BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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Application of PACIFIC GAS AND ELECTRIC COMPANY (U39E) for a Certificate of Public Convenience and Necessity Authorizing the Construction of the S-238 Hinkley Compressor Station Electrical Upgrades Project.	Application 25-04-004 (Filed April 9, 2025)

RESPONSE OF THE UTILITY REFORM NETWORK TO PG&E's MOTION TO WITHDRAW

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February 17, 2026

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RESPONSE OF THE UTILITY REFORM NETWORK TO PG&E's MOTION TO WITHDRAW

Pursuant to Rule 11.1 of the Commission's Rules of Practice and Procedure, The Utility Reform Network ("TURN") submits this response to PG&E's "Motion to Withdraw Application No. 25-04-004" ("Motion"), filed on February 4, 2026.

I. INTRODUCTION AND SUMMARY

In its Motion, PG&E requests authority to withdraw this application, and states that it will pursue this project without first obtaining a Certificate of Public Convenience and Necessity ("CPCN") based on the emergency exemption under Section IV.B.c. of General Order ("GO") 177.

TURN does not opine on the factual or legal questions regarding the appropriateness of granting PG&E's request to withdraw the application based on the emergency exemption, though TURN questions the completeness of PG&E's factual showing.

TURN does raise several significant concerns we have with the issue of cost recovery and the appropriateness of the project as proposed, especially in light of certain information provided by PG&E in its Supplemental Testimony. Moreover, TURN questions PG&E's blithe assertion that cost issues can be litigated in other proceedings. If the Commission decides to grant PG&E's Motion, TURN explains why any such grant should be conditioned with a requirement that all costs for the project be subject to a reasonableness review prior to rolling any capital additions into rate base; and such a review should explain whether the scope and costs should be reduced due to the likely need for smaller gas compression capacity at the Hinkley Compressor Station. At a minimum, the Commission should order PG&E to provide certain data and information concerning the project in its next (2031) general rate case.

II. PG&E's SHOWING CONCERNING AN EMERGENCY LACKS ANY FACTUAL DETAILS

In its Motion, PG&E has only one sentence concerning the emergency conditions that warrant an exemption to GO 177 requirements: "On January 20, 2026, due to electrical equipment failures and ongoing obsolescence issues, PG&E commenced the Project to prevent an emergency, including Station outages that could result in loss of gas supply to customers." (Motion, p. 2) PG&E states that it filed an Advice Letter providing "Notice of Claimed Exemption Pursuant to General Order 177." However, in that Advice Letter, PG&E primarily explains the importance of the compressor station, which TURN does not dispute. Again, TURN found only one sentence explaining the emergency: "Recent component failures and ongoing obsolescence issues that emerged in late summer 2025, after submittal of the CPCN application for this Project, have elevated concerns that the Station's electric distribution equipment may not remain functional through the CPCN application review period." (Advice Letter 5175-G, p. 4)

While TURN has not conducted any factual investigation and cannot challenge PG&E's conclusions, we believe that this one sentence conclusion does not provide any specific information or verified attestation concerning the nature of any component failures, or any explanation of why the entire project needs to be immediately pursued to prevent a failure of the compressor station such that it could not deliver essential services. TURN hoped and expected that PG&E's advice letter submission would have provided more detailed explanation of any engineering or technical problems that justify the exemption. TURN is particularly concerned, given our review of the electrical system at the Station, including prior issues (such as aging circuit breaker rack-out mechanisms in specific switchgear) and the presence of multiple

redundancies in the electrical system design, that PG&E has not explained why the entire project must be immediately undertaken to prevent a loss of essential service.

III. THE COMMISSION SHOULD IMPOSE CONDITIONS IF IT AUTHORIZES AN EXEMPTION FOR PG&E'S HINKLEY PROJECT

A. TURN Has Concerns Regarding the Reasonableness of PG&E's Cost Forecasts

TURN has conducted significant discovery concerning the need for and the scope of the proposed project. TURN has significant concerns regarding the need to replace all of the electrical switchgear and motor control centers, given the lack of operational problems and the history of prior investments in the station. However, TURN has not yet developed firm recommendations concerning a more reasonable scope of work.

B. Those Concerns Were Significantly Magnified by PG&E Supplemental Testimony

On January 9, 2026, PG&E served Supplemental Testimony responding to several questions posed in the Scoping Memo issued by Assigned Commissioner Matthew Baker on November 24, 2025. PG&E explained that the amount of gas throughput capacity was based on the number and power of the gas compressors; but that the electrical equipment that was being replaced as part of this project did not impact gas throughput capacity but was only necessary to power onsite ancillary support equipment. This was consistent with representations made to TURN during a meet and confer, and TURN does not disagree with the statement that the electrical equipment does not impact gas throughput capacity at the Hinkley compressor station.

However, PG&E's supplemental testimony provided a troubling explanation of the compressor capacity sizing that strongly indicates that existing station compression capacity

could be reduced immediately, and that the electrical work could also be reduced by eliminating unnecessary compression capacity.

PG&E's testimony explains three key points that impact our evaluation of this project. First, and perhaps most critical as new information, PG&E explained that the compressor capacity is sized "to meet a demand on a 1:10 peak day as well as throughput the year." Second, PG&E explained that the ancillary electrical equipment is not related to the compression capacity of the station:

> The ancillary support systems are sized in accordance with the operating needs of the compressors, as well as other Station operations. … The operating level of the ancillary support systems and the electrical power delivered to these systems, such as cooling systems, must be increased or decreased based on many factors including the number of compressors in operation, the operating level of the compressors, and the ambient temperatures (e.g., increased cooling is required on hot summer days). (Supplemental Testimony, p. 3, lines 21-30.)

Third, PG&E concludes that:

> It is possible that **a future reduction in the compression capacity of the Station, through removing or downsizing the currently installed compressors, could allow for a reduction in size of the ancillary systems that support the compressors**. In-turn, the electrical distribution system that distributes power to the ancillary support systems could potentially be modified based on the power requirements of modified ancillary support systems. However, there are too many unknowns and variables to estimate the compression capacity of the Station that will be required to meet theoretical future gas demand declines, let alone how and whether future modifications to the compression capacity of the Station may impact the design of the ancillary support systems and electrical distribution equipment. No reductions in the compression capacity of the Station are planned, thus all assets included in the Project are required for operation of the Station for the foreseeable future. (Supp Testimony, p. 4, lines 17-29.)

TURN suggests that these three explanations raise significant questions concerning the need for the proposed project as scoped in the application. First of all, TURN strongly questions the fundamental need to size compressor capacity to meet the 1-in-10 peak day standard. Even if

this was the appropriate standard way back when this compressor station was first built in the early 1950's, there appears to be little rationale for maintaining such a level of compression capacity at this time. PG&E, as well as independent providers, have developed gas storage fields to meet peak demand during the year. In a series of Decisions starting with D.04-09-022, the Commission made clear that for core customers the utilities required holdings of intrastate pipeline capacity should be based on the **average daily demand** during a 1-in-10 cold dry year,[1] but that the utility can meet the 1-in-ten peak day demand standard using **a mix of both pipeline and gas storage capacities.**[2] The Commission recently re-affirmed the core supply standards for pipeline and storage capacities in D.22-07-002.[3]

Indeed, in its current 2027 rate case (A.25-05-009), PG&E proposes to spend about $100 million to drill eight new storage wells, and PG&E explains that the Peak Day Supply Standard (PDSS) is "the overarching driver guiding the storage well investments."[4] TURN is extremely concerned that rather than optimizing a mix of intrastate pipeline capacity and storage withdrawal capacity in order to meet peak demand reliability criteria, PG&E is sizing **both** its intrastate compression system and its gas storage system independently to meet the same peak day demand standard, thus duplicating its reliability capacities. TURN questions the need for maintaining a compression capacity at Hinkley based on a 1-in-10 peak day standard, even under

[1] TURN notes that the Baja Intrastate Pipeline from Hinkley is upstream of any storage fields. This intrastate backbone pipeline can thus be sized based on upstream flow supplies. Local transmission pipelines, which receive gas from both upstream transmission and storage would need to be sized to supply maximum local peak demand.

[2] See, D.04-09-022, pp. 28-35. See, also, D.06-07-010, Section III.B; D.06-09-039, Sec. I.A and D; D.23-12-003, pp. 36-38.

[3] See, D.22-07-002, pp. 20-25.

[4] A.25-05-009, Ex. PG&E-03, p. 7-22. See, also, pp. 9-67 to 9-80 for a detailed discussion of the PDSS.

current gas demand. This concern is even greater given the forecasts of decreasing annual demand in the future.[5]

If the compression capacity at Hinkley could be decreased by removing or downsizing one or more of the existing compressors, then, consistent with PG&E's supplemental testimony, a "reduction in size of the ancillary systems that support the compressors" would be possible. PG&E claims that there are too many unknowns to determine at this time what reductions may be possible. However, TURN suggests that PG&E might be able to reduce the capacity of this station by appropriately taking into consideration the use of gas storage to meet peak demand. While TURN initially agreed not to conduct discovery related to gas throughput based on PG&E's representations, TURN intends to conduct such discovery to address the facts disclosed in the supplemental testimony.

C. It Does Not Appear Likely that Cost Issues Would be Litigated in Any Other Proceeding

The Scoping Memo listed four issues related to project costs within the scope of the proceeding, including 1) whether PG&E has already received authorization to recover project costs; 2) whether it is seeking cost recovery in any other proceeding; 3) whether the project cost estimate of $93 million is reasonable; and 4) whether the Commission should set a cost cap or provide any other cost recovery direction for the Project.[6]

[5] TURN withdrew discovery questions concerning historical throughput and capacities at Hinkley based on PG&E's representations. TURN intends to renew these discovery requests and ask other questions concerning the supplemental testimony.

[6] Scoping Memo, p. 4.

In its Motion, PG&E claims to respond to all four of these issues, without providing any explanation or citation to evidence. PG&E claims that:

- "In the 2023 GRC, PG&E received revenue requirements **related to the Project** for 2023-2026."
- "PG&E's 2027 GRC included updated capital costs for 2025 and 2026 and requested the associated revenue requirement for years 2027-2030."
- "Ongoing cost recovery will be requested in subsequent GRC cases, such as PG&E's 2031 GRC."

TURN suggests that all three of these statements fail to materially address the issues posed in the scoping memo.

First of all, any revenue requirements "related to the Project" authorized in the 2023 GRC likely cover only a small portion of the estimated Project costs. In discovery, PG&E provided data to TURN showing that the 2023 GRC authorized a total of just under $25 million for all work in the relevant MAT 76P.[7]

Second, PG&E's statements regarding the rate case pinpoint the actual problem. PG&E's own testimony in that rate case makes clear that no Hinkley costs are included in the 2027 rate case forecast:

> Other projects with unit capture in the 2023 GRC cycle may have closeout tasks that extend in the 2027 GRC cycle, for example:
>
> − _S-1095 Hinkley Compressor Station Replace Controls; and
>
> − _S-1266 Hinkley K Unit Controls Systems Upgrade.
>
> The 2027 forecast decrease, as compared to 2024 recorded, is primarily driven by an increase of work pace in 2024 (and increased costs) on a controls project at Hinkley. This

[7] Data Response TURN 001-Q12 attached as Appendix A.

was possible because another project at Hinkley (**electrical upgrades project, MAT 76P, not part of this application**) was delayed due to GO-177 *Establishing Rules* 16 *for Application, Notification, and Reporting Requirements for Gas Infrastructure Located in California*."[8]

The meaning of the phrase "closeout tasks" is clarified in electronic Workpaper Table 3-14, which shows a 2024 recorded cost of $7.8 million for both the Hinkley and Topock Electrical Upgrade projects, and a forecast of $21.7 million for each year 2025 and 2026.[9] In the current rate case, the Commission will adopt a revenue requirement for 2027 that is based on a **forecast** of capital additions in 2025 and 2026.

Thus, some amount of 2025 and 2026 costs forecast for the Hinkley project may already be included in the 2027 GRC capital cost forecast, although the record is absent as to the amount of those costs, given that the PG&E 2027 GRC workpaper does not disaggregate Topock and Hinkley, and given that the testimony claims the Hinkley electrical project is "not part of the application."

D. If the Commission Authorizes a Withdrawal of this Application, the Commission Should Impose Conditions to Ensure a Reasonableness Review of the Hinkley Costs in the Next Rate Case

PG&E is technically correct that cost recovery for actual capital expenditures in 2025, 2026 and 2027 that are **not** already included in the 2027 rate case forecast could eventually be added to a plant account when the project is used and useful, and would then be "rolled into rate base" during the true-up for the next rate case test year, currently scheduled for 2031. In that next

[8] A.25-05-009, PG&E Testimony PG&E-03, p. 6-20.

[9] A pdf of this workpaper is attached as Appendix B. TURN intends to conduct discovery concerning the allocation of the costs between the Hinkley and Topock stations.

rate case, parties could in theory litigate the reasonableness of the actual capital expenditures for the project.

However, the year 2026 will be the year **before** the next base year of 2027. In our experience, it is extremely difficult and painstaking to litigate in a rate case actual costs that were recorded prior to the base year. Teasing out such costs requires significant discovery efforts, even assuming someone remembers to ask about this project when PG&E files its next rate case. Absent explicit directive in this proceeding, PG&E's actual costs for the Hinkley Project might easily escape any review in the future.

If the Commission grants this request to withdraw the application, it should ensure that any costs for the project are comprehensively reviewed to assess the reasonableness of PG&E's actions by ordering PG&E, in the next rate case or a separate application, to provide a separate discussion within the appropriate exhibit volume of the costs and rationale for the Hinkley project, including:

- A detailed listing of capital and expense costs by category and year;
- A justification of the future compression capacity at Hinkley based on historical and forecast gas average and peak throughputs at Hinkley;
- An explanation of how PG&E optimizes intrastate pipeline capacity and storage capacity to meet the Peak Demand Supply Standard; and
- An explanation of why the scope of work for the electrical upgrade work was reasonable in light of the circumstances already known at this time.

Providing this information and data should not be onerous, and is in theory consistent with the information PG&E should present for any capital addition that it seeks to roll into rate base. However, absent such explicit directives, the 2025-2027 costs for the Hinkley electrical upgrade project may be hidden within a single line item for MAT 76P, and any future intervenor may not remember and know to ask questions to evaluate the reasonableness of this capital project.

TURN understands and appreciates that, even if PG&E is forecasting 50% more in costs than reasonable, we are fighting here about less than $50 million in capital expenditures. Such an amount may seem paltry to the other amounts at issue in the rate case; however, given the current affordability crisis in electric rates, TURN suggests that it is critical to pay attention to such a project, especially if it is designed to support the continued operation of a compressor station that is already designed to provide too much natural gas into the system.

IV. CONCLUSION

Based on the arguments presented above, TURN recommends that **if** the Commission grants PG&E's Motion, it require PG&E to explicitly identify and justify any costs it incurs to complete the Hinkley project, either in a separate application or in the next general rate case.

TURN does not take a position on whether it is reasonable to grant PG&E's request based on an emergency exemption to GO 177.

February 17, 2026

Respectfully submitted,

By: 

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Appendix A

PACIFIC GAS AND ELECTRIC COMPANY
S-238 Hinkley Compressor Station Electrical Upgrades Project CPCN
Application 25-04-004
Data Response

PG&E Data Request No.:	TURN_001-Q012
PG&E File Name:	S-238-HinkleyCompressorStationElectricalUpgrades_DR_TURN_001-Q012
Request Date:	April 30, 2025
Requester DR No.:	TURN-001
Requesting Party:	The Utility Reform Network
Requester:	Marcel Hawiger
Date Sent:	May 23, 2025
PG&E Witness(es):	Lucy Redmond – Gas Engineering

SUBJECT: VARIOUS

QUESTION 012

Please provide a table showing any amounts authorized in historic rate cases for capital expenditures related to any of the electrical distribution equipment being replaced as part of this project. Please provide the amount authorized, the year authorized, and the relevant rate case decision number.

ANSWER 012

Please see the tables below for the adopted/imputed amounts of the applicable rate case decisions where PG&E included a request for the 76P Program – GT Electrical Upgrades at Hinkley and Topock. This program includes performing the electrical system upgrade projects at Hinkley and Topock Compressor stations.

2015 GT&S: Application A.13-12-012				
Decision Number			D.16-06-056	
Decision Date			6/23/2016	
MAT	**2015 Adopted**	**2016 Imputed**	**2017 Imputed**	**2018 Imputed**
76P	$0	$0	$0	$0

2019 GT&S: Application A.17-11-009				
Decision Number			D.19-09-025	
Decision Date			9/12/2019	
MAT	**2019 Adopted**	**2020 Imputed**	**2021 Imputed**	**2022 Imputed**
76P	$4,269,678	$3,930,537	$3,654,287	$3,414,998

2023 GRC: Application A.21-06-021				
Decision Number			D.23-11-069	
Decision Date			11/16/2023	
MAT	**2023 Adopted**	**2024 Imputed**	**2025 Imputed**	**2026 Imputed**
76P	$6,303,659	$6,100,946	$6,109,888	$6,212,010

Appendix B

Workpaper Table 3-14
Pacific Gas and Electric Company
2027 General Rate Case
Exhibit (PG&E-3), Chapter 3, Gas Operations Risk Management
Loss of Containment at Gas M&C and C&P Facility - Recorded and Forecast Control Costs - Capital

Line No.	Risk Program ID	Risk Program Name	Chapter	MAT	NOMINAL DOLLARS 2024	2025	2026	2027	2028	2029	2030	Total (2024-2030)	Total (2027-2030)	MILLIONS OF DOLLARS (NPV) [1] Program Cost (2027-2030) [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR [2], [3], [4] [C]/([A]+[B])
1	LOCTM-C019, MCCPF-C018, NGSWR-C010	Cathodic Protection	5	3K6	$ 2,928,846	$ 4,113,085	$ 4,113,085	$ 6,200,718	$ 6,330,154	$ 6,470,020	$ 6,606,137	$ 36,762,045	$ 25,607,029	92.4	1.4	1,743.1	18.6
2	LOCTM-C019, MCCPF-C018, NGSWR-C010	Cathodic Protection	5	3K7	$ 7,061,618	$ 7,477,483	$ 7,587,647	$ 7,522,084	$ 7,679,102	$ 7,848,773	$ 8,013,897	$ 53,190,605	$ 31,063,856				
3	LOCTM-C019, MCCPF-C018, NGSWR-C010	Cathodic Protection	5	3K8	$ 862	$ 119,381	$ 120,595	$ 750,931	$ 766,606	$ 783,544	$ 800,028	$ 3,341,947	$ 3,101,109				
4	LRGOP-C001, MCCPF-C004	GT M&C Station Rebuilds (Simple)	6	763	$ 7,878,870	$ 9,519,061	$ 13,529,000	$ 10,418,474	$ 10,635,953	$ 10,870,956	$ 11,099,660	$ 73,951,974	$ 43,025,043	43.5	-	1.5	0.03
5	LRGOP-C002, MCCPF-C005	GT M&C Station Rebuilds (Complex)	6	764	$ 55,504,306	$ 41,682,575	$ 40,640,703	$ 54,692,915	$ 55,834,592	$ 57,068,267	$ 58,268,876	$ 363,692,234	$ 225,864,650	228.5	-	5.0	0.02
6	LRGOP-C003, MCCPF-C006	GT M&C Terminal Upgrades	6	765	$ 5,281,273	$ 11,644,869	$ 4,349,000	$ 31,081,657	$ 31,730,465	$ 32,431,555	$ 33,113,855	$ 149,632,675	$ 128,357,533	129.9	-	9.7	0.07
7	LRGOP-C004, MCCPF-C007	GT Routine M&C	6	75C	$ 11,672,286	$ 5,802,611	$ 5,409,012	$ 10,887,879	$ 11,115,156	$ 11,360,747	$ 11,599,756	$ 67,847,445	$ 44,963,537	60.0	-	1,237.4	20.6
8	LRGOP-C008, MCCPF-C009	GD Regulator Station Rebuild	6	50C	$ 35,740,877	$ 34,998,668	$ 34,998,668	$ 39,106,625	$ 39,325,534	$ 39,627,709	$ 40,076,404	$ 263,874,485	$ 158,136,272	163.5	-	16.5	0.1
9	LRGOP-C009, MCCPF-C010	GD Regulator Station Component Replacement	6	50L	$ 10,668,263	$ 8,970,230	$ 8,970,230	$ 10,600,175	$ 10,659,512	$ 10,741,419	$ 10,863,042	$ 71,472,871	$ 42,864,148	44.3	-	29.4	0.7
10	MCCPF-C017	Facility Corrosion Control Program	5	3K1	$ 290,789	$ 2,842,550	$ 3,706,031	$ 3,235,187	$ 3,302,719	$ 3,375,693	$ 3,446,711	$ 20,199,679	$ 13,360,310				Step 3 Exempt
11	MCCPF-C020	GT Routine C&P	6	76N	$ 41,534,009	$ 33,794,232	$ 17,266,479	$ 38,356,999	$ 39,157,675	$ 40,022,870	$ 40,864,877	$ 250,997,140	$ 158,402,420	185.0	-	20.2	0.1
12	MCCPF-C021	GT Elect Upgrd-Hinkley&Topock 1	6	76P	$ 7,840,139	$ 21,730,000	$ 21,706,000	$ -	$ -	$ -	$ -	$ 51,276,139	$ -				Step 3 Exempt
13	MCCPF-C023	GT Compressor Controls Upgrade	6	76T	$ 13,549,019	$ 21,938,000	$ 12,121,000	$ 8,609,941	$ 8,789,667	$ 8,983,877	$ 9,172,881	$ 83,164,385	$ 35,556,366				Step 3 Exempt
14	MCCPF-C024	GT C&P Compressor Replacements	6	76X	$ 12,428,294	$ 8,510,338	$ 33,673,000	$ 40,959,786	$ 41,814,793	$ 42,738,698	$ 43,637,841	$ 223,762,750	$ 169,151,118	171.1	-	0.1	0.0006
15	MCCPF-C025	GT Physical Security Upgrades	6	76Z	$ 3,764,865	$ 7,273,305	$ 6,790,000	$ 14,560,659	$ 14,864,603	$ 15,193,039	$ 15,512,672	$ 77,959,143	$ 60,130,973				Step 3 Exempt
16		**Total**			**$ 216,144,315**	**$ 220,416,388**	**$ 214,980,450**	**$ 276,984,030**	**$ 282,006,531**	**$ 287,517,167**	**$ 293,076,637**	**$ 1,791,125,518**	**$ 1,139,584,365**				
17		Total Chapter 5			$ 10,282,115	$ 14,552,499	$ 15,527,358	$ 17,708,920	$ 18,078,581	$ 18,478,030	$ 18,866,774	$ 113,494,276	$ 73,132,305				
18		Total Chapter 6			$ 205,862,200	$ 205,863,889	$ 199,453,092	$ 259,275,111	$ 263,927,950	$ 269,039,137	$ 274,209,864	$ 1,677,631,242	$ 1,066,452,061				
19		**Total**			**$ 216,144,315**	**$ 220,416,388**	**$ 214,980,450**	**$ 276,984,030**	**$ 282,006,531**	**$ 287,517,167**	**$ 293,076,637**	**$ 1,791,125,518**	**$ 1,139,584,365**				

20 Notes:
21 (1) NPV uses a base year of 2024.
22 (2) CBR calculations include allocated Foundational Activity program costs.
23 (3) CBRs for mitigation or controls associated with more than one major work category (MWC) or maintenance activity type (MAT) are listed only once, the first time they appear on this schedule.
24 (4) **Step 3 Exempt** indicates this program is exempt from Step 3 Supplemental Analysis in the GRC and does not require a CBR to be calculated. For additional information on Step 3 Supplemental Analysis, See D.22-12-027, Appendix A, p. A-17, No. 28.