

Transmission Project Review (TPR) Process

CPUC Energy Division Staff Comments on Pacific Gas and Electric Company (PG&E) November 2025 TPR Process Data April 6, 2026

As part of the Transmission Project Review (TPR) Process approved by the California Public Utilities Commission (CPUC) in Resolution E-5252, Energy Division Staff of the CPUC (CPUC Staff) provide these comments to Pacific Gas and Electric Company (PG&E) on its November 2025 TPR Process Review Period.

1. Introduction

On November 3, 2025, PG&E issued its November 2025 TPR Process Project Spreadsheet (PS), along with numerous project Advance Authorizations (AA) or reauthorized AAs and Business Cases (BC). The November 2025 TPR Process PS, based on data pulled from PG&E systems on September 10, 2025, included 2,551 discrete projects or programs. Overall, PG&E's November 2025 TPR PS reports capital expenditures from the 2021 to 2030 period, a change from the May 2025 TPR with 2020 being eliminated and 2030 being added for the first time.

The reported \$7.4 billion total in actual capital expenditures in the 2021 to 2025 period were \$284 million lower than reported in the May 2025 TPR PS for the same period, with \$221 million of that difference attributable to lower 2025 capital expenditures. For the forecast period, capital expenditures in the overlapping years between the May 2025 TPR PS and the November 2025 TPR PS (i.e., 2026 to 2029) increased by \$222 million, with \$213 million of that in 2026. Most of that 2026 increase is concentrated in Major Work Category (MWC) 82 – Work Requested by Others, which increased by \$171.8 million for 2026 from the May 2025 TPR PS.

PG&E's transmittal letter noted numerous updates to the PS in response to Stakeholder feedback, particularly its inclusion of the Load Facility Type as defined in the Rule 30 application (Application 24-11-007) for large retail load interconnection projects.¹ PG&E also noted updates to Data Field 66 (Cost-Benefit Analysis) for 62 projects and shared improvements it has made to the models and risk values used to determine these ratios.²

The PS contains \$5.497 billion in 410 new programs and projects, with 122 being less developed and having only Investment Codes and 288 being Planning Orders (PO).³ Of the 410 new projects, 101 are CAISO-approved in the Transmission Planning Process or generator interconnection process. Additionally, the CPUC notes that there are a growing number of

¹ See PG&E's November 1, 2025 TPR Process Transmittal Letter, page 2.

² See PG&E's November 1, 2025 TPR Process Transmittal Letter, page 5.

³ See PG&E's November 1, 2025 TPR Process Transmittal Letter, page 6.

CAISO “big-ticket” projects, with just two projects (the North Oakland Reinforcement and Greater Bay Area Reinforcement Projects) combining to cost approximately \$1.8 billion⁴. This could have significantly outsized impacts on the cost trends due to different project cost estimates as the TPR data is reporting current project costs for just these two projects at far below the original estimates (\$222 million and \$2 million respectively), reflecting an apparent \$1.58 billion swing. Focusing just on the current project costs, there are 21 new projects with current project costs greater than \$50 million in total projected costs, which represent \$2.8 billion (or just over 50 percent) of the total \$5.497 billion in new project costs. The CPUC also notes PG&E’s continued “prioritization” of significant projects beyond the 2030 time frame. The impact of project delays on system reliability and the interconnection of new generators would cause otherwise unnecessary actions, as the CAISO (in the TPP) and PG&E (in their TPR Stakeholder meeting) have reported multiple instances of mitigation measures to address transmission project delays.

During this TPR Review Period, PG&E provided information on several newly approved CAISO projects that have just entered PG&E’s internal planning process (e.g., North Oakland Reinforcement Project, South Bay Reinforcement Project) and other major projects (e.g., San Jose A – Station Rebuild, Salinas Area Reinforcement). Updates were shared on PG&E’s portion of competitively bid projects that are nearing completion (e.g., LS Power Round Mountain and Gates 500kV Dynamic Voltage Support projects) and four additional LS Power projects: New Collinsville 500 kV Substation, New Manning 500 kV Substation, Power Santa Clara Valley, and Power the South Bay. PG&E’s deployment of new technologies, like Dynamic Line Ratings and High Temperature Low Sag conductors, was also discussed. The CPUC also continued its evaluation of projects subject to “prioritization” such as the Gold Hills Project (T.0004950) and Moraga Upgrade Project (T.0011323) recently reported to have delayed In-Service Dates from 2022 to 2029 and 2024 to 2029, respectively. Closer examination of PG&E’s policies governing the application of Allowance for Funds Used During Construction (AFUDC), and how these policies affected project costs, is needed, especially as sudden project restarts are reported or discovered and create new and unexpected cost data.

2. CPUC Summary of the November 2025 TPR Process PS

PG&E’s November 2025 TPR PS reports capital expenditures from the 2021 to 2030 period, a change from the May 2025 TPR with 2020 being eliminated and 2030 being added for the first time.

Reported actual capital expenditures in the 2021 to 2025 period were \$284 million lower than reported in the May 2025 TPR PS for the same period, with \$221 million of that difference attributable to lower 2025 capital expenditures. This reduction reflected the changes in programmatic projects for tower coating and SCADA, and also removal of projects that no

⁴ 2025 CAISO Transmission Plan

longer met the TPR cost or capital expenditure requirements. Conversely, for the forecast period, capital expenditures in the overlapping years between the May 2025 TPR PS and the November 2025 TPR PS (i.e., 2026 to 2029) increased by \$222 million, with \$213 million of that in 2026. Most of that 2026 increase is concentrated in Major Work Category (MWC) 82 – Work Requested by Others, which increased by \$171.8 million for that year from the May 2025 TPR PS, as well as projects that slipped from 2025 to 2026, such as the LS Power Round Mountain Area 500kV Dynamic Project (T.0006815) and the 70Y 2024 Planning and Construction Planning Order (5531938)

Table 1 and Figure 1 present, by Major Work Category (MWC), the actual capital expenditures and percentage of total \$7.4 billion in actual capital expenditures for work conducted in the 2021 to 2025 period. Transmission MWCs represent more than half of PG&E’s capital expenditures from 2021 to 2025 (53.3%), with “Replace Lines, Poles and Structures” and “Line Preventative Work” representing nearly 40% of all actual capital spending in the TPR PS. In the Substation MWCs, representing 29.8% of the 2021 to 2025 capital expenditures, Station Capacity is the largest at 10.6%. Work Requested by Others (WRO) and IT/Security MWCs represent 8.7% and 6.7% of the actual 2021 to 2025 capital expenditures.

Table 1: Actual Capital Expenditures by Functional Category and MWC (\$000) – 2021 to 2025

MWC	MWC Description	Total Number of Projects 2021 to 2025	Actual Costs (\$000s)					Total 2021 to 2025	Percentage of 2021 to 2025 Total
			2021	2022	2023	2024	2025		
Transmission		717	900,407	926,762	772,909	672,809	672,784	3,945,671	53.3%
60	Line Capacity	177	48,469	120,861	75,376	55,362	72,928	372,996	5.0%
70	Replace Line Poles and Structures	114	289,307	311,545	341,791	277,222	253,446	1,473,311	19.9%
71	Replace Line ROW Access	11	30,705	22,432	13,041	24,170	26,868	117,217	1.6%
72	Replace Line Underground	12	3,763	2,520	1,629	10,286	13,875	32,073	0.4%
92	Emergency Line Response	37	151,835	76,819	52,145	37,212	48,028	366,039	4.9%
93	Line Preventative Work	276	267,380	311,119	261,880	265,550	248,955	1,354,884	18.3%
94 (T)	ET Reliability - Transmission	90	108,947	81,466	27,047	3,007	8,683	229,149	3.1%
Substation		1,004	470,387	456,728	343,175	435,845	501,222	2,207,356	29.8%
61	Station Capacity	281	121,928	108,867	118,609	186,082	252,451	787,938	10.6%
64	Replace Substation Breakers	46	17,162	15,382	6,321	8,397	14,508	61,770	0.8%

MWC	MWC Description	Total Number of Projects 2021 to 2025	Actual Costs (\$000s)					Total 2021 to 2025	Percentage of 2021 to 2025 Total
			2021	2022	2023	2024	2025		
65	Replace Substation Equipment - Emergency	106	63,219	45,321	50,974	45,699	43,747	248,960	3.4%
66 (Sub)	Replace Substation Other Equipment	32	38,800	33,898	5,631	5,138	4,013	87,480	1.2%
67	Electric System Automation	135	52,486	53,057	51,723	79,804	100,789	337,858	4.6%
68	Replace Substation Transformers	25	41,587	45,073	26,044	9,207	4,749	126,659	1.7%
94 (Sub)	ET Reliability - Substation	55	101,100	102,284	48,887	70,847	32,700	355,818	4.8%
3F	System Protection	324	34,105	52,847	34,986	30,670	48,265	200,873	2.7%
IT/Security		200	83,644	73,837	85,306	125,874	125,835	494,497	6.7%
2F	IT Infrastructure and Technology	65	33,540	39,603	30,786	49,353	40,624	193,906	2.6%
3N	Security	15	17,242	10,412	14,540	22,575	6,300	71,069	1.0%
63	Electric Systems Operations	70	20,812	16,251	38,264	44,830	52,380	172,538	2.3%
66 (Sec)	Replace Substation Other Equipment	50	12,049	7,571	1,715	9,116	26,531	56,984	0.8%
Other		18	24,949	59,467	15,052	9,112	5,508	114,088	1.5%
5	Tools	4	5,360	5,189	4,050	5,219	1,360	21,178	0.3%
12	Environmental	2	410	204	190	416	360	1,580	0.0%
21	Operations Support	9	9,155	14,628	5,456	2,950	3,786	35,974	0.5%
23	Manage Buildings	3	10,025	39,447	5,356	526	2	55,356	0.7%
3R	Battery	0	-	-	-	-	-	-	0.0%
Work Requested by Others		309	25,284	94,529	134,393	168,122	222,882	645,210	8.7%
82	Work Requested by Others	309	25,284	94,529	134,393	168,122	222,882	645,210	8.7%
Total		2,248	1,504,671	1,611,324	1,350,835	1,411,761	1,528,230	7,406,822	100.0%

Figure 1: 2021 to 2025 Capital Expenditures by MWC and Percentage of Total (\$000s)

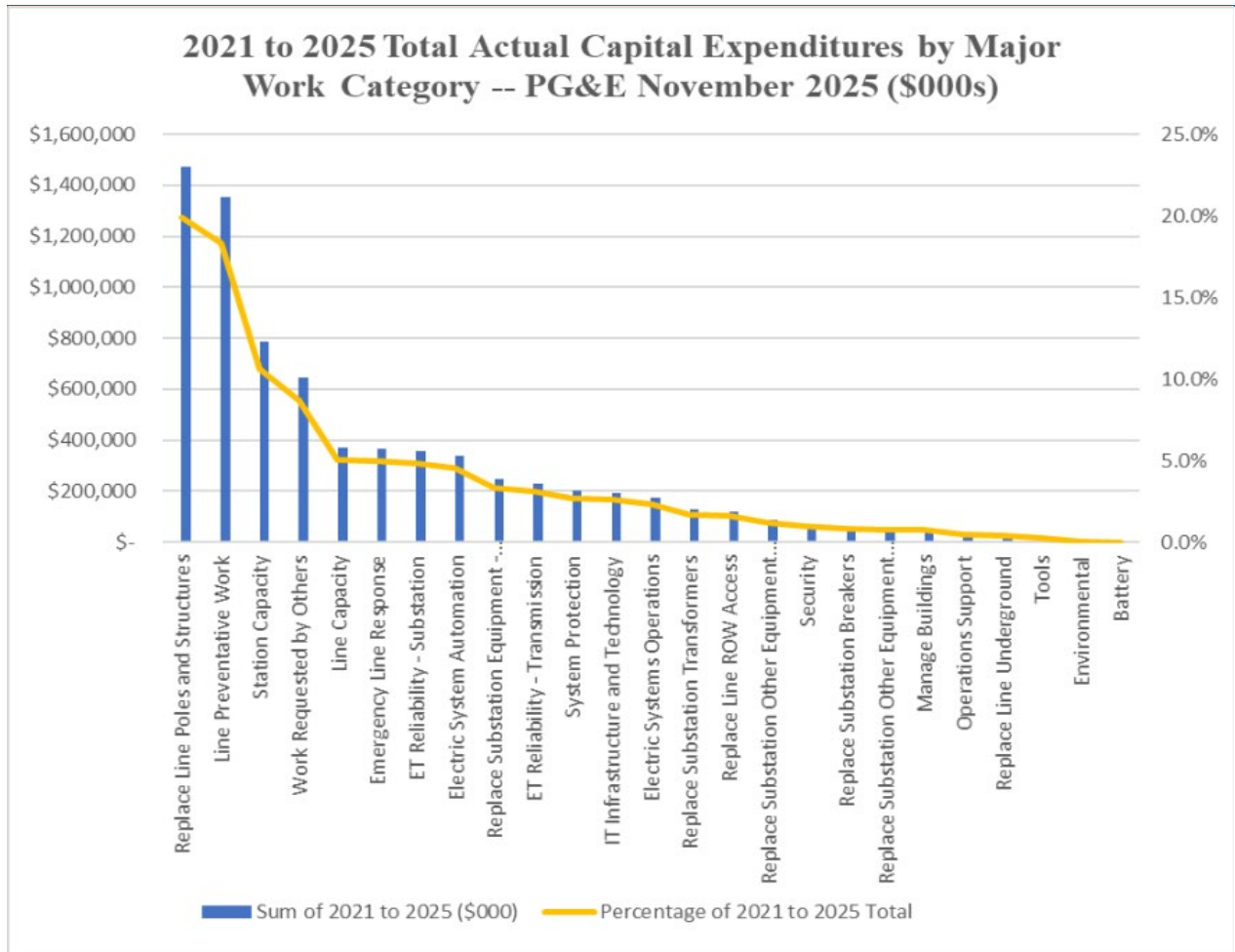


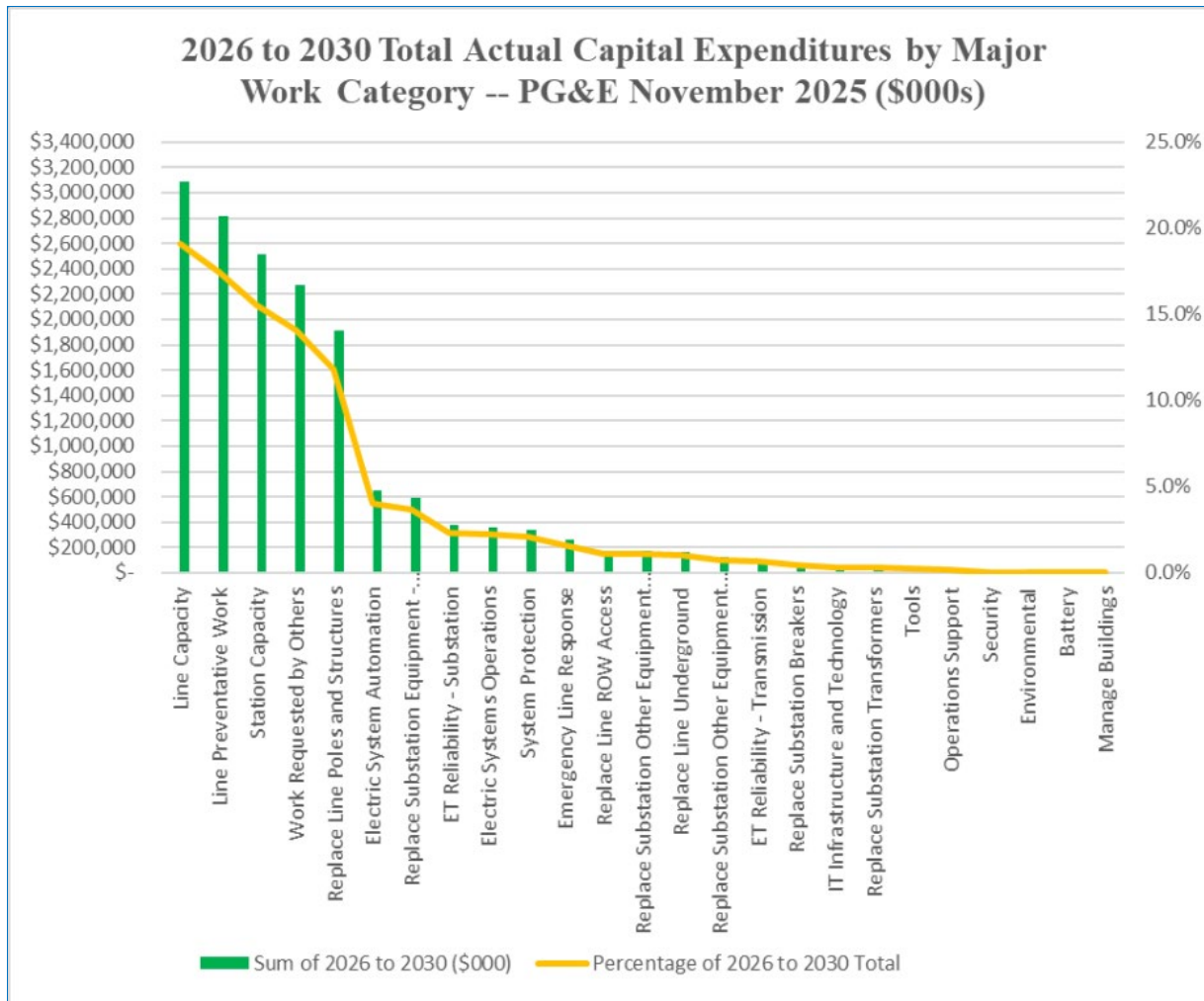
Table 2 and Figure 2 present, by Functional Category and MWC, the capital expenditures and percentage of the total capital expenditures for forecast work to be conducted in the 2026 to 2030 period. The Transmission and Substation areas represent the largest shares of the \$16.2 billion in forecast capital expenditures during the 2026 to 2030 period, at 52.7% and 29.1%. Work Requested by Others (WRO) is a bit higher, at 14.1%, whereas 2021 to 2025 WRO “actuals” were 8.7% of the total. This disparity is caused by the WRO actual costs in earlier years reflecting payments from customers, which, at least for now, reduce the total amount for this category that has been borne by electric transmission ratepayers.

Table 2: Forecast Capital Expenditures by Functional Category and MWC, 2026 to 2030

MWC	MWC Description	Total Number of Projects 2026 to 2030	Forecast Costs (\$000s)						
			2026	2027	2028	2029	2030	Total 2026 to 2030	Percentage of 2026 to 2030 Total
Transmission		360	1,069,464	1,503,797	1,843,170	2,013,124	2,100,301	8,529,856	52.7%
60	Line Capacity	153	298,658	668,163	768,112	656,078	697,094	3,088,105	19.1%
70	Replace Line Poles and Structures	60	308,445	308,477	318,874	439,538	538,501	1,913,834	11.8%
71	Replace Line ROW Access	6	32,988	37,048	32,254	29,065	46,439	177,795	1.1%
72	Replace Line Underground	14	23,428	58,514	58,372	11,968	9,168	161,450	1.0%
92	Emergency Line Response	9	49,226	50,080	52,013	54,021	56,107	261,447	1.6%
93	Line Preventative Work	89	346,216	379,037	598,939	773,828	719,741	2,817,762	17.4%
94 (T)	ET Reliability - Transmission	29	10,503	2,477	14,606	48,626	33,252	109,463	0.7%
Substation		603	885,139	1,106,666	1,093,306	846,875	783,718	4,715,705	29.1%
61	Station Capacity	199	564,746	646,858	627,320	410,447	266,372	2,515,743	15.5%
64	Replace Substation Breakers	33	23,091	11,006	7,293	14,058	16,201	71,649	0.4%
65	Replace Substation Equipment - Emergency	51	62,000	123,016	155,522	128,668	118,658	587,862	3.6%
66 (Sub)	Replace Substation Other Equipment	27	7,204	28,942	19,826	30,511	39,201	125,683	0.8%
67	Electric System Automation	117	131,603	176,336	137,855	102,592	100,927	649,313	4.0%
68	Replace Substation Transformers	10	6,316	8,150	15,082	8,545	13,300	51,394	0.3%
94 (Sub)	ET Reliability - Substation	22	41,986	47,681	64,778	73,197	147,246	374,888	2.3%
3F	System Protection	144	48,193	64,677	65,631	78,858	81,815	339,173	2.1%
IT/Security		78	129,763	139,435	121,885	140,017	62,833	593,933	3.7%
2F	IT Infrastructure and Technology	13	27,988	8,451	8,873	9,317	-	54,629	0.3%
3N	Security	5	6,060	-	-	-	-	6,060	0.0%

MWC	MWC Description	Total Number of Projects 2026 to 2030	Forecast Costs (\$000s)						
			2026	2027	2028	2029	2030	Total 2026 to 2030	Percentage of 2026 to 2030 Total
63	Electric Systems Operations	18	63,761	83,328	94,000	75,700	41,200	357,989	2.2%
66 (Sec)	Replace Substation Other Equipment	42	31,954	47,656	19,012	55,000	21,633	175,255	1.1%
Other		16	9,714	10,665	10,030	17,330	16,901	64,640	0.4%
5	Tools	4	4,952	7,324	7,735	7,021	7,058	34,090	0.2%
12	Environmental	2	174	186	191	197	203	952	0.0%
21	Operations Support	10	4,587	3,155	2,103	10,111	9,640	29,597	0.2%
23	Manage Buildings	0	-	-	-	-	-	-	0.0%
3R	Battery	0	-	-	-	-	-	-	0.0%
Work Requested by Others		206	517,927	394,389	458,743	476,929	426,942	2,274,930	14.1%
82	Work Requested by Others	206	517,927	394,389	458,743	476,929	426,942	2,274,930	14.1%
Total		1,263	2,612,008	3,154,951	3,527,134	3,494,276	3,390,695	16,179,064	100.0%

Figure 2: 2026 to 2030 Capital Expenditures by MWC and Percentage of Total (\$000s)



November 2025 New Projects

PG&E indicates in its transmittal letter that there are “410 new projects..., with 122 being Investment Codes and 288 being POs.”⁵ In total, they represent \$5.497 billion in “Current Projected Total or Actual Final Cost.” Table 3 provides the total number of new POs by Functional Category, along with both the sum of 2021 to 2030 capital expenditures and “Current Projected Total or Actual Final Cost”, indicating the remaining \$1.4 billion to be spent in 2031 and beyond but required to be reported in the current TPR PS.

⁵ See PG&E’s November 1, 2025 TPR Process Transmittal Letter, page 6.

Table 3: New Projects by Functional Category and MWC

MWC	MWC Description	Total Number of Projects 2021 to 2030	Sum of 2021 to 2030 Capital Expenditures (\$000)	Sum of Current Projected or Total Actual Final Cost (\$000)
Transmission		107	1,415,807	2,963,637
60	Line Capacity	48	421,144	1,074,249
70	Replace Line Poles and Structures	24	441,221	465,042
71	Replace Line ROW Access	2	9,640	11,698
72	Replace Line Underground	1	7,500	9,000
92	Emergency Line Response	2	103,603	131,267
93	Line Preventative Work	29	432,698	597,451
94 (T)	ET Reliability - Transmission	1	-	4,930
Substation		217	1,155,693	1,766,946
61	Station Capacity	47	263,102	463,250
64	Replace Substation Breakers	12	30,045	43,154
65	Replace Substation Equipment - Emergency	39	566,742	712,912
66 (Sub)	Replace Substation Other Equipment	16	72,001	90,783
67	Electric System Automation	13	41,986	110,858
68	Replace Substation Transformers	3	22,502	121,502
94 (Sub)	ET Reliability - Substation	-	-	-
3F	System Protection	87	159,316	224,487
IT/Security		24	196,018	198,003
2F	IT Infrastructure and Technology	8	37,511	37,496
3N	Security	-	-	-
63	Electric Systems Operations	6	43,755	45,755
66 (Sec)	Replace Substation Other Equipment	10	114,752	114,752
Other		3	6,234	8,159
5	Tools	-	-	-
12	Environmental	-	-	-
21	Operations Support	3	6,234	8,159
23	Manage Buildings	-	-	-
3R	Battery	-	-	-
Work Requested by Others		59	1,347,526	1,229,881
82	Work Requested by Others	59	1,347,526	1,229,881
Total		410	4,121,278	5,496,625

Table 4 identifies each of the 21 new projects and programs (i.e. a subset of the 410 projects discussed above) with 2021-2030 capital expenditures or “Current Projected Total or Actual Final Cost” over \$50 million. The bulk of the project costs are centered on MWC 60 Line Capacity (\$536 million), MWC 65 Replace Substation Equipment – Emergency (\$493 million), MWC 93 Line Preventative Work (\$343 million) and MWC 82 Work Requested by Others (\$322 million).

Table 4: New Projects with Current Projected Total or Actual Final Cost Greater than \$50 Million

MWC ⁶	Planning Order	Project Name	Sum of 2021 to 2030 Capital Expenditures (\$000)	Current Projected Total or Actual Final Cost (\$000)
60	5812199	REEDLEY- DINUBA LN REBUILD	52,101	52,101
82	5813934	Private Load Interconnection Project	53,088	53,088
70	5562022	HFTD-Pole Replacement-NBC	53,681	53,755
93	EX113578	Switch Replacement Program	43,699	56,961
60	5812914	Camden-Kingsburg 70kV Line Reconductor	59,046	61,046
82	5815018	Private Load Interconnection Project	61,790	61,790
60	EX138977	South Oakland Reinforcement Project	24,732	69,131
65	EX139162	Emergency Transmission Xfmr 500kV Banks Replacement	61,500	76,200
68	EX139253	Transmission Xfmr Non 500kV Banks (6 Banks) Planned Replacement	12,000	81,000
65	EX139131	Emergency Transmission Circuit Breaker Replacement of Failed and JIT	74,045	91,325
61	5812672	French Camp: Rebuild Sub	23,559	106,205

⁶ MWC 60 – Line Capacity, MWC 61 – Station Capacity, MWC 65 - Replace Substation Equipment - Emergency, MWC 68 - Replace Substation Transformers. MWC 70 - Replace Line Poles and Structures, MWC 82 - Work Requested by Others. MWC 92 - Emergency Line Response. MWC 93 - Line Preventative Work

82	5814133	Private Load Interconnection Project	108,259	110,973
92	EX130519	Just In Time Asset Replacement	101,134	128,798
60	EX138970	South Bay Reinforcement Project	86,299	131,299
65	EX139129	Emergency Transmission Other/Minor Equipment Replacement	108,000	135,000
82	5555047	82N DET Plan - Load	285,111	157,473
70	5562021	HFTD-Pole Replacement-North Valley	187,591	187,590
65	EX139130	Emergency Transmission Xfmr non-500kV Banks Replacement	150,823	190,541
60	EX138976	North Oakland Reinforcement Project	2,000	222,000
93	EX130433	IGP_Repl TL Equipment	191,223	286,278
82	5554999	82W DET Plan - EGI	479,877	479,877

Projects Removed from the November 2025 TPR PS

The PS does not include 473 POs or Investment Codes that were included in the May 2025 TPR PS. These sum to \$5.010 billion in “Current Projected Total or Actual Final Cost.” 157 MWC 82 non-FERC-jurisdictional generation interconnection projects and 45 MWC 82 non-FERC-jurisdictional Load Facility Type 1 projects were removed with the remaining 271 attributable to the removal of projects with a “Current Projected or Actual In-Service Date” in 2020 or earlier years. Several “Investment Codes” associated with the expansion of substation capacity were also removed, signaling the formal kick-off of projects. Significant projects removed include:

- MWC 60, PO 5731444 -- Embarcadero - Potrero 230kVUndGrLineCons, with a “Current Projected Total or Actual Final Cost” of \$166.945 million that was completed in 2015.
- MWC 61, PO 5731443 -- New 230 kV Switchyard at Potrero, with a “Current Projected Total or Actual Final Cost” of \$74.588 million, also completed in 2015.
- MWC 65, PO 5506263 -- Emergency Replacement, Overall Budget, a “forecast placeholder” with a “Current Projected Total or Actual Final Cost” of \$814.4 million.

Table 5 summarizes the number of removed projects by programmatic area and MWC. Individual projects were evaluated to ensure no significant, active projects had been inadvertently removed from the TPR PS.

Table 5: Summary of Projects Included in May 2025 TPR PS but Removed from November 2025 TPR PS

MWC	MWC Description	Total Number of Projects 2020 to 2029	Sum of 2020 to 2029 Capital Expenditures (\$000)	Current Projected Total or Actual Final Cost (\$000)
Transmission		111	633,641	1,525,664
60	Line Capacity	20	186,072	409,427
70	Replace Line Poles and Structures	16	299,140	591,546
71	Replace Line ROW Access	2	6,197	8,391
72	Replace Line Underground	3	7,746	139,843
92	Emergency Line Response	4	4,747	15,010
93	Line Preventative Work	18	105,482	219,444
94 (T)	ET Reliability - Transmission	48	24,256	142,002
Substation		143	1,289,558	2,489,136
61	Station Capacity	49	484,987	965,961
64	Replace Substation Breakers	18	22,506	84,793
65	Replace Substation Equipment - Emergency	8	617,267	983,466
66 (Sub)	Replace Substation Other Equipment	9	4,090	23,646
67	Electric System Automation	13	17,529	60,737
68	Replace Substation Transformers	10	49,164	89,770
94 (Sub)	ET Reliability - Substation	9	4,696	87,528
3F	System Protection	27	89,318	193,235
IT/Security		29	200,868	410,885
2F	IT Infrastructure and Technology	8	14,192	22,988
3N	Security	1	4,093	5,093
63	Electric Systems Operations	10	52,231	95,841
66 (Sec)	Replace Substation Other Equipment	10	130,352	286,963
Other		3	23,031	53,541
5	Tools			
12	Environmental			
21	Operations Support	1	16,000	24,000
23	Manage Buildings	2	7,031	29,541
3R	Battery	-	-	-
Work Requested by Others		187	833,091	530,335
82	Work Requested by Others	187	833,091	530,335
Total		473	2,980,190	5,009,561

On Hold Projects

The November 2025 TPR PS indicates that 174 POs, with a “Current Projected Total or Actual Final Cost” of \$3.188 billion, are now on hold. This is an increase in both the number and cost from the May 2025 TPR PS, where 155 POs with a “Current Projected Total or Actual Final Cost” of \$1.48 billion were on hold. The change is also a trend from the November 2024 TPR PS which reported 104 projects on hold, totaling \$770 million. That is a 67% increase in projects and 314% increase in project costs for that 12-month period. Table 6 illustrates, by TPR Review Period, this growth trend.

In addition to these projects with a Project Status of “On Hold,” beginning August 1, 2024, PG&E implemented the automated pausing of AFUDC within its fixed asset financial system, if certain criteria were met and capital expenditures to date on a project were less than \$15 million. However, none of these projects are marked as “On Hold” in the TPR, understating the true value of projects that are “On Hold” or are not progressing to project completion.

Table 6: On Hold Planning Orders by TPR Review Period

TPR Review Period	Number of POs “On Hold”	Current Projected Total or Actual Final Cost of “On Hold” POs
November 2024	104	\$769.9 million
May 2025	155	\$1.48 billion
November 2025	174	\$3.188 billion

Table 7 shows the 14 largest projects, totaling nearly \$2 billion of the \$3.188 billion in “Current Projected Total or Actual Final Cost,” that are now on hold. These Planning Orders have “Current Projected or Actual In-Service Dates” between 2029 and 2037.

Table 7: Significant Projects “On Hold”

Planning Order	Project Name	Inception to Date (\$000)	Current Projected Total or Actual Final Cost (\$000)
5794780	BRIGHTON-GRAND ISLAND PH3 I-5 E DEVELOPE	789	58,240
5766463	HSR Interconnection ET Sites 4-7 (82)	275	62,610
5788362	MOSS LANDING: Replace 500kV Bank 9	684	69,643
5765140	Mission-Larkin #2 115 kV Cable (X-Y 2)	3,077	70,156
5768170	LARKIN: Upgd 115 KV Reliability	245	78,751
5778135	OLEUM - G #2 CONDUCTOR REPL (7/50-11/72)	2,451	86,705
5766318	HSR Interconnection ET Sites 8-13 (82)	413	98,290
5765139	Potrero-Larkin #3 115 kV Cable (A-Y 3)	3,578	126,670

5782298	Martinez Junction to Oleum Substation	8,797	127,756
5777901	Ignacio - Alto - Sausalito 60kV Twr Repl	3,356	156,820
5760988	POTRERO: CONVERT 115 KV BUS TO GIS BAAH	2,098	172,065
5765141	Potrero-Mission #2 115 kV (A-X-2)	3,986	180,088
5792443	RAVENSWOOD-BAIR #1 115KV PH2	2,555	285,490
5777912	Pittsburg - San Mateo 230kV Twr Repl	1,441	383,041
Total		33,745	1,956,323

Prioritization Projects

Prioritization refers to PG&E’s process of updating its “portfolio forecast within the Electric Transmission (ET) budget targets through a combination of project and program forecast refinement and continued project and program prioritization, which could include extending project implementation schedules and the pace of program volume execution.”⁷ Table 8 shows the number of POs and their associated cost where PG&E’s “Reason for Change in Service Date” includes “prioritization.”

Table 8: “Prioritized Projects” by Project Spreadsheet Issuance Date

Data Spreadsheet Date	Number of Projects	Current Projected Total or Actual Final Cost (billions)
May 2024 (TPR)	413	\$4.785
November 2024 (TPR)	567	\$6.407
May 2025 (TPR)	568	\$6.661
November 2025 (TPR)	529	\$7.572

As shown in Table 8, the number of projects subject to “prioritization” appears to have declined, but the cost of the projects has increased. Some of this decline in project number is partially attributable to a shift of the reporting period from 2020 - 2029 to 2021 - 2030, with 178 projects already in-service and no expected capital expenditures before 2021, and another 151 generator interconnection projects similarly dropped from the TPR reporting. Projects such as these may be “paused” through PG&E’s automated system and delayed but not marked as such in the TPR PS, which further impedes the CPUC and Stakeholders from accurately tracking project spending and completion. The CPUC continues to evaluate projects that have been delayed for significant periods of time and assess whether they have been placed “on hold” to reduce the accrual of Allowance for Funds Used During Construction (AFUDC) or whether long-delayed projects should be cancelled.

⁷ See PG&E’s May 1, 2025 TPR Process Transmittal Letter, page 9.

CAISO Projects

PG&E indicated that it has included all projects assigned to PG&E in the 2024-2025 CAISO Transmission Plan in the November 2025 TPR PS as either active projects with unique POs or as Investment Codes, with the exception of the Moraga-Sobrante 115kV Line reconductor project, which remains on hold, and the now-cancelled Ravenswood 230/115kV transformer #1 Limiting Facility Upgrade.⁸ Projects assigned to PG&E in the 2024-2025 CAISO Transmission Plan are shown in Table 9.⁹

Table 9: PG&E Assigned Projects in CAISO’s 2024-25 Transmission Planning Process

Project Name	Expected In-Service Date	CAISO Project Cost (in millions of dollars)
Reliability Projects		3,623.2
Ames Distribution – Palo Alto 115kV transmission line	2034 Q2	84
Cortina #3 60kV Reconductoring	2031 Q2	55.5
Gold Hill-El Dorado Reinforcement	2032 Q2	127
Greater Bay Area 500kV Transmission Reinforcement	2034 Q2	700
Jefferson-Stanford 60kV Recabling *	2029 Q2	40
Konocti – Eagle Rock 60kV Line Reconductoring *	2030 Q2	32.5
Metcalf Substation 500/230kV Transformer Bank Addition	2034 Q2	182
Metcalf-Piercy & Swift and Newark-Dixon Landing 115kV Upgrade Rescope	2027 Q1	135
Moraga 230/115kV Transformer Bank Addition *	2031 Q2	40
North Oakland Reinforcement Project	2032 Q2	1,127
Pittsburg-Kirker 115kV Line Section Limiting Elements Upgrade *	2028 Q2	0.2
San Jose B – NRS 230kV line	2030	200
San Mateo 230/115kV Transformer Bank Addition Project	2032 Q2	110
San Miguel New 70kV Line *	2032 Q2	30
Sobrante 230kV Bus Upgrade *	2033 Q2	15
South Bay Reinforcement Project	2034 Q2	434
South Oakland Reinforcement Project	2032 Q2	250
West Fresno 115kV Voltage Support	2031 Q2	60
Policy-Driven		289.5
Eagle Rock- Fulton- Silverado 115kV Line Reconductor	2034	92.9
Reconductor of GWF – Kingsburg 115kV line	2034	81.6
New Helm 230/70kV Bank #2	2034	115
Grand Total		3,912.7

⁸ See PG&E’s November 1, 2025 Transmittal Letter, page 7.

⁹ See CAISO’s 2024-2025 Transmission Plan, pages 193 to 194, found at [iso-board-approved-2024-2025-transmission-plan.pdf](#). Please note the names of the projects, including the *, are as indicated in the CAISO’s document. It is unclear what the * is to indicate.

3. Data Quality

The CPUC generally finds PG&E’s numeric data quality to be acceptable, with limited updates to material provided in each reporting period. However, we continue to seek more robust cost-benefit ratios, discussed later in this document.

The CPUC also appreciates PG&E’s continuation to include subject matter experts in the Stakeholder discussions and provide meeting materials that are responsive to parties’ requests. PG&E also provided during the Stakeholder meeting the unedited “chat” dialogue after the end of the morning meeting, and again in the afternoon. Promptly receiving the “chat” was helpful in developing follow-up data requests.

Finally, the CPUC acknowledges that PG&E continues to respond to data requests in a reasonably timely manner. While some limited responses are delayed, PG&E has provided the requisite notice required when a delay is anticipated and has, at times, provided responses prior to their due date. Given the schedule for these TPR reviews, continued timely responses are necessary to allow Stakeholders adequate time for review and follow-up.

4. Data Request Responses

During the November 2025 TPR Process Review, the CPUC submitted 87 data requests, four of which were confidential, to PG&E. Compared to the November 2024 TPR Review period, PG&E has more consistently provided timely responses over the last year. While not all responses are provided by the due date, the CPUC acknowledges the effort to provide timely, complete responses to parties.

The CPUC’s data requests sought additional information on numerous topics, including significant new projects like the “Reedley-Dinuba Ln Rebuild,” “Moraga: Upgrade 230kV Bus,” “South Bay Reinforcement Project,” and the “North Oakland Reinforcement Project.” These projects are just being added to the TPR, and the CPUC anticipates continued review of these and other significant projects as they move through the planning and engineering phases. Updates on the status of PG&E’s four Construction Work in Progress (CWIP) Incentive Projects (i.e., Collinsville, Manning, Newark, and Metcalf) were also requested. Long-delayed programs for circuit breakers, as well as newly added circuit breaker replacement work were assessed, along with PG&E’s just-in-time and emergency replacement programs for transformers and circuit breakers. Other delayed projects like the Egbert Switching Station and the California High Speed Rail were also assessed with updates reporting minor progress and portions of construction still to be started.

PG&E’s responses were reasonably thorough, although at times summaries of requested documents were provided, rather than the documents themselves. In other responses, particularly on paused work orders, PG&E provided the requested financial detail showing a payment had been recorded but did not provide details about the actual work performed or the activity that

required payment¹⁰. As a result, some follow-up data requests were needed or will be needed to delve a bit more deeply into project issues and to gain additional clarity.

5. Stakeholder Meetings

The CPUC and Stakeholders in the TPR Process provided a draft agenda for the February 4, 2026 TPR Stakeholder Meeting to PG&E on January 20, in accordance with the TPR Review Period’s timelines. At the Stakeholder meeting, PG&E ensured that appropriate personnel were present to respond to questions on a variety of topics, as discussed further below.

From a process perspective, PG&E provided the February 4, 2026 presentation only one-business day beforehand, providing over 150-pages of high-level information to support the interactive discussion. The CPUC continues to encourage PG&E to provide meeting materials with enough time, before the Stakeholder Meetings, for attendees to review and prepare in advance. Given the breadth of information to cover in the all-day meeting, PG&E relied extensively on the “chat” feature for questions and responses during the meeting. While this is certainly helpful in keeping the meeting on schedule, reliance on the chat for information sharing does limit parties’ ability to ask direct questions of presenters. The CPUC acknowledges that this is a hard balance to strike, between being responsive to questions but also needing to stay on a timeline given the number of participants. The quick responses in “chat,” along with the provision of both morning and afternoon unedited transcripts of the chat, were helpful to the CPUC and Stakeholders.

PG&E also announced at the outset of the Stakeholder Meeting that the “Artificial Intelligence” or “AI” feature used to record the previous Stakeholder meeting had been disabled, and no recording should be enabled.

On substantive issues, the CPUC found the discussion and visual displays of information generally helpful. However, as many projects are newly added to the TPR, information on the project needs and timelines is limited, and it is anticipated that as new projects mature through the planning and engineering process, PG&E will share project specific visuals, schedule, and financial information. Of particular interest will be the numerous projects for which PG&E has been granted, or is seeking, the CWIP Incentive at FERC. Given the costs of these projects will be added to electric transmission rates as they are incurred, rather than held in CWIP until the project is “used and useful,” continued, timely detailed assessments will be merited to ensure these projects stay on track and are completed in a timely manner.¹¹

Information was also shared on other large projects, although PG&E’s ability to share the complete scope, project need, status, risks, and project dependencies was limited in some cases,

¹⁰ See TPR-Process_DR_ED_017-Q004 and TPR-Process_DR_ED_017-Q004-Atch01.xlsx

¹¹ See, for example, pages 83 to 94 of the February 4, 2026 TPR Stakeholder Meeting presentation. Also see PG&E Petition for Declaratory Order in FERC Docket EL26-42 to place six new projects under CWIP Incentive Ratemaking.

given the projects are still in their early planning stages. The CPUC appreciated the opportunity to learn more directly what is and is not known about each project as it matures through PG&E's planning, engineering, and construction process.¹²

PG&E also updated Stakeholders on new technologies it is deploying in its system, including Dynamic Line Rating, High Temperature Low Sag Conductor, and other monitoring equipment. Updates on PG&E's Risk-Based Portfolio Planning Framework (RBPPF), Integrated Grid Planning (IGP), and cost-benefit ratio development initiatives were also informative.

6. Issues of Note

During the November 2025 TPR Review period, the CPUC continued its focus on project delays and their impact on system reliability, generator interconnection, and cost to electric transmission customers, along with numerous other issues. Specific issues, discussed in more detail below, include: a) PG&E management's unilateral decisions to halt project construction but continuing to accrue AFUDC even though the project is not being advanced to completion; b) PG&E's multiple portfolio planning tools should focus on getting work completed; c) Costs associated with faulty workmanship should not be borne by electric transmission ratepayers; d) PG&E's advance procurement of long-lead time materials is crucial, but the creation of multiple Investment Codes for emergency materials appears to conflict with PG&E's Other balance sheet mechanism; e) Ratemaking treatment for "Pilot" programs lacks clarity; f) As PG&E replaces wood poles with steel poles, a better understanding of the difference in service life is needed; and g) Robust cost-benefit ratios are important inputs to the project selection process.

a. PG&E's Prioritization Initiative is Unjustly Imposing Additional Financial Costs on Electric Transmission Ratepayers

The CPUC has previously shared its concerns about the financial impact of project delays due to PG&E's prioritization initiative.¹³ At PG&E management's discretion, projects that were actively in construction have been halted, additional costs have been incurred for security and storage and crew demobilization, budgets to complete those projects have been diverted to other projects, and other projects in development have been delayed for years, yet PG&E has failed to actively suspend the accrual of AFUDC to the halted projects and has continued to charge costs to these projects even though they are not related to constructing and completing the project. A number of these projects were highlighted in the CPUC's Comments to PG&E on the May 2025 TPR Review.

¹² See, for examples, pages 75 to 76 of the February 4, 2026 TPR Stakeholder Meeting presentation discussing numerous large projects including Salinas Area Reinforcement, San Jose Substation A Rebuild, Wheeler Ridge, Estrella, Ignacio-Mare Island, and Morgan Hill-Watsonville.

¹³ See CPUC Energy Division Staff Comments on Pacific Gas and Electric Company's (PG&E) on the May 2025 TPR Process Cycle, September 30, 2025, pages 13 to 14.

By PG&E’s own definition of “prioritization,” projects have been reprioritized so that PG&E could pursue other higher risk impacting work, such as wildfire mitigation, and other transmission capacity projects that address nearer-term needs and have been rescheduled to later years where PG&E’s portfolio will allow for the cost of the project.¹⁴ As a result, projects subject to “prioritization” are effectively not funded, and therefore the projects do not advance in any meaningful way.

While AFUDC costs have long been recognized as a cost associated with utility capital investments, provisions do exist for suspending AFUDC if a project is delayed. Generally, as indicated in Public Utility Accounting, “if construction is delayed or postponed for substantial lengths of time, AFUDC is discontinued until construction resumes.”¹⁵ FERC has also indicated that “No AFUDC should be accrued during periods of interrupted construction...”.¹⁶ However, since 2021 when PG&E began implementation of its “prioritization” framework, PG&E has failed to adequately monitor and suspend AFUDC accruals on projects its management has unilaterally decided to delay.

Prior to August 2024, when PG&E initiated its “Automated Pause” process within its accounting system, PG&E relied on its “Deferred Order Procedure” where projects with spending greater than \$500,000, with interrupted construction or postponement for a definite period of time, at a minimum of six months, could be deferred.¹⁷ “Deferred” status is described in the same document as “Status 21,” meaning “capital orders in Status 21 do not accrue an Allowance for Funds Used During Construction (AFUDC), are locked for direct charges (e.g., labor, materials, and contracts), and are recorded in Construction Work in Progress (CWIP).”¹⁸ PG&E has indicated that “there are no transmission work orders in SAP Deferred status as of Dec 2025.”¹⁹ This conclusion is surprising, given PG&E continues to delay advancement of many projects because of “prioritization.”

In August 2024, PG&E increased the threshold limit for “deferring” a project from \$500,000 to \$15 million,²⁰ and implemented its “Automated Pause” procedure, which had no dollar threshold that needed to be reached before the project could be paused.²¹ Under this process, as outlined in the July 23, 2024 Capital Order Management Standard, “capital orders that have interruptions in construction without any direct charges... or accounting adjustments

¹⁴ See PG&E’s Response to Information Request FERC-TO21_AU_CPUC-PGE_03-Q99, dated August 18, 2025.

¹⁵ <https://www.publicpower.org/system/files/documents/Public%20Utility%20Accounting%20Manual%202018.pdf>, page 94.

¹⁶ See “[Capitalization of Allowance for Funds Used During Construction | Federal Energy Regulatory Commission](https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/capitalization-allowance-funds-used-during)” at <https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/capitalization-allowance-funds-used-during>

¹⁷ See PG&E’s FIN-3820P-01, “Deferred Order Procedure,” page 2 of 10. This document was provided as Attachment 3 to PG&E’s Response to Data Request TPR-Process_DR_ED_020-Q020, dated March 6, 2026.

¹⁸ Ibid, page 7 of 10.

¹⁹ See PG&E’s February 4, 2026 TPR Stakeholder Meeting presentation, page 103.

²⁰ See PG&E’s Response to Data Request TPR-Process_DR_ED_020-Q016, dated March 6, 2026.

²¹ See PG&E’s Response to Data Request TPR-Process_DR_ED_017-Q001-Atch01, page 3 of 11 of “Capital Order Management Standard”, dated December 9, 2025.

for 6 consecutive months or longer, AFUDC will be automatically paused.”²² However, unlike the previous “Deferred Order Procedure” where such a charge would have been expensed and closed to new direct charges until construction begins, “AFUDC will start accruing again once a direct charge or an accounting adjustment is recorded to the order.”²³ This change essentially allows an order to be reopened to pay an invoice, even though the payment is not related to construction, and it is not advancing the project toward completion.

The CPUC analyzed the 17 months of PG&E’s monthly “Automated Pause” reports that were available in January 2026.²⁴ The CPUC’s assessment revealed that a number of orders have been “paused” for the entire 17-month period that this “automated pause” procedure has been in place. This indicates that there was no activity on the order for at least the six months prior to August 2024 when the “pause” process was implemented; as a result, additional AFUDC was accrued for at least six months, if not longer, before the pause was implemented, despite no activity on the order. After such a long project delay, questions must be asked as to whether the project will ever be completed and if the costs incurred to date should be expensed.

In reviewing the time series data from the same monthly “Automated Pause” reports, other orders were found to be initially paused, removed from the pause reports for six to seven months and then the pause was reinstated. PG&E provided the monthly accounting detail showing the amount that caused the work order to be reopened, but failed to provide any detailed explanation as to what the charges entailed.²⁵ Using Planning Order 5767363/Work Order 74000919 for KERN-MAGUNDEN-WITCO 115KV RERATE²⁶ as an example, PG&E paused the order in August 2024, lifted the pause in October 2024 to pay a \$10,463 contract payment, and accrued an additional \$23,284 in AFUDC accruals until the order was again “paused” in April 2025 and the order remained paused for the rest of the months available at the time of the analysis. It is obvious that this project has not advanced to construction, and given the order is again paused, one can presume the \$10,463 was not for construction activities. However, electric transmission ratepayers are presented with a \$23,284 bill for paying a \$10,463 invoice. While this amount may seem minor on an individual order basis, this pattern is repeated across many orders, and, when aggregated, represents significant costs that should not be imposed on electric ratepayers when the expenditures do not appear to be related to actual construction or moving the project toward completion. Under PG&E’s previous “deferred” order mechanism, direct costs associated with an order in “deferred status” would have been expensed and not booked to the capital order, nor would additional AFUDC have been accrued.

Another even more egregious example of the same “on/off/on pause” pattern is found for PO 5738689/Work Order 74001175, “MOSHER-LOCKFORD 60KV RECOND.”²⁷ This PO was

²² Ibid. See Paragraph 3.3 on page 3 of 11 of the Capital Order Management Standard.

²³ Ibid. See Paragraph 3.4 on page 3 of 11 of the Capital Order Management Standard.

²⁴ These reports were provided in response to TPR-Process_DR_ED_018-Q025, dated January 9, 2026.

²⁵ See PG&E’s Response to Data Request TPR-Process_DR_ED_020-Q016, dated March 6, 2026.

²⁶ See PG&E’s Response to Data Request TPR-Process_DR_ED_020-Q016, Attachment 3, dated March 6, 2026.

²⁷ See PG&E’s Response to Data Request TPR-Process_DR_ED_020-Q016, Attachment 3, dated March 6, 2026.

also paused in August 2024, reopened in October 2024 to pay a \$10,463 contract cost [Note: this is the exact same amount noted in the earlier example], and then paused again in April 2025 after no additional activity on the project. This time the cost to ratepayers in additional AFUDC charges accrued during that six-month period, with no construction activity or project advancement, was \$161,978. To reiterate, this is \$161,978 in AFUDC costs to pay a \$10,463 bill.

Furthermore, a review of the November 2025 TPR data for this PO shows that, of the \$4.7 million reported in the “Inception to Date” field of the TPR PS, PG&E reported negative capital expenditures shown in the TPR from 2021 to 2023 and *de minimis* capital expenditures for 2024 and 2025, corresponding initially to the period there was no “deferral” in place, and then when the automated pause was temporary lifted. Fundamentally, PG&E incurred the \$4.7 million on this project prior to 2021 and has not advanced it toward completion in the last five years.

These patterns appear to be inconsistent with FERC policies on pausing AFUDC during periods of interrupted construction. The CPUC strongly recommends that PG&E actively place orders that are not actively being developed in “Deferred Status,” regardless of the amount that has been spent to date. The current \$15 million threshold to place a project in “Deferred Status” does not adequately protect electric transmission ratepayers from costs that do not get the projects completed. *De minimis* charges do not constitute a substantive resumption of construction activities nor do they represent a trajectory of spending that is consistent with a project actually moving forward to a used and useful state and should therefore be expensed.

b. PG&E’s Multiple Portfolio Planning Tools Should Focus on Getting Work Completed

As part of the TPR Process, PG&E has provided overviews of its Risk-Based Portfolio Planning Framework (RBPPF); Integrated Grid Planning (IGP); Transmission Line Asset Strategy; Transmission Composite Model; Probability and Consequence of Failure models; Asset Risk Matrix; cost-benefit ratios; readiness metrics; Health Scores that combine asset age, failure rate, maintenance, system configuration, environmental issues, and safety impacts; and other tools PG&E uses or plans to use in evaluating its system and plan future work.²⁸ However, none of these tools appear to provide sufficient granularity to allow a rank ordering of planned work from the highest priority to the very lowest priority. In fact, PG&E acknowledges that the RBPPF “scoring rubric does not produce a unique score for each proposed investment.”²⁹ Additionally, many electric transmission projects do not have an RBPPF score, and the IGP process is lacking in transparency.

The CPUC appreciates its efforts to develop and validate information on PG&E’s assets and to use that information to inform its system planning. However, the plethora of initiatives to

²⁸ See PG&E’s February 4, 2026 TPR Stakeholder Meeting Presentation. References to these terms are found throughout the presentation.

²⁹ See PG&E’s February 4, 2026 TPR Stakeholder Meeting Presentation, page 54.

develop metrics and analyze every possible iteration appears to be doing little to advance actual project completion. The CPUC recommends PG&E evaluate the value of each of these tools in terms of how it actually supports project completion. While a robust decision-making framework is key to effective portfolio planning, the sheer number of metrics being developed may add needless complexity to the work prioritization and detract from driving projects to completion.

c. Costs Associated with Faulty Workmanship Should Not be Borne by Electric Transmission Ratepayers

PG&E is nearing completion of its interconnection of the LS Power Grid California's Fern Road Substation STATCOM Facility to the Round Mountain 500kV line. This is among the first of several substation projects competitively bid by the California Independent System Operator (CAISO) and built by entities other than PG&E. PG&E is responsible for interconnecting the facility to the electric transmission grid.

In the CPUC's September 30, 2025 "Comments to PG&E on the May 2025 TPR Review,"³⁰ the CPUC noted its concern with PG&E subcontractor's failure to install a piece of equipment per the vendor's design, which led to a flashover event. PG&E indicated increased costs attributable to that failure.³¹ While PG&E's claim for liquidated damages against the contractor for the flawed work is still pending, the CPUC strongly encourages PG&E to ensure that its contracts with subcontractors and other vendors include remedies that adequately protect electric transmission ratepayer interests. Ratepayers should bear no cost responsibility for imprudently incurred costs, whether due to PG&E or a contractor's negligence or faulty equipment. As PG&E will be interconnecting at least four other competitively bid projects in the coming years (e.g., the Manning, Collinsville, Newark, and Metcalf projects), adequate oversight of subcontractors, engineering controls, and strong liquidated damage provisions are essential in maintaining system reliability, protecting worker safety, and managing the cost to ratepayers.

d. PG&E's Advance Procurement of Long-Lead Time Materials is Crucial, but the Creation of Multiple Investment Codes for Emergency Materials Appears to Conflict with PG&E's Other Balance Sheet Mechanism

PG&E has previously shared information about its "Transmission Substation Emergency Preparedness Long-Lead Time Materials Procurement Program."³² PG&E designed the program to ensure that "additional material purchases are needed to maintain an adequate emergency inventory level in response to a significant market increase in lead time and our increasing trend in substation equipment failure rates."³³ The materials would be tracked through PG&E's "Other Balance Sheet" or OBS process, wherein any costs are treated as prepayments or deposits and, once the material was received, the costs would be moved to the specific Planning Order.

³⁰ CPUC Energy Division Staff Comments on Pacific Gas and Electric Company's (PG&E) on the May 2025 TPR Process Cycle, September 30, 2025, page 15.

³¹ See PG&E's Response to FERC-TO21_AU_CPUC-PGE_06-Q202, attachment 1, dated November 13, 2025.

³² See PG&E's Response to Data Request TPR-Process_DR_ED_008-Q005, Attachment 1, March 13, 2025.

³³ See PG&E's Response to Data Request TPR-Process_DR_ED_011-Q008, July 21, 2025.

However, in the November 2025 TPR, PG&E included at least 20 Investment Codes for “forecast failure” of transformers and circuit breakers.³⁴ It remains unclear why these Investment Codes were created when no specific project has been initiated. The Investment Codes also appear to conflict with the intent of the OBS mechanism, which would track advance procurement for emergencies and unexpected failures and transfer equipment to specific work orders once the material was delivered – and the work identified. Furthermore, to the extent these items are procured for unidentified emergencies, they should be placed in inventory rather than generic planning orders until the actual project is identified.

As a result, it is unclear why these myriad Investment Codes were created. The CPUC recommends that PG&E revisit its strategy in creating these Investment Codes, which offer little transparency into the work that will actually be performed. It is also unclear how all these Investment Codes may duplicate the work set forth in other forecasts for emergency replacements. To the extent PG&E has information that can better clarify how all these initiatives interact, it should be shared with the CPUC and Stakeholders to build understanding of PG&E’s internal planning mechanisms.

e. Ratemaking Treatment for “Pilot” Programs Lacks Clarity

PG&E has several “pilot” programs underway, using a variety of technologies. These include deployment of Smart Wires, High Temperature Low Sag Conductor, Dynamic Line Ratings (DLR), and tower monitoring pilot programs. However, the use of the term “pilot” is creating confusion on whether a project is a new, experimental technology that is being tested for future use on the transmission system or whether the technology has been deployed elsewhere but is just now being used in PG&E’s service territory. This lack of clarity creates ambiguity about whether the cost to deploy a technology should be capitalized, expensed, or if it is being funded through research and development initiatives like the Electric Program Investment Charge (EPIC).

For example, PG&E’s DLR “demonstrations” are funded through EPIC and PG&E has indicated these demonstrations are to be completed by the fall of 2027.³⁵ Because EPIC is separately funded on customer bills, it is clear that these costs are not being added to electric transmission rate base or considered an Operations and Maintenance (O&M) expense.

However, in the case of the “Smart Wires SmartValve” units PG&E is deploying on the Los Esteros-Nortech 115kV line, PG&E has said that while it indicated in the Stakeholder meeting that it was “piloting” the technology, PG&E is actually capitalizing these costs because “the technology is proven elsewhere and used by other utilities” even though PG&E is implementing this product for the first time on its system.³⁶

³⁴ See, for example, PG&E’s Responses to Data Requests TPR-Process_DR_ED_018-Q024, dated January 13, 2026, TPR-Process_DR_ED_018-Q035, dated January 21, 2026, TPR-Process_DR_ED_018-Q036, dated January 21, 2026, and TPR-Process_DR_ED_018-Q037, dated January 20, 2026.

³⁵ See PG&E’s Response to Data Request ED_20-Q013, dated March 6, 2026.

³⁶ See PG&E’s Response to Data Request ED_020-Q015, dated March 6, 2026.

Other new technologies for PG&E include tower monitoring and substation infrared cameras. Both programs are shown to be “pilot” and are expensed.³⁷

The CPUC recommends that PG&E be more measured in its use of the term “pilot.” It is not a catch-all phrase for every new technology that PG&E is adding to its system. Clarity around the ratemaking treatment for any new technology implementation is also helpful for Stakeholders to understand how and for how long customers will be paying for new technologies.

f. As PG&E Replaces Wood Poles with Steel Poles, a Better Understanding of the Difference in Service Life is Needed

PG&E has indicated that the average service life of a wood pole ranges from approximately 45 years to 73 years.³⁸ However, steel structures are expected to have a lifespan greater than 50 years, with life expectancies exceeding 100 years with proper maintenance.³⁹ The costs of both types of poles, however, are recorded primarily to FERC Plant Account 355 for Poles and Fixtures, which currently has an average service life of 56 years.⁴⁰

Given PG&E’s initiatives to replace most of its wood poles with steel poles, the CPUC recommends that, in its next Transmission Owner Rate Case Depreciation Study, PG&E carefully evaluate the distribution of wood and steel poles in its system and assess whether the current average service life of 54 years for FERC Account 355 remains appropriate, given the increasing population of steel poles in PG&E’s service territory.

g. Robust Cost-Benefit Ratios are Important Inputs to the Project Selection Process

The CPUC has previously shared its displeasure with PG&E’s lack of progress in developing cost-benefit ratios (CBR) for electric transmission projects.⁴¹ While the CBR value should not be the sole justification in moving a project forward, accurate and timely assessments of the CBR are essential to ensure that PG&E is appropriately capturing the benefits of a project in its prioritization process.

The CPUC recommends that PG&E seek information from a wide range of Stakeholders on the “white paper” it is currently developing on the TPR project CBR calculation framework and methodology.⁴² At a minimum, provision of the white paper and a Stakeholder meeting dedicated to a discussion of the white paper is warranted. PG&E has previously indicated the white paper would be available in the first quarter of 2026. The CPUC looks forward to PG&E expeditiously sharing that workpaper. Furthermore, PG&E should maintain its timeline to

³⁷ See PG&E’s Response to Data Request ED_020-Q013(b), dated March 18, 2026.

³⁸ See PG&E’s Response to Data Request ED_020-Q006, dated March 6, 2026.

³⁹ Ibid.

⁴⁰ Ibid.

⁴¹ See, for example, CPUC Energy Division Staff Comments on Pacific Gas and Electric Company’s (PG&E) on the May 2025 TPR Process Cycle, September 30, 2025, pages 15 to 16.

⁴² PG&E discussed its Cost Benefit Analyses progress extensively during the February 4, 2026 TPR Stakeholder Meeting. Please see slides 56 to 67 of the meeting presentation.

develop a “Minimum Viable Product” (MVP) for transmission and substation asset level models by the end of 2026, which will allow it to provide more robust CBRs in its May 2027 TPR PS.

7. Conclusion

Energy Division Staff appreciate PG&E’s continued engagement in this TPR Process, including PG&E’s data quality and responsiveness to data requests. There remain specific areas Energy Division Staff urge PG&E to address and improve on in future TPR Process Cycles. Removals and additions of projects in PG&E’s TPR PS were significant for this cycle and highlighting those changes in transmittal letters or in the data itself would greatly assist Stakeholders and the CPUC. The CPUC has submitted multiple data requests related to the ratepayers impacts from projects that are on-hold, experiencing major delays, and accruing AFUDC when progress toward “used and useful” isn’t apparent.. PG&E should make every effort to provide all relevant information, thoroughly respond to data requests, and leverage its multiple portfolio planning tools to support project completion efforts. This also includes addressing long-lead time for materials, being transparent on the status of “pilot” projects/technology, and making more progress on the cost-benefit analysis provided in the TPR Process.

Energy Division Staff will continue to evaluate PG&E’s plans to ensure safe, reliable, and affordable electric transmission solutions for its customers.

PG&E should direct any questions or comments on the TPR Process to the email address tpprocess@cpuc.ca.gov