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PACIFIC GAS AND ELECTRIC COMPANY

2023 GENERAL RATE CASE

REBUTTAL TESTIMONY

EXHIBIT (PG&E-18)

ENERGY SUPPLY

PACIFIC GAS AND ELECTRIC COMPANY
2023 GENERAL RATE CASE
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ENERGY SUPPLY

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REBUTTAL TESTIMONY OF
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A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Thomas R. Baldwin. This testimony responds to the direct testimony of The Utility Reform Network (TURN).[1] No other parties addressed PG&E's forecasts for Nuclear Operations Costs. I summarize TURN's positions in Section B below.

Q 2 Does TURN make recommendations concerning specific projects and programs?

A 2 Yes.

Q 3 Do you dispute TURN's recommendations?

A 3 Yes, I respond to TURN's recommendations in Section C.

TURN disputes the labor forecasts for all Nuclear Major Work Categories (MWC).[2] Additionally, TURN disputes the need for the DCPP Aging Management program, proposes disallowance of the Unit 2 Polisher Computer workstation project, and recommends that 50 percent of the costs for two other capital projects be collected through Decommissioning Trust funds.[3]

Q 4 Are there programs that parties do not dispute or do not address?

A 4 Yes, programs for MWC AK, Manage Environmental Operations, and MWC EO, Provide Nuclear Support are not disputed. See Table 3-1 and 3-2 below.

Q 5 Do you have any adjustments or corrections to the forecasts as provided in the February 28, 2022, version of your initial testimony and/or workpapers?

A 5 No, PG&E does not have any adjustments to its forecasts.

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[1] TURN-14, pp. 6-7, pp. 9-10, pp. 41-52, p. 83.

[2] *Id*., p. 9, line 9 to p. 10, line 21.

[3] *Id*., p. 41, line 16 to p. 42, line 19.

Q 6 Do you have any non-forecast related adjustments or corrections to the February 28, 2022, version of your initial testimony and/or workpapers?

A 6 No.

B. Summary of Parties' Positions

Q 7 Please provide PG&E's current forecast and parties' recommendations.

A 7 PG&E's current forecast and the parties' recommendations are set forth in Table 3-1 (expense) and Tables 3-2 and 3-3 (capital expenditures) below.

TABLE 3-1
2023 EXPENSE FORECAST – PG&E AND PARTIES
(THOUSANDS OF NOMINAL DOLLARS

			PG&E			Proposed Increases/(Reductions)	
Line No.	Program or MWC Description	MWC]	Filed Forecast[a]	Errata or Forecast Adjustments[b]	2023 Adjusted Forecast	Cal Advocates	TURN
1	Manage Environmental Operation	AK	$2,105	–	$2,105	–	–
2	Manage DCPP Business	BP	13,297	–	13,297	–	$(559)
3	DCPP Loss Prevention	BQ	43,664	–	43,664	–	(3,776)
4	Operate DCPP Plant	BR	77,743	–	77,743	–	(6,123)
5	Maintain DCPP Plant Assets	BS	90,688	–	90,688	–	(4,846)
6	Enhance DCPP Personnel Perfor.	BT	15,841	–	15,841	–	(141)
7	Maintain DCPP Plant Config.	BV	35,018	–	35,018	–	(2,580)
8	Provide Nuclear Support	EO	10	–	10	–	–
9	Operational Management	OM	7,675	–	7,675	–	(767)
10	Operational Support	OS	24,999	–	24,999	–	(2,615)
11	Regulatory Balancing Account	IG	2,608	–	2,608	–	(133)
12	Total		$313,648	–	$313,648	–	$(21,540)

Note: PG&E's 2020-2023 current recorded and forecast expense amounts for all activities included in Exhibit (PG&E 5) (Feb. 28, 2022), Chapter 3 (adjusted for errata and concessions) as of June 13, 2022, are shown in Table 3-4 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

TABLE 3-2
2023-2026 CAPITAL EXPENDITURES FORECAST –PARTIES ADJUSTED FORECASTS
(THOUSANDS OF NOMINAL DOLLARS)

			Adjusted Forecast[a]				Cal Advocates				TURN			
Line No.	Program or MWC Description	MWC	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)
1	Office Furniture and Equipment	3	–	–	–	–	–	–	–	–	–	–	–	–
2	Fleet Equipment	4	–	–	–	–	–	–	–	–	–	–	–	–
3	Tools	5	$748	–	–	–	–	–	–	–	–	–	–	–
4	DCPP Capital	20	10,252	$6,000	$1,000	–	–	–	–	–	$(4,201)	$(4,954)	$(998)	–
5	Total		$11,000	$6,000	$1,000	–	–	–	–	–	$(4,201)	$(4,954)	$(998)	–

(a) PG&E's 2020-2026 recorded and forecast capital costs (adjusted for errata and concessions) are shown in Table 3-5.

TABLE 3-3
2023-2026 CAPITAL EXPENDITURES – PG&E'S ADJUSTED FORECAST
(THOUSANDS OF NOMINAL DOLLARS)

			Filed Forecast[a]				Errata or Forecast Adjustments[b]				Adjusted Forecast			
Line No.	Program or MWC Description	MWC	2023 Filed Forecast	2024 Filed Forecast	2025 Filed Forecast	2026 Filed Forecast	2023 Errata or Forecast Adj.	2024 or Forecast Adj.	2025 or Forecast Adj.	2026 or Forecast Adj.	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast
1	Office Furniture and Equipment	3	–	–	–	–	–	–	–	–	–	–	–	–
2	Fleet Equipment	4	–	–	–	–	–	–	–	–	–	–	–	–
3	Tools	5	$748	–	–	–	–	–	–	–	$748	–	–	–
4	DCPP Capital	20	10,252	$6,000	$1,000	–	–	–	–	–	10,252	$6,000	$1,000	–
5	Total		$11,000	$6,000	$1,000						$11,000	$6,000	$1,000	–

Note: PG&E's 2020-2026 current recorded and forecast capital expenditures amounts as included in Exhibit (PG&E-5) (Feb. 28, 2022), Chapter 3 (adjusted for errata and concessions) as of June 13, 2022, are shown in Table 3-5 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

Q 8 Does PG&E disagree with any of TURN's recommendations?

A 8 Yes, PG&E disagrees with TURN's recommendations regarding the following programs:

- Manage DCPP Business MWC BP;
- DCPP Loss Prevention MWC BQ;
- Operate DCPP Plant MWC BR;
- Maintain DCPP Plant Assets MWC BS;
- Enhance DCPP Personnel Performance MWC BT;
- Maintain DCPP Plant Configuration MWC BV;
- Manage Var Balancing Acct Processes MWC IG;
- Operational Management MWC OM;
- Operational Support MWC OS; and
- DCPP Capital MWC 20.

PG&E responds to parties' recommendations in Section B.

C. PG&E's Response to Parties' Recommendations Concerning Specific Programs or Projects

Q 9 What was TURN's recommendation with regard to headcount and the resulting reduction to PG&E's expense forecast?

A 9 In general, TURN examined the results of the actual 2021 headcount for Nuclear Operations compared to the forecast for end of year 2021 and concluded that PG&E was overstating its headcount forecast—a critical factor in developing the labor cost estimates.[4] Figure 3-1 shows that 2021 actual headcount was approximately 7 percent less than forecast with various explanations and reconciliations showing that this result was simply ahead of schedule or temporary. TURN concluded that this 2021 result should lead to a 15 percent reduction in 2024 and 2025 labor costs[5] and that an additional 10 percent should be reduced and monitored in a one-way balancing account for lack of certainty for 2023 through 2025.[6]

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4 *Id*., p. 86, lines 6-9.

5 *Id*., p. 87, lines 23-25.

6 *Id*., p. 88, lines 1-3.

FIGURE 3-1
2021 HEADCOUNT – ORIGINAL FORECAST VS ACTUAL

		Forecast	Actual	Difference	
		yr	yr	yr	
		2021	2021	2021	Comments
BP & IG	Manage DCPP Business & Balancing Acct	31	31	-	
BQ	DCPP Loss Prevention	265	253	12	Protective Strategy - net (8); Delay in Hiring (4)
BR	Operate DCPP Plant	291	272	19	Earlier attrition than expected
BS	Maintain DCPP Plant Assets	243	220	23	Earlier attrition than expected (22) - 10 are Capital Only; Delay in Hiring (4); Offset by Reduction Strategy not achieved (3)
BT	Enhance DCPP Personnel Performance	10	13	(3)	Reduction Strategy not achieved
BV	Maintain DCPP Plant Configuration	149	131	18	Earlier attrition than expected (11) 1 is Fuel Only ; Delay in Hiring (9); Offset by Reduction Strategy not achieved (2)
OM	Operational Management	44	37	7	Earlier attrition than expected (8); Offset by Reduction Strategy not achieved (1)
OS	Operational Support	161	153	8	Earlier attrition than expected (8); Delay in Hiring (4); Offset by Reduction Strategy not achieved (4)
Total		1,194	1,110	84	
				7.04%	Percent Favorable Variance

Q 10 Do you agree with TURN's conclusions?

A 10 No. Headcount levels are an important factor in labor cost estimates; however, they are not the only element. Overtime rates, non-expense order charging (non-productive, indirect, capital), temporary additional hires, and the amount of contracting are all significant contributors to determining labor costs. Explanations shown in Figure 3-1 were ignored by TURN but have significant impacts on labor costs. Figure 3-2 below shows the 2021 labor forecast from the original GRC testimony versus actual 2021 labor costs.

FIGURE 3-2
2021 LABOR COSTS – ORIGINAL FORECAST VS ACTUAL

		Forecast	Actual	Difference	
		yr	yr	yr	
		2021	2021	2021	Comments
BP & IG	Manage DCPP Business	$6,161	$5,440	$721	
BQ	DCPP Loss Prevention	$30,752	$32,027	($1,275)	Higher Overtime - 28% vs 14% for 2021
BR	Operate DCPP Plant	$50,497	$45,634	$4,863	Delays in hiring and earlier attrition; higher Overtime - 14% vs 13%
BS	Maintain DCPP Plant Assets	$41,371	$44,602	($3,230)	Capital Headcount not impacting expense; higher overtime - 10% vs 8%
BT	Enhance DCPP Personnel Performance	$1,390	$2,390	($999)	Reorganization - Procedure Writers from BR, BV, BS
BV	Maintain DCPP Plant Configuration	$21,446	$18,992	$2,454	Capital Headcount not impacting expense - Design Engineering;
OM	Operational Management	$8,458	$8,828	($371)	
OS	Operational Support	$26,688	$26,702	($14)	Includes Learning Services which is below forecast offset by Work Control and Outage Management
Total		**$186,764**	**$184,615**	**$2,148**	
				1.15%	Percent Favorable Variance

Figure 3-2 shows that the actual labor costs for 2021 were approximately 1 percent favorable to forecasted labor costs. The comments make clear that higher overtime for some of the organizations and headcount reductions that do not impact expense result in a very different picture when all labor cost elements are considered—1 percent variance in labor costs versus a 7 percent variance in headcount. This result emphasizes that the labor costs are driven by the work scope necessary to meet regulatory requirements, maintain plant equipment reliability, and to ensure the security and safety of the plant and employees.

Q 11 How do the 2021 labor cost results affect the 2023 labor forecast provided in the original filing?

A 11 PG&E explained to TURN in a data response[7] that two critical issues drove lower headcount in 2021. The first was attrition that occurred earlier than expected. The headcount forecast leading to 2023 assumed that the attrition would spread out for 2020 through 2023 until the end of the Tier 2 retention period. Since the attrition has occurred earlier than expected and with employee severance payment eligibility on the horizon,[8] we anticipate that there will be less attrition in 2022 and 2023. This will leave us in approximately the same position as originally assumed. The second issue was the delay in hiring for vacancies at the end of 2021. A total of 21 positions are expected to be filled in 2022. This hiring has already been occurring in 2022 with Hiring Hall staffing in Maintenance but also in Security, Engineering, and Operational Support functions. The approximate cost of these 21 hires will be $3.2 million on an annual basis thus exceeding the favorable labor variance at the end of 2021. Furthermore, lower headcount can actually result in higher labor costs due to overtime premium pay and the higher cost of Hiring Hall and Temporary additional employees.

Q 12 Are there other concerns with TURN's testimony regarding labor?

A 12 Yes. TURN made an error in TURN-14, page 10 and page 87.

Q 13 Please identify this error.

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[7] PG&E's response to Data Request TURN_213_Q008Atch01, dated 6/6/22 in Appendix A, at the end of this exhibit.

[8] Decision (D.) 18-01-022, p. 24.

A 13 TURN asserts it has proposed a 25 percent reduction in staffing levels for 2024 and 2025.[9] Nevertheless, Table 5 states 15 percent and the numbers calculated reflect a 15 percent reduction proposed.[10]

Q 14 Please describe each of the programs and address TURN's issues.

A 14 Each of the MWCs will be addressed separately below because the issues are different for each of them.

1. Manage DCPP Business (MWC BP) and Balancing Account (MWC IG)

FIGURE 3-3
AVERAGE HEADCOUNT SUMMARY – MWC BP & IG

MWC		Year End Actual	Average Positions PG&E Filing			Average Positions TURN 15% Reduction			Average Positions TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC BP & IG	Headcount Proposed	31	30	28	26	30	24	22	27	21	20
	Headcount Proposed Change (TURN)					-	4	4	3	2	2

Q 15 Briefly, what is the scope of MWC BP and MWC IG?

A 15 MWC BP includes non-labor costs for STARS fees, Diablo Canyon Independent Safety Committee (DCISC) member fees and related costs, Institute of Nuclear Power Operators (INPO) fees, and 50 percent of Nuclear Energy Institute (NEI) fees. STARS is an alliance of southwestern nuclear facilities. DCISC is a 3-person Committee charged by the state of California with reviewing and making recommendations concerning the safety of operations at DCPP. INPO is a private nuclear industry oversight organization. NEI is a private nuclear education and policy organization. This MWC also includes charges for the Land Management Program and property leasing. MWC BP also includes the labor associated with the DCPP Facilities Maintenance and the Risk Management organization. Cyber Security work scope is a part of the Risk Management organization and this work is charged to MWC IG. The Facilities Maintenance Department provides repair and maintenance services for all non-power block buildings and facilities and does minor project work. The Risk

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9 TURN-14, p. 10, line 8 and p. 87, lines 19-22.

10 *Id.*, p. 10, line 20 and p. 87, lines 23-25.

organization provides risk assessment and analysis for all DCPP programs and ensures the Cyber Security for DCPPs critical infrastructure.

Q 16 Which parties commented on MWC BP and IG?

A 16 TURN was the only party to address these programs.

Q 17 What is TURN's recommendation?

A 17 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 18 What is the basis for TURN's proposed reduction?

A 18 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[11] than the number that formed the basis for the labor costs included in PG&E's forecast.[12]

Q 19 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 19 No. PG&E disagrees with TURN's recommendation because MWC BP headcount at the end of both 2020 and 2021 are equal to the forecasted headcount for those years. It is logical to assume that the remaining forecast for 2023 through 2025 is reasonable.

Q 20 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC BP?

A 20 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 27—4 positions lower than the end of 2021. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 21 and 20, respectively. The level of funding recommended by TURN is not enough for PG&E to complete the facility maintenance and risk assessment and analysis required for safe operation of plant equipment and the safety of the employees. The work hours requested for this program are the minimum required for this work.

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11 TURN-14, p. 86, lines 6-9.

12 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

2. DCPP Loss Prevention (MWC BQ)

FIGURE 3-4
AVERAGE HEADCOUNT SUMMARY – MWC BQ

		Year End	Average Positions			Average Positions			Average Positions		
MWC		Actual	PG&E Filing			TURN 15% Reduction			TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC BQ	Headcount Proposed	253	261	261	258	261	222	219	235	200	197
	Headcount Proposed Change (TURN)					-	39	39	26	22	22

Q 21 Briefly, what is the scope of MWC BQ?

A 21 The DCPP Loss Prevention MWC BQ is comprised of the Security department. The Security Operations group: (1) implements NRC requirements; (2) formulates tactical responses; (3) implements searches; (4) assesses barriers; and (5) evaluates alarm monitoring to make certain that safeguards are effective on a continuous basis. This program is more fully discussed in PG&E's prepared testimony.[13]

Q 22 Which parties commented on MWC BQ?

A 22 TURN was the only party to address this program.

Q 23 What is TURN's recommendation?

A 23 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 24 What is the basis for TURN's proposed reduction?

A 24 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[14] than the number that formed the basis for the labor costs included in PG&E's forecast.[15]

Q 25 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 25 No. PG&E disagrees with TURN's recommendation because while MWC BQ's end of year 2020 and 2021 headcount were both lower than PG&E's forecast, the Security organization is a minimum staffing organization wherein Federal regulation requires designated posts to be manned every hour of every year. While the 2021 recorded headcount for Security was lower than was forecasted, the associated labor hours were compensated

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13 Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-35, line 15 to p. 3-36, line 14.

14 TURN-14, p. 86, lines 6-9.

15 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

with over time labor. In fact, the 2021 overtime rate for the Security department was nearly 28 percent compared to a filing assumption of just under 14 percent. This differential in overtime rate is equal to 27 full time equivalent positions in terms of labor dollars – higher than the shortfall in the headcount forecast for both 2020 and 2021.[16] It is also worth noting that these positions are subject to federal workhour limits; therefore, precluding an ability to compensate further reductions with higher over time.

Q 26 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC BQ?

A 26 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 235—18 positions lower than the end of 2021. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 200 and 197, respectively. The level of funding recommended by TURN is not enough for PG&E to provide for the required security of plant equipment and the safety of employees and the public. The work hours requested for this program is the minimum level required for this work and it must be met with permanent employees, overtime, or temporary hires. PG&E's proposal is the least expensive option.

3. Operate DCPP Plant (MWC BR)

FIGURE 3-5
AVERAGE HEADCOUNT SUMMARY – MWC BR

		Year End	Average Positions			Average Positions			Average Positions		
MWC		Actual	PG&E Filing			TURN 15% Reduction			TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC BR	Headcount Proposed	272	284	280	229	284	238	195	256	214	175
	Headcount Proposed Change (TURN)					-	*42*	*34*	*28*	*24*	*19*

Q 27 Briefly, what is the scope of MWC BR?

A 27 The Operate DCPP Plant MWC BR consists of the following groups: Operations Services, Chemistry Department (including Environmental

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16 Based on filed overtime hours for Security of 70,104 and an average overtime rate of 1.6 and 2,080 hours per full time equivalent. 70,104 X 1.6 = 112,166. 112,166/2,080 = 54. Since the overtime rate doubled, the increase is 27 full time equivalents.

Management transferred from MWC AK), and Radiation Protection. Each of these groups and the work that they perform are briefly described below.

Operations Services includes: the operation of the plant, radiation control, monitoring of plant chemistry, managing radioactive waste and hazardous waste generation, nuclear fuel movement, environmental engineering, and reactor physics testing.

The Chemistry Program includes plant chemistry control as well as radiological effluent monitoring and control for the DCPP site.

Radiation Protection provides oversight for control of radioactive material and support to plant workers on radiation safety. The primary focus of this section is to maintain radiation dose received by workers as low as reasonably achievable. This program is more fully discussed in PG&E's prepared testimony.[17]

Q 28 Which parties commented on MWC BR?

A 28 TURN was the only party to address this program.

Q 29 What is TURN's recommendation?

A 29 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 30 What is the basis for TURN's proposed reduction?

A 30 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[18] than the number that formed the basis for the labor costs included in PG&E's forecast.[19]

Q 31 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 31 No. PG&E disagrees with TURN's recommendation because while MWC BR end of year 2020 and 2021 headcount were both lower than PG&E's forecast, the Operations organization forecast for the test year 2023 is only 12 higher than the end of 2021. The attrition has occurred earlier than expected for the Operations group; nevertheless, with the Tier 2 retention agreement running through August 2023 and with employee severance

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17 Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-36, line 16 to p. 3-38, line 3.

18 TURN-14, p. 86, lines 6-9.

19 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

payment eligibility on the horizon,[20] it is unlikely that DCPP will see many more Operation's employees leaving early. Additional overtime will be required to compensate for fewer employees until new employees can be hired. In the unlikely event that additional attrition did occur, DCPP leadership will take the necessary steps to ensure that the critical activities of this group are adequately staffed. Those steps include more overtime, hiring replacement Operations staff or even rehiring former operators who move into Decommissioning positions. The criticality of this group to safe, compliant, and reliable operations, along with the lead time necessary to train a new employee requires maintaining a headcount above bare minimum that can staff the watch bill unimpeded by an unplanned departure.

Q 32 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC BR?

A 32 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 256—16 positions lower than the end of 2021. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 214 and 175, respectively. The level of funding recommended by TURN is not enough for PG&E to provide for the operations functions critical to the reliable and safe operation of plant equipment and the safety of employees. The work hours requested for this program is the minimum level required for this work. This emphasizes that the labor costs are driven by the work scope necessary to meet regulatory requirements, maintain plant equipment reliability, and to ensure the safety of the plant and employees.

4. Maintain DCPP Plant Assets (MWC BS)

FIGURE 3-6
AVERAGE HEADCOUNT SUMMARY – MWC BS

		Year End	Average Positions			Average Positions			Average Positions		
MWC		Actual	PG&E Filing			TURN 15% Reduction			TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC BS	Headcount Proposed	220	229	199	160	229	169	136	206	152	122
	Headcount Proposed Change (TURN)					-	30	24	23	17	14

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[20] D.18-01-022, p. 24.

Q 33 Briefly, what is the scope of MWC BS?

A 33 The Manage DCPP Plant Assets MWC BS includes groups and sections within the Maintenance Department, Outage Management Department, and Project Services group.

The Maintenance Department plans and performs preventive maintenance, corrective maintenance, and maintenance surveillance testing of DCPP mechanical, electrical, and Instrument and Control equipment. This program is more fully discussed in PG&E's prepared testimony.[21]

Q 34 Which parties commented on MWC BS?

A 34 TURN was the only party to address this program.

Q 35 What is TURN's recommendation?

A 35 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 36 What is the basis for TURN's proposed reduction?

A 36 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[22] than the number that formed the basis for the labor costs included in PG&E's forecast.[23]

Q 37 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 37 No. PG&E disagrees with TURN's recommendation because while MWC BS end of year 2021 headcount was lower than PG&E's forecast, the Maintenance organization forecast for the test year 2023 is still very close to the end of 2021 (only 9 lower). The attrition has occurred earlier than expected for the Maintenance Department; nevertheless, half of the attrition was associated with employees that worked only on capital work scope and Maintenance planned to hire additional staff in 2022 to offset the lower 2021 headcount. In fact, the Maintenance group is hiring additional Hiring Hall employees to complete required work to reduce significant over time. With the Tier 2 retention agreement running through August 2023 and with employee severance payment eligibility on the horizon,[24] it is unlikely that

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[21] Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-38, line 5 to p. 3-40, line 3.

[22] TURN-14, p. 86, lines 6-9.

[23] Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

[24] D.18-01-022, p. 24.

DCPP will see many more Maintenance employees leaving early. In the unlikely event that this did occur, DCPP leadership will take the necessary steps to ensure that the critical activities of this group are adequately staffed. Those steps include more overtime, bringing in Hiring Hall employees or Temporary Additional staff or even rehiring former Maintenance employees who have moved into Decommissioning positions or retired. In fact, PG&E has developed an arrangement with IBEW for bringing in temporary additional staff that can stay through end of operations.

Q 38 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC BS?

A 38 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 206—14 positions lower than the end of 2021. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 152 and 122, respectively. The level of funding recommended by TURN is not enough for PG&E to provide for the maintenance activities critical to the reliable and safe operation of plant equipment and the safety of employees. With the headcount levels proposed by TURN, it is very possible that the maintenance activities planned during the refueling outages planned for 2023 and 2024 could not be adequately resourced and could result in inadequate experience, longer outage durations, significant rework, and unforeseeable safety concerns. The work hours requested for this program is the minimum level required for this work.

5. Nuclear Generation Fees (MWC BT)

FIGURE 3-7
AVERAGE HEADCOUNT SUMMARY – MWC BT

		Year End	Average Positions			Average Positions			Average Positions		
MWC		Actual	PG&E Filing			TURN 15% Reduction			TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC BT	Headcount Proposed	13	9	6	4	9	5	3	8	5	3
	Headcount Proposed Change (TURN)					-	1	1	1	1	0

Q 39 Briefly, what is the scope of MWC BT?

A 39 The Nuclear Generation Fees MWC BT consists of the Performance Improvement Department and Learning Services Contracts.

The Performance Improvement Department has overall programmatic responsibility for performance improvement at DCPP. Performance improvement elements include problem identification and resolution via the corrective action program (CAP), station improvement via operating experience, human performance, self-assessment, benchmarking, and the Employee Concerns Program.[25]

Q 40 Which parties commented on MWC BT?

A 40 TURN was the only party to address this program.

Q 41 What is TURN's recommendation?

A 41 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 42 What is the basis for TURN's proposed reduction?

A 42 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[26] than the number that formed the basis for the labor costs included in PG&E's forecast.[27]

Q 43 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 43 No. PG&E disagrees with TURN's recommendation because MWC BT end of year 2020 and 2021 headcount was higher than PG&E's forecast. It is logical to assume that the remaining forecast for 2023 through 2025 is reasonable.

Q 44 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC BT?

A 44 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 8—5 positions lower than the end of 2021. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 5 and 3, respectively. The level of funding recommended by TURN is not

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25 Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-40, lines 5-23.

26 TURN-14, p. 86, lines 6-9.

27 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

enough for PG&E to provide for the performance improvement support functions critical to the reliable and safe operation of plant equipment and the safety of employees and to comply with the regulatory requirements of 10CFR50 App. B which is inspected through the NRC Problem Identification and Resolution inspections. Additionally, the Performance Improvement Department performs regulatory functions such as screening CAP notifications, performance trending, causal evaluations, etc. This workload does not reduce as you approach end of license as we are legally required to maintain a corrective action program, identify and correct causes of events, and continue performance trending. The work hours requested for this program is the minimum level required for this work.

6. Maintain DCPP Plant Configuration (MWC BV)

FIGURE 3-8
AVERAGE HEADCOUNT SUMMARY – MWC BV

		Year End	Average Positions			Average Positions			Average Positions		
MWC		Actual	PG&E Filing			TURN 15% Reduction			TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC BV	Headcount Proposed	131	145	139	107	145	118	91	131	106	82
	Headcount Proposed Change (TURN)					-	21	16	15	12	9

Q 45 Briefly, what is the scope of MWC BV?

A 45 The Maintain Plant Configuration MWC BV consists of Engineering and Nuclear Fuels Procurement.

The Engineering Department's fundamental responsibility is to maintain the configuration of the plant. Configuration management is essential to continuing the health and regulatory compliance of the plant. Safe operations and NRC regulations require nuclear plants to examine all potential changes to the plant. This ensures that plant operations will not be compromised and complete, accurate, up-to-date records will be maintained which exactly reflect the current configuration of plant facilities.[28] Engineering also provides safe, compliant, and efficient engineering solutions supporting critical maintenance and problem solving. Engineering's role becomes even more critical in light of significantly

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[28] Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-41, line 2 to p. 3-42, line 6.

reduced equipment replacement projects and an increased emphasis on engineered bridging strategies to reach the end of plant license.

Q 46 Which parties commented on MWC BV?

A 46 TURN was the only party to address this program.

Q 47 What is TURN's recommendation?

A 47 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 48 What is the basis for TURN's proposed reduction?

A 48 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[29] than the number that formed the basis for the labor costs included in PG&E's forecast.[30]

Q 49 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 49 No. PG&E disagrees with TURN's recommendation because while MWC BV end of year 2021 headcount was lower than PG&E's forecast, the Engineering organization forecast for the test year 2023 is still very close to the end of 2021 (only 14 lower). The attrition has occurred earlier than expected for the Engineering group; nevertheless, 1 of the positions was associated with employees that worked only on fuel procurement work scope and Engineering planned to hire 9 additional staff in 2022 to offset the lower 2021 headcount. With the Tier 2 retention agreement running through August 2023 and with employee severance payment eligibility on the horizon,[31] it is unlikely that DCPP will see many more Engineering employees leaving early. In the unlikely event that this did occur, DCPP leadership will take the necessary steps to ensure that the critical activities of this group are adequately staffed. Those steps include more overtime, contracting specific work scope, or even rehiring former Engineering employees who have moved into Decommissioning positions or retired.

Q 50 Did TURN comment on any specific MWC BV departments?

A 50 Yes, TURN commented on the Nuclear Fuels Purchasing Department. TURN states, "it seems implausible that the full staff of 3 will be needed until

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29 TURN-14, p. 86, lines 6-9.

30 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

31 D.18-01-022, pp. 24-25.

the absolute last day that Unit 2 is operating."[32] TURN's premise is based on there being no need to buy nuclear fuel for the plant. TURN's lack of knowledge of plant operations, organization, and responsibilities is displayed since the Nuclear Fuel's Department is also responsible for the maintenance of the Independent Spent Fuel Storage Installation (ISFSI) until the end of plant operations.

Q 51 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC BV?

A 51 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 131—equal to the end of 2021 without consideration of additional planned hiring. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 106 and 82, respectively. The level of funding recommended by TURN is not enough for PG&E to provide for the engineering activities critical to the reliable and safe operation of plant equipment and the safety of employees. The work hours requested for this program is the minimum level required for this work.

7. Operational Management (MWC OM)

FIGURE 3-9
AVERAGE HEADCOUNT SUMMARY – MWC OM

		Year End	Average Positions			Average Positions			Average Positions		
MWC		Actual	PG&E Filing			TURN 15% Reduction			TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC OM	Headcount Proposed	37	33	33	30	33	28	26	30	25	23
	Headcount Proposed Change (TURN)					-	5	5	3	3	3

Q 52 Briefly, what is the scope of MWC OM?

A 52 The Operational Management MWC OM consists of Directors and VPs of all individual departments at DCPP who charge their time to specific orders. In essence, these people manage the work forecast in the other expense and capital MWCs.[33]

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32 TURN-14, p. 86, lines 17-18.

33 Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-42, line 8 to p. 3-43, line 3.

Q 53 Which parties commented on MWC OM?

A 53 TURN was the only party to address this program.

Q 54 What is TURN's recommendation?

A 54 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 55 What is the basis for TURN's proposed reduction?

A 55 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[34] than the number that formed the basis for the labor costs included in PG&E's forecast.[35]

Q 56 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 56 No. PG&E disagrees with TURN's recommendation because while MWC OM end of year 2020 and 2021 headcount was lower than PG&E's forecast, the Operation Management MWC forecast for the test year 2023 is still lower than the end of 2021 (4 lower). The attrition has occurred earlier than expected for the Operational Management group; nevertheless, the forecasted reductions for 2023 were very aggressive. With the Tier 2 retention agreement running through August 2023 and with employee severance payment eligibility on the horizon,[36] it is unlikely that DCPP will see many more Operational Management employees leaving early.

Q 57 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC OM?

A 57 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 30. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 25 and 23, respectively. The level of funding recommended by TURN is not enough for PG&E to provide for the Operational Management function critical to the reliable and safe operation of plant equipment and the safety of employees. Leadership and management of the station becomes even more critical as DCPP navigates a complex transition to decommissioning while continuing to ensure the safe

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34 TURN-14, p. 86, lines 6-9.

35 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

36 D.18-01-022, pp. 24-25.

and reliable operation of the plant. The work hours requested for this program is a reasonable level required for this work.

8. Operational Support (MWC OS)

FIGURE 3-10
AVERAGE HEADCOUNT SUMMARY – MWC OS

MWC		Year End Actual	Average Positions PG&E Filing			Average Positions TURN 15% Reduction			Average Positions TURN Additional 10% Reduction		
		2021	2023	2024	2025	2023	2024	2025	2023	2024	2025
MWC OS	Headcount Proposed	153	154	138	116	154	117	99	139	106	89
	Headcount Proposed Change (TURN)					-	*21*	*17*	*15*	*12*	*10*

Q 58 Briefly, what is the scope of MWC OS?

A 58 The Operational Support MWC OS consists of numerous support organizations including: Quality Verification, Regulatory Services, Learning Services, Outage Management and Work Control, General Clerical, and Emergency Services. In essence, the people in these organizations support the work forecast in the other expense and capital MWCs.[37]

Q 59 Which parties commented on MWC OS?

A 59 TURN was the only party to address this program.

Q 60 What is TURN's recommendation?

A 60 TURN proposes a total 2023 expense reduction as provided in Table 3-1.

Q 61 What is the basis for TURN's proposed reduction?

A 61 TURN bases its recommendation on a lower number of 2021 headcount over-all across the total of all MWCs[38] than the number that formed the basis for the labor costs included in PG&E's forecast.[39]

Q 62 Do you agree with TURN's recommendations for reducing PG&E's forecasts? Please explain.

A 62 No. PG&E disagrees with TURN's recommendation because while MWC OS end of year 2021 headcount was lower than PG&E's forecast, the Operation Support MWC forecast for the test year 2023 is very close to the end of 2021 (only 1 higher). The attrition has occurred earlier than expected

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[37] Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-43, line 5 to p. 3-44, line 25.

[38] TURN-14, p. 86, lines 6-9.

[39] Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-106.

for the Operational Support group and TURN gave no consideration to plans to hire additional staff in 2022. With the Tier 2 retention agreement running through August 2023 and with employee severance payment eligibility on the horizon,[40] it is unlikely that DCPP will see many more Operational Support employees leaving early.

Q 63 Is TURN's recommended funding level sufficient for PG&E to complete the work required in MWC OM?

A 63 No, the recommended funding level is insufficient. Taking TURN's global staffing recommendation and applying it at the MWC level results in a proposed 2023 headcount of 139. Additionally, TURN proposed reducing the 2024 and 2025 headcount to 106 and 89, respectively. The level of funding recommended by TURN is not enough for PG&E to provide for the Operational Support function critical to the safe, compliant, and reliable operation of plant equipment and the safety of employees. The work hours requested for this program is a reasonable level required for this work.

Q 64 Do you have any further comments about MWC OS?

A 64 Yes. TURN submits testimony regarding the Learning Services Department staffing levels and labor estimates.[41] TURN infers a knowledge and understanding of all the drivers of Learning Services headcount and surmises that the number of training presentations is the primary factor that determines the staffing needs for this department. TURN has provided no evidence of a knowledge of regulatory requirements, reporting requirements, expectations of industry organizations that certify training programs for Nuclear plants, or any other special knowledge giving them insight into the staffing needs for DCPP. Additionally, they cite to a data request response (TURN footnote 133) that has nothing to do with Learning Services. TURN believes Learning Services should be at 25—30 headcount at the end of 2021.[42] They already know that the actual headcount was 41.[43] As shown above in Figure 3-2, MWC OS, of which Learning Services is a part, the

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40 D.18-01-022, pp. 24.-25.

41 TURN-14, p. 85, line 17 to p. 86, line 2.

42 TURN-14, p. 85, lines 24-26.

43 PG&E's response to Data Request TURN_213_Q008Atch01, dated 6/6/22 in Appendix A, at the end of this exhibit.

labor costs are very close for the forecast and actuals for 2021—within $14,000. Furthermore, 10CFR50.120 and 10CFR55.4 provide the requirements for maintaining a systematic approach to training. We are required to conduct operations training to maintain our licenses but we are also required to maintain 12 accredited training programs. The NRC has adopted INPO's accreditation processes as described in Inspection Procedure 41500. This requires use of initial and continuing training for maintenance and technical training programs as well as performance improvement training to build/enhance knowledge and skills for our craft. The headcount numbers provided are the minimum allowable to meet these requirements and benchmark as some of the lowest in the industry.

9. DCPP Capital (MWC 20)

Q 65 Briefly, what is the scope of MWC 20?

A 65 The MWC 20 work scope is primarily Aging/Obsolescence/Emergent Capital work that has been established to cover the increasing likelihood of the necessity to replace plant equipment and components due to their degraded condition or failure in the latter years of plant life, caused by the preceding dramatic decline in the portfolio of projects that were implemented to avoid such risk. As the station's Capital investment and portfolio of projects declines the likelihood of equipment and component failures this work was intended to avoid becomes virtually inevitable. Since the exact scope of this emergent Capital work cannot be identified or precisely scaled, it is prudent to create and fund a contingency account for this type of work that is, by Generally Accepted Accounting Principles and Utility standards, capital in nature.[44]

Q 66 Which parties commented on MWC 20?

A 66 TURN was the only party to address this program.

Q 67 What is TURN's recommendation?

A 67 TURN proposes a 2023 through 2025 capital reduction as provided in Table 3-2.

Q 68 What is the basis for TURN's proposed reduction?

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44 Exhibit (PG&E-5) (Feb. 28, 2022), p. 3-12, lines 14-28.

A 68 TURN disputes the need for the DCPP Aging Management program, proposes disallowance of the Unit 2 Polisher Computer workstation project, and recommends that 50 percent of the costs for two other capital projects be collected through Decommissioning Trust funds.

Q 69 What is TURN's reasoning for recommending the elimination of funding for the DCPP Aging Management program?

A 69 TURN bases its recommendation on the imprecise work scope and estimates for this emergent work.[45]

Q 70 Do you agree with TURN's recommendations for reducing PG&E's forecasts and tracking the capital costs in a memorandum account? Please explain.

A 70 No. PG&E disagrees with TURN's recommendation. The depreciation expense for all MWC 20 capital additions is already subject to true-up to reflect actual depreciation and capital spending.[46] Consequently, if no emergent capital work arises, the customers will not be asked to pay for those costs.

Additionally, DCPP Nuclear Operations has, in fact, experienced unforeseen capital work scope nearly every year. In 2021 and 2022, emergent work includes main generator manifolds, the remote robotic cameras, security defensive strategy upgrades, spent fuel pool cameras, security LED lighting, TCV-23 Actuators, low pressure dog bone condenser joint replacements, and other projects. The need for the DCPP Aging Management Program is unassailable.

Q 71 What is TURN's position regarding the Unit 2 Polisher Computer workstation project?

A 71 TURN proposes to disallow recovery of the Unit 2 Polisher Computer workstation project due to delays, cost increases, work scope increases and because the project will not be needed after the plant closes.[47]

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45 TURN-14, p. 7, lines 5-14.

46 The Commission approved this ratemaking in the Diablo Canyon Retirement decision, D.18-01-022, pp. 46-47, and affirmed it in PG&E's 2020 GRC decision, D.20-12-005, p. 153.

47 TURN-14, p. 50, lines 12-16.

Q 72 Do you agree with TURN's position?

A 72 No. The Condensate Polishing System is essential to the Steam Generator health. The Unit 1 system was upgraded and operative in October 2020. Unit 2 continues to have an obsolete Condensate Polisher Computer System and a data acquisition and control system that were installed in 1992. Microsoft Corporation no longer supports Windows NT 4.0 operating system. National Instruments Lookout (NIL) Human Machine Interface (HMI) software is several versions old and is no longer supported. Rockwell Automation (Allen Bradley) is migrating customers from PLC-5/40 to new technology. Additionally, the current operating system is unable to comply to NRC cyber security requirements.

Q 73 Please address the delays to Unit 2 implementation.

A 73 U2 Condensate Polisher Computer System (CPCS) was in preparation for Pre-SAT (Site Acceptance Testing) and SAT to be completed in 2020 but there were incompatibility issues with the Plant Process Computer (PPC) and server model DELL 640s. The Station had moved up the start date for the 2R22 refueling outage from April 2021 to February 2021, and this caused delays in meeting project milestones to install U2 during 2R22. Also due to COVID-19 response, the team was unable to perform SAT in the development lab as employees were mandated to work remotely from home. A project options analysis was developed with options presented to Senior Leadership. The options focused on the timing of the project (online or during an outage) and the completion of server upgrades apart from the Polisher computer upgrades. The final decision by leadership, was to break out the upgrade of the computer servers work from the Polisher Computer replacement. The servers upgrade was completed and capitalized in 2021. The remainder of the project was deferred from 12/1/2021 to re-start 6/15/2022 and implementation of the remaining work scope will be completed during the 2R23 refueling outage in October 2022.

Q 74 Is the Unit 2 Polisher Computer System upgrade project still needed?

A 74 Yes. With Unit 1 already implemented and the Unit 2 servers already upgraded, the replacement of the Polisher Computer system for Unit 2 is all that remains. If the Polisher Computer were lost, it would inhibit the ability to regenerate polisher vessel resin on schedule resulting in the need to ramp offline as a minimum of 6 (of 7) vessels must be in service to support 100 percent power operation. Without this upgrade, the system remains vulnerable to failure and Unit 2 would have to be shut down to protect the Steam Generators.

Q 75 TURN proposed to reduce capital expenditures in 2021, 2022, and 2023 for the Polisher Computer System by $1.328 million, $1.849 million, and $0.030 million, respectively. Do you agree that these are the correct numbers forecast for this project?

A 75 No. While an update of planned expenditures was provided to TURN with those numbers, PG&E has not proposed a change in our forecast. If this TURN proposal was accepted by the Commission, it should be based on the original capital expenditures forecast by PG&E which is $1.012 million in 2021 only.[48]

Q 76 Please describe TURN's position regarding the two projects that TURN wants to fund with Decommissioning Trust Funds.

A 76 TURN proposes to fund 50 percent of two projects with Decommissioning Trust Funds—the Integrated Video Management System and the Plant Air Compressors (PAC) projects.

Q 77 Do you agree with TURN's position?

A 77 No. The Commission has already concluded that plant investments will be recovered over the remaining plant life.[49] While the integrated video management system and plant air compressors may continue to be used post shutdown, implementation of these projects is necessary for operations. These projects are not decommissioning projects nor are they related to decommissioning projects. Accordingly, no portion of these capital projects can be funded by the nuclear decommissioning trusts.[50]

Q 78 TURN proposed to reduce capital expenditures in 2021 and 2022 for these projects by $1.990 million and $2.333 million, respectively (50 percent of updated capital expenditures) and collect these costs from the

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48 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-75, line 3.

49 D.18-01-022, pp. 46-47.

50 See 10 CFR §§ 50.82(a)(8)(ii) and 50.2.

Decommissioning Trust Fund.[51] Do you agree that these are the correct numbers forecast for these projects?

A 78 No. While an update of planned expenditures was provided to TURN with those numbers, PG&E has not proposed a change in our forecast. TURN's proposal should be based on the original capital expenditures forecast by PG&E, which is $0.907 million in 2021 only.[52]

D. Conclusion

Q 79 What is PG&E's recommendation for Nuclear Operations?

A 79 For the reasons discussed above, PG&E recommends that its 2023 expense forecast in Table 3-4 and its 2020-2026 recorded and forecast capital expenditures be adopted.

Q 80 Does this conclude your rebuttal testimony?

A 80 Yes, it does.

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51 TURN-14, p. 7, lines 13 (TURN Table 3).

52 Exhibit (PG&E-5) (Feb. 28, 2022), WP 3-75, lines 6 and 9 multiplied by 50%.

TABLE 3-4
PG&ES 2020-2023 ADJUSTED RECORDED AND FORECAST EXPENSE AMOUNTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast
1	Miscellaneous Expense	AB	$14,673	$14,711	$(29,422)	–
2	Manage Environmental Operation	AK	1,996	2,000	2,050	$2,105
3	Manage the Business	BP	13,247	12,844	13,600	13,297
4	DCPP Loss Prevention	BQ	48,877	42,422	44,357	43,664
5	Operate DCPP Plant	BR	78,523	75,992	83,742	77,743
6	Maintain DCPP Plant Assets	BS	109,165	98,803	119,529	90,688
7	Enhance DCPP Personnel Performance	BT	15,899	15,378	15,795	15,841
8	Procure DCPP Materials & Services	BU	(1,111)	–	–	–
9	Maintain DCPP Plant Configuration	BV	38,770	35,870	39,294	35,018
10	Provide Nuclear Support	EO	(23)	9	9	10
11	Regulatory Balancing Account	IG	2,900	3,192	2,548	2,608
12	Operational Management	OM	8,084	8,458	6,498	7,675
13	Operational Support	OS	26,229	24,572	26,629	24,999
14	Total		$357,230	$334,251	$324,629	$313,648

Note: PG&E’s 2020-2023 recorded and forecast expense costs have been adjusted for errata and concessions as filed on Feb. 28, 2022.

TABLE 3-5
PG&ES 2020-2026 ADJUSTED RECORDED AND FORECAST CAPITAL COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast
1	Office Furniture & Equipment	3	–	–	–	–	–	–	–
2	Tools & Equipment	5	$422	$681	$739	$748	–	–	–
3	DCPP Capital	20	43,283	21,319	12,261	10,252	$6,000	$1,000	–
4	Nuclear Safety and Security	3I	5,945	–	–	–	–	–	–
5	Total		$49,650	$22,000	$13,000	$11,000	$6,000	$1,000	–

Note: PG&E's 2020-2026 recorded and forecast capital costs have been adjusted for errata and concessions as filed on Feb 28, 2022

(PG&E-18)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

REBUTTAL TESTIMONY OF

ERIC VAN DEUREN

HYDRO OPERATIONS COSTS

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
REBUTTAL TESTIMONY OF
ERIC VAN DEUREN
HYDRO OPERATIONS COSTS

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Eric Van Deuren. This testimony responds to the direct testimony of Public Advocates Office at the California Public Utilities Commission (Cal Advocates or CA),[1] The Utility Reform Network (TURN),[2] and California Trout, Inc., Friends of the Eel River, Inc., and Trout Unlimited, Inc. (collectively referred to as CalTrout).[3] I summarize parties' positions in Section B below.

Q 2 Do parties make recommendations concerning specific projects and programs?

A 2 Yes.

Q 3 Do you dispute any of the parties' recommendations?

A 3 Yes, I address parties' recommendations in Section C.

Q 4 Are there programs that parties do not dispute or do not address?

A 4 Yes, see Tables 4-1 and 4-2.

Q 5 Do you have any adjustments or corrections to the forecasts as provided in the February 28, 2022, version of your initial testimony and/or workpapers?

A 5 No, PG&E does not have any adjustments to its forecasts.

Q 6 Do you have any non-forecast related adjustments or corrections to the February 28, 2022, version of your initial testimony and/or workpapers?

A 6 No.

B. Summary of Parties' Positions

Q 7 Please provide PG&E's current forecast and parties' recommendations.

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1 CA-08.

2 TURN-14.

3 CalTrout-1.

A 7 PG&E's current forecast and the parties' recommendations are set forth in Table 4-1 (expense), and Tables 4-2 and 4-3 (capital expenditures) below.

TABLE 4-1
2023 EXPENSE FORECAST – PG&E AND PARTIES
(THOUSANDS OF NOMINAL DOLLARS

			PG&E			Proposed Increases/(Reductions)	
Line No.	Program or MWC Description	MWC	Filed Forecast[(a)]	Errata or Forecast Adjustments[(b)]	2023 Adjusted Forecast	Cal Advocates	TURN
1	Misc. Expense	AB	$7,473	–	$7,473	–	–
2	Manage Environmental Opera.	AK	1,167	–	1,167	–	–
3	Maint Resv.	AX	28,883	–	28,883	–	$(4,500)
4	Habitat and Species Protection	AY	267	–	267	–	–
5	Perf Reimburse Work for Others	BC	–	–	–	–	–
6	Manage Property & Bldgs	EP	1,254	–	1,254	–	–
7	Implement Environment Projects	ES	–	–	–	–	–
8	Manage Var Bal Acct Processes	IG	30,552	–	30,552	$(2,600)	(13,120)
9	Operate Hydro Generation	KG	37,091	–	37,091	–	–
10	Maint Hydro Generating Equip	KH	23,640	–	23,640	–	–
11	Maint Hydro Bldg.	KI	14,590	–	14,590	–	–
12	License Compliance Hydro Gen	KJ	24,179	–	24,179	–	–
13	Catastrophic Events	LX	84	–	84	–	–
14	Operational Management	OM	3,180	–	3,180	–	–
15	Operational Support	OS	4,047	–	4,047	(900)	–
16	Corporate Items	ZC	1,500	–	1,500		
17	Multiple MWCs	Various	–	–	–	–	(17,460)
18	Total		$177,909	–	$177,909	$(3,500)	$(35,080)

Note: PG&E's 2020-2023 current recorded and forecast expense amounts for all activities included in Exhibit (PG&E-5) (February 28, 2022), Chapter 4 (adjusted for errata and concessions) as of June 13, 2022, are shown in Table 4-6 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

TABLE 4-2
2023-2026 CAPITAL EXPENDITURES FORECAST – PARTIES ADJUSTED FORECASTS
(THOUSANDS OF NOMINAL DOLLARS)

			Adjusted Forecast[a]				Cal Advocates				TURN			
Line No.	Program or MWC Description	MWC	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)
1	Office Furniture & Equipment	03	–	–	–	–	–	–	–	–	–	–	–	–
2	Tools & Equipment	05	$567	$645	$706	$788	–	–	–	–	–	–	–	–
3	Relicensing Hydro Gen	11	4,250	4,000	500	–	–	–	–	–	$(4,000)	$(4,000)	$(500)	–
4	Implement Environment Projects	12	425	1,000	500	1,000	–	–	–	–	–	–	–	–
5	Instl/Rpl for Hydro Safety & Reg	2L	62,960	48,087	26,058	18,648	–	–	–	–	(34,217)	(69,807)	(35,740)	$(24,626)
6	Instal/Repl Hydro Generating Eqp	2M	84,460	93,852	134,430	118,105	–	–	–	–	(16,621)	(58,752)	(103,644)	(89,150)
7	Instal/Repl Resv	2N	42,682	30,754	25,322	24,788	–	–	–	–	(15,393)	(28,613)	(23,891)	(27,674)
8	Instl/Repl Hydr Bldg.Grnd. Infrst.	2P	26,574	14,553	12,954	9,650	(6,500)	–	–	–	(8,284)	(10,245)	(11,903)	(8,100)
9	Hydroelec Lic. & Lic Conditions	3H	144,247	155,128	103,296	88,334	(46,947)	–	–	–	(115,318)	(117,428)	(118,078)	(96,406)
10	Catastrophic Events	3Q	121	124	127	129	–	–	–	–	–	–	–	–
11	Total		$366,287	$348,143	$303,893	$261,443	$(53,447)	–	–	–	$(193,833)	$(288,846)	$(293,757)	$(245,955)

(a) PG&E's 2020-2026 recorded and forecast capital costs (adjusted for errata and concessions) are shown in Table 4-7.

TABLE 4-3
2023-2026 CAPITAL EXPENDITURES – PG&E'S ADJUSTED FORECAST
(THOUSANDS OF NOMINAL DOLLARS)

			Filed Forecast(a)				Errata or Forecast Adjustments(b)				Adjusted Forecast			
Line No.	Program or MWC Description	MWC	2023 Filed Forecast	2024 Filed Forecast	2025 Filed Forecast	2026 Filed Forecast	2023 Errata or Forecast Adj.	2024 or Forecast Adj.	2025 or Forecast Adj.	2026 or Forecast Adj.	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast
1	Office Furniture & Equipment	03	–	–	–	–	–	–	–	–	–	–	–	–
2	Tools & Equipment	05	$567	$645	$706	$788	–	–	–	–	$567	$645	$706	$788
3	Relicensing Hydro Gen	11	4,250	4,000	500	–	–	–	–	–	4,250	4,000	500	–
4	Implement Environment Projects	12	425	1,000	500	1,000	–	–	–	–	425	1,000	500	1,000
5	Instl/Rpl for Hydro Safety & Reg	2L	62,960	48,087	26,058	18,648	–	–	–	–	62,960	48,087	26,058	18,648
6	Instal/Repl Hydro Generating Eqp	2M	84,460	93,852	134,430	118,105	–	–	–	–	84,460	93,852	134,430	118,105
7	Instal/Repl Resv	2N	42,682	30,754	25,322	24,788	–	–	–	–	42,682	30,754	25,322	24,788
8	Instl/Repl Hydr Bldg.Grnd. Infrst.	2P	26,574	14,553	12,954	9,650	–	–	–	–	26,574	14,553	12,954	9,650
9	Hydroelec Lic. & Lic Conditions	3H	144,247	155,128	103,296	88,334	–	–	–	–	144,247	155,128	103,296	88,334
10	Catastrophic Events		121	124	127	129	–	–	–	–	121	124	127	129
11	Total		$366,287	$348,143	$303,893	$261,443	–	–	–	–	$366,287	$348,143	$303,893	$261,443

Note: PG&E's 2020-2026 current recorded and forecast capital expenditures amounts as included in Exhibit (PG&E-5) (February 28, 2022), Chapter 4 (adjusted for errata and concessions) as of June 13, 2022, are shown in Table 4-7 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

TABLE 4-4
2023 EXPENSE FORECAST – TURN'S ADJUSTMENTS
(THOUSANDS OF NOMINAL DOLLARS

Line No.	Issues	MWC	2023 Increases/ (Reductions)
1	License Condition Projects With Pending Licenses	IG	$(12,915)
2	Set Capex and Expenses for LUWR Equal to Those From 2020 RAMP	IG	(205)
4	Total	IG	$(13,120)
5	Reduce O&M by 7.14 percent	Multiple MWCs	$(12,703)
6	Headcount related reduction	Multiple MWCs	(4,757)
7	Total	Multiple MWCs	$(17,460)

TABLE 4-5
2023-2026 CAPITAL EXPENDITURE FORECAST – TURN'S ADJUSTMENTS
(THOUSANDS OF NOMINAL DOLLARS

Line No.	Issues	MWC	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)
1	Capex and Exp = 2020 RAMP	2L	$(8,679)	$(27,376)	$(11,739)	$(7,385)
2	Forecast After 2023 TY	2L	(25,537)	(29,654)	(20,321)	(14,261)
3	Operative Date Before 2024	2L	–	(12,778)	(3,680)	(2,980)
4	Total	2L	$(34,217)	$(69,807)	$(35,740)	$(24,626)
5	Forecast After 2023 TY	2M	$(16,621)	$(51,502)	$(96,644)	$(82,150)
6	Operative Date Before 2024	2M	–	(7,250)	(7,000)	(7,000)
7	Total	2M	$(16,621)	$(58,752)	$(103,644)	$(89,150)
8	Capex and Exp = 2020 RAMP	2N	$(6,388)	$(10,348)	$(6,592)	$(9,000)
9	Emergent Work	2N	(394)	(2,987)	(3,793)	(3,087)
10	Forecast After 2023 TY	2N	(8,611)	(12,272)	(9,712)	(12,500)
11	Operative Date Before 2024	2N	–	(3,005)	(3,793)	(3,087)
12	Total	2N	$(15,393)	$(28,613)	$(23,891)	$(27,674)
13	Capex and Exp =2020 RAMP	3H	$12,910	$40,200	$(14,432)	$(9,500)
14	LC Projects with Pending FERC Lic.	3H	(8,771)	(3,570)	(1,530)	(1,572)
15	Forecast After 2023 TY	3H	(119,457)	(142,629)	(91,316)	(74,734)
16	Operative Date Before 2024	3H	–	(11,429)	(10,800)	(10,600)
17	Total	3H	$(115,318)	$(117,428)	$(118,078)	$(96,406)

Q 8 Does PG&E disagree with any of parties recommendations?

A 8 Yes, PG&E disagrees with recommendations made by parties regarding the following programs:

- Hydro Expense Forecast based on historical recorded average (multiple MWCs);
- Adjustment to Expense related Staffing (multiple MWCs);
- Operational Support (MWC OS);
- Recreation Point Group Campground (MWC IG);
- JBB Willow Creek Road Stabilization (MWC 2P);
- UNFFR, McCloud Pit, Drum Spaulding License Condition projects (MWC 3H);
- Emergent Work Capital and Expense (AX & 2N);
- Hydro License Condition projects with pending FERC license renewal (3H & IG); and
- Potter Valley Transformer Project (not included in 2023 GRC forecast).

PG&E responds to parties' recommendations in Section C.

C. PG&E's Response to Parties' Recommendations Concerning Specific Programs or Projects

1. Hydro Expense Forecast Based on Historical Recorded Average (Multiple MWCs)

Q 9 Briefly, what is the scope of PG&E's Hydro Expense Forecast?

A 9 The PG&E Hydro Expense Forecast covers the direct operations & maintenance expenses for the 64 hydro powerhouses and support facilities, as well as the operational management and support services.

Q 10 Which parties commented on using historical recorded average for PG&E's Hydro Expense Forecast?

A 10 TURN was the only party to comment on using historical recorded average as a basis for the PG&E Hydro Expense Forecast.

Q 11 What was TURN's recommendation?

A 11 TURN is recommending a 7.14 percent reduction, or $12.7 million, in the PG&E Hydro Expense Forecast in TY 2023 as shown in Table 4-4.[4]

Q 12 What was the basis for TURN's recommendation?

A 12 TURN states that, "PG&E should use the average of 2016-2019 as the basis for its O&M forecast."[5]

Q 13 Do you agree with TURN's recommendations for reducing PG&E's Hydro Expense Forecast? Please explain.

A 13 No. PG&E disagrees with TURN's recommendations for two reasons:

- TURN incorrectly asserts that, "PG&E relied on recorded expenses for 2015-2020 to develop its justification" [for 2021-2023 O&M expense forecasts].[6]
- TURN incorrectly asserts that 2020 is an inflated starting point because of the percentage of one-time hydro non-labor O&M costs (i.e., specific planning orders) in 2020 is higher than the 2015-2019 range.[7]

Q 14 Did PG&E rely on 2015-2020 recorded expense forecast for 2021-2023 expenses?

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4 TURN-14, p. 4, lines 11-13.

5 *Id.*

6 TURN-14, p. 34, lines 14-18.

7 TURN-14, p. 36, lines 27-29.

A 14 No. The 2021-2023 expense forecast was constructed using a bottoms-up approach at the planning order level, as shown in its workpapers.[8]

Q 15 Why does TURN assert that "PG&E relied on recorded expenses for 2015-2020 to develop its justification" [for 2021-2023 expense forecasts].[9]

A 15 TURN asserts this by referencing PG&E's data request response[10], "Please explain why PG&E's Hydro expenses in 2020 total $157.2 million, but only average $135.2 million (in nominal dollars) for 2015-2019 inclusive." PG&E's response provides two drivers for 2020: (1) inflation, (2) additional spending in MWC KG – Operate Hydro Generation, with more details provided in the response.

Q 16 In TURN DR 104 Q013[11], did PG&E indicate that it relied on recorded expenses for 2015-2020 to develop its justification for 2021-2023 O&M expense forecasts?

A 16 No. PG&E was asked by TURN to explain the differences between 2015-2019 inclusive and 2020. PG&E made no assertion that it relied on the 2015-2019 values to develop the 2021-2023 forecasts.

Q 17 Why does TURN assert that 2020 is an inflated starting point?

A 17 TURN asserts this by analyzing one-time hydro non-labor O&M costs (i.e., Specific Planning Orders) in 2020 as a percentage of total spend relative to the 2015-2019 average percentage of those same costs. The 2020 percentage is 30 percent, with an average of 23 percent.[12]

Q 18 Why is TURN's assertion incorrect?

A 18 TURN's use of the percentage of one time hydro non labor O&M costs (i.e., Specific Planning Orders) in 2020 as a percentage of total spend relative to the 2015-2019 average is fundamentally flawed because those one-time hydro nonlabor costs are within discrete projects that vary from year-to-year.

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[8] Exhibit (PG&E-5) (Feb. 28, 2022), WP 4-3 to WP 4-24.

[9] TURN-14, p. 34, lines 14-18.

[10] PG&E's response to Data Request TURN_104-Q013, dated 2/14/22 in Appendix A, at the end of this exhibit.

[11] *Id*.

[12] TURN -14, p. 36, lines 28-29.

PG&E's 2021-2023 expense forecast was constructed using a bottoms-up approach at the planning order level, as shown in its workpapers.[13]

Q 19 Are 2021, 2022 and 2023 one-time hydro non-labor expense costs (i.e., Specific Planning Orders) based on escalation of those same costs from 2020?

A 19 No. The costs of the individual projects included in the hydro forecast, i.e., specific planning orders, are estimated on a project-specific basis.[14] PG&E's forecast is based on a bottoms-up calculation of the expected costs for the projects and programs to be implemented in the forecast year. The cost estimates for these programs and projects were developed using a combination of the following: (1) actual costs for similar work, adjusted as appropriate; (2) the knowledge and experience of PG&E's program and project managers; (3) contractor and consultant experience with similar work; and (4) estimates from potential vendors. Project estimates follow the Association for the Advancement of Cost Engineering (AACE) International guidelines.[15]

Q 20 Is TURN's recommended funding level sufficient for PG&E to complete the work required for expense in the hydro system?

A 20 No, the recommended funding level is insufficient. The level of funding recommended by TURN is not enough for PG&E to complete all the ongoing work associated with expense in the hydro system.

2. Adjustments to Expense Related Staffing (Multiple MWCs)

Q 21 Which parties commented on Power Generation's expense related staffing levels?

A 21 TURN was the only party to address Power Generation's expense related staffing levels, although Cal Advocates questioned specific hires in the Asset Management group. A separate section in this chapter addresses Cal Advocates' concerns.

Q 22 Briefly, what is the recommendation on expense related staffing levels for Power Generation?

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13 Exhibit (PG&E-5) (Feb. 28, 2022), WP 4-3 to WP 4-24.

14 *Id*.

15 AACE International Recommended Practice No. 18R-97, Revised March 1, 2016.

A 22 TURN recommends using the average headcount from 2010 to 2020 (i.e., 804) for PG&E's 2023 staffing level for Power Generation instead of PG&E's proposed level of 830,[16] a $4.8 million reduction as shown in Table 4-4.

Q 23 What was the basis for TURN's expense related staffing reduction recommendation?

A 23 TURN indicated that PG&E "has provided no cost-benefit analysis for such hiring [of vacant positions] or demonstrated that full staffing is likely to occur."[17]

Q 24 Do you agree with TURN's recommendations for using historical average headcount of 804? Please explain.

A 24 No. PG&E disagrees with TURN's recommendations on using a historical average headcount in place of its forecast. The CPUC approves forecast costs in the GRC, not headcount. PG&E must constantly manage its workforce to meet the ever-changing business needs of stakeholders. Using a historical average headcount does not meet the forecast business needs of Power Generation.

Q 25 Should PG&E be expected to provide a cost-benefit analysis for vacant positions? Please explain.

A 25 No. Quantifying an individual employee's benefits as part of a larger organization is seldom straightforward. There is an enormous diversity in roles and responsibilities. PG&E also regularly measures its workforce versus industry benchmarks.

Q 26 Do you agree with TURN's statement that PG&E "has…[not] demonstrated that full staffing is likely to occur?

A 26 No. As of December 31, 2021, Power Generation had 885 full time equivalent employees, exceeding the 830 forecasted in the GRC submittal.[18]

Q 27 Did TURN recommend a forecast reduction associated with the staffing level recommendation?

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[16] TURN-14, p. 9, lines 17-20.

[17] TURN-14, p. 76, lines 7-9.

[18] PG&E's response to Data Request TURN_213-Q001, dated 6/6/22 in Appendix A, at the end of this exhibit.

A 27 Yes. TURN recommended a forecast reduction of approximately $4.8 million (2021 dollars).[19]

Q 28 Do you agree with TURN's recommendations for a forecast reduction of approximately $4.8 million? Please explain.

A 28 No. PG&E disagrees with TURN's recommendation. As previously stated, Power Generation's full time equivalent employees as of December 31, 2021, exceeded the GRC forecast. Also, as previously stated in PG&E's response to TURN Data Request 130, filling vacant positions will have a net neutral impact on costs due to savings from a variety of sources. For example, PG&E expects filling vacant positions will reduce overtime; potentially reduce unbudgeted forced outage work as we work through our preventive maintenance backlogs; reduce contractor costs as we insource more work; and increase the potential for less costly or otherwise superior project solutions and better cost management as we hire additional engineers to support the workload.[20]

Q 29 Does PG&E have other concerns with TURN's staffing recommendation?

A 29 Yes. TURN is double counting its proposed expense reductions by recommending both expense staffing reductions and hydro expense forecast reductions. PG&E believes this amounts to $3.0 million in redundant reductions. [21]

3. Operational Support (MWC OS)

Q 30 Briefly, what is the scope of Operational Support forecast in PG&E's hydro system?

A 30 Operational Support (MWC OS) includes staffing costs. This MWC includes labor and employee related costs to provide services and support that are unrelated to supervision and management. Examples include Business Finance and Sourcing that support the LOBs.[22] The forecast increase is primarily driven by filling vacancies in support organizations like Asset

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19 TURN-14, p. 9, lines 17-20.

20 PG&E's response to Data Request TURN_130-Q009 (a), dated 3/7/22 in Appendix A, at the end of this exhibit.

21 Exhibit (PG&E-18), WP 4-1.

22 Exhibit (PG&E-5) (Feb. 28, 2022), p. 4-48, lines 6-9.

Management and Hydro Outage and Project Management and escalation of O&M costs.

Q 31 Which parties commented on the Operational Support forecast?

A 31 Cal Advocates was the only party to address to Operational Support forecast.

Q 32 Do you agree with Cal Advocates' recommendation for reducing PG&E's forecasts to MWC OS? Please explain.

A 32 No. PG&E disagrees with Cal Advocates' recommendation. The six new hires were necessary to establish programmatic and process improvement changes required to address the major and minor nonconformances (gaps) identified in the Lloyd's Register ISO 55000 analysis in 2020.[23]

Cal Advocates incorrectly asserts that the headcount is needed for a limited assignment. In fact, the six new hires were necessary to establish programmatic and process improvement changes required to address the major and minor non-conformances (gaps) identified in the Lloyd's Register ISO 550000 analysis in 2020.

Q 33 What is ISO 55000 certification?

A 33 ISO 55000 is an internationally recognized Asset Management System standard that details out the requirements for a business to ensure it is maximizing the value of its assets and minimizing its risks. ISO 55000 standards are aligned with the concept of risk and data informed investment decision making and requires a significant improvement in the way Power Generation treats and maintains its data.

Q 34 Can you explain the need for 6 new hires?

A 34 Yes. In order to achieve and maintain ISO 55000 certification, additional controls, programs and reviews must be established and maintained to provide evidence of control against each of the clauses found in the ISO 55000 standard. These new processes must be designed, implemented and maintained for the life of the certification; therefore, the additional headcount is not a limited assignment as Cal Advocates suggests. The additional headcount is needed to maintain the processes that were added to the scope of the organization based on the major and

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[23] CA-08, p. 11, lines 21-25.

minor non-conformances identified by Lloyds Register. Depending on additional non-conformances that may be found in future certification audits, additional processes may be established in order to maintain ISO 55000 certification. Better tracking of maintenance notifications to support life cycle management, establishment of a tool's calibration program and the establishment of management review and other Asset Management processes and documentation that did not previously exist are examples of improvements that require additional resources.

Q 35 Was Power Generation able to achieve ISO 55000 certification?

A 35 Yes. Power Generation was able to achieve ISO 55000 certification in April 2022.

Q 36 If certification was achieved in 2022, why does PG&E still need the additional headcount?

A 36 These resources are needed to maintain the processes put in place to maintain the certification during future annual audits.

Q 37 What was the driver for Power Generation pursuing ISO 55000 certification?

A 37 As part of the 2020 GRC Settlement, PG&E agreed to make a good-faith effort to apply for and attain an ISO 55000 certification from an accredited organization for its dams by the end of 2022. In addition, PG&E agreed to begin the gap analysis required to initiate an ISO 55000 certification process for the other assets in its then-existing hydroelectric portfolio in 2023 or earlier.[24] ISO 55000 provides a standard for businesses to meet in order to achieve a balance between risks, costs, and performance of its assets. Recognizing the efficiency of common processes across all of Power Generation, PG&E not only met its commitment of achieving ISO 55000 certification of its dams by 2022 but was also able to achieve certification on its entire portfolio, including: hydro powerhouses, civil infrastructure, fossil, solar, battery storage, physical data and data assets.

Q 38 Why does PG&E believe Power Generation's existing asset management staffing was unable to achieve ISO 55000 certification?

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24 PG&E's response to Data Request CalAdvocates_165-Q04 (a), dated 12/3/21 in Appendix A, at the end of this exhibit. See also PG&E 2020 GRC Settlement Agreement adopted in the final GRC decision, Decision, (D.) 20-12-005, Section 2.4.4.

A 38 Achieving certification required personnel to manage the reoccurring bi-annual audit process, engage with stakeholders throughout the organization to establish action plans in response to non-conformances with the standard, and to develop and maintain processes and procedures in order to provide evidence of conformance with the standard. The existing asset management personal did not have the capacity to take on these additional roles given the magnitude of non-conformances that were found during the initial gap assessment.

Q 39 Why didn't Lloyds Register's analysis specifically identify the shortfall in headcount?

A 39 The purpose of Lloyds Register's analysis was to identify the gaps in Power Generation's asset management systems and processes that prevented the business from meeting the requirements in the ISO 55000 standard. Lloyds Register is not tasked to identify the resources needed to meet the standard. They are tasked with identifying non-conformances with the standard. It is up to the business owner to identify the required resources that are needed to close any non-conformances that are found by the auditors and to maintain the new processes going forward.

Q 40 What about the gaps identified by Lloyd's made it resource intensive to the point additional staff was required?

A 40 Lloyd's register's assessment identified major and minor non-conformances. These non-conformances are summarized as follows:

1) The establishment of asset management system documentation (both creating and maintaining), such as a policy, a strategic asset management plan (SAMP) and asset management plans for each of the eight asset families within the Power Generation organization.
2) The creation of a risk informed budget prioritization framework that is consistently applied across all asset families and used for long term planning investment decisions.
3) The alignment of asset management objectives from the enterprise vision and mission with performance goals and metrics within the Power Generation business.
4) The further improvement in the organizations ability to track, monitor, and close out maintenance notifications.

5) Further IT improvements in the organization's ability to manage its asset data and ensuring there are checks and records to ensure the workforce has the appropriate competencies to succeed in their role.

Following a subsequent certification audit at the beginning of 2022, Power Generation was able to close all major non-conformances and is currently working to close a total of 7 minor non-conformances.

4. Recreation Point Group Campground Project (MWC IG)

Q 41 Briefly, what is the scope of Recreation Point Group Campground project?

A 41 This is one of the recreation projects required by the Crane Valley Recreation Settlement Agreement between PG&E and the US Forest Service (executed October 28, 2002). It includes planning, design, installation, rehabilitation, and repair of several recreational facilities at Bass Lake. The Settlement Agreement between PG&E and the US Forest Service became a requirement of the FERC license for the Crane Valley Project (FERC No. 1354) when the license was issued September 16, 2003.[25]

Q 42 Which parties commented on the Recreation Point Group Campground Project?

A 42 Cal Advocates was the only party to address to Recreation Point Group Campground Project.

Q 43 What was Cal Advocate's recommendation?

A 43 Cal Advocates recommends reducing the forecast to MWC IG by $2.6 million in 2023 as shown in Table 4-1 for the Recreation Point Group Campground Project and include it in the next GRC.[26]

Q 44 What is the basis for Cal Advocates' proposed reduction?

A 44 Cal Advocates asserts PG&E has not provided sufficient documentation supporting the costs for the Recreation Point Campground. Additionally, Cal Advocates claims that deferring consideration of the project to PG&E's next GRC will allow the Forest Service to fund the project.

25 PG&E's response to Data Request CalAdvocates_080-Q01Supp01, dated 10/13/21 in Appendix A, at the end of this exhibit.

26 CA-08, p. 14, lines 5-12.

Q 45 Do you agree with Cal Advocates' recommendation for removing PG&E's forecast for this project? Please explain.

A 45 No. PG&E disagrees with Cal Advocates' recommendation. Work on the project must begin in 2023 to support project completion by 2025. As such, it is reasonable to include the forecast in 2023 for this project even though it may not be completed until 2025. Additionally, PG&E cannot rely—as Cal Advocates assumes—on Forest Service funding for the project. To date, there is no evidence that the Forest Service will fund the project.

Q 46 How is the scope of the project determined?

A 46 The timing and magnitude of activities are determined by Forest Service Staff.

Q 47 Why would PG&E forecast dollars in 2023 if the project is to be complete in 2025?

A 47 The project will include scoping/design, procurement, permitting, and construction, all of which occurs over multiple years. PG&E's forecast assumes that the first two years of the project will involve design and permitting, with construction in 2025.

Q 48 How common are 3-year schedules for projects of this type of work?

A 48 Recreational facility improvement projects can require multiple years to get through design, permitting, and construction. A multi-year forecast is common.

Q 49 Why couldn't a more detailed or accurate forecast of this work be developed at the time of inclusion in the 2023 GRC?

A 49 The exact schedule and scope of the project are dictated and provided to PG&E by Forest Service staff. PG&E provided the best forecast possible in light of the remaining uncertainty regarding the scope of the project over which PG&E has no control.

Q 50 Does PG&E believe that the Forest Service will fund this project?

A 50 No. As noted above, PG&E has no reason to believe the Forest Service will be funding this project. In accordance with the Crane Valley Recreational Settlement Agreement and FERC License Article No. 414, it is PG&E's responsibility to move forward with the recreational facility improvements listed in the Crane Valley Recreational Settlement Agreement.

Q 51 What was PG&E's reasoning for using Hydro Licensing Balancing Account (HLBA) for this line item?

A 51 In the 2020 GRC, the Commission approved a Settlement expanding the scope of the HLBA to include the costs associated with the Crane Valley Recreation Settlement Agreement. The inclusion of these costs in the HLBA is appropriate because of the uncertainty created by the fact that the timing and scope of the project are determined solely by the Forest Service staff.

5. JBB Willow Creek Road Stabilization (MWC 2P)

Q 52 Briefly, what is the scope of JBB Willow Creek Road Stabilization project?

A 52 The scope of the project is to restore the road access to the James B. Black siphon at the request of the Forest Service.

Q 53 Which parties commented on the JBB Willow Creek Road Stabilization Project?

A 53 Cal Advocates was the only party to JBB Willow Creek Road Stabilization Project.

Q 54 What was Cal Advocate's recommendation?

A 54 Cal Advocates recommends a 2023 forecast of $0 for JBB Willow Creek Road Stabilization project in the 2023 GRC resulting in a reduction in MWC 2P of $6.5 million in 2023 as shown in Table 4-2.[27]

Q 55 What is the basis for Cal Advocates' proposed reduction?

A 55 Cal Advocates claims that PG&E has not adequately supported the project because it did not complete an alternatives analysis and recommends deferring consideration of this project to PG&E's next GRC to provide an opportunity to review the alternatives considered for the project.

Q 56 Do you agree with Cal Advocates' recommendation for reducing PG&E's forecast to MWC 2P? Please explain.

A 56 No. PG&E disagrees with Cal Advocates' recommendation. Regardless of the alternative that is selected, the project needs to move forward as forecast so that vehicular access can be restored to the JBB siphon. The siphon is a segment of the water conveyance that carries water to the powerhouse. Vehicular access to the siphon is necessary for PG&E to perform inspections and maintenance and respond quickly if emergency

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27 CA-08, p. 20, lines 5-14.

repairs were required to that portion of water conveyance. It is not an acceptable risk for PG&E to have prolonged lack of appropriate access to critical powerhouse infrastructure. If PG&E were to wait until the next GRC to give Cal Advocates an opportunity to review the alternatives considered for the project, the project would have already been completed and PG&E would not receive the capital-related revenue requirement associated with the investment in 2024-26 since the project is scheduled to be operative at the end of 2023. It is simply not prudent to wait until the 2027 GRC to seek approval of this project. Under Cal Advocates' recommendation, the project would either need to be delayed four years in order to get advanced Commission approval or PG&E would implement the project as proposed in this GRC and forego three years of capital-related revenue requirement. Neither of these two options is acceptable.

Q 57 Why must road access to be restored?

A 57 Moderate to severe weather near James B Black Powerhouse previously impacted by forest fires appear to have contributed to the premature failure of roadway in several locations. More sediment than normal from fire damaged area may be clogging drainage pipes and abnormal hydraulic conditions caused by large amounts of sediment likely caused sections of erodible soils to fail along the roadway. This resulted in loss of vehicular access to the JBB siphon.

Q 58 Are there any agencies requesting PG&E to restore access?

A 58 Yes. The Forest Service.

Q 59 What is driving urgency and timing of the project?

A 59 PG&E is unable to do inspection and maintenance work on the siphon without vehicular access. The siphon is a segment of the water conveyance (enclosed pipe) that carries water to the powerhouse to generate power. If an issue were to occur with the siphon, PG&E would not have the access needed to make repairs. This could result in additional forced outage time to the powerhouse and emergent costs of repairing the road in an emergency situation both creating additional and unnecessary costs.

6. UNFFR, McCloud Pit, Drum Spaulding FERC License Condition projects (MWC 3H)

Q 60 Briefly, what is the scope of these projects?

A 60 These three projects implement expected capital-related FERC-mandated license conditions that are expected once FERC approves the new licenses for the Upper North Fork Feather River (UNFFR), McCloud Pit, and Drum Spaulding FERC Licenses. Each of these three projects are expected to be operational in December 2026.

More specifically, for UNFFR, the scope includes the cost of planning, permitting, and construction of the following:

- Project road work;
- Last Chance family campground;
- Day use areas including Canyon Dam, Westwood beach, Stumpy Beach;
- East shore group camp area: and
- North Fork fishing trail.

For McCloud Pit, the scope includes the cost of planning, permitting, and construction of the following:

- McCloud Dam low level outlet;
- Project roads;
- Gage modifications and equipment to improve high flow readings;
- Erosion and sediment control measures and recreation, and recreation improvements; and
- New recreation facilities.

For Drum Spaulding, the scope includes the cost of planning, permitting and construction of the following:

- Spillway channel improvements;
- Wildlife crossing over canals;
- Recreation plan and new recreation facilities; and
- Project road improvements.

Q 61 Which parties commented on these FERC License Condition projects?

A 61 Cal Advocates was the only party to address these FERC License Condition projects.

Q 62 What was Cal Advocate’s recommendation?

A 62 Cal Advocates recommends a 2022 and 2023 forecast of $0 for these three projects resulting in a reduction in the MWC 3H forecast of $15 million and $47 million in 2022 and 2023, respectively, as shown in Table 4-2.[28]

Q 63 What is the basis for Cal Advocates' proposed reduction?

A 63 Since the operative dates for these three FERC license condition projects are December 2026, these projects will not affect the 2023 GRC revenue requirement so Cal Advocates recommends removal of these capital expenditure forecasts from this GRC. In addition, Cal Advocates stated that PG&E's reply to provide a cost breakdown for these projects was vague.

Q 64 Do you agree with Cal Advocates' recommendation for reducing PG&E's forecasts for MWC 3H? Please explain.

A 64 No. PG&E disagrees with Cal Advocates' recommendation.

Q 65 Why did PG&E include these capital expenditure forecasts in this GRC even though the capital projects have an operative date of December 2026?

A 65 By presenting these capital expenditure forecasts in this GRC, PG&E is simply complying with the Commission's Rate Case Plan. The Rate Case Plan states that the GRC application provides detailed forecasts of the applicant's capital investment expenses and its operating and maintenance (O&M) expenses for a designated "test year" as well as forecasts for two subsequent post-test years, or "attrition years."[29] The Rate Case Plan also changed the number of attrition years from two to three.[30]

Q 66 Is there another reason PG&E includes a capital expenditure forecast in this GRC for projects that won't be operative until late in the attrition period?

A 66 Yes. PG&E is required to file a Risk Spending Accountability Report (RSAR) annually.[31] The RSAR includes the authorized and actual spending for the risk mitigation programs identified in the program risk assessment and mitigation phase (RAMP) and other programs related to safety, reliability or maintenance presented in the General Rate Case (GRC) application. Since the capital expenditure forecasts for these three projects

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28 CA-08, p. 19, lines 1-7.

29 Decision (D.) 20-01-002, p. 8.

30 *Id*.

31 D.19-04-020, p. 64, Ordering Paragraph 8.

span 2021-2026, and MWC 3H is considered a program related to safety, reliability or maintenance, the capital expenditure forecast must be included in the GRC regardless of the operative date.

7. Emergent Work Capital and Expense Projects (AX and 2N)

Q 67 Briefly, what is the scope of Emergent Work Capital and Expense projects?

A 67 These programs fund emergent work on water conveyance facilities. Historically, weather events, seismic events, and wildfires have resulted in unplanned work due to failures of water conveyance facilities. These facility failures are typically corrected by rebuilding canal sections, installing retaining walls or replacing flume sections.

PG&E's hydro water conveyance facilities are susceptible to damage during severe weather, seismic events, and wildfires. Also, due to the dispersed nature of the hydro water conveyance facilities they often do not correspond with state-designated disaster areas that may be declared following such events. For these reasons this work is not normally covered through other funding mechanisms such as the Catastrophic Events Memorandum Account (CEMA).[32]

Q 68 Which parties commented on the Emergent Work Capital and Expense Projects?

A 68 TURN was the only party to address Emergent Work Capital and Expense Projects.

Q 69 What was TURN's recommendation?

A 69 TURN recommends removing the forecast for these projects in all years resulting in a reduction to PG&E's 2023 expense forecast for MWC AX of $0 million and a reduction to PG&E's capital expenditure forecast of $0.4 million, $3.0 million, $3.8 million, $3.0 million for 2023, 2024, 2025, and 2026, respectively, as shown in Table 4-5. TURN also recommends tracking the costs associated with Emergent Work Capital and Expense Projects using a memorandum account and then justified in a new GRC.[33]

Q 70 What is the basis for TURN's proposed reduction?

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32 Exhibit (PG&E-5) (Feb. 28, 2022), WP 4-240.

33 TURN-14, p. 33, lines 15-29.

A 70 TURN states that it is unreasonable to include these forecasts without any sort of justification other than professional judgement and/or historic PG&E cost data for similar work.[34]

Q 71 Do you agree with TURN's recommendation for reducing PG&E's forecast for these projects? Please explain.

A 71 No. PG&E disagrees with TURN's recommendation. These projects are specifically for funding expense and capital emergent work on water conveyance facilities. PG&E's hydro water conveyance facilities are susceptible to damage during severe weather, seismic events and wildfires that often do not correspond with state-designated disaster areas that may be declared following such events. Without an emergent work fund, these emergent projects displace other important work that was approved in the GRC. This creates a deferred work situation that PG&E endeavors to avoid.

Q 72 Did PG&E adequately justify the forecasts associated with this work?

A 72 Yes. As described in its workpapers, PG&E based its cost forecast assumptions on the following: (a) the professional judgment of the engineers and licensing professionals familiar with this type of work; and/or (b) historic PG&E cost data for similar work.[35]

Q 73 Does PG&E agree with TURN's recommendation for establishing a memorandum account for this work?

A 73 No. The sole purpose of a memorandum account is to address the prohibition of retroactive ratemaking. Memo accounts are necessary when a utility is unable to develop a forecast or when a utility has not made a forecast available for review by parties. PG&E has provided a reasonable forecast for this work.

Q 74 Does PG&E discuss the financial implications of establishing new memorandum accounts elsewhere in its testimony?

A 74 Yes. PG&E discusses the financial implications of establishing new memorandum accounts in Exhibit (PG&E-14), Chapter 3.

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[34] TURN-14, p. 33, lines 10-12.

[35] Exhibit (PG&E-5) (Feb. 28, 2022), WP 4-240.

8. Hydro License Condition Projects With Pending FERC Licenses (3H and IG)

Q 75 Briefly describe the scope of License Condition projects for pending FERC licenses?

A 75 New FERC license conditions are uncertain until the new license order has been issued by FERC; however, the licensee's cost forecasts (capital and expense) for compliance with anticipated new license requirements are based on engagement with regulatory agencies and stakeholders during the relicensing proceeding, various environmental reviews (National Environmental Policy Act and California Environmental Quality Act) and regulatory processes and intermediate steps. Cost estimates to implement new license requirements are refined by the licensee throughout the relicensing process based on growing availability of information as the regulatory proceeding matures.[36]

Q 76 Which parties commented on the License Condition projects for pending FERC licenses?

A 76 TURN was the only party to address to License Condition projects for pending FERC licenses.

Q 77 What was TURN's recommendation?

A 77 TURN recommends that the expenditures related to meeting license conditions for projects that do not currently have licenses should not be included in PG&E's forecasts in this proceeding and that the Commission should reject these requests without prejudice.[37] TURN also recommends that instead of simply including them in the HLBA, PG&E should bring forth a proposal to include these costs in rates once PG&E can persuasively demonstrate the timing and amount of these expenses.[38]

Q 78 Does TURN quantify the resulting reduction in PG&E's capital or expense forecast as a result of its recommendation.

A 78 No.

Q 79 What is the basis for TURN's proposed reduction?

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36 Exhibit (PG&E-5) (Feb. 28, 2022), WP 4-242 to WP 4-243.

37 TURN-14, p.105, lines 28-30.

38 TURN-14, p. 105, line 32 to p. 106, line 2.

A 79 TURN claims that the forecasts for this capital and expense work is highly dependent on information that is unknowable at this time (i.e., the dates upon which licenses will be issued, the license conditions that will be included in those licenses, and the costs of meeting those license conditions).[39]

Q 80 Do you agree with TURN's recommendation for not including project forecasts for pending license conditions? Please explain.

A 80 No. By presenting these capital expenditure forecasts in this GRC, PG&E is simply complying with the Commission's Rate Case Plan. The Rate Case Plan states that the GRC application provides detailed forecasts of the applicant's capital investment expenses and its operating and maintenance (O&M) expenses for a designated "test year" as well as forecasts for subsequent post-test years, or "attrition years."

Q 81 Is there another reason PG&E includes a capital expenditure forecast in this GRC for projects that won't be operative until late in the attrition period?

A 81 Yes. PG&E is required to file a Risk Spending Accountability Report (RSAR) annually. The RSAR includes the authorized and actual spending for the risk mitigation programs identified in the program risk assessment and mitigation phase (RAMP) and other programs related to safety, reliability or maintenance presented in the GRC application. Since the capital expenditure forecasts for these license condition projects span 2021-2026, and MWC 3H is considered a program related to safety, reliability or maintenance, the capital expenditure forecast must be included in the GRC regardless of the operative date.

Q 82 Does TURN provide an alternative recommendation?

A 82 Yes. TURN further states that if the Commission believes that it is important to consider these speculative costs in this proceeding, TURN proposes that the costs be authorized and that actual capital and O&M expenses be tracked in a discrete sub-account of the one-way HLBA along with the adopted capital and O&M levels adopted in this proceeding. Once the project becomes used and useful, PG&E can include the lesser of the actual or the authorized costs in rates (either through its GRC or an AET). If actual

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[39] TURN-14, p. 105, lines 22-25.

costs exceed authorized costs, PG&E can come to the Commission in the next GRC to attempt to demonstrate the reasonableness of the actual costs and request cost recovery.[40]

Q 83 What is PG&E's response to TURN alternative recommendation?

A 83 PG&E's response to this alternative proposal is addressed in Chapter 8.

9. Potter Valley Transformer Project

Q 84 Briefly, what is the scope of the Potter Valley Transformer project?

A 84 In summer 2021, the transformer at the Potter Valley Project powerhouse failed. In early 2022, PG&E made the decision to replace the transformer. PG&E estimates that the replacing the transformer will cost $8.9 million and plans to recover this cost within the approved 2023 GRC forecast amount. PG&E did not forecast the cost of this project in the GRC because the timing of the decision to replace the transformer was after PG&E had finalized its forecast for this GRC.[41]

Q 85 Which parties commented on the Potter Valley Transformer Project?

A 85 CalTrout was the only party that commented on this project.

Q 86 What was CalTrout's recommendation?

A 86 It is unclear what CalTrout's recommendation is for the Potter Valley Transformer project. PG&E surmises that CalTrout's recommendation is that PG&E should not be allowed to recover the costs for this project within the approved 2023 GRC forecast amount.

Q 87 What is the basis for CalTrout's recommendation?

A 87 CalTrout claims that average flows and power production are likely to fall further during the remaining years of Project operation. This leads PG&E to believe that CalTrout is questioning the economic viability of the project, suggesting that going forward with the project is not in the best interest of the customer.

Q 88 Does PG&E agree with CalTrout's suggestion that the Potter Valley Transformer project is uneconomic?

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40 TURN-14, p. 106, lines 4-11.

41 PG&E's response to Data Request CaliforniaTrout_001-Q006 dated 3/29/22 and PG&E's response to Data Request CaliforniaTrout_001-Q007, dated 3/29/22 in Appendix A, at the end of this exhibit.

A 88 No. PG&E’s economic analysis utilizes current forward price curves for energy pricing and historical generation data of the plant to determine the economic viability of the plant. It also looks at ancillary service and capacity (resource adequacy) value which are additional market components that need to be factored into the assessment. CalTrout shares its opinion on how much it believes the Potter Valley powerhouse may generate in the future and how much water flows will be. It is very difficult, if not impossible, to predict the water year types and amount of water that may be available to the powerhouse to generate. PG&E has a dedicated water management team and Energy Procurement department who are subject matter experts in managing the water flows, dispatch profiling, and energy pricing of PG&E’s hydro system. It is unreasonable to believe that CalTrout is in better position to forecast water flows, generation, and market pricing than PG&E. PG&E uses a 30-year historical average when doing economic analyses on a project because is important to look over a long enough time frame to account for potential changes in water flows.

Q 89 Are there other reasons CalTrout may conclude its not in the best interest of customers to replace the transformer?

A 89 Yes. CalTrout assumes decommissioning can begin in 4 years and PG&E’s analysis assumes decommissioning can begin in 10 years.[42]

Q 90 What is the basis for CalTrout’s shorter regulatory timeframe?

A 90 CalTrout suggests that Potter Valley will be decommissioned in a much shorter time than the Kilarc and Klamath because, in its opinion, the longer decommissioning periods for Kilarc was due to the delays in obtaining a water quality certification under Section 401 of the Clean Water Act (“Section 401 certification”) and for Klamath due to the need to transfer the operating license and that neither of these circumstances will be applicable to the Potter Valley decommissioning process.[43] Without this requirement, CalTrout asserts that PG&E will be able to get through the Potter Valley

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42 PG&E’s response to Data Request CaliforniaTrout_001-Q005 dated 3/29/22 in Appendix A, at the end of this exhibit.

43 CalTrout-1, p. 3, line 12 to p.10, line 6.

license surrender process in four years and that decommissioning can then begin.[44]

Q 91 Does PG&E agree with CalTrout's interpretation?

A 91 No. PG&E has found no example of a hydroelectric facility completing the license surrender process in 4 years. Even if you assume a 4-year license surrender process, the actual decommissioning work would not begin immediately upon issuance of the FERC order, since additional planning and permitting would be needed. The transformer should still be replaced because PG&E is unable to return the powerhouse to service until a new transformer is installed. This is impacting PG&E's customers because the longer it is out of service, the longer the powerhouse is not able to generate and produce any revenue.

Q 92 Are there other factors that PG&E considers when it decided to proceed with the Potter Valley transformer project?

A 92 Yes. In addition to the economic analysis, PG&E took into consideration its ability to sell the transformer, serve distribution need and use of the transformer in other locations in PG&E's hydro system. Additionally, Potter Valley provides local capacity benefits. These are additional factors PG&E considered when making the determination if the project should move forward.[45]

D. PG&E's Response to Parties' General Criticisms and Global Recommendations

1. PG&E's Response to Parties' General Criticisms

Q 93 Do parties generally criticize PG&E's Hydro Operations. Please describe.

A 93 No.

2. PG&E's Response to Parties' Global Recommendations

Q 94 Do parties make any global recommendations related to PG&E's forecast for PG&E's Hydro Operartions? Please describe.

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44 *Id*.

45 PG&E's response to Data Request CaliforniaTrout_001-Q009 and CaliforniaTrout_001-Q010, dated 3/29/22 in Appendix A, at the end of this exhibit.

A 94 Yes. Cal Advocates recommends that PG&E use the 2021 recorded capital expenditures rather than PG&E's 2021 forecast.[46]

TURN recommends the following:

- Disallowance of PG&E capital expenditures for projects with operative dates after the Test Year. TURN's alternate proposal is a one-way balancing account for these projects with expenditures that exceed the approved amounts being tracked in a Memorandum Account. If there is a positive balance in the Memorandum Account, PG&E should have the opportunity to try to justify these expenditures in the next GRC. If there is a negative balance, the difference between the authorized amount and the actual costs should be refunded to customers.[47]
- Disallowance of PG&E capital expenditures for projects with forecast after 2023 with operative dates on or before the Test Year.[48]
- Costs for PG&E's capital and expenses for 2023-2026 for 24 Large Uncontrolled Water Release (LUWR) projects proposed in the 2020 RAMP should be set equal to those found in the 2020 RAMP.[49]
- "PG&E should not be allowed to bring forth generation projects [for new capacity] in its GRC that have not been vetted through the Commission's Integrated Resource Planning (IRP) process."[50]

Q 95 Do you agree with Cal Advocates' recommendation regarding the use of 2021 recorded capital expenditure rather than PG&E's 2021 forecast?

A 95 See Exhibit (PG&E-14), Chapter 2, Summary of PG&E's 2023 General Rate Case."

Q 96 Do you agree with TURN's recommendation regarding the disallowance of PG&E capital expenditures for projects with operative dates after the Test Year?

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46 CA-08, p. 16, lines 1-5.

47 TURN-14, p. 24, lines 2-10.

48 TURN-14, p. 24, lines 12-14.

49 TURN-14, p. 29, lines 11-14.

50 TURN-14, p. 55, lines 3-5.

A 96 No. PG&E does not agree with TURN's recommendation since GRC cycles are approved for four years of capital forecast, starting with the test year followed by three attrition years.

Q 97 How is the forecast years for the GRC decided?

A 97 The CPUC Rate Case Plan established how and when a GRC should be filed.[51]

Q 98 Does the plan specify which years should be included in a GRC forecast and how the Commission's decision is based?

A 98 Yes. The Rate Case Plan states that a GRC application provides detailed forecasts of the applicant's capital investment expenses and its operating and maintenance (O&M) expenses for a designated "test year," as well as forecasts for two subsequent post-test years, or "attrition years." The Commission's decision is based on its extensive review of the test year forecasts.[52] The Rate Case Plan also changed the number of attrition years from two to three.[53]

Q 99 Does PG&E agree with TURN's recommendation for establishing a memorandum account for this work?

A 99 No. The sole purpose of a memorandum account is to address the prohibition of retroactive ratemaking. Memo accounts are necessary when a utility is unable to develop a forecast or when a utility has not made a forecast available for review by parties. PG&E has provided a reasonable forecast for this work.

Q 100 Does PG&E discuss the financial implications of establishing new memorandum accounts elsewhere in its testimony?

A 100 Yes. PG&E discusses the financial implications of establishing new memorandum accounts in Exhibit (PG&E-14), Chapter 3.

Q 101 Do you agree with TURN's recommendation regarding the disallowance of PG&E capital expenditures for projects with forecast after 2023 with operative dates on or before the Test Year?

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51 D.20-01-002.

52 D.20-01-002, p. 8.

53 *Id*.

A 101 No. PG&E does not agree with TURN's recommendation. TURN misunderstands the use of operative dates at the project or planning order level. Projects with forecast after 2023 with operative dates on or before the Test Year are appropriate to include in the 2023 GRC forecast. Certain types of projects or programs can have operative dates prior to when the forecast ends.

Q 102 What are the reason projects might have a forecast after 2023 but an operative before the Test Year?

A 102 There are two primary reasons why this occurs. (1) Many of the capital projects are multi-year projects with engineering/design in the first year, procurement of long lead equipment in the second year, and construction and close-out in the third and fourth year. So, there may be an operative date in the year of the construction but there is still a forecast in the subsequent year for project close out activities such as demobilization and the development of as-build drawings. (2) Capital projects at the planning order level can be programmatic meaning there is certain scope of work that will be completed across many plants/locations in the hydro system. In this situation, typically after the first year of the forecast, the scope of work has been completed at certain plants or locations and so the operative date reflects the first year of the forecast. In other words, the scope of work continues at other locations or plants in the subsequent years.

Q 103 Can you provide examples to support this reasoning?

A 103 Yes. The Scada Powerhouse Automation project or Early Warning System projects are programmatic. Automation of powerhouses and installation of early warnings systems will occur at certain plants/locations each year over a multiple year period. However, the operative date will reflect the first year of the forecast when the scope of work for certain number of plants/locations have been completed even though the forecast goes out to 2027 for both projects. The operative date matches when the first location or plant is completed. Examples of multi-year projects that require engineering, procurement, construction and close out would be the Pit 7 Replace Transformer Bank 1 and 2, and JBB Replaced Transformer Bank. Operative dates for these projects are after construction complete in 2022 and 2023 respectively. The construction (our outage) window for this work can be in the Fall so close-out for the project occurs in the next year. Close-out can be substantial for construction projects of this size. Transformer Bank replacement projects on hydro plants require typically a 3-4 year schedule depending on the specific plant which consists of engineering in the first year, procurement of the transformer bank which is long lead piece of equipment in the second year, construction in the third year and closeout in the fourth year.

Q 104 How common is it for the operative dates to be in a year prior to the end of the forecast?

A 104 It is very common as larger, more complex capital projects for various equipment replacement span multiple years and for programmatic work being executed across all or a portion of the system can extend over several years.

Q 105 Do you agree with TURN's recommendations regarding the costs for PG&E's capital and expenses for 2023-2026 for 24 Large Uncontrolled Water Release (LUWR) projects proposed in the 2020 RAMP should be set equal to those found in the 2020 RAMP.[54]

A 105 No. PG&E does not agree with TURN's recommendation. There is a significant timing difference between when 2020 RAMP forecast was developed and when the 2023 GRC forecast was developed so it's reasonable for forecasts to change within this period as PG&E gets new information to inform its forecasts.

Q 106 How much time did TURN state transpired between the preparation of the 2020 RAMP and 2023 GRC forecast?

A 106 TURN stated the preparation of the filings were "within months" of each other.

Q 107 Is this an accurate statement?

A 107 It's misleading at best. Almost a full year had passed between the preparation of the capital and expense forecast for the 2020 RAMP Report (first quarter of 2020) and the preparation of the capital and expense forecast for the 2023 GRC (fourth quarter of 2020).[55] Due to the amount of

54 TURN-14, p. 29, lines 5-15.

55 PG&E's revised response to Data Request TURN_130-Q017, dated 6/9/22 in Appendix A, at the end of this exhibit.

time required to produce testimony and the results of operation calculations, forecasts must be finalized several months before the RAMP or GRC is filed with the Commission.

Q 108 Is it reasonable for project forecasts to change in this amount of time?

A 108 Yes. Projects forecasts are being updated through the course of year as the scope of work for the project is further refined, especially for years 2025-2026 when forecasts for 2020 RAMP and 2023 GRC are developed 5-6 years in advance.

Q 109 In which years is the majority of the variance between the RAMP and GRC forecast?

A 109 Years 2025 and 2026 have the majority of the capital variance of $32.7 million and $25.9 million lower, respectively, in the RAMP forecast compared to the 2023 GRC forecast. There is only a $2.1 million and $2.5 million capital variance in the forecasts for 2023 and 2024.

Q 110 What are the reasons for the variance between the RAMP and GRC forecast in the LUWR projects?

A 110 One of the primary reasons for the capital forecast change in the 2023 GRC compared to the 2020 RAMP was the identification of additional actions in the 2023 GRC to reduce the risk of a Large Uncontrolled Water Release (LUWR). This represents a $33 million capital expenditure increase over the 2021-2026 forecast period. Additionally, the scope of various spillway projects to reduce the LUWR risk were refined through the course of the year which is common as PG&E gets further into the project scoping and alternative analyses. In Chapter 8, PG&E highlights the complexity, length of time, and variability of dam spillway project costs. Spillway projects are regulated by both FERC and DSOD and require design approval by these agencies. Additionally, a third-party independent board of consultants, comprising of an industry experts provide input through the life of these projects. It is therefore very reasonable for scope and alternatives to change significantly on these types of projects. The refinement in scope of the spillway improvement projects planned in 2025 and 2026 accounts for over 30 percent of the variance increase in years 2025 and 2026. Lastly, the refinement of the construction scope for the Pit 7 Radial Gate Trunnion projects attributed to an additional 20 percent of the variance.[56]

Q 111 Does TURN have an alternate proposal regarding hydro capital and expense forecasts for LUWR mitigation?

A 111 Yes. TURN states in its testimony that a reasonable alternate proposal would be for the Commission to set the capital and expense forecasts at the average between the 2020 RAMP and PG&E's proposed forecasts. TURN further states that such a reduction would recognize that both forecasts were developed within months of each other.[57]

Q 112 Would PG&E be able to implement the LUWR mitigations it has proposed in this GRC if TURN's recommendation or alternate proposal is adopted?

A 112 No. PG&E didn't stop working on identifying additional actions to reduce the risks of a LUWR after the RAMP was filed. It continued to refine the scope of proposed projects and identifying other opportunities to reduce risk.

Q 113 Do you agree with TURN's recommendation that PG&E should not be allowed to bring forth generation projects in its GRC that have not been vetted through the Commission's Integrated Resource Planning (IRP) process?

A 113 Yes. PG&E agrees, in general, with TURN's recommendation for new capacity projects to be vetted through the IRP process first except when the project is in response to other regulatory requests that may require faster implementation and inhibit PG&E's ability to have the project formally vetted through the IRP process. For example, the Helms Uprate project and Gateway Evaporative Cooling projects stem from PG&E responding to the CPUC Order Institution Rulemaking Emergency (OIR) 20-11-003 directing PG&E to seek additional supply-side capacity as a result of the summer of 2020 when the CAISO was forced to institute rotating electricity outages in California in the midst of a west-wide extreme heat wave. The OIR was opened at the end of 2020 and PG&E prepared and submitted its 2023 GRC forecast in 2021. In addition, PG&E decided to evaluate opportunities to uprate Helms Pumped Storage Hydroelectric Plant around the time when

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56 PG&E's revised response to Data Request TURN_104-Q025 (e), dated 2/14/22 in Appendix A, at the end of this exhibit.

57 TURN-14, p. 31, lines 10-13.

the CPUC issued Rulemaking 20-05-003: Administrative Law Judge's Ruling Seeking Feedback On Mid-Term Reliability Analysis And Proposed Procurement Requirements on 2/22/21. This ruling indicated a need for additional long-duration storage resources. It was prudent for PG&E to consider these projects for inclusion in 2023 GRC although they had not been finished going through the IRP process.[58]

E. Conclusion

Q 114 What is PG&E's recommendation for Hydro Operations.

A 114 For the reasons discussed above, PG&E recommends that its 2023 expense forecast in Table 4-6 and its 2020-2026 recorded and forecast capital expenditures in Table 4-7 be adopted.

Q 115 Does this conclude your rebuttal testimony?

A 115 Yes, it does.

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58 PG&E's response to Data Request TURN_104-Q08(c), dated 2/14/22 in Appendix A, at the end of this exhibit.

TABLE 4-6
PG&ES 2020-2023 ADJUSTED RECORDED AND FORECAST EXPENSE AMOUNTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast
1	Misc. Expense	AB	$5,205	$5,681	$8,913	$7,473
2	Manage Environmental Opera.	AK	1,046	1,136	1,163	1,167
3	Maint Resv.	AX	28,426	24,540	27,784	28,883
4	Habitat and Species Protection	AY	112	251	259	267
5	Perf Reimburse Work for Others	BC	23	–	–	–
6	Manage Property & Bldgs	EP	1,400	1,175	1,213	1,254
7	Implement Environment Projects	ES	–	–	–	–
8	Manage Var Bal Acct Processes	IG	16,954	26,556	30,948	30,552
9	Operate Hydro Generation	KG	43,462	36,285	36,107	37,091
10	Maint Hydro Generating Equip	KH	23,121	23,493	23,134	23,640
11	Maint Hydro Bldg.	KI	8,946	10,429	12,073	14,590
12	License Compliance Hydro Gen	KJ	21,964	24,211	24,142	24,179
13	Catastrophic Events	LX	–	78	81	84
14	Operational Management	OM	2,794	2,647	2,732	3,180
15	Operational Support	OS	2,836	3,794	3,916	4,047
16	Corporate Items	ZC	2,008	1,500	1,500	1,500
17	Total		$158,297	$161,776	$173,966	$177,909

Note PG&E's 2020-2023 recorded and forecast expense amounts have been adjusted for errata and concessions as shown in Table 4-1 above.

TABLE 4-7
PG&ES 2020-2026 ADJUSTED RECORDED AND FORECAST CAPITAL COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast
1	Office Furniture & Equipment	03	–	–	–	–	–	–	–
2	Tools & Equipment	05	$1,898	$701	$986	$567	$645	$706	$788
3	Relicensing Hydro Gen	11	567	550	1,750	4,250	4,000	500	-
4	Implement Environment Projects	12	84	24	10	425	1,000	500	1,000
5	Instl/Rpl for Hydro Safety & Reg	2L	29,592	42,983	39,083	62,960	48,087	26,058	18,648
6	Instal/Repl Hydro Generating Eqp	2M	94,880	93,128	69,240	84,460	93,852	134,430	118,105
7	Instal/Repl Resv	2N	45,193	38,322	27,658	42,682	30,754	25,322	24,788
8	Instl/Repl Hydr Bldg.Grnd. Infrst.	2P	8,015	19,372	16,148	26,574	14,553	12,954	9,650
9	Hydroelec Lic. & Lic Conditions	3H	17,708	27,787	72,956	144,247	155,128	103,296	88,334
10	Catastrophic Events	3Q	–	116	119	121	124	127	129
11	Total		$197,937	$222,983	$227,948	$366,287	$348,143	$303,893	$261,443

Note: PG&E's 2020-2026 recorded and forecast capital costs have been adjusted for errata and concessions as shown in the Table 4-3.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

PG&E'S GENERATION SYSTEM

THIS CHAPTER HAS NO REBUTTAL

(PG&E-18)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
REBUTTAL TESTIMONY OF
STEVE ROYALL
NATURAL GAS AND SOLAR GENERATION OPERATIONS COSTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
REBUTTAL TESTIMONY OF
STEVE ROYALL
NATURAL GAS AND SOLAR GENERATION OPERATIONS COSTS

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Steve Royall. This testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates or CA),[1] The Utility Reform Network (TURN),[2] and Joint Community Choice Aggregators (JCCA).[3] Pacific Gas and Electric Company (PG&E) summarizes parties' positions in Section B below.

Q 2 Do parties make recommendations concerning specific projects and programs?

A 2 Yes.

Q 3 Do you dispute any of the parties' recommendations?

A 3 Yes, I address parties' recommendations in Section C.

Q 4 Are there projects that parties do not dispute or do not address?

A 4 Yes, see Tables 5-1 and 5-2.

Q 5 Do you have any adjustments or corrections to the forecasts as provided in the February 28, 2022, version of your initial testimony and/or workpapers?

A 5 Yes, TURN proposed a removal of the 2021-2023 capital forecast ($3 million for each year). In accordance with TURN's recommendation, PG&E agrees to decrease its 2021, 2022 and 2023 forecast by $3 million, $3 million, and $3 million, respectively.

B. Summary of Parties' Positions

Q 6 Please provide PG&E's current forecast and parties' recommendations.

A 6 PG&E's current forecast and the parties' recommendations are set forth in Table 5-1 (expense) and Tables 5-2 and 5-3 (capital expenditures) below.

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1 CA-08.

2 TURN-14.

3 JCCA-01.

TABLE 5-1
2023 EXPENSE FORECAST – PG&E AND PARTIES
(THOUSANDS OF NOMINAL DOLLARS

			PG&E			Proposed Increases/(Reductions)		
Line No.	Program or MWC Description	MWC	Filed Forecast[a]	Errata or Forecast Adjustments[b]	2023 Adjusted Forecast	Cal Advocates	TURN	JCCA
1	Manage Environmental Oper	AK	$2,807	–	$2,807	–	–	–
2	Operate Fossil Generation	KK	14,314	–	14,314	–	–	–
3	Maint Fossil Generating Equip	KL	29,543	–	29,543	–	–	–
4	Maint Fossil Bldg	KM	3,045	–	3,045	–	–	–
5	Operate Alternative Gen	KQ	467	–	467	–	–	–
6	Maint AltGen Generating Equip	KR	1,268	–	1,268	–	–	–
7	Maint AltGen Bldg	KS	521	–	521	–	–	–
8	Operations Mgmt	OM	293	–	293	–	–	–
9	Operations Support	OS	–	–	–	–	–	–
10	Total		$52,258	–	$52,258	–	–	–

Note: PG&E's 2020-2023 current recorded and forecast expense amounts for all activities included in Exhibit (PG&E-5) (Feb. 28, 2022), Chapter 5 (adjusted for errata and concessions) as of June 13, 2022 are shown in Table 5-5 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

TABLE 5-2
2023-2026 CAPITAL EXPENDITURES FORECAST –PARTIES ADJUSTED FORECASTS
(THOUSANDS OF NOMINAL DOLLARS)

			Adjusted Forecast[a]				TURN[b]				Cal Advocates			
Line No.	Program or MWC Description	MWC	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)
1	Office Furniture and Equipment	03	–	–	–	–	–	–	–	–	–	–	–	–
2	Tools and Equipment	05	$397	$405	$414	$423	–	–	–	–	–	–	–	–
3	Instl/Rpl for Fossil Safety&Reg	2R	–	–	–	–	–	–	–	–	–	–	–	–
4	Instal/Repl Fossil Generating Eqp	2S	3,640	7,929	8,568	6,196	$(3,235)	$(2,347)	$(2,854)	$(4,447)	–	–	–	–
5	Instl/Repl Fosl Bldg/GrndInfrst	2T	1,578	110	–	–	–	–	–	–	–	–	–	–
6	Instl/Rpl for AltGen Safty&Reg	3A	$7	$7	7	7	–	–	–	–	–	–	–	–
7	Instal/Repl AltGen GneratngEqp	3B	714	730	745	760	–	–	–	–	–	–	–	–
8	Construct New Alternative Gen	3D	–	–	–	–	–	–	–	–	–	–	–	–
9	Total		$6,335	$9,181	$9,733	$7,386	$(3,235)	$(2,347)	$(2,854)	$(4,447)	–	–	–	–

(a) PG&E's 2020-2026 recorded and forecast capital costs (adjusted for errata and concessions) are shown in Table 5-6.
(b) TURN recommended overall forecast reduction in MWC 2S is broken down by individual project in Table 5-4.

TABLE 5-3
2023-2026 CAPITAL EXPENDITURES – PG&E'S ADJUSTED FORECAST
(THOUSANDS OF NOMINAL DOLLARS)

			Filed Forecast[a]				Errata or Forecast Adjustments[b]				Adjusted Forecast			
Line No.	Program or MWC Description	MWC	2023 Filed Forecast	2024 Filed Forecast	2025 Filed Forecast	2026 Filed Forecast	2023 Errata or Forecast Adj.	2024 or Forecast Adj.	2025 or Forecast Adj.	2026 or Forecast Adj.	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast
1	Office Furniture and Equipment	03	–	–	–	–	–	–	–	–	–	–	–	–
2	Tools and Equipment	05	$397	$405	$414	$423	–	–	–	–	$397	$405	$414	$423
3	Instl/Rpl for Fossil Safety&Reg	2R	–	–	–	–	–	–	–	–	–	–	–	–
4	Instal/Repl Fossil Generating Eqp	2S	6,640	7,929	8,568	6,196	(3,000)[c]	–	–	–	3,640	7,929	8,568	6,196
5	Instl/Repl Fosl Bldg/GrndInfrst	2T	1,578	110	–	–	–	–	–	–	1,578	110	–	–
6	Instl/Rpl for AltGen Safty&Reg	3A	7	7	7	7	–	–	–	–	7	7	7	7
7	Instal/Repl AltGen GneratngEqp	3B	714	730	745	760	–	–	–	–	714	730	745	760
8	Construct New Alternative Gen	3D	–	–	–	–	–	–	–	–	–	–	–	–
9	Total		$9,336	$9,181	$9,734	$7,386	(3,000)	–	–	–	$6,336	$9,181	$9,734	$7,386

Note: PG&E's 2020-2026 current recorded and forecast capital expenditures amounts as included in Exhibit (PG&E-5) (Feb. 28, 2022), Chapter 5 (adjusted for errata and concessions) as of June 13, 2022, are shown in Table 5-6 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

(c) Reflects a forecast adjustment made based on TURN's proposal to remove the Gateway Evaporative Cooler project from MWC 2S.

TABLE 5-4
2023-2026 CAPITAL EXPENDITURES – PARTIES ADJUSTED FORECAST BY PROJECT
(THOUSANDS OF NOMINAL DOLLARS)

				TURN			
Line No.	Project Description	Planning Order	MWC	2023 Increases/ (Reductions)	2024 Increases/ (Reductions)	2025 Increases/ (Reductions)	2026 Increases/ (Reductions)
1	Humboldt Engine Emission Modules		2S	$(235)	$(347)	$(354)	$(361)
2	Fossil Emergent Capital Work		2S	–	(2,000)	(2,500)	(4,086)
3	Gateway Evaporative Cooling Project		2S	(3000)	–	–	–
4	Total		2S	$(3,235)	$(2,347)	$(2,854)	$(4,447)

Q 7 Does PG&E disagree with any of parties recommendations?

A 7 Yes, PG&E disagrees with recommendations made by TURN regarding MWC 2S and MWC KL with regard to the following projects:

- Humboldt Engine Emission Modules (MWC 2S)
- Fossil Emergent Capital Work (MWC 2S);
- Gateway Evaporative Cooling Project (MWC 2S); and
- Long Term Service Agreement (LTSA) (MWC KL).

C. PG&E's Response to Parties' Recommendations Concerning Specific Programs or Projects

1. Humboldt Engine Emission Modules (MWC 2S)

Q 8 Briefly, what is the scope of Humboldt Engine Emission Modules project?

A 8 The Humboldt Engine Emission Modules project is an annual project that replaces the different exhaust path catalysts used in the 10 Engines at Humboldt Bay Generation Station (HBGS) to maintain emissions levels at or below those required by the North Coast Air Quality Management District.[4]

Q 9 Which parties commented on the Humboldt Engine Emission Module project?

A 9 TURN was the only party to address this project.

Q 10 What is TURN's recommendation?

A 10 TURN proposes an annual capital reduction to MWC 2S as shown in Table 5-4.

Q 11 What is the basis for TURN proposed reduction?

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4 Exhibit (PG&E-5) (Feb. 28, 2022), WP 5-83.

A 11 TURN bases its recommendation on the fact that PG&E presents in this GRC a higher annual forecast than it proposed in its 2020 GRC[5] and higher than historic costs for these engine module replacements.[6]

Q 12 Do you agree with TURN recommendations for reducing PG&E's forecast? Please explain.

A 12 No. PG&E disagrees with TURN's recommendation. PG&E's estimate of $201,000 per engine module replacement was an approximate value intended to capture the overall module replacement cost at the engine level recognizing that the exact quantity and types of modules requiring replacement on each engine could not be known prior to the fourth quarter 2020 deadline for the 2023 GRC forecasts to be finalized to meet the GRC filing date.[7]

Q 13 How was the $201,000 per engine module replacement derived?

A 13 It was derived from a review of the historical recorded costs and anticipation of increased module replacements in the 2023 GRC period as the engines get further into their operating life.[8]

Q 14 For forecasting engine module replacements, is it appropriate to look solely at historical expenditures to inform forecast costs in the 2023 GRC?

A 14 No. There are 3 different types of emission modules that are used in each engine: SCR Catalyst for NOx reduction, Ammonia Slip Catalyst to reduce the residual ammonia emissions, and Oxidation Catalyst for CO reduction. Each module type has its own life cycle, and the life cycle varies based on the engine's operating profile (operating history). Therefore, there is variability in the scope of the module replacement from engine to engine and year to year. The exact scope for the year on a given engine can't be known in advance. This creates a challenge in solely relying on historical costs to forecast going forward.[9]

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5 TURN-14, p. 55, lines 7-9.

6 TURN-14, p. 55, lines 10-11.

7 PG&E's response to Data Request TURN_130-Q004 (d), dated 3/7/22 in Appendix A, at the end of this exhibit.

8 PG&E's response to Data Request TURN_130-Q004 (d), dated 3/7/22 in Appendix A, at the end of this exhibit.

9 PG&E's response to Data Request TURN_130-Q004 (a), dated 3/7/22 in Appendix A, at the end of this exhibit.

Q 15 Is TURN's position that actual historical costs have been lower accurate?

A 15 No, as TURN states in their testimony, "PG&E's actual costs per module is 2-3 times greater than PG&E's forecast cost in the 2020 GRC" and "from the actual cost data from 2018-2021 provided by PG&E, the average cost (in 2021 $) is about $168k per module".[10] Although this is slightly lower than, the $201,000 per module cost PG&E used to derive its forecast, TURN's estimate doesn't take into consideration the types of modules where the average cost per module varied from $130,000 per module to $237,000 per module in the 2018-2021 time period.[11]

Q 16 What are the reasons for variability in actual per module cost for the different module types?

A 16 Accessibility of the specific module (i.e., the amount of time/labor it takes to remove the old module and reinstall the new module) and varying material costs (non-escalation) depending on the module type cause the costs to vary year to year. PG&E took these into consideration when using it's $201,000 per module replacement forecast.

Q 17 Is the timing or decision for a module replacement discretionary?

A 17 No, the timing of the module replacements is not discretionary. The modules must be replaced as inspection and monitoring dictates through the course of the year to maintain compliance with the air quality permit. If this project is not adequately funded annually, PG&E would have to limit the production at HBGS putting customer reliability at risk so it will not exceed the air quality emissions requirements.[12]

2. Fossil Emergent Capital Work (2S)

Q 18 Briefly, what is the scope of Fossil Emergent Capital Work?

A 18 Fossil Emergent Capital Work forecasts the anticipated reliability expenditures that will be needed in future years to maintain reliable operations of Gateway, Colusa, and Humboldt Bay Generating Stations. These costs capture equipment replacement that will be needed outside of

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10 TURN-14, p. 68, lines 14-15.

11 TURN-14, p. 68, lines 5-7.

12 PG&E's response to Data Request TURN_130-Q004 (e), dated 3/7/22 in Appendix A, at the end of this exhibit.

the equipment covered in the LTSA. This includes station service and ancillary system equipment which are necessary for the operations of the plants.[13]

Q 19 Which parties commented on the Fossil Emergent Capital Work replacement project?

A 19 TURN was the only party to address this project.

Q 20 What is TURN's recommendation?

A 20 TURN proposes removing the capital forecast for this project under MWC 2S as shown in Table 5-4 and establishing a memorandum account.[14]

TURN further states that if the Commission decides to approve any of PG&E's requested capital expenditures for the Fossil Emergent Capital Work project, then this approval should be recovered through a one-way balancing account with expenditures that exceed the approved amounts being tracked in a Memorandum Account.[15]

Q 21 What is the basis for TURN's proposed reduction?

A 21 TURN asserts that PG&E has no basis for this forecast other than relying on historical expenditures and PG&E was unable to provide the calculations that it used to derive the forecast or demonstrate that its past forecasts for this project were correct.[16]

Q 22 Do you agree with TURN recommendations for removing PG&E's capital forecast for this project? Please explain.

A 22 No. PG&E disagrees with TURN's recommendation. Fossil emergent capital work is used to estimate reliability costs in the outer years so that the MWC 2S forecast is consistent with historical expenditures. The forecast for Fossil Emergent Capital Work ensures reasonable funding for expected capital work in MWC 2S in the outer years of the rate case, when identifying

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13 Exhibit (PG&E-5) (Feb. 28, 2022), WP 5-85.

14 TURN-14, p. 8, lines 20-24.

15 TURN-14, p. 72, lines 8-14.

16 TURN-14, p. 8, lines 14-19.

the specific components/equipment that will likely fail becomes less predictable.[17]

Q 23 What types of projects are MWC 2S intended to capture?

A 23 MWC 2S is primarily used to capture equipment replacement projects to maintain the reliability of the natural gas plants.

Q 24 Are specific projects identified in the capital GRC forecast under MWC 2S?

A 24 Yes. Excluding the capital emergent work project, there are 29 projects forecasted in MWC 2S. 25 of these projects are specific projects with forecast dollars in 2021-2023 and 4 are forecast for 2024-2026.

Q 25 Why are there only 4 projects identified in 2024-2026?

A 25 The 2023 GRC forecast was finalized during the fourth quarter 2020. It is very difficult to predict specific reliability projects related to the balance of plant and ancillary systems with a high level of accuracy. Therefore, the fossil capital emergent work project is used to capture the reliability projects that can't be identified with certainty at the time of the 2023 GRC forecast.

Q 26 Does PG&E expect the cost of the reliability projects for the natural gas plants to decrease over time?

A 26 No. PG&E expects reliability project costs, at a minimum, to be consistent with past expenditures and likely to go up over time.

Q 27 What leads PG&E to believe that the reliability projects will be consistent or higher than compared to historical spend in MWC 2S in years 2024-2026 where fewer specific projects are identified.

A 27 There are two primary reasons:

1) The natural gas plants are moving much further into their 30-year life. On average, the plants will nearly reach 50 percent (15 years) of their life cycle at the end of 2023. PG&E expects that equipment will need to be replaced at increased rates as various equipment reaches end of life, to keep the plant reliable and minimize forced outages as it gets further into its life cycle.
2) Plant operations have changed significantly from the original design to meet changing market conditions where plants need to be ramped up and ramped down quickly. The plants were originally designed for base

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17 Exhibit (PG&E-5) (Feb. 28, 2022), WP 5-85.

load operations and have been experiencing higher levels of cycling for most of their lives.

Q 28 Are there any specific examples PG&E can provide where increased cycling of the plants has increased reliability expenditures under MWC 2S.

A 28 Yes. Cracked bypass valves at Colusa were discovered in 2021 and will be replaced in 2022. A cracked block valve was discovered on the heat recovery steam generator (HRSG) at Gateway and was replaced in 2021. The valve body cracks in both situations were emergent issues, resulted from plant cycling, and were unable to be repaired, resulting in the need for a capital project. Additionally, cracked steam turbine check and stop valves were discovered during the 2022 Gateway outage which will be replaced in 2023. The cost for replacement of these valves (including purchasing of spare valves) will be approximately $3 million representing a substantial percentage of the overall forecast for MWC 2S for any given year. This does not include several other isolation or bypass valves that have been replaced in the 2019 and 2021 timeframe most of which were not specifically forecast in the 2020 GRC.

Q 29 Does PG&E anticipate additional valve replacements?

A 29 Yes. PG&E expects more emergent valve replacements over the next rate case period as well as the need to procure spare valves to minimize outage time when replacements are required. PG&E leverages its high energy piping inspection program to identify higher risk areas and replace these valves when inspection results warrant it. However, as can be seen in the MWC 2S forecast, there are very few valve replacements projects identified. PG&E anticipates more valve replacements projects to be identified in 2024-2026 as the plants continue to experience high levels of cycling.

Q 30 Does PG&E believe the capital emergent work project forecast for years 2024-2026 is reasonable?

A 30 Yes. When evaluating the reasonableness of Fossil Emergent Capital Work under MWC 2S, it's important that it is reviewed as part of the overall forecast for MWC 2S which is intended to capture all fossil capital reliability projects. The forecast for "Fossil Emergent Capital Work" ensures a reasonable forecast for expected capital work in MWC 2S is reflected in the outer years of the rate case, when identifying the specific components/equipment that will likely fail becomes less predictable.[18] This is a very reasonable way to forecast reliability projects in the outer years when there is uncertainty in the specific component or equipment that will require replacement such as isolation and bypass valves that have been experiencing fatigue and cracking from cycling.

Q 31 What has PG&E provided to show reasonableness of its forecast for MWC 2S for years 2024-2026?

A 31 In PG&E's response to TURN data request 130-Q005, PG&E provided an analysis comparing the 2021-2026 forecast for MWC 2S with actual expenditures from 2016- 2020. The average annual forecast in 2024-2026 for MWC 2S is less than the average annual recorded expenditures in the 2016-2020 timeframe when compared in 2020 dollars. The average annual forecast in 2024-2026 for MWC 2S is also less than the average total annual forecast expenditures in the 2021-2023 timeframe when compared in 2020 dollars.[19] It is reasonable to expect the average annual reliability expenditure forecast in 2024-2026 for 2S to be relatively consistent with historical annual recorded expenditures as well as forecasted annual expenditures for the 2021-2023 timeframe for this MWC.[20]

Q 32 Does PG&E agree with TURN's recommendation for establishing a memorandum account?

A 32 No. Establishing a memorandum account for natural gas plant reliability work is unnecessary and redundant. The sole purpose of a memorandum account is to address the prohibition of retroactive ratemaking. Memorandum accounts are necessary when a utility is unable to develop a forecast or when a utility has not made a forecast available for review by parties pursuant to proper procedures. PG&E has provided a reasonable forecast for MWC 2S which is setup to capture reliability costs for the natural gas plants. A reasonableness review of reliability expenditures can already

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18 PG&E's response to Data Request TURN_130-Q005, dated 3/7/22 in Appendix A, at the end of this exhibit.

19 PG&E's response to Data Request TURN_130-Q005Atch05, dated 3/7/22 in Appendix A, at the end of this exhibit.

20 PG&E's response to Data Request TURN_ 130-Q005, dated 3/7/22 in Appendix A, at the end of this exhibit.

be done by reviewing historical spend on MWC 2S where forecasted reliability costs are consistent with historical for the MWC. Although all reliability projects under MWC 2S cannot be identified in years 2024-2026 at the time the forecast was developed for the 2023 GRC, it is reasonable to expect reliability costs to be consistent with 2021-2023 where individual reliability projects are identified as well as historical costs under 2S which is made up of individual reliability projects.

Q 33 Does PG&E discuss the financial implications of establishing new memorandum accounts elsewhere in its testimony?

A 33 Yes. PG&E discusses the financial implications of establishing new memorandum accounts in Exhibit (PG&E-14), Chapter 3.

3. Gateway Evaporative Cooling Project (2S)

Q 34 Briefly, what is the scope of the Gateway Evaporative Cooling Project?

A 34 The Gateway Evaporative Cooling project provides a power output and efficiency increase when there is high ambient temperatures and low relative humidity. The system will cool the combustion turbine compressor intake air through humidification, raising relative humidity and lowering the inlet temperature. Inlet air cooling increases the air mass flow rate and compressor functionality, resulting in higher turbine output power and efficiency. This will benefit customers during hot, dry months, typically summer.[21]

Q 35 Which parties commented on this project?

A 35 TURN and JCCA were the only parties who commented on this project.

Q 36 What is TURN's recommendation?

A 36 TURN proposes a removal of the 2021-2023 capital forecast for this project as provided in Table 5-4 and recommends a memorandum account be established. Additionally, TURN recommends that PG&E should not be allowed to bring forth generation projects in its GRC that have not been vetted through the Commission's Integrated Resource Planning (IRP) process. TURN would require PG&E to get approval for generation projects in the IRP before new capacity is built and included in GRC.[22]

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21 Exhibit (PG&E-5) (Feb. 28, 2022), WP 5-87.

22 TURN-14, p. 7, line 21 through p. 8, line 3.

Q 37 What is the basis for TURN proposed for removal of the forecast for this project?

A 37 TURN objects to the project, asserting that PG&E has not provided a cost-effectiveness analysis to justify the Evaporative Cooling project at Gateway Generating Station and that the project will not be online until 2024, which is after the Test Year.[23]

Q 38 Do you agree with TURN recommendations for removing PG&E's forecast for this project? Please explain.

A 38 Yes. PG&E agrees with TURN's recommendation to remove the forecast because the project has been determined to be cost prohibitive based on preliminary engineering studies received after the GRC filing showing that extensive foundation work would be required to implement the project. Seismic standards have changed and are more stringent than they were when the plant was constructed. To install this technology, the combustion turbine foundations would have to be rebuilt to comply with current seismic standard.

Q 39 Will a memorandum account be necessary now that PG&E is withdrawing this project from its forecast?

A 39 No. Additionally, memorandum accounts are necessary when a utility is unable to develop a forecast or when a utility has not made a forecast available for review by parties pursuant to proper procedures. PG&E had provided a reasonable forecast for this work.

Q 40 Does PG&E discuss the financial implications of establishing new memorandum accounts elsewhere in its testimony?

A 40 Yes. PG&E discusses the financial implications of establishing new memorandum accounts in Exhibit (PG&E-14), Chapter 3.

Q 41 What is the basis for TURN proposal that PG&E be required to get approval for generation projects in the Commission's established IRP process before new capacity projects are included in the GRC for cost recovery.

A 41 TURN argues that it was not appropriate for PG&E to include the Gateway Evaporative cooling project and Helms Capacity uprate projects in the 2023 GRC for rate recovery before obtaining approval through the

[23] TURN-14, p. 54, line 29 to p. 55, line 2.

Commission's established IRP process and it is unreasonable for PG&E to include in rates the capital costs of projects that may not ultimately be found to be reasonable by the Commission in the IRP or other resource planning proceedings.[24]

Q 42 Do you agree with TURN's recommendation for PG&E should not be allowed to bring forth generation projects for new capacity in its GRC that have not been vetted through the Commission's Integrated Resource Planning (IRP) process?

A 42 This recommendation is addressed in Exhibit 18 Chapter 4 under the Helms Uprate Capacity project.

Q 43 What is JCCA's recommendation?

A 43 JCCA recommend that (1) the revenue requirement of the Gateway plant be split into two components, with the proportion of the plant's overall capacity related to the efficiency upgrades from this project (3.1 percent) be separated from the rest of the Gateway revenue requirement.[25]

Q 44 What is the basis for JCCA's proposed change in revenue requirement ?

A 44 The basis of JCCA's proposed change in revenue requirement is the assertion that this evaporative cooling project represents a new commitment at Gateway on behalf of bundled customers.[26] Additionally, JCCA asserts that the project requires Commission approval and PG&E did not obtain approval for these specific enhancements at Gateway for which PG&E is requesting cost recovery in this proceeding.[27]

Q 45 Do you agree with JCCA's recommendation to change the Gateway revenue requirement methodology? Please explain.

A 45 No. The 17 MW output increase from this project does not actually increase the nameplate capacity of the plant. In other words, it does not provide an additional 17 MW of output on top of the current capacity of the plant. The

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24 TURN-14, p. 65, line 26 to p. 66, line 7.

25 JCCA, p. ii. lines 9-13.

26 JCCA-01, p. 11., lines 21-22.

27 JCCA-01, p. 24., lines 15-17.

project decreases curtailments by allowing the turbine to operate during high ambient temperature periods when it would be otherwise restricted.[28]

Q 46 How does JCCA arrive at the 3.1 percent that should be separated from the rest of the Gateway revenue requirement?

A 46 JCCA takes 17 MW divided by what they surmise is the new total capacity, 547 MW, to derive the 3.1 percent.[29]

Q 47 Is this methodology reasonable for splitting the revenue requirement at Gateway as a result of the Gateway Evaporative Cooling project?

A 47 No. The project is not increasing its actual capacity above 530 MW by 17 MW as JCCA contends. Rather, as a result of the projects, PG&E would be able to operate Gateway with less restrictions during high ambient temperature periods.

Q 48 What was the justification for PG&E including this project in the 2023 GRC proceeding for cost recovery?

A 48 The CPUC Order Instituting Rulemaking (OIR) 20-11-003 which stated the following: "To develop new resources, this OIR will consider multiple options, including directing each investor-owned utility (IOU) to develop new supply-side resources to the extent they can be brought online in 2021 and to bring additional capacity online by procuring incremental capacity from the existing resources, implementing efficiency upgrades to existing generators, and retrofitting existing generators that are set to retire, such as Once-Through-Cooling (OTC) generators." The installation of evaporative cooling was one of the ways PG&E identified for achieving the near-term capacity increase.[30]

Q 49 Why does JCCA assert that this project requires specific approval from the Commission?

A 49 JCCA references D.21-02-028, which authorizes the IOUs to seek approval for certain procurement, including procurement of incremental capacity from existing power plants through efficiency upgrades that met the requirements

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28 PG&E's response to Data Request TURN_104-Q008 (a), dated 2/14/22 in Appendix A, at the end of this exhibit.

29 JCCA-01, p. 6, lines 3-7, fn. 11.

30 PG&E's response to Data Request TURN_104-Q008 (c), dated 2/14/22 in Appendix A, at the end of this exhibit.

set forth in that decision and PG&E did not seek approval from the Commission to request recovery for this proceeding.[31]

Q 50 Why did PG&E not seek approval from the Commission prior to including this project in the 2023 GRC forecast?

A 50 The project does not qualify as an incremental capacity increase and therefore did not require explicit approval for the project before the project could be considered in the 2023 GRC forecast. PG&E was also attempting to be responsive to OIR 20-11-003 as a result of the summer of 2020 when California experienced several high heat days that negatively impacted the State's overall energy supply.

4. Long Term Service Agreement (LTSA) (MWC KL)

Q 51 Briefly, what is the scope of the LTSA?

A 51 LTSAs are commonly used in the industry to provide high reliability and efficiency for combined cycle power plants. The LTSAs provide an effective cost and risk control measure for the major planned and unplanned maintenance activities at Gateway and Colusa Generating Stations. The LTSAs cover all the planned maintenance costs for the combustion turbines and steam turbines and include all inspections, maintenance, replacements and/or repairs due to wear and tear. General Electric performs planned maintenance inspections and repairs over the term of the LTSAs.[32]

Q 52 Which parties commented on the LTSA?

A 52 TURN was the only party to address the LTSA.

Q 53 What is TURN's recommendation?

A 53 TURN does not object to giving PG&E the flexibility to adjust the amortization of milestone payments. However, TURN believes that both upward and downward adjustments in the amortization of the milestone payments should occur consistent with the actual performance of the combined cycle units. TURN also recommends that PG&E submit reports to the Commission and other interested parties showing the factors that affect

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[31] JCCA-01, p. 24, lines 13-17.

[32] Exhibit (PG&E-5) (Feb. 28, 2022), p. 5-49.

the timing of the LTSA outages and LTSA milestone payments as well as the derivation of the amortization of the LTSA milestone payments.[33]

Q 54 What is the basis for TURN's proposal?

A 54 In its opening testimony, PG&E requested that the Commission authorize PG&E to adjust on a prospective basis the schedule for amortization of milestone payments so that PG&E can true-up its recovery of milestone payments in the next GRC. PG&E had only requested amortization adjustments when the natural gas plants are operated more than expected.[34] TURN also recommends that PG&E submit reports to the Commission and other interested parties showing the factors that affect the timing of the LTSA outages and LTSA milestone payments (e.g., starts, stops, and hours of operation) as well as the derivation of the amortization of the LTSA milestone payments. TURN claims that this will ensure that PG&E is appropriately adjusting amortization if actual operation differs from forecasted operation of the gas units.[35]

Q 55 Does TURN's proposal change PG&E's forecast for the LTSA in this GRC?

A 55 No.

Q 56 Do you agree with TURN recommendations related to the LTSA amortization? Please explain.

A 56 Yes. PG&E agrees with TURN's recommendations. After a review of the current method for amortizing milestone payments, decrease and increases of milestone payments as a result of changes in outage timing (and milestone payments) is already taken into consideration. Whether a milestone payment may become due earlier or later than PG&E forecasts in the GRC as a result of a plant being dispatched less or more frequently, the amortization of milestone payments in the next GRC are adjusted up or down. For example, in the 2020 GRC, milestone payments were adjusted down as a result of outage timing forecast to be later than anticipated in the 2017 GRC.

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33 TURN-14, p. 73, lines 13-21.

34 TURN-14, p.72, line 27 to p. 73, line 3.

35 TURN-14, p. 73, lines 17-22.

Q 57 Do you agree with TURN recommendations for PG&E to provide LTSA reporting? Please explain.

A 57 No. PG&E already provides 17 pages of LTSA confidential workpapers that provide the methodology for all components of PG&E's LTSA forecast including amortization of milestone payments as well as the derivation of the amortization of the LTSA milestone payments.[36] By reviewing these workpapers, the Commission can see that that the amortization is adjusted for each rate case submission to account for the actual operation and any changes in expected outage timing. In addition, the factors that affect the timing of the outages (starts, stops, and hours of operation) are described in PG&E's testimony.[37]

D. Conclusion

Q 58 What is PG&E's recommendation for Natural Gas and Solar Operations?

A 58 For the reasons discussed above, PG&E recommends that its 2023 expense forecast in Table 5-5 and its 2020-2026 recorded and forecast capital expenditures in Table 5-6 be adopted.

Q 59 Does this conclude your rebuttal testimony?

A 59 Yes, it does.

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[36] Exhibit (PG&E-5) (Feb. 28, 2022), WP 5-25 to WP 5-41.

[37] Exhibit (PG&E-5) (Feb. 28, 2022), p. 5-50.

TABLE 5-5
PG&E'S 2020-2023 ADJUSTED RECORDED AND FORECAST EXPENSE AMOUNTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast
1	Manage Environmental Oper	AK	$2,400	$2,653	$2,724	$2,807
2	Operate Fossil Generation	KK	13,662	13,528	13,895	14,314
3	Maint Fossil Generating Equip	KL	27,785	27,208	28,002	29,543
4	Maint Fossil Bldg	KM	2,238	2,878	2,956	3,045
5	Operate Alternative Gen	KQ	1,080	639	454	467
6	Maint AltGen Generating Equip	KR	1,608	1,609	1,232	1,268
7	Maint AltGen Bldg	KS	430	501	506	521
8	Operations Mgmt	OM	137	277	284	293
9	Operations Support	OS	21	–	–	–
10	Total		$49,360	$49,293	$50,054	$52,258

Note PG&E's 2020-2023 recorded and forecast expense amounts have been adjusted for errata and concessions as shown in Table 5-1 above.

TABLE 5-6
PG&E'S 2020-2026 ADJUSTED RECORDED AND FORECAST CAPITAL COSTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast	2024 Adj. Forecast	2025 Adj. Forecast	2026 Adj. Forecast
1	Office Furniture and Equipment	03	–	–	–	–	–	–	–
2	Tools and Equipment	05	$153	$382	$389	$397	$405	$414	$423
3	Instl/Rpl for Fossil Safety&Reg	2R	454	–	–	–	–	–	–
4	Instal/Repl Fossil Generating Eqp	2S	12,480	8,756	4,175	3,640	7,929	8,568	6,196
5	Instl/Repl Fosl Bldg/GrndInfrst	2T	2,331	200	100	1,578	110	–	–
6	Instl/Rpl for AltGen Safty&Reg	3A	–	6	6	7	7	7	7
7	Instal/Repl AltGen GneratngEqp	3B	557	688	700	714	730	745	760
8	Construct New Alternative Gen	3D	–	–	–	–	–	–	–
9	Total		$15,975	$10,033	$5,370	$6,336	$9,181	$9,734	$7,386

Note: PG&E's 2020-2026 recorded and forecast capital costs have been adjusted for errata and concessions as shown in the Table 5-3.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

REBUTTAL TESTIMONY OF

CANDICE K. CHAN

ENERGY PROCUREMENT ADMINISTRATION COSTS

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
REBUTTAL TESTIMONY OF
CANDICE K. CHAN
ENERGY PROCUREMENT ADMINISTRATION COSTS

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Candice K. Chan. This testimony responds to the direct testimony of the Public Advocates Office of the California Public Utilities Commission (Cal Advocates or CA).[1] No other intervenor testimony was received regarding Energy Procurement Administration Costs. I summarize Cal Advocates' position in Section B below.

Q 2 Does Cal Advocates make recommendations concerning specific projects and programs?

A 2 Yes, Cal Advocates recommends a $918,000 reduction to the 2023 Test Year (TY) forecast of MWC CV, Acquire & Manage Gas Supply.[2]

Q 3 Do you dispute Cal Advocates' recommendation?

A 3 Yes, I address Cal Advocates' recommendation in Section C.

Q 4 Are there Major Work Categories (MWC) that Cal Advocates does not dispute or does not address?

A 4 Yes, Cal Advocates does not dispute any MWC other than MWC CV. See Tables 6-1 and 6-2 below.

Q 5 Do you have any adjustments or corrections to the forecasts as provided in the February 28, 2022, version of your initial testimony and/or workpapers?

A 5 Yes, as described in the relevant sections below, Pacific Gas and Electric Company (PG&E) is making an adjustment to its forecast for MWC CV, which is listed in Table 6-1 (expense). PG&E does not have a capital forecast for Energy Procurement Administration Costs.

Q 6 Do you have any non-forecast related adjustments or corrections to the February 28, 2022, version of your initial testimony and/or workpapers?

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[1] CA-08, pp. 23-26.

[2] CA-08, p. 26, lines 4-5.

A 6 No, PG&E does not have any non-forecast related adjustments or corrections.

B. Summary of Parties' Positions

Q 7 Please provide PG&E's current forecast and parties' recommendations.

A 7 PG&E's current forecast and the one recommendation from Cal Advocates are both set forth in Table 6-1 (expense) below.

TABLE 6-1
2023 EXPENSE FORECAST – PG&E AND PARTIES
(THOUSANDS OF NOMINAL DOLLARS)

			PG&E			Proposed Increases/ (Reductions)
Line No.	Program or MWC Description	MAT [or MWC]	Filed Forecast[a]	Errata or Forecast Adjustments[b]	2023 Adjusted Forecast	Cal Advocates
1	Administration	AB	$801	--	$801	--
2	Acq & Manage Elec Supply	CT	30,320	--	30,320	--
3	Acq & Manage Gas Supply	CV	3,130	$(685)	2,445	$(918)
4	Manage Electric Grid Ops.	CY	10,220	--	10,220	--
5	Total		$44,471	$(685)	$43,786	$(918)

Note: PG&E's 2020-2023 current recorded and forecast expense amounts for all activities included in Exhibit (PG&E-5) (February 28, 2022), Chapter 6 (adjusted for errata and concessions) as of June 13, 2022, are shown in Table 6-2 at the end of this rebuttal testimony.

(a) Reflects forecast as of February 28, 2022.

(b) Reflects errata or forecast adjustments identified after February 28, 2022.

Q 8 Does PG&E agree with Cal Advocates' recommendation?

A 8 No, PG&E does not agree with Cal Advocates' recommendation regarding MWC CV. PG&E responds to Cal Advocates' recommendation in Section C.

C. PG&E's Response to Parties' Recommendations Concerning Specific MWCs or Projects

1. Acquire and Manage Gas Supply – MWC CV

Q 9 Briefly, what is the scope of this MWC?

A 9 The scope of MWC CV includes developing and executing gas purchase and hedging plans to acquire gas supplies, pipeline, and storage services; initiating and maintaining contracts with suppliers; scheduling the receipt and delivery of natural gas supplies on pipelines and storage fields; optimizing pipeline and storage assets to balance customer demands and meet pipeline requirements; selling excess gas supply and releasing unused pipeline transportation capacity; representing PG&E in regulatory matters and preparing and filing various compliance reports.[3]

Q 10 Which parties commented on MWC CV?

A 10 Cal Advocates was the only party to address this MWC.

Q 11 What is Cal Advocates' recommendation?

A 11 Cal Advocates recommends that the Commission authorize zero dollars in ratepayer funding for the five headcount requested for implementation of PG&E's biomethane procurement program, created in accordance with California Senate Bill No. 1440, Energy: biomethane: biomethane procurement (SB 1440), and implemented through Commission Decision (D.) 22-02-025. Cal Advocates proposes a 2023 total expense funding level of $43.553 million for Energy Procurement Administration Costs, which is a $918,000 reduction to PG&E's forecast in MWC CV.[4]

Q 12 What is the basis for Cal Advocates' proposed reduction?

A 12 Cal Advocates states that hiring five headcount for implementing PG&E's biomethane procurement program is not reasonable, and the language in SB 1440 does not direct PG&E to hire five new employees. Cal Advocates

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3 Exhibit (PG&E-5), (Feb. 28, 2022) p. 6-12, lines 13-28.

4 CA-08, p. 23, Table 8-12, p. 26, lines 4-6.

proposes that PG&E should "go slow to start," utilizing lessons learned from its past procurement programs, and that PG&E should adhere to its own testimony in regard to complying with new mandates, "EPP must develop new processes, and may enact organizational changes to incorporate these new requirements into ongoing operations while minimizing increases to staffing levels."[5]

Q 13 Do you agree with Cal Advocates' basis for its proposed forecast reduction?

A 13 No, Cal Advocates bases its recommendation on: (1) a statement from a PG&E presentation in December 2019, long before the Commission established the biomethane procurement program;[6] (2) because SB 1440 did not contain "language stating that 5 new hires were necessary to carry out this task,"[7] and (3) because PG&E "has been operating sufficiently without the need for 5 new biomethane employees."[8] Each of these recommendations is addressed below.

Q 14 Did PG&E have any knowledge of the scope of the Commission's biomethane procurement mandate in December 2019?

A 14 No, at that time PG&E believed that the biomethane procurement program would be implemented gradually. PG&E first learned of the aggressive scope and schedule of the program on June 1, 2021, when Administrative Law Judge (ALJ) Bemesderfer issued a ruling directing parties to comment on an Energy Division Staff Proposal implementing a biomethane procurement program.[9] D.22-02-025 directs PG&E and the other California gas Investor-Owned Utilities (IOUs) to each implement a comprehensive biomethane procurement program with aggressive timelines and procurement targets (e.g., 3.3 percent of their 2020 bundled core customer demand by 2025 and 12.2 percent by 2030). In fact, PG&E estimates that it

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5 CA-08, p. 25, lines 12-14, p. 26, lines 4-14.

6 PG&E's *"SB 1440 Implementation"* presentation, p. 7, CPUC Technical Workshop, Dec. 6, 2019, <https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_website/content/utilities_and_industries/energy/energy_programs/gas/natural_gas_market/pgeworkshopsb1440.pdf> (as of July 2, 2022).

7 CA-08, p. 25, lines 16-17.

8 CA-08, p. 25, lines 17-18.

9 R.13-02-008, Administrative Law Judge's Ruling Directing Parties to File Comments on Phase 4A Staff Proposal and Related Questions (June 3, 2021).

will require more than five incremental headcount to implement D.22-02-025.

Q 15 Is it reasonable for Cal Advocates to expect SB 1440 to specify headcount targets for the IOUs to implement their biomethane procurement programs?

A 15 No, SB 1440 directs the CPUC "to consider additional policies to support the development and use in the state of renewable gas that reduce short-lived climate pollutants in the state."[10] It does not define the details of the program but rather provides high-level guidance to the Commission to create a biomethane procurement program. It is unreasonable for Cal Advocates to expect SB 1440 to include details such as headcount required for PG&E to implement its biomethane procurement program.

Q 16 Has PG&E been operating sufficiently without the need for five new biomethane employees prior to D.22-02-025?

A 16 Yes, PG&E had sufficient staff to perform its natural gas procurement function because, prior to D.22-02-025, there was no work related to biomethane procurement. Implementation of D.22-02-025 requires incremental staff to achieve the aggressive timeline and targets defined in D.22-02-025. PG&E's existing natural gas procurement staff (in MWC CV) is working at full capacity and cannot absorb this new work.

Q 17 Given the requirements of D.22-02-025, does PG&E need to modify its General Rate Case (GRC) request for five new headcount to implement its biomethane procurement program?

A 17 Yes, although D.22-02-025 represents a substantial increase in workload for PG&E's gas procurement function, PG&E withdraws its request for the five new headcount because D.22-02-025 provides for balancing account recovery of "program administration costs to support biomethane procurement and pilots."[11] At this time, PG&E does not require GRC funding to implement D.22-02-025.

Q 18 Do you agree with the amount ($918,000) of Cal Advocates' recommendation for reducing PG&E's forecast?

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[10] SB 1440 (2017-2018 Reg. Sess.).

[11] D.22-02-025, pp. 71-72, Ordering Paragraph 54.

A 18 No, PG&E plans to reduce its 2023 forecast by $685,000 (as shown in the workpaper supporting this exhibit), in accordance with D.22-02-025, which was issued too late to be incorporated in PG&E's February 22, 2022, forecast/testimony.

Q 19 Why is PG&E's $685,000 forecast reduction lower than Cal Advocates' $918,000 recommended forecast reduction?

A 19 PG&E's forecast reduction only pertains to its 2023 TY forecast. Cal Advocates' $918,000 proposed reduction is the sum of PG&E's 2022 forecast and its 2023 TY forecast for labor expenses associated with the five requested headcount. The $918,000 amount is a component of PG&E's $2.23 million staffing variance between 2020 recorded year (RY) expenses and the 2023 TY forecast.[12] The $2.23 million staffing variance is disclosed in PG&E's testimony.[13]

Q 20 What are the key assumptions underlying PG&E's $685,000 forecast reduction for the five headcount?

A 20 As noted in the workpaper supporting this exhibit, PG&E assumes that two headcount will be hired in 2022 (average salary $155,000), and an additional three headcount will be hired in 2023 (average salary $161,000). An April 1 hiring date is assumed for the new headcount, which is incorporated into the expense forecast.

D. Conclusion

Q 21 What is PG&E's recommendation for Energy Procurement Administration Costs?

A 21 PG&E recommends that its adjusted forecast of $43.786 million for 2023 Energy Procurement Administration Costs as shown below in Table 6-2 be adopted.

Q 22 Does this conclude your rebuttal testimony?

A 22 Yes, it does.

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12 PG&E's response to Data Request CalAdvocates_018-Q05, dated 8/23/21, 2021 and attachment CalAdvocates_018-Q05Atch02 in the Appendix, at the end of this exhibit.

13 Exhibit (PG&E-5) (Feb. 28, 2022), p. 6-4, Figure 6-1 and Table 6-3.

TABLE 6-2
PG&ES 2020-2023 ADJUSTED RECORDED AND FORECAST EXPENSE AMOUNTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MWC [or MAT]	2020 Adj. Recorded	2021 Adj. Forecast	2022 Adj. Forecast	2023 Adj. Forecast
1	Administration	AB	$678	$300	$310	$801
2	Acquire & Manage Electric Supply	CT	26,646	28,230	29,930	30,320
3	Acquire & Manage Gas Supply	CV	2,151	2,570	2,618	2,445
4	Manage Electric Grid Operations	CY	11,260	9,400	10,010	10,220
5	Total		$40,734	$40,500	$42,868	$43,786

Note PG&E’s 2020-2023 recorded and forecast expense amounts have been adjusted for errata and concessions as shown in Table 6-1 above.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ENERGY SUPPLY TECHNOLOGY PROGRAMS

THIS CHAPTER HAS NO REBUTTAL

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

REBUTTAL TESTIMONY OF

REBECCA R. DOIDGE

ENERGY SUPPLY RATEMAKING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
REBUTTAL TESTIMONY OF
REBECCA R. DOIDGE
ENERGY SUPPLY RATEMAKING

A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Rebecca R. Doidge. This testimony responds to the direct testimony of the California Public Utilities Commission (CPUC or Commission), Public Advocates Office at the California Public Utilities Commission (Cal Advocates or CA),[1] The Utility Reform Network (TURN)[2] and California Trout, Inc., Friends of the Eel River Inc., and Trout Unlimited (collectively referred to as "Cal Trout").[3] I summarize parties' positions in Section B below.

B. Summary of Issues

Q 2 Please provide a summary of parties' policy positions to which you will be responding.

A 2 This testimony responds to parties' testimony concerning PG&E's proposals to continue the decommissioning accrual for hydroelectric facilities, to continue the two-way Hydro Licensing Balancing Account (HLBA), and to establish the Helms Capacity Memorandum Account (HCMA). Each issue is discussed in Section C below.

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1 CA-15, p. 26, line 12, Table 15-7 to p. 29, line 5.

2 TURN-14, p. 11, lines 3-21; TURN-14, p. 97, lines 10-17; TURN-14, p. 101, lines 4-8; and TURN-13, p. 24, line 11 to p. 26, line 13.

3 CalTrout-01, p. 3, lines 13-22; CalTrout-02, pp. 2-7; and CalTrout-02, p. 9, lines 4-23.

Q 3 Are there ratemaking proposals that parties do not dispute or do not address?

A 3 Yes. Most of PG&E's Energy Supply ratemaking proposals are unopposed. None of the parties oppose PG&E's ratemaking proposals on the following items:

- Continue to recover the net book value associated with Diablo Canyon Power Plant (DCPP) through the Diablo Canyon Retirement Balancing Account (DCRBA) and close the DCRBA at the end of plant life;
- Continue the two-way balancing account for expense costs related to implementation of Nuclear Regulatory Commission (NRC) requirements and close the balancing account at the end of plant life;
- Modify the methodology for forecasting the proceeds from the Department of Energy litigation settlements by utilizing the amounts explicit to Nuclear Operations and Humboldt Bay Power Plant and DCPP Decommissioning;
- Continue amortization through 2025 for recovery of DCPP surplus materials inventory at end of plant life;
- Continue to levelize the costs associated with the Colusa and Gateway Generating Station major outages associated with their Long-Term Service Agreements (LTSA); and
- Additionally, none of the parties oppose the continuation of a decommissioning accrual for hydroelectric facilities, but Cal Advocates and Cal Trout have proposed changes to the supporting decommissioning estimates and related accrual.

C. PG&E's Response to Parties' Policy Positions

1. Hydro Decommissioning Accrual

Q 4 What is the first policy position you are addressing?

A 4 The first issue I will address is Cal Advocates' position on the Hydro Decommissioning Accrual.

Q 5 What are the differences between PG&E's position on Hydro Decommissioning and Cal Advocates' position?

A 5 PG&E proposes an annual accrual of $62.2[4] million for the hydro decommissioning reserve based on a high-level estimating methodology that looks at potential decommissioning costs for its small (under 30 megawatts) hydro projects. While the estimates are conceptual, PG&E used conservative assumptions in an attempt to keep the accrual request reasonable.

Cal Advocates proposes an accrual of only $23.9 million[5] for the hydro decommissioning reserve, by arguing that there should be significant reductions in the estimate for decommissioning the Battle Creek Hydroelectric Project and by increasing the number of years over which the Battle Creek decommissioning costs would be recovered.

Q 6 Do you agree with Cal Advocates' position? Please discuss.

A 6 No. First, Cal Advocates made an error in calculating the proposed reduced accrual of $23.91 million. Cal Advocates incorrectly states that PG&E forecasts $50.458 million as annual decommissioning costs for each year from 2023 to 2026 for the Battle Creek Hydroelectric facility.[6] The proposed annual accrual associated with the Battle Creek Project is $37.843[7] million. Further, Cal Advocates incorrectly calculates the annual accrual if the total Battle Creek cost were to be amortized over eight years instead of four. Using the same methodology as shown in CA's workpapers, the table below presents a corrected calculation that would result in a reduced accrual of $35.22 million.

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4 Original decommissioning accrual amount of $78.8 million annually in Exhibit (PG&E-10) (Feb. 28, 2022), WP 11-372, Table 11-58, line 14 and revised in PG&E's response to Data Request CalAdvocates_126-Q10Rev01 and attachment CalAdvocates_126-Q10Rev01Atch01, dated 1/13/22 in Appendix A, at the end of this exhibit.

5 CA-15, p. 26, Table 15-7.

6 CA-15, p. 27, lines 20-21.

7 PG&E response to Data Request CalAdvocates_126 -Q010, Rev01 dated 1/13/22 and attachment CalAdvocates_126-Q10Rev01Atch01, in Appendix A, at the end of this exhibit.

TABLE 8-1
DECOMMISSIONING ACCRUAL CALCULATION CORRECTION
(THOUSANDS OF DOLLARS)

Line No.	Description	CA workpaper[(a)]	Correction
1	Total Annual Accrual (2023-2026)	$62.176	$62.176
2	Battle Creek Annual Accrual (2023-2026)	50.458	37.843
3	Difference uncontested	11.718	24.333
4	8-year amortization for Battle Creek	12.188	10.884
5	Revised total	$23.91	$35.22

(a) CA-15-WP 6-6-2022 Tab 4. Decommissioning.

Q 7 Besides the calculation error, are there other aspects of Cal Advocates' proposal with which you disagree?

A 7 Yes. Cal Advocates proposes to use the low end cost estimate of $44 million for the base construction cost for Battle Creek decommissioning.[8] While PG&E's decommissioning estimates are not intended to presume the specific requirements that would result from the Federal Energy Regulatory Commission (FERC) process for license surrender and decommissioning, the estimate that was used for the Battle Creek project is already conservative, without including additional cost reductions. PG&E's estimate is based on the assumption that many of the project components would remain in place or be safely abandoned.

Furthermore, PG&E disagrees with the Cal Advocates proposal to collect costs for Battle Creek over eight years, as opposed to four years. The intent of the reserve is to accrue decommissioning dollars while the plant is used and useful; therefore the accrual calculation is generally based on the forecast retirement dates, rather than the earliest decommissoning start year.[9] In the case of Battle Creek, the estimated retirement year corresponds with the license expiration (2026), but for purposes of the accrual calculation, PG&E proposes to spread over the entire GRC period, or four years.[10]

8 CA-15, p. 28, line 18.

9 Exhibit (PG&E-5) (Feb. 28, 2022), p. 8-13, lines 14-18.

10 Exhibit (PG&E-10) (Feb. 28, 2022), WP 11-372, Table 11-58, line 5.

Q 8 Do other parties provide testimony on PG&E's Hydro Decommissioning proposal?

A 8 Yes. Cal Trout also provided testimony with no objection to the continued accrual into the reserve for hydro decommissioning but with assertions that PG&E's estimate for the Potter Valley Hydroelectric Project (Potter Valley) was too low and that PG&E's assumed 10-year timeframe to receive a FERC decommissioning order is too long.

Q 9 What is the basis for Cal Trout's assertion that the Potter Valley decommissioning estimate is too low?

A 9 First, Cal Trout points out that the probability factor applied to the Potter Valley decommissioning estimate should be increased from 20 percent to 100 percent, because the parties who were seeking to relicense the Potter Valley Project did not meet the application deadline with FERC. Further, Cal Trout provides an argument that PG&E's decommissioning estimate is unrealistically low because it does not include costs for removal of the two dams.

Q 10 Do you agree with Cal Trout's position on the probability of Potter Valley decommissioning? Please discuss.

A 10 Yes. At the time of PG&E's filing, a process was underway at FERC for other parties to relicense and take ownership of the project.[11] The FERC process would have ultimately dictated project transfer and potentially continued operation, so PG&E applied a 20 percent probability that PG&E would have the decommissioning liability. Since that time, the parties who were seeking to relicense Potter Valley have missed the application deadline with FERC, and FERC has ordered PG&E to provide a schedule for license surrender. Therefore, PG&E agrees that the probability factoris for Potter Valley should be increased. However, PG&E is not proposing to revise the calculation for the decommissioning accrual at this time. The decommissioning accrual is intended to be trued-up in each rate case to reflect refined estimates (including probabilities of decommissioning) and actual activity.

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[11] Exhibit (PG&E-5) (Feb. 28, 2022), p. 8-14, fn. 26.

Q 11 Do you agree with Cal Trout's argument that PG&E's estimate to decommission Potter Valley is unrealistically low because it does not include removal of the two dams? Please explain.

A 11 No. The intent of PG&E's decommissioning estimate in the GRC is to form the basis for a reasonable accrual. The estimates are based on concept-level decommissioning studies and are not intended to predetermine the actual scope of any project's ultimate decommissioning (i.e., which hydro facilities would be removed, restored, etc.). The decommissioning requirements will be determined as part of the license surrender process governed by FERC and not as part of the GRC proceeding.

In both the 2020 and 2023 GRC filings, PG&E purposefully used conservative assumptions in an effort to maintain a reasonable accrual request. PG&E will continue to refine and true up the estimates in future rate cases.

Q 12 Do you agree with Cal Trout's claim that the process with FERC to surrender the license and receive the decommissioning order for the Potter Valley Project can be accomplished in four years?[12] Please explain?

A 12 No. PG&E is not aware of any other FERC license surrender process that has been completed in only four years. However, as stated before, the decommissioning estimate does not reflect PG&E's plans for the license surrender process or decommissioning. The estimate is theoretical in nature and is intended as the basis for the reasonable accrual calculation. When PG&E proposed the establishment of the decommissioning reserve in its 2020 GRC, it developed a high-level estimating methodology based on a number of assumptions. The 10-year timeframe to complete FERC's license surrender regulatory process is one of these assumptions. This timeline serves only to provide an estimated year in which decommissioning activities would occur, so that the conceptual cost estimate can then be escalated to those years.[13] Again, the hydro decommissioning estimate does not reflect PG&E's plans relative to any specific hydro project.

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[12] CalTrout-02, p. 3, lines 14-16.

[13] Exhibit (PG&E-5) (Feb. 28, 2022), WP 8-1, lines 7 and 23, WP 8-2, lines 7 and 23, and WP 8-3, lines 7 and 23.

2. Hydro Licensing Balancing Account

Q 13 What is the next policy issue you are addressing?

A 13 The next issue I will address is TURN's proposal on the Hydro Licensing Balancing Account.

Q 14 What are the differences between PG&E's position on the HLBA and TURN's position?

A 14 First, TURN proposes that the expenditures related to FERC license requirements that flow to the HLBA should be subject to reasonableness review,[14] and they propose a couple of alternatives for achieving that purpose. The first is for the HLBA to become a one-way Balancing Account, such that, if expenditures exceed the adopted amount for projects subject to the HLBA, then the overspending will be tracked in a memorandum account, which PG&E can request review and approval of through a future application.[15] The alternative proposal suggested by TURN is a cost sharing treatment of costs whereby only 90 percent is recovered in rates (without an after-the-fact reasonableness review) and 10 percent is absorbed by PG&E's shareholders.[16]

Q 15 Do you agree with TURN's position? Please discuss.

A 15 No. The Commission authorized the two-way balancing account in PG&E's 2014 GRC,[17] determining that "a separate recovery mechanism is warranted to address the forecasting uncertainty associated with FERC Hydro Licensing and License Implementation." The Commission went further to say that "Since the balancing account will track both over and undercollections of revenue based on our adopted forecast, both ratepayers and shareholders will be made whole for any forecasting variances over time."[18] The Commission authorized continuation of the HLBA in the 2017 and 2020 GRCs.[19] Customers have benefited tremendously from the

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[14] TURN-14, p. 11, lines 3-10.

[15] TURN-14, p. 89, lines 3-5.

[16] TURN-13, p. 26, lines 2-6.

[17] Decision (D.) 14-08-032, p. 736, Ordering Paragraphs 24-27.

[18] D.14-08-032, p. 380.

[19] D.17-05-013, p. 119 and D.20-12-005, pp. 135-136.

HLBA. Since the establishment of the HLBA, PG&E refunded the over-collected December 31, 2016, balance and the over-collected December 31, 2019, balance in the HLBA to customers. TURN has not cited any reasons or evidence that the currently adopted two-way balancing account is not adequate in addressing the uncertainties impacting PG&E's forecast related to ongoing FERC relicensing activities. Establishing another rate recovery mechanism, as proposed by TURN, is unnecessary, overly burdensome, and impacts the financial health of PG&E, as discussed in detail in Exhibit (PG&E-14) Chapter 3.

Q 16 Do you agree with TURN's position that a reasonableness review is necessary for these costs? Please discuss.

A 16 No, the HLBA is beneficial, because customers only pay for actual costs, rather than the forecasted amount. Any overcollection or undercollection is trued up in the next GRC, and parties have an opportunity to review the actual amounts recorded to the account for compliance and accuracy as part of the next GRC. Moreover, the costs that are captured in the HLBA are the results of requirements from state and federal agencies; PG&E does not have an incentive to spend money on these projects unwisely. Putting at risk the cost recovery of these required expenditures is untenable. These costs are driven by regulatory requirements; thus, PG&E does not have discretion over whether to complete the projects or not. TURN's proposal that a reasonableness review be performed on each one of these projects takes time, effort and resources from the Commission, intervenors and PG&E, and there is no reason to believe that this level of scrutiny is warranted.

Q 17 Are there other arguments raised by TURN that you would like to address?

A 17 Yes. TURN also proposes that the Commission should reject without prejudice PG&E's proposed capital and expense expenditures for hydro projects that have submitted a license renewal but have yet to receive it. TURN contends that the costs are speculative, because the forecasts are "highly uncertain estimates."[20] TURN further states that if the Commission believes that it is important to consider these speculative costs in this

[20] TURN-14, p. 101, lines 4-8.

proceeding, TURN proposes that the costs be authorized and that actual capital and O&M expenses be tracked in a discrete sub-account of the one-way HLBA along with the adopted capital and O&M levels adopted in this proceeding. If actual costs exceed authorized costs, PG&E can come to the Commission in the next GRC to attempt to demonstrate the reasonableness of the actual costs and request cost recovery.[21]

Q 18 Do you agree with TURN's proposal?

A 18 No. PG&E has shown in its past GRC filings that it is able to forecast costs associated with these regulatory-related activities, but the timing of issuance of the requirements and approvals from FERC and other agencies are beyond PG&E control. This uncertainty is appropriately addressed through a two-way balancing account. Significant delays in issuance of new FERC hydro licenses have deferred the timing of incurring tens of millions of dollars in actual costs compared to adopted forecast amounts in license implementation related work. However, there is no harm to customers when PG&E's actual expenditures are delayed because the overcollection is returned to customers in the next GRC.

As noted in the Commission's decision authorizing the establishment of the HLBA, the two-way balancing account is the appropriate mechanism for these types of costs, because both ratepayers and shareholders will be made whole for any forecasting variances over time. TURN's proposal is overly complicated and unnecessary.

Continued operation of the HLBA as a two-way balancing account is beneficial to customers because (1) it ensures full funding of and compliance with regulatory-required activities that are difficult to predict but critically important; (2) to the extent that this work is delayed or costs are less than adopted, unspent funds will be returned to customers; and (3) to the extent that the cost of this work is greater than expected, the mechanism will provide a vehicle for cost recovery in the next GRC and will not affect the funding for other important work.

Q 19 Are there any other points you would like to address related to TURN's testimony on the HLBA?

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21 TURN-14, p.106, lines 4-11.

A 19 Yes. TURN proposes that the scope of the HLBA revert back to original purpose of only allowing costs associated with license conditions and that costs associated with spillway improvement be excluded. TURN asserts that "These projects are undertaken at PG&E's discretion and not because of provisions imposed as part of a hydro license."[22]

Q 20 Do you agree with this proposal?

A 20 No. In the 2020 GRC, PG&E proposed establishing a new cost category in the HLBA for emergent costs associated with new requirements that resulted from the 2017 Oroville Spillway Incident, and in D.20-12-005, the Commission authorized this new category, "because regulatory fees and work as a result of the Oroville spillway incident are necessary costs that will be incurred by PG&E"[23] These new requirements are imposed by both California Department of Water Resources, Division of Safety of Dams (DSOD) and FERC. Following the Oroville incident in 2017, PG&E was required to complete significant additional inspection work on its spillways. Mitigation plans were developed out of those inspections resulting in significant additional capital work; these mitigation plans now comprise the Spillway Assessment and Improvement Program (SAIP). This work is a mitigation to the Large Uncontrolled Water Release (LGUWR) Risk.[24]

Costs associated with the SAIP are proposed to be included in the HLBA, because, similar to activities resulting from FERC licensing processes, they are regulatory-required, take years to complete and include uncertainty as to the timing of costs. For each spillway in PG&E's portfolio, a spillway assessment and mitigation plan is developed based on a collaborative analysis process through which PG&E receives concurrence from FERC and DSOD as to the project objectives for the Probable Maximum Flood. Once the objectives are established, PG&E can develop design requirements for various alternatives to be presented to the agencies. The process to develop design alternatives, receive feedback

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22 TURN-14, p. 97, lines 16-17.

23 D.20-12-005, p. 136.

24 Exhibit (PG&E-5) (Feb. 28, 2022), p. 2-10, line 5 to p. 2-12, line 5.

from agencies, and ultimately, gain approval from both FERC and DSOD, on the appropriate mitigation solution, can take years to complete.

Beyond the long regulatory process, these spillway mitigation projects can also suffer delays during implementation, due to the remote locations and the need to control water during construction. Seasonal restrictions from both weather and environmental resources can mean that the construction window lasts for only a couple of months each year. This contributes more uncertainty to the timing of spend, because a single project can span over multiple years and can see significant unexpected delays, due to something as small as a spring snowfall event.

Contrary to TURN's assertion, these projects are not done at PG&E's discretion. Rather, they are part of a long collaborative process, the results of which are regulatory required mitigation actions, not discretionary projects.

TURN provides testimony on the changing nature of PG&E forecasts, making the point that the costs flowing through the HLBA are increasing in magnitude and continually being pushed into later years.[25] This was precisely the reason to establish the HLBA in the first place- to prepare for large costs with unpredictable timing and to prevent this uncertain timing from impacting customers. Inclusion of the spillway costs in the HLBA will ensure customers are not unduly impacted by the unpredictability of these costs. The two-way balancing account addresses the uncertainty in the cost and timing of the work associated with FERC licenses and other regulatory requirements by providing recovery only of actual costs that are incurred.

Q 21 What is the risk of not recovering these costs through the HLBA?

A 21 Revenues included in the HLBA forecast are only used to fund categories of work that are authorized there, and there is no reallocation of funds to other utility purposes. If the SAIP costs are not recovered through the HLBA, they would need to be forecasted along with other capital projects. The likely result would be that other reliability-related work would be impacted, if SAIP work was prioritized due to its regulatory compliance requirements.

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25 TURN-14, p. 89, lines 1-2.

Q 22 Are there any other issues you would like to address in TURN's testimony on the HLBA?

A 22 Yes. TURN objects to the inclusion of costs associated with license-related work from settlement agreements in the HLBA, noting that since there is no forecast in the GRC, these costs would never be subject to a reasonableness review.[26]

Q 23 Do you agree with TURN's position? Please discuss.

A 23 No. In this GRC, PG&E's proposal is merely to add a category of costs to the HLBA, such that costs incurred from license-related settlement agreements can flow to the HLBA. When the HLBA was first established, it was proposed to allow for recovery of costs associated with licenses issued on or after January 1, 2012. As PG&E described in opening testimony, the 2012 threshold date is not appropriate for the license-related settlement agreements. The settlement agreements that predate 2012 are still being implemented, and the costs associated with them should be included in the HLBA. These settlement agreements are negotiated during the long relicensing process in many instances with other agencies, such as the United States Forest Service (Forest Service). The projects and activities that are ultimately required by the settlement agreements are determined solely at the discretion of the Forest Service, and there is no required timeline by which the Forest Service must make these determinations as to scope and timing of the required projects. As a result, the implementation of the settlement agreements often takes more than a decade to complete, as is the case with the Spring Gap-Stanislaus Recreation Settlement Agreement that was developed in 2006. PG&E does not present a forecast in this GRC for activities under the Spring Gap-Stanislaus Agreement, but there are outstanding obligations in the agreement for which PG&E will need to plan in the future. Again, the timing of this is at the Forest Service's discretion.

3. Helms Capacity Memorandum Account

Q 24 What is the next policy issue you are addressing?

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[26] TURN-13, p. 26, lines 7-13.

A 24 The next issue I will address is TURN's position on the Helms Capacity Memorandum Account (HCMA).

Q 25 What are the differences between PG&E's position on the HCMA and TURN's position?

A 25 PG&E proposes to establish the HCMA to record costs in connection with the uprate of the three existing units at Helms Pumped Storage Facility (Helms). The project is still in preliminary phases of analysis, but the Helms Uprate has an expected-case scenario of 1 unit coming online in 2027, 1 unit in 2028, and 1 unit in 2029.[27] TURN alleges that it is premature to establish a memorandum account for this project, because PG&E has not yet identified the scope and schedule and that there are regulatory processes which have not yet begun. TURN points to PG&E discovery response on schedule of the project that the units would not be online during the GRC period.

Q 26 Do you agree with TURN's position? Please discuss.

A 26 No. PG&E has not yet developed a detailed scope, schedule and forecast for this unique project but is evaluating alternatives in response to the CPUC's identified need for incremental long duration storage. To achieve online dates in 2027 through 2029 for the three units,[28] work on the uprate project will occur in the 2024-2026 time period. While the uprated units may not be operational until 2027 or beyond, without the memorandum account, PG&E doesn't have the opportunity to request recovery of costs for this project through a future application. TURN even points out that establishment of the HCMA "does not obligate ratepayers to bear the costs of PG&E's efforts".[29]

Q 27 What is TURNs other reason for opposing the HCMA?

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27 PG&E response to Data Request TURN_130-Q018, e), dated 3/7/22 in Appendix A, at the end of this exhibit.

28 PG&E response to Data Request TURN_130-Q018 (e), dated 3/7/22 in Appendix A at the end of this exhibit.

29 TURN-14, p. 41, lines 3-5.

A 27 TURN states that because PG&E cannot provide examples of memorandum accounts being established for other generation projects before a cost estimate is established that a memorandum account is not necessary.[30]

Q 28 Do you agree?

A 28 No. A memorandum account is typically merely a placeholder for recording costs that may or may not ultimately be recoverable in rates. The sole purpose of a memorandum account is to address the prohibition of retroactive ratemaking. Memorandum accounts are necessary when a utility is unable to develop a forecast or when a utility has not made a forecast available for review by parties pursuant to proper procedures.

Q 29 What is retroactive ratemaking?

A 29 It is a well-established tenet of the Commission that ratemaking is done on a prospective basis. The Commission's practice is not to authorize increased utility rates to account for previously incurred expenses, unless, before the utility incurs those expenses, the Commission has authorized the utility to book those expenses into a memorandum or balancing account for possible future recovery in rates.

Q 30 Would establishing the memorandum account harm customers?

A 30 No. PG&E is proposing a memorandum account in order to preserve the opportunity for PG&E to request recovery of these costs at a future date through an application with the Commission. PG&E would not include amounts recorded in the account in rates unless and until the Commission approved recovery through that future application.

D. Conclusion

Q 31 Does this conclude your rebuttal testimony?

A 31 Yes, it does.

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30 TURN-14, p. 41, lines 10-15.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

REBUTTAL TESTIMONY OF

GREG RYBKA

UTILITY OWNED GENERATION RE-VINTAGING FOR PURPOSES OF POWER CHARGE INDIFFERENCE ADJUSTMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
REBUTTAL TESTIMONY OF
GREG RYBKA
UTILITY OWNED GENERATION RE-VINTAGING FOR PURPOSES OF POWER CHARGE INDIFFERENCE ADJUSTMENT

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A. Introduction

Q 1 Please state your name and the purpose of this rebuttal testimony.

A 1 My name is Greg Rybka. This rebuttal testimony responds to the direct testimony of the Joint Community Choice Aggregators (JCCA). I summarize the JCCA's position in Section B below.

B. Summary of Issues

Q 2 Please provide a summary of the JCCA's testimony to which you will be responding.

A 2 This rebuttal testimony responds to the JCCA's testimony concerning cost recovery of PG&E's utility-owned generation (UOG) revenue requirement from both bundled service and departing load (i.e., unbundled) customers. The JCCA proposes a general framework for re-vintaging UOG assets, which would be applied in PG&E's General Rate Case (GRC) to determine the generation revenue requirement used to calculate the Power Charge Indifference Adjustment (PCIA) rate in Energy Resource Recovery Account (ERRA) forecast proceedings.[1] This testimony also responds to the JCCA's proposal to establish a separate revenue requirement for the cost of the incremental capacity and/or energy related efficiency upgrades at PG&E's Gateway Generating Station and assign a 2023 PCIA resource vintage to that revenue requirement for purposes of determining PCIA rates in the next ERRA forecast proceeding.[2] Finally, this testimony responds to the JCCA's re-vintaging proposal for hydroelectric facilities, which is based on the GRC

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1 See generally, JCCA-01.

2 *Id.*, pp. 23-28.

test year in which PG&E proposed in a depreciation study to extend the lives of those assets for accounting purposes.[3]

C. PG&E's Response to the JCCA's Position

1. General Vintaging Framework

Q 3 What is the first position PG&E is addressing?

A 3 PG&E first addresses the general framework the JCCA proposes to be applied in future GRCs to allocate cost of ongoing investments in UOG between bundled service and departing load customers.

Q 4 Please describe the JCCA's proposed framework for re-vintaging UOG assets for purposes of the PCIA cost recovery mechanism?

A 4 The JCCA proposes a PCIA resource re-vintaging framework that:

- Step 1: Defines the end of operating life for all UOG facilities
- Step 2: Identifies whether any new commitments made in a GRC trigger reconsideration of that facility's PCIA resource vintage assignment – either for the full facility or portions thereof.

With regard to Step 2, the JCCA's assert that an existing UOG facility must be re-vintaged when the utility makes a new commitment that constitutes a significant overhaul of a facility, defined as:

1) A change in the underlying purpose or use of a facility for the benefit of bundled service customers (e.g., baseload plant modified to serve more targeted peaking or ramping needs).
2) A significant capacity addition to the facility's original committed capacity for the benefit of bundled service customers.
3) An extension in the expected operating life of a facility.[4]

Q 5 What is PG&E's overall position on the proposal for the Commission to adopt a general framework for application in future GRCs?

A 5 PG&E agrees with the Commission's well-established and existing framework and well-supported findings on PCIA resource vintaging. In Decision (D.) 18-10-019, the Commission found that any analysis of plant investments to justify a different vintage treatment for those investments than for the underlying facility "must be fact-specific to the plants and

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[3] *Id.*, pp. 33-44.

[4] *Id.*, pp. 46-47.

spending in question and is better suited to a GRC evaluating such spending."[5] The Commission has already determined that investments (e.g., commitments) should be reviewed on a *case-by-case* basis when specific capital investments are proposed for a facility. A pre-determination using a general framework as the JCCA propose is unwarranted and could result in cost shifting, especially when such investments benefit both bundled service and departing load customers.

Q 6 Why does the Commission's determination make sense?

A 6 Investments needed to operate power plants vary significantly depending on the plants' characteristics, e.g., technology-type, age, condition, design, geographical location, interconnection point, environmental conditions, regulatory restrictions. The investments required to continue to safely and reliably operate and maintain PG&E's portfolio of power plants requires regular assessment as a result of changing needs and conditions. To maintain the principles of cost causation and customer indifference, each investment must be assessed individually to fairly allocate the costs according to the drivers. A pre-determined framework for making such determinations such as that proposed by JCCA is likely to lead to instances of cost allocations that are not just and reasonable.

Q 7 Does PG&E agree with the JCCA's underlying assumption that departing load customers do not benefit from capital investments or the extension of operating life for UOG facilities?

A 7 PG&E does not agree; there is no merit to this assumption. Numerous benefits result from capital investments in or extending the operating life of UOG facilities. Examples include: reliability in locally (e.g., transmission constrained) areas, local reliability if natural gas access is limited, reliability during Public Safety Power Shutoff (PSPS) events, voltage support, and black-start capability. Specific examples are provided in Section C.3 below.

2. Evaporative Cooling Project at Gateway Generating Station

Q 8 What is the second position PG&E is addressing?

A 8 Second, PG&E addresses the JCCA's proposal related to the evaporative cooling project at the Gateway Generating Station.

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5 D.18-10-019, p. 135.

Q 9 What is PG&E's position?

A 9 Based on its review of additional engineering studies indicating that installation of the evaporative coolers would require both gas turbine foundations to be completely rebuilt to meet new seismic standards, PG&E will not be moving forward with the evaporative cooling project at Gateway Generating Station during the record period for this proceeding. As such, PG&E will remove this project from its forecast in this GRC.

Q 10 Is the JCCA's position regarding the evaporative cooling project at Gateway Generating Station relevant in that context?

A 10 No, given that PG&E does not plan to move ahead with the project and will remove it from the GRC forecast, the JCCA's proposal is no longer relevant. This is further addressed in Chapter 5, Section C.3.

Q 11 Assuming PG&E still planned to implement the project, does PG&E agree with the JCCA that the project would only have benefitted bundled service customers and, thus, would require a PCIA resource re-vintaging?

A 11 No, PG&E does not agree. Implementing the project would have benefited all customers – both bundled service and departing load customers. The project would be providing system reliability benefits, especially during times of high demand conditions. Gateway Generating Station would have been able to provide an additional 17 MW at times where it would have otherwise been derated due to high ambient temperatures and low relative humidity.[6] High ambient temperatures correlate with high load and thus are at times when reliability is most likely to be compromised.[7] PG&E notes that Rulemaking 20-11-003 directed the IOUs to take actions on behalf of all customers—both bundled service and departing load customers—to prepare for potential extreme weather in the summers of 2021, 2022, and 2023. These actions could have included efficiency upgrades to UOG facilities, among other things. PG&E reiterates its position in Section C.1 that investments (e.g., commitments) must be reviewed on a *case-by-case* basis when specific capital investments are proposed for a facility. In other words, implementation of investments, whether at the Gateway Generating Station

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6 PG&E response GRC-2023-PhI_DR_JointCCAs_008-Q19, dated 1/3/22 in Appendix A, at the end of this exhibit.

7 *Ibid.*

or another facility, results in increased system reliability, benefits all customers, and/or meets the directives of the Commission to take certain actions on behalf of all customers, a PCIA resource re-vintaging is without merit.

Q 12 Are the JCCAs correct in arguing that since cost allocation mechanism (CAM) cost recovery was not proposed by PG&E that departing load customers do not benefit from the proposed proect?

A 12 No. The costs and benefits of the project would continue to be borne by bundled service and departing load customers within the PCIA cost recovery mechanism using the current PCIA resource vintage.

3. Re-Vintaging Hydroelectric Facilities with Extended Lives

Q 13 What is the third position PG&E is addressing?

A 13 Lastly, PG&E addresses the JCCA's position that the Commission should re-vintage hydroelectric facilities for which PG&E is pursuing relicensing.[8]

Q 14 What is PG&E's position?

A 14 PG&E believes the legacy UOG vintage should be retained for its hydroelectric facilities for as long as these facilities continue operating. Extending the lives of these hydroelectric facilities benefits all customers. Notably, the majority of these facilities are in local (e.g., transmission constrained) areas such that continued operation provides system and local reliability benefits, especially for departing load customers that make up the majority of customers in PG&E's service territory. The reliability benefits are one of the value streams (along with energy, ancillary service, and environmental attributes) that continue as a result of extending the life of PG&E's hydroelectric facilities. The Portfolio Allocation Balancing Account (PABA), used in PCIA cost recovery, fairly allocates both costs and revenues from these facilities. Further, the PCIA can be a net credit received by departing load customers, if utility portfolios provide a positive net market value as demonstrated through actual recorded market transactions and realized revenue.

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8 JCCA-01, p. 5.

Q 15 How does PG&E assess whether to extend and/or relicense a hydroelectric facility?

A 15 PG&E assesses whether to relicense a hydroelectric facility based on the specific facility's economics along with other factors. The economics are assessed based on the net present value of the ongoing capital investments and operating expenses along with the forecasted market revenues. It is important to note that such an analysis determines whether the facility is economic overall and not whether it is economic solely for the benefit of bundled service customers. That is, the analysis does not consider bundled service customers compliance or energy needs. Moreover, a variety of other factors that are difficult to quantify are also taken into consideration, many of which benefit all customers, including departing load customers. Some of those factors are local area reliability, local reliability if natural gas access is limited, reliability during PSPS events, voltage support, black-start capability, fulfillment of water rights, and recreational use.

Q 16 Are there specific examples of UOG facilities that benefit both bundled service and departing load customers?

A 16 Yes. Hydroelectric facilities and non-hydroelectric facilities offer such benefits. For example, Humboldt Bay Generating Station (HBGS) generators are critical for electric reliability in the Humboldt area. During high customer natural gas demand or unavailability of the gas transmission line feeding the Humboldt area, HBGS's natural gas use is curtailed requiring the facility to transfer to distillate fuel to generate electricity and support local reliability. Likewise, during high customer electrical demand or unavailability of electric transmission import capability feeding the Humboldt area, the highly-flexible HBGS is available to support the Humboldt area electrical needs (electrical demand and voltage support). It is important to note that Redwood Coast Energy Authority is the community choice aggregator program serving customers in the Humboldt area. To assert that departing load customers do not benefit from UOG facilities is based upon flawed logic. Additional examples of UOG facilities that provide benefits to all customers the Lower Pit River and Upper Pit River watersheds that provide high voltage support and control and the Caribou 1 and 2 powerhouses that provide resiliency and support of local load during islanding conditions (e.g., during PSPS events). PG&E has also designated 12 hydroelectric resources as Black-Start Resources and there are additional hydroelectric units that have this capability. Lastly, the Helms Pumped Hydroelectric Storage facility has 2,100 MW of flexibility spanning from 1,200 MW in the generation mode to 900 MW of pumping demand. This flexibility 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. These are just a few examples of UOG facilities within PG&E's portfolio offering a variety of benefits that are equitably shared across bundled service and departing load customers.

Q 17 The JCCA proposes that hydroelectric facilities be assigned a new vintage based on the year of the GRC in which PG&E presented a depreciation study reflecting an extended life for each hydroelectric facility.[9] Does this make sense?

A 17 No. This is a false construct which cannot serve as the basis for PCIA resource re-vintaging of these hydroelectric facilities. The JCCA appears to conflate Commission approval of PG&E's depreciation studies with approval to continue operating those facilities. This is not the case. As a practical matter, there is no end of life for a hydroelectric facility. PG&E must continue complying with existing license requirements until FERC issues an order on its relicensing or surrender application.[10] Annual licenses are automatically issued until a new license is issued.[11] The ongoing costs to maintain the dams and reservoirs necessary to support hydroelectric facility operations do not change based on who the service provider is for customers in PG&E's service territory. As such, removing the hydroelectric facility revenue requirement from the PCIA rate based on an artificial "relicensing" date is arbitrary and violates the principle of maintaining customer indifference.

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9 JCCA-01, p. 8, Table 1.

10 16 U.S.C. Section 808(a)(1).

11 *Id.*

Q 18 Should relicensing trigger any changes?

A 18 No. Given the requirement to continue complying with existing license requirements until FERC issues a new license[12] and the fact that the ongoing costs to maintain the dams and reservoirs necessary to support hydroelectric facility operations are not sensitive to changes in PG&E's bundled service and departing load customer mix, relicensing is not a triggering event. The Commission should consider cost responsibility for ongoing operation of PG&E's hydroelectric facilities in the same manner PG&E proposes for other UOG assets, on a case-by-case basis in GRCs where PG&E forecasts capital and expense to support ongoing operation of those hydroelectric facilities.

Q 19 What do the JCCA propose for Kilarc Cow Creek?

A 19 The JCCA proposes PCIA resource re-vintaging to 2020 for the Kilarc Cow Creek (Kilarc) hydroelectric facility.

Q 20 Does PG&E agree with this proposal?

A 20 No. Kilarc is a hydroelectric facility that PG&E chose to surrender rather than to relicense. All customers who received the benefit of operating this facility should be responsible for the costs of surrender and decommissioning. No re-vintaging should occur for Kilarc.

Q 21 Are departing load customers responsible for decommissioning costs of UOG facilities?

A 21 Yes. Even if the Commission adopts or assigns a date upon which departing load customers should no longer be responsible for all or a portion of the revenue requirement for a UOG facility – which PG&E disagrees with for the reasons stated above – departing load customers should be responsible for the decommissioning costs of all of these hydro facilities (as well as the decommissioning costs of fossil and solar facilities). Currently, there is not a separate rate component to recover the cost to decommission hydroelectric, fossil or solar facilities. The Commission must ensure customers who received the benefit of the energy and capacity from these UOG facilities also contribute to the cost to decommission them.

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12 *Id.*

Q 22 Is JCCA correct in saying that only bundled service customers benefit from ongoing operation of UOG facilities?

A 22 No. PG&E's economic analysis does not take into consideration the historical or expected load profile of PG&E's bundled service customers. The decisions on whether to relicense a given hydroelectric resource consider benefits that positively impact all customers, e.g., local area reliability, local reliability if natural gas access is limited, reliability during PSPS events, voltage support, black-start capability, fulfillment of water rights, and public recreational use. The majority of PG&E's hydroelectric fleet provide benefits that positively impact all customers.

Q 23 What is PG&E's recommendation regarding PCIA resource re-vintaging of hydroelectric facilities with extended lives?

A 23 PG&E recommends the Commission retain the Legacy UOG vintage for hydroelectric facilities and that all benefiting customers be responsible for ongoing and decommissioning costs. If re-vintaging of hydroelectric facilities is warranted, it must be based on a case-by-case specific review of PG&E's decisions to relicense a facility that examines the economics of each project along with other factors. Modifying the vintaging process long after relicensing decisions were made by PG&E creates a potential for an undue cost shift to bundled service customers and violates the indifference principle. PG&E has provided clear and specific examples in which departing load customers benefit from these UOG facilities.

Q 24 JCCA also proposes to re-vintage three hydroelectric facilities from prior GRCs. What is your position on that proposal?

A 24 The three facilities are Kerckhoff #1, Narrows, and Chili Bar. Kerckhoff #1 is located in a local area and contributes to local and system reliability and should not be re-vintaged for the reasons set forth above. Ratemaking impactful to the Narrows and Chili Bar facilities was addressed in two Commission decisions approving PG&E's sale of those facilities to third parties. With respect to Narrows, on October 10, 2019, the Commission adopted D.19-10-010, which authorized the sale of the Narrows project to Yuba County Water Agency and approved PG&E's proposed approach to ratemaking on the transaction. With respect to Chili Bar, on November 19, 2020, the Commission adopted D.20-11-024, which authorized the sale of the Chili Bar project to Sacramento Municipal Utility District, and approved PG&E's proposed ratemaking on the transaction. Therefore, no revintaging is appropriate.

D. Conclusion

Q 25 Does this conclude your rebuttal testimony?

A 25 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

DATA RESPONSES INCLUDED AS APPENDIX A TO PG&E'S REBUTTAL TESTIMONY

Pacific Gas and Electric Company
2023 General Rate Case
A.21-06-021
Energy Supply - Exhibit (PG&E-18)
Data Responses Included as Appendix A to PG&E's Rebuttal Testimony

Line No.	Chapter	Data Request Number	Topic
1	3	GRC-2023-PhI_DR_TURN_213-Q008	DCPP Headcount Actuals vs Forecast for 2020 and 2021
2	4	GRC-2023-PhI_DR_CalAdvocates_080-Q01Supp01	Crane Valley Recreation Settlement Agreement
3	4	GRC-2023-PhI_DR_CalAdvocates_165-Q04	ISO 55000 certification
4	4	GRC-2023-PhI_DR_CaliforniaTrout_001-Q005	Potter Valley Project Decommissioning
5	4	GRC-2023-PhI_DR_CaliforniaTrout_001-Q006	Potter Valley Transformer Project
6	4	GRC-2023-PhI_DR_CaliforniaTrout_001-Q007	Potter Valley Transformer Project
7	4	GRC-2023-PhI_DR_CaliforniaTrout_001-Q009	Potter Valley Transformer Project
8	4	GRC-2023-PhI_DR_CaliforniaTrout_001-Q010	Potter Valley Transformer Project
9	4	GRC-2023-PhI_DR_TURN_084-Q03	Hydro Operations and Maintenance Expense
10	4	GRC-2023-PhI_DR_TURN_084-Q05	Hydro Operations and Maintenance Expense
11	4	GRC-2023-PhI_DR_TURN_104-Q013	Hydro Operations and Maintenance Expense
12	4	GRC-2023-PhI_DR_TURN_104-Q025 (e)	2020 RAMP forecact vs 2023 GRC forecast
13	4	GRC-2023-PhI_DR_TURN_130-Q009	Vacant Headcount Position
14	4	GRC-2023-PhI_DR_TURN_130-Q017Rev01	2020 RAMP forecast filing and 2023 GRC forecast filing
15	4	GRC-2023-PhI_DR_TURN_213-Q001	Headcount for Power Generation
16	5	GRC-2023-PhI DR TURN_104-Q008 (c)	Gateway Evaporative Cooling project
17	5	GRC-2023-PhI DR_TURN_130-Q004 (a)	HBGS Engine Module Replacement
18	5	GRC-2023-PhI DR_TURN_130-Q004 (d)	HBGS Engine Module Replacement
19	5	GRC-2023-PhI DR_TURN_130-Q004 (e)	HBGS Engine Module Replacement
20	5	GRC-2023-PhI DR_TURN_130-Q005	Fossil Capital Emergent Work
21	6	GRC-2023-PhI_DR_CalAdvocates_018-Q05	Additional forecasted positions
22	8	GRC-2023-PhI_DR_CalAdvocates_126-Q10Rev01	Hydro Decommissioning Accrual
23	8	GRC-2023-PhI_DR_TURN_130-Q018	Helms Capacity Memorandum Account
24	9	GRC-2023-PhI_DR_JCCAs_008-Q019	Gateway Evaporative Cooling project

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_213-Q008		
PG&E File Name:	GRC-2023-PhI_DR_TURN_213-Q008		
Request Date:	May 26, 2022	Requester DR No.:	TURN-PG&E-213
Date Sent:	June 6, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Tom Baldwin	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

QUESTION 008

Refer to PG&E's Response to TURN Data Request 182, Question 1, Attachment 1. Please respond to the following questions about that response:

a. Explain why actual headcount exceeds forecast for certain departments in 2020 and 2021. Does PG&E expect that actual headcounts in these departments will continue in 2022-2025? If so, why? If not, why not?

b. Please explain why PG&E's actual headcount for Nuclear Operations at the end of 2021 is 84 less than the forecast headcount for the end of 2021.

ANSWER 008

a. See attachment GRC-2023-PhI_DR_TURN_213-Q008Atch01.

b. See attachment GRC-2023-PhI_DR_TURN_213-Q008Atch01. For this response, the actual headcount by PCC was restated to adjust actuals to a GRC organization basis due to reorganizations since the GRC was filed – see columns L – O. The reasons for variance at the end of 2021 are described at the bottom of the spreadsheet.

Pacific Gas and Electric Company
2020 General Rate Case
Exhibit 5, Chapter 3
Nuclear Operations
Forecast and Actual Year-end Headcount by Department for 2020 / 2021

			Forecast		Actual - Adjusted *		Variance		
MWC	**Department Description**	**PCC**	**2020 End of Year**	**2021 End of Year**	**2020 End of Year**	**2021 End of Year**	**2020 End of Year**	**2021 End of Year**	**2021 Variance Explanation**
OM	Chief Nuclear Officer	14886	5	5	5	5	-	-	
OS	Quality Verification	10533	25	22	23	21	2	1	Delay in Hiring
OM	Sr. Dir., Eng, Tech, & Emerg. Svcs.	10541	7	7	6	7	1	-	
BV	Technical Support Engineering	10543	34	33	24	20	10	13	
BV	Mechanical Systems	10544	31	31	43	31	(12)	-	Earlier attrition than expected (10) and Delay in Hiring (9)
BV	Design Engineering	10545	34	34	39	23	(5)	11	
BV	ICE Systems	10546	29	29	27	34	2	(5)	
BS	Project Services	10568	12	12	-	5	12	7	Earlier attrition than expected; Capital Charging Only
BQ	Security Operations	10559	245	247	235	228	10	19	Protective Strategy capital mods (15) and Delay in Hiring (4)
BR	Fire Protection	10564	21	21	21	20	-	1	Earlier attrition than expected
BQ	Access & Badging	14902	5	5	5	5	-	-	
BQ	Emergency Svcs. Performance	14903	18	13	20	20	(2)	(7)	Protective Strategy - Reduction Strategy not achieved
OS	Emergency Planning	10796	9	9	8	7	1	2	Earlier attrition than expected
OM	Station Director	12680	5	5	9	5	(4)	-	
OM	Director, Maintenance Svcs.	10566	26	26	20	18	6	8	Earlier attrition than expected
BS	Maintenance Planning O&M	12890	25	27	28	23	(3)	4	Earlier attrition than expected
BS	Maintenance Planning Capital	12725	7	7	10	5	(3)	2	Earlier attrition than expected; Capital Charging Only
BP	Facility Maintenance	12742	15	15	15	13	-	2	Earlier attrition than expected
BS	Facility Projects	15500	5	5	4	4	1	1	Earlier attrition than expected; Capital Charging Only
BS	I&C Maintenance	10567	51	51	52	47	(1)	4	Delay in Hiring
BS	Electrical Maintenance	10569	38	38	40	39	(2)	(1)	Reduction Strategy not achieved
BS	Mechanical Maintenance	10922	56	59	67	51	(11)	8	Earlier attrition than expected
BS	Site Service Supplier	13634	-	-	-	-	-	-	
BS	Maintenance Support Teams	10923	44	44	48	46	(4)	(2)	Reduction Strategy not achieved
BR	Operations Services	10562	181	182	169	164	12	18	Earlier attrition than expected
BR	Chemistry & Environmental	10565	15	15	15	16	-	(1)	Reduction Strategy not achieved
BR	Radiation Protection	10563	75	73	72	72	3	1	Earlier attrition than expected
OS	Work Control/Scheduling	10558	10	10	11	14	(1)	(4)	Reduction Strategy not achieved
OS	Outage Management	12724	14	13	15	13	(1)	-	
OM	B&TS Sr Director Office	15991	1	1	2	2	(1)	(1)	Reduction Strategy not achieved
OS	Learning Services	10606	51	48	47	41	4	7	Earlier attrition than expected (4); Delay in Hiring (3)
BT	Performance Improvement	13564	13	10	14	13	(1)	(3)	Reduction Strategy not achieved
OS	Regulatory Services	10549	12	9	12	9	-	-	
BP	Risk Mgmt and Cyber Security	15857	16	16	16	18	-	(2)	Reduction Strategy not achieved
BV	Nuclear Fuels Purchasing	10540	5	5	5	4	-	1	Earlier attrition than expected - Fuels Charging Only
OS	Nuclear Business Operations	14141	12	12	15	10	(3)	2	Earlier attrition than expected
OS	General Services	10560	39	38	41	38	(2)	-	
BV	Geosciences	10325	19	17	19	19	-	(2)	Reduction Strategy not achieved
						-			
	Nuc. Gen Org Totals		1,210	1,194	1,202	1,110	8	84	

	Forecast		Actual - Adjusted *		Variance		
2021 Variance Explanation Summary	**2020 End of Year**	**2021 End of Year**	**2020 End of Year**	**2021 End of Year**	**2020 End of Year**	**2021 End of Year**	
Reduction Strategy not achieved						(16)	Strategies from late 2020 not fully realized
Earlier attrition than expected						60	Slightly offset by higher overtime
Protective Strategy - net						8	Slightly offset by higher overtime
Earlier attrition than expected - Fuels Charging Only						1	No impact on expense
Earlier attrition than expected - Capital Charging Only						10	No impact on expense
Delay in Hiring						21	Vacant positions expected to be filled
						84	

		Forecast		Actual - Adjusted *		Variance		
MWC	**Department Description**	**2020 End of Year**	**2021 End of Year**	**2020 End of Year**	**2021 End of Year**	**2020 End of Year**	**2021 End of Year**	**2021 Variance Explanation**
BP	Manage DCPP Business	31	31	31	31	-	-	
BQ	DCPP Support Services	268	265	260	253	8	12	Protective Strategy - net (8); Delay in Hiring (4)
BR	Operate DCPP Plant	292	291	277	272	15	19	Earlier attrition than expected
BS	Maintain DCPP Plant Assets	238	243	249	220	(11)	23	Earlier attrition than expected (22) - 10 Capital Only; Delay in Hiring (4); Offset by Reduction Strategy not achieved (3)
BT	Nuclear Generation Fees	13	10	14	13	(1)	(3)	Reduction Strategy not achieved
BV	Maintain DCPP Plant Configurtn	152	149	157	131	(5)	18	Earlier attrition than expected (11) 1 is Fuel Only ; Delay in Hiring (9); Offset by Reduction Strategy not achieved (2)

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_080-Q01		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_080-Q01Supp01		
Request Date:	September 23, 2021	Requester DR No.:	PubAdv-PG&E-080-LJL
Date Sent:	October 6, 2021 (Original) October 13, 2021 (Supplemental)	Requesting Party:	Public Advocates Office
PG&E Witness:	Eric Van Deuren	Requester:	Lindsay Loethen

SUBJECT: ENERGY SUPPLY

QUESTION 01

Referring to page 4-2 of Ex. PG&E-5, PG&E forecasts $30.95 million for its Hydro Balancing Account expenses for 2023. PG&E states:

> "These costs are associated with (1) relicensing its hydro facilities; (2) FERC and California Division of Safety of Dams (DSOD) regulatory fees; (3) costs associated with implementation of the Crane Valley Recreation Settlement Agreement, and (4) costs associated with work required following the 2019 Oroville spillway incident."

a. Provide a summary of historical (2016-2020) and the 2023 forecast for each relicensing of all hydro facilities by project.

b. Provide timing and scheduling for each hydro relicensing for each project forecasted. Describe typically how much time it takes per hydro project and approximately how long PG&E has to spend for each relicensing.

c. Provide any cost effectiveness studies PG&E used when determining its hydro relicensing forecast for each project.

d. Provide a summary of historical (2016-2020) and the 2023 forecast for PG&E's Regulatory Fees to be paid to FERC and California Division of Safety of Dams.

e. Provide a summary of the Crane Valley Recreation Settlement Agreement including dates. Please provide a breakdown of costs associated with the Crane Valley Recreation Settlement Agreement.

f. Provide any cost effectiveness studies PG&E used when determining its forecast for the Crane Valley Recreation Settlement Agreement.

g. Describe why on p. 4-5, line 24 of exhibit PG&E-5, PG&E uses the year 2019 for the Oroville Spillway Incident when the spillway broke in 2017.

h. Describe the associated work that is still required after the 2017 Oroville Spillway Incident and why work has not yet been completed.

i. Provide a summary of historical (2016-2020) and the forecast for PG&E's expenses associated with the Oroville Spillway Incident. Please provide what was authorized for the 2017 Oroville Spillway Incident in the 2020 GRC.

j. Provide any cost effectiveness studies PG&E used when determining its Oroville 2019 Spillway forecast.

ANSWER 01

On page 4-2 of Exhibit-5, PG&E forecasts $30.6 million for its Hydro Balancing Account expenses for 2023, not $30.95 million.

The paragraph starting at line 14, addresses both Balancing Account capital and Balancing Account expense.

Balancing Account capital costs are associated with (1) relicensing of hydro facilities; (2) new FERC license implementation capital work; and (3) capital costs associated with work required following the 2017 Oroville spillway incident as described in more detail on pages 4-72 to 4-74 and as shown in Chapter 4 workpapers in MWC 3H on pages WP 4-85 and WP 4-86.

Balancing Account expense costs are associated with (1) new FERC license implementation expense work; (2) Federal Energy Regulatory Commission (FERC) and California Division of Safety of Dams (DSOD) regulatory fees; (3) costs associated with implementation of the Crane Valley Recreation Settlement Agreement and (4) expense costs associated with work required following the 2017 Oroville spillway incident as described in more detail on pages 4-74 to 4-75 and as shown in Chapter 4 workpapers in MWC IG on pages WP 4-10 and WP 4-12.

a. As discussed above, relicensing of hydro facilities is capital. Cal Advocates appears to be interested in Hydro Balancing Account expenses in this data request. Please see Attachment GRC-2023-PhI_DR_CalAdvocates_080-Q01Atch01 for FERC license condition implementation expense work for historical (2016-2020) and 2021-2023 forecast by project. This information can also be found in the Chapter 4 workpapers on pages WP 4-10 and WP 4-11.

b. Please refer to WP 4-109 for the FERC Relicensing Timetable. This table includes numerous dates including the estimated license issuance date and a description of the license status. The duration and timing of issuance of the licenses is uncertain, and therefore the cost and timing of the implementation expenditures are uncertain. It is difficult to forecast when FERC will issue new licenses for hydro projects because the regulatory process includes a number of stakeholders and several separate state and federal reviews that run in parallel with the FERC process. For example, the California SWRCB must issue a water quality certification under Section 401 of the Clean Water Act and related CEQA analysis as part of the relicensing process. Additionally, the USFS and certain other federal agencies also have mandatory conditioning authority to propose enhancements to or mitigation on federal lands to the extent a hydro project is on or establishes a nearby impact to federal lands. The FERC process includes a separate National Environmental Policy Act analysis. Historically, the FERC licensing process has exceeded the targeted dates for completion by several years.

For example, FERC license 2105 for the Upper North Fork Feather River, the license expired on 10/31/2004. PG&E filed its Application for relicensing on 10/23/2002 and at the time of this GRC filing PG&E estimated the license to be renewed in September 2021, nearly 19 years after the license application was made. At the time of the drafting of this data request response, PG&E has still not received this renewed license.

c. Information responsive to this question, if any, will be provided by October 14.

d. Please see attachment GRC-2023-PhI_DR_CalAdvocates_080-Q01Atch02 for PG&E's FERC Fees and California Division of Safety of Dams fees for historical (2016-2020) and 2021-2023 forecast.

e. Information responsive to this question, if any, will be provided by October 14.

f. Information responsive to this question, if any, will be provided by October 14.

g. During our preparation of this data response, PG&E found an inadvertent error in our testimony. PG&E's response below provides the correction, which will also be included in our next submission of errata to the service list.

   In Exhibit-5, Chapter 4, p. 4-2, line 24, PG&E refers to the 2019 Oroville spillway incident. The Oroville Spillway Incident occurred in 2017 rather than 2019. PG&E's errata will replace the year 2019 with the year 2017.

h. Following the 2017 major spillway incident at Oroville Dam, the FERC had requested that PG&E perform focused assessments of spillways at 36 PG&E-owned dams. The DSOD separately requested comprehensive condition assessments of the spillways on a subset of those dams. PG&E completed the spillway assessments, resulting in over 400 recommendations. These are prioritized by urgency and funded via the spillway assessment program expense and capital mitigations planning orders.

   Please see Attachment GRC-2023-PhI_DR_CalAdvocates_080-Q01Atch03 for the list of spillway inspection and repair projects for historical (2016-2020) and 2021-2023 forecast. Majority of the spend in this project list is related to spillway inspection as the spillway repair work is performed mainly under Balancing Account Capital. The Facility Safety Program team is still performing alternative analyses and working with FERC and DSOD for their comments on any further work necessary after the spillway inspections. This is a multi-year inspection and analysis program for 36 PG&E owned dams.

i. Please see PG&E's response to subpart h above for the current forecast. During the 2020 GRC, PG&E forecast was primarily for detailed spillway inspections and totaled $1.0 million for 2020.

j. Oroville Dam is owned and operated by the State of California Department of Water Resources. PG&E did not provide a forecast for any work at Oroville Dam.

c. PG&E did not use cost effectiveness studies to develop the FERC license condition implementation expense forecast presented in this proceeding. For Projects for which FERC has issued a new license, PG&E used the conditions specified in the license to develop the license condition implementation expense forecast. For Projects for which FERC has not yet issued a new license, PG&E used the input received during the relicensing process and any preliminary conditions communicated to PG&E to develop its FERC license condition implementation expense forecast.

PG&E does perform an economic analysis prior to filing a final license application with FERC and then performs another economic analysis just prior to FERC license acceptance.

e. Attachment GRC-2023-PhI_DR_CalAdvocates_080-Q01Supp01Atch01 includes the Crane Valley Settlement Agreement. PG&E's forecast for Crane Valley Settlement Agreement provides funding for the planning, design, installation, rehabilitation, and repair of various recreation facilities as required by Crane Valley Recreation Settlement Agreement between PG&E and the US Forest Service (executed in 2002). The Settlement Agreement between PG&E and the US Forest Service became a requirement of the FERC license for the Crane Valley Project (FERC No. 1354) when the license was issued September 16, 2003. The Settlement Agreement states that if the US Forest Service cannot provide funding, PG&E is required to fund the full cost of rehabilitating the facilities but on a delayed implementation schedule. Due to various factors the implementation has been delayed. The timing and magnitude of activities are determined by Forest Service staff, and thus beyond PG&E's control. Therefore, PG&E requested and received balancing account treatment of these costs in the 2020 GRC. A breakdown of PG&E's forecast for 2021 through 2023 is shown in the table below.

Thousands of Dollars

	2021	**2022**	**2023**
Bass Lake Recreation Office	150	2,545	700
Recreation Point Group Campground	0	0	2,574
Total	150	2,545	3,274

f. PG&E did not use cost effectiveness studies to develop the Crane Valley Recreation Settlement Agreement forecast presented in this proceeding.

The Crane Valley Recreation Settlement Agreement became a requirement of the FERC license for the Crane Valley Project (FERC No. 1354) when the license was issued September 16, 2003. It is required by FERC Order 414. FERC Order 414 states the following:

Recreational Facilities. The licensee shall, within 1 year of new license issuance, file for Commission approval, a recreation plan for the enhancement of the public use of project's recreational resources. At a minimum, the plan shall incorporate the provisions, guidelines, and implementation schedule for recreation facility improvements included in U.S. Forest Service (FS) condition no. 11. The recreation plan also shall be consistent with the July 1997 Phase 1 Agreement of the Crane Valley Project Committee, the licensee's Shoreline and Water Surface Management Plan (1999), and the Historic Properties Management Plan (article 412).

Pacific Gas and Electric Company

Hydro Generation
245 Market Street, Room 1103-N11C
San Francisco, CA 94105
Mailing Address
Mail Code N11C
P.O. Box 770000
San Francisco, CA 94177
415/973-5311

January 22, 2003

Ms. Cynthia A. Whelan
Assistant Lands Officer
Sierra National Forest
1600 Tollhouse Road
Clovis, CA 93611-4809

Re: Settlement Agreement for Recreation Resources
Crane Valley Hydroelectric Project, FERC No. 1354.

Dear Ms. Whelan:

Enclosed for your files and for distribution to other Forest Service personnel are the executed original and 5 copies of the *Settlement Agreement for Recreation Resources between Pacific Gas and Electric Company and the U.S. Department of Agriculture Forest Service*.

I greatly appreciate your efforts and cooperation, the support and cooperation of the Sierra National Forest Supervisor and the Bass Lake District Ranger, and the efforts and cooperation of the Regional Hydropower Assistance Team in reaching agreement on the shared responsibilities for managing, maintaining, and improving the specified recreation facilities at Bass Lake.

If you have any questions, please call me at (415) 973-5358 or send a message to njm1@pge.com via email.

Sincerely,

Nicholas J. Markevich

Nicholas J. Markevich
Senior License Coordinator and
Crane Valley Relicensing Project Manager
Hydro Generation Department

Enclosures

NJMarkevich(223-5358):njm(c:\data\liccom\crane\crane149a.doc)

bcc: John Gourley
Forrest Sullivan

File: FERC 1354, 025.11 and PLAC

United States Department of Agriculture
Forest Service
Pacific Southwest Region

Regional Office, R5
1323 Club Drive
Vallejo, CA 94592
(707) 562-8737 Voice
(707) 562-9130 Text (TDD)

File Code: 2770-2
Date: OCT 28 2002

Gregory M. Rueger
Senior Vice President
Pacific Gas and Electric Company
P.O. Box 770000, Mail Code N11C
San Francisco, CA 94177

FERC 1354
File: 025.11

G.M. RUEGER
NOV 4 2002

Dear Mr. Rueger:

I am pleased to enclose the signed Settlement Agreement for Recreation Resources for the Crane Valley Hydroelectric Project. This agreement represents years of collaborative work between your staff, the Sierra National Forest Supervisor and his staff, and our Regional Hydropower Assistance Team. I appreciate your support of the agreement, and recognize your actions to implement key portions of the settlement while our staff refined the language of the final draft. The benefits to the public that will result from this agreement will be significant.

As you know, we are approaching the last stages of the relicensing process, and we anticipate issuing our final Section 4(e) conditions in late November. Please don't hesitate to contact Regional Hydropower Coordinator Bob Hawkins at 916-930-3994, or Sierra National Forest Assistant Lands Officer Cindy Whelan at 559-297-0706, ext. 4931, if you have any questions. Thank you again for your efforts.

Sincerely,

Bernie Weingardt
for JACK A. BLACKWELL
Regional Forester

Enclosure

cc: Forest Supervisor, Sierra N.F., Jack Gipsman, OGC

SETTLEMENT AGREEMENT FOR RECREATION RESOURCES
between
PACIFIC GAS AND ELECTRIC COMPANY
and the
U. S. DEPARTMENT OF AGRICULTURE FOREST SERVICE

This Settlement Agreement (Agreement) is made and entered into by and between Pacific Gas and Electric Company, hereinafter referred to as the Company, and the United States Department of Agriculture Forest Service, hereinafter referred to as the Forest Service. The Company and the Forest Service are also hereinafter referred to collectively as the Parties.

I. BACKGROUND:

The Federal Energy Regulatory Commission (FERC) license for the Crane Valley Project, FERC No. 1354, expired on April 30, 1989. The Company filed an application for new license on April 29, 1986. The Forest Service provided final conditions under Section 4(e) of the Federal Power Act by letter to FERC dated November 26, 1991. The FERC issued a draft Environmental Assessment on March 11, 1992 indicating that it could not issue a license with certain conditions relating to the level of Bass Lake during the summer recreation period and suggesting that the Forest Service file revised 4(e) conditions. The Company objected to the proposed conditions on the basis that the cost of implementing the proposed conditions would make the Crane Valley Project uneconomic. The Company indicated that it could not accept a new license with the proposed conditions.

Negotiations between the Company and the Forest Service were initiated in 1995 and the Crane Valley Project Committee (CVPC) was established in 1996 to resolve resource management issues relating to the Crane Valley Project. The CVPC concluded Phase 1 negotiations with the signing of the Phase 1 Agreement on June 27, 1997. It was agreed that additional negotiations (Phase 2) were needed in order to identify and obtain non-licensee funding sources to implement the recommendations of the Phase 1 Agreement.

During the Phase 2 negotiations it became apparent that the Company and the Forest Service had come to an impasse regarding ownership, funding, and operation of the recreation facilities proposed for rehabilitation during the Crane Valley Project's next FERC license term. In order to resolve this impasse the Parties requested assistance from the FERC's Dispute Resolution Service (DRS). The DRS agreed to provide facilitation and meditation services to help resolve the impasse. A number of telephone conferences and meetings were held between November 1999 and June 2000 to define the nature of the impasse and to reach agreement on how the impasse could be resolved. This Agreement is the result of the negotiations to resolve the impasse between the Company and the Forest Service.

II. PURPOSE:

The purpose of this Agreement is to resolve the impasse between the Parties regarding the ownership, funding, and operation of various recreation facilities in the vicinity of Bass Lake, California, occupying Sierra National Forest (SNF) lands which are administered by the Forest Service. The SNF is a part of the Forest Service's Pacific Southwest Region.

This Agreement is intended to provide a framework of cooperation between the Parties concerning the management of these recreation facilities, the sharing of costs to rehabilitate, upgrade, and maintain these facilities, and the timing of inclusion of these facilities as a part of the new license to be issued by FERC for the Crane Valley Project. The Company is the current licensee for the Crane Valley Project.

Such cooperation will benefit National Forest resources, the public, and the Parties. Such cooperation is also necessary if the Company is to accept a new license for the Crane Valley Project.

III. STATEMENT OF MUTUAL BENEFITS AND INTERESTS:

The Forest Service is a land management agency responsible for the National Forest System lands in 43 states and comprised of 191 million acres of land. The Forest Service is dedicated to the management of the Nation's natural resources, and has major responsibilities for the protection and management of habitats for fish, wildlife, and plants on National Forests as well as management of recreation resources.

The Company is a public utility supplying electricity and natural gas to much of northern and central California. The Company owns and operates 26 FERC-licensed hydropower projects, including the Crane Valley Project of which Bass Lake is the primary water storage facility. In addition to power generation benefits, Bass Lake provides considerable economic benefits to and recreational opportunities in eastern Madera County.

The Company and the Forest Service have responsibilities and interests in the management of Bass Lake and various recreation facilities in the vicinity of Bass Lake. The Parties are also interested in the management and conservation of natural resources in the Crane Valley Project area. The Parties agree that the public's desire to recreate at Bass Lake needs to be accommodated by a combination of private and public facilities, both for day-use and overnight stays. However, there is a finite level of accommodation that can take place without a significant alteration of the character of the natural environment of Bass Lake and the surrounding area that is sought by the public visiting the area.

In consideration of the above premises, the Parties agree to the following provisions, responsibilities, terms, and conditions.

IV. GENERAL PROVISIONS

1. This Agreement applies only to the public recreation facilities in the vicinity of Bass Lake that are listed on the Implementation Schedule for Rehabilitating Recreation Facilities at Bass Lake (see Attachment 1).

2. The FERC project boundary shall be modified to include all of the land area occupied by the subject recreation facilities as indicated on the attached exhibit maps (see Attachment 2).

3. The Company's land on the southwest side of Bass Lake (see Attachment 3) shall also be included within the FERC project boundary to preserve the area as open space.

4. Each of the public recreation facilities identified in Attachment 1 shall remain the total responsibility of the Forest Service and shall not be part of the FERC project license until it is cooperatively rehabilitated by the Parties or until the milestone date specified in Attachment 1 is reached, which ever comes first.

5. The terms of this Agreement are not severable one from the other. This Agreement is made on the understanding that each term is in consideration and support of every other term, and each term is a necessary part of the entire Agreement.

6. Without limiting the applicability of rights granted to the public pursuant to applicable law, this Agreement shall not create any right or interest in the public, or any member thereof, as a third party beneficiary hereof, and shall not authorize any third party to maintain a suit at law or equity pursuant to this Agreement. The duties, obligations, and responsibilities of the Parties with respect to third parties shall remain as imposed under applicable law.

7. The terms of this Agreement will be proposed as preliminary conditions by the Forest Service under Section 4(e) of the Federal Power Act. If, after public comment on the preliminary conditions, any 4(e) condition to be proposed by the Forest Service is inconsistent with this Agreement, the Forest Service will meet and confer with the Company in an attempt to reach agreement regarding the proposed inconsistent conditions. This meeting will occur prior to the Forest Service providing notice and comment of the proposed 4(e) conditions pursuant to 36 CFR §215.5. If no agreement is reached during such meeting, the Company retains all its rights to appeal the inconsistency in the final 4(e) conditions during the 45-day appeal period under 36 CFR §215.13. The Forest Service will submit final 4(e) conditions for inclusion in the new license for the Crane Valley Project. The Company retains all its rights to seek judicial review and relief.

If the final 4(e) conditions for recreation are inconsistent with the Agreement, and the parties cannot resolve the differences, the Agreement is terminated.

8. This Agreement shall be binding on the successors and assigns of the Company. Upon completion of a succession or assignment, the Company shall no longer be a Party to this

Agreement. No change in ownership of the Crane Valley Project or transfer of the existing or new FERC project license by the Company shall in any way modify or otherwise affect the Forest Service's interests, rights, responsibilities, or obligations under this Agreement. Unless prohibited by applicable law, the Company shall provide in any transaction for a change in ownership of the Crane Valley Project or transfer of the existing or new FERC project license, that the new owner shall be bound by and shall assume the rights and obligations of this Agreement upon completion of the change of ownership and approval by FERC of the license transfer. In the event applicable law prohibits the new owner from assuming the rights and obligations of this Agreement, the Forest Service may withdraw from this Agreement. A transferring or assigning Party shall provide notice to the other Party at least 30 days prior to completing such transfer or assignment.

9. Neither Party shall be liable to the other Party for breach of this Agreement as a result of a failure to perform or for delay in performance of any provision of this Agreement due to any cause reasonably beyond its control. This may include, but is not limited to, natural events, labor or civil disruption, or breakdown or failure of project works. The Party whose performance is affected by a force majeure shall notify the other Party in writing within twenty one (21) days after becoming aware of any event that such affected party contends constitutes a force majeure. Such notice will: identify the event causing the delay or anticipated delay; estimate the anticipated length of delay; state the measures taken or to be taken to minimize the delay; and estimate the timetable for implementation of the measures. The affected Party shall make all reasonable efforts to promptly resume performance of this Agreement, and, when able to resume performance of its obligations and give the other Party written notice to that effect.

10. Implementation of the terms of this agreement may require actions on the part of other State or Federal agencies having statutory authority over some aspects of the planning, permitting, and construction of the facilities described in Attachment 1 of this Agreement. If actions or inactions of a State or Federal agency cause delays to either Party's performance of its responsibilities under the terms of this Agreement, the implementation schedule in Attachment 1 shall be adjusted by the same amount of time as the delay, or rearranged by mutual agreement. (For example, consultation with the U.S. Fish and Wildlife Service (FWS) may be required under Section 7 of the Endangered Species Act. If the FWS does not issue a Biological Opinion in time for inclusion in a request by the Sierra National Forest for Forest Service Capital Investment Program funding and it results in a one year delay for the proposal to be submitted and considered, then the implementation schedule will be adjusted by one year to reflect the delay caused by not having a FWS Biological Opinion.)

11. The new Crane Valley Project license and any other terms of this Agreement over which a federal agency has jurisdiction shall be governed, construed, and enforced in accordance with the statutory and regulatory authorities of such agency. This Agreement shall otherwise be governed and construed under the laws of the State of California. By executing this Agreement, the Forest Service is not consenting to the jurisdiction of a state court unless such jurisdiction otherwise exists. All activities undertaken pursuant to this Agreement shall be in compliance with all applicable law.

12. Pursuant to Title 41, United States Code, section 22, no member of, or Delegate to, Congress shall be admitted to any share or part of this instrument, or any benefits that may arise therefrom.

13. Except as otherwise expressly set forth herein, this Agreement does not and shall not be deemed to make either Party the agent for or partner of the other Party.

14. Any reference in this Agreement to any federal or state regulation shall be deemed to be a reference to such regulation, or successor regulation, in existence as of the date of the action.

15. Except as otherwise provided in this paragraph, any Notice required by this Agreement shall be written. It shall be sent to the other Party by first-class mail or comparable method of distribution and shall be filed with FERC. For the purpose of this Agreement, a notice shall be effective 7 days after the date on which it is mailed or otherwise distributed. When this Agreement requires notice in less than 7 days, notice shall be provided by telephone, facsimile or electronic mail and shall be effective when provided. For the purpose of notice, the list of authorized representatives of the Parties as of the effective date is shown below. The Parties shall provide notice of any change in the authorized representatives designated below.

V. COMPANY RESPONSIBILITIES:

1. The Company shall file revised exhibit drawings indicating the agreed upon changes to the project boundaries with its amended application for new license for the Crane Valley Project.

2. The Company, in consultation with the Forest Service, shall prepare a recreation plan that includes the rehabilitation and upgrade of the public recreation facilities that are covered by this Agreement (see Attachment 1). The plan will be submitted to FERC after approval by the Forest Service.

3. The Company shall fund half of the cost of rehabilitating each of the public recreation facilities that are covered by this Agreement and identified in Attachment 1. If matching funds from the Forest Service, from increased user fees, or from other non-Company sources are not available, the licensee shall fund the full cost of rehabilitating and improving each of the public recreation facilities, but on a delayed implementation schedule that makes the present value of the Company's outlays similar in all cases.

4. The Recreation Plan specified in Item 2 of this Section shall define the role of the Company, the Forest Service, and the Forest Service's permittee with regard to the operation and maintenance (O&M) of the public recreation facilities. In addition the Company shall be given the opportunity to review and provide comments on the Forest Service's bid

prospectus and the permittee's performance of the daily O&M of the public recreation facilities. The Company will not participate in the selection of the permittee.

5. The Company shall participate in annual inspections by the Forest Service of the public recreation facilities covered by this Agreement and provide comments regarding the condition of the facilities, maintenance activities, and performance of the permittee.

6. After a pubic recreation facility identified in Attachment 1 is included in the FERC license as a Crane Valley Project facility, the Company shall be responsible for funding the rehabilitation of such facilities in accordance with Item 3 of this Section.

7. The terms and conditions of this agreement will be reflected in the license application submitted by the Company to FERC.

VI. FOREST SERVICE RESPONSIBILITIES:

1. The terms of this Agreement shall be proposed as preliminary conditions by the Forest Service under Section 4(e) of the Federal Power Act.

2. The Forest Service or its permittee shall be responsible for the condition of the public recreation facilities identified in Attachment 1 until such time as the facilities become part of the Crane Valley Project license as defined in Item 4 of Section IV (see Attachment 1).

3. The Forest Service shall provide, for review and comment, the Company with a copy of the bid prospectus used to select a permittee for operating and maintaining the Forest Service's public recreation facilities identified in Attachment 1.

4. After each public recreation facility identified in Attachment 1 becomes part of the Crane Valley Project license, the Forest Service or its permittee shall still be responsible for operating and maintaining the public recreation facilities and for collecting any user fees associated with these facilities. The Forest Service or its permittee shall be responsible for performing at their expense any required "tenant" maintenance and reconditioning of these recreation facilities. Tenant maintenance and reconditioning is defined as any maintenance that can be expensed per the IRS code. This maintenance work includes, but is not limited to, painting, minor repairs, replacing facility components, trash pickup and removal, maintaining paths, trails, roadways, and landscaping.

5. The Forest Service shall notify the Company if any public health and safety problems are noted with respect to the condition of the recreation facilities that require major repairs or reconditioning to resolve. Such major repairs or reconditioning are any repairs that can be capitalized per the IRS tax code, including, but not limited to, new or substantially rebuilt facilities, new roofs, new infrastructure, new paths, trails, and roadways.

6. The Forest Service shall request approval for the expenditure of Capital Investment Program (CIP) dollars for half of the costs of rehabilitating and upgrading the recreation

facilities in the vicinity of Bass Lake in accordance with the schedule in Attachment 1 of this Agreement or an amended schedule agreed to by both Parties. The request shall be made at least three years prior to the scheduled project implementation date.

7. The Forest Service shall participate in FERC environmental and public use inspections (EPUIs) and annual operating inspections (OPSIs) of the Crane Valley Project facilities.

VII. IT IS MUTUALLY AGREED AND UNDERSTOOD BY AND BETWEEN THE SAID PARTIES THAT:

1. The accountability and responsibility of each Party for operating, maintaining, and rehabilitating the Forest Service's recreation facilities within the proposed FERC project boundary of the Crane Valley Project (see Attachment 1) shall be defined by this Agreement.

2. The Parties shall cooperate to accelerate implementation of rehabilitation measures identified in this Agreement, the license application, and the mandatory conditions.

3. The Parties shall continue to cooperate on the rehabilitation of projects selected by the Crane Valley Project Committee that are to be jointly funded by the Parties. If the Forest Service cannot provide funding, the Company shall rehabilitate facilities still in need of improvement in accordance with the delayed schedules on the attached Implementation Schedule for Rehabilitating Recreation Facilities at Bass Lake (see Attachment 1).

4. The Parties shall rehabilitate and upgrade the public recreation facilities listed in Attachment 1 in accordance with universal design concepts, including: repair of all health and safety defects, maintenance or restoration of infrastructure such as roads and barriers to current engineering standards appropriate to Development Scale IV or V (as appropriate); repair or replacement, as necessary, of utility systems such as sewer and water lines; repair or replacement, as necessary of toilets, water hydrants, bulletin boards, and other fixtures necessary and customary for Development Scale IV and V recreation sites. Development Scale IV improvements shall include the installation of showers. Development Scale V improvements shall include all facilities appropriate in Development Scale IV with the inclusion of sewer, water, and electrical hookups at each individual trailer pad. These improvements shall be designed and constructed to be accessible to people of all abilities pursuant to the Americans with Disabilities Act of 1990. The scope and development scale of improvements at a particular recreation facility may be reduced by mutual agreement of the Parties to reduce the cost and accelerate implementation if CIP funding is not approved by the Forest Service.

5. All improvements shall meet Forest Service standards appropriate to the use, motif, and character of Bass Lake. The Forest Service shall approve rehabilitation plans prepared by the Company at least three months prior to the start of construction.

6. Each recreation facility shall be rehabilitated in accordance with the schedules shown on the attached implementation schedule (Attachment 1). Facilities will be rehabilitated during

the earliest schedule year if Forest Service CIP funding is approved. If CIP funding is not approved, the rehabilitation of a particular recreation facility will be delayed until the second schedule year if higher user fees or other non-Company funds are used to recover half of the total rehabilitation costs of a given recreation facility. If the Company is to fund the total cost of rehabilitation, the project will be delayed until the latest year shown for that particular recreation facility.

7. In the event of any disagreements or disputes related to this Agreement or the Crane Valley Project license, the Parties agree to participate in a non-binding alternative dispute resolution (ADR) process before resorting to legal action. Unless the Parties agree otherwise, as a minimum the ADR process will consist of the following. The Party claiming a dispute shall give Notice pursuant to item 15 of Section IV above. The Parties will hold at least two informal meetings within 60 days of the Dispute Notice in an attempt to resolve the dispute. If informal meetings fail to resolve the dispute, the Parties shall attempt to resolve the dispute using a jointly selected neutral mediator. Either party may request participation by FERC's Dispute Resolution Service. If FERC is unable to participate, the Parties shall select a mediator from the sources described in 18 CFR Section 385.604(c)(3). Each party shall bear its own costs for participation in the ADR process. If, after compliance with these ADR procedures, agreement cannot be reached, either Party may seek, in a court of competent jurisdiction, specific performance of the Agreement.

8. The Forest Service retains the option to manage the recreation facilities on federal lands under its jurisdiction through means other than a permittee.

9. Improvements placed on National Forest System land at the direction of either of the Parties, shall thereupon become property of the United States, and shall be subject to the same regulations and administration of the Forest Service as other National Forest improvements of a similar nature.

10. Any press release which references this Agreement, or the relationship established between the parties of this Agreement, shall have prior approval of both Parties.

11. Meetings will be scheduled periodically, but not less frequently than once a year, to discuss and identify opportunities for mutually beneficial projects and activities that meet the intent of this Agreement.

12. This Agreement in no way restricts the Parties from participating in similar activities with other public or private agencies, organizations, or individuals.

13. No part of this instrument shall entitle the Company to any share or interest in the recreation facilities on National Forest System lands other than the right to use and enjoy the same under the existing regulations of the Forest Service.

14. Nothing herein shall be considered as obligating the Forest Service to expend or as involving the United States in any contract or other obligations for the future payment of

money in excess of funding approved and made available for payment under this instrument and modifications thereto.

15. Nothing in this Agreement shall be considered as obligating the Company to accept a new FERC license for the Crane Valley Project. The Company, at its sole discretion, shall have the right to determine whether the terms and conditions of any new FERC license for the Crane Valley Project are acceptable to it.

16. This Agreement is executed as of the last date shown below and will remain in force, unless terminated pursuant to items 7 or 8 of Section IV above, as long as the Company (or its assigns or successors) is the power project licensee for the Crane Valley Project.

17. The terms of this Agreement may be amended by the mutual agreement of both Parties. If the amendment requires revision to 4(e) conditions, the Forest Service will file those revisions with FERC after agency review. However, no modification or change to this Agreement shall be binding or effective unless expressly set forth in writing and signed by the respective Party's representatives authorized to execute this Agreement. In the event of any inconsistency between this Agreement and the new license issued by FERC for the Crane Valley Project, the terms of the FERC license shall control.

18. This Agreement and all the terms and provisions hereof shall inure to the benefit of and be binding upon the successors and assigns of the respective Parties hereto.

19. The Parties executing this Agreement swear and attest that they have the authority to bind their respective organizations to the terms and conditions of this Agreement. Each signatory to this Agreement certifies that he or she is authorized to execute this Agreement and to legally bind the Party he or she represents, and that such Party shall be fully bound by the terms hereof upon such signature without any further act, approval, or authorization by such Party.

20. The principal contacts for this Agreement shall initially be:

Ms. Cynthia Whelan
Sierra National Forest
1600 Tollhouse Road
Clovis, CA 93612
(559) 297-0706 ext. 4923

Mr. Nicholas Markevich
Pacific Gas and Electric Company
P.O. Box 770000, Mail Code N11C
San Francisco, CA 94177
(415) 973-5358

IN WHITNESS WHEREOF, the parties hereto have executed this Agreement as of the last written date below.

for Jack A. Blackwell
Regional Forester
USDA Forest Service

10/28/02
Date

for Gregory M. Rueger
Senior Vice President
Pacific Gas and Electric Company

11/12/02
Date

VIII. ATTACHMENTS:

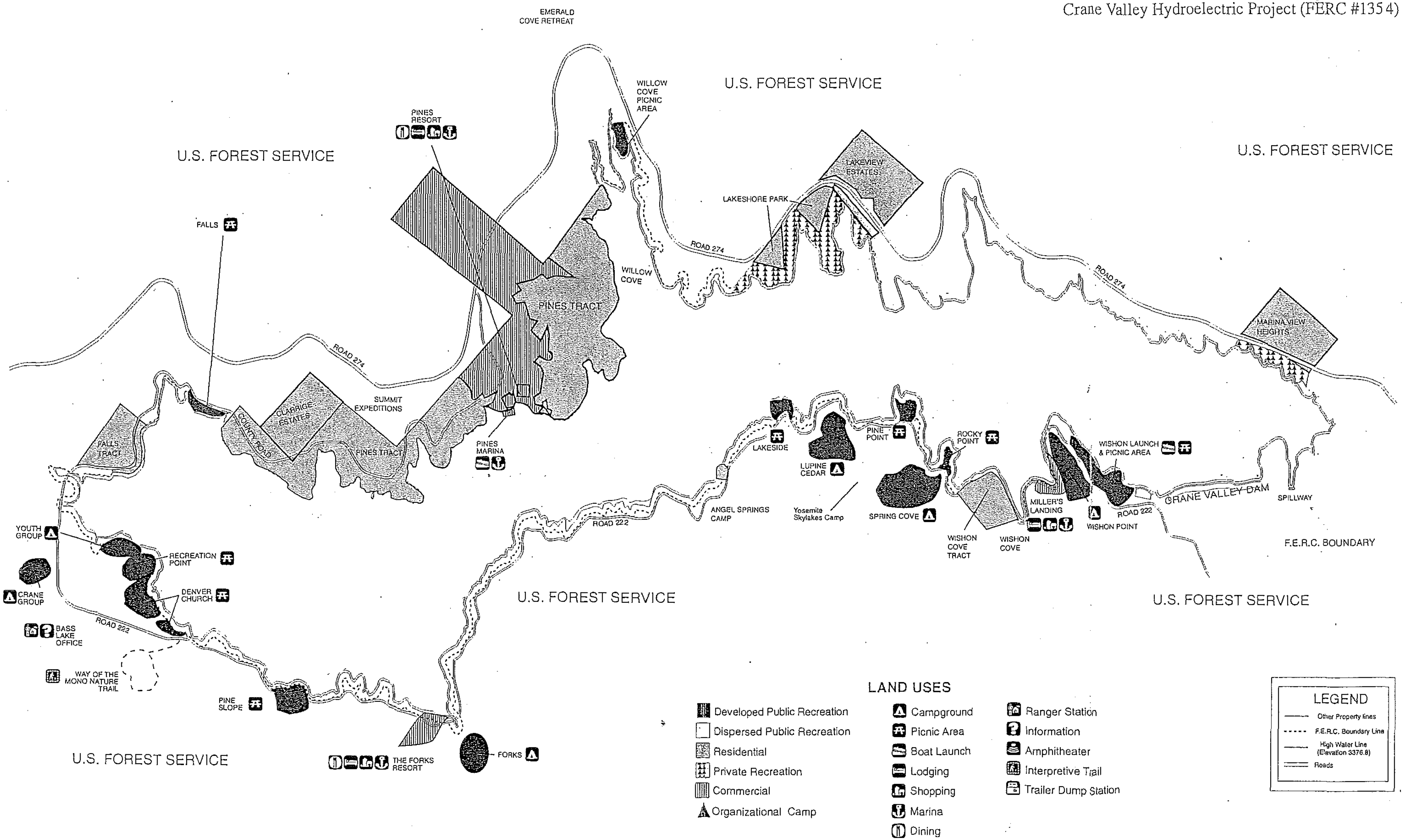
The following attachments are a part of this Agreement.
1. Implementation Schedule for Rehabilitating Recreation Facilities at Bass Lake
2. Exhibit Maps Showing the Recreation Facility Areas at Bass Lake
3. Legal Description of Company Land on the Southwest Side of Bass Lake

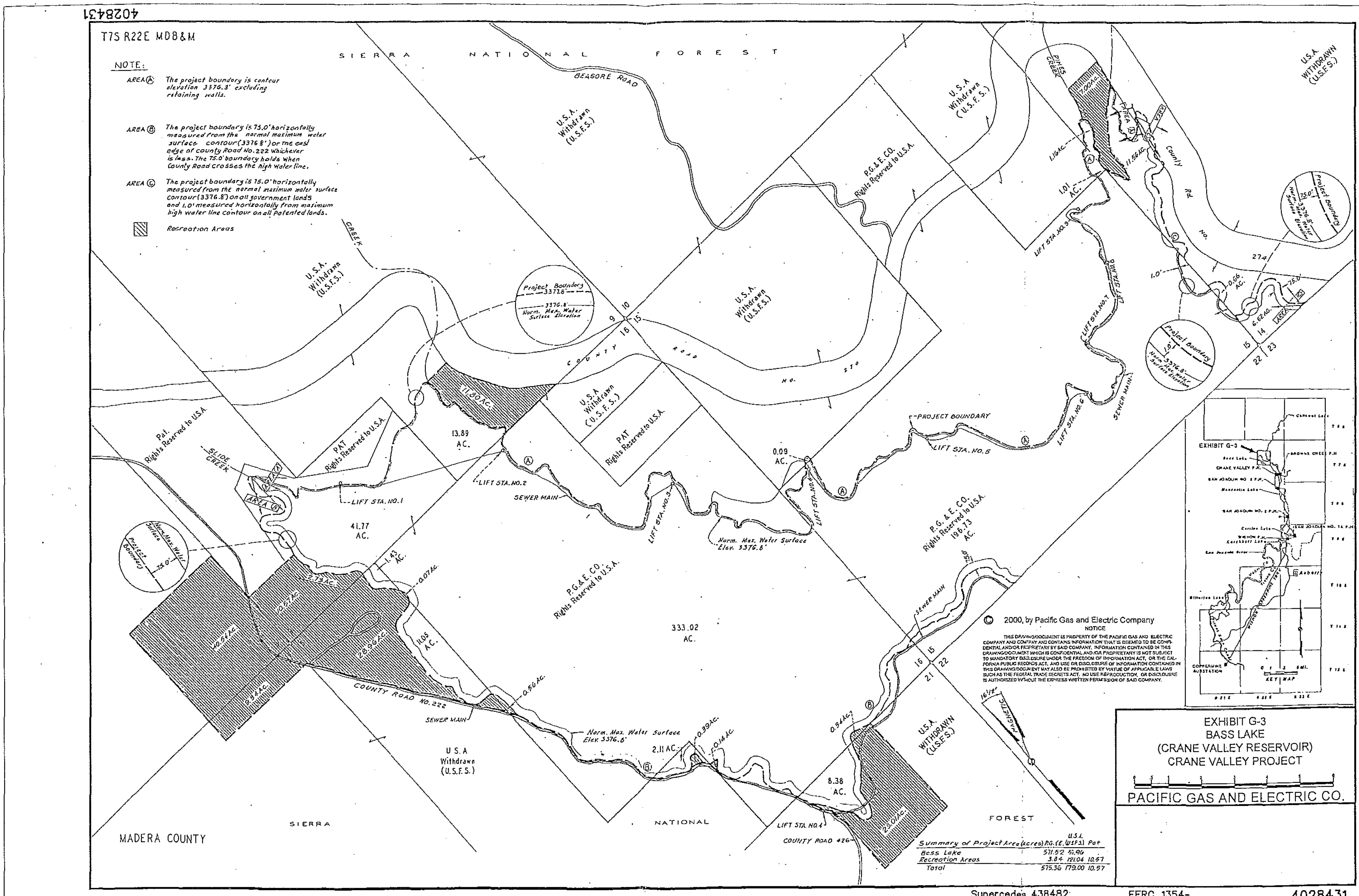
Attachment 1. Implementation Schedule for Rehabilitating Recreation Facilities at Bass Lake

Facility Name	With CIP Funding	With Other Funding Sources	With Licensee Funding Only
Lakeside Day Use	2001	— *	— *
Forks Campground and RV Dump Site	2002	— *	— *
Spring Cove Campground	2004	— *	— *
Denver Church Day Use	2004	2009	2014
Falls Beach Day Use	2005	2010	2015
Recreation Point Day Use and Campground	2005	2010	2015
Crane Valley Group Campground	2006	2011	2016
Pine Point, Rocky Point, and Pine Slope Day Use	2007	2012	2017
Wishon Point Campground	2008	2013	2018
Bass Lake Recreation Office and Amphitheater	2009	2014	2019
Lupine-Cedar Campground	2010	2015	2020
Willow Cove Day Use	2011	2016	2021
Wishon Day Use and Boat Ramp	2012	2017	2022

* CIP funding approved for this facility.

Figure 1
Existing Land Uses
Crane Valley Hydroelectric Project (FERC #1354)





Summary of Project Area (acres)	P.G.&E.	U.S.A. (USFS)	Pat
Bass Lake	571.52	57.96	
Recreation Areas	3.84	121.04	10.57
Total	575.36	179.00	10.57

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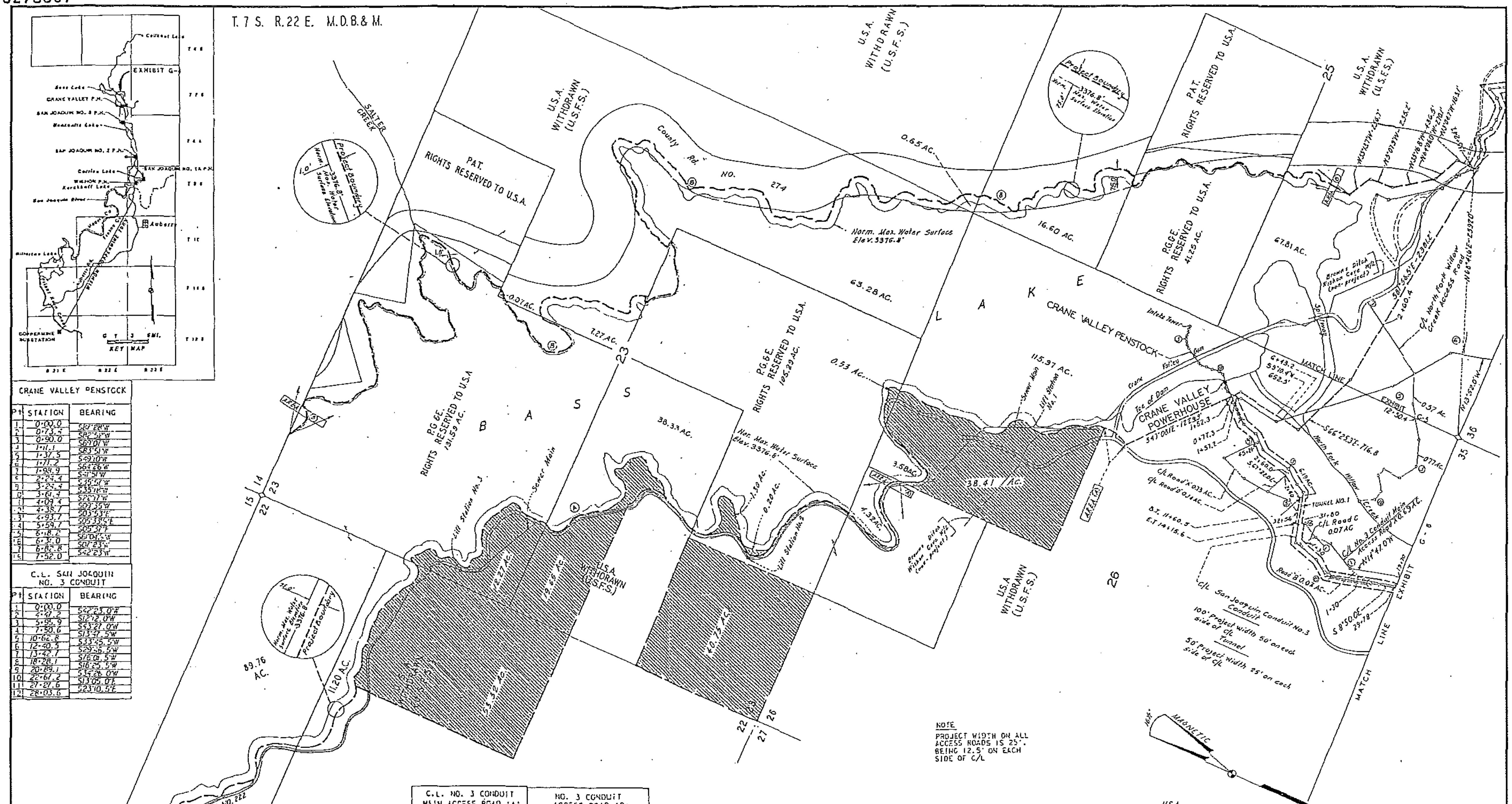

CRANE VALLEY PENSTOCK		
Pt	STATION	BEARING
1	0+00.0	S67°28'W
2	0+73.4	S82°52'W
3	0+90.0	S67°01'W
4	1+11.1	S83°51'W
5	1+37.5	S49°10'W
6	1+71.2	S64°26'W
7	1+99.9	S41°51'W
8	2+24.4	S39°57'W
9	3+24.4	S35°16'W
10	3+61.4	S22°17'W
11	4+09.4	S07°35'W
12	4+38.7	S05°53'E
13	4+93.7	S05°35.5'E
14	5+59.7	S05°37'E
15	6+18.2	S01°04.5'W
16	6+37.0	S07°23'W
17	6+82.8	S42°23'W
18	7+52.0	

C.L. SAN JOAQUIN NO. 3 CONDUIT		
Pt	STATION	BEARING
1	0+00.0	S42°23.0'W
2	4+47.2	S12°12.0'W
3	5+95.9	S43°27.0'W
4	7+50.6	S13°47.5'W
5	10+62.8	S33°45.5'W
6	12+40.5	S29°56.5'W
7	13+42.7	S16°01.5'W
8	18+28.1	S16°25.5'W
9	20+89.1	S34°26.0'W
10	22+61.2	S13°05.0'E
11	27+27.6	S23°10.5'E
12	28+03.6	

C.L. NO. 3 CONDUIT MAIN ACCESS ROAD "A"		
Pt	STATION	BEARING
1	25+18.5	N28°26'E
2	27+91.4	N 3°34'W
3	29+51.7	N22°22'E
4	31+35.5	N35°18'E
5	34+23.6	N 2°36'W
6	36+43.8	N 4°14'E
7	39+20.5	N19°47'E
8	41+86.3	S49°34'E
9	45+41.0	

NORTH FORK WILLOW CREEK ACCESS ROAD		
Pt	STATION	BEARING
1	0+00.0	S30°59'W
2	8+31.4	S66°24'W
3	11+40.4	S55°08'W
4	14+82.7	S74°45'W
5	17+54.9	N55°32'W
6	19+34.5	N 1°41'E
7	21+18.4	N61°59'W
8	22+00.8	S57°58'W
9	23+54.9	N24°52'W
10	24+42.2	N26°02'W
11	25+99.4	

NO. 3 CONDUIT ACCESS ROAD "B"		
Pt	STATION	BEARING
1	0+00.0	S18°26'W
2	2+21.3	S12°53'E
3	5+39.1	

NO. 3 CONDUIT ACCESS ROAD "C"		
Pt	STATION	BEARING
1	0+00.0	N36°15'W
2	1+86.0	S25°27'W
3	4+18.6	S20°33'W
4	5+87.5	S10°18'E
5	7+01.3	

NOTE:
PROJECT WIDTH ON ALL ACCESS ROADS IS 25'. BEING 12.5' ON EACH SIDE OF C/L

NOTE:

AREA (A) The project boundary is 75.0' horizontally measured from the maximum high water line contour (3376.8) or the east edge of County Road No. 222 whichever is less. The 75.0' boundary holds when County Road crosses the high water line.

AREA (B) The project boundary is 75.0' horizontally measured from the maximum high water line contour (3376.8) on all government lands and 1.0' measured horizontally from maximum high water line contour on all Patented lands.

Recreation Area

Summary of Project Areas (Acres)	PG&E Co.	USA (USFS)
Bass Lake	372.21	324.76
Conduit	—	6.19
Access Roads	—	3.04
Recreation Areas	14.30	152.13
Totals	386.51	491.51

EXHIBIT G-4
BASS LAKE, CRANE VALLEY P.H. CONDUIT
ACCESS ROADS, 12KV TRANSMISSION LINE
CRANE VALLEY PROJECT

PACIFIC GAS AND ELECTRIC CO.

Supercedes 438483 FERC 1354-___ 4028432-1

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Attachment 3. Legal Description of Company Land on the Southwest Side of Bass Lake

(APN 59-064-10 & 11 and 59-151-06 & 08)

All that certain parcel of land situate in Sections 23 and 26, Township 7 South, Range 22 East, Mount Diablo Base and Meridian, recorded on February 18, 1911 in Volume 55, Page 378 of Deeds of the County of Madera, State of California, particularly described therein as follows:

The Southeast one-quarter of the Southwest one-quarter and the West one-half of the Southeast one-quarter of said Section 23 and the Northeast one-quarter of the Northwest one-quarter of said Section 26.

EXCEPTING THEREFROM that portion of said Section 26 described in Exhibit "A" of grant deed to the County of Madera recorded on July 19, 1994 as Serial Number 9421593 of Official Records of the County of Madera particularly described therein as follows:

PARCEL 1:
Commencing at the Northwest corner of said Section 23 according to the Record of Survey filed in Book 28, Page 142 of Maps of the County of Madera, thence
South 0° 05' 22" East 2678.76 feet to the West one-quarter corner of said Section 23 according to said Record of Survey; thence
South 33° 58' 10" East 4424.56 feet to the TRUE POINT OF BEGINNING being marked by a 5/8" diameter rebar tagged LS 5509; thence
North 52° 18' 07" East 64.30 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 44° 43' 29" East 79.05 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 19° 27' 56" East 88.62 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 70° 32' 04" West 83.53 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 19° 27' 56" West 105.78 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 37° 41' 53" West 36.02 feet more or less to the Point of Beginning.

PARCEL2:
Commencing at the Northwest corner of said Section 23 according to the Record of Survey filed in Book 28, Page 142 of Maps of the County of Madera, thence
South 0° 05' 22" East 2678.76 feet to the West one-quarter corner of said Section 23 according to said Record of Survey; thence
South 32° 26' 48" East 4382.88 feet to the TRUE POINT OF BEGINNING being marked by a 5/8" diameter rebar tagged LS 5509; thence
North 45° 22' 47" East 55.13 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 44° 37' 13" East 105.72 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 45° 22' 47" West 55.13 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 44° 37' 13" West 105.72 feet to the Point of Beginning.

PARCEL 3
Commencing at the Northwest corner of said Section 23 according to the Record of Survey filed in Book 28, Page 142 of Maps of the County of Madera, thence

South 0° 05' 22" East 2678.76 feet to the West one-quarter corner of said Section 23 according to said Record of Survey; thence
South 26° 58' 18" East 3142.47 feet to the TRUE POINT OF BEGINNING being marked by a 5/8" diameter rebar tagged LS 5509; thence
South 59° 40' 14" East 54.50 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 30° 19' 46" West 88.50 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 59° 40' 14" West 54.50 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 30° 19' 46" East 88.50 feet more or less to the Point of Beginning.

ALSO EXCEPTING THEREFROM that portion deeded to the County of Madera recorded on July 18, 1994 as Serial Number 9421472 of Official Records of the County of Madera, particularly described therein as follows:

Commencing at the West one-quarter of Section 23 according to the Record of Survey filed in Book 28, Page 142 of Maps of the County of Madera, thence
South 34° 22' 09" East 3872.77 feet to the TRUE POINT OF BEGINNING; thence
Westerly along a curve to the right having a radius of 105.00 feet and a radial bearing of North 28° 39' 16" West, from said Point of Beginning, through a central angle of 29° 52' 16" an arc distance of 54.74 feet; thence
along a tangent curve to the right having a radius of 130.00 feet through a central angle of 109° 00' 00" an arc distance of 247.31 feet; thence
North 20° 13' 00" East 2.19 feet; thence
North 22° 20' 04" East 82.03 feet; thence
North 14° 35' 58" East 371.18 feet; thence
along a tangent curve to the left having a radius of 565.00 feet through a central angle of 11° 32' 15" an arc distance of 113.78 feet; thence
North 3° 03' 42" East 88.99 feet; thence
along a tangent curve to the left having a radius of 110.00 feet through a central angle of 62° 38' 54" an arc distance of 120.28 feet; thence
North 59° 35' 11" West 56.28 feet; thence
along a tangent curve to the right having a radius of 735.00 feet through a central angle of 6° 04' 17" an arc distance of 77.88 feet; thence
North 53° 30' 54" West 28.41 feet; thence
along a tangent curve to the left having a radius of 410.00 feet through a central angle of 11° 30' 25" an arc distance of 82.34 feet; thence
North 75° 35' 14" West 95.01 feet; thence
North 80° 28' 46" West 100.54 feet; thence
North 87° 05' 57" West 103.76 feet; thence
North 1° 47' 43" West 34.72 feet to a point which lies South 37° 38' 16" East, 2630.06 feet more or less from said West one-quarter corner of said Section 23; thence
North 1° 47' 43" West 20.00 feet; thence
North 88° 12' 17" East 37.16 feet; thence
along a tangent curve to the right having a radius of 360.00 feet through a central angle of 13° 53' 17" an arc distance of 87.26 feet; thence
South 77° 54' 26" East 97.01 feet; thence along a tangent curve to the right having a radius of 455.00 feet through a central angle of 24° 23' 32" an arc distance of 193.70 feet; thence
South 53° 30' 54" East 28.41 feet; thence

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along a tangent curve to the left having a radius of 690 feet through a
central angle of 6° 04' 17" an arc distance of 73.12 feet; thence
South 59° 35' 11" East 56.28 feet; thence
along a tangent curve to the right having a radius of 155.00 feet through a
central angle of 62° 38' 54" an arc distance of 169.48 feet; thence
South 3° 03' 42" West 88.99 feet; thence along a tangent curve to the right having a radius of 610 feet through a central angle of 11° 32' 15" an arc distance of 122.83 feet; thence
South 14° 35' 58" West 371.18 feet; thence
along a tangent curve to the right having a radius of 435.00 feet through a
central angle of 5° 37' 02" an arc distance of 42.65 feet; thence
South 20° 13' 00" West 48.57 feet; thence
along a tangent curve to the left having a radius of 80.00 feet through a
central angle of 109° 00' 00" an arc distance of 152.19 feet; thence
along a tangent curve to the left having a radius of 55.00 feet through a
central angle of 38° 32' 28" an arc distance of 37.00 feet; thence
South 37° 19' 30" East 50.00 feet to the beginning of a non-tangent curve to the right having a radius of 105.00 feet and a radial bearing of North 37° 19' 30" West; thence
Westerly along said non-tangent curve through a central angle of 8° 40' 14" an arc distance of 15.89 feet to the Point of Beginning.

ALSO EXCEPTING THEREFROM that portion deeded to James P. Green recorded on May 31, 1996 as Serial Number 9614581 of Official Records of the County of Madera particularly described therein as follows:

Commencing at the West one-quarter corner of said Section 23; thence
South 38° 25' 15" East 3969.57 feet to the TRUE POINT OF BEGINNING, said point being a 1" iron pipe that also lies South 69° 37' 46" East 447.44 feet from the Northeast corner of Lot 1 as shown on Record of Survey as recorded in Book 42, Pages 135-136, of Maps of the County of Madera; thence
South 79° 55' 00" West 14.35 feet to a point now defined point "A"; thence
North 3° 53' 23" East 232.36 feet to a point now defined as point "B"; thence
North 85° 55' 19" East 4.81 feet; thence
South 87° 42' 39" East 51.98 feet; thence
South 69° 08' 25" East 43.26 feet; thence
South 62° 08' 40" East 23.01 feet; thence
South 40° 48' 40" East 61.81 feet; thence
South 22° 40' 42" East 79.48 feet; thence
South 26° 52' 17" East 46.74 feet; thence
South 11° 05' 05" East 38.57 feet; thence
South 2° 41' 07" West 81.95 feet; thence
South 24° 14' 35" West 16.04 feet; thence
South 33° 43' 25" West 12.03 feet; thence
North 70° 52' 10" West 178.86 feet; thence
North 35° 17' 30" West 56.49 feet to the Point of Beginning.

ALSO EXCEPTING THEREFROM that portion deeded to Jackson Street, LLC recorded on April 19, 1996 as Serial Number 9610544 of Official Records of the County of Madera, particularly described therein as follows:

Commencing at the West one-quarter corner of said Section 23; thence
South 38° 03' 17" East 3956.02 feet to the TRUE POINT OF BEGINNING, said point being a 1" iron pipe that also lies South 67° 39' 28" East 422.94 feet from the Northeast corner of Lot 1 as shown on Record of Survey as recorded in Book 42, Pages 135-136, of Maps of the County of Madera; thence
South 39° 22' 52" West 146.35 feet; thence
North 74° 44' 08" West 139.79 feet; thence
North 24° 17' 00" East 190.40 feet; thence
North 28° 34' 49" East 77.04 feet; thence
North 36° 56' 44" East 36.38 feet; thence
North 71° 34' 41" East 44.20 feet; thence
North 70° 33' 51" East 78.31 feet; thence
North 85° 55' 19" East 4.82 feet to a new point now defined as point "B"; thence
South 3° 53' 23" West 232.38 feet to a point now defined as point "A"; thence
South 79° 55' 00" West 14.36 feet to the Point of Beginning.

ALSO EXCEPTING THEREFROM that portion deeded to Wishon Cove Homeowners Association recorded on October 27, 1994 as Serial Number 9432062 of Official Records of the County of Madera, particularly described therein as follows:

Commencing at the Northwest corner of said Section 23 according to the Record of Survey filed in Book 28, Page 142 of Maps of the County of Madera; thence
South 0° 05' 22" East, 2678.76 feet to the West one-quarter corner of said Section 23 according to said Record of Survey; thence
South 37° 11'58" East 2658.28 feet to the TRUE POINT OF BEGINNING, being marked by to a 5/8" diameter rebar tagged LS 4298; thence
South 87° 05' 57" East 103.76 feet to a 5/8" diameter rebar tagged LS 4298; thence
South 80° 28' 46" East 100.54 feet to a 5/8" diameter rebar tagged LS 4298; thence
South 75° 35' 14" East 95.01 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the right having a radius of 410.00 feet through a central angle of 11° 30' 25" an arc distance of 82.34 feet to a 5/8" diameter rebar tagged LS 5509; thence.
South 53° 30' 54" East 12.53 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 53° 30' 534" East 15.88 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the left having a radius of 735.00 feet through a central angle of 6° 04' 17" an arc distance of 77.88 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 59° 35' 11" East 13.63 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 59° 35' 11" East 15.61 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 59° 35' 11" East 27.04 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the right having a radius of 110.00 feet through a central angle of 60° 56' 06" an arc distance of 116.99 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the right having a radius of 110.00 feet through a central angle of 1° 42' 48" an arc distance of 3.29 to a 5/8" diameter rebar tagged LS 5509; thence

South 3° 03' 42" West 88.99 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the right having a radius of 565.00 feet through a central angle of 0° 39' 41" an arc distance of 6.52 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the right having a radius of 565.00 feet through a central angle of 8° 51' 02" an arc distance of 87.28 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the right having a radius of 565.00 feet through a central angle of 2° 01' 33" an are distance of 19.98 to a 5/8" diameter rebar tagged LS 5509; thence
South 14° 35' 58" West 64.88 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 14° 35' 58" West 79.12 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 14° 35' 58" West 80.81 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 14° 35' 58" West 71.66 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 14° 35' 58" West 74.72 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 22° 20' 04" West 2.59 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 22° 20' 04" West 82.03 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 66° 11' 30" West 146.31 feet to a 1 1/4" diameter iron pipe tagged LS 5509; thence
North 87° 02' 37" West 34.08 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 20° 25' 38" West 70.42 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 20° 25' 38" West 2.65 feet to a 5/8" diameter rebar tagged LS 5509; thence
along a tangent curve to the left having a radius of 140.00 feet through a central angle of 25° 09' 08" an arc distance of 61.46 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 4° 43' 31" East 12.39 feet to a 5/8" diameter rebar tagged LS 5509; thence
South 4° 43' 31" East 85.09 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 73° 42' 52" West 43.38 feet to a 1 1/4" diameter iron pipe tagged LS 5509; thence
North 73° 42' 52" West 159.32 feet to a 1 1/4" diameter iron pipe tagged LS 5509; thence
North 73° 42' 52" West 40.00 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 16° 16' 22" East 79.51 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 21° 00' 43" East 82.57 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 30°16'13" East 82.56 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 30° 01' 25" East 80.13 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 25° 18' 21" East 77.80 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 9° 52' 12" East 49.12 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 30° 01' 49" West 68.83 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 48° 23' 53" West 29.48 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 48° 23' 53" West 29.49 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 48° 23' 53" West 29.48 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 48° 23' 53" West 29.49 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 48° 23' 53" West 29.48 to a 5/8" diameter rebar tagged LS 5509; thence
North 2° 20' 52" East 60.00 feet to a 1 1/4" diameter iron pipe tagged LS 5509; thence
North 2° 20' 52" East 161.89 feet to a 1 1/4" diameter iron pipe tagged LS 5509; thence
North 75° 08' 27" East 29.72 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 14° 39' 37" East 51.22 feet to a 5/8" diameter rebar tagged LS 5509; thence
North 74° 35' 46" West 86.64 feet to a 5/8" diameter rebar tagged LS 4298; thence
North 8° 26' 16' East 141.64 feet more or less to the Point of Beginning.

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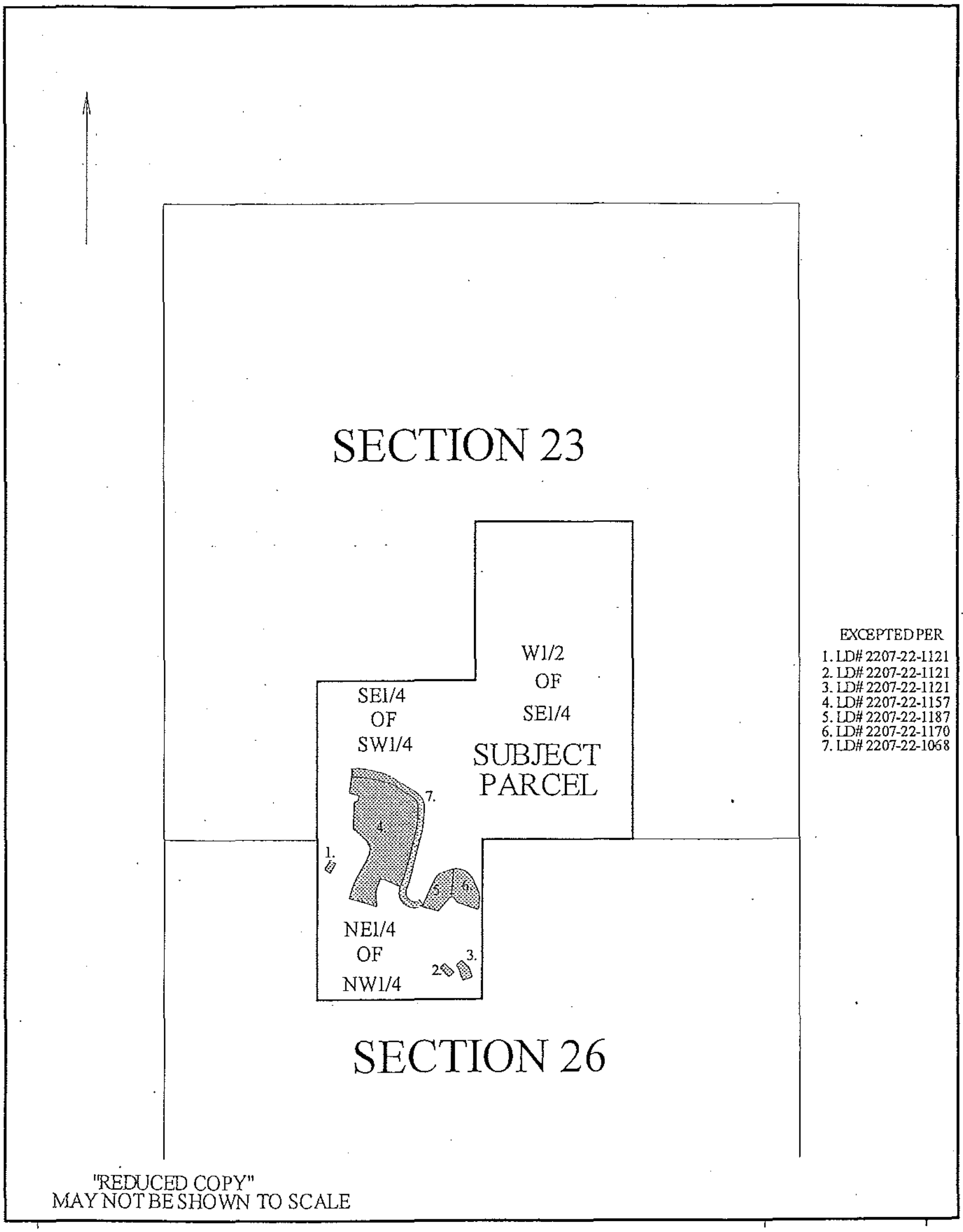

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PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CalAdvocates_165-Q04		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_165-Q04		
Request Date:	November 19, 2021	Requester DR No.:	PubAdv-PG&E-165-LJL
Date Sent:	December 3, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Eric Van Deuren	Requester:	Lindsay Loethen

SUBJECT: HYDRO OPERATIONS

QUESTION 04

Referring to PG&E's response to data request CalAdvocates_121-Q05, PG&E states "Decision 20-12-005 requires PG&E to make a 'good faith effort' to attain ISO 55000 certification from an accredited organization for its dams by the end of 2022."

a. Please provide the excerpt and page number in which D.20-12-005 directs PG&E to make a "good faith effort" and attain ISO 55000 certification.

b. Please describe how PG&E determined that 6 new hires are needed and necessary to help PG&E apply for and make a good faith effort to attain ISO 55000 certification.

c. Was there a cost benefit analysis conducted for the benefit of these 6 new hires? If yes, please provide a copy of the analysis. If no, please explain why a study was not conducted.

d. Provide documentation PG&E's management prepared, prior to this data request, that explains and demonstrates how PG&E staffed and addressed activities associated with obtaining ISO 55000 certification and making good faith efforts during 2016-2020. If these activities were never done, state so in the response and explain why this was never done.

ANSWER 04

a. Ordering Paragraph 1 of Decision 20-12-005 grants the January 14, 2020 "Joint Motion for Approval of Settlement Agreement regarding Pacific Gas and Electric Company's (PG&E) Test Year 2020 General Rate Case, including Post-Test Years (PTY) 2021 and 2022" (Settlement Motion) subject to certain modifications to the Settlement Agreement unrelated to the ISO 55000 certification. Section 2.4.4 on pages 17 and 18 of the 2020 Settlement Agreement, among other things, states the following: "PG&E will make a good-faith effort to apply for and attain an ISO 55000 certification from an accredited organization for its dams by the end of 2022."

b. PG&E conducted a gap analysis in 2020 as part of its "good faith effort to apply for and attain an ISO 55000 certification from an accredited organization for its dams by the end of 2022." Lloyd's Register conducted the gap analysis for PG&E on

November 16-19, 2020. This gap analysis is included as Attachment GRC-2023-PhI_DR_CalAdvocates_165-Q04Atch01. The purpose of this gap analysis was to determine if any gaps existed that would prevent PG&E from attaining an ISO 55000 certification from an accredited organization for its dams by the end of 2022. In this gap analysis, Lloyd's Register noted, "Lloyd's Register EMEA believe it would be reasonable, subject to the availability of appropriate resources, for PG&E PGen to either close the existing gaps or provide sufficient evidence of progress toward closure such that the gaps would not constitute a barrier to certification at formal assessment within the expressed timescale. That timescale envisaged a formal assessment to be completed by year-end 2022 although no firm dates are yet arranged. However, it should be reiterated that an appropriate level of resource availability is critical in order to prepare the business, carry out readiness assessments and resolve non-conformances etc. across the organization for delivering certification within the aforementioned period."[1] The 6 new hires support gap closure in areas that Lloyd's identified as preventing a good faith effort to achieving ISO 55000 certification by the end of 2022. In addition, these 6 new hires will support the gap analysis required to initiate an ISO 55000 certification process for its entire hydroelectric portfolio in 2023 or earlier as required by Ordering Paragraph 1 of Decision 20-12-005 and Section 2.4.4 of the 2020 GRC Settlement Agreement. These 6 new hires will also help PG&E take all reasonable efforts to maintain certification status during the three-year certification period as required by Ordering Paragraph 1 of Decision 20-12-005 and Section 2.4.4 of the 2020 GRC Settlement Agreement.

c. Each new hire request must be presented before a workforce hiring committee and be approved on the merits of the role as it pertains to supporting PG&E's operating success including controlling risks. The committee questions the need for the role, alternative approaches to filling the role, such as absorbing the work within existing workforce or hiring contractors if the role is more temporary in nature, and the cost component, in terms of how the role will be funded. This committee was informed prior to approval of the gaps identified by Lloyd's, the good faith effort required to close these gaps, and how these resources support gap closure. PG&E considers these new hires as a requirement in order to make a good-faith effort to apply for and attain an ISO 55000 certification from an accredited organization for its dams by the end of 2022, as required by Decision 20-12-005.

d. PG&E had not attempted to obtain ISO 55000 certification prior to executing the 2020 GRC Settlement Agreement because it had no specific commitment to obtain ISO 55000 certification during much of this time frame and did not complete a gap assessment to feed the ISO 55000 implementation roadmap until the fourth quarter of 2020. Please see Attachment GRC-2023-PhI_DR_CalAdvocates_165-Q04Atch01 for the gap assessment.

1 Lloyd's Register Gap Analysis for PG&E, page 3.

ISO 55001: 2014

Gap Analysis

Report for:

PG&E Power Generation

LR EMEA reference:	PRJ11082653
Assessment dates:	16th – 19th November 2020
Assessment location:	Remote via Teams
Assessment criteria:	ISO 55001: 2014
Assessment team:	P Glaholm, B Woods
LR office:	Birmingham

Lloyd's Register

Contents

1. Executive report

Assessment outcome:

A Gap Analysis of PG&E Power Generation (PGen) was carried out remotely, due to COVID-19, over four days. PG&E PGen has contracted Lloyd's Register (LR) to conduct this gap analysis. The Lloyd's Register Group was a sponsor and key contributor to the development of PAS 55– 1: 2008 (PAS 55), which involved detailed research on good asset management practices worldwide and is the forerunner of ISO 55001: 2014. As leaders in this development process, LR is able to draw on a detailed knowledge of the specification itself and its guidance. LR has also certified many companies around the world to PAS 55 and ISO 55001 in, amongst others, the nuclear, utilities and transportation sectors. ISO 55001 seeks objective evidence that the asset management system is totally aligned to the overall business strategic objectives and therefore covers all parts of the business. This gap analysis reviewed the asset management system for PG&E Power Generation.

The compliance of PG&E PGen with the asset management system requirements clauses of ISO 55001 was reviewed at a level consistent with the time available and the methodology of remote assessment.

It is common that the output from a gap analysis can be seen as overly negative, but the purpose of a gap analysis is to identify areas of concern so that these can be addressed before any formal certification assessment.

This report was produced following this visit and is based on both subjective and objective evidence seen during the office visit. It has been produced for illustration purposes only, as part of a four-day ISO 55001 Gap Analysis. Findings are raised only to indicate potential non-conformances should similar objective evidence be found during a formal audit.

Lloyd's Register EMEA believe it would be reasonable, subject to the availability of appropriate resources, for PG&E PGen to either close the existing gaps or provide sufficient evidence of progress toward closure such that the gaps would not constitute a barrier to certification at formal assessment within the expressed timescale. That timescale envisaged a formal assessment to be completed by year-end 2022 although no firm dates are yet arranged. However, it should be reiterated that an appropriate level of resource availability is critical in order to prepare the business, carry out readiness assessments and resolve non-conformances etc. across the organization for delivering certification within the aforementioned period.

All PG&E PGen staff involved with this gap analysis cooperated fully with the assessment team by providing evidence as requested and engaging in open and frank discussion.

System effectiveness and continual improvement

The effectiveness of the Asset Management System will become clearer following the implementation of the developing policies, standards and procedures but it could be demonstrated that there are many improvements already underway. There are still a significant number of areas of the asset management system in PG&E PGen which do not currently meet the requirements of ISO 55001. There was recognition within the PG&E PGen management team of the need for continued improvement of the asset management system as a whole and of the need to build process, understanding and integration across and between the business streams within the organization. A commitment to continual improvement across the Asset Management process was expressed at all levels and in all parts of the business touched by this gap analysis. This gap analysis provided good insight into the current state of the AM system and gave the assessors some comfort that the business is progressing towards a certifiable system in 2022.

There appeared to be good plans in place for the further roll out of processes important to the AM system and these will be further tested at the next visit in 2021. Should the good work, which is currently ongoing, continue then the assessors see no reason why the business would not be ready for formal assessment during the course of 2022. However, the business must not underestimate the challenges ahead, particularly in the areas of Asset Management Objectives and Plans, Asset Management Information Systems, Prioritization and Optimization of Capital and Expense spending and Change Management.

Strengths Seen:

- Good commitment to the process with a very open and honest approach to the current position of the organisation.
- Good plans in place to develop the critical Asset Management Plans which will be key to delivering the program.
- Training and competency management processes are well developed.
- The CAP process appears to be well embedded and accepted in the business.
- An array of data and metrics are in place to inform management decisions and, whilst these may require further development, provide a solid base.
- Communication both internally and externally is well developed and mature.
- Good emergency planning processes.
- Robust document review process.

Areas for management attention:

During the gap assessment some areas of non-conformance were identified against some of the following ISO 55001 clauses which, had this been an accreditation assessment, would have been raised as findings as below. Where no non-conformances were found at this time, a brief commentary has been provided on that clause. It should be noted that some non-conformances may be applicable to multiple clauses e.g. communication of system documentation such as Policy, SAMP, the AM System etc. In order to demonstrate that an ISO 55001 compliant management system is operated at PG&E PGen, prioritized action would need to be taken against the Major Non-Conformances with a corrective action plan in place to address the Minor Non-Conformances. It should be noted that it is not necessary to fully close out minor non-conformances but that there needs to be an appropriate corrective action plan in place to rectify them. It is important that PG&E PGen fully consider the implications of all the non-conformances on their processes and procedures and that the corrective action to be taken meets the business needs rather than a short-term fix to temporarily close out the non-conformance. Non-conformances, Scopes for Improvement (SFI) and Lloyd's Register Prompts (LRP) are contained in the findings log at the rear of this report.

7 Major Non-Conformances and 4 Minor Non-Conformances have been identified during the gap analysis against each of the following areas;

- **Clause 4.1 Understanding the Organization**
  Whilst the processes are still immature, PGen has carried out a great deal of work to align the documentation and information required to implement an appropriate set of organizational objectives throughout the business. The SAMP and AM System are aligned, although not yet implemented and communicated, and form a good basis for the development of good asset management practices moving forward.

- **Clause 4.2 Understanding the Needs of Stakeholders**
  Stakeholder engagement is linked to the wider PG&E strategy but drives down to PGen specific stakeholders both internally and externally. Internal and external stakeholders have been defined and there are regular and varied methods of communication with them linked to a set of strategic requirements and outreach/communication objectives. Key internal and external messages are defined around the key business goals of; safety, reliability, risk and compliance, optimization etc.

- **Clause 4.3 Scope**
  The scope of the Asset management System has been clearly defined and documented and covers eight Asset Families; Dams, Civil Infrastructures, Powerhouses, Physical Data Assets, Solar Generation, Fossil Generation, Asset Information and Battery Storage. Hydrogen Generation and Nuclear Generation are not in scope. The scope is linked to the SAMP, Policy and AM System.

- **Clause 4.4 Asset Management System**
  A separate, draft, Power generation Asset Management System Manual has been developed and is aligned to the SAMP and Policy documents. The document covers the scope of the PGen assets and the roles and responsibilities of the Asset Family Owners. The document is still in the development phase and has not been implemented or communicated in the wider business as yet. It will be subject to the same, general, Major Non-conformance, with regards to communication and implementation, as the Policy and SAMP. In order to ensure there is no non-conformance in this area at certification, the document will need to be finalized, issued, implemented and communicated. Additionally, the assessors felt that the inclusion of the Fig 1 from the Manual in the SAMP would aid understanding of the process. **Major NC PG&E PGenGA001nand SFI PG&E PGenGA012 refer.**

- **Clause 5.1 Leadership and Commitment**
  It is clear that there is a commitment and desire from the PGen management team to drive compliance with ISO55001 and good asset management practices through the business. A great deal of work has been undertaken to develop additional documentation, systems and roles and responsibilities in line with the standard. A Responsible, Accountable, Consulted and Informed (RACI) matrix has been developed to demonstrate the job roles and current individual against appropriate clauses of the standard. In addition to this, senior management are encouraging good collaboration and best practice sharing across the Asset Families and with other parts of the business, including; Gas Operations (ISO55001 Certified), Electric Operations (Stage 1 Complete) and their own Nuclear Generator (Diablo Canyon). There are a lot of improvements underway in the business already and plans were shared to continue to develop these over the coming months around the strap line of; Power Generation Asset Excellence (PGAE).

- **Clause 5.2 Policy**
  A policy document; PG-02 rev 0 has been produced and circulated to the extended leadership team at the 10/20/20 Power Generation Leadership team meeting and the Policy document appears to be appropriate to the business. An Asset Management commitment poster was shared with the extended leadership team at the same time and a follow up email to the leadership team contained the AM policy, AM commitments, and a document titled AM Talking Points. These documents have not yet been communicated to the wider business or fully implemented in the organization. In addition, it was noted that Stakeholders are not currently mentioned in the Policy and the assessors believe that this would enhance the document and show a clear link to stakeholder engagement. **Major NC PG&E PGenGA001 and SFI PG&E PGenGA013 refer.**

- **Clause 5.3 Roles, Responsibilities and Authorities**
  As previously stated, a RACI matrix exists outlining roles and responsibilities for the AM System in PGen. An Asset Management Steering Committee is in place and could be seen to demonstrate a level of governance across asset management decision making. In addition to this, roles and responsibilities are outlined in the SAMP which, again, demonstrates important links in the AM documentation and process. Detailed organograms exist for the organizational structure and these were utilized throughout the assessment to demonstrate responsibilities in each area. However, there was reference in various documents to; Asset Family Owners, Asset Family Specialists and Asset Family Leads and the assessors believe that standardization of this terminology would be of benefit moving forward. **SFI PG&E PGenGA014 refers.**

- **Clause 6.1 Risk & Opportunity**
  A Generation Integrated Risk Management process exists and this revolves around; Enterprise, Operational and Project Risks. Currently, PGen employs a Probabilistic Risk Assessment (PRA) methodology and there is risk documentation in both current (Enterprise and Operational Risk Management Procedure) and draft (Generation Integrated Risk Management Procedure) form and the proposals for the new PGen document was outlined. Risk modelling for high-risk assets is based on PRA and Fault Tree Analysis which allows for the ranking and prioritization of events via a software package – Computer Aided Fault Tree Analysis (CAFTA) provided by EPRI. The process for a future Risk Informed Budget Prioritization process was outlined with a roadmap and mapping to ISO 55001 included with a potential to move this to the Copperleaf system in future. Whilst risk processes exist within PGen, it appears that these are, at present, somewhat inconsistent with limited links to the prioritization and optimization of capital and expense planning. **Minor NC PG&E PGenGA008 refers.**

- **Clause 6.2.1 Objectives**
  The 2020 – 2024 Generation Operating Plan contains the high-level business objectives which then track through to the SAMP which contains; Company strategic objectives, Power Generation strategic objectives, and Asset Management objectives. However, there was no evidence that asset management objectives had been driven down to individual roles and responsibilities and, as such, it could not be demonstrated that objectives were established at all relevant functions and levels and clearly linked to AM plans. **Major NC PG&E PGenGA002 refers**

- **Clause 6.2.2 Planning for Achievement**
  Asset Management Objectives will be linked to the requirements of the Asset Families (AFs) and their owners. Budget allocation for each of the AFs is in place and was demonstrated but this is not yet fully linked to risk and prioritization. PGen are currently in the process of documenting Asset Management Plans (AMPs) across their eight Asset Families. An external resource is being used to assist with this process and these plans will be key to achieving the stated goal of compliance with ISO 55001 by 2022. There is a mixture of data information quality and availability across the Hydro, Fossil and Solar assets and this requires some work to develop a consistent and coherent process which provides the levels of information required in order to make sound asset management decisions. There is no overarching system for work planning and management currently although Damwatch is used for certain purposes in Hydro and can issue “job tickets” and this is being reviewed to certify Damwatch as a “System of Record”.
  A long-term planning process is in place with an “A” plan (1 – 6 years), “B” plan (6 – 10 years) and a “C” plan which delivers the first-year objectives of the longer-term A and B plans. Prioritization currently takes place through ongoing planning meetings but there appears to be inconsistent application of risk, prioritization and optimization considerations at this point.
  With regards to capital projects, there is a “gated” governance process in place and whilst the business currently reviews the “net present value” of assets, there is no benefits realization process to enable the business to understand if the expenditure has had the desired outcomes. **Major NC PG&E PGenGA003, Minor NC PG&E PGenGA008, SFI PG&E PGenGA015 & LRP PG&E PGenGA017 refer.**

- **Clause 7.1 Resource**
  As in many organizations, resources are finite and can be subject to fluctuation. Currently, there are a number of posts unfilled within the business which amounts to around 6% of the year end FTE target. The business is confident that these roles will be filled and adequate resources are available to deliver the current plans. However, resource constraints were mentioned during a number of the sessions and the assessors will further review this area in future, with a heavy recommendation that PGen ensures that all necessary resources are in place to deliver the business objectives and plans alongside the additional challenge of further developing their Asset Management System. **LRP PG&E PGenGA018 refers.**
  There did not appear to be any issues with regards to current financial resources and expenditure appeared to be on track in the Power Generation Performance Book.
  Included in the area of resources is the management of tools and equipment, required to ensure that assets are tested, inspected and maintained appropriately, and which may require testing or calibrating themselves. Some evidence was provided in the area of precision measuring equipment e.g. micrometers, calipers etc. but the broader testing and calibration of equipment such as; flukes, ohmmeters, torque wrenches etc. could not be established. There is limited guidance and documentation around verification of equipment status both internally and for contractor equipment and if processes are fully in place and adhered to. PGen may find it useful to benchmark this area with both Gas Operations and Electric Operations within PG&E who have been developing their processes in this area. **Major NC PG&E PGenGA005 refers**

- **Clause 7.2 Competence**
  It was demonstrated that there is good collaboration across the Enterprise with regards to the delivery of training. COVID has provided some challenges with face-to face training but the embargo was lifted in August and this type of training is being managed as appropriate. Information on training sits in the MyLearning system and this is managed by the Power Generation Learning Team. Restrictions are in pace for certain types of training e.g. crane operator that mean an operator cannot continue if their training and certification is not renewed. Some contractor training is provided but that would be for PGen specific requirements and not general training requirements. It was noted that there are concerns around resource availability to both deliver and attend training. In the main, requirements of the standard are met but there are still improvements underway to enhance the process. **LRP PG&E PGenGA018 refers.**

- **Clause 7.3 Awareness & Clause 7.4 Communication**
  Whilst there are many methods of communication and awareness deployed in the business, PGen have not, currently, widely communicated the asset management principles or much of the documentation that will drive its ultimate goal of compliance with ISO 55001 and good asset management practice. There was limited evidence of any specific asset management communication and awareness training amongst the broader workforce, contractors and suppliers or stakeholders. Plans are in place to address this and documentation production is underway in all areas. **Major NC PG&E PGenGA001 refers.**

- **Clause 7.5 Information Requirements**
  Physical Data Assets (PDA) has been stood up as an Asset Family with data gathering begun and a plan to upload the information on PowerBase. Demarcation between PDA and the IT service provider has been defined and a Service Level Agreement is in place defining roles responsibilities. Again, there are challenges with resources in this area particularly in the disciplines of instrument control and electrical technicians.
  Information systems appear to be many and disparate across the business ranging from paper records and personal spreadsheets through to functional IT systems but even these may not cover all of the business. Asset Family risks are monitored at various levels and fed into the Long-Term Planning Process with RIBA also utilized to monitor asset risk but this did not appear to be consistent.

PGen recognizes that this is a critical area for the business and that the disparate data and information streams across the AFs needs to have greater levels of consistency and granularity and, in many areas, require a “single source of truth”. It may be useful for PGen to develop a plan to gather all the relevant information based on criticality of both the assets and the associated asset information. In addition to this, it could not be ascertained, to any great detail, how the physical asset information feeds through to financial asset information although some work orders are tied to financial codes in SAP. Work is ongoing in this area and the business is currently developing a plan to resolve many of the issues presented, however, this is not yet timelined or resourced and, as such, it is unclear when delivery will be in place. **Major NC PG&E PGenGA006, Minor NC PG&E PGenGA010, SFI PG&E PGenGA016, LRP PG&E PGenGA019, LRP PG&E PGenGA020, & LRP PG&E PGenGA021 refer.**

- **Clause 7.6 Documented Information**
  PGen follows the PG&E Enterprise process and clearly has a controlled procedure for creating, updating and managing documentation such as; Policies, Standards, Procedures, Guidance Documents and Job Aids. Systems such as; Documentum and ECTS are in place to manage controlled documents and ensure their regular and timely update with, reportedly, only eight documents past their due date out of nine hundred which is commendable. However, as mentioned elsewhere, the specific documentation around the Asset Management System and supporting documents such as the SAMP and Policy are yet to be finalized, communicated and Implemented. **Major NC PG&E PGenGA001 refers**

- **Clause 8.1 Operational Planning and Control**
  Recurring, or preventative, maintenance is carried out differently across the different types of generation with SAP work management (WM). In Fossil and Solar, SAP WM seems to work well with little backlog. In Hydro, they rely more on supervisors and journey level technicians to manage work planning and backlog within SAP Work Management.. It is recognized that data and information in this area is inconsistent and requires cleansing to ensure that the full picture is understood. SAP tags can be issued with quite high-level requirements e.g. “inspect generator” which does not allow for any level of granular understanding regarding what work has been carried out on the asset. No QA/QC process currently exists to review work order close out. With regards to new assets, maintenance requirements are currently decided by the maintenance department based, primarily, on existing knowledge and experience. Resource challenges exist in this regard and the late delivery of O&M manuals exacerbates the problem. Missed compliance tags would generate a self-report to the appropriate regulator. **Major NC PG&E PGenGA003, Minor NC PG&E PGenGA008, & LRP PG&E PGenGA018 refer.**

- **Clause 8.2 Management of Change**
  There is currently little evidence available of Management of Change (MoC) processes within the business and any that may exist is described as inconsistent but there is a great deal of work going on to ensure that this area develops over the coming months. An Enterprise MoC Standard is expected to be in place by the end of the year with a PGen MoC procedure planned for March 2021. PGen have developed a draft timeline for implementation of processes by year end 2021 and should ensure that any existing Plant Modification Procedures are incorporated into the process. The (Draft) PG Guidance Document Management Process was seen and appears to be appropriate to good document management processes moving forward. **Major NC PG&E PGenGA004 refers.**

- **Clause 8.3 Outsourcing**
  Currently, PGen documentation in this area broadly follows the Enterprise structure and this is due to be updated in 2021. There are processes in place for the onboarding and ongoing management, including competency of contractors and suppliers. A supplier qualification process is in place for bid event and the scoring system can be refined dependent upon the type of product or contract to be let. Additionally, all suppliers and contractors go through safety pre-

tender process and results are recorded on ISNet. Suppliers also undergo a third party risk assessment before proceeding to work with PG&E. Supplier and contractor scorecards are utilized and this provides some level of ongoing evaluation, although this is not completed for all and can be somewhat ad-hoc in its application. There are no other formal methods of evaluation provided. **Minor NC PG&E PGenGA009 refers.**

- **Clause 9.1 Monitoring, Measuring, Analysis and Evaluation**
  The main reference for monitoring performance in the business is the Power Generation Performance Book and this was reviewed. Information is provided by the Performance Reporting Team and managers are expected to pre-read the material prior to the monthly Power Generation Leadership Team Meeting with issues being dealt with "by exception". The book operates a RAG system and any items that are currently in red are dealt with through the responsibilities of the director in that area. There are currently no trending arrows on the information provided and no formal methodology for verification of the information provided. **SFI PG&E PGenGA016 refers.**

- **Clause 9.2 Internal Audit**
  An Internal Audit process currently exists within PGen. This process utilizes multiple inputs, including results of the Enterprise audit team, to help determine which programs and processes to evaluate. While the results of the Enterprise audit team are utilized as inputs, at present there is no formal review of areas that may be duplicated by them and the PGen internal audit team. A Utility Standard; 'Operations Review of Power Generation Facilities', provides guidance on evaluating PGen facility compliance with applicable regulations, standard operating procedures and clearance procedures. The intent, moving forward, is to deliver targeted evaluations with independent PGen employees who are trained as Audit Team Leaders (ATLs), Certified Quality Auditors (CQAs), or personnel working under the direction of an ATL or CQA. Additional subject matter experts (SMEs) may be utilized during the evaluations and they will be independent of the areas they will be evaluating. Issues identified from the evaluations are recorded and managed in the CAP system. PGen personnel have the ability to generate reports for tracking and monitoring these issues while significant issues will be periodically monitored by the PGen internal audit team. Significant issues are discussed at the senior leadership level in weekly meetings as well as in the Risk and Compliance Committee meeting where appropriate. Some of the processes are still work in progress and, as such **LRP PG&E PGenGA022 refers.**

- **Clause 9.3 Management Review**
  No formal Management Review is currently carried out with regards to asset management requirements. However, there are many and varied metrics and meetings that can be utilized in this area and PGen should review the most optimized way of carrying this out in the future. A draft Management Review procedure and flowchart have been developed utilizing existing practices in the PG&E organization and this is a good basis for developing the process moving forward. **Major NC PG&E PGenGA007 refers.**

- **Clauses 10.1 Non-conformity and Corrective Action & 10.2 Preventative Action**
  The CAP program is embedded and established in the organization with good compliance in many areas but some levels of difficulty which are being addressed. CAP provides a repository for issues raised in the business and a prioritization and action tracking system to allow issues to be managed and resolved. However, there does appear to be a lack of guidance and understanding regarding when CAP or SAP should be used to record and manage asset faults or failures and **Minor NC PG&E PGenGA011 refers.**

- **Clause 10.3 Continual Improvement**
  It was clear across the Gap Analysis that there are many and varied areas of continual improvement in PGen and the assessors are of the opinion that the ongoing drive towards achieving compliance with ISO 55001 will only enhance this. It was also clear that there is a

commitment from senior managers to ensure that this happens and inclusion in the business objectives of these aims ensure that there will be management focus on the outcomes.

It should be noted that these findings are not raised formally as part of the ISO 55001 certification process but only as an indication of where deficiencies would occur during the certification process if the same gaps were identified at stage. It should also be noted that the level of Non-Conformance raised in this report is not untypical for an organization at this stage of the ISO 55001 certification process.

Details of all the findings are contained within the findings logs at the rear of this report.

Scope of the Gap Analysis

The scope of the gap analysis was the eight Generation Asset Families, noted in the SAMP, and owned and operated by PG&E Power Generation.

The scope for any future certification assessment will need to be confirmed prior to Stage 1.

The specification used was International Standard; ISO 55001: 2014 Asset management; Management systems - Requirements

The analysis was performed over four days remotely and the scheduling was designed to facilitate availability of appropriate PG&E PGen staff whilst minimizing impact on operations. The analysis was conducted by remote desktop document review and interview involving directors and managers across the business. Further analysis will be required at greater depth as part of ongoing assessments as the business progresses.

Limitations of the Gap Analysis

This gap analysis is based, in the main, on desk top document reviews and interviews and has not necessarily sought confirming evidence for descriptions and explanations given by PG&E PGen staff as would be the practice at formal assessment. There is, therefore, the possibility that some issues have remained unidentified during this visit. Consequently, the absence of comment on any area or system element does not necessarily imply conformance with the relevant requirements of ISO 55001.

Assessors

Peter Glaholm & Bernie Woods of Lloyd's Register EMEA.

Lloyd's Register

2. Non-Conformance Findings Log – ISO 55001: 2014

Grade of finding	Assessed ISO 55001 Clause	Finding	Ref.
Major NC	4.4, 5.2, 7.3, 7.4, 7.6	**Significant documents such as the AP Policy, SAMP and Plans etc. are yet to be communicated and, in some cases, developed for the wider organization. PGen need to ensure that all required documentation is developed, implemented and communicated across the business.**	PG&E PGenGA001
Major NC	6.2.1	**Currently, objectives set at the business level do not flow through to individual objectives and, as such, alignment of objectives and plans cannot be determined. In order to ensure that a "Line of Sight" is in place throughout the organization, individual, team and operating unit objectives and plans should be documented and reflect the higher-level objectives of the business.**	PG&E PGenGA002
Major NC	6.2.2, 8.1	**Coherent and consistent plans for both Capital and Expense expenditure across the various asset families of the business are not currently available in the business and could not be seen to reflect risk, prioritization and optimization. PGen needs to ensure that clarity is demonstrated as to how plans are developed, implemented, managed and, ultimately, clearly linked to risk.**	PG&E PGenGA003
Major NC	8.2	**Whilst there is some level of Plant Modification Processes, wider Change Management at both operational and organization levels are still under development. Comprehensive Operational and Organizational change management procedures are required to ensure that any risk, due to change, is managed in a timely and appropriate manner.**	PG&E PGenGA004
Major NC	7.1	**The current testing and calibration procedure appear to be limited to certain types of equipment and is unclear in a number of areas including electrical test equipment and control of contractor supplied equipment. This are will be more fully tested at any future site visits and PGen may benefit from benchmarking the approach that has been adopted in other parts of the wider PG&E business.**	PG&E PGenGA005
Major NC	7.5	**There currently appears to be myriad business systems, documentation and individual spreadsheets etc. with regards to asset data and information. A clear, consistent and coherent approach is required to ensure that appropriate information is available to the organization. Information management is a critical area for the business and a lack of clarity in this area will make it difficult to demonstrate that the decision-making process for asset management has been carried out in a manner which truly addresses risk.**	PG&E PGenGA006
Major NC	9.3	**Whilst a Management Review process is currently being considered and documented, there is no process in place at present. Management Review is a requirement of the Standard and must be carried out prior to the Stage 2 assessment to ensure the award of certification.**	PG&E PGenGA007
Minor NC	6.2.2, 8.1,	**There does not appear to be an overall consistent approach to risk management and how this risk informs both capital and expense planning decisions to allow formal optimization and prioritization. Risk, along with Information Management, is critical in ensuring that the business is prioritizing and optimizing its approach to managing assets based on the risk and criticality it has assigned to them.**	PG&E PGenGA008
Minor NC	8.3	**There appears to be inconsistencies in the operational management of contractors and suppliers with regards to evaluation and scorecard completion. PGen must ensure that they are monitoring and measuring the activities of suppliers and contractors to ensure that the standards and requirements of the business are being met to the quality levels that they set.**	PG&E PGenGA009

Grade of finding	Assessed ISO 55001 Clause	Finding	Ref.
Minor NC	7.5	**There is a lack of consistency and clarity with regards to performance and condition monitoring across, and between, the Asset Families. This is linked to the non-conformance around information management and requires PGen to determine the type and amount of information that is required across the Asset Families and ensure that there are processes in place to allow this information to be collected and ensure that issues and deficiencies are tracked and managed.**	PG&E PGenGA010
Minor NC	10.2, 10.3	**There does not appear to be any guidance available for when to complete a CAP item and/or create a SAP tag for equipment faults or failures. Where there are multiple systems for reporting faults and deficiencies, PGen must ensure that guidance and instruction is in place to ensure that the correct reporting methodology is utilized, thus allowing the correct remedial actions to be taken in a timely manner.**	PG&E PGenGA011

Lloyd's Register

3. Improvements Findings Log – ISO 55001: 2014

Grade of finding	Assessed PAS55-1 Clause	Finding	Ref.
Scope for Improvement	4.4,	**To include the Figure 1 from the PG AM System manual in the SAMP which will increase understanding and consistency across the documents.**	PG&E PGenGA012
Scope for Improvement	5.2	**To include reference to Stakeholders in the Policy document. This will ensure clarity with regards to Stakeholders being part of the consideration of the business at all levels.**	PG&E PGenGA013
Scope for Improvement	5.3	**To include the roles and responsibilities of Asset Family Owners and Asset Family Specialists (Principles/Leads?) in the SAMP and to clarify the wording. Again, this will ensure clarity and consistency across the documentation.**	PG&E PGenGA014
Scope for Improvement	6.2.2	**To include a full benefits realization process for capital expenditure in addition to the current "Net Present Value" review. It is important that the organization understands that the interventions that they make on the assets, particularly with regards to capital expenditure, have achieved the desired results and provided the benefits that should be outlined in any project proposal documentation.**	PG&E PGenGA015
Scope for Improvement	7.5, 8.1, 9.1	**To consider the use of trending arrows to the overview table in the Power Generation Performance Book and also consider how to formally ensure verification of the information provided, perhaps through the internal audit process. This should give clear indication where a metric or KPI is trending in the wrong direction so appropriate and timely interventions can be made.**	PG&E PGenGA016
Lloyd's Register Prompt	6.2.2	**To review how the long-term planning process is linked to risk. This process is quite complex and the assessors would like to delve deeper in this area to fully understand the process and linkage.**	PG&E PGenGA017
Lloyd's Register Prompt	7.1, 7.2	**To review how the resource management in the business is progressing with regards to many references, throughout the Gap Assessment, suggesting resource may be an issue.**	PG&E PGenGA018
Lloyd's Register Prompt	7.5	**Further review of the systems which link financial and non-financial asset information and data. Again, this is a complex area which may require further, in depth analysis, to fully understand the linkage between the systems currently utilized in the business.**	PG&E PGenGA019
Lloyd's Register Prompt	7.5	**To further review how information and metrics are derived for the Performance Book, in particular, around compliance reporting.**	PG&E PGenGA020
Lloyd's Register Prompt	7.5	**To further investigate the current state of AM systems across the Asset Families. Given the many and varied systems in the organization a further, in depth, review would be required to fully understand all of the processes.**	PG&E PGenGA021
Lloyd's Register Prompt	9.2	**To further investigate the development and embedding of the Internal Audit process. The approach to this is quite new and requires embedding in the business.**	PG&E PGenGA022

Grade of finding	Assessed PAS55-1 Clause	Finding	Ref.

ISO 55001 Grading Definitions	
Major Non Conformity (Major NC)	**Objective evidence demonstrates that an element from the ISO 5501 standard has not been documented implemented or maintained. Certification to ISO 55001 cannot be granted where there are outstanding Major NCs at stage 2.**
Minor Non Conformity (Minor NC)	**Objective evidence demonstrates a weak element in the management system, procedure, registration or control for the effective implementation of ISO 55001. The absence of timely corrective actions could lead to a situation in which the organization fails to meet the requirements of ISO 55001. Certification to ISO 55001 can be granted with outstanding Minor NCs provided a corrective action plan is agreed.**
Scope For Improvement (SFI)	**Indicate potential improvements for the organization.**
LR Prompt	**Indicates a prompt for the Lloyd's Register Assessors at their next assessment visit**

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CaliforniaTrout_001-Q005		
PG&E File Name:	GRC-2023-PhI_DR_CaliforniaTrout_001-Q005		
Request Date:	March 15, 2022	Requester DR No.:	001
Date Sent:	March 29, 2022	Requesting Party:	California Trout, Inc.
PG&E Witness:	Rebecca Doidge	Requester:	Matthew Clifford/ Edward T. Schexnayder

QUESTION 005

On what data/evidence does PG&E base its assumption of a 15-year decommissioning period for the Potter Valley Project (see Exhibit PG&E-5 at pp 8-12 & 13)? Please provide this data and evidence.

ANSWER 005

Please see Exhibit (PG&E-5), p 8-13, lines 10-13. “PG&E has continued to assume a rough timeline of 15 years to decommission a hydro project. Physical decommissioning project work is assumed to take five years to complete.” In order to establish the decommissioning forecast, PG&E has assumed it will take 10 years to complete the regulatory process with the Federal Energy Regulatory Commission (FERC) to surrender the license and receive the decommissioning order. Furthermore, PG&E has assumed that physical decommissioning would take five years so the forecast costs are spread evenly over five years. This “rough timeline” was used as a base assumption for all projects in the decommissioning estimate and is not based on specific data, nor intended to determine the future timeline for the Potter Valley project.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CaliforniaTrout_001-Q006		
PG&E File Name:	GRC-2023-PhI_DR_CaliforniaTrout_001-Q006		
Request Date:	March 15, 2022	Requester DR No.:	001
Date Sent:	March 29, 2022	Requesting Party:	California Trout, Inc.
PG&E Witness:	Eric Van Deuren	Requester:	Matthew Clifford/ Edward T. Schexnayder

QUESTION 006

What is the estimated all-in cost of providing a new transformer to the Potter Valley Project?

ANSWER 006

PG&E estimates the cost to replace the transformer at approximately $8.9M.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CaliforniaTrout_001-Q007		
PG&E File Name:	GRC-2023-PhI_DR_CaliforniaTrout_001-Q007		
Request Date:	March 15, 2022	Requester DR No.:	001
Date Sent:	March 29, 2022	Requesting Party:	California Trout, Inc.
PG&E Witness:	Eric Van Deuren	Requester:	Matthew Clifford/ Edward T. Schexnayder

QUESTION 007

If PG&E intends to recover any of the costs of this new transformer from the ratepayers, what is the anticipated authorization and timing for the cost recovery?

ANSWER 007

PG&E will recover the transformer replacement costs as a hydro capital investment within the approved forecast of the 2023 GRC. PG&E did not include the forecast for the replacement of the transformer in the 2023 GRC because it had not yet decided to replace the transformer when the GRC forecast was developed. Nonetheless, PG&E will recover the cost of the transformer replacement within the authorized amounts approved by the CPUC for the generation revenue requirement within the 2023 GRC.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CaliforniaTrout_001-Q009		
PG&E File Name:	GRC-2023-PhI_DR_CaliforniaTrout_001-Q009		
Request Date:	March 15, 2022	Requester DR No.:	001
Date Sent:	March 29, 2022	Requesting Party:	California Trout, Inc.
PG&E Witness:	Eric Van Deuren	Requester:	Matthew Clifford/ Edward T. Schexnayder

QUESTION 009

Does PG&E assume that the new transformer will be able to be transferred for use at another facility after the Potter Valley Project is decommissioned?

ANSWER 009

PG&E objects to this data request on grounds that it is irrelevant to the subject matter under review in this proceeding.

Subject to and without waiving that objection, PG&E anticipates that the new transformer could be used at another facility after Potter Valley is decommissioned or that it could continue to be used at Potter Valley as a substation asset.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	CaliforniaTrout_001-Q010		
PG&E File Name:	GRC-2023-PhI_DR_CaliforniaTrout_001-Q010		
Request Date:	March 15, 2022	Requester DR No.:	001
Date Sent:	March 29, 2022	Requesting Party:	California Trout, Inc.
PG&E Witness:	Eric Van Deuren	Requester:	Matthew Clifford/ Edward T. Schexnayder

QUESTION 010

If yes, please provide the factual basis for that assumption, including any supporting documents.

ANSWER 010

PG&E objects to this data request on grounds that it is irrelevant to the subject matter under review in this proceeding.

Subject to and without waiving that objection, PG&E responds that it has another hydro location, Hat Creek Powerhouse, that has a similar sized transformer where the new transformer could be used in the future. PG&E also believes that there could be a market for a used transformer in the broader power generation industry. Lastly, PG&E could elect to continue using the transformer at Potter Valley Substation to continue to provide power to its distribution customers.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_084-Q03		
PG&E File Name:	GRC-2023-PhI_DR_TURN_084-Q03		
Request Date:	January 6, 2022	Requester DR No.:	TURN-PG&E-084
Date Sent:	January 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Eric Van Deuren	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

The following questions related to PG&E's energy supply testimony (PGE-5) and some miscellaneous questions.

QUESTION 03

Please provide for the period from 2015 through 2020 the actual O&M expenses for PG&E's hydro plants disaggregated by labor, materials, and all other costs for each hydro plant.

ANSWER 03

Attachment GRC-2023-PhI_DR_TURN_084-Q03Atch01 provides the actual O&M expenses for each hydro plant by planning order for the period 2015 through 2020 disaggregated by labor, materials, and all other costs. Note that this attachment includes the costs for each hydro plant receiver cost center and the common receiver cost centers. Common receiver costs centers include costs that can't be directly assigned to a particular hydro plant. For example, if an expense project benefits all the facilities covered by the McCloud-Pit Project (FERC License 2106) then the costs are assigned to the FERC Project 2106 Common receiver cost center.

Due to changes in the SAP master data, the values in the attachment at the level of disaggregation requested do not exactly match the values included in the GRC workpapers.

Hydro O&M Expense by Receiver Cost Center

			YTD Dec Actual	YTD Dec Actual	YTD Dec Actual	YTD Dec Actual	YTD Dec Actual	YTD Dec Actual
		Fiscal year	2015	2016	2017	2018	2019	2020
Budget Level 1	**Receiver Cost Center**	**CE Mjr Resource Grp**	* 1,000 $	* 1,000 $	* 1,000 $	* 1,000 $	* 1,000 $	* 1,000 $
Overall Result			**164,643**	**129,893**	**138,855**	**114,928**	**127,544**	**157,182**
Generation	Hat Creek 1	Contract	1,306	190	14	0		
Generation	Hat Creek 1	Labor External	10	1	0			
Generation	Hat Creek 1	Labor Internal	559	162	120	193	146	146
Generation	Hat Creek 1	Materials	28	14	10	8	8	8
Generation	Hat Creek 1	Other	-12	3	2	3	1	6
Generation	Hat Creek 2	Contract	6	15	11	2		-0
Generation	Hat Creek 2	Labor External		0	1			
Generation	Hat Creek 2	Labor Internal	359	217	186	172	132	290
Generation	Hat Creek 2	Materials	16	30	29	18	16	15
Generation	Hat Creek 2	Other	3	3	6	4	4	14
Generation	FERC Project 2661 Common	Contract	6	42	100	81	324	159
Generation	FERC Project 2661 Common	Labor External	309	92	97	190	92	4
Generation	FERC Project 2661 Common	Labor Internal	117	57	44	42	58	58
Generation	FERC Project 2661 Common	Materials	0	3	0	2	4	8
Generation	FERC Project 2661 Common	Other	61	148	16	14	19	19
Generation	Pit 3	Contract	220	197	39	376	16	134
Generation	Pit 3	Labor External	80	67	22	4		61
Generation	Pit 3	Labor Internal	2,710	1,451	573	872	515	1,051
Generation	Pit 3	Materials	33	46	13	126	102	236
Generation	Pit 3	Other	5	6	6	16	11	44
Generation	Pit 4	Contract	409	290	126	64	5	53
Generation	Pit 4	Labor External		11	52	69		
Generation	Pit 4	Labor Internal	1,063	469	288	350	702	457
Generation	Pit 4	Materials	94	49	33	33	291	51
Generation	Pit 4	Other	91	7	3	6	30	18
Generation	Pit 5	Contract	406	555	4,030	267	110	67
Generation	Pit 5	Labor External	3	1	5	0	2	
Generation	Pit 5	Labor Internal	3,142	1,906	1,789	1,174	1,083	1,232
Generation	Pit 5	Materials	90	135	384	193	60	59
Generation	Pit 5	Other	9	13	107	-4,222	-895	29
Generation	FERC Project 233 Common	Contract	816	327	471	585	680	654
Generation	FERC Project 233 Common	Labor External	1,101	1,197	570	443	287	227
Generation	FERC Project 233 Common	Labor Internal	663	406	322	430	371	318
Generation	FERC Project 233 Common	Materials	1	83		4	1	14
Generation	FERC Project 233 Common	Other	42	81	155	149	496	316
Generation	FERC Project 2687 Pit 1	Contract	1,572	2,748	135	282	225	186
Generation	FERC Project 2687 Pit 1	Labor External	418	379	262	156	143	153
Generation	FERC Project 2687 Pit 1	Labor Internal	1,573	684	562	545	525	641
Generation	FERC Project 2687 Pit 1	Materials	67	33	27	80	21	36
Generation	FERC Project 2687 Pit 1	Other	25	12	31	45	41	64
Generation	James B Black	Contract	190	521	164	67	287	279
Generation	James B Black	Labor External		7	1			8
Generation	James B Black	Labor Internal	959	490	527	360	363	743
Generation	James B Black	Materials	39	89	151	7	16	68
Generation	James B Black	Other	-2	8	9	-45	-7	11
Generation	Pit 6	Contract	517	71	101	60	373	134
Generation	Pit 6	Labor External	28	79			9	21
Generation	Pit 6	Labor Internal	668	414	336	204	461	295
Generation	Pit 6	Materials	131	68	37	15	104	52
Generation	Pit 6	Other	-8	10	9	-21	-13	-13
Generation	Pit 7	Contract	395	95	100	911	168	331
Generation	Pit 7	Labor External	8	10	1	8		9
Generation	Pit 7	Labor Internal	556	409	230	453	397	475
Generation	Pit 7	Materials	85	64	28	66	44	30
Generation	Pit 7	Other	-286	8	1	-686	-133	16
Generation	FERC Project 2106 Common	Contract	8	2	37	175	2,220	-373
Generation	FERC Project 2106 Common	Labor External	42	4	5	2	9	7
Generation	FERC Project 2106 Common	Labor Internal	54	51	49	357	325	70
Generation	FERC Project 2106 Common	Materials	1	2		49	11	5
Generation	FERC Project 2106 Common	Other	193	288	284	296	298	281
Generation	Volta 1	Contract	19	150	633	85		527
Generation	Volta 1	Labor External	7	108	222	40	59	107
Generation	Volta 1	Labor Internal	568	231	307	329	280	1,123
Generation	Volta 1	Materials	9	4	16	9	29	283
Generation	Volta 1	Other	166	-0	-7	-0	3	57
Generation	Volta 2	Contract	0	94		0		122
Generation	Volta 2	Labor External		0	1	3		
Generation	Volta 2	Labor Internal	317	176	87	112	123	148
Generation	Volta 2	Materials	3	39	-3	8	6	12

Generation	Volta 2	Other	6	2	-0	0	1	9
Generation	South	Contract	10	244	178	0		
Generation	South	Labor External	6	18	21		9	
Generation	South	Labor Internal	452	670	398	192	233	171
Generation	South	Materials	17	79	293	8	21	10
Generation	South	Other	1	9	28	1	5	2
Generation	Inskip	Contract	89	243	13	166		
Generation	Inskip	Labor External	16	22	17	0		
Generation	Inskip	Labor Internal	870	561	342	245	90	107
Generation	Inskip	Materials	22	50	5	5	1	1
Generation	Inskip	Other	40	54	4	0	1	1
Generation	Coleman	Contract	124	57	10	41	-11	27
Generation	Coleman	Labor External	13	20	15		9	
Generation	Coleman	Labor Internal	769	586	340	437	454	406
Generation	Coleman	Materials	80	64	50	4	37	17
Generation	Coleman	Other	10	11	4	3	8	5
Generation	FERC 1121 Common	Contract	1	19	52	1	65	87
Generation	FERC 1121 Common	Labor External	70	72	30	110	23	4
Generation	FERC 1121 Common	Labor Internal	617	293	257	255	294	343
Generation	FERC 1121 Common	Materials	17	13	6	4	5	6
Generation	FERC 1121 Common	Other	-446	-224	-99	-249	-98	-88
Generation	Kilarc	Contract	97	149	130	39	91	22
Generation	Kilarc	Labor External	26	18	3	18	4	
Generation	Kilarc	Labor Internal	422	424	197	268	150	33
Generation	Kilarc	Materials	23	19	8	27	10	
Generation	Kilarc	Other	14	3	-2	4	4	0
Generation	Cow Creek	Contract	5	9	2	0	65	
Generation	Cow Creek	Labor External	6	10	17	6	2	
Generation	Cow Creek	Labor Internal	373	245	217	230	271	214
Generation	Cow Creek	Materials	5	53	18	11	33	17
Generation	Cow Creek	Other	8	6	3	1	24	3
Generation	FERC Project 606 Common	Contract					9	0
Generation	FERC Project 606 Common	Labor Internal	1	8	4	4	20	7
Generation	FERC Project 606 Common	Other	4	4	5	5	5	5
Generation	Shasta Common	Contract	2,213	1,119	1,258	466	747	684
Generation	Shasta Common	Labor External	240	211	247	66	93	99
Generation	Shasta Common	Labor Internal	3,243	1,906	1,521	1,435	1,561	1,621
Generation	Shasta Common	Materials	88	166	207	208	221	194
Generation	Shasta Common	Other	462	303	294	353	438	513
Generation	Manton Headquarters Common	Contract	170	569	459	562	808	584
Generation	Manton Headquarters Common	Labor External	12	8	6	1	7	24
Generation	Manton Headquarters Common	Labor Internal	230	113	122	109	93	197
Generation	Manton Headquarters Common	Materials	12	6	37	49	53	60
Generation	Manton Headquarters Common	Other	-8	-2	-7	-1	-11	184
Generation	Pit 3 Switching Common	Contract					4	2
Generation	Pit 3 Switching Common	Labor Internal			712	751	745	1,085
Generation	Pit 3 Switching Common	Materials						0
Generation	Pit 3 Switching Common	Other					-0	-0
Generation	Lake Britton Common	Contract	89	9	190	95	215	290
Generation	Lake Britton Common	Labor External	64	250	59	204	34	7
Generation	Lake Britton Common	Labor Internal	75	93	75	52	56	99
Generation	Lake Britton Common	Materials	2	5	11	16	3	49
Generation	Lake Britton Common	Other	7	14	-6	4	5	-2
Generation	Pit 5 Switching Common	Labor Internal			711	659	665	935
Generation	Pit 5 Switching Common	Materials					1	
Generation	Pit 5 Switching Common	Other					0	1
Generation	Butt Valley	Contract	85	150	403	144	610	2
Generation	Butt Valley	Labor External	26	61	48	31	11	3
Generation	Butt Valley	Labor Internal	631	291	445	410	646	529
Generation	Butt Valley	Materials	16	4	86	13	24	14
Generation	Butt Valley	Other	2	8	11	12	-16	6
Generation	Caribou 1	Contract	84	307	553	361	228	278
Generation	Caribou 1	Labor External	10	30	45	40	22	13
Generation	Caribou 1	Labor Internal	2,261	1,403	1,180	1,381	1,501	2,275
Generation	Caribou 1	Materials	100	33	403	55	69	110
Generation	Caribou 1	Other	12	12	58	42	-65	43
Generation	Caribou 2	Contract	568	99	61	8	40	12
Generation	Caribou 2	Labor External	1	5	3		2	
Generation	Caribou 2	Labor Internal	1,040	264	307	207	199	323
Generation	Caribou 2	Materials	44	43	9	40	32	12
Generation	Caribou 2	Other	101	23	8	6	12	6
Generation	Belden	Contract	268	314	697	40	1,615	962
Generation	Belden	Labor External	60	58	330	42	95	59
Generation	Belden	Labor Internal	749	579	370	335	585	368
Generation	Belden	Materials	38	71	40	26	14	3
Generation	Belden	Other	7	-41	19	15	5	10
Generation	Oak Flat	Contract	18	3		23	0	1

Generation	Oak Flat	Labor External	1		1			
Generation	Oak Flat	Labor Internal	154	87	43	96	125	120
Generation	Oak Flat	Materials	1	1	0	0	14	3
Generation	Oak Flat	Other	-0	-0	1	1	3	4
Generation	FERC Project 2105 Common	Contract	118	66	565	270	526	551
Generation	FERC Project 2105 Common	Labor External	299	406	80	489	72	20
Generation	FERC Project 2105 Common	Labor Internal	347	180	275	335	249	252
Generation	FERC Project 2105 Common	Materials	23	4	10	1	1	61
Generation	FERC Project 2105 Common	Other	84	26	79	-145	-115	41
Generation	Rock Creek	Contract	363	481	834	1,220	247	477
Generation	Rock Creek	Labor External	56	110	68	59	11	1
Generation	Rock Creek	Labor Internal	2,280	1,501	1,827	1,455	1,339	1,868
Generation	Rock Creek	Materials	62	39	94	122	21	91
Generation	Rock Creek	Other	9	40	29	15	16	35
Generation	Cresta	Contract	64	112	82	937	114	1
Generation	Cresta	Labor External	1	8	13	10	17	1
Generation	Cresta	Labor Internal	617	391	437	452	480	460
Generation	Cresta	Materials	30	105	31	41	37	43
Generation	Cresta	Other	15	19	14	34	76	17
Generation	FERC Project 1962 Common	Contract	27	26	162	319	275	269
Generation	FERC Project 1962 Common	Labor External	626	526	852	855	629	176
Generation	FERC Project 1962 Common	Labor Internal	634	294	335	386	357	460
Generation	FERC Project 1962 Common	Materials	2	4	13	0	7	1
Generation	FERC Project 1962 Common	Other	12	12	8	14	20	11
Generation	Hamilton Branch	Contract	138	75	7	23	20	10
Generation	Hamilton Branch	Labor External	30	28	15	16	18	6
Generation	Hamilton Branch	Labor Internal	621	307	229	282	156	130
Generation	Hamilton Branch	Materials	20	16	1	4	11	4
Generation	Hamilton Branch	Other	87	-20	3	7	3	12
Generation	Bucks Creek	Contract	94	299	286	268	583	2,246
Generation	Bucks Creek	Labor External	2	16	22	35	50	58
Generation	Bucks Creek	Labor Internal	724	461	515	294	603	612
Generation	Bucks Creek	Materials	83	16	40	10	28	14
Generation	Bucks Creek	Other	4	10	21	1	18	49
Generation	FERC 619 Common	Contract	12	11	126	91	55	61
Generation	FERC 619 Common	Labor External	167	185	71	105	103	88
Generation	FERC 619 Common	Labor Internal	112	38	33	27	45	35
Generation	FERC 619 Common	Materials	7		0	0		
Generation	FERC 619 Common	Other	19	19	18	23	22	13
Generation	Grizzly	Contract	243	659	406	263	734	4,989
Generation	Grizzly	Labor External	14	50	27	47	21	287
Generation	Grizzly	Labor Internal	349	237	315	217	150	1,217
Generation	Grizzly	Materials	69	36	38	39	11	182
Generation	Grizzly	Other	-650	-955	-849	-588	-985	-6,606
Generation	FERC Project 2107 Poe	Contract	313	1,208	1,537	460	243	530
Generation	FERC Project 2107 Poe	Labor External	1	9	111	20	99	126
Generation	FERC Project 2107 Poe	Labor Internal	616	737	1,096	497	825	943
Generation	FERC Project 2107 Poe	Materials	263	30	243	33	155	88
Generation	FERC Project 2107 Poe	Other	4	-4	41	34	222	144
Generation	DeSabla Common	Contract	801	577	821	747	2,460	1,271
Generation	DeSabla Common	Labor External	9	34	13	25	33	71
Generation	DeSabla Common	Labor Internal	2,369	1,312	1,456	1,759	1,579	2,409
Generation	DeSabla Common	Materials	73	97	93	120	235	181
Generation	DeSabla Common	Other	295	381	316	455	446	559
Generation	Caribou Switching Common	Contract			198			
Generation	Caribou Switching Common	Labor External			7			
Generation	Caribou Switching Common	Labor Internal			1,005	1		
Generation	Caribou Switching Common	Materials			10			
Generation	Caribou Switching Common	Other			13	-0	-191	
Generation	Feather Common	Contract		12	15	41	221	27
Generation	Feather Common	Labor External				7	2	
Generation	Feather Common	Labor Internal		13	7	0	22	20
Generation	Feather Common	Other			-1	-1	-1	
Generation	Rock Creek Switching Common	Contract		7	30			
Generation	Rock Creek Switching Common	Labor Internal		0	0	2		
Generation	Rock Creek Switching Common	Other	2	3	4	0	3	0
Generation	Butte Common	Contract	209	172	331	170	371	718
Generation	Butte Common	Labor External	0	9	3	6	12	
Generation	Butte Common	Labor Internal	360	231	315	457	476	208
Generation	Butte Common	Materials	17	32	80	78	56	25
Generation	Butte Common	Other	-2	4	17	10	145	5
Generation	Toadtown	Contract				0	11	1
Generation	Toadtown	Labor External	2					
Generation	Toadtown	Labor Internal	439	197	198	170	154	102
Generation	Toadtown	Materials	8	10	7	4	6	3
Generation	Toadtown	Other	-12	-17	-19	-17	-16	-24
Generation	DeSabla	Contract	294	238	477	193	548	370

Generation	DeSabla	Labor External	20	17	46	9	6	49
Generation	DeSabla	Labor Internal	1,300	1,025	777	677	779	871
Generation	DeSabla	Materials	29	101	91	79	70	163
Generation	DeSabla	Other	21	18	13	4	11	280
Generation	Centerville	Contract	191	62	110	199	24	12
Generation	Centerville	Labor External	2	2		4		
Generation	Centerville	Labor Internal	637	186	118	92	110	70
Generation	Centerville	Materials	23	20	2	2	7	5
Generation	Centerville	Other	2	5	-2	-2	1	1
Generation	FERC Project 803 Common	Contract		16	91	-10		
Generation	FERC Project 803 Common	Labor External	208	254	101	119	109	143
Generation	FERC Project 803 Common	Labor Internal	197	151	146	80	64	98
Generation	FERC Project 803 Common	Materials	6	0	0	0	0	57
Generation	FERC Project 803 Common	Other	57	135	116	47	90	151
Generation	Lime Saddle	Contract	83	366	57	102	77	41
Generation	Lime Saddle	Labor External	8	42	3	4	14	
Generation	Lime Saddle	Labor Internal	788	679	434	438	185	182
Generation	Lime Saddle	Materials	22	53	18	7	12	9
Generation	Lime Saddle	Other	0	12	6	2	7	12
Generation	Coal Canyon	Contract	79	27	38	32		83
Generation	Coal Canyon	Labor External		1				
Generation	Coal Canyon	Labor Internal	432	274	320	204	56	82
Generation	Coal Canyon	Materials	9	31	24	9	7	3
Generation	Coal Canyon	Other	1	3	2	1	1	0
Generation	Potter Valley	Contract	668	521	869	912	1,821	2,888
Generation	Potter Valley	Labor External	665	832	529	537	174	231
Generation	Potter Valley	Labor Internal	2,175	1,363	1,382	1,162	1,570	1,455
Generation	Potter Valley	Materials	92	23	36	64	48	101
Generation	Potter Valley	Other	332	202	134	134	206	288
Generation	[+] FERC Project 2310	Contract	1,165	854	614	678	669	1,580
Generation	[+] FERC Project 2310	Labor External	191	137	127	1	36	76
Generation	[+] FERC Project 2310	Labor Internal	9,066	4,725	2,818	2,535	2,865	3,332
Generation	[+] FERC Project 2310	Materials	496	298	325	268	321	371
Generation	[+] FERC Project 2310	Other	144	149	167	170	383	-27
Generation	[+] North Yuba	Contract	178	24	3	12	65	0
Generation	[+] North Yuba	Labor External	43	50	11	-0		
Generation	[+] North Yuba	Labor Internal	518	333	133	195	167	30
Generation	[+] North Yuba	Materials	56	34	2	8	24	0
Generation	[+] North Yuba	Other	45	65	30	35	37	9
Generation	[+] Drum Common	Contract	3,006	2,907	3,544	3,316	4,045	3,223
Generation	[+] Drum Common	Labor External	441	370	106	339	557	360
Generation	[+] Drum Common	Labor Internal	5,271	3,401	4,688	5,052	5,161	7,131
Generation	[+] Drum Common	Materials	240	240	404	394	480	639
Generation	[+] Drum Common	Other	48	119	61	87	89	272
Generation	[+] FERC Project 2155	Contract	55	8	51	338	178	27
Generation	[+] FERC Project 2155	Labor External	60	10	23	25	0	
Generation	[+] FERC Project 2155	Labor Internal	407	295	245	259	217	214
Generation	[+] FERC Project 2155	Materials	45	19	23	30	14	6
Generation	[+] FERC Project 2155	Other	47	86	113	59	59	74
Generation	[+] Phoenix	Contract	81	128	18	41	29	19
Generation	[+] Phoenix	Labor External	74	50	22	27	15	21
Generation	[+] Phoenix	Labor Internal	1,486	622	487	548	388	682
Generation	[+] Phoenix	Materials	69	60	39	10	66	23
Generation	[+] Phoenix	Other	42	45	6	2	7	10
Generation	[+] FERC Project 2130	Contract	344	632	828	245	404	280
Generation	[+] FERC Project 2130	Labor External	561	607	491	153	35	19
Generation	[+] FERC Project 2130	Labor Internal	2,429	1,413	1,145	1,077	1,047	1,392
Generation	[+] FERC Project 2130	Materials	223	151	286	72	75	124
Generation	[+] FERC Project 2130	Other	485	1,753	570	335	293	295
Generation	[+] Ferc Project 137	Contract	1,006	2,101	1,982	1,194	1,987	2,593
Generation	[+] Ferc Project 137	Labor External	627	744	510	166	182	104
Generation	[+] Ferc Project 137	Labor Internal	6,660	4,545	3,326	4,020	3,026	5,096
Generation	[+] Ferc Project 137	Materials	401	445	400	736	418	648
Generation	[+] Ferc Project 137	Other	-315	153	114	331	-741	209
Generation	[+] Ferc Project 2467	Contract	10					
Generation	[+] Ferc Project 2467	Labor External	20	2	2			
Generation	[+] Ferc Project 2467	Labor Internal	410	132	83		2	
Generation	[+] Ferc Project 2467	Materials	5	2	1			
Generation	[+] Ferc Project 2467	Other	2	0	-24			
Generation	[+] Mother Lode Common	Contract	720	766	1,790	1,076	1,261	1,121
Generation	[+] Mother Lode Common	Labor External	276	295	77	309	98	65
Generation	[+] Mother Lode Common	Labor Internal	2,268	1,250	1,951	1,548	1,759	2,224
Generation	[+] Mother Lode Common	Materials	122	39	88	53	78	195
Generation	[+] Mother Lode Common	Other	439	443	469	564	593	670
Generation	Kerckhoff 1	Contract	28	147	22	6	4	
Generation	Kerckhoff 1	Labor External			1			
Generation	Kerckhoff 1	Labor Internal	413	428	234	120	95	42

Generation	Kerckhoff 1	Materials	16	78	31	2	13	16
Generation	Kerckhoff 1	Other	55	51	54	55	54	56
Generation	Kerckhoff 2	Contract	1,360	964	31	157	321	52
Generation	Kerckhoff 2	Labor External	31	0	4	0		
Generation	Kerckhoff 2	Labor Internal	982	389	434	510	480	409
Generation	Kerckhoff 2	Materials	80	78	62	122	47	216
Generation	Kerckhoff 2	Other	-5	-19	169	-9	5	12
Generation	FERC Project 96 Common	Contract	123	198	560	114	4	
Generation	FERC Project 96 Common	Labor External	205	128	-1			
Generation	FERC Project 96 Common	Labor Internal	137	58	34	47	29	18
Generation	FERC Project 96 Common	Materials			1			
Generation	FERC Project 96 Common	Other	-2	-3	-53	2	1	
Generation	Haas	Contract	211	200	116	203	108	86
Generation	Haas	Labor External		1				3
Generation	Haas	Labor Internal	578	718	532	1,172	476	678
Generation	Haas	Materials	42	43	45	101	66	112
Generation	Haas	Other	11	12	13	61	16	27
Generation	Kings River	Contract	53	19	113		233	36
Generation	Kings River	Labor External	2				19	
Generation	Kings River	Labor Internal	348	289	303	210	272	212
Generation	Kings River	Materials	16	23	28	22	25	27
Generation	Kings River	Other	5	15	7	11	17	9
Generation	FERC Project 1988 Common	Contract			64	28		
Generation	FERC Project 1988 Common	Labor External			22			
Generation	FERC Project 1988 Common	Labor Internal			20	8	3	17
Generation	FERC Project 1988 Common	Other			-1	-0		
Generation	Balch 1	Contract	173	19	23	2	10	
Generation	Balch 1	Labor External	5					
Generation	Balch 1	Labor Internal	555	233	223	228	261	354
Generation	Balch 1	Materials	22	14	29	26	28	55
Generation	Balch 1	Other	7	17	6	8	34	24
Generation	Balch 2	Contract	103	112	322	36	66	59
Generation	Balch 2	Labor External	12		10			
Generation	Balch 2	Labor Internal	1,792	384	576	316	715	683
Generation	Balch 2	Materials	72	41	29	24	69	35
Generation	Balch 2	Other	23	16	17	27	22	16
Generation	FERC 175 Common	Contract	127	170	159	135	115	134
Generation	FERC 175 Common	Labor External					0	
Generation	FERC 175 Common	Labor Internal	514	427	428	291	213	312
Generation	FERC 175 Common	Materials	46	98	51	36	15	32
Generation	FERC 175 Common	Other	48	164	126	89	94	86
Generation	Crane Valley	Contract	19	11	5	3	9	1
Generation	Crane Valley	Labor Internal	437	415	205	300	411	271
Generation	Crane Valley	Materials	22	42	4	61	68	24
Generation	Crane Valley	Other	1	8	5	5	9	3
Generation	San Joaquin 1A	Contract	7	10	7		7	7
Generation	San Joaquin 1A	Labor External	9	7	6	8	1	
Generation	San Joaquin 1A	Labor Internal	298	188	235	118	144	191
Generation	San Joaquin 1A	Materials	8	11	15	15	11	13
Generation	San Joaquin 1A	Other	1	2	5	1	1	1
Generation	San Joaquin 2	Contract	11	2				
Generation	San Joaquin 2	Labor External	5	-3				
Generation	San Joaquin 2	Labor Internal	485	299	171	81	65	68
Generation	San Joaquin 2	Materials	17	25	18	14	0	3
Generation	San Joaquin 2	Other	2	5	2	4	0	0
Generation	San Joaquin 3	Contract	19	98	6	19		
Generation	San Joaquin 3	Labor External	5	6				
Generation	San Joaquin 3	Labor Internal	341	375	100	92	74	72
Generation	San Joaquin 3	Materials	16	31	2	5	6	2
Generation	San Joaquin 3	Other	3	8	-1	0	0	2
Generation	AG Wishon PH	Contract	130	196	5		25	49
Generation	AG Wishon PH	Labor External		16	1			
Generation	AG Wishon PH	Labor Internal	694	310	310	260	365	353
Generation	AG Wishon PH	Materials	57	21	52	26	35	43
Generation	AG Wishon PH	Other	10	2	10	7	10	7
Generation	FERC Project 1354 Common	Contract	3	75	117	20	209	180
Generation	FERC Project 1354 Common	Labor External	346	196	450	180	22	6
Generation	FERC Project 1354 Common	Labor Internal	296	223	247	182	223	281
Generation	FERC Project 1354 Common	Materials	17		0		1	
Generation	FERC Project 1354 Common	Other	1	-1	-1	-2	1	-2
Generation	FERC Project 1333 Tule	Contract	345	57	184	63	0	
Generation	FERC Project 1333 Tule	Labor External	24	3			0	
Generation	FERC Project 1333 Tule	Labor Internal	515	391	332	250	111	73
Generation	FERC Project 1333 Tule	Materials	13	24	35	14	16	4
Generation	FERC Project 1333 Tule	Other	2	2	7	51	14	0
Generation	FERC Project 178 Kern	Contract	14	92	114	36	38	24
Generation	FERC Project 178 Kern	Labor External	60	6	0			

Generation	FERC Project 178 Kern	Labor Internal	588	360	323	108	78	94
Generation	FERC Project 178 Kern	Materials	10	25	24	10	37	35
Generation	FERC Project 178 Kern	Other	4	20	12	2	16	24
Generation	Kings Crane Common	Contract	866	1,000	1,233	1,067	1,997	1,744
Generation	Kings Crane Common	Labor External	409	297	91	291	53	25
Generation	Kings Crane Common	Labor Internal	5,050	2,263	2,209	1,676	1,638	2,237
Generation	Kings Crane Common	Materials	109	220	196	171	158	169
Generation	Kings Crane Common	Other	258	304	300	282	311	1,365
Generation	Lower Kings River Common	Contract	17	1				
Generation	Lower Kings River Common	Labor External	41	13	-1			
Generation	Lower Kings River Common	Labor Internal	19	5	4	2	1	0
Generation	Lower Kings River Common	Materials	10	1	4	-0		0
Generation	Lower Kings River Common	Other	8	5	2	2	2	11
Generation	Helms PSP	Contract	3,223	2,181	3,556	2,301	2,787	4,370
Generation	Helms PSP	Labor External	43	84	-21	77	102	117
Generation	Helms PSP	Labor Internal	5,251	2,817	3,339	4,132	3,874	5,147
Generation	Helms PSP	Materials	404	560	499	434	673	502
Generation	Helms PSP	Other	458	427	585	531	586	599
Generation	Hydro Common	Contract	8,194	8,311	7,915	5,908	5,365	11,264
Generation	Hydro Common	Labor External	2,814	2,887	2,007	1,466	2,171	7,127
Generation	Hydro Common	Labor Internal	14,136	22,739	24,744	20,643	21,579	24,485
Generation	Hydro Common	Materials	488	225	506	647	500	1,358
Generation	Hydro Common	Other	209	-9,103	-5,529	-3,705	-4,240	-4,284
Generation	Hydro LOB	Contract	11		20	126	205	156
Generation	Hydro LOB	Labor Internal	294	1,702	2,063	1,532	1,457	1,181
Generation	Hydro LOB	Materials	20	34	19	136	76	254
Generation	Hydro LOB	Other	34	15	42	169	159	129
Generation	YCWA	Contract	46	139				
Generation	YCWA	Labor External	39	38				
Generation	YCWA	Labor Internal	280	143				
Generation	YCWA	Materials	47	2,411				
Generation	YCWA	Other	-451	-2,714				
Generation	SID	Contract			4	165	119	-0
Generation	SID	Labor External			1	14		
Generation	SID	Labor Internal	122	1	49	107	146	50
Generation	SID	Materials	6		4	56	1	0
Generation	SID	Other	-146	-1	-53	-278	-329	-56
Generation	PCWA	Contract		1		28	15	2
Generation	PCWA	Labor External		17	16		2	3
Generation	PCWA	Labor Internal	6	5	6	5	52	104
Generation	PCWA	Materials						2
Generation	PCWA	Other		-31	-23	-33	-61	-120
Generation	MID	Labor Internal			1	70	49	
Generation	MID	Materials				5	1	
Generation	MID	Other			-7	-76	-49	
Generation	Other Generation Common	Labor External	97	1				
Generation	Other Generation Common	Labor Internal	168	3				
Generation	Other Generation Common	Other	-0	-0				
Generation	HLLCBA - Hydro Licensing and License Cos	Contract	312	343	309	958	2,501	2,216
Generation	HLLCBA - Hydro Licensing and License Cos	Labor External	74	1			281	189
Generation	HLLCBA - Hydro Licensing and License Cos	Labor Internal	2	4	2	4	183	500
Generation	HLLCBA - Hydro Licensing and License Cos	Materials	0				1	
Generation	HLLCBA - Hydro Licensing and License Cos	Other	7,747	7,411	10,185	9,563	8,862	9,437

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_084-Q05		
PG&E File Name:	GRC-2023-PhI_DR_TURN_084-Q05		
Request Date:	January 6, 2022	Requester DR No.:	TURN-PG&E-084
Date Sent:	January 21, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Tom Baldwin Eric Van Deuren Steve Royall	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

The following questions related to PG&E's energy supply testimony (PGE-5) and some miscellaneous questions.

QUESTION 05

On page 3-48 of Exhibit PG&E-5, lines 4-9, PG&E describes the manner in which it estimates Expense Non-Labor Costs for Nuclear: "The non-labor costs are charged directly to orders and are estimated based on a combination of trending and specifically identified non-recurring costs. For expense project orders, we removed one-time projects from 2020 that had been completed, updated our cost estimates of continuing expense programs and used our planning and budget process to identify new or continuing projects that will occur in 2023." Please respond to the following questions for ALL of PG&E's generation types:

a) Did PG&E use a similar approach for estimating Expense Non-Labor costs for its hydro and gas-fired generation as it did for its Nuclear generation. If not, please explain why not.

b) Please provide expense non-labor costs for the period from 2015-2020 disaggregated between "one-time projects" and other non-labor costs. Provide these expense non-labor costs separately for nuclear, hydro, and gas. Please identify each "one-time project" during the period from 2015-2020 and explain why PG&E believes that it is a "one-time project".

ANSWER 05

a) For hydro and natural gas/solar generation, PG&E's approach for estimating costs is described in Exhibit (PG&E-5) Chapter 4 testimony on pages 4-63 through 4-65 and Chapter 5 testimony on pages 5-62 through 5-64.

b) PG&E is not sure how TURN defines "one-time projects" in the context of this data request. With that qualification, PG&E responds that projects with a planning order starting with 55 are standing planning orders. Projects with a standing planning order are on-going projects that occur every year. Projects with a planning order starting with 57 are specific planning orders. Projects with a specific planning order tend to be one-time projects. See PG&E Exhibit (PG&E-10), Chapter 10, pp. 10-8 and 10-9 for discussion of standing and specific planning orders.

For Nuclear, see Attachment GRC-2023-PhI_DR_TURN_084-Q05Atch01. For Hydro, see Attachment GRC-2023-PhI_DR_TURN_084-Q05Atch02. For Natural Gas and Solar, see Attachment GRC-2023-PhI_DR_TURN_084-Q05Atch03.

Power Generation
Hydro
2015 - 2020 Non-labor Expense Costs
Standing Planning Order (Base) and Specific Planning Order (Projects) Separately Shown

		Fiscal Year						
Category	**Cost Element Major Resource Group**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Grand Total**
Standing Planning Order	Material	$4,177,870	$6,620,773	$4,706,641	$4,456,481	$4,361,881	$5,389,429	$29,713,075
	Contract	$31,289,361	$32,393,497	$30,870,436	$26,658,370	$28,843,356	$37,889,817	$187,944,837
	Other	$9,966,528	$10,638,935	$15,530,566	$14,581,969	$13,813,297	$10,691,452	$75,222,747
Subtotal		$45,433,759	$49,653,205	$51,107,642	$45,696,820	$47,018,534	$53,970,698	$292,880,659
Specific Planning Order	Material	$916,049	$552,383	$1,249,051	$740,889	$924,051	$1,922,818	$6,305,241
	Contract	$15,243,958	$14,130,643	$17,856,597	$9,591,827	$17,013,302	$21,283,413	$95,119,738
	Other	$38,196	($48,293)	$126,238	($4,667,416)	($1,766,430)	$180,859	($6,136,845)
Subtotal		$16,198,203	$14,634,733	$19,231,886	$5,665,299	$16,170,923	$23,387,090	$95,288,134
Grand Total		**$61,631,962**	**$64,287,938**	**$70,339,528**	**$51,362,119**	**$63,189,457**	**$77,357,788**	**$388,168,792**

The following costs have been excluded:
PG&E Labor, including labor burdens
Capital, Non-Earnings and Other Balance Sheet Overhead credits related to management support (MWC OM/OS)
Below the line costs (Project Cancellation costs)

Power Generation
Hydro
2015 - 2020 Non-labor Expense Costs ($000s)
Specific Planning Order (Project) Detail

Planning Order	Row Labels	Sum of 2015	Sum of 2016	Sum of 2017	Sum of 2018	Sum of 2019	Sum of 2020	Grand Total
5256060	2017 MLode Jan-Feb Storm Work (Roads)			$81				$81
5256125	2017 Mok Storm Dmg TC Abay Dredge			$726		-$756		($29)
5270132	2020 Butte Common FRMMA Expense						$673	$673
5240972	AG Wishon - Exp Material Conditon Improv	-$1	$0					($0)
5250356	AG Wishon - Generator CO2 Cleaning		$93					$93
5250362	AG Wishon - Penstock Alt Analysis		$5	$1				$6
5245700	AG Wishon - U4 Re Needle Shaft/Repl Bush		$3					$3
5215872	Almanor Dredge Prattville Intake		$58	$120	$112	$0	$2	$291
5241207	Alta PH Repair roof - Expense	$72						$72
5265792	AM: Applications and Tools					$37	$390	$427
5266213	AM: Engineering Effort					$61	-$3	$58
5247332	Balch 1 - CO2 Clean Generator	$79						$79

5238780	Balch Abay - LLO Project Revegetation	$41	$13	-$1	$0			$53
5227054	Balch Camp - Cultural Resource Plan	$2						$2
5236314	Balch Ground Grid repairs	$8						$8
5216175	Bear River Conveyance Patching Annual	$186	$233					$419
5260436	Bear River Suspension Bridge M20 Repairs						$1	$1
5215842	Belden Dam Paint Radial Gates				$12			$12
5212912	Belden Forebay Repair Bridge Abutment	$30	$15	$73	$16			$134
5272592	Belden Forebay Spillway Repairs SAIP				$19	$1,081	$932	$2,033
5267613	Belden PH Rebuild WG Upthrust Assembly						$76	$76
5232333	Belden Repair Lower Draft Tube	$17	$234	$459		$292		$1,002
5245437	Belden Siphon & Penstock Drainage Repair	$11	$21	$0				$32
5258674	Belden Spillway Hoist Deck Spalling Eval				$16			$16
5245436	Belden Spillway Wall Panel & Drain Repai	$221	$14					$235
5254498	Belden Spillway Wall Panel Alt Analysis			$183	$13			$196
5251692	Belden Spillway Wall Panel Temp Repair		$21					$21
5240655	BRC-Krause II flume monitoring 2013	$0						($0)
5241274	Bucks Clean Rocktraps & Tunnel Repair	-$64						($64)
5245442	Bucks Cr Ground Grid Modification		$13	$104				$117
5215877	Bucks Cr Penstock Drainage Repair	$24						$24
5263407	Bucks Creek Pnstk Erosion Mitigation						$30	$30
5272593	Bucks Storage Spillway Repairs SAIP				$22	$142	$0	$165
5245439	Butt Valley Ground Grid Modification	$13	$119	$17				$149
5236320	Butt Valley Penstock Remove Rocks	$80						$80
5264932	Butt Valley Remove Wicket Gate Shims					$475		$475
5272594	Butt Valley Spillway Repairs SAIP					$425	$6	$431
5250317	Butte Fire Support	$57	$1					$58
5243037	CalTrans Bridge Replacement Support		-$26	-$32	-$35	-$174	-$30	($297)
5225875	Camp 9 Road - Maintain/Patch	$5						$5
5267615	Canyon Dam Evaluate Outlet Structure						$20	$20
5219994	Canyon Dam Outlet Protection				$59	$6		$65
5253924	Cape Horn Dam Abut Stairs Veg Mgmt		$9	$70				$79
5266012	Cape Horn Dam Fish Screen Ladder AoA					$7		$7
5272057	Cape Horn Dam Spillway Repair SAIP						$73	$73
5253874	Caribou 1 Intake Repair Walkway Anchor		$12	$13	$77	$58	$114	$274
5254494	Caribou 1 Pstk Rock Anchor Liftoff Test			$44	-$44	$28	$1	$28
5245441	Caribou 1 Repl Wheel Cover Lifting Brkts		$29	$75	$1			$105
5250378	Caribou 2 Evaluate-Repair Intake Gate	$154	-$11					$143
5254495	Caribou 2 Penstock Expansion Joint Eval			$19	$8			$27
5263403	Caribou 2 Penstock Modify Rock Bolts					$1	$10	$11
5248494	Caribou 2 Penstock Repack Joint 6	$52	$0					$52
5263404	Caribou 2 Penstock Slope Lidar Phase 2					$1		$1

5241278	Caribou 2 U5 Draft Tube Platform Support	$1	$144					$145
5215721	Caribou Camp - Repair Camp Buildings	$10	$72	$44	$76		$2	$204
5241277	Caribou Penstock Monitoring	$88	$0			$1		$89
5256293	Caribou Rd Repair Storm Damage @ Siphon			$190		-$191		($2)
5250379	Caribou Road Milepost 7 Install Rip Rap	$299	-$6					$293
5253873	Centerville Decomm Transformer Support				$1			$1
5237792	Centerville Ground Grid Repairs	$0						$0
5269152	Cherokee Fire Expense			$9				$9
5255872	Chili Bar Bypass Tailrace Gate Repair			$24	$2			$26
5260812	Chili Bar Gate Hoists Wire Rope Replace				$69			$69
5264412	Chili Bar Ground Grid Mitigation					$2		$2
5215605	Chili Bar License Conditions-Expense	$51	$27					$77
5260813	Chili Bar LLO Gate Inspection				$265	$7		$272
5245734	Chili Bar Segment Governor Turb/Bypass		-$7					($7)
5253320	Coleman Ground Grid Mitigation					$43	$3	$46
5252261	Coleman Refurbish TSV Actuator Motor Exp		$9					$9
5253192	Cow Creek Penstock Support Reinforcement		$8	$26				$35
5250575	Cow Creek Penstock Support Repairs	$6	$11					$17
5230672	Crane Valley - Ditch Repairs		$21					$21
5241292	Crane Valley Dam - Mitigation/Monitoring	$325	$322	$506	$110	$4		$1,267
5254421	Cresta Dam Assess Drum Gate #1			$81	$0			$81
5254426	Cresta Dam Inspect Intake Gate			$15	-$2			$13
5236323	Cresta Dam Paint Gates			$18	$775	$3		$795
5242950	Cresta Dam Radial Gate Automation	$1						$1
5215820	Cresta Insp/Maint Drum Gates	$0						$0
5244253	Cresta PH Clean PSVs	$0						($0)
5261732	Cresta PH Repair Trxfmr Bank A Bushing				$83	$67		$150
5263074	Cresta Repair 24" Bypass Valve Leak					$17	$0	$16
5236324	Cresta Repair Tailrace Erosion					$16	$2	$18
5254425	Cresta Tunnel Clean Surge Chamber			$13	-$1			$13
5253514	CV - Lakeshore Park Lot Sale Reimburse		$6	$17	$1	$0		$25
5263353	Dam Surveillance IA Action Plan					$108		$108
5271842	DamWatch USES licensing fee & Supp. Serv						$108	$108
5261153	Decommissioning Study Program						$149	$149
5249813	Deer Creek CB 30 disconnects and bypass		$3					$3
5236325	Deer Mortality Protection Assessment	$12	$0					$12
5232293	Des Cent LC - Implementation Expense	$54	$101	$2				$156
5263405	DeSabla - BTH Rigging Equipment						$0	$0
5248496	DeSabla 2015 Storm Response	$40						$40
5263732	DeSabla 2018 Camp Fire Response				$388	$1,955	$397	$2,740
5267114	DeSabla Area NERC Security Repairs					$108	$214	$322

5265765	DeSabla Area WSIP Equipment Repairs					$41	$3	$45
5265763	DeSabla Area WSIP Infrastructure Repairs					$5	$2	$7
5232336	DeSabla Consolidate SWTCH Ctr		$0					$0
5258853	DeSabla Forebay LLO Abandon AoA						$15	$15
5267538	DeSabla Forebay Slope Erosion Control						$63	$63
5258856	DeSabla Ground Grid Mitigation				$7			$7
5261813	DeSabla Helicopter LZ Structural Evaltn				$46			$46
5215825	DeSabla Inspect Philbrook Outlet	$38						$38
5267612	DeSabla Repair Fishing Platform						$33	$33
5272053	DeSabla Spillways FSP Engr SAIP					$175	$342	$517
5265492	Drum - Bridge Repairs					$50		$50
5265412	Drum - Canal Escape Aid Design/Eval					$77	$47	$124
5251693	Drum - NID Condemnation Support		$0			$11		$11
5260792	Drum - SYC 8.5 Mile Avalanche				$0			$0
5259936	Drum 1 & 2 - Ground Grid Mitigation					$13	$0	$13
5258709	Drum Canal US Hwy 20 Uplift			$63	$0			$62
5246179	Drum -FERC Patching Annual					$84	$204	$288
5272071	Drum Forebay Spillway Repair SAIP						$77	$77
5241320	Drum Mobility Platform ConveynceData Sht	$54						$54
5260352	Drum Penstock Access Evaluation				$20	-$3		$17
5251694	Drum PS3 Intake Gate Investigation		$96	-$1	$2			$97
5225873	Drum Rec Sites - Repair Vandalism/Overus					$6		$6
5258698	Drum Rock Crk Res ROV Inspection			$12				$12
5272032	Drum Spillways FSP Engr SAIP					$527	$565	$1,092
5256058	Drum Storm Work			$456	-$2			$454
5245416	Drum Tunnel Expense Repair - Grouting	$130	$669	-$2				$798
5245417	Drum Watershed USA Underground	$39	$0					$39
5245418	Dutch Flat 1 Ground Grid Upgrades	$41						$41
5271172	Dutch Flat Roof Installl Snow Guards						$25	$25
5265055	EH Butte Common WSIP/CWIP					$157		$157
5265052	EH Drum Common WSIP/CWIP					$290	$0	$290
5265054	EH Feather Common WSIP/CWIP					$222	-$10	$212
5265014	EH FERC 233 Com WSIP/CWIP					$218		$218
5265013	EH FERC 2661 Com WSIP/CWIP					$103		$103
5265053	EH KingsCrane Common WSIP/CWIP					$440	$4	$444
5265056	EH Manton HQ Common WSIP/CWIP					$243		$243
5265058	EH Mokelumne Common WSIP/CWIP					$130	$5	$134
5265015	EH Potter Valley WSIP/CWIP					$23		$23
5265016	EH Shasta Common WSIP/CWIP					$247		$247
5265057	EH Stanislaus Common WSIP/CWIP					$26		$26
5250192	Electra PH Ground Grid Mitigation	$16	$2					$18

5245419	Electra Smoke Detection	$1						$1
5250359	ENGR: FERC Security Plans		$5	$10	$0			$16
5245420	Fordyce Dam Leakage Reduction EXPENSE		$70					$70
5260994	Fordyce Paint Radial Gates 2019					$1	$48	$49
5265077	FSP: Dam Safety 2.0 Implementation					$211	$903	$1,114
5261877	Grizzly Cr Xing Assess and Repair Tunnel				$2	$16	$11	$29
5263072	Grizzly FB Dam Alt Analysis				$45	$186	$50	$281
5254422	Grizzly Forebay Surface Debris Removal						$1	$1
5254424	Grizzly Frby Remove Debris Subsurface			$4	$11	$66	$2,012	$2,094
5267544	Guidance Documents						$869	$869
5253412	Haas - Repair/Insulate Collector Rings		$86	-$1				$86
5271457	Haas Deferred Maint Crane Repairs						$37	$37
5248412	Halsey - Natel Generation Feasibility	$24						$24
5263087	Halsey Afterbay Spillway Repair SAIP				$34	$48	$81	$163
5235184	Halsey Governor L&S DOO, Training	$12						$12
5254652	Halsey ground grid mitigation			$37	$30			$67
5236332	Halsey Inspect & Repair Draft Tubes			$140	-$34			$106
5262173	Halsey PH Repair Roof				$51	$0		$51
5229752	Halsey Tunnel 5 Repair	$108						$108
5215750	Hamilton Br Canal - Repair Undermining	$0						$0
5241279	Hamilton Br Grounding Modifications	$63						$63
5245743	Hamilton Br Repair Clear Cr Undermine		$43	$0				$42
5241280	Hamilton Br Repair Indian Ole Leak	-$1			$14	$0		$13
5263408	Haskins Valley CG Repair Boat Ramp					$2		$2
5245744	Hat 1 PH Remove Lead Paint (MCI)	$1,009	$28					$1,038
5241288	Hat Creek 1 Ground Grid Repairs	$136	$1					$137
5269333	HC Dropped Objects Mitigation Program						$2,499	$2,499
5250361	HC Powerhouse Flow Reporting- Testing						$2	$2
5210392	HC: Hydro OIT Program					$48		$48
5256714	HC: Lead and Mercury Mitigation Plan			$32	$7	-$10		$30
5251913	HC: Roadway Safety Improvement Project		$37	$40	-$1			$77
5257852	Helms - 2017 Penstock 1 Weld 2 Inspec			$76	$0			$76
5256812	Helms - 2017 STORM DAMAGE			$5				$5
5246172	Helms - Evaluate HQ Comm Tower Footing	$1	$16	-$3	$3			$17
5256628	Helms - McKinley Grove Rd Failure STORM			$170	$26			$196
5256772	Helms - McKinley Grove Rd Patching STORM			$463	-$9			$454
5222375	Helms - Outage Expense Work	$20	$2					$22
5267052	Helms - Rplc CB270/CB280 Interrupters					$333	$10	$343
5241972	Helms - Support Fac Leachfield Study	$310	$240	-$34				$517
5245350	Helms - T2 Plug & Bypass Drain Repairs	$1		$168				$169
5228492	Helms - Tunnel Safety Study	-$4	$0					($4)

5249444	Helms - U1 Main Stator Testing/Repair	$128						$128
5266792	Helms - U2 Draft Tube Repair/Slab Leak					$111	$24	$134
5243256	Helms - U3 Inspection/Reinstallation	$20						$20
5226013	Helms - Ventilation Study	$3						$3
5230994	Helms - Wastewater Treatment Repl. Study	$0						$0
5244398	Helms - Wishon Res. Repair Spillgate 6	$62	$0					$62
5263392	Helms Cycling Study					$30	$0	$30
5263393	Helms Rotor Field Warranty Inspection					$7	$9	$16
5272092	Helms Spillways FSP Engr SAIP						$101	$101
5265134	Helms SPOF Study					$6	-$1	$5
5269345	Helms U1 Draft Tube Door Seal Repair						$357	$357
5247532	Hendricks 6/4 Flume Repair	$43	$0					$43
5243036	Hydro Install Emerg Eye/Body Wash Sta Ex	$20						$20
5251412	Hydro PH Disposition Support	$20	$237	$392	$546	$301	$314	$1,810
5236339	Hydro Waterwy Public Safety Exp	$1,599	$1,334	$1,434	$731	$886	$1,014	$6,998
5247774	Inskip Diversion Repr Spillway Cladding	$73	$166	-$3				$236
5255352	Inskip Eagle Cyn DivDam Abutment Erosion			$12	$0			$12
5253923	Inskip Header Box Sedimentation Evaluati		$38	$3				$40
5263639	Inskip Repair Eagle Canyon Flume				$152			$152
5252815	Inskip Repair South Wet Crossing		$28	$7				$35
5266134	Integrated Seismic Risk Mgmt Prog- Hydro					$105	$95	$200
5272077	Inundation Maps	$384	$343	$309	$958	$745	$588	$3,327
5269273	ISO 55000 Certification						$76	$76
5245745	JBB Ground Grid Modification	$57	-$2					$55
5215832	JBB Repair PH Roof Seams	$2						$2
5256813	KCV - 2017 STORM DAMAGE			$37				$37
5247925	KCV - Kerckoff Mitigation Feasibility St	$67						$67
5249454	KCV - SLG Fault Telecomm Mitigation	$12	-$5					$7
5263207	Kelly Lake (Drum) Remove Tree Stumps					$6	$3	$9
5260392	Kelly Lake Spillway Repair				$88	-$24		$64
5241293	Kerckhoff 2 - Refurbish Runner	$1,203	$888					$2,091
5250354	Kerckhoff 2 - Repair Ground Grid		$0					$0
5243674	Kerckhoff 2 - Unit Alignment	$19	-$2					$17
5271458	Kerckhoff 2 Tunnel Drain						$3	$3
5256814	KERN - 2017 STORM DAMAGE			$106	$1			$107
5215940	Kern Canyon Ground Grid Rprs	$7	$0					$7
5262613	Kidd Lake Spillway Repair SAIP				$58	-$1		$57
5265852	Kilarc Canal Repairs					$5		$5
5272062	Kings Crane Spillways FSP Engr SAIP						$32	$32
5250154	Kings River - Rough Fire Support	$58	$4					$62
5236344	Kings River Ground Grid repair	$6						$6

5246945	Kings River PH - UOG Rough Zone Evaluati	$5						$5
5265076	Kunkle Reservoir Make Safe					$19		$19
5261873	LA Tower Evaluate Low Level Outlet Gates				$8	$8		$16
5257172	LA Tower Recondition Gate Operators			$213	$0			$213
5272056	Lake Almanor Spillway Repairs SAIP					$621	$72	$692
5261874	Lake Fordyce Spillway Repair SAIP				$34	-$9		$25
5215601	Lake valley Conveyance Patching Semi Ann						$13	$13
5262612	Lake Valley Spillway Repair SAIP				$35			$35
5252259	Lime Saddle Penstock Leak Perm Repair		$25	$5				$30
5267614	Lovelock Tunnel Repair Liner Boards						$74	$74
5256094	Lower Drum Conveyance Patching Annual			$279	$312	$126	$63	$779
5241318	Lower Drum Flume Repair Halbolm	-$1						($1)
5238788	Lower Drum Spillway Review & Improv	-$1	$1					($0)
5241319	Lyons Dam - Repair Concrete Face	$64	$49					$113
5235191	Lyons Dam foundation dental grouting	$66	$17					$83
5272069	Macumber Dam Spillway Repair SAIP						$27	$27
5222749	Main Tuolumne Canal - Flume Maint (GC)	$15	$0					$15
5267516	McCloud Dam LLO Hydraulic Leak Repair					$2,213	-$364	$1,849
5215863	McCloud Dam Radial Gates Assessment	$27	$200	-$3				$224
5261837	McCloud Spillway Repairs SAIP				$255	$0		$255
5272596	McCloud Spillway Slide Evaluation SAIP					$42	$42	$85
5231019	MeadowDamSpill-Repair Concrete Erosion	$86						$86
5235212	Merced Falls - Reinforce Training Wall	$33						$33
5255492	Merced Falls 2017 Outage			-$27				($27)
5256059	ML Storm Work			$338		-$235		$103
5254653	Mok - Lwr Blue - Repair M-3 Weir			$3	$5		$9	$18
5262332	Mok Twin Lakes Crest Width Improvements				$29			$29
5255413	Mok Up Blue Seismic Stability Mitigation			$18				$18
5272054	Motherlode Spillways FSP Engr SAIP					$69	$123	$191
5226093	Narrows Fisheries Enhancement Fund	$22	$20	$20	$20	$20		$102
5264892	Narrows Tram Repl Wire Rope					$53		$53
5245422	Narrows Tramway Drainage Improvements	$164						$164
5236349	NERC Compliance Matrix Dvlpmt & Prc Impr				$161	$115	$88	$365
5263273	NERC Regulations & Guidance					$83	$100	$183
5255038	NERC Relay Settings Evaluation			$467	$174	$35	$0	$677
5256312	Newcastle Ground Grid Upgrade				$17	$4		$20
5269492	Newcastle Replace Main Bank HO Bushing						$41	$41
5250098	North Battle Creek Dam Repair Upstr Face		$116	$693	$1			$811
5272064	North Battle Creek Spillway Repairs SAIP						$29	$29
5256292	Oak Flat Repair PH Access Road			$1				$1
5250993	PE Monitoring Plan - Exp	$30	$12					$42

5241355	PE: Electrical One Lines and P&IDs	$1,035	$112	$116	$70	$28		$1,362
5258794	PE: Rock Creek Yard Uninstall Trailers			$2	$10			$13
5242514	PE: Std Construction Spec Templ Develop2	-$2						($2)
5248716	PG Capital Excellence Program	$450						$450
5269338	PG CMM - Gap Closer Plan						$2,146	$2,146
5243452	PG Driving Safety Initiatives	$65	$49	$81	$49	$44		$288
5234638	PG Learning Contract Costs	$400	$555	$290	$154	$137	$142	$1,677
5253198	PG Probability Risk Assessment		$93	$0				$92
5272058	Philbrook Spillway Repairs SAIP						$36	$36
5241205	Phoenix - Lyons Dam Radial Gate Repair	$3						$3
5267521	Phoenix Ground Grid Mitigation						$8	$8
5255895	Phoenix Main Tuolumne Flume Maint 2017			$3	$26	$0	$0	$29
5241315	Phoenix PH Grounding Repairs	$0						($0)
5269754	Pillsbury Pines Erosion Repairs						$93	$93
5241285	Pit 1 Forebay Radial Gate Inspection	-$13						($13)
5269295	Pit 1 Forebay Spillway DSE Support SAIP						$6	$6
5272066	Pit 1 Forebay Spillway Repairs SAIP						$47	$47
5215833	Pit 1 Repair Valvehouse Roof	-$5	-$2					($7)
5238786	Pit 1 River Gate House Overhaul	$1,411	$2,657	$0				$4,068
5245340	Pit 1 Spillway Repair Upstm Rt Abutment	$95	$6	$1				$101
5244554	Pit 1 Tailrace Engineering Assessment	$3						$3
5244552	Pit 1 Valvehouse Remove Lead Paint	$12						$12
5245335	Pit 3 Britton Dam Concrete Bridge Repair	$129	$54	$3			$28	$214
5245755	Pit 3 Ext Tailrace Wall Rmv Lead Paint		$38	$39				$77
5245332	Pit 3 PH Ground Grid Modifications			$1	$41	$22	$6	$69
5245337	Pit 3 RCC Repair Tunnel Spall	$63	$116	-$144				$35
5267076	Pit 3 Refurbish LLO No. 1 (expense)						$26	$26
5243872	Pit 3 Tailrace Bridge Expense Upgrade	$4			$75		$306	$385
5216964	Pit 345 Road Management Plan (Expense)	$86	$90	$50	$103	$0	$14	$343
5245756	Pit 4 Ground Grid Modifications		$11					$11
5267073	Pit 4 PH Ground Grid Mitigation						$24	$24
5240192	Pit 4 U2 Draft Tube & TSV Repair	-$8						($8)
5253692	Pit 4 U2 Refurbish Bearings		$65	$48				$113
5254974	Pit 4 Unit 2 Repair TSV Seats		$78	$16				$94
5245757	Pit 5 Diversion Gates Paint					$15		$15
5215762	Pit 5 Dredge Tailrace	$4	$0					$4
5235213	Pit 5 OC low level outlet abandonment	$0						($0)
5256632	Pit 5 PH Dredge Tailrace 2017 Storm Dmge			$2,657	-$2,324	-$497	-$3	($167)
5256104	Pit 5 PH Exp Restoration 17 storm damage			$1,425	-$1,957	-$367		($898)
5267072	Pit 5 PH Mitigate Ground Grid						$3	$3
5255973	Pit 5 PH Road 2017 Storm Damage Expense			$291	-$255	-$48		($12)

5245347	Pit 5 Spoil Pile 5A Repair	$8						$8
5249614	Pit 5 Switchgear Breaker Panel Repairs	$9	$65					$74
5261142	Pit 5 U3 3 Repair Turbine Guide Bearing				$122			$122
5263148	Pit 5 Unit 4 Repair Penstock				$291	$78		$369
5227516	Pit 6 CB Actuator Upgrade	$229	$8					$237
5252692	Pit 6 Dam Radial Gate Assessment		$5					$5
5260415	Pit 6 Draft Tube Structural Retrofit					$1	$101	$102
5245334	Pit 6 PH Ground Grid Modifications	$207	$2					$209
5245761	Pit 6 Repair PH Roof Deck Seams			$3	$2			$5
5245763	Pit 7 Dam Radial Gate Assessment		$12	-$1				$11
5269442	Pit 7 Dam Repair Drains/Piezos						$226	$226
5245341	Pit 7 LLO #1 Repair and Stoplog Removal	$286	-$26					$260
5244004	Pit 7 PH Ground Grid Mitigation Expense	$17						$17
5245765	Pit 7 Repair PH Roof Deck Seams		$7					$7
5238787	Pit 7 Repair Spillway Flip Buckets	-$295						($295)
5258413	Pit 7 Repr Spillway Flip Bucket Strm Dmg				$66	-$111		($45)
5260128	Pit 7 Unit 2 Recoat Intake Gates					$5		$5
5245595	Poe Assess CW Strainer Project	$3						$3
5263197	Poe Dam Paint Bypass Gates					$4	$1	$5
5215846	Poe Dam Paint Skimmer				$26	$0		$25
5258852	Poe Dam Repair Toe Voids				$49	$114	$30	$193
5261975	Poe LC- Prepare Historic Properties Plan					$92	$38	$131
5254430	Poe PH Bridge Repair	$57	-$20	$232	$46			$315
5254492	Poe PH Ground Grid Modification		$3	$206				$209
5262015	Poe PH Repair U1 Generator				$126	-$125	$166	$168
5257055	Poe PH Repair U2 Generator			$1,317	$2			$1,320
5261061	Poe PH Rock Slide at Station Service					$20		$20
5251733	Poe Tunnel Temp Repair 2015		$870					$870
5245767	Poe U2 Repair Draft Tube			$7	$8			$15
5215765	PoeLC-Develop Plans for Bio Measures					$47	$30	$77
5236356	PoeLC-License Management					$122	$82	$204
5215854	PoeLC-New Lic Plans, Drawing updates					$23	$17	$40
5236355	PoeLC-Prepare Land Dept Plans					$41	$28	$69
5258854	Potter Valley Dredge Fish Hotel					$193		$193
5264542	Potter Valley PM Closeout					$2		$2
5238212	Potter Valley Repair Lower Penstock Leak	$15						$15
5255065	Proj. Mgmt. - Systems / Tools		$24	$223	$38	$4	$4	$293
5265912	PSPS event 6.7.19					$9		$9
5268482	Public Safety Plan Exp						$14	$14
5254976	Pumped Storage Due Diligence		$49	-$8				$41
5252653	PV Arc Flash Test & Modify Relays		$2	$2				$3

(PG&E-18)

5218518	PV Evaluate Gates at Scott Dam	$78	-$4					$75
5261073	PV Evaluate Old Intake					$5	$5	$10
5248455	PV Repair Leak in Penstock Bifurcation	$40						$40
5215646	PV Scott Dam Paint Radial Gates	$2						$2
5258066	PV Scott Dam Recoat US Slide Gates				$24	$22	$1,038	$1,084
5272076	PV Scott Dam Spillway Repairs SAIP						$20	$20
5244113	PV Van Arsdale Fish Screen Alarms	$56	$1					$57
5241992	RC 480V Switchgear Refurbi Expense	$24	$33	$1				$58
5263402	RCC Dams LLO Restoration Evaluation					$27	$24	$51
5236336	Records Management Initiative - exp	$1,073	$547	$667	$411	$504	$660	$3,864
5258826	Relay and Battery Test				$190	$221	$397	$809
5272055	Relief Spillway Repair SAIP						$6	$6
5257552	Rock Cr Dam Hinge Plate Repair			$206				$206
5236360	Rock Cr Dam Paint Gates			$19	$776	$5		$800
5245444	Rock Cr Dam Repair Aux Supply Pipe	$56	$50	$1				$107
5250237	Rock Cr Dam Repair Toe Voids		$163	$199	-$176			$186
5257872	Rock Cr PH Recoat Valve House Penstock			$17	$0			$17
5261777	Rock Creek Aux Dam Tree Root Removal				$13			$13
5245769	Rock Creek Ground Grid Modification		$15	$0				$15
5238789	Rock Creek VH - Concrete Ceiling Repairs			$1	$54	$48	$1	$105
5248733	Rock Crest Camp Repairs	$81	$12	$25	$1	-$1		$117
5254437	Rodgers Flat SC Office Additions		$7	$23				$29
5245445	Round Valley Reservoir Repair Weirs	$1						$1
5272060	Round Valley Spillway Repairs SAIP						$44	$44
5263113	Rucker Lake Spillway Repair SAIP				$18			$18
5252792	SAH - Bark Beetle Veg Mgmt		$18					$18
5245423	Salt Springs Dam Radial Gate Repair	$3		$0	$176	$88	$0	$268
5247772	Salt Springs Ground Grid Mitigation	$1			$45	$1		$47
5272063	Salt Springs Spillway Repair SAIP						$119	$119
5245424	Salt Springs Unit 2 Governor Mods		$3	$5				$8
5245772	San Joaquin 2 Ground Grid Modifications	$6	$0					$6
5266252	SCADA Documentation/File Review/Creation					$445	$38	$483
5237693	Shasta PE-GC Trailers - Trailer & Setup	-$1						($1)
5272061	Shasta Spillways FSP Engr SAIP					$186	$372	$558
5215938	SJ#3 Ground Grid Repairs		$19					$19
5216173	South Conveyance Patching Annual	$40						$40
5247475	South PH Canal Flume Remove/Repair	$14						$14
5250096	South PH CO2 Cleaning		$97					$97
5253321	South PH Ground Grid Mitigation					$29		$29
5253952	South PH Refurbish Trashrake Expense		$56	$104	$3			$163
5251552	South Yuba Canal Patching		$51	$50	$40			$141

5255894	South Yuba Conveyance Patching Annual			$334	$193	$105	$243	$875
5200049	South Yuba Flumes Maintenance 2016	$147	$62					$209
5241196	South Yuba Pipe - Rock Removal/Bench Imp	$315						$315
5251917	Spaulding 2 - Evaluate Elevator		$27					$27
5263116	Spaulding 2 Aux Spillway Repair SAIP				$4			$4
5263117	Spaulding 2 Primary Spillway Repair SAIP				$25	$50		$75
5245774	Spaulding 2 Runner Repair and Rebalance						$0	$0
5259155	Spaulding 3 Penstock Leak Repair			$0	$57			$57
5245426	Spaulding Dam 1 Patching	$21	$392	$0			$722	$1,134
5253132	Spaulding Dam LLO Dredge		$2					$2
5223752	Spaulding Tram Timber Repairs Annual	$15			$9	$4	$7	$35
5258012	Spillway Assessments SAIP			$1,439	$472	$146		$2,057
5268973	Spillway Contracts and Consulting SAIP						$230	$230
5260075	Spring Gap Ground Grid Mitigation					$11		$11
5261367	Spring Gap Main Bank Failure				$8			$8
5241316	SpringGapPH-Repair Removable Bridge	$3		$1				$4
5253717	SQS: Bearings Intiative		$74	$3	$6			$83
5248052	SQS: Confined Space	$35	$4					$39
5235188	SQS: Develop Hydro Lockout/Tagout	$287	$0					$287
5248117	SQS: Energy Storage RFO	$96	$1					$97
5256593	SQS: Work Management Tool Enhancement			$49				$49
5235952	SQS:Hydro ERM Gaps 1,2,3,4 & 7	$184	$12					$196
5237919	SQS:WM Equipment Records	$175	$20					$196
5223734	Stanislaus - General Maintenance/Paint			$26				$26
5236365	Stanislaus Ground Grid repairs	$0	$61	$0				$61
5245431	Stan-Relief Repair Concrete Spillway	$45						$45
5238791	Strawberry Dam - Repair Concrete (E)	$1						$1
5251695	Strawberry Dam LLO Repair Gate Valve		$237					$237
5254654	Tiger Ck Canal - Sta 196 - Manage Slide			$2				$2
5236366	Tiger Cr Ground Grid repair	$0	$10	$4				$14
5264902	Tiger Creek AB Repair Structural Members					$201	$513	$714
5245432	Tiger Creek Afterbay LLO	$74	$847	$9				$930
5245433	Tiger Creek Afterbay Radial Gate Repair	$210	$39	$14				$263
5241197	Tiger Creek Canal - Clear Sub-Drains	$2			$9			$10
5257976	Tiger Creek Penstock Bellows Leak			$3				$3
5261876	Tiger Creek Reg Spillway Repair SAIP					$240	-$6	$234
5258062	Tiger Crk Abay Dam DS Bulkhead Removal			$70	$0			$71
5258701	Tiger Crk Reg Resurface Spillway Chute				$24			$24
5260394	Towle Canal Tunnel 1 Survey				$2			$2
5249939	Tule - Wood Stave Pipe Repairs	$364	$41					$405
5215934	Tule Grounding Repairs		$0					$0

5247378	Upper Bear Dam - Repair Gunite Liner		$22	$4				$26
5261875	Upper Bear Spillway Repair SAIP				$22			$22
5256136	Upper Drum Conveyance Patching 2017			$80				$80
5202233	Upper Drum Conveyance Patching Annual	$105	$50		$88	$33	$119	$395
5263119	Upper Peak Lake Spillway Repair SAIP				$47		$12	$58
5260054	Upper Wise Tunnel 8 Grouting					$703	$8	$711
5260447	Upr Rck (Drum) Restor Crst to Desgn Elev				$75			$75
5257972	Volta 1 Ground Grid Mitigation				$40	$1		$41
5253553	Volta 1 Lake Grace Embankment Repairs			$106	$48	$30	$495	$679
5247652	Volta 1 Lake Grace Repair Penstk Joint	$19	$0					$19
5257952	Volta 1 Lake Nora Embankment Repairs				$33	$28	$337	$398
5246195	Volta 1 Lake Nora Penst Foundation Mitig	$2	$109	$20				$131
5262369	Volta 1 Lake Nora Repair Spill Basin						$24	$24
5241287	Volta 1 PH Ground Grid Repairs	$2						$2
5250593	Volta 1 Repl McCumber Gate Actuator Oil	$144	$22	$9				$174
5245348	Volta 2 Penstock Ground Grid Repairs	$0	$92					$92
5245775	West Point PH Generator Cleaning		$185	$0				$185
5258697	West Point PH Ground Grid Mitigation				$34			$34
5271339	West Point Valve House Pave Access Road						$62	$62
5216174	Wise Canal Patching Annual	$42						$42
5262614	Wise Forebay Spillway Repair SAIP				$50			$50
5260093	Wise Forebay Tree Removal/Rebuild Berm					$34	$282	$316
5256352	Wishon Dam - Repair Shoulder			$41	$15			$56
5260894	Wishon Dam - Upstream Face Repair				$177			$177
	Grand Total	**$16,198**	**$14,635**	**$19,232**	**$5,665**	**$16,171**	**$23,387**	**$95,288**

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_104-Q013		
PG&E File Name:	GRC-2023-PhI_DR_TURN_104-Q013		
Request Date:	January 31, 2022	Requester DR No.:	TURN-PG&E-104
Date Sent:	February 14, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Eric Van Deuren	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

Follow-up on PG&E responses to TURN DR 84

QUESTION 013

Please explain why PG&E’s Hydro O&M expenses in 2020 total $157.2 million but only average $135.2 million (in nominal dollars) for 2015-2019 inclusive.

ANSWER 013

There are two drivers of 2020 Hydro O&M expenses being above the average of 2015-2019.

First is inflation. When converting from nominal dollars to 2020 base dollars, the average is $144.1 million for 2015-2019 inclusive. Please refer to Attachment GRC-2023-PhI_DR_TURN_104-Q13_Atch01 for analysis.

Second is additional spending in Major Work Category KG – Operate Hydro Generation. Per the 2020 Risk Spending Accountability Report (4-9, Line 8), PG&E recorded actual costs of $43.5 million versus an imputed adopted amount of $30.8 million. Program expenses were above imputed adopted values due to several key drivers, including (1) emergent costs related to achieving full compliance for all risks at Level 3 per PG&E's Compliance Maturity Model; (2) an emergent hydro system-wide powerhouse safety mitigation program to mitigate safety risks resulting from dropped objects from heights (e.g. tools from scaffolding); (3) costs related to accelerating guidance document completion to meet Level 3 compliance deadline; and (4) emergent physical security and cybersecurity costs at our FERC-regulated facilities to meet new regulations from FERC.

Attachment GRC-2023-PhI_DR_TURN_104-Q13Atch01

(values shown are in thousands of dollars)

Line	Description	2015*	2016	2017	2018	2019	2020
1	O&M values provided in GRC-2023-PhI_DR_TURN_084-Q03_Atch01	164,643	129,893	138,855	114,928	127,544	157,182
2							
3	**Conversion of nominal values to base 2020 values:**						
4	O&M Nominal Totals (WP 4-1, Line 17)	NA	132,026	140,617	116,717	129,642	158,297
5	O&M 2020 Base $ Totals (WP 4-2, Line 17)	NA	145,725	151,053	120,325	129,675	158,297
6	% Increase (Cumulative; Line 5 divided by Line 4)	10.38%	10.38%	7.42%	3.09%	0.03%	0.00%
7	% Increase (Per year; difference between cumulative totals on Line 6)	2.95%	2.95%	4.33%	3.07%	0.03%	
8							
9	Calculation: O&M values provided in GRC-2023-PhI_DR_TURN_084-Q03_Atch01 converted into 2020 base $ (Line 1 x (1+Line 6))	**181,727**	**143,371**	**149,160**	**118,481**	**127,576**	**157,182**
10							
11	2015-2019 Average	**144,063**					
12							
13	*2015 recorded costs are not included in 2023 GRC workpapers. Although available in 2017 GRC workpapers, the calculation uses 2017 base $, which then needs to be converted to 2020 base $. For simplicity, we have assumed a 0% escalation between 2015 and 2016.						

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_104-Q025		
PG&E File Name:	GRC-2023-PhI_DR_TURN_104-Q025		
Request Date:	January 31, 2022	Requester DR No.:	TURN-PG&E-104
Date Sent:	February 14, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Eric Van Deuren	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

Hydro

QUESTION 025

Refer to workpaper “ES_Compare RAMP v GRCErrata.xlsx”. Please respond to the following questions regarding that workpaper:

a. Please indicate the date(s) upon which the “RAMP filing” estimates presented in this workpaper were prepared.

b. Were the capital and expense estimates from the “RAMP filing” included in PG&E’s 2020 GRC application? If not, please explain why not.

c. Were the capital and expense estimates from the “RAMP filing” included in the authorized capital and expense levels in the 2020 GRC? Provide workpapers supporting your response.

d. Please indicate the date(s) upon which the “2023 GRC” estimates presented in this workpaper were prepared.

e. Please explain each of the annual differences in capital and expenses between the “RAMP filing” and the “2023 GRC”. Please provide these explanations by year and by MWC for both RAMP and GRC. Provide workpapers supporting your explanations.

f. Please explain why PG&E’s total GRC 2023 capital expenditure forecast for 2022 for LGUWR is almost $26 million less than from the RAMP filing. Provide workpapers supporting your explanations.

g. Please explain why PG&E’s total GRC 2023 capital expenditure forecast for 2025 for LGUWR is almost $33 million more than from the RAMP filing. Provide workpapers supporting your explanations.

h. Please explain why PG&E’s total GRC 2023 capital expenditure forecast for 2026 for LGUWR is almost $26 million more than from the RAMP filing. Provide workpapers supporting your explanations.

i. Please explain why PG&E’s total expense forecasts for years 2021-2024 exceed the total expense forecasts from the RAMP filing for those years. Provide workpapers supporting your explanations.

ANSWER 025

a. The 2020 RAMP filing forecasts presented in this workpaper were prepared during the first quarter of 2020.

b. The 2020 GRC predates the 2020 RAMP. The 2020 GRC was filed in December 2018. The 2020 RAMP was filed in June 2020. The 2020 RAMP is the precursor to the 2023 GRC. The 2020 RAMP is not the precursor to the 2020 GRC. The four mitigations activities for the Large Uncontrolled Water Release risk were the same between the 2020 RAMP and 2020 GRC filing. However, the mitigations forecasts differ due to the passage of time between the two filings.

c. The 2020 GRC predates the 2020 RAMP. The 2020 GRC was filed in December 2018. The 2020 RAMP was filed in June 2020. The 2020 RAMP is the precursor to the 2023 GRC. The 2020 RAMP is not the precursor to the 2020 GRC. In the 2020 GRC final decision, the Commission adopted, with limited modifications, a Settlement between most of the 2020 GRC Parties. As such, the 2020 GRC authorized the collection of revenue requirements, but did not authorize program specific forecasts. PG&E performed an imputation calculation to derive “imputed adopted values” by MAT code, or Major Work Category where MAT code is not applicable. The 2020 RAMP filing mitigations forecasts were not included in the 2020 GRC final decision imputed adopted values because the 2020 RAMP was filed after the 2020 GRC was filed.

d. The 2023 GRC forecasts presented in this workpaper were prepared during the fourth quarter of 2020.

e. The tables below show the annual differences in capital and expenses between the “RAMP filing” and the “2023 GRC”. Below each table is an explanation of the annual differences. Please see Attachment GRC-2023-PhI_DR_TURN_104-Q025eAtch01 for the workpapers supporting the explanation of the annual differences.

		Year 2020	Thousands of Nominal Dollars		
Line No.	MWC	MWC Description	RAMP 2020	2023 GRC 2020	Difference 2020
1	2L	Install/Replace Hydro Safety and Regulatory	18,002	17,904	(99)
2	2N	Install/Replace Reservoirs, Dams, and Waterways	12,803	9,766	(3,037)
4	3H	Relicensing and New License Implementation	-	2,028	2,028
3	AX	Maintain Reservoirs, Dams, Waterways	6,814	1,157	(5,657)
5	IG	Manage Various BA Processes	-	2,369	2,369
			37,619	33,223	(4,396)
		TOTAL MITIGATIONS - CAPITAL	30,805	29,697	(1,108)
		TOTAL MITIGATIONS - EXPENSE	6,814	3,526	(3,288)

<u>Variance explanation:</u>

2L : Immaterial difference in forecast

2N: Spillway Assessment and Improvement (SAIP) forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, reduction in Bucks Storage Spillway Improv SAIP forecast by $1.5 million during 2023 GRC.

3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.

AX: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision. Reduction in Belden Forebay Spillway Repairs SAIP forecast by $1 million in 2023 GRC.

IG: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision.

		Year 2021	Thousands of Nominal Dollars		
Line No.	MWC	MWC Description	RAMP 2021	2023 GRC 2021	Difference 2021
1	2L	Install/Replace Hydro Safety and Regulatory	20,612	24,025	3,413
2	2N	Install/Replace Reservoirs, Dams, and Waterways	23,863	4,539	(19,324)
4	3H	Relicensing and New License Implementation	-	9,645	9,645
3	AX	Maintain Reservoirs, Dams, Waterways	7,115	507	(6,608)
5	IG	Manage Various BA Processes	-	8,414	8,414
			51,589	47,130	(4,460)
		TOTAL MITIGATIONS - CAPITAL	44,474	38,209	(6,266)
		TOTAL MITIGATIONS - EXPENSE	7,115	8,921	1,806

Variance explanation:

2L : increase in Fordyce Dam Leakage Reduction forecast by $4.6 million in 2023 GRC

2N: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, reduction in McCloud Spillway Improvements SAIP forecast by $5.5 million and Lower Bucks Spillway Restoration SAIP forecast by $3.7 million in 2023 GRC.

3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.

AX: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision.

IG: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision.

Year 2022			Thousands of Nominal Dollars		
Line No.	MWC	MWC Description	RAMP 2022	2023 GRC 2022	Difference 2022
1	2L	Install/Replace Hydro Safety and Regulatory	31,794	25,619	(6,176)
2	2N	Install/Replace Reservoirs, Dams, and Waterways	44,679	4,331	(40,348)
4	3H	Relicensing and New License Implementation	-	20,714	20,714
3	AX	Maintain Reservoirs, Dams, Waterways	2,345	2,223	(122)
5	IG	Manage Various BA Processes	-	2,402	2,402
			78,818	55,289	(23,529)
		TOTAL MITIGATIONS - CAPITAL	76,474	50,664	(25,809)
		TOTAL MITIGATIONS - EXPENSE	2,345	4,625	2,280

Variance explanation:

2L : Reduction in Lower Bucks Dam Resurface DS Face forecast by $8.6 million in 2023 GRC

2N: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, reduction in Tiger Creek Reg Spillway Improv SAIP forecast by $15.2 million and Spillway Assessment Prgm Cap Mitigation forecast by $7.8 million in 2023 GRC.

3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.

AX: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision. Also, increase in Pit 3 Refurbish LLO No. 1 forecast by $1.6 million in 2023 GRC.

IG: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision.

		Year 2023	Thousands of Nominal Dollars		
Line No.	MWC	MWC Description	RAMP 2023	2023 GRC 2023	Difference 2023
1	2L	Install/Replace Hydro Safety and Regulatory	39,962	48,641	8,679
2	2N	Install/Replace Reservoirs, Dams, and Waterways	80,452	8,140	(72,312)
4	3H	Relicensing and New License Implementation	-	65,790	65,790
3	AX	Maintain Reservoirs, Dams, Waterways	350	4,500	4,150
5	IG	Manage Various BA Processes	-	555	555
			120,763	127,626	6,863
		TOTAL MITIGATIONS - CAPITAL	120,413	122,571	2,157
		TOTAL MITIGATIONS - EXPENSE	350	5,055	4,705

Variance explanation:

2L : Increase in Pit 6 Radial Gate1 Repl Arms & Trunnions forecast by $3.2 million, Pit 6 Spillway Apron Replace Block 3 forecast by $3.7 million and Fordyce Dam Leakage Reduction forecast by $1.4 million in 2023 GRC.

2N: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, reduction in Spillway Assessment Prgm Cap Mitigation forecast by $13.6 million in 2023 GRC.

3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.

AX: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision. Also, increase in Pit 3 Refurbish LLO No. 1 forecast by $4.5 million in 2023 GRC.

IG: SAIP forecast moved from MWC AX to MWC IG following 2020 GRC decision.

Line No.	MWC	Year 2024 MWC Description	RAMP 2024	2023 GRC 2024	Difference 2024
			Thousands of Nominal Dollars		
1	2L	Install/Replace Hydro Safety and Regulatory	8,800	36,176	27,376
2	2N	Install/Replace Reservoirs, Dams, and Waterways	108,100	10,748	(97,352)
4	3H	Relicensing and New License Implementation	-	67,500	67,500
3	AX	Maintain Reservoirs, Dams, Waterways	-	2,250	2,250
5	IG	Manage Various BA Processes	-	-	-
			116,900	116,674	(226)
		TOTAL MITIGATIONS - CAPITAL	116,900	114,424	(2,476)
		TOTAL MITIGATIONS - EXPENSE	-	2,250	2,250

Variance explanation:

2L : Increase in Fordyce Dam Leakage Reduction forecast by $11.5 million, Lower Bucks Dam Resurface DS Face forecast by $8.1 million and Pit 6 Radial Gate 2 Repl Arms & Trunnions forecast by $6 million in 2023 GRC.

2N: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, reduction in Spillway Assessment Prgm Cap Mitigation forecast by $26 million in 2023 GRC.

3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.

AX: Increase in Pit 3 Refurbish LLO No. 1 forecast by $2.3 million in 2023 GRC.

IG: N/A

		Year 2025	Thousands of Nominal Dollars		
Line No.	MWC	MWC Description	RAMP 2025	2023 GRC 2025	Difference 2025
1	2L	Install/Replace Hydro Safety and Regulatory	7,000	18,739	11,739
2	2N	Install/Replace Reservoirs, Dams, and Waterways	40,000	6,592	(33,408)
4	3H	Relicensing and New License Implementation	-	54,432	54,432
3	AX	Maintain Reservoirs, Dams, Waterways	-	-	-
5	IG	Manage Various BA Processes	-	-	-
			47,000	79,763	32,763
		TOTAL MITIGATIONS - CAPITAL	47,000	79,763	32,763
		TOTAL MITIGATIONS - EXPENSE	-	-	-

Variance explanation:

2L : Increase in Fordyce Dam Leakage Reduction forecast by $4.5 million and Pit 7 Radial Gate1 Repl Arms & Trunnions forecast by $6.4 million in 2023 GRC.

2N: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, increase in Spillway Assessment Prgm Cap Mitigation and Lower Bucks Spillway Restoration SAIP forecast by $9 million each in 2023 GRC.

3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.

AX: N/A

IG: N/A

		Year 2026	Thousands of Nominal Dollars		
Line No.	MWC	MWC Description	RAMP 2026	2023 GRC 2026	Difference 2026
1	2L	Install/Replace Hydro Safety and Regulatory	5,500	12,885	7,385
2	2N	Install/Replace Reservoirs, Dams, and Waterways	40,000	9,000	(31,000)
4	3H	Relicensing and New License Implementation	-	49,500	49,500
3	AX	Maintain Reservoirs, Dams, Waterways	-	-	-
5	IG	Manage Various BA Processes	-	-	-
			45,500	71,385	25,885
		TOTAL MITIGATIONS - CAPITAL	45,500	71,385	25,885
		TOTAL MITIGATIONS - EXPENSE	-	-	-

Variance explanation:

2L : Increase in Pit 7 Radial Gate 2 Repl Arms & Trunnions forecast by $6.9 million in 2023 GRC.
2N: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision. Also, increase in Spillway Assessment Prgm Cap Mitigation forecast by $9 million and Lower Bucks Spillway Restoration SAIP forecast by $4.5 million in 2023 GRC.
3H: SAIP forecast moved from MWC 2N to MWC 3H following 2020 GRC decision.
AX: N/A
IG: N/A

f. Please see PG&E’s response to Question 25 e above.

g. Please see PG&E’s response to Question 25 e above.

h. Please see PG&E’s response to Question 25 e above.

i. Please see PG&E’s response to Question 25 e above.

2023 General Rate Case
Comparing RAMP Forecast to 2023 GRC Forecast
Large Uncontrolled Water Release
Thousands of Nominal Dollars

Line No.	Expense / Capital	Planning Order No.	Planning Order Description	Mitigation or Control Name	2023 GRC MWC	RAMP MWC	2020 (2023 GRC)	2021 (2023 GRC)	2022 (2023 GRC)	2023 (2023 GRC)	2024 (2023 GRC)	2025 (2023 GRC)	2026 (2023 GRC)	2020 RAMP	2021 RAMP	2022 RAMP	2023 RAMP	2024 RAMP	2025 RAMP	2026 RAMP	2020 Diff	2021 Diff	2022 Diff	2023 Diff	2024 Diff	2025 Diff	2026 Diff
1	CAP	5745679	Fordyce Dam Leakage Reduction	M1 - Internal Erosion Mitigation	2L	2L	3,163	20,399	20,400	21,700	13,000	4,500	500	3,674	15,803	17,228	20,262	1,500	-	-	(511)	4,596	3,172	1,438	11,500	4,500	500
2	CAP	5760041	Lower Bucks Dam Install Upstream Liner	M3 - Seismic Retrofit	2L	2L	13,944	450	-	-	-	-	-	12,000	250	-	-	-	-	-	1,944	200	-	-	-	-	-
3	CAP	5782990	LA Tower Replace Actuators	M4 - LLO Refurbishment	2L	2L	505	1,350	-	-	-	-	-	1,000	1,000	-	-	-	-	-	(495)	350	-	-	-	-	-
4	CAP	5779214	Pit 6 Spillway Apron Replace Block 3	M2 - Spillway Remediation	2L	2L	-	-	91	3,653	-	-	-	-	101	4,059	-	-	-	-	-	(101)	(3,967)	3,653	-	-	-
5	CAP	5771200	Pit 6 Radial Gate1 Repl Arms & Trunnions	M3 - Seismic Retrofit	2L	2L	30	1,160	2,250	11,444	88	-	-	150	150	1,400	8,200	500	-	-	(120)	1,010	850	3,244	(412)	-	-
6	CAP	5776722	Pit 6 Radial Gate2 Repl Arms & Trunnions	M3 - Seismic Retrofit	2L	2L	-	-	1,203	2,250	11,479	88	-	-	-	-	1,400	5,400	100	-	-	-	1,203	850	6,079	(12)	-
7	CAP	5771199	Pit 7 Radial Gate1 Repl Arms & Trunnions	M3 - Seismic Retrofit	2L	2L	10	6	6	1,204	2,264	11,881	88	7	7	7	1,100	1,400	5,500	100	3	(1)	(1)	104	864	6,381	(12)
8	CAP	5776723	Pit 7 Radial Gate2 Repl Arms & Trunnions	M3 - Seismic Retrofit	2L	2L	-	-	-	-	1,246	2,270	12,296	-	-	-	-	-	1,400	5,400	-	-	-	-	1,246	870	6,896
9	CAP	5783541	Lower Bucks Dam Resurface DS Face	M3 - Seismic Retrofit	2L	2L	69	270	360	8,100	8,100	-	-	300	300	9,000	9,000	-	-	-	(231)	(30)	(8,640)	(900)	8,100	-	-
10	CAP	5774800	Crane Valley Intake Tower Stabilization	M3 - Seismic Retrofit	2L	2L	182	390	1,308	290	-	-	-	323	3,000	100	-	-	-	-	(141)	(2,610)	1,208	290	-	-	-
11	CAP	5789680	Strawberry Dam (Stan)-Replace Liner 2023	M1 - Internal Erosion Mitigation	2N	2N	-	-	-	360	-	-	-	-	-	-	400	-	-	-	-	-	-	(40)	-	-	-
12	CAP	5777489	Strawberry Dam (Stan)-Replace Liner 2021	M1 - Internal Erosion Mitigation	2N	2N	-	360	-	-	-	-	-	-	400	-	-	-	-	-	-	(40)	-	-	-	-	-
13	CAP	5777490	Strawberry Dam (Stan)-Replace Liner 2022	M1 - Internal Erosion Mitigation	2N	2N	-	-	360	-	-	-	-	-	-	400	-	-	-	-	-	-	(40)	-	-	-	-
14	CAP	5789718	Strawberry Dam (Stan)-Replace Liner 2024	M1 - Internal Erosion Mitigation	2N	2N	-	-	-	-	374	-	-	-	-	-	-	400	-	-	-	-	-	-	(27)	-	-
15	CAP	5772935	Tiger Crk Abay LLO Gate Replace	M4 - LLO Refurbishment	2N	2N	4,444	720	-	-	-	-	-	3,625	96	-	-	-	-	-	819	624	-	-	-	-	-
16	CAP	5779207	Helms - Repl Courtright LLO Bypass Valve	M4 - LLO Refurbishment	2N	2N	5	40	171	2,980	245	11	-	50	250	3,250	100	-	-	-	(45)	(210)	(3,079)	2,880	245	11	-
17	CAP	5785096	Pit 3 Restore LLO No.1 (capital)	M4 - LLO Refurbishment	2N	2N	-	180	1,350	4,500	4,500	180	-	-	200	1,000	1,000	-	-	-	-	(20)	350	3,500	4,500	180	-
18	CAP	5720633	DSP: Dam Capital	M1/M3 Seismic Retrofit and Intern	2N	N/A	-	-	-	-	1,800	3,150	4,500	-	-	-	-	-	-	-	-	-	-	-	1,800	3,150	4,500
19	CAP	5720633	DSP: Dam Capital	M1/M3 Seismic Retrofit and Intern	2N	N/A	-	-	-	-	1,800	3,150	4,500	-	-	-	-	-	-	-	-	-	-	-	1,800	3,150	4,500
20	CAP	5779219	Wise Intake Replace Side Spill Gate	M2 - Spillway Remediation	2N	2N	-	-	50	150	-	-	-	-	0	50	150	-	-	-	-	(0)	-	-	-	-	-
21	CAP	5779222	Halsey Forebay Install Seepage Drain	M1 - Internal Erosion Mitigation	2N	2N	71	299	-	-	-	-	-	100	700	-	-	-	-	-	(29)	(401)	-	-	-	-	-
22	CAP	5753478	Lake Valley Dam LLO Pipe Replace	M4 - LLO Refurbishment	2N	2N	4,433	111	-	-	-	-	-	2,501	64	-	-	-	-	-	1,932	48	-	-	-	-	-
23	CAP	5785442	Canyon Dam LLO Install Cutoff Wall	M4 - LLO Refurbishment	2N	2N	448	1,500	-	-	-	-	-	300	1,500	-	-	-	-	-	148	-	-	-	-	-	-
24	CAP	5780885	Fordyce Dam Replace LLO and Guard Valves	M4 - LLO Refurbishment	2N	2N	153	206	150	150	2,029	102	-	142	203	2,029	102	-	-	-	11	3	(1,879)	49	2,029	102	-
25	CAP	5787318	JBB IC Dam LLO Replace Actuator & Piping	M4 - LLO Refurbishment	2N	2N	212	1,122	2,250	-	-	-	-	750	750	-	-	-	-	-	(538)	372	2,250	-	-	-	-
26	EXP	5267076	Pit 3 Refurbish LLO No. 1 (expense)	M4 - LLO Refurbishment	AX	AX	28	225	1,613	4,500	2,250	-	-	50	-	-	-	-	-	-	(22)	225	1,613	4,500	2,250	-	-
27	EXP	5245426	Spaulding Dam 1 Reface	M1 - Internal Erosion Mitigation	AX	AX	811	50	-	-	-	-	-	800	-	-	-	-	-	-	11	50	-	-	-	-	-
28	EXP	5247476	Lower Bear Dam (Mok) Repr U/S Concr Face	M1 - Internal Erosion Mitigation	AX	AX	-	132	-	-	-	-	-	-	79	-	-	-	-	-	-	53	-	-	-	-	-
29	EXP	5260093	Wise Forebay Tree Removal/Rebuild Berm	M1 - Internal Erosion Mitigation	AX	AX	319	100	610	-	-	-	-	250	750	-	-	-	-	-	69	(650)	610	-	-	-	-
30	CAP	5794030	Lake Almanor Spillway Improv SAIP	M2 - Spillway Remediation	3H	N/A	38	180	1,811	-	-	-	-	-	-	-	-	-	-	-	38	180	1,811	-	-	-	-
31	CAP	5794034	McCloud Spillway Slide Evaluation SAIP	M2 - Spillway Remediation	3H	N/A	-	270	1,800	-	-	-	-	-	-	-	-	-	-	-	-	270	1,800	-	-	-	-
32	CAP	5794031	Lower Bucks Spillway Restoration SAIP	M2 - Spillway Remediation	3H	2N	142	315	4,500	-	-	-	-	460	4,000	-	-	-	-	-	(318)	(3,685)	4,500	-	-	-	-
33	CAP	5794027	Butt Valley Spillway SAIP Improvements	M2 - Spillway Remediation	3H	N/A	-	225	450	9,000	-	-	-	-	-	-	-	-	-	-	-	225	450	9,000	-	-	-
34	CAP	5794013	Belden Forebay Spillway Improv SAIP	M2 - Spillway Remediation	3H	2N	282	180	225	900	4,500	9,000	4,500	250	200	250	1,000	15,000	-	-	32	(20)	(25)	(100)	(10,500)	9,000	4,500
35	CAP	5794035	Tiger Creek Reg Spillway Improv SAIP	M2 - Spillway Remediation	3H	2N	963	1,620	2,520	13,500	18,000	432	-	500	500	17,700	17,700	17,700	-	-	463	1,120	(15,180)	(4,200)	300	432	-
36	CAP	5794098	Spillway Assessment Prgm Cap Mitigation	M2 - Spillway Remediation	3H	2N	-	2,070	2,250	6,390	9,000	9,000	9,000	-	5,000	10,000	20,000	35,000	-	-	-	(2,930)	(7,750)	(13,610)	(26,000)	9,000	9,000
37	CAP	5794032	McCloud Spillway Improvements SAIP	M2 - Spillway Remediation	3H	2N	-	4,500	7,008	36,000	36,000	36,000	36,000	500	10,000	10,000	40,000	40,000	40,000	40,000	(500)	(5,500)	(2,992)	(4,000)	(4,000)	(4,000)	(4,000)
38	CAP	5794026	Belden Spillway Fence Replacement SAIP	M2 - Spillway Remediation	3H	N/A	603	50	-	-	-	-	-	-	-	-	-	-	-	-	603	50	-	-	-	-	-
39	CAP	5794037	Wise Canal Inst SAIP Head Gate Autotrip	M2 - Spillway Remediation	3H	N/A	-	85	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-
40	CAP	5794029	Halsey Spillway Improvements SAIP	M2 - Spillway Remediation	3H	N/A	-	150	150	-	-	-	-	-	-	-	-	-	-	-	-	150	150	-	-	-	-
41	EXP	5272074	Lake Tabeaud Spillway Improvements SAIP	M2 - Spillway Remediation	IG	N/A	-	-	78	12	-	-	-	-	-	-	-	-	-	-	-	-	78	12	-	-	-
42	EXP	5272073	Iron Canyon Spillway Repair SAIP	M2 - Spillway Remediation	IG	N/A	-	9	176	-	-	-	-	-	-	-	-	-	-	-	-	9	176	-	-	-	-
43	EXP	5272072	Lower Bear Spillway Improvements SAIP	M2 - Spillway Remediation	IG	N/A	-	45	78	12	-	-	-	-	-	-	-	-	-	-	-	45	78	12	-	-	-
44	EXP	5272071	Drum Forebay Spillway Repair SAIP	M2 - Spillway Remediation	IG	AX	74	90	-	-	-	-	-	150	-	-	-	-	-	-	(76)	90	-	-	-	-	-
45	EXP	5272068	Pit 5 Spillway Repair Open Conduit SAIP	M2 - Spillway Remediation	IG	N/A	-	158	175	-	-	-	-	-	-	-	-	-	-	-	-	158	175	-	-	-	-
46	EXP	5272067	Upper Blue Spillway Improvements SAIP	M2 - Spillway Remediation	IG	N/A	-	180	39	6	-	-	-	-	-	-	-	-	-	-	-	180	39	6	-	-	-
47	EXP	5272066	Pit 1 Forebay Spillway Repairs SAIP	M2 - Spillway Remediation	IG	AX	48	193	-	-	-	-	-	98	215	-	-	-	-	-	(49)	(21)	-	-	-	-	-
48	EXP	5272065	Courtright Spillway Repair SAIP	M2 - Spillway Remediation	IG	AX	-	227	-	-	-	-	-	75	302	-	-	-	-	-	(75)	(75)	-	-	-	-	-
49	EXP	5272063	Salt Springs Spillway Repair SAIP	M2 - Spillway Remediation	IG	AX	107	270	-	-	-	-	-	75	300	-	-	-	-	-	32	(30)	-	-	-	-	-
50	EXP	5272062	Kings Crane Spillways FSP Engr SAIP	M2 - Spillway Remediation	IG	AX	29	270	-	-	-	-	-	130	130	120	-	-	-	-	(101)	140	(120)	-	-	-	-
51	EXP	5272061	Shasta Spillways FSP Engr SAIP	M2 - Spillway Remediation	IG	AX	672	320	252	310	-	-	-	310	355	625	300	-	-	-	362	(36)	(373)	10	-	-	-
52	EXP	5272059	Main Strawberry Spillway Repair SAIP	M2 - Spillway Remediation	IG	AX	1	369	-	-	-	-	-	75	410	-	-	-	-	-	(74)	(41)	-	-	-	-	-
53	EXP	5272056	Lake Almanor Spillway Repairs SAIP	M2 - Spillway Remediation	IG	AX	89	450	450	-	-	-	-	750	500	-	-	-	-	-	(661)	(50)	450	-	-	-	-
54	EXP	5272055	Relief Spillway Repair SAIP	M2 - Spillway Remediation	IG	AX	26	461	-	-	-	-	-	75	513	-	-	-	-	-	(49)	(51)	-	-	-	-	-
55	EXP	5272092	Helms Spillways FSP Engr SAIP	M2 - Spillway Remediation	IG	AX	91	540	-	-	-	-	-	150	150	500	50	-	-	-	(59)	390	(500)	(50)	-	-	-
56	EXP	5272054	Motherlode Spillways FSP Engr SAIP	M2 - Spillway Remediation	IG	AX	110	709	388	62	-	-	-	300	300	500	-	-	-	-	(190)	409	(112)	62	-	-	-
57	EXP	5272053	DeSabla Spillways FSP Engr SAIP	M2 - Spillway Remediation	IG	AX	310	845	78	12	-	-	-	125	125	100	-	-	-	-	185	720	(22)	12	-	-	-
58	EXP	5272032	Drum Spillways FSP Engr SAIP	M2 - Spillway Remediation	IG	AX	508	1,283	85	14	-	-	-	700	700	110	-	-	-	-	(192)	583	(25)	14	-	-	-
59	EXP	5272070	Crane Valley Spillway Repair SAIP	M2 - Spillway Remediation	IG	AX	-	110	-	-	-	-	-	40	125	-	-	-	-	-	(40)	(15)	-	-	-	-	-
60	EXP	5272069	Macumber Dam Spillway Repr EP-02-3 SAIP	M2 - Spillway Remediation	IG	N/A	32	125	-	-	-	-	-	-	-	-	-	-	-	-	32	125	-	-	-	-	-
61	EXP	5272076	PV Scott Dam Spillway Repairs	M2 - Spillway Remediation	IG	N/A	20	150	604	126	-	-	-	-	-	-	-	-	-	-	20	150	604	126	-	-	-
62	EXP	5272064	North Battle Creek Spillway Repairs SAIP	M2 - Spillway Remediation	IG	AX	32	289	-	-	-	-	-	145	289	-	-	-	-	-	(113)	-	-	-	-	-	-
63	EXP	5272060	Round Valley Spillway Repairs SAIP	M2 - Spillway Remediation	IG	AX	80	371	-	-	-	-	-	150	371	-	-	-	-	-	(70)	-	-	-	-	-	-
64	EXP	5272058	Philbrook Spillway Repairs SAIP	M2 - Spillway Remediation	IG	AX	37	450	-	-	-	-	-	150	450	-	-	-	-	-	(113)	-	-	-	-	-	-
65	EXP	5272057	Cape Horn Dam Spillway Repairs SAIP	M2 - Spillway Remediation	IG	N/A	103	500	-	-	-	-	-	-	-	-	-	-	-	-	103	500	-	-	-	-	-
66	CAP	5777488	Strawberry Dam (Stan)-Replace Liner 2020	M1-Internal Erosion Mitigations	2N	2N								400	-	-	-	-	-	-	(400)	-	-	-	-	-	-
67	EXP	5047496	Motherlode Spillways Maint SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	26	113	-	-	-	-	-	(26)	(113)	-	-	-	-	-
68	EXP	5258066	PV Scott Dam Recoat US Slide Gates	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	900	20	-	-	-	-	-	(900)	(20)	-	-	-	-	-
69	EXP	5261834	Iron Canyon Spillway Repairs SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	-	10	195	-	-	-	-	-	(10)	(195)	-	-	-	-
70	EXP	5261835	Pit 5 Open Conduit Spillway Repairs SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	-	176	195	-	-	-	-	-	(176)	(195)	-	-	-	-
71	EXP	5261952	Belden Forebay Spillway Repairs SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	1,000	-	-	-	-	-	-	(1,000)	-	-	-	-	-	-
72	EXP	5263073	Cape Horn Dam Spillway Repair SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	75	200	-	-	-	-	-	(75)	(200)	-	-	-	-	-
73	EXP	5263119	Upper Peak Lake Spillway Repair SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	116	133	-	-	-	-	-	(116)	(133)	-	-	-	-	-
74	EXP	5263399	Butt Valley Spillway Repairs SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	50	-	-	-	-	-	-	(50)	-	-	-	-	-	-
75	EXP	5267515	PV Scott Dam Spillway Repairs SAIP	M2-Spillway Remediations	AX	AX	-	-	-	-	-	-	-	50	400	-	-	-	-	-	(50)	(400)	-	-	-	-	-
76	CAP	5773911	PV Scott Dam Replace Radial Gate Hoist	M2-Spillway Remediations	2L	2L								548	-	-	-	-	-	-	(548)	-	-	-	-	-	-
77	CAP	5777493	Belden Spillway Refurbish Wall Panel	M2-Spillway Remediations	2N	2N								105	-	-	-	-	-	-	(105)	-	-	-	-	-	-
78	CAP	5780440	Pit 7 Radial Gate Inst Backup Pwr Supply	M2-Spillway Remediations	2N	2N								79	-	-	-	-	-	-	(79)	-	-	-	-	-	-
79	CAP	5780441	Pit 6 Radial Gate Inst Backup Pwr Supply	M2-Spillway Remediations	2N	2N								73	-	-	-	-	-	-	(73)	-	-	-	-	-	-
80	CAP	5782982	Belden Dam Spillway Deck Improvements	M2-Spillway Remediations	2N	2N								17	-	-	-	-	-	-	(17)	-	-	-	-	-	-
81	CAP	5783174	Bucks Storage Spillway Improv SAIP	M2-Spillway Remediations	2N	2N								1,500	-	-	-	-	-	-	(1,500)	-	-	-	-	-	-
82	CAP	5766145	Pit 1 LLO & Replace Radial Gate Retrofit	M4-Low Level Outlet Refurbishme	2N	2N								1,450	-	-	-	-	-	-	(1,450)	-	-	-	-	-	-
							33,223	47,130	55,289	127,626	116,674	79,763	71,385	37,619	51,589	78,818	120,763	116,900	47,000	45,500	(4,396)	(4,460)	(23,529)	6,863	(226)	32,763	25,885

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
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Data Response

PG&E Data Request No.:	TURN_130-Q009		
PG&E File Name:	GRC-2023-PhI_DR_TURN_130-Q009		
Request Date:	February 18, 2022	Requester DR No.:	TURN-PG&E-130
Date Sent:	March 7, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Steve Royall Eric Van Deuren	Requester:	Hayley Goodson

SUBJECT: PG&E-05, ENERGY SUPPLY - GENERATION

QUESTION 009

Regarding PG&E's response to TURN Data Request 104, Question 11:

a. Does PG&E contend that by filling vacant positions in its Power Generation unit it will reduce other employee-related costs? If so, please provide PG&E's best estimate of the reduction in other employee-related costs (e.g., overtime, benefits, payroll taxes).

b. Please identify any and all benefits to PG&E customers related to increasing headcount in PG&E's Power Generation unit. Please provide any cost-benefit analyses associated with PG&E's proposal to increase headcount for Power Generation. If no cost-benefit analysis exists, please so state.

ANSWER 009

a. Filling vacant positions will have a net neutral impact on costs due to savings from a variety of sources. For example, PG&E expects filling vacant positions will reduce overtime; potentially reduce unbudgeted forced outage work as we work through our preventive maintenance backlogs; reduce contractor costs as we insource more work; and increase the potential for less costly or otherwise superior project solutions and better cost management as we hire additional engineers to support the workload. PG&E does not have an estimate of the reduction in other employee-related costs that would result from filling the vacant positions as the drivers for filling the vacancies are not solely related to reducing other employee-related costs.

b. Please see PG&E's response to part a. PG&E does not have a cost-benefit analysis for filling these vacant positions.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_130-Q017		
PG&E File Name:	GRC-2023-PhI_DR_TURN_130-Q017Rev01		
Request Date:	February 18, 2022	Requester DR No.:	TURN-PG&E-130
Date Sent:	March 7, 2022 (Original) June 9, 2022 (Revised)	Requesting Party:	The Utility Reform Network
PG&E Witness:	Eric Van Deuren	Requester:	Hayley Goodson

SUBJECT: PG&E-05, ENERGY SUPPLY - GENERATION

QUESTION 017

Regarding PG&E's response to TURN Data Request 104, Question 25:

a. Please provide the citation to the 2020 GRC decision that ordered PG&E to move "Spillway Assessment and Improvement (SAIP)" capital expenditures from MWC 2N to MWC 3H and to move expenses from MWC AX to MWC IG.

b. Please confirm that all capital expenses categorized under MWC 3H in the 2023 GRC are recovered through the HLBA. If this is not the case, please explain which capital expenses for Planning Orders are expected to be recovered through the HBLA and which Planning Orders are not expected to be recovered through the HBLA.

c. Please confirm that all expenses categorized under MWC IG in the 2023 GRC are recovered through the HLBA. If this is not the case, please explain which expenses for Planning Orders are expected to be recovered through the HBLA and which Planning Orders are not expected to be recovered through the HBLA.

d. Aside from PG&E's reliance on the 2020 GRC decision to re-categorize capital expenditures from MWC 2N to MWC 3H, please provide all other reasons why PG&E believes that it is reasonable to re-categorize these costs.

e. Aside from PG&E's reliance on the 2020 GRC decision to re-categorize expenses from MWC AX to MWC IG, please provide all other reasons why PG&E believes that it is reasonable to re-categorize these costs.

f. Please provide PG&E's best estimate as to the date upon which the 2020 RAMP capital and expense forecasts were finalized in advance of filing the 2020 RAMP.

g. Please provide PG&E's best estimate as to the date upon which the 2023 GRC capital and expense forecasts were finalized in advance of filing the 2023 GRC.

h. In your response, you state that certain forecasts of capital costs are moved from MWC 2N to MWC 3H and that certain forecasts of expenses are moved from MWC AX to MWC IG. For each year, please provide the total amount of forecasted capital and expense moved from MWC 2N to MWC 3H or from MWC AX to MWC IG, respectively. Please list all Planning Order Descriptions and Planning Order Numbers associated with each moved forecast.

i. Please confirm that in the attachment to PG&E's response to TURN 104, Q 25, if a line item has a "RAMP MWC" of "N/A" that this was not included in the 2020 RAMP. If this is not the case, please explain the meaning of the "N/A" designator.

j. Please confirm that in the attachment to PG&E's response to TURN 104, Q 25, if a line item has a "RAMP MWC" of "2N" and a 2023 GRC MWC of "3H" that this means that the item was reclassified from MWC 2N in the 2020 RAMP to MWC 3H in the 2023 GRC. If this is not the case, please explain the meaning of the change in designator.

k. Please confirm that in the attachment to PG&E's response to TURN 104, Q 25, if a line item has a "RAMP MWC" of "AX" and a 2023 GRC MWC of "IG" that this means that the item was reclassified from MWC AX in the 2020 RAMP to MWC IG in the 2023 GRC. If this is not the case, please explain the meaning of the change in designator.

l. Please explain why the sum of all annual differences between RAMP 2020 and 2023 GRC for 2023 GRC MWCs 2N, 3H, AX, and IG from the attachment to PG&E's response to TURN 104, Question 25 do not equal the differences for 2020-2026 presented in PG&E's response. For example, the sum of all differences for 2023 GRC MWC 2N for 2020 from the attachment equals -1,327 while in PG&E's response the difference is -3,037 (see p. 2 of response to TURN 104, Question 25)

m. Please confirm that aside from the "DSP : Dam Capital," PG&E increased its capital forecasts for 2020-2023 by approximately $14.8 million between the time that the 2020 RAMP was filed and the 2023 GRC was filed. Please explain why these capital costs were not included in the 2020 RAMP forecasts but were included in the 2023 GRC forecast.

ANSWER 017 REVISED 01

a. Ordering Paragraph 1 from D.20-12-005 adopted, in part, the January 14, 2020 "Joint Motion for Approval of the Settlement Agreement regarding Pacific Gas and Electric Company's (PG&E) Test Year 2020 General Rate Case. The Settlement Agreement continues the Hydro Licensing Balancing Account (HLBA) but modifies it to include regulatory fees, costs associated with implementation of the Crane Valley Recreation Settlement Agreement, and costs associated with work required due to the 2017 Oroville spillway incident.[1] PG&E's 2020 GRC, Exhibit (PG&E-5), Chapter 4 testimony explains that balancing account costs are assigned to MWCs IG and 3H.

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1 Settlement Agreement of the 2020 Generation Rate Case of Pacific Gas and Electric Company, Section 4.4.4.3.

2020 GRC, Exhibit (PG&E-5) Workpapers, page WP 4-120, includes a table showing the expense and capital expenditures proposed for balancing account treatment by MWC including MWCs 2N, 3H, AX, and IG. As explained in PG&E's response to TURN data request 104, Question 24, the HLBA tracks adopted amounts compared to actual amounts at the program level using MWC IG for expenses and MWC 3H for capital. After the 2020 GRC decision, PG&E moved newly approved costs from MWCs AX and KJ to MWC IG for expense and from MWC 2N to 3H for capital so that proper balancing account treatment would occur.

b. PG&E confirms that all the capital forecasts categorized under MWC 3H in the 2023 GRC are recovered through the HLBA.

c. PG&E confirms that all the expense forecasts categorized under MWC IG in the 2023 GRC are recovered through the HLBA.

d. To comply with the 2020 GRC decision, PG&E reassigned certain costs from MWC 2N to 3H. The reason why PG&E requested in its 2020 GRC that additional cost categories be included in the HLBA is described in its 2020 GRC Exhibit(PG&E-5), Chapter 8 testimony.

e. To comply with the 2020 GRC decision, PG&E reassigned certain costs from MWCs AX and KJ to MWC IG. The reason why PG&E requested in its 2020 GRC that additional cost categories be included in the HLBA is described in its 2020 GRC Exhibit(PG&E-5), Chapter 8 testimony.

f. The 2020 RAMP filing forecasts presented in this workpaper were prepared during the first quarter of 2020.

g. The 2023 GRC capital and expense forecasts were finalized during the fourth quarter of 2020.

h. Please see PG&E's response to TURN data request 104, Question 25e, Attachment GRC-2023-PhI_DR_TURN_104-Q025eAtch01.

i. In the attachment to PG&E's response to TURN data request 104, Question 25e, if a line item has a "RAMP MWC" of "N/A" then that particular line item was not included in the 2020 RAMP. However, that particular line item may have been included as part of another line item.

j. In the attachment to PG&E's response to TURN data request 104, Question 25e, if a line item has a "RAMP MWC" of "2N" and a 2023 GRC MWC of "3H" that this means that the item was reclassified from MWC 2N to MWC 3H.

k. In the attachment to PG&E's response to TURN data request 104, Question 25e, if a line item has a "RAMP MWC" of "AX" and a 2023 GRC MWC of "IG" that this means that the item was reclassified from MWC AX to MWC IG.

l. The sum of all annual differences between RAMP 2020 and 2023 GRC for 2023 GRC MWCs 2N, 3H, AX, and IG from the attachment to PG&E's response to TURN 104, Question 25 do equal the differences for 2020-2026 presented in PG&E's response. Using the example TURN presented for 2020 MWC 2N, filtering on column F, 2023 GRC MWC, for MWC 2N yields a 2020 (2023 GRC) total of $9,766 (cell H89). Next, after clearing the column F filter, filter on column G, RAMP MWC, for MWC 2N yields a 2020 RAMP total of $12,803 (cell O89). The difference between the 2020 forecast from the 2023 GRC and the 2020 RAMP forecast is -$3,037. TURN errored by not filtering on MWC 2N separately for the 2020 forecast from the 2023 GRC and the 2020 RAMP, resulting in not counting the line items who's MWC changed from 2N to 3H between the RAMP and the 2023 GRC.

m. PG&E decreased its capital forecasts for 2020-2023 by approximately $31 million between the time that the 2020 RAMP was filed and the 2023 GRC was filed. This is due to further scoping of work and the resulting improvement of cost forecasts. This resulted in a shifting of some cost forecasts to the outer years.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
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Data Response

PG&E Data Request No.:	TURN_213-Q001		
PG&E File Name:	GRC-2023-PhI_DR_TURN_213-Q001		
Request Date:	May 26, 2022	Requester DR No.:	TURN-PG&E-213
Date Sent:	June 6, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Eric Van Deuren, Steve Royall	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

QUESTION 001

Please provide actual headcount for Power Generation for the end of 2021.

ANSWER 001

As of 12/31/2021 Power Generation had 885 full time equivalent employees.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_104-Q008		
PG&E File Name:	GRC-2023-PhI_DR_TURN_104-Q008		
Request Date:	January 31, 2022	Requester DR No.:	TURN-PG&E-104
Date Sent:	February 14, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Steve Royall	Requester:	Hayley Goodson

SUBJECT: ENERGY SUPPLY – GENERATION

Natural Gas and Solar

QUESTION 008

Refer to Exhibit PG&E-5, p. 5-58, which discusses Evaporative Cooling at Gateway Generation Station (GGS). Please respond to the following questions regarding this proposal:

a. Please explain how the Evaporative Cooling project at GGS will increase the capacity at GGS.

b. Did PG&E include the capacity increase of 17 MW associated with the Evaporative Cooling at GGS in its most recent Integrated Resource Plan (IRP) submitted to the Commission? If so, please provide a citation to where this capacity addition is discussed in PG&E's most recent IRP. If not, please explain why it was not discussed.

c. How many hours per year does PG&E expect that this Evaporative Cooling project to operate in a normal weather year?

d. How many years does PG&E expect to use the additional 17 MW of generating capacity associated with this project? If PG&E has conducted any modeling to support this estimate, provide the modeling results.

ANSWER 008

a. The evaporative cooling project provides a power output and efficiency increase when there is high ambient temperatures and low relative humidity. The system will cool the combustion turbine compressor intake air through humidification, raising relative humidity and lowering the inlet temperature. Inlet air cooling increases the air mass flow rate and compressor functionality, resulting in higher turbine output power and efficiency. This will benefit customers during hot, dry months, typically summer.

b. PG&E did not include the capacity increase of 17 MW associated with the Evaporative Cooling at GGS in its most recent Integrated Resource Plan (IRP) submitted to the Commission. The timing of PG&E's most recent IRP was earlier than the development of the Gateway Evaporative Cooling project scope and forecast developed for this GRC.

c. PG&E expects to benefit from the installation of the evaporative coolers during summer month periods when there are high ambient temperatures, low humidity in combination with high customer demand periods. It is difficult to predict the amount of time the additional output will be utilized. The additional output is expected to be utilized, at a minimum, when there are extreme heat periods which is difficult to forecast but have high consequence when they occur. For example, on August 14 and 15, 2020, the CAISO was forced to institute rotating electricity outages in California in the midst of a west-wide extreme heat wave. This project will play a part in helping to mitigate these types of situations.

   Additionally, the project is in response to the CPUC Order Instituting Rulemaking (OIR) 20-11-003 which stated the following:

   To develop new resources, this OIR will consider multiple options, including directing each investor-owned utility (IOU) to develop new supply-side resources to the extent they can be brought online in 2021 and to bring additional capacity online by procuring incremental capacity from the existing resources, implementing efficiency upgrades to existing generators, and retrofitting existing generators that are set to retire, such as Once-Through-Cooling (OTC) generators.[1]

   In response to this OIR, PG&E conducted a systematic review of its UOG portfolio, and the costs and benefits associated with improving its facilities, specifically which options would provide the best approach for achieving enhanced operations and increasing capacity to meet net peak demand, with customer affordability in mind. After careful review, PG&E identified achievable near-term opportunities for increasing capacity for summer 2021 and 2022. The installation of Evaporative Cooling at Gateway is one of the approaches PG&E identified for achieving the near-term capacity increase.

   Attachment GRC-2023-PhI_DR_TURN_104-Q008Atch01 includes OIR 20-11-003.

d. See PG&E’s response to c. PG&E expects to utilize the additional capacity, when the right conditions are met, through the operating life of the plant.

1 OIR 20-11-003, p.10.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_130-Q004		
PG&E File Name:	GRC-2023-PhI_DR_TURN_130-Q004		
Request Date:	February 18, 2022	Requester DR No.:	TURN-PG&E-130
Date Sent:	March 7, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Steve Royall	Requester:	Hayley Goodson

SUBJECT: PG&E-05, ENERGY SUPPLY - GENERATION

QUESTION 004

Regarding PG&E's response to TURN Data Request 104, Question 5:

a. Please provide actual capital expenditures by year for 2018-2021 for HBGS Engine Emissions Module Replacements. Also, please indicate the actual cost per engine for the emissions module replacements for 2018-2021.

b. Please provide the assumed number of emission module replacements per year used to develop the forecast in PG&E's 2020 GRC presented in PG&E's response to TURN DR 104, Q5.

c. On page WP 5-83 of Exhibit PG&E-5 WPv2, it indicates that there were zero dollars expended in 2020. Does this mean that PG&E did not expend any capital in 2020 on the HBGS Emissions Module Replacements? Please explain.

d. Please provide a workpaper deriving the total forecasted costs presented in WP 5-83 that reconciles the approximate $201,000 cost per engine emissions module replacement cost provided in PG&E's response with the total cost per year in WP 5-83.

e. Please explain why the total annual costs for HBGS Engine Emissions Module Replacements in 2021 and 2022 in PG&E's 2023 GRC is 2.2 to 2.5 times higher than in PG&E's 2020 GRC. Please provide workpapers supporting your response.

ANSWER 004

a. There are 3 different types of emission modules that are used in each engine: SCR Catalyst for NOx reduction, Ammonia Slip Catalyst, and Oxidation Catalyst for CO reduction. Each module type has its own life cycle, and the life cycle varies based on the engine's operating profile (operating history). Therefore, there is variability in the scope of the module replacement from engine to engine and year to year.

The actual cost per module replacement by year is provided in the table below.

Year	2020 GRC Forecast Engine Module Replacement Cost	Actual Module Quantity			Actual Cost per Module			Total Actual Engine Module Replacement Cost
		SCR	Ammonia	CO	SCR	Ammonia	CO	
2018	$456,603	3	2	4	$152,973	$156,025	$222,652	$1,661,577
2019	$468,018	6	2	0	$130,372	$208,079	-	$1,198,388
2020	$478,782	3	3	2	$170,995	$188,914	$237,392	$1,554,509
2021	$488,837	7	1	0	$114,794	$146,517	-	$950,072

b. 7 emission module replacements per year were used to develop the forecast in PG&E's 2020 GRC.

c. PG&E spent $1,554,509 on module replacements in 2020. WP 5-83 is missing the 2020 module replacement expenditure, but it is included in WP 5-46 line 18 and WP 5-59 line 64.

d. The $201,000 cost was an approximate value intended to capture the overall module replacement cost at the engine level (1 to 2 modules per engine) for forecasting purposes recognizing that the exact quantity and types of modules requiring replacement on each engine could not be known prior to fourth quarter 2020 deadline for the 2023 GRC forecasts to be finalized to develop a more accurate forecast. It is derived from a review of the historical recorded costs and anticipation of increased module replacements in the 2023 GRC period as the engines get further into their operating life.

   As can be seen in the recorded costs in the table in subpart a. above, the scope and cost can vary significantly from year to year. Modules are replaced through the course of the operating year on the engines as a result of inspections and emissions monitoring. The exact scope for the year on a given engine is not known.

e. PG&E has realized since the last GRC that the cost to replace each emission module is higher than PG&E forecasted in the 2020 GRC and as the engines age and service hours increase, the modules are reaching end of life sooner. As a result, PG&E expects the quantity of module replacements to increase during the 2023 GRC period and has increased its forecast accordingly.

   The timing of the module replacements is not discretionary. The modules must be replaced as inspection and monitoring dictates through the course of the year to maintain compliance with the air quality permit.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
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Data Response

PG&E Data Request No.:	TURN_130-Q005		
PG&E File Name:	GRC-2023-PhI_DR_TURN_130-Q005		
Request Date:	February 18, 2022	Requester DR No.:	TURN-PG&E-130
Date Sent:	March 7, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Steve Royall	Requester:	Hayley Goodson

SUBJECT: PG&E-05, ENERGY SUPPLY - GENERATION

QUESTION 005

Regarding PG&E's response to TURN Data Request 104, Question 6:

a. Please provide all workpapers supporting the estimates of "Fossil Emergent Capital Work" in the 2020 and 2023 GRC. Please provide these workpapers in Excel format with links and formulae intact.

b. Please provide any analysis comparing PG&E's prior forecasts of "Fossil Emergent Capital Work" against the actual capital expenditures made by PG&E for the years forecast. For example, please demonstrate why PG&E's forecast of "Fossil Emergent Capital Work" for 2020 and 2021 from its 2020 GRC is a reasonable approximation of actual capital expenditures by PG&E for 2020 and 2021 for MWC 2S. Please provide any such analysis in Excel format with links and formulae intact. If no such analysis exists, please so state.

ANSWER 005

a. Refer to Attachment GRC-2023-PhI_DR_TURN_130-Q005Atch01 and Attachment GRC-2023-PhI_DR_TURN_130-Q005Atch02 for the 2020 workpapers on "Fossil Emergent Capital Work". Refer to Attachment GRC-2023-PhI_DR_TURN_130-Q005Atch03 and Attachment GRC-2023-PhI_DR_TURN_130-Q005Atch04 for the 2023 workpapers on "Fossil Emergent Capital Work".

b. When evaluating the reasonableness of "Fossil Emergent Capital Work" under MWC 2S, it's important that it is reviewed as part of the overall forecast for MWC 2S which is intended to capture all fossil capital reliability projects.

   Refer to Attachment GRC-2023-PhI_DR_TURN_130-Q005Atch05 for an analysis comparing the 2021-2026 forecast for MWC 2S with actual expenditures from 2016-2020. As discussed in PG&E's response to TURN Data Request 104, Question 6, this attachment shows how the "Fossil Emergent Capital Work" planning order is used to estimate reliability costs in the outer years so that the MWC 2S forecast is consistent with historical expenditures. The forecast for "Fossil Emergent Capital Work" ensures a reasonable forecast for expected capital work in MWC 2S is reflected in the outer years of the rate case, when identifying the specific components/equipment that will likely fail becomes less predictable.

The average annual forecast in 2024-2026 for MWC 2S is less than the average annual recorded expenditures in the 2016-2020 timeframe when compared in 2020 dollars. The average annual forecast in 2024-2026 for MWC 2S is also less than the average total annual forecast expenditures in the 2021-2023 timeframe when compared in 2020 dollars.

It is reasonable to expect the average annual reliability expenditure forecast in 2024-2026 for 2S to be relatively consistent with historical annual recorded expenditures as well as forecasted annual expenditures for the 2021-2023 timeframe for this MWC.

Pacific Gas and Electric Company
2023 General Rate Case
Exhibit (PG&E-5), Chapter 5
Natural Gas and Solar Generation Operations
Analysis of MW 2S and Fossil Common Emergent Work Planning Order

MW 2S (in Nominal Dollars)

Line No.	Planning Order	Dollar Type	MWC	MWC Description	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Comments
1	Multiple	In Nominal Dollars	2S	Instal/Repl Fosil Gneratng Eqp [1]	9,771	4,495	4,822	4,252	12,480	11,756	7,175	6,640	7,929	8,568	6,196	Total Forecast for MWC 2S
2	5767987	In Nominal Dollars	2S	Fossil Common Emergent Work [2]						-	-	-	2,000	2,500	4,086	Forecast for Fossil Common Emergent Work PO
3	Multiple	In Nominal Dollars	2S	Specific Capital Projects [3]						11,756	7,175	6,640	5,929	6,068	2,110	Total Forecast for all other capital projects/planning orders under MWC 2S
4	Multiple	In Nominal Dollars	2S	Instal/Repl Fosil Gneratng Eqp						11,756	7,175	6,640	7,929	8,568	6,196	Total of lines 2 and 3 =Total forecast for MWC 2S

[1] (WP 5-47, Line 59)
[2] (WP 5-46, Line 19)
[3] (WP 5-46 and WP 5-47, Lines 10-58, excluding Line 19)

MW 2S (in 2020 Dollars)

Line No.	Planning Order	Dollar Type	MWC	MWC Description	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Comments
1	Multiple	In 2020 Dollars	2S	Instal/Repl Fosil Gneratng Eqp	10,761	4,802	5,125	4,422	12,480	11,291	6,774	6,143	7,195	7,590	5,374	Total Forecast for MWC 2S
2	5767987	In 2020 Dollars	2S	Fossil Common Emergent Work						-	-	-	2,000	2,500	4,086	Forecast for Fossil Common Emergent Work PO
3	Multiple	In 2020 Dollars	2S	Specific Capital Projects						11,756	7,175	6,640	5,929	6,068	2,110	Total Forecast for all other capital projects/planning orders under MWC 2S
4	Multiple	In 2020 Dollars	2S	Instal/Repl Fosil Gneratng Eqp						11,756	7,175	6,640	7,929	8,568	6,196	Total of lines 2 and 3 =Total forecast for MWC 2S

Line No.	Dollar Type	MWC		
5	In 2020 Dollars	2S	Average 2016-2020 Recorded	6,896
6	In 2020 Dollars	2S	Average 2018-2020 Recorded	7,343
7	In 2020 Dollars	2S	Average 2021-2023 Forecast	8,069
8	In 2020 Dollars	2S	Average 2024-2026 Forecast	6,720

Line No.	Year	Capital Escalation Rate [4]
1	2016	3.10
2	2017	0.50
3	2018	2.20
4	2019	4.00
5	2020	1.90
6	2021	2.10
7	2022	1.70
8	2023	2.00
9	2024	2.20
10	2025	2.10
11	2026	2.10

	In 2020 Dollars	In 2021 Dollars	In 2022 Dollars	In 2023 Dollars	In 2024 Dollars	In 2025 Dollars	In 2026 Dollars
2026 Foreca	5,374	5,478	5,595	5,692	5,808	5,939	6,066
2025 Foreca	7,590	7,737	7,903	8,039	8,203	8,388	
2024 Foreca	7,195	7,335	7,492	7,622	7,754		
2023 Foreca	6,143	6,262	6,397	6,507			
2022 Foreca	6,774	6,905	7,053				
2021 Foreca	11,291	11,510					

[4] Chapter 5 Natural Gas and Solar Generation Operations Expense and Capital Escalation 2021-26 WP 22, Lines 42-52

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
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Data Response

PG&E Data Request No.:	CalAdvocates_018-Q05		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_018-Q05		
Request Date:	August 9, 2021	Requester DR No.:	PubAdv-PG&E-018-LJL
Date Sent:	August 23, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Tom Baldwin, Eric Van Deuren, Steve Royall, Candice Chan, Dana Longmire	Requester:	Truman Burns

SUBJECT: ENERGY SUPPLY

QUESTION 05

For each of the business units/programs within Energy Supply Departments provide in an Excel spreadsheet the documentation that demonstrates PG&E's forecast for additional positions/FTEs for TY 2023 and the detailed breakdown of the calculation, including the basis/source for each estimate, for the associated expenses. In the response include the job title, job description and associated salary.

ANSWER 05

As context, PG&E's Exhibit (PG&E-5) TY 2023 forecast is presented at the Major Work Category level. In general, forecasts are developed based on the work being completed, not based on headcount.

For DCPP, PG&E is not requesting any additional funding for additional headcount/FTE for TY 2023.

For Hydro, PG&E (Exhibit-5) Workpaper page WP 4-106 indicates an increase of 41 headcount from Dec 31, 2020 actuals to 2021 forecast headcount (which matches 2022 & 2023 forecast headcount). The purpose of the increase is to close existing vacancies, i.e. hire for positions that are currently vacant due to employees taking other positions, leaving the company, or retiring. Only a small subset of these existing vacancies is forecast to increase expense costs to PG&E. PG&E estimated that six new hires, at an average annual cost of $150k each, that join the Asset Management/PG Asset Excellence organization will charge to orders in MWC OS. PG&E (Exhibit-5) Workpaper page WP 4-38 includes the MWC OS walk. This workpaper shows an increase of $918k in the 2021 forecast costs, with most of that increase due to the addition of the six hires ($150k x 6 = $900k). The remainder of the increase is due to the reorganization of the Generation line of business, which resulted in employees exiting and entering different provider cost centers (PCCs) that charged to orders in MWC OS. Since employees generally earn different wages, changing the employee composition of a PCC will have an impact on the forecast costs.

New hires that do not charge to orders in MWC OS (examples: O&M, engineers, project managers) are forecast to have their labor costs fully offset by reduced use of contractors and/or reduced use of overtime/double-time from the existing workforce. Since MWC OS is the only MWC impacted by increased expenses due to filling existing vacancies, PG&E is limiting its response to providing job titles, job descriptions and associated salaries for those relevant positions. Attachment GRC-2023-PhI_DR_CalAdvocates_018-Q05Atch01 provides the job title, job description and associated salary for the six new hires in the Asset Management/PG Asset Excellence organization.

For Natural Gas and Solar, PG&E is not requesting any additional funding for additional headcount/FTE for TY 2023.

For Energy Procurement, PG&E is not requesting any additional funding for additional headcount/FTE for TY 2023. The cost of additional staffing has been completely offset by a reduction in non-labor costs as described in PG&E (Exhibit-5), Chapter 6, p. 6-6. PG&E (Exhibit-5) Workpaper page WP 6-7 incorporates the impact of five additional positions needed for compliance with SB 1440, the Biomethane Procurement Mandate. These new positions are forecasted at EPP's average salary of $159k over the requisite timeframe. In addition, the workpaper includes the impact of resuming the salary forecast of the EPP Senior Vice President, beginning in 2023. This is consistent with CPUC Resolution E-4963, which applies to Utility officers that are non-SEC Rule 240.3b-7 designated officers. The remainder of the increase is attributed to EPP's reduction in forecasted staffing vacancies, from 15% to 13%. The aggregated impact of these items represents total staffing additions in the workpaper. In Attachment GRC-2023-PhI_DR_CalAdvocates_018-Q05Atch02, PG&E provides job titles, job descriptions, salary ranges, and the underlying basis for these additional positions, along with a breakout of the components of total staffing additions in the workpaper.

For the Energy Supply Technology Program, PG&E's forecast is not based on any additional headcount/FTE for TY 2023.

Attachment GRC-2023-PhI_DR_CalAdvocates_018-Q05Atch02

Energy Procurement Administration Costs

FTE	Job Title	Job Description	Salary Ranges ($)*	Basis for Request
2	Principal, Biomethane Contract Transactor	Lead solicitations, negotiate and execute renewable supply contracts, develop procurement plans	126,000 - 200,000	Implementation of SB 1440, Biomethane Procurement
1	Expert/Sr. Gas Regulatory Analyst	Produce plans and forecasts, perform analysis, compile reports for regulatory agencies	118,000 - 188,000	Implementation of SB 1440, Biomethane Procurement
1	Career, Biomethane Analyst	Administer CPUC filings, prepare reports, respond to data requests	90,000 - 136,000	Implementation of SB 1440, Biomethane Procurement
1	Settlements Analyst	Settlement of renewable gas contracts	68,000 - 102,000	Implementation of SB 1440, Biomethane Procurement
5	**Total Additional FTE**			

Staffing Additions - Summary

Description		Impact
5 Additional Biomethane Procurement staff (2 FTE in 2022, 3 FTE in 2023, Avg. Salary $159k)	$	918,000
Resumption of including forecast labor costs/FTE for the EPP SVP. Per CPUC Resolution E-4963, only the salaries/benefits of SEC Rule 240.3b-7 officers will be excluded from the 2023 forecast.		471,000
Reduction in EPP staffing vacancy rate from 15% to 13%.		841,000
Total Staffing Variance per Exhibit (PG&E-5), Chapter 6, WP 6-7.	$	2,230,000

* Does not include benefits, salaries are per Human Resources.

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Data Response

PG&E Data Request No.:	CalAdvocates_126-Q10		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_126-Q10Rev01		
Request Date:	October 28, 2021	Requester DR No.:	PubAdv-PG&E-126-ANU
Date Sent:	November 12, 2021 (Original) January 13, 2022 (Revised)	Requesting Party:	Public Advocates Office
PG&E Witness:	Beatrix Greenwell, Rebecca Doidge	Requester:	Anusha Nagesh

SUBJECT: FOLLOW UP TO DATA REQUESTS PUBADV-PG&E-083-ANU, PUBADV-PG&E-052-ANU AND EXHIBITS PG&E-5, CH. 8 AND PG&E-10, CH. 11

QUESTION 10

Referring to exhibit PG&E-10, Chapter 11 workpaper titled “Ex 10 Ch 11 WP – PUBLIC,” in tab “11-58,” Column titled K, please answer the following questions:

a. Explain in detail how PG&E calculated “Remaining Years” for all the listed hydro-decommissioning projects.

b. Provide all calculations in MS Excel and all other related documents supporting the forecasted “Remaining Years” in column K, lines 1 to 9.

ANSWER 10

a. As described in Exhibit (PG&E-5), Chapter 8, p. 8-13, the intent of the decommissioning reserve is to accrue decommissioning dollars while the plant is used and useful. Therefore, the annual accrual calculation is generally based on the forecast retirement dates, rather than the earliest decommissioning start year. As described at the bottom of Exhibit (PG&E-10), Chapter 11, WP Table 11-58, decommissioning amounts are recovered over the useful life of the plant, through the year prior to the estimated retirement year.

   As a general rule, base year 2023 was subtracted from the “Assumed End of Depreciation Life” shown in Exhibit (PG&E-10), WP 12-33 to obtain “Remaining Years” for each project. For those projects (Phoenix and DeSabla-Centerville) whose “Assumed End of Depreciation Life” dates were earlier than 2023, the “Remaining Years” were set to 1 in order to recover/refund the forecast remaining amount as of 12/31/2022 shown in column J of WP Table 11-58. The “Remaining Years” was used in Column L to calculate the annual accrual for years 2023-2026. Similar to the decommissioning methodology used in prior GRCs for retired fossil plants, when plant is retired prior to the test year, or during the rate case period for which rates are being proposed, PG&E’s methodology is to allocate the remaining amount to recover over the current rate case cycle (2023-2026 for the 2023 GRC).

When reviewing Table 11-58, it was noted that the calculations did not result in the spread of costs as described above. The plants with a number of years less than four should have received a “4” in the calculation to properly spread the cost over the rate case cycle. A corrected table with an additional column, L1, showing the amortization period is attached as GRC-2023-PhI_DR_CalAdvocates_126-Q10Atch01. PG&E will file an erratum at the next opportunity to correct the revenue requirement. The change will be from $78 million per year to $62 million per year. See subpart b. for further details on the forecast retirement dates and remaining lives used to support the hydro decommissioning accruals in WP Table 11-58.

b. As discussed in subpart a., the remaining years are based on the forecast retirement date, or assumed end of depreciation life, of the hydro facilities. For many of the Company’s hydro facilities, the end of the FERC license was used to estimate the probable retirement date. However, due to changing operational and economic circumstances, some of the Company’s hydro facilities are expected to be retired earlier than the expiration of the facility’s FERC license. For these facilities, the estimated retirement date is consistent with these expectations as described in the table below.

See the table below for a listing of the projects and reason behind the “Assumed End of Depreciation Life” date and the calculation of the remaining years included in Exhibit (PG&E-10), Chapter 11, WP Table 11-58, Column K. These items are being provided in Word below, due to the relative simplicity of the calculations.

Project	Remaining Years Table 11-58, Column K	Forecast Retirement Year	Calculation of Remaining Years	Reason for Assumed End of Depreciation Life
Crane Valley	12	2035	2035-2023 = 12	Planned for future sale, but process had not yet begun; if sale is unsuccessful, PG&E may surrender license early; decommissioning could begin in 2035.
Tule River	10	2033	2033-2023 = 10	FERC license expiration date
Hat Creek	9	2032	2032-2023 = 9	FERC license expiration date
Hamilton Branch	2	2025	2025-2023 = 2	Active sale negotiations. If sale is unsuccessful, PG&E may retire project early.
Battle Creek	3	2026	2026-2023 = 3	FERC license expiration date
Phoenix	1	2022	2022-2023 = -1 Use 1	Active sale negotiations. If sale is unsuccessful, PG&E may surrender license early.

Project	Remaining Years Table 11-58, Column K	Forecast Retirement Year	Calculation of Remaining Years	Reason for Assumed End of Depreciation Life
Kerckhoff 1	4	2027	2027-2023 = 4	Project is proposed to be decommissioned as part of relicensing process for overall project. End of GRC period established as end of depreciation life, so that funds for decommissioning are accrued over course of 4 years.
DeSabla - Centerville	1	2022	2022-2023 = -1 Use 1	Active sale negotiations. If sale is unsuccessful, PG&E may surrender license early.
Potter Valley	3	2026	2026-2023 = 3	In regulatory process. If transfer is unsuccessful, PG&E may surrender license early.

ANSWER 10 REVISED 01

a. As described in Exhibit (PG&E-5), Chapter 8, p. 8-13, the intent of the decommissioning reserve is to accrue decommissioning dollars while the plant is used and useful. Therefore, the annual accrual calculation is generally based on the forecast retirement dates, rather than the earliest decommissioning start year. As described at the bottom of Exhibit (PG&E-10), Chapter 11, WP Table 11-58, decommissioning amounts are recovered over the useful life of the plant, through the year prior to the estimated retirement year.

As a general rule, base year 2023 was subtracted from the “Assumed End of Depreciation Life” shown in Exhibit (PG&E-10), WP 12-33 to obtain “Remaining Years” for each project. For those projects (Phoenix and DeSabla-Centerville) whose “Assumed End of Depreciation Life” dates were earlier than 2023, the “Remaining Years” were set to 1 in order to recover/refund the forecast remaining amount as of 12/31/2022 shown in column J of WP Table 11-58. The “Remaining Years” was used in Column L to calculate the annual accrual for years 2023-2026. Similar to the decommissioning methodology used in prior GRCs for retired fossil plants, when plant is retired prior to the test year, or during the rate case period for which rates are being proposed, PG&E’s methodology is to allocate the remaining amount to recover over the current rate case cycle (2023-2026 for the 2023 GRC).

When reviewing Table 11-58, it was noted that the calculations did not result in the spread of costs as described above. The plants with a number of years less than four should have received a “4” in the calculation to properly spread the cost over the rate case cycle. Also, to add clarity, an additional column K, “Forecast Retirement Year” will be added to Table 11-58, and the Tule River forecast retirement year will be updated from 2033 to 2018. A corrected table that adds column K, with an additional column, L1, “Cost Allocation Years”, showing the amortization period is attached as GRC-2023-PhI_DR_CalAdvocates_126-

Q10Rev01Atch01. PG&E will file an erratum at the next opportunity to correct the revenue requirement. The change will be from $78 million per year to $62 million per year. See subpart b. for further details on the forecast retirement dates and remaining lives used to support the hydro decommissioning accruals in WP Table 11-58.

b. As discussed in subpart a., the remaining years are based on the forecast retirement date, or assumed end of depreciation life, of the hydro facilities. For many of the Company's hydro facilities, the end of the FERC license was used to estimate the probable retirement date. However, due to changing operational and economic circumstances, some of the Company's hydro facilities are expected to be retired earlier than the expiration of the facility's FERC license. For these facilities, the estimated retirement date is consistent with these expectations as described in the table below.

See the table below for a listing of the projects and reason behind the "Assumed End of Depreciation Life" date and the calculation of the remaining years included in Exhibit (PG&E-10), Chapter 11, WP Table 11-58, Column K. These items are being provided in Word below, due to the relative simplicity of the calculations.

Project	Remaining Years Table 11-58, Column K	Forecast Retirement Year	Calculation of Remaining Years	Reason for Assumed End of Depreciation Life
Crane Valley	12	2035	2035-2023 = 12	Planned for future sale, but process had not yet begun; if sale is unsuccessful, PG&E may surrender license early; decommissioning could begin in 2035.
Tule River	-5	2018	2018-2023 = -5 Use 4	Project out of service since late 2017 due to wildfire; active sale negotiations
Hat Creek	9	2032	2032-2023 = 9	FERC license expiration date
Hamilton Branch	2	2025	2025-2023 = 2 Use 4	Active sale negotiations. If sale is unsuccessful, PG&E may retire project early.
Battle Creek	3	2026	2026-2023 = 3 Use 4	FERC license expiration date
Phoenix	1	2022	2022-2023 = -1 Use 4	Active sale negotiations. If sale is unsuccessful, PG&E may surrender license early.
Kerckhoff 1	4	2027	2027-2023 = 4	Project is proposed to be decommissioned as part of relicensing process for overall project. End of GRC period established as end of depreciation life, so that funds for decommissioning are accrued over course of 4 years.

Project	Remaining Years Table 11-58, Column K	Forecast Retirement Year	Calculation of Remaining Years	Reason for Assumed End of Depreciation Life
DeSabla - Centerville	1	2022	2022-2023 = -1 Use 4	Active sale negotiations. If sale is unsuccessful, PG&E may surrender license early.
Potter Valley	3	2026	2026-2023 = 3 Use 4	In regulatory process. If transfer is unsuccessful, PG&E may surrender license early.

Table 11-58

Pacific Gas and Electric Company
2023 General Rate Case Application
Exhibit (PG&E-10), Chapter 11 - Depreciation Reserve and Expense
Hydro Decommissioning Remaining Cost Forecast and Annual Amortization
(Thousands of Dollars)

Ln	Facility	Cost Estimate	Recorded Accumulated Decommissioning Accruals as of December 31, 2020	Forecast Decommissioning Accruals 2021	Forecast Decommissioning Spend 2021	Forecast Decommissioning Accruals 2022	Forecast Decommissioning Spend 2022	Forecast Decommissioning Balance as of December 31, 2022	Forecast Remaining Cost as of December 31, 2022	Forecast Amount Required to Recover as of December 31, 2022	Forecast Retirement Year	Remaining Years	Cost Recovery Period	Annual Accrual 2023 - 2026
	A	B	C	D	E	F	G	H=C+D-E+F-G	I	J = I - H	K	L = J.1-2023	L1	M = J/L1 (see note 1)
1	Crane Valley	65,284	1,227	1,227		1,227		3,682	65,284	61,601	2035	12	12	5,133
2	Tule River	1,544	633	633		633		1,898	1,544	(354)	2018	(5)	4	(89)
3	Hat Creek	43,503	83	83		83		250	43,503	43,253	2032	9	9	4,806
4	Hamilton Branch	8,269	1,554	1,554		1,554		4,661	8,269	3,608	2025	2	4	902
5	Battle Creek	161,801	3,559	3,559	125	3,559	125	10,427	161,801	151,374	2026	3	4	37,843
6	Phoenix	509	317	317		317		950	509	(441)	2022	(1)	4	(110)
7	Kerckhoff 1	35,914	0	0		0		0	35,914	35,914	2027	4	4	8,979
8	DeSabla - Centerville	8,831	2,042	2,042		2,042		6,126	8,831	2,705	2022	(1)	4	676
9	Potter Valley	26,586	3,482	3,482		3,482		10,445	26,586	16,141	2026	3	4	4,035
14	Total	352,242	12,897	12,897	125	12,897	125	38,441	352,242	313,801				62,176

Note (1)
Decommissioning amounts are generally recovered over the useful life of the plant, through the year prior to the estimated retirement year. See Exhibit (PG&E-5), Chapter 8 testimony.
For facilities with 4 years or less of remaining years in column L, the annual accrual in column M is calculated by dividing the amount in column J by 4 (years 2023-2026 of this GRC rate case cycle) as shown in column L1.
Cost estimates in Column B are after the application of the probability of decommissioning. Refer to Exhibit (PG&E-5), Chapter 8 testimony and associated workpapers.

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Data Response

PG&E Data Request No.:	TURN_130-Q018		
PG&E File Name:	GRC-2023-PhI_DR_TURN_130-Q018		
Request Date:	February 18, 2022	Requester DR No.:	TURN-PG&E-130
Date Sent:	March 7, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Eric Van Deuren	Requester:	Hayley Goodson

SUBJECT: PG&E-05, ENERGY SUPPLY - GENERATION

QUESTION 018

Regarding PG&E's response to TURN Data Request 104, Question 26:

a. Has PG&E begun preparation of an amendment to its FERC License to allow the Helms uprate? If not, when does PG&E plan to begin work on this application? How long does PG&E expect that preparation of such an application will take? How long does PG&E believe it will take to receive approval from FERC? What is the likelihood that PG&E's application would be denied by FERC?

b. Has PG&E begun preparation of an application to CAISO to obtain an amendment to its interconnection agreement with CAISO to accommodate the Helms uprate? If not, when does PG&E plan to begin work on this application? How long does PG&E expect that preparation of such an application will take? How long does PG&E believe it will take to receive approval from CAISO? What is the likelihood that PG&E's application would be denied by CAISO?

c. Has PG&E requested to establish a Memorandum Account to track costs of development or uprating of other generation projects? If so, please list those projects and whether the Commission approved establishment of the Memorandum accounts. Please also provide citations to any such applications to establish Memorandum Accounts.

d. On page 4-18 of Exhibit PG&E-5, PG&E contends that "the uprated units are expected to be operational in the 2024-2026 timeframe. Please explain how it is possible that the project could be operational by 2024 given the possible 2-5 year term PG&E suggests to obtain an amendment to its FERC license for Helms.

e. Please provide any updates to the schedule for having the Helms uprates online.

ANSWER 018

a. PG&E has not begun preparing the amendment to its FERC License for the proposed Helms Uprate. PG&E plans to begin the FERC License amendment process once the preliminary engineering and economic analysis have determined the cost effectiveness of the proposed Helms Uprate, which is expected to be complete in Quarter 2 2022. If the analysis concludes the proposed Helms Uprate is cost effective, then PG&E will begin preparing the FERC License amendment and will submit it to FERC in Quarter 4 2022. PG&E estimates it will take FERC 1.5 – 4 years to approve. PG&E does not know the likelihood of FERC denying the License amendment.

b. PG&E has not begun preparing an application to CAISO to increase Helms Interconnection Capacity. PG&E plans to begin the CAISO application process once the preliminary engineering and economic analysis have determined the cost effectiveness of the proposed Helms Uprate, which is expected to be complete in Quarter 2 2022. If the analysis concludes the proposed Helms Uprate is cost effective, then PG&E will begin preparing the CAISO application and will submit it to CAISO Quarter 4 2023. PG&E estimates it will take CAISO about 1 year to determine the preliminary scope required to increase the generation capacity at Helms for energy only status. PG&E does not know the likelihood of CAISO denying the application.

c. Yes.

   Decision 11-05-018 ordered PG&E to transfer the balance in the Gateway Settlement Balancing Account to the Utility Generation Balancing Account when the total costs of the project were known, and that PG&E close out the Gateway balancing account at that time. Decision 11-05-018 also allowed PG&E, in accordance with Decision 06-11-048, to retroactively true up the difference between estimated capital cost and the actual capital cost of the project in the next GRC following commercial operation.

   Resolution E-4949 authorized PG&E to record the revenue requirement based on actual costs up to the adopted cost forecast associated with the Moss Landing Project (Elkhorn Battery Energy Storage) once the project achieves commercial operation to the New System Generation Balancing Account (NSGBA). Once included in the General Rate Case (GRC), the revenue requirement associated with the Moss Landing Project will be forecast as part of the GRC but transferred to the NSGBA for recovery through the New System Generation Charge (NSGC).

d. PG&E initially believed a reasonable timeframe for the proposed Helms Uprate to come online was between 2024-2026 based on applying for a non-capacity FERC License amendment. PG&E now anticipates submitting a capacity FERC License amendment, which it expects will take from 1.5 – 4 years to obtain FERC approval.

e. PG&E's current schedule for the Helms Uprate has an expected-case scenario of 1 unit coming online in 2027, 1 unit in 2028, and 1 unit in 2029.

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Data Response

PG&E Data Request No.:	JointCCAs_008-Q19		
PG&E File Name:	GRC-2023-PhI_DR_JointCCAs_008-Q19		
Request Date:	December 20, 2021	Requester DR No.:	008
Date Sent:	January 3, 2022	Requesting Party:	City and County of San Francisco/ East Bay Community Energy/ Marin Clean Energy/ Peninsula Clean Energy Authority/ Pioneer Community Energy/ San José Clean Energy/ Silicon Valley Clean Energy Authority/ Sonoma Clean Power Authority
PG&E Witness:	Steve Royall	Requester:	Jacob Schlesinger

QUESTION 19

For the four projects listed above in 8.17, is any of the incremental capacity necessary to serve unbundled customers? If so, please provide all supporting analyses or justifications.

ANSWER 19

The only project listed in 8.17 that provides any incremental capacity is the Gateway Evaporative Cooling Project. This project allows PG&E to limit the capacity restrictions experienced by combined cycle plants during periods of high ambient air temperature by lowering the temperature of the air as it enters the combustion turbines. Reducing the existing capacity restrictions caused by high ambient air temperatures reduces the likelihood of system blackouts caused by capacity shortfalls, particularly in the summer months. Capacity caused system blackouts affects all customers, bundled and unbundled.