Attachment B, as a workpaper (in a spreadsheet format) to its ERRA Compliance Application.

Included in the spreadsheet (Attachment B), PG&E will provide separate tabs for each of line 2 through line 7, including monthly GHG emissions for the record year, for each source contributing to the total emissions per category recorded as of December close. For example: Line 2 would include 12 months entries for each of PG&E's three UOG facilities.

Public Advocates Office at the California Public Utilities Commission (Cal Advocates formerly known as ORA) will use PG&E's data provided in Attachment B to draw its sample (see Section 3).

C. Cal Advocates' Sample

The purpose of the sampling approach is for Cal Advocates to perform a thorough review and verification of PG&E's calculations of GHG emissions and associated GHG costs for the Record Year under review.

The sample will be based on data submitted by PG&E in Attachment B (*Modified* Template D-2 of Attachment D of D.15-01-024).

Provided that PG&E submits a completed Attachment B at the time it files its ERRA Compliance Application, Cal Advocates will draw and provide the sample to PG&E no later than a month from the date PG&E files its ERRA Compliance Application.

D. PG&E's Response to Cal Advocates Sample

No later than three weeks from the date Cal Advocates provides the Sample to PG&E, PG&E will provide the information listed in Section 5.1 through Section 5.3 to Cal Advocates.

5.1) PG&E's GHG Emissions Recorded During the Record Period From Its UOG Facilities, Specified Imports and Unspecified Imports

a. Calculations of GHG Emissions

PG&E to provide detailed calculations of GHG emissions (in an active spreadsheet format, showing all calculations, assumptions and formulas used), by source for each of the months sampled by Cal Advocates.

PG&E's official system of record to calculate the GHG emissions is Endur. While PG&E can replicate calculations performed in Endur to produce the sampled month's emissions volume, numbers calculated in the spreadsheet provided may have variances due to rounding in the Endur system versus the spreadsheet.

b. Supporting Evidence

PG&E to demonstrate that the methodology used to calculate the GHG emissions is consistent with the draft emissions calculated under the California Air Resources Board Mandatory Reporting Regulation. Supporting evidence will be calculated using the UOG facility's gas burns during the record period and an emission factor from the facility's previous year's Mandatory Reporting Regulation verified report.

5.2) PG&E's GHG Emissions Recorded During the Record Year From Its Physically-Settled Contracts and/or Tolling Agreements

a. Calculations of GHG Emissions:

PG&E to provide detailed calculations of GHG emissions, for each source for each of the months provided in Cal Advocates' sample.

PG&E will use a spreadsheet in a format similar to the spreadsheet provided by PG&E in the 2016 ERRA Compliance case labelled "Data Request 15 (GHG volumes and costs)" in response to ORA's Data Request 15 Q-2.2; with the addition of one data point: GHG unit cost (such as Intercontinental Exchange Inc. (ICE) forward price etc.).

For ease of reference, the following Table 12A-1 for information on physically-settled contracts provides the fields that should be included to populate the spreadsheet:

TABLE 12A-1

Source Name	Unit	Log number	Contract Type (Tolling/QF/Other)	Emission Date (Year and Month)	GHG Emissions (metric tons of carbon dioxide equivalent (mtCO2e))	Physically-Settled Contracts: Unit GHG Cost ($/mtCO2e)	GHG Costs ($)	ERRA Tariff line item

b. Supporting Evidence:

Invoices showing final settled emissions data and payments. References and excerpts from contracts showing settlement terms covering the calculations of GHG emissions and costs. (See examples from PG&E responses in the 2016 ERRA Compliance case to ORA DR 15, A.17-02-005)

5.3) PG&E's Recorded GHG Emissions Recorded During the Record Year From Its Financially-Settled Contracts and/or Tolling Agreements

a. Calculations of GHG Emissions and Costs

PG&E to provide detailed calculations of GHG emissions and associated costs for each source for each of the months provided in Cal Advocates' sample. PG&E will use a spreadsheet in a format similar to the spreadsheet provided by PG&E labelled in the 2016 ERRA Compliance case "Data Request 15 (GHG volumes and costs)" in response to Cal Advocates' Data Request 15 Q-2.2); with the addition of one data point: GHG unit cost (such as ICE forward price etc.).

For ease of reference, see the following Table 12A-2 for information on financially-settled contracts, which provides the fields that should be included to populate the spreadsheet:

TABLE 12A-2

Source Name	Unit	Log number	Contract Type (Tolling/QF/Other)	Emission Date (Year and Month)	GHG Emissions (mtCO2e)	Physically-Settled Contracts: Unit GHG Cost ($/mtCO2e)	GHG Costs ($)	ERRA Tariff line item

b. Supporting Evidence

Invoices showing settled emissions data and payments during the record period.

References and excerpts from contracts showing settlement terms covering the calculations of GHG emissions and costs.

(See examples from PG&E responses in the 2016 ERRA Compliance case to ORA DR 15, A.17-02-005)

ATTACHMENT B

Modified Template D-2: Annual GHG Emissions and Associated Costs[(a)]

ERRA Compliance Application for Record Period Under Review
(GHG Emissions Recorded in January through December of Record Year)

Line No.	Description	[Year]
1	Direct GHG Emissions (mtCO2e)	
2	UOG	
3	Physically Settled Tolling Agreements	
4	Energy Imports (Specified)	
5	Energy imports (Unspecified)	
6	Physically Settled QF Contracts	
7	Financially Settled GHG Emissions (mtCO2e)	
8	Contracts with Financial Settlement	
9	Subtotal	
10	GHG Costs ($)	
11	Direct Physical GHG Costs	
12	Direct GHG Costs - Financial Settlement	

(a) As of December, Close of Record Year. Any information recorded or available after December Close will not be reflected in Attachment B.

Notes:

(1) "Attachment B" is a modified version of Template D-2 of Attachment D of D.15-01-024. When filing "Attachment B," PG&E will follow the definitions and conventions as required in Template D-2 of Attachment D of D.15-01-024. PG&E will clearly identify and provide explanation including supporting calculations of any entries deviating from the requirements in Template D-2 of Attachment D of D.15-01-024.

(2) PG&E's Note: Multiplying monthly WACs shown in Table A and monthly physical emissions shown in Table B will not necessarily replicate monthly accounting entries to ERRA line item 5 ag due to PG&E's utilization of gross-on, gross-off accounting.

ATTACHMENT A
TABLE 12A-3: REPORTING TEMPLATE TO CALCULATE WEIGHTED AVERAGE COST (WAC) OF COMPLIANCE INSTRUMENTS IN RECORD YEAR

Month	Transaction Date	Transaction Type	Quantity	Cost ($/MT)	Sales Price ($)	Total Cost ($)	Inventory Balance ($)	Total Qty in Inventory	WAC
No Formula	No Formula	No Formula	No Formula	Formula	No Formula	Formula	Formula	Formula	Formula

TABLE 12A-4: PG&E RECORDED DIRECT PHYSICAL GHG COSTS IN PABA (TARIFF LINE ITEM 5.AG.)

Line No.	Month	MM-YY
1	End of Month WAC	Supported by Table 1
2	Monthly Emissions (MT)	Fixed Number, No Formula
3	End of Month WAC * Monthly Emissions	$Formula
4	Balancing Account Entry with adjustment (as recorded to line 5ah) (Refer to Note 4)	Fixed Number, No Formula (supported by Accounting Entries)

Notes:

(1) "Attachment A" reflects Template C of Attachment C-1 of D.19-04-016. When filing "Attachment A," PG&E will follow the definitions and conventions as required in Template C of Attachment C-1 of D.19-04-016. PG&E will clearly identify and provide explanation including supporting calculations of any entries deviating from the requirements in Template C of Attachment C-1 of D.19-04-016.

(2) "Attachment A" or Template C of Attachment C-1 of D.19-04-016 is based (amongst other data) on running weighted average costs of compliance instruments held in inventory since the inception of the program (i.e. since the First Compliance Period under the Cap-and-Trade Program).

(3) PG&E is to provide "Attachment A" in an active spreadsheet format i.e., showing all calculations and formulas used.

(4) PG&E is to provide references and explanation including calculations to any hard entries (not resulting from a calculation or not linked to a referenced calculation).

(5) PG&E is to provide calculations including supporting data used to produce entries recorded under "Balancing Account Entry with adjustment (as recorded to line 5ad)," as applicable. Note: however, the supporting documentation provided for the monthly entries may differ in future years as PG&E will rely on Endur's automation process to post the monthly entries. Accounting will provide calculations or reconciliations to demonstrate the GHG emissions expenses recorded during each month as reported, to line 5ad, was appropriately calculated. For definitions and descriptions, refer to Attachment C of D.19-04-016. Attachment A and resulting WAC calculation are confidential.

TABLE 12A-5: PG&E RECORDED DIRECT GHG COSTS IN PABA, ERRA & NEW SYSTEM GENERATION BALANCING ACCOUNT (NSGBA) (TARIFF LINE PABA ITEM 5 AG & 5 AC, NSGBA ITEM 5.B.2.I) AMOUNTS ARE IN MIL$

Line No.		ERRA	PABA	NSGBA	Total
1	UOG	–	$37.6	–	$37.6
2	Imported (out-of-state) UOG	–	–	–	–
3	Tolling Contracts[a]	–	16.8	$11.7	28.5
4	Total	–	$54.4	$11.7	$66.1

(a) Tolling contracts represent GHG costs that are financially settled and embedded within the contract payments made to the counterparty.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

ATTACHMENT B

GHG EMISSIONS AND COSTS

PACIFIC GAS AND ELECTRIC COMPANY
2020 ERRA Compliance

Line No.	Description	**2020**
1	<u>Direct GHG Emissions (MT CO2e)</u>	[redacted]
2	Utility Owned Generation (UOG)	
3	Tolling Agreements	
4	Energy Imports (Specified)	
5	Energy imports (Unspecified)	
6	Qualifying Facility (QF) Contracts	
7	Contracts with Financial Settlement	
8	Subtotal	
15	<u>GHG Costs ($)</u>	
16	Direct GHG Costs	
17	Direct GHG Costs - Financial Settlement	
20	**<u>Total Costs ($)</u>**	

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		2019 Recorded GHG Emissions (MT)												
Name	**Resource ID/Log Number**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**
Colusa	PGECOLUSA	[redacted]												
Gateway	PGEGATEWAY													
Humboldt	PGEHUMBOLDT													
Total														

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		2020 Recorded GHG Emissions (MT)												
Name	Resource ID/Log Number	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
		[redacted]												
Total														

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	2020 Recorded GHG Emissions (MT)												
Name	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**
Specified Imports	[redacted]												
Total													

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	2020 Recorded GHG Emissions (MT) [1]												
Name	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**
Unspecified Imports	[redacted]												
Total													

(1) PG&E will use RPS Adjustments to bring total recorded import GHG obligations to zero MT on its 2020 CARB EPE Report.

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		2020 Recorded GHG Emissions (MT)												
Name	**Resource ID/Log Number**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**
		[redacted]												
Total														

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		2020 Recorded DIrect GHG Emissions (MT)												
Log Number	Name	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
24B001FHP	CHEVRON MCKITTRICK	[redacted]												
33B121	Badger Creek													
33B112	Bear Mountain													
33B105QSA	CAMS-Double C													
33B106QSA	CAMS-High Sierra													
33B107QSA	CAMS - Kern Front													
33B097	Calpine Gilroy													
33B099	Calpine Los Esteros Upgrade													
33B075	Calpine Russell City Energy Center													
33B124	Chalk Cliff													
33B108	GWF Hanford													
33B109	GWF Henrietta													
33B101	GWF Tracy													
33B093	GenOn Marsh Landing													
33B122	Live Oak													
33B092	Mariposa													
33B123	Mckittrick													
33B074	Starwood													
33B091	Midway Sunset													
33B118	Kern River Cogen Company													
33B208	Calpine Agnews													
Total														

Total Direct GHG Costs ($)	[redacted]

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	2020 Recorded Direct GHG Emissions (MT)												
Category	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**
UOG (line 2)	[redacted]												
Bilats (Line 3)													
Unspecified Imports (line 5)													
QF (line 6)													
Total													

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		2020 Recorded Direct GHG Costs - Financial Settlement ($)													
Resource ID/Log Number	**Name**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Total**	
24B001FHP	CHEVRON MCKITTRICK	[redacted]													
33B121	Badger Creek														
33B112	Bear Mountain														
33B105QSA	CAMS-Double C														
33B106QSA	CAMS-High Sierra														
33B107QSA	CAMS - Kern Front														
33B097	Calpine Gilroy														
33B099	Calpine Los Esteros Upgrade														
33B075	Calpine Russell City Energy Center														
33B124	Chalk Cliff														
33B108	GWF Hanford														
33B109	GWF Henrietta														
33B101	GWF Tracy														
33B093	GenOn Marsh Landing														
33B122	Live Oak														
33B092	Mariposa														
33B123	Mckittrick														
33B074	Starwood														
33B091	Midway Sunset														
33B118	Kern River Cogen Company														
33B208	Calpine Agnews														No GHG costs, as quantity is below threshold
Total Direct GHG Costs - Financial Settlement															

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

SUMMARY OF ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES FOR THE RECORD PERIOD

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
SUMMARY OF ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES FOR THE RECORD PERIOD

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 13
SUMMARY OF ENERGY RESOURCE RECOVERY ACCOUNT ENTRIES FOR THE RECORD PERIOD

A. Introduction

This chapter presents the accounting entries made to Pacific Gas and Electric Company's (PG&E) Energy Resource Recovery Account (ERRA) for the period January 1 through December 31, 2020 (record period). This testimony demonstrates that the entries to the ERRA comply with the recovery requirements adopted by the California Public Utilities Commission (CPUC or Commission). This chapter also discusses the 2020 activity in the Renewables Portfolio Standard Cost Memorandum Account (RPSCMA), which is authorized for recovery through the ERRA application.

B. The Energy Revenue Recovery Account

The ERRA is a balancing account that was originally established in Rulemaking (R.) 01-10-024, pursuant to Decision (D.) 02-10-062, Ordering Paragraph (OP) 14, and subsequently modified by D.02-12-074. The ERRA was substantially modified by D.18-10-019, which addressed the Power Charge Indifference Amount (PCIA) in rulemaking R.17-06-026.[1] The revised ERRA records power costs applicable solely to PG&E's bundled customers while power costs incurred on behalf of both bundled and departing load customers are recorded in the Portfolio Allocation Balancing Account (PABA), or one of the other four non-bypassable charge balancing accounts.[2]

1. Overview of ERRA Entries

The ERRA records net generation revenues and net costs attributable to bundled customers, except for bundled customers served under the

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[1] PG&E submitted Advice Letter (AL) 5440-E on December 10, 2018, which was approved May of 2019 with an effective date of January 1, 2019. PG&E implemented the changes authorized in AL 5440-E during the June 2019 business close.

[2] The other non-bypassable charge balancing accounts include: The Modified Transition Cost Balancing Account, the New System Generation Balancing Account (NSGBA), the Tree Mortality Non-Bypassable Charge Balancing Account, and the Bioenergy Market Adjusting Tariff (BioMAT) Non-Bypassable Charge Balancing Account.

Green Tariff Shared Renewables Program (GTSR) rate schedules E-GT and E-ECR.[3] The ERRA revenue and costs are described below:

- Customer Revenues: PG&E records bundled customer's net billed generation revenues to ERRA, which exclude the PCIA portion of bundled customer's generation rate that is allocated to the PABA vintage subaccounts. Additionally, as noted below in the *Utility-Owned Generation Balancing Account Entries* category, all 2020 residual revenues related to Utility-Owned Generation (UOG) facilities are transferred to the ERRA.
- Retained Portfolio Attribute Value: There are four entries that record the portfolio value for Renewable Energy Credit attributes and Resource Adequacy (RA) attributes associated with PG&E's PCIA-eligible resource portfolio. The value of these attributes used for bundled customers compliance with the Renewable Portfolio Standard (RPS) Program as defined in PG&E's RPS plan and with the RA requirements implemented through the Commission's RA Program are transferred from the various recovery accounts (i.e., PABA, Modified Transition Cost Balancing Account, BioMAT Non-Bypassable Charge Balancing Account, and Tree Mortality Non-Bypassable Charge Balancing Account) to ERRA for recovery from bundled customers.[4] Two of the entries are for use throughout the year on the initial forecast market price benchmark. The other two entries are for use when a final market price benchmark is issued by the Energy Division each November.
- Utility Generation Balancing Account (UGBA Entries: There is one entry to record bundled customers' share of the Energy Supply Administration (ESA) costs which are authorized in Phase 1 of PG&E's General Rate

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3 Costs for the GTSR Program are recorded to the Green Tariff Shared Renewables Memorandum Account (GTSRMA) and Green Tariff Shared Renewables Balancing Account (GTSRBA) and are recovered from bundled customers that are on the E-GT and E-ECR rates schedules. The GTSRMA and GTSRBA are presented in Chapter 11.

4 For further discussion of PG&E's RPS Program activity, please see Chapter 12, Section C.2. PG&E's RA Program activity is discussed in Chapter 8.

Case.[5] All 2020 residual revenues related to UOG facilities for rebate and rebills of prior record periods are recorded directly to the ERRA.

- California Independent System Operator (CAISO) Charges and Revenues: There are five entries to record CAISO charges and revenues, three of which record load-related charges or revenues: generation-related charges and revenues in the day ahead and real-time markets, ancillary services markets for generation resources recovered in ERRA, and miscellaneous charges/revenues for load and generation.[6] The other two entries recover costs and revenues associated with congestion revenue rights and convergence bidding.[7]
- Fuel Costs: There is one entry to record fuel costs, fuel transportation, and miscellaneous costs for contracts recovered through ERRA.
- Contract Costs: There are three entries to record short-term contracts related to bilateral, renewable contracts, or Qualifying Facility/Combined Heat and Power (QF/CHP) Program that are not eligible for recovery through the PCIA or other non-bypassable charges. The ERRA also includes one entry to record the transfer of QF/CHP contract costs and Marsh Landing costs to the NSGBA.
- Greenhouse Gas (GHG) Costs: There is one entry to record costs associated with physically settled greenhouse compliance instruments for contracts. During 2020, there were no direct GHG compliance costs associated with contracts recorded in ERRA.
- Miscellaneous Costs: There are six entries to record costs incurred for bundled customers, including: forward hedges, net energy metering payments, and energy storage evaluation program funding. PG&E is also authorized to recover other indirect costs that support PG&E's

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5 ESA costs are portfolio-wide costs that were previously recovered in the UGBA and are now proportionally allocated to the generation-related balancing accounts pursuant to the approval of AL 5440-E.

6 Generation resource costs recovered in ERRA exclude resources that are recovered through PG&E's generation-related non-bypassable charges including, the Ongoing competition transition charge, PCIA, New System Generation Charge (NSGC), Tree Mortality Non-Bypassable Charge, and BioMAT Non-Bypassable Charge.

7 For further discussion of PG&E's CAISO settlements and monitoring activity, please see Chapter 10.

management of its procurement/generation resource portfolio. These costs include: credit and collateral, Western Renewable Energy Generation Information System certificates, and third-party independent evaluator reviews. See Testimony Chapter 12, PABA, Section C.9. *Miscellaneous Costs* for a detailed discussion of how these costs are assigned and allocated among PABA, ERRA, and the NSGBA. Finally, this category includes other power procurement costs related to resources that are the sole responsibility of bundled customers and authorized to be recovered through ERRA.

2. NSGBA-Resource Costs

D.06-07-029 and D.07-09-044 approved guidelines for allocation of costs and benefits for resources authorized for the Cost Allocation Mechanism (CAM), which recovers the net capacity costs for resources providing RA benefits. D.10-12-035 subsequently authorized recovery of net capacity costs for certain contracts arising from the QF/CHP Settlement. Both CAM and QF/CHP resource types (NSGBA Resources) are recovered through the CAM rate and recorded to the NSGBA. The Commission authorized the CAM effective January 1, 2012.[8] Net capacity costs that are eligible for recovery through the CAM are credited out of ERRA and recovered through the NSGBA.

3. PCIA Financing Subaccount

In D.18-10-019 the Commission established a cap for the PCIA rate increase by vintage at no more than 0.5 cents per kilowatt-hour, and directed major electric utilities to file a Tier 2 AL to establish an under-collection balancing account that would track the accrued PCIA-obligation when the 0.5 cent cap is reached. In December 2019, AL 5624-E was approved to establish this account as well as other consistent balancing account modifications. One such modification included the establishment of a new PCIA Financing Subaccount to track the amount financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers.

8 D.11-12-031, OP 1.

4. Recorded Balances

In OP 19 of D.02-12-074, the Commission directed the three California Investor-Owned Utilities (IOU) to submit ERRA balancing account activity reports (ERRA activity reports) each month to the Energy Division no later than 20 days following the end of the month. These monthly reports provide the Commission with an opportunity to review monthly transactions in advance of the annual ERRA Compliance Review application.[9] As of December 31, 2020, the balance in the ERRA is shown to be over collected at $271.5 million. This balance represents the balance of ERRA's PCIA Financing subsidiary account, which tracks the amount financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers.[10] Pursuant to the 2021 ERRA Forecast Decision (D.20-12-038), the over collected balance recorded to ERRA (excluding the PCIA Financing Subaccount) as of December 31, 2020 was transferred to PABA. This transfer of $442.1 million was recorded in Accounting Procedure 5.ae. of Preliminary Statement Part CP. Table 13-2 summarizes the monthly accounting entries made to the ERRA from January 1 through December 31, 2020.

On January 16, 2014, the Commission issued D.14-01-011, which among other things approved a settlement agreement (SA) between PG&E and the *Public Advocates Office* at the California Public Utilities Commission (Cal Advocates), formerly called the Office of Ratepayer Advocates.[11] Section 2.4.3 of the SA provided that PG&E perform an accounting audit of the ERRA at least once every four years. The first two audits covered the periods of January 1, 2013 to December 31, 2013 and the January 1, 2017 to December 31, 2017 record periods, respectively. The next audit will occur no later than the 2021 record period (January 1, 2021 to December 31, 2021).

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9 A full set of these 2019 reports are included in PG&E's confidential response to Cal Advocates Master Data Request #1.3.1. Please see attachments to ERRA-2019-PGE-Compliance_DR_CalAdvocates_MDR001-Q27.docm.

10 Please see PG&E's Preliminary Statement Part CP at https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_PRELIM_CP.pdf, Section 6, "PCIA Financing Subaccount."

11 OP 1 of D.14-01-011 approved the SA.

C. PG&E's Solar Choice Program

The GTSR Program became effective January 1, 2016. Consistent with the legislative requirement that non-participating customers remain rate indifferent to the GTSR Program, the Commission determined that each IOU is required to establish a balancing account to track the costs and revenues of the program. ERRA accounting procedures 5.y, 5.z, 5.aa, 5.ab, and 5.ac enable the transfer of costs between ERRA and the GTSR balancing accounts. In addition, the IOUs are required to establish a memorandum account to track the program administrative and marketing costs. Chapter 11 of PG&E's Prepared Testimony includes a presentation of administrative and marketing costs incurred in the GTSR Memorandum Account in 2020 that are subject to reasonableness review in this proceeding and includes a showing of the GTSRBA entries for the record period.

D. Other Cost Recovery

The RPSCMA was established to track third-party consultant costs incurred by the CPUC and paid by PG&E in connection with the CPUC's implementation and administration of the Renewable Portfolio Standard, as authorized in D.06-10-050. The CPUC's Energy Division reviews and approves invoices it receives from independent consultants. PG&E pays the invoiced amount and records the costs in the RPSCMA, and D.06-10-050 authorizes PG&E to request recovery in rates through the ERRA application or other proceeding as authorized by the Commission. In 2020, the Energy Division staff did not submit any invoices to PG&E for payment of consulting services.

E. Variance Analysis

In Table 13-1, PG&E provides a summary of the ERRA procurement costs recorded in the current record period compared to the forecast included in its 2020 ERRA Forecast November Update Application, approved by the Commission in D.20-02-047.

TABLE 13-1
2020 ACTUAL RECORDED COSTS COMPARED TO APPROVED FORECAST

Line #	Description	Recorded ERRA	Forecast $M	Variance $M
1	Contract Costs	[redacted]	[redacted]	[redacted]
1a	Contract Costs (2018 REC Sales Adjustments)	[redacted]	[redacted]	[redacted]
2	UOG Costs (GRC Costs)	[redacted]	[redacted]	[redacted]
3	Market Purchases & CAISO Cost	[redacted]	[redacted]	[redacted]
4	Hedging Costs	[redacted]	[redacted]	[redacted]
5	Collateral and interest Expense	[redacted]	[redacted]	[redacted]
6	Retained RA	[redacted]	[redacted]	[redacted]
7	Retained RPS	[redacted]	[redacted]	[redacted]
7.a.	Retained RPS (D.20-02-047)	[redacted]	[redacted]	[redacted]
8	Miscellaneous Costs	[redacted]	[redacted]	[redacted]
9	**Total Procurement Costs in ERRA Forecast Proceeding**	[redacted]	[redacted]	[redacted]

As Table 13-1 indicates, PG&E's procurement costs recorded across the portfolio were [redacted] million higher-than-forecasted, primarily due to higher-than-forecast costs for retained RA and RPS attributes, as offset by lower-than-forecast CAISO net market purchases. Retained RA attribute costs are higher than expected due to a higher final RA benchmark for 2020, partially offset by higher unsold RA. Retained RPS attribute costs are higher than expected largely due to the recognition of additional 2019 retained RPS values as part of the implementation of D.20-02-047. CAISO net market purchases are lower than expected due to lower market prices than forecast and CAM net revenue not being included in the forecast. A more detailed variance analysis of forecasted and actual amounts is included in PG&E's confidential workpapers for Chapter 13.

F. Conclusion

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

TABLE 13-2
FOR THE YEAR ENDING DECEMBER 31, 2020

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
Customer Billed Revenue															
5.a.	CR	A credit entry equal to the revenue from the ERRA rate component from bundled customers during the month, excluding the allowance for Revenue Fees and Uncollectible (RF&U) Accounts expense.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(4,457,728,156)
5.a.			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2,334,401,874
5.b.	CR	A credit entry equal to revenues received from Schedule TBCC (Transitional Bundled Commodity Cost);	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(7,306,832)
Retained RPS and RA Value															
5.c.	DR	A debit entry equal to the Retained Renewable Portfolio Standard (RPS) Value, determined using the most current Commission-adopted RPS Adder, multiplied by Actual Retained RPS quantities. A corresponding credit entry equal the Retained RPS Value is recorded in PABA, MTCBA, and the BNBCBA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	301,672,466
5.d.	DR/CR	A debit or credit entry to true-up the Retained RPS Value, determined using the Forecast RPS Adder to the 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 PABA, MTCBA, and the BNBCBA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(25,841,256)
5.e.	DR	A debit entry equal the Retained Resource Adequacy (RA) Value, determined using the most current Commission-adopted RA Adder, multiplied by the Actual Retained RA quantities. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in PABA, MTCBA, and the BNBCBA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	483,126,537
5.f.	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 RPS Adder. A corresponding credit or debit entry equal to the true-up of the Retained RA Value is recorded in PABA, MTCBA, and the BNBCBA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	68,458,658
UOG Costs															-
5.g.	CR	Revenues associated with UOG Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(550,733,207)
5.g.	DR/CR	A debit or credit entry, as appropriate, to record ESA costs associated with bundled customer portfolio/procurement activity (which is embedded in the annual authorized revenue requirements associated with PG&E's owned generation).	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	77,438,400
5.g.	DR/CR	Ex Parte Penalty for Elec Gen, net of RF&U: 2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(436,601)
5.g.	DR/CR	Cost of Capital Adjustment - 2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(25,802)
ISO Related Charges/ Revenues															-
5.h.	DR/CR	A debit or credit entry equal to the net charges or revenues for energy associated with load and generating resources recovered in ERRA and the New System Generation Balancing Account (NSGBA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,376,185,993
5.i.	DR/CR	A debit or credit entry equal to the net charges or revenues for miscellaneous CAISO charges/credits associated with load and generating resources recovered in ERRA and NSGBA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	66,914,956
5.j.	DR/CR	A debit or credit entry equal to the net charges or revenues for ancillary services associated with load and generating resources recovered in ERRA and the NSGBA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	39,757,563
5.k.	DR/CR	A credit or debit entry equal to the revenues or costs related to Congestion Revenue Rights;	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(34,589,041)
5.l.	DR/CR	A credit or debit entry equal to the revenues or costs related to convergence bidding;	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-
Fuel Costs															-
5.m.	DR	A debit entry equal to fuel and related transportation and miscellaneous costs for contracts recovered through ERRA.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(90,452)
Contract Costs															-
5.n.	DR	A debit entry equal to short-term bilateral contract obligations.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	246,340,643
5.o.	DR/CR	A debit or credit entry equal to short-term renewable contract obligations, expenses or revenues associated with renewable energy credits (REC), and fees associated with participating in WREGIS;	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	491,602
5.p.	DR	A debit entry equal to the short-term capacity and energy costs for QF/CHP Program contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	10,714,332
5.q.	CR	A credit entry equal to the net capacity costs recorded in the QF/CHP Program and Marsh Landing subaccounts of the New System Generation Balancing Account (NSGBA).	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	(177,946,538)

TABLE 13-2
FOR THE YEAR ENDING DECEMBER 31, 2020
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
GHG Costs															-
5.r.	DR	A debit entry equal to greenhouse gas costs related with physically settled compliance instruments associated with contracts.	[redacted]												-
Miscellaneous Costs															-
5.s.	DR	A debit entry equal to financial hedging contract obligations.	[redacted]												2,664,784
5.t.	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;													6,929,443
5.u.	DR	A debit entry equal to any other power costs associated with procurement.													(737,869)
5.v.	DR	A debit entry equal to the incremental IE costs through 2010 related to RFOs seeking terms of less than five years. After 2010, a debit entry equal to all IE costs related to all RFOs;													294,452
5.w.	DR	A debit entry equal to power purchase payments provided to eligible Net Energy Metering customers for energy produced by on-site generation in excess of consumption over a 12-month period. Power purchase payments may include additional compensation for renewable attributes where applicable.													4,340,326
5.x.	DR	A debit entry equal the authorized energy storage procurement evaluation program fund amount authorized in D.14-10-045													-
5.ae.	DR/CR	A debit or credit entry equal, as appropriate, to record the transfer of amounts to or from other accounts as approved by the CPUC.													582,019,653
Green Tariff Shared Renewables Program Accounting Procedures															-
5.y.	DR/CR	A credit or debit entry to reflect the solar generation expense associated with the interim pool of renewable resources used to support the GTSR Program, equal to Solar Charge rate associated with these resources, multiplied by the kWh delivered under the GTSR Program to Schedule E-GT customers for the month, and/or entry to reflect any subsequent true-up of the interim pool renewable expense to actual costs.	[redacted]												-
5.z.	DR/CR	A credit or debit entry to reflect the Program Charge expense associated with the GTSR Program, excluding marketing and administrative expenses, for customers taking service under Schedule E-GT, equal to the 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													(2,318,909)
5.aa.	DR	A credit or debit entry to reflect Program Charge expense associated with the GTSR Program, excluding marketing and administration expenses, for customers taking service under Schedule E-ECR, equal to the Program Charge rate, multiplied by the subscription level of the E-ECR customer in kWh, and/or entry to reflect any subsequent true-up of the Program Charge components' expense to actual costs													-
5.ab.	DR	A debit or credit entry equal to expenses associated with the GTSR Program's Enhanced Community Solar (ECR) option resources that is unsubscribed													-
5.ac.	DR	A debit or credit entry to transfer expenses from the GTSRBA for renewable resources procured to serve customers taking service under Schedule E-GT that are in excess of the E-GT program subscription pursuant to the backstop provision in Pub. Util. Code §2833(s)													3,386,283
Disadvantage Communities Green Tariff															-
															-
5.ad.	DR/CR	A debit/credit entry to record the transfer of the revenues financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers. A corresponding credit/debit entry is reflected in Accounting Procedure 6a below.	[redacted]												271,523,521
		Total Monthly Activity Before Interest	**(5,984,376)**	**(26,214,967)**	**31,021,728**	**107,201,299**	**(91,965,821)**	**(39,391,428)**	**(90,673,939)**	**80,047,323**	**27,564,663**	**37,756,194**	**100,109,646**	**489,436,503**	**618,906,826**

TABLE 13-2
FOR THE YEAR ENDING DECEMBER 31, 2020
(CONTINUED)

Tariff Line Item	DR/CR	Tariff Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	FY 2020 YTD
Interest Expense and Other															
5.af.	**DR/CR**	An entry equal to interest on the average balance in the account at the beginning of the month and the balance after the above entries, 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; and	[redacted]												(2,568,706)
		Unreconciled Item - Mar 2019	[redacted]												
		Unreconciled Item - Jan 2020													(18,691)
		April 2020 GTSR Program Charge double entered in RCC and ERRA's BA Account & Interest													(212,287)
		Adjustment needed for Feb 2020 to SAP	[redacted]												(95,963)
		Beginning Balance	(616,011,174)	(622,869,342)	(650,026,966)	(619,517,387)	(513,207,602)	(605,632,691)	(645,177,310)	(736,016,801)	(654,662,651)	(627,177,858)	(589,502,164)	(489,378,212)	(616,011,174)
		ERRA Ending Balance	**(622,869,342)**	**(650,026,966)**	**(619,517,387)**	**(513,207,602)**	**(605,632,691)**	**(645,177,310)**	**(736,016,801)**	**(654,662,651)**	**(627,177,858)**	**(589,502,164)**	**(489,378,212)**	**6**	**6**
6. POWER CHARGE INDIFFERENCE (PCIA) SUBACCOUNT															
		Beginning Balance	-	-	-	-	-	**(12,032,628)**	**(49,258,483)**	**(92,978,542)**	**(136,057,336)**	**(179,011,869)**	(214,416,083)	(240,773,641)	-
6.a.	**DR/CR**	A credit/debit entry to record the transfer of the revenues financed by bundled customers related to the revenue shortfall associated with capped PCIA rates for departing load customers. A corresponding debit/credit entry is reflected in Accounting Procedure 5ac above.	[redacted]												(271,523,521)
6.b.	**DR/CR**	A debit or credit entry, as appropriate, to record the transfer of amounts to or from other accounts, upon approval by the CPUC.	[redacted]												-
6.c.	**DR/CR**	A monthly entry equal to interest on the average balance in the subaccount at the beginning of the month and the balance after the above entries, 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]												-
		PCIA Subaccount Ending Balance	**-**	**-**	**-**	**-**	**(12,032,628)**	**(49,258,483)**	**(92,978,542)**	**(136,057,336)**	**(179,011,869)**	**(214,416,083)**	**(240,773,641)**	**(30,749,880)**	**(271,523,521)**
		TOTAL ERRA Ending Balance	**(622,869,342)**	**(650,026,966)**	**(619,517,387)**	**(513,207,602)**	**(617,665,318)**	**(694,435,793)**	**(828,995,343)**	**(790,719,987)**	**(806,189,727)**	**(803,918,247)**	**(730,151,854)**	**(271,523,515)**	**(271,523,515)**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 14

MAXIMUM POTENTIAL DISALLOWANCE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
MAXIMUM POTENTIAL DISALLOWANCE

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CHAPTER 14
MAXIMUM POTENTIAL DISALLOWANCE

A. Introduction

The purpose of this chapter is to present the maximum potential disallowance calculation for Standard of Conduct 4 (SOC4) violations for the January 1-December 31, 2020 record period. SOC4 states that:

> …the utilities shall prudently administer all contracts and generation resources and dispatch the energy in a least-cost manner.[1]

Pacific Gas and Electric Company (PG&E) agreed to provide this chapter in its Settlement Agreement with the Office of Ratepayer Advocates in the 2014 Energy Resource Recovery Account Compliance proceeding (Application (A.) 15-02-023) (Settlement Agreement).[2] By providing this testimony, PG&E is not explicitly or implicitly indicating that there were any SOC4 violations during the January 1-December 31, 2020 record period. Rather, PG&E does not believe that there were any SOC4 violations but is providing this calculation consistent with the Settlement Agreement.

B. Calculation Methodology for Maximum Potential Disallowance

PG&E's SOC4 is limited to the administration of electric procurement contracts and generation resources and to the dispatch of energy in a least-cost manner. Expenses that are included under SOC4 include the following: contract negotiation and management; dispatch of Utility-Owned Generation (UOG) and third-party resources; and fuel costs to UOG facilities. There are costs at issue in this proceeding that do not fall under the purview of SOC4, such as the costs for UOG replacement energy.

SOC4 is limited in scope and, accordingly, the potential for disallowance is also limited. In Decision (D.) 02-12-074, the California Public Utilities Commission (Commission) adopted a limit for potential disallowances of SOC4 in Ordering Paragraph (OP) 25. The maximum potential disallowance risk is

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1 D.02-10-062, pp. 50-52.

2 Settlement Agreement, § 3.8. The Settlement Agreement was approved at the Commission on December 20, 2016 in D.16-12-045.

equal to two times PG&E's annual procurement administrative expenditures.[3] The Commission further defined that "annual procurement administrative expenditures" include costs related to "utility-related generation, renewables, QFs, demand-side resources, and any other procurement resources."[4] In D.03-06-067, the Commission modified OP 25 to state that the specific dollar amounts for each utility shall be reviewed in each General Rate Case (GRC) or cost of service proceeding.[5]

C. Calculation of Maximum Potential Disallowance

In 2018, PG&E filed is 2020 GRC Application. The Commission approved application (A.18-12-009) in D.20-12-005 and stated that:

> "we find the settlement amount of $36.584 million for EPP costs reasonable".[6]

As described above, the maximum potential disallowance risk is based on PG&E's procurement-related administrative expenses and is determined by the most recently adopted GRC decision.

For this Compliance proceeding, PG&E calculated the 2020 Imputed Regulatory Values of the four Major Work Categories (MWC) that support expenses for the Energy Policy and Procurement organization in compliance with D.20-12-005. The 2020 Imputed Regulatory Values are shown in Table 14-1.

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3 D.02-12-074, pp. 77-78, OP 25.

4 *Id.*, p. 55.

5 D.03-06-067, p. 23, OP 3a.

6 D.20-12-005, p. 145

TABLE 14-1
2020 IMPUTED REGULATORY VALUES
2020 GRC SETTLMENT DECISION
(THOUSANDS OF DOLLARS)

Line No.	MWC	MWC Description	2020 Imputed Regulatory Values
1	CT	Acquire and Manage Electric Supply	$23,244
2	CV	Acquire and Manage Gas Supply	2,086
3	AB	Misc. Expense/Support	488
4	CY	Manage Electric Grid Operations (GII)	10,766
5	Total		$36,584

D. Conclusion

PG&E requests that the Commission approve its 2020 calculation of the maximum potential disallowance of $73.168 million, which is two times $36.584 million.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 15

REVIEW ENTRIES RECORDED IN THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES BALANCING ACCOUNT AND THE DISADVANTAGED COMMUNITY – SINGLE-FAMILY AFFORDABLE SOLAR HOMES MEMORANDUM ACCOUNT

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A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents for review its 2020 Disadvantaged Community – Single-Family Affordable Solar Housing (DAC SASH) funding and administrative costs recorded to the DAC SASH subaccount in the Public Policy Charge Balancing Account (referred as Disadvantaged Community – Single-Family Affordable Solar Housing Balancing Account (DACSASHBA) in this chapter) and the Disadvantaged Community – Single-Family Affordable Solar Housing Memorandum Account (DACSASHMA), as directed by the California Public Utilities Commission (Commission) in Decision (D.) 18-06-027, the *Alternate Decision Adopting Alternatives to Promote Solar Distributed Generation in Disadvantaged Communities*.

Assembly Bill 327 required the Commission to develop alternatives to increase the adoption and growth of renewable generation in disadvantaged communities. D.18-06-027 adopted the DAC SASH Program, along with the Disadvantaged Community Green Tariff and Community Solar Green Tariff programs, as discussed in Chapter 5.

B. DACSASHBA

1. Funding of the DAC SASH Program and Transfer to Balancing Account

Pursuant to Ordering Paragraph (OP) 8 of D.18-06-027, the annual budget of $10 million for the program is funded first through Green House Gas (GHG) allowance proceeds. If such funds are exhausted, the program will be funded through the Public Purpose Charge component of the Public Purpose Program funds. PG&E's proportionate share of the $10 million per year is 43.7 percent, or $4.37 million per year.[1] In the 2020 Energy Resource Recovery Account (ERRA) Forecast proceeding (Application 19-06-001), PG&E stated that its proportionate share of $4.37 million for DAC SASH funding could be wholly covered by GHG allowance proceeds during the 2020 record year. In February, the Commission approved this use of GHG allowance proceeds in D.20-02-047 and the $4.37 million was transferred from Greenhouse Gas Revenue Balancing Account to DACSASHBA.[2]

2. Expenses of the DAC SASH Program Recorded to Balancing Account

An overview of the expenses recorded in 2020 to the DACSASHBA[3] are shown in Table 15-1 below.

TABLE 15-1
DACSASHBA RECORDED EXPENSES IN 2020

Line No.	Description	Amount
1	PG&E Program Management	$25,349
2	Program Administrator (PA) Administrative Expenses	$853,777
3	Incentives	$3,424,872
4	Total	$4,303,998

PG&E incurred $25,349 in internal PG&E Program Management expenses to the DACSASHBA during 2020. Activities associated with this work included:

- Reviewing and approving administration and incentive invoices;
- Ensuring compliance with all regulatory requirements;

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1 D.18-06-027, Appendix A, p. A-6.

2 Advice Letter (AL) 5363-E, the DACSASHBA Implementation AL, was approved on January 24, 2019 and effective as of September 19, 2018. Interest on the account balance is calculated and recorded based on the average balance in this account at the beginning and the end of the month, at a rate equal to one-twelfth of the interest rate on the three-month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

3 Interest on the account balance is calculated and recorded based on the average balance in this account at the beginning and the end of the month, at a rate equal to one-twelfth of the interest rate on the three-month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

- Drafting, reviewing, and responding to regulatory filings;
- Financial planning and analysis for the program; and
- Annual third-party security review for the Program Administrator, GRID Alternatives.

For the Program Administrative Expenses incurred by GRID Alternatives, there is a co-funding agreement between the Investor-Owned Utility (IOU) which is managed by Southern California Edison Company. In 2020, PG&E paid four invoices totaling $853,777 for PG&E's share of the administrative costs for GRID Alternatives. In 2020, PG&E paid incentive invoices to Grid Alternatives totaling $3,424,872 for completed DAC SASH projects.

3. Request for Cost Recovery of 2020 PG&E Administrative Costs

OP 6 of D.20-12-003 authorizes the IOUs to submit Tier 2 ALs with proposed annual budgets for reasonable administrative costs needed to support the DAC SASH program, starting with the 2021 proposed PG&E budget. OP 7 of D.20-12-003 authorizes PG&E to seek recovery of its approved administration costs through its DACSASHBA and to include such costs in its annual ERRA proceedings for reasonableness review. Given that D.20-12-003 was issued in December 2020, PG&E did not have an opportunity to submit an AL requesting approval of a 2020 PG&E budget. Accordingly, PG&E requests approval and seeks recovery of $25,349 for the PG&E expenses incurred in 2020 to the DACSASHBA in this ERRA Compliance proceeding.

C. DACSASHMA

In the 2019 ERRA Compliance Testimony, PG&E defined startup costs as expenses incurred from January 2019 to the launch of the DAC-SASH Program (September 2019). No additional start-up costs were incurred in 2020, so no expenses were booked to the memorandum account (DACSASHMA[4]). PG&E

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4 AL 5361-E, the DACSASHMA Implementation AL approved on December 14, 2018 and effective as of August 20, 2018. Interest on the account balance is calculated and recorded based on the average balance in this account at the beginning and the end of the month, at a rate equal to one-twelfth of the interest rate on the three-month Commercial paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor.

will report on this memorandum account in future proceedings only if costs are incurred during the applicable record period.

D. Conclusion

In this chapter, PG&E described its 2020 funding and recorded expenses for the DAC SASH Program. PG&E requests that the Commission find the program incentive and third-party administrative expenses incurred in 2020 to be reasonable and also approve cost recovery of PG&E's 2020 expenses incurred and recorded in the DACSASHBA.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 16

CENTRAL PROCUREMENT ENTITY ENTRIES RECORDED TO THE CENTRALIZED LOCAL PROCUREMENT SUB-ACCOUNT

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CHAPTER 16
CENTRAL PROCUREMENT ENTITY ENTRIES RECORDED TO THE CENTRALIZED LOCAL PROCUREMENT SUB-ACCOUNT

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E) presents its administrative costs for the Central Procurement Entity (CPE) recorded to the Centralized Local Procurement Sub-Account (CLPSA).

In Decision (D.) 20-06-002 (CPE Decision), issued June 17, 2020, the California Public Utilities Commission (CPUC) ordered PG&E to serve as the CPE for PG&E's distribution service area for the multi-year local Resource Adequacy (RA) program. Starting with the 2023 RA compliance year, the CPE is responsible for procuring the total local RA requirement for all local areas in PG&E's distribution service area on behalf of Commission-jurisdictional Load Serving Entities. The CPE Decision established that both procurement costs and administrative costs incurred in serving the central procurement function shall be recoverable under the Cost Allocation Mechanism, and directed PG&E to submit the administrative costs in the ERRA Forecast and Compliance proceedings.[1]

The CPUC approved Advice Letter 5919-E, effective September 16, 2020, which established the CLPSA in the New System Generation Balancing Account for recording procurement and administrative costs associated with PG&E's role as the CPE.

B. Administrative Expenses Recorded to the CLPSA During the Record Period

PG&E began work in 2020 to establish the function of the PG&E CPE and incurred administrative costs in doing so. These administrative costs resulted from implementation work performed by the newly established PG&E CPE Implementation Team, Information Technology (IT) project costs for scoping of necessary system updates, and Independent Evaluator (IE) expenses related to

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[1] D.20-06-022, pp. 55-56.

consultation and review of CPE work product as required by the CPE Decision. These amounts were recorded to the CLPSA as follows:

TABLE 16-1
2020 PG&E CPE ADMINISTRATIVE COSTS

Line No.	Description	Amount ($)
1	CPE Systems (IT Support)	
2	Contract Costs	150,410
3	Overhead	24,499
4	CPE Implementation Team costs	
5	Labor	186,697
6	Other	1,499
7	Consulting Services	6,900
8	Total	370,005

1. CPE Implementation Team Established

The CPE is tasked with a number of functions in the CPE Decision, including, but not limited to: (1) conducting one or more competitive, all-source solicitations for local RA procurement with specific requirements outlined in the CPE Decision, (2) evaluating and selecting bids in the solicitation in accordance with the all-source selection criteria, (3) complying with various regulatory requirements, and (4) contracting with counterparties for procurement beginning in 2021. To ensure compliance with CPE competitive neutrality rules, PG&E established on October 1, 2020, a separate and walled off team to perform the duties of the PG&E CPE. Once established, the CPE Implementation Team began work on the initial elements of the PG&E CPE implementation, including the development of the PG&E CPE Code of Conduct, development of the PG&E CPE Procurement Plan, and development of CPE RA standard form agreements. CPE Implementation Team administrative costs totaled $188,196 for 2020.

2. CPE Systems

PG&E plans to utilize existing systems for CPE procurement processes. These systems include, but are not limited to, PG&E’s trade capture and settlements system, middle office systems for market and credit risk, as well as systems that support PG&E’s contract administration functions and processes. In order to be prepared for a 2021 PG&E CPE solicitation, PG&E initiated a CPE-focused IT project to determine scope and requirements for changes to systems needed to accommodate the functions of the CPE. Included in this scope will be any system updates needed to ensure compliance with established competitive neutrality rules requiring CPE-related market sensitive information to be restricted from employees performing RA procurement functions on behalf of PG&E's bundled customers. In 2020, PG&E incurred $174,909 in expense for work related to scoping of CPE-impacted systems.

3. IE

The CPE Decision requires the PG&E CPE to consult regularly with an IE on various aspects of the CPE procurement process including, but not limited to, development of the CPE Code of Conduct, development of CPE solicitation protocols and processes, and evaluation of bids and offers into the CPE solicitation. PG&E engaged with Merrimack Energy Group to act as the initial IE for CPE procurement activities in 2020 and 2021. In 2020, the IE consulted with PG&E on the development of both the PG&E CPE Code of Conduct and the PG&E CPE Procurement Plan. Total expense for engagement with the IE in 2020 was $6,900.

C. Conclusion

The above testimony describes CPE administrative costs that were incurred during the record period and demonstrates that these costs were reasonable and prudently incurred.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF THOMAS R. BALDWIN

Q 1 Please state your name and business address.

A 1 My name is Thomas R. Baldwin, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant, San Luis Obispo California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of Generation Business Planning, responsible for the Generation line of business strategic and integrated planning, General Rate Case (GRC) activities, and matrixed organizations including business finance and supply chain.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of Colorado, Boulder, in 1984. I joined PG&E in 1985 as a Design Engineer in the Mechanical and Nuclear Engineering Department. I have since held positions as the Supervisor of Systems Engineering, Manager of Regulatory Services, Manager of Procedures Services, Operations Senior Reactor Operator (licensed by the Nuclear Regulatory Commission), Director of Site Services, and the Director of Business Operations for Nuclear Generation. Additionally, I was a Witness in PG&E's 2018 GRC proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2021 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 4, "Utility-Owned Generation: Nuclear."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DONNA L. BARRY

Q 1 Please state your name and business address.

A 1 My name is Donna L. Barry, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Regulatory Principal in Electric Rates Department within the Regulatory Affairs organization. I am responsible for developing testimony and analysis to support proceedings filed at the California Public Utilities Commission on matters related to energy procurement and cost recovery.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Civil Engineering from Washington State University and a Master's degree in Business Administration from Santa Clara University.

I began my career with PG&E in 1989 as an Engineer in the Engineering and Construction Business Unit's Gas Construction Department managing gas distribution and pipeline replacement construction projects. From there, I took an assignment in the Gas Supply Business Unit in the Gas Engineering and Construction (GEC) Department as a Project Manager, managing three gas backbone transmission projects before joining the Gas Planning section in GEC where I analyzed the reliability of local transmission and distribution systems. I subsequently joined the Cost of Service section in the Rates Department where I performed Cost of Service studies and marginal cost analyses supporting various gas and electric rate applications.

I joined the Electric Restructuring Cost Recovery section of the Revenue Requirements Department in 2001 and Electric Energy Revenue and Analysis and Ratemaking section in 2002. I was a Principal Case Manager and Witness for the Energy Resource Recovery Account (ERRA) Forecast and ERRA Compliance Review proceedings between 2003 and 2014 responsible for case managing and testimony development. The department and section were renamed as the Energy Supply Proceedings Department in 2012. In 2014, I moved to the Revenue Requirements and

Analysis Department and moved to my current position in Electric Rates in 2017.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E’s 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 11, “Review Entries Recorded in the Green Tariff Shared Renewables Memorandum Account and the Green Tariff Shared Renewables Balancing Account”:
  - Section A;
  - Section C; and
  - Section D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF CANDICE K. CHAN

Q 1 Please state your name and business address.

A 1 My name is Candice K. Chan, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am currently the Director of the Energy Contract Management and Settlements section of the Energy Policy and Procurement Department, responsible for managing back office contract management and settlement operations associated with electric and gas procurement.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Communication Studies, with a specialization in Business Administration from the University of California, Los Angeles, and a Master's degree in Business Administration from the Haas School of Business at the University of California, Berkeley. In 2002, I joined PG&E as a Manager of Performance Management in the Shared Services organization, responsible for: consulting on financial analysis; reporting; operational performance metrics and management; performance data systems; and performance improvement initiatives. In 2004, I joined PG&E's Finance Department, leading the business planning function for Shared Services. From 2006 to 2009, I served as the Program Director and Chief of Staff to the Office of the President and Chief Executive Officer, managing: key operational planning; and governance and communication activities on behalf of the senior executive team. In 2009, I joined the Energy Policy and Procurement Department in my current role.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 9, "Contract Administration"; and
- Chapter 10, "CAISO Settlements and Monitoring."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KELLY A. EVERIDGE

Q 1 Please state your name and business address.

A 1 My name is Kelly A. Everidge, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of the Risk, Compliance and Reporting Department within PG&E's Energy Policy and Procurement (EPP) organization. In this position, I am responsible for overseeing EPP's compliance with the California Public Utilities Commission, Federal Energy Regulatory Commission and North American Electric Reliability standards and obligations affecting its recovery of energy procurement costs. In addition, I am responsible for ensuring the organization's compliance with the Securities and Exchange Commission reporting requirements, Section 404 of the Sarbanes-Oxley Law, all internal audit recommendations, and plans for systems and process improvement.

Q 3 Please summarize your educational and professional background.

A 3 I joined Energy Policy and Procurement from Business Finance, where I was responsible for managing the business planning function, including budget, forecasting, operational performance analysis, and strategic planning. I joined PG&E in 1997 and have held various roles of increasing scope and responsibility. I spent five years in Energy Policy and Procurement, where I served as Director, Energy Contract Management and Settlements and Chief of Staff, responsible for contract management, settlement, payments, and financial reporting operations associated with electric and gas procurement. Prior to joining Energy Policy and Procurement, I served in roles within the Risk Management and Finance organizations, and managed front, middle, and back office functions at PG&E's former subsidiary, the National Energy Group. I received a Bachelor of Science degree in Finance from California State University, Sacramento, and a Master's degree in Business Administration from Golden Gate University, San Francisco.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 14, "Maximum Potential Disallowance."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF LIZ FINNEGAN

Q 1 Please state your name and business address.

A 1 My name is Liz Finnegan, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Principal Program Manager for the Disadvantaged Community - Green Tariff (DAC-GT) and Community Solar Green Tariff (CS-GT) programs in the Customer Energy Solutions – Clean Energy Programs organization. In this role, I manage the administration for some of PG&E's distributed generation programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in International Affairs and a minor in Archaeology from the George Washington University and a Master of Business Administration (MBA) from Duke University Fuqua School of Business. I joined PG&E in 2016 as a summer intern and was then hired full time in 2017 as a Fellow in PG&E's MBA Leadership Development Program. Since starting at PG&E, I have worked as an individual contributor and management as gas operations, electric operations, energy policy and procurement, and currently in our customer organization as a Principal Program Manager for three solar programs, the DAC-GT, the CS-GT, and the California Solar Initiative program Multifamily Affordable Solar Housing program. Prior to my MBA, I worked as in sales and relationship management in a data technology and in a consulting firm.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony jointly with Ryan Stanley in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 5, "Review Entries Recorded In The Disadvantaged Community – Green Tariff Balancing Account and the Community Solar Green Tariff Balancing Account."

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF TIFFANY HANSON

Q 1 Please state your name and business address.

A 1 My name is Tiffany Hanson, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Program Manager for low income solar programs in the Customer Energy Solutions – Clean Energy Programs organization. In this role, I manage the administration for some of PG&E's solar incentive programs.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Mechanical Engineering from University of California, San Diego and a Master's degree in Mechanical Engineering from Boston University. I joined PG&E in 2019 as a Program Manager for low income solar programs, including Solar on Multifamily Affordable Housing, Multifamily Affordable Solar Housing, Single-Family Affordable Solar Homes, Disadvantaged Community – Single-Family Solar Homes. Prior to PG&E, I worked as a Project Manager at a solar design company, and a solar design engineer at NRG Energy, Inc.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony jointly with Ryan Stanley in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 15, "Review Entries Recorded in the Disadvantaged Community – Single-Family Affordable Solar Homes Balancing Account and the Disadvantaged Community – Single-Family Affordable Solar Homes Memorandum Account."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOSH HARMON

Q 1 Please state your name and business address.

A 1 My name is Josh Harmon, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Senior Program Manager for Distributed Generation Programs in the Customer Energy Solutions organization. In this role, I oversee the development and management of PG&E's customer-facing solar incentive and renewable energy programs. My focus in this role is management of the Green Tariff Shared Renewables Programs: Green Tariff and Enhanced Community Renewables.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Global Studies from the University of Illinois at Urbana-Champaign and a Master's degree in International Affairs from the George Washington University. I joined PG&E in 2018 as a Strategic Analyst and moved to the Distributed Generation team in 2019. Before working at PG&E, I worked at the George Washington University Solar Institute where I produced and directed short educational films on Solar PV as part of the U.S. Department of Energy Sunshot Initiative. I've also interned in the Office of Energy Efficiency and Renewable Energy at the U.S. Department of Energy and worked as a consultant at a boutique advisory firm in Chicago.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding.

- Chapter 11, "Review Entries Recorded in the Green Tariff Shared Renewables Memorandum Account and the Green Tariff Shared Renewables Balancing Account":
  - Section A;
  - Section B; and
  - Section D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF KELLY JOHNSTON

Q 1 Please state your name and business address.

A 1 My name is Kelly Johnston, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am an Expert Portfolio Management Analyst in the Portfolio Management group in PG&E's Energy Policy and Procurement (EPP) organization and am responsible for greenhouse gas (GHG) commercial activity and position management.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Psychology from the University of California, Berkeley in 2007. I joined PG&E in 2014 as an Associate Contract Management Analyst on the EPP Contract Management team, performing contract administration duties for various power purchase agreements, including tolling, GHG, and RPS agreements. In 2018, I joined the Portfolio Management group in my current role. Prior to my employment with PG&E, I worked at UnitedHealthcare as a financial underwriter in its national accounts sector.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 7, "Greenhouse Gas Compliance Instrument Procurement."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MICHAEL KOWALEWSKI

Q 1 Please state your name and business address.

A 1 My name is Michael Kowalewski, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Portfolio Manager in the Energy Policy and Procurement Department. I am responsible for managing the financial position of PG&E's electric portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics from the University of California, Berkeley, in 1992. From 1992 to present, I have been employed by PG&E in various positions including Manager of PG&E's Electric Portfolio Gas Trading Operations, Renewable Energy Transactor, Gas Trader, Product Manager, Project Manager, and Financial and Regulatory Analyst.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Section H and I.
- Attachment B, "Generation Fuel Costs."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MARK MAYER

Q 1 Please state your name and business address.

A 1 My name is Mark Mayer, and my business address is Pacific Gas and Electric Company, Diablo Canyon Power Plant.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Manager in the Nuclear Fuels Purchasing group for Diablo Canyon Power Plant (Diablo Canyon). I am responsible for contracts associated with the fabrication of nuclear fuel for Diablo Canyon and the purchase of feed materials (uranium, conversion services, and enrichment services).

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Nuclear Engineering from the Massachusetts Institute of Technology. I have worked for PG&E at Diablo Canyon for over 30 years, primarily in engineering. My previous engineering responsibilities have included reactor engineering and system and transient analysis. I am a registered Professional Engineer in the state of California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Section E;
  - Section F; and
- Attachment B, "Generation Fuel Costs."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF GIA MILBRANDT

Q 1 Please state your name and business address.

A 1 My name is Gia Milbrandt, and my business address is Diablo Canyon Power Plant, San Luis Obispo, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Supervisor of Outage Hiring at PG&E, with knowledge of the Strategic Teaming and Resource Sharing (STARS) Alliance Management Council.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Theater from the University of California, Los Angles, in 1987. In 2011, I joined PG&E as an Executive Assistant supporting Senior Leaders at Diablo Canyon Power Plant. After seven years, I supported Outage Management as a Sr. Work Week Manager for two and a half years. In addition, I assumed the role of STARS Management Council Representative from DCPP in June of 2020. I assumed my current position in December of 2020 and kept my role with STARS.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Section G; and
- Attachment C, "Annual Report of Utility on the Activities of Stars Alliance, LLC.; Utility Savings/Avoided Costs by Stars Team/Project; and Independent Auditor's Report and Financial Statements."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF AMOL PATEL

Q 1 Please state your name and business address.

A 1 My name is Amol Patel, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 As Chief, Central Procurement Entity Implementation, I am a lead within the newly formed central procurement entity (CPE) department which will focus on the implementation of procurement processes for PG&E's role as the CPE for PG&E's distribution service area.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Biological Systems Engineering in 2000 from the University of California, Davis. I have worked in the energy industry for over 20 years, 15 of which, have been for PG&E where I have held several leadership positions in the Energy Contract Management and Settlements department within the Energy Policy and Procurement organization.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 16, "Central Procurement Entity Entries Recorded to the Centralized Local Procurement Sub-Account."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SCOTT RANZAL

Q 1 Please state your name and business address.

A 1 My name is Scott Ranzal, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am currently the Director of the Portfolio Management section of the Energy Policy and Procurement Department. I am responsible for managing the wholesale power portfolio including, strategy, management, and compliance required for PG&E's energy portfolio of products including Energy, Capacity, Congestion Revenue Rights, Greenhouse Gas, and Low Carbon Fuel Standard among others.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Communication from the University of Colorado at Boulder in 1993 and a Master of Science in Accountancy form San Jose State University in 2004. In 2007, I joined PG&E as a Supervisor in External Reporting in PG&E's Finance Department. Between 2007 and 2012, I held several roles in PG&E's Finance Department. In 2012, I joined Market and Credit Risk Management in PG&E's Finance and Risk Department; Market and Credit Risk Management is responsible for modeling, risk metrics, portfolio risks, and stress testing of the energy procurement portfolio. In 2019, I joined the Energy Policy and Procurement Department in my current role.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 8, "Resource Adequacy";
- Chapter 12, "Summary of Portfolio Allocation Balancing Account Entries for the Record Period":
  - Section C.3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF WILLIAM REINWALD

Q 1 Please state your name and business address.

A 1 My name is William Reinwald, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Analyst in the Risk and Compliance Department within the Energy Policy and Procurement organization. I am responsible for preparing, validating, and submitting energy procurement reports to state and federal regulatory agencies.

Q 3 Please summarize your educational and professional background.

A 3 I graduated with a Bachelor of Science degree in Nuclear Engineering in 1994 and a Master of Business degree in 2001, both from the University of Cincinnati.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 12, "Summary of Portfolio Allocation Balancing Account Entries for the Record Period":
  - Section C.2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEVE ROYALL

Q 1 Please state your name and business address.

A 1 My name is Steve Royall, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director for Operations and Maintenance of PG&E's generation facilities in the northern portion of our system in PG&E's Power Generation organization.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E in 2007 as Director in the Generation Department, responsible for managing the Gateway Generating Station. Prior to PG&E, I worked at Northern California Power Agency, where I was the Assistant General Manager of Power Generation and the Manager of Gas Fired Generation. I have more than 37 years of experience working in power generation projects in the areas of operation, engineering, construction, and commissioning. I have been involved in projects that resulted in approximately 3,500 megawatts of new generation in California and Washington over the last 37 years, including PG&E's new Gateway Generating Station, and Colusa Generating Station. Other former employers include: Calpine Corporation, Phillips Oil Company, and Freeport McMoRan Corporation. I am the Chairperson of the Electric Utility Cost Group Fossil committee and the former chairman of the Combined Cycle Users Group. I was a Witness in PG&E's 2014-2018 Energy Resource Recovery Account Compliance Review proceedings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 3, "Utility-Owned Generation: Fossil and Other Generation."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF RYAN STANLEY

Q 1 Please state your name and business address.

A 1 My name is Ryan Stanley, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Manager in the Energy Accounting Department within the Corporate Accounting organization at PG&E. In this position, I am responsible for overseeing and advising on cost recovery. I am also responsible for leading various reporting activities on the monthly accounting entries made into the Energy Resource Recovery Account balancing account, in compliance with California Public Utilities Commission directives.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Business Administration, from the Walter A. Haas School of Business, University of California at Berkeley. I received my Master's in Business Administration from the Walter A. Haas School of Business, University of California at Berkeley.

I have over 14 years of regulated utility accounting, financial forecasting, and regulatory experience from having held positions of increasing responsibility at PG&E, in the Controller's and Regulatory Affairs organizations.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2019 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 5, "Review Entries Recorded In The Disadvantaged Community – Green Tariff Balancing Account and the Community Solar Green Tariff Balancing Account";
- Chapter 12, "Summary of Portfolio Allocation Balancing Account Entries for the Record Period";
- Attachment A, "GHG Emissions and Costs";

- Attachment B, “Final Joint Proposal on Potential Verification Method for PG&E’s Greenhouse Gas Emissions and Weighted Average Costs (WAC) for Future ERRA Compliance Filing”;
- Chapter 13, “Summary of Energy Resource Recovery Account Entries for the Record Period”; and
- Chapter 15, “Review Entries Recorded in the Disadvantaged Community – Single-Family Affordable Solar Homes Balancing Account and the Disadvantaged Community – Single-Family Affordable Solar Homes Memorandum Account.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ALVA J. SVOBODA

Q 1 Please state your name and business address.

A 1 My name is Alva J. Svoboda, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Principal Day Ahead Analyst of Market Design Integration in the Short-Term Electric Supply Department of the Electric & Gas Acquisition organization at PG&E. I am responsible for supporting the optimization of short-term operations

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Mathematics from University of California, Santa Barbara in 1980; a Master of Science degree in Operations Research from University of California, Berkeley in 1984; and a Doctorate in Operations Research from University of California, Berkeley in 1992. I joined PG&E in 1997 and have worked in Short Term Electric Supply from that time to the present.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 1, "Least Cost Dispatch and Economically-Triggered Demand Response":
  - Section A;
  - Section B; and
  - Section D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOMO THORNE

Q 1 Please state your name and business address.

A 1 My name is Jomo Thorne, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Manager of Demand Response Operations & Programs. In this role I lead a team of program managers and support staff responsible for designing, marketing, and operating PG&E's Demand Response program portfolio.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in History from Harvard University in Cambridge, Massachusetts. I've also received a Master of Business Administration, and a Master of Public Policy from the University of Michigan. In 2008, I joined PG&E and have since held various positions of increasing responsibility, including Renewable Transactor where I negotiating renewable energy power purchase agreements with third-party developers; Manager of Renewable and Clean Energy Strategy in the run up to implementation of California's 33 percent Renewable Portfolio Standard law; Manager of Value Based Reliability via which I conducted a comprehensive review of power plant outage scheduling business processes, and governance, across merchant and operational lines of business and implemented broad change-management strategy; and Manager of Market Initiatives Implementation where I was charged with implementing California Independent System Operator initiatives that impact the design, policy, and operations of California's wholesale energy markets, as well as conducting all market monitoring functions.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 1, "Least-Cost Dispatch and Economically-Triggered Demand Response":

  – Section A;
  – Section C; and
  – Section D.

- Attachment A, “Summary of Triggered Dispatch From Demand Response Programs”;
- Attachment B, “Summary of 2020 Capacity Bidding Program Events”; and
- Attachment C, “Summary of Total Energy Dispatched From Demand Response Programs.”

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF JOHN ULLOA

Q 1 Please state your name and business address.

A 1 My name is John Ulloa, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 My current title is Manager, Electric Gas Supply in the Electric and Gas Acquisition Department, which is part of the Energy Policy and Procurement organization. I am responsible for physical and financial trading of gas in support of PG&E's utility-owned generation plants and PG&E's tolling agreements.

Q 3 Please summarize your educational and professional background.

A 3 I earned a Bachelor of Arts degree in Economics and Business Administration from Saint Mary's College of Moraga, in 1995. From 1998 to present, I have been employed by PG&E in various positions, including Financial Portfolio Manager in Electric Gas Supply, and currently Manager in the Electric Gas Supply Department.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 6, "Generation Fuel Costs and Electric Portfolio Hedging":
  - Section B;
- Attachment A, "Letter From Ruby Pipeline Officer Certifying PG&E's "Most Favored Nations" (Lowest Rate) Status"; and
- Attachment B, "Generation Fuel Costs."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ERIC A. VAN DEUREN

Q 1 Please state your name and business address.

A 1 My name is Eric A. Van Deuren, and my business address is Pacific Gas and Electric Company, 12840 Bill Clark Way, Auburn, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Senior Director of Hydro Operations and Maintenance (O&M) in PG&E's Power Generation department responsible for O&M of PG&E's hydro generation facilities. In this position, my responsibilities include leading the operating and maintenance of the company's hydroelectric facilities.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science in Civil and Environmental Engineering from the University of Wisconsin, Madison, in 1990. I am a Licensed Professional Engineer in California. Prior to joining PG&E in 2013, I spent 23 years at Mead & Hunt, Inc., starting out as an entry-level Engineer in 1990, progressing to the position of Vice President and Group Leader of Water Resources, and serving on the Board of Directors for eight years. During my tenure at Mead & Hunt, I specialized in dam safety work; participated in, or acted as, the Federal Energy Regulatory Commission (FERC)-approved Independent Consultant for over 120 FERC Part 12 inspections; and performed engineering evaluations, and design, and on many dam and hydropower-related projects. I joined PG&E Power Generation in 2013, as Senior Manager of Project Engineering (including both project engineering and project management); moving into the role of Safety, Quality and Standards Director for Power Generation in 2015, moving into role of Director of Engineering for Power Generation in 2018, and moving to my current position as Senior Director of Hydro Operations and Maintenance in 2020.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Energy Resource Recovery Account Compliance Review Proceeding:

- Chapter 2, “Utility-Owned Generation: Hydroelectric”;
- Attachment A, “PG&E Powerhouses and Generating Units”;
- Chapter 6, “Generation Fuel Costs and Electric Portfolio Hedging”:
  - Section C and D.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.