Application: 25-05-009
(U 39 M)
Exhibit No.: (PG&E-16)
Date: March 31, 2026
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2027 GENERAL RATE CASE

REBUTTAL TESTIMONY

EXHIBIT (PG&E-16)

ELECTRIC DISTRIBUTION

CHAPTER 22

VOLUME 4 OF 6

(PG&E-16)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 22

REBUTTAL TESTIMONY ON

GRID MODERNIZATION AND GRID TECHNOLOGY

Advanced Distribution Applications (CAP MWC 63/MAT 63C; EXP MWC HG/MAT HGC)		**See Section D of Rebuttal**
PG&E TY 2027 Request ($000s)	**Capital: $64,517** **Expense: $4,385**	**Units: N/A**
Advanced Distribution Applications is a program of continuing investments in the Advanced Distribution Management System (ADMS) software platform that PG&E uses for outage management and real-time visibility and control of the distribution system. These investments will enable a diverse array of new operational capabilities in ADMS leading directly to improvements in customer affordability, reliability and DER integration, among other benefits.		
Party Financial Recommendations – Increases / (Reductions) ($000s)		
Public Advocates Office (Cal Advocates)	Capital: $(25,351)	

PG&E Response:
PG&E disputes Cal Advocates' recommended 2027 forecast reduction of approximately 39% to six subprograms in the Advanced Distribution Applications scope:

(1) Volt-Var Optimization (VVO)
(2) Load Flow/State Estimation (LFSE)
(3) Load Forecasting
(4) Engineering Analysis
(5) Protection Analysis
(6) Field Switching Digital Transformation (FSDT)

The VVO program is cost effective. Even under Cal Advocates' preferred inputs, the VVO's benefit-cost ratio would still be 1.61.

Results from the LFSE pilot have affirmed technical feasibility and support PG&E's plans to go forward with this program. PG&E's cost estimate quantified costs consistent with Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimation methodology.

The Load Forecasting application will assist with voltage optimization, feeder reconfiguration and switching, DER dispatch, equipment overload prevention and outage mitigation.

Engineering Analysis application's benefits include optimal voltage regulator or capacitor placements that deeper energy savings in the VVO Program and enable reduced line losses and increased system capacity.

Protection Analysis benefits include enhanced safety and fire risk mitigation, improved reliability and operational efficiency through on demand protection analysis directly within the ADMS interface in place of less time efficient. Through the timely identification of protection issues, the application also allows PG&E to avoid costs associated with equipment damage.

PG&E's FSDT cost benefit analysis quantified positive benefits from thirteen distinct value streams that will result from the project. As PG&E's FSDT cost benefit analysis shows, the project is primarily justified by efficiency improvements in the field switching process leading to faster outage response times and enhanced workforce productivity.

PG&E requests full funding for all subprograms in the Advanced Distribution Applications scope. If Cal Advocates positions are adopted, PG&E will not be in a position to invest in the ADMS platform and opportunities for customer affordability, reliability and DER integration benefits will be correspondingly lost or delayed.

Party Non-Financial Recommendations
None.

Distributed Energy Resources Management Systems (DERMS) (EXP MWC HG/MAT HG#, CAP MWC 63/MAT 63#)		See Section E of Rebuttal
PG&E TY 2027 Request ($000s)	**Capital: $18,632** **Expense: $1,299**	**Units: N/A**
DERMS provides capabilities to manage Distributed Energy Resources (DERs) at scale on the distribution grid. PG&E's DERMS currently supports customer-owned telemetry compliance obligations for Rule 21 and CPUC Resolution E-5038, operationalization of the Distribution Deferral Investment Framework (DIDF) contracts, and the enablement of operational flexibility and faster energization for DER customers via PG&E's Flex Connect program. New investments in DERMS will continue to support these existing programs while providing the ability to scale and integrate with emerging use cases like Vehicle-Grid Integration (VGI), aggregations of DERs (e.g., into virtual power plants [VPPs]), provisioning of grid services, and the orchestration of DERs across multiple variables.		
Cal Advocates Financial Recommendations – Increases / (Reductions) ($000)		
Public Advocates Office (Cal Advocates)	Capital: $(2,795)	
PG&E Response: PG&E disputes Cal Advocates' recommendation to reduce DERMS capital expenditures by 15% and proposal to reclassify DERMS licensing capital costs as expense. PG&E has proposed a judicious approach to DERMS implementation that balances the need to prudently scale existing programs and operational benefits while investing in new capabilities like VGI and VPPs that are beneficial to customers and the grid. PG&E's capitalization of DERMS licensing costs meets GAAP and FERC accounting standards. Cal Advocates does not acknowledge the savings that capitalization of the license has to the overall DERMS program costs. PG&E proposes a judicious approach to DERMS implementation that balances the need to prudently scale existing programs and operational benefits while investing in new capabilities like VGI and VPPs that are beneficial to customers and the grid. If Cal Advocates' positions are adopted, it will not only result in higher DERMS licensing costs to ratepayers but will also position PG&E's DERMS negatively in regard to scaling for customer benefit and impacting the ability to realize the value of emergent programs and technologies.		
Party Non-Financial Recommendations		
None.		

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A. Introduction

This rebuttal testimony responds to the direct testimony of the Public Advocates Office at the California Public Utilities Commission (Cal Advocates)[1] regarding Pacific Gas and Electric Company's (PG&E) Exhibit (PG&E-4), Chapter 22, Grid Modernization and Grid Technology.[2]

PG&E is proposing to deploy several new functionalities to its two core distribution operations technology platforms: (1) the Advanced Distribution Management System (ADMS), which PG&E uses for outage management and visibility and control of the distribution grid, and (2) the Distributed Energy Resource Management System (DERMS), which PG&E uses for visibility and control of distributed energy resources (DERs). The new investments in these platforms will enable a wide array of new operational capabilities, leading directly to cost-effective improvements in reliability, safety, affordability, and DER integration. As this testimony demonstrates, PG&E is taking a strategic, measured approach to deployment by targeting new functionality only where it is necessary and will provide the highest value to customers. This approach ensures PG&E's investments will deliver immediate benefits to customers while also enabling continued development of advanced capabilities in the ADMS and DERMS platforms that will position PG&E to seize opportunities and confront challenges associated with an increasingly complex distribution grid.

Party positions are summarized in Section B, which presents a summary table of financial recommendations, and in Section C, which identifies overarching issues raised by Cal Advocates. PG&E responds to Cal Advocates' specific contentions in Sections D and E.

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1 CA-02, CA-07.

2 All references to PG&E exhibits are to the testimony filed on May 15, 2025, and as updated in PG&E's November 10, 2025, errata filing.

B. Summary of Party Positions

1. Summary of Party Positions

PG&E's forecast[3] and party recommendations are set forth in Table 22-1 (expense) and Table 22-2 (capital) below. No party contests PG&E's expense forecasts. Cal Advocates recommends reductions to various items in PG&E's capital forecast.

[3] All references to PG&E forecasts represent the most up-to-date forecast as reflected in testimony filed on May 15, 2025, and as updated in PG&E's November 10, 2025 errata filing.

TABLE 22-1
2027 EXPENSE FORECAST – PG&E AND PARTIES (ALL PROGRAMS)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or Major Work Category (MWC) Descriptions	Maintenance Activity Type (MAT) or MWC	PG&E Filed Forecast[a]	Parties' Proposed Increases/(Reductions)[b] Cal Advocates[c]	PG&E Rebuttal Position [d]
1	Community Microgrid Enablement Program (CMEP) and High Distributed Energy Resource (DER)-Driven Planning Tools	AB	$3,413	$0	$3,413
2	Grid Research Innovation and Development Operations	CY	4,000	0	4,000
3	Distribution Operations Technology	HG	5,684	0	5,684
4	Distribution Deferral Non-Procurement Costs	IG	556	0	556
5	IGP Information Technology (IT) Infrastructure and Non-High DER-Driven Planning Tools	JV	–	0	–
6	Total[e]		$13,653	$0	$13,653

(a) Reflects the most up-to-date forecast as reflected in testimony filed on May 15, 2025, as updated in PG&E's November 10, 2025 errata filing.
(b) Forecast may reflect calculation if recommendation was to increase/reduce forecast by a percentage.
(c) CA-02, p. 3, Table 2-1.
(d) Reflects PG&E forecast position as of March 31, 2026.
(e) Totals may include rounding differences.

TABLE 22-2
2025-2030 CAPITAL FORECAST – PG&E AND PARTIES (ALL PROGRAMS)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC	MAT or MWC	PG&E Filed Forecast[a]						Parties' Proposed Increases/(Reductions)[b]			
									Cal Advocates[c]			
			2025	2026	2027	2028	2029	2030	2025	2026	2027	2028- 2030[d]
1	Advanced Distribution Management System (ADMS)	63	$73,589	$30,153	–	–	–	–	–	–	–	–
2	Advanced Distribution Applications	63	–	–	–	–	–	–	–	–	–	–
3	Volt Var Optimization		–	–	$3,983	$17,667	$20,765	$37,768	–	–	$(2,235)	–
4	Load Flow/State Estimation (LFSE)		3,362	3,610	8,952	9,187	9,429	9,679	$(2,394)	$(2,570)	(6,374)	–
5	Load Forecasting		1,155	1,352	3,547	3,640	3,736	3,835	(1,155)	(1,352)	(3,547)	–
6	Engineering Analysis		577	676	1,773	1,820	1,868	1,917	(577)	(676)	(1,773)	–
7	Protection Analysis		866	1,014	2,660	2,730	2,802	2,876	(866)	(1,014)	(2,660)	–
8	Field Switching Digital Transformation (FSDT)		–	–	8,762	13,230	12,122	–	–	–	(8,762)	–
9	Data Enablement for ADMS		–	–	2,197	1,689	1,391	1,486	–	–	–	–
10	ADMS Hardware/Software Refresh		210	5,900	32,643	14,860	12,759	–	–	–	–	–
11	Advanced Distribution Applications Subtotal		$6,170	$12,552	$64,517	$64,823	$64,872	$57,561	$(4,992)	$(5,612)	$(25,351)	–
12	Distributed Energy Resource Management System (DERMS)	63	16,377	11,664	18,632	10,770	8,830	21,665	(9,512)	(1,750)	(2,795)	–
13	MWC 63 Subtotal		$96,136	$54,369	$83,149	$75,592	$73,701	$79,225	$(14,504)	$(7,362)	($28,146)	–
14	IGP IT Infrastructure and Non High DER-Driven Planning Tools	2F	$17,800	$20,480	$4,532	$4,532	$4,532	$4,532	–	–	–	–
15	High DER-Driven Planning Tools	21	4,359	3,684	5,378	5,429	5,371	5,376	–	–	–	–
16	Total[e]		$118,294	$78,532	$93,059	$85,553	$83,604	$89,133	$(14,504)	$(7,362)	$(28,146)	–

Line No.	Program or MWC	MAT or MWC	PG&E Filed Forecast[f]					
			2025	2026	2027	2028	2029	2030
17	ADMS	63	$73,589	$30,153	–	–	–	–
18	Advanced Distribution Applications	63	–	–	–	–	–	–
19	Volt Var Optimization		–	–	$3,983	$17,667	$20,765	$37,768
20	LFSE		3,362	3,610	8,952	9,187	9,429	9,679
21	Load Forecasting		1,155	1,352	3,547	3,640	3,736	3,835
22	Engineering Analysis		577	676	1,773	1,820	1,868	1,917
23	Protection Analysis		866	1,014	2,660	2,730	2,802	2,876
24	FSDT		–	–	8,762	13,230	12,122	-
25	Data Enablement for ADMS		–	–	2,197	1,689	1,391	1,486
26	ADMS Hardware/Software Refresh		210	5,900	32,643	14,860	12,759	-
27	Advanced Distribution Applications Subtotal		–	$6,170	$12,552	$64,517	$64,823	$64,872
28	DERMS	63	16,377	11,664	18,632	10,770	8,830	21,665
29	MWC 63 Subtotal		–	$96,136	$54,369	$83,149	$75,592	$73,701
30	IGP IT Infrastructure & Non High DER-Driven Planning Tools	2F	17,800	20,480	4,532	4,532	4,532	4,532
31	High DER-Driven Planning Tools	21	4,359	3,684	5,378	5,429	5,371	5,376
32	Total[e]		$118,294	$78,532	$93,059	$85,553	$83,604	$89,133

(a) Reflects the most up-to-date forecast as reflected in testimony filed on May 15, 2025, as updated in PG&E's November 10, 2025 errata filing.

(b) Forecast may reflect calculation if recommendation was to increase/reduce forecast by a percentage.

(c) Cal Advocates-07, Table 07-2 and Table 07-3. These amounts differ from the values in Cal Advocates-07, Table 07-2 and Table 07-3 because they reflect the correction to Cal Advocates' recommended VVO funding levels noted in CalAdvocates' response to PG&E Data Request PGE-CalAdvocates_023-Q01, dated 3/2/26 in Appendix A, at the end of this exhibit.

(d) See Exhibit (PG&E-23), Ch. 1, for PG&E's overall response to Cal Advocates' post test-year recommendations.

(e) Totals may include rounding differences.

(f) Reflects PG&E forecast position as of March 31, 2026.

2. Uncontested Programs

As shown in the tables above, no party made recommendations related to PG&E's forecast for the following programs:

- ADMS (MAT 63C, MAT HGC);
- Advanced Distribution Applications expenses (MAT HGC);
- Two Advanced Distribution Applications capital subprograms:
  - ADMS Hardware/Software Refresh (MAT 63C);
  - Data Enablement for ADMS (MAT 63C);
- DERMS expenses (MAT HG#);
- Distribution Engineering Planning Tools (MWCs 21, 2F AB, JV);
- Distribution Deferral Non-Procurement Costs (MAT IG);
- Community Microgrid Enablement Program (MWC AB);
- Grid Research Innovation and Development (MWC CY); and
- IGP IT Infrastructure (MWCs 2F, JV).

3. Summary of Parties' Non-Financial Recommendations

Parties did not identify any non-financial recommendations for this Chapter.

C. Overarching Issues

Cal Advocates identified three overarching issues it says are present throughout PG&E's Exhibit (PG&E-4), Chapter 22, Grid Modernization and Grid Technology testimony: (1) that PG&E's proposals do not demonstrate ratepayer value;[4] (2) that PG&E's proposals are not supported by quantified benefits and costs;[5] and (3) that PG&E's proposals do not demonstrate proper sequencing or a demonstrated need.[6]

PG&E disagrees and will respond in the program-specific context in which the issues are raised in the sections that follow.

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4 CA-07, p. 5, line 2 to p. 6, line 14.

5 CA-07, p. 6, lines 15-26.

6 CA-07, p. 6, line 27 to p. 7, line 9.

D. Advanced Distribution Applications (MWC HG/MAT HGC, MWC 63/MAT 63C) [Witness: Alex Haralambous]

Advanced Distribution Applications is a program of continuing investments in the ADMS software platform that PG&E uses for outage management and real-time visibility and control of the distribution system.[7] These new investments in the ADMS platform will enable a diverse array of new operational capabilities leading directly to improvements in customer affordability, reliability and DER integration, among other benefits.[8]

The Advanced Distribution Applications Program is divided into eight subprograms, six of which are contested by Cal Advocates. Details of Cal Advocates' subprogram-level recommendations are provided in the corresponding sections below and in Table 22-2.

PG&E disputes all of Cal Advocates' proposed funding reductions for the Advanced Distribution Applications Program. In the sections that follow, PG&E will address Cal Advocates' recommendations for each of the six contested Advanced Distribution Applications subprograms.

1. Volt-Var Optimization

a. PG&E Request

Volt-Var Optimization (VVO) is an ADMS-based application that senses grid conditions, determines the device-level adjustments necessary to optimally regulate voltage and reactive power, and communicates control commands to grid devices in real-time.[9] VVO will improve operational efficiency, reduce Rule 2 violations, and help actively manage voltage issues caused by DER interconnections, but it is primarily justified by the energy and capacity savings it will achieve through reduced line losses and automated Conservation Voltage

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7 Exhibit (PG&E-4), WP 22-25 to WP 22-36.

8 Exhibit (PG&E-4), WP 22-37 to WP 22-47.

9 Exhibit (PG&E-4), p. 22-11, lines 13-15.

Reduction (CVR).[10] PG&E proposes enabling VVO on 220 circuits associated with 85 substation banks in this General Rate Case (GRC) cycle.[11] PG&E's TY 2027 forecast for VVO is $3.983 million and its forecast for the full 2027-2030 GRC period is $80.182 million.[12]

b. Cal Advocates Position

Cal Advocates recommends $1.748 million in funding for VVO in TY 2027, which is $2.235 million lower than PG&E's TY 2027 forecast of $3.983 million.[13] Cal Advocates recommends this same proportional reductions of approximately 56 percent to each year of PG&E's VVO forecast, equating to a recommendation of $35.193 million total funding for VVO from 2027-2030.[14] Cal Advocates' recommendation is based on limiting PG&E's proposed 85 substation bank, 220 circuit VVO deployment, to only 72 "Supervisory Control and Data Acquisition (SCADA)-ready" circuits.[15] PG&E responds to the arguments Cal Advocates uses to reach this conclusion in the sections below.

c. PG&E's VVO Cost-Benefit Analysis Methodology Is Reasonable

1) Cal Advocates Argument

Cal Advocates argues that PG&E's VVO cost-benefit analysis contains three methodological problems: (1) PG&E's VVO cost-benefit analysis shows inflated cost effectiveness because it used a 7.0 percent discount rate instead of a 7.8 percent discount rate;[16] (2) PG&E's benefit forecasts are inflated because it should

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10 Exhibit (PG&E-4), WP 22-37 to WP 22-38. CVR refers to the physical characteristic of devices using less energy when supplied at lower voltage. VVO achieves energy savings and peak load reduction by delivering the lowest possible average customer voltage, while also ensuring all customers remain supplied with voltages within the allowable range.

11 Exhibit (PG&E-4), WP 22-77, Table 22-23, line 2.

12 Exhibit (PG&E-4), WP 22-23, Table 22-13, line 11.

13 Cal Advocates' response to PG&E Data Request PGE-CalAdvocates_023-Q01, dated 3/6/26 in Appendix A, at the end of this exhibit.

14 Cal Advocates' response to PG&E Data Request PGE-CalAdvocates023-Q1, dated 3/6/26 in Appendix A, at the end of this exhibit.

15 CA-07, p. 17, lines 11-12.

16 CA-07, p. 10, lines 14-18.

have weighted the results of its own 2015 VVO pilot project more heavily in the formula PG&E used to estimate expected project benefits;[17] and (3) PG&E's analysis did not include a scenario analysis to test program cost-effectiveness in scenarios where benefits are lower than anticipated.[18]

2) PG&E Response

a) VVO Cost Effectiveness Is Not Inflated Based on Marginal Differences in the Discount Rate

PG&E acknowledges its analysis should have used the 7.27 percent discount rate aligned with PG&E's nominal after-tax Weighted Average Cost of Capital in the approved version of the E3 Avoided Cost Calculator at the time of submitting testimony but disagrees with Cal Advocates' usage of a 7.8 percent discount rate that does not align with the approved value in the E3 Avoided Cost Calculator.[19] Changing the discount rate from 7.0 percent to 7.27 percent lowers the program's benefit-cost ratio from 1.72 to 1.68.[20] Even if Cal Advocates' preferred discount rate of 7.8 percent were used, the VVO Program's benefit-cost ratio would decrease only marginally, from 1.72 to 1.61, and the program would remain cost-effective overall.[21]

b) PG&E's VVO Benefit Estimation Method Appropriately Weighs Prior Studies

PG&E's approach for estimating energy and capacity savings from VVO was to perform a weighted average of savings estimates from its own 2015 VVO pilot program,

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17 CA-07, p. 12, line 14 to p. 13, line 5.

18 CA-07, p. 10, line 25 to p. 11, line 5.

19 2024 E3 Avoided Cost Calculator, available at: <https://www.cpuc.ca.gov/dercosteffectiveness> (accessed Mar. 19, 2026). Refer to cell C4 of the "IRP Inputs" tab, at the link entitled "2024 ACC Electric Model v1b".

20 Refer to Attachment A of this chapter. Scenario analysis regarding the project discount rate can be performed by toggling the value in cell J9.

21 Refer to Attachment A of this chapter.

two model-based savings estimation approaches from Pacific Northwest National Laboratory and Electric Power Research Institute, and two broad surveys of energy savings from VVO implementations at other utilities conducted by the United States (U.S.) Department of Energy.[22] This savings estimation approach ensured that a diversity of estimation methods and realized savings from a wide swath of different utility implementations was factored into savings projection for PG&E's future program.

Cal Advocates objected to this approach, arguing PG&E should have more heavily weighted the results of its own 2015 VVO Pilot Program, which saw lower savings than were observed or projected in the industry studies, because results from this pilot were derived directly from PG&E's system and therefore more likely to be predictive of the savings in PG&E's future implementation.[23] PG&E disagrees because its 2015 pilot is not a perfect model for savings expectations in the future program. At the time of PG&E's VVO pilot in 2015, it was acknowledged that future savings would be higher once PG&E possessed the ADMS software integration between SCADA and DMS that would prevent the VVO solution from needing to be disabled each time a VVO circuit experienced abnormal switching.[24]

Relatedly, Cal Advocates also claimed PG&E performed no benchmarking with other utilities to ensure savings realized in other utility implementations would be applicable to the PG&E system.[25] PG&E disagrees because it sees no compelling

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22 Exhibit (PG&E-4), WP 22-77, Table 22-23, lines 27-32.

23 CA-07, p. 12, lines 11-16.

24 The Voltage and Reactive Power Optimization Smart Grid Pilot Project Final Report stated: "The VVO project's results indicate that VVO deployment has an improved value proposition after PG&E integrates DMS with Distribution SCADA." (Advice Letter (AL) 4990-E, p. 136).

25 CA-07, p. 12, line 18 to p. 13, line 5.

reason why savings in its VVO Program would differ from the median savings realized at other utilities. PG&E's savings estimation method is premised on an expectation of achieving comparable savings to peer utilities and Cal Advocates presents no argument why this should not be true.

c) The VVO Cost-Benefit Analysis Does Not Merit Additional Scenario Analysis

Lastly, PG&E believes the California Public Utilities Commission (CPUC or Commission) should focus its analysis on the scenario representing the single likeliest VVO benefit outcome, which is reflected in PG&E's cost-benefit analysis, rather than less probable upside or downside scenarios. Cal Advocates' scenario analysis method is to multiply a base case benefits forecast by arbitrary round-numbered benefit discount factors, which is an overly-simplistic approach that does not add meaningful insight into the probability of various VVO benefit outcomes.[26] Cal Advocates' scenario analysis also focuses exclusively on downside risk and ignores the possibility that benefits could exceed PG&E's forecast, which PG&E contends is an even likelier outcome given the several VVO benefits streams that PG&E did not attempt to quantify, including improvements to DER integration, operational efficiency, grid visibility, and Rule 2 compliance.

d. Deployment Should Not Be Limited Only to SCADA-Ready Circuits

1) Cal Advocates Argument

Cal Advocates argues that because the cost to equip voltage regulators, capacitors, and substation load-tap controllers with SCADA comprises a high percentage of PG&E's overall VVO forecast, the program's cost-effectiveness would be improved if deployment were limited only to 72 circuits that already have the

26 CA-07, p. 14, Table 07-6 and p. 15, Table 07-7.

necessary SCADA equipment, rather than the 85-bank, 220-circuit deployment proposed by PG&E.[27]

2) PG&E Response

a) VVO Cost-Effectiveness Is Driven by Energy Savings Potential, Not Whether SCADA Must Be Installed

Cal Advocates' recommendation that the VVO deployment be limited to SCADA-ready circuits relies on an incorrect assumption that the presence of existing SCADA equipment is the dominant factor in determining the cost-effectiveness of deploying VVO on any given circuit. In truth, the dominant factor is the level of energy savings potential from VVO that exists on the circuit in the first place, given the circuit's unique topography, loading, and voltage profile characteristics.

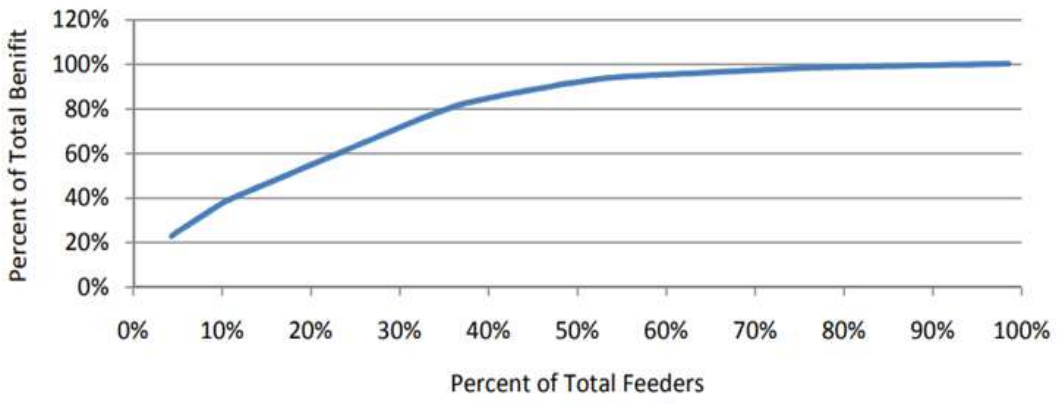
There is wide variability in the amount of energy savings potential from VVO that exists for any given circuit, and most circuits do not show good potential. As illustrated in the image below taken the Pacific Northwest National Laboratory's "Evaluation of Conservation Voltage Reduction (CVR) on a National Level" study, over 80 percent of total VVO benefits come from only 40 percent of feeders.[28]

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27 CA-07, p. 11, line 6 to p. 15, line 20.

28 Pacific Northwest National Laboratory, Evaluation of Conservation Voltage Reduction (CVR) on a National Level, (July 2010), p. 39, available at: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf (accessed Mar. 19, 2026).

FIGURE 22-1
PERCENT TOTAL VVO BENEFITS VS.
PERCENT TOTAL NUMBER OF FEEDERS IN THE U.S.



Results from PG&E's 2015 VVO pilot also illustrate this concept. The pilot's final report stated:

> The pilot results show that while not all banks in PG&E's service territory are likely to be good candidates for VVO, when a bank with the appropriate characteristics is selected using the right approach, VVO can deliver substantial benefits and deliver a B/C Ratio above 1.0. For example, a deployment of VVO to banks similar to Woodward Bank 2 is expected to yield a B/C Ratio above 1.0.[29]

Any VVO implementation must first start with an analysis of which circuits possess requisite energy savings potential prior to assessing other factors that may influence cost-effectiveness, like the presence of pre-existing SCADA equipment.

b) Limiting VVO Deployment to SCADA-Enabled Circuits Would Lead to a Less Cost-Effective Program

Cal Advocates' recommendation of a circuit-level VVO deployment driven by pre-existing SCADA equipment also fails to recognize that VVO implementations must occur at the bank-level, not the circuit-level. Since voltage regulation at the substation transformer bank influences all downstream circuits,

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29 AL 4990-E, p. 163. The pilot found Woodward Bank 2 achieved approximately 2.1 percent energy savings, while the pilot's lowest performing bank (Airways Bank 1) achieved only 0.2 percent energy savings.

any one circuit on the bank not participating in the automated voltage optimization effort will serve as a binding constraint for all circuits on the same bank, undermining energy savings for the whole group.

Adding to the implausibility of Cal Advocates' proposal to deploy VVO to just 72 SCADA-ready circuits is the fact that there is only approximately this number of SCADA-ready circuits in PG&E's entire service territory,[30] and an even smaller number that are associated with a substation bank where all constituent circuits are SCADA-ready.[31,32]

Cal Advocates' recommendation to deploy VVO to 72 "SCADA-ready" circuits would result in a less cost-effective program by effectively requiring PG&E to deploy VVO to all existing SCADA-ready circuits without consideration of other important determinative factors of the deployment's cost-effectiveness.

PG&E is committed to deploying VVO in the most cost-effective manner possible in consideration of *all* factors that will influence the investment's cost-effectiveness. This first and foremost includes an assessment of the energy savings potential from VVO on a substation bank's circuits, but will also

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30 PG&E defined a "SCADA-ready circuit" as a circuit having at least one SCADA-enabled voltage regulator or capacitor and zero non-SCADA voltage regulators or capacitors in PG&E's response to Data Request CalAdvocates_136-Q006Rev01d, dated 11/6/25 in Appendix A, at the end of this exhibit. In that data request, PG&E identified a total of 67 "SCADA-ready" circuits in its service territory by that definition. PG&E assumes Cal Advocates uses this same definition.

31 Attachment B of this chapter shows there are 6 fully SCADA-ready substation banks in PG&E's service territory, encompassing 11 total circuits.

32 Cal Advocates incorrectly characterized PG&E's proposal as separately targeting 72 SCADA-ready and 148 non-SCADA ready circuits when PG&E in fact made no commitment to separately target fully SCADA-ready circuits. As PG&E made clear in PG&E's response to Data Request CalAdvocates_136-Q006Rev01b, dated 11/6/25 in Appendix A, at the end of this exhibit, its proposal was based on disproportionally "targeting banks with *lower-than-average number of non-SCADA capacitors or voltage regulators*, either by virtue of SCADA having already been installed on devices, or by avoiding the selection of circuits with very high numbers of non-SCADA capacitors or voltage regulators."

include consideration of factors such as: (1) the number of SCADA installations needed on the bank's circuits, (2) the need for conditioning work such as phase balancing on the bank's circuits, (3) the need for regulator and capacitor relocations on the bank's circuits, (4) existing or forecasted DER-related voltage regulation issues on the bank's circuits that VVO could mitigate, (5) the reliability of SCADA communications on the bank's circuits, and (6) avoidance of major planned work on the bank's circuits.[33] PG&E will conduct this holistic analysis of the 85 substation banks where VVO can be most cost-effectively deployed during the Plan/Analyze phase of the VVO project in 2027.

PG&E's proposed 85-bank, 220-circuit deployment is already prudently sized, with PG&E already having scaled back 50 percent from the 2015 VVO Pilot's finding that a 170-bank deployment would be cost-effective.[34] PG&E proposed this smaller program to ensure that its initial VVO deployment focused only on a smaller subset of 85 banks with the very highest expected cost-effectiveness.

Cal Advocates' flawed circuit selection methodology would result in a less cost-effective program, and its smaller proposed scale would delay the realization of cost-effective benefits to customers.

e. VVO Should Not Be Analyzed Through the Lens of "Grid Modernization," Since Its Primary Purpose Is Energy Savings, Not DER-Integration

1) Cal Advocates Argument

Cal Advocates argues that the Commission should not view VVO as a priority "Grid Modernization" DER-enablement investment in this GRC because PG&E did not commit to selecting VVO circuits

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33 PG&E's response to Data Request CalAdvocates_136-Q005d, dated 10/6/25 in Appendix A, at the end of this exhibit.

34 AL 4990-E, p. 196.

based on DRP planning-tool outputs demonstrating that a DER-integration challenge exists on the circuit within the three-year GRC cycle.[35]

2) PG&E Response

PG&E generally agrees with the idea that the Commission should not view VVO primarily through the lens of Grid Modernization. While improved DER-integration support is an important ancillary benefit of the VVO Program, it is not the investment's chief justification. As evidenced in PG&E's cost-benefit analysis, the VVO investment is primarily justified by energy savings, capacity savings, and direct customer bill savings.

As noted above, PG&E's VVO circuit selection process will balance many factors, including the circuit's energy savings potential, the cost of implementing VVO on a given circuit, and whether VVO can offer DER-integration benefits on that circuit. The potential for DER-integration benefits will not be among the most heavily weighted factors, but it will be considered and may influence circuit selection on the margins. During this process, PG&E will indeed use DRP planning-tool outputs to identify circuits that have DER integration needs that VVO may help address.

2. Load Flow/State Estimation

a. PG&E Request

LFSE refers to the capability of the ADMS system to model real-time power flows at any location on a distribution circuit using a combination of SCADA telemetry, physical properties of network features stored in Geographic Information System and CYME, device settings stored in PowerBase, and the as-switched state of the grid in ADMS.[36] This LFSE-provided visibility into real-time conditions along a full circuit is foundational to the optimal performance of ADMS advanced applications that automate various grid control actions, such as VVO and Protection

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35 CA-07, p. 16, lines 1-30.

36 Exhibit (PG&E-4), WP 22-39.

Analysis. PG&E proposes enabling LFSE on the 220 VVO circuits and 30 additional circuits for DERMS-related use cases in this GRC cycle.[37] PG&E's TY 2027 capital forecast for LFSE is $8.952 million and its capital forecast for the full 2027-2030 GRC period is $37.246 million.[38]

b. Cal Advocates Position

Cal Advocates recommends $2.578 million in funding for LFSE in TY 2027, which is $6.374 million lower than PG&E's TY 2027 forecast of $8.592 million,[39] and recommends this same proportional reduction be applied to each year of PG&E's LFSE forecast.[40] Cal Advocates' recommendation is based on limiting PG&E's proposed 250 circuit LFSE implementation to the same 72 SCADA-ready circuits that Cal Advocates recommends be approved for VVO.[41] PG&E responds to the arguments Cal Advocates uses to arrive at this conclusion in the sections below.

c. Scaling LFSE Should Not Depend on Pilot Feasibility Results or on Having Precisely Known Costs and Benefits

1) Cal Advocates Argument

Cal Advocates states that the scale of PG&E's LFSE proposal should be limited because PG&E has not yet completed its 56-circuit LFSE pilot, which would provide the Commission with useful information on program costs, benefits, and deployment timelines.[42] Cal Advocates also criticizes the lack of quantified costs and benefits provided in support of PG&E's LFSE Program proposal and

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37 PG&E's response to Data Request CalAdvocates_091-Q002b, dated 8/29/25 in Appendix A, at the end of this exhibit.

38 Exhibit (PG&E-4), WP 22-23, Table 22-13, line 12. The share of the Advanced Application Enablement forecast attributable to LFSE can be calculated by multiplying the full program forecast by 52.9 percent.

39 CA-07, p. 9, lines 6-9.

40 CA-07, p.17, lines 8-10.

41 CA-07, p. 26, lines 11-16.

42 CA-07, p. 20, lines 1-10.

labels the program as a "learning deployment" where additional information on program costs and benefits will be gathered.[43]

2) PG&E Response

a) The LFSE Pilot Has Demonstrated Technical Feasibility

The scale of PG&E's LFSE proposal should not be limited because PG&E has not yet completed its 56-circuit LFSE pilot. Cal Advocates argues that completing this pilot would provide the Commission with useful information on LFSE Program costs, benefits, and deployment timelines, but these are not deliverables of the LFSE pilot. Rather, the pilot's aim is to prove the technical feasibility of enabling the LFSE solution on live circuits in PG&E's ADMS platform.[44] Results from the pilot have affirmed this technical feasibility: PG&E has validated the core functionality of the LFSE software product and verified that the LFSE solution can be successfully implemented on live circuits with estimated voltage, power, and current values within 20 percent of observed SCADA measurements.[45]

b) LFSE Costs Were Quantified

PG&E disagrees with Cal Advocates' assertion that LFSE costs were not quantified.[46] PG&E provided a detailed, line-item cost estimate of the work required to implement the Advanced Application Enablement scope with estimates of the percentage of the effort attributable to LFSE.[47] In alignment with its own Project Cost Management Standard, PG&E

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43 CA-07, p. 23, lines 1-10.

44 PG&E's response to Data Request CalAdvocates_091-Q002a, dated 8/29/25 in Appendix A, at the end of this exhibit.

45 PG&E's response to Data Request CalAdvocates_205-Q008a, dated 11/10/25 and attachment CalAdvocates_205-Q008Atch01 in Appendix A, at the end of this exhibit. Bringing this number to within its ultimate goal of 10 percent was not an explicit aim of the pilot, but PG&E is confident this can be done with some additional tuning effort and the data that will be provided by the Data Enablement for ADMS Program.

46 CA-07, p. 21, lines 22-23.

47 PG&E's response to Data Request CalAdvocates_121-Q002b and attachment CalAdvocates_121-Q002Atch01, dated 9/23/25 in Appendix A, at the end of this exhibit.

accounted for the uncertainty inherent in forecasting costs for work that has not yet been designed in detail by applying an Association for the Advancement of Cost Engineering (AACE) Class 4 cost estimation methodology to the LFSE forecast.[48] Cal Advocates themselves ultimately did not take issue with the substance of PG&E's LFSE cost forecast, evidenced by its use of PG&E's cost forecast in its recommendation to proportionally reduce PG&E's LFSE forecast in the same amount as the VVO scope.[49]

c) LFSE is Justified Based on a Qualitative Description of Benefits

Regarding the lack of quantified benefits provided in support of PG&E's LFSE proposal, PG&E maintains there is no reasonable method of comprehensively forecasting the benefits from LFSE data that is foundational to many wide-ranging use cases in ADMS and that qualitative benefit descriptions stand on their own as justification for the investment.[50] As a matter of principle PG&E will provide a quantified benefits forecast where a reasonable method of quantifying benefits exists, as it did with the VVO and FSDT cost-benefit analyses provided in support of this chapter, but will not when the analysis would be too theoretical and assumptions-driven to be useful in evaluating the proposal. PG&E has long held the position that certain benefits from ADMS, including those related to LFSE, are not quantifiable, having successfully argued this position in two consecutive GRC rebuttals prior to this one.[51] Cal Advocates does not dispute that these benefits are unquantifiable or offer a proposal for how to quantify them.

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48 Attachment C of this chapter, p. 24.

49 CA-07, p. 21, lines 9-13.

50 PG&E's response to Data Request CalAdvocates_091-Q002c, dated 8/29/25 in Appendix A, at the end of this exhibit.

51 Application (A.) 18-12-009, HE-20: Exhibit (PG&E-18), pp. 19-15, line 25 to pp. 19-16, line 25; A.21-06-021, Exhibit (PG&E-17), pp. 21-13, lines 19-22.

Having already made a significant foundational investment in ADMS, it would be a mistake to restrict comparatively small investments in the individual applications that will unlock some of the highest value use-cases of ADMS, which for LFSE include but are not limited to:

- Better safety and situational awareness through identification of real time grid overloads;
- Improved reliability from optimized switching recommendations and improved protective device coordination;
- Enhanced DER integration via VVO-enabled voltage constraint mitigation and the dispatch of DER assets in response to modeled grid conditions;
- Improved affordability through higher VVO-enabled energy savings, avoided line losses, and the increased utilization of capital assets;
- Improved compliance with Rule 2 voltage limits via better VVO-enabled voltage control.[52]

d) The Proposed Scale Is Appropriate to Test and Evaluate LFSE

Finally, PG&E largely agrees with Cal Advocates' characterization of its LFSE Program proposal as a "learning deployment."[53] It is a natural expectation that improved information on program costs and benefits will be gathered through production implementation experience. Cal Advocates arrived at the conclusion that a learning deployment is warranted themselves, ultimately recommending a proposal that will allow PG&E to:

> …test and evaluate LFSE performance and benefits under real operating conditions; and…refine its understanding of

[52] Exhibit (PG&E-4), WP 22-39 to WP 22-40.

[53] CA-07, p. 23, lines 1-10.

LFSE deployment costs, data dependencies, and DERMS interactions.[54]

d. The LFSE Program Can Proceed Effectively in Parallel with the Electric AMI 2.0 and Data Enablement Projects

1) Cal Advocates Argument

Cal Advocates argues that the dependency of optimal LFSE application performance on phase identification and meter-to-transformer relationship data that will be provided by the in-flight Electric AMI 2.0 and Data Enablement for ADMS projects adds a layer of timing and performance uncertainty to PG&E's LFSE Program, considering that: (1) the Location Awareness application that will provide this data is unproven, and (2) that PG&E has not yet determined where the Electric AMI 2.0 meters that will help provide the needed data will be deployed.[55]

2) PG&E Response

a) The Location Awareness Application That Will Provide Data for LFSE Is Not Unproven

The scale of PG&E's LFSE proposal should not be limited on account of timing or performance uncertainty related to the Electric AMI 2.0 and Data Enablement for ADMS projects because PG&E is confident it can effectively run these projects in parallel. Cal Advocates' argument is based partially on a claim that the Location Awareness application is "unproven," but this is incorrect;[56] PG&E did in fact test the Location Awareness application in the Electric Program Investment Charge (EPIC) 3.43 project and found the application, which is built on the AMI 2.0 meter's phasor telemetry and peer-to-peer comparison capabilities, correctly identified the meter's phase identification

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54 CA-07, p. 26, lines 5-8.

55 CA-07, p. 21, lines 3-21.

56 CA-07, p. 21, lines 7-9. Cal Advocates claims that PG&E did not provide any pilot or field results specific to the Location Awareness application in this record, but Cal Advocates did not request this information in discovery.

and transformer relationship in 100 percent of test cases.[57] The results from this testing give PG&E confidence that the application is ready to be scaled and will produce high quality data when this scaling occurs.

b) LFSE Is Not Fully Contingent on the Location Awareness Application

Additionally, while the higher quality phasing and meter-to-transformer relationship data that will be provided by these projects is indeed important for the optimal performance of LFSE and downstream applications such as VVO that utilize LFSE, the availability of this data is not a hard dependency. PG&E's LFSE pilot has demonstrated that it can achieve convergent load flow solutions that enable reliable system monitoring without this data,[58] and PG&E's 2015 VVO Pilot demonstrated that cost-effective VVO energy savings are achievable without this data.[59] The LFSE and VVO projects can proceed even in the unlikely event the acquisition of data from these projects is delayed.

PG&E has not yet determined where the Electric AMI 2.0 meters that will help provide the needed data will be deployed because the location of these deployments will be decided in conjunction with the circuit selection process for the VVO and Advanced Application Enablement scope.[60] PG&E is confident it can coordinate the timing of LFSE and VVO bank-level deployments to occur after the deployment of Electric AMI 2.0 meters on those banks, and to the extent the data availability lags for any given bank, the LFSE and VVO applications will still provide interim value until the data becomes available.

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57 Refer to Attachment D of this chapter.

58 PG&E's response to Data Request CalAdvocates_205-Q008a, dated 11/10/25 and attachment CalAdvocates_205-Q008Atch01 in Appendix A, at the end of this exhibit.

59 AL 4990-E, p. 163.

60 PG&E's response to Data Request CalAdvocates_091-Q003d, dated 8/29/25 in Appendix A, at the end of this exhibit.

e. LFSE Should Be Sized in Accordance with the VVO Program with Funding for 30 Additional Feeders Supporting DERMS

1) Cal Advocates Argument

Despite its various objections to LFSE, Cal Advocates acknowledges the importance of LFSE to VVO and recommends LFSE Program funding be approved for all 72 feeders in its recommended VVO scope.[61]

Cal Advocates takes issue with PG&E's proposed extension of the LFSE scope to 30 additional feeders for DERMS-related use cases that are not part of the proposed VVO Program, stating that PG&E has not identified the specific DERMS use-cases or the benefits of LFSE for the DERMS system.[62]

Furthermore, Cal Advocates suggests these 30 additional feeders should not be added to the LFSE scope because PG&E may be able to reduce the size of its LFSE Program by approximately this amount if it reuses circuits from the 56-circuit LFSE pilot for the VVO Program or DERMS use-cases.[63]

2) PG&E Response

Given the important interdependencies between the LFSE and VVO projects, PG&E agrees with the premise in Cal Advocates' recommendation that funding for the 220-circuit or 88 percent share of the LFSE scope intended to support VVO should be proportional to funding for VVO. However, as noted previously, PG&E disagrees with Cal Advocates' recommendation of reduced funding and scope for VVO and therefore also disagrees with any proportional reduction to LFSE.

Regarding the 30-circuit or 12 percent share of the LFSE scope intended to support DERMS, PG&E disagrees with Cal Advocates' assertion that it did not identify DERMS use-cases that will benefit from LFSE; PG&E did in fact identify the DERMS Flex Connect

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61 CA-07, p. 26, lines 1-4.

62 CA-07, p. 26, lines 7-8.

63 CA-07, p. 24, line 19 to p. 25, line 7.

program as having a dependency on the availability of LFSE data.[64] PG&E further explained that LFSE significantly expands the reach and benefits of DERMS because DERMS requires measurements of grid conditions in order to operate, which in the absence of LFSE can only be provided in a limited number of locations where SCADA is present.[65] The ability of DERMS to scale effectively in this rate case cycle would be impaired if funding to extend LFSE to these 30 additional circuits is denied.

Lastly, PG&E disagrees with Cal Advocates' suggestion that its LFSE scope may be reduced by approximately 30 circuits by reusing approximately this number from the 56-circuit LFSE pilot. The potential for cost avoidance through selection of LFSE enabled circuits will be a minor consideration in circuit selection for the VVO and DERMS programs, but this selection process will be driven by a holistic assessment of the circuit's cost-effectiveness and PG&E cannot commit to reusing any of the 56 LFSE pilot circuits at this time.

3. Load Forecasting

a. PG&E Request

Load Forecasting is an extension of the LFSE application that allows LFSE to model *future* power flows at any location on a distribution circuit, effectively transforming ADMS from a reactive monitoring and control system into a predictive decision-support system.[66] This Load Forecasting-provided visibility into future conditions along a full circuit is foundational to the optimal performance of ADMS advanced applications that automate various grid control actions, such as VVO and Protection Analysis. PG&E proposes enabling Load Forecasting on the 220 VVO circuits and 30 additional circuits for DERMS-related use cases in this

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64 PG&E's response to Data Request CalAdvocates_205-Q008j, dated 11/10/25 in Appendix A, at the end of this exhibit.

65 PG&E's response to Data Request CalAdvocates_205-Q008g, dated 11/10/25 in Appendix A, at the end of this exhibit.

66 Exhibit (PG&E-4), WP 22-40.

GRC cycle.[67] PG&E's TY 2027 capital forecast for Load Forecasting is $3.547 million and its capital forecast for the full 2027-2030 GRC period is $14.758 million.[68]

b. Cal Advocates Position

Cal Advocates recommends full disallowance of PG&E's Load Forecasting forecast of $3.547 million in TY 2027 and full disallowance of PG&E's Load Forecasting forecast in all other years.[69] PG&E responds to the arguments Cal Advocates uses to arrive at this conclusion in the sections below.

c. Load Forecasting Is Needed in This GRC Cycle

1) Cal Advocates Argument

Cal Advocates argues that funding for the Load Forecasting application should be denied because: (1) PG&E has not identified specific safety, reliability, or DER integration deficiencies in the 2027-2030 GRC cycle that the Load Forecasting application is required to address;[70] (2) that VVO does not have any near-term use cases for Load Forecasting;[71] and (3) that the near-term value of the Load Forecasting application to DERMS is in question because DERMS already possesses certain load forecasting capabilities.[72]

2) PG&E Response

PG&E disagrees that it has not identified specific safety, reliability, or DER integration deficiencies in this GRC cycle that the Load Forecasting application is required to address. The Load

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67 PG&E's response to Data Request CalAdvocates_091-Q002e, dated 8/29/25 in Appendix A, at the end of this exhibit.

68 Exhibit (PG&E-4), WP 22-23, Table 22-13, line 12. The share of the Advanced Application Enablement forecast attributable to Load Forecasting can be calculated by multiplying the full program forecast by 20.9 percent.

69 CA-07, p. 26, lines 24-30.

70 CA-07, p. 27, line 21 to p. 28, line 2.

71 CA-07, p. 29, lines 9-18.

72 CA-07, p. 28, lines 3-13.

Forecasting application will provide the critical ability for PG&E's advanced applications to anticipate, rather than simply react to, grid conditions that may pose a safety, reliability, or DER integration related issue, and PG&E provided several examples of how the Load Forecasting application will assist with voltage optimization, feeder reconfiguration and switching, DER dispatch, equipment overload prevention and outage mitigation.[73]

Cal Advocates' contention that PG&E did not identify any near-term VVO use cases for Load Forecasting data is incorrect; a PG&E discovery response to Cal Advocates stated that Load Forecasting will allow the VVO algorithm to:

> …proactively tune capacitor banks, voltage regulators, and smart inverters, which improves voltage stability, reduces losses, and prevents customer voltage violations…[and] optimize for minimized device tap changes, which can extend equipment life.[74]

This latter point is especially critical. In the absence of Load Forecasting data, PG&E would need to apply more conservative voltage control setpoints to guard against a purely reactive VVO algorithm inducing excessive device operations that can damage or prematurely wear out equipment. With the benefit of Load Forecasting data, the VVO can optimize voltage setpoints in a manner that balances the dual objectives of reducing voltage while minimizing device operations, thereby both extending equipment life and deepening energy savings from VVO.

Lastly, the load forecasting capability currently available to DERMS is fundamentally different from what will be provided by Load Forecasting integrated with LFSE. Without LFSE-based Load Forecasting, PG&E DERMS is limited to only serving customers who are constrained at locations with SCADA measurements available. As PG&E explained:

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73 PG&E's response to Data Request CalAdvocates_091-Q002e, dated 8/29/25 in Appendix A, at the end of this exhibit.

74 PG&E's response to Data Request CalAdvocates_091-Q002e, dated 8/29/25 in Appendix A, at the end of this exhibit.

Currently, PG&E DERMS does not forecast at 'all locations on the polyphase grid.' PG&E DERMS currently uses a measurement-based forecast that only looks at locations that have SCADA values (e.g., Substation Transformer Bank, Feeder Head, Distribution Recloser).[75]

By enabling load forecasts at all locations on a given circuit rather than just a few select locations with SCADA, the Load Forecasting application will expand the reach of DERMS to address forecasted constraints that may exist anywhere on a circuit, significantly increasing its potential reach and benefits.

d. Load Forecasting Approval Should Not Depend on a Pilot Completion or on Bringing LFSE to Scale

1) Cal Advocates Argument

Cal Advocates argues that development of Load Forecasting should be delayed until the value of LFSE and the Location Awareness application can be more demonstrably proven[76] and observes that PG&E has not yet conducted a pilot of the Load Forecasting application.[77]

2) PG&E Response

PG&E disagrees with Cal Advocates' argument that investment in the Load Forecasting application should be delayed until after the LFSE and Location Awareness applications are more proven. The technical feasibility of both LFSE and the Location Awareness application has already been demonstrated in pilots[78] and PG&E sees minimal delivery risk in the production phase. The risk of stranded investment in Load Forecasting is further minimized because the timing of the Load Forecasting investment will generally

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75 Rulemaking (R) 21-06-017. *Pacific Gas and Electric Company's (U 39 E) Response to Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections*, (Nov. 25, 2025), p. 3.

76 CA-07, p. 28, lines 14 to p. 29, line 8.

77 CA-07, p. 30, lines 18-20.

78 PG&E's response to Data Request CalAdvocates_205-Q008a and attachment CalAdvocates_205-Q008Atch01, dated 11/10/25 in Appendix A, at the end of this exhibit. Also refer to Attachment D of this chapter.

lag and be contingent upon the success of the LFSE investment. It would be imprudent to delay Load Forecasting's benefits on account of low-probability delivery or stranded investment risk.

PG&E disagrees that a pilot of the Load Forecasting application should be required. Load Forecasting is not an appropriate candidate for a pilot under the EPIC Program because PG&E plans to implement an off-the-shelf, vendor-supported, commercially available technology that is widely used throughout the utility industry. This technology is too mature for demonstration in a program like EPIC whose goal is to "supports assisting technology development through the 'valley of death' and toward commercialization."[79] Additionally, given its small scale covering only approximately 6 percent of PG&E's service territory and the relatively large share of costs associated with early stage project work such as application analysis, design, testing, and end-user training, PG&E's proposed Load Forecasting program itself is not functionally very different from a "pilot" and requiring a separate pilot would be duplicative.

e. Load Forecasting Approval Should Not Depend on Having Precisely Known Costs and Benefits

1) Cal Advocates Argument

Cal Advocates also argues that funding for the Load Forecasting application should be denied because: (1) PG&E did not specifically quantify the Load Forecasting application's costs;[80] and (2) PG&E did not supply a quantitative benefit estimate for the application.[81]

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79 D.12-05-037, p. 7.

80 CA-07, p. 31, lines 4-17.

81 CA-07, p. 30, lines 5-17.

2) PG&E Response

a) Load Forecasting Costs Were Quantified

PG&E disagrees with Cal Advocates' assertion that Load Forecasting costs are not quantified. PG&E provided a detailed, line-item cost estimate of the work required to implement the Advanced Application Enablement scope with estimates of the percentage of the effort attributable to Load Forecasting.[82] In alignment with its own Project Cost Management Standard, PG&E accounted for the uncertainty inherent in forecasting costs for work that has not yet been designed in detail by applying an AACE Class 4 cost estimation methodology to the Load Forecasting forecast.[83]

b) Load Forecasting Benefits Are Unquantifiable and the Application Is Justified Based on a Qualitative Description of Benefits

Regarding the lack of quantified benefits provided in support of the Load Forecasting application, PG&E's response is similar to the discussion provided for the LFSE application. These points are summarized below:

- There is no reasonable method of forecasting the benefits from Load Forecasting data that is foundational to many wide-ranging use cases in ADMS, and a qualitative description of Load Forecasting's benefits stands on its own as justification for the investment.[84]
- PG&E will provide a quantified benefits forecast where a reasonable method of quantifying benefits exists, as it did for VVO and FSDT, but will not when the analysis would be

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82 PG&E's response to Data Request CalAdvocates_137-Q011b, dated 10/6/25 in Appendix A, at the end of this exhibit.

83 Attachment C of this chapter, p. 24.

84 PG&E's response to Data Request CalAdvocates_091-Q002e, dated 8/29/25 in Appendix A, at the end of this exhibit.

too theoretical and assumptions-driven to be useful in evaluating the proposal.

- That certain benefits from ADMS, like those related to Load Forecasting, are unquantifiable is a long-held position by PG&E spanning multiple rate case cycles.[85]
- Cal Advocates does not dispute that these benefits are unquantifiable or offer a proposal for how to quantify them.
- Having already made a significant foundational investment in ADMS, it would be a mistake to restrict comparatively small investments in the individual LFSE-based applications that will unlock some of the highest value use-cases of ADMS.

The benefits that justify the Load Forecasting investment include, but are not limited to:

- Improved safety and situational awareness through proactive identification and mitigation of future grid overloads;
- Improved reliability from switching recommendations and protective device settings recommendations that fully anticipate future grid conditions;
- Enhanced DER integration via dispatch of DER assets in response to modeled constraints at all locations on a circuit;
- Improved affordability through higher VVO-enabled energy savings, avoided line losses, and the increased utilization of capital assets.[86]

4. Engineering Analysis

a. PG&E Request

Engineering Analysis is a suite of ADMS-based applications that will allow PG&E to identify the optimal locations of voltage regulators and

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85 A.18-12-009, HE-20: Exhibit (PG&E-18), p. 19-15, line 25 to p. 19-16, line 25; A.21-06-021, Exhibit (PG&E-17), p. 21-13, lines 19-22.

86 PG&E's response to Data Request CalAdvocates_091-Q002e, dated 8/29/25 in Appendix A, at the end of this exhibit.

capacitors on a circuit.[87] Strategically placing voltage regulators and capacitors maximizes the ability of the VVO algorithm to optimize circuit-level voltage and reactive power, bringing deeper energy and capacity savings through reduced average circuit voltage levels and lower system losses and increased capacity through improved reactive power management.[88] PG&E proposes enabling Engineering Analysis on the 250 LFSE circuits in this GRC cycle.[89] PG&E's TY 2027 capital forecast for Engineering Analysis is $1.773 million and its capital forecast for the full 2027-2030 GRC period is $7.378 million.[90]

b. Cal Advocates Position

Cal Advocates recommends full disallowance of PG&E's Engineering Analysis forecast of $1.773 million in TY 2027 and full disallowance of PG&E's Engineering Analysis forecast in all other years.[91] PG&E responds to the arguments Cal Advocates uses to arrive at this conclusion in the sections below.

c. Engineering Analysis Is Needed to Support VVO in This GRC Cycle

1) Cal Advocates Argument

Cal Advocates argues that funding for the Engineering Analysis application should be denied because: (1) it is not necessary to support the VVO Program in this GRC cycle;[92] and (2) PG&E does not demonstrate the deficiency of existing tools for determining the location of capacitors and voltage regulators.[93]

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87 Exhibit (PG&E-4), WP 22-40.

88 PG&E's response to Data Request CalAdvocates_091-Q002f-g, dated 8/29/25 in Appendix A, at the end of this exhibit.

89 PG&E's response to Data Request CalAdvocates_091-Q002g, dated 8/29/25 in Appendix A, at the end of this exhibit.

90 Exhibit (PG&E-4), WP 2-23, Table 22-13, line 12. The share of the Advanced Application Enablement forecast attributable to Engineering Analysis can be calculated by multiplying the full program forecast by 10.5 percent.

91 CA-07, p. 32, line 28 to p. 33, line 3.

92 CA-07, p. 33, line 21 to p. 34, line 9.

93 CA-07, p. 34, lines 11-12.

2) PG&E Response

PG&E disagrees that the Engineering Analysis application is not needed to support the VVO Program in this GRC cycle. Optimally locating capacitors and voltage regulators on a circuit plays a crucial role in the management of the circuit's voltage profile, and therefore in the ability of VVO to deliver energy savings by optimizing voltage delivery in the low end of the allowable range.

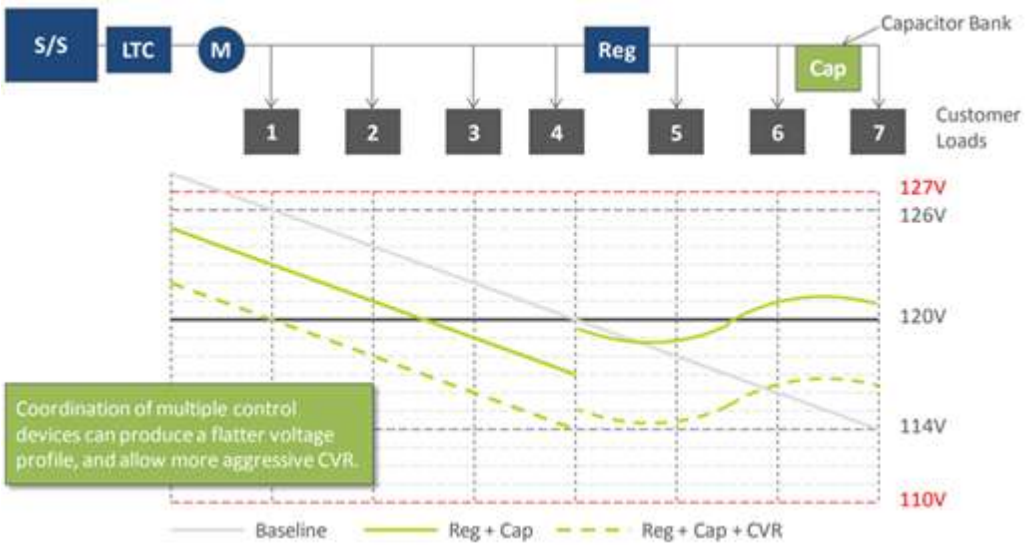
This concept is illustrated in the image below.[94] Without regulation, circuit voltage levels drop as the distance from the substation increases. If the regulator in this example were placed downstream from its current location, the voltage setpoint at the Load Tap Controller (LTC) in the substation would need to be correspondingly raised to avoid an under-voltage violation near Customer Loads 4 and 5. The effect of raising the voltage setpoint at the LTC to compensate for the suboptimal placement of the voltage regulator would be to raise the average delivery voltage for Customers 1-4, thereby reducing the energy and peak demand savings achievable for these customers through VVO.[95]

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94 U.S. Department of Energy's, Application of Automated Controls for Voltage and Reactive Power Management (Dec. 2012), p. 7, available at: <https://www.energy.gov/sites/prod/files/Voltage%26ReactivePower_Dec2012Final.pdf > (Accessed 12/3/2025).

95 PG&E's response to Data Request CalAdvocates_279-Q005, dated 12/10/25 in Appendix A, at the end of this exhibit.

FIGURE 22-2
ILLUSTRATION OF OPTIMAL PLACEMENT OF VOLTAGE REGULATING DEVICES



PG&E also disagrees that existing CYME tools used for determining placements of capacitors and voltage regulators can provide the necessary data for VVO.[96] These tools utilize offline load flow studies providing static snapshots of system conditions that fall short of capturing the dynamic real-time and time-sensitive nature of voltage and reactive power behavior across varying operational scenarios. This limitation compromises accuracy and hinders responsiveness in system planning and operations.

By contrast, in using ADMS LFSE data as its foundation, the Engineering Analysis application builds upon a rich historical dataset enabling temporal and spatial analysis of voltage and reactive power trends. This LFSE-based analysis allows grid operations and engineers to pinpoint areas of reactive power imbalance, voltage instability, or congestion with greater accuracy and timeliness, leading to improved decisions about placement of voltage regulating devices.[97]

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96 CYME is a software used by PG&E for distribution planning analysis. It does not integrate with ADMS.

97 PG&E's response to Data Request CalAdvocates_091-Q002h, dated 8/29/25 in Appendix A, at the end of this exhibit.

d. Engineering Analysis Approval Should Not Depend on Having Quantified Incremental Benefits Attributable to the Tool

1) Cal Advocates Argument

Cal Advocates also argues that funding for the Engineering Analysis application should be denied because PG&E did not attempt to estimate the incremental VVO energy savings that would result directly from the Engineering Analysis application.[98]

2) PG&E Response

Regarding the lack of quantified benefits provided in support of the Engineering Analysis application, PG&E's response is similar to the discussion already provided for the LFSE and Load Forecasting applications. These points are summarized below:

- Quantifying the incremental benefits of relocating a voltage regulator or capacitor requires detailed site-specific analysis and no reasonable method exists to extrapolate an inherently local analysis to the full system. Quantifying avoided voltage regulator or capacitor relocations from new insight provided to the VVO bank selection process is a similarly unquantifiable question prior to the detailed bank-level analyses that will occur during this process.[99]
- PG&E will provide a quantified benefits forecast where a reasonable method of quantifying benefits exists, as it did for VVO and FSDT, but will not when the analysis would be too theoretical and assumptions-driven to be useful in evaluating the proposal.

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98 CA-07, p. 34, lines 17-23.

99 PG&E's response to Data Request CalAdvocates_279-Q001a, dated 12/10/25 in Appendix A, at the end of this exhibit.

- That certain benefits from ADMS like those related to Engineering Analysis are unquantifiable is a long-held position by PG&E spanning multiple rate case cycles.[100]
- Cal Advocates does not dispute that these benefits are unquantifiable or offer a proposal for how to quantify them.
- Having already made a significant foundational investment in ADMS, it would be a mistake to restrict comparatively small investments in the individual LFSE-based applications that will unlock some of the highest value use-cases of ADMS.

Qualitative descriptions of the Engineering Analysis application's benefits stand on their own as justification for the investment. These include, but are not limited to:

- Optimal voltage regulator or capacitor placements enabling deeper energy savings in the VVO Program through reduced average circuit voltage levels.
- Optimal voltage regulator or capacitor placements enabling reduced line losses and increased system capacity through improved reactive power management.
- Avoided costs in the VVO Program through helping steer bank selection toward banks with higher percentages of voltage regulators or capacitors that are already optimally placed.

5. Protection Analysis

a. PG&E Request

Protection Analysis is a suite of ADMS-based applications that will transform PG&E's system protection capabilities by enabling on-demand protection coordination analysis built from LFSE modeled power flows and the as-switched state of the network. Transitioning PG&E's coordination studies from an offline analysis built on non-real time, planned conditions into the live environment of ADMS will bring benefits

[100] A.18-12-009, HE-20: Exhibit (PG&E-18), pp. 19-15, line 25 to pp. 19-16, line 25; A.21-06-021, Exhibit (PG&E-17), pp. 21-13, lines 19-22.

related to safety, fire risk, reliability and operational efficiency.[101] PG&E proposes enabling Protection Analysis on the 250 LFSE circuits in this GRC cycle. PG&E's TY 2027 capital forecast for Engineering Analysis is $2.660 million and its capital forecast for the full 2027-2030 GRC period is $11.068 million.[102]

b. Cal Advocates Position

Cal Advocates recommends full disallowance of PG&E's Protection Analysis forecast of $2.660 million in TY 2027 and full disallowance of PG&E's Engineering Analysis forecast in all other years.[103] PG&E responds to the arguments Cal Advocates uses to arrive at this conclusion in the sections below.

c. The Protection Analysis Application Is Justified Based on a Qualitative Description of Its Benefits

1) Cal Advocates Argument

Cal Advocates argues that funding for the Protection Analysis application should be denied because PG&E has not quantified the need for or benefit of the application.[104] Cal Advocates states that PG&E is unable to quantify the number of outages or equipment failures that would be avoided by the tool or predict exactly which outages or equipment failures the tool would prevent.[105]

2) PG&E Response

Cal Advocates does not offer a substantive critique of the Protection Analysis application's merits but does criticize the lack of quantified benefits provided in support of the application.

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101 PG&E's response to Data Request CalAdvocates_091-Q002j, dated 8/29/25 in Appendix A, at the end of this exhibit.

102 Exhibit (PG&E-4), WP 223-23, Table 22-13, line 12. The share of the Advanced Application Enablement forecast attributable to Protection Analysis can be calculated by multiplying the full program forecast by 15.7 percent.

103 CA-07, p. 35, line 25 to p. 33, line 3.

104 CA-07, p. 37, lines 16-19.

105 CA-07, p. 36, line 21 to p. 37, line 14.

Cal Advocates' argument is centered on PG&E's inability to produce a comprehensive historical dataset of outages that would have been prevented by this tool, but it is not a reasonable expectation that PG&E should be able to produce this data. Outages caused by protective device miscoordination can only be identified through manual investigation of the circumstances surrounding an outage by a system operator or engineer. Confirming that an outage was caused by protective device miscoordination is a complex determination that involves analysis of the as-switched grid topology at the time of the fault, the settings on protective devices at the time of the fault, the timing of device operations, the location of the fault, the fault current provided by the fault, among other factors. It would not be possible to conduct this level of analysis on every outage on PG&E's system in an effort to maintain a comprehensive dataset of outages caused by protective device miscoordination.[106]

Even if PG&E were able to provide a comprehensive dataset of all outages caused by protection miscoordination, any attempt to predict which historic outages would have been prevented by the application would be highly speculative and assumptions based.[107]

In general, PG&E's response regarding the lack of quantified benefits provided in support of the Protection Analysis application is similar to the discussion already provided for the LFSE, Load Forecasting, and Engineering Analysis applications. These points are summarized below:

- There is no reasonable method of forecasting benefits from Protection Analysis and a qualitative description of the

[106] PG&E's response to Data Request CalAdvocates_216-Q003e, dated 11/13/25 in Appendix A, at the end of this exhibit.

[107] PG&E's response to Data Request CalAdvocates_216-Q003g, dated 11/13/25 in Appendix A, at the end of this exhibit.

application's benefits stands on its own as justification for the investment.[108]

- PG&E will provide a quantified benefits forecast where a reasonable method of quantifying benefits exists, as it did for VVO and FSDT, but will not when the analysis would be too theoretical and assumptions-driven to be useful in evaluating the proposal.
- That certain benefits from ADMS like those related to Protection Analysis are unquantifiable is a long-held position by PG&E spanning multiple rate case cycles.[109]
- Cal Advocates does not dispute that these benefits are unquantifiable or offer a proposal for how to quantify them.
- Having already made a significant foundational investment in ADMS, it would be a mistake to restrict comparatively small investments in the individual LFSE-based applications that will unlock some of the highest value use-cases of ADMS.

The benefits justifying the Protection Analysis investment include, but are not limited to:

- Enhanced safety and fire risk mitigation through real-time visibility into miscoordination issues or protection gaps that can potentially cause ignition events.
- Improved reliability through proactive identification of protection vulnerabilities that can cause unnecessary outages.
- Improved operational efficiency through on-demand protection analysis directly within the ADMS interface in place of less time-efficient offline study methods.
- Avoidance of costs associated with equipment damage through early and timely identification of protection issues.

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108 PG&E's response to Data Request CalAdvocates_216-Q003g, dated 11/13/25 in Appendix A, at the end of this exhibit.

109 A.18-12-009, HE-20: Exhibit (PG&E-18), p. 19-15, line 25 to p. 19-16, line 25; A.21-06-021, Exhibit (PG&E-17), p. 21-13, lines 19-22.

- Brings PG&E closer to its ultimate vision of fully automated, closed-loop system protection where device settings adapt autonomously to grid conditions in real time.[110]

6. Field Switching Digital Transformation

a. PG&E Request

The FSDT project will extend the visibility and functionality of ADMS to field personnel through deployment of the ADMS Field Client application to tablet devices carried by PG&E crews.[111] Currently, PG&E field crews must rely on verbal and written communication with control center operators to understand the real-time as-switched state of the distribution grid, to receive and document switching instructions, and to confirm and document completion of the switching plan. The FSDT project will provide field crews with self-service visibility into the real-time ADMS as-switched network map and will digitize the field switching workflow, bringing improved PG&E outage response times, enhanced worker productivity, better field crew situational awareness and troubleshooting capability, and reduced risk of procedural error through verbal miscommunication.[112] PG&E's TY 2027 capital forecast for FSDT is $8.762 million and its capital forecast for the full 2027-2030 GRC period is $34.114 million.[113]

b. Cal Advocates Position

Cal Advocates recommends full disallowance of PG&E's forecast of $8.762 million in TY 2027 for FSDT and full disallowance of PG&E's FSDT forecast in all other years.[114] PG&E responds to the arguments Cal Advocates uses to reach this conclusion in the sections below.

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[110] PG&E's response to Data Request CalAdvocates_091-Q002j, dated 8/29/25 in Appendix A, at the end of this exhibit.

[111] Exhibit (PG&E-4), WP 22-40.

[112] Exhibit (PG&E-4), WP 22-40 to WP 22-41.

[113] Exhibit (PG&E-4), WP 22-23, Table 22-13, line 13.

[114] CA-07, p. 38, lines 9-13.

c. PG&E's FSDT Cost-Benefit Analysis Methodology Is Reasonable

1) Cal Advocates Argument

Cal Advocates argues that PG&E's cost-benefit analysis is unreliable because it uses subject matter expert judgement for some inputs and because it is not informed by a benchmarking analysis of benefits accrued at other utilities who have implemented the product.[115]

2) PG&E Response

PG&E's FSDT cost-benefit analysis quantified benefits from thirteen distinct value streams that will result from the project.[116] PG&E's methodology for quantifying the benefits of each value stream was to estimate how the FSDT project would save time relative to PG&E's existing business processes in a manner translating into improved customer reliability or PG&E workforce productivity.[117] Certain underlying assumptions in PG&E's analysis used input from distribution operators, field crews, and field operations managers who participate directly in the business processes PG&E is seeking to improve,[118] which is a reasonable approach when intimate knowledge of those processes is required to produce an estimate of the time savings from a process improvement or of the percentage of outages a process improvement would apply to.

Cal Advocates argues that instead of relying on an analysis of its own business processes informed by the experience of expert participants in those processes, PG&E's cost-benefit analysis should have been based on a benchmarking analysis of the benefits accrued at other utilities such as Arizona Public Service and Austin

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[115] CA-07, p. 39, line 8 to p. 40, line 4.

[116] PG&E's response to Data Request CalAdvocates_091-Q004, dated 8/29/25 and attachment CalAdvocates_091-Q004Atch02 in Appendix A, at the end of this exhibit.

[117] PG&E's response to Data Request CalAdvocates_091-Q004, dated 8/29/25 and attachment CalAdvocates_091-Q004Atch03 in Appendix A, at the end of this exhibit.

[118] These distribution operators and field crews are the "subject matter experts" cited in PG&E's analysis.

Energy that have implemented the same ADMS Field Client product that PG&E is proposing. However, benchmarking is not an appropriate benefits measurement methodology for a technology whose value derives from the highly specific context of PG&E business practices. An analysis of benefits from the implementation of the technology at another utility would not be generalizable to the context of PG&E where the preexisting baseline business practices related to operator-field communication or the documentation of field switching steps, to take two examples, may be fundamentally different from what currently exists at PG&E.

Regardless, the benefits data from other utilities that Cal Advocates claims PG&E's analysis should be based on does not exist. Other utilities who have implemented the product have not conducted retrospective quantitative analyses of the benefits realized from their implementations.

d. Cal Advocates' Analysis Demonstrating Likely Negative Net Benefits from FSDT Is Flawed

1) Cal Advocates Argument

Cal Advocates argues that negative net benefits from FSDT are likely because PG&E's forecasted 1.07 benefit-cost ratio leaves little margin for error, while also claiming that PG&E should not have included avoided apprentice wages in its analysis, which if omitted would narrow the margin of cost-effectiveness even further.[119]

Cal Advocates also argues that FSDT operational efficiency gains offer no guarantee of ratepayer benefit and that if these benefits are excluded from the analysis the benefit-cost ratio for the project would be negative.[120]

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[119] CA-07, p. 40, lines 8-23.

[120] CA-07, p. 39, line 8 to p. 40, line 4.

2) PG&E Response

a) PG&E's FSDT Cost-Benefit Analysis Used Several Conservative Assumptions

Cal Advocates' characterization of PG&E's FSDT cost-benefit analysis as "optimistic" and its observation that PG&E's projected 1.07 benefit-cost ratio leaves little margin for error ignores four conservative assumptions used in PG&E's analysis that make a scenario where benefits exceed PG&E's forecast much likelier than Cal Advocates' scenario, which arbitrarily discounted PG&E's benefits analysis by the 7 percent amount required to make the project's benefit-cost ratio show as negative.[121]

The four conservative assumptions used in PG&E's FSDT cost-benefit analysis were:

- Most significantly, PG&E's analysis claimed zero reliability benefits from non-residential customers,[122] which PG&E chose to exclude due to concern that the Interruption Cost Estimator (ICE) calculator[123] may overstate these benefits. Holding all other assumptions equal, if the ICE calculator's non-residential reliability benefit estimate were included in PG&E's analysis, the FSDT benefit-cost ratio would increase nearly 4x, from 1.07 to 4.04.[124] Regardless, considering the especially high cost of electric service interruptions for businesses, the reliability value from FSDT

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[121] CA-07, p. 40, lines 9-13.

[122] PG&E noted the omission of these non-residential reliability benefits in multiple places including PG&E's response to Data Request CalAdvocates_091-Q004d, dated 8/29/25 in Appendix A, at the end of this exhibit, and p. 13 of attachment CalAdvocates_091-Q004Atch02 in Appendix A, at the end of this exhibit.

[123] The ICE calculator is a resource developed jointly by the U.S. DOE and Lawrence Berkeley National Laboratory to help utilities estimate the economic costs associated with power interruptions. Additional information may be found on the ICE calculator website, available at: <https://icecalculator.com/> (accessed Mar. 19, 2026).

[124] Refer to attachment E of this chapter, specifically the Reliability Benefits Scenario toggle in cell F26 of the "Updated Benefits Financials" tab and resulting benefit-cost ratio in cell D34.

for these customers is undoubtedly higher than zero, making this a highly conservative assumption in PG&E's original analysis.

- PG&E's analysis used a 10.05 percent discount rate instead of the 7.8 percent rate Cal Advocates claims should have been used for the VVO benefits analysis[125] or the 7.27 percent rate that aligns with the discount rate in the approved version of the E3 Avoided Cost Calculator.[126] Holding all other assumptions equal, if PG&E's analysis had used a 7.27 percent discount rate, the FSDT benefit-cost ratio would increase from 1.07 to 1.19.[127]
- PG&E's analysis assumed benefits would not fully materialize until 2031, more than one year after PG&E's anticipated project go-live date in 2029. Holding all other assumptions equal, if PG&E's analysis had assumed benefits would fully materialize in the first year after project go-live, the FSDT benefit-cost ratio would increase from 1.07 to 1.10.[128]
- PG&E's analysis did not attempt to quantify several other benefits of the project, including those associated with avoided work procedure errors and improved troubleshooting capability through enablement of field-based meter pings and device tracing analysis.[129]

In a scenario where all three conservative assumptions used in PG&E's analysis are reversed (the ICE calculator's

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125 CA-07, p. 10, lines 14-16.

126 2024 E3 Avoided Cost Calculator, available at: <https://www.cpuc.ca.gov/dercosteffectiveness> (accessed Mar. 19, 2026). Refer to cell C4 of the "IRP Inputs" tab.

127 Refer to attachment E of this chapter, specifically the Discount Rate Assumption toggle in cell C26 of the "Updated Benefits Financials" tab and resulting benefit-cost ratio in cell D34.

128 Refer to attachment E of this chapter, specifically the 2030 Benefits Realization Percentage toggle in cell K2 of the "Updated Benefits Financials" tab and resulting benefit-cost ratio in cell D34.

129 Exhibit (PG&E-4), WP 22-41 to WP 22-42.

non-residential reliability benefits are included, a 7.27 percent benefits discount rate is used, and project benefits begin in 2030), the project benefit-cost ratio would increase from 1.07 to 4.58.

b) Avoided Training Costs Are Small, But Real Benefit of FSDT

PG&E's claim of reduced training costs through the simpler business processes enabled by FSDT was the only one of PG&E's thirteen FSDT benefit streams that Cal Advocates took specific methodological issue with. PG&E disagrees with Cal Advocates' argument that apprentice wages should not be treated as an avoided cost because PG&E believes there is measurable value in shortening apprenticeship durations or reallocating training time to other tasks.[130] Regardless, PG&E's claim of avoided training costs from FSDT constitutes only 1 percent of total program benefits and removing these benefits from the analysis has a near-negligible impact on the program's benefit-cost ratio, reducing it from 1.07 to 1.06.[131]

c) Customers Benefit from PG&E Workforce Productivity Improvements

Finally, PG&E disagrees with Cal Advocates' argument that operational efficiency benefits from FSDT should not be counted as a customer benefit unless PG&E has committed to a specific mechanism through which these efficiency gains will be realized as a benefit by customers. PG&E contends that any workforce productivity gain is, by definition, a customer benefit because it will allow PG&E to either reduce its workforce or redeploy its existing resources to other value-added activities.[132]

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[130] PG&E's response to Data Request CalAdvocates_091-Q004d, dated 8/29/25 in Appendix A, at the end of this exhibit.

[131] CA-07, p. 40, lines 20-22.

[132] PG&E's response to Data Request CalAdvocates_152-Q006a, dated 10/14/25 in Appendix A, at the end of this exhibit.

Cal Advocates' expectation that PG&E should be able to identify the specific way in which these FSDT operational efficiency gains will be passed to customers five years in advance of their full realization in 2031 and beyond the time horizon of this GRC cycle, is not realistic.

Even if the project's operational efficiency benefits were completely removed from the analysis, the project benefit-cost ratio would be 3.06 in a scenario where non-residential reliability benefits are included.[133]

e. PG&E Has Demonstrated the Need for FSDT

1) Cal Advocates Argument

Cal Advocates claims that PG&E has not demonstrated a need for the FSDT Program because it was unable to produce a comprehensive list of work procedure errors that would have been avoided through use of FSDT technology.[134]

2) PG&E Response

PG&E disagrees because its quantitative justification for the FSDT project was not based on the avoidance of work procedure errors caused by miscommunication, human error, or maps not reflecting real-time conditions. While the reduced risk of these errors is an important ancillary benefit of the FSDT project, PG&E did not attempt to quantitatively value this benefit because there is no reasonable method of doing so. As PG&E's FSDT cost-benefit analysis shows, the project is primarily justified by efficiency improvements in the field switching process leading to faster outage response times and enhanced workforce productivity.[135]

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[133] Refer to attachment E of this chapter, specifically the Operational Efficiency Scenario toggle in cell L26 of the "Updated Benefits Financials" tab and resulting benefit-cost ratio in cell D34.

[134] CA-07, p. 41, lines 12-20.

[135] PG&E's response to Data Request CalAdvocates_091-Q004, dated 8/29/25 and attachments CalAdvocates_091-Q004Atch02 and CalAdvocates_091-Q004Atch03 in Appendix A, at the end of this exhibit.

A lack of support for an ancillary project benefit not included in the project cost-benefit analysis is not a reasonable justification for denying the entire request, as Cal Advocates claims[136]–but setting this aside, Cal Advocates' expectation that PG&E should have been able to produce a comprehensive list of work procedure errors that would have been avoided through use of FSDT technology is also not realistic. PG&E's outage database does not have a mechanism of tracking outages caused by the highly specific scenarios sought by Cal Advocates.[137] Through a manual search of its data PG&E did provide Cal Advocates with ten examples of errors it believes may have been avoidable through FSDT technology,[138] but any attempt to predict with certainty which of these examples would have been prevented by future technology would be speculative. This difficulty in obtaining a dataset of work procedure errors avoidable through use of FSDT technology illustrates why PG&E elected not to include this benefit stream in its quantitative cost-benefit analysis, and instead chose to support its claim through a qualitative description of how FSDT will help avoid work procedure errors, which includes:[139]

- A structured and guided workflow for executing switching plans with required acknowledgements of completing each step before proceeding to the next, ensuring that crews follow a pre-defined sequence of steps.
- Alarms and automated validations that provide further guardrails against skipped steps, actions performed out of sequence or attempts to make unauthorized actions.

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136 CA-07, p. 41, lines 21-23.

137 PG&E's response to Data Request CalAdvocates_152-Q002a, dated 10/14/25 in Appendix A, at the end of this exhibit.

138 PG&E's response to Data Request CalAdvocates_091-Q004b, dated 8/29/25 in Appendix A, at the end of this exhibit.

139 PG&E's response to Data Request CalAdvocates_152-Q002g, dated 10/14/25 in Appendix A, at the end of this exhibit.

7. Conclusion

For the reasons discussed above, PG&E recommends that its recorded and forecast capital expenditures for Advanced Distribution Applications in Table 22-5 be adopted.

E. Distributed Energy Resource Management System (MWC HG/MAT HG#, MWC 63/MAT 63#) [Witness: Alex Portilla]

A DERMS provides capabilities to manage DERs at scale on the distribution grid.[140] PG&E's DERMS currently supports customer-owned telemetry compliance obligations for Rule 21 and CPUC Resolution Res.E-5038,[141] operationalization of the Distribution Deferral Investment Framework (DIDF) contracts, and the enablement of operational flexibility and faster energization for DER customers via PG&E's Flex Connect program. New investments in DERMS will continue to support the growth of these existing programs while providing the ability to scale and integrate with emerging use cases like Vehicle-Grid Integration (VGI), aggregations of DERs (e.g., into Virtual Power Plants (VPP)), provisioning of grid services, and the orchestration of DERs across multiple variables.[142]

Cal Advocates recommends $15.837 million in capital funding for TY 2027 which is $2.795 million lower than PG&E's TY 2027 capital forecast of $18.632 million.[143] In addition, Cal Advocates suggests the removal of capital expenditures in TY 2025 for a 5-year DERMS license and to reclassify DERMS licensing and subscription costs as expenses.[144]

PG&E disputes all of Cal Advocates' proposed funding reductions and reclassifications for the DERMS Program. In the sections that follow, PG&E will address the capital recommendations raised by Cal Advocates regarding the DERMS scope.

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[140] Exhibit (PG&E-4), WP 22-16.

[141] Res.E-5038 (Aug. 19, 2021).

[142] Exhibit (PG&E-4), WP 22-19.

[143] CA-07, p. 3, Table 07-1.

[144] CA-07, p. 44, lines 10-20.

1. DERMS Software License Capitalization

a. PG&E's Request

PG&E proposes that the DERMS software license continue to be treated as a capital investment per PG&E's capitalization criteria, which is in alignment with Generally-Accepted Accounting Principles (GAAP) and Federal Energy Regulatory Commission (FERC) accounting standards.

b. Cal Advocates' Position

Cal Advocates recommends reducing PG&E's proposed DERMS licensing capital expenditures to $0 for 2025, 2026, and 2027, and that PG&E's $8.30 million capital expenditure in 2025 for a 5-year DERMS license should be removed as a capital addition.[145] Cal Advocates opposes capitalization on the grounds that it believes capitalization of multi-year software licenses increases ratepayer costs over time, and calculates that treating the DERMS license as capital totals ~$10.43 million vs ~$9.99 million if treated as expense.[146] While Cal Advocates was not explicit in their testimony for the corresponding recommended expense cost change, PG&E believes the updated expense forecast additions required are shown in Table 22-3 below.

[145] CA-07, p. 44, lines 10-20.

[146] CA-07, p. 44 lines 3-7.

TABLE 22-3
ACCOUNTING CHANGE AFFECTING EXHIBIT (PG&E-4), CHAPTER 22
2025 - 2029 EXPENSE FORECAST – PARTIES RECOMMENDATION
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Accounting Adjustment	MWC	Financial Implications of Cal Advocates' Recommendations – Increases/(Reductions)[a, b, c] 2025	2026	2027	2028	2029
1	Implied DERMS Accounting Adjustment - Expense	HG#	$1,783	$1,872	$1,966	$2,064	$2,167

(a) Where parties did not quantify the financial impacts of their recommendations, PG&E extrapolated the impact based on values provided by PG&E in response to Data Request Cal Advocates_227-Q001,(*) and shows the extrapolated recommendation with italicized text.

(b) Values may include rounding differences.

(c) CA-07, p. 42, Table 07-13. Cal Advocates did not have recommended adjustments to PG&E's forecast. As indicated in note (a), the amount shown is extrapolated in a manner consistent with Cal Advocate's recommendations in CA-07, p. 44 Lines 10-20.

(*) PG&E's response to Data Request CalAdvocates_227 Q001, dated 11/19/25 in Appendix A, at the end of this exhibit.

c. PG&E Response

1) Capitalization of DERMS Licensing Costs Is Consistent with Accounting Principles

PG&E disputes Cal Advocate's recommendation to remove the $8.3M DERMS 5-year license from the 2025 capital forecast. This expenditure meets PG&E's capitalization criteria, which is in alignment with GAAP (ASC 350-40 Intangibles–Goodwill and Other – Internal-Use Software) and FERC Accounting standards.[147]

2) Cal Advocates' Calculations on Ratepayer Impacts Are Incorrect

PG&E disagrees with Cal Advocate's claim that treating the 5-year license as a capital expenditure increases the overall revenue requirement. First, PG&E does not calculate revenue requirements on a per-program or per-asset basis, as stated in response to Cal Advocates.[148] Second, Cal Advocates overstates

[147] PG&E's response to Data Request CalAdvocates_073-Q003a, dated 8/20/25 in Appendix A, at the end of this exhibit.

[148] PG&E's response to Data Request CalAdvocates_137-Q001c, dated 10/6/25 in Appendix A, at the end of this exhibit.

the rate base by, for instance, excluding the impact of accumulated deferred income tax and existing net operating loss carryforwards and repeatedly including the depreciated value in the rate base in subsequent years, even though the asset was put into production in Year 1. In this way, PG&E believes Cal Advocates' calculation is overstating the estimated revenue requirement of the asset.

Third, PG&E disagrees with Cal Advocates' decision to exclude from its savings calculation the additional $0.50 million in capital that PG&E saved ratepayers by negotiating a multi-year agreement as described to Cal Advocates in response to GRC-2027-Ph1_DR_CalAdvocates_137-Q001. While this discount was applied to the Implementation Services contract for DERMS, it still amounted to a savings for ratepayers made possible through PG&E's negotiation of a multi-year licensing contract that would not have been possible if PG&E were to follow Cal Advocates' recommendations to expense licensing via annual contracts. Even using Cal Advocates' own projection of $10.43 million, which PG&E previously explained was erroneously high, shows that a simple subtraction of $0.5 million yields $9.93 million. That amount is still less than the $9.99 million in expense that Cal Advocates recommends. Additionally, securing a 5-year term license eliminates annual escalation which is typically 5 percent.[149]

d. Conclusion

PG&E maintains that the 2025 capital expenditure for a 5-year DERMS software license should not be retroactively converted to expense, as it not only meets PG&E's capitalization criteria, which is in alignment with GAAP and FERC Accounting standards, but also yields savings to the overall DERMS Program cost for ratepayers.

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149 PG&E's response to Data Request CalAdvocates_137-Q001, dated 10/6/25 and attachment CalAdvocates_137-Q001Atch01CONF in Appendix A, at the end of this exhibit.

2. Scale of DERMS Deployment

a. PG&E's Request

PG&E proposes that the full requested DERMS capital funding amount be approved in order to support existing DERMS programs that provide value to customers, to scale DERMS to meet emerging use cases, and to maintain regulatory compliance.

b. Cal Advocates' Position

Cal Advocates recommends PG&E should reduce DERMS capital expenditures by 15 percent[150] claiming the magnitude and pace of DERMS expansion tied to VGI/VPPs are speculative and unproven.[151] Cal Advocates also asserts that this reduction is warranted because PG&E prioritizes customer-centric benefits rather than system cost reductions[152] and because PG&E does not show commensurate, quantifiable saving to ratepayers in this cycle.[153] PG&E responds to the arguments Cal Advocates' uses to reach this conclusion in the sections below.

c. PG&E's Response

Cal Advocates' proposed 15 percent reduction to the forecast is not warranted for the following reasons:

1) Initial Investment in VGI and VPPs Is Required to Realize Their Potential

DERMS and associated programs are a rapidly evolving and nascent area that requires PG&E to be agile in responding to the changing technology and environment. PG&E's DERMS investment plan is a prudent and flexible approach in the face of uncertainty of how the industry and technology landscape will progress. PG&E has been a leader in the space, and a model for innovation of new programs like Flex Connect. PG&E's real-world experience

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[150] CA-07, p. 50 line 27.

[151] CA-07, p. 48, line 10 to p. 50, line 1.

[152] CA-07, p. 46, lines 14-17.

[153] CA-07, p. 46, lines 10-11.

implementing these DERMS programs has shown the need for flexibility to manage changing customer needs and adoption, varying vendor abilities, new technologies, and evolving programs. Through this experience, PG&E finds Cal Advocates' assertion that PG&E should have already pre-scoped expanded geographies or implementations of continuously evolving programs,[154] to not be grounded in the reality of deploying new technology and programs. Similarly, while Cal Advocates states they support cost-effective VGI and VPP programs,[155] it should be recognized that initial investment is still needed to implement, test, study, and realize the value of emergent programs and technology. Reductions to the DERMS forecast are not merited if PG&E is to invest in VGI and VPP potential.

2) PG&E's DERMs Solution Provides System Benefits and Customer Benefits

Cal Advocates assertion that PG&E's DERM's deployment is overly customer-centric is flawed. Cal Advocates' own Distribution Grid Electrification Model 2025 Study and Report states that:

> …mass shifting of peak EV load to beneficial times could save between $5 billion and $18 billion dollars in distribution grid costs by 2040.[156]

PG&E agrees that there are long-term benefits and the potential for significant savings through better DER orchestration, such as Electric Vehicle (EV) optimized charging. PG&E's own Electrification Impacts Study (EIS) Part 2 Report also estimated that under the Enhanced Demand Flexibility Scenario, distribution infrastructure (primary and secondary) costs could be reduced by approximately $1.8 billion through 2040, if orchestrated, and that

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154 CA-07, p. 46, lines 3-4.

155 CA-07, p. 50, lines 11-13.

156 Distribution Grid Electrification Model 2025 Study and Report, Cal Advocates, (Oct. 2025), p. 83, available at: <251030-public-advocates-office-distribution-grid-electrification-model-2025.pdf> (accessed Mar. 19, 2026).

summer system peak loads could be reduced by ~2.8 gigawatts in 2040.[157] The Demand Flexibility modeled in the EIS Part 2 assumes technical investments are implemented, such as DERMS, as well as policy drivers such as dynamic rates and customer programs.[158]

PG&E's Flex Connect program is also a clear example of PG&E leading the industry in this space to both manage EV and DER load, bringing customers speed to power, and better utilizing existing assets with over 3 gigawatt-hours of incremental load served as of November 1, 2025.[159]

3) DERMS Is Justified Even as Value Quantification Evolves

In order to avoid premature or unnecessary investments, PG&E is implementing DERMS in a judicious manner by deploying DERMS in selective geographic areas of the grid where DERMS delivers value. This strategy controls costs while also building out and validating foundational functionality incrementally.[160] Since PG&E is still in the early stages of DERMS development, validating functionality at a smaller scale is prudent prior to full system wide deployment.[161]

PG&E does not currently believe there is a reasonable or comprehensive method to quantify clear cost-benefit calculations, as Cal Advocates requests, that is not overly theoretical.[162]

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[157] PG&E's (U 39 E) EIS Part 2 Report, PG&E, (Jan. 28, 2026), available at: <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=861520> (accessed Mar. 19, 2026).

[158] PG&E's (U 39 E) EIS Part 2 Report, PG&E, (Jan. 28, 2026), available at: <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=861520> (accessed Mar. 19, 2026).

[159] PG&E's response to Data Request CalAdvocates_205-Q001, dated 11/10/25 in Appendix A, at the end of this exhibit.

[160] PG&E's response to Data Request CalAdvocates_205-Q001, dated 11/10/25 in Appendix A, at the end of this exhibit.

[161] PG&E's response to Data Request CalAdvocates_205-Q001, dated 11/10/25 in Appendix A, at the end of this exhibit.

[162] PG&E's response to Data Request CalAdvocates_074-Q002, dated 8/20/25 in Appendix A, at the end of this exhibit.

Cal Advocates' own $5 to $18 billion dollar estimates demonstrate how difficult it is to have a defined benefit value in this area without a $13 billion range.[163] PG&E's explanations of program need, analysis of alternatives, detailed cost estimates, and qualitative descriptions of program benefits stand as justification for the investment.[164]

d. Conclusion

PG&E proposes a judicious approach to DERMS implementation that balances the need to prudently scale existing programs and operational benefits while investing in new capabilities like VGI and VPPs that are beneficial to customers and the grid. Cal Advocates' proposed reduction should be rejected.

3. Conclusion

Based on the arguments set forth above, PG&E recommends that its recorded and forecast capital expenditures for DERMS in Table 22-5 be adopted.

F. Conclusion

For the reasons discussed above, PG&E recommends that its 2027 expense forecast in Tables 22-4 and its 2027-2030 capital expenditures forecast in Table 22-5 be adopted.

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[163] Distribution Grid Electrification Model 2025 Study and Report, Cal Advocates, (Oct. 2025), available at: <251030-public-advocates-office-distribution-grid-electrification-model-2025.pdf> (accessed Mar. 19, 2026).

[164] PG&E's response to Data Request CalAdvocates_074-Q002, dated 8/20/25 in Appendix A, at the end of this exhibit.

TABLE 22-4
2027 ADJUSTED EXPENSE FORECAST – PG&E (ALL PROGRAMS)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MAT or MWC	Filed Forecast[a]	Errata or Forecast Adjustments[b]	PG&E Rebuttal Position[c]
1	CMEP and High DER-Driven Planning Tools	AB	$3,413	–	$3,413
2	Grid Research Innovation and Development Operations	CY	4,000	–	4,000
3	Distribution Operations Technology	HG	5,684	–	5,684
4	Distribution Deferral Non-Procurement Costs	IG	556	–	556
6	IGP IT Infrastructure and Non-High DER-Driven Planning Tools	JV	–	–	–
7	Total[d]		$13,653	–	$13,653

(a) Reflects PG&E forecast as filed on May 15, 2025, and as updated in PG&E's November 10, 2025, errata filing.

(b) Reflects PG&E forecast updates since the November 10, 2025, errata filing.

(c) Reflects PG&E forecast position as of March 31, 2026.

(d) Totals may include rounding differences.

TABLE 22-5
2027-2030 ADJUSTED CAPITAL FORECAST – PG&E (ALL PROGRAMS)
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program or MWC Description	MAT or MWC	Filed Forecast[a]				Errata or Forecast Adjustments[b]				PG&E Rebuttal Position[c]			
			2027	2028	2029	2030	2027	2028	2029	2030	2027	2028	2029	2030
1	ADMS	63	–	–	–	–	–	–	–	–	–	–	–	–
2	Advanced Distribution Applications													
3	Volt Var Optimization	63	$3,983	$17,667	$20,765	$37,768	–	–	–	–	$3,983	$17,667	$20,765	$37,768
4	LFSE	63	8,952	9,187	9,429	9,679	–	–	–	–	8,952	9,187	9,429	9,679
5	Load Forecasting	63	3,547	3,640	3,736	3,835	–	–	–	–	3,547	3,640	3,736	3,835
6	Engineering Analysis	63	1,773	1,820	1,868	1,917	–	–	–	–	1,773	1,820	1,868	1,917
7	Protection Analysis	63	2,660	2,730	2,802	2,876	–	–	–	–	2,660	2,730	2,802	2,876
8	FSDT	63	8,762	13,230	12,122	–	–	–	–	–	8,762	13,230	12,122	–
9	Data Enablement for ADMS	63	2,197	1,689	1,391	1,486	–	–	–	–	2,197	1,689	1,391	1,486
10	ADMS Hardware/Software Refresh	63	32,643	14,860	12,759	–	–	–	–	–	32,643	14,860	12,759	–
11	Advanced Distribution Applications Subtotal	63	$64,517	$64,823	$64,872	$57,561	–	–	–	–	$64,517	$64,823	$64,872	$57,561
12	DERMS Subtotal	63	$18,632	$10,770	$8,830	$21,665	–	–	–	–	$18,632	$10,770	$8,830	$21,665
13	MWC 63 Subtotal		$83,149	$75,592	$73,701	$79,225	–	–	–	–	$83,149	$75,592	$73,701	$79,225
14	IGP IT Infrastructure & Non-High DER-Driven Planning Tools	2F	4,532	4,532	4,532	4,532	–	–	–	–	4,532	4,532	4,532	4,532
15	High DER-Driven Planning Tools	21	5,378	5,429	5,371	5,376	–	–	–	–	5,378	5,429	5,371	5,376
16	Total[d]		$93,059	$85,553	$83,604	$89,133	–	–	–	–	$93,059	$85,553	$83,604	$89,133

(a) Reflects PG&E forecast as filed on May 15, 2025, and as updated in PG&E's November 10, 2025, errata filing.

(b) Reflects PG&E forecast updates since the November 10, 2025, errata filing.

(c) Reflects PG&E forecast position as of March 31, 2026.

(d) Totals may include rounding differences.

(PG&E-16)

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 22

ATTACHMENT A

VVO COST BENEFIT ANALYSIS

THIS NATIVE FILE CAN BE FOUND AS A STANDALONE DOCUMENT ON PG&E'S AZURE WEBSITE

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 22

ATTACHMENT B

SCADA ENABLED BANKS

Bank Name	Circuit Count	Count of SCADA Enabled Capacitors of Regulators	Count of Non-SCADA Enabled Capacitors of Regulators	Fully SCADA Enabled Indicator
BEN LOMOND_2	1	2	0	Y
CARRIZO PLAINS_1	1	2	0	Y
NEWBURG_1	2	4	0	Y
PINEDALE_1	3	15	0	Y
SWIFT_1	2	5	0	Y
TWISSELMAN_1	2	9	0	Y

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 22

ATTACHMENT C

PROJECT COST MANAGEMENT STANDARD

Project Cost Management Standard

SUMMARY

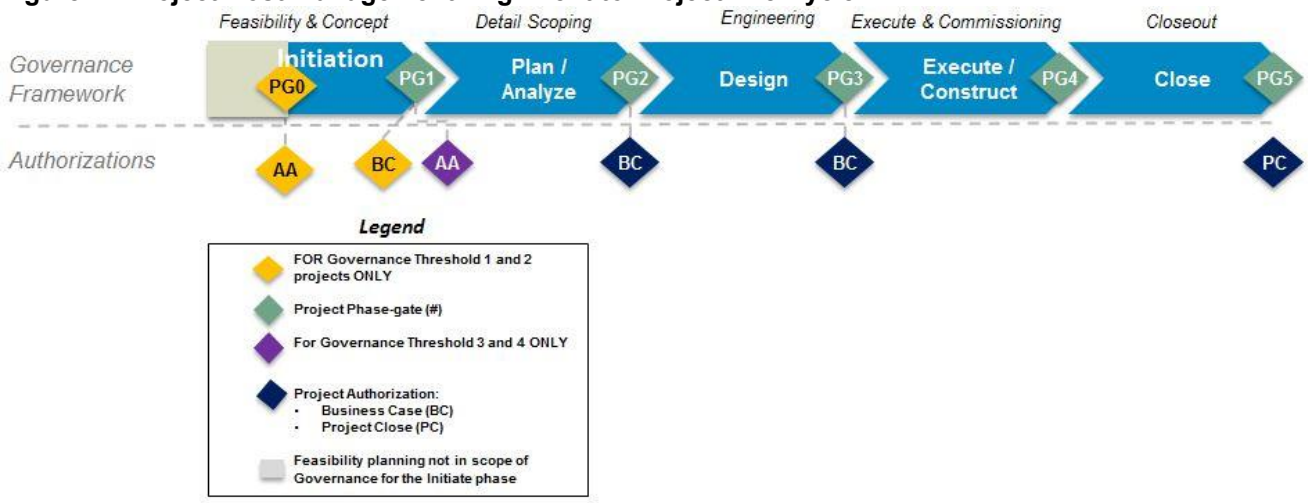
This Standard describes the requirements of Project Cost Management, which apply to all PG&E projects with an estimated Total Gross Project Cost of at least $1 million.

Projects with an estimated Total Gross Project Cost of less than $1 million are not subject to the requirements set out in this Standard. Lines of Business (LOBs) are responsible and have discretion for establishing cost management guidance for projects less than $1 million.

This Standard provides requirements and guidance on projects for Work Breakdown Structure (WBS), Project Cost Estimating, Project Cost Baseline, Risk Management, and Cost Control.

Project Cost Management aligns with the project life cycle from PM-1010S, "Project Management Governance Standard", and is illustrated in Figure 1 below, which is to be used as a reference in the interpretation of this Standard.

Figure 1 - Project Cost Management Alignment to Project Life Cycle



TARGET AUDIENCE

This Standard applies to Project Sponsors, Line of Business Project Leadership, Project Managers, Project Controls Analysts, Project Stakeholders and all other employee and non-employee workers (together, personnel) of PG&E Corporation (Corporation) and its controlled subsidiaries, including Pacific Gas and Electric Company (Utility) (together, PG&E) working on PG&E projects.

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Project Cost Management Standard

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Project Cost Management Standard

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Project Cost Management Standard

REQUIREMENTS

1 LOB Applicability Requirements

1.1 PG&E Organizations that perform or are responsible for projects with an estimated Total Gross Project Cost of $1 million or greater must have procedures in accordance with GOV-2001P-01, "Guidance Document Development, Review, and Revision Procedure" that implement the requirements contained within this Standard.

1.2 Projects within Information Technology (IT) using an Agile approach (e.g., IT's Business Technology Digital Catalyst projects) are exempt from the requirements within this Standard.

2 Work Breakdown Structure (WBS)

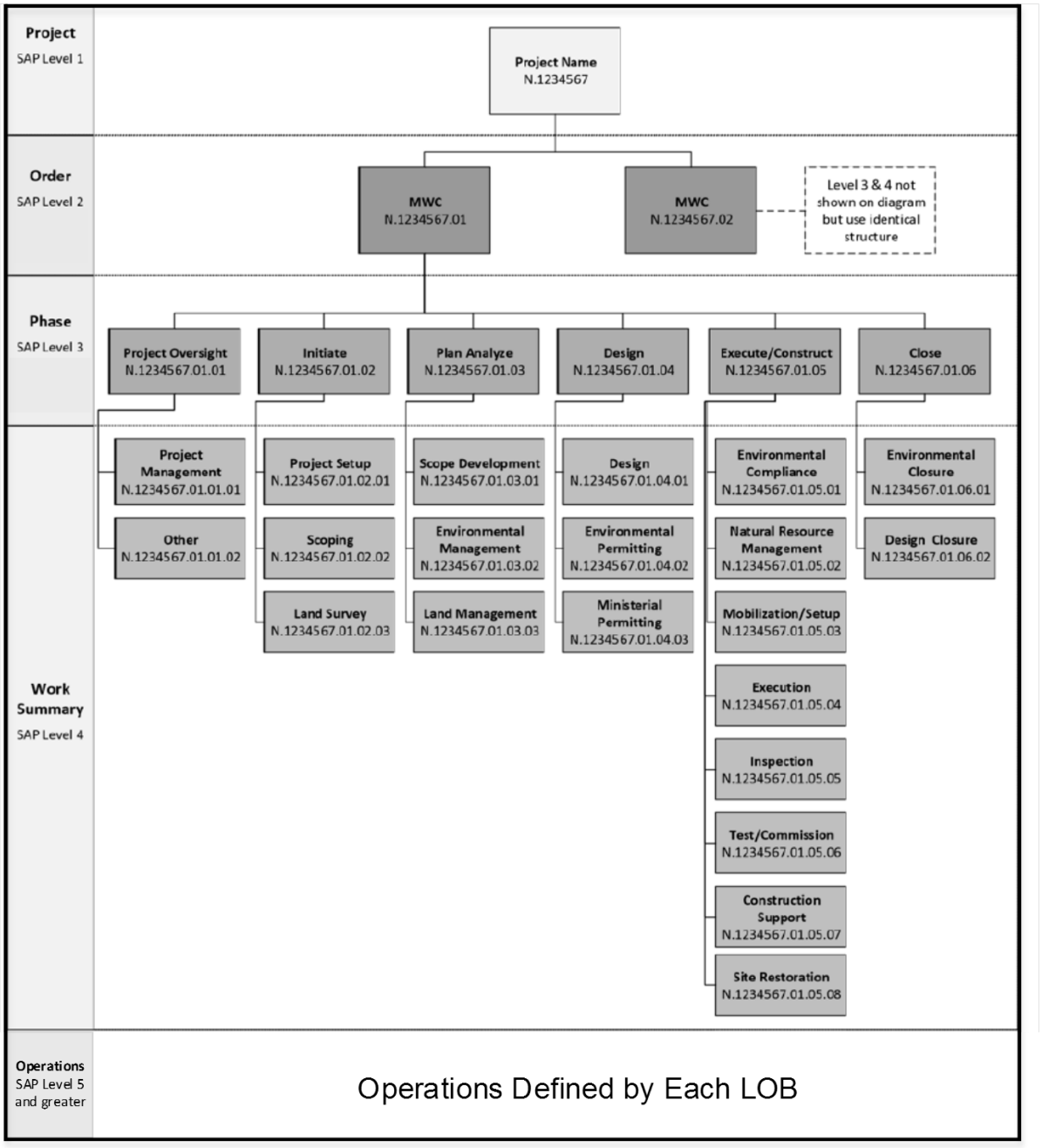
2.1 All projects must use the appropriate levels, elements, and numbering scheme (as defined in this Standard) of the WBS shown in Figure 2. Applies only to SPSI managed projects.

1. The WBS must be developed through a decomposition of the project scope of work into discrete elements for which work can be planned and managed effectively.
2. The WBS must reflect the total scope of work to be performed on the project.
3. The WBS must be used to establish the Project Cost Baseline against which project cost performance is measured and controlled.
4. The WBS must be the common reference for internal and/or external project reporting.
5. There must be only one WBS for each project.
6. All costs (including labor, material, contracts, and overhead) and resources for a project must be mapped to a WBS element.
7. The WBS must be updated to include revisions for approved changes and modifications throughout the project's life cycle.
8. The WBS must be in the SAP Project Systems (SAP PS) WBS of the SAP Enterprise Central Component (ECC) or other EPM approved tool
9. The WBS numbering scheme must meet the requirements listed in Figure 2.
10. LOB specific WBS's are documented in Appendix D of PM-1010S, "Project Management Governance Standard". Any further exceptions must be approved by the EPMO and documented.

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Project Cost Management Standard

Figure 2 - PG&E Standard WBS

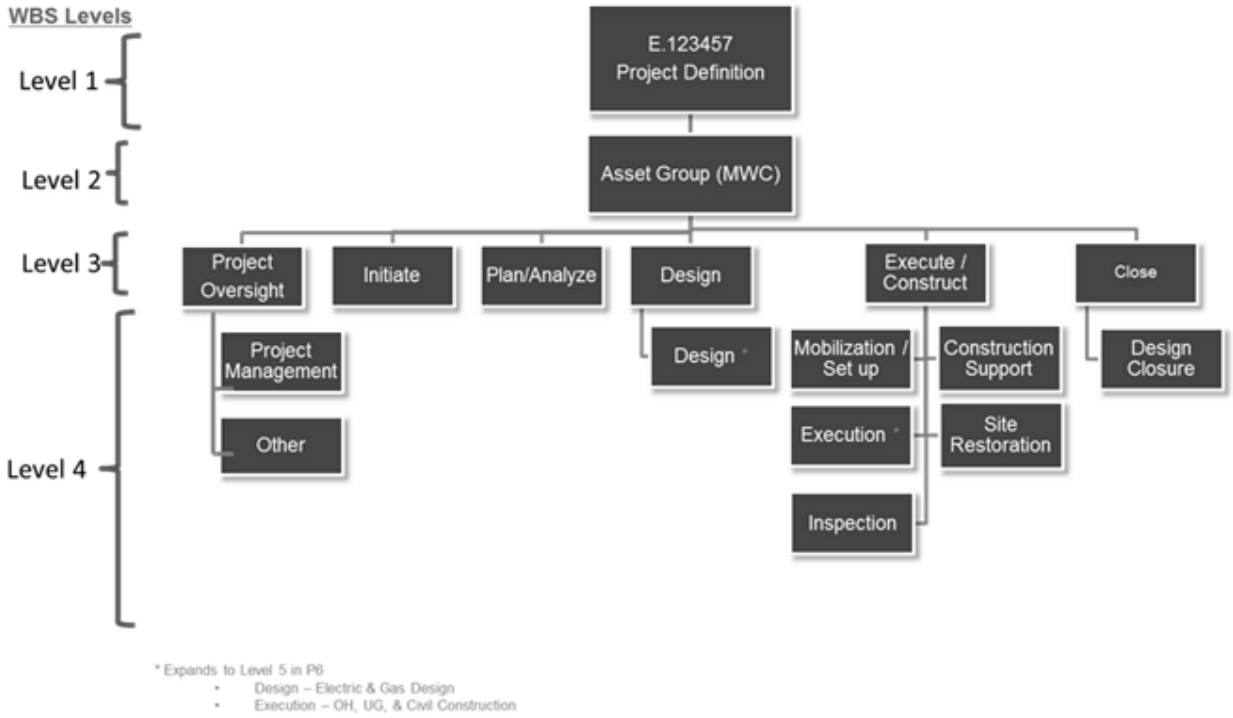


2.2 For Governance Threshold 4 projects, LOBs may use the Small WBS depicted in Figure 3 if the Expected Case if less than $5 Million.

1. All the requirements for Step 2.1 must be maintained with the Small WBS.

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Figure 3 - Small WBS



2.3 Plant Maintenance (PM) Orders with Operational Account Assignment

1. The operations associated with PM orders must be used to define level 5 elements of the WBS (SEE Appendix B, "Example LOB Operation Codes").

2. LOB-specific operations must represent the scope of work separated into manageable parts that correspond to project deliverables.

3. The additional levels must be in a hierarchical structure that maps back to level 4 and follows the same numbering system for levels and elements as used for levels 1 to 4.

4. The fully developed WBS must have as many levels beyond level 4 as is necessary to accurately estimate the full scope of work.

2.4 WBS Dictionary

1. LOBs must develop a Standard WBS Dictionary that describes each of the work elements and levels below WBS level 4 (Work Summary).

2. The WBS Dictionary must be a single document used for all projects within a given LOB.

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3. LOBs must use the elements in the WBS in a consistent and repeatable fashion for all projects.

4. Attributes of the WBS Dictionary must include:

   a. The end result or expected work product

   b. Units of measure

5. LOBs must use the EPM WBS Dictionary for WBS levels 1 – 4, SEE Appendix A, "WBS Dictionary".

6. Once the additional levels and associated WBS Dictionary are developed, they must be approved by the EPMO and placed under revision control.

2.5 Relationships between WBS Level 2, Major Work Category (MWC), Planning Order, and Plant Maintenance (PM) Order:

1. The WBS must be designed such that there is a one to one relationship between the below listed key elements, REFER TO Figure 4:

   a. A Planning Order (PO) and WBS Level 2 Major Work Category (MWC)

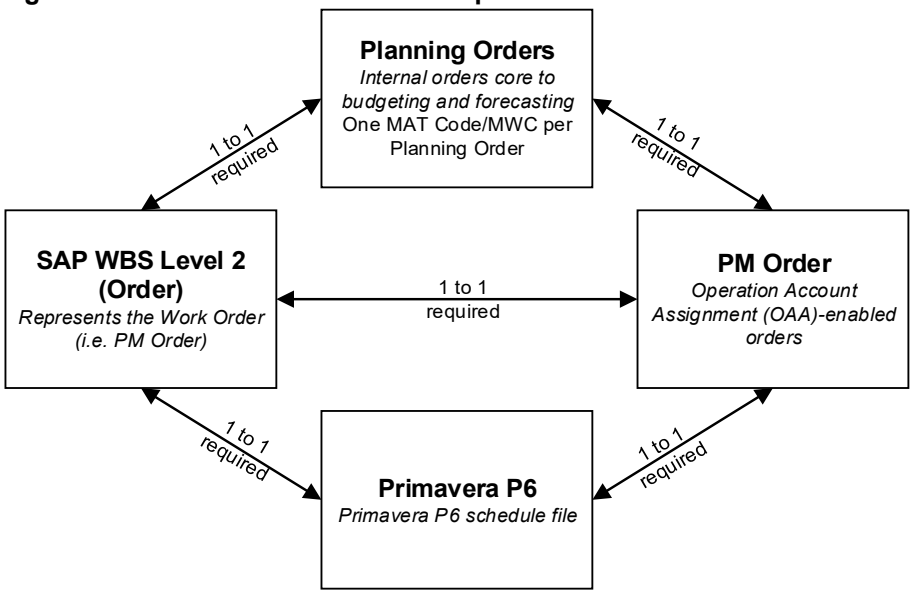
   b. WBS Level 2 MWC and Primavera P6 Schedule

   c. Primavera P6 Schedule and a Plant Maintenance (PM) Order

   d. Planning Order (PO) to Plant Maintenance (PM) Order

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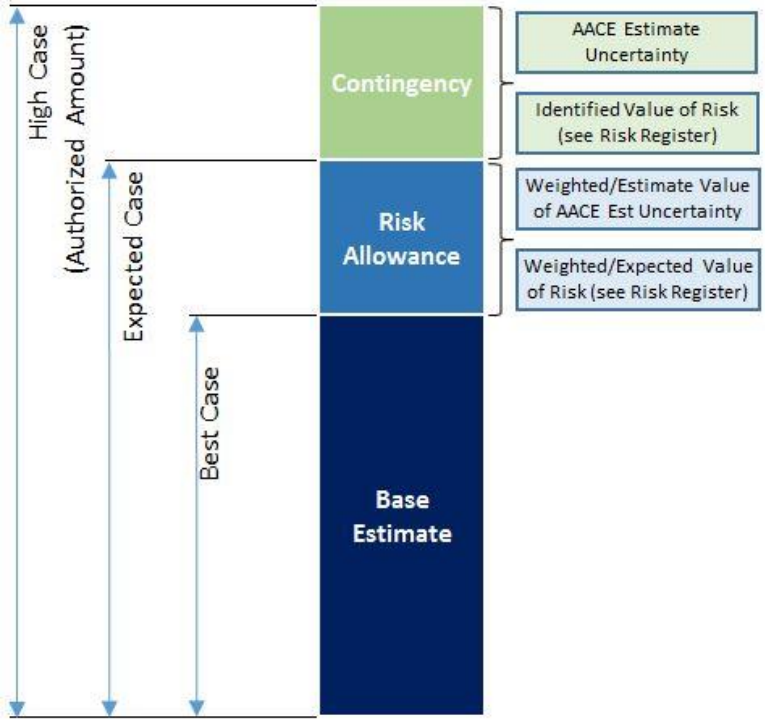
Figure 4 - WBS One-to-One Order Requirements



3 Project Cost Estimating

3.1 The project cost estimate must comprise the following items shown in Figure 5.

Figure 5 - PG&E Estimate Components



3.2 AACE Cost Estimate Classification System

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1. LOBs must define and implement an AACE Cost Estimate Classification System to align with the requirements in Table 1. The design of the AACE Estimate Classification System must be based on the appropriate AACE Recommended Practices listed in section Developmental References.

Table 1 - Estimate Classification System

AACE Cost Estimate Class	Maturity level of project definition expressed as % of complete definition	Typical Estimating Methods
Class 5	0% to 2%	Probabilistic: e.g., Top down, historical, parametric, analogous, capacity factored
Class 4	1% to 15%	Primarily Probabilistic: e.g., Equipment factored, parametric modelling
Class 3	10% to 40%	Probabilistic/Deterministic: e.g., Semi-detailed unit costs, quantity take-offs.
Class 2	30% to 75%	Primarily Deterministic: e.g., Bottom up, detailed unit costs, limited take-offs.
Class 1	65% to 100%	Deterministic: e.g., Bottom up, detailed unit costs.

2. The Estimate Classification System must define the maturity level of project deliverables based on typical criteria required to achieve a specific estimate classification, SEE Appendix C, "Estimate Classification".

    a. The AACE Estimate Classification System must have a set of deliverables for a project estimate to be classified at a specific AACE Estimate Class.

        (1) The set of deliverables must be split into required and optional.

        (2) If all of the deliverables for a specific class are not complete, the project must remain classified at the lower level until all items are complete.

3.3 Estimate Phase Gate application

1. LOBs must align the development of each AACE Cost Estimate Class to Phase Gates as depicted in Table 2.

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Table 2 - Estimate Phase Gate Application

Project Governance Threshold	Phase Gate 1	Phase Gate 2	Phase Gate 3
4	Class 5	**Class 2** Depending on LOB selection for Full Authorization	
3, 2 & 1	Class 5	Class 3	Class 2

3.4 Estimate development

1. In accordance with Table 2 above, LOBs must perform all of the below activities during the development of each Estimate Class:

   a. Similar steps must be used in the development of each estimate, with the level of inputs and detail increasing as the project progresses from Phase Gate 1 to Phase Gate 3.

   b. Activities are not normally sequential and may be iterative.

   c. Activities may be combined into a single step depending on the specific process being used.

2. Quantify the scope

   a. LOBs must collect and evaluate the current documented scope basis and defining technical deliverables as key inputs into the estimate.

   b. Scope documents must first be quantified (e.g., take-off) in terms or formats required to add cost factors by the necessary units/parameters.

   c. The project specific scope must be assigned to the appropriate WBS elements.

   d. Indirect costs must be assigned to a project's unburdened cost in accordance with the Enterprise Cost Model (e.g., project management, home-office, engineering/design/management not accounted as direct cost).

3. Cost and resource load the scope

   a. The quantifiable areas of scope on the project must have an associated cost factor attributed to the labor, material, equipment, contract, or other attribute required to execute that portion of the scope.

   b. LOBs must have a process to quantify cost for each scope attribute.

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c. Costs must be assessed for project and scope specific conditions that may include waste, spoilage allowance, accuracy of measurement (e.g., take-off) allowance, specification, function, or content difference.

4. Incorporate impact of risk and AACE Uncertainty Factor

a. SEE Subsection 5, "Risk Management"

5. Cash flow for the estimate

a. For Estimate Classes 1, 2 and 3, the estimate must be time-phased in accordance with the schedule and must address monthly cash flow and cost constraints.

6. Document the estimate

a. Estimates must be documented. Documentation requirements vary by Governance Threshold. SEE Step 3.5, "Basis of Estimate".

7. Develop the Job Estimate

a. The Job Estimate and Settlement Rules must be completed in accordance with FIN-3805S, “Capital Job Estimate Standard” by Phase Gate 3 or at full project authorization.

8. Establish Earning Rules

a. LOBs must define Earned Value Earning Rules in accordance with the guidance provided in Appendix F, "Earned Value Earning Rules" and aligned with the PMI Standard Practice for Earned Value Management.

3.5 Basis of Estimate

1. For Governance Threshold 1 and 2 projects, LOBs must prepare and maintain a Basis of Estimate (BOE) to support Phase Gate 2 and Phase Gate 3 approvals (SEE Appendix E, "Basis of Estimate Template").

3.6 Estimate validation

1. For Governance Threshold 1 projects, a check estimate must be performed prior to Board of Directors review at Phase Gate 2 and prior to execution at Phase Gate 3.

2. Check estimates must be based on recommendations outlined in AACEI Recommended Practice 31R-03 section “Reviewing Estimates Prepared by Others”.

3. The check estimate must be validated against the Basis of Estimate to allow the LOB to understand any difference in the key inputs and processes used to develop the estimate.

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4. For all check estimates, whether internal or external, independence from the project must be a key consideration to obtain objective, unbiased input.

    a. Those preparing the estimate validation should be reasonably free from undue influence by the stakeholders; i.e., their pay or career is not primarily determined by the recipient of the estimate.

3.7 Project cost records

1. LOBs must include the final project cost and associated documents used to support the estimate's development as part of the project's cost records.

    a. The BOE must be included in the project cost records for Governance Threshold 1 and 2 projects.

    b. LOBs must store project cost records in accordance with GOV-7101S, "Enterprise Records and Information Management Standard".

4 Project Cost Baseline

4.1 LOBs must define an initial Project Cost Baseline to reflect the Expected Case to be included within the approved business case (or approved proxy) at Phase Gate 2 (not required for Governance Threshold 4 projects).

4.2 The Project Cost Baseline must reflect the Expected Case shown in the business case submitted at Phase Gates 2 and/or 3 (depending on Governance Threshold).

1. The Project Cost Baseline must be the cost basis against which the cost performance of the project is measured.

2. Governance Threshold 4 projects are not required to define a Project Cost Baseline until Phase Gate 3.

4.3 For each Project Cost Baseline update, the Expected Case, Authorized Amount, Best Case, Risk Allowance, and Contingency must be captured in the Enterprise Project Management tool or other EPM approved tool.

4.4 For each Project Cost Baseline update, the project must revise the monthly cash flow for the whole project.

4.5 Changes to the Project Cost Baseline must be in accordance with the PM-1012S, "Integrated Change Control Standard".

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5 Risk Management

5.1 Risk Identification

1. Project Specific Risk Identification

    a. LOBs must establish a process to plan, assess, treat, and control the risks on projects.

    b. LOB risk process requirements must vary based on Governance Thresholds.

        - For example, for Governance Threshold 4 projects, LOBs may identify the typical risks associated with work in a specific MWC or MAT. However, the LOB must not use this to apply an arbitrary cost multiplier to determine risk allowance or contingency.

    c. Risks must be identified in all phases of the project lifecycle.

    d. For Governance Threshold 1 and 2 projects, LOBs must hold a project risk identification workshop or a risk kick-off meeting prior to development of a project's Business Case.

    e. A Risk Register must be prepared as an output of the risk identification process (SEE Appendix D, "Risk Management" for an example Risk Register template).

    f. Any changes to a project submitted and approved through ICC must be assessed for risk and added to the Risk Register as necessary, if not previously included (SEE PM-1012S, "Integrated Change Control Standard").

    g. Risks must be reviewed, validated, and closed on an ongoing basis as defined by the LOB.

    h. LOB procedures must require that Risk Owners develop response plans for each risk.

    i. All risks must remain in the Risk Register throughout the life of the project, even if they are deactivated, or if they materialize into actual issues or benefits, so that the entire evolution of all the risks is captured.

    j. LOBs wishing to analyze and report risk at a portfolio level must use Primavera P6 / Enterprise PM Tools or other EPM approved tool

5.2 Risk Allowance Determination

1. Risk Allowance, which is inclusive of the following elements, must be added to the Base Estimate to determine the value for the Expected Case:

    a. Weighted/Expected Value of AACE Estimate Uncertainty

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b. Weighted/Expected Value of Risks

2. The Expected Value of the Risk portion of the Risk Allowance must reflect the probabilistic determination of identified risks.

   a. Each risk in a project risk register must be assigned an impact (monetary) value should the risk occur.

   b. Each risk in the project risk register must assign a probability (chance of occurrence) that the risk will materialize.

   c. The impact value multiplied by the probability (chance of occurrence) provides the expected value of risk for each individual item.

   d. The expected value of risk for each individual item.

$$Weighted/Expected\ Value\ of\ Risk = (chance\ of\ occurrence)\ \text{x}\ (impact\ value)$$

   e. The sum of all Expected Risks on the risk register must be included within the Risk Allowance.

$$Project\ Weighted/Expected\ Value\ of\ Risk = \sum All\ Weighted/Expected\ Value\ of\ Risks\ on\ a\ project$$

Table 3 - Complexity Factors

Estimate Class	Low Complexity		High Complexity	
	Weighted/Expected Value of AACE Estimate Uncertainty (% of base estimate + risk to be added)	**Total Value of AACE Estimate Uncertainty** (% of base estimate + risk to be added)	**Weighted/Expected Value of AACE Estimate Uncertainty** (% of base estimate + risk to be added)	**Total Value of AACE Estimate Uncertainty** (% of base estimate + risk to be added)
Class 5	10%	20%	70%	100%
Class 4	5%	15%	15%	50%
Class 3	5%	5%	10%	30%
Class 2	0%	5%	5%	20%
Class 1	0%	3%	0%	10%

3. For governance threshold projects 3 and 4, the AACE Estimate Uncertainty factor from Table 3 must be based on the systemic risk profile of the project (i.e., the level of complexity and/or risk associated with the project) as defined in Scalability in PM-1010S, "Project Management Governance Standard". Within Risk Allowance, AACE Risk is a major systemic risk factor.

   a. Governance threshold projects 1 and 2 must categorize their projects as high complexity.

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5.3 Contingency determination

1. A Contingency must be added to the Expected Case Estimate to reflect the following elements:

   a. The AACE Estimate Uncertainty

   b. The Identified Risk

2. The AACE Estimate Uncertainty must correspond to the same complexity (high or low) chosen for the determination of Risk Allowance.

3. LOBs must add the Identified Risk, which is the difference between the dollar value of the full impact of identified project risks and the total value of Expected Risks.

$$Identified\ Risk = \sum All\ Risk\ Impacts - \sum All\ Expected\ Risks$$

5.4 Alternative Risk Analysis methods

1. If an LOB utilizes an alternative risk analysis method, such as Monte Carlo Simulation, the LOB must obtain approval from the EPMO.

6 Cost Control

6.1 Cost Validation

1. All actual costs must be reviewed for accuracy by the project team.

2. LOBs must evaluate work performed on the project to date to ensure actuals reflect work performed.

6.2 Risk Allowance Management

1. Projects must maintain a log to track all Risk Allowance usage, including the amount of the release and an explanation.

6.3 Actual Cost

1. All charges to the project must be charged to Operations (WBS level 5 and below) that rolls up to the appropriate WBS level 4 elements.

2. A Goods Receipt must be created for work performed or products received in the same month the work is performed (accrual accounting).

3. The Goods Receipt amount must be charged to the appropriate operational WBS (WBS level 5 and below).

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4. The creation of the Goods Receipt must happen independently of receiving or paying an invoice.

5. Committed Cost must be recorded to Operations (WBS level 5 and below) that rolls up to the appropriate WBS level 4 elements.

6. Actual Cost plus Committed Cost must not exceed the authorized amount at any time during the life of a project from initiation to close.

6.4 Monthly cash flow projections

1. LOBs must maintain a projected monthly cash flow for the project life cycle.

2. Projects must provide a monthly cash flow for the Base Estimate at the time of authorization at Phase Gate 2, and for each subsequent authorization and/or Project Cost Baseline revision.

3. The cash flow projection must be consistent with the project schedule.

6.5 Project Cost Analysis

1. On a monthly basis a project cost analysis must be performed that calculates the following and enters the data into the Enterprise Project Management tool or other EPM approved tool:

   a. Best Case Estimate at Completion: The cost projected at the completion of the project without the risk allowance or contingency (updated Best Case).

   b. For Governance Threshold 1, 2 and 3 projects that are between Phase Gate 2 and Phase Gate 3, the Base Case Estimate at Completion (EAC) must also be calculated to complete the work to get to Phase Gate 3.

   c. Remaining Risk Allowance: The Risk Allowance as identified in the Project Cost Baseline less any dollars allocated to the project.

   d. Remaining contingency: This must be obtained from the Integrated Change Control tracking log, system, or tool that is used to control drawdown of contingency dollars.

   e. For Governance Threshold 1 and 2 projects, earned value must be calculated on a monthly basis for each level 4 element in the WBS by using Earning Rules (SEE Substep 3.4.8).

   f. To comply with DET timing requirements, every year LOBs must update and provide the monthly cash flow for the duration of the project, based on the project's Best Case.

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6.6 Following the definition of the Project Cost Baseline (SEE Subsection 4, "Project Cost Baseline"), LOBs must capture the following data elements at least monthly in Enterprise PM Tools/EPM approved tool until Phase Gate 5 Project Close:

- Actual Costs
- Committed Costs
- An assessment of cost performance and anticipated ability to meet project cost objectives
- Current Best Case and remaining Risk Allowance
- Current Authorized Amount (i.e., approved funding)
- Spend to date
- Current year budget
- Year to date total spend
- Current year forecast
- Variance Analysis
- Cost impacts from approved change orders

7 Monitoring and Compliance

7.1 The LOBs must establish a monitoring and compliance program to validate their procedures are operating in accordance with this standard, referenced standards, and associated LOB procedures.

END of Requirements

DEFINITIONS

Definitions can be accessed through PM1510, “Project Management Glossary”

IMPLEMENTATION RESPONSIBILITIES

NA

GOVERNING DOCUMENT

PM-1010S, “Project Management Governance Standard”

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COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

NA

REFERENCE DOCUMENTS

Developmental References:

- AACEI Total Cost Management Framework, Second Edition
- AACEI RP 18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries
- AACEI RP 20R-98: Project Code of Accounts
- AACEI RP 33R-15: Developing the Project Work Breakdown Structure
- AACEI RP 34-05: Basis of Estimate
- AACEI RP 55R-09: Analyzing S-Curves
- AACEI RP 80R-13: Estimate at Completion (EAC)
- AACEI RP 82R-13: Earned Value Management (EVM) Overview and Recommended Practices Consistent with EIA-748-C
- AACEI RP 86R-14: Variance Analysis Reporting
- AACEI RP 31R-03: Reviewing, Validating, and Documenting the Estimate
- Project Management Institute (PMI) Standard Practice for Earned Value Management
- Project Management Institute (PMI) Practice Standard for Project Estimating

Supplemental References:

- GOV-7101S, “Enterprise Records and Information Management Standard”
- GOV-2001P-01, “Guidance Document Development, Review, and Revision Procedure”
- PM-1012S, "Integrated Change Control Standard"
- PM-1001P-01, “Project Authorization and Approval Procedure”
- FIN-3805S, “Capital Job Estimate Standard”
- AACE RP 18R-97: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries

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- AACE RP 56R-08: Cost Estimate Classification System – As Applied for the Building and General Construction Industries
- AACE RP 69R-12: Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Hydropower Industry

APPENDICES

- Appendix A, "WBS Dictionary"
- Appendix B, "Example LOB Operation Codes"
- Appendix C, "Estimate Classification"
- Appendix D, "Risk Management"
- Appendix E, "Basis of Estimate Template"
- Appendix F, "Earned Value Earning Rule"[Insert text.]

ATTACHMENTS

EPM Cost Standard Risk Register Template

DOCUMENT RECISION

Utility Procedure: PG-001, "Project Risk Management Procedure", Effective 06/01/13, Rev 1

Utility Standard: GM-1005S, “Project Cost Estimating Standard”, Effective 01/05/18, Rev 1

DOCUMENT APPROVER

Don Clark, Director, Enterprise Project Management

DOCUMENT OWNER

Franklin Lyons, Business Analyst, Principal, Enterprise Project Management

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REVISION NOTES

Where?	What Changed?
Summary Figure 1	Updated to reflect Project Life Cycle to be aligned with Front End Planning and Project Governance framework
Section 3.1 Figure 5	Revised for alignment with Major Project Business Case methodology

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Section 5.2 Table 3	Updated Complexity Factors table for alignment with Major Project Business Case methodology
Section 7	Added Monitoring and Compliance Subsection
Appendix D	Provided 3x3 risk matrix, provided mapping for a 5x5 risk matrix to a 3x3 Business Case
Appendix G	Added WBS Attribute Table, Naming Conventions, Abbreviations
Appendix H	Added Project Cost estimate example
Definitions	Deleted definitions, refer to the Glossary for all project management definitions.

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Appendix A, WBS Dictionary
Page 1 of 2

A. SAP WBS Dictionary

1. Additional attributes that may be found in a WBS dictionary include:

   - Relationships and dependencies between elements of work
   - Optional elements
   - Assumptions or limitations
   - Technical specifications
   - Other supporting documents

2. The WBS dictionary must contain the same information for all WBS elements

SAP PS WBS Level 1 & 2	SAP PS WBS Description
Level 1	Represent the project at the highest level in SAP PS.
Level 2	SAP PS WBS Element representing the Major Work Category or Planning Order.
SAP PS WBS Level 3	**SAP PS WBS Description**
Project Oversight	Includes project overhead costs that do not align in a clean fashion to Project Phases.
Initiate	Includes creation of a project, preliminary project authorization, and creation of a work order in SAP PS and, where applicable, a Primavera P6 schedule.
Plan/Analyze	Includes development of cost, schedule, and resource estimates. Other ongoing activities triggered during this phase include risk and issue management and preliminary engineering assessments (enough design needs to occur for scope approval by the end of the phase).
Design	Includes development of the detailed engineering design, identification of scope/cost/ schedule baselines, and pre-construction activities. Other ongoing activities triggered during this phase include variance analysis/ change control, and performance reporting.
Execute/Construct	Includes mobilization, construction, testing, and other activities required to complete construction.
Close	Includes administrative and financial closeout of a project and project documentation.
SAP PS WBS Level 4 Description	**SAP PS WBS Description**
Project Management	Includes the activities associated with managing a project from initiation to close out. Resources such as Project Managers, PCA's and Schedulers would be aligned to this SAP PS WBS Level 4 Element.
Other	Includes activities not identified or defined by the other WBS Level 4 descriptions.

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Project Set Up	Includes activities needed to create a project and include it in annual budgets and long-term plans.
Scoping	Includes activities in the Initiate Phase for engineering and planning to develop a project definition and Class 5 estimate.
Land Survey	Includes activities related to taking a position of the project location or surrounding area.
Scope Development	Includes activities needed to define a project scope to a level of detail that allows for a Class 4 Estimate to be developed.
Environmental Management	Includes activities necessary for environmental permitting and other environmental requirements on a project.
Land Management	Includes activities related to managing the land permitting, inspections and code enforcement for a project.
Design	Includes activities related to detailed design of a project.
Encroachment Permitting	Includes activities related to the placement of encroachments within, under, or over the State highway rights of way
Ministerial Permitting	If applicable, includes activities needed for complying with and obtaining a permit for meeting standards associated with zoning ordinances.
Environmental Compliance	Includes activities necessary to meet environmental standards, including, but not limited to storm water pollution prevention.
Natural Resource Management	Includes activities related to managing water, soil, plant and animal implications on a project.
Mobilization/Set-up	Includes activities associated with getting resources on site and getting a project site set up to begin execution/construction.
Execution	Includes activities associated with construction/completion of the work defined in the project plan. .
Inspection	Includes activities for on-site reviews and inspections during execution
Test/Commission	Includes activities for testing and commissioning equipment and systems
Construction Support	Includes activities related to health & safety, construction administration and other supporting work.
Site Restoration	Includes activities necessary to return a project site back to an operational standard
Environmental Closure	Includes activities for obtaining approval for closure of permits and other environmental requirements.
Design Closure	Includes activities for completing and approving design drawings and as-built records

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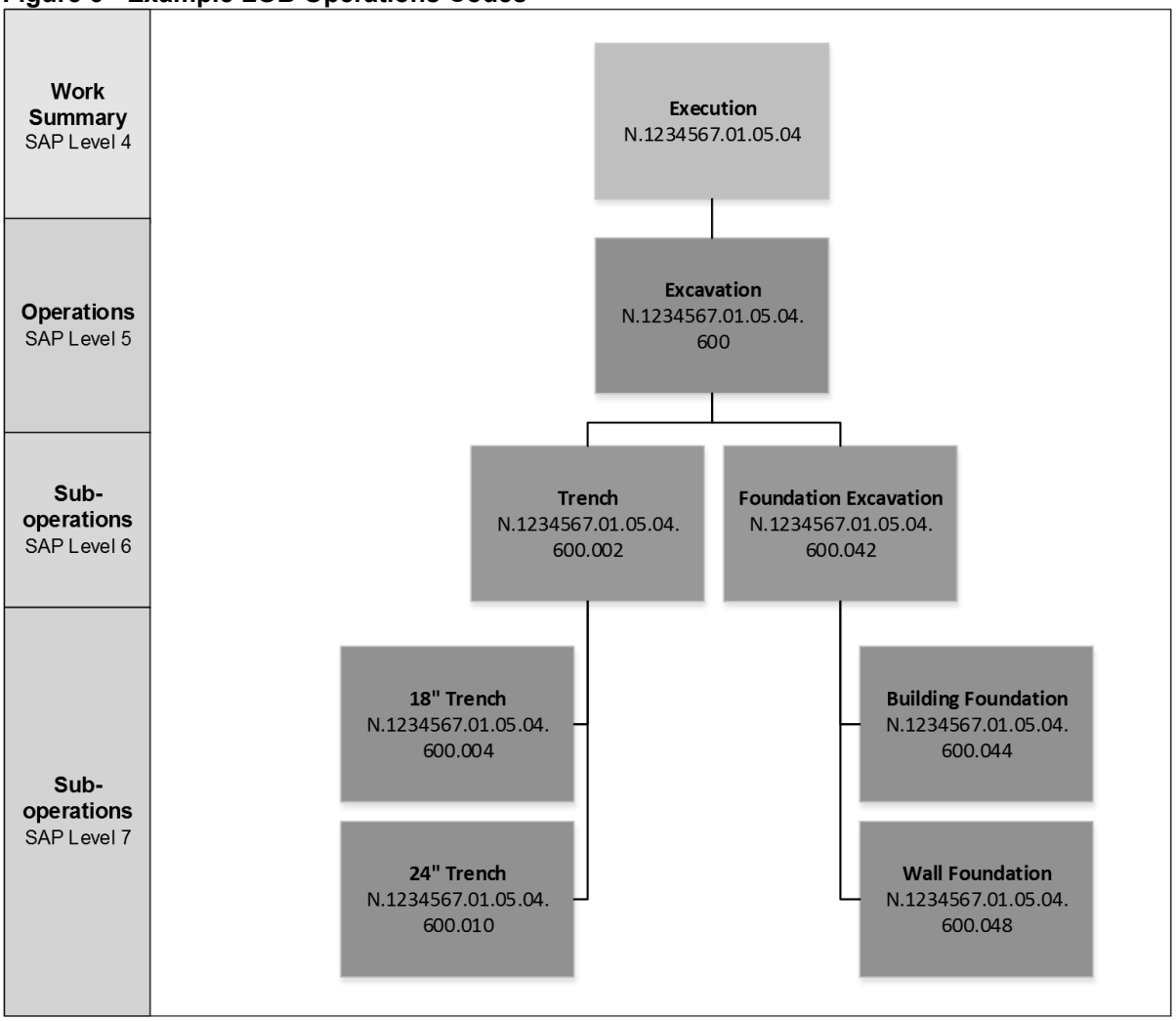
Appendix B, Example LOB Operation Codes

A. LOBs may develop a code of accounts similar to the examples provided below

1. LOBs must develop code of accounts for as many levels to require to accurately estimate the full scope of work.

2. Operations (WBS Level 5 and lower) and Sub-operations (levels below Operations) should be used for scope management and refined estimating. If work is performed by a third party/vendor, scope should be divided into necessary parts as applicable to manage the contract and associated schedule of values.

Figure 6 - Example LOB Operations Codes



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Appendix C, Estimate Classification
Page 1 of 3

A. Example Estimate Classification System

1. The AACE Classes are driven by generic risk management principles in 17R-97, which provides cross-industry consistency.

   a For example, Class 3 reflects the level of definition at which research shows there is little further risk reduction from doing more definition.

   b Class 4 is the level of definition where one can economically select a single scope option, but with measurable scope risk remaining.

2. Determination of Cost Estimate Class

   a Class 5 Estimate

   Description: Class 5 project estimates correspond to projects in the early concept and planning phase, often before a project team has been assigned. Class 5 estimates are prepared based on limited information (e.g., a very high-level investment objective provided by a sponsor) and subsequently have a wide range of potential outcomes.

   Typical Inputs: Facility type, capacity, location, and investment objectives.

   End Usage: Advanced Authorization (AA).

   Estimating Methodology: Class 5 estimates generally use probabilistic estimating methods such as cost/capacity curves and factors, historical benchmarks, and other parametric techniques.

   b Class 4 Estimate

   Description: Class 4 estimates are based on a selected asset alternative and are prepared with limited scope information and have a wide range of potential outcomes. Execution strategy alternatives (e.g., routing/siting, contracting strategy) are typically not yet selected.

   Typical Inputs: <15% overall engineering design, feasibility design for several alternative layouts/routes, facility capacity, preliminary one-line diagrams, and comprehensive user requirements.

   Estimating Methodology: Class 4 estimates generally use probabilistic estimating methods, including equipment factors, gross unit costs/ratios, and other parametric modeling.

   c Class 3 Estimate

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Description: Class 3 estimates are based on a detailed scope of work, execution strategy, and preliminary engineering design.

Typical Inputs: 30-60% overall engineering design, e.g., contracting/procurement strategy, substantially complete geotechnical investigations, preliminary earthwork drawings for excavation, complete one line diagrams, equipment performance specifications.

End Usage: Phase Gate 2 Authorization (SEE PM-1010S, “Project Management Governance Standard”), Initial Project Cost Baseline. Any changes after Phase Gate 2 must meet the requirements of PM-1012S, "Integrated Change Control Standard". Note: Phase Gate 2 requirements do not apply to Governance Threshold 4 projects.

Estimating Methodology: Class 3 estimates involve more deterministic estimating methods than probabilistic methods. They usually involve the predominant use of unit cost line items, although these may be at an assembly level of detail rather than individual components. The estimate should be based on scope of work documents as well as expected permit costs. Factoring and other probabilistic methods may be used to estimate less-significant areas of the project.

For Governance Threshold 1 projects, a Class 3 estimate, at a minimum, is required for authorization by the PG&E Board of Directors, SEE PM-1010S, “Project Management Governance Standard.

d Class 2 Estimate

Description: Class 2 estimates are based on detailed engineering designs and execution plans.

Typical Inputs: 60-90% engineering design, detailed resource plans, critical path execution schedules, and vendor quotes for substantial portions of equipment, material, and construction services.

End Usage: Phase Gate 3 Authorization (SEE PM-1010S, “Project Management Governance Standard"), project re-authorization, change orders, updated Project Cost Baseline.

Estimating Methodology: Class 2 estimates generally involve a high degree of deterministic estimating methods, including quantity takeoff and detailed resource/contracting plans. Class 2 estimates are prepared in detail and often involve numerous unit cost line items. Note: Governance Threshold 4 projects are not required to develop a Class 2 estimate at Phase Gate 3.

e Class 1 Estimate

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Description: A Class 1 estimate represents the highest level of estimating certainty. It assumes 100% of engineering is complete, all work is under contract, and enough progress has been made to extrapolate performance trends.

Typical Inputs: 100% engineering design, awarded contracts, execution progress and performance measures, detailed execution and commissioning plans.

End Usage: Re-authorization, change orders

Estimating Methodology: Class 1 estimates generally involve the highest degree of deterministic estimating methods and require a significant amount of effort. Class 1 estimates are prepared in great detail and are therefore usually performed on only the most important or critical areas of the project. Items in the estimates are usually based on bids based on final design specifications or accurate unit cost line items based on actual design quantities. In cases where construction is already underway, a Class 1 estimate may be based on earned value management metrics and performance trending analysis.

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Appendix D, Risk Management
Page 1 of 3

A. Recommendations for Risk Management (Plan, Assess, Treat, Control)

1. Plan: Develop a plan to manage risks for each project.

   a For example, utilize a Risk Register to track and manage risks: EPM Cost Standard Risk Register Template

2. Assess: Identify risks and perform analysis.

   a Commonly used risk identification techniques include:

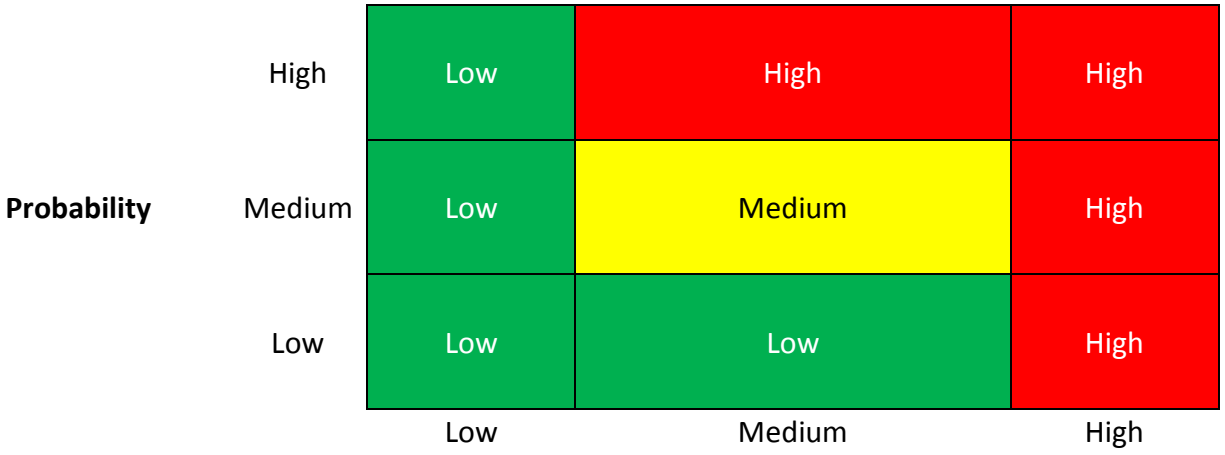
   - Brainstorming: Generate potential risks through free-form discussion or structured interviewing, then categorize by risk type for further definition.
   - Checklists: Use a list of commonly occurring risks that was developed based on knowledge that has accumulated from previous projects within the LOB or from other LOBs.
   - Root Cause Analysis: Identify a problem and discover the underlying causes, which can then lead to the development of preventative actions or potential risks.
   - Lessons Learned and Knowledge Transfer: Obtain risk-related knowledge from lessons learned. Review the Risk Registers from previous projects.

   b Qualitative Risk Analysis (Risk Ranking)

   - Qualitative Risk Analysis is a method to rank risks according to criticality and significance to a project.
   - Estimated probabilities and impact ratings for each of the identified risks must be developed. At a minimum, a 3x3 matrix must be used with High / Medium / Low values as shown below. A matrix higher than a 5x5 may not be used.

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Risk Score Matrix (3x3)



Impact to Cost and Impact to Schedule

- The Risk Register (Excel, Primavera P6, or other LOB specific method) must include the following information:

  (1) Probability: Level of probability that the risk will transform into an issue or benefit.

  (2) Cost and Schedule Impacts: Level of impact the risk can have on the total project cost or schedule.

  (3) Risk Score: The Risk Register must calculate an overall Risk Score. The overall Risk Score is equal to the Probability (P), plus the Impact to Cost (IC), plus the Impact to Schedule (IS), i.e., the Risk Score = P + IC + IS. A Red, Amber, or Green (RAG) Heatmap status must be assigned to each risk.

- If a 5x5 matrix is used it must be mapped to the High / Medium / Low (H/M/L) ratings used in a Business Case or Major Projects Business Case. The mapping is VH / H = H, M = M, and L / VL = L. The H/M/L Risk Score output, or RAG heatmap status, from a 5x5 risk analysis, must be consistent with the risk section of the Business Case or Major Project Business Case.

3. Treat: Identify Risk Owners and Risk Response

   a Assign a Risk Owner for each risk.

   b Develop a response strategy for each risk: Accept, Avoid, Reduce, or Transfer.

4. Control: Monitor and Control Risk

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a New risks must be added to the Risk Register.

b Risks must be reviewed on a periodic basis. Significant changes to the project, for example a scope change, must include a risk review.

c All risks must remain in the Risk Register for the duration of the project to ensure the entire evolution of the risks is captured.

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Appendix E, Basis of Estimate Template
Page 1 of 1

A. Threshold 1 and 2 projects must use the Basis of Estimate Template

1. Link – Template under development

2. Threshold 3 and 4 projects may implement the Basis of Estimate template or similar for use

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Appendix F, Earned Value Earning Rules
Page 1 of 2

A. Guidance for setting up Earned Value (Governance Threshold 1 & 2 projects only)

1. Earned Value is a measure of the work performed on a project. The implementation of Earned Value requires a pre-defined method of measurement for the project progress, also known as Earning Rules.

2. To accommodate the different types of work performed on a project, there are a number of acceptable methods that LOBs may use to measure progress.

3. Earned Value earning rules must be defined prior to starting the project using one of the options below:

   a Milestone based (weighted milestones)

   - The measurement of the work package is divided in measureable segments, each ending with a significant milestone.
   - A weighted value is assigned to the achievement of each milestone (e.g., Milestone 1 – 10%, Milestone 2 – 50%, Milestone 3 – 100%).

   b Percent Complete

   - An estimate of the percentage of the work complete is assessed at the end of each measurement period.
   - This method must be based on objective and quantifiable work completion.
   - There must be sufficient activities in the schedule to minimize EV inaccuracy .i.e., schedules EV accuracy is improved by breaking long duration activities into several short duration activities.

   c Physical Measurement (e.g., each, linear feet, square feet, etc.)

   - Measurement of work using units that can be explicitly related to the completion of work (e.g., number of tower erected, length of pipe laid).

   d Level of effort (must only be used for indirect work (e.g., project management or overheads))

   - Activities that do not directly produce defined end products that can be objectively measured.
   - Includes project management and other overhead activities that occur through the life of a project.

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- Usually measured by number of hours x billing (hourly) Rate against a predefined allocation for the project.

4. Once earning rules are established on a project, the rules must not be changed.

   - Any changes to the configuration of the earnings rules during a project must be approved by the EPMO. This may occur if earning rules were established before the full scope of the project was fully known.

5. LOBs may define common earning rules by project/work type.

6. LOBs must consider the following elements when deciding which type of earning rules to implement:

   - Characteristics of work (duration and measurability)
   - Requirements
   - Measurement Units (hours or other measureable units)
   - Risk
   - Level of accuracy to measure (cost, schedule, and performance)

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Appendix G, WBS Attribute Table, Naming Conventions, Abbreviations
Page 1 of 3

A. Guidance for setting up a project in SAP Project Systems for use by LOBs:

1. Figure 1 (SEE page 5) and Table 1 should be referenced when setting up a project in SAP Project Systems to verify the WBS is applied per the requirements of the PM-1015S, "Project Cost Management Standard."

2. The Standard WBS and approved variations can be found on the Enterprise Project Management Office (EPMO) SharePoint Site:

   a Standard WBS

   b Reduced WBS

   c Environmental Remediation WBS

   d IT Standard WBS

   e IT Reduced WBS

3. SPSI WBS Naming Conventions

   a Requirements

   - LOBs must select the appropriate WBS structures based on the requirements Section 2 of the Project Cost Management Standard and Project Governance Standard. See WBS Attribute Matrix (SEE Figure 7, "WBS Attribute Matrix")
   - Any additional structures must be approved by the EPMO
   - Naming convention is based on ("LOB – "WBS Structure Name") – See Attribute matrix for additional requirements

Table 4 - SPSI WBS Naming Conventions

Project Type SPSI Naming Convention	Description	Applicability (reference WBS Attribute Matrix for further detail)
ET-LPE	ET&S-Standard WBS Project-Expense	*All thresholds for ET&S Expense projects*
ET-LPC	ET&S-Standard WBS Project-Capital	*All thresholds for ET&S Capital projects*
ED-LPE	ED-Standard WBS Project-Expense	*All thresholds for ED Expense projects*

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ED-LPC	ED-Standard WBS Project-Capital	*All thresholds for ED Capital projects*
GT-LPE	GT-Standard WBS Project-Expense	*All thresholds for GT Expense projects*
GT-LPC	GT-Standard WBS Project-Capital	*All thresholds for GT Capital projects*
GD-LPE	GD-Standard WBS Project-Expense	*All thresholds for GD Expense projects*
GD-LPC	GD-Standard WBS Project-Capital	*All thresholds for GD Capital projects*
ET-SPE	ET&S-Reduced WBS Project-Expense	ET&S *Governance Threshold 4 Expense projects only*
ET-SPC	ET&S-Reduced WBS Project-Capital	*ET&S Governance Threshold 4 Capital projects only*
ED-SPE	ED-Reduced WBS Project-Expense	*ED Governance Threshold 4 Expense projects only*
ED-SPC	ED-Reduced WBS Project-Capital	*ED Governance Threshold 4 Capital projects only*
GT-SPE	GT-Reduced WBS Project-Expense	*GT Governance Threshold 4 Expense projects only*
GT-SPC	GT-Reduced WBS Project-Capital	*GT Governance Threshold 4 Capital projects only*
GD-SPE	GD-Reduced WBS Project-Expense	*GD Governance Threshold 4 Expense projects only*
GD-SPC	GD-Reduced WBS Project-Capital	*GD Governance Threshold 4 Capital projects only*
IT-PJE	IT Standard WBS Project-Expense	*All thresholds for IT Expense projects*
IT-PJC	IT Standard WBS Project-Capital	*All thresholds for IT Capital projects*
IT-SPE	IT Reduced WBS Project-Expense	*IT Governance Threshold 4 Expense projects only*
IT-SPC	IT Reduced WBS Project-Capital	*IT Governance Threshold 4 Capital projects only*
IT-CO	IT-Core (Non-project)-Expense	*Specific IT work only*
IT-NP	IT-NP App Enhancement (Non- project)-Expense	*Specific IT work only*
IT-OM	IT-O&M (Non-project)-Expense	*Specific IT work only*
PF-LPE	PGEN Fossil - Standard WBS Project - Expense	*All thresholds for PGEN Fossil Expense projects*

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PF-LPC	PGEN Fossil - Standard WBS Project - Capital	*All thresholds for PGEN Fossil Capital projects*
PH-LPE	PGEN Hydro - Standard WBS Project - Expense	*All thresholds for PGEN Hydro Expense projects*
PH-LPX	PGEN Hydro - Standard WBS Project - Capital	*All thresholds for PGEN Hydro Capital projects*

Figure 7 - WBS Attribute Matrix

WBS KEY	Name	Governance Threshold				LOBs									
		GT1 >$100M	GT2 >$20M	GT3 <$20M	GT4 <$20M	IT (K)	CRESS (*tbd*)	DCPP (D) Not Used	ET&S (T)	ED (E)	GT (N)	GD (G)	PGEN Fossil (F)	PGEN Hydro (H)	ER (*tbd*)
LPC or LPE	Standard WBS	Y	Y	Y	Y	N	N	N	Y	Y	Y	Y	Y	Y	N
SPC or SPE	Reduced WBS	N	N	N	Y	N	N	N	Y	Y	Y	Y	N	N	N
TBD	Remediation WBS	Y	Y	Y	Y	N	N	N	N	N	N	N	N	N	Y
IT-LPC or IT-LPE	IT Standard WBS	Y	Y	Y	Y	Y	N	N	N	N	N	N	N	N	N
IT-SPC or IT-SPE	IT Reduced WBS	N	N	N	Y	Y	N	N	N	N	N	N	N	N	N
IT-CO	IT Core (Non-project)	N/A	N/A	N/A	N/A	Y	N	N	N	N	N	N	N	N	N
IT-NP	IT NPAE (Non-project)	N/A	N/A	N/A	N/A	Y	N	N	N	N	N	N	N	N	N
IT-OM	IT O&M (Non-project)	N/A	N/A	N/A	N/A	Y	N	N	N	N	N	N	N	N	N

WBS KEY	Name	Allocation		Cost Limit			WBS Image
		Expense (E)	Capital (C)	Minimum Estimated Total Gross Project Cost	AACE Class 5 Maximum Base Estimate Limit (Low Complexity)	Estimated Total Gross Project Cost	
LPC or LPE	Standard WBS	Y	Y	>$1M	n/a	n/a	Standard WBS
SPC or SPE	Reduced WBS	Y	Y	>$1M	<$15M	$<20M	Reduced WBS
TBD	Remediation WBS	Y	Y	>$1M	n/a	n/a	Env Rem
IT-LPC or IT-LPE	IT Standard WBS	Y	Y	>$1M	n/a	n/a	IT Standard WBS
IT-SPC or IT-SPE	IT Reduced WBS	Y	Y	>$1M	<$15M	$<20M	IT Reduced WBS
IT-CO	IT Core (Non-project)	Y	N	n/a	n/a	n/a	IT Core WBS (Non-project, expense only)
IT-NP	IT NPAE (Non-project)	Y	N	n/a	n/a	n/a	IT Non-Project App Enhancement (Non-project, expense only)
IT-OM	IT O&M (Non-project)	Y	N	n/a	n/a	n/a	IT Operations & Maintenance (Non-project, expense only)

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Project Cost Management Standard

Appendix H, Project Cost Estimate Example
Page 1 of 1

A. Example Scenario: Project X has a best case base estimate of $39.6M. The project is classified as a high complexity project with an AACE Class 3 The project has actuals of $2.5M and commitments of $0.5M. The project has the following information in the Risk Allowance Table.

Risk Allowance Table									
	Gate 1				Gate 2				
Risk #	Likelihood	Weight	Risk ($ M)	Weighted Risk ($M)	Likelihood	Weight	Risk ($ M)	Weighted Risk ($M)	
1	M	0.5	$ 10.0	$ 5.0	L	0.2	$ 10.0	$ 2.0	
2	L	0.2	$ 2.0	$ 0.4	L	0.2	$ 1.0	$ 0.2	
3	M	0.5	$ 2.0	$ 1.0	L	0.2	$ 1.5	$ 0.3	
4		-	$ -	$ -	L	0.2	$ 10.0	$ 2.0	
5		-	$ -	$ -	L	0.2	$ 2.0	$ 0.4	
Total			$ 14.0	$ 6.4			$ 24.5	$ 4.9	

1. High Case (Authorized Amount) Estimate Calculation

   a High Case = Best Case + Total Identified Risk + Total AACE

   - Total Identified Risk = $14.0M + 24.5M = $38.5M
   - Total AACE = AACE Factor X (Best Case + Total Risk – Incurred Cost) = 30% X ($39.6M+38.5M-$2.5M) = $22.7M
   - High Case = $39.6M + $38.5M + $22.7M = $100.7M

2. Expected Case Estimate Calculation

   a Expected Case = Best Case + Expected Value of Risk + Expected AACE Uncertainty

   - Expected AACE Uncertainty = AACE Factor X Total AACE = 10% X $22.7M = $2.3M
   - Expected Value of Risk (Risk Register) = $6.4M + $4.9M = $11.3M
   - Expected Case = $39.6M + $11.3M + $2.3M = $53.1M

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 22

ATTACHMENT D

EPIC 3.43 MOMENTARY OUTAGE

Pacific Gas and Electric Company

EPIC Final Report

Program	***Electric Program Investment Charge (EPIC)***
Project	***High Density Data Meters, Residential Electric Integrity Sensor, and Next Generation Smart Meter Evaluations***
Reference Name	***EPIC 3.43 Momentary Outage***
Department	*Distribution Grid Operations*
Project Sponsor	[redacted] – Asset Health Performance Center
Project Business Lead	[redacted]
Project Technical Lead	[redacted]
Contact Info	EPIC_Info@pge.com
Date	February 27, 2026
Version Type	*Final*
Version	7.0

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Table of Acronyms

AHPC	Asset Health & Performance Center
AMI	Advanced Metering Infrastructure
AMM	Advanced Meter Management
ATS	Applied Technology Services
AWG	American Wire Gauge
CPUC	The California Public Utilities Commission
DI	Distributed Intelligence
EPIC	Electric Program Investment Charge
HTFD	High Threat Fire District
ILIS	Integrated Logging Information System
PG&E	Pacific Gas & Electric
PLC	Power Line Carrier
RF	Radio Frequency
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric Company

1 Executive Summary

The widespread deployment of electric smart meters by utilities over the past ten years has in many ways paralleled the uptake by consumers of smartphones in the marketplace over the past twenty. Both are electronic communication and measurement tools that feature miniaturized chipsets of embedded microprocessors, memory, and modems whose affordability have increased with the reduction in computed, storage, and bandwidth costs. Perhaps it was inevitable that smart meter equipment and network vendors are now adopting the smartphone "app store" model too. Specialized features and functions packaged as purpose-built code, are now published by the meter vendors or third party developers to the smart meter store, to be downloaded to run on a utility's smart meters to accomplish specific goals. The first smart meter applications (hereinafter "apps") concentrated on helping consumers manage their energy usage and budget, but apps are now increasingly available to maintain the health of the grid by providing alerts on anomalies or concerning load and voltage patterns found on the distribution network. The specific use cases featured in this report concentrates on the merit of two apps published by the smart meter vendor we have partnered with that promise to alert anomalies of concern on PG&E's distribution network. Both apps can theoretically lower the risk of outages and even ignition.

The Location Awareness app ostensibly identifies misregistered meter-transformer pairs; in this way it indirectly helps to identify transformers that may be servicing loads that are too large for the transformer's capacity to safely service. The same app can identify the phase of transformers, which can also contribute to safety by making load imbalances by phase more visible to PG&E's distribution planning team. In turn, a more considered plan to install equipment to balance load and phase would increase equipment life, and by extension, the safety margin of the equipment.

Finally, the High Impedance app lowers outage and ignition risk by identifying service drops with an anomaly between the meter panel and the terminals on the secondary side of the service transformer. The anomalies that can increase impedance are typically of two sorts that interrupt the steady flow of current along the secondary: vegetation contact with bare conductor, and incomplete or intermittent connections such as those caused by corrosion, bad splicing, or loose sockets . Any of these can lead to heat at the point of the anomaly which can eventually lead to an outage, or even ignition if arcing occurs across a gap in the conductor or connector.

This trial of the Next Generation Meter using two apps had two purposes. First, the use cases identified above are all beneficial to PG&E and our customers, so the ability to field test the package of smart meters and apps were the explicit value proposition of this project. Second, if the first two apps and smart meters could prove their mettle, then PG&E would have the technical and business confidence to examine other apps and use cases that might be focused on customer needs, safety, grid operations, and other important metrics.

Key Objectives

- To evaluate whether a high density stream of meter data can detect or predict service transformer failures, including those that may lead to outages, or correlate to some risk of ignition, if left unaddressed
- To evaluate if a residential electrical integrity sensor can be used to detect faults and outages on the distribution network, deduced from voltage irregularities and high frequencies carried by the voltage signal, some of which provides some risk of ignition if left unaddressed; data was collected from sensors which were previously plugged into the 120 V / 240 V wall sockets inside roughly 11,000 PG&E customer premises
- To evaluate whether Next Generation Smart Meters, installed on PG&E's secondary distribution network, and running applications, can detect various anomalies (phase ID, transformer/meter matching, and high impedance issues) whichmay lead to outages, or carry some risk of ignition, if left unaddressed. Anomalies expected to be identified originate on the secondary network only, along shared and dedicated conductors, and the connectors between conductors, service transformers, and meters

Key Accomplishments

- High Density Data Analysis: Installed, ran, and collected data from the high density data analysis application running on 500,000 production meters; developed machine-learning models to determine if high density data could predict transformer-based outages better than status quo data density
- Residential Electric Integrity Sensors: Investigated a subset of event data collected from several thousand homes in PG&E territory; the subset consisted of 32 events analyzed by a trained machine-learning model to electrically classify and physically locate the anomaly; validated whether Residential Electric Integrity sensors could, as a first step, agree with PG&E on the presence, classification and location of these faults and outage events
- Next Generation Smart Meters: Installed, ran, and collected data from two "distributed intelligence" applications, or "apps", running on 410 dedicated Next Generation Smart Meters; validated whether these apps could locate physical anomalies in the secondary that could identify secondary impedance issues thatcause ignition, detect transformers that were mis-registered to the wrong service drop, and identify the relative phase of service drops

Key Takeaways

- High Density Data Analysis: Compared with existing production smart meter data streams (15-minute, 60-minute, and instantaneous data alerts, or "traps"), the more frequent High Density Density Analysis five-minute and corresponding richer trap data was less accurate (59% vs 66%) in predicting "one-day ahead" transformer failures despite its greater sampling granularity. The accuracy shortfall compared to the baseline was likely due to higher data error and data incompleteness rates of the high density data streams, and the low number of validated transformer failures captured over the six-month learning period (585 failed

transformers). These issues likely resulted in a below optimum dataset for training the machine learning models in the time allotted.

- Residential Electric Integrity: Prior to the formalized event-based correlation study described below, and at the beginning of a collaboration the vendor of the Residential Electric Integrity Sensor, PG&E examined detected events originating in its service territory that were not tied to PG&E faults or outage events. It was an effort to determine whether Residential Electric Integrity sensors were capable of identifying emerging or incipient anomalies that could eventually lead to faults or outages. During the course of about six months, the vendor would report their events to PG&E, which would follow up by examining local smart meter data and the dispatch of a troubleman crew to the locations identified. This preliminary study was inconclusive, in that no emerging physical anomalies were found at the locations identified. PG&E then analyzed 32 events in detail during the more formal collaboration between the two parties:

    - Starting with a Residential Electric Integrity event: The vendor identified six arcing events. Only two of the six events could be corroborated. Of the 19 Residential Electric Integrity sensors involved in detected the two corroborated faults, 11 identified the wrong circuit as the location.

    - Starting with a PG&E event: Switching strategies, PG&E then analyzed 26 events (outages or faults) already logged on its Integrated Logging Information System (ILIS) event platform, to determine if Residential Electric Integrity had detected them as well. Of these 26 events, 20 were outages. 13 of these outages were due to a downed conductor or a broken pole and Residential Electric Integrity detected 12. Residential Electric Integrity sensors classified the 12 as either a sag or some combination of sag, power outage, brownout, frequency issue, or high-energy arcing. In aggregate, 1692 sensors detected these twelve outages, but 84.4% of them (1428 of 1692) identified the wrong circuit.

    During this study, even when multiple Residential Electric Integrity sensors did corroborate an actual PG&E event by timestamp:

    - it was rare for the geographical center of simultaneous Residential Electric Integrity events from multiple sensors to come within 1000 feet of the actual event location

    - it was rare for the actual circuit featuring the anomaly to produce Residential Electric Integrity events from a majority of its Residential Electric Integrity sensors. Instead, a much larger multiple of Residential Electric Integrity sensors in the area did not respond at all. It may be explained by the fact that each Residential Electric Integrity sensor is connected to a home circuit, and as such, sensors may have a difficult time detecting anomalies external to the premise in which they are located. In other words, the sensor and its machine learning tool must filter out both home circuit signals and secondary distribution signals as well. As such, the primary-side circuit anomaly may become buried in this noise.

    - the main issue was the location of the Residential Electric Integrity sensors that provided positive corroboration (Residential Electric Integrity sensors detecting an event at the same time that PG&E did as well). In general, when an event was

corroborated, a higher proportion of Residential Electric Integrity sensors *not* on the PG&E circuit of interest shared the timestamp with the PG&E's event log. This locational inaccuracy would be a challenge if Residential Electric Integrity sensors were relied upon to anticipate emerging faults and trigger the dispatch of multiple patrols to multiple circuits. It would have helped to further characterize the quality of Residential Electric Integrity events by having the quantity and locations of those Residential Electric Integrity sensors that *did not* corroborate an event. That would have allowed PG&E to weight Residential Electric Integrity events by the proportion of those Residential Electric Integrity sensors that detected an event vs those on the same circuit that did not, thereby allowing PG&E to weight the circuits, or even sections of circuits, where there was a higher proportion of positive Residential Electric Integrity activity. Circuits featuring a larger proportion of Residential Electric Integrity sensors that corroborated an event could be weighted higher in importance, but this data was not forthcoming.

In contrast to Residential Electric Integrity Sensors, when other sensor technologies are deployed by PG&E on these same circuits, they have correctly identified the event's circuit 100% of the time with no false positives on other circuits. The sensors are typically deployed along each circuit strategically so that together with modelling and universally installed protection equipment, PG&E can consistently narrow down the location of an anomaly causing an event to within 1000 feet.

- Next Generation Smart Meter: The High Impedance app issued seven alerts intended to identify conductor and connection anomalies. In four of those cases, it correctly found electro-mechanical issues that could lead to ignition along the shared secondary network. Greater accuracy could probably be achieved with an adjustable high impedance trigger value that could account for differences in secondary conductor gauge and length and service transformer capacity. Next Generation Smart Meter's Location Awareness app was 100% accurate in identifying the seven instances where PG&E misregistered a service drop's correct transformer. In practice, this reduces both the risk of overloading transformers, and also reduces the risk of crews arriving at the wrong location or repairing the wrong equipment when responding to an event. The same app was also 100% accurate in determining the correct relative phase supplied by 24 service transformers. Accurately identifying relative phase everywhere in a circuit also reduces the risk of overloading, which in turn reduces the outage rate as well as damage to equipment, while more accurately locating open circuit faults.

Recommendations

- High Density Meter Analysis: Although the machine learning models were likely trained insufficiently due to a lack of data in the time allotted, additional fine-tuning would have likely provided only a marginal improvement in its predictive powers when compared with existing normal data density smart meter data. PG&E's Asset Health and Performance Center (AHPC) also determined that the next generation of meters would greatly surpass the capabilities of High Density Meter Analysis (which had a sample rate of 4 kHz at the time). Moreover, the

cost of implementing High Density Meter Analysis software would have reached approximately $10.5M to implement. Given that existing data is more accurate than High Density Meter Analysis identifying both healthy and failing / failed transformers, it was determined that two other smart meter investments would yield more actionable and cost-effective results, and inform the recommendations to discontinue High Density Meter Analysis:

  - fine-tune existing 15-minute smart meter data modelling (this has subsequently evolved into the IONA program, a production version of EPIC 3.20 "Data Analytics for Predictive Maintenance".
  - invest in Next Generation Smart Meters and their grid health apps (the subject of the third demonstration discussed in detail in this report); note that High Density Data Analytic's logic has since been subsumed into various Next Generation Smart Meter DI apps

- Residential Electric Integrity: To be deemed valuable for detection, any detector must:

  - be precise in identifying an emerging anomaly's location; for example it should at least unambiguously identify its circuit. Identifying a precise location after PG&E has already logged an event is not of much value, but would at least show correlation to real-world conditions. Today, smart meter data provides the closest source-side device in terms of location, and as a result outperforms the Residential Electric Integrity results in the study

  - be sensitive enough so that the magnitude of the signal from an emerging anomaly it detects is proportional to its scale of concern, and grows as the physical anomaly grows. At least in the context of this study, neither the proportion of anomalies on a given circuit compared with others, or the size of the anomalies gave any indication of the degree of anomaly severity

  The results of the Residential Electric Integrity study were ambiguous for location and magnitude, and as a result, it is recommended that PG&E not proceed with the technology at this time.

- Next Generation Smart Meter: Due to the anomaly and phase identification success of the two Next Generation Smart Meter apps, it is recommended that the Next Generation Smart Meter undergo the PG&E certification process as quickly as possible. Pending meter and app qualification, the Next Generation Smart Meter ecosystem can start replacing existing production meters across the entire distribution network at PG&E, and in so doing, reduce the risk of ignition. In parallel, it is recommended that the apps described and any additional apps developed for the Next Generation Smart Meter platform to detect anomalies that could lead to ignition, should be tested both in the lab and in future demonstration projects.

Conclusion

- Next Generation Smart Meters running just two apps appropriate to the distribution network's health and integrity during this demonstration showed great promise in safeguarding life, environment, and utility assets. The "app" approach running on production meters is very likely the path forward for PG&E and other utilities to protect the safety of customers and the health of the grid. High Density Data Analytics capability has been eclipsed by both Next Generation Smart Meter technology and existing smart meter data, while Residential Electric Integrity has issues finding anomalies that can develop into faults or outages, and cannot precisely locate logged events that have already occurred, which smart meters can already find with precision. As a result, the main body of this report will concentrate on the success of the Next Generation Smart Meter demonstration which will be recommended for promotion to production.

2 Introduction

This report documents the EPIC 3.43 Momentary Outage Information project achievements, highlights key learnings from the project that have industry-wide value, and identifies future opportunities for PG&E to leverage this project.

The California Public Utilities Commission (CPUC) passed two decisions that established the basis for this demonstration program. The CPUC initially issued D. 11-12-035, *Decision Establishing Interim Research, Development and Demonstrations and Renewables Program Funding Level*[1], which established the Electric Program Investment Charge (EPIC) on December 15, 2011. Subsequently, on May 24, 2012, the CPUC issued D. 12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020*[2], which authorized funding in the areas of applied research and development, technology demonstration and deployment (TD&D), and market facilitation. In this later decision, CPUC defined TD&D as "the installation and operation of pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of the operational and performance characteristics and the financial risks associated with a given technology."[3]

The decision also required the EPIC Program Administrators[4] to submit Triennial Investment Plans to cover three-year funding cycles for 2012-2014, 2015-2017, and 2018-2020. On November 1, 2012, in

[1] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/156050.PDF

[2] http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/167664.PDF

[3] Decision 12-05-037 pg. 37

[4] Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Southern California Edison (SCE), and the California Energy Commission (CEC)

A.12-11-003, PG&E filed its first triennial Electric Program Investment Charge (EPIC) Application with the CPUC, requesting $49,328,000 including funding for 26 Technology Demonstration and Deployment Projects. On November 14, 2013, in D.13-11-025, the CPUC approved PG&E's EPIC plan, including $49,328,000 for this program category. On May 1, 2014, PG&E filed its second triennial investment plan for the period of 2015-2017 in the EPIC 2 Application (A.14-05-003). CPUC approved this plan in D.15-04-020 on April 15, 2015, including $51,080,200 for 31 TD&D projects.[5] On April 28, 2017, in A.17-04-028, PG&E filed its third triennial EPIC Application at the CPUC, requesting authorization for its for 43 Technology Demonstration and Deployment Projects. CPUC approved this plan through D.18-10-052 on October 25, 2018, and D.20-02-003 on February 10, 2020, and authorized $49,771,845 for the 43 TD&D projects.

Pursuant to PG&E's approved 2015-2017 EPIC triennial plan, PG&E initiated, planned and implemented the following project: 3.43 Momentary Outage Information. Through the annual reporting process, PG&E kept CPUC staff and stakeholder informed on the progress of the project. The following is PG&E's final report on this project.

3 Project Summary

The Next Generation Smart Meter demonstration was funded as part of EPIC 3.43, along with two other projects run by PG&E's Asset Health and Performance Center (AHPC). All three EPIC 3.43 projects feature new technologies that were evaluated to determine if they can reliably alert to distribution anomalies that may lead to ignition. The general value proposition of the Next Generation Smart Meter is that it can run multiple specialized "apps", like a smart phone, in addition to metering usage and demand to high precision for billing, as is expected of a production meter. These apps promise a distributed intelligence approach to monitoring the grid, by processing data onboard, and arriving at preliminary conclusions at the edge of the network from multiple Next Generation Smart Meters.

PG&E strove to determine if the EPIC 3.43 mission of finding distribution anomalies could be satisfied with two apps designed by a meter vendor. The two apps chosen for the demonstration, Location Awareness and High Impedance, would be evaluated for their efficacy in monitoring the distribution network on the secondary side of each service transformer. Budget and time constraints provided the demonstration with 410 Next Generation Smart Meters for twelve to fifteen months. The Next Generation Smart Meters were installed next to the customers' billing meter using a special meter socket adapter so that customer service and billing would not be interrupted. The meters were located at residences on the Silverado 2104 distribution circuit. The entirety of the test population, in

5 In the EPIC 2 Plan Application (A.14-05-003), PG&E originally proposed 30 projects. Per CPUC D.15-04-020 to include an assessment of the use and impact of EV energy flow capabilities, Project 2.03 was split into two projects, resulting in a total of 31 projects.

Angwin and in Deer Park, was located within a Tier 3 high fire threat district (HFTD), a detail in keeping with the EPIC WMP (wildfire mitigation plan) mandate.

4 Project Activities, Results, and Findings

The scope of work for this project included:

(1) Installing the Next Generation Smart Meters co-located with production smart meters at 410 residences, as well as seven access points to constitute a dedicated Next Generation Smart Meter demonstration mesh network
(2) Loading the two apps on the Next Generation Smart Meter pilot meters
(3) Running jobs to collect and forward the app data to the analysis platform
(4) Data analysis of the alerts forwarded by the two apps, and of non-alert (conforming) data
(5) Field inspections to validate Next Generation Smart Meter app data for true and false positives and for true and false negatives

4.1 Planning

Silverado 2104 was the distribution circuit selected by AHPC for the demonstration in late 2021. This circuit offered multiple advantages for the demonstration. For example, it contained the towns of Angwin and Deer Park, and a portion of Saint Helena, offering a relatively high density of service points for a rural area, to help shorten the installation timeline. More importantly, the proposed deployment areas lie within a Tier 3 high fire threat district (HFTD), which would be an ideal proving ground for the lessons learned from apps chosen mainly for their promise of ignition avoidance. To that point, the circuit features lush vegetation, and relatively long secondary conductors comprising both the shared secondary network and the participating service drops.

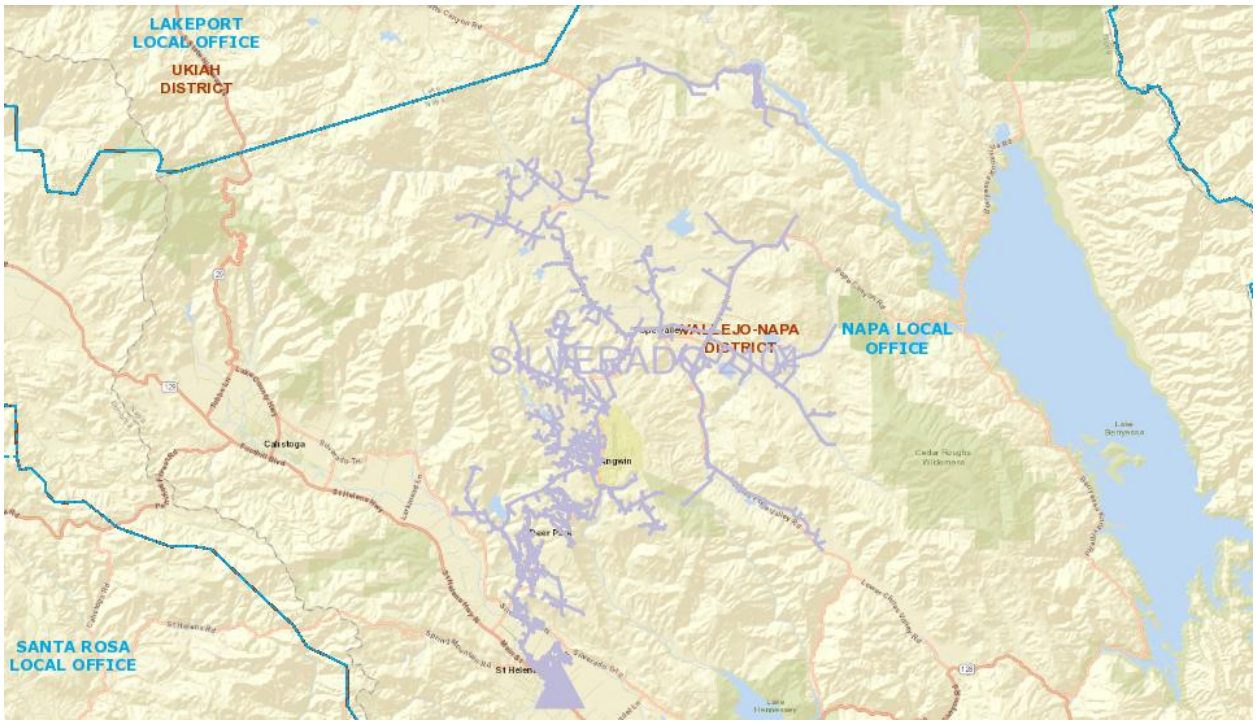


Fig 1. Silverado 2104 in the North Bay division was the ultimate circuit selected for the demonstration. It spans the city of Angwin and parts of St Helena and Deer Park, and is shown here in purple, with the triangle represented the substation.

After the final budget was determined, and during the planning phase (December 2021- October 2022), PG&E took an iterative approach to select Next Generation Smart Meter pilot sites:

- AHPC submitted about 1230 sites to the vendor that met its account and location criteria
- The vendor in turn conducted a preliminary network design on these sites, yielding:
    - a subset of 432 service point candidates for Next Generation Smart Meter installation. These would be "dual- socketed" along with the "production" billing meter already onsite
    - a subset of eight service points located to connect the candidate meter sites and provide a backhaul to the data platform. These "access points" take the form of a meter socket for the purposes of the demonstration. These "socket APs" would plug into the existing meter base, and serve as the new meter base for the production meter already onsite
- AHPC provided these 440 customer sites on the circuit to the PG&E Infrastructure team that validates telecom reliability, to serve as a check on the network design. Some service points were swapped out to maintain integrity of the design as a result
- The PG&E Customer Engagement team contacted these candidate customers
    - to inform them of the goals of the pilot
    - to alert them to what would likely be a very short interruption of their electrical service during installation, and
    - to provide them with a customer outreach representative in case they had any concerns or if they wished to opt out
- During this planning phase, less than a dozen customers elected not to participate in the Next Generation Smart Meter demonstration. These were replaced by backup service points that were reasonably close to the original sites, to minimize network re-design

- The vendor's network team confirmed the cellular service and mesh network viability of these alternate sites

By the end of the planning phase, two geographic pockets of meter installations and supporTed access point installations emerged. Both pockets were well within Tier 3 High Fire Threat Districts:

1. Angwin, with 83% of meter sites and five of the eight access points
2. Deer Park / Saint Helena Hospital, with the remaining meters and three access points.

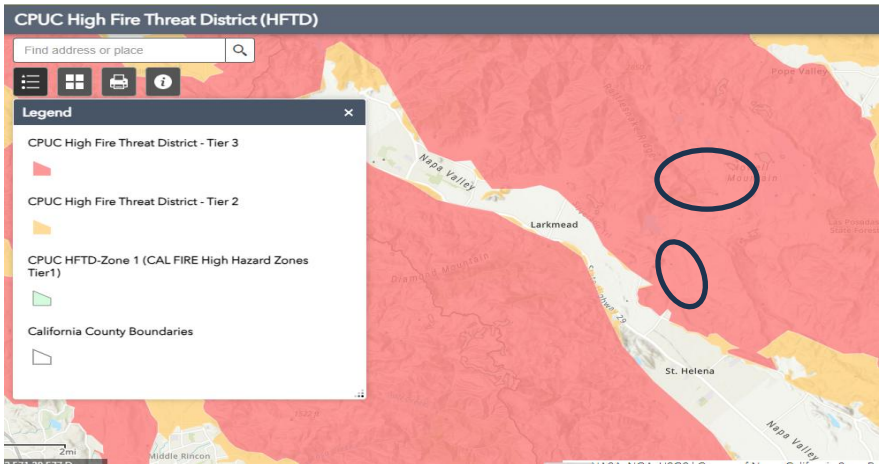


Fig. 2 The planned Next Generation Smart Meter installation areas included a northeast pocket centered on the densest part of Angwin to the northeast, and a smaller southwest pocket in Deer Park and by the Saint Helena Hospital / Adventist Health campus in the southwest. All meters were contained within a Tier 3 High Fire Threat District.

Simultaneously during the planning phase, critical technical tasks to support the pilot were completed in advance of deployment:

- A representative sample of meters was tested in January and February of 2022 at PG&E's Applied Technology Services Laboratory (ATS) to confirm they would meet high voltage requirements
- AHPC partnered with PG&E's North Bay Field Metering group to perform the installations. This local meter installation and maintenance team conducted internal training
- Dual socket adapters were ordered and tested
- Training sessions with a sample of Next Generation Smart Meters, production meters, and dual socket adapters
- The vendor and PG&E collaborated to configure two portals for use during the demonstration:
  - a Next Generation Smart Meter instance of Advanced Meter Management (AMM), a meter management portal, configured to be accessible from inside PG&E's firewall. Meter device files and meter location files would be uploaded to this site regularly as installations were completed. This site would be constantly monitored to validate meter operational status and to alert the pilot team to any installation errors
  - a dedicated platform to deploy Distribute Intelligence (DI) agents to the meters and to collect DI app data from the meters for analysis and display in a dashboard. This

dedicated repository prevented the possibility of any interference with the collection of proprietary customer usage and billing data

- The first article Next Generation Smart Meters, with a distinctive yellow patch on the nameplate, and labelled “non-PROD,” arrived for inspection by the Meter Engineering team in early September 2022 and passed inspection shortly thereafter

4.2 Installation

Next Generation Smart Meter and access point deployment stretched from December 2022 through June 2023, which included an intense storm season that lengthened the planned installation schedule. With customer opt-outs, and locations where there was insufficient clearance to fit the dual-socket adapter on and around the electrical panels, the total number of meters installed was 410.



An installation for the demonstration in the horizontal configuration. The Next Generation Smart Meter is on the left, directly above the meter socket, while the billing “production” meter is on the right. This orientation ensures that the Next Generation Smart Meter does not appear as billable load to the billing meter.

The meters themselves would be co-located with the participating billing, or "production" meter. The dual-socket adapter was installed, and then both meters were socketed together inside the adapter before rings and seals were replaced.



A typical vertical installation for the pilot with the Next Generation Smart Meter on top. Use of the vertical dual socket adapter ensured that the breaker panel to the right could be accessed.

Upon completion, the installation footprint in the Angwin pocket:

- included 339 meters and five access points
- measured 1.5 miles north to south, and 1.25 miles east to west, with the entirety to the west of the local airport, and stretching into some of the vineyard estates west of the dense residential core

The Deer Park / Saint Helena Hospital pocket was longer, thinner, and sparser:

- comprised 71 meters and three access points across Deer Park and the northeastern -most reaches of Saint Helena
- measured nine-tenths of a mile north to south, and just one-quarter of a mile east to west

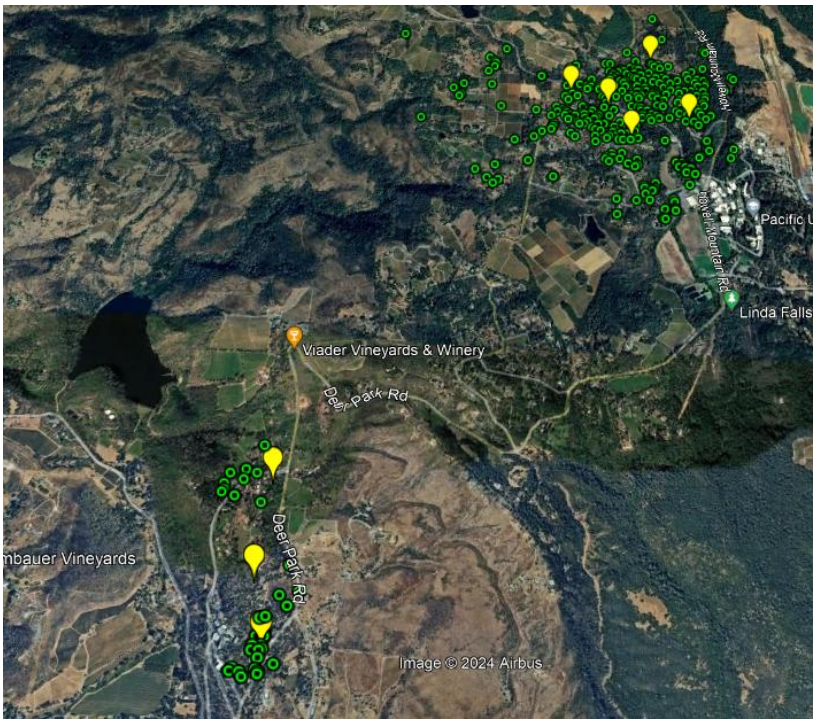


Fig. 3 The final install footprint, featuring two pockets on Silverado 2104 shown in the Google Earth application. The larger Angwin pocket is at the top right, while the Deer Park / Saint Helena Hospital area is at bottom left. Access points are shown in yellow, while meters are coded in green.

4.3 Location Awareness: Theory of Operation

The Next Generation Smart Meter vendor put forth two value propositions for the Location Awareness app that PG&E subsequently tested:

1. identifying which meter-transformer pairs are false
2. identifying the phase of each service

Theory of Meter-Transformer Mismatches with Location Awareness

Misidentifying the transformer belonging to a service drop has profound implications for electric utilities. It can lead to load imbalance, overheating, deferred servicing and upgrading with catastrophic implications. During an outage, it can contribute to mistaken switching, and a delay of precious minutes or longer in finding the correct transformer to service when ignition may be imminent. Anecdotally industry-wide, at least a few percent of a utility's transformers are matched to the wrong customer service, which in the case of PG&E, would amount to tens of thousands of mismatches.

Next Generation Smart Meters are equipped with a power line carrier, or "PLC" chipset, running firmware that the vendor licenses from a third party. Theoretically, only Next Generation Smart Meters that share a service transformer can communicate with each other over the PLC protocol, because PLC signals originating from the Next Generation Smart Meter are constrained to the secondary side of each service transformer. The physical decoupling between a transformer's primary

and secondary coils serves to mostly prevent crosstalk with meters connected to far-away transformers from talking with each other via PLC.

Regularly, installed Next Generation Smart Meters loaded with the Location Awareness app broadcast their IDs over PLC and then listen for any responses from other meters that include their own IDs. In this way, each meter builds a table of its transformer's other meters, and rebroadcasts upon meter reboot, in case meters are moved to another transformer.

Via broadcast, Next Generation Smart Meters running Location Awareness also regularly exchange their voltage line's sinusoidal zero-crossing timestamp and its voltage polarity on top of their 900 MHz AMI signal. Thus, each Next Generation Smart Meter can calculate its phase relative to the rest of its peer AMI population. Again, this phase ID broadcast is repeated when meters are powered back up in case meters are moved.

Thus, for meters connected to single-phase transformers:

1. For any Next Generation Smart Meter whose PLC channel is silent, its phasing and the capability to identify its nearest neighbors via the AMI mesh protocol can provide an approximate location.
2. For any Next Generation Smart Meter whose PLC channel is active, its "transformer group", consisting of other Next Generation Smart Meters on the same transformer, can be identified. If the transformer's registered location is accurate, the meter (and all Next Generation Smart Meters in the group) can be explicitly found.

The practical implications of this theory of operation require that each participating transformer be connected to at least two Next Generation Smart Meters as the ideal situation. That is not always possible even in a full deployment of Next Generation Smart Meters where there are typically some transformers connected to a single meter (although the proportion varies widely by circuit). In the case of the Next Generation Smart Meter demonstration, per the histogram below, 47 transformers out of 139 connected to just one Next Generation Smart Meter each:

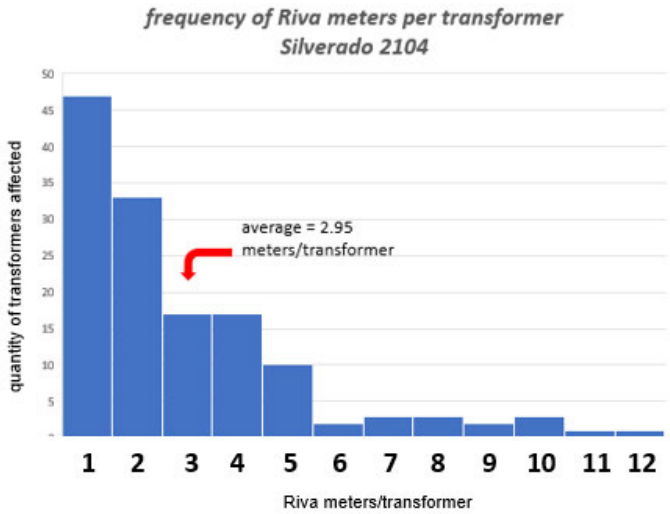


Fig 4. On average, just under three Next Generation Smart Meters shared the same transformer, although 47 meters were knowingly deployed with no other Next Generation Smart Meters on their transformers and would not necessarily benefit from Location Awareness.

Theory of Phasing with Location Awareness

At its most basic, the theory of Next Generation Smart Meter phasing involves each Next Generation Smart Meter broadcasting its zero-crossing timestamp, and its polarity at the instant of crossing (negative-going or positive-going). Meters can then be grouped according to the lag between their zero crossings of the same polarity. The broadcasts are transmitted on the meter's 900 MHz RF channel, the same channel as its AMI communications, rather than via the PLC protocol, on a channel used to establish transformer groups and general location.

The Next Generation Smart Meter deployment area on Silverado 2104 includes a step-down transformer. On the source side of this transformer (the side closest to the substation), the circuit is 21 kV 4-wire wye, while the stepped-down side of the circuit is transformed into a 12 kV 3-wire delta configuration.

In theory, each side of the circuit can provide a two-wire service drop through a transformer's primary side in six possible ways. With the phase designated as A serving as a reference for convenience, and its positive-going zero-crossing designated as 0 degrees, here are the twelve possible service wiring combinations for each meter:

possible service combinations	
connection & polarity	relative phase
wye-side (L-N)	
AN	0
BN	120
CN	-120
NA	180
NB	-60
NC	60
delta-side (L-L)	
AC	30
CB	-90
BA	150
CA	-150
BC	90
AB	-30

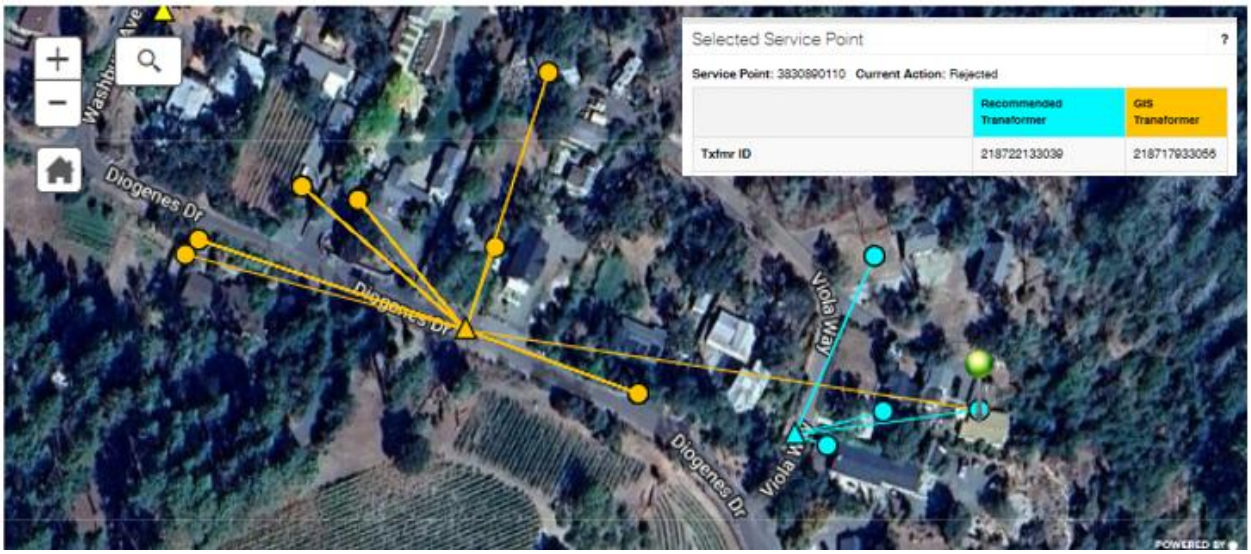
Table 1. Theoretical service phase combinations

4.4 Location Awareness Meter-Transformer Mismatches: Data and Results

In the summer of 2023 after meter installations were completed, PG&E provided installation details for the 410 Next Generation Smart Meter locations to the meter vendor, in the form of an xml file. This "distribution equipment hierarchy", or DEH file, encoded every meter's presumed physical location, together with its officially registered transformer, each transformer's location, as well other circuit details.

Meanwhile, the Location Awareness app directed each Next Generation Smart Meter to attempt communication over the PLC protocol, establishing which meters were connected to which transformer. Meters grouped by a common PLC session to the same transformer were compared to the processed results of the DEH file, which in turn triggered an alert whenever there was a discrepancy between the two sources of data.

The first of six discrepancies were immediately triggered and displayed by the DI dashboard, in the form of a "discrepancy report" which identified alleged meter-transformer mismatches. About a month later in the fall, another discrepancy was reported in the dashboard, for a total of seven. For each discrepancy in the report, the dashboard provided the service premise of the meter affected by the transformer mismatch, PG&E's transformer of record for that Next Generation Smart Meter location, along with the transformer it had calculated to be the correct one for that same location.



A meter-transformer mismatch is identified by a line item displaying the relevant equipment IDs, and a pushpin in an overlay of a satellite image taken from the vendor's discrepancy report within the Next Generation Smart Meter DI dashboard. The PG&E's transformer of record for the pinned location is the orange triangle, while the blue triangle represents the transformer that the Location Awareness app concludes is the correct one. Other service drops for both transformers are shown as circles.

A few months later, in the Fall of 2023, Location Awareness was given a reference phase for a handful of transformers, which in turn enabled the app to phase most of the transformers participaTed in the demonstration on the northern section of the circuit. This phasing, collected over the 900 MHz RF mesh network, provided the additional value of a partial check on the app's meter-transformer pairings (as meters sharing a transformer must be on the same phase).

PG&E validated the accuracy of Location Awareness in several different ways:

1. Physical inspection of Location Awareness discrepancies. A PG&E crew consisting of Asset Health and Performance Center (AHPC) staff and a Napa division troubleman was dispatched in these cases to conduct these inspections.

2. Audits of two neighborhoods via physical inspection confirming status quo. These are theoretical cases where the Location Awareness app *did not alert* to a discrepancy between meter and transformer, and PG&E elected to verify that not alerting was the correct (non-) action. AHPC conducted these inspections on a sample of 130 Next Generation Smart Meters. as well, joined by other PG&E and vendor staff associated with the Next Generation Smart Meter project.

Physical inspection of Location Awareness Discrepancy Sites

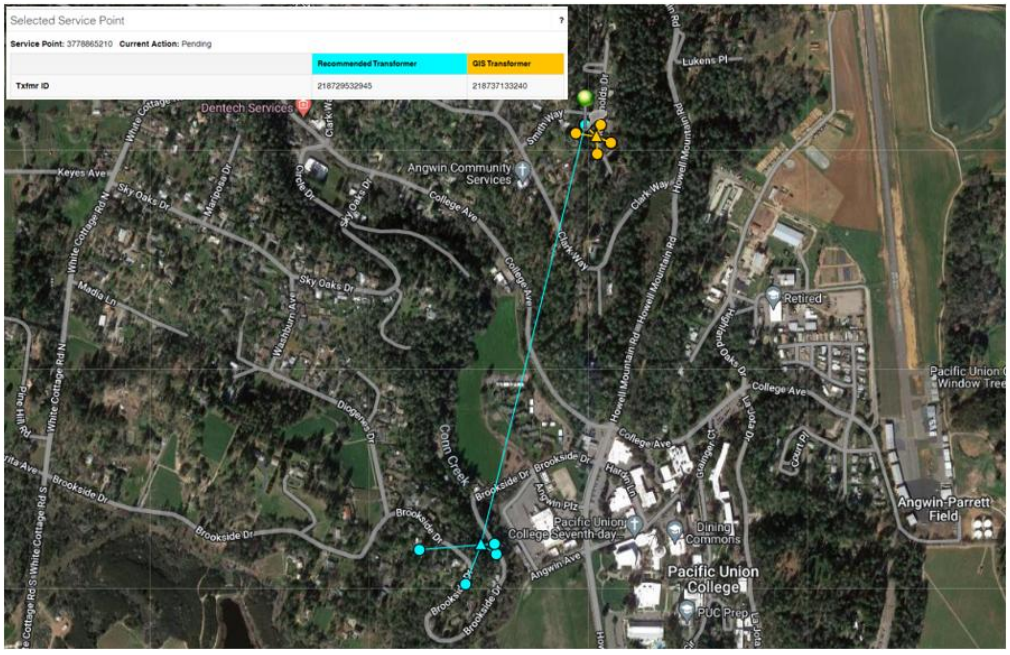
The table below summarizes the results of these app alert discrepancy locations collected through 2023. In the case of all seven alerts sent to the app's dashboard, the onsite physical inspection proved that the Next Generation Smart Meter app was correct. In fact, the app was correct in two ways in each case:

a. in asserting that the transformer that PG&E had registered to a service drop was wrong
b. In suggesting the "correct" transformer. In the seven cases listed in the accompanying table, the correct transformer was confirmed by physical inspection

meter ID	actual street	PG&E's original transformer of record	Riva app's correction for this meter's transformer	Riva meters on this transformer now	inspection result
9252	College Ave	218723833209	218725133237	4	Riva app was correct
9277	Newton Way	218719033333	218719033302	10	Riva app was correct
9415	Sanitarium Rd	218644832235	218648732258	4	Riva app was correct
9434	Brookside Dr	218737133240	218729532945	5	Riva app was correct
9490	Manzanita Dr	218731933354	218727733370	3	Riva app was correct
9560	Viola Way	218717933056	218722133039	3	Riva app was correct
9606	Sky Oaks Dr	218713433164	218712733170	7	Riva app was correct

Table 2. list of meter-transformer mismatch alerts

Notable in the discrepancy summary table above is that each "true" transformer suggested by the Next Generation Smart Meter app was connected to multiple Next Generation Smart Meters, purposely due to the nature of using PLC to validate meter-transformer pairs with other meters sharing the same transformer.



A meter initially deployed for the demonstration in a northern neighborhood of Angwin, depicted by the pushpin above, was moved south by our field metering team to accommodate another specialized meter. The Location Awareness app identified the new transformer for that meter about a mile south, marked as the teal triangle at the bottom of the image above, implying the meter was reinstalled there. A physical inspection confirmed the app's assertion.

The most interesting case involved meter 9434, installed on McReynolds Drive in Angwin, and the last location to trigger an alert. This alert did not arrive immediately upon the installation of the app, but rather well into the fall, showing up in the dashboard alert on a transformer located about a mile's drive south of the original. This sequence of events was unlike the other six, which had their discrepancies identified immediately, suggesting that PG&E simply misidentified the correct transformer. Rather, because meter 9434 was not originally associated with a discrepancy, it was clear that the app was suggesting that the meter had been moved after the demonstration had begun. Sure enough, during a November physical inspection, the meter had been moved to the transformer identified by the Location Awareness app, to accommodate a special meter that the resident had requested.

Note that in all seven cases, the actual transformer of record was associated with multiple Next Generation Smart Meters, which confirmed communication with the meter of interest via the PLC protocol. Stated a different way, finding a mis-registered or moved meter via Location Awareness alone, without regard to its phase or its RF communications with nearby meters, guarantees that the meter of interest will be found on a transformer with other Next Generation Smart Meters.

4.5 Location Awareness Phase Identification of Meters: Data and Results

The phasing capability of the Location Awareness app was tested on both sides of the circuit's stepped down transformer described in the *theory of operation* section. First, PG&E brought phase identification equipment to the circuit and took readings on both sides of the step-down transformer. After the utility collected relative references for each conductor, it also identified five transformers – three on McReynolds Drive, on the delta side of the circuit, and two on Clark Way, on the wye side, all connected to Next Generation Smart Meters. PG&E determined which primary-side conductors (road, middle, and/or field in relative terms) were connected to the Next Generation Smart Meter-servicing transformers.



Fig 5. The location of the five reference transformers in Angwin provided the vendor with their relative conductor connections. Transformers 1, 2, and 3 are along McReynolds Drive, on the stepped down, 12 kV 3-wire delta side of the Silverado 2104 circuit. Transformers 4 and 5 are located on Clark Way along the 21 kV 4-wire wye side.



Conductors can be seen connected (road on the right, field on the left) to a transformer servicing several Next Generation Smart Meters enrolled in the demonstration. This transformer is served by the three-wire delta portion of the demonstrationed circuit.

The connections (road, middle, field) for each transformer were provided to the vendor. The vendor used these readings to establish the relative phases of these five, plus another 20 Next Generation Smart Meter-connected transformers on both sides of the circuit. Note that a total of 173 transformers were connected to Next Generation Smart Meters across the circuit, so this phase identification test for 24 transformers involved about 14% of participating transformers.

transformer ID	*Phase Relative to AN*	*relative transformer connection*	*validated by inspection?*
218736833281	-150°	BA	yes
218731933237	0°	AN	yes
218734233322			yes
218731933354			yes
218730133304			yes
218727733370			yes
218725433388			yes
218722633365			yes
218722633338			yes
218722233355			yes
218719033333			yes
100000111372			yes
218732833277			yes
218731933273			yes
218725833264			yes
218723033278			yes
218719033302			yes
218734033169			yes
218733033206			yes
218734733256			yes
218736833306	30°	AC	yes
218736733266			yes
218738433201	90°	CB	yes
218737133240	150°	AB	yes

Table 3. The vendor's Location Awareness app correctly identified the five phases of 24 transformers participated in the Next Generation Smart Meter demonstration.

The results of the vendor's phase identification were conclusive. The vendor correctly identified the relative phase of each meter within each transformer group, (and by extension, the conductors connected on the primary side of each service transformer, and their polarity on the secondary side).

In so doing, they correctly determined that the wye-connected transformers they phased were all connected as AN to their Next Generation Smart Meters, while the delta-connected transformers were variously connected as AC, CA, BA, and CB to their meters. These results support an initial finding of 100% accuracy for Location Awareness phasing given the sample population.

According to the vendor, due to gaps in continuous AMI mesh network coverage, further identification across all participating transformer groups would require reference connections to an additional two or three more transformers. There is some theoretical constraint on verifying the vendor's conclusions for those portions of the circuit that are underground.

4.6 High Impedance: Theory of Operation

In addition to the Location Awareness app, the vendor loaded its High Impedance app on the 410 demonstration meters for PG&E to test. The app was specifically designed to detect abnormally high impedances anywhere between the meter panel and the secondary side of the transformer, including a service point's service drop and any secondary conductors it shares with other customers. High impedances are often synonymous with downed conductors on the primary side of the distribution system, but on the secondary side, causes could include:

- transformer
    - corroded, damaged, or loose connections at the transformer bushings
- shared secondary
    - broken / fraying conductor or mismatched / weathered splices along the overhead conductors
- service drop
    - vegetation contact
    - broken / fraying conductor or mismatched / weathered splices along the overhead conductors
    - poor splicing entering the weather head
    - heat damage inside the conduit

- meter panel
    - corroded, damaged, or loose connections inside the meter panel

High impedance creates an increased risk of undervoltage along the secondary network, which in turn can damage sensitive equipment operated by the customer. Of even more concern is a root cause of the high impedance that can increase the chances of ignition, such as a buildup of heat inside the conduit along the service drop, igniting insulation, or a dry branch igniting after making contact.

The app derives impedance by measuring small changes in load current while monitoring the service voltage. However, there must be a minimum current change of 810 mA for a measurement to be forwarded to the back-office platform. The app measures the impedance along three closed loops, so there can be a maximum of three impedance values provided for any meter at a given collection time:

a. Leg 0 = hot leg 1 & neutral
b. Leg 1 = hot leg 2 & neutral
c. Leg 2 = hot leg 1 & hot leg 2

Prior to data collection, the vendor set the app's High Impedance threshold in the hosted back office, above which an alert is issued to the utility's dashboard. A setting of 200 mΩ was selected for this demonstration, based on feedback from other utilities. At PG&E's request after the demonstration data collection had begun, the vendor provided all impedance measurements meeting data validation, not just those that rose to the alert level.

Reviewing all the secondary network impedances over time, as reported by the app, can determine the app's credibility and provide deeper insights. This is true for the vendor population of service points enrolled in the demonstration and those that the app reported to be above the high impedance threshold. Specifically:

a. do the app's average impedance values fall within a range predicted by a simple impedance model that accounts for the most significant variables?
b. Is there any underlying structure to how these values vary (for example, how they are clustered) that can be explained by the specifics of PG&Es approach to its secondary network?
c. can the fluctuation of these values over time be explained by physical phenomena separate from secondary design details, such as environmental factors?
d. do some or all of the secondaries that trigger a high impedance alert show anomalies upon inspection, that can cause ignition if not repaired?
e. for those service points that send a high impedance alert, but for which there seems to be no issue upon inspection, can the sensitivity of the alerts be adjusted to a value that better reflects the impedance spreads and fluctuations in a – c above?

The next section examines the impedance data collected from mid-2023 through early 2024 to answer these questions.

4.7 High Impedance: Data and Results

During the data collection period, the vendor's high impedance app provided two data streams:

a. a two-week sliding window of impedance values
    i. both average and maximum, regardless of value, measured in mΩ
    ii. for each of three 2-wire loops measured by each meter from panel to its transformer and back (see the previous section): Legs 0, 1, and 2

b. an alert, for any instantaneous impedance value that exceeds 200 mΩ
    i. the alert is specific to a particular three-wire loop for that service, named as a "phase" or "leg"
    ii. the impedance of the loop setting off the alert is compared to the impedance of the other loops on that same service, over time
    iii. a comparison of the impedances of the other Next Generation Smart Meter service drops connected to that same transformer

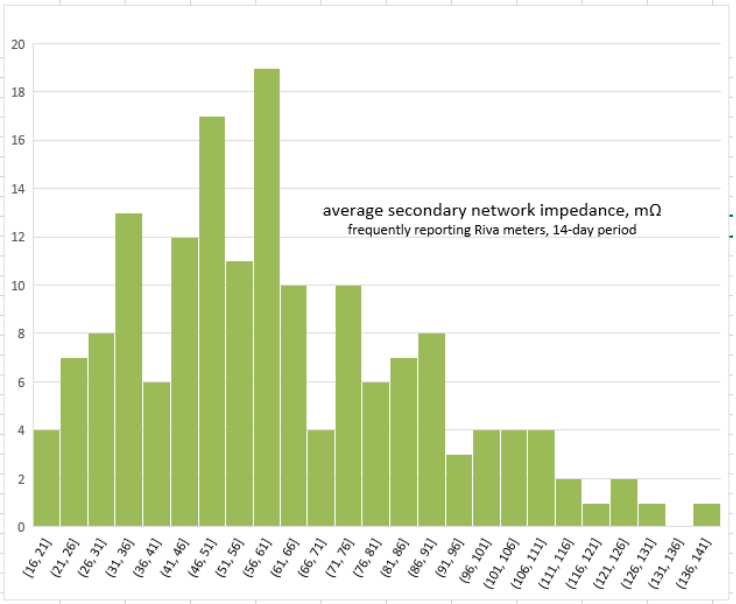


Fig 6. The average impedance of Next Generation Smart Meter demonstration meters over a two-week period. The High Impedance app must sense enough change in load to trigger a measurment. This population constitutes the most sampled phase amongst 164 meters that reported an impedance on at least half of all days in the reporTed window. The spread reflects the wide variety of secondary conductor lengths, gauges, and transformers.

Below, the daily impedance data as a whole is modelled to determine its credibility. If found credible, the high impedance alerts can be considered trustworthy beyond mere coincidence.

Modelling the validity of impedance data from the Next Generation Smart Meter high impedance app

The average impedance values for meters with significant load activity, captured during a two-week period in early 2024, shows wide variability of values given the significant design differences of the secondary network across the demonstration area. For example, impedance is heavily dependent on conductor gauge, and there are sizable populations of different gauge combinations connected to the Next Generation Smart Meters participating in the demonstration. Although aluminum is the material

120 / 240 V service drop gauges		possible neutral wire gauges (AWG)	
hot leg gauge (AWG)	1/0:	1/0	2
	2:	2	4

of choice, the

Table 4. Secondary conductor gauge combinations found in the demonstration depolyment area

gauge combinations can vary. Although the absolute quantities are not strictly documented, the vast majority of deployed conductor, classified by the gauge of the two hot legs of any three-wire service

drop are classsified 1/0, with some 2 American Wire Gauge (AWG). The neutral must always be of the same gauge or less (see table above), but its specific gauge was not readily verfiable online. There is a also a smaller presence of AWG 4 neutrals. The shared secondary on the other hand, is composed mostly of 1/0 hot legs and neutrals. As a result of these different gauge combinations of the installed conductors in the demonstration area, variation in impedance can be significant.

Given the tens of thousands of "in compliance" Next Generation Smart Meter impedance measurements collected from the demonstration's meters daily, which in turn serve as the basis of the occasional high impedance alert that would be acted upon as evidence of a serious anomaly, PG&E's AHPC found it necessary to determine if the app's data could be validated independently. AHPC did so by modelling the impedances of 55 Next Generation Smart Meter service point secondaries. They were chosen because:

1. their secondary conductor hot-leg gauge, material, and length are all documented
2. they have no shared secondary to reduce complexity and error; each secondary consists entirely of a dedicated service drop
3. the Next Generation Smart Meter app reports their impedance frequently and consistently within 14-day windows

By modelling the impedances of these 55, the derived number could be compared to the corresponding Next Generation Smart Meter app measurement, and serve as a check on its credibility. The model conformed to basic impedance theory, to yield the service drop impedance as the sum of two contributions - transformer impedance $\mathbf{Z_{xfmr}}$ and service drop conductor impedance $\mathbf{Z_{drop}}$:

$$Z_{servicepoint} = Z_{xfmr} + Z_{drop}$$

Of these right-hand side components, the transformer component consists of:

$$Z_{xfmr} = Z\%_{xfmr} \times Z_{base}$$

- where $\mathbf{Z\%_{xfmr}}$ is the percentage of the rated primary voltage required to circulate the rated current through the windings when the secondary is short-circuited. $\mathbf{Z\%_{xfmr}}$ values typically range from 1.6% down to 1% for the transformer sizes participaTed in the demonstration, decreasing with higher kVA. Typical quoted and derived values from Eaton's short-circuit online calculation guide were used.[6]

- where $\mathbf{Z_{base}}$ is the base impedance of the transformer, dependent on a transformer's capacity, and its secondary operaTed voltage:

$$Z_{base} = (V_{sec})^2 / (VA_{xfmr})$$

[6] *https://www.eaton.com/content/dam/eaton/products/electrical-circuit-protection/fuses/solution-center/bus-ele-tech-lib-electrical-formulas.pdf*

- where $\mathbf{VA_{xfmr}}$, transformer capacity, ranges from 10 kVA to 50 kVA.
- where $\mathbf{V_{sec}}$, secondary-side stepped-down service voltages are 240 V for all Next Generation Smart Meter service points.

The service drop component of $\mathbf{Z_{servicepoint}}$, designated here as $\mathbf{Z_{drop}}$, is modelled strictly on the properties of the three-wire conductors constituTed each service drop: material (exclusively aluminum for the demonstration), gauge (AWG 1/0, 2, or 4/0), and length.

Explicitly:

$$Z_{drop} = (R^2_{con} + X^2_{con})^{1/2}$$

where $\mathbf{R_{con}}$ is the conductor's resistance, and $\mathbf{X_{con}}$ is the conductor's reactance. The model uses the California Electric Code's 60 Hz values for all conductor configurations deployed with the Next Generation Smart Meters, but for a rather high 167 °F.[7]

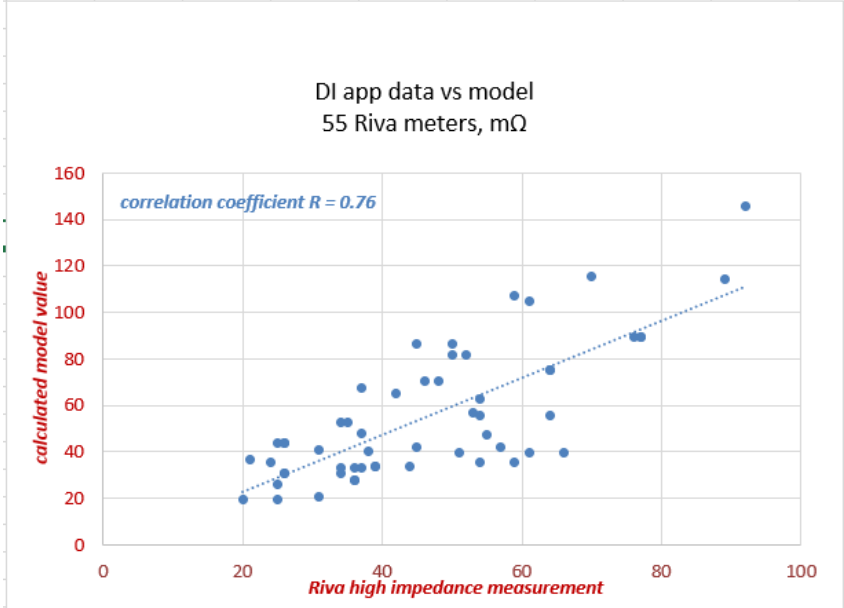


Fig 7. The correlation between the model's derived service drop impedance and the collected Next Generation Smart Meter impedance app values is represented by an R value of 0.76, indicated that the measurements are realistic, providing credibility to alerts when they occur. The best-fit line has been added.

The results indicate a strong correlation between measurement and model, represented by a coefficient of 0.76. Modelling suggests that the Next Generation Smart Meter impedance app provides trusted measurements that bolster the credibility of any high impedance alert when it is triggered. The chart also puts the 200 mΩ trigger into perspective: Next Generation Smart Meter impedance data from the 55 modelled service points is spread widely from 20 mΩ, requiring an

[7] https://up.codes/viewer/california/ca-electric-code-2019/chapter/9/tables#9

anomaly to cause a 10X impedance jump to trigger an alert, to 92 mΩ, which requires an anomaly to just double the impedance.

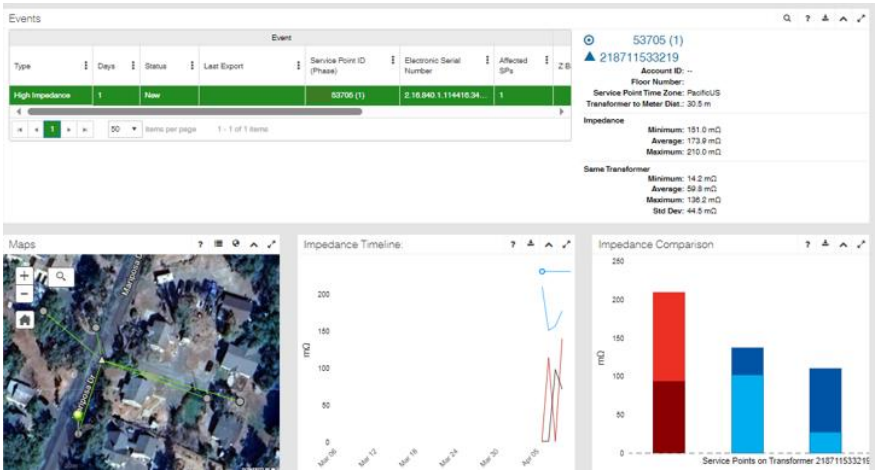
It is notable that the model did not aim for several significant figures of accuracy; instead, it was designed to produce an approximation so that its correlation to the Next Generation Smart Meter DI data could be measured. For example, several variables were ignored (e.g. no temperature correction to match the measurement days. Higher temperatures increase the resistance contribution to conductor impedance) and others were just estimates (e.g., Z%, the transformer percent rating, was not obtained from each transformer's nameplate, which were difficult to obtain, but instead, an industry average for a given capacity was used). Also, there were many instances among the 55 samples that the quoted service drop length was in multiples of 10 feet, suggesting possible rounding. In the case of shorter drops, this could add considerable impedance to the model.

In the next section, the high impedance alerts collected during the demonstration are discussed in an effort to determine the app's value as an early warning system for potentailly dangerous secondary anomalies.

Results: High impedance alerts

Over the course of the demonstration, seven high impedance alerts exceeding the 200 mΩ threshold were collected. Each alert was detailed on the dedicated Next Generation Smart Meter DI app dashboard, which consisted of (see a screenshot of the dashboard immediately below):

- service drop and transformer identifiers, with a map that includes any other Next Generation Smart Meters serviced by the same transformer
- the minimum and average impedances during the previous two weeks, and the maximum value that triggered the alert; for context, these values are:
    - compared with those of any other Next Generation Smart Meters on the same transformer
    - identified by service drop leg and charted on a timeline



All seven high impedance locations were visited by AHPC staff and a North Bay district troubleman, grouped over three visits across ten months, and within weeks after the trigger was received. The seven all occurred in the northeast Angwin pocket of deployment.



Site of the first high impedance alert. After the ST800 diagnostic tool confirmed a power quality issue, the service drop was physically inspected. The state of the service drop splices at the weather head provided a possible root cause.

At each location, customers, when on the premises, were made aware that service would be interrupted. The service drop and any shared secondary were physically inspected, and any anomalies noted. The meter was then removed. The meter, the meter socket and the inside of the meter panel were physically inspected for any loose connections or corrosion. In one instance, corrosion was clearly visible on one hot leg connection behind the socket.

During each high impedance inspection, the troubleman conducted a continuity check with a diagnostic tool. At four of the seven alert locations, the tool detected a continuity failure. In those four instances, repairs were made during the visit, and the tool confirmed the anomaly was no longer present. Subsequently, the app reporting platform was accessed to verify that the Next Generation Smart Meter was no longer reporting a high impedance alert.



The original splices removed from the first high impedance location. The splices were examined at PG&E's ATS Laboratory, where they were found to be significantly corroded.

In the case of the first inspection captured in the photograph above, the diagnostic tool discovered an issue with continuity. The troubleman determined that the quality of the triplexed splice above the weather head was suspect, and he decided to remove and re-splice immediately.

The second instance of a high impedance alert that was confirmed by inspection, involved overhead conductor. Specifically, two conductor gauges constituting the drop were mismatched when they were spliced together. Due to the mismatch, the splice was coming apart, which was concerning, as the location of the splice was close to tree branches above the property's front yard.



Mismatched conductors causing a splice to come apart at the second high impedance alert location. Nearby vegetation increased the risk of a dangerous complication.

It is plausible in this situation that as the branches grow, so does the risk of ignition. The repair was made, and continuity was confirmed with the diagnostic tool.



The repaired splice at the second location identified by the Next Generation Smart Meter high impedance app and verified by the ST800. The conductors were matched, and the branches were pared back.

A third location that triggered an alert featured corrosion inside the rear of the meter panel near where one of the two hot legs entered and connected. PG&E also noticed that the panel was being supported by a rotting wood riser.





The fourth and final verified high-impedance location. The transformer on the left was outfitted with a riser to run the secondary to the junction box on the right, which connected to the underground span. The troubleman is pointing to the loose connector that was re-secured. An ST800 test then confirmed continuity, and impedance readings have remained low since.

Although the corrosion could not be immediately addressed because the panel is not owned by the utility, the customer was on-premises, and was informed of the various issues so that she could hire an electrician to bring the panel up to code.

The fourth and last service drop that triggered an alert and that could be verified during the analysis period, featured an underground span connected to the transformer via conduit running down the pole to a junction box at its foot. Once the diagnostic tool provided a failed reading, the troubleman began his inspection by opening the underground junction box. He quickly verified a likely culprit – the plug connecting the two runs of cable had loosened.

After re-tightening the connection and securing it with additional material, the service drop passed the ST800 test back at the meter panel, and service was restored. As with the first two overhead splice anomalies that caused high impedance alerts, this service location was monitored post-repair from the app dashboard, and the readings were verified to have dropped below 200 mΩ, and have remained steady since.

meter ID triggering high-impedance alert	street	inspection tour num	ST800 (on-site electrical) results	phyiscal inspection results	disposition	post-inspection impedance
9418	Clark Way	1	failed, verified issue	corrosion on splices at weather head	respliced	normal readings
9500	Sky Oaks Dr	1	failed, verified issue	loosening overhead splice between mismatched conductors, near vegetation	respliced	normal readings
9249	Mariposa Dr (1)	1	passed	no anomaly found	n/a	normal readings
4259	Tobin Avenue	2	passed	no anomaly found	n/a	normal readings
9367	Walnut Lane	2	failed, verified issue	corrosion in rear of meter panel	customer repairs required	
9255	Mariposa Dr (2)	3	passed	no anomaly found	n/a	normal readings
9558	Brookside Dr	3	failed, verified issue	loose connection in underground junction box	loose connection repaired and secured	normal readings

Table 5. Results of electrically and physically inspecting seven sites that had triggered a high impedance alert during the data collection and analysis period. In four of the seven cases, a serious anomaly was found along the secondary which could account for high impedance.

During the three inspection tours of the Angwin area, three sites that caused alerts turned up no anomaly either electrically or physically. Possible explanations triggering these temporarily elevated values could include secondaries that operate at the higher end of the impedance range just below 200 mΩ, and which could surpass this trigger during a heat wave or some other environmental stress on the conductor(s). For example, Leg 1 of meter 9249's service that caused an alert in the heat of last summer, normally operates at about 130 mΩ, with peaks that often surpass 170 mΩ, just under the alert floor. Similarly, Leg 0 of meter 9255 operates at about 140 mΩ with peak readings that can often surpass 180 mΩ that are even closer to the alert value.

5 Value proposition

The purpose of EPIC funding is to support investments in technology demonstration and deployment projects that benefit the electricity customers of PG&E, San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). EPIC 3.43 Momentary Outage Information demonstrated that a next generation meter with grid edge capability can provide very valuable information that supports safety, advanced metrics, and potentially useful information for customers.

5.1 Primary Principles

The primary principles of EPIC are to invest in technologies and approaches that provide benefits to electric ratepayers by promoting greater reliability, lower costs, and increased safety. This EPIC project contributes to these primary principles in the following ways:

- Greater reliability: The work on this project has shown that the use of Next Generation Smart Meters offer have the capability to identify potential issues before they occur.

- Lower costs: The cost savings from this project largely accrue from reduction in ignitions, but also include fewer outages due to quickly identifying high-impedence issues.
- Increased safety and/or enhanced environmental sustainability: Increased safety will result from earlier detection of high-impedence issues, due to quicker identification and repair of the potential problem. Safety will also be enhanced by properly matching meters and transformers.

5.2 Secondary Principles

EPIC also has a set of complementary secondary principles. This EPIC project contributes to the following three secondary principles: greenhouse gas (GHG) emissions reduction, and efficient use of ratepayer funds.

- Greenhouse gas (GHG) emissions reduction: reduction in wildfire directly leads to lower GHG emissions.
- Efficient use of ratepayer funds: this project, in addition to the principles and value already noted, has served as a foundational technology for PG&E. This project is serving as a springboard for further grid edge computing capabilities that we anticipate will offer great savings to PG&E customers.

5.3 Accomplishments and Recommendations

5.3.1 Key Accomplishments

The following summarize some of the key accomplishments of the project over its duration:

- Procured and installed 410 Next Generation Smart Meters on PG&E's Silverado 2104 circuit.
- Demonstrated that the app Location Awareness could successfully be used to detect meter-transformer mismatches, contributing to managing load balancing, overheating, and switching errors.
- Demonstrated that the app Location Awareness could accurately identify phasing to support load balancing efforts
- Showed the app High Impedance could identify instances where loss of integrity in the secondary distribution equipment. Reduciing high impedance increases risk of undervoltage along the secondary network, which in turn can damage sensitive equipment operated by the customer. Of even more concern is a root cause of the high impedance that can increase the chances of ignition, such as a buildup of heat inside the conduit along the service drop, igniting insulation, or a dry branch igniting after making contact.
-

5.3.2 Key Recommendations

The success of the field tests of the Next Generation Smart Meter apps and use cases, it is recommended that the Next Generation Smart Meter begin the PG&E certification process. Additionally, the success of these trials indicates that we should consider replacing existing production meters across the entire distribution network at PG&E, and in so doing, reduce the risk of ignition.

Finally, it is recommended that the apps described and any additional apps developed for the Next Generation Smart Meter platform to detect anomalies that could lead to ignition, should be tested both in the lab and in future demonstration projects.

5.4 Technology transfer plan

5.4.1 IOU's technology transfer plans

A primary benefit of the EPIC program is the technology and knowledge sharing that occurs both internally within PG&E, and across the other IOUs, the CEC and the industry. In order to facilitate this knowledge sharing, PG&E will share the results of this project in industry workshops and through public reports published on the PG&E website. Specifically, below is information sharing forums where the results and lessons learned from this EPIC project were presented or plan to be presented:

Information Sharing Forums Held

- *DistribuTECH 2025, Dallas TX "Wildfire Detection for Safer Grid Management"*

Information Sharing Forums Planned

None, because other initiatives featuring Next Generation Smart Meters development are under way and will take the communications role.

5.4.2 Adaptability to other Utilities and Industry

The following findings of this project are relevant and adaptable to other utilities and the industry:

- Grid-edge computing has proven to be useful for many utility tasks that were not available with prior technology, and many more applications have been identified but not yet tested.
- PG&E has been actively communicating and collaborating with other utilities and a variety of vendors to investigate emerging issues, operational remediation, and technology developments.

5.5 Data Access

Upon request, PG&E will provide access to data collected that is consistent with the CPUC's data access requirements for EPIC data and results.

6 Metrics

The following metrics were identified for this project and included in PG&E's EPIC Annual Report as potential metrics to measure project benefits at full scale.[8] Given the proof of concept nature of this EPIC project, these metrics are forward looking.

[8] 2015 PG&E EPIC Annual Report. Feb 29, 2016.
http://www.pge.com/includes/docs/pdfs/about/environment/epic/EPICAnnualReportAttachmentA.pdf

D.13-11-025, Attachment 4. List of Proposed Metrics and Potential Areas of Measurement (as applicable to a specific project or investment area)	Reference
4. Environmental benefits	
a. GHG emissions reductions (MMTCO2e)	Section 5.2
5. Safety, Power Quality, and Reliability (Equipment, Electricity System)	
a. Outage number, frequency and duration reductions	Section 5.1

7 Conclusion and Recommendations

The 410 Next Generation Smart Meters installed on the Silverado 2104 circuit and outfited with two distributed intelligence apps, were remarkably effective in demonstrating value towards wildfire prevention. Although the number of events were limited with the the meter population being small, results were definitive. Specifically the two apps identified or addressed two types of secondary conductor anomalies, three use cases in total:

- *direct reduction to wildfire risk*. The high impedance app identified conductor anomalies such as bad splices, corrosion, and loose connections that could contribute to downed conductors, excessive heating, and arcing. In turn, these could cause faults, outages, or even ignition, especially in the presence of vegetation. Of the seven alerts, four identified both a physical and electrical anomaly, and three of the four were repaired immediately upon verification. It is feasible that the three false positives could have been reduced or eliminated with an alert setting that could be adjusted to the specific parameters of each service drop, lowering the possibility of service calls made in error if Next Generation Smart Meters became the next official billing meter. Regardless, the four out of seven true positives were shown to be more than coincidental after modelling established the credibility of the app's impedance data given the limited footprint of the demonstration.

- *indirect reduction to wildfire risk*. The location awareness app proved very accurate in:

    - identifying meter-transformer misregistration. The app discovered meters paired to the wrong transformer, and just as importantly, identified the correct transformer. Attributing a meter to the correct transformer contributes to more accurate transformer sizing, which reduces the risk of overloading transformers. It also reduces the chance of a service call to the wrong location during an outage or ignition event, consuming valuable time. Of the seven "discrepancy report" entries, all seven were transformer mismatches upon inspection. If all transformers participate in the demonstration serviced two Next Generation Smart Meters or more, one could have expected an additional misregistration, for a mismatch rate of about 2%. Applied to the entire PG&E territory, this rate represents about 110,000 service points for which

transformers could be properly identified and sized, leading to faster and more accurate service calls.

- identifying a transformer's relative phase. The Location Awareness app correctly identified the five relative phases of 24 meters participating in the demonstration with no errors, given a reference phase for each of a three-wire portion and and a four-wire portion of the circuit. Accurate phasing, even if relative, is extremely important to preventing voltage imbalances and fault current. It allows the outage management system to more precisely predict the scope and location of outages, and for protection devices to operate more efficiently during a fault or outage, reducing safety hazards.

Path-to-Production Considerations

Based on the significant outcomes of this modest study featuring just two DI apps and 410 meters, the Next Generation Smart Meter is extremely effective in identifying issues that can significantly reduce the risk to people and property along the distribution network, both directly and indirectly. The realistic path to production for deploying these two apps across PG&E's territory would require certifying the Next Generation Smart Meter to replace the current AMI billing meter models over time.

Furthermore, provided it involves a mere change to the alert value in each meter's configuration file, the High Impedance app can benefit from a high impedance trigger more specific to each service point's secondary, in order to improve the app's accuracy when identifying an anomaly of concern.

(PG&E-16)

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CHAPTER 22

ATTACHMENT E

FSDT COST BENEFIT ANALYSIS

THIS NATIVE FILE CAN BE FOUND AS A STANDALONE DOCUMENT ON PG&E'S AZURE WEBSITE

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CHAPTER 23

ELECTRIC DISTRIBUTION SUPPORT ACTIVITIES

THIS CHAPTER HAS NO REBUTTAL